Appendix E – Thermal

E.1 Thermal Projects – Database Table of Contents

Appendix E - Thermal

E.2 Natural Gas Price Forecast Scenarios

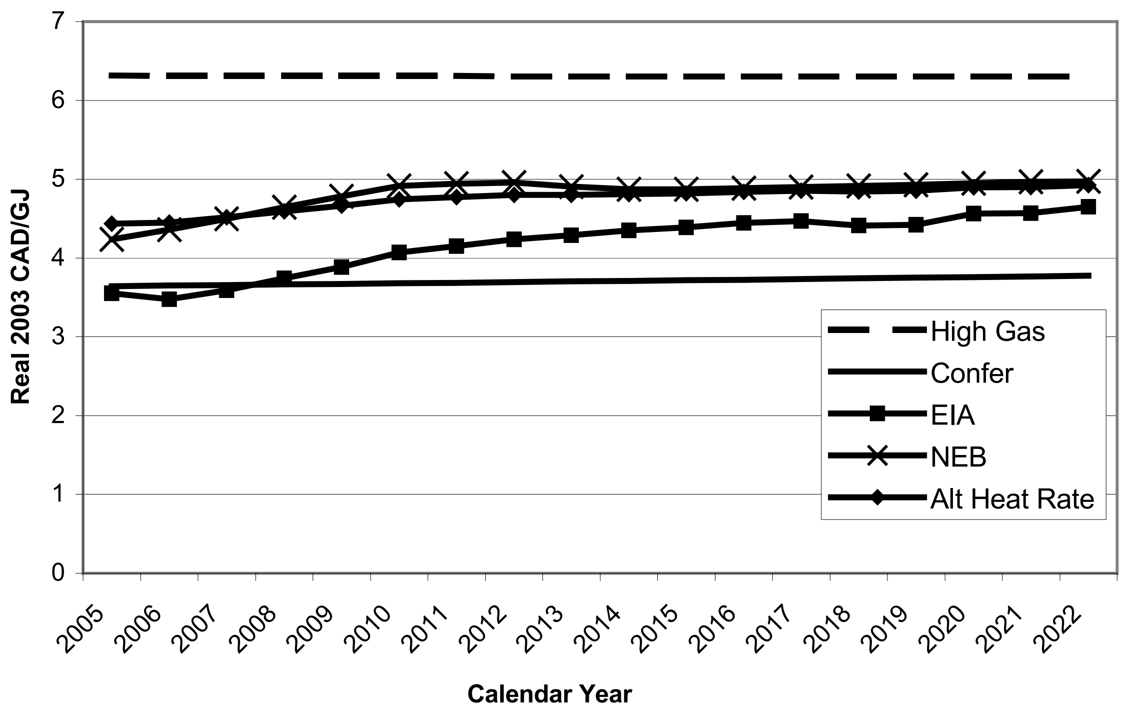
Unit energy cost estimates were developed for thermal options included in the database. A summary of the results is provided in the report.

BC Hydro has selected scenarios to represent a broad range of possible future outcomes. A levelized representative average cost of fuel for natural gas projects was estimated using four forecasts as described in this report and in more detail in Part 5 of the IEP.

Three third-party gas price forecasts are used: the long-run cost projection from the U.S. Energy Information Administration's (EIA) Reference Case; industrial consultant, Confer Consulting; and the National Energy Board of Canada's (NEB) Techno Vert Case. These forecasts provide a wide but plausible range of possible outcomes. As well, a high gas price forecast which extends current high gas prices into the future is also modelled. The scenarios are described in detail below:

Figure E.1 shows the gas price forecasts at the B.C. Border (Sumas). Additional detailsaround the forecasts used is described in the following sections.

Figure E.1. Gas price forecast at B.C. Border (Sumas)



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. The fifth scenario is specific to electricity prices, rather than natural gas prices, and is discussed in Part 5 of the IEP. For each scenario, there is a matching gas and electricity price forecast. Table E.1 summarizes the scenarios:

Table E.1. Market scenarios Used in IEP

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
Date Issued	December 2002	July 2003	January 2003	August 2003
Description	Relatively optimistic view of ability of technology to keep ahead of demand leads to relatively low price forecast.	Increased concerns about environment, significant improvements in technology, with government support, 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.	Continued present high price into the future. Captures the possibility that prices remain high or fluctuate around a high average.
Environmental Situation Assumptions	Moderate: Not major focus.	Strong: major focus.	Moderate. Considered in detail.	N/A
Technological Innovation Assumptions	Strong enough to keep prices low.	Strong. Environment enhancing and cost saving.	Moderate specification of technological parameters.	N/A

E.2.1 Energy Information Agency

The Energy Information Agency (EIA) of the U.S. Department of Energy produces annually a complete energy forecast, the latest one being reported in *Annual Energy Outlook 2003*, which was published in December 2002.

EIA's forecast is for all forms of energy and is linked to an economic outlook that specifies the rate of economic and population growth. The forecast is produced using substantial modelling resources; numerical projections are generated by the National Energy Modeling System (NEMS). Interactions between the different energy categories are estimated; prices and quantities are forecast simultaneously for all important energy categories including oil, coal, natural gas, electricity and green energy. The impact of macro-economic environment and of government regulation and policy is considered.

The EIA Reference Case aims to be the most reasonable and comprehensive forecast that can be made on the basis of currently available information. The approach is thorough and relies heavily on modelling.

For long-run natural gas prices, a key issue is whether technology and exploration will be able to keep pace with growing demand by finding sufficient supplies and developing them at an economic cost. On this issue, EIA's Reference Case position is that exploration and technology will have difficulty keeping up and that, as a consequence, real gas prices for natural gas will rise steadily in the long run.

The EIA Reference Case has U.S. real GDP growing at a rate of 3.0 per cent per year for the period from 2005 to 2025. For the same period, population grows at an annual rate of 0.8 per cent and the Consumer Price Index grows at 2.9 per cent.

Energy intensity (thousands of BTU per 1996 dollar of GDP) declines at the rate of -1.4 per cent per year.

Natural gas consumption, for the U.S. in the Reference Case, increases at 1.8 per cent per year from 24.60 trillion cubic feet per year in 2005 to 34.93 trillion cubic feet per year in 2025. Consumption of natural gas for electricity generation grows at 3.1 per cent per year over the period to 2025.

Imports of natural gas to the U.S. grow at 3.6 per cent per year from 2005 to 2025. These consist of imports from Canada growing at 2.1 per cent and liquefied natural gas from outside North America growing at 6.5 per cent. While the liquefied natural gas growth is higher, it starts from a very small base and remains well below the level of imports forecast from Canada. The EIA forecast shows new gas supplies from the Mackenzie Delta become significant from 2016 onward, with supplies from Alaska coming in 2021.

The world oil price is projected as $23.27 (in non-inflated 2001 U.S. dollars) per barrel in 2005 and $26.57 in 2025.

Current market prices for natural gas are higher than the EIA Reference Case projections. However, current high prices may not be sustained and the EIA forecast is based on long-run supply, demand and technological considerations. Over the period from 2005 to 2025, the Reference Case forecasts real wellhead natural gas prices in the U.S. will rise at a rate of 1.5 per cent per year. This steady increase reflects an expectation of tightening natural gas supplies relative to demand.

It should be noted that the EIA 2003 Reference Case price outlook was higher than the forecast made in 2002, in turn higher than the 2001 forecast. The upward trend in forecast prices reflects both the gradual extent of change in any large-model forecasting tool, as well as the steady flow of new information showing continued expectations for demand growth but continued softness in supply response.

E.2.2 Confer

Confer Consulting Ltd., a Calgary-based consulting firm that has provided services to BC Hydro since 1981, forecasts the lowest natural gas price scenario among the base cases of the various price outlooks (based on Confer Consulting Ltd.'s forecast presented to BC Hydro on December 12, 2002). Its long-run marginal cost (LRMC) of natural gas at the Henry Hub, one of the major North American gas system hubs, increases slowly from $3.14 (in non-inflated 2002 U.S. dollars) per MMBtu in 2005 to $3.20 in 2025.

The lower level of Confer's price forecast as compared with EIA is due to Confer's view that demand in North American for natural gas will be lower than forecast by the EIA and that improvements in technology will continue and lower the cost of new gas supply below that forecast by the EIA. Confer states that:

> "…reliance on improvements in technology and on demand responses to higher prices result in real future increases in LRMC at modest levels." And,
>
> "The challenge in forecasting the longer-term future path of LRMC focuses on the balance between technology and resource location and condition. By forecasting ever-increasing real prices to the end of its forecast outlook in 2025, the AEO concludes that there will not be equilibrium between these forces in the future and that the increase in costs of resource location and condition will, from now on, be such that the benefits of technology

improvements will fail to mitigate real price increases. On the other hand, Confer's outlook, and those of other parties that do not have as steep a price increase as the AEO, is based on a more stable balance between these two forces."

The basic analysis performed by Confer is to examine the underlying factors that drive the demand for natural gas in North America, and then assess the supply potential to meet demand at economic prices. The potential supply is assessed by analyses of the long-run marginal cost of new gas supply; that is, the full cost of investing in and operating new gas supply through its economic life. Several supply sources and technologies are assessed. Strong demand growth expectations for natural gas cause the need to examine the long-run marginal costs of supply from remote areas, such as the Mackenzie Delta; non-conventional technology, such as coalbed methane; and imports of liquefied natural gas.

Confer points out that in the EIA Reference Case, a large fraction of incremental gas supply comes from the Western U.S. where costs have higher historical levels, but where supply has increased significantly in the past several years. Confer sees significant supplies from liquefied natural gas, Mackenzie Delta becoming available sooner than the EIA estimates at costs that are higher than historical supply costs but still economic. Confer forecasts that the Mackenzie pipeline may be built by 2009 and Alaska some time well after 2012, whereas EIA indicates 2016 for Mackenzie and 2021 for Alaska. Confer notes that liquefied natural gas imports have become economic and can be expected to increase supply. Confer estimates the LRMC of Mackenzie gas delivered to the Alberta AECO hub to be in the range U.S.$2.15 to $2.35 per MMBtu. This would correspond to a Henry Hub price of $3.00 or less, all based on an exchange rate of U.S.$0.64 per C$1.00. Confer also stresses that sustained high gas prices will lead to significant demand destruction. The EIA outlook may underestimate this demand effect.

E.2.3 National Energy Board of Canada

The latest long-term natural gas forecasts of the National Energy Board of Canada (NEB) are reported in Canada's Energy Future: Scenarios for Supply and Demand to 2025, July 2003. The previous NEB forecast was issued in 1999.

Unlike the EIA, which produces scenarios based on massive data sets integrated by means of a large-scale model, NEB sets out two pictures of the future to assess the pace of technological development and the level of action on environmental issues. The first scenario, called Techno-Vert, is characterized by high action on the environment and a high pace of technological development.

The main theme of the Techno-Vert scenario is heightened concern for the environment leading to environmentally friendly products and cleaner burning fuels. Customers are willing to pay more for these features and prices of energy are higher. While governments assist with research and development program funding, reliance is primarily placed on market solutions. New technologies increase energy supplies and efficiency of utilization. Productivity is high resulting in high economic growth.

In the Techno-Vert scenario, real Canadian GDP grows at a rate of 2.7 per cent per year from 2001 to 2025. Energy intensity declines at the rate of 1.7 per cent per year. The Canadian Consumer Price Index grows at 2.0 per cent and Canadian population grows at 0.6 per cent. Energy demand in Canada grows by one per cent per year.

Oil prices are assumed to be a constant $22 (in non-inflated 2001 U.S. dollars) per barrel for the whole period from 2005 to 2025. This compares with EIA's projection of $23.27 in 2005 and $26.57 in 2025.

The NEB Techno-Vert scenario results in natural gas demand being relatively high, because of the clean-burning qualities of natural gas in an arena of enhanced environmental concern. The additional demand puts upward pressure on gas prices, which are uniformly higher than the EIA Reference Case in all of the period from 2005 to 2025. Henry Hub prices in Techno-Vert increase from $3.53 (in non-inflated 2002 U.S. dollars) per MMBtu in 2005 to $4.06 in 2025 giving an average growth rate of 0.7 per cent per year. The higher prices increase supply from conventional and non-conventional sources of production.

E.2.4 High Gas

Natural gas prices for the year 2003 seem headed to establishing a record high average annual value, estimated in September 2003 to be $5.29 (in non-inflated 2002 U.S. dollars) per MMBtu at Henry Hub. This scenario is not based on any model or analytics. The high gas scenario simply assumes that this high market price persists in real terms to 2025. Given the unique set of circumstances that created the high prices in the first half of 2003 (low storage and coldest winter in 20 years in the East), and the current supply response, it is very unlikely that these prices could persist for an extended period.

Therefore, this scenario should not be used on the same basis as the previous three forecasts referenced. The High Gas case should only be used as a "stress test" in performing economic evaluations.

E.3 Coal, Oil and Diesel Price Forecasts

One scenario was used to evaluate coal, oil and gas prices and that was the U.S. Department of Energy EIA forecasts. Figures E.3 through E.5 display BC Hydro's forecasts for these fossil fuels.

Figure E.3. Coal Price Forecast

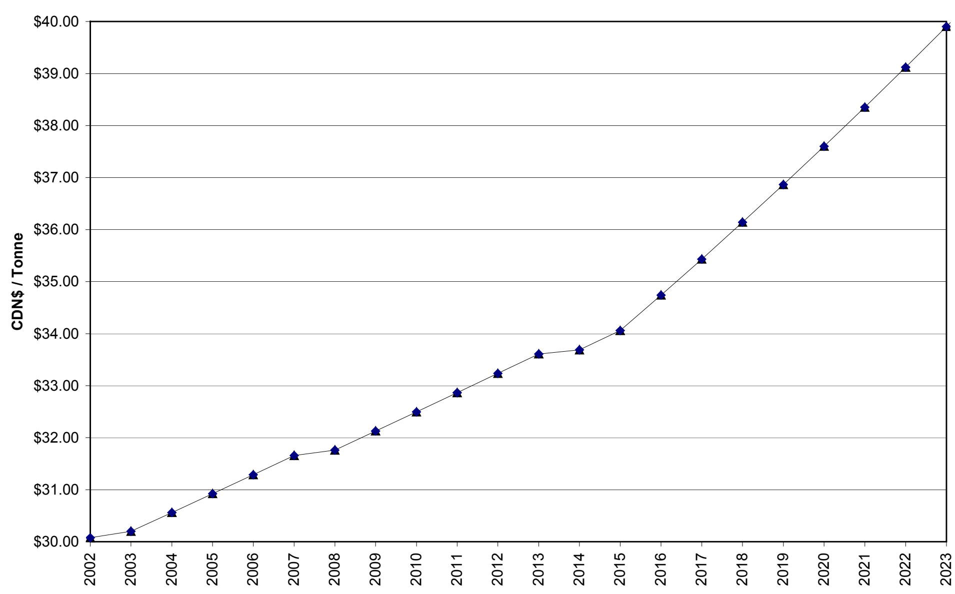


Figure E.4. Oil Price Forecast

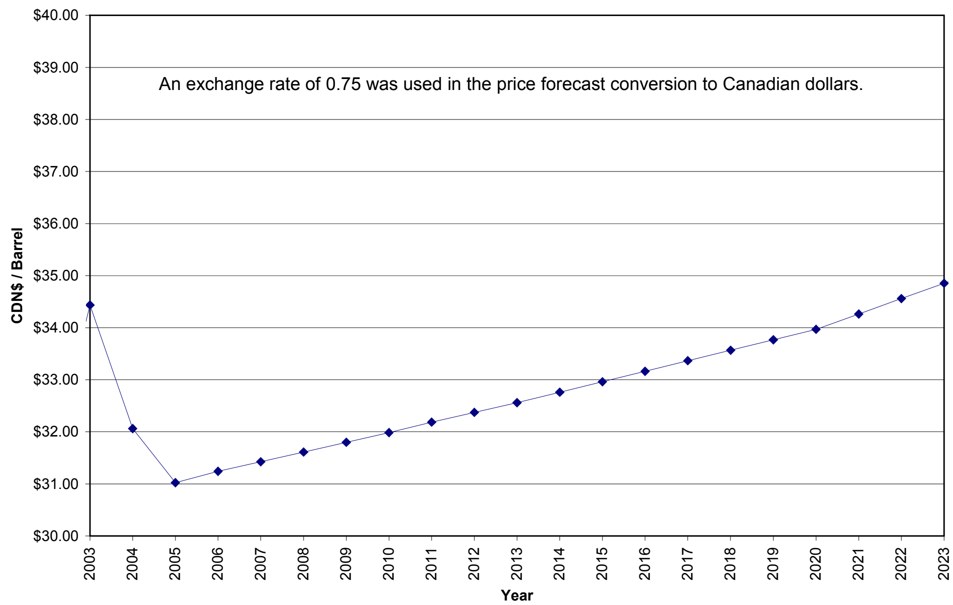
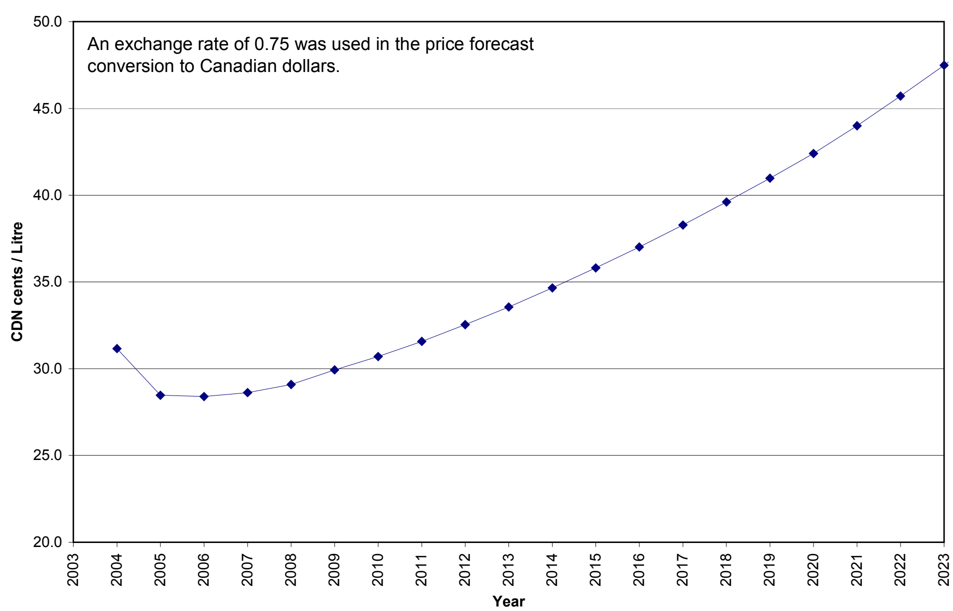


Figure E.5. Diesel Price Forecast



E.4 Cogeneration Estimates

The national study used seven different price and policy scenarios to estimate the cogeneration potential in Canada, including high electricity prices, high gas prices, total technically achievable and other factors.

