IN THE MATTER OF

TERASEN GAS (VANCOUVER ISLAND) INC.

2004 RESOURCE PLAN FILING
AND
CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY APPLICATION FOR A LIQUIFIED NATURAL GAS (“LNG”) STORAGE PROJECT

DECISION

February 15, 2005

Before:

Lori Ann Boychuk, Chair
Nadine F. Nicholls, Commissioner
Peter E. Vivian, Commissioner

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TERASEN GAS (VANCOUVER ISLAND) INC.
2004 RESOURCE PLAN FILING AND
CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY APPLICATION
FOR AN LNG STORAGE PROJECT

1.0 INTRODUCTION

1.1 TGVI Filings

This Decision responds to two filings by Terasen Gas (Vancouver Island) Inc. (“TGVI”, “Utility”) under the Utilities Commission Act (the "Act”):

1. A Resource Plan Report dated June 18, 2004 and filed with the Commission on June 21, 2004, covering the Vancouver Island and Sunshine Coast services areas (the “Resource Plan”) and prepared with a view to satisfying the Commission’s Resource Planning Guidelines (“RP Guidelines”) issued in December 2003 following the enactment of subsections 45(6.1) and 45(6.2) of the Act ; and

2. An application for a Certificate of Public Convenience and Necessity (“CPCN”) filed on August 4, 2004, pursuant to Section 45 of the Act, to construct and operate a proposed new Liquefied Natural Gas (“LNG”) Storage Facility at a location referred to as Mount Hayes in the Cowichan Valley Regional District in the vicinity of Ladysmith (the “CPCN Application”).

Resource Planning is intended to support the selection of resources that will ensure the cost-effective delivery of secure and reliable energy services for ratepayers over the long run. A Resource Plan evaluates demand and supply options over a long term planning horizon and assesses impacts and tradeoffs related to such matters as rates and rate stability, reliability, security of supply, risk mitigation and specific social or environmental characteristics (RP Guidelines, Exhibit B-1, Appendix A, pp. 1-2).

The TGVI Resource Plan identified a requirement to expand the TGVI system in order to meet the expected growth in natural gas demand in the TGVI service area (TGVI Argument, p. 4). TGVI noted that the TGVI system currently operates at full capacity and that a shortfall in capacity is expected to occur by 2007 (Exhibit B-1, p. 1). The Resource Planning process reviewed options for addressing this shortfall and identified three types of resource portfolios: LNG Storage – an LNG Storage facility followed by phased pipe and compression additions; Pipe and Compression (“P&C”) – phased pipe and compression additions; and Pipe and Compression and Curtailment (“PCC”) – phased pipe and compression additions with industrial curtailment (Exhibit B-1, p. V). TGVI's Resource Plan concluded that LNG storage is the preferred resource addition to meet forecast load growth, including service to existing and proposed gas-fired electricity generators on Vancouver Island.

The proposed LNG Storage Project which is the subject of the CPCN Application consists of an LNG storage facility at Mount Hayes located approximately six kilometres northwest of Ladysmith, two pipelines to connect the storage facility to the TGVI transmission system, and related facilities. The LNG storage facility would have a useable capacity of 1,075 terajoules ("TJ") (one billion standard cubic feet of gas) and could provide approximately 107 TJ/day (100 million standard cubic feet per day) of natural gas to the TGVI system.

1.2 TGVI System

TGVI is a wholly-owned subsidiary of Terasen Inc., which is a publicly traded company. Terasen Gas Inc. ("Terasen Gas"), Terasen Gas (Squamish) Inc. ("Terasen Squamish") and Terasen Gas (Whistler) Inc. ("Terasen Whistler") also are wholly-owned subsidiaries of Terasen Inc. Terasen Whistler operates a propane vapour grid system in Whistler, B.C.

TGVI provides natural gas transmission and distribution services to approximately 80,000 residential, commercial and industrial customers on Vancouver Island and the Sunshine Coast. Service is provided through approximately 640 km of high pressure transmission pipeline, including three compressor stations, and over 3,200 km of distribution mains. TGVI's largest customers are the Vancouver Island Gas Joint Venture ("VIGJV") which represents seven large pulp and paper mills, and British Columbia Hydro and Power Authority ("BC Hydro") serving the Island Cogeneration Plant ("ICP"). Natural gas transmission and distribution on Vancouver Island and the Sunshine Coast began in 1991 with the completion of the Vancouver Island Natural Gas Pipeline. TGVI is the present owner and operator of the system.

The large majority of TGVI's customers are located in southern Vancouver Island, at or near the end of the pipeline system which is a distance of 467 km from the start of the system at Eagle Mountain in Coquitlam. Natural gas for TGVI customers is delivered from upstream sources on the Duke Energy

(Westcoast) pipeline system to the Huntingdon/Sumas trading point near Abbotsford. From this point TGVI contracts transport capacity across the Terasen Gas Coastal Transmission System to the inlet of the TGVI transmission system in Coquitlam. The pressure of gas received at Coquitlam is increased and maintained near the 2,160 psig maximum operating pressure of the TGVI pipeline system using three parallel gas turbine-compressor units at the V1 Coquitlam compressor station and gas turbine compressor units at the V3 compressor station at Port Mellon and the V4 compressor station on Texada Island. Natural gas is transported through TGVI's pipeline, including dual marine crossings of the Malaspina and Georgia Straits, to metering and pressure regulating stations located near the communities served by TGVI.

Figure 1.1 is a map showing the TGVI system.

Figure 1.1
Existing TGVI Transmission System

Source: Exhibit B-2, p. 9, Figure 5.2

1.3 Procedural History and Background

TGVI requested that the Commission's review of its Resource Plan and CPCN Application take place concurrently. After receiving written comments from interested parties, the Commission agreed to consider the filings concurrently and, by Order No. G-79-04, established a Workshop and Pre-Hearing Conference held in Vancouver on September 13, 2004 to consider issues and procedural matters associated with the filings.

Following the Pre-Hearing Conference, the Commission issued Order No. G-83-04 establishing a regulatory timetable for an oral public hearing to commence in Nanaimo on November 17, 2004.

On November 2, 2004, in view of several developments related to the VIGJV demand and anticipating that the results of the BC Hydro Call for Tenders ("CFT") would be announced on November 3, 2004, the Commission before proceeding with the hearing scheduled to commence on November 17, 2004, requested that TGVI respond on an expedited basis to Commission Information Request ("IR") No. 2 (Exhibit A-8).

In its response to Commission IR No. 2, TGVI explained that a new arrangement had been reached between TGVI and the VIGJV which will reduce the long-term demand forecast of the VIGJV firm demand from the previous assumption of 33.6 TJ/day to 12.5 TJ/day and that peaking gas supply will be reduced to 0 TJ/day. TGVI also reported that BC Hydro had announced the outcome of its CFT process on Vancouver Island and that BC Hydro had selected, subject to Commission acceptance of the filed electricity purchase agreement which is the subject of a separate Commission proceeding, a 252 MW gas-fired Duke Point Power Limited Partnership ("Duke Point Power") project which, if accepted, is expected to require 45 TJ/day of firm gas transportation.

TGVI suggested that the developments related to the VIGJV and the BC Hydro CFT process provide more clarity on the forecast design day loads, although TGVI acknowledged that some uncertainty remains with respect to BC Hydro's firm commitments in view of the fact that TGVI and BC Hydro have been unable to enter into a firm Transportation Service Agreement ("TSA") beyond the arrangements related to the ICP which would expire on December 31, 2004. The key impediment to the negotiation of an appropriate TSA relates largely to differing views on tolling and cost allocation principles (BC Hydro Argument, p. 3) which were not, and could not, be part of this proceeding or be dealt with in another proceeding within a reasonable time frame. TGVI maintained, however, that the construction schedule related to the proposed LNG facility requires that the Commission grant a CPCN by January 2005 in order to have the LNG facility in place to meet BC Hydro's anticipated requirements for the winter of 2007/08. TGVI advised the Commission that it expected to have firm commitments in place with BC Hydro by the end of 2004 (Exhibit B-8, BCUC IR 49.3).

TGVI stated that given the revised forecast associated with the long-term requirements of the VIGJV, the need for new facilities will depend on the requirement to meet the firm service associated with the proposed facility of Duke Point Power (Exhibit B-8, BCUC IR 49.5). TGVI stressed that if BC Hydro does not commit to using firm service at ICP or if BC Hydro only commits to firm service for the proposed Duke Point Power facility and not ICP, TGVI will re-evaluate its portfolios and the requirement for and/or timing of the LNG facility. As a result of the recent developments, TGVI revised its Base Forecast and suggested that only two outcomes need be considered in this process to reflect possible outcomes of the CFT generation proceeding (Revised Base +45) or not proceeding (Revised Base +0) (Exhibit B-8, BCUC IR 48.1).

On November 10, 2004, TGVI filed its List of Panel Members and Panel Issues for three proposed witness panels: 1. Resource Plan; 2. Technical; and, 3. Project Justification (Exhibit B-9).

In its letter dated November 12, 2004, the Commission stated that the Hearing should commence as scheduled on November 17; however, the Commission would, as a preliminary matter, seek submissions from parties on a potential postponement to the week commencing December 6 of some or all of the evidence of TGVI's Panel 3 which included "contractual commitments." Submissions were heard on this matter at the commencement of the proceeding and the Commission Panel determined that in the circumstances it was appropriate to proceed with the hearing and a postponement of Panel 3 and related issues to December 6, 2004 (T1: 74-82).

In addition to the other matters identified in the Preliminary Issues List (Exhibit A-3), as revised by the Commission following the Pre-Hearing Conference (Exhibit A-4), considerable effort was expended on the issues related to the core market annual demand forecast (issue 4), load forecast for other customers (issue 5) and industrial curtailment and peaking supply (issue 6), during the written interrogatory and oral hearing phases of the proceeding.

The oral public hearing proceeded as scheduled on November 17-19, 2004 in Nanaimo and then resumed in Vancouver from December 6-13, 2004.

During the hearing two registered intervenors, Williams Gas Pipeline Company and Mr. K. Farquharson, withdrew from the proceeding, while a third intervenor, the VIGJV reached an agreement with TGVI wherein the VIGJV agreed to not oppose TGVI's CPCN Application (Exhibit A-19, Appendix A, Article 10).

Following the hearing, written argument was received from TGVI and the remaining active intervenors: the B.C. Old Age Pensioners' Organization et al. ("BCOAPO"), BC Hydro and the Ministry of Energy and Mines ("MEM"). Argument ended with the filing of TGVI's Reply on January 14, 2005.

TGVI maintained throughout the proceeding that the timing of the CPCN Application and the requirement for an early Commission decision are driven by the need for new facilities to be available to serve the peak loads that would occur on the TGVI system in the winter of 2007/08, when the step-change in natural gas demand is expected due to new loads associated with the results of BC Hydro's CFT process, specifically the major new load of the proposed Duke Point Power plant (TGVI Argument, p. 5). As noted by the MEM, it is the potential demand of BC Hydro that is the central component that either triggers an expansion or not (MEM Argument, p. 39). If the potential increased load and step change in demand do not materialize, then, in accordance with the Revised Base +0 forecast, no new facilities will be required (Exhibit B-8, BCUC IR 48.2). This Decision considers and evaluates the resource portfolio options presented by TGVI to meet the potential increased load and step change in demand for 2007/08. This Decision does not consider or take a position in any way on the merits of the proposed Duke Point Power facility and electricity purchase agreement, which are the subject of a separate Commission proceeding.

Chapters 2 through 6 of this Decision will focus initially on the various objectives and components of the resource planning process, including demand forecast scenarios and DSM, and the financial evaluation of the supply portfolios and the preferred portfolio option. The proposed LNG storage facility will then be discussed (Chapter 7), changes to Resource Plan assumptions are next discussed (Chapter 8), followed by a comprehensive examination/assessment (Chapter 9) and a financial comparison of the resource portfolio options (Chapter 10). Chapter 11 discusses rate impacts and Revenue Deficiency Deferral Account ("RDDA") recovery and Chapter 12 deals with contractual arrangements. Chapter 13 contains the Commission's Determinations.

2.0 RESOURCE PLAN BACKGROUND

2.1 The Utilities Commission Act Section 45 Plans

TGVI affirmed that it took into consideration the provincial government's Energy Policy "Energy for Our Future: A Plan for BC" ("Energy Plan") in its entirety when developing its resource plan (Exhibit B-1, p. 4; Exhibit B-6, MEM IR 1.11.1).

The provincial government Energy Policy[1] that was released in November 2002 concluded, among other things that:

1. The British Columbia Utilities Commission will provide regulatory oversight of the least-cost resource acquisition processes of energy utilities while maintaining the BC Clean goal (Policy Action #12); and

2. The Act will be amended to remove a disincentive for energy distributors to invest in conservation and energy efficiency (Policy Action #23).

In order to implement the new Energy Policy, section 45 of the Act was amended in 2003. Subsection 45 (6.1) requires a public utility to file, in the form and at the times required by the Commission, a resource plan, and subsection 45 (6.2) gives the Commission the discretion to establish a review process for the plan and to determine the rate recovery of those expenditures referred to in the plan.

[1] Energy for Our Future: A Plan for BC – http://www.gov.bc.ca/em/popt/energyplan/htm#eof

Subsequent to the amendment of section 45 of the Act, the BCUC issued RP Guidelines in December 2003 to assist public utilities in the development of resource plans (Exhibit B-1, Appendix A). Further, in March 2004, the Commission issued Certificate of Public Convenience and Necessity Application Guidelines ("CPCN Guidelines"), (Exhibit A-21). The primary purpose of the CPCN Guidelines is to provide general guidance regarding Commission expectations of the information that should be included in a CPCN application. As a resource plan is expected to deal with significant aspects of project justification, the CPCN Guidelines refer to linkages with the resource planning process and to a public utility's annual statement of the planned extension of facilities as required in subsection 45 (6) of the Act (CPCN Guidelines, pp. 2-3).

It is in the context of this regulatory development of an expanded BCUC mandate in terms of utility resource planning that TGVI embarked on a resource planning process, its first since 1996. This process resulted in the Resource Plan that was filed with the Commission on June 18, 2004.

2.2 Objectives of Resource Planning

Resource planning is intended to facilitate the selection of cost-effective resources that yield the best overall outcome of expected impacts and risks for ratepayers over the long run. The resource planning process aids in defining and assessing market-based costs and benefits, and assesses tradeoffs among the expected impacts which may vary across alternative resource portfolios (RP Guidelines, pp. 1-2).

Prior to the TGVI filing in June 2004, the first utility to file a resource plan and have it considered by the Commission pursuant to the new section 45 requirements was BC Hydro. In March, 2004 BC Hydro filed two documents, an Integrated Electricity Plan ("IEP") which is a 20-year outlook and a Resource Expenditure and Acquisition Plan ("REAP") which is part of the IEP and which identifies initiatives that BC Hydro plans to undertake over the next four years. BC Hydro stated that it intends to file IEPs on a bi-annual basis and to file a REAP annually. BC Hydro suggested that the form of the REAP will depend upon whether it is filed concurrently with a revenue requirements application and that the REAP will replace BC Hydro's current annual filings required by subsection 45(6) of the Act. BC Hydro's section 45 plans were discussed during the hearing of BC Hydro's 2004/05 to 2005/06 Revenue

Requirements Application ("BC Hydro RRA") and in the Commission's October 29, 2004 Decision ("BC Hydro Decision").

TGVI stated that its Resource Plan was filed in advance of those of the other Terasen Inc. operating units in order to help support decisions related to: (i) the VIGJV option to renew its TSA by December 31, 2004; (ii) the gas transportation that may be needed to resolve reliability concerns associated with the retirement of BC Hydro's High Voltage Direct Current ("HVDC") cables serving Vancouver Island; and (iii) BC Hydro's CFT process for competitive bids from Independent Power Producers ("IPP") (Exhibit B-1, p. 2). The Resource Plan includes an Action Plan that describes the actions that TGVI intends to pursue over the next four years (Exhibit B-1, pp. 66-7).

In the hearing, Mr. Wong of TGVI testified that the approach TGVI adopted when preparing the Resource Plan was not to get into the specifics and details of the planned programs because TGVI believes that the Resource Plan is a background document (T2: 294). The Utility takes the position that this Resource Plan is a contextual document and, therefore, it is not requesting any specific approval from the Commission for the items in the report (T6: 1013). TGVI argues that the Resource Plan is an overview or outlook of what the utility expects to be doing and key factors that affect the business (TGVI Argument, p. 4).

BC Hydro did not make any submissions on the objectives of the resource planning process. BCOAPO observed that in the context of this hearing, the CPCN Application is inextricably linked to the Resource Plan and the necessary review by the Commission can be done under the CPCN Application (BCOAPO Argument, pp. 2, 3). However, BCOAPO did not make any comments on the scope of future resource plan updates. MEM observed that "the evidence in the record relates primarily to the CPCN and has naturally evolved through the proceedings. The result has been that areas of the Resource Plan relating to the CPCN have evolved further than those areas not related to the LNG storage facility analysis". MEM submits that the next update to the Resource Plan should be considered in an independent proceeding (MEM Argument, p. 45).

The Commission Panel acknowledges that resource plans may deal with significant aspects of project justification and recognizes that TGVI has filed its 2004 Resource Plan "with the primary purpose" of supporting decisions related to the CPCN Application (T2: 289). However, the Commission is charged with directing and evaluating resource plans and the Commission Panel is of the view that resource plans should serve a broader function than simply supporting *ad hoc* applications such as CPCN applications.

The Commission Panel notes that TGVI is operating under unique circumstances. At the time of the hearing, the Utility was engaged in an Annual Review process from a multi-year negotiated settlement, where approval sought and obtained in an Annual Review implies approval of some of the items in the Action Plan for the coming year (Exhibit A-20; T6: 1009). The Utility uses five-year cycle capital expenditures forecasting and it has concerns that justifying such expenditures in the Resource Plan could run into issues related to timing and level of detail (Exhibit B-3, BCUC IR 23.1; T6: 1010). As well, timing issues related to the sequencing of other filing requirements, such as the Annual Gas Contracting Plan ("AGCP") which has a three to five-year outlook and the Price Risk Management Plan which has a two to three-year horizon (T6: 1014, 1015), have been raised in this hearing because of the timing of the Resource Plan filing and the late filing of the AGCP in this instance. Also, notwithstanding the provision in the CPCN Guidelines that "in some cases, with the approval of the Commission, a resource plan and related capital expenditure action plan filed pursuant to subsection 45(6.1)(a) of the Act may meet the requirements of section 45(6)...", TGVI expressed its intention to file its statement of extensions of facilities separately from its annual resource plan (T6: 1021).

The Commission Panel is mindful of the Commission's expected regulatory function related to capital expenditures plans, Demand Side Management ("DSM") expenditures and resource acquisition costs, and of the discretionary power it possesses to establish a process to review resource plans. The Commission Panel is of the opinion that in certain circumstances and for certain utilities, a more detailed level of review of a resource plan, other than as a contextual document, may be warranted and may be more efficient.

2.3 Prior BCUC Determinations on Resource Plans – the BC Hydro Decision

As noted above, BC Hydro filed two plans with the Commission on March 31, 2004: a 20-year IEP and a 4-year Action Plan REAP. BC Hydro did not seek approval at the time of filing for any of the portfolios identified in the IEP except in so far as they would be approved as part of the REAP review.

BC Hydro argued that there is nothing in the IEP that requires approval as it makes no commitment to specific expenditures. In its view, it is the REAP that would undergo review and receive approval. Because the IEP is a long-term plan, BC Hydro did not believe that the adversarial process is suited to debates on long-range thinking and it also wished to maintain flexibility for the long-term options (BC Hydro Decision, p. 58).

The Commission commented during the oral argument phase of the BC Hydro RRA hearing that it is important that the Commission intrude more into BC Hydro's planning process than BC Hydro's proposal permits, given the views and interests of the intervenors in that process and that the Commission was dealing not only with a process issue but an issue that was core to the decisions that BC Hydro needed to make over the next few years (BC Hydro Decision, p. 58). As a result of those comments, BC Hydro proposed a parallel process that would focus on a third document that BC Hydro would produce, a Resource Option Report ("ROR"). The ROR will identify resource types and specific capacity for each resource type, establish energy and capacity target ranges, and establish an expected unit energy cost range for each resource type. The ROR would involve a public review process. In the BC Hydro Decision, the Commission accepted the ROR process and determined that it would expect to decide on the nature of any review of an IEP at the end of the ROR process. The Commission accepted that the 2004 IEP as presented was not susceptible to meaningful review at that time given the evolving regulatory review process (BC Hydro Decision, pp. 47-65). The Decision approved the various components of the BC Hydro 2004 REAP (BC Hydro Decision, Chapter 6.8 REAP and Chapter 9 Demand-Side Management).

This Commission Panel notes that although both BC Hydro and TGVI contend that the long-term resource planning documents are contextual documents, TGVI has not argued, as BC Hydro had in its IEP filing in 2004, that the Resource Plan is not subject to review. TGVI applied for a review and was granted a regulatory review process by Commission Orders G-79-04 and G-83-04 (Exhibit A-1; Exhibit A-4). Furthermore, TGVI has not argued, again as BC Hydro had, that the document is not submitted for approval because of concerns over flexibility or other disadvantages that would come from an adversarial process. The main issues for TGVI are the scope and level of detail of future resource plans, as well as the related but separate applications that will follow the Resource Plan, including some of the items in the Action Plan (T6: 1013).

The Commission Panel concludes that it will approach the review of this Resource Plan having regard to the unique circumstances of TGVI and its current filing and associated CPCN Application. That is, TGVI's Resource Plan will be considered to be a contextual document and no specific expenditure approvals will be determined based on the review of the Resource Plan related to the items described in the Action Plan, other than item 1 related to the proposed LNG Storage facility.

3.0 EVALUATION OF THE TGVI RESOURCE PLANNING PROCESS

3.1 Summary of the Resource Plan

The Resource Plan describes the acquisition of resources to meet forecasted customer demand for natural gas over 20 years. Part of the Resource Plan is a four-year Action Plan which identifies the new resources that will require approval from the Commission within those four years (Exhibit B-1, pp. 66, 67; T2: 227).

Four resource planning objectives were selected as the basis for evaluating potential resource portfolios (Exhibit B-1, Table1-1). They are:

- Ensure reliable and secure supply;
- Provide service to customers at least delivered cost;
- Reduce rate volatility; and
- Balance socio-economic and environmental impacts.

Although TGVI does not specifically assign weighting factors to these objectives, the financial evaluation measurement for the least delivered cost objective lends itself most readily to quantitative analysis (Exhibit B-3, BCUC IR 1.1; T2: 204). The Net Present Value ("NPV") analysis of the cost of service was more thoroughly debated during the review process and in the CPCN Application than the measures for the other objectives.

TGVI created five demand forecast scenarios to bracket the forecast uncertainties for the core market peak demand, the VIGJV contract demand requirements, the BC Hydro contract to serve the ICP and the demand for gas that could result from the BC Hydro CFT process (Exhibit B-1, p. 15). The Utility also identified three types of supply-side resources that can be used to increase the physical capacity of the pipeline system: pipeline looping, compression and on-system storage. Industrial curtailment or fuel switching was also added to the supply-side strategy (Exhibit B-1, p. 52).

