

2004

Integrated Electricity Plan



Part 5 Portfolio Evaluation Process

National Library of Canada Cataloguing in Publication Data

B.C. Hydro.

2004 integrated electricity plan. Part 5, Portfolio
evaluation process

ISBN 0-7726-5088-8

1. B.C. Hydro. 2. Electric power systems - British
Columbia - Planning. 3. Electric utilities - British
Columbia - Planning. I. Title. II. Title: Integrated
electricity plan.

HD9685.C33B32 2003

333.79'32'09711

C2003-960249-4

Contents

Executive Summary	3
1 Planning for the Future – An Overview	6
2 Introduction	8
2.1. The Role of Portfolio Evaluation	8
2.2. Portfolio Performance	8
3 The Portfolio Modelling Process	10
3.1. Overview of the Portfolio Construction and Modelling Process	10
3.2. Portfolio Construction	10
3.2.1. Key Inputs	10
3.2.2. Planning Assumptions	12
3.3. Energy Market: Gas and Electricity Price Forecast Scenarios	13
3.3.1. Years F2005 to F2012	13
3.3.2. Year F2013 and Beyond	14
3.3.3. Market Price Scenarios	15
3.4. Resource Scheduling	18
3.4.1. General Approach	18
3.4.2. Energy Balancing	18
3.4.3. Least-Cost Capacity Resources	18
3.5. Portfolio Operational Simulation	19
3.5.1. Portfolio Modelling and Operational Simulation	19
3.6. Evaluation of Portfolio Attributes	21
3.6.1. Net Present Value	21
3.6.2. Reliability Planning Criteria	23
3.6.3. Private Sector Involvement	23
3.6.4. Clean Target	23
3.6.5. Rate Impact	23
3.6.7. Dependable Capacity	23
3.6.8. Diversity	24
3.6.9. Employment	24
3.6.10. Greenhouse Gas Emissions and Local Air Emissions	24
3.6.11. Footprint	24
3.6.12. Communities	25
4 Portfolio Evaluation, Risk and Sensitivity Analysis	26
4.1. Objective of Risk Analysis	26
4.2. Risk Assessment	26
4.2.1. Streamflow Variability	27
4.2.2. Scenario Analysis	27
4.2.3. Sensitivity Analysis	27

Appendix A – Portfolio Transmission Modelling Process

Appendix B – Natural Gas Price Forecast Description

Executive Summary

This Part of the Integrated Electricity Plan (IEP) describes the process used to develop alternative resource portfolios that meet the future electricity requirements of BC Hydro's customers. BC Hydro uses the process to evaluate the performance of these portfolios against the planning objectives of the IEP and also to test them against a number of future uncertainties.

Portfolio Modelling Process

BC Hydro constructs alternative 20-year portfolios by first adjusting the demand forecast to account for the amount of demand-side resources (Power Smart) specified in the portfolio. Various combinations of generation resources are added to the existing supply to serve the demand net of Power Smart 2.

Table E.1 summarizes the attributes used to evaluate the performance of the portfolios. Four key performance attributes link to the objectives of the 2002 B.C. Energy Plan. A number of supplementary attributes further examine the performance of the portfolios.

New resources are scheduled based on the planning criteria discussed in Part 2 of the IEP. The schedule of resource additions determines the sequence of capital and fixed costs associated with the demand-side management, generation and transmission elements of the portfolio. The schedule of resource additions is also used to measure impacts associated with the portfolio, such as the footprint and employment attributes.

The schedule of resources, their costs and attributes is assembled and evaluated in the Multi-Attribute Portfolio Analysis model (MAPA), an Excel spreadsheet developed by BC Hydro. MAPA includes the firm energy and dependable capacity demand-supply balances used to schedule new resource options to create portfolios. Once the schedule of new resources is determined, the portfolios are analyzed with BC Hydro's hydrological system simulation model (HYSIM) to determine the expected annual generation from each resource. The expected generation determines the annual variable cost for each portfolio, including the cost of imports and the revenue from market exports. These annual variable costs are consolidated with the capital and fixed costs in MAPA.

MAPA also uses the expected generation to calculate attributes that vary with the amount of electricity generated. For example, the greenhouse gas emissions and the local air emissions for a thermal resource based on energy output and the associated emission rates¹. MAPA calculates the present value of the annual costs net of export revenues over the 20-year study period for each portfolio in real dollars, i.e. net of inflation, using a range of discount rates (six, eight and 10 per cent). MAPA also calculates the annual revenue requirement per unit of energy sales as an estimate of the impact (net of inflation) each portfolio has on customer rates.

MAPA is used to conduct scenario analysis and sensitivity analysis with system simulation results, if required, provided by HYSIM.

¹ For example, 2000 GWh/year x 500 tonne GHG/GWh = 1 million tonnes GHG.

Table E.1. Summary of Portfolio Attributes

Key Performance Attributes		
Attribute	Unit of Measure	Objective
Net present value (NPV)	Discounted cash flow of total cost less export revenues in real F2003 dollars ^{2,3}	Minimize ratepayer costs
Reliability planning criteria	Meets Criteria (Yes/No)	Secure and reliable supply
Private sector involvement	Percentage of new energy provided by private sector Percentage of new energy owned by private sector	IPP involvement
Clean target	Percentage of newly acquired energy (GWh) that meets the definition of B.C. Clean Energy	50% Clean target

Supplementary Attributes		
Attribute	Unit of Measure	Objective
Rate impact	20-year change in rates (net of inflation) relative to the first year	Minimize ratepayer costs
Dependable capacity	MW installed capacity MW dependable capacity	Secure and reliable supply
Diversity	Number of new resource types	Secure and reliable supply
Employment	Temporary/construction (person-years) Long-term (full-time equivalents)	Social responsibility
Greenhouse gases and Local emissions	Greenhouse Gases: Tonnes of CO ₂ equivalent Local Emissions: Tonnes of nitrogen oxides (NO _x), sulphur oxides (SO _x), and particulate matter (PM)	Social responsibility Environmental responsibility
Footprint	Hectares of total surface area affected by a portfolio	Social responsibility Environmental responsibility
Communities	Qualitative comments with respect to affected communities including First Nations and stakeholder feedback	Social responsibility

Risk Assessment

Risk assessment examines portfolio performance over a range of uncertain future outcomes. Measuring the variability of attributes and evaluating the risk helps to discern portfolio preferences in the IEP. For example, portfolios that include gas-fired generation are subject to future gas price uncertainty. The analysis evaluates portfolios under five scenarios for gas and electricity market prices. Portfolios that include capital-intensive projects are more sensitive to the discount rate, reflecting the weighted average cost of capital. Discount rate sensitivities are calculated at six, eight and 10 per cent. The analysis also

² Includes customer costs to implement demand side management programs.

³ All dollars are Canadian dollars unless indicated.

examines sensitivity to uncertainties in generation and transmission capital costs. The risk due to regulatory uncertainties focuses on the risk of a charge being imposed on greenhouse gas emissions from thermal resources owned or contracted by BC Hydro. High and low load forecast scenarios focus on the impact of high and low electricity demand on resource timing.

