Integrated Resource Plan

Appendix 3A-1

2013 Resource Options Report Update

2013 Resource Options Report Update

BC hydro

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2013 Resource Options Report Update

Chapter 1

Overview

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1.1 Introduction

The 2013 Resource Options Report (**ROR**) Update presents an assessment of the potential resource options available to meet the needs of BC Hydro's electricity customers over the next 20 to 30 years.[1] The information presented in this report reflects a targeted update to the 2010 ROR which include three of the five demand-side management (**DSM**) options, wood-based biomass, municipal solid waste (**MSW**), onshore/offshore wind, run-of-river, Resource Smart and natural gas-fired generation. Refer to section 1.5 for more details.

The 2013 ROR Update considers demand-side and supply-side resource options that are consistent with the policy and legislated objectives of the B.C. Government, including those specified in its 2010 *Clean Energy Act* (***CEA***). All identified options are inventoried in the Resource Options Database (**RODAT**), which is a Microsoft Access database, and the Resource Options Mapping Database (**ROMAP**), which is a spatially enabled Geographical Information System (**GIS**) version of RODAT.

Both databases contain key details about potential resource options such as the project description, as well as technical, financial, environmental and economic development information. They are used as input into the Integrated Resource Plan (**IRP**) portfolio analysis where the costs and impacts of new resource additions to meet the energy and capacity needs of BC Hydro's domestic customers are assessed on a system-wide basis over the planning period, including DSM, generation and transmission resources.

1.2 Structure of the 2013 ROR Update

The 2013 ROR Update consists of six chapters and 13 appendices.

Chapter 1 provides an overview of the ROR components, including brief descriptions of the appendices.

1 BC Hydro's long-term planning period extends 20 years for DSM and generation resources and 30 years for transmission options.

Chapter 2 presents a summary of the 2013 ROR Update including DSM options, energy resource options, capacity resource options and transmission options.

Chapter 3 describes the high level attributes used in the resource options comparison and evaluation process, e.g., technical, financial, environmental and economic development attributes and data confidence.

Chapter 4 presents two sets of DSM options, which include five energy and capacity options and two capacity-focused options with their varying levels of confidence.

Chapter 5 presents an overview of the supply-side resource options including generation, storage and transmission resources with their underlying assumptions.

Chapter 6 describes the cost adjustment process to facilitate a high level comparison of costs across resource types and to reflect the cost of resources delivered to the Lower Mainland load center.

Appendix 1 - Resource Options Update Consultation Report describes the objectives of the consultation process, the process used, the input BC Hydro received, and how BC Hydro considered the input.

Appendix 2 - Environmental Attributes Review and Update presents a description of the selected attributes and the criteria used for their selection and a discussion of the resource options and their land and water footprints.

Appendix 3 - Resource Options Database (RODAT) Summary Sheets present details of the resource options that are further considered in the portfolio analysis.

Appendix 4 - Economic Development Attributes describes the methodology, data and assumptions used by BC Hydro to develop economic development attributes for long-term resource planning.

Appendix 5 - Resource Options Mapping (ROMAP) contains the following documents:

- **Appendix 5-A** is the ROMAP Report that presents over 7,700 potential resource options in B.C. in a spatially enabled GIS version. It includes 17 attachments that were too large to include with the ROMAP Report as one file (these are labelled as ROR Appendices 5-A1 to 5-A17). There are also two appendices to the ROMAP Report that are provided as one file (this is labelled as ROR Appendix 5-A18).
- **Appendices 5-A1 to 5-A14** present the mapped generation resource options by resource type
- **Appendix 5-A15** shows the existing transmission system and region delineation
- **Appendices 5-A16 and 5-A17** show the energy and capacity density of B.C. potential resource options respectively
- **Appendix 5-A18** contains two appendices to the ROMAP report:
  - Appendix A - Density Analysis Using GIS
  - Appendix B - Roads & Power Lines Cost Estimation Using GIS

Appendix 6 - Wood Based Biomass Potential Report provides an update to the 2010 modeling study conducted by a team of consultants including Industrial Forest Services Ltd., M.D.T. Ltd., and Murray Hall Consulting Ltd. to forecast the potential availability of wood based biomass fuels, with associated cost, that may be used for electricity generation over the planning period.

Appendix 7 - Wind Cost Review Report provides Garrad Hassan Canada Inc.'s capital and operational and maintenance (**O&M**) cost data reflective of 2010/2011 market conditions for the onshore and offshore wind.

Appendix 8 - Run-of-River contains the following documents:

- **Appendix 8-A** is the Run-of-River Report that provides an update to Kerr Wood Leidal's (**KWL**) March 2011 Run-of-River potential study.

- **Appendix 8-A1** shows the location of nearly 7,300 run-of-river potential sites with associated size and estimated unit energy cost range.
- **Appendix 8-A2** contains three appendices to the Run-of-River report:
  - Appendix A: Hydrologic Gauge Data
  - Appendix B: Roads & Power Lines Cost Estimation Using GIS
  - Appendix C: Hydropower Potential by Transmission Region

Appendix 9 - Pumped Storage contains the following two documents:

- **Appendix 9-A** consists of two Pumped Storage Reports prepared by Knight Piésold, which present a screening assessment of the pumped storage potential in the Lower Mainland and Vancouver Island region, and the North Coast region of B.C.
- **Appendix 9-B** is the Mica Pumped Storage Report prepared by Hatch Ltd., which provides a preliminary study and cost estimate for addition of pumped storage at Mica Dam.