The portfolio measurement results for all five scenarios from the Resource Plan are presented in Table 3.1 below. Although some of these numbers have been updated by the CPCN Application, the numbers from the Resource Plan are still used here because they are comprehensive and allow comments to be made on the resource planning process. The changes that TGVI made to its assumptions and methodology between the Resource Plan and the CPCN Application are summarized in Chapter 8.

BCOAPO argued that the differences between the financial performance measures in the Resource Plan and the CPCN are material (BCOAPO Argument, pp. 4-5), while the MEM observed that much of the demand information has changed, rendering the original demand forecasts stale (MEM Argument, p. 31).

Table 3.1
Financial Evaluation Results – Resource Plan
(Present Value millions of dollars)

6.1 Percent Discount Rate	**LNG Storage**	**Pipe and Compression**	**Pipe Compression Curtailment**
Base Case + 0	89	163	90+?
Base Case + 20	123	218	136+?
Base Case + 45	174	246	194+?
High-High Case	223	0	243+?
Low-Low Case	82	100	46+?
10.0 Percent Discount Rate			
Base Case + 0	61	101	57+?
Base Case + 20	82	142	87+?
Base Case + 45	115	164	125+?
High-High Case	146	0	164+?
Low-Low Case	57	64	29+?

Source: Exhibit B-1, Appendix L

Notes: (1) Base Case refers to the base demand forecasts for the core market customers, the VIGJV base forecast and the demand by BC Hydro for the ICP. The base plus-cases refer to possible outcomes of the CFT process, in terms of TJ/d of additional daily demand.
(2) The "+?" notation for the Pipe Compression Curtailment scenarios refers to the additional cost of curtailment, which was not quantified in the Resource Plan.

As seen from the Resource Plan financial evaluation results using a 6.1 percent discount rate, the LNG Storage portfolio has a lower cost than the Pipe and Compression ("P&C") portfolio for all scenarios and a lower cost than the Pipe Compression Curtailment ("PCC") portfolio for all but the Low-Low Case Scenario. Using a 10.0 percent discount rate, financial evaluation results show the LNG Storage has a lower cost than all the P&C portfolios and a lower cost than the PCC portfolios for all scenarios with the exception of the Base Case + 0 TJ/day Scenario and the Low-Low Cases. However, without the curtailment agreements with BC Hydro, TGVI takes the position that the actual costs in the PCC portfolio remain vague (T6: 822).

Subsequent to the Resource Plan filing, TGVI reached a new agreement with the VIGJV which will reduce the long-term forecast of the VIGJV firm demand from the previous base case assumption of 33.6 TJ/day to 12.5 TJ/day. Consistent with the reduction in firm demand, standard curtailment will no longer be available from the VIGJV (Exhibit 8, BCUC IR 48.0; Exhibit A-19, p. 6; Exhibit B-28). BC

Hydro also released the results of its CFT process on November 3, 2004 and indicated that it had selected a 252 MW gas-fired Duke Point Power Project from its CFT process on Vancouver Island (Exhibit C6-5). TGVI expects that this proposed gas-fired generation plant would require 45 TJ/day of firm gas transportation (Exhibit B-8, BCUC IR 48.1).

As a result of these developments, TGVI was asked to revise its forecasts. TGVI updated its forecast to two discrete outcomes: Revised Base + 0 assuming the CFT generation does not proceed and Revised Base + 45 assuming that the CFT generation does proceed. The Revised Base Case reflects the new lower VIGJV contract demand. TGVI used these two discrete scenarios to develop new resource portfolios based on similar assumptions and criteria used in the Resource Plan and the CPCN Application. It is TGVI's position that if the Duke Point Power Project is not built, it would not proceed with the LNG project (Exhibit B-8, BCUC IR 48.2, p. 3; T1: 70, 71). TGVI maintains that, for the Revised Base +45 case, the present value analysis continues to support the LNG Storage portfolio as having the least cost and being the preferred alternative. Table 3.2 summarizes the results from the analysis subsequent to the Resource Plan filing.

Table 3.2
Financial Evaluation Results – Revised Base +45 Forecast
(Present Value in Millions of Dollars)

	LNG Storage	**Pipe Compression**	**PCC 53 Hours**	**PCC 240 Hours**
6.1 Percent Discount Rate	153	274	188	156
10.0 Percent Discount Rate	103	177	120	100

Exhibit B-8, IR 48.3, Tables 48.3 a, b & c; Exhibit B-16, p. 4

3.2 Evaluation of Resource Planning Principles, Criteria and Methodology

TGVI developed the 2004 Resource Plan by broadly following the RP Guidelines (Exhibit B-1, pp. 4, 5). The major conclusions reached by TGVI are:

1. The outcome of the CFT process is the most influential future event affecting gross design-day demand (Exhibit B-1, p. 30).

2. An expansion of the pipeline system will be required to resolve the shortfall based on the 2004 load duration analysis and the 2007 Base +20 TJ/day forecasts (Exhibit B-1, p. 42).

3. The financial evaluation supports the LNG Storage portfolio as the preferred alternative to meet the objective of providing service to customers at least delivered cost using 6.1 percent and 10.0 percent after-tax nominal discount rates (Exhibit B-1, p. 57).

Evidence adduced through information requests and at the oral hearing suggests that many issues and elements in the TGVI Resource Plan require specific comment from the Commission. Those issues and elements can be categorized as follows:

- Resource planning objectives;
- Planning period;
- Discount rates for NPV analysis; and
- Risks and uncertainties.

The last category, risks and uncertainties, deals with risks related to core market and transportation customers demand, and uncertainties related to the term and price of curtailment and its extensive use outside normal planning criteria. These issues will be addressed respectively in Chapter 4 on load forecast and Chapter 5 on supply side resources.

3.2.1 Principles in Identifying Objectives of a Resource Plan

Some examples of the objectives of a resource plan are set out in the RP Guidelines (RP Guidelines, p. 3, Item#1). When selecting its resource plan objectives, TGVI imposed another layer of requirement to allow for the ability to measure the attributes and to differentiate between portfolios using the same objective.

No intervenors have raised any major issues with the criteria employed by TGVI in the selection criteria of resource plan objectives, or raised issues with the objectives themselves.

The Commission Panel accepts the criteria used by TGVI and acknowledges that the objectives selected are not inconsistent with the RP Guidelines.

3.2.2 Planning Period

The RP Guidelines expect that a utility would plan for the next 15 to 20 years when forecasting gross demand and assembling resource portfolios (RP Guidelines, p. 4, Item #5).

TGVI uses the gas contract year which is November 1 through October 31 when discussing design day loads and system capacity and calendar year when referring to facilities additions as it relates to capital expenditures (Exhibit B-3, BCUC IR 8.7). Storage capacity is in storage years from April 1 to March 31 (Exhibit B-6, BC Hydro IR 17.0 (a).

TGVI's load forecast period shows a forecast period from 2004 to 2026 (Exhibit B-1, Figure 3-5; Exhibit B-9, TGVI Core Market Peak Demand Forecast, Slide 16; Exhibit B-3, BCUC IR 8.6). The MEM noted that a forecast period from 2005 to the horizon year 2026 would create a 22-year planning period (Exhibit B-6, MEM IR 1.27.1).

According to TGVI, the planning period for resource plan analysis is 20 years because the beginning year is 2007 when the first new facility additions are required (Exhibit B-1, Figure 5-7; Exhibit B-6, MEM IR 1.1.1). However, the Utility admits that the study period used for present value analysis is from 2004 to 2026 (Exhibit B-10, MEM IR 2.1.1).

TGVI has used a 23-year time horizon (2004 to 2026) for demand forecasting (T2: 184). It has used 20 years (2007 to 2026) for planning resources and 23 years (2004 to 2026) for its present value analysis. Although TGVI is able to explain the reason why 2007 was chosen as the beginning of the planning period, that is, when the first new facility additions are required, it is not able to explain why 2007 would still be chosen as the beginning of the planning period if the first new resource is added some time after that date, for example, in 2009 (Exhibit B-10, MEM IR 2.20.1).

The evidence shows that the choice of the planning period for the NPV analysis may have been arbitrary. It is noted that TGVI expressed concern that a 15-year planning period may lead to a sub-optimal solution (Exhibit B-6, MEM IR 1.27.2; Exhibit B-10, MEM IR 2.20.3). The Commission Panel finds that this concern alone does not justify the arbitrary selection of the planning period chosen by TGVI.

In future resource plans, to address TGVI's concerns about sub-optimal solutions, the Commission Panel recommends that the Utility also conduct 15-year and 25-year evaluations as sensitivity cases to assess the effect of the length of the study period.

3.2.3 Discount Rates

Two distinct issues regarding discount rates were raised during the resource plan review process. The first issue is related to risk profile analysis and the second issue relates to the choice of an after-tax as opposed to a before-tax rate.

Risk Profile Analysis

TGVI selected a discount rate of 6.1 percent based on its calculated weighted after-tax cost of capital to reflect its corporate risk profile during the planning period. It also conducted a sensitivity case to reflect the uncertainty of future demands and costs by using a 10.0 percent discount rate (Exhibit B-1, p. 55). TGVI submits that the 10.0 percent rate already reflects a 390 basis point premium over the 6.1 percent rate and that increasing the discount rate beyond 10.0 percent would not be appropriate or meaningful (Exhibit B-6, MEM IR 1.8.3).

In the 2003-2005 negotiated settlement, TGVI's short-term debt cost was set at 30 day Bankers Acceptances plus 80 basis points. TGVI calculates its weighted average cost of capital according to its 65:35 debt/equity ratio which has a 6.2 percent debt cost and a weighted average cost of capital of 6.11 percent (Exhibit B-3, BCUC IR 45.4). TGVI was asked to identify the long term debt that it assumes and the corresponding component cost of debt. TGVI responded indirectly by making reference to the outlook of 30 year Canada bonds at 6 percent by 2006 to justify that its ROE at 9.92 percent has already considered the TGVI risk profile and is reasonable (Exhibit B-3, BCUC IR 45.3).

BC Hydro suggested that if TGVI has a higher risk profile than Terasen Gas and if the LNG portfolio is riskier than others, such risk should be reflected in the discount rate (T5: 782). TGVI responded to BC Hydro's suggestion, arguing that as a regulated utility, the allowed ROE already reflects a risk premium and that it has to use a regulated return to evaluate risks (T5: 783).

As the cessation of royalty revenue credit and pay down of the Revenue Deficiency Deferral Account ("RDDA") is within the planning period, TGVI will be operating under a different risk profile and is likely to proceed with refinancing its indebtedness in 2005 in the capital markets (T5: 750, 778; Exhibit B-6, MEM IR 13.1).

BCOAPO submits that the use of both discount rates has merit (BCOAPO Argument, p. 10). MEM observed that shortening the analysis period and increasing the discount rate lowers the present value of incremental facilities for the PCC portfolios relatively more than for the LNG portfolio (MEM Argument, p. 18).

The Commission Panel accepts TGVI's calculation method of current weighted average cost of capital but disagrees with TGVI's assertion that there is no need to consider a discount rate greater than 10 percent for the portfolio evaluation. The Commission Panel notes that it would take a discount rate of over 33.1 percent for the PCC (53 hours) portfolio to have a lower cost than the LNG portfolio in the Revised Base Case. However, the issue of sensitivity analysis is relevant because the discount rate should reflect a possible higher long-term corporate risk during the 20-year planning period (Exhibit B-10, BCUC IR 74.1).

The Commission Panel notes that TGVI has not included an outlook or long-term view of its debt structure in its Resource Plan despite TGVI's argument that a resource plan is an overview or outlook of what the utility expects to be doing and key factors that affect the business (TGVI Argument, p. 4). Although TGVI has provided evidence of its past 1997-2004 weighted after-tax cost of capital (Exhibit B-10, MEM IR 2.4.3), the Commission Panel expects the Utility to provide a long-term vision or outlook of the cost of capital (e.g. expected credit ratings from credit rating agencies) given the long-term nature of a resource plan.

After-tax vs Before-tax Discount Rates

BC Hydro submitted that the use of 9.33 percent or the pre-tax cost of capital could be a more appropriate rate than the 6.11 percent used by TGVI (Exhibit C7-8; C7-10; T6: 865).

Mr. Loski testified that it is necessary for TGVI to take into consideration that TGVI is a taxable entity and therefore the discount rate cannot ignore the income tax effect as well as the tax shield effect of the interest expense (T6: 869, 870). Although TGVI accepted that there is a heated debate over which rate is preferred, it takes the position that, in the end, both rates would result in the same conclusion on ranking the projects as long as adjustments are made to the revenue flow streams (T6: 872-874).

Central to TGVI's submission is that a present value analysis by either a cash flow model or a revenue requirement model would yield the same ranking of net present values between two projects (Exhibit B-24; T6: 880, 881).

In Argument, BC Hydro pointed out that the Commission had not previously addressed the pre-tax/after-tax question, nor the fact that ratepayers have a higher average discount rate than the Utility. However, the Commission did conclude in the Southern Crossing Pipeline Decision that the nominal discount rate in the order of 10 percent was more appropriate in that case than the 6.18 percent used by BC Gas (BC Hydro Argument, p. 19).

BC Hydro argues that the Commission ought to consider the pre-tax/post-tax question although at the same time it concedes that the record is not as complete as it could be as no expert evidence was led (BC Hydro Argument, p. 20). It further argues that even though the sensitivity test of 10 percent TGVI has used in this hearing is the same as in the Southern Crossing Pipeline Decision, its rationale for choosing 10 percent is not the same (BC Hydro Argument, pp. 24, 25).

TGVI argues that it has demonstrated in Exhibit B-24 that the present value of revenue requirements analysis and the present value of discounted cash flow analysis are equivalent. The cost of service in any year yields a net cash flow, which will be the after-tax return to TGVI. Applying a pre-tax discount rate is acceptable if appropriate adjustments are made, for example, in the tax sheltering benefit of debt financing in particular (Reply Submissions, pp. 19, 20).

The Commission Panel notes that the use of either a 10 percent discount rate to reflect TGVI's pre-tax cost of capital and the LNG project's long time horizon, or a 6.1 percent rate to reflect TGVI's weighted average cost of capital will not affect the conclusion of the financial evaluation results in the Resource Plan. The Commission Panel considers that insufficient analysis and evidence was adduced during this proceeding to determine the merits of before tax/after tax discount rates. In any event, the Commission Panel is satisfied that no significant difference in ranking the resource addition portfolios would result in this instance, given the evidence presented in this proceeding.

The Commission recommends that TGVI consider its capital structure for the planning period in the annual Resource Plan updates, and use a range of discount rates to reflect the possible capital structure. In future Resource Plans, TGVI should present financial comparisons using both a discount rate that is based on its after-tax cost of capital, and higher discount rates to reflect risks to cash flows.

3.3 Resource Plan Updates

In the hearing, the Panel Chair advised TGVI that the Commission Panel would be making determinations related to the purpose and effect of the Utility's Resource Plan as well as on the regulator's role with respect to review and approval of resource plans (T2: 297, 298).

Mr. Wong testified that "the primary purpose of filing our Resource Plan is essentially to support our CPCN Application for the LNG project" (T2: 289). Mr. Stout, testifying to policy issues on behalf of TGVI, stated that the filed Resource Plan "…would be overview material, background material" (T6: 1013).

The Commission Panel acknowledges that in this hearing, the Resource Plan is used to support a CPCN Application and that undeniably these two are interlinked. It is precisely because they are interlinked that the Commission merged the two distinct filings into one review in order to eliminate duplication or overlap of activities (Exhibit A-1; Exhibit A-3). However, the 2004 Resource Plan was filed pursuant to subsection 45 (6.1), separate and apart from, and in advance of, a CPCN application. Although in most circumstances CPCN applications should be supported by resource plans, resource plans are also expected to facilitate the review of utility revenue requirements and rate applications. During cross-examination, witnesses from TGVI acknowledged that some items documented in the CPCN Application, but currently not in the Resource Plan, should be included in future resource plans. Examples of these items are: CPI, interest rate, natural gas price forecast, and price of alternative energy for present value analysis. TGVI also accepted that expenditures and budgets related to DSM evaluation should be part of resource plan updates (T2: 198; T6: 1015-1016).

The Commission Panel accepts that there is an uncertainty related to the proposed Duke Point Power project and that the CPCN Application hinges on the step change in demand related to the power project.

The RP Guidelines provides for a contingency plan in the action plan for events such as changes in load, market conditions and resource options (Exhibit B-1, Appendix A, p. 5, Item #7). The Commission Panel concludes that in this case, the four-year Action Plan would be the plan to address the contingency of the CFT and the Electricity Purchase Agreement that may follow. In the event of CFT generation not proceeding, the Resource Plan need not be re-done, except for the LNG CPCN item in the Action Plan (Exhibit B-8, BCUC IR 48.2; T4: 549). The Commission Panel considers that the Resource Plan considered in this proceeding should continue to serve the purpose of informing the Commission and the public about the planning process utilized for the selection of cost-effective resources in the interim period until the proposed Resource Plan update.

The Commission Panel’s recommendations related to the content of future Resource Plan updates are found in Chapter 6.0 of this Decision.

4.0 DEMAND FORECAST AND DEMAND SIDE MANAGEMENT PROGRAMS

The gross demand forecast in TGVI's Resource Plan was summed up by Ms. Des Brisay as follows: "We see a step change in 2007, we are forecasting that the transport load stays constant after that, so the only growth on the system really is the core load growth." (T5: 704)

4.1 Load Forecasting Methodology

The gross demand forecast for resource planning purposes was developed by analyzing the four major end-users on the TGVI system:

1. core market customers who are made up of residential, commercial and small industrial customers;
2. VIGJV which has firm transportation contract demand;
3. BC Hydro which provides gas to the ICP, a gas-fired generating plant and was undertaking a CFT process for a second gas-fired generation plant on Vancouver Island; and
4. a local distribution company, Terasen Squamish.

The Terasen Squamish and the potential Terasen Whistler markets are expected to have only a small impact on the TGVI peak demand system and were, therefore, not separately analyzed in the Resource Plan.

4.1.1 Core Market Peak Demand

Core market peak demand is a function of the number of customers and the peak use rate. The peak use rate is highly correlated to fluctuations in temperatures (Exhibit B-1, Figure 3-3).

TGVI forecasts customer additions by segmenting the time period of that forecast into Implementation (1991 to 1998), Actual Transition (1999 to 2003), Forecast Transition (2004 to 2011), and Maturity (2012 to 2026) Phases. The number of customers are recorded at the beginning and end of the calendar year and the average annual growth rates are calculated from the records (Exhibit B-3, BCUC IR 6.1).

TGVI forecasts an estimated average of 2,400 customer additions per year between 2004 and 2026 (Exhibit B-9, Core Market Peak Demand Forecast, Slide 8). In the Forecast Transition Phase, TGVI uses three forecast scenarios: Base, High, Low. The total addition in the Base Case is expected to come from conversions of around 1,200 per year and from new construction activities created by new household formations approximating 1,900 a year on a declining trend basis. This annual total is then netted off by around 500 disconnections or abandonments (Exhibit B1, p. 20; T2: 164). The average annual growth rate for the Base Case is 3.1 percent, bounded by 3.8 percent for the High Case and 2.0 percent for the Low Case. Thereafter the growth falls to 2 percent per year in all three scenarios during the Maturity Phase (Exhibit B-1, Figure 3-5).

For the peak use rate per customer forecast, TGVI collects the historical data by rate class and analyzes the use per customer data relative to heating degree days to estimate the design day use rate. The design day is defined as the coldest day in the last 25 years and based on this definition, the design day has 28.4 heating degree days in the model (Exhibit B-1, p. 24; Exhibit B-3, BCUC IR 8.1; Exhibit B-2, Appendix 3, p. 66). This is equivalent to a design day temperature of -10.4^{0}C.

During cross-examination by BCOAPO on end use rates during the forecast period and on the opposing forces affecting this rate, Mr. Wong described the process as subjective and judgmental. He explained that the forecasting process involves going back in history to confirm whether the approach is reasonable or not (T2: 174-7).

The Commission Panel notes that the effects of a subjective approach can result in a significant impact on the load forecast. An example is the subjective assumption of the capture rate. If TGVI were to use the historical capture rate of 80 percent, that would increase its base case forecasts by roughly between 15,000 to 20,000 customers, and this increase could translate into another 18 to 24 TJ per day (T2: 213).

The Commission Panel accepts that judgmental or subjective forecast methodology may be appropriate for some utilities. In the special circumstances of TGVI where it is a relatively new utility with limited historical data and where the customers on its system are not totally exposed to the price of the gas commodity (T2: 214; T2: 341), the Commission Panel recognizes that looking at reasonableness may be the preferred approach. The Commission Panel, however, is of the view that a non-formula methodology should still be methodical and transparent. Some examples of the lack of transparency and methodical approach in the forecast methodology are:

1. The use of calendar year in data input and analysis (Exhibit B-3, BCUC IR 8.4) combined with the use of gas contract year for model outputs (Exhibit B-3, BCUC IR 8.7). The lack of explanation if there is a time lag effect in the BC Stats calendar year projections (Exhibit B-1, p. 20) and customer additions.
2. The lack of proper documentation of assumptions used. For example, there was no proper documentation on the assumptions and justification of the mix of customer base in the Resource Plan. The assumptions only appeared in the response to an Information Request (Exhibit B-3, BCUC IR 8.6). Where an assumption is explicitly stated, as for example in competitive pricing for natural gas, it is not apparent how this is factored into the forecasting methodology (T2: 340, 341).
3. There is insufficient scenario analysis to assess the impact of changes in assumptions. The Base, High and Low cases are only applicable to the Forecast Transition years.

The Commission Panel recommends that TGVI improve its forecasting methodology and the documentation related thereto based on the foregoing comments.

4.1.2 Transport Customer Forecast

The design day transport customer demand is the sum of the expected contract demands of those customers. In its Resource Plan TGVI presented a matrix of gross demand scenarios to take in account the uncertainties surrounding the demand of its two major transport customers: the VIGJV and BC Hydro.

When the Resource Plan was being prepared, the VIGJV (whose members have energy alternatives such as oil, hog fuel or coal) was facing a decision regarding the extension of its long-term contract demand by December 31, 2004. TGVI's forecast methodology for the VIGJV was based on discussions with the customer to determine the likely demand. TGVI used recent consumption experience and the business health of the pulp industry to develop three cases of base, high and low, with forecast demand ranging from 20 TJ/day to 40 TJ/day (Exhibit B-1, pp. 25, 26).

TGVI's forecast for BC Hydro consists of two parts: the ICP demand, and the potential demand resulting from the BC Hydro CFT process. BC Hydro currently has a short-term contract for gas transportation service to the ICP. TGVI used the IEP as the source of reference for forecasting the ICP demand of 45 TJ/day at full operation (T2: 220). In its Resource Plan, TGVI created three scenarios to capture the possible outcomes of BC Hydro's CFT process: no demand; 20 TJ/day to reflect the equivalent of 100-150 MW of new gas-fired generation; and 45 TJ/day to reflect the equivalent of 250 MW of gas-fired generation.