1 Planning for the Future – An Overview

An integrated electricity plan (IEP) presents an electric utility's long-term plan for acquiring electricity resources to meet forecast customer needs. IEPs have been an integral part of BC Hydro's overall business planning process for many years. These plans provide the framework to support prudent investments in demand-side management (DSM), generation facilities and transmission infrastructure. This, in turn, ensures that BC Hydro meets its obligation to supply reliable electricity service to its customers at the least cost, consistent with other planning objectives.

Integrated electricity systems are complex and capital-intensive. Most new resources also require significant lead times to build. As a result, electric utilities plan ahead to be sure that the required resources will be in place when needed. IEPs are typically based on load forecasts and resource options that cover 15 to 20 years. Taking this long-term view, however, does not mean that BC Hydro is locked into each of the resource options identified over the planning horizon. In fact, the IEP must be sufficiently flexible to respond to changing market conditions and future uncertainties. In other words, the IEP must meet planning objectives against a range of possible futures as these futures cannot be predicted with certainty.

BC Hydro periodically reviews and updates its IEP. BC Hydro's most recent published IEP was issued in 2000 as an update to the 1995 IEP. A new IEP was to have been completed in 2001. However, the 2001 IEP planning process was put on hold in August 2001, pending the B.C. government's review of provincial energy policy. The B.C. Energy Plan, released in November 2002, enabled BC Hydro to proceed with the development of the 2004 IEP.

The primary purpose of BC Hydro's 2004 IEP is to project the nature and quantity of BC Hydro's resource needs over the next 20 years. This strategic direction guides the management of BC Hydro's owned and contracted energy resources, as well as future acquisition processes.

Specifically, the 2004 IEP:

- Provides the planning foundation for future demand-side management programs (Power Smart), private sector calls for electricity, and other resource acquisitions;
- Demonstrates to First Nations, stakeholders and the B.C. Utilities Commission (BCUC) that BC Hydro has a plan to meet future customer demand for electricity that recognizes key risks and uncertainties;
- Considers and incorporates, where feasible, feedback from the First Nation and stakeholder engagement process;
- Demonstrates how environmental, social and economic considerations are included in electricity planning; and
- Identifies an Action Plan that specifies initiatives to implement the needs identified in the IEP.

BC Hydro's 2004 IEP has nine components:

- Summary
- Part 1. Introduction and Planning Objectives
- Part 2. Demand-Supply Outlook
- Part 3. Resource Options
- Part 4. First Nations and Stakeholder Engagement
- Part 5. Portfolio Evaluation Process
- Part 6. Portfolio Evaluation Results
- Part 7. Action Plan
- Glossary

2 Introduction

2.1. The Role of Portfolio Evaluation

The 2004 IEP presents BC Hydro's current outlook for the types and quantity of resources required over the next 20 years. This long-term resource plan provides a framework to support investment in demand-side management, generation and transmission.

A portfolio is a sequence of new and existing resources scheduled over the 20-year planning period to meet the energy and dependable capacity needs of BC Hydro's domestic customers. Part 5 of the IEP, "Portfolio Evaluation Process," describes the process and methodology used to develop portfolios, evaluate their performance against planning objectives and test their performance under a range of future conditions. The role of the portfolio evaluation process is to:

- Evaluate the performance of new resources integrated with the existing BC Hydro system;
- Assess the potential advantages, disadvantages and risks of the resource options;
- Identify the portfolios that fail to meet the reliability planning criteria; and
- Evaluate portfolios against the key planning objectives of the 2004 IEP.

Part 6 of the IEP, "Portfolio Evaluation Results," sets out the results of the evaluation process. The information drawn from this evaluation process is used to develop the Action Plan described in Part 7 of the IEP.

2.2. Portfolio Performance

The electricity planning objectives presented in the B.C. Energy Plan provide the basis upon which to develop, evaluate and select resource options. Table 2.1 summarizes the 2004 IEP planning objectives and their relationship to the B.C. Energy Plan objectives.

To meet the IEP planning objectives, BC Hydro develops and evaluates a range of portfolios. The performance of the portfolios is measured on the basis of four key portfolio attributes that align directly to the 2004 IEP objectives. In addition to the four key portfolio attributes, the analysis compares other attributes that provide supplementary information about the environmental, social and economic performance of the portfolios.

Table 2.1. B.C. Energy Plan and 2004 Integrated Electricity Plan Objectives

B.C. Energy Plan Objectives	2004 Integrated Electricity Plan Objectives
Low electricity rates and public ownership of BC Hydro	Minimize long-term ratepayer costs by establishing the least-cost sequence of resources on a risk-adjusted basis that meets customers' needs as well as other BC Hydro and provincial government policy objectives.
Secure, reliable supply	Maintain adequate dependable capacity and energy capability to meet customer needs through the application of relevant electricity industry and BC Hydro reliability planning criteria.
Private sector development of new electricity generation	Seek proposals from the private sector to supply power to BC Hydro.
Environmental responsibility and no nuclear power sources	Enhance environmental and social responsibility with a voluntary 50 per cent Clean Energy target through Customer-Based Generation, Green Energy ⁴ , Resource Smart Programs and project proposals that meet or exceed environmental and social requirements. Achieving the Clean Energy target may result in electricity rate increases of between 0.1 to 0.2 per cent per year over the next decade.

2.3. Uncertainties and Risks Inherent in Electricity Planning

Long-term electricity planning is executed in a complex environment characterised by uncertainties and risks associated with various input variables. For example, the volatility in demand, gas and electricity prices, project lead times, cost of resource options and environmental regulations affect the actual performance of portfolios. This uncertain future environment makes it essential to test and evaluate the performance of the various resource portfolios against the possible range of future scenarios. This is explained in Section 4.

⁴ The term "Green" refers to energy resources that meet BC Hydro's definition of energy that is renewable, environmentally and socially responsible and licensable.

3 The Portfolio Modelling Process

3.1. Overview of the Portfolio Construction and Modelling Process

This section describes the various stages of the portfolio analysis process.

As Figure 3.1 illustrates, the heart of the portfolio analysis is the Multi-Attribute Portfolio Analysis (MAPA) model. BC Hydro uses this spreadsheet-based model to perform majority of the portfolio evaluation steps, including discounted cash flow (economic) analysis and the assessment of portfolio performance attributes. The variable cost component, which is the function of resource dispatch simulation, is derived by BC Hydro's hydrological system simulation model (HYSIM). The HYSIM output is entered into the MAPA's discounted cash flow analysis to arrive at the various IEP attributes. This process is executed for each resource portfolio.

3.2. Portfolio Construction

Portfolio construction involves assembling key inputs, which include the types, quantities and timing of resource additions. These inputs are assembled within the planning assumptions. The portfolios also satisfy BC Hydro's capacity and energy planning criteria. The key inputs and associated planning assumptions are described in this section.

3.2.1. Key Inputs

Demand

BC Hydro's reference load forecast is a fundamental input to the portfolio development process. The low and high load scenarios are used to assess the required timing of new resource additions. These high and low scenarios capture the expected volatility of the reference load forecast. Part 2 of the IEP, "Demand-Supply Outlook," presents the description of BC Hydro's current energy and peak demand forecasts for the integrated system, both with and without the current Power Smart 2 program.