Appendix 10 - Coal-Fired Generation with Carbon Capture and Sequestration presents Powertech Labs Inc.'s assessments on the coal and carbon dioxide (**CO_2**) sequestration (**CCS**) locations in B.C., the potential of coal-fired power generation with integrated gasification combined cycle (**IGCC**)-CCS in B.C., an update on the clean coal technology status, and the cost of coal-fired generation with CCS.

Appendix 11 - Ocean Renewable Energy Group (OREG) Submission provides OREG's view on the exploration of the B.C. ocean energy resources opportunities.

Appendix 12 - Firm Energy Cost Adjustments provides more details on the cost adjustment process and how the cost adjusters were developed and applied.

Appendix 13 - Glossary of Acronyms provides the list of acronyms used in the ROR.

1.3 ROR Consultation

The 2010 ROR consultation process is described below. BC Hydro did not consult specifically on the 2013 ROR Update prior to its release in the IRP.

The 2010 ROR consultation process consisted of working with people who have technical expertise to gather and review technical information on supply-side and demand-side[2] resource options in B.C. The objectives of the 2010 ROR consultation process were:

- Promote mutual understanding of the resource options data and continue to foster constructive working relationships
- Seek input on methodology applied to updating the resource options data and attributes where appropriate
- Seek input to accurately reflect resource options potential in the B.C. provincial context

The review of the generation resource options was initiated in May 2010 and was followed by technical review sessions with targeted stakeholders on the technical, financial, environmental and economic development attributes of the options and associated assumptions.

Engagement on the update of individual resource options was launched through a workshop held on September 14, 2010, that among other topics, addressed the scope and timing of the 2010 ROR. During the workshop, resource-specific break-out sessions were held to introduce the proposed scope of assessment for specific resources. Participants attending these sessions had the opportunity to sign up and further participate in the resource-specific update process. Following this workshop, resource-specific engagement sessions were scheduled by the BC Hydro

[2] BC Hydro worked with its Electricity Conservation and Efficiency (**EC&E**) Advisory Committee as it constructed plan options for DSM.

resource options task leads to review technical studies with interested participants and contracted consultants.

As part of the environmental attributes update, targeted meetings occurred to review the proposed attributes with government staff in August 2010, as well as representatives of environmental organizations in September 2010.

A report-out session was held on December 8, 2010, during which participants were presented preliminary results and the draft 2010 ROR. A written comment period, from December 8 to December 31, 2010, provided additional opportunities for interested parties to review the draft 2010 ROR and submit comments, which were considered in finalizing the 2010 ROR.

A detailed 2010 ROR consultation report is included in Appendix 1 of the 2013 ROR Update.

1.4 Limitations of the 2013 ROR Update

The 2013 ROR Update provides an assessment of the potential resource options at a level of detail and accuracy that is appropriate for long-term resource planning and portfolio analysis.

It should be noted that the 2013 ROR Update planning level information, associated with the generation and transmission resource options, is not considered sufficiently accurate to establish the characteristics of site-specific resource options for development or acquisition purposes. Specific on-site studies would be required to determine the technical feasibility and cost-effectiveness of potential projects.

In the 2013 ROR Update, all resource options are presented as options for consideration and do not commit BC Hydro to the implementation of any particular options.

1.5 Comparison to the 2010 ROR

The 2010 ROR was developed based on information from BC Hydro's project experience, consultant studies, and First Nations and stakeholder input, including input from people with relevant technical expertise and information such as independent power producers (**IPPs**). In addition, technical studies were conducted by BC Hydro and its consultants on a number of options, including coal-fired generation with CCS, run-of-river hydroelectric, wood-based biomass and pumped storage. These studies are referenced under each individual resource option.

For the 2013 ROR Update, information obtained in the 2010 ROR was reviewed for material changes to availabilities or costs. BC Hydro resources and those resource options bid into previous acquisitions processes by IPPs have been reviewed and updated. These updates include three of the five DSM options, some Resource Smart projects such as the GM Shrum generating station (**GMS**) Units 1-5 Capacity Increase, and updates to available resource options including wood-based biomass, MSW, onshore/offshore wind, run-of-river and natural gas-fired generation. There have also been updates to other resources such as geothermal, pumped storage and solar resource options.

The Unit Energy Costs (**UECs**) and Unit Capacity Costs (**UCCs**) have been updated for all resource options using BC Hydro's updated Weighted Average Cost of Capital (**WACC**) to reflect long-term forecasts of project borrowing costs and the lower financing costs available in the markets. BC Hydro-owned projects utilized a 5 per cent real cost of capital. Third party developed projects utilized a 7 per cent real cost of capital. All results are presented in constant dollars as of January 1, 2013 ($2013).

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Chapter 2

Resource Options Results Summary

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2.1 Introduction

The following chapter presents a summary of the resource options results.

2.2 Demand-Side Management Options

As summarized in Table 2–1, two sets of demand-side management (**DSM**) options were developed: energy and capacity options and capacity-focused options.