Two scenarios of interest were evaluated for the 2004 IEP:

Business As Usual simulates the amount of cogeneration that would be installed with no new policy or price interventions.

Business as Usual Cogeneration Potential for B.C. (MW)

Year	1995	2000	2005	2010	2015
Industrial Sector	240	228	237	257	273
Commercial	0	4	7	10	13
Residential	0	0	0	0	0
Total	240	232	244	267	286

Total Achievable Potential estimates the maximum amount of cogeneration likely to be installed with new policies and prices (i.e., not quite as high as total *technically* achievable).

Total Achievable Cogeneration Potential for B.C. (MW)

Year	1995	2000	2005	2010	2015
Industrial Sector	2,073	2,140	2,246	2,398	2,564
Commercial	635	704	731	794	835
Residential	1,477	1,562	1,351	1,443	1,395
Total	4,185	4,406	4,327	4,635	4,794

For the 2004 IEP, the Business As Usual scenario was used to confirm the estimate of overall cogeneration potential in B.C. The Business As Usual scenario was selected since the national study recommended its use in forecasts such as the Canadian Emissions Outlook Update.

PROJECT: **Natural Gas Fired IC Engines**

Resource Category: Thermal - Natural Gas   Level of Study: Unknown   Region: All

PROJECT DESCRIPTION

Reciprocating or Internal Combustion (IC) engines are the most common and technically mature of distributed energy technologies. They are available in small sizes (e.g., 5 kW for residential back-up generation) to larger generators (e.g., 7 MW). When used in combination with a 1-5 minute UPS (uninterruptible power supply), the system is able to supply seamless power during a utility outage. In addition, larger IC engine generators may be used as base load, grid support, or peak-shaving devices.

IC engines convert the energy contained in a fuel into mechanical power. This mechanical power is used to turn a shaft in the engine. A generator is attached to the IC engine to convert the rotational motion into power. There are two methods for igniting the fuel in an IC engine. In spark ignition (SI), a spark is introduced into the cylinder (from a spark plug) at the end of the compression stroke. Fast-burning fuels, like gasoline and natural gas, are commonly used in SI engines. In compression ignition (CI), the fuel-air mixture spontaneously ignites when the compression raises it to a high-enough temperature. CI works best with slow-burning fuels, like diesel. This resource option describes a generic 7MW Natural Gas Fired Spark Ignition Internal Combustion Engine - 7MW represents the upper range of available data.

Please refer to "Other Thermal" Resource options section for an equivalent analysis on Diesel IC Engines.

FINANCIAL INFORMATION

Total Capital Cost ($1000s of 2003$)	$3,100
Fixed Operating And Maintenance Cost ($1000s/year)	$187
Variable Operating And Maintenance Cost ($/MWh)	$69
Project Life (Years)	30
Project Lead Time (Years)	1
Unit Energy Cost ($/MWh)	$172

All financial figures represent a natural gas engine acting as standby power and running for 500-1000 hours annually. Total Capital Cost figures are for the basic genset cost alone. The total installed cost is site specific but is usually 50-100% more than the engine itself. As a rule of thumb, Capital and Operating and Maintenance (O&M) costs for natural gas engines are on average roughly 25% higher than the costs for the diesel engine. Another way to look at it is that a natural gas engine yields 75% of the energy provided by a diesel engine, for an equivalent cost.

Project capital costs were broadly estimated based on BC Hydro experience that peaking generators with natural gas or multiple fuel capability are at least 30% more expensive than their similar capacity diesel counterpart. Please see the diesel peaking project description for further discussion.

Variable O&M costs do not include the cost of the fuel and include:
* IC engine heads and blocks rebuilds after about 8,000 hours of operation.
* Regular oil and filter changes at 700 - 1000 hours of operation.

Unit energy costs for thermal resource options depend largely on the market price of fuel and plant usage, which varies over time. In order to provide a unit energy cost estimate for thermal resource options a fixed set of financial assumptions and the resource option spreadsheet-model were used, as outlined in the Resource Option report. It was assumed that dispatch was 20% for smaller peaking thermal projects in order to estimate an annual average energy and representative unit energy cost.

Natural gas project unit energy costs were estimated using gas prices from BC Hydro's four gas price scenarios. Using these scenarios the unit energy costs ranged from $159/MWh to $193/MWh. A representative unit energy cost of $172/MWh, based on the average of the four gas price scenarios is presented here.

Unit energy costs for projects used for peaking, such as simple cycle and internal combustion engines, tend to be much higher because dispatch is lower than plants used for base load.

Natural gas is usually less expensive than diesel fuel for the same heat content. If the IC engine is to be used for a large number of hours per year, the total cost to operate the gas unit may be lower. Natural gas may not be available at all locations, while diesel can be transported anywhere. However, diesel engine emission levels are higher and their use is significantly restricted in in some parts of the world.

PROJECT: **Natural Gas Fired IC Engines**

Resource Category: Thermal - Natural Gas		Level of Study: Unknown		Region: All

TECHNICAL INFORMATION

Installed Capacity (MW)	7
Average Annual Energy (GWh/year)	11.7
Dependable Capacity (MW)	6.7
Firm Energy (GWh/year)	11.7
Average Heat Rate (GJ/GWh)	9426

Dependable capacity is assumed to be 95% of installed capacity. It was assumed that dispatch was 20% for small thermal projects used for peaking in order to estimate an average annual energy value for calculation of a representative unit energy cost. Firm energy estimates were based on the assumption that a firm fuel contract would be available and contracted.

One of the weaknesses of IC engines is the frequency of maintenance intervals. When used as in standy power, the frequency of maintnenance is no longer an issue (maintenance performed during the down time) and the genset is avalable for electricity production 100% of the time.

Reciprocating engines may last for 20-35 years while smaller engines (<1MW) tend to have shorter lifespans. Reciprocating engines have efficiencies that range from 25% to 45%. In general, diesel engines are more efficient than natural gas engines because they operate at higher compression ratios.

Average heat rate values for Natural Gas IC engines range from 9,500 to 10,900 GJ/GWh depending on the type and size of engine, the application of the engine, and the source of the data. The higher heating values are associated with small, high speed, natural gas-fired, spark-ignited units.

SOCIAL AND ENVIRONMENTAL INFORMATION

Meets BC Hydro Clean Criteria	No
Greenhouse Gas Emission Factor (Tonnes CO2 equivalent/GWh)	510

Atmospheric Emissions (Metric Tonnes/GWh)	SOx	NOx	CO	VOC	PM 10	PM 2.5	Hg
	0.0055	0.07	0.22	0.75	0.07	Unknown	0

Project Footprint (Hectares)	1

Note: Some footprint aspects have not been estimated specifically.

Emission rates for a particular type and size ranges of engines vary from manufacturer to manufacturer. Similarly, emission rates for each type of engine within a manufacturer's product line may vary considerably from the smallest to the largest units in the line. Reasons for these variations include differences in combustion chamber geometry, fuel air mixing patterns, fuel/air ratio, combustion technique (open chamber), and ignition timing from model to model.

Three basic types of emission control systems for ICEs include:
* Three-Way Catalyst (TWC) Systems - reduce NOx, CO and unburned hydrocarbons by 90% or more. TWC systems are widely used for automotive applications.
* Selective Catalytic Reduction (SCR) - SCR is normally used with relatively large (>2 MW) lean-burn reciprocating engines. In SCR, a NOx-reducing agent, such as ammonia is injected into the hot exhaust gas before it passes through a catalytic reactor. The NOx can be reduced by about 80-95%.
* Oxidation Catalysts - promote the oxidation of CO and unburned hydrocarbons to CO2 and water. CO conversions of 95% or more are readily achieved.

The figures in the table above represent an average of controlled emission data for a Wartsila IC Natural Gas engine of 7.7 MW.

The project footprint was assumed to be nominally 1 ha. This assumption was based on a fraction of the footprint size for the larger thermal fuel projects.

The project footprint estimates for most thermal projects does not include a "life-cycle" footprint, but rather the physical footprint attributable to the turbine and associated equipment. Infrastructure such as pipelines and roads, and footprints associated with the fuel sources (such as gas wells, coal mines, and roads), have not been included here in these estimates.

Job Creation

Construction Jobs Created (Person-years)	Unknown
Permanent Jobs Created (Full time equivalents)	Unknown

No data on employment was available.

PRIVATE SECTOR INVOLVEMENT

Estimated Level of Private Sector Involvement	100%: Private sector ownership

UNCERTAINTY

Development Uncertainty	Medium

This option is for a proven technology, however without economic or regulatory drivers significant development is unlikely.

Price Uncertainty	Low

Price uncertainty is low since this is standard equipment and costs were provided by equipment supplier.

REFERENCES

Wartsila, Wartsila Performance Data for Internal Combustion Engine, http://www.wartsila.com/english/index.jsp, 2003.

Amec, Report 142194, "2004 Integrated Electricity Plan - General Thermal Review", January 2004.

AMEC, E&C Services Limited (D. McCann), Document entitled: Thermal Power Plant Performance, Emissions and Costs Review, November 2003.

Electrical Power Research Institute, Technical Assessment Guide (TAG) - Distributed Resources, January 2002.

California Energy Commission, Distributed Energy Resource Guide, http://www.energy.ca.gov/distgen/, January 2002.

PROJECT: **Simple Cycle Gas Turbine - 47MW**

Resource Category: Thermal - Natural Gas   Level of Study: Conceptual   Region: All

PROJECT DESCRIPTION

This project assumes an 47MW (nominal) General Electric LM 6000 PD Simple Cycle Gas Turbine (SCGT). Plants such as this are most efficient when run to meet the peak load, versus a Combine Cycle Gas Turbine (CCGT) that are more efficiently run constantly to meet base load energy requirements. This unit would be equiped with a dry low NOx (DLN) control system.

FINANCIAL INFORMATION

Total Capital Cost ($1000s of 2003$)	$37,000
Fixed Operating And Maintenance Cost ($1000s/year)	$545
Variable Operating And Maintenance Cost ($/MWh)	$4
Project Life (Years)	30
Project Lead Time (Years)	2
Unit Energy Cost ($/MWh)	$110

Costs have been escalated to 2003$ from the Bantrel 2000$ estimates using inflation rates provided by BC Hydro Engineering, Estimating and Scheduling group for Thermal equipment (2003$=127.4/119.0 x 2000$).

The machine is assumed to be located at an existing gas-fired powerplant site and would therefore not require development of site infrastructure. Capital Cost includes Development Costs ($87/kW) and Construction Costs ($1090/kW). Capital Costs also include the incorporation of Selective Catalytic Reduction (SCR) technology which reduced the plant's NOx emissions by up to 90%. Variable operation and maintenance figures do not include fuel costs.

Unit energy costs for thermal resource options depend largely on the market price of fuel and plant usage, which varies over time. In order to provide a unit energy cost estimate for thermal resource options a fixed set of financial assumptions and the resource option spreadsheet-model were used, as outlined in the Resource Option report. It was assumed that dispatch was 20% for smaller peaking thermal projects in order to estimate an annual average energy and representative unit energy cost.

A representative unit energy cost of $110/MWh, based on the average of the four gas price scenarios is presented here.

Unit energy costs for projects used for peaking, such as simple cycle and internal combustion engines, tend to be much higher because dispatch is lower than plants used for base load.

TECHNICAL INFORMATION

Installed Capacity (MW)	47
Average Annual Energy (GWh/year)	78.2
Dependable Capacity (MW)	44.7
Firm Energy (GWh/year)	78.2
Average Heat Rate (GJ/GWh)	8961

Heat rate estimate is the lower heating value and is for a clean and new turbine. Over time there will be degradation in the heat rate on the order of 1% to 5% depending in the location of the unit, the maintenance schedule and time between turbine overhauls. Consistent annual maintenance limits the heat rate degradation to 1-2%

This technology is generally used to meet peaking requirements. Dependable capacity is assumed to be 95% of Installed capacity. It was assumed that dispatch was 20% for small thermal projects used for peaking in order to estimate an average annual energy and firm energy value for calculation of a representative unit energy cost. Firm energy estimates were based on the assumption that a firm fuel contract would be available and contracted.

PROJECT: **Simple Cycle Gas Turbine - 47MW**

Resource Category: Thermal - Natural Gas | Level of Study: Conceptual | Region: All

SOCIAL AND ENVIRONMENTAL INFORMATION

Meets BC Hydro Clean Criteria	No
Greenhouse Gas Emission Factor (Tonnes CO2 equivalent/GWh)	530

Atmospheric Emissions (Metric Tonnes/GWh)	SOx	NOx	CO	VOC	PM 10	PM 2.5	Hg
	0.0053	0.05	0.03	0.002	0.03	Unknown	0

Project Footprint (Hectares)	2

Note: Some footprint aspects have not been estimated specifically.

Within the past decade, the commercial introduction of low NOx combustors and high temperature catalytic controls for NOx and CO, has enabled the control of of NOx and CO emissions from SCGT's to levels comparable to combined cycle power plants. Air emmision controls including water injection plus selective catalytic reduction (SCR) for NOx control and an oxidation catalyst for CO control guarantee NOx and CO emmisions less than 25ppm.

Small quantities of ammonia are also emitted associated with the use of selective catalytic reduction (SCR) technology to reduce NOx. Although ammonia is not classified as a greenhouse gas the ammonia emission is usually regulated to a concentration of 7 mg/m3.

Opacity which is a measure of the visible plume of emission gasses exhausted by the facility is usually regulated to a opacity measure of less than 10%.

The project footprint was assumed to be nominally 1 ha. This assumption was based on a fraction of the footprint size for the larger thermal fuel projects.

The project footprint estimates for most thermal projects do not include a "life-cycle" footprint, but rather the physical footprint attributable to the generation plant and associated equipment. Major infrastructure such as pipelines and roads, and footprints associated with the fuel sources (such as gas wells, coal mines, and roads), have not been included here in these estimates.

Job Creation

Construction Jobs Created (Person-years)	40
Permanent Jobs Created (Full time equivalents)	Unknown

Employment estimates were provided by SNC Lavalin Inc.; Thermal Power Division

PRIVATE SECTOR INVOLVEMENT

Estimated Level of Private Sector Involvement	100%: Private sector ownership

UNCERTAINTY

Development Uncertainty	Medium

Social and environmental approval of small natural gas projects is dependant to some extent on site location. Based on recent regulatory and public experience the development uncertainty is low to medium. Medium has been entered as a conservative estimate

Price Uncertainty	Medium

No site specific studies have been conducted, and therefore price uncertainty is medium. Costs estimates in the database may be high due to market conditions and the strength of the Canadian Dollar as of October 2003.

REFERENCES

General Electric Power Company, GE Power Systems Product and Service Guide, LM6000PC online datasheet at www.gepower.com, June 2002.

SNC LAVALIN Inc., Thermal Power Division (R. Wesley), Document entitled: Comments on BC Hydro RO-DAT Report, November 19, 2003.

Puget Sound Energy's Least Cost Plan, Appendix G - Detailed Electric Resource Descriptions, August 2003.

General Electric, GE Performance Data for Simple Cycle and Combined Cycle Gas Turbines, October 2000.