Existing Supply

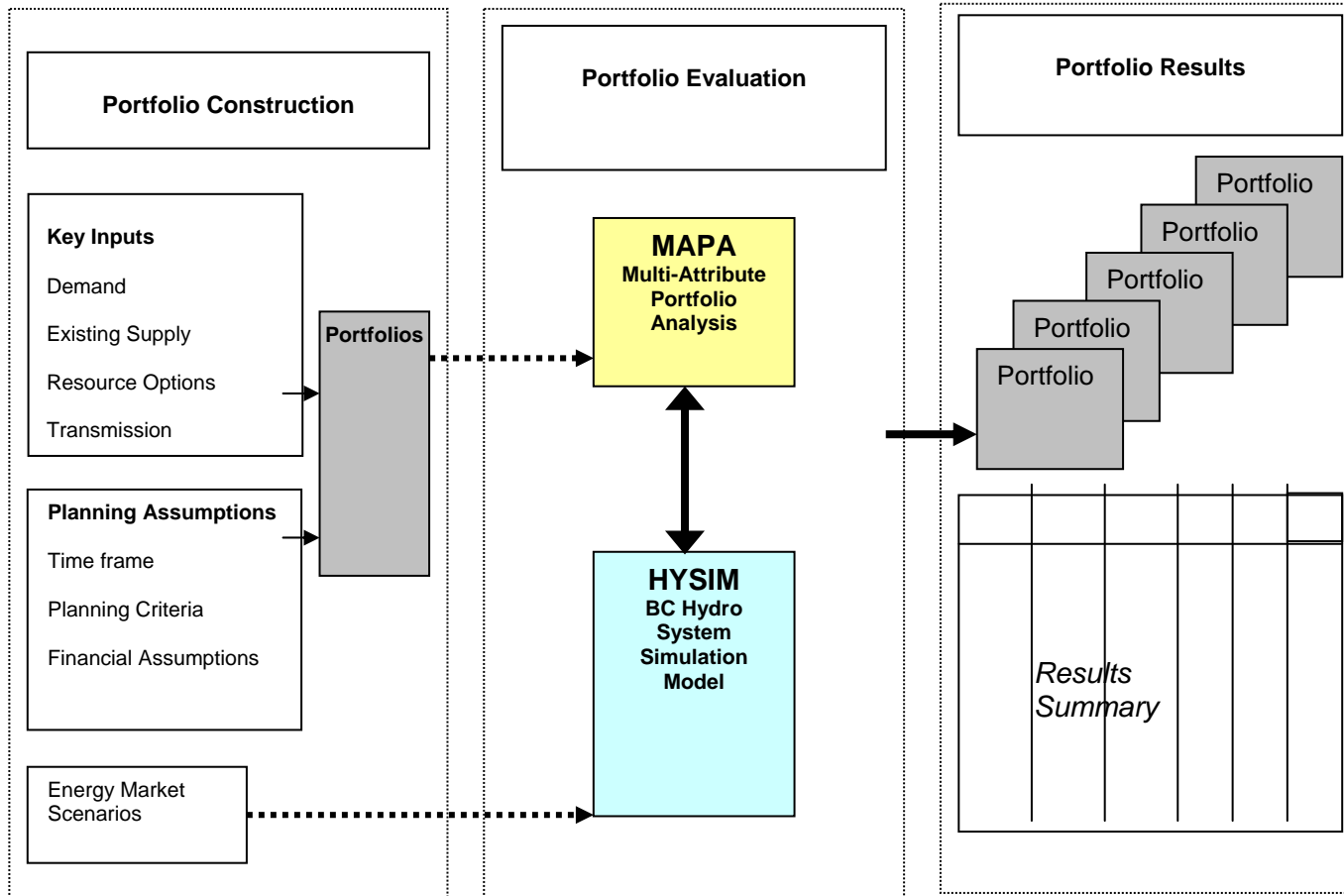
BC Hydro's existing supply consists of:

- The dependable capacity and firm energy capability of BC Hydro's *existing* system of hydroelectric and thermal generating stations, which are now designated as the Heritage Resources; and
- The dependable capacity and firm energy capability of *existing* supply provided from contracts with independent power producers (IPPs).

Resource Options

Part 3 of the IEP "Resource Options" describes the various new resource options, including generation, transmission and demand-side management options. Their characteristics, including energy capability and dependable capacity, their costs (fixed and variable), their technical characteristics and their environmental and communities impacts are used to construct various portfolios.

Figure 3.1. Stages of Portfolio Modelling and Evaluation



Transmission Inputs

Based on BC Hydro's sequence of generating resource additions and the load forecast (adjusted for the amount of demand-side resources), British Columbia Transmission Corporation (BCTC) identifies the new or upgraded transmission infrastructure required to maintain system reliability. BCTC also determines the estimated cost required to meet the load with the scheduled generation capability in the resource portfolio. The transmission details are included in Appendix A.

BCTC assesses the system for both *adequacy* and *security*.

- *Adequacy* means the existence of sufficient facilities in the system to satisfy the consumer load demand and system operation constraints. Adequacy is associated with static conditions that do not consider dynamic and transient disturbances of the system.
- *Security* relates to the system's ability to respond to dynamic or transient disturbances arising within the system such as transient electromechanical instability and voltage instability.

3.2.2. Planning Assumptions

Planning Period

- The planning **period** for the IEP is 20 years starting F2004⁵ and ending F2023.

Financial Assumptions

Financial assumptions used in the planning process are described below.

- **Cost of new IPP resources:** The B.C. Energy Plan requires that the additional new resources, with some exceptions, be built by the private sector. To **accurately** reflect the risks faced by an IPP having a long-term utility-backed electricity purchase agreements (EPAs), 12 per cent after-tax return on equity was assumed. The investment costs for the IPP projects were determined from the IPP perspective. The investment costs includes the costs required for studies, permits, financial charges, taxes and contingencies, engineering, procurement and construction costs. The financial assumptions are described in Part 3 of the IEP.
- **Cost of new BC Hydro resources:** BC Hydro-based programs (DSM, Resource Smart and transmission) are evaluated on the basis of investment, operating and maintenance costs.
- **Vancouver Island Gas Transportation Cost:** The cost of firm gas transportation from Sumas Hub to generation sites on Vancouver Island is based on toll information provided by Terasen Gas Inc. These tolls, in nominal dollars range, from \$1.1/GJ in F2004 to \$0.9/GJ in F2023.⁶

⁵ Year ending March 31,2004

⁶ BC Hydro uses these gas tolls to estimate an annual fixed cost to obtain firm supply. The Island Cogeneration Plant has a contract demand of 45,000 GJ per day and an annual throughput of 14.8 million GJ. The Vancouver Island call for tenders is assumed to require a contract demand of 25,000 GJ per day with an annual throughput of 8.2 million GJ. A future on-island 250 MW CCGT is assumed to have a contract demand of 43,000 GJ per day and an annual throughput of 14 million GJ.

- **Discount Rate:** A real discount rate of six per cent, BC Hydro's weighted average cost of capital, is used to estimate the net present value (NPV) of the costs of each portfolio. Sensitivity analysis is also conducted using discount rates of eight and 10 per cent.
- **Exchange Rate:** An exchange rate of U.S.\$0.75 to CDN\$1.00 is used in the development of the gas and electricity market forecasts.