Table 2–1 Summary of DSM Options

DSM Energy and Capacity Options	Total Resource Cost ($/MWh)	Utility Cost ($/MWh)
Option 1: A scaling back of the current DSM activities to generally meet 66 per cent of the load growth.	32	18
Option 2: An update of BC Hydro's current DSM plan with a balanced offering of codes and standards, conservation rate structures, and programs.	32	18
Option 3: Expands programs to the limit of cost-effectiveness. Keeps codes and standards and conservation rate structures the same as in Option 2.	35	22
Option 4: Builds upon Option 3 and expands the codes and standards and conservation rate structure tools.	47	30
Option 5: Reflects an aggressive effort to change market parameters and societal norms and patterns in order to save electricity.	49	29
DSM Capacity-Focused Options	**Total Resource Cost ($/kW-year)**	**Utility Cost ($/kW-year)**
Industrial Load Curtailment: Targets large customers who agree to curtail load on short notice to provide capacity relief during peak periods.	31	45
Capacity-Focused Programs: Utilize equipment and load management systems for peak load reductions.	55	69

2.3 Supply-Side Generation Resource Options

For the 2013 Resource Options Report (**ROR**) Update, the unit energy cost (**UEC**) of the potential supply-side resource options at point of interconnection (**POI**) were determined and then adjusted to reflect the cost of resources delivered to the Lower Mainland. The results are summarized in Table 2–2 and Figure 2–1 as follows:

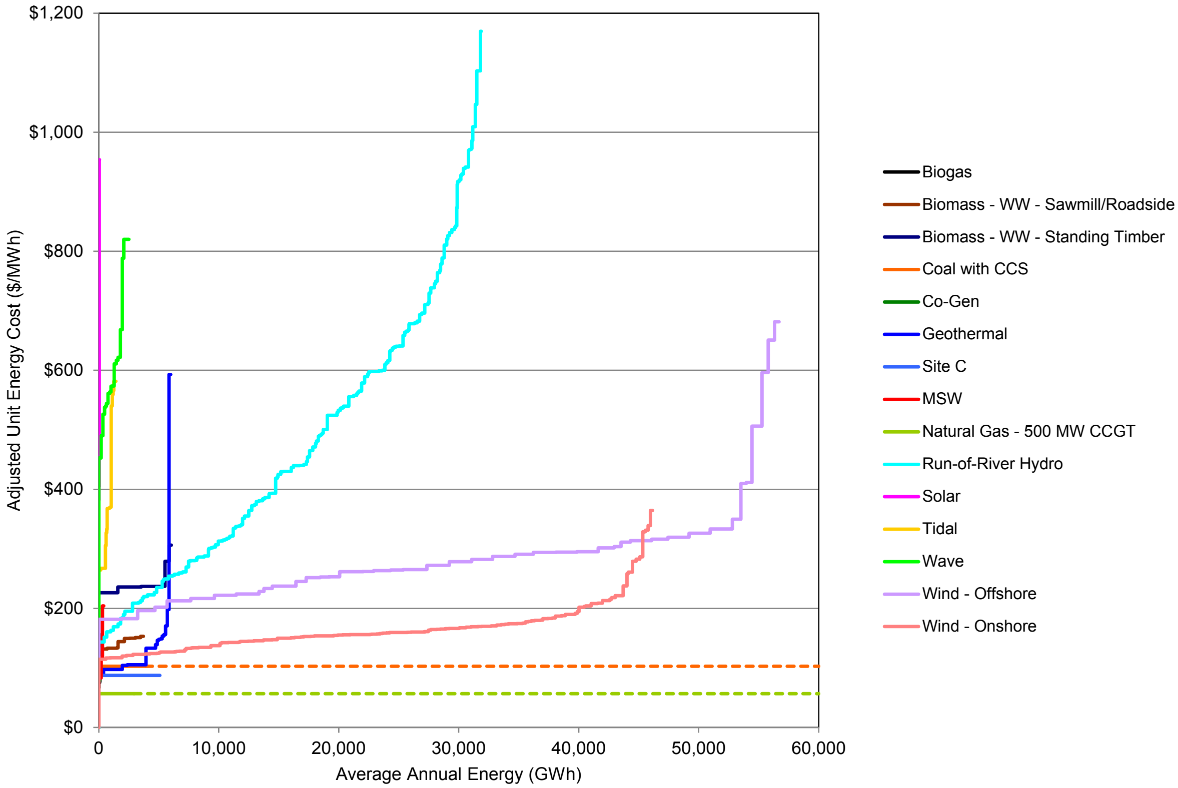
Table 2–2 Summary of Supply-Side Energy Resource Options[1]

Energy Resource	Total FELCC Energy (GWh/year)	Total DGC or ELCC Capacity (MW)	UEC at POI @ 7% Real ($2013/MWh)	Adjusted Firm UEC[2] @ 7% Real ($2013/MWh)
Biomass – Wood Based	9,772	1,226	122 – 276	132 – 306
Biomass – Biogas	134	16	59 – 154	56 – 156
Biomass – Municipal Solid Waste	425	50	85 – 184	83 – 204
Wind – Onshore	46,165	4,271	90 – 309	115 – 365
Wind – Offshore	56,700	3,819	166 – 605	182 – 681
Geothermal	5,992	780	91 – 573	90 – 593
Run-of-River	24,543	1,149	97 – 493	143 – 1,170
Site C[3]	4,700	1,100	83	88
Combined Cycle Gas Turbine and Cogeneration[4]	6,103	774	58 – 92	57 – 86
Coal-fired Generation with Carbon Capture and Sequestration	3,896	556	88	103
Wave	2,506	259	440 – 772	453 – 820
Tidal	1,426	247	253 – 556	264 – 581
Solar	57	12	266 – 746	341 – 954

Notes:

1. The resources and UEC values shown for each category in the table reflect the resource potential analyzed and may not include all possible resources that may be available at an expected higher cost.
2. The details of how the cost adjusters were developed and applied are provided in Appendix 12.
3. The Site C values presented in this table are based on information provided in the Site C Environmental Impact Statement (**EIS**) submission filed in January 2013, and the UEC is calculated assuming 5 per cent real discount rate.
4. Representative projects were used to characterize the natural gas-fired and coal-fired resource options, and the resource potential is generally considered to be unlimited.