AMEC, E&C Services Limited (D. McCann), Document entitled: Thermal Power Plant Performance, Emissions and Costs Review, November 2003.

Northwest Power and Conservation Council Generating Resources Advisory Committee, Natural Gas Simple Cycle Gas Turbine Power Plants, May 2002.

Amec, Report 142194, "2004 Integrated Electricity Plan - General Thermal Review", January 2004.

PROJECT: **Greenfield Combined Cycle Gas Turbine - 250 MW**

Resource Category: Thermal - Natural Gas   Level of Study: Feasibility   Region: Kelly / Nicola

PROJECT DESCRIPTION

This project describes a generic greenfield combined cycle power station located near pipeline and transmission facilities. The project consists of an F Class 1x1x1 Combined Cycle Gas Turbine (CCGT) configuration with nominal net output of 250MW. Combined cycle gas-fired generation is a specific use of the exhaust heat from a natural gas-fired turbine generator to make steam that is used in a steam turbine to drive a second cycle of electricity generation.

All project financial and technical data is based on results from the BC Hydro price forecast team methodology.

The project consists of the following major equipment:

* One natural gas fuelled General Electric PG7241FA packaged gas turbine generator set with dry low NOx emissions technology (DLN).
* One unfired heat recovery steam generator (HRSG) with three pressure levels and condensate heater equipped with an SCR and with space for future retrofit of a CO catalyst.
* One 100MW (nominal) reheat condensing steam turbine generator set.
* Associated auxiliary systems including cooling towers, water treatment plant and distributed control system (DCS).

FINANCIAL INFORMATION

Total Capital Cost ($1000s of 2003$)	$304,000
Fixed Operating And Maintenance Cost ($1000s/year)	$6,000
Variable Operating And Maintenance Cost ($/MWh)	$5
Project Life (Years)	25
Project Lead Time (Years)	3
Unit Energy Cost ($/MWh)	$60

Unit energy costs for the 250 MW and 500 MW CCGT were estimated based on the BC Hydro price forecast team project assumptions, but using an 80% assumed dispatch rate to be consistent with other thermal resource characterization. The spreadsheet based model originally created for Resource Option alternative energy projects, was used to estimate unit energy costs with assumptions which would be typical of an independent private sector developer.

The representative average unit energy cost displayed above of $60/MWh is based on an average of the four gas price scenarios ($4.8/GJ used) as described in the Resource Options report. Additional details on gas and electricity price estimations can be found in the relevant Appendices of the report, and parts of the BC Hydro document entitled "Vancouver Island - Call For Tenders Addendum", Addendum Number 1, Subject: Quantitative Evaluation Methodology, 14 November 2003.

Based on the gas price range of the four scenarios (Confer scenario and High Gas scenario respectively), unit energy costs may vary from $52 to $72/MWh, not including price uncertainty due to project technical assumptions or level of study detail.

Project lead time has been estimated at 3 years. Variable O&M does not included any cost associated with fuel (transport or purchase).

PROJECT: **Greenfield Combined Cycle Gas Turbine - 250 MW**

Resource Category: Thermal - Natural Gas   Level of Study: Feasibility   Region: Kelly / Nicola

TECHNICAL INFORMATION

Installed Capacity (MW)	256
Average Annual Energy (GWh/year)	1947
Dependable Capacity (MW)	243.3
Firm Energy (GWh/year)	1947
Average Heat Rate (GJ/GWh)	7240

Heat rate estimates are higher heating values (HHV) for a clean and new turbine. Over time there will be degradation in the heat rate on the order of 1% to 5% depending in the location of the unit, the maintenance schedule and time between turbine overhauls. Industry standard is to use a heat rate degradation of 3%. However, at this level of study no assumptions on heat rate degradation were included in project calculations.

This technical information assumes that the site is located at an elevation of 2000 feet (approximately 600 m).

Dependable or net capacity was quoted directly from the BCH Price Forecast Long Run Unit Energy Cost spreadsheet. The installed or gross capacity was calculated as net capacity plus 5% to account for auxilary plant losses. Availability is assumed to be 91.3% or 8000 hours per year. Since cost estimates for the 250MW and 500MW CCGT are based on a dispatch equal to availability, annual average energy presented here is estimated on a 91.3% capacity factor. However, other thermal resource options used an 80% (20% for peaking units) capacity factor assumption for annual average energy.

SOCIAL AND ENVIRONMENTAL INFORMATION

Meets BC Hydro Clean Criteria	No
Greenhouse Gas Emission Factor (Tonnes CO2 equivalent/GWh)	350

Atmospheric Emissions (Metric Tonnes/GWh)	SOx	NOx	CO	VOC	PM 10	PM 2.5	Hg
	0.0043	0.05	0.06	0.01	0.03	Unknown	0

Project Footprint (Hectares)	28

Note: Some footprint aspects have not been estimated specifically.

The greenhouse gas factor and local air emission factors are from AMEC estimates, and represent a typical value for this type of resource option. Local air emissions data were estimated with a low heating value heat rate. Small quantities of ammonia are also emitted associated with the use of selective catalytic reduction (SCR) technology to reduce NOx. Although ammonia is not classified as a greenhouse gas the ammonia emission is usually regulated to a concentration of 7 mg/m3.

Opacity which is a measure of the visible plume of emission gasses exhausted by the facility is usually regulated to a opacity measure of less than 10%.

The project footprint estimates for most thermal projects do not include a "life-cycle" footprint, but rather the physical footprint attributable to the generation plant and associated equipment. Major infrastructure such as pipelines and roads, and footprints associated with the fuel sources (such as gas wells, coal mines, and roads), have not been included here in these estimates.

Job Creation

Construction Jobs Created (Person-years)	400
Permanent Jobs Created (Full time equivalents)	40

Construction period is 20 months. Employment estimates were provided by SNC Lavalin Inc.; Thermal Power Division

PRIVATE SECTOR INVOLVEMENT

Estimated Level of Private Sector Involvement	100%: Private sector ownership

UNCERTAINTY

Development Uncertainty	Medium

Social and environmental approval of large natural gas projects can depend on site location. Sites located away from populations are estimated as medium, but based on recent regulatory and public experience the development uncertainty could be high.

Price Uncertainty	Low

No site specific studies have been conducted; however, the capital cost for CCGT turbines is well established. Therefore, price uncertainty is low to medium. Price uncertainty is based on the capital cost and does not include uncertainty in gas prices.

REFERENCES

Newell, A., BCH Price Forecast Long Run Unit Energy Cost: File PriceForecast-LongRunUEC-Rev1.xls, November 2003.

BC Hydro 1995 Integrated Electricity Plan, Appendix E, ISSN 1180-2561, October 1995.

AMEC, E&C Services Limited (D. McCann), Document entitled: Thermal Power Plant Performance, Emissions and Costs Review, November 2003.

General Electric, GE Performance Data for Simple Cycle and Combined Cycle Gas Turbines, October 2000.

Bantrel Inc., Greenfield Combined Cycle Gas Turbine Feasibility Study - Phase II Technology Assessment, April 2001.

SNC LAVALIN Inc., Thermal Power Division (R. Wesley), Document entitled: Comments on BC Hydro RO-DAT Report, November 19, 2003.

General Electric, GE 7FA Operations and Maintenance Data, Turbomachinery May/June, 1997.

PROJECT: **Greenfield Combined Cycle Gas Turbine - 500 MW**

Resource Category: Thermal - Natural Gas Level of Study: Feasibility Region: Kelly / Nicola

PROJECT DESCRIPTION

This project describes a generic greenfield combined cycle power station located near pipeline and transmission facilities. The project consists of an F Class 2x2x1 Combined Cycle Gas Turbine (CCGT) configuration with nominal net output of 500MW. Combined cycle gas-fired generation is a specific use of the exhaust heat from a natural gas-fired turbine generator to make steam that is used in a steam turbine to drive a second cycle of electricity generation.

All project financial and technical data is based on results from the BC Hydro price forecast team methodology.

The project consists of the following major equipment:

* Two natural gas fuelled General Electric PG7241FA packaged gas turbine generator set with dry low NOx emissions technology (DLN).
* Two unfired heat recovery steam generator (HRSG) with three pressure levels and condensate heater equipped with an SCR and with space for future retrofit of a CO catalyst.
* One 200MW (nominal) reheat condensing steam turbine generator set.
* Associated auxiliary systems including cooling towers, water treatment plant and distributed control system (DCS).

FINANCIAL INFORMATION

Total Capital Cost ($1000s of 2003$)	$530,000
Fixed Operating And Maintenance Cost ($1000s/year)	$6,100
Variable Operating And Maintenance Cost ($/MWh)	$5
Project Life (Years)	25
Project Lead Time (Years)	3
Unit Energy Cost ($/MWh)	$56

Unit energy costs for the 250 MW and 500 MW CCGT were estimated based on the BC Hydro price forecast team project assumptions, but using an 80% assumed dispatch rate to be consistent with other thermal resource characterization. The spreadsheet based model originally created for Resource Option alternative energy projects, was used to estimate unit energy costs with assumptions which would be typical of an independent private sector developer.

The representative average unit energy cost displayed above of $56/MWh is based on an average of the four gas price scenarios ($4.8/GJ used) as described in the Resource Options report. Additional details on gas and electricity price estimations can be found in the relevant Appendices of the report, and parts of the BC Hydro document entitled "Vancouver Island - Call For Tenders Addendum", Addendum Number 1, Subject: Quantitative Evaluation Methodology, 14 November 2003.

Based on the gas price range of the four scenarios (Confer scenario and High Gas scenario respectively), unit energy costs may vary from $48 to $68/MWh, not including price uncertainty due to project technical assumptions or level of study detail.

Project lead time has been estimated at 3 years. Variable O&M does not included any cost associated with fuel (transport or purchase).

PROJECT: **Greenfield Combined Cycle Gas Turbine - 500 MW**

Resource Category: Thermal - Natural Gas   Level of Study: Feasibility   Region: Kelly / Nicola

TECHNICAL INFORMATION

Installed Capacity (MW)	519
Average Annual Energy (GWh/year)	3954
Dependable Capacity (MW)	494.2
Firm Energy (GWh/year)	3954
Average Heat Rate (GJ/GWh)	7252

Heat rate estimates are higher heating values (HHV) for a clean and new turbine. Over time there will be degradation in the heat rate on the order of 1% to 5% depending in the location of the unit, the maintenance schedule and time between turbine overhauls. Industry standard is to use a heat rate degradation of 3%. However, at this level of study no assumptions on heat rate degradation were included in project calculations.

This technical information assumes that the site is located at an elevation of 2000 feet (approximately 600 m).

Dependable or net capacity was quoted directly from the BCH Price Forecast Long Run Unit Energy Cost spreadsheet. The installed or gross capacity was calculated as net capacity plus 5% to account for auxilary plant losses. Availability is assumed to be 91.3% or 8000 hours per year. Since cost estimates for the 250MW and 500MW CCGT are based on a dispatch equal to availability, annual average energy presented here is estimated on a 91.3% capacity factor. However, other thermal resource options used an 80% (20% for peaking units) capacity factor assumption for annual average energy.

SOCIAL AND ENVIRONMENTAL INFORMATION

Meets BC Hydro Clean Criteria	No
Greenhouse Gas Emission Factor (Tonnes CO2 equivalent/GWh)	350

Atmospheric Emissions (Metric Tonnes/GWh)	SOx	NOx	CO	VOC	PM 10	PM 2.5	Hg
	0.0043	0.05	0.06	0.01	0.03	Unknown	0

Project Footprint (Hectares)	35

Note: Some footprint aspects have not been estimated specifically.

The greenhouse gas factor and local air emission factors are from AMEC estimates, and represent a typical value for this type of resource option. Local air emissions data were estimated with a low heating value heat rate. Emissions data were estimated with a low heating value heat rate. Small quantities of ammonia are also emitted associated with the use of selective catalytic reduction (SCR) technology to reduce NOx. Although ammonia is not classified as a greenhouse gas the ammonia emission is usually regulated to a concentration of 7 mg/m3.

Opacity which is a measure of the visible plume of emission gasses exhausted by the facility is usually regulated to a opacity measure of less than 10%.

The project footprint estimates for most thermal projects do not include a "life-cycle" footprint, but rather the physical footprint attributable to the generation plant and associated equipment. Major infrastructure such as pipelines and roads, and footprints associated with the fuel sources (such as gas wells, coal mines, and roads), have not been included here in these estimates.

Job Creation

Construction Jobs Created (Person-years)	700
Permanent Jobs Created (Full time equivalents)	50

Construction period is 26 months. Employment estimates were provided by SNC Lavalin Inc.; Thermal Power Division

PRIVATE SECTOR INVOLVEMENT

Estimated Level of Private Sector Involvement	100%: Private sector ownership

UNCERTAINTY

Development Uncertainty	Medium

Social and environmental approval of large natural gas projects can depend on site location. Sites located away from populations are estimated as medium, but based on recent regulatory and public experience the development uncertainty could be high.

Price Uncertainty	Medium

No site specific studies have been conducted; however, the capital cost for CCGT turbines is well established. Therefore, price uncertainty is low to medium. Price uncertainty is based on the capital cost and does not include uncertainty in gas prices.

REFERENCES

Bantrel Inc., Greenfield Combined Cycle Gas Turbine Feasibility Study - Phase II Technology Assessment, April 2001.

SNC LAVALIN Inc., Thermal Power Division (R. Wesley), Document entitled: Comments on BC Hydro RO-DAT Report, November 19, 2003.

General Electric, GE 7FA Operations and Maintenance Data, Turbomachinery May/June, 1997.

AMEC, E&C Services Limited (D. McCann), Document entitled: Thermal Power Plant Performance, Emissions and Costs Review, November 2003.

Newell, A., BCH Price Forecast Long Run Unit Energy Cost: File PriceForecast-LongRunUEC-Rev1.xls, November 2003.

General Electric, GE Performance Data for Simple Cycle and Combined Cycle Gas Turbines, October 2000.

PROJECT: **Greenfield Combined Cycle Gas Turbine - 60 MW**

Resource Category: Thermal - Natural Gas Level of Study: Feasibility Region: Kelly / Nicola

PROJECT DESCRIPTION

This project describes a generic greenfield combined cycle power station located near pipeline and transmission facilities. The project consists of a LM 6000 1x1x1 Combined Cycle Gas Turbine (CCGT) configuration with nominal net output of 57MW. Combined cycle gas-fired generation is a specific use of the exhaust heat from a natural gas-fired turbine generator to make steam that is used in a steam turbine to drive a second cycle of electricity generation.

The project consists of the following major equipment:

* One natural gas fuelled General Electric LM6000PD packaged gas turbine generator set with low dry emissions technology (DLN).
* One unfired heat recovery steam generator (HRSG) with three pressure levels and condensate heater equipped with an SCR and with space for future retrofit of a CO catalyst.
* One 15MW (nominal) condensing steam turbine generator set.
* Associated auxiliary systems including cooling towers, water treatment plant and distributed control system (DCS).

FINANCIAL INFORMATION

Total Capital Cost ($1000s of 2003$)	$110,000
Fixed Operating And Maintenance Cost ($1000s/year)	$3,000
Variable Operating And Maintenance Cost ($/MWh)	$4
Project Life (Years)	30
Project Lead Time (Years)	3
Unit Energy Cost ($/MWh)	$77

Costs have been escalated to 2003$ using inflation rates provided by BC Hydro Engineering, Estimating and Scheduling group for Thermal equipment. A review by AMEC and SNC Lavalin indicate that capital costs estimated here may be high, however results are based on the best available information.

Operations and maintenance (O&M) cost estimates exclude fuel, and were based on data published by General Electric. Capital Costs also include the incorporation of Selective Catalytic Reduction (SCR) technology which reduces the plant's NOx emissions by up to 90%. Project lead time has been estimated at 3 years.

Unit energy costs for thermal resource options depend largely on the market price of fuel and plant usage, which varies over time. In order to provide a unit energy cost estimate for thermal resource options a fixed set of assumptions were used, as outlined in the Resource Option report.

Natural gas project unit energy costs were estimated using gas prices from BC Hydro's four gas price scenarios. Using these scenarios the unit energy costs ranged from $69/MWh to $88/MWh. A representative unit energy cost of $77/MWh, based on the average of the four gas price scenarios is presented here.

Project lead time has been estimated at 3 years. Variable O&M does not included any cost associated with fuel (transport or purchase).

PROJECT: **Greenfield Combined Cycle Gas Turbine - 60 MW**

Resource Category: Thermal - Natural Gas   Level of Study: Feasibility   Region: Kelly / Nicola

TECHNICAL INFORMATION

Installed Capacity (MW)	60
Average Annual Energy (GWh/year)	400
Dependable Capacity (MW)	57
Firm Energy (GWh/year)	500
Average Heat Rate (GJ/GWh)	6747

Heat rate estimates are lower heating values (LHV) for a clean and new turbine. Over time there will be degradation in the heat rate on the order of 1% to 5% depending in the location of the unit, the maintenance schedule and time between turbine overhauls. Industry standard is to use a heat rate degradation of 3%. However, at this level of study no assumptions on heat rate degradation were included in project calculations.