Developments since the filing of the Resource Plan have reduced the uncertainty surrounding the transport customer forecast. The VIGJV's forecast demand is more certain following the Amending Agreement, the related Order in Council and Commission approval of the Amending Agreement by Order No. G-113-04 (Exhibit A-19; Exhibit B-28). The number of demand scenarios resulting from BC Hydro's CFT process was reduced by BC Hydro's selection of the Duke Point Power project, with a requirement for 44.6 TJ/day (Exhibit C6-5), although whether the project will proceed is still uncertain. In addition, the uncertainty surrounding the ICP demand remains, as BC Hydro and TGVI recently extended the short-term contract to October 31, 2005 but have not reached a long-term agreement.

TGVI's Amending Agreement with the VIGJV covers the period January 2005 through December 2012. Contract demand during the period between 2006 to 2012 is a maximum of 12.5 TJ/day, but may be reduced to 8 TJ/day beginning in 2007. Evidence from the VIGJV filed before the Amending Agreement cited the probability of a decrease in gas requirements to 8 TJ/day, with the possibility of further reductions after 2012 (Exhibit C3-4, BCUC IR 2.1; 5.2). TGVI maintains that 12.5 TJ/day is VIGJV's probable demand throughout the study period (T4: 579). The Commission Panel notes that the terms of the Amending Agreement prevent the VIGJV from opposing TGVI's CPCN Application. The VIGJV evidence was not withdrawn. Therefore, the VIGJV's silence on the issue during the hearing does not necessarily mean agreement with TGVI's forecast. **The Commission Panel accepts TGVI's forecast of 12.5 TJ/day for 2006 through 2010 but finds that 8 TJ/day is a more reasonable forecast for the remaining years of the forecast period given the VIGJV's earlier evidence related to further potential fuel switching possibilities.** The Commission Panel notes that the Resource Plan's low case did not anticipate VIGJV demand below 20 TJ/day.

The ICP forecast of 45 TJ/day is based on TGVI's belief that BC Hydro requires firm service of that amount at the ICP for the remaining 15 years of BC Hydro's contract with the operator of the ICP. TGVI attributed the lack of a long-term contract to BC Hydro's ongoing consideration of the Georgia

Strait Crossing ("GSX") pipeline project as a supply option. However, after BC Hydro announced that GSX was no longer a consideration (T5: 815), it signed only a short-term agreement with TGVI for service to the ICP. **Therefore, the Commission Panel finds that uncertainty remains concerning the forecast demand for the ICP, and therefore a long-term contract for ICP service would be a necessary condition of any CPCN.**

4.2 Demand Forecast Scenarios

The matrix of gross demand scenarios in the Resource Plan shows five gross demand forecast scenarios. The relevance in analyzing the Base Case, the High-High and Low-Low and any additional scenario analysis is for the purpose of understanding how an increased demand outcome would impact the choice of additions to the portfolio analysis and, conversely, how a lower demand would defer any resource additions.

The Base Case in the Resource Plan comprises:

(i) the base demand scenario of core market customers growing at 3.1 percent during the Forecast Transition Phase and 2.0 percent during the Maturity Phase with constant per customer use rate throughout the forecast years;
(ii) the VIGJV contracting 33.6 TJ/day between 2006 to 2026 after 37.6 TJ/day in 2005; and
(iii) BC Hydro contracting the full capacity of 45 TJ/day for the ICP by 2007. The Base Case had three probable discrete events to accommodate potential outcomes of the BC Hydro CFT process: the Base +0 Case to reflect no gas-fired generation, the Base +20 Case to reflect a 100 to 150 MW gas-fired generation plan, and a Base +45 to reflect a 250 MW gas-fired generation plant.

As the year 2007 is the year of step change with the retirement, for planning purposes, of the HVDC cables (Exhibit B-3, BCUC IR 10.5), gross total demand scenarios for all the five cases for year 2007 is presented in Table 4.1 below. The demand for the Base +20 Case is 211 TJ/day.

Table 4.1
Base Case Demand in 2007 – Resource Plan (TJ/day)

TJ/day	CORE	JV	BCH – ICP	BCH – CFT	SQUAMISH	TOTAL
High-High	113.3	40	45	45	5.1	248.4
Base +45	107.3	33.6	45	45	5.1	236.0
Base +20	107.3	33.6	45	20	5.1	211.0
Base +0	107.3	33.6	45	0	5.1	191.0
Low-Low	102.7	20	45	0	5.1	172.8

Source: Exhibit B-3, BCUC IR 10.5; BCUC IR 8.6
Exhibit B-2, Appendix 3
Exhibit B-1, p. 15

The demand forecast for the VIGJV was overtaken by the VIGJV TSA Amending Agreement (Exhibit A-19) which reduced the VIGJV demand to between 8 TJ to 12.5 TJ/day. In the Revised Base Forecast, the Revised Base +45 forecasts a total of 214.9 TJ/day for 2007 (Exhibit B-8, BCUC IR 48.1).

TGVI was asked to undertake two additional scenario analyses. In the first instance, it lowered the assumed growth rate of the core demand from 2 percent per year in the Maturity Phase to 1 percent per year. This had no effect on the core market demand for 2007 although demand decreased by 22 TJ/day from 160.3 TJ/day to 138.2 TJ/day for the horizon year (Exhibit B-3, BCUC IR 8.6; Exhibit B-10, BCUC IR 76.2; T2: 178-188). TGVI submits that since the Base +0 Case has a demand that is 20 TJ/day lower than the Revised Base +45 Case and has been shown to support the LNG option, this implies that the LNG portfolio would still make sense under the 1 percent growth scenario (T2: 189, 190).

In the second instance, TGVI was asked to assume a core market growth rate of 2.4 percent in the transition period and 1 percent in the maturity phase. The results show that the lower growth core demand scenario results in higher mitigation revenue and a deferral in resource addition. The LNG storage facility scenario actually became more valuable as a gas supply resource to TGVI under these assumptions (Exhibit B-15, Undertaking #4, p. 5).

In the hearing Ms. Des Brisay of TGVI suggested that a more useful approach when determining core demand sensitivity tests is to ask what change in growth rate for the core demand would be required to make an impact on the portfolios that are developed (T2: 186). The Commission Panel finds that this approach is appropriate, perhaps even desirable, in a CPCN application to determine if the capital investment can be supported by demand. In the opinion of the Commission Panel, this approach should be used to test the robustness of the preferred portfolio. TGVI's proposed approach is only a benchmarking exercise and it does not address the deficiency in sensitivity analysis in load forecasting which is needed to present the likelihood of the forecast range as contemplated by the RP Guidelines (Exhibit B-1, Appendix A, p. 3).

TGVI submits that the core market base case design day demand forecast contained in the response to BCUC IR 48.1 (the Revised Base forecast) is the most likely scenario and a reasonable forecast to use in planning for facility additions (TGVI Argument, p. 10). The Commission Panel notes that the core market number in Exhibit B-8, BCUC IR 48.1 is identical to the number for core customers in the Base scenario in the Table in Exhibit B-3, BCUC IR 8.6.

With the adjustment to the VIGJV demand, the Commission Panel accepts that the Revised Base +0 and Revised Base +45 forecasts are reasonable to use for planning purposes. As no information was presented using an adjusted Revised Base forecast, the Commission Panel accepts the use of the Revised Base forecast as presented by TGVI in Exhibit B-8, for the purposes of the quantitative analysis in this Decision.

4.3 Demand Side Management

As a relatively new utility, TGVI's focus is to expand its core market customer base to help spread the costs (Exhibit B-1, p. 34). Since it started delivering natural gas, the Utility has been pursuing a number of customer programs through funding from the provincial government and through its marketing functions. The expenditures on customer programs are charged to a one-year deferral account and are considered and approved in a revenue requirement process (Exhibit B-3, BCUC IR 13.1.3; IR 23.9).

In the Resource Plan, TGVI concluded that one of the possible solutions to build load, especially energy efficient load such as encouragement of switching from electricity space heat to gas, is to embark on a

DSM program where expenditures are capitalized and can be amortized over a number of years (Exhibit B-1, p. 39).

BCOAPO argues that savings will be realized as the Utility moves from its transition phase towards maturity and DSM programs are in place (BCOAPO Argument, p. 6). The Commission Panel notes that TGVI defines maturity in the Resource Plan in terms of customer addition growth rates rather than per customer account use rate (T2: 173).

Currently, TGVI is applying for funding for new DSM programs and is also in the process of preparing the terms of reference for a Conservation Potential Review ("CPR") which will be the precursor to the Utility's DSM portfolio (Exhibit B-1, Action Plan, Items #4, 5; Exhibit B-3, BCUC IR 11.1).

The 2004 Resource Plan does not have sufficient information related to the DSM strategy and programs (T2: 293). Currently, the DSM strategy is mixed with marketing efforts and is not isolated from the natural growth load forecast as contemplated in the RP Guidelines (RP Guidelines, p. 3, Item #2; Exhibit B-6, MEM IR 4.10).

The Commission Panel recognizes that the Utility is in an early stage of development of its DSM strategy and has not clearly defined the respective roles of its marketing and DSM functions (Exhibit B-3, BCUC IR 13.1.1; 13.1.2). TGVI anticipates that some DSM projects would be the subject of an application to the Commission for approval in a manner similar to a CPCN application (T6: 1017).

As a result of the joint Resource Plan and CPCN Application review process, the Commission Panel expects that TGVI will in future be analyzing the load building initiatives in the core market and balancing these initiatives against the attractiveness of lower demand growth which would result in additional mitigation revenue should the LNG facility proceed.

The Commission Panel expects that a more detailed long-term DSM plan will accompany future annual updates and will contain information as outlined in the Recommendations in Chapter 6 of the Decision. The Commission Panel recommends that TGVI seek approval through the Resource

Plan review process for the DSM budgets and projects, as appropriate, contained in the annual Resource Plan updates.

5.0 SUPPLY PORTFOLIOS

5.1 Supply Side Resources

Three major types of supply side resources can be used to increase the physical capacity of a pipeline system: pipeline looping, compressor, and storage. Pipeline looping consists of adding a second pipeline to increase the cross-sectional area of the pipelines to allow a greater flow rate for a given pressure differential. Compressor additions are of two types; either adding compressor units to increase the pressure differential across an existing station, or adding stations along the pipeline to maintain a higher average pressure. LNG Storage meets the peak requirements of TGVI by physically increasing the system capacity through the introduction of a second source of supply of gas when and as required (Exhibit B-6, BC Hydro IR 1.4(f)).

A fourth type of resource to meet system demand is DSM industrial curtailment. Due to the unique circumstances of TGVI, the general strategy for DSM is related to load building in the core market rather than conservation. It is considered unlikely that there will be significant capacity decreases as a result of the core market DSM programs (Exhibit B-1, p. 50; T1: 130). However, for industrial curtailment, it is TGVI's strategy to have the ability to recall capacity by arrangements with transport customers based on the transport customers' ability to switch to an alternative fuel. The curtailment may or may not include rights to the customers' gas supply during the curtailment period (Exhibit B-1, pp. 40, 41). Specific commitments from the transport customers BC Hydro and VIGJV are required to understand the fixed and variable costs, dispatch rights, restrictions, and risks associated with curtailment (Exhibit B-6, BC Hydro IR 14.0 (a) (ii)).

In the Resource Plan, the amount of curtailment that was expected to be available was modelled on the basis of then existing agreements with the VIGJV and BC Hydro (Exhibit B-1, p. 51). With the decrease in contract demand from VIGJV as of 2006, the potential amount of curtailment is reduced. In the Revised Base Case analysis, the cost of the curtailment peaking gas arrangements was based on parameters provided by BC Hydro (T5: 713).

The last physical capacity resource added to the TGVI system was the V4 (Texada) Compressor Station, which was added to meet the 28 TJ/day step change in 2001 when the ICP commenced operations. The next step change was in 2002 when service to the ICP was increased to 38 TJ/day. This increase is being met by curtailment at ICP. TGVI's position is that an expansion of the pipeline system is required to accommodate the step change forecast for 2007 (Exhibit B-1, p. 42).

The Commission Panel considers that it is appropriate for TGVI to make reasonable assumptions about the cost and availability of curtailment and peaking for Resource Planning. However, there appear to be significant differences of view between TGVI and BC Hydro related to the likely availability and cost of curtailment. Consequently, when TGVI brings forward a specific proposal such as a CPCN application, it should ensure that its assumptions about curtailment rights are supported by executed contracts where these can be negotiated.

5.2 Financial Evaluation of Portfolios in Resource Plan

A resource portfolio is a portfolio of investments in capacity resource additions, based on a modelled output from long-term system plans created to meet the demand requirements of each forecast. Resource portfolios are differentiated by type and timing. For the purposes of resource planning, resource portfolios serve to enable assessment of a preferred option. Therefore, each portfolio is organized in the most efficient way to come up with the lowest capital cost (Exhibit B-1, p. 45).

TGVI testified that the LNG project is a turnkey type project and the bulk of the risk in cost overrun is borne by the contractor whereas the contractors for linear pipeline projects tend to be reluctant to assume such risks (T5: 641, 642). The Commission Panel notes that costs in the portfolios in the Resource Plan are estimates only and CPCN applications will be required to seek approval of significant capital expenditures in the alternative portfolios. The CPCN Application for the preferred LNG storage facility that is being considered in this proceeding is an example.

Three types of portfolios have emerged from the resource planning based on hydraulic characteristics and TGVI planning criteria (Exhibit B-1, p. 52; Exhibit B-3, BCUC IR 35.1). They are:

- LNG Storage followed by phased pipe and compression additions;
- Phased Pipe and Compression Additions; and
- Phased Pipe and Compression Additions with Industrial Curtailment.

These portfolios were evaluated for all of the five demand forecast scenarios.

The financial measures that TGVI used in the evaluation are incremental facilities cost, storage benefits, fuel differential, and curtailment cost (Exhibit B-1, Table 6-1). Unlike the P&C Portfolio, the LNG Portfolio produces mitigation benefits which include reduced peak day transport requirements across the Terasen Gas Coastal Transmission System, reduced costs to TGVI for downstream storage for core customers and payment by Terasen Gas for use of LNG capacity that is in excess of TGVI demand (Exhibit B-1, Appendix C, p. 1; Exhibit B-3, BCUC IR 18.2, IR 19.8). Under the excess LNG mitigation revenue assessment, should the amount of LNG capacity that is required by core customers or transport customers be lower than the capacity of the facility, TGVI has the ability to sell the excess LNG capacity to other parties that are not on the TGVI system, principally Terasen Gas. TGVI has made certain assumptions on the capacity splits between TGVI and third parties based on the demand forecast for each scenario, and the resulting revenue from third parties (Exhibit B-3, BCUC IR 19.6). TGVI estimated its gas supply cost savings and the mitigation revenue on the basis of the value of the LNG capacity being equal to the equivalent cost of underground gas storage.

Table 5.1 is a summary of the present analysis of costs and benefits for the Base +0 Case. The Table shows that storage benefits (which include gas supply cost savings and the mitigation revenues from excess LNG storage capacity) reduce overall incremental costs by 50 percent for that portfolio. Hence, certainty of realization of those revenues is pivotal to the ranking of the LNG portfolio.

Table 5.1
Analysis of Costs and Benefits - Base Case +0 Forecast
(2004-2026 Present Value in Millions of Dollars)

6.1 Percent Discount Rate	**LNG**	**P&C**	**PCC**
Incremental Facility Cost	178	167	88
Storage Benefit	(89)	(5)	2
Fuel Differential	0	0	0
Curtailment Cost	0	0	?
Effective Cost	89	163	90+

10.0 Percent Discount Rate			
Incremental Facility Cost	120	104	55
Storage Benefit	(59)	(2)	1
Fuel Differential	0	0	0
Curtailment Cost	0	0	?
Effective Cost	61	101	57+

Exhibit B-1, Table 6-1

Since the filing of the Resource Plan, TGVI updated the assumptions and refined the analysis in a number of areas that are summarized in Chapter 8. **The Commission Panel accepts TGVI's approach to assembling portfolios in the Resource Plan. However, it should be noted that acceptance of the Resource Plan does not constitute approval of the expenditures.**

5.3 Preferred Portfolio

The financial evaluation undertaken by TGVI in the Resource Plan shows that at a 10.0 percent discount rate, the LNG portfolio is the least cost portfolio under the base case gross demand scenarios. To test the LNG portfolio as the most cost-effective resource, TGVI compared the LNG portfolio to the three other planning objectives selected by TGVI at the beginning of the planning process:

- Ensure reliable and secure supply;
- Reduce rate volatility; and
- Balance socio-economic and environmental impacts.

TGVI measured reliable and secure supply by evaluating the storage as a source of additional supply which can be used in the event that gas supply is interrupted.

TGVI measured rate volatility with trade-offs between rate impacts and rate volatility. It considered the ability for LNG to mitigate commodity price increases during peak periods because the storage facility is close to the major markets, and the ability to increase the regional supply capacity and decrease the risk of a regional price disconnect (Exhibit B-6, MEM IR 1.2.3). The trade-off exercise is qualitative, involving a binary discrete choice of whether the LNG portfolio has the feature or it does not (Exhibit B-6, MEM IR 1.5.1).

TGVI measured socio-economic and environmental impacts by measuring emission factors (e.g. tonnes or kg/TJ delivery), land use impacts (hectares) and employment impacts (person-years during construction and permanent positions during operations). The analysis shows that on a relative basis, all portfolios are the same (Exhibit B-10, BCUC IR 89.1; T5: 668-669). TGVI also pointed out that the analysis has excluded the greenhouse gas emissions for the use of alternative fuels during curtailment; they are only calculated for the TGVI facilities (T5: 670).

The Resource Plan concludes that an LNG facility commissioned in 2007, combined with compression and pipe looping as required by 2007 or later to meet future incremental demand, represents the best alternative for TGVI and its customers.

6.0 COMMISSION DETERMINATION ON RESOURCE PLAN

This Resource Plan is the Utility's first resource plan under the new RP Guidelines. **The Commission Panel accepts the 2004 Resource Plan for filing.** TGVI has not sought approval of expenditures and the Commission Panel notes that acceptance of the Resource Plan for filing does not constitute approval of future expenditures. TGVI must seek specific approval of such expenditures.

The Commission Panel recommends that the following undertakings and reports be included in future Resource Plan updates in order to facilitate and streamline the regulatory review process.

Recommendations:

1. The most current Annual Review materials that are part of any multi-year negotiated settlements should be included in the annual updates.

2. The annual statement of extensions under subsection 45(6) should be submitted together with the resource plan.

3. The five-year major capital plans with capital expenditure schedules and summary of justification should be referenced in the resource plan.

4. A summary of the non-confidential aspects of information related to price risk management strategy and costs of gas as well as outlook on alternative fuels should be included in the resource plan.

5. Long term load forecasts (before DSM) should be standard reports in a resource plan.

6. Long term load forecasts with impacts from DSM initiatives should be included as soon as DSM programs are in place.

7. DSM programs, total budgets for program expenditures and incentives, and related operating and maintenance expenditures should be included, with breakdown by program where possible.

8. Measurement of DSM program benefits and costs and standard measurement criteria should be standard reports in a resource plan.

9. An update and outlook of the corporate capital structure for the planning period should be included in the annual updates. The assumptions on CPI, interest rates, outlook on natural gas cost and alternative energy prices used in the evaluation of portfolios should also be included.

10. TGVI should present financial comparisons using both a discount rate that is based on its after-tax cost of capital and higher discount rates to reflect risks to cash flows.

11. Where practical, applications for approval of items in the Action Plan should be sought as part of the resource plan filing, to preclude the necessity of subsequent CPCN and other applications especially for approval of relatively small expenditures.

7.0 LNG STORAGE FACILITY

Based on the Resource Plan conclusion that LNG storage is the preferred resource addition to meet forecast load growth, TGVI applied for a CPCN pursuant to Section 45 of the Act to construct and operate a LNG storage facility. This Chapter describes the LNG facility and its siting. Subsequent chapters evaluate the proposed LNG facility in comparison to other resource addition options.

7.1 LNG and its Uses

Natural gas is composed primarily of methane. It may also contain ethane, some heavier hydrocarbons, and small amounts of other components like nitrogen, carbon dioxide, water and sulphur compounds. After natural gas has been purified to remove the latter components and the gas has been cooled to a temperature of approximately -162^{o}C (-260^{o}F) at atmospheric pressure, it condenses to a liquid called liquefied natural gas ("LNG"). One volume of LNG is formed from approximately 620 volumes of natural gas at atmospheric pressure and ambient temperature (Exhibit B-2, Appendix 1).

LNG is a colourless liquid that is approximately one-half as heavy as water. It will not burn or explode, and must be vapourized and then mixed in a ratio of 5 to 15 percent gas in air before it will support combustion. As LNG boils at approximately -162^{o}C, facilities to handle it must be made of materials that are suitable for these cryogenic temperatures. Nine percent nickel alloy steel, aluminum, stainless steel and concrete are proven in use at these very low temperatures.

The large volume of gas to the corresponding volume of LNG makes storage of natural gas in the liquid state attractive. However, the cost of the storage and liquefaction facilities and the operating costs for liquefaction and vapourization means that stored LNG is usually reserved for providing peaking supply during very cold weather or other peak demand situations. The greatly-reduced volume of LNG also makes possible alternate methods of transportation. LNG tankers are used to transport LNG from remote regions where natural gas is abundant to import terminals near large gas markets in North America and other areas. These import terminals usually are base-load facilities, and need approximately three times the amount of storage as the Mount Hayes LNG facility in order to receive an LNG tanker (Exhibit B-3, BCUC IR 5.5).

If an import terminal were established in the region (e.g. at Prince Rupert), barges could be used to distribute LNG from the terminal to areas where pipeline service is inadequate. LNG can also be transported by LNG tanker truck, and used to supply gas to communities where the pipeline connection has been temporarily interrupted, or to serve communities without a pipeline connection using a satellite LNG storage and vapourization facility.

7.2 Design of the LNG Facility

The proposed LNG storage facility would be built at the Mount Hayes site in the Cowichan Valley Regional District, approximately 6 km northwest of Ladysmith. It would have a usable storage capacity of 1075 TJ (1.0 billion standard cubic feet) of natural gas, and would be capable of vapourizing LNG and sending out gas to the TGVI System at up to 107 TJ/d (100 million standard cubic feet per day). It would be capable of liquefying approximately 5 TJ/d (5 million standard cubic feet per day) of natural gas (Exhibit B-2, pp. 2, 10, 12). The maximum gas send-out from the LNG facility would be approximately one-half of the peak day demand on the TGVI system. A full LNG storage tank would be capable of 10 days supply at maximum gas send-out.