3.3. Energy Market: Gas and Electricity Price Forecast Scenarios

Uncertainty in gas and electricity wholesale price forecasting is assessed through scenario analysis. BC Hydro uses a range of sources to forecast future natural gas and the corresponding electricity prices. The sources for the gas price forecasts are selected based on:

- credibility of the source;
- confidentiality of the forecast (whether it can be made public); and
- whether the scenarios represent a broad range of possible future energy market outcomes.

For each gas price forecast, a corresponding electricity price forecast is developed. The gas price forecasts have a monthly resolution. The electricity price forecasts have monthly resolution pricing for monthly heavy load hours (HLH) and light load hours (LLH). The various sources for the gas price forecast are presented in Section 3.3.3. The electricity price forecast for the next 20 years is derived in three stages. For 2004 and 2005, the forecast is based on the market forwards. Beyond F2005 and until F2012, the Henwood model is used to create the electricity price forecast. Beyond F2012 until F2023, the electricity price is based on the estimated unit cost of a CCGT. The next section describes the second and the third stages.

3.3.1. Years F2005 to F2012

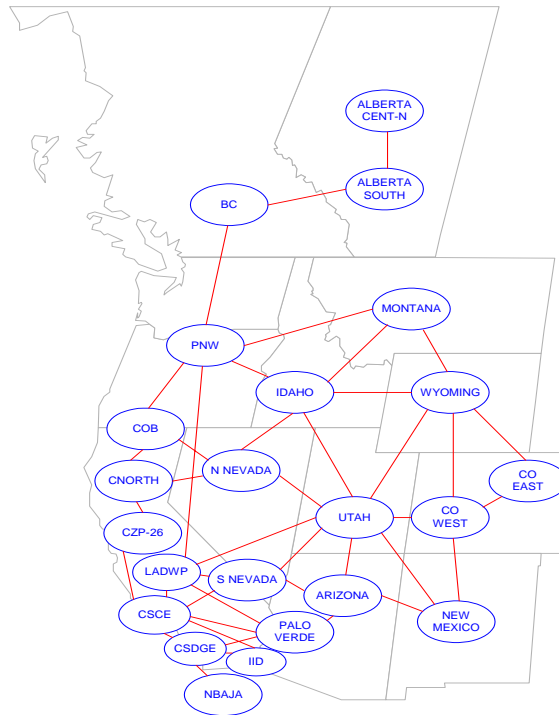
The Henwood simulation software developed by Henwood Energy Services is used by BC Hydro to forecast electricity prices from F2005 to F2012. The Henwood model simulates the expected hourly supply and demand of electricity and the corresponding market prices for the Western Electricity Coordinating Council (WECC) regional market, which includes the Western U.S., B.C. and Alberta. Monthly and yearly average prices are obtained by aggregating the computed hourly prices. Characteristics in the Henwood model are:

- Hourly simulation of more than 20 WECC areas;
- Expected WECC load growth (2 per cent);
- Expected hourly load shape (estimated from historical hourly load data from 1993 to 2000);
- Expected BC Hydro electricity load forecast and resource plan;
- Forecast natural gas prices;
- Average hydrological conditions throughout WECC;
- Existing WECC resource base less expected retirements plus expected additions;

- Generic resources added to maintain reserve margin targets for WECC sub-regions;
- Expected inflation; and

Expected long-term transmission limits, losses and costs; Figure 3.2 provides a schematic of the WECC market's transmission configuration.

Figure 3.2. Henwood WECC Market Model Transmission Area Configuration



3.3.2. Year F2013 and Beyond

Electricity prices for F2013 and beyond are based on the unit cost of a generic natural gas-fired combined cycle gas turbine (CCGT). Its capital and operating costs are based primarily on third party sources. Assumptions include:

- Greenfield project (i.e., not a repowering) in the Lower Mainland;
- 262 MW (average over life) F-series Combined Cycle Gas Turbine (CCGT);
- Capital cost = US \$200 million;
- Variable operating and maintenance cost = US \$3.15/MWh;
- Fixed operating and maintenance cost = US \$2.15/MWh;
- Forecast natural gas prices;
- Fuel tax = 7 per cent;

- Heat Rate = 6,863 MMBtu/GWh or 7,240 GJ/GWh HHV (higher heating value) average over life;
- Unit average availability = 91.3 per cent;
- Project life = 25 years; and
- Seasonal shape of prices estimated from the shape of the 2007-2012 forecast of prices in the Henwood model.

3.3.3. Market Price Scenarios

The BC Hydro long-term price forecasting process employs a multiple scenario-based approach to price forecasting. BC Hydro has selected five scenarios to represent a broad range of possible future energy market outcomes. For each scenario, there is a matching gas and electricity price forecast. Table 3.1 summarizes five gas and electricity price scenarios. Three third-party sources form the basis of gas price forecasts: the long-run cost projection from an industry consultant, Confer Consulting; the U.S. Energy Information Administration's (EIA) Reference Case; and the National Energy Board of Canada's (NEB) Techno Vert Case. These forecasts provide a wide but plausible range of possible outcomes. The lowest gas price is the Confer forecast. The highest is the High Gas scenario based on historically high U.S. gas price levels. Appendix B describes each of the scenarios in detail.

For each of these gas price scenarios, electricity market prices for corresponding monthly heavy load hours (HLH) and light load hours (LLH) were derived. In particular, for the first four gas price scenarios, the market electricity price in the long term is based on the full cost of a CCGT. This results in a market heat rate in the order of 11,300 GJ/GWh for these scenarios. Market heat rate is the market electricity price divided by the cost of gas; i.e. \$/GWh divided by \$/GJ. For the fifth gas price scenario, a lower market heat rate of 8,650 GJ/GWh was assumed. This is based on a potential future in which the current market heat rate persists. The rationale for this assumption is discussed further in Appendix B.

All gas and electricity price scenarios are based on data available as of October 2003. Figures 3.2 and 3.3 provide summary graphs of the gas and electricity price forecast scenarios. Average annual gas prices for F2004 are based on a partial year (October 2003 to March 2004).

Table 3.1. Gas and Electricity Price Scenario Summary

Scenario Description	Confer Consultant Study of North American Gas Market	Techno Vert National Energy Board (NEB)	Energy Information Administration (EIA) Reference Case	High Gas (Highest priced 12 contiguous months at Henry Hub*) BC Hydro	Alternative Market Heat Rate BC Hydro
Description	Relatively optimistic view of ability of technology to keep ahead of demand leads to relatively low price forecast.	Strong focus on the environment, and significant improvements in technology lead to a relatively high price forecast.	Strong demand growth and cost of production increase with cumulative consumption. Prices increase at a relatively high rate.	Continues present high price into the future. Captures the possibility that prices remain high or fluctuate around a high average.	Lower market heat rate than other scenarios. Provides a fundamentally different gas-to-electricity price relationship.

*One of the major pipeline hubs of the North American natural gas market, located in Louisiana, used as a reference point for quoting the market price of gas.

