Appendix A – Database Table of Contents and Fields

A.1 Project and Program Database – Table of Contents

Appendix D – Alternative and Clean - Other

Biomass

Geothermal

A.2 Resource Option Database Fields

Resource option information has been prepared for BC Hydro's electricity planning purposes only. This information should not be relied upon by others for design, financing or development decision-making. It is expected that based on further study and verification, actual technical and financial project information may vary from that shown here.

Table A.1. Resource Option Database Fields

Field Name	Entry Format (text, restricted text selection, or numerical)	Description
Project Index		
Project Name	Text	Resource Options were named to identify the resource/region/proponent/specific project that was being characterized.
Resource Type	Demand Side-Management Alternative Thermal Hydro Resource Smart Imports Transmission	Resources have been broadly classified as Alternative, Hydro, Thermal, Transmission, Imports and Demand Side Management (DSM). Some resources have been further categorized to identify technologies or fuel types (i.e. wind, biomass, natural gas).

Field Name	Entry Format (text, restricted text selection, or numerical)	Description
Level of Study	Conceptual Pre-Feasibility Feasibility Design In Progress	Five categories of study indicate the level of detail that the resource option is based on. The categories are defined as follows: Conceptual – project data is based on limited research and no specific resource data. Pre-feasibility – a project of this level has had some resource studies completed and includes site specific data. Feasibility – the project includes information from resource studies and detailed site studies. Design – full detailed estimates and specific site plans have been completed and drawn up for the project. In Progress – partially complete projects (Power Smart 2).
Region	Lower Mainland (LM) Vancouver Island (VI) Central Interior (CI) North Coast (NC) Peace Region (PR) Kelly Nicola (KN) Selkirk (SE) East Kootenays (EK) All. (Any region or no region specifically).	Projects are separated into one of the eight geographic Transmission Regions. Transmission Resources use receiving region as Region Definition. Power Smart/Demand Side Management were considered not specific to one region and are valid for all regions.
Project Description	Text	General description of project location, technology and resource. Comments on specific issues regarding the development of the project may be included.
Financial Information		
Total Capital Cost	2003 $	Costs at site including interconnection and all project development costs; typically does not include interest during construction, a corporate overhead adder, and inflation. For Power Smart and DSM the equivalent field name is Utility Cost.
Project Life	Years	Lifetime of project, used in calculation of unit energy cost.
Project Lead Time	Years	Includes the time needed for permitting and construction, unless otherwise stated.
Fixed OMA	$ per year	Annual fixed operation and maintenance costs.
Variable OMA	$ per MWh	Operation and maintenance costs that vary depending on the energy output of the facility. Variable OMA for natural gas project entries does not include fuel cost as that is incorporated in system modelling and Portfolio Evaluation.

Field Name	Entry Format (text, restricted text selection, or numerical)	Description
Unit Energy Cost	$ per MWh at site	Unit energy cost of production at the site. Transmission losses to be added at portfolio level. Power Smart Unit Energy Cost will be represented as Total Resource Unit Energy Cost.
Technical Information		
Installed Capacity	MW	For generation plants, this is the nameplate capacity rating. Power Smart does not have an installed capacity equivalent calculated.
Annual Dependable Capacity	MW per year	A Dependable Capacity Definition for Alternatives was completed and used. For Power Smart an Equivalent Dependable Capacity is presented for winter high load hours.
Average Annual Energy	GWh per year	Average Energy is generally calculated using the "annual availability". Annual availability is defined as percentage of a year a generating unit, transmission line, or other facility is capable of providing service, whether or not it actually is in service. For Power Smart the total projected energy savings of the program is presented.
Annual Firm Energy	GWh per year	Primarily applicable to thermal resources and the link between firm energy and a firm fuel supply contract. Unknown for most renewable sources without further hydrologic, wind or other resource analysis.
Social and Environmental Information		
Greenhouse Gas (GHG) Emission Factor	Metric tonnes of CO_2 equivalents per GWh	The equivalent number of tonnes of CO_2 (carbon dioxide) produced per GWh. Equivalent metric tonnes of CO_2 are calculated for methane and nitrous oxide as follows: CH_4 (methane) tonnes x 21, and N_2O (nitrous oxide) x 310 until 2012. After 2013 use factors: CH_4 x 23, and N_2O x 296.
Project Footprint	Hectares (ha)	Area of land used by a new project including roads, new reservoir, transmission lines, etc. if data available.
SOx	Metric tonnes per GWh	Sulphur Oxides
NOx	Metric tonnes per GWh	Nitrous Oxides
CO	Metric tonnes per GWh	Carbon Monoxide
VOC	Metric tonnes per GWh	Volatile Organic Compounds
PM 10	Metric tonnes per GWh	Particulate Matter less than 10 microns in diameter.
PM 2.5	Metric tonnes per GWh	Particulate Matter less than 2.5 microns in diameter.