TGVI has engaged Chicago Bridge & Iron ("CB&I") to prepare the facility design, including the review and recommendation of the type of refrigerant cycle. CB&I currently has two LNG import terminal projects underway and has been awarded an Engineering Procurement and Construction ("EPC") contract for a 1.2 billion standard cubic feet LNG peak shaving facility in Connecticut (Exhibit B-10, BCUC IR 60.1). TGVI anticipates that the design of its facility will use a mixed refrigerant system, similar to the Terasen Gas Tilbury LNG Plant in the Lower Mainland (Exhibit B-10, BCUC IR 59.2). The main components of the LNG facility and a breakdown of the CB&I EPC cost estimate is:

Table 7.1
LNG Storage Facility Capital Cost Breakdown

Pretreatment (natural gas purification)	5 percent
Liquefaction	18 percent
LNG storage	28 percent
Vapourization and send out	17 percent
Ancillary plant equipment and facilities	32 percent
	100

(Exhibit B-2, pp. 11-16; B-17)

In addition to the LNG facility, the project includes two pipelines that are 219 mm (8 inches) and 273 (10 inches) in diameter and approximately 5 km in length to connect the LNG facility to the TGVI transmission system. The liquefaction compressor will be electric powered, and the project includes a substation and 25 kV electric transmission line. It also includes a fibre optics communications line and upgrading of the access road.

7.3 Cost Estimate and EPC Contract

TGVI estimates the cost of the project at $94.4 million in 2004 dollars, not including Allowance for Funds Used During Construction ("AFUDC") and Overhead, as shown in Table 7.2.

Table 7.2
LNG Project Capital Cost
(Millions of 2004 dollars)

EPC for LNG Facility	$73.8
Land and road upgrade	$ 1.6
Interconnecting gas pipelines	$ 5.6
Electrical connection	$ 2.2
Site preparation and other	$ 1.5
Project services	$ 7.9
Contingency	$ 1.8
Total	$94.4

The corresponding estimate in as-spent dollars and including AFUDC is $106.0 million (Exhibit B-3, BCUC IR 28.1, 28.4; Exhibit B-10, BCUC IR 60.7).

TGVI estimates the direct cost in 2004 dollars would be $70.7 million for a 0.5 billion standard cubic feet storage facility and $124.1 million for a 1.5 billion standard cubic feet facility (Exhibit B-3, BCUC IR 36.8).

TGVI has a contract with CB&I to deliver a firm price EPC bid and detailed schedule by January 27, 2005. CB&I has provided a preliminary estimate for the EPC contract of $75.9 million (which is slightly higher than the $73.8 million estimate that TGVI used), and assurances that this estimate should be accurate +/-15 percent (Exhibit B-10, BCUC IR 60.2, 60.3, 60.4; Exhibit B-17). TGVI states that it has a confidence level of +/-5 percent for owner's costs, and in Argument stated that the estimate of $94.4 million should be within +/-15 percent. TGVI also stated that the cost estimates for pipeline looping and compressors that were used to calculate the cost of other portfolio options have confidence levels of +/-25 percent and +/-15 percent, respectively.

TGVI stated that LNG projects are often built using a sole source EPC arrangement, due in part to the cost of developing a firm EPC price and the limited number of acceptable contractors. TGVI believes a sole source contract is the best way to get a firm EPC price at the least development cost, with a facility design that is acceptable to TGVI (Exhibit B-3, BCUC IR 28.6).

Although the EPC price is referred to as a firm price, there are several reasons why the actual cost could be different. Currency exchange risk will be dealt with at the time of the bid, by TGVI either accepting a Canadian dollar bid, or hedging the exchange rate. TGVI will pay the actual cost of the steel for the storage tank that is determined at the time it is ordered. Also, TGVI will be responsible for any additional costs to deal with geological issues. TGVI believes that scope changes will not be a significant issue since it is developing the scope with the contractor. Also, if a force majeure event causes the contractor to stop work, each party bears its own costs during such an event (T3: 482-5).

In Argument TGVI stated that it believes the estimate of $94.4 million is reasonable and that the maximum increase in the cost of the facility will not be likely to exceed $12 million. TGVI also believes that it would be reasonable for the Commission to make a CPCN Order subject to the EPC bid being no more than 115 percent of the $75.9 million estimate (TGVI Argument, p. 5). In its Reply, TGVI stated that any cost collar should be established after receipt of the EPC bid, and not as a condition of the CPCN (Reply, p. 22).

The BCOAPO submitted that a cost collar of +/- 5 percent would be appropriate for this project, and stated that the CPCN Application should be denied if the EPC contract price is 115 percent of the estimate. BC Hydro stated at page 28 of its Argument that a 15 percent cap on capital costs has the effect of a 15 percent excess in capital cost going to the customers' account, and that this would cause the cost of the LNG portfolio to exceed the present value costs of several alternative portfolios. TGVI replied that the appropriate comparisons are those using the expected costs for all portfolios (TGVI Reply Submission, p. 12).

The Commission Panel accepts the $94.4 million cost estimate as reasonable for the project, and considers that it is comparable with respect to confidence level to the estimates for the other portfolio options. In the event the project goes ahead, the estimate would be used in progress reports as the basis for comparisons to actual expenditures. Also, if the project proceeds, TGVI will be expected to justify the prudency of the actual expeditions, particularly any costs in excess of this estimate.

The Commission Panel considers that any CPCN for the LNG facility should be conditional on an EPC bid price that is not more than more than 110 percent of the $75.9 million estimate. The Commission believes this condition is necessary so that approval of the project will be revisited in the event the EPC bid price is higher than current expectations. The Commission believes that it would also be appropriate to confirm that the firm EPC bid is consistent with the evidence in the proceeding. Any CPCN for the project will require TGVI to file the detailed firm EPC bid price and detailed project schedule, along with confirmation that the total project cost is based on steel prices and other information that are current.

7.4 Project Schedule

TGVI wishes to have the LNG facility in service for the winter of 2007/08 in order to meet the increase in demand for firm capacity for ICP and a new gas-fired generation facility that may result from the BC

Hydro Vancouver Island CFT (T5: 704). CB&I has stated that the project can be constructed in 28 months. TGVI confirmed that a one-month delay in the award of the EPC contract to CB&I can be accommodated (T3: 491; Exhibit B-10, BCUC IR 62.2). TGVI's key LNG milestone dates filing shows the adjusted schedule. If a CPCN is approved by February 28, 2005, filling the LNG tank could commence in mid-August 2007 and the LNG tank would be one-third full at the beginning of November 2007 (Exhibit B-14).

In the event that final approval to go ahead with the LNG project was delayed until April or May of 2005, it would be difficult but potentially feasible to have the LNG facility in service for late 2007. The contractor would likely need to incur additional costs to reduce the construction period. There is limited ability to proceed with work on the project pending final approval, since a major commitment for steel for the tank would need to be made shortly after the EPC contract is awarded (T3: 494-6).

At page 41 of its Argument, TGVI stated that it would not be adverse to a "sunset clause" in a CPCN for the LNG facility. On the basis that BC Hydro may be able to delay its need for firm transportation by one year, TGVI suggested that a condition of the CPCN could be that construction of the LNG facility commence by December 31, 2005 (T7: 1175-7; TGVI Argument, p. 41). **The Commission Panel considers that such a sunset clause should be a condition of any CPCN approval.**

7.5 Safety and Integrity

The design, construction and operation of the LNG facilities and connecting pipelines would be regulated by the Oil and Gas Commission. The power line would be constructed to BC Hydro Engineering and Construction standards. The LNG facilities would conform to all applicable standards, codes and regulation, primarily CSA Z276-01 (LNG Production, Storage and Handling), and the National Building Code of Canada. They would also meet any more stringent requirements in the U.S. National Fire Protection Association ("NFPA") Standard 59A-2001 (Production, Storage and Handling of Liquefied Natural Gas (LNG)) (Exhibit B-2, p. 45; Exhibit B-6, BC Hydro IR 25.0(a). The LNG facility will be designed for a Safe Shutdown Earthquake with a return period of 1: 2475 years, which is consistent with recent revisions to the Canadian National Building Code (which applies to buildings at the facility) and the NFPA requirements (Exhibit B-2, p. 48; Exhibit B-10, BCUC IR 58.1, 58.2; Exhibit B-3, BCUC IR 25.2).

The LNG storage tank would be surrounded by a secondary containment earthen dike capable of holding the entire volume of the LNG tank. TGVI would remove trees from a minimum of 100 m from the dyke, and maintain control over land around the facility to provide a permanent buffer zone. The Utility expects that the thermal radiation zone would extend to approximately 400 m from the centre of the facility (Exhibit B-2, pp. 13-15, 47-51). The facility would have water monitors at strategic locations that are fed from a water storage tank that would be replenished from a pond to collect runoff water. The facility would be staffed on a continuous basis, and its operation would be monitored at Terasen Gas' gas control centre in Surrey, B.C. It would have remote control and shutdown systems.

The facility design by CB&I would be subject to a complete Hazard and Operability Analysis Review. TGVI would develop a site-specific Emergency Response Plan to address operator actions for all emergency scenarios (Exhibit B-2, p. 53; Exhibit B-6, BC Hydro IR 25.0(a), 27.0(b)).

The CPCN Application states that LNG has been safely handled for many years throughout the world and has an excellent safety record. Over the past 50 years, there have been no impacts to any member of the public as a result of any incident from LNG operations of the kind proposed for Mount Hayes. There are about 240 peak shaving LNG facilities worldwide (Exhibit B-2, p. 49).

In Argument, TGVI notes that Terasen Gas is the owner and operator of the existing Tilbury LNG storage facility in the Lower Mainland, which has operated without incident since going into service in 1971. The Utility states that Terasen Gas provides management services to TGVI and will be able to provide the necessary training and develop the necessary standards for the proposed facility (TGVI Argument, p. 6).

7.6 Siting and Public Consultation

TGVI engaged in an extensive round of public consultations in the areas that were considered as possible locations for the LNG storage facility. The extent of the area for possible location of the project was a 10 km wide band centred on the TGVI main transmission pipeline on Vancouver Island (Exhibit B-2, p. 16). Originally, 25 sites were considered. These possible sites were culled to seven and finally the list was reduced to a shortlist of three, one of which included lands adjacent to the proposed Duke Point Power facility that is the triggering demand side requirement that the LNG facility is to meet.

Generally, the site selection process assessed various criteria set out in the Environmental and Social Review ("ESR") (Exhibit B-3, BCUC IR 26.1, pp. 130-2 and www.TerasenGas/PipelinesandFacilities/ LNGStorageProject). This report dealt only with the Mount Hayes location but the criteria employed were used as well at the other possible sites under consideration early on in the selection process. In brief, the selection process covered physical, biological and human environments, and facility and public safety.

Presentations were made to local governments (municipal and regional) and First Nations. Open Houses were held in December 2003 in Duncan and Cedar to brief members of the public on the project, to educate interested parties on the characteristics of LNG and its safety record and to answer questions (Exhibit B-2, p. 17). A further Open House was held in January 2004 after selection of the proposed site. The public consultations are described in more detail in the Resource Plan (Exhibit B-1, Section 7, pp. 60-65). Consultations were also held with BC Hydro.

The three sites on the shortlist were:

Site 18 - West of Mount Hayes;
Site 21 - West of Mount Prevost; and
Site 25 - Duke Point Industrial Area.

Reasons for selecting Mount Hayes included:

- geotechnical conditions;
- no near proximity to population centres;
- no environmental or archaeological complications;
- existing road access; and
- no expressed public concerns.

(Exhibit B-3, BCUC IR 26.1)

TGVI did not provide detailed evidence in the proceeding of the pros and cons of the various sites considered or of the weighting of the selection criteria that it used to build the short list and to finally select Mount Hayes as the preferred location for the project.

TGVI considered the Mount Prevost site less attractive than Mount Hayes due to:

- The proximity to Mount Prevost that has spiritual values to the Cowichan First Nation and is used extensively by the public for recreation;
- Crown land ownership which added complexity to the land acquisition process;
- The larger number of land owners potentially affected by the connecting pipeline;
- Geology and foundation conditions that are suitable but less favourable;
- Potential visibility impacts; and
- Higher cost.

TGVI considered the Duke Point site less attractive than Mount Hayes due to:

- Limited land area available and considerably higher land cost;
- Costs and impacts of required upgrading of the existing Duke Point lateral;
- Geology and foundation conditions suitable but less favourable;
- Proximity to nearby homes;
- Potential visibility impacts; and
- Higher cost.

(Exhibit B-3, BCUC IR 26.5)

The CPCN Application was presented to the Commission Panel for approval without any alternate proposal. Accordingly, the role of the Panel is to assess the information and evidence before it and to make an accept/reject decision in respect of the Mount Hayes LNG location.

There was some brief discussion as to whether there was any possibility of the proposed LNG storage facility serving as an LNG import terminal and if so, whether that possibility should have influenced the site selection and the requirement for deep water access to the facility (T3: 509-11). An import terminal would have considerable capital costs, and the TGVI project schedule would not allow for the approval and construction of such facilities for 2007 (Exhibit B-3, BCUC IR 5.5, 5.8, 5.9). The location of the facility at Mount Hayes does not provide the flexibility of supplying LNG by tanker or barge, now or in the future. There is a contingency plan to build the capability of supplying the facility by tanker truck similar to the capability at Terasen Gas' Tilbury Island LNG storage facility. However, this is seen as an emergency supply alternative only at this time. The Commission Panel is satisfied that considerations of developing the project as a dual purpose storage and import facility were rightly discarded by TGVI as amounting to a project in scale and scope far different than the proposed peaking storage facility, and at several times the cost.

The public consultations carried out by TGVI appear to have been adequate and there was a comprehensive attempt to explain the operation and safety-related issues of an LNG storage facility to members of the general public. The Commission Panel notes that there were no adverse submissions by any intervenor in this proceeding that centred upon safety or environmental concerns related to the LNG storage facility.

7.7 Environmental

TGVI has confirmed that no application is required under either the BC Environmental Assessment Act ("BCEAA") or under the Canadian Environmental Assessment Act ("CEAA") (Exhibit B-2, p. 43).

Environmental issues at the proposed Mount Hayes site were considered in some depth in the ESR and with two exceptions, no significant environmental impact from the proposed facility was discovered. The two exceptions relate to water and aquatic systems and vegetation, both of which can be neutralized with mitigation efforts recommended in the report.

The proceeding did not deal in detail with Greenhouse Gas Emissions ("GHG") and the differentials that might be realized under the various portfolios under study. Nor were the costs of such emissions factored into the comparative financial analyses of the portfolios. However, TGVI did present a comparative analysis of the emissions expected under each Resource Portfolio (Exhibit B-1, p. 58, Table 6-3). These estimates were updated to take into consideration the updated portfolio scenarios that were evaluated later in the proceeding and the updated data for the Base + 45 emissions is presented in Table 89.1 (Exhibit B-10, BCUC IR 89.1). In brief, for CO_2 emissions, there is a differential of only 15 percent as between the LNG, P&C and PCC portfolios and the Commission Panel is of the view that this is not significant.

7.8 Land Rights and Other Approvals

TGVI has an option to buy the Mount Hayes property from Weyerhauser Company Limited, that expires on July 31, 2005 or with an extension, on July 31, 2006 (Exhibit B-3, BCUC IR 24.0, Appendix A, pp. 3-4). The purchase price is $614,000. This property consists of the 12 hectare plant site and the 20 hectare buffer zone to the east of the rezoned property, both of which will be purchased from Weyerhauser. The property has the potential of accommodating an additional storage tank of up to 1.5 billion standard cubic feet should there be a need to expand the capacity of the storage facility.

In addition, TGVI will seek a crown lease of a 20 hectare parcel of Crown land to the west of the rezoned property. The issue of the Crown lease has been referred to the Chemainus First Nation for comment (Exhibit B-3, BCUC IR 24.4). It is anticipated by TGVI that a Memorandum of Understanding ("MOU") with the Chemainus First Nation will be required. Negotiations have taken place but as yet, there is no firm agreement. TGVI is of the view that the MOU will result in an agreement and that the Crown lease will be forthcoming within the timeframe necessary to have the Mount Hayes facility operational by 2007. The estimated costs of the MOU have been included in TGVI's overall project estimate of $94.4 million.

Further, TGVI has obtained the necessary re-zoning (U-1 Utility LNG) of the Mount Hayes property from the Cowichan Valley Regional District ("CWRD") (Exhibit B-2, App. 7, p. 2). This approval permits TGVI to construct two LNG storage tanks of up to 1.5 billion standard cubic feet capacity each on the site.

Finally, TGVI will require rights-of-way access to build the connecting gas pipelines to the proposed facility and to provide for electric and communications transmission lines. No problems are anticipated by TGVI in securing the necessary rights-of-way from the Crown and the private property owners involved.

7.9 Commission Determination on Mount Hayes Facility

In summary, TGVI has satisfied the Commission Panel that the selection of the proposed site was performed with adequate due diligence, sufficient public and municipal consultations, and with a comprehensive Environmental and Social Review and operational and safety considerations. The Commission Panel commends TGVI for the extensive background work, public education, and thorough site analysis that have been carried out for the proposed Mount Hayes facility.

Subject to the further required approvals discussed above, the Mount Hayes site seems well suited for the location of the project. The Commission Panel is satisfied that the construction and operation of the proposed LNG storage facility at Mount Hayes, with the mitigation measures and safeguards proposed by TGVI, would not result in any significant health, safety or other impacts on the public.

8.0 CHANGES TO RESOURCE PLAN ASSUMPTIONS

In the CPCN Application and during the proceeding, TGVI made a number of changes to the Resource Plan assumptions and evaluation methodology. This Chapter provides a summary of the changes.

8.1 Changes for the CPCN Application

TGVI identified the following changes to Resource Plan methodology that were included in the CPCN Application (Exhibit B-3, BCUC IR 33.1):

- The Cost of Service of Incremental TGVI Facilities summaries were revised to reflect updates to the assumptions and other information;
- Transport Fuel Differentials were shown separately, rather than as part of the Fuel Differential;
- Gas Supply Differentials were based on gas supply costs that were evaluated using the Sendout model to determine a least-cost gas supply solution for each resource addition portfolio. The analysis considered the benefit of peaking gas arrangements for each resource

addition portfolio. The TGVI gas supply costs and cost differentials in the CPCN Application include the cost of system fuel gas for core market (sales) customers;

- LNG Mitigation revenue from sales of excess LNG capacity was shown separately, rather than as part of the Storage Benefit;
- Peaking Mitigation Revenue is additional LNG mitigation revenue that is made possible by the use of peaking gas supply with the LNG portfolio, and was included as an additional benefit of an LNG facility; and
- TGVI also updated the cost estimates for the resource additions in each portfolio. The incremental facilities cost for the LNG facility was reduced by $10 million on a present value basis to reflect site-related costs that are specific for the Mount Hayes site.

8.2 Changes for Exhibit B-8

Subsequent to filing the CPCN Application, TGVI made several additional changes to assumptions. Some of the changes resulted from responses to Information Requests. Others resulted from the amendment to the VIGJV TSA that TGVI and the Joint Venture entered into in October 2004. That amendment reduced the forecast VIGJV demand to 12.5 TJ/d and eliminated the VIGJV standard curtailment peaking gas supply, resulting in a lower Revised Base forecast (Exhibit B-8, BCUC IR 48.1, BCUC IR 48.2, pp. 4, 5). When preparing Exhibit B-8, TGVI used the following updated assumptions and information:

- TGVI updated its resource addition portfolios, and included PCC portfolios that assumed 53 hours and 240 hours of fuel switching capability at the ICP;
- The incremental wheeling costs to transport gas from Huntingdon to the TGVI system at Eagle Mountain in Coquitlam were included in the financial analysis (Exhibit B-3, BCUC IR 37.1);
- The performance of the existing compressor units at station V1 in Coquitlam was based on upgraded units (Exhibit B-6, BC Hydro IR 3.0(a));
- Retention of the Texada Island V4 compressor was assumed to occur in late 2005;
- Operating and maintenance costs for the LNG facility were increased by $230,000 per year, to $1.78 million per year in 2004 dollars. The variable component of these costs is $1.34 for each gigajoule of natural gas that is returned to the TGVI system (Exhibit B-10, BCUC IR 59.3);

- The cost of curtailment and peaking gas arrangements was assumed to be a $500,000 annual demand charge and a $15.00/GJ commodity charge indexed to CPI, which represents BC Hydro's out-of-pocket costs for fuel switching (Exhibit B-10, BC Hydro IR 50.0; Exhibit C7-12);

- Fuel costs associated with third party LNG storage services was applied to reduce LNG Mitigation Revenue, rather than including it in the Transportation Fuel Differential;

- Depreciation rates were updated to 3.5 percent for compression, 1.97 percent for pipe and 3.77 percent for buildings, to be consistent with TGVI's current Revenue Requirements Settlement (Exhibit B-3, BCUC IR 47.2);

- Cost of service summaries were provided in a calendar year format to allow consistency with schedules showing system costs and customer impacts;

- Large Corporation Tax was reduced to 0 percent by 2008;

- Oil and gas price forecasts were based on the October 2004 Gilbert Laustsen Jung Associates Ltd. forecast (Exhibit B-3, BCUC IR 38.1);

- A currency exchange rate of US $0.75/$Cdn was used for determining future oil and gas costs and mitigation revenue, rather than US$0.71/$Cdn (Exhibit B-3, BCUC IR 38.2); and

- Electricity rates for the "soft cap" mechanism were based on a 6 percent increase over 2003 rates to 2005, and annual increases of one-half CPI thereafter.

The Commission Panel commends TGVI for updating the CPCN Application, and for expeditiously preparing Exhibit B-8 in response to the amendment of the VIGJV TSA and BC Hydro's announcement of the results of the CFT process. Nevertheless, when a large amount of new information is filed during a proceeding, it is difficult for participants to properly evaluate and test it.

9.0 RESOURCE PORTFOLIO OPTIONS

Section 5 of the Resource Plan describes how TGVI developed its three supply-side resource portfolio options: pipe and compression, pipe and compression and curtailment, and LNG storage. It is perhaps more accurate to describe them as three resource addition strategies, since the resource additions and their timing vary from one scenario to another depending on assumptions such as load forecast and the availability of curtailment and peaking. The resource additions under each scenario were identified using a computer model that simulates the hydraulic characteristics of the TGVI transmission system, and TGVI's planning criteria (Exhibit B-1, p. 45; Exhibit B-2, pp. 22, 23). TGVI provided a summary of its planning criteria and the Gregg Engineering pipeline simulation program (Exhibit B-3, BCUC IR 35.1, 35.2, 35.3). The Utility also provided system flow diagrams for several scenarios based on output from the Gregg program.

As a result of the amendment to the VIGJV TSA, TGVI revised its Base forecast and provided updated information for the Revised Base +45 and Revised Base + zero forecasts in Exhibit B-8. Exhibit B-11 subsequently revised some of this information. PCC portfolios were developed for one scenario based on ICP's existing 53 hours of distillate storage capacity and a second scenario assuming 240 hours per year of fuel switching is available. TGVI concluded that no new facilities are required for 2007 for the Revised Base + zero forecast if the PCC (53 hour) scenario for ICP curtailment is used. That is, the LNG facility could be deferred and could be displaced by other future resource additions (Exhibit B-8, BCUC IR 48.2, p. 3).

A significant clarification was provided when counsel for BC Hydro advised the Commission Panel that it will not be necessary to consider further the merits of the GSX pipeline as an option for the TGVI resource portfolios (T5: 815).

In this circumstance the principal portfolio options for Commission consideration are the four options for the Revised Base +45 forecast that are set out on Figure BCUC IR 48.2 c, which is attached as Figure 9.1. All of the portfolios assume that TGVI purchases the V4 Texada compressor from BC Hydro in 2005. The remainder of this Chapter reviews the four portfolio options, while the next Chapter provides a financial comparison of the options.