Figure 3.2 Natural Gas Price Scenarios at Sumas Hub

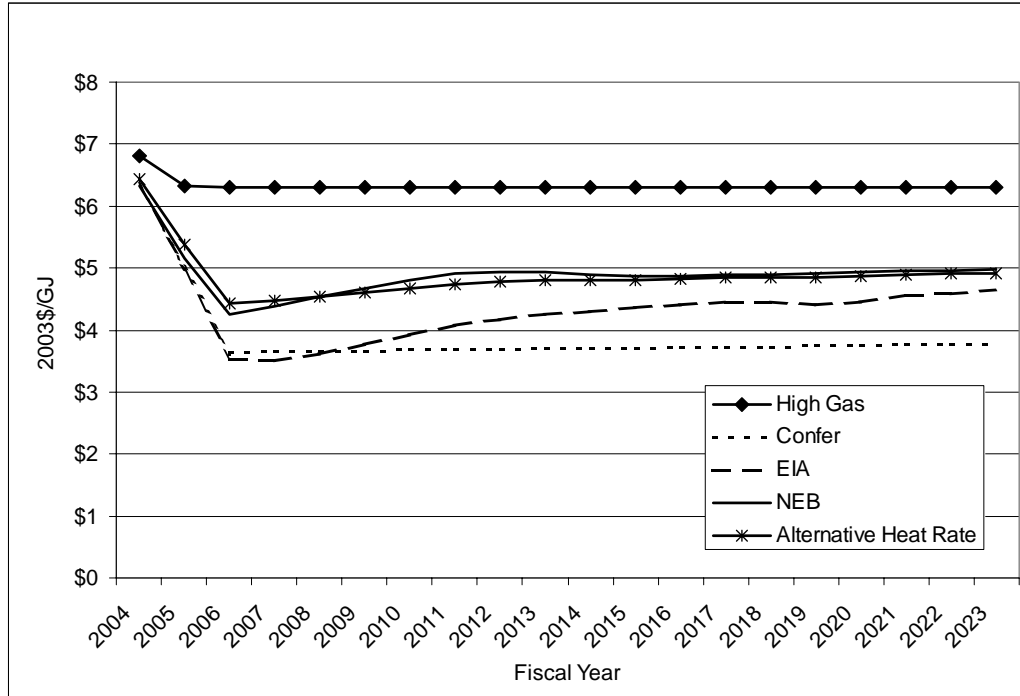
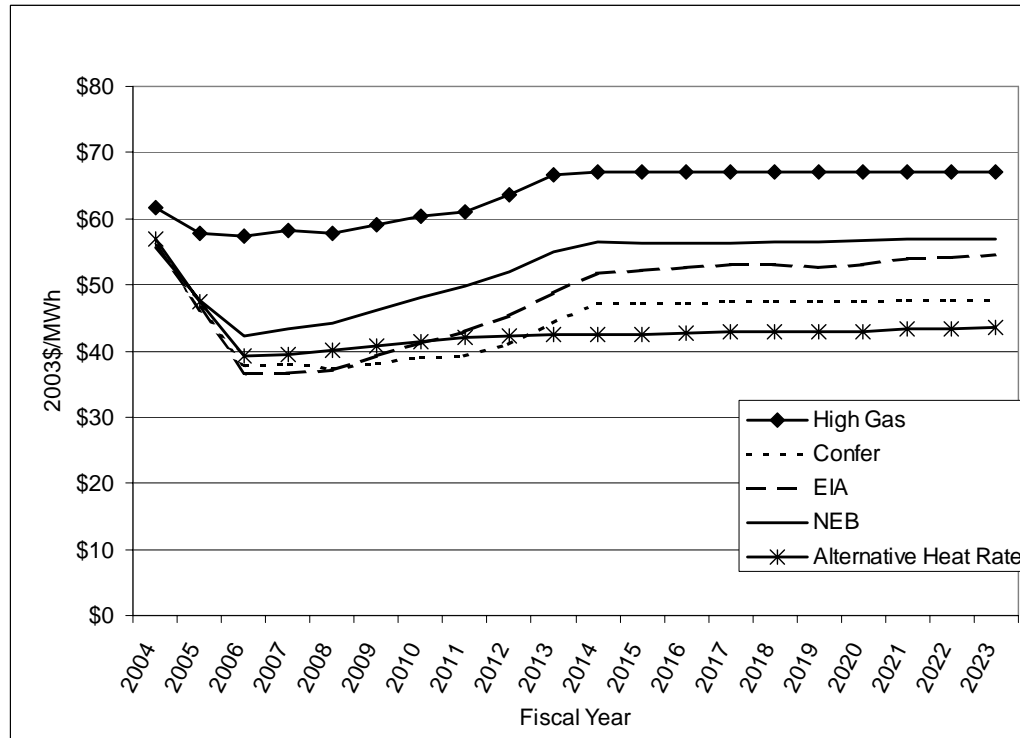


Figure 3.3. Electricity Price Scenarios at B.C. Border



3.4. Resource Scheduling

3.4.1. General Approach

The resources are scheduled in the portfolios so as to satisfy the energy and capacity planning criteria for each of the 20-year planning period. The firm energy and dependable capacity supply-demand balance presented in Part 2 of the IEP serves as a starting point for the scheduling process.

When adding new resources, the schedule effectively balances both the needs for energy and capacity. BC Hydro schedules capacity projects as well as energy projects to maintain a balance between energy and capacity needs. The type of resource additions depends on the energy and capacity characteristics of the individual resource. For example, run-of-river hydroelectric projects tend to have low dependable capacity compared to hydroelectric projects with streamflow regulation.

To evaluate portfolios with additional Power Smart beyond the current program, the load forecast is adjusted to account for the impact of existing as well as new Power Smart activities. This revised forecast is then used to schedule generation and transmission resources.

3.4.2. Energy Balancing

To facilitate comparison among portfolios, incremental energy is added to the portfolios such that all portfolios end up with same energy capability at the end of the scheduling period (F2018). All the portfolios are matched to the portfolio having the highest level of energy in F2018. The resources added to balance the portfolio have the same marginal cost, capacity characteristics and other attributes as the previous scheduled resource. The rationale for scheduling resources only until F2018 is as follows:

- To focus the analysis on the medium-term time horizon.
- The quantity of energy required in F2018 is large enough to schedule and test different types of resources without having to rely on less certain and higher priced resources, which are typically scheduled last in the supply curve.
- Beyond F2018 any additional resource requirements are satisfied by spot market purchases.

3.4.3. Least-Cost Capacity Resources

The least-cost capacity resources are the new generating units at Revelstoke and Mica dams. The powerhouse at both of these facilities accommodates the existing four units and also has a provision for adding two new generating units. This new potential of 1,740 MW (four new units, two each at Revelstoke and Mica) of dependable capacity is cheaper than the next best capacity resource a simple cycle gas turbine (SCGT)⁷, even after considering the required transmission. For example, the capital cost of Revelstoke Unit 5, which provides 480 MW of new dependable capacity is \$105 million, which is equivalent to \$220/kW. By comparison, the capital cost of a 47 MW SCGT is \$37 million, which is equivalent to \$790/kW.

⁷ The SCGT has a lower capital cost than a CCGT, and is therefore used as a peaking plant.