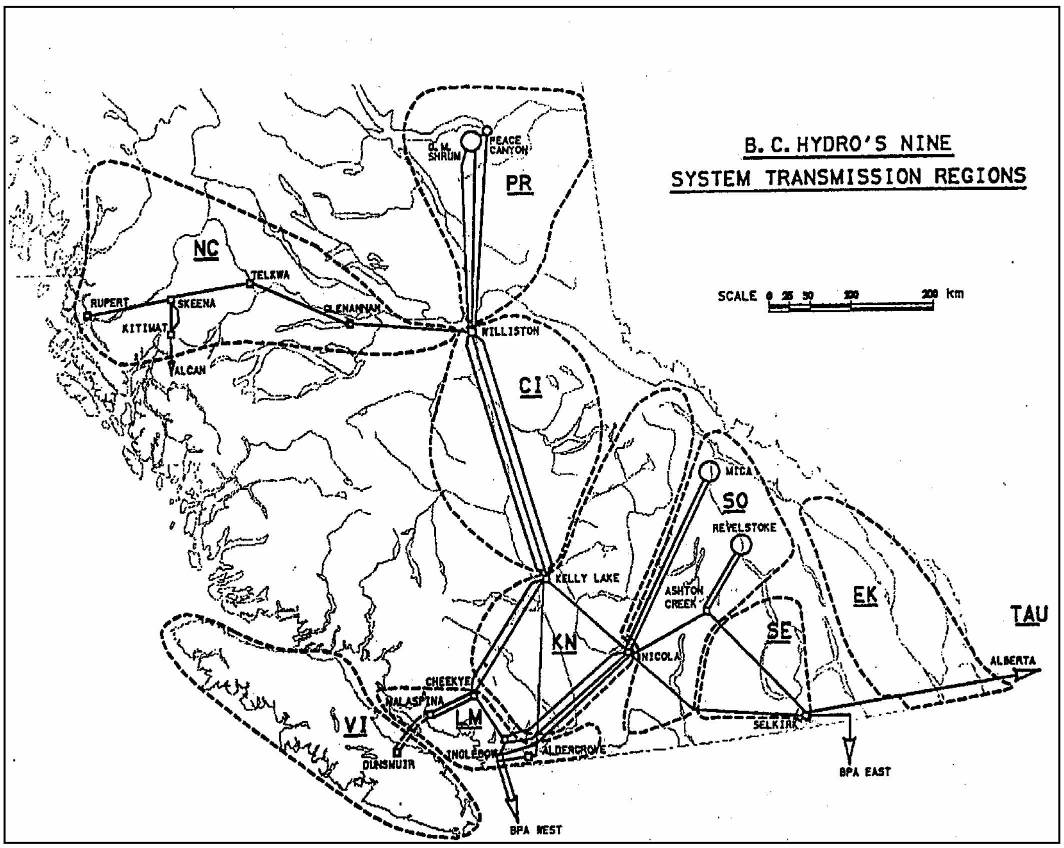
Field Name	Entry Format (text, restricted text selection, or numerical)	Description
Hg	Metric tonnes per GWh	Mercury. Generally this emission applies only to coal fired generation. Coal in B.C. tends to have low mercury content. The Ministry of Water, Land and Air Protection, Coal-Fired Power Boiler Emission Guidelines does not currently regulate mercury.
Clean Energy	Yes or No	B.C. Clean Energy includes: Alternative Energy Resource Smart Low impact large hydro Cogeneration
Construction Jobs Created	# of person-years	The number of jobs directly attributable to the project during the construction phase. Shown in person-years annually, calculated over project life.
Operation Jobs Created	Full time equivalents	Number of full time permanent positions created by project, over the project life.
Private Sector Involvement		
Private Sector Involvement	Illustrative rating only. Level and % economic involvement	1. 0 - 5% - almost no private sector involvement. This would be very small, or very specialized applications. 2. 5 - 25% - Tertiary involvement - limited private sector products/equipment and services. Percentage based on % of total program or project dollars distributed to the private sector. 3. 25% - 50% - Secondary Involvement: moderate private sector provision of products and services. Percentage based on % of total program or project dollars distributed to the private sector. 4. 50 - 99 % - Primary Involvement: Significant private sector design, build, operate, or provision of other products and services. 5. 100 % - Private sector design, build, operate, and ownership.
Uncertainty - Likelihood Ranking		
Development Ranking	1 = Low 2 = Medium 3 = High	Subjective ranking of likelihood that a project will not be developed.
Price Ranking	1 = Low 2 = Medium 3 = High	Subjective ranking of likelihood that the unit energy cost will be greater than predicted.