Figure 9.1
Incremental Facility Requirements
Revised Base +45 Forecast

Year	LNG Storage			PC			PC&C (53 hrs)			PC&C (240 hrs)		
	Required TGVI Facilities	Forecast Direct (millions 2004$)	System Fuel (%)	Required TGVI Facilities	Forecast Direct (millions 2004$)	System Fuel (%)	Required TGVI Facilities	Forecast Direct (millions 2004$)	System Fuel (%)	Required TGVI Facilities	Forecast Direct (millions 2004$)	System Fuel (%)
2004												
2005	V4	15		V4	15		V4	15		V4	15	
2006	CFT MS	2		CFT MS	2		CFT MS	2		CFT MS	2	
2007	LNG, V2, spares	121	4.6%	V1U4, V2, V3b, V5, loop 25km d/s WS, loop 12km d/s V2, spares	117	4.2%	V1U4, V2, V3b, V5, spares	82	4.4%	V1U4, V2, V3b, V5, spares	82	4.3%
2008			4.6%	loop 27km d/s V3b	25	4.2%			4.4%			4.3%
2009			4.6%	loop 40km d/s WF	36	4.1%			4.4%			4.4%
2010			4.6%			4.1%			4.4%			4.4%
2011	V1U4	15	4.7%			4.1%	loop 25km d/s WS	23	4.4%			4.4%
2012			4.7%	V1U5	15	4.1%			4.4%			4.5%
2013	V3b	20	4.7%			4.1%	loop 12km d/s V2	12	4.4%			4.5%
2014			4.7%			4.1%			4.4%			4.6%
2015			4.7%			4.0%			4.4%			4.6%
2016			4.7%			4.0%			4.4%			4.6%
2017			4.7%	loop 19km d/s PM	17	4.0%			4.5%			4.7%
2018			4.8%			4.0%	loop 27km d/s V3b	17	4.4%	loop 25km d/s WS	23	4.6%
2019			4.8%			4.0%			4.4%			4.6%
2020			4.8%			4.0%	loop 40km d/s WF	36	4.4%	loop 12km d/s V2	12	4.5%
2021			4.8%			4.0%			4.4%			4.5%
2022			4.9%			4.0%	V1U5	15	4.3%			4.4%
2023			4.9%	loop 10km d/s V4	12	4.0%			4.3%	loop 27km d/s V3b	25	4.4%
2024			4.9%	loop 7km d/s V5, loop 10km d/s WS	16	4.0%	loop 7km d/s V5	7	4.3%	loop 7km d/s V5	7	4.3%
2025			4.9%			4.0%			4.3%	loop 40km d/s WF	36	4.3%
2026			5.0%			4.0%			4.3%			4.2%

Legend

CFT MS	CFT Meter Station	V1U5	5th unit to VI - Coquitlam Compr	V1U5
d/s	'downstream of'	V2	V2 - Squamish Compressor Stat	V2
km	'kilometre'	V3b	V3b - Secret Cove Compressor :	V3b
LNG	Mt Hayes LNG Storage Facility	V4	V4 - Texada Compressor Statior	V4
PM	'Port Mellon'	V5	V5 - Dunsmuir Compressor Stati	V5
spares	Spare Compressor Engines	WF	'Woodfibre'	WF
V1U4	4th unit to VI - Coquitlam Compressor Station	WS	'Watershed'	WS

Notes

System fuel includes compressor fuel plus 0.5% for meter station fuel, 1% for UAF

Source: Exhibit B-8, BCUC IR 48.2c, p. 14

9.1 Pipe and Compression Option

In addition to the Texada compressor, the P&C option requires a fourth compression unit at V1 (Coquitlam), and new compressor stations at V2 (Squamish), V3b (Secret Cove) and V5 (Dunsmuir) for 2007. This option would also require 37 km of pipeline looping for 2007 and extensive additional looping in subsequent years.

9.2 Pipe and Compression and Curtailment Options

Both of the PCC options require a fourth compressor unit at V1 (Coquitlam) and new compressor stations at V2 (Squamish), V3b (Secret Cove) and V5 (Dunsmuir) for 2007. The 53-hour scenario requires extensive pipeline looping starting in 2011, while the 240-hour case does not require looping until 2018.

In its evidence and Argument, TGVI presents several reasons why it considers that the PCC portfolios are not the best option (TGVI Argument, pp. 15-20). First, only the portfolio for curtailment of ICP for 53 hours is feasible at this time without changes at the ICP facility. TGVI also claims that more extensive use of curtailment extending into normal winter conditions would introduce a new set of operating conditions and reduce flexibility and reliability of the system (Exhibit B-8, BCUC IR 48.2, pp. 7-9).

One TGVI planning criterion is that curtailment and peaking would only be used for colder than normal weather. That is, transmission system capacity is maintained to meet the Normal Peak Day, which is equivalent to the sixth coldest day in a design year. TGVI subsequently relaxed this requirement when it analyzed the PCC (240 hour) curtailment scenario. However, TGVI also stated that the assumption of perfect nomination of curtailment for scenarios that rely on more extensive use of curtailment should include an additional 9 TJ/d margin of pipeline capacity to account for forecast variation. This would require that resource additions after 2007 should be advanced by three years (at a cost of $15 million present value at 6.1 percent discount rate) to maintain a capacity reserve margin (Exhibit B-3, BCUC IR 35.5; Exhibit B-8, BCUC IR 48.2, pp. 7-9; T5: 719-720).

Another planning criterion is the lowest acceptable system operating pressure at Victoria, which is modeled as 700 psig during colder than normal weather and 1,000 psig during normal weather. This is done to provide a reserve margin relative to 500 psig, which is the highest pressure at which TGVI is required to deliver gas to its customers. In the hearing, TGVI noted that it normally operates the transmission system at 1,200 psig at Victoria. The Utility provided evidence that below about 1,400 psig, increases in demand can quickly pull down pipeline pressures (T7: 1052, 1057-1059; Exhibit B-26, pp. 7-14). A 1,200 psig pressure at Victoria would provide a capacity reserve in the range of 5 to 10 percent.

For curtailment greater than 7.5 TJ/d, ICP would not be able to operate at full capacity for part of the day without switching to distillate for 24 hours, as peak hour flow cannot exceed 5 percent of the daily nomination (Exhibit B-3, BCUC IR 34.1; Exhibit B-10, BC Hydro IR 50.0 (a)).

In addition, in Exhibit B-8, TGVI used a BC Hydro assumption for the cost of curtailment and peaking that represents BC Hydro's out-of-pocket costs of fuel switching (Exhibit C7-12). These costs do not include any amount for value of service or cost allocation effects, and do not constitute an offer by BC Hydro. BC Hydro indicated that pricing for ICP curtailment and peaking gas would likely include "an appropriate value of service charge" (Exhibit C7-4, BCUC IR 2.4; Exhibit C7-12). TGVI also argues that the term sheet in Exhibit C7-14 refers to BC Hydro providing capacity curtailment, but not the corresponding peaking gas supply. (The BC Hydro Argument at page 27 confirms this interpretation.) TGVI goes on to argue that, if the value of service charge for curtailment equalled the value that the curtailment provided, then the financial analysis of the PCC portfolio would be the same as for the P&C portfolio.

In its Argument, BC Hydro took issue with several of TGVI's concerns, questioning the need for a capacity reserve margin and for any change to the system design pressure criteria at Victoria (BC Hydro Argument, pp. 7-11). BC Hydro stated that TGVI does not recognize the intra-day operational flexibility of curtailment and peaking, and noted that it had confirmed that ICP can switch fuels on two hours notice (Exhibit C7-13). BC Hydro also questioned the need for the 5 percent hourly flow restriction. BC Hydro explained that it is exploring options to increase fuel switching at ICP to 240 hours, and that the proposed Duke Point project schedule has sufficient time to permit fuel switching to be included at that facility (BC Hydro Argument, pp. 25-27). BC Hydro submits that the term sheet in Exhibit C7-14 forms the basis for a commercial offer for curtailment and peaking supply (BC Hydro Argument, p. 26).

TGVI replied that, as the terms for curtailment set out in Exhibit C7-14 do not include BC Hydro making its gas supply available to TGVI, there are unlikely to be any gas supply benefits from such an arrangement. Furthermore, the 10 percent discount on its firm transport that BC Hydro would require, would be a cost to TGVI of $1.5 million per year for ICP. The present value for either ICP or DPP would be $14 million at a 6.1 percent discount rate, and $10 million at a 10 percent discount rate, and TGVI argued that this cost should be included in the comparison of the options (T6: 994-995; TGVI Reply Submission, pp. 4-6).

The Commission Panel recognizes that, in the absence of a signed agreement for curtailment and peaking, there is considerable uncertainty about its availability and cost. At the same time, it is evident that curtailment and peaking are available from ICP, and that it could have potentially large benefits for all TGVI ratepayers by reducing the amount of system addition expenditures that are necessary. The evidence of BC Hydro in the hearing indicates that it may expect to receive more than reimbursement of its out-of-pocket costs associated with fuel switching (Exhibit C7-12; Exhibit C7-14). Nevertheless, the Commission Panel concludes that the assumption that TGVI made in Exhibit B-8 about the cost of curtailment and peaking is reasonable for the purposes of the present analysis.

In order to give more weight to facts rather than to possibilities, the Commission Panel takes a relatively conservative view of the availability and benefits of curtailment and peaking, and substantially disregards the options of 240 hours of fuel switching at ICP and of potential fuel switching at a Duke Point Power facility, because there is no firm evidence related to the availability or cost of those options.

With regard to the concern about the use of perfect knowledge for nominating, and the need for a capacity reserve margin for the PCC portfolios, the Commission Panel notes that it principally needs to obtain a fair comparison between the portfolio options. The appropriate transmission system design criteria are a subject for a future proceeding, that is, when TGVI requests approval of a compressor or pipeline looping project. In the meantime, it seems reasonable to expect that TGVI would have applied the same system pressure criteria for the PCC and the P&C portfolios, and also when projecting future resource additions under the LNG portfolio. Moreover, the LNG facility would have limited storage capacity relative to underground storage facilities. In addition, the Commission Panel concluded in sub-section 4.1.2 that 8 TJ/d is a more reasonable forecast of the VIGJV demand commencing in 2011, and this change would offset in part the need to advance TGVI system additions to provide a capacity reserve margin. **In these circumstances, the Commission does not accept that a capacity reserve margin adjustment would be appropriate for the PCC options.**

9.3 LNG Storage Option

The LNG storage option requires the LNG facility and a new compressor station at V2 in 2007. This option would also require additional compression, starting in 2011. The forecast additions after 2007 for all portfolios depend on core load growth. If a CPCN is approved for the LNG facility, TGVI will also need to apply for a CPCN for the V2 compressor station.

TGVI states that the LNG Storage facility provides transmission system capacity benefits, peaking gas supply benefits and reduced wheeling fees for TGVI to move gas across the Terasen Gas system discussed below. TGVI also identified a number of other benefits of LNG storage on Vancouver Island (Exhibit B-2, pp. 34-7; Exhibit B-3, BCUC IR 32.1).

9.3.1 Security of Supply

An on-Island supply of gas will mitigate upstream pipe or compression outages, avoiding curtailment of customers and reducing the potential need to relight customers. It will also provide more flexibility in taking the pipeline and compressors out of service for maintenance (Exhibit B-3, BCUC IR 32.1). When the LNG plant is in operation, it increases transmission pipeline pressures and makes the system more robust and better able to withstand system upsets (Exhibit B-26, p. 15; T6: 934-935).

The Commission Panel recognizes that improvements to security of supply would be a significant benefit of an LNG facility, within the limit of the amount of LNG in the storage tank.

9.3.2 Reduced Rate Volatility

In its Argument, TGVI quotes a National Energy Board study that says “The main physical tool for dealing with gas price volatility which reflects short-term changes in gas demand, is storage” (TGVI

Argument, p. 30). The Lower Mainland area has very little storage compared to the U.S. Pacific Northwest (Exhibit B-1, Appendix D; Exhibit B-6, MEM IR 1.23.3).

The Commission accepts that, at least directionally, additional LNG storage capacity should reduce gas price volatility.

9.3.3 Reduced Terasen Gas Coastal Transmission System Capacity

The LNG facility would reduce the amount of Terasen Gas capacity needed to wheel gas across the Terasen Gas system from Huntingdon to Coquitlam. To the extent Terasen Gas contracts for surplus LNG capacity, such gas would be delivered to Terasen Gas by displacement at Huntingdon and this would further reduce the load on the Terasen Gas Coastal Transmission System (Exhibit B-3, BCUC IR 32.1).

The Commission recognizes this positive impact on the Terasen Gas transmission system, and considers that the effect on TGVI will be the financial impact that is discussed in the next Chapter.

9.3.4 Balancing

The LNG facility would not be constrained by pipeline re-nomination schedules or TGVI's contracted curtailment arrangements. This would permit TGVI to respond quickly and accurately to variations in demand as they occur (Exhibit B-2, p. 36). Also, nominations for capacity curtailment cannot as easily be recalled or changed and the associated cost may be sunk (Exhibit B-8, BCUC IR 48.2, pp. 7, 8). In its Argument, TGVI states that LNG storage would have superior load-following capability and would be a more automated process compared to capacity curtailment, resulting in more efficient use of available volumes compared to capacity curtailment arrangements (TGVI Argument, p. 30).

While LNG storage would be useful for balancing, particularly when the facility is in the mode of vapourizing LNG, TGVI has other balancing options. Capacity curtailment arrangements appear to be less flexible for balancing, but nevertheless useful, particularly if TGVI was able to negotiate more flexible contract terms. Also, TGVI uses line pack, and Aitken Creek and Mist storage to balance supply and demand (Exhibit B-3, BCUC IR 32.2). The Commission Panel considers that LNG storage would be a useful addition to the balancing resources available to TGVI, but the limited amount of LNG in storage will be a constraint.

9.3.5 Risk of Stranded Assets

TGVI intends to use surplus LNG capacity to provide LNG storage service to Terasen Gas and others. As there is expected to be a ready market for all LNG capacity that TGVI does not need, this reduces the risk of stranded assets if expected demand growth on the system does not materialize. Once pipeline or compression capacity has been constructed, TGVI has no means to mitigate the cost of such capacity if it proves to be in excess of requirements (Exhibit B-3, BCUC IR 20.3, 43.2; T5: 682, 685).

The Commission Panel notes that, while TGVI should be able to obtain mitigation revenue from unused LNG capacity, the initial block of capacity that is added by an LNG facility is larger than for compression or pipeline looping. Pipe and compression options have more flexibility with respect to adding resources incrementally as the load develops. Moreover, the LNG Mitigation Revenue does not fully offset the cost of the unused capacity (Exhibit B-31). Nevertheless, the Commission Panel considers that, on balance, the ability to mitigate costs by leasing unused LNG capacity supports the LNG portfolio.

The Commission Panel concludes that, in addition to the financial costs and benefits discussed in the next Chapter, the LNG portfolio would have several material benefits for TGVI ratepayers, compared to portfolios that include only compression, pipeline looping and curtailment.

10.0 FINANCIAL COMPARISON OF PORTFOLIO OPTIONS IN CPCN APPLICATION

In section 6 of the CPCN Application, TGVI states that it compared the incremental costs and benefits of the portfolio options over 20 years commencing in 2007 on a present value basis using discount rates of 6.1 percent and 10.0 percent (Exhibit B-2, pp. 22-34). Exhibit B-8 updated this comparison in tables summarizing the incremental costs and benefits for the P&C, PCC (53-hours), PCC (240-hours) and

LNG portfolios at both discount rates (Exhibit B-8, BCUC IR 48.3, p. 42, Exhibit B-16, p. 4). These tables indicate that the present values are for the period 2005 through 2027. In its Argument, TGVI maintains that a shorter planning period would lead to a suboptimal solution (TGVI Argument, p. 22).

For each portfolio option, TGVI provided the present value of the cost of service of incremental TGVI facilities, incremental transport fuel cost, gas supply benefit, LNG storage and peaking gas mitigation revenue, and incremental wheeling costs. The BC Hydro CFT has resulted in an EPA for a generation facility that would increase demand by 44.6 TJ/d if the EPA is accepted and the facility is built, and so the next section will evaluate the present value of these items for the Revised Base +45 forecast.

10.1 Financial Comparison for the Revised Base +45 Forecast

10.1.1 Incremental Facility Costs

For each of the four portfolio options, TGVI provided an expanded Cost of Service for Incremental TGVI Facilities summary for 2005 through 2027, and Present Value Incremental Costs for 2005 to 2027 using discount rates of 6.1 and 10.0 percent (Exhibit B-8, BCUC IR 48.2, Attachment 4, pp. 17-20). The expanded Cost of Service Summaries are based on the parameters in Appendix 6 of the CPCN Application, along with the revisions that were discussed in Chapter 8. Costs associated with capacity curtailment arrangements are excluded from incremental facility costs, as they are included in the cost of peaking gas resources in gas supply costs (Exhibit B-8, BCUC IR 48.2, pp. 7-8; 17-20). The summaries also show incremental capital additions and accumulated depreciation.

The Commission Panel accepts the incremental facility costs as presented.

10.1.2 Transport Fuel Differential

The Transport Fuel Differential measures the difference relative to the P&C portfolio of the cost of system fuel gas that would be provided in-kind by transportation customers. (The cost of system fuel for sales (core) customers is included in gas supply costs.) The system fuel percentages for each portfolio are shown on Figure BCUC IR 48.2c in Exhibit B-8. The P&C portfolio results in the largest amount of pipeline capacity being added to the system, which reduces system fuel requirements.

The Commission Panel accepts the Transport Fuel Differentials as presented.

10.1.3 Gas Supply Differential

The Gas Supply Differential measures the gas supply cost for TGVI's sales (core) customers for each portfolio option, relative to the cost for the P&C portfolio. Gas supply costs were determined using the Sendout linear programming application, and include the cost of system fuel gas used by core customers.

TGVI provided a description of the Sendout model and how it works (Exhibit B-3, BCUC IR 39.1). The Utility refused to provide information about inputs to the Sendout program, typical input and output screens or detailed output cost information, on the basis that the information is proprietary and commercially sensitive. Total fixed and variable costs for each year were provided (Exhibit B-3, BCUC IR 39.2, 39.3, 39.4). TGVI also provided an annual breakdown by supply resource category for the LNG and PCC portfolios (Exhibit B-10, BCUC IR 69.6). This analysis indicates the following Gas Cost Differentials, based on the gas prices, cost of peaking supply and other assumptions in the CPCN Application.

Table 10.1
TGVI Core Market Gas Supply Differentials
(Present Value in Millions of Dollars)

Discount Rate	P&C	PCC	LNG
6.1 percent	0	34.4	57.2
10.0 percent	0	22.1	37.5

The Gas Supply Differentials for the PCC and LNG portfolios measure the dollar benefit of on-system peaking gas from curtailment or LNG storage. Most of the savings result from avoiding the fixed costs of other peaking and storage resources.

In Exhibit B-8, TGVI provided an updated Summary of Core Market Gas Supply Costs (Exhibit B-8, BCUC IR 48.2, Attachment 5, p. 23). This information indicates the following Gas Supply Differentials:

Table 10.2
Updated TGVI Core Market Gas Supply Differentials
(Present Value in Millions of Dollars)

Discount Rate	P&C	PCC 53-hours)	PCC (240-hours)	LNG
6.1 percent	0	16	14	57
10.0 percent	0	8	7	36

The updated forecast of gas supply costs does not materially change the Gas Supply Differential for the LNG portfolio of, for example, $37.5 million present value at a 10.0 percent discount rate. However, the Gas Supply Differential for the PCC portfolio at a 10.0 percent discount rate was reduced from $22 million to $7 - $8 million. TGVI provided no discussion about the change in forecast gas supply costs.

The revised differentials for the PCC portfolio reflect the price for curtailment and peaking gas that TGVI assumed, on the basis that BC Hydro stated these costs would be representative of its out-of-pocket expenses for fuel switching (Exhibit C7-12, Supplemental Response to IR 1.2.4). TGVI attributed the very slightly lower differential for the 240-hour portfolio to the much larger use of peaking by the core in that scenario (TGVI Argument, p. 24).

BC Hydro in its Argument identifies several concerns about the Sendout model results, and notes that each Gas Supply Differential is calculated as the difference of two large numbers (BC Hydro Argument, pp. 16-17). BC Hydro states that without some way to verify the model's results, it is difficult to conclude that one portfolio is more cost-effective than another. BCOAPO also recognized that it is difficult to quantify Gas Supply Differentials, and submitted that TGVI should report on gas supply benefits at its Annual Reviews. TGVI replied that the Gas Supply Differentials are primarily due to differences in fixed costs, where a 1 percent variance in the results of the Sendout model would have a comparatively small effect (TGVI Reply, p. 9).

The Commission Panel does not consider it necessary in this Decision to direct TGVI to report on gas supply benefits in its Annual Reviews.

The Commission Panel accepts that a linear programming model should be a preferred methodology for determining the optimal gas supply portfolio and for estimating the minimum gas supply cost to meet customer demand for a given set of supply resources. Nevertheless, the input data, assumptions and constraints used in the model can have a material impact on the results. The Commission Panel is concerned that the confidential nature of much of the information has significantly restricted the ability of participants to assess and test the model and the results that it calculates. The revised information for the PCC portfolios is particularly worrisome, as these differentials are significantly different from the earlier results and it is not obvious, for example, that 53-hours and 240-hours of peaking supply should have substantially the same benefit. The change in Gas Supply Differential for the PCC portfolios is quite material to the financial comparison of the portfolios.

At the same time, TGVI pointed out on several occasions that the peaking gas price assumption of BC Hydro was not put forward as a firm offer. Furthermore, references by BC Hydro to a curtailment and peaking gas price that includes a "value for service" component support the view that the gas cost benefit of on-system peaking supply from curtailment, compared to other peaking resources, may be relatively low. Consequently, with some reluctance due to the limited ability to test the data, **the Commission Panel accepts the Gas Supply Differentials calculated by TGVI in Exhibit B-8**.

10.1.4 LNG Mitigation Revenue

LNG Mitigation Revenue is the value of the revenue received by TGVI from Terasen Gas or potentially others, as a result of contracting surplus LNG capacity to them. The amount of surplus LNG capacity will vary from year to year, depending on the needs of TGVI. The present value of this revenue is estimated at $27.6 million at a 6.1 percent discount rate and $18.4 million at a 10.0 percent discount rate (Exhibit B-8, BCUC IR 48.2, Attachment 5, p. 22). The value of excess LNG capacity was assumed by TGVI to be $12.00/GJ for 6 day capacity and $8.25/GJ for 10 day capacity (Exhibit B-1, Appendix C, p. 5; Exhibit B-2, p. 26). These values were based on the avoided cost of Mist storage, but TGVI considered the derivation of the values to be confidential (Exhibit B-3, BCUC IR 18.4; Exhibit B-10, BCUC IR 55.3, 55.4, 55.5, 55.6). TGVI confirmed that the estimate of LNG Mitigation Revenue for the review period is substantially the same as the unadjusted demand charges to Terasen Gas that are shown on Schedule C of the Liquefied Natural Gas Storage and Transportation Agreement that is Exhibit B-13 (T7: 1151-1152).