BC Hydro is currently studying the operational advantages of these new units to determine the sequence of capacity additions of Revelstoke 5 and Mica 5 (the costs of the units are similar). The IEP assumes that Unit 5 at Revelstoke would be built first, followed by Unit 5 at Mica and Unit 6 at Revelstoke and Mica, respectively.

Although the new capacity additions of Revelstoke and Mica provide relatively small amount of additional new energy capability, they are valuable as they provide flexibility to the BC Hydro system. These new capacity additions are expected to contribute to BC Hydro's ability to shape the electricity generation.

3.5. Portfolio Operational Simulation

3.5.1. Portfolio Modelling and Operational Simulation

After developing the schedule of resources in MAPA, the next step involves simulation of BC Hydro's system, including the planned new resource additions. This simulation is executed with BC Hydro's hydrological system simulation model or HYSIM. HYSIM has the ability to simulate the year-to-year variability in streamflow conditions and the sizeable energy storage capability of the system. HYSIM is used to determine the expected annual energy generation, including imports and exports, based on the resources scheduled in the portfolios.

The HYSIM simulation is executed over the range of historical streamflow conditions for each of the gas and electricity price forecast scenarios in Section 3.3.3. The gas price forecast is used to calculate the fuel cost for gas-fired resources, such as Burrard, Island Cogeneration Project (ICP) and the future CCGTs, by multiplying the gas price (after fuel tax) and the plant's heat rate. The corresponding monthly HLH and LLH electricity prices represent the cost of imports and the value of exports.

Monthly import and export energy limits act as constraints in HYSIM. These constraints are the transmission intertie capabilities at various neighbouring jurisdictions. The intertie import and export capability is in the order of 1,950 MW and 2,400 MW, respectively. The monthly energy limits on the transmission intertie fall within the following range:

- Heavy Load Hour imports 750 to 850 GWh
- Light Load Hour Imports 550 to 650 GWh
- Heavy Load Hour Exports 900 to 1,100 GWh
- Light Load Hour Exports 600 to 900 GWh

In addition to the intertie capacities, the imports are constrained by the generation limits on the BC Hydro system, which includes the minimum required flow constraints to support fish, the contribution of non-dispatchable generation and the generation constraints associated with meeting system inertia requirements.⁸ HYSIM captures the impact of the first two minimum generation constraints but does not consider the issue of inertia. The main constraint for export to the U.S. is not the intertie capabilities, but the Interior-to-Lower Mainland transmission capability, which restricts HLH exports in winter. HYSIM currently does not capture this export limitation.

⁸ At times, particularly during periods of low load, generation within BC transmission regions must be run at minimum levels to avoid unacceptable frequency excursions in the event of a system disturbance.

HYSIM dispatches⁹ the existing and new resources scheduled in the portfolio to meet domestic energy requirements for each year of the 20-year planning horizon. HYSIM dispatches the resource based on its variable operating cost or dispatch cost, that is resources with lower dispatch cost are dispatched first. This includes the energy from take-or-pay IPP contracts.

- HYSIM then uses BC Hydro's run-of-river hydroelectric and smaller hydroelectric projects that do not have significant storage capability. Their variable cost is the provincial water rental fees.
- For hydroelectric projects with significant reservoir storage, the dispatch is based on the value of water stored in the reservoir. That is an estimate of the expected future cost savings that could be realized by not dispatching the water in the current planning period and instead storing it for future generation. In other words, the value of water represents the opportunity cost of releasing water in the current time period rather than storing it for future use. This considers factors such as current reservoir elevations, available reservoir storage and the range of potential future inflows.

To determine the economic dispatch from the hydroelectric capability, HYSIM compares the value of stored water in each month to the variable cost of dispatchable thermal resources (such as Burrard, Island Cogeneration Project and any future CCGTs) as well as the cost of imports and the value of exports. Depending on the monthly electricity price, HYSIM may schedule imports rather than dispatching higher-cost resources.

To assess portfolio performance under a range of future streamflow conditions, the dispatch for each of the 20 years is simulated for 60 historical streamflow sequences. These 60 streamflow sequences are based on historical data from 1940 through 2000.¹⁰ These sequences cover a range of water conditions from low to high, which provide a large enough sample to accurately estimate the average hydroelectric output. Generation output for each year is calculated by averaging the resulting 60 dispatch scenarios corresponding to the each streamflow sequence. The results provide the expected 20-year monthly dispatch of each resource and corresponding expected imports and exports.

The expected generation obtained from HYSIM, along with gas and electricity price forecast data, is used to calculate the annual variable operating costs of gas-fired resources, the cost of imports and the revenues from exports. The expected generation from the hydroelectric system is used to calculate its variable cost, which is predominantly water rentals. The MAPA model incorporates these variable costs into the discounted cash flow analysis.

The expected generation is also used to calculate other portfolio attributes, such as annual greenhouse gas and local emissions, which depend on the expected generation from the thermal resource. This information is consolidated in MAPA.

⁹ Dispatchability refers to a supply-side or demand-side resource that can have the power output adjusted for short-term variation in load or resource balance due to weather changes, unit outages, market price changes and non-power considerations.

¹⁰ The first 20-year sequence matches the F2004 to F2023 load years with the historical water conditions from 1940/41 to 1959/60. The second 20-year sequence matches the F2004 to F2023 load years with the historical water conditions from 1941/42 to 1960/61, and so on. Later sequences match the load years to the historical water conditions up to 2000/01 and then loop back to 1940/41.

3.6. Evaluation of Portfolio Attributes

BC Hydro evaluates the portfolios based on a set of system performance attributes. These attributes are calculated in MAPA with input from HYSIM.

The 2004 IEP considers four key performance attributes, which align with the B.C. Energy Plan and the BC Hydro planning objectives. These attributes track the performance of the portfolios under a range of future conditions such as the five gas and electricity price scenarios. In addition to the four key portfolio attributes, the analysis also tracks supplemental environmental, social and economic attributes for each portfolio.

Table 3.2 summarizes the performance attributes used in the 2004 IEP. The attributes are quantified in terms of their primary measurement unit, for example, real dollars for the net present value of costs, percentage of rate impact, tonnes of emissions or hectares of footprint. Monetary effect of greenhouse gas emissions on portfolio performance is assessed by scenario analysis. Table 3.3 depicts the alignment of supplementary attributes.

For comparison purposes, the analysis assembles a summary of the performance of each portfolio over the 20-year evaluation period for all of the attributes across each of the five gas and electricity price scenarios. The annual performance of each portfolio is tracked in MAPA.

The following sections describe the attributes used in portfolio evaluation.

3.6.1. Net Present Value

MAPA calculates the net present value (NPV) of costs for BC Hydro projects for each portfolio by discounting costs and summing it over the 20-year planning horizon. The NPV is the sum of the present value of the capital and fixed annual and variable operating cost and cost of imports net of exports. The cost for the IPP projects includes only the contract costs and the variable operating cost.

The NPV analysis does not include costs that are common across all the portfolios, such as the fixed costs of existing resources. The NPV analysis also includes the costs associated with DSM, generation and transmission additions, plus the incremental costs associated with the existing system. All costs are represented in real 2003 dollars. The NPV is calculated using a six per cent real discount rate with sensitivities performed at eight per cent and 10 per cent.