A.3 Project and Technical Information

Geographic regions were based on the BC Hydro transmission regions because the ability of supply to meet load depends on the transfer capacity of the transmission lines from one region to another. The location of demand and the ability of the transmission system to serve that demand is an important factor in IEP studies. There are eight geographic / transmission regions (See Figure A.1) for the 2004 IEP as follows:

- Central Interior (CI);
- East Kootenays (EK);
- Kelly/Nicola (KN);
- Lower Mainland (LM);
- North Coast (NC);
- Peace River (PR);
- Selkirk Area (SE); and
- Vancouver Island (VI).

Figure A.1 BC Hydro Transmission Regions



Note that Figure A.1 shows the eight regions used in the 2004 IEP and includes an additional ninth region, South Okanagan (SO). For the purposes of the 2004 IEP, South Okanagan was included in Selkirk, although South Okanagan is currently outside the BC Hydro service area.

For most projects in the resource option database, the region was self-evident from the project location. However, some boundaries, like the Lower Mainland (LM) need some clarification for a new reader. Lower Mainland is generally regarded as the part of the province southwest of the Nicola and Kelly Lake substations, east of Georgia Strait and north of the U.S. border. The map, BC Hydro's Nine System Transmission Regions, which has been a part of the "Value of Electricity Report" for the last eight years, shows Lower Mainland encompassing Cheekye, Meridian and Clayburn and part of the major transmission lines between Lower Mainland and Kelly/Nicola.

The above boundary rules were consistent with the existing definitions and practices at the BC Transmission Corporation (BCTC). For some of the boundaries there were challenges in defining the region because the areas are fed from both sides of the station. However, this is a level of detail that was beyond the resource option characterization descriptions

A.4 Financial Assumptions

Projects and programs likely or assumed to be developed or financed by BC Hydro (Power Smart, Resource Smart, Large Hydro and transmission options[1]) reflect financial assumptions of BC Hydro. Levies and transfer payments to municipalities and the provincial government by BC Hydro compensate for the omission of taxes. BC Hydro financial assumptions were as follows:

- An inflation rate of two per cent;
- Real weighted average cost of capital of six per cent (BC Hydro adopted a six per cent real discount rate for financial analysis in October 2003.);
- No income taxes included;
- Interest during construction included where the construction period was more than a year; and
- Net present value (NPV) calculated for the costs over an estimated project life of 20 to 70 years (depending on the resource).

Project cost estimates requiring escalation to October 2003 dollars were calculated using Statistic Canada Indices provided in March 2003. Subsequently, the Statistic Canada Seven City Composite rate was updated in October 2003. The following projects associated costs were updated using the October 2003 rate: Mica New Units 5 and 6, and Revelstoke New Units 5 and 6. Note that prior to 1997 a Non-Residential Index D 481601 and since 1997 the Seven City V7717829 Composite and Consumer Price Index (for 2002 and 2003) were used.

A.4.1 Alternative Energy Financial Assumptions

A spreadsheet-based model was developed to estimate the economic cost of renewable energy projects based on a set of project inputs and financial assumptions. The following assumptions were incorporated into a spreadsheet to estimate unit energy costs for alternative and Clean Energy:

- Resource type (i.e. geothermal, wind, wave, solar, biomass, small hydro);

[1] Transmission projects would be developed by BCTC and financed by BC Hydro.

- Installed capacity (MW)
- Average annual energy (GWh per year);
- Firm energy (GWh per year) where estimated;
- Total capital cost;
- Fixed operations and maintenance; and
- Variable operations and maintenance.

Financial assumptions were set for projects that were run through the model:

• Long-term debt interest rate	eight per cent
• Internal rate of return (on equity)	12 per cent, after tax, over 20 years
• Interest during construction:	100 basis points above the long-term rate
• Debt/equity ratio	70:30
• Long-term debt term:	20 years for small hydro or geothermal, 15 years for wind or biomass, eight years for solar, wave, or tidal
• Inflation	two per cent (applied to working capital, revenues, fixed expenses and variable expenses)

The project life assumptions were 40 years for small hydro, 30 years for geothermal and 20 years for other projects.