BCOAPO submitted that TGVI must make best efforts to formulate contract terms in its LNG storage agreement with Terasen Gas that will capture the forecasted LNG revenue (BCOAPO Argument, p. 8). BC Hydro stated that mitigation revenues are essential to making the LNG project economics work, and expressed concern that TGVI had not adequately supported the storage mitigation revenues (BC Hydro Argument, pp. 14-15).

The Commission Panel is concerned about the lack of transparency with regard to the basis for the value assumed for excess LNG capacity and also the quantum of the value that TGVI assumed. For example, the actual cost of Mist storage for April 2003 to March 2004 was $1.60/GJ, or $2.70/GJ assuming cycling did not occur (Exhibit B-10, BCUC IR 55.2). Also, the tariff rate for 10 day capacity is $3.72/GJ for the Plymouth LNG facility and $6.05/GJ for the Pine Needle LNG facility (Exhibit B-31). At the same time, the Commission Panel recognizes that, as TGVI explained, the Plymouth facility was built in 1975, and is more than twice the size of the Mount Hayes LNG facility. The Pine Needle facility was built in 1999 and is four times the size of the proposed Mount Hayes facility.

There is little question that excess LNG capacity will have value, and, on the basis that the indicated value to TGVI will be confirmed by a contract with Terasen Gas, the Commission Panel accepts the estimate of LNG Mitigation Revenue presented by TGVI.

10.1.5 Peaking Mitigation Revenue

Peaking Mitigation Revenue is the value of additional third party revenue from excess LNG capacity that can be released because on-system peaking gas supply is available (Exhibit B-2, p. 32). The cost of peaking supply was based on the assumption provided by BC Hydro as representative of its out-of-pocket cost of fuel switching. The estimated present value amount is $8 million at a 10.0 percent discount rate. In its Reply, TGVI noted that its estimate of Peaking Mitigation Revenue was based on using peaking gas from BC Hydro and concluded that based on the BC Hydro term sheet in Exhibit C7-14, this value should be reduced to zero (TGVI Reply, p. 5).

Due to the uncertainty about the availability and price of on-system peaking, the Commission Panel is not persuaded that Peaking Mitigation Revenue should be included in the financial analysis and determines that no such revenue will be included.

10.1.6 Incremental Wheeling Costs

Incremental Wheeling Costs are the costs to TGVI of additional wheeling (transportation) capacity over the Terasen Gas Coastal Transmission System from Huntingdon to the TGVI system in Coquitlam. TGVI must hold firm wheeling capacity to match the capacity of its transmission pipeline system. TGVI assumed the incremental wheeling capacity would be acquired at the average unit cost of TGVI's existing arrangement with Terasen Gas (Exhibit B-3, BCUC IR 37.1).

The Commission Panel accepts TGVI's estimates of Incremental Wheeling Costs.

10.1.7 Financial Comparison Summary

Table 10.3 summarizes the financial comparison results that TGVI presented in Exhibits B-8 and B-16 for the four portfolio options. To be consistent with the Commission Panel's determination in sub-section 10.1.5, zero Peaking Mitigation Revenue is shown in Table 10.3.

Table 10.3
Financial Comparison – Revised Base +45 Forecast
(Present Value in Millions of Dollars)

6.1 Percent Discount Rate	**P&C**	**PCC (53-hours)**	**PCC (240-hours)**	**LNG**
Incremental Facilities Costs	243	175	144	212
Transport Fuel Differential	0	7	8	14
Gas Supply Differential	0	(16)	(14)	(57)
LNG Mitigation Revenue	0	0	0	(28)
Peaking Mitigation Revenue	0	0	0	0
Incremental Wheeling Costs	31	21	17	11
	274	188	156	153

10.0 Percent Discount Rate	**P&C**	**PCC (53-hours)**	**PCC (240-hours)**	**LNG**
Incremental Facilities Costs	157	110	92	141
Transport Fuel Differential	0	5	5	9
Gas Supply Differential	0	(9)	(8)	(36)
LNG Mitigation Revenue	0	0	0	(18)
Peaking Mitigation Revenue	0	0	0	0
Incremental Wheeling Costs	20	14	11	7
	177	120	100	103

Net Plant in Service in 2027 (millions of nominal dollars)	185	176	182	85

Based on its financial comparison of the resource portfolios for the Revised Base +45 forecast, TGVI concluded that the LNG portfolio is the least cost solution. The Utility noted that the P&C portfolio is the most costly, and has the highest stranded asset risk. TGVI stated that the assumptions for the PCC portfolios depend on the ability of BC Hydro to provide curtailment and peaking, and on the price it would charge TGVI. In particular, the PCC (240-hour) scenario would require additional distillate facilities and may cause TGVI additional operational difficulties (TGVI Argument, p. 27).

In its Argument, BC Hydro provided a comparison of the cost to store peak-shaving energy as natural gas in LNG storage or distillate oil in tanks. BC Hydro estimated that the annual cost to store 900 TJ would be $17.5 million for LNG and $9.1 million for distillate, but acknowledged that the analysis is not complete (BC Hydro Argument, p. 2).

In its Argument, BC Hydro identified several concerns that it had with TGVI's financial analysis (BC Hydro Argument, pp. 11-14). BC Hydro noted that the cumulative capital commitment to 2007 for the LNG portfolio of $138 million is higher than the $99 million for the PCC (240 hours) portfolio. BC Hydro noted that the LNG portfolio is more dependent on mitigation revenue and Gas Supply Differential, and argued that these numbers are less certain than the cost of service for incremental facilities. Also, BC Hydro identified two scenarios with 240 hours of curtailment at both ICP and Duke Point that have lower present value costs than the LNG portfolio. These scenarios are both based on 240 hour curtailment assumptions that the Commission Panel has concluded are unlikely.

Table 10.1 illustrates the significance of the assumptions related to the availability and price of capacity curtailment and peaking supply. The LNG portfolio is projected to be cheaper than the PCC (53-hours) portfolio but approximately equal in cost to the PCC (240-hours) portfolio. The same result is arrived at using either the 6.1 percent or the 10.0 percent discount rate. However, recognizing the uncertainties related to capacity curtailment and peaking at this time, the Commission Panel believes that it is appropriate to take a conservative approach and to give more weight to the PCC (53-hour) portfolio results. This conclusion is reinforced by statements by BC Hydro that it may expect to receive more than reimbursement of its out-of-pocket costs associated with fuel switching (Exhibit C7-12). With regard to concerns that were raised about the larger initial capital investment for the LNG facility, the Commission Panel notes that this option also has a much lower Net Book Value in 2027 than the P&C or PCC options.

The Commission Panel concludes that the financial analysis favours the LNG option compared to the P&C or likely PCC options.

10.2 Impact of Lower Demand Forecasts

10.2.1 Lower Core Demand

In response to concerns raised by BCOAPO about future core demand, TGVI provided further analysis of the portfolios based on a lower demand projection (Exhibit B-15, pp. 5-6; Exhibit B-29). This scenario used lower core market customer growth assumptions of 2.4 percent in the Transition Phase and 1.0 percent in the Maturity Phase (Exhibit B-10, BCUC IR 76.2, T2: 192).

Table 10.4 is a summary of this scenario using a 10.0 percent discount rate and including the adjustment for zero Peaking Mitigation Revenue.

Table 10.4
Financial Comparison – Lower Core Demand
(Present Value in Millions of Dollars)

10.0 Percent Discount Rate	**PCC (53-hours)**	**PCC (240-hours)**	**LNG**
Incremental Facilities Costs	88	81	127
Transport Fuel Differential	2	3	8
Gas Supply Differential	(6)	(6)	(36)
LNG Mitigation Revenue	0	0	(18)
Peaking Mitigation Revenue	0	0	0
Incremental Wheeling Costs	10	6	2
	94	84	83

In Exhibit B-29, TGVI concluded the LNG portfolio continues to be the preferred portfolio in a low core demand scenario.

The Commission Panel notes that, with the adjustment to Peaking Mitigation Revenue, the LNG portfolio financial result continues to be approximately equal to that for the PCC (240-hour) scenario, and less costly than the result for the more likely PCC (53-hour) scenario.

10.2.2 Breakeven Analysis

In order to test the minimum additional transportation demand that is needed to justify the LNG facility, TGVI provided Exhibit B-20, which is a preliminary evaluation of a Revised Base +25 forecast scenario. This represents approximately 150 Megawatts of additional gas fired generation (Exhibit B-20, p. 4).

With the adjustment to zero Peaking Mitigation Revenue, Table 10.5 is a summary of this analysis, using a 6.1 percent discount rate.

Table 10.5
Financial Comparison – Revised Base +25 Forecast
(Present Value in Millions of Dollars)

6.1 Percent Discount Rate	**P&C**	**PCC 53-hours)**	**PCC (240-hours)**	**LNG**
Incremental Facilities Costs	188	125	96	175
Transport Fuel Differential	0	4	4	10
Gas Supply Differential	0	(16)	(14)	(57)
LNG Mitigation Revenue	0	0	0	(28)
Peaking Mitigation Revenue	0	0	0	0
Incremental Wheeling Costs	25	16	11	7
	213	129	97	108
10.0 Percent Discount Rate	133	82	60	73

TGVI argues that the analysis shows the LNG portfolio is preferred if the BC Hydro Call for Tenders results in additional gas demand that is greater than 25 TJ/d. With the Commission Panel's adjustment, the analysis indicates that the LNG portfolio is less expensive than the PCC (53-hours) portfolio, but somewhat more expensive than the PCC (240-hours) portfolio.

The Commission Panel notes that this is a preliminary analysis. As the results for the LNG portfolio are approximately half way between the two PCC scenarios, **the Commission Panel concludes that additional analysis would be needed to confirm the financial ranking of the portfolio options if the result of the BC Hydro CFT is substantially less than 45 TJ/d of additional demand.**

10.3 Alternative Sequence of Resource Additions

10.3.1 Delay LNG Facility by Several Years

In response to questions from participants, TGVI evaluated several options to use compression, curtailment and pipeline looping to meet the demand for 2007, with an LNG facility to be added in 2011 or later (Exhibit B-3, BCUC IR 36.4, 36.6; Exhibit B-10, BC Hydro IR 54.0(a), 54.0(b), 54.0(c)). TGVI provided updated information for the Revised Base +45 forecast and the BC Hydro IR 54.0(a) scenario using a discount rate of 10.0 percent. TGVI also provided updated information for the BC Hydro IR 54.0(c) scenario which assumed that 240-hours of curtailment and peaking is available at each of the

ICP and the proposed Duke Point Power project. This information is summarized in Table 10.6, including zero Peaking Mitigation Revenue.

Table 10.6
Financial Comparison – Delayed LNG Project
(Present Value in Millions of Dollars)

10.0 Percent Discount Rate	**LNG (Ex. B-16, p.4)**	**Delay LNG (ICP 53-hours) (Ex. B-16, p. 9)**	**Delay LNG (ICP 240-hours) (Ex. B-16, p. 5)**	**Delay LNG (ICP/Duke 240) Ex. B-15, p. 14)**
Incremental Facilities Costs	141	142	107	96
Transport Fuel Differential	9	8	7	8
Gas Supply Differential	(36)	(26)	(18)	(8)
LNG Mitigation Revenue	(18)	(16)	(5)	(10)
Peaking Mitigation Revenue	0	0	0	0
Incremental Wheeling Costs	7	9	9	8
	103	117	100	94
LNG Facility In-Service	2007	2011	2018	2015

TGVI noted that delaying the LNG facility requires the construction of compressor station V5 (Dunsmuir), which becomes redundant with the addition of LNG storage (Exhibit B-3, BCUC IR 36.6, Exhibit B-10, IR 54.0(a)).

TGVI stated in its Argument that scenarios involving curtailment at Duke Point Power are entirely hypothetical due to the uncertainties respecting availability, cost and operational reliability, and that such a portfolio is not a credible choice as a resource option. In its Argument, TGVI also noted the step change in demand in 2007, and stated that the more gradual nature of investment requirements after that would make it more difficult to justify the level of investment that would be required to add an LNG facility after 2007 (TGVI Argument, pp. 28, 42).

The Commission Panel considers that any cost savings from delaying the LNG project are likely to be small over the long term, and are likely to be overshadowed by the other benefits of the LNG facility that are discussed in Chapter 9. The Commission Panel accepts TGVI's arguments that a scenario that assumes fuel switching will be available at the proposed Duke Point Power plant for 2007 is too speculative to be used for planning purposes.

10.3.2 Delay LNG Facility to 2008

As discussed previously, it will become increasingly difficult and potentially more expensive to complete the LNG facility for winter 2007/08 if final approval is delayed significantly beyond the end of February 2005. On the other hand, the compression associated with the PCC options could accommodate a somewhat later final approval date, while maintaining a November 2007 in-service date. TGVI stated that development work on compression additions would need to start no later than April 2005, given uncertainties related to environmental and land acquisition issues, particularly regarding a site for the V5 Dunsmuir compressor. The cost of such development work was estimated at $120,000 per month for April through June, 2005 (Exhibit B-3, BCUC IR 31.6, Exhibit B-10, BCUC IR 62.3, 62.4).

Comparing the Incremental Facility Requirements for the LNG and PCC options, both require compressor stations V2 and V4 by 2007. For 2007 the PCC options also require the fourth unit at Coquitlam (V1U4, which LNG does not need until 2001), Secret Cove station (V3b, which LNG does not need until 2013) and the Dunsmuir station (V5, which LNG does not need in the study period).

TGVI provided the information in Table 10.7 about the maximum amount of firm transportation capacity that could be provided to the proposed Duke Point Power plant in winter 2007/08 without the Dunsmuir compressor (Exhibit B-15, p. 43). The analysis assumes that the V4 Texada compressor is part of the TGVI system.

Table 10.7
2007/08 Firm Transportation Capacity for Duke Point Power
(TJ/d)

Compressors added to Existing System	PCC (53-hours)	PCC (240-hours)
V1U4 + V2 + V3b	40	40
V1U4 + V2	26	37
V2	22	36

In its Reply, TGVI requested that the Commission Panel make it clear that it expects the resource portfolio with the lowest long-term costs to be constructed to meet the requirements for natural gas on Vancouver Island and the Sunshine Coast. TGVI submitted the Commission Panel should indicate that it does not expect BC Hydro to delay a contractual commitment so that the timetable to meet the needs of the proposed new gas-fired generation on Vancouver Island can only be achieved through construction of sub-optimal facilities. TGVI stated that such a delay would not change its position that LNG storage is the least cost solution, but may impact TGVI's ability to provide firm service to BC Hydro during the winter of 2007/08 (TGVI Reply, p. 3).

The uncertainty about the availability and cost of curtailment and peaking has been discussed previously. Table 10.5 indicates that compressors V1U4, V2 and V3b would be needed to provide 40 TJ/d of firm transportation capacity for Duke Point Power under the PCC (53-hour) scenario. There would be a cost to advance the timing of the V1U4 and V3b compressors. At the same time, it may be possible for TGVI, BC Hydro and Terasen Gas to work together to provide a sufficiently high delivery pressure at Coquitlam that compressor unit V1U4 would not be needed for 2007/08 (Exhibit B-6, VIGJV IR 5.6, Exhibit B-10, BC Hydro IR 54.0(b), 61.0(c)).

This information indicates that for winter 2007/08 TGVI could come reasonably close to meeting the full needs of Duke Point Power without the LNG facility or the V5 Dunsmuir compressor. At the same time, the Commission Panel is convinced that the LNG option is the preferred resource addition in the event the proposed Duke Point Power plant is built, and would consider a compression alternative to be a short term contingency measure. **In the event that the LNG facility is delayed to 2008 and TGVI needs to bring a bridging proposal to the Commission, the Commission Panel expects TGVI to include a full suite of completed contracts, including agreements for transportation service, curtailment and peaking, delivery of gas to Coquitlam and recovery of incremental costs caused by the delay of commitments that support the LNG project.**

11.0 RATE IMPACTS AND RDDA RECOVERY

Section 7 of the CPCN Application provides estimates of the expected rate impacts of the LNG project based on the current approved rate design principles for TGVI (Exhibit B-2, pp. 38-42). TGVI presented this information as illustrative, since it recommends that the allocation of costs and the design of rates to recover the cost of the LNG facility should be the subject of a future revenue requirements or rate design proceeding (Exhibit B-6, MEM IR 28.2). Exhibit B-8 provided updated system costs and indicative cost allocation information for each of the four portfolio options for the Revised Base +45 forecast, and Exhibit B-11 revised some of this information.

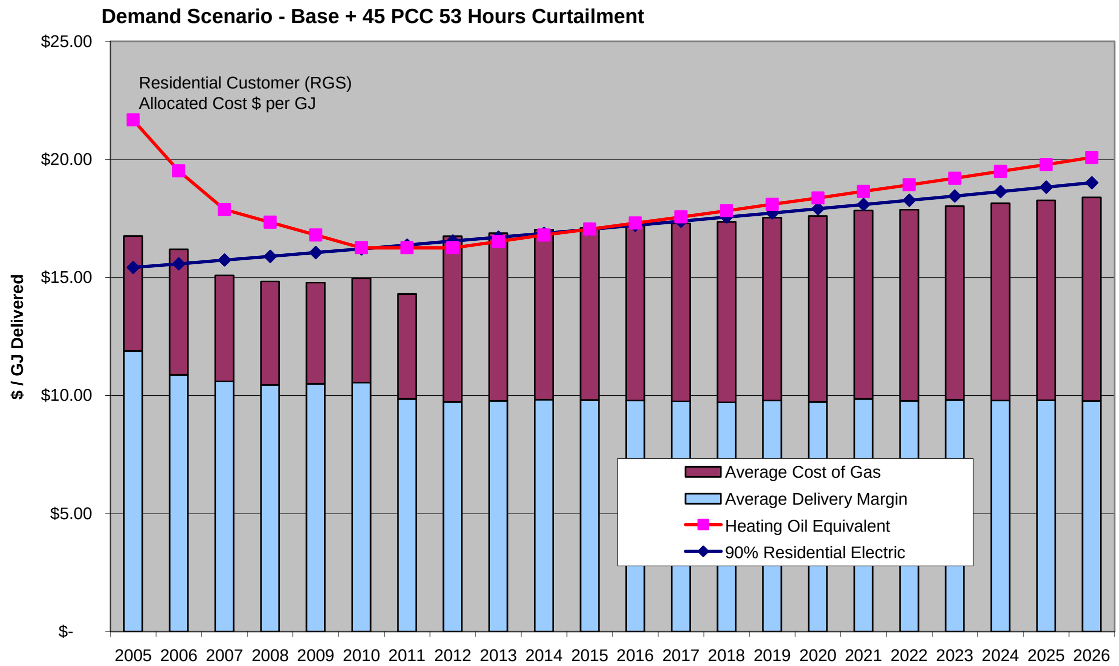
11.1 Rate Impacts

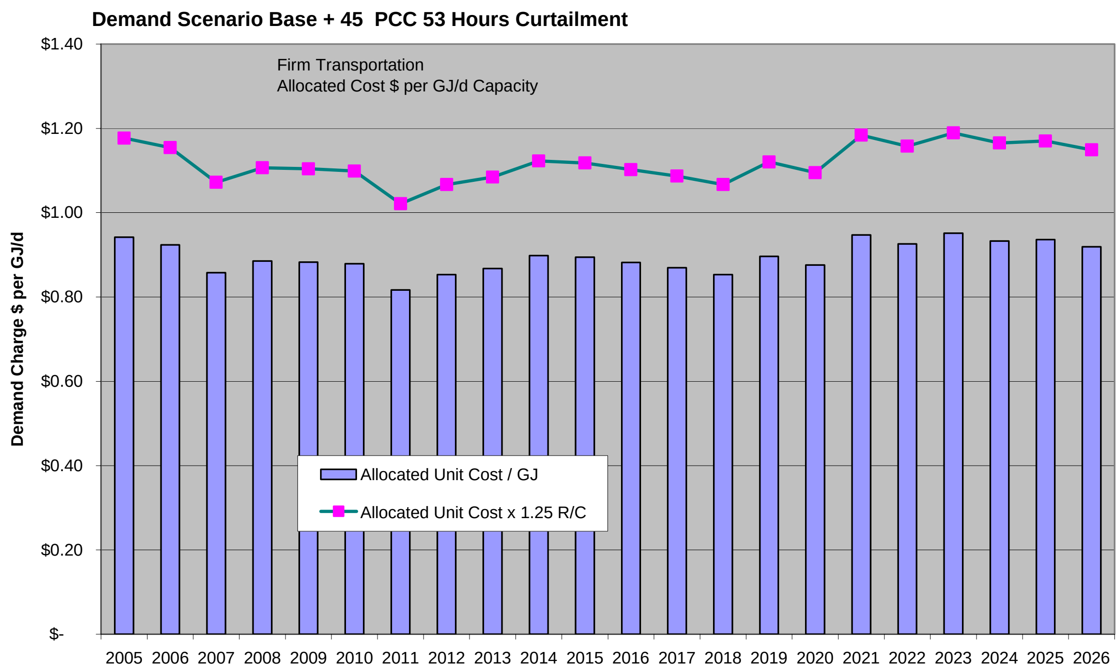
The CPCN Application described TGVI's system cost allocation assumptions (Exhibit B-2, pp. 38-39; Exhibit B-3, BCUC IR 41.1, 41.4, 41.6, 41.7). The cost of service of the LNG facility and net third party mitigation revenue associated with the LNG facility were allocated on a system-wide basis. The toll for firm transportation service assumed the current revenue to cost ratio of 1.25.

Exhibit B-8 provided figures and summary schedules showing expected allocated unit costs and rates for residential and firm transportation customers, for each of the four portfolio options. For the LNG facility, information was provided for one case where the LNG facility costs and third party mitigation revenue are allocated system-wide in the same manners as transmission asset costs, and a second case where LNG facility costs and mitigation revenue are allocated only to core distribution system ("CDS") customers.

The rate impact figures for the PCC (53-hours) option and the LNG portfolio option (with system-wide allocation) are attached as Figure 11.1 and 11.2 respectively. For residential customers, the rate impacts are remarkably similar. Expected gas rates are well below the forecast competing cost of oil and electricity from 2007 to 2011, are marginally competitive from 2012 to 2015 and then become more competitive. The change from 2011 to 2012 results from the expiry of the Royalty Credits from the Province at the end of 2011, which causes the net cost of gas to increase significantly (Exhibit B-10, MEM IR 2.9.2). During the 2012 to 2015 period, LNG is slightly less competitive than the PCC (53-hours) option (e.g. the expected 2012 rate with the LNG option is $16.81/GJ, while the expected rate with the PCC option is $16.75/GJ).