Most of the resource options have an economic life that extends beyond the 20-year planning period. Adjustments are therefore made to the NPV to reflect the costs and benefits that continue beyond the planning period. Without this adjustment, any longer-lived resources would be disproportionately penalized, because all of their capital costs would be included within the planning period, whereas most of the benefits that accrue during their useful lives would not be included.

This end-value adjustment to the NPV of each portfolio is done with the residual, or salvage value, adjustment. This adjustment adds an estimate of the residual value of each resource at the end of the planning period. Thus a 25-year life project with little residual value would get very little value added back, whereas a 70-year project that still had a long life expectancy might get a significant value added back. The assumed economic lives of the resource options are given in Part 3.

Table 3.2. Summary of Portfolio Attributes

Four Key Performance Attributes		
Attribute	Unit of Measure	Objective
Net present value (NPV)	Discounted cash flow of total cost less export revenues in real 2003 dollars	Minimize ratepayer costs
Reliability planning criteria	Meets criteria (Yes/No)	Secure and reliable supply
Private sector involvement	Percentage of new energy provided by private sector Percentage of new energy owned by private sector	IPP involvement
Clean target	Percentage of newly acquired energy (GWh) that meets the definition of BC Clean Energy	50% Clean target

Supplementary Attributes		
Attribute	Unit of Measure	Objective
Rate impact	20-year change in rates (net of inflation) relative to first year	Minimize ratepayer costs
Dependable capacity	MW of installed capacity MW of dependable capacity	Secure and reliable supply
Diversity	Number of new resource types	Secure and reliable supply
Employment	Temporary/construction (person-years) Long-term (full-time equivalents)	Social responsibility
Greenhouse gases and Local emissions	Greenhouse Gases: Tonnes of CO ₂ equivalent. Local Emissions: Tonnes of nitrogen oxides (NO _x), sulphur oxides (SO _x), and particulate matter (PM)	Social responsibility Environmental responsibility
Footprint	Hectares of total surface area affected by a portfolio	Social and Environmental responsibility
Communities	Qualitative comments with respect to stakeholder feedback or affected communities	Social responsibility

Table 3.3. Alignment of Supplementary Attributes

Attributes	Low-cost Electricity	Secure and Reliable Supply	Social Responsibility	Environmental Responsibility
Rate impact	✓			
Dependable capacity		✓		
Diversity		✓		
Employment			✓	
GHG and local emissions			✓	✓
Footprint				✓
Communities			✓	

3.6.2. Reliability Planning Criteria

Portfolios are checked to determine if they meet the reliability planning criteria.

3.6.3. Private Sector Involvement

Private sector opportunities generated by the resource additions in the portfolios are tracked by the following measures:

- percentage of private sector involvement;¹¹ and
- percentage ownership by the private sector.

3.6.4. Clean Target

This attribute measures the percentage of new load met by Green Energy since November 2002. The results are shown as of F2013 and F2018.¹²

3.6.5. Rate Impact

The rate impact attribute is used to compare the relative changes in the portfolio units costs (\$/MWh) across various portfolios. For each portfolio, the attribute also measures the relative changes to the unit costs (\$/MWh) across a range of gas and electricity prices.

Rates are estimated by dividing the total annual costs by the annual billable load. To estimate the relative change of the rate impact over the 20-year planning period, a "levelized rate" is calculated and compared to a base or benchmark rate, which is representative of the first year's total system cost.

To estimate the rates in the future years, the capital costs associated with resource additions are first converted to uniform annual charges. These charges are calculated by using a six per cent real discount rate and an amortization period matching the lives of the resources. Future rates are then calculated by increasing each year's cost from the base year's cost by the annualized cost of the resource additions, including the electricity imports and exports, and dividing the total annual cost by the total annual domestic sales.

The levelized rate is equal to the ratio of the present value of the annual costs over the planning horizon and the present value of the forecasted annual domestic sales. The levelized rate impact is the ratio of the levelized rate and the benchmark rate.

3.6.7. Dependable Capacity

This attribute records the installed and dependable capacity of resource additions in a portfolio. Installed capacity is the capacity rating of the project under ideal or unconstrained operating conditions. Dependable capacity takes

¹¹ Private sector involvement is based on the percentage of total program or project dollars that are allocated to the private sector. It indicates how much of the design, build, and operation activity is performed by the private sector.

¹² As outlined in the B.C. Energy Plan, BC Clean electricity refers to alternative energy technologies that result in a net environmental improvement relative to existing energy production. The scope of the "BC Clean" definition is subject to further refinement and approval by the Minister of Energy and Mines.

into consideration external limitations that affect the capacity a resource can reliably provide to meet the peak demand. For example external limitations for hydroelectric resources include reservoir elevations and flow limitations.

Dependable capacity is an important attribute for resource options. Many green and alternative resources have low dependable capacity because they depend on intermittent natural resources such as wind, wave and tidal current. This attribute contributes to an understanding of how the individual portfolio resources complement one another. Differences in the dependable capacity between resource options is accounted for in the NPV analysis, since resources that make less contribution to meeting dependable capacity requirements result in the advancement of other capacity resources.

3.6.8. Diversity

A common approach to managing risk involves diversification across multiple resource technologies. Each resource technology has its own advantages and disadvantages. Thus, uncertainties about supply, future gas and electricity price markets, legislative changes regarding emissions control standards, and costs for local emissions suggest a need for a diversified portfolio. The diversity attribute records the number of types of resources in a portfolio over time.

3.6.9. Employment

This attribute measures the direct employment in each portfolio over 20-year planning period. The employment attribute record the amount of work generated on a short-term basis (the number of person-years during construction) and long-term basis (the number of full-time equivalent employees).

3.6.10. Greenhouse Gas Emissions and Local Air Emissions

The measures in the Kyoto Agreement, which Canada has ratified, are aimed at reducing GHG emissions. GHG emissions include carbon dioxide (CO₂), carbon monoxide (CO) and methane (CH₄), which result from fossil fuel combustion. The latter two can be expressed as CO₂ equivalent emissions. The GHG attribute presents the total cumulative GHG emissions, in CO₂ equivalent, from BC Hydro and IPP sources, over the 20-year planning period and therefore represents the total greenhouse gas emissions from BC Hydro's owned and contracted resources.

Local emissions effect local air quality and include nitrogen oxides (NO_x), sulphur oxides (SO_x), and particulate matter (PM). The local air emissions attribute tracks emissions in tonnes.

3.6.11. Footprint

Most of the 2004 IEP portfolios are not project-specific, which means that the precise location and the environmental impacts of specific resource options is unknown. Consequently, an assessment of the environmental impact of the total portfolio is difficult. The footprint attribute gives an indication of portfolio impact on the environment. It shows the total surface area (in hectares) affected by a new resource addition. The surface area of the resource types within a portfolio are summed into a total footprint and could include dam sites with reservoirs, new penstock corridors, thermal sites, wind farms, wave farms, auxiliary structures such as new access roads, and new transmission lines. Part 3 of the IEP describes how the footprint of a resource type is derived.

3.6.12. Communities

This attribute reflects qualitative statements made by affected communities and organizations with respect to the resources in the portfolios. The statements can include descriptions or comments on the resource options, a community's expressed opposition to, or desire for, certain types of developments, and other First Nations and stakeholder feedback.