Figure 2–1 Energy Resource Options Supply Curves (Adjusted Firm UEC $/MWh)



Notes:

1. The resources and UEC values shown for each category in the table reflect the resource potential analyzed and may not include all possible resources that may be available at an expected higher cost.
2. The Site C values presented in this table are based on information provided in the Site C EIS submission filed in January 2013.
3. Representative projects were used to characterize the natural gas-fired and coal-fired resource options. Dotted lines indicate additional potential, which is generally considered to be unlimited.

The unit capacity costs (**UCCs**) of the supply-side capacity resource options are summarized in Table 2–3 as follows.

Table 2–3 Summary of Supply-Side Capacity Resource Options

Resource Type	Capacity Options	Dependable Capacity (MW)	UCC at POI @ 7% Real ($2013/kW-year)
Resource Smart	GMS Units 1-5 Capacity Increase	220	35 *
Resource Smart	Revelstoke Unit 6	488	50 *
Natural Gas – fired Generation	SCGTs at various locations	98 or 101	84 or 180
Pumped Storage	PS at Mica Generating Station	465	100*
Pumped Storage	PS at various Locations	1,000	118 – 124

Notes:
1. GMS Units 1-5 Capacity Increase numbers are based on conceptual level estimates.
2. Simple Cycle Gas Turbine (**SCGT**) and Pumped Storage (**PS**) only include fixed costs.
3. UCCs for GMS Units 1-5 Capacity Increase, Revelstoke Unit 6, and PS at Mica Generating Station are calculated assuming 5 per cent real discount rate.
4. Two SCGT representative projects are used to characterize the Natural Gas resource option.
5. Presentation of PS data is limited to results below $125/kW-year.

2.4 Supply-Side Transmission Resource Options

The bulk transmission resource options considered in the 2013 ROR Update are presented in Table 2–4.

Table 2–4 Transmission Reinforcement Options Considered in Long-Term Resource Planning

Item No.	Upgrade Option Description	Lead Time (Years)	2013 Direct Cost ($ Million)	Incremental Capacity (MW)	Line Length (km)
	North Interior				
TO-01	New 500 kV, 50 per cent series compensated transmission circuit 5L8 between GMS and Williston	8	388.3	1470	278
TO-02	New 500 kV, 50 per cent series compensated transmission circuit 5L14 between Williston and Kelly Lake	8	341.1	2120	330

Item No.	Upgrade Option Description	Lead Time (Years)	2013 Direct Cost ($ Million)	Incremental Capacity (MW)	Line Length (km)
TO-03	New +/-500 kV HVDC bipole transmission circuit between Peace River and Lower Mainland - Phase 1	8	1,482.9	1000	928
TO-04	New +/-500 kV HVDC bipole transmission circuit between Peace River and Lower Mainland - Phase 2	8	246.8	1000	N/A
TO-05	Series compensation upgrade at Kennedy from 50 per cent to 65 per cent on GMS to Williston 500 kV lines 5L1, 5L2, 5L3 and 5L7 with thermal upgrades to 3000A rating.	3	59.5	360 (CI-KLY/NIC) and 300 (PR-CI)	N/A
TO-06	Series compensation upgrade at McLeese from 50 per cent to 65 per cent on Williston to Kelly 500 kV lines 5L11, 5L12 and 5L13 with thermal upgrades to 3000A rating.	3	57.2	390 (CI-KLY/NIC) and 330 (PR-CI)	N/A
TO-07	500 kV Shunt compensation: • At Williston add one 300 MVAr SVC and two 250 MVAr switchable capacitor banks. • At Kelly Lake add one 250 MVAr shunt capacitor	3	65.1	650 (CI-KLY/NIC) and 580 (PR-CI)	N/A
	North Coast				
TO-08	New 500 kV circuit Williston-Glenannan-Telkwa-Skeena parallel to the existing 5L61 - 5L62 and 5L63 lines.	8	1,031.6	970	449
TO-09	Series compensation of the WSN-SKA 500 kV lines 5L61, 5L62 and 5L63 plus voltage support and transformation addition in the existing BC Hydro substations	3	142.3	580	N/A
TO-21	A new +/-500 kV HVDC bipole transmission circuit between WSN and SKA	8	1,091.6	2000	449