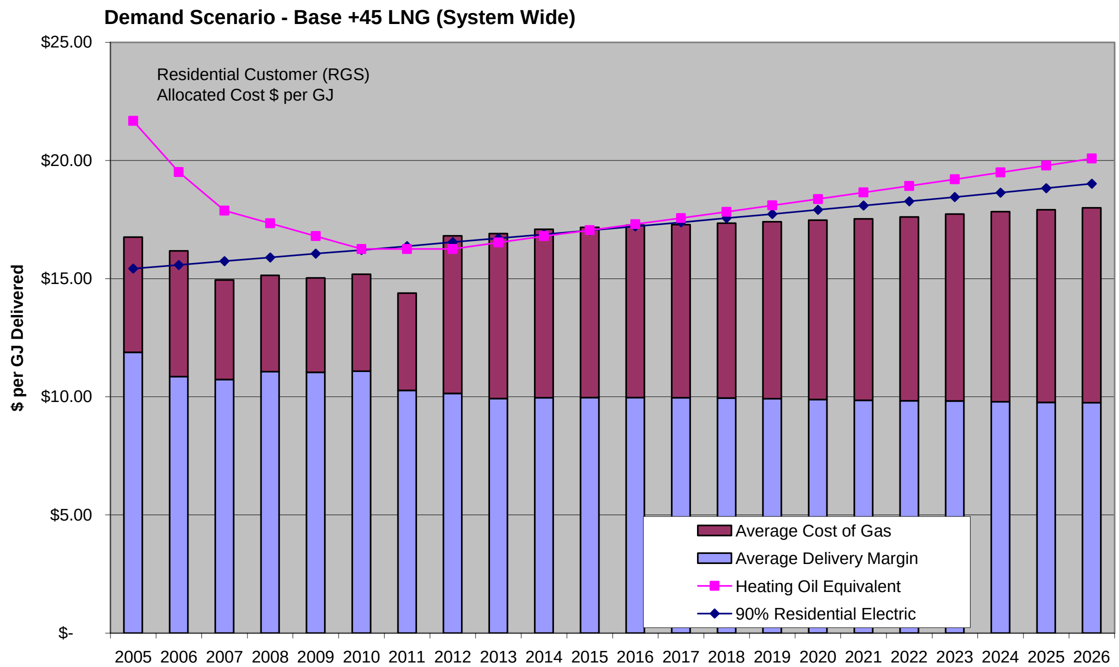
Figure 11.1
Allocated Unit Cost of Service
Revised Base +45 Forecast – PCC (53-hours) Portfolio

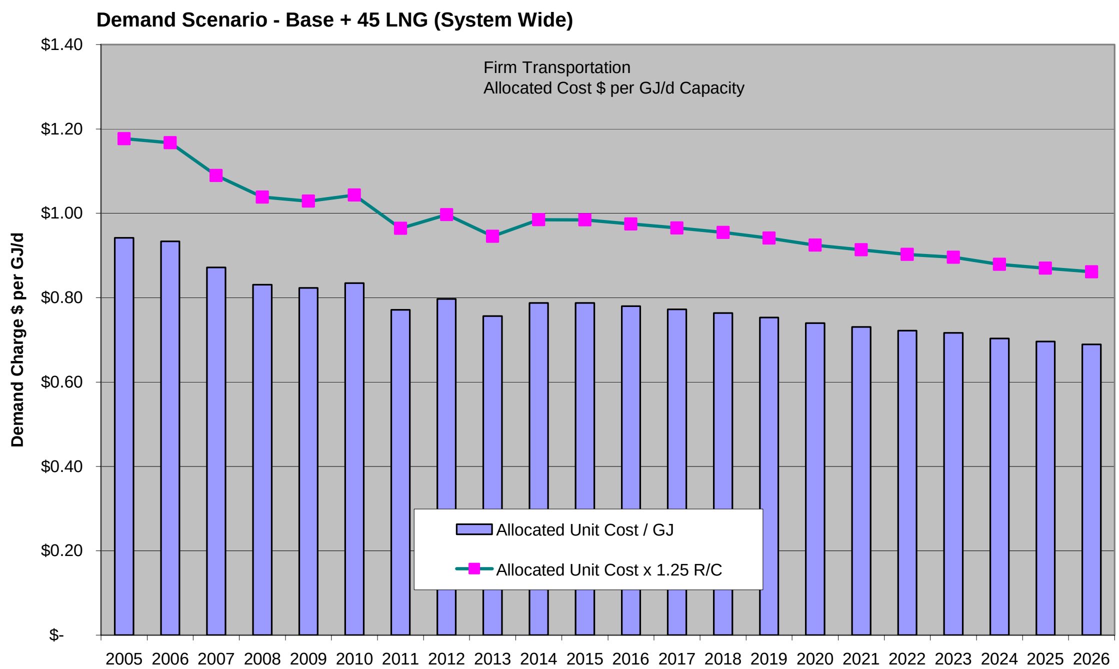




Source: Exhibit B-11, Revised Response to BCUC IR 48.2, p. 35

Figure 11.2
Allocated Unit Cost of Service
Revised Base +45 Forecast – LNG Portfolio





Source: Exhibit B-11, Revised Response to BCUC IR 48.2, p. 26

Firm transportation rates with the LNG option are expected to be generally similar to those under the PCC (53-hours) options through 2011. After 2011, transportation rates are expected to generally decline under the LNG option and to generally increase under the PCC (53-hours) option.

The PCC (240-hours) option is shown to result in slightly lower rates than the PCC (53-hours) option. The P&C option gives higher rates, particularly during 2012 to 2020.

Exhibit B-8 shows that the impact on residential rates is quite similar whether the cost of the LNG facility is allocated system-wide or only to core customers. Firm transportation rates are similar through 2011 under both cases, but after 2011 transportation rates are shown to be higher if LNG costs and mitigation revenues are allocated only to core customers.

In its Argument, MEM recognized the complexities associated with cost allocation and rate design, and the importance of least delivered cost when assessing the CPCN Application. Nevertheless, MEM stated that TGVI rates have little room to absorb commodity price fluctuations, and submitted that the system expansion should be evaluated in the context of marginal costs, average costs and incremental revenue. MEM expressed concern regarding the lack of evidence that TGVI provided related to the cost allocation and rate design attributes of the LNG facility (MEM Argument, pp. 36-8).

TGVI responded that it agreed the Commission Panel should consider rate impacts, and submitted that since the LNG option will result in the lowest costs it will have the lowest long-term revenue requirements and therefore the lowest overall rates to TGVI customers. TGVI noted that the concerns raised by MEM will be present if any significant LNG storage, compression or pipeline looping are constructed (TGVI Reply, p. 2).

The Commission Panel recognizes that the financial situation of TGVI is likely to continue to be somewhat delicate. Nevertheless, no evidence has been presented which indicates that the financial future of TGVI or other ratepayers will be harmed by providing firm transportation service to the proposed Duke Point Power facility (assuming a firm service contract with BC Hydro is in place). Moreover, any assessment of future TGVI rates and their competitiveness depends heavily on the assumptions that are made about gas prices and the prices of competing fuels. As between the system expansion options for providing service to Duke Point Power, the information indicates that residential rates are expected to be similar under the two scenarios and transportation rates would be lower with the LNG facility. Given that expected result, the determination of the impacts of the cost of an LNG facility on individual rate classes can be addressed in a future proceeding.

11.2 Recovery of RDDA Balance

The cost allocation that was used to estimate rate impacts includes the amortized recovery of the current balance of the Revenue Deficiency Deferral Account ("RDDA"), consistent with the approved rate design methodology. The VIGJV and Terasen Squamish do not contribute to the repayment of the RDDA. The end-of-2004 RDDA balance is projected at $60.0 million (Exhibit B-10, BCUC IR 85.1). In all scenarios, TGVI forecasts that the RDDA will be fully recovered by the end of 2011 (Exhibit B-2, p. 38; Exhibit B-10, BCUC IR 86.0).

In its Argument, the MEM expressed concern that rate design issues related to the LNG facility remain unresolved, and argued that the impact of the LNG facility on the recovery of the RDDA balance cannot be determined based on the evidence in this proceeding alone (MEM Argument, p. 46).

The Commission Panel concludes that the allocated unit cost figures for the LNG and PCC options, particularly the expected competitiveness of rates through 2011, supports TGVI's contention that the RDDA balance will be fully paid back within that time period, under the assumption that firm transportation service is provided to BC Hydro for ICP and the proposed Duke Point Power facility.

12.0 CONTRACTUAL ARRANGEMENTS

12.1 BC Hydro Transportation Service Agreement

On several occasions during the hearing and at page 38 of its Argument, TGVI maintained its position that it will not proceed with major capital additions to its system (either LNG storage or compression and pipeline looping) to serve gas-fired generation on Vancouver Island without a long-term contractual commitment from BC Hydro.

TGVI has not completed a long-term firm TSA with BC Hydro for ICP and the proposed Duke Point Power plant. TGVI filed a pro forma firm TSA, and a Summary of Principal Terms as proposed by TGVI for service to BC Hydro (Exhibit B-10, BCUC IR 65.2; Exhibit B-25). BC Hydro filed Exhibit C7-14, which includes a Summary of Key Transportation Principles for a TSA that would meet BC Hydro's needs. Exhibit C7-14 also includes a Summary of Key Tolling and Cost Allocation Principles that BC Hydro states would need to be in place before it would execute a TSA with TGVI. Counsel for BC Hydro advised the Commission that BC Hydro would not sign a long-term transportation service agreement without some certainty on Key Tolling Principles (T4: 557).

On page 38 of its Argument, TGVI expressed surprise at BC Hydro's position, since in its CFT evaluation process BC Hydro used information from TGVI that assumed construction of the proposed LNG facility and the current TGVI rate design methodology.

In its Argument, BC Hydro's position is that, after the RDDA balance is recovered, BC Hydro ratepayers should not have to pay for amounts that result from TGVI rates that do not recover its cost of service (BC Hydro Argument, pp. 3-4). BC Hydro acknowledged that both it and TGVI are adamant in their positions, and the divergent views on tolling principles may need to be resolved in a separate proceeding.

The Commission Panel is not prepared to approve a CPCN for the proposed LNG facility without an executed TSA that provides assurance of the customer demand and revenue that are needed to justify the expansion of the TGVI system. The same is expected to apply to an application for a CPCN for the addition of compression or pipeline loops to expand the system and is intended to ensure that other customers are not put at risk for the cost of the new facilities, in the event that the additional revenue from BC Hydro is not realized. Consequently, if the EPA from the CFT process is accepted and BC Hydro wishes to be assured of firm transportation service for 2007, the timely execution of a satisfactory TSA is critical.

At the same time the Commission Panel understands that it would be imprudent for BC Hydro to execute a TSA for service to the proposed Duke Point Power plant without Commission acceptance of the EPA with Duke Point Power. As TGVI will be required to obtain approval of the BC Hydro TSA as a rate schedule, and timing may become a constraint, the Commission Panel believes it is appropriate to outline what it believes are likely to be the key terms of a satisfactory TSA with BC Hydro for service to ICP and the proposed Duke Point Power facility, as follows:

- a form of TSA that is generally consistent with Exhibit B-25 and TGVI's General Terms and Conditions for Gas Transportation Service;

- a Contract Demand for the ICP of approximately 45 TJ/d and for Duke Point Power of approximately 44.6 TJ/d, with the combined total Contract Demand to be not less than 85 TJ/d;

- a contract term that commences by approximately November 2007;

- an ICP Initial Term that expires on April 12, 2022 and a Duke Point Power Initial Term that expires on the 25th Anniversary of the Duke Point Power Service Commencement Date;

- tolls for firm and interruptible transportation service that are approved by the Commission from time-to-time;

- charges for firm service that are based on approved firm service tolls and are billed on a demand charge (take-or-pay) basis;

- exit fees for early termination that appropriately allocate the then-undepreciated net book value of incremental expansion facilities on the transmission system. As the amount of such fees may be significant and both TGVI and BC Hydro are public utilities under the Act, it may be appropriate to provide for Commission approval of the exit fee in the event of early termination; and

- in the TSA or a separate agreement, an arrangement that provides for the incremental wheeling capacity required by TGVI at a price that is consistent with the average unit cost under TGVI's Wheeling Agreement with Terasen Gas.

Contractual arrangements related to capacity curtailment and peaking supply will be discussed in the next section. Also, while the Commission Panel is supportive of the intent of the Coordination Agreement that is described in Section 15.3 of the Summary of the Principal Terms in Exhibit B-25, it will not require the completion of such an agreement in the context of the CPCN Application.

The Commission Panel is largely prepared to accept the terms and conditions for firm transportation service that TGVI sets out in Exhibit B-25, subject to further clarification of the proposed exit fee. A review of Exhibit C7-14 indicates that BC Hydro's view may differ from TGVI's with respect to exit fees and the terms for capacity curtailment and peaking supply. However, the major difference between the positions of the parties is with respect to firm service tolls, which BC Hydro believes should be established according to the Summary of Key Tolling and Cost Allocation Principles in Exhibit C7-14.

The Commission Panel accepted the view of TGVI and others early in the proceeding that it would not be appropriate or feasible to consider rate design matters in this proceeding. Moreover, the Commission is unlikely to approve a TSA that could have the effect of constraining its jurisdiction to set fair, just and reasonable rates based on the evidence and argument in a future proceeding. Where the Commission has in the past approved a service agreement that provided long-term rate certainty for a customer, it has done so in circumstances where the customer had a competitive alternative. The Bypass Transportation Agreement dated November 27, 1998 between BC Hydro and Terasen Gas that is referred to on page 5 of the Summary of Principle Terms in Exhibit B-25 is such an agreement. With respect to tolls under a TSA to serve ICP and Duke Point Power, the Commission considers that BC Hydro will have the opportunity to address its concerns about such tolls in future TGVI rate design and revenue requirements proceedings. This approach is consistent with the views that BC Hydro expressed in its Argument.

In its Argument, TGVI stated that it would be acceptable if the Commission included as a condition of the CPCN a requirement that prior to the commencement of construction there be an executed long term TSA for the ICP and Duke Point Power (TGVI Argument, p. 40). TGVI also acknowledged that the LNG storage project will not proceed in the absence of Commission acceptance of the BC Hydro arrangements with Duke Point Power.

BCOAPO expressed concern that, with the proposed term of the TSA and the 3 percent depreciation rate for the LNG facility, there is risk of under-recovering the capital cost of the facility. The Commission Panel believes that it would be difficult for BC Hydro to commit to a term for firm gas transportation that is longer than the terms of its electricity purchase agreements for ICP and Duke Point Power.

The Commission Panel notes that with approval of a CPCN, significant expenditures are likely to commence following TGVI's acceptance of the EPC bid, although construction may not start for some time. **The Commission Panel concludes that, in order to protect the Utility and other TGVI customers, it will require, as a condition of any CPCN for the LNG facility, an executed TSA that is satisfactory to the Commission. To avoid unduly constraining TGVI, the CPCN condition will refer to the start of construction, but will be on the basis that any stranded costs resulting from proceeding with the LNG project without the approved TSA will not be the responsibility of TGVI core market customers.**

While the LNG project should not proceed in the absence of acceptance of the Duke Point Power electricity purchase agreement, the Commission Panel expects that any approval of the BC Hydro TSA will be conditional on the Duke Point Power project going ahead, and so does not believe that it is necessary to specifically condition the CPCN in this respect.

12.2 Capacity Curtailment and Peaking Supply Agreement

TGVI filed a draft Peaking Agreement in the proceeding. The agreement provides for both the curtailment of firm transportation capacity and the corresponding supply to TGVI of peaking gas (Exhibit B-10, BCUC IR 65.2). In sections 7 and 11 of the Summary of Principal Terms for Transportation Service in Exhibit B-25, TGVI included terms for capacity curtailment and peaking gas supply. The pricing terms appear to reflect those identified by BC Hydro in Exhibit C7-12 as representing its out-out-pocket expenses for fuel switching.

When it filed the draft Peaking Agreement, TGVI stated that the determination of key terms such as peaking gas quantities and charges would need to be negotiated on an individual customer basis taking into consideration the unique operating characteristics of the customer's facilities and the operational issues of TGVI.

In its Argument, TGVI stated that construction of the LNG facility does not require that peaking gas or curtailment arrangements be in place with BC Hydro (TGVI Argument, pp. 38-39).

The Commission Panel accepts that TGVI needs to negotiate terms for curtailment and peaking supply that are likely to be unique for each customer. The Commission Panel considers that a completed agreement for curtailment and peaking supply is not an essential part of the contractual arrangements to support the CPCN Application for the LNG facility. It is expected that agreements for capacity curtailment and peaking supply, would be necessary parts of any CPCN application for compression or pipeline looping to expand the TGVI transportation system.

12.3 LNG Storage and Transportation Agreement

TGVI filed an unexecuted Liquefied Natural Gas Storage and Transportation Agreement ("LNG Storage Agreement") with Terasen Gas as Exhibit B-13. In the cover letter, TGVI stated that the parties had agreed to all the terms of the agreement including pricing. TGVI stated that the parties would execute the agreement after making any adjustments to the service quantities that result from the completed TSA with BC Hydro. The LNG Storage Agreement will then be filed for Commission approval. At page 39 of its Argument, TGVI confirmed that under the agreement it would be providing a public utility service to Terasen Gas and the charges for such service will be a "rate" as defined in the Act. Accordingly the agreement would need to be filed pursuant to subsection 61(1) of the Act.

Schedule A of the LNG Storage Agreement sets out the LNG storage, vapourization and liquefaction capacity that TGVI would provide for each year from 2008/09 to 2026/27. Article XII of the agreement provides for an annual demand charge for storage capacity and liquefaction and transportation to the Mount Hayes facility of $1.44/GJ per year for each GJ of storage capacity contracted. The agreement also provides for an annual demand charge for vapourization and redelivery of $57.60 for each GJ per day of vapourization contracted. Article XIII provides for a commodity charge of $0.75/GJ of gas liquefied and Article XIV provides that Terasen Gas will provide fuel in-kind for transportation and LNG facility use. Other charges and adjustments are included so that TGVI recovers its allocated variable costs.

In its Argument, TGVI states that it considers it would be reasonable for the Commission to include a CPCN condition requiring that the LNG Storage Agreement between TGVI and Terasen Gas be executed before construction of the LNG facility commences (TGVI Argument, p. 41).

The BCOAPO submitted that the LNG storage agreement with Terasen Gas must capture the benefits that TGVI assumes in its financial analysis (BCOAPO Argument, p. 8). In its Argument, BC Hydro recommended that the Commission not accept the LNG Storage Agreement in its present form. BC Hydro stated that a CPCN condition should require that TGVI file a reworked agreement for review and that the Commission invite submissions on the agreement. BC Hydro submitted that the reworked agreement should address the agreement's relationship with TGVI's general terms and conditions and the services offered to other transportation shippers, such as interruptible transportation services (BC Hydro Argument, p. 28).

The LNG Storage Agreement was not filed for Commission approval, and its principal role in this proceeding is to support TGVI's estimate of LNG Mitigation Revenues discussed in Chapter 10. The Commission Panel notes that TGVI and Terasen Gas are affiliated regulated companies and that the Commission has not yet reviewed the prudency of Terasen Gas committing to LNG storage service from TGVI.

The Commission Panel expects TGVI to proceed with the completion of the LNG Storage Agreement with Terasen Gas, and to file it for Commission approval in a timely fashion. Based on the discussion of the agreement in the hearing, the Commission Panel believes that it would be helpful to identify the following matters for TGVI to address in a reworked agreement that it files for Commission approval:

- Further to statements in the TGVI Argument, in order to provide assurance that the LNG Mitigation Revenue assumed by TGVI in its financial analysis will be realized, Terasen Gas should have the right and obligation to contract for all LNG storage capacity that TGVI determines is excess to the needs of TGVI and its customers (TGVI Argument, p. 38);

- It would significantly reduce the value of the arrangement to TGVI if there is risk that commitments to Terasen Gas could reduce the flexibility of TGVI's use of the LNG facility and perhaps require TGVI to construct system expansions that would not otherwise be necessary. While Terasen Gas should have reasonable notice of TGVI's requirements, a long-term schedule of surplus LNG capacity appears unnecessarily constraining;

- TGVI should review the effect that the LNG Storage Agreement may have on other transportation shippers on its system, particularly interruptible shippers; and

- In its Argument, TGVI refers to its testimony that the charges under the agreement are market-based charges (TGVI Argument, p. 40). However, as discussed in Chapter 10, the estimated value for surplus LNG capacity was based on charges for Mist underground gas storage, which has somewhat different characteristics than LNG storage. Also, it seems unlikely that TGVI will offer surplus LNG capacity to other potential customers. When TGVI files the reworked agreement, it should provide justification of the proposed rates, and address whether the rates should be revisited periodically.

The Commission Panel determines that a condition of any CPCN will be that an executed and approved LNG Storage Agreement, that assures TGVI an amount of LNG Mitigation Revenue consistent with the amount assumed in the financial analysis, must be in place prior to the start of construction of the LNG facility.

13.0 COMMISSION DETERMINATIONS

In its Argument, TGVI submitted that the evidence in the proceeding supports the granting of a CPCN for the LNG storage, and requested that the Commission grant the CPCN in time for the LNG facility to provide service anticipated for the winter of 2007/08. In its Reply, TGVI stated that concerns about the long-term viability of TGVI and rate impacts to customers can best be addressed by approving the LNG Storage facility, since that is the resource portfolio with the lowest long-term costs. Based on statements in the BC Hydro Argument, TGVI submitted that the costs of the PCC portfolio options are likely to be significantly higher than the costs developed by TGVI in its analysis. TGVI also submitted that BC Hydro's views on facility additions must not compromise TGVI's obligation to provide safe and reliable service.

The BCOAPO stated that it would not oppose the granting of a CPCN for the LNG facility if the Commission Panel grants the CPCN with conditions. The BCOAPO submitted that the conditions proposed by TGVI in its argument are necessary.

The Ministry took no position on approval or denial of the CPCN, but requested that the Commission consider the long-term viability of TGVI, the impact on ratepayers of system expansion and the role of BC Hydro.

BC Hydro argued that TGVI has not met the two minimum criteria for a CPCN of need and cost-effectiveness, and stated that the CPCN Application should be denied. It further argued that in the event the Commission Panel decides to grant a CPCN for the LNG facility, it should include appropriate conditions such as an executed long term TSA for both ICP and Duke Point.

In the preceding Chapters, the Commission Panel has reviewed TGVI's Resource Plan, the proposed LNG storage facility and the analysis of resource portfolios that include the LNG storage facility in comparison to other portfolio options. In the Resource Plan, TGVI concluded that LNG storage is the preferred resource addition to meet forecast load growth.

In Chapter 7, the Commission Panel concluded that the Mount Hayes site is well suited for the project, and was satisfied that the construction and operation of the LNG storage facility at the site would not result in any significant health, safety or other impacts on the public.

In Chapter 9, the Commission Panel concluded that, in addition to financial considerations, the LNG portfolio would have several material benefits for TGVI ratepayers, compared to portfolios that include only compression, pipeline looping and curtailments.

In Chapter 10, the Commission Panel concluded that the financial analysis favours the LNG portfolio compared to the P&C portfolio or the likely PCC portfolio, and that this conclusion did not change for scenarios based on lower demand forecasts or alternative sequences of resource additions. The PCC portfolios that compared favourably to the cost of the LNG portfolio assumed amounts of curtailment that the Commission Panel concluded were unlikely.