4 Portfolio Evaluation, Risk and Sensitivity Analysis

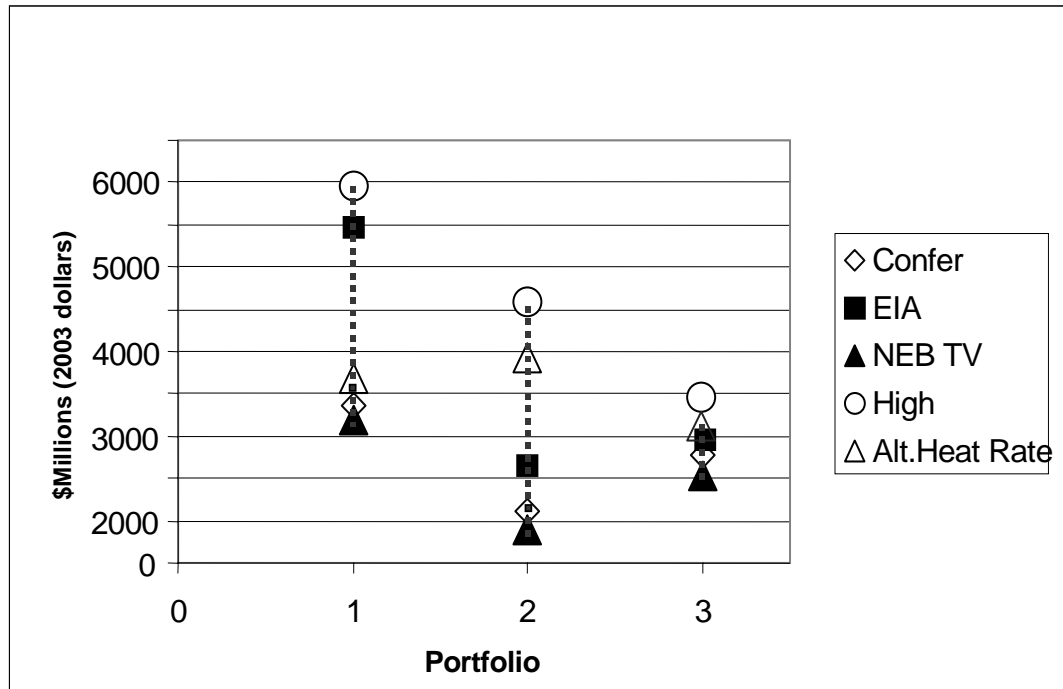
4.1. Objective of Risk Analysis

The evaluation process assesses the portfolio performances for the expected conditions. The next stage involves testing the portfolio performances over a wide range of conditions. The intent of the evaluation is to focus discussion on portfolios that have different risk profiles.

Risk is defined as the magnitude of an attribute's variability for a range of key input scenarios. For example, a portfolio that has less exposure to gas price volatility will show a small range of variability in the net present value attribute over the range of five gas and electricity market conditions.

Figure 4.1 illustrates the importance of considering the variability of the NPV in addition to the objective of identifying the least-cost portfolios. The NPV cost of Portfolio 1 is generally higher under all price scenarios. The NPV cost of Portfolio 2 is lower than Portfolio 3, but has greater risk (a larger magnitude of variability) than Portfolio 3. It may therefore be preferred to acquire the resources associated with Portfolio 3.

Figure 4.1. Hypothetical Comparison of Portfolio Costs



4.2. Risk Assessment

BC Hydro's risk exposure is evaluated using HYSIM, scenario analysis and sensitivity analysis. The purpose of the risk assessment is to identify the portfolios that have the least risk exposure under a range of possible future conditions.

4.2.1. Streamflow Variability

Historically, annual streamflow conditions for the BC Hydro system have varied randomly or stochastically. As discussed in Section 3.5, HYSIM model simulates the operation of the 20-year portfolios over the range of the historical streamflow records for BC Hydro's system to derive the expected generation from each resource in the portfolio and expected imports and exports. This is done by averaging the results from sixty 20-year water sequences. The model uses that expected generation to derive the 20-year NPV of the variable cost of the portfolio. By conducting this detailed system simulation over the range of water conditions, the impact of streamflow variability over the long term is reflected in the analysis.

4.2.2. Scenario Analysis

Scenario analysis is used to evaluate gas and electricity market price uncertainty, load forecast uncertainty and regulatory uncertainty associated with future greenhouse gas regulation.

Market Price Uncertainties

The NPV cost of the portfolios is evaluated for each of the five gas and electricity price scenarios described in Section 3. This involves simulating the operation of the system for each portfolio with each of the gas and electricity price forecasts to determine expected generation and expected variable cost net of export revenues. The analysis reviews the portfolios to establish which portfolios lead to the least market price risk.

Demand Uncertainties

Section 3.6 of Part 2 of the IEP, "Load Forecast Uncertainties," describes uncertainties of the long-term demand forecast. To reflect the overall uncertainties in the load forecast process, low and high load forecasts are developed in addition to the reference forecast. Scenarios with low and high demand forecasts are investigated as part of the risk evaluation to examine the impact of changes in the load forecast on the timing of major resource additions. The focus is to determine if a resource's lead time would accommodate the advancement of resources if they were required under a high load forecast scenario, and the impact of lower than expected load growth on the required timing of new resources, particularly large capital projects.

Uncertainties Regarding GHG Regulation

Changes in regulatory requirements can affect the economic cost of emissions for both greenhouse gas and local emissions and add uncertainty to future portfolio costs. To examine the potential cost impact of this future uncertainty, an emissions charge of \$10/tonne of GHG emissions was applied to the expected annual generation of the BC Hydro-owned or contracted thermal resources in each portfolio based on the GHG emissions rate for that resource.

4.2.3. Sensitivity Analysis

Sensitivity analysis is performed on key input parameters, such as the cost of generation projects and the discount rate.

Sensitivity analysis for generation project costs is based on the price uncertainty rating described in Part 3 of the IEP. Projects are ranked as low, medium or high for their price uncertainty, which correspond to the following price ranges:

- Low: –10% to +20% of expected cost
- Medium: –10% to +40% of expected cost
- High: –10% to +60% of expected cost

Table 4.1 summarizes the stochastic variables analyzed, and the scenarios and sensitivities performed as part of the risk evaluation process.

Table 4.1. Uncertainties Investigated in the Risk Evaluation Process

	Reference case	Scenario/Sensitivities Tested
Stochastic Variables Hydrological variability	60 years of monthly historical stream flows (1940-2000) in 20-year sequences	Variability of inflows intrinsically reflected in the analysis of each portfolio
Scenarios Gas and electricity market scenarios Demand scenario Environmental – Regulatory costs associated with GHG	No one market price forecast is assumed to be a base case Reference forecast No cost	Confer Energy Information Administration NEB Techno-Vert High Gas Alternative market heat rate Low forecast High forecast 10\$/tonne of GHG emissions from BC Hydro and IPP generation
Sensitivities Discount rate Supply – Generation capital cost and fixed costs and/or IPP contract fixed cost	6% real Expected cost	8% and 10% real Low: –10 to +20% of expected value Medium: –10 to +40% of expected value High: –10 to +60% of expected value