Item No.	Upgrade Option Description	Lead Time (Years)	2013 Direct Cost ($ Million)	Incremental Capacity (MW)	Line Length (km)
	South Interior				
TO-10	New 500 kV, 50 per cent series compensated transmission circuit 5L97 between Selkirk and Vaseaux Lake	8	226.7	750	163
TO-11	New 500 kV, 50 per cent series compensated transmission circuit 5L99 between Vaseaux Lake and Nicola	8	196.3	750	138
TO-12	50 per cent series compensation of the 500 kV lines 5L91 and 5L98	3	61.8	133 (SEL-KLY/NIC) and 147 (SEL-REV/ACK)	N/A
TO-13	50 per cent series compensation of 500 kV lines 5L71 and 5L72	Committed in 2014	46.0	950	N/A
TO-14	50 per cent series compensation of 500 kV lines 5L76, 5L79, and 5L96	3	60.3	112	N/A
TO-19	50 per cent Series compensation of 500 kV line 5L92 SEL-CBK.	3	31.2	150	N/A
TO-20	A new 500 kV line between Selkirk and Cranbrook parallel to the existing 500 kV line 5L92	8	651.1	1550	180
	Interior to Lower Mainland				
TO-15	New 500 kV, 50 per cent series compensated transmission circuit 5L83 between Nicola and Meridian	Committed in 2015	609.2	1550	247
TO-16	New 500 kV, 50 per cent series compensated transmission circuit 5L46 between Kelly Lake and Cheekye	8	656.7	1384	197

Item No.	Upgrade Option Description	Lead Time (Years)	2013 Direct Cost ($ Million)	Incremental Capacity (MW)	Line Length (km)
TO-17	500 kV and 230 kV shunt compensation: • At Meridian 230 kV add two 110 MVAr capacitor banks • At Nicola 500 kV add one 250 MVAr capacitor bank	3	10.1	570	N/A
	Lower Mainland to Vancouver Island				
TO-18	New 230 kV transmission circuit 2L124 between Arnott and Vancouver Island terminal	6	230.1	600	67

Note: TO-15 presented in this table is based on information filed with BCUC in November 2011.

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Chapter 3

Resource Options Attributes

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3.1 Introduction

To compare and evaluate the resource options, technical, financial, environmental and economic development attributes of the resource options were developed as described in the following sections.

3.2 Technical Attributes

The technical attributes considered for each resource option are:

- Installed Capacity (MW)
- Dependable Generating Capacity (**DGC**) for non-intermittent resources (MW), and Effective Load Carrying Capability (**ELCC**) for intermittent (or variable) generation resources (MW)
- Average Annual Energy (GWh/year)
- Firm Energy Load Carrying Capability (**FELCC**) (GWh/year)
- Monthly per cent of Average Annual Energy

A summary of the generation reliability criteria, assumptions and methods of development is contained in Table 3-1.

Table 3-1 Generation Reliability Assumptions and Methods

Potential Generation Resources	DGC[1] and ELCC[2] Assumptions and Methods of Determination	FELCC[3] Assumptions and Methods of Determination
Run-of-river	ELCC: Weighted average of approximately 60 per cent of the forecasted average MW of potential in the December/January period	Region specific factors applied to the average annual energy
Biomass	DGC: 100 per cent of installed capacity for wood-based biomass; 97 per cent of installed capacity for municipal solid waste; and 95 per cent of installed capacity for biogas	100 per cent of average annual energy
Wind – Onshore	ELCC: 26 per cent of installed capacity	100 per cent of average annual energy
Wind – Offshore	ELCC: 26 per cent of installed capacity	100 per cent of average annual energy
Geothermal	DGC: 100 per cent of installed capacity	100 per cent of average annual energy
Natural Gas-fired Generation and Cogeneration	DGC: Varies from 88 per cent to 100 per cent of installed capacity	Based on 18 per cent capacity factor for SCGT; and 90 per cent for Combined Cycle Gas Turbine (**CCGT**)
Site C[4]	DGC: 1,100 MW	4,700 GWh/year
Pumped Storage	DGC: 100 per cent of installed capacity	N/A
Wave	ELCC: Assumed 24 per cent of installed capacity	Assumed the same as offshore wind at 100 per cent of average annual energy
Tidal	ELCC: 40 per cent of installed capacity	100 per cent of average annual energy
Solar	ELCC: Assumed 24 per cent of installed capacity	Assumed the same as onshore wind at 100 per cent of average annual energy
Resource Smart (GMS Units 1-5 Capacity Increase)	DGC: 220 MW	To be determined but likely to be small
Resource Smart (Revelstoke Unit 6)	DGC: 488 MW	26 GWh/year
Coal-fired Generation with Carbon Capture and Sequestration	DGC: 75 per cent of installed capacity	100 per cent of average annual energy

Note:

1. DGC is the amount of megawatts a plant can reliably produce when required, assuming all units are in service.

2. ELCC is the maximum peak load that a generating unit or system of units can reliably supply such that the loss of load expectation will be no greater than one day in 10 years.
3. FELCC is the maximum amount of annual energy that a hydroelectric system can produce under critical water conditions.
4. Site C value is based on information provided in the Site C Environmental Impact Statement (**EIS**) submission filed in January 2013 with the Canadian Environmental Agency and the B.C. Environmental Assessment Office.

3.3 Financial Attributes

The following financial attributes and assumptions were used in developing the 2013 Resource Options Report (**ROR**) Update:

- **Weighted Average Cost of Capital**: 5 per cent and 7 per cent real cost of capital rates are used in determining unit energy costs (**UEC**) of BC Hydro resources and IPP resources, respectively. In comparison to the 2010 Resource Options assessment, lower costs of capital are implemented to reflect a reduction in project borrowing costs. These rates do not presume or prescribe a specific capital structure.
- **UEC & Unit Capacity Cost (UCC) Methodology**: The UEC and UCC measures reflect the levelized cost of a unit of energy or capacity of a resource option. The methodology used to calculate these values is unchanged from the 2006 Integrated Electricity Plan (**IEP**) and the 2008 Long-Term Acquisition Plan (**LTAP**) resource options updates.
- The resource options costs are shown as UECs and UCCs at point of interconnection (**POI**) in constant dollars on January 1, 2013 ($2013).