In Chapter 11, the evidence indicated that rates for residential and transportation customers under the LNG portfolio would likely be similar to or lower than rates under other portfolio options, and the Commission concluded that determinations related to the impact on individual rate classes can be addressed in a future proceeding. The Commission Panel accepted TGVI's contention that the RDDA will be paid back by 2011, providing BC Hydro continues to be a firm service customer.

The foregoing conclusions and determinations are all based on the assumptions made by TGVI in its Revised Base +45 forecast for the purpose of this proceeding, that the Duke Point Power facility proceeds, and that TGVI executes a long-term TSA with BC Hydro to provide firm transportation service to ICP and Duke Point Power. The conclusions and determinations are reinforced by the ongoing uncertainty about the availability and the cost to TGVI of curtailment and peaking supply, and the related question as to whether the PCC portfolio options are likely to be less costly than the P&C option.

Based on the evidence in the proceeding and in the context of a step-change in demand in 2007, the Commission Panel concludes that LNG storage, combined with compression and pipeline looping as required, is the preferred resource addition to meet forecast load growth. This is similar to the conclusion that TGVI reached in the Resource Plan. The Utility, with Commission oversight, is responsible for planning system additions to provide reliable service to its customers at the lowest long-term cost. The Commission Panel is persuaded that other system expansion options would have higher costs and fewer non-financial benefits for TGVI and its ratepayers. In the event that there is a large increase in gas demand on Vancouver Island in 2007 but the LNG project cannot be completed for 2007, the Commission Panel considers that this may result in a sub-optimal portfolio of gas facilities being put into place with potentially negative cost impacts for TGVI's customers.

In the circumstances, the Commission Panel approves the CPCN for the proposed LNG facility but, for reasons that are set out in detail in the preceding Chapters, concludes that the CPCN must include the following conditions:

- the EPC bid price that TGVI accepts for the LNG facility will not exceed 110 percent of $75.9 million;
- a firm, long-term TSA for service to ICP and Duke Point will be executed by TGVI and BC Hydro and approved by the Commission prior to the commencement of construction of the LNG project;
- an LNG Storage Agreement that assures TGVI of LNG Mitigation Revenue consistent with the amounts that TGVI used in its financial analysis will be executed by TGVI and Terasen Gas and approved by the Commission prior to the commencement of construction of the LNG project; and
- the CPCN will terminate if construction of the LNG project has not commenced by December 31, 2005.

Dated at the City of Vancouver, in the Province of British Columbia, this 15th day of February, 2005.

L.A. Boychuk

Lori Ann Boychuk
Panel Chair and Commissioner

N Nicholls

Nadine F. Nicholls
Commissioner

P. Vivian

Peter E. Vivian
Commissioner

BRITISH COLUMBIA
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ORDER NUMBER C-2-05

IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

A Submission by Terasen Gas (Vancouver Island) Inc.
for Review of a Resource Plan dated June 18, 2004

and

An Application dated August 4, 2004 for a
Certificate of Public Convenience and Necessity
for a Liquefied Natural Gas Storage Project

BEFORE: L.A. Boychuk, Panel Chair and Commissioner
N.F. Nicholls, Commissioner
P.E. Vivian, Commissioner

February 15, 2005

O R D E R

WHEREAS:

A. On June 21, 2004, Terasen Gas (Vancouver Island) Inc. ("TGVI") filed with the Commission its Resource Plan Report dated June 18, 2004, covering the Vancouver Island and Sunshine Coast service areas ("Resource Plan") prepared with a view to satisfying the Commission's Resource Planning Guidelines issued in December 2003 related to the new subsections 45(6.1) and 45(6.2) of the Utilities Commission Act ("the Act"); and

B. On August 4, 2004, TGVI filed with the Commission an application ("the CPCN Application") for a Certificate of Public Convenience and Necessity ("CPCN") to construct and operate a new Liquefied Natural Gas ("LNG") Storage Facility at a location referred to as Mount Hayes in the Cowichan Valley Regional District in the vicinity of Ladysmith and certain related facilities (the "LNG Project"); and

C. In both its June 21 and August 4, 2004 filings, TGVI requested that the Commission's review of the Resource Plan and the CPCN Application take place concurrently or jointly as part of the regulatory review and approval process required; and

D. Following a written process, the Commission determined that the Resource Plan and the CPCN Application should be heard concurrently; and

E. The Commission, by Order No. G-79-04, established a Pre-hearing Conference on September 13, 2004, to consider issues and procedural matters associated with the Resource Plan and CPCN Application, including timing and steps in the review process; and

F. Commission Order No. G-83-04 established an oral public hearing which commenced on November 17, 2004 in Nanaimo, BC to review the Resource Plan and the CPCN Application, and set out the Regulatory Agenda for the proceeding; and

G. The oral public hearing took place on November 17 to 19, 2004 in Nanaimo and on December 6 to 13, 2004 in Vancouver. Written argument was completed when TGVI filed its Reply Submission on January 14, 2005; and

H. The Commission has considered the Resource Plan and the CPCN Application, the written evidence filed prior to the hearing, the evidence presented at the hearing and the written arguments that were filed after the hearing, and has determined that a CPCN should be approved for the LNG Project providing the conditions in this Order are met.

NOW THEREFORE the Commission orders as follows:

1. The Commission accepts the Resource Plan for filing, pursuant to subsections 45(6.1) and 45(6.2) of the Act.

2. Pursuant to Section 45 of the Act, the Commission approves a Certificate of Public Convenience and Necessity for the LNG Project as set out in the CPCN Application with an estimated cost of $94.4 million, subject to the following conditions:

2.1 The Engineering, Procurement and Construction ("EPC") bid price that TGVI accepts for the LNG Storage Facility will not exceed 110 percent of $75.9 million.

2.2 A firm, long-term transportation service agreement to serve the Island Co-generation Plant and the proposed Duke Point Power Limited Partnership facility will be executed by TGVI and British Columbia Hydro and Power Authority and approved by the Commission, prior to the commencement of construction of the LNG Project.

2.3 An LNG Storage Agreement that assures TGVI of LNG mitigation revenue consistent with the amount of such revenue that TGVI used in its financial analysis will be executed by TGVI and Terasen Gas Inc. and approved by the Commission, prior to commencement of construction of the LNG Project.

2.4 The Certificate of Public Convenience and Necessity will terminate if construction of the LNG Project has not commenced by December 31, 2005.

3. TGVI will file the detailed firm EPC bid price and detailed project schedule with the Commission in a timely fashion, and will confirm that the estimate of total project costs is based on steel prices and other information that is current.

4. TGVI will file with the Commission monthly progress reports on the LNG Project schedule and costs, followed by a final report upon project completion. TGVI will determine the form and content of the reports in consultation with Commission staff.

DATED at the City of Vancouver, in the Province of British Columbia, this 15th day of February 2005.

BY ORDER

Lori Ann Boychuk
Chair

APPEARANCES

G.A. FULTON	COMMISSION COUNSEL
C. JOHNSON R. EZEKIEL	TERASEN GAS (VANCOUVER ISLAND) INC.
J. KLEEFELD	B.C. HYDRO AND POWER AUTHORITY
K. GUSTAFSON, Q.C.	VANCOUVER ISLAND GAS JOINT VENTURE
S. SNARR	WILLIAMS GAS PIPELINE COMPANY
M. D'ANTONI	MINISTRY OF ENERGY AND MINES
P. MacDONALD R.J. GATHERCOLE	BCOAPO ET AL. (B.C. OLD AGE PENSIONERS' ORGANIZATION, COUNCIL OF SENIOR CITIZENS ORGANIZATIONS OF B.C., END LEGISLATED POVERTY SOCIETY, FEDERATED ANTI-POVERTY GROUPS OF B.C., SENIOR CITIZENS' ASSOCIATION OF B.C., AND WEST END SENIORS' NETWORK)
D. FITZGERALD	NORSKE CANADA LTD.
M. McCORDIC	AVISTA ENERGY CANADA, LIMITED
J. CAMPBELL	SELF
K. FARQUHARSON	SELF

J.B. WILLISTON E. CHENG R. BROWNELL P.W. NAKONESHNY	COMMISSION STAFF
ALLWEST REPORTING LTD.	COURT REPORTERS

IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473
and
Terasen Gas (Vancouver Island) Inc.
2004 Resource Plan and
Certificate of Public Convenience and Necessity Application
for a Liquefied Natural Gas ("LNG") Storage Project

EXHIBIT LIST

Exhibit No.	Description
A-1	Commission Order No. G-79-04 and Notice of Pre-Hearing Conference combining the reviews of the 2004 Resource Plan and the Certificate of Public Convenience and Necessity Application for a Liquefied Natural Gas (LNG) Storage Project
A-2	Commission letter dated August 23, 2004 regarding July 2004 Update Report dated August 16, 2004
A-3	Letter dated September 10, 2004 and Agenda for the Pre-hearing Conference
A-4	Letter and Order No. G-83-04 with Regulatory Agenda, Notice of Oral Hearing and Issues List dated September 15, 2004
A-5	Commission Information Request No. 1 dated September 17, 2004
A-6	Letter dated September 24, 2004 to Ken Farquharson regarding Filing Dates for Information Requests and Evidence
A-7	Response letter dated October 7, 2004 to Ken Farquharson regarding request for late filing of Evidence
A-8	Commission Information Request No. 2 to Terasen Gas (Vancouver Island) Inc. dated November 2, 2004
A-9	Hearing Procedures Information dated November 2, 2004
A-10	Commission Information Request No. 1 to Williams Gas Pipelines dated November 3, 2004
A-11	Commission Information Request No. 1 to Vancouver Island Gas Joint Venture dated November 3, 2004

Exhibit No.	Description
A-12	Commission Information Request No. 1 to Ken Farquharson dated November 3, 2004
A-13	Commission Information Request No. 1 to Calpine Island Cogeneration Limited Partnership dated November 3, 2004
A-14	Commission Information Request No. 1 to BC Hydro dated November 3, 2004
A-15	Commission Information Request No. 3 to Terasen Gas (Vancouver Island) Inc. dated November 3, 2004
A-16	Letter and Attachments regarding Consultation with Witnesses under Cross-Examination dated November 4, 2004
A-17	Potential postponement to week commencing December 6th of evidence of TGVI's Panel 3 dated November 12, 2004
A-18	Commission Information Request No. 4 to Terasen Gas (Vancouver Island) Inc.
A-19	Terasen Gas (Vancouver Island) Inc. letter dated November 17, 2004 to Amend Transportation Service Agreement and Peaking Gas Management Agreement submitted December 7, 2004
A-20	Excerpt from Terasen Gas (Vancouver Island) Inc. 2004 Annual Review - Summary of Plant in Service-Schedule 4 dated November 5, 2004 – submitted December 8, 2004
A-21	Letter No. L-18-04, Certificate of Public Convenience and Necessity Application Guidelines and Order No. G-28-04 dated March 31, 2004 submitted December 8, 2004
A-22	Page from October 29, 2004 Report No. 4 of the Independent Reviewer regarding summarization of determinations by BC Hydro submitted December 13, 2004
B-1	Terasen Gas (Vancouver Island) Inc. letter and Application dated June 18, 2004 for Approval of the 2004 Resource Plan (Binder)
B-2	Terasen Gas (Vancouver Island) Inc. letter and Application dated August 4, 2004 for a Certificate of Public Convenience and Necessity - LNG Storage Project (Binder)
B-3	Responses to BCUC Information Request No. 1 dated October 6, 2004 (Binder Volume 2)

Exhibit No.	Description
B-4	Letter dated October 4, 2004 - Invitation to view Tilbury LNG Plant October 29, 2004
B-5	Revised pages 298 and 299 dated October 12, 2004 to be included in responses to Commission Information Request No. 1 (See Exhibit B-3)
B-6	Responses to Intervenor Information Requests dated October 20, 2004 and Response to BC Hydro Information Request 15© dated October 21, 2004 (Binder)
B-7	Information Request to William Gas Pipeline Company dated November 3, 2004
B-8	Responses to Commission Information Request No. 2 dated November 8, 2004 (Binder)
B-9	Exhibits submitted November 10, 2004 : - List of Panel Members and Panel Issues - Witness Data - Stakeholder Workshop Presentation for October 22, 2004
B-10	Responses to Commission Information Request No. 3, BC Hydro Information Request No. 2, Ministry of Energy and Mines Information Request No. 2 and Williams Gas Information Request No. 1 dated November 10, 2004 (Binder)
B-11	Revisions to Response to Commission Information Request No. 1 Question 48.2 (Exhibit B-8) and Revisions to Response to BC Hydro Information Request No. 2 Questions 54(a) and 54(c) (Exhibit B-10) dated November 16, 2004
B-12	BC Hydro News Release regarding Intention to approach private sector for 2000 GwH of new energy dated October 28, 2002 – received November 18, 2004
B-13	Letter dated November 30, 2004 filing the Draft Liquefied Natural Gas Storage and Transportation Agreement between Terasen Gas (Vancouver Island) Inc. and Terasen Gas Inc.
B-14	Letter dated November 25, 2004 providing the key milestone dates for the LNG project
B-15	Letter dated December 2, 2004 filing Responses to Undertakings made during the November 17 through 19 hearing days
B-16	Letter dated December 2, 2004 filing Responses to Commission Information Request No. 4

Exhibit No.	Description
B-17	Response to Undertakings No. 16 and 17 from Hearing dated December 3, 2004
B-18	Affidavit for Notice of Pre-Hearing Conference filed at the Hearing December 6, 2004
B-19	Affidavit for Notice of Oral Hearing filed at the Hearing December 6, 2004
B-20	“Breakeven Analysis” filed at the Hearing December 8, 2004
B-21	Reworked Spreadsheet in response to Exhibit C7-10 filed at the Hearing December 8, 2004
B-22	Reworked Spreadsheet regarding Exhibits C7-10 and B-21 filed at the Hearing December 8, 2004
B-23	Article “Evaluating a Public Utility’s Investments: Cash Flow vs. Revenue Requirement” from May 10, 1990-Public Utilities Fortnightly filed at the Hearing December 8, 2004
B-24	Comparison of Discounted Cash Flow and Revenue Requirement filed at the Hearing December 8, 2004
B-25	Principal Terms for Transportation Service Arrangements with BC Hydro dated December 9, 2004
B-26	Response to Undertakings provided in the Hearing – No. 21 submitted December 13, 2004
B-27	Response to Undertakings provided in the Hearing – No. 22 submitted December 13, 2004
B-28	Order in Council No. 1224 – Special Direction No. 2 dated December 11, 2004 –submitted on December 13, 2004
B-29	Response to Undertaking regarding responses to Commission Information Requests 74.1 and 78.1 submitted December 13, 2004
B-30	Calculation of Termination Payment submitted December 13, 2004
B-31	Response dated December 20, 2004 to Undertakings provided in the Hearing – submitted December 13, 2004
B-32	Clarification of answer provided by Mr. Bennett in Transcript Volume 7 Page 1140 – dated December 21, 2004

Exhibit No.	Description
C1-1	**WestPac Terminals** - Notice of Intervention dated August 3, 2004
C2-1	**Ministry of Energy and Mines** – Notice of Intervention dated August 19, 2004
C2-2	Information Request No. 1 dated October 12, 2004 from the Ministry
C2-3	Information Request No. 2 to Terasen Gas (Vancouver Island) Inc. dated November 3, 2004
C2-4	Information Request No. 1 to Williams Gas Pipelines dated November 3, 2004
C3-1	**Karl E. Gustafson, Lang Michener** – Notice of Intervention representing Vancouver Island Gas Joint Venture dated August 24, 2004
C3-2	Information Request No. 1 dated October 13, 2004 on behalf of Vancouver Island Gas Joint Venture
C3-3	Copies of Transportation Service and Peaking Gas Management Agreements on behalf of Vancouver Island Gas Joint Venture dated October 20, 2004
C3-4	Response to BCUC Information Request No. 1 on behalf of Vancouver Island Gas Joint Venture dated November 10, 2004
C4-1	**Curtis Mahoney, Calpine Island Cogeneration** – Notice of Intervention dated September 5, 2004
C4-2	Responses to BCUC Information Request No. 1 dated November 9, 2004
C5-1	**James Campbell** – Notice of Intervention dated September 7, 2004
C6-1	Richard J. Gathercole, **BC Public Interest Advocacy Centre** – Notice of Intervention representing BCOAPO dated September 7, 2004
C6-2	Request from BCPIAC adding Bill Harper of **Econalysis Consulting Services** as lead consultant to BCOAPO dated September 24, 2004
C6-3	Letter dated October 12, 2004 on behalf of BCOAPO - Will not be filing Information Requests at this stage

Exhibit No.	Description
C6-4	BCOPAO concerns over statements in BCUC letter of November 12, 2004 – dated November 15, 2005
C6-5	Copy of Commission Letter, Order No. G-99-04 and Appendix A to Order No. G-99-04 presented on behalf of BCOAPO November 17, 2004
C6-6	The Vancouver Sun newspaper article dated November 16, 2004 regarding “The flaws in the Duke Point deal” presented on behalf of BCOAPO November 17, 2004
C6-7	Copy of DSM Status Report presented by BCPIAC November 17, 2004
C6-8	Terasen Gas Inc. 2005 Revenue Requirements - Gas Sales and Transportation Volumes presented by BCPIAC November 18, 2004
C6-9	BC Hydro News Release dated November 3, 2004 regarding “Duke Point Power Project will help ensure continued reliable supply of electricity for Vancouver Island after 2007” presented by BCPIAC November 18, 2004.
C6-10	BC Hydro letter dated December 1, 2004 regarding Terasen Gas (Vancouver Island) Inc. 2004 Annual Review (Exhibit C7-4) submitted December 6, 2004
C6-11	Commission Decision dated May 21, 1999 regarding BC Gas Utility Ltd. Southern Crossing Pipeline Project for a Certificate of Public Convenience and Necessity submitted December 7, 2004
C6-12	Response dated July 8, 2004 to Commission Information Requests No. 2 and 4 regarding Resource Plan submitted December 7, 2004
C7-1	**British Columbia Hydro and Power Authority -** Notice of Intervention dated September 7, 2004 from Richard Stout
C7-2	Information Request No. 1 dated October 13, 2004 – further documents regarding Questions 27 and 31 to follow.
C7-3	Information Request No. 2 to Terasen Gas (Vancouver Island) Inc. dated November 3, 2004
C7-4	Responses to BCUC Information Request No. 1 dated November 10, 2004 (Binder)
C7-5	Responses to Williams Gas Pipeline Company’s Information Request No. 1 dated November 10, 2004.

Exhibit No.	Description
C7-6	"TGVI's Resource Planning/CPCN Environment: Then and Now" presented by BC Hydro on November 17, 2004.
C7-7	Letter dated November 25, 2004 providing the key milestone dates for the Duke Point project
C7-8	Witness Aid – Discount Rates Based on Weighted Pre-Tax Cost of Capital - submitted December 7, 2004
C7-9	Commission Decision regarding BC Gas Utility Ltd. Southern Crossing Pipeline Project for Certificate of Public Convenience and Necessity dated April 3, 1998 – submitted December 7, 2004
C7-10	Witness Aid – NPV of Cost of Service – submitted December 7, 2004
C7-11	Ministry of Finance, Corporate Registries – BC Company Summary for Terasen Gas (Vancouver Island) Inc. dated November 2, 2004 – submitted December 8, 2004
C7-12	Supplementary Information regarding (Exhibit C7-4) response to BCUC IR 1.2.4 dated December 9, 2004 – submitted December 13, 2004
C7-13	Supplementary Information dated December 10, 2004 regarding Exhibit C7-4 response to Commission Information Request 1.6.4 also clarification of Calpine Island Cogeneration's response to Commission Information Request 1.2.5 (Exhibit C4-2) – submitted December 13, 2004
C7-14	Response to Terasen Gas (Vancouver Island) Inc.'s term sheet for gas transportation arrangements dated December 13, 2004 – submitted December 13, 2004
C8-1	**Thomas Hackney, GSX Concerned Citizens Coalition** - Notice of Intervention dated September 8, 2004
C9-1	**Mary McCordic, Avista Energy Canada, Ltd.** - Notice of Intervention dated September 8, 2004
C10-1	**Dennis Fitzgerald, NorskeCanada** – Notice of Intervention dated September 9, 2004

Exhibit No.	Description
C11-1	**Ken G. Farquharson** – Notice of Intervention dated September 4, 2004
C11-2	Ken G. Farquharson Information Request to Commission dated September 15, 2004
C11-3	Information Request to Terasen Gas (Vancouver Island) Inc. dated September 28, 2004
C11-4	Information Request No. 2 to Terasen Gas (Vancouver Island) Inc. dated October 4, 2004
C11-5	Letter dated October 4, 2004 requesting late filing of Evidence
C11-6	October 8, 2004 reply to BCUC letter regarding late filing of Evidence
C11-7	October 10, 2004 filing of Evidence – reserve right to file further evidence at hearing. Attachments received November 9, 2004 (in hard copy only)
C11-8	Responses to Commission Information Requests dated November 10, 2004
C11-9	Overview of landslide which destroyed BC Hydro tower, Sechelt December 12, 2002 presented by Ken Farquharson November 19, 2004
C11-10	E-mail withdrawing as Intervenor – submitted December 8, 2004
C12-1	**Steven W. Snarr, Williams Gas Pipeline Company** – Notice of Intervention dated October 15, 2004
C12-2	Evidence filed October 27, 2004 by Williams Gas Pipeline Company
C12-3	Information Request No. 1 to Terasen Gas (Vancouver Island) Inc. dated November 3, 2004
C12-4	Information Request No. 1 to BC Hydro dated November 3, 2004
C12-5	Responses to Information Request from BCUC, Ministry of Energy and Mines and Terasen Gas (Vancouver Island) Inc. dated November 10, 2004 (Reference material available in Hard Copy only)
C12-6	Request to withdraw intervention from proceeding dated December 10, 2004 – submitted December 13, 2004

Exhibit No.	Description
D-1	**Mike Tippett, Cowichan Valley Regional District** – Notice of Interested Party status dated September 3, 2004
D-2	**Bill Neill** – Notice of Interested Party status dated September 7, 2004
D-3	**Brian Barnett, Resort Municipality of Whistler** – Notice of Interested Party status dated September 8, 2004
E-1	**Ministry of Energy and Mines** – Response to Commission Letter No. L-35-04 dated June 30, 2004 requesting comments on, and preference for, either a joint process or separate processes for reviewing the Resource Plan and the LNG CPCN Application
E-2	**Vancouver Island Gas Joint Venture** – Response to Commission Letter No. L-35-04 dated June 30, 2004 requesting comments on, and preference for, either a joint process or separate processes for reviewing the Resource Plan and the LNG CPCN Application
E-3	**British Columbia Hydro and Power Authority** – Response to Commission Letter No. L-35-04 dated June 30, 2004 requesting comments on, and preference for, either a joint process or separate processes for reviewing the Resource Plan and LNG CPCN Application
E-4	**Terasen Gas (Vancouver Island) Inc.** – Response to Commission Letter No. L-35-04 and interested party letters providing comments on, and preference for, either a joint process or separate processes for reviewing the Resource Plan and the LNG CPCN Application