The time period for debt repayment was assumed to be 20 years for small hydro or geothermal projects. Higher risk technologies were assumed to have a shorter time for repaying the debt.

For wind projects, the model includes a premium of $0.01 per kilowatt-hour in the revenue stream for the first ten years, from the federal government's Wind Power Production Incentive. There are some funding and timing restrictions on the production incentive, the details of which have not been considered in these cost estimates.

Model outputs include the unit energy price, net present value (NPV), internal rate of return (IRR), minimum debt service coverage ratio, and average debt service coverage ratio. The model estimates the unit energy price required to achieve a zero net present value based on a 12 per cent after-tax return on equity. As a verification of the calculations, the IRR over the full life of the project is also calculated and will be equal to the 12 per cent rate for projects with 20 year lives, and greater than the 12 per cent rate for longer lived projects. The minimum debt service coverage ratio provides a tool for the project financiers, who generally require a minimum ratio of 1.3.

Five different tax depreciation rates were incorporated into the model to derive the net income of each alternative energy project. The "tax shields" function by depreciating the capital cost of the project at rates which vary according to each tax depreciation class:

- Class 43.1 – Allows for an accelerated tax depreciation rate of 30 per cent per year, and applies to equipment that produces energy in a more efficient manner or equipment that produces energy from renewable sources;

- Class 17 – Allows a medium depreciation rate of eight per cent, and applies to electrical generating assets that do not qualify for Class 43.1.
- Class 1 – Allows for the depreciation of buildings, dams, and other long-lived assets at four per cent per year.
- Canadian Renewable and Conservation Expenses (CRCE) – Allows for the 100 per cent write-off of intangible expenses, such as feasibility and resource assessment studies, in the year they were incurred for renewable energy and energy conservation projects; and
- Fees – Transaction fees were depreciated over five years using a straight-line calculation.

The model assumes a breakdown of the capital cost of projects for each tax shield class which varies with project type and size, but falls broadly into the following ranges:

- Class 43.1 50 to 72 per cent
- Class 17 0 to 25 per cent
- Class 1 five to eight per cent
- CRCE four to 10 per cent
- Fees four to 10 per cent

A.4.2 Thermal Financial Assumptions

Unit energy costs for natural gas, coal, diesel and oil-fired generation options depend on the price of their respective fuels and the actually dispatch (usage) of the plant. A dispatch of 80% was assumed for larger, base load projects and 20% for small, peaking projects. The actual usage and subsequent unit energy cost for natural gas fired projects will be estimated in the system model HySim and MATA model as part of the portfolio evaluation process. Long term debt repayment for thermal projects was assumed to be 20 years, with large natural gas projects set at 25 years.

A.4.2.1 Natural Gas

Natural Gas assumptions, information and unit energy costs were referenced from the BC Hydro spreadsheet LongRunUEC-Master.xls, as described in the information sheets that follow. Greenfield CCGT project lives were assumed to be 25 years.

A.4.2.2 Coal, Oil and Diesel

An assumption of an 80 per cent dispatch capacity factor was used for coal, oil and diesel plants to estimate unit energy cost.

A range of energy costs for fossil fuel-fired generation has been estimated using the same financial model as the Clean Energy and alternative resources, minus the tax treatment for renewable energy sources. A levelized average cost of fuel was input into the financial spreadsheet, along with dispatch rates, and other cost estimates for capital and operation and maintenance costs to estimate a unit cost of energy. Project life for coal assumed to be 35 years.

Table A.2 Resource Option Fuel Cost Estimates

Fuel	Average Levelized Fuel Price forecast
Natural Gas	4.8 $/GJ
Coal	33 $/ tonne
Oil	33 $/Barrel
Diesel	34 cents/litre

The details behind these scenarios for cost estimates can be found in Appendix E.

A.5 Environmental and Social

BC Hydro uses a definition of Green Energy similar to many definitions throughout the world. For a project to be considered "Green" by BC Hydro it must be:

- **Renewable:** The energy source must be replenishable by natural processes within a reasonable length of time, at the longest, within about one average human life span. For example, hydroelectric generation relies on water, which is a renewable resource. Natural gas-fired electrical generation relies on a fossil fuel, a resource that does not meet this renewable criterion.
- **Licensable:** The project must meet all relevant regulations and standards.
- **Socially responsible:** The project must be developed in a socially responsible manner on a site-specific basis. Every project within BC Hydro's Green Energy acquisition process is reviewed according to specific social responsibility criteria.
- **Low environmental impact:** The project must avoid unacceptably high environmental impacts, such as damage to fish populations, endangered species or air quality. This criterion is evaluated on a site- and technology-specific basis. Every Green Energy project within BC Hydro's acquisition process is reviewed according to the criteria that correspond to the project's technology.