3.4 Environmental Attributes

The same environmental attributes developed for the 2010 ROR are used to characterize the resource options. These attributes were selected based upon the following criteria:

- Appropriate for provincial-scale portfolio comparisons
- Science-based and defendable

- Measurable in a "quantity"-based approach that facilitate comparison between portfolios of resource options
- Representative of relevant biophysical resources
- Based on existing data or easily acquired data
- Easy to understand for long-range planning and stakeholder engagement purposes

A consultant team consisting of Kerr Wood-Leidal, HEMMERA, and HB Lanarc was retained by BC Hydro to develop the environmental attributes. A detailed description of the environmental attributes, associated methodology and rationale can be found in Appendix 2.

The environmental attributes are grouped into four environmental categories: land, atmosphere, freshwater and marine (a new category selected to accommodate emerging energy potential, such as offshore wind, tidal and wave resource options) and are further broken down into indicators as described in Table 3-2.

Table 3-2 Environmental Attributes

Environmental Category	Indicator	Unit of Measure	Classifications
Land	Net Primary Productivity (**NPP**) (gC/m2/year)	hectares (**ha**) per class	Low (0 to < 69)
			Medium (69 to < 369)
			High (> 369)
	Remoteness – Linear Disturbance Density (km/km2)	ha per class	Wilderness (< 0.2)
			Remote (0.2 to < 0.66)
			Rural (0.66 to 2.2)
			Urban (> 2.2)
	High Priority Species Count (percentile)	ha per class	0 to < 20
			20 to < 40
			40 to < 60
			60 to 80
			> 80

Environmental Category	Indicator	Unit of Measure	Classifications
Atmosphere	Greenhouse Gas Emissions	Tonnes/GWh	CO2e
	Air Contaminant Emissions	Tonnes/GWh	Sulphur Dioxide
			Oxides of Nitrogen
			Carbon Monoxide
			Volatile Organic Compounds
			Fine Particulates: PM 2.5 (reported when data is available)
			Fine Particulates: PM 10 (reported when data is available)
			Fine Particulates: PM Total
			Mercury
Freshwater	Reservoir Aquatic Area	ha	Site C (Pumped Storage and Resource Smart if applicable/available)
	Affected Stream Length	km	Run-of-river and Site C (Pumped Storage and Resource Smart if applicable/available)
	Riparian Area	ha	Sum of riparian area per class based on stream order (Run-of-river, Pumped Storage, roads and power line crossings if applicable/available)
	Priority Fish Species (number of priority fish species per watershed)	ha per class	No Priority Species (0)
			Low Species Diversity (1 to 12)
			Moderate Species Diversity (13 to 23)
			High Species Diversity (24 to 38)
Marine	Bathymetry	ha per class	Photic (0 to < 20 m)
			Shallow (20 to 200 m)
			Deep (200 to 1000 m)
			Abyssal (> 1000 m)
	Valued Ecological Features (number of valued ecological features)	ha per class	None (0)
			Low (1 to 2)
			Medium (3 to 5)
			High (> 5)
	Key Commercial Bottom Fishing Areas	ha per class	No bottom fisheries
			1 bottom fishery
			2 to 3 bottom fisheries
			> 3 bottom fisheries

The Resource Options Mapping (**ROMAP**) geographical information system (**GIS**) was used to overlay the footprint of potential supply-side resource options onto the B.C. land base and calculate the attributes (land, freshwater and marine) of the footprint. For each potential supply-side resource option, the evaluated footprint includes the 'at gate' plant area (**G**), and the associated new road (**R**) and new transmission (**T**) corridors required to operate and link the plant to existing infrastructures.

The environmental update has taken the approach of estimating the footprint of the potential projects during their operation phase, aggregated into resource options bundles or clusters.

These high-level environmental attributes and footprints are appropriate for comparison of resource options across provincial-scale portfolios. Since detailed site-specific information is unknown for the majority of the potential sites in the database, these environmental attributes are not appropriate, or intended to be used, for individual site-specific resource option evaluations and comparisons. The 2013 ROR Update presents a summary of the environmental attributes of resource options in the Resource Options Database (**RODAT**) summary sheets of Appendix 3.

3.5 Economic Development Attributes

The same economic development attributes developed for the 2010 ROR are used to characterize the resource options. These attributes were selected based upon the following criteria:

- Appropriate for provincial-scale portfolio comparisons;
- Address the government's *Clean Energy Act* objective with regard to economic development and the creation and retention of jobs
- Measurable in a quantity-based approach that facilitate comparison between portfolios of resource options

- Representative of accepted best practice in economic impact analysis
- Based on existing data or easily acquired data
- Easy to understand for long-range planning and stakeholder engagement purposes

The economic development attributes are categorized into three economic groups: gross domestic product (**GDP**), employment, and government revenue and are further broken down into indicators described in Table 3-3.