This technical information assumes that the site is located at an elevation of 2000 feet (approximately 600 m).

Dependable capacity is estimated as the net capacity based on an availablity of 95%. It was assumed that dispatch was 80% of net capacity for larger thermal projects in order to estimate an average annual energy and calculate the representative unit energy cost. Firm energy estimates were based on the assumption that a firm fuel contract would be available and contracted for the net capacity.

SOCIAL AND ENVIRONMENTAL INFORMATION

Meets BC Hydro Clean Criteria	No
Greenhouse Gas Emission Factor (Tonnes CO2 equivalent/GWh)	400

Atmospheric Emissions (Metric Tonnes/GWh)	SOx	NOx	CO	VOC	PM 10	PM 2.5	Hg
	0	0.05	0.2	0.002	0.03	Unknown	0

Project Footprint (Hectares)	13

Note: Some footprint aspects have not been estimated specifically.

The greenhouse gas factor and local air emission factors are based emission estimates by AMEC, November 2003. Emissions data were estimated with a low heating value heat rate.

Small quantities of ammonia are also emitted associated with the use of selective catalytic reduction (SCR) technology to reduce NOx. Although ammonia is not classified as a greenhouse gas the ammonia emission is usually regulated to a concentration of 7 mg/m3.

Carbon Monoxide (CO) emissions are stated for a project without a catalyst (with a catalyst installed, CO emissions would be reduced to 0.02 metric tonnes/GWh).

Opacity which is a measure of the visible plume of emission gasses exhausted by the facility is usually regulated to a opacity measure of less than 10%.

The project footprint estimates for most thermal projects do not include a "life-cycle" footprint, but rather the physical footprint attributable to the generation plant and associated equipment. Major infrastructure such as pipelines and roads, and footprints associated with the fuel sources (such as gas wells, coal mines, and roads), have not been included here in these estimates.

Job Creation

Construction Jobs Created (Person-years)	120
Permanent Jobs Created (Full time equivalents)	20

Construction period is 15 months. Employment estimates were provided by SNC Lavalin Inc.; Thermal Power Division

PRIVATE SECTOR INVOLVEMENT

Estimated Level of Private Sector Involvement	100%: Private sector ownership

UNCERTAINTY

Development Uncertainty	Medium

Social and environmental approval of small natural gas projects is dependant to some extent on site location. Based on recent regulatory and public experience the approval uncertainty of a fossil fuel plant of this size is medium.

Price Uncertainty	Medium

No site specific studies have been conducted; however, the capital cost for CCGT turbines is well established. Therefore, price uncertainty is low to medium. Price uncertainty is based on the capital cost and does not include uncertainty in gas prices.

REFERENCES

SNC LAVALIN Inc., Thermal Power Division (R. Wesley), Document entitled: Comments on BC Hydro RO-DAT Report, November 19, 2003.

AMEC, E&C Services Limited (D. McCann), Document entitled: Thermal Power Plant Performance, Emissions and Costs Review, November 2003.

General Electric, GE 7FA Operations and Maintenance Data, Turbomachinery May/June, 1997.

Bantrel Inc., Greenfield Combined Cycle Gas Turbine Feasibility Study - Phase II Technology Assessment, April 2001.

General Electric, GE Performance Data for Simple Cycle and Combined Cycle Gas Turbines, October 2000.

PROJECT: **Crofton Mill - Power Cogeneration Project (NCEP)**

Resource Category: Thermal - Natural Gas   Level of Study: Pre-feasibility   Region: Vancouver Island

PROJECT DESCRIPTION

NorskeCanada proposes to install new electric power cogeneration facilities and power demand reduction projects at three of their pulp and paper mills on Vancouver Island:
- Crofton Pulp and Paper Mill located near Duncan.
- Port Alberni Paper Mill located in Port Alberni.
- Elk Falls Pulp and Paper Mill located north of Campbell River.

This data sheet summarizes the new power generation facilities proposed for the Crofton Pulp and Paper Mill, located near Duncan. This portion of the NorskeCanade Energy Projects (NCEP) will provide 107 MW of winter operating MW, from the installation of 2 gas turbines and steam turbine cogeneration facilities integrated with the mill utilities.

The material presented here is taken directly from NorkseCanada's evidence as filed with the British Columbia Utilities Commission on May 26th, 2003. The data has been included in the 2004 Integrated Energy Plan but would need to be confirmed and refined as the project develops.

FINANCIAL INFORMATION

Total Capital Cost ($1000s of 2003$)	$123,000
Fixed Operating And Maintenance Cost ($1000s/year)	Unknown
Variable Operating And Maintenance Cost ($/MWh)	Unknown
Project Life (Years)	25
Project Lead Time (Years)	2
Unit Energy Cost ($/MWh)	Unknown

Costs include contingencies and development costs but not capitalized interest during construction. The Norske proposal assumes that BC Hydro would accept the gas price risk and additional capacity on Terasen Gas Vancouver Island would be $1.13/GJ for the entire NCEP suite. Project lead time has been estimated at 2 years.

TECHNICAL INFORMATION

Installed Capacity (MW)	107
Average Annual Energy (GWh/year)	Unknown
Dependable Capacity (MW)	107
Firm Energy (GWh/year)	Unknown
Average Heat Rate (GJ/GWh)	Unknown

The main component of the system is the GE LM6000PD aeroderivative gas turbine. The NCEP proposal incorporates partially-fired, natural-circulation-type, heat recovery steam generators ("HRSGs"). The HRSG takes heat from the gas turbine exhaust gases and produces steam for use within the mill steam systems and power generation through a condensing steam turbine ("CST"). In effect, the gas formerly used in the gas-fired boilers to generate steam, is now used to generate both steam and power. This makes for more efficient use of the gas fuel. Thus, energy efficiency at the mills is improved and the environmental effects of the additional power generation facilities are reduced. See NorskeCanada's Proposal as submitted to the BCUC for more details.

The installed capacity is reported as the winter operating MW as stated by Norske Canada.

SOCIAL AND ENVIRONMENTAL INFORMATION

Meets BC Hydro Clean Criteria	Yes
Greenhouse Gas Emission Factor (Tonnes CO2 equivalent/GWh)	Unknown

Atmospheric Emissions (Metric Tonnes/GWh)	SOx	NOx	CO	VOC	PM 10	PM 2.5	Hg
	Unknown	Unknown	Unknown	Unknown	Unknown	Unknown	Unknown

Project Footprint (Hectares)	0

Note: Some footprint aspects have not been estimated specifically.

The installation of the cogeneration facilities at the Crofton, Elk Falls and Port Alberni mills will result in some increased air emissions. Key air emissions will be nitrogen oxides, carbon monoxide, sulphur dioxide, carbon dioxide, volatile organic compounds ("VOCs"), ammonia, and low levels of fine particulates. Air emission data was included in the NCEP proposal for the entire project suite, not by specific projects. Therefore it has not been included here. Please see NorskeCanada's Proposal as submitted to the BCUC for more details regarding emission levels.

The NCEP will use dry low NOx gas turbines that minimize the generation of air contaminants. Selective catalytic reduction ("SCR") systems will be used to further control NOx levels.

It is expected that there would be no net increase in footprint for this project because it would be located at an existing industrial site with direct access to transmission lines. The project footprint estimates for most thermal projects do not include a "life-cycle" footprint, but rather the physical footprint attributable to the generation plant and associated equipment. Major infrastructure such as pipelines and roads, and footprints associated with the fuel sources (such as gas wells, coal mines, and roads), have not been included here in these estimates.

The NCEP is considered to be 58% (165 MW) BC Clean by the BCUC as stated in the decision on the Vancouver Island Generation Project in September 2003.

Job Creation

Construction Jobs Created (Person-years)	Unknown
Permanent Jobs Created (Full time equivalents)	Unknown

The complete NCEP suite will generate 500 person-years worth of on-site labour.

PRIVATE SECTOR INVOLVEMENT

Estimated Level of Private Sector Involvement	100%: Private sector ownership

UNCERTAINTY

Development Uncertainty	Medium

Uncertainties are difficult to assess as the data provided was limited, and not initially computed for the purposes the 2004 IEP study.

Price Uncertainty	Medium

Cost information provided by project proponent, and specific financial assumptions are unknown. Costs were not initially computed for the purposes the 2004 IEP study.

REFERENCES

Norske Skog Canada Ltd., Evidence of Norske Skog Canada Ltd. submitted to British Columbia Utilities Commission, May 2003.

AMEC and VECO Canada Ltd., NorskeCanada Energy Project, Project Suite Technical Report and Cost Estimate, May 2003.

British Columbia Utilities Commission, Vancouver Island Generation Project Decision, September 8, 2003.

PROJECT: **Elk Falls - Power Cogeneration Project (NCEP)**

Resource Category: Thermal - Natural Gas Level of Study: Pre-feasibility Region: Vancouver Island

PROJECT DESCRIPTION

NorskeCanada proposes to install new electric power cogeneration facilities and power demand reduction projects at three of their pulp and paper mills on Vancouver Island:
- Crofton Pulp and Paper Mill located near Duncan.
- Port Alberni Paper Mill located in Port Alberni.
- Elk Falls Pulp and Paper Mill located north of Campbell River.

This data sheet summarizes the new power generation facilities proposed for the Elk Falls Pulp and Paper Mill, near Duncan Bay, 10 km north of Campbell River. This portion of the NorkseCanada Energy Project (NCEP) will provide 104 MW of winter operating capacity, from the installation of gas turbine and steam turbine cogeneration facilities integrated with the mill utilities.

Note that completion of the Elk Falls project suite (Elk Falls, Elk Falls TMP and Demand Management) are dependent on the order of completion. The steam turbine project (12 MW within 104 winter MW) must be completed before the TMP (28 MW) project can be implemented. After completion of these two projects, the 80 MW curtailment can be implemented.

The material presented here is taken directly from NorkseCanada's evidence as filed with the British Columbia Utilities Commission on May 26th, 2003. The data has been included in the 2004 Integrated Energy Plan but would need to be confirmed and refined as the project develops.

FINANCIAL INFORMATION

Total Capital Cost ($1000s of 2003$)	$127,000
Fixed Operating And Maintenance Cost ($1000s/year)	Unknown
Variable Operating And Maintenance Cost ($/MWh)	Unknown
Project Life (Years)	25
Project Lead Time (Years)	2
Unit Energy Cost ($/MWh)	Unknown

Costs include contingencies and development costs but not capitalized interest during construction. The Norske proposal assumes that BC Hydro would accept the gas price risk and additional capacity on Terasen Gas Vancouver Island would be $1.13/GJ for the entire NCEP suite. Project lead time has been estimated at 2 years.

TECHNICAL INFORMATION

Installed Capacity (MW)	104
Average Annual Energy (GWh/year)	Unknown
Dependable Capacity (MW)	104
Firm Energy (GWh/year)	Unknown
Average Heat Rate (GJ/GWh)	Unknown

The main component of the system is the GE LM6000PD aeroderivative gas turbine. The NCEP proposal incorporates partially-fired, natural-circulation-type, heat recovery steam generators (“HRSGs”). The HRSG takes heat from the gas turbine exhaust gases and produces steam for use within the mill steam systems and power generation through a condensing steam turbine (“CST”). In effect, the gas formerly used in the gas-fired boilers to generate steam, is now used to generate both steam and power. This makes for more efficient use of the gas fuel. Thus, energy efficiency at the mills is improved and the environmental effects of the additional power generation facilities are reduced. See NorskeCanada's Proposal as submitted to the BCUC for more details.

The installed capacity is reported as the winter operating MW as stated by Norske Canada.

PROJECT: **Elk Falls - Power Cogeneration Project (NCEP)**

Resource Category: Thermal - Natural Gas   Level of Study: Pre-feasibility   Region: Vancouver Island

SOCIAL AND ENVIRONMENTAL INFORMATION

Meets BC Hydro Clean Criteria	Yes
Greenhouse Gas Emission Factor (Tonnes CO2 equivalent/GWh)	Unknown

Atmospheric Emissions (Metric Tonnes/GWh)	SOx	NOx	CO	VOC	PM 10	PM 2.5	Hg
	Unknown	Unknown	Unknown	Unknown	Unknown	Unknown	Unknown

Project Footprint (Hectares)	0

Note: Some footprint aspects have not been estimated specifically.

The installation of the cogeneration facilities at the Crofton, Elk Falls and Port Alberni mills will result in some increased air emissions. Key air emissions will be nitrogen oxides, carbon monoxide, sulphur dioxide, carbon dioxide, volatile organic compounds (“VOCs”), ammonia, and low levels of fine particulates. Air emission data was included in the NCEP proposal for the entire project suite, not by specific projects. Therefore it has not been included here. Please see NorskeCanada's Proposal as submitted to the BCUC for more details regarding emission levels.

The NCEP will use dry low NOx gas turbines that minimize the generation of air contaminants. Selective catalytic reduction (“SCR”) systems will be used to further control NOx levels.

It is expected that there would be no net increase in footprint for this project because it would be located at an existing industrial site with direct access to transmission lines. The project footprint estimates for most thermal projects do not include a "life-cycle" footprint, but rather the physical footprint attributable to the generation plant and associated equipment. Major infrastructure such as pipelines and roads, and footprints associated with the fuel sources (such as gas wells, coal mines, and roads), have not been included here in these estimates.

The NCEP is considered to be 58% (165 MW) BC Clean by the BCUC as stated in the decision on the Vancouver Island Generation Project in September 2003.

Job Creation

Construction Jobs Created (Person-years)	Unknown
Permanent Jobs Created (Full time equivalents)	Unknown

The complete NCEP suite will generate 500 person-years worth of on-site labour.

PRIVATE SECTOR INVOLVEMENT

Estimated Level of Private Sector Involvement	100%: Private sector ownership

UNCERTAINTY

Development Uncertainty	Medium

The project feasibility seems to be linked to the entire suite of projects in the NCEP. An development issue that arises in one portion of the NCEP could affect others.

Price Uncertainty	Medium

Cost information provided by project proponent, and not initially computed for the purposes the 2004 IEP study.

REFERENCES

AMEC and VECO Canada Ltd., NorskeCanada Energy Project, Project Suite Technical Report and Cost Estimate, May 2003.

Norske Skog Canada Ltd., Evidence of Norske Skog Canada Ltd. submitted to British Columbia Utilities Commission, May 2003.

British Columbia Utilities Commission, Vancouver Island Generation Project Decision, September 8, 2003.

PROJECT: **Port Alberni - Power Project (NCEP)**

Resource Category: Thermal - Natural Gas Level of Study: Pre-feasibility Region: Vancouver Island

PROJECT DESCRIPTION

NorskeCanada proposes to install new electric power cogeneration facilities and power demand reduction projects at three of their pulp and paper mills on Vancouver Island:
- Crofton Pulp and Paper Mill located near Duncan.
- Port Alberni Paper Mill located in Port Alberni.
- Elk Falls Pulp and Paper Mill located north of Campbell River.

This data sheet summarizes the new power generation facilities proposed for the Port Alberni Paper Mill, located in Port Alberni. This portion of the NorkseCanada Energy Project (NCEP) will provide 45 MW of winter operating capacity, from the installation of gas turbine.

The material presented here is taken directly from NorkseCanada's evidence as filed with the British Columbia Utilities Commission on May 26th, 2003. The data has been included in the 2004 Integrated Energy Plan but would need to be confirmed and refined as the project develops.

FINANCIAL INFORMATION

Total Capital Cost ($1000s of 2003$)	$55,000
Fixed Operating And Maintenance Cost ($1000s/year)	Unknown
Variable Operating And Maintenance Cost ($/MWh)	Unknown
Project Life (Years)	25
Project Lead Time (Years)	2
Unit Energy Cost ($/MWh)	Unknown

Costs include contingencies and development costs but not capitalized interest during construction. The Norske proposal assumes that BC Hydro would accept the gas price risk and additional capacity on Terasen Gas Vancouver Island would be $1.13/GJ for the entire NCEP suite. Project lead time has been estimated at 2 years.

TECHNICAL INFORMATION

Installed Capacity (MW)	45
Average Annual Energy (GWh/year)	Unknown
Dependable Capacity (MW)	45
Firm Energy (GWh/year)	Unknown
Average Heat Rate (GJ/GWh)	Unknown

The heart of the system is the GE LM6000PD aeroderivative gas turbine. The NCEP proposal incorporates partially-fired, natural-circulation-type, heat recovery steam generators (“HRSGs”). The HRSG takes heat from the gas turbine exhaust gases and produces steam for use within the mill steam systems and power generation through a condensing steam turbine (“CST”). In effect, the gas formerly used in the gas-fired boilers to generate steam, is now used to generate both steam and power. This makes for more efficient use of the gas fuel. Thus, energy efficiency at the mills is improved and the environmental effects of the additional power generation facilities are reduced. See NorskeCanada's Proposal as submitted to the BCUC for more details.

The installed capacity is reported as the winter operating MW as stated by Norske Canada.