The definition for Clean Energy is currently under review by the Government of B.C. The government is seeking input from stakeholders including BC Hydro prior to finalizing a definition. For the purposes of the resource option database, Clean Energy was assumed to be defined as included in the 2002 B.C. Energy Plan :

> "B.C. Clean electricity refers to alternative energy technologies that result in a net environmental improvement relative to existing energy production. Examples include small/micro hydro, wind, solar, photovoltaic, geothermal, tidal, wave and biomass energy, as well as cogeneration of heat and power, energy from landfill gas and municipal solid waste, fuel cells, and efficiency improvements at existing facilities.."

A.6 Project and Price Uncertainties

In general, risk is evaluated as a *likelihood* (odds that something will occur) combined with a *consequence* (the negative outcome that could occur).

Risk = Likelihood x Consequence

Likelihood can be measured quantitatively, with exact numbers for probability and odds that an event may occur. Alternatively, when specific numbers are not available, likelihood can be estimated using a qualitative measure like a rating (e.g., low, medium high). Simply put, the likelihood of precipitation tomorrow could be measured in both ways: either quantitatively (e.g. 60 per cent chance of rain), or qualitative (medium likelihood of rain).

A.6.1 Development Uncertainty

Development uncertainty translates into a "risk of non-development." A rating of low, medium or high was estimated to demonstrate the likelihood that a project will *not* be financed, built or approved. Reasons for the uncertainty could include, but not limited to:

- Technology advances required for a resource to be developable in the IEP time frame;
- Environmental or social concerns that could restrict licensing;
- Financing or technical barriers for large, high-risk projects;
- Technical challenges that make project completion less likely; or
- The need for new regulatory support to ensure development.

Business risk mitigation measures can be put in place for these development risks. However, mitigation does not eliminate business risk to BC Hydro and may increase the overall cost of energy by transferring risk to the developer. For instance, the uncertainty related to a project not being developed is typically passed on to the developer through mitigation measures such as:

- Liquidated damages in the power purchase agreement in the event of delay and/or contract termination; or
- Financial guarantees from the developer prior to entering power purchase agreements.

However, the developer may still abandon the project or the project may not be approved, and these measures could not remove all risk to BC Hydro.

These development risks and the necessity for their mitigation will have an important bearing on future portfolio trade-off analysis and were thus characterized in the resource option database for future portfolio evaluation.

A.6.2 Price Uncertainty

Price uncertainty translates into a risk to BC Hydro that the price included for planning purposes in the resource option database is lower (or higher) than actual future costs. Since no additional resource studies were conducted as part of the 2004 IEP uncertainty exists in project assumptions for less studied projects. A likelihood rating of low, medium or high was given for each resource or project based on the uncertainty around the values used for unit energy cost estimation. High uncertainty around financial assumptions would result in a high likelihood of price estimates being different in future.

Reasons for a high likelihood of price variance may be:

- The characterization of emerging technologies;
- A conceptual level of project information available; or

- Professional judgement that potential product options were under-priced based on industry standards.

For instance, the financial estimates in a conceptual level study for a project or technology have an accuracy of less than 50 per cent, which leads to significant uncertainty in the estimated price of energy.

In addition, new technologies such as ocean wave and tidal current that have not yet been developed at a large commercial scale would likely benefit from technology improvement. Prices in the future may decline as wind energy prices did in the 1990s due to technology improvement and economies of scale. However, predicting this price reduction is difficult without evidence of development at a large scale.

Ratings for price uncertainty were as follows:

Low – Design levels studies or well establish non-site specific information. Unit energy cost estimate uncertainty assumed to be –10 per cent to +20 per cent for illustrative purposes only.

Medium – Feasibility level studies, or well established non-site specific information. Unit energy cost estimate uncertainty assumed to be –10 per cent to +40 per cent for illustrative purposes only.

High – Pre-feasibility or conceptual level studies, non-B.C. specific industry standard information used for assumptions, or developing technologies. Unit energy cost estimate uncertainty assumed to be –10 per cent to +60 per cent for illustrative purposes only.

Mitigation of price uncertainty and the business risk to BC Hydro inherent in this uncertainty will be evaluated in future stages of the 2004 IEP and related business planning.