Table 3-3 Economic Development Attributes

Economic Development Category	Sub-Category	Unit of Measure	Classifications
Provincial GDP	Construction/Operation	$ and $/year	Direct
			Indirect
			Induced
Employment	Construction/Operation	Jobs	Direct
			Indirect
			Induced
Provincial Government Revenue	Construction/Operation	$ and $/year	Direct
			Indirect
			Induced

Note: Jobs, sometimes referred to as person years (**PYs**), reflect the average jobs in the affected industries, which may not always be full-time. In general, construction jobs are shorter-term and higher in number, whereas operating jobs are longer-term and last the life expectancy of the project.

These high-level economic development attributes are appropriate for comparison of resource options across provincial-scale portfolios, but not appropriate, or intended to be used, for individual site specific resource option evaluations and comparisons. The 2013 ROR Update presents a summary of the economic development attributes of resource options in the RODAT summary sheets of Appendix 3.

A detailed account of the economic development attributes is presented in Appendix 4.

3.6 Data Confidence

The data assessed in the 2013 ROR Update have varying levels of confidence. The levels of confidence depend on the level of study, resource type related uncertainties and cost uncertainties. The criteria used to define the levels of confidence are summarized in Table 3-4.

Table 3-4 Levels of Data Confidence for Resource Options

Uncertainty	Rating	Criteria
Level of Study	Survey	First, or preliminary, level of study that typically uses data derived from existing sources to yield new general information. Does not thoroughly examine all the parameters related to specific projects or settings. The primary intent is to synthesize emerging patterns. Based on a preliminary methodology or analysis technique, may or may not be supported by documentation or research.
	Pre-feasibility	Secondary level of evaluation study that assesses the cost and extent of implementation and impact for a specific project or group of projects and usually identifies more detailed needs assessment. Evaluation studies tend to focus on site specific conditions and use a range of qualitative and quantitative tools. Clearly attempts to describe the specific project conditions and outcomes and provides sufficient contextual information for someone to generalize and possibly replicate the results. Pre-feasibility study results are usually used to determine if it is worthwhile to proceed to the feasibility study stage.
	Feasibility	A comprehensive evaluation study for a proposed project designed to identify the implications of carrying out a project, including the site-specific technical, financial, environmental and economic attributes and requirements of a proposed project. This level of study can include descriptive, quantitative and formal research designs.
Resource Type Related Uncertainty	Low, Medium, High	These ratings are applicable to the following: • Technology specific issues, e.g., maturity of technology, emerging technology hurdles, experimental prototype • Development experience, e.g., lack of B.C. based development experience, permitting hurdles, resource potential confirmation, exploration risks, competing resource uses, public acceptance
Cost Uncertainty	Low: -10 per cent / +20 per cent	Design-level studies or well-established site-specific information. Capital cost uncertainty estimated to be -10 per cent to +20 per cent unless specific range of cost uncertainty is available for specific project.

	Medium: -10 per cent / +40 per cent	Feasibility-level studies or well-established non-site-specific information. Capital cost uncertainty estimated to be -10 per cent to +40 per cent unless a specified range of cost uncertainty is available for specific project.
	High: -10 per cent / +60 per cent	Pre-feasibility or conceptual-level studies or developing technologies. Capital cost uncertainty estimated to be -10 per cent to +60 per cent unless a specified range of cost uncertainty is available for specific project.

2013 Resource Options Report Update

Chapter 4

Demand-Side Management Options

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4.1 Introduction

In a long-term resource planning context, BC Hydro looks at demand-side management (**DSM**) as a resource option since the energy savings that come from DSM initiatives reduce future load growth and therefore minimize the need for future supply-side resources. Attributes of DSM considered in the resource planning framework include relatively low cost, low environmental impact, and economic benefits associated with job creation and contributions to provincial GDP. DSM is also a flexible resource to a degree, meaning that it has some ability to be ramped up or down based on the future need for resources.

Outside of a resource planning context, DSM has other important benefits to BC Hydro and its customers. Specifically, it provides an opportunity for customers to reduce their energy bills and an incentive to make energy efficient investment decisions through cost-effective investments on both the customer and BC Hydro's part.

4.1.1 Overview of DSM Options

At a high level, BC Hydro has developed two sets of DSM options: energy and capacity options and capacity-focused options. BC Hydro's current DSM plan is energy-focused, and is expected to deliver capacity savings as well. In contrast, capacity-focused options are designed to deliver capacity savings, during BC Hydro's peak load periods on the electrical system, through management and control of a customer's electricity demand rather than energy consumption.

For the 2010 ROR, BC Hydro developed five energy and capacity DSM options (DSM Options 1 through 5) and two[1] capacity-focused DSM options (industrial load curtailment and capacity-focused programs). This 2013 ROR Update provides a targeted update to energy and capacity Options 1, 2, and 3 to reflect new

[1] At the time of the 2010 ROR development BC Hydro also considered Time-Based Rates as a category of capacity resource option; since then, in accordance with government policy, BC Hydro has no plans to implement Time-Based Rates to address capacity requirements.

information on: 1) economic/market conditions: 2) customer participation; and 3) load forecast and economic conservation potential. Options 1, 2 and 3 have the same parameters as in the 2010 ROR:

- BC Hydro's current DSM target of 7,800 GWh/year and 1,400 MW is DSM Option 2, which was built from the DSM targets established in the 2008 LTAP
- Option 1 continues to be designed to meet the *CEA* energy objective of reducing the increase in demand of electricity by at least 66 per cent by F2021 (per *CEA* subsection 2(b))
- Option 3 continues to target more electricity savings than Option 2 by expanding program efforts while keeping the level of activity for codes and standards, and conservation rate structures, consistent with Option 2

Energy and capacity Options 4 and 5 and capacity-focused options were not updated for the 2013 ROR Update, because they have been found to not be viable for long-term planning purposes at this time. While not updated for the 2013 ROR, a description of these options is included here.