PROJECT: **Port Alberni - Power Project (NCEP)**

Resource Category: Thermal - Natural Gas   Level of Study: Pre-feasibility   Region: Vancouver Island

SOCIAL AND ENVIRONMENTAL INFORMATION

Meets BC Hydro Clean Criteria	Yes
Greenhouse Gas Emission Factor (Tonnes CO2 equivalent/GWh)	Unknown

Atmospheric Emissions (Metric Tonnes/GWh)	SOx	NOx	CO	VOC	PM 10	PM 2.5	Hg
	Unknown	Unknown	Unknown	Unknown	Unknown	Unknown	Unknown

Project Footprint (Hectares)	0

Note: Some footprint aspects have not been estimated specifically.

The installation of the cogeneration facilities at the Crofton, Elk Falls and Port Alberni mills will result in some increased air emissions. Key air emissions will be nitrogen oxides, carbon monoxide, sulphur dioxide, carbon dioxide, volatile organic compounds ("VOCs"), ammonia, and low levels of fine particulates. Air emission data was included in the NCEP proposal for the entire project suite, not by specific projects. Therefore it has not been included here. Please see NorskeCanada's Proposal as submitted to the BCUC for more details regarding emission levels.

The NCEP will use dry low NOx gas turbines that minimize the generation of air contaminants. Selective catalytic reduction ("SCR") systems will be used to further control NOx levels.

It is expected that there would be no net increase in footprint for this project because it would be located at an existing industrial site with direct access to transmission lines.The project footprint estimates for most thermal projects do not include a "life-cycle" footprint, but rather the physical footprint attributable to the generation plant and associated equipment. Major infrastructure such as pipelines and roads, and footprints associated with the fuel sources (such as gas wells, coal mines, and roads), have not been included here in these estimates.

The NCEP is considered to be 58% (165 MW) BC Clean by the BCUC as stated in the decision on the Vancouver Island Generation Project in September 2003.

Job Creation

Construction Jobs Created (Person-years)	Unknown
Permanent Jobs Created (Full time equivalents)	Unknown

The complete NCEP suite will generate 500 person-years worth of on-site labour.

PRIVATE SECTOR INVOLVEMENT

Estimated Level of Private Sector Involvement	100%: Private sector ownership

UNCERTAINTY

Development Uncertainty	Medium

Uncertainties are difficult to assess as the data provided was limited, and not initially computed for the purposes the 2004 IEP study.

Price Uncertainty	Medium

Cost information provided by project proponent, and not initially computed for the purposes the 2004 IEP study.

REFERENCES

AMEC and VECO Canada Ltd., NorskeCanada Energy Project, Project Suite Technical Report and Cost Estimate, May 2003.

British Columbia Utilities Commission, Vancouver Island Generation Project Decision, September 8, 2003.

Norske Skog Canada Ltd., Evidence of Norske Skog Canada Ltd. submitted to British Columbia Utilities Commission, May 2003.

PROJECT: **VIGP - A VIEC application to the BCUC**

Resource Category: Thermal - Natural Gas Level of Study: Feasibility Region: Vancouver Island

PROJECT DESCRIPTION

The Vancouver Island Energy Corporation (VIEC) is a wholly-owned subsidiary of British Columbia Hydro and Power Authority (BC Hydro). On March 12, 2003 VIEC applied for a Certificate of Public Convenience and Necessity (CPCN) for the Vancouver Island Generation Project (VIGP) to the British Columbia Utility Commission (BCUC).

The VIGP design incorporates a GE 7FA natural gas-fired, combined cycle power plant, a connection and upgrade to the existing transmission grid, and a short feeder pipeline to supply natural gas to the plant; a water supply line from the existing Harmac treatment system; and upgrade to the transmission circuits that provide electicity to industrial users in the Duke Point area; and temporary works needed during construction and start-up.

The information below represents BC Hydro's estimate of VIGP's financial, technical, environmental and economic data as laid out in the March 2003 CPCN application to the BCUC.

FINANCIAL INFORMATION

Total Capital Cost ($1000s of 2003$)	$347,000
Fixed Operating And Maintenance Cost ($1000s/year)	$6,400
Variable Operating And Maintenance Cost ($/MWh)	$5
Project Life (Years)	25
Project Lead Time (Years)	4
Unit Energy Cost ($/MWh)	$73

Financial, dispatch and fuel price assumptions presented in the VIGP CPCN estimated a unit energy cost of $65/MWh. The financial spreadsheet-model assumed dispatch of 80% and October 2003 gas price forecasts were used for VIGP A in the 2004 IEP.

Costs included in VIGP A and VIGP B are not final and are based on VIGP CPCN application data and include uncertainty. BC Hydro is developing more refined estimates for use in tender evaluation and other processes. Costs have been escalated to 2003$ from 2002$ using inflation rates provided by BC Hydro Engineering, Estimating and Scheduling group. Conservative estimates of project lead time range from 3 to 5 years depending on the regulatory approval process. Construction time is a fixed estimate of 24 months.

OTHER COSTS

Fixed Operating and Maintenance Costs exclude gas transmission costs and were extracted from the VIEC initial application to the BCUC in March, 2003. Variable O&M does not include fuel costs, as for all natural gas options in the database.

Unit energy costs for thermal resource options depend largely on the market price of fuel and plant usage. In order to provide a unit energy cost for thermal resource options, an assumption was made about fuel prices as outlined in the Resource Option report. Natural gas generation unit energy costs would vary depending on gas prices, similar to the gas price scenarios.

A representative cost of $73/MWh was estimated, which could range from $61/MWh to $81/MWh depending on fuel price. Unit energy costs were estimated using the resource option financial model spreadsheet. These values are indicative for comparison purposes for the IEP only.

TECHNICAL INFORMATION

Installed Capacity (MW)	295
Average Annual Energy (GWh/year)	1962
Dependable Capacity (MW)	265
Firm Energy (GWh/year)	2100
Average Heat Rate (GJ/GWh)	7308

Heat rate estimates are for a clean and new turbine. Over time there will be degradation in the heat rate on the order of 1% to 5% depending in the location of the unit, the maintenance schedule and time between turbine overhauls. Consistent annual maintenance limits the heat rate degradation to 1-2%.

The combined cycle system proposed for the plant is a combustion turbine designed to produce 170MW of electricity, a heat recovery steam generator (HRSG) to generate steam from the hot turbine exhaust gasses, and a steam turbine that will produce 95MW of electricity, increased to 125MW through the inclusion of duct firing technology. The firm capacity of the plant is limited to the supply of natural gas under contractural agreements, and is planned to be 265MW with an annual energy and firm energy capability of 2,100 GWh/year. BC Hydro intends to aquire, through contract, a minimum of 465MW of natural gas. It is anticipated that there will be enough on-demand gas to fire the remaining 30MW of installed capacity. Power generated by the plant will be supplied to the BC Hydro grid at Duke Point, near Nanaimo.

Annual average energy estimates are based on an assumed dispatch of 80% with duct firing 50% of the time, which results in a lower value than firm capability.

The VIGP's natural gas consumption would be up to 46TJ/day in base mode (i.e up to 265MW without duct firing) and up to 53TJ/day in duct firing mode (i.e up to 295 MW). The plant's efficiency would be approximately 54.8% (lower heating value - LVH) in base mode load with allowance for degradation, and decrease to about 53.7% in duct firing mode. The plant heat rate above represents the plant operating as base loaded on the basis of gas higher heating value (HHV). The equivalent heat rate based on the gas' lower heating value (LHV) is 6,577 GJ/GWh.

The VIGP's estimated natural gas consumption rates are projected for a plant after it has been in use for some time and has suffered some reduction in efficiency (degradation), typically experienced with use. As mentioned above, the difference between the operating efficiency experienced over time and the manufacturer's project efficiency (clean and new) depends on how well the plant is maintained.

Dependable capacity and firm energy values are based on the VIGP Application to the BCUC, March 2003. It was assumed that dispatch was 80% for larger thermal projects in order to estimate an average annual energy and representative unit energy cost for consistency with emissions calculations, duct burning at full capacity is assumed for half of this time.

PROJECT: **VIGP - A VIEC application to the BCUC**

Resource Category: Thermal - Natural Gas   Level of Study: Feasibility   Region: Vancouver Island

SOCIAL AND ENVIRONMENTAL INFORMATION

Meets BC Hydro Clean Criteria	No
Greenhouse Gas Emission Factor (Tonnes CO2 equivalent/GWh)	362

Atmospheric Emissions (Metric Tonnes/GWh)	SOx	NOx	CO	VOC	PM 10	PM 2.5	Hg
	0.0045	0.04	0.077	0.0062	0.0054	Unknown	Unknown

Project Footprint (Hectares)	33

Note: Some footprint aspects have not been estimated specifically.

Emission controls for VIGP include DLN (dry low Nox) combustor technology and Selective Catalytic Reduction (SCR -aqueous ammonia injection). Emission data was extracted from the VIEC application to the British Columbia Environmental Assessment Office. Estimated emissions are based on operation of the plant with duct firing 50% of the year, with duct burning on at 100% of maximun. The plant would have a net power output of 295MW in winter and 279MW in summer, with an overall output of 287MW.

PM 10 emissions are for total particulate including the filterable and condensable fraction assumed to be 100% PM 2.5. PM 10 includes PM 2.5 emissions.

Land and general impacts are considered negligable.

The project footprint estimates for most thermal projects do not include a "life-cycle" footprint, but rather the physical footprint attributable to the generation plant and associated equipment. Major infrastructure such as pipelines and roads, and footprints associated with the fuel sources (such as gas wells, coal mines, and roads), have not been included here in these estimates.

Job Creation

Construction Jobs Created (Person-years)	239
Permanent Jobs Created (Full time equivalents)	20

Project work is expected to take place over a 24 month period. It is estimated that about 425,000 person hours of work will be required for facility construction, which is equivalent to about 235 person years of employment. In addition, it is estimated that tie-in construction will create approximately 4 additional person years of employment, The peak workforce for VIGP is estimated at 250 people at site. The operational powerplant will create 20 permanent full time positions.

PRIVATE SECTOR INVOLVEMENT

Estimated Level of Private Sector Involvement	Primary: 50% to 99%

This project could be developed using a variety of development and financing arrangements. In some cases the selected development approach would require a policy decision outside the bounds of BC Hydro's decision making authority. To be conservative, the lower expectation for private sector involvement (primary) was selected, although the project could be 100% private sector owned.

UNCERTAINTY

Development Uncertainty	Medium

Until results from the BC Hydro Call for Tenders process (intiated in September 2003) are available the development uncertainty of this project is estimated as medium.

Price Uncertainty	Low

Detailed studies and cost estimates have been completed for this project.

REFERENCES

VIGP, BCUC Nanaimo hearing, VIGP Witness panel number 5, June 2003.

Vancouver Island Energy Corporation, VIGP application to the British Columbia Environmental Assessment Office, Volume 1, June 2002.

Vancouver Island Energy Corporation, VIGP application to the British Columbia Utilities Commission, March 2003.

PROJECT: **VIGP - B BCUC response to VIEC**

Resource Category: Thermal - Natural Gas | Level of Study: Feasibility | Region: Vancouver Island

PROJECT DESCRIPTION

The Vancouver Island Energy Corporation (VIEC) is a wholly-owned subsidiary of British Columbia Hydro and Power Authority (BC Hydro). On March 12, 2003 VIEC applied for a Certificate of Public Convenience and Necessity (CPCN) for the Vancouver Island Generation Project (VIGP). On September 8, 2003 the British Columbia Utility Commission (BCUC) issued its decision on the application by BC Hydro for a CPCN for VIGP. Based on the evidence given in the hearing process, the commission determined that BC Hydro has not fully established that VIGP is the most cost effective means to reliably meet Vancouver Island's power needs. The commission therefore denied the application for a CPCN.

The commission panel encouraged BC Hydro to proceed with a Call For Tender (CFT). Based on the results of the CFT the commission is prepared to consider any future applications for CPCN approval or Electricity Purchase Agreement approval on a expedited basis.

The following adjustments (among others) were made by the BCUC to BCH's original bid:

* Peak demand forecast for 2007/8 reduced by 159MW to 2,161MW
* BC Hydro's present dependable capacity increased by 30MW to 2,045MW
* BC Hydro's projected capacity deficit for 2007/2008 decreased from 213MW to 116MW

The information below represents BCUC's response to BC Hydro's CPCN application.

FINANCIAL INFORMATION

Total Capital Cost ($1000s of 2003$)	$311,000
Fixed Operating And Maintenance Cost ($1000s/year)	$14,000
Variable Operating And Maintenance Cost ($/MWh)	$0
Project Life (Years)	25
Project Lead Time (Years)	4
Unit Energy Cost ($/MWh)	$85

Costs included in VIGP A and VIGP B are not final and are based on VIGP CPCN application data and BCUC responses and include uncertainty. BC Hydro is developing more refined estimates for use in tender evaluation and other processes. Costs have been escalated to 2003$ from 2002$ using inflation rates provided by BC Hydro Engineering, Estimating and Scheduling group (2003$=127.4/124.7 x 2002$). Conservative estimates of project lead time Range from 3 to 5 years depending on the regulatory approval process. Construction time is a fixed estimate of 24 months.

The Commission Panel concluded that a reasonable range for the expected capital cost of VIGP is provided by the P50 and P90 estimates (see VIGP - A). It also concluded, however, that the best representation of costs should be on a "from here on in" basis: The best method to compare VIGP to other tenders resulting from the CFT process is to subtract any sunk costs that BC Hydro has incurred to date. The commission found that, after deducting sunk costs ($50.7 million), a capital cost estimate of $295 million in 2003 dollars should be used as the lower cost scenario (P50) and a cost estimate of $326 million be used as the upper cost scenario (P90) for analyzing the VIGP. The Capital Cost number in the table is the average of these two figures.

CAPITAL COSTS:
VIEC provided P50 and P90 estimates of VIGP capital cost for a June 2006 in-service date, as shown in the table below. (The P50 estimate has a 50 percent probability that the actual cost will not exceed the estimate while the P90 estimate has a 90 percent probability.)

	P50	P90
Major equipment	136.0	142.5
Other direct costs	155.4	186.3
Overhead	6.1	6.6
Interest during construction	36.8	42.6
Contingency	12.9	0.0
Total, 2003 dollars	$347.0	$378.0

Note: Data includes BC Hydro's sunk costs.

There is an apparent inconsistency between the data represented in the table above and the Capital Cost Data at the beginning of this section. The latter Capital Cost data is an average of BCH's cost data (P50 and 90 - inclusive of sunk costs), less BC Hydro's estimated sunk costs (Sunk costs were estimated at $51 million in the VIEC March application to the BCUC). This subtraction was made for the sake of comparison with "VIGP - b) BCUC response to VIEC" resource option - please refer to this (BCUC Response) resource option for reasons behind the subtraction of sunk costs.

OTHER COSTS

The OMA numbers are estimates from IPP's based on their experience in operating plants similar to VIGP, with a number of site-specific adjustments. The fixed OMA costs includes costs under a long service agreement offered by General Electric for the maintenance of the Natural Gas Turbines. OMA costs include property taxes that are estimated at $3 million per year. Fixed OMA costs represent fixed major ($5.2 million) maintenance costs only. Fixed non-major maintenance costs are estimated at $8.7 million.

Variable OMA costs are estimated at $0.47/MWh, which may show as $0 in the database due to automatic rounding. However, $0.47/MWh will be used for modelling and evaluation purposes. Variable costs are estimated by the BCUC as $875,000 nominal dollars (<$1/MWh). These cost total to be the same annually as VIGP - A.

The unit energy cost for this project is estimated to range from $72/MWh to $93/MWh, based on the BCUC assumptions, the four IEP gas scenarios and using resource option financial spreadsheet model for indicative purposes only.

TECHNICAL INFORMATION

Installed Capacity (MW)	295
Average Annual Energy (GWh/year)	1799
Dependable Capacity (MW)	265
Firm Energy (GWh/year)	2100
Average Heat Rate (GJ/GWh)	7308

Heat rate estimates are for a clean and new turbine. Over time there will be degradation in the heat rate on the order of 1% to 5% depending in the location of the unit, the maintenance schedule and time between turbine overhauls. Consistent annual maintenance limits the heat rate degradation to 1-2%.

The project installed capacity is either 265MW or 295MW depending on whether duct firing technology is included. BC Hydro planned to include duct firing technology. The combined cycle system proposed for the plant is:
* a combustion turbine designed to produce 170MW of electricity with
* a heat recovery steam generator (HRSG) to generate steam from the hot turbine exhaust gasses, and
* a steam turbine that will produce 95MW of electricity, increased to 125MW through the inclusion of duct firing technology.

The firm capacity of the plant is limited to the supply of natural gas under contractual agreements. BC Hydro intends to acquire, through contract, a minimum of 265MW of natural gas. It is anticipated that there will be enough on-demand gas to fire the remaining 30MW of installed capacity. Power generated by the plant will be supplied to the BC Hydro grid at Duke Point, near Nanaimo. Firm energy was estimated from VIGP A assumptions.

The VIGP's natural gas consumption would be up to 46TJ/day in base mode (i.e up to 265MW without duct firing) and up to 53TJ/day in duct firing mode (i.e up to 295 MW). The plant's efficiency would be approximately 54.8% (lower heating value - LVH) in base mode load with allowance for degradation, and decrease to about 53.7% in duct firing mode. The plant heat rate above represents the plant operating as base loaded on the basis of gas higher heating value (HHV). The equivalent heat rate based on the gas' lower heating value (LHV) is 6,577 GJ/GWh.

The VIGP's estimated natural gas consumption rates are projected for a plant after it has been in use for some time and has suffered some reduction in efficiency (degradation), typically experienced with use. As mentioned above, the difference between the operating efficiency experienced over time and the manufacturer's project efficiency (clean and new) depends on how well the plant is maintained.

The average annual energy figures are based on a 77.5% plant utilization rate.

SOCIAL AND ENVIRONMENTAL INFORMATION

Meets BC Hydro Clean Criteria	No
Greenhouse Gas Emission Factor (Tonnes CO2 equivalent/GWh)	362

Atmospheric Emissions (Metric Tonnes/GWh)	SOx	NOx	CO	VOC	PM 10	PM 2.5	Hg
	0.0045	0.04	0.077	0.0062	0.0054	Unknown	Unknown

Project Footprint (Hectares)	33

Note: Some footprint aspects have not been estimated specifically.

Emission controls for VIGP include DLN (dry low Nox) combustor technology and Selective Catalytic Reduction (SCR -aqueous ammonia injection). Emission data was extracted from the VIEC application to the British Columbia Environmental Assessment Office. Estimated emissions are based on operation of the plant with duct firing 50% of the year., with duct burning on at 100% of maximun. The plant would have a net power output of 295MW in winter and 279MW in summer, with an overall output of 287MW.

PM 10 emissions are for total particulate including the filterable and condensable fraction assumed to be 100% PM 2.5. PM 10 includes PM 2.5 emissions.

Land and general impacts are considered negligable.

The project footprint estimates for most thermal projects do not include a "life-cycle" footprint, but rather the physical footprint attributable to the generation plant and associated equipment. Major infrastructure such as pipelines and roads, and footprints associated with the fuel sources (such as gas wells, coal mines, and roads), have not been included here in these estimates.

Job Creation

Construction Jobs Created (Person-years)	239
Permanent Jobs Created (Full time equivalents)	20

Project work is expected to take place over a 24 month period. It is estimated that about 425,000 person hours of work will be required for facility construction, which is equivalent to about 235 person years of employment. In addition, it is estimated that tie-in construction will create approximately 4 additional person years of employment, The peak workforce for VIGP is estimated at 250 people at site. The operational powerplant will create 20 permanent full time positions.

PRIVATE SECTOR INVOLVEMENT

Estimated Level of Private Sector Involvement	Primary: 50% to 99%

This project could be developed using a variety of development and financing arrangements. In some cases the selected development approach would require a policy decision outside the bounds of BC Hydro's decision making authority. To be conservative, the lower expectation for private sector involvement (primary) was selected, although the project could be 100% private sector owned.

UNCERTAINTY

Development Uncertainty	Medium

Until results from the BC Hydro Call for Tenders process (intiated in September 2003) are available the development uncertainty of this project is estimated as medium.

Price Uncertainty	Low

Detailed studies and cost estimates have been completed for this project.

REFERENCES

VIGP, BCUC Nanaimo hearing, VIGP Witness panel number 5, June 2003.

Vancouver Island Energy Corporation, VIGP application to the British Columbia Environmental Assessment Office, Volume 1, June 2002.

Vancouver Island Energy Corporation, VIGP application to the British Columbia Utilities Commission, March 2003.

British Columbia Utilities Commission, Analysis of Vancouver Island Generation Project, Sept 2003.

PROJECT: **Mine-mouth Coal Fired Station - 250 MW**

Resource Category: Thermal - Coal | Level of Study: Conceptual | Region: East Kootenays

PROJECT DESCRIPTION

This generic non-site specific project was included to nominally represent the coal resources in this region. However, the availability of coal reserves to supply such a project have not been confirmed. It is possible that more or less capacity could be installed depending on actual resource availability.

British Columbia has large thermal coal reserves in the areas of East Kootenays, Hat Creek (Clinton), Peace Region, and Vancouver Island. This project is assumed to be located in the East Kootenays Transmission Region and is meant to represent planning level data for a conventional steam coal fired station using a pulverized coal-fired unit of subcritical steam cycle design. The plant would be equipped with low-NOx burners and selective catalytic reduction for control of nitrogen oxides, as well as flue gas desulfurization, fabric filter particulate control and activated charcoal injection for additional reduction of mercury emissions. Typically, one unit would be installed to reduce capital and operating costs while maintaining the desired energy output. It is assumed that this project would be located near the mine-mouth, with immediate access to fuel supply and transmission.

The intent is to characterize a reasonably typical facility, recognizing that any actual new plant could differ from these assumptions in many respects.

FINANCIAL INFORMATION

Total Capital Cost ($1000s of 2003$)	$430,000
Fixed Operating And Maintenance Cost ($1000s/year)	$11,000
Variable Operating And Maintenance Cost ($/MWh)	$13
Project Life (Years)	35
Project Lead Time (Years)	6
Unit Energy Cost ($/MWh)	$59

All capital and operation and maintenance costs were derived from an average of costs for representative coal project data in integrated resource plans for jurisdictions in the Western United States, and estimates from thermal power generation consultants at Black & Veatch, and SNC LAVALIN Inc. Variable O&M figures include the cost of coal, estimated at $33 per tonne for thermal grade coal, levelized over 2003 to 2023. If waste coal is available there may be fuel cost savings.

In general, US based cost estimates are higher than estimated costs for plants to be built in Canada; labour costs and productivity being significant factors. Capital costs may be lower than data included in the database due to strengthening of the Canadian Dollar with respect to the US Dollar. An exchange rate of 0.75 $CDN/$USD was assumed for cost conversions.

Unit energy costs for thermal resource options depend largely on the market price of fuel and plant usage, which varies over time. However, coal prices in Canada are relatively stable. In order to provide a unit energy cost estimate for thermal resource options a fixed set of financial assumptions and the resource option spreadsheet-model were used, as outlined in the Resource Option report. It was assumed that dispatch was 80% for larger thermal projects in order to estimate an annual average energy and representative unit energy cost.

The project lead time could be reduced to five years if the permitting could be completed in 16 months.

PROJECT: **Mine-mouth Coal Fired Station - 250 MW**

Resource Category: Thermal - Coal   Level of Study: Conceptual   Region: East Kootenays

TECHNICAL INFORMATION

Installed Capacity (MW)	250
Average Annual Energy (GWh/year)	1629
Dependable Capacity (MW)	233
Firm Energy (GWh/year)	1853
Average Heat Rate (GJ/GWh)	10460

The heat rate estimate is assumed for operation at base load, higher heating values (HHV) for a clean and new turbine are quoted. Over time there will be degradation in the heat rate on the order of 4% averaged over 15 years. Based on an O&M budget to maintain availability and annual capacity factor over its lifetime, the likelihood is that unit heat rate would be restored to near its design value at least once in its lifetime. However, at this level of study no assumptions on heat rate degradation were included in project calculations.

Dependable or net capacity is estimated based on an availablity of 93% of installed or gross capacity. It was assumed that dispatch was 80% for larger thermal projects in order to estimate an average annual energy and representative unit energy cost.

SOCIAL AND ENVIRONMENTAL INFORMATION

Meets BC Hydro Clean Criteria	No
Greenhouse Gas Emission Factor (Tonnes CO2 equivalent/GWh)	920

Atmospheric Emissions (Metric Tonnes/GWh)	SOx	NOx	CO	VOC	PM 10	PM 2.5	Hg
	0.46	0.36	0.092	0.011	0.016	Unknown	0.0000027

Project Footprint (Hectares)	17

Note: Some footprint aspects have not been estimated specifically.

The greenhouse gas factor and local air emission factors are from AMEC (VOC, CO, PM10), and the PacifiCorp Integrated Resource Plan, which are based on operational results from the Environmental Protection Agency and Federal Energy Regulation Commission (GHG, SOx, NOx, Hg).

This type of plant is assumed to have scrubbers to remove SO2 and other emissions. The plant would be equipped with low-NOx burners and selective catalytic reduction for control of nitrogen oxides. The plant would also be equipped with flue gas desulfurization, fabric filter particulate control and activated charcoal injection for additional reduction of mercury emissions.

New coal fired generation projects in the province would be governed by the BC Ministry of Water, Land, and Air Protection's Coal Fired Power Boiler Emission Guidelines, which state limits for:

Total Particulates = 0.11 tonnes/GWh
NOx = 1.37 tonnes/GWh
SOx = 1.97 to 3.17 tonnes/GWh, and
Opacity = 20%.

Mercury levels in BC coal are low compared to other regions, and are not regulated provincially, therefore a permit for mercury emissions is not required.

The land impacts are unknown, but assumed to be low as the plant is assumed to located at mine mouth within an existing mining facility. It is assumed that no new transmission right of way would be required as a mine facility would likely be interconnected to the transmission system. The project footprint was estimated from the 95 IEP 200 MW coal project and does not include area of a mine.

The project footprint estimates for most thermal projects do not include a "life-cycle" footprint, but rather the physical footprint attributable to the generation plant and associated equipment. Major infrastructure such as pipelines and roads, and footprints associated with the fuel sources (such as gas wells, coal mines, and roads), have not been included here in these estimates.

Job Creation

Construction Jobs Created (Person-years)	900
Permanent Jobs Created (Full time equivalents)	50

Employment estimates were provided by SNC Lavalin Inc.; Thermal Power Division

PRIVATE SECTOR INVOLVEMENT

Estimated Level of Private Sector Involvement	100%: Private sector ownership

UNCERTAINTY

Development Uncertainty	Medium

Coal fired generation raises concerns over environmental impacts, particulary air emissions, which may delay or prevent development. However, there may be regional support for resource based economic growth and the coal industry.

Price Uncertainty	Medium

Estimates are in line with industry equipment costs, however no site specific studies have been completed.

REFERENCES

BC Ministry of Water, Air, and Climate Change Branch, Industrial Emissions Guidelines for Coal Fired Power Boilers, http://wlapwww.gov.bc.ca/air/industrial/#1, 2003.

PacifiCorp, PacifiCorp's 2003 Integrated Resource Plan - Assuring a bright future for our customers, 2003.

AMEC, E&C Services Limited (D. McCann), Document entitled: Thermal Power Plant Performance, Emissions and Costs Review, November 2003.

BC Hydro 1995 Integrated Electricity Plan, Appendix E, ISSN 1180-2561, October 1995.

Black & Veatch Corporation, Energy Services Division, Results of Review for Coal Units Letter, September 26, 2003.

Idaho Power Company, 2002 Integrated Resource Plan, June 2002.

Puget Sound Energy's Least Cost Plan, Appendix G - Detailed Electric Resource Descriptions, August 2003.

Technical Assessment Guide- Central Stations: TAG -CS, EPRI, Palo Alto, CA: 2001. 1003998

SNC LAVALIN Inc., Thermal Power Division (R. Wesley), Document entitled: Comments on BC Hydro RO-DAT Report, November 19, 2003.

PROJECT: **Mine-mouth Coal Fired Station (KN) - 500 MW**

Resource Category: Thermal - Coal   Level of Study: Conceptual   Region: Kelly / Nicola

PROJECT DESCRIPTION

A generic, non-site specific coal project has been included in the database in this region to represent the central interior coal resources. Based on previous BC Hydro project studies at Hat Creek coal resource, a project in the Clinton area coal reserves may need to be on the order of 1,500 MW to 2,000 MW to be economically viable.

Data presented are planning level estimates for a conventional steam coal fired station using a pulverized coal-fired unit of subcritical steam cycle design. The plant would be equipped with low-NOx burners and selective catalytic reduction for control of nitrogen oxides, as well as flue gas desulfurization, fabric filter particulate control and activated charcoal injection for additional reduction of mercury emissions.Typically, one unit would be installed to reduce capital and operating costs while maintaining the desired energy output. It is assumed that this project would be located near the mine-mouth, with immediate access to fuel supply and transmission.

The intent is to characterize a reasonably typical facility, recognizing that any actual new plant could differ from these assumptions in many respects.

FINANCIAL INFORMATION

Total Capital Cost ($1000s of 2003$)	$800,000
Fixed Operating And Maintenance Cost ($1000s/year)	$20,000
Variable Operating And Maintenance Cost ($/MWh)	$12
Project Life (Years)	35
Project Lead Time (Years)	6
Unit Energy Cost ($/MWh)	$52

All capital and operation and maintenance costs were derived from an average of costs for representative coal project data in integrated resource plans for jurisdictions in the Western United States, and estimates from thermal power generation consultants at Black & Veatch, and SNC LAVALIN Inc. Variable O&M figures include the cost of coal, estimated at $33 per tonne for thermal grade coal, levelized over 2003 to 2023. If waste coal is available there may be fuel cost savings.

In general, US based cost estimates are higher than estimated costs for plants to be built in Canada; labour costs and productivity being significant factors. Capital costs may be lower than data included in the database due to strengthening of the Canadian Dollar with respect to the US Dollar. An exchange rate of 0.75 $CDN/$USD was assumed for cost conversions.

Unit energy costs for thermal resource options depend largely on the market price of fuel and plant usage, which varies over time. However, coal prices in Canada are relatively stable. In order to provide a unit energy cost estimate for thermal resource options a fixed set of financial assumptions and the resource option spreadsheet-model were used, as outlined in the Resource Option report. It was assumed that dispatch was 80% for larger thermal projects in order to estimate an annual average energy and representative unit energy cost.

The project lead time could be reduced to 5 years if the permitting could be completed in 16 months.

PROJECT: **Mine-mouth Coal Fired Station (KN) - 500 MW**

Resource Category: Thermal - Coal Level of Study: Conceptual Region: Kelly / Nicola

TECHNICAL INFORMATION

Installed Capacity (MW)	500
Average Annual Energy (GWh/year)	3259
Dependable Capacity (MW)	465
Firm Energy (GWh/year)	3707
Average Heat Rate (GJ/GWh)	10230

The heat rate estimate is assumed for operation at base load, higher heating values (HHV) for a clean and new turbine are quoted. Over time there will be degradation in the heat rate on the order of 4% averaged over 15 years. Based on an O&M budget to maintain availability and annual capacity factor over its lifetime, the likelihood is that unit heat rate would be restored to near its design value at least once in its lifetime. However, at this level of study no assumptions on heat rate degradation were included in project calculations.

Dependable or net capacity is estimated based on an availablity of 93% of installed or gross capacity. It was assumed that dispatch was 80% for larger thermal projects in order to estimate an average annual energy and representative unit energy cost.

A heat rate of 10,230 GJ/GWh is assumed based on planning estimates used by other jurisdictions in the Western United States.

SOCIAL AND ENVIRONMENTAL INFORMATION

Meets BC Hydro Clean Criteria	No
Greenhouse Gas Emission Factor (Tonnes CO2 equivalent/GWh)	900

Atmospheric Emissions (Metric Tonnes/GWh)	SOx	NOx	CO	VOC	PM 10	PM 2.5	Hg
	0.46	0.36	0.092	0.011	0.016	Unknown	0.000003

Project Footprint (Hectares)	625

Note: Some footprint aspects have not been estimated specifically.

The greenhouse gas factor and local air emission factors are from AMEC (VOC, CO, PM10), and the PacifiCorp Integrated Resource Plan, which are based on operational results from the Environmental Protection Agency and Federal Energy Regulation Commission (GHG, SOx, NOx, Hg).

This type of plant is assumed to have scrubbers to remove SO2 and other emissions. The plant would be equipped with low-NOx burners and selective catalytic reduction for control of nitrogen oxides. The plant would also be equipped with flue gas desulfurization, fabric filter particulate control and activated charcoal injection for additional reduction of mercury emissions.

New coal fired generation projects in the province would be governed by the BC Ministry of Water, Land, and Air Protection's Coal Fired Power Boiler Emission Guidelines, which state limits for:

Total Particulates = 0.11 tonnes/GWh
NOx = 1.37 tonnes/GWh
SOx = 1.97 to 3.17 tonnes/GWh, and
Opacity = 20%.

Mercury levels in BC coal are low compared to other regions, and are not regulated provincially, therefore a permit for mercury emissions is not required.

The total land impacts are unknown, but are expected to be greater for a project that requires a new mine site (e.g., Clinton/Hat Creek) than one using an existing mine site. Project footprint was based on estimates from the 1987 Woodley memo and includes only limited area for footprint of mineworks. The project footprint estimates for most thermal projects does not include a "life-cycle" footprint, but rather the physical footprint attributable to the turbine and associated equipment. Infrastructure such as pipelines and roads, and footprints associated with the fuel sources (such as gas wells, coal mines, and roads), have not been included here in these estimates.

PROJECT: **Mine-mouth Coal Fired Station (KN) - 500 MW**

Resource Category: Thermal - Coal Level of Study: Conceptual Region: Kelly / Nicola

Job Creation

Construction Jobs Created (Person-years)	1500
Permanent Jobs Created (Full time equivalents)	60

Employment estimates were provided by SNC Lavalin Inc.; Thermal Power Division

PRIVATE SECTOR INVOLVEMENT

Estimated Level of Private Sector Involvement	100%: Private sector ownership

UNCERTAINTY

Development Uncertainty	Medium

Coal fired generation raises concerns over environmental impacts, particulary air emissions, which may delay or prevent development. However, there may be regional support for resource based economic growth and the coal industry.

Price Uncertainty	Medium

Estimates are in line with industry equipment costs, however no site specific studies have been completed.

REFERENCES

Woodley M., Project Summaries, BC Hydro inter-office memo, File # 527.1.17, July 1987.

BC Ministry of Water, Air, and Climate Change Branch, Industrial Emissions Guidelines for Coal Fired Power Boilers, http://wlapwww.gov.bc.ca/air/industrial/#1, 2003.

SNC LAVALIN Inc., Thermal Power Division (R. Wesley), Document entitled: Comments on BC Hydro RO-DAT Report, November 19, 2003.

AMEC, E&C Services Limited (D. McCann), Document entitled: Thermal Power Plant Performance, Emissions and Costs Review, November 2003.

Technical Assessment Guide- Central Stations: TAG -CS, EPRI, Palo Alto, CA: 2001. 1003998

PacifiCorp, PacifiCorp's 2003 Integrated Resource Plan - Assuring a bright future for our customers, 2003.

Puget Sound Energy's Least Cost Plan, Appendix G - Detailed Electric Resource Descriptions, August 2003.

Black & Veatch Corporation, Energy Services Division, Results of Review for Coal Units Letter, September 26, 2003.

Idaho Power Company, 2002 Integrated Resource Plan, June 2002.

PROJECT: **Mine-mouth Coal Fired Station (PR) - 500 MW**

Resource Category: Thermal - Coal Level of Study: Conceptual Region: Peace River

PROJECT DESCRIPTION

A generic, non-site specific coal project was included to nominally represent the coal resources in this region. However, the availability of coal reserves to supply such a project have not been confirmed. It is possible that more or less capacity could be installed depending on actual resource availability.

British Columbia has large thermal coal reserves in the East Kootenays, Hat Creek (Clinton), Peace Region, and Vancouver Island. This project is assumed to be located in the Peace Transmission Region and is meant to represent planning level data for a conventional steam coal fired station using a pulverized coal-fired unit of subcritical steam cycle design. The plant would be equipped with low-NOx burners and selective catalytic reduction for control of nitrogen oxides, as well as flue gas desulfurization, fabric filter particulate control and activated charcoal injection for additional reduction of mercury emissions.Typically, one unit would be installed to reduce capital and operating costs while maintaining the desired energy output. It is assumed that this project would be located near the mine-mouth,with immediate access to fuel supply and transmission.

The intent is to characterize a reasonably typical facility, recognizing that any actual new plant could differ from these assumptions in many respects.

FINANCIAL INFORMATION

Total Capital Cost ($1000s of 2003$)	$800,000
Fixed Operating And Maintenance Cost ($1000s/year)	$20,000
Variable Operating And Maintenance Cost ($/MWh)	$14
Project Life (Years)	35
Project Lead Time (Years)	6
Unit Energy Cost ($/MWh)	$52

All capital and operation and maintenance costs were derived from an average of costs for representative coal project data in integrated resource plans for jurisdictions in the Western United States, and estimates from thermal power generation consultants at Black & Veatch, and SNC LAVALIN Inc. Variable O&M figures include the cost of coal, estimated at $33 per tonne for thermal grade coal, levelized over 2003 to 2023. If waste coal is available there may be fuel cost savings.

In general, US based cost estimates are higher than estimated costs for plants to be built in Canada; labour costs and productivity being significant factors. Capital costs may be lower than data included in the database due to strengthening of the Canadian Dollar with respect to the US Dollar. An exchange rate of 0.75 $CDN/$USD was assumed for cost conversions.

Unit energy costs for thermal resource options depend largely on the market price of fuel and plant usage, which varies over time. However, coal prices in Canada are relatively stable. In order to provide a unit energy cost estimate for thermal resource options a fixed set of financial assumptions and the resource option spreadsheet-model were used, as outlined in the Resource Option report. It was assumed that dispatch was 80% for larger thermal projects in order to estimate an annual average energy and representative unit energy cost.

The project lead time could be reduced to 5 years if the permitting could be completed in 16 months.

PROJECT: **Mine-mouth Coal Fired Station (PR) - 500 MW**

Resource Category: Thermal - Coal Level of Study: Conceptual Region: Peace River

TECHNICAL INFORMATION

Installed Capacity (MW)	500
Average Annual Energy (GWh/year)	3259
Dependable Capacity (MW)	465
Firm Energy (GWh/year)	3707
Average Heat Rate (GJ/GWh)	10230

The heat rate estimate is assumed for operation at base load, higher heating values (HHV) for a clean and new turbine are quoted. Over time there will be degradation in the heat rate on the order of 4% averaged over 15 years. Based on an O&M budget to maintain availability and annual capacity factor over its lifetime, the likelihood is that unit heat rate would be restored to near its design value at least once in its lifetime. However, at this level of study no assumptions on heat rate degradation were included in project calculations.

Dependable or net capacity is estimated based on an availablity of 93% of installed or gross capacity.It was assumed that dispatch was 80% for larger thermal projects in order to estimate an average annual energy and representative unit energy cost. A heat rate of 10,230 GJ/GWh is assumed based on planning estimates used by other jurisdictions in the Western United States.

SOCIAL AND ENVIRONMENTAL INFORMATION

Meets BC Hydro Clean Criteria	No
Greenhouse Gas Emission Factor (Tonnes CO2 equivalent/GWh)	900

Atmospheric Emissions (Metric Tonnes/GWh)	SOx	NOx	CO	VOC	PM 10	PM 2.5	Hg
	0.46	0.36	0.092	0.011	0.016	Unknown	0.0000026

Project Footprint (Hectares)	25

Note: Some footprint aspects have not been estimated specifically.

The greenhouse gas factor and local air emission factors are from AMEC (VOC, CO, PM10), and the PacifiCorp Integrated Resource Plan, which are based on operational results from the Environmental Protection Agency and Federal Energy Regulation Commission (GHG, SOx, NOx, Hg).

This type of plant is assumed to have scrubbers to remove SO2 and other emissions. The plant would be equipped with low-NOx burners and selective catalytic reduction for control of nitrogen oxides. The plant would also be equipped with flue gas desulfurization, fabric filter particulate control and activated charcoal injection for additional reduction of mercury emissions.

New coal fired generation projects in the province would be governed by the BC Ministry of Water, Land, and Air Protection's Coal Fired Power Boiler Emission Guidelines, which state limits for:

Total Particulates = 0.11 tonnes/GWh
NOx = 1.37 tonnes/GWh
SOx = 1.97 to 3.17 tonnes/GWh, and
Opacity = 20%.

Mercury levels in BC coal are low compared to other regions, and are not regulated provincially, therefore a permit for mercury emissions is not required.

The land impacts are unknown, but expected to be small as the plant is assumed to located at mine mouth within an existing mining facility. It is assumed that no new transmission right of way would be required as a mine facility would likely be interconnected to the transmission system. The project footprint was estimated from the 95 IEP 200 MW coal project, taking into account the larger project size. The footprint size does not include area of a mine.

The project footprint estimates for most thermal projects do not include a "life-cycle" footprint, but rather the physical footprint attributable to the generation plant and associated equipment. Major infrastructure such as pipelines and roads, and footprints associated with the fuel sources (such as gas wells, coal mines, and roads), have not been included here in these estimates.

Job Creation

Construction Jobs Created (Person-years)	1500
Permanent Jobs Created (Full time equivalents)	60

Employment estimates were provided by SNC Lavalin Inc.; Thermal Power Division

PRIVATE SECTOR INVOLVEMENT

Estimated Level of Private Sector Involvement	100%: Private sector ownership

UNCERTAINTY

Development Uncertainty	Medium

Coal fired generation raises concerns over environmental impacts, particulary air emissions, which may delay or prevent development. However, there may be regional support for resource based economic growth and the coal industry.

Price Uncertainty	Medium

Estimates are in line with industry equipment costs, however no site specific studies have been completed.

REFERENCES

AMEC, E&C Services Limited (D. McCann), Document entitled: Thermal Power Plant Performance, Emissions and Costs Review, November 2003.

Technical Assessment Guide- Central Stations: TAG -CS, EPRI, Palo Alto, CA: 2001. 1003998

SNC LAVALIN Inc., Thermal Power Division (R. Wesley), Document entitled: Comments on BC Hydro RO-DAT Report, November 19, 2003.

Black & Veatch Corporation, Energy Services Division, Results of Review for Coal Units Letter, September 26, 2003.

PacifiCorp, PacifiCorp's 2003 Integrated Resource Plan - Assuring a bright future for our customers, 2003.

Puget Sound Energy's Least Cost Plan, Appendix G - Detailed Electric Resource Descriptions, August 2003.

BC Hydro 1995 Integrated Electricity Plan, Appendix E, ISSN 1180-2561, October 1995.

Idaho Power Company, 2002 Integrated Resource Plan, June 2002.

BC Ministry of Water, Air, and Climate Change Branch, Industrial Emissions Guidelines for Coal Fired Power Boilers, http://wlapwww.gov.bc.ca/air/industrial/#1, 2003.

PROJECT: **Quinsam Coal Vancouver Island Project**

Resource Category: Thermal - Coal   Level of Study: Pre-feasibility   Region: Vancouver Island

PROJECT DESCRIPTION

Quinsam Coal is a wholly owned subsidiary of Hillsborough Resources Limited and has proposed to produce electricity from a coal-fired thermal power facility located at the Quinsam Coal mine site. The Quinsam Energy Partnership has registered to bid in the Vancouver Island Call for Tenders, November 2003. The project data presented here was taken directly from publicly available information provided by Hillsborough Resource Limited, during the British Columbia Utilities Commission hearing for the Vancouver Island Energy Corporation application for a Certificate of Public Convenience and Necessity for the Vancouver Island Generation Project in Spring 2003. Energy estimates, operations and maitainence, unit energy costs, heat rates, emissions and footprintl data were not available and estimated as outlined under each heading.

The project equipment is proposed to be relocated from the United States and equipped with modern and emissions control technology. Design plans were to run on the mine's waste-coal and will therefore contribute to the sustainable operation of the mine by reducing the volume of refuse coal on site and eliminating the need for new tailings ponds. The Quinsam coal mine is located 27 kilometres southwest of Campbell River on Vancouver Island and is the only underground coal mine in operation in Canada.

FINANCIAL INFORMATION

Total Capital Cost ($1000s of 2003$)	$65,000
Fixed Operating And Maintenance Cost ($1000s/year)	$5,400
Variable Operating And Maintenance Cost ($/MWh)	$18
Project Life (Years)	25
Project Lead Time (Years)	3
Unit Energy Cost ($/MWh)	$61

Capital costs include the development costs required to mine coal. The information indicated capital costs are considerably lower than the industry standard for this type of plant due to the purchase and re-use of second hand equipment. A review of the financial information by Black & Veatch Corporation, Energy Services Division, and SNC Lavalin indicated that the costs appeared low, especially if the best available emission control technology is used and waste coal is burned. Operation and maintenance data was derived from estimates provided by Black & Veatch, and SNC LAVALIN Inc. Variable O&M figures include the cost of coal, estimated at $33 per tonne for thermal grade coal, levelized over 2003 to 2023. If waste coal is available there may be fuel cost savings.

Unit energy costs for thermal resource options depend largely on the market price of fuel and plant usage, which varies over time. However, coal prices in Canada are relatively stable. In order to provide a unit energy cost estimate for thermal resource options a fixed set of financial assumptions and the resource option spreadsheet-model were used, as outlined in the Resource Option report. It was assumed that dispatch was 80% for larger thermal projects in order to estimate an annual average energy and representative unit energy cost.

PROJECT: **Quinsam Coal Vancouver Island Project**

Resource Category: Thermal - Coal   Level of Study: Pre-feasibility   Region: Vancouver Island

TECHNICAL INFORMATION

Installed Capacity (MW)	60
Average Annual Energy (GWh/year)	391
Dependable Capacity (MW)	56
Firm Energy (GWh/year)	445
Average Heat Rate (GJ/GWh)	12100

The heat rate estimate is assumed for operation at base load, higher heating values (HHV) for a clean and new turbine are quoted. Over time there will be degradation in the heat rate on the order of 4% averaged over 15 years. Based on an O&M budget to maintain availability and annual capacity factor over its lifetime, the likelihood is that unit heat rate would be restored to near its design value at least once in its lifetime. However, at this level of study no assumptions on heat rate degradation were included in project calculations.

Quisam's plant would use equipment from the U.S. and it is expected that the boiler will include fluidized bed technology, which is the most efficient method of burning waste coal with minimal emissions. The preferred plant would have two boilers, installed side-by-side for efficiency of operation. The steam turbine will be a General Electric or similar unit.

Energy data was estimated for this project. Dependable capacity is estimated as the net capacity based on an availablity of 93%. It was assumed that dispatch was 80% for larger thermal projects in order to estimate an average annual energy and representative unit energy cost.

SOCIAL AND ENVIRONMENTAL INFORMATION

Meets BC Hydro Clean Criteria	No
Greenhouse Gas Emission Factor (Tonnes CO2 equivalent/GWh)	1060

Atmospheric Emissions (Metric Tonnes/GWh)	SOx	NOx	CO	VOC	PM 10	PM 2.5	Hg
	0.46	0.42	0.117	0.014	0.036	Unknown	0.0000031

Project Footprint (Hectares)	5

Note: Some footprint aspects have not been estimated specifically.

The greenhouse gas factor and local air emission factors are from AMEC (GHG, VOC, CO), and the PacifiCorp Integrated Resource Plan, which are based on operational results from the Environmental Protection Agency and Federal Energy Regulation Commission (SOx, NOx, Hg, PM10).

This type of plant is assumed to have scrubbers to remove SO2 and other emissions. The plant would be equipped with low-NOx burners and selective catalytic reduction for control of nitrogen oxides. The plant would also be equipped with flue gas desulfurization, fabric filter particulate control and activated charcoal injection for additional reduction of mercury emissions.

New coal fired generation projects in the province would be governed by the BC Ministry of Water, Land, and Air Protection's Coal Fired Power Boiler Emission Guidelines, which state limits for:

Total Particulates = 0.11 tonnes/GWh
NOx = 1.37 tonnes/GWh
SOx = 1.97 to 3.17 tonnes/GWh, and
Opacity = 20%.

Mercury levels in BC coal are low compared to other regions, and are not regulated provincially, therefore a permit for mercury emissions is not required.

The total sulphur dioxide loading in the Campbell River airshed are expected to be minimal as there are no other significant emitters in this area. Mercury levels in BC coal are relatively low, and are not regulated provincially, therefore a permit for mercury emissions is not required.

The project proponent expected that incremental (additional) land impacts would to be minimal since the facility will be located at an existing mine site. Project footprint was roughly estimated to be 5 ha based on larger coal resource options. Hillsborough estimates that the project will reduce the amount of waste coal at the mine site by roughly 150,000 tonnes per year and delay the need for new tailing disposal ponds. No assumption was made for footprint due to transmission right-of-way requirements.

The project footprint estimates for most thermal projects do not include a "life-cycle" footprint, but rather the physical footprint attributable to the generation plant and associated equipment. Major infrastructure such as pipelines and roads, and footprints associated with the fuel sources (such as gas wells, coal mines, and roads), have not been included here in these estimates.

Job Creation

Construction Jobs Created (Person-years)	175
Permanent Jobs Created (Full time equivalents)	30

Hillsborough estimate that 30 full time permanent jobs will be created by this project over the 25 year life of the project, twenty in the power plant and ten in the mine. The construction period is expected to be 14 months, and will employ 150 employees. Erection of the plant includes new foundations, power lines, and cooling water systems.

PRIVATE SECTOR INVOLVEMENT

Estimated Level of Private Sector Involvement	100%: Private sector ownership

UNCERTAINTY

Development Uncertainty	Medium

Uncertainties are difficult to assess as the data provided was limited, and not initially computed for the purposes the 2004 IEP study.

Price Uncertainty	Medium

Limited information was available for project and would need to be verified through specific studies. Industry review indicated that estimates appeared low.

REFERENCES

AMEC, E&C Services Limited (D. McCann), Document entitled: Thermal Power Plant Performance, Emissions and Costs Review, November 2003.

Technical Assessment Guide- Central Stations: TAG -CS, EPRI, Palo Alto, CA: 2001. 1003998

BC Ministry of Water, Air, and Climate Change Branch, Industrial Emissions Guidelines for Coal Fired Power Boilers, http://wlapwww.gov.bc.ca/air/industrial/#1, 2003.

SNC LAVALIN Inc., Thermal Power Division (R. Wesley), Document entitled: Comments on BC Hydro RO-DAT Report, November 19, 2003.

Hillsborough Resources Limited, Intervenor response to the CPCN Application for the Vancouver Island Energy Corporation, August 13, 2003.

Black & Veatch Corporation, Energy Services Division, Results of Review for Coal Units Letter, September 26, 2003.

Hillsborough Resources Limited Intervenor repsonse to the CPCN Application for the Vancovuer Island Energy Corporation, August 13, 2003.

BC Hydro 1995 Integrated Electricity Plan, Appendix E, ISSN 1180-2561, October 1995.

PROJECT: **Mobile Generators**

Resource Category: Thermal - Oil   Level of Study: Pre-feasibility   Region: All

PROJECT DESCRIPTION

Preliminary enquiries with the equipment vendor (GE Canada) indicated that there are mobile generators available for lease or purchases. These mobile generators (TM2500's) are truck mounted and operate on distillate or alternatively dual fuel. They are rated 23 MW each and can be available with very short lead time (less than 1 year). These units are mobile and can be sited in favourable locations to reduce infrastructure costs (i.e. transmission interconnection). Due to emission concerns, they will be permitted for and operated on emergency basis only.

These units can be dual fuel fired (which will require gas transportation) or distillate fired.

FINANCIAL INFORMATION

Total Capital Cost ($1000s of 2003$)	$35,400
Fixed Operating And Maintenance Cost ($1000s/year)	$32,800
Variable Operating And Maintenance Cost ($/MWh)	$4
Project Life (Years)	Unknown
Project Lead Time (Years)	1
Unit Energy Cost ($/MWh)	Unknown

Financial information is based on bundle of seven units for a five year lease term. Fixed O&M cost includes yearly equipment lease. Project lead time is likely to be less than one year. Unit energy cost is not applicable for this project.

TECHNICAL INFORMATION

Installed Capacity (MW)	161
Average Annual Energy (GWh/year)	38.5
Dependable Capacity (MW)	161
Firm Energy (GWh/year)	Unknown
Average Heat Rate (GJ/GWh)	Unknown

Installed and dependable capacity and average annual energy has been estimated for the total seven units. Each unit has an installed and dependable capacity of 23 MW and an estimated average annual energy of 5.5 GWh/y. Annual average energy is based on 10 days of operation per year.

SOCIAL AND ENVIRONMENTAL INFORMATION

Meets BC Hydro Clean Criteria	No
Greenhouse Gas Emission Factor (Tonnes CO2 equivalent/GWh)	Unknown

Atmospheric Emissions (Metric Tonnes/GWh)	SOx	NOx	CO	VOC	PM 10	PM 2.5	Hg
	Unknown	Unknown	Unknown	Unknown	Unknown	Unknown	Unknown

Project Footprint (Hectares)	0

Note: Some footprint aspects have not been estimated specifically.

Actual emission levels are unknown at this time.

There will likely be one air emissions discharge permit for generation sited in each location. That permit can have multiple air emissions discharge points at the single location or facility. Air permit is likely to take between 6-8 months. If the size of project exceeds 50 MW, an environmental assessment certificate may also be required.

There are likely two types of permit restrictions - a restriction on the number of start-ups and a restriction on the number of hours of operation on distillate or a restriction on the time of year in which operation on distillate can occur.

Job Creation

Construction Jobs Created (Person-years)	Unknown
Permanent Jobs Created (Full time equivalents)	Unknown

No employment data was available.

PRIVATE SECTOR INVOLVEMENT

Estimated Level of Private Sector Involvement	Unknown

BC Hydro can approach equipment vendor directly to lease or purchase the equipment to supply capacity shortfall or alternatively, issue a Request for Proposal or Call for Tenders whereby private sector suppliers supply a turnkey solution (build/own/operate).

UNCERTAINTY

Development Uncertainty	Unknown

Price Uncertainty	Unknown

REFERENCES

BC Hydro, Personal Communication with Borden Ladner Gervais LLP, February 2004.

BC Hydro, Personal Communication with GE Canada, February 2004.

PROJECT: **Oil Fired Simple Cycle Combustion Turbine**

Resource Category: Thermal - Oil   Level of Study: Conceptual   Region: All

PROJECT DESCRIPTION

This project assumes a General Electric LM 6000PC Aeroderivative gas turbine generator with NOx Control water injection, following selective catalyctic reduction fired on oil distillate fuel (Oil #2). Plants such as this are most efficient when run to meet the peak load, versus a Combined Cycle Combustion Turbine (CCCT), which are more efficient when run continously to meet base load energy requirements.

FINANCIAL INFORMATION

Total Capital Cost ($1000s of 2003$)	$41,000
Fixed Operating And Maintenance Cost ($1000s/year)	$750
Variable Operating And Maintenance Cost ($/MWh)	$60
Project Life (Years)	30
Project Lead Time (Years)	2
Unit Energy Cost ($/MWh)	$133

Capital cost includes a medium temperature Selective Catalytic Reduction (SCR). Variable operation and maintenance costs include the cost of fuel estimated at $33 per barrel (2001 Canadian $).

Unit energy costs for thermal resource options depend largely on the market price of fuel and plant usage, which varies over time. In order to provide a unit energy cost estimate for thermal resource options a fixed set of financial assumptions and the resource option spreadsheet-model were used, as outlined in the Resource Option report. It was assumed that dispatch was 20% for smaller peaking thermal projects in order to estimate an annual average energy and representative unit energy cost.

Unit energy costs for projects used for peaking, such as simple cycle and internal combustion engines, tend to be much higher because dispatch is lower than plants used for base load.

TECHNICAL INFORMATION

Installed Capacity (MW)	42.3
Average Annual Energy (GWh/year)	70.4
Dependable Capacity (MW)	40.9
Firm Energy (GWh/year)	70.4
Average Heat Rate (GJ/GWh)	9487

Heat rate estimates is the lower heating value for a clean and new turbine. Over time there will be degradation in heat rate on the order of 1% to 5% between major overhauls and operation and maintence of the turbines. Heat rate degradation depends on the operation and maintainence of the unit, and location. Consistent annual maintenance would place heat rate degradation on the order of 1% to 2%. However, at this level of study no assumptions on heat rate degradation were included in project calculations.

This technical information assumes that the site is located at ISO conditions. This technical information assumes that the site is located at sea level. A increase in altitude would result in a decrease in the output of the plant (as for the site in the Kelly/Nicola region).

Dependable capacity is assumed to be 95% of installed capacity. It was assumed that dispatch was 20% for small thermal projects used for peaking in order to estimate an average annual energy value for calculation of a representative unit energy cost. Firm energy estimates were based on the assumption that a firm fuel contract would be available and contracted, and an availability of 95%

The heat rate is based on fuel low heating value and net output. It is assumed that this resource option would be used as a peaking plant.

PROJECT: **Oil Fired Simple Cycle Combustion Turbine**

Resource Category: Thermal - Oil Level of Study: Conceptual Region: All

SOCIAL AND ENVIRONMENTAL INFORMATION

Meets BC Hydro Clean Criteria	No
Greenhouse Gas Emission Factor (Tonnes CO2 equivalent/GWh)	790

Atmospheric Emissions (Metric Tonnes/GWh)	SOx	NOx	CO	VOC	PM 10	PM 2.5	Hg
	2.2	0.19	0.07	0.002	0.13	Unknown	0

Project Footprint (Hectares)	1

Note: Some footprint aspects have not been estimated specifically.

The SOx emissions are directly related to the sulphur content of the fuel oil. The value here is based on an assumed 0.5% suphur content. NOx emission rate is controlled by water injection into the gas turbine and selective catalytic reduction (SCR) installed on the exhaust. There will be ammonia emissions, and no Carbon Monoxide catalyst is assumed to be installed.

The project footprint estimates for most thermal projects does not include a "life-cycle" footprint, but rather the physical footprint attributable to the turbine and associated equipment. Infrastructure such as pipelines and roads, and footprints associated with the fuel sources (such as gas wells, coal mines, and roads), have not been included here in these estimates.

Job Creation

Construction Jobs Created (Person-years)	20
Permanent Jobs Created (Full time equivalents)	2

PRIVATE SECTOR INVOLVEMENT

Estimated Level of Private Sector Involvement	100%: Private sector ownership

UNCERTAINTY

Development Uncertainty	Low

This is a standard unit with many years of service. There is a small risk in prolonged operation on distillate oil.

Price Uncertainty	Low

This is a standard unit and costs are well known. It is possible to obtain fixed turn key Engineer Procure Construct pricing.

REFERENCES

General Electric Power Systems, GE Aeroderivative Gas Turbines - Design and Operation Features, Technical Paper GER-3695E.

AMEC, E&C Services Limited (D. McCann), Document entitled: Thermal Power Plant Performance, Emissions and Costs Review, November 2003.

Amec, Report 142194, "2004 Integrated Electricity Plan - General Thermal Review", January 2004.

PROJECT: **Diesel Fired IC Engines**

Resource Category: Thermal - Diesel Level of Study: Conceptual Region: All

PROJECT DESCRIPTION

Reciprocating or Internal Combustion (IC) engines are the most common and technically mature of distributed energy technologies. They are available from small sizes (e.g., 5 kW for residential back-up generation) to large generators (e.g., 7 MW). When used in combination with a 1-5 minute UPS (uninterruptible power supply), the system is able to supply seamless power during a utility outage. In addition, large IC engine generators may be used as base load, grid support, or peak-shaving devices.

A reciprocating, or internal combustion (IC), engine converts the energy contained in a fuel into mechanical power. This mechanical power is used to turn a shaft in the engine. A generator is attached to the IC engine to convert the rotational motion into power. There are two methods for igniting the fuel in an IC engine. In compression ignition (CI), the fuel-air mixture spontaneously ignites when the compression raises it to a high-enough temperature. CI works best with slow-burning fuels, like diesel. In spark ignition (SI), a spark is introduced into the cylinder (from a spark plug) at the end of the compression stroke. Fast-burning fuels, like gasoline and natural gas, are commonly used in SI engines.This resource option describes a generic 7MW Diesel Fired Compression Ignition Internal Combustion Engine - 7MW represents the upper range of available data.

FINANCIAL INFORMATION

Total Capital Cost ($1000s of 2003$)	$4,000
Fixed Operating And Maintenance Cost ($1000s/year)	$150
Variable Operating And Maintenance Cost ($/MWh)	$149
Project Life (Years)	30
Project Lead Time (Years)	1
Unit Energy Cost ($/MWh)	$205

Financial figures represent a diesel engine running in a peak-shaving application, for 500-1000 hours annually. If a diesel engine is to be used as base loaded, there is more justification to purchase a heavier and more efficient engine, with costs significantly (3 to 4 times) higher than those listed above. The total capital cost data is for the basic genset cost alone. The total installed cost is site specific but is usually 50-100% more than the engine itself.

The project capital cost was estimated based on BC Hydro experience that portable peaking diesel generators typically cost $300,000 to $500,000 for a 2 MW unit. The generators used for peaking purposes only are much cheaper than a similar capacity unit used for base load, because base load units need to be more reliable and have more permanent infrastructure (e.g. cranes) installed with them.

The Operating and Maintenance costs are directly proportional to the hours of operation of the diesel genset, in this case 500 to 1000 hours annually. Variable Operating and Maintenance cost includes fuel costs. Variable Operating and Maintenance Costs include:

* IC engine heads and blocks rebuilds after about 8,000 hours of operation.
* Regular oil and filter changes at 700 - 1000 hours of operation.
* Levelized cost of fuel cost estimated at $0.34 per litre.

Unit energy costs for thermal resource options depend largely on the market price of fuel and plant usage, which varies over time. In order to provide a unit energy cost estimate for thermal resource options a fixed set of financial assumptions and the resource option spreadsheet-model were used, as outlined in the Resource Option report. It was assumed that dispatch was 20% for smaller peaking thermal projects in order to estimate an annual average energy and representative unit energy cost.

Unit energy costs for projects used for peaking, such as simple cycle and internal combustion engines, tend to be much higher because dispatch is lower than plants used for base load.

Diesel fuel is described in this section although natural gas is usually less expensive than diesel fuel for the same heat content (diesel engine emission levels are higher than natural gas). If the IC engine is to be used for a large number of hours per year, the total cost to operate with natural gas may be lower. However, natural gas may not be available at all locations, while diesel can be transported widely.

PROJECT: **Diesel Fired IC Engines**

Resource Category: Thermal - Diesel   Level of Study: Conceptual   Region: All

TECHNICAL INFORMATION

Installed Capacity (MW)	7
Average Annual Energy (GWh/year)	11.7
Dependable Capacity (MW)	6.7
Firm Energy (GWh/year)	11.7
Average Heat Rate (GJ/GWh)	8584

Dependable capacity is assumed to be 95% of installed capacity. It was assumed that dispatch was 20% for small thermal projects used for peaking in order to estimate an average annual energy value for calculation of a representative unit energy cost. Firm energy estimates were based on the assumption that a firm fuel contract would be available and contracted.

One of the weaknesses of IC engines is the frequency of maintenance intervals. When used in standy power applications, the frequency of maintnenance is no longer an issue (maintenance performed during the down time) and the genset is available for electicity production 100% of the time. Dependable capacity is assumed to be 95% of Installed capacity.

Reciprocating engines may last for 20-35 years while smaller engines (<1MW) tend to have shorter lifespans. Reciprocating engines have thermal efficiencies that range from 25% to 45%. In general, diesel engines are more efficient than natural gas engines because they operate at higher compression ratios.

Average heat rate values for Diesel IC engines range from 9,500 to 10,900 GJ/GWh depending on the type and size of engine, the application of the engine, and the source of the data. The higher heating value is based on Wartsila performance data for a low NOx engine.

PROJECT: **Diesel Fired IC Engines**

Resource Category: Thermal - Diesel Level of Study: Conceptual Region: All

SOCIAL AND ENVIRONMENTAL INFORMATION

Meets BC Hydro Clean Criteria	No
Greenhouse Gas Emission Factor (Tonnes CO2 equivalent/GWh)	705

Atmospheric Emissions (Metric Tonnes/GWh)	SOx	NOx	CO	VOC	PM 10	PM 2.5	Hg
	0.49	7.9	0.33	Unknown	0.43	Unknown	0

Project Footprint (Hectares)	1

Note: Some footprint aspects have not been estimated specifically.

Emission rates for a particular type and size ranges of engines vary from manufacturer to manufacturer. Similarly, emission rates for each type of engine within a manufacturer's product line may vary considerably from the smallest to the largest units in the line. Reasons for these variations include differences in combustion chamber geometry, fuel air mixing patterns, fuel/air ratio, combustion technique (open chamber versus PC), and ignition timing from model to model.

Three basic types of emission control systems for ICEs include:
* Three-Way Catalyst (TWC) Systems - reduce NOx, CO and unburned hydrocarbons by 90% or more. TWC systems are widely used for automotive applications.
* Selective Catalytic Reduction (SCR) - SCR is normally used with relatively large (>2 MW) lean-burn reciprocating engines. In SCR, a NOx-reducing agent, such as ammonia is injected into the hot exhaust gas before it passes through a catalytic reactor. The NOx can be reduced by about 80-95%.
* Oxidation Catalysts - promote the oxidation of CO and unburned hydrocarbons to CO2 and water. CO conversions of 95% or more are readily achieved.

The emission figures in the above table were provided by estimates completed by AMEC, November 2003. The CO and PM10 values are controlled emission rates.

The project footprint was assumed to be nominally 1 ha. This assumption was based on a fraction of the footprint size for the larger thermal fuel projects.

The project footprint estimates for most thermal projects do not include a "life-cycle" footprint, but rather the physical footprint attributable to the generation plant and associated equipment. Major infrastructure such as pipelines and roads, and footprints associated with the fuel sources (such as gas wells, coal mines, and roads), have not been included here in these estimates.

Job Creation

Construction Jobs Created (Person-years)	Unknown
Permanent Jobs Created (Full time equivalents)	Unknown

No data on employment was available.

PRIVATE SECTOR INVOLVEMENT

Estimated Level of Private Sector Involvement	100%: Private sector ownership

UNCERTAINTY

Development Uncertainty	Medium

This option is for a proven technology, however without economic or regulatory drivers significant development is unlikely.

Price Uncertainty	Medium

Capital costs were broadly estimated based on BC Hydro experience and could be significantly different depending on actual project configuration.

REFERENCES

Amec, Report 142194, "2004 Integrated Electricity Plan - General Thermal Review", January 2004.

Electrical Power Research Institute, Technical Assessment Guide (TAG) - Distributed Resources, January 2002.

AMEC, E&C Services Limited (D. McCann), Document entitled: Thermal Power Plant Performance, Emissions and Costs Review, November 2003.

Caterpillar Online Datasheets, http://www.caterpillar.com/, 2003.

California Energy Commission, Distributed Energy Resource Guide, http://www.energy.ca.gov/distgen/, January 2002.