4.1.1.1 Energy and Capacity Options

The five energy and capacity DSM options are created as integrated packages of DSM tools that are interrelated and employed in concert to achieve a particular path of energy savings over time. The specific tools include codes and standards, conservation rate structures and programs.

- Codes and standards are public policy instruments enacted by Federal, Provincial and Municipal governments to influence energy efficiency. Examples include building codes, energy efficiency regulations, tax measures, and local government zoning and building permitting processes.
- Conservation rate structures are aimed at conserving energy, promoting energy efficiency, or reducing the energy demand that BC Hydro must serve, such as

inclining block (stepped) rate structures. BC Hydro has conservation rates in place (or with planned implementation) for over 90 per cent of its domestic load. Over the past seven years, BC Hydro implemented four conservation rate structures for residential, commercial, and industrial customers.

- Programs are designed to support the development of and address the remaining barriers after codes and standards and rate structures and thereby capture additional energy efficiency and conservation potential. Programs include load displacement projects, which reduce the energy demand that BC Hydro must serve as a result of existing customers self-supplying through self-generation.

In addition, there are a number of supporting initiatives – public awareness and education, community engagement, technology innovation, information technology, and indirect and portfolio enabling – that provide a critical foundation for awareness, engagement, and other conditions to support the success of BC Hydro’s DSM initiatives.

In addition to these tactics, BC Hydro develops DSM options in consideration of a strategic framework where DSM initiatives can be targeted to different contexts: individual, market and social. While all DSM options include initiatives targeting individual, market and social contexts, to reach higher levels of energy savings, BC Hydro must rely on market and societal transformation to a greater degree.

4.1.1.2 Capacity-Focused Options

Capacity-focused DSM specifically targets capacity savings. Experience will need to be gained to increase certainty of the expected capacity reductions. Two options were developed as follows:

- **Industrial Load Curtailment:** This option targets large customers who agree to curtail load on short notice to provide BC Hydro with capacity relief during peak periods. BC Hydro has implemented a load curtailment program targeted at shorter term (one to three years) operational capacity needs in recent years, and customers have delivered as requested. However, it is not clear how easily these can be translated into long-term agreements that can reliably reduce peak demand over a longer-term.

- **Capacity-focused Programs:** This option contains programs that leverage equipment and load management systems to enable peak load reductions to occur automatically or with intervention. These voluntary programs may involve payment for customer equipment and a financial payment for participation in the program. Examples of capacity-focused programs include load control of water heaters, heating, lighting and air conditioning. Thus capacity-focused programs are a collection of several activities; both demand response and load control, spread across different customer classes. The participation rate and savings per participant are key aspects of the uncertainty of capacity savings.

4.1.2 Attributes of DSM

4.1.2.1 DSM Technical and Financial Attributes

The cost-effectiveness of DSM is determined by the Total Resource Cost (**TRC**) and Utility Cost (**UC**) tests as described by the *California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects*,[2] (**California Standard Practice Manual**).

- The TRC measures the overall economic efficiency of a DSM initiative from a resource options perspective. In particular, the TRC measures the costs of a DSM initiative based on the net costs of the initiative, including both participant and utility costs. The benefits are the avoided supply costs – BC Hydro refers to this result as the **gross TRC**. The California Standard Practice Manual and many other jurisdictions also recognize that DSM results in a range of other benefits, such as a reduction in capacity costs (generation, transmission and

[2] October 2001; available at the California Energy Commission's website at www.energy.ca.gov.

distribution), specific non-energy benefits (e.g., operation and maintenance savings resulting from the installation of an energy efficient measure) and avoided participant costs aside from electric utility bills (such as natural gas and water savings) – BC Hydro refers to this result as the **net TRC**. Inclusion of these benefits increases the cost-effectiveness of DSM. Except where specifically noted, BC Hydro uses the net TRC.

- The UC measures the costs of the DSM initiative from the utility's perspective, excluding any costs of the participant. The benefits are similar to the TRC utility benefits (avoided supply costs and capacity). The UC test result indicates the change in total utility bills (revenue requirements) due to DSM.

The BCUC's determination of DSM cost-effectiveness is also guided by the Demand-Side Measures Regulation[3] (**DSM Regulation**). The DSM Regulation contains among other things modifications to the TRC test (referred to as the **modified TRC**) that the BCUC must follow when assessing DSM expenditure schedules submitted by public utilities pursuant to subsection 44.2(1)(a) of the *Utilities Commission Act*. The DSM Regulation provides a deemed value for natural gas savings and a deemed non-energy benefit adder of 15 per cent.

DSM Amortization

The DSM amortization period, which aligns DSM costs and benefits over time, uses a 15-year period to reflect the average persistence of DSM program savings.

Uncertainty and Risk

The five energy and capacity DSM options described in this ROR provide insight into the incremental DSM costs and uncertainties of pursuing additional quantities of energy conservation. There are two main uncertainties with respect to DSM: cost

[3] B.C. Reg. 228/2011.

and energy savings. Table 4-1 summarizes the DSM option cost uncertainty confidence levels.

Table 4-1 Levels of Data Confidence for DSM Options

	Resource Option	Resource Type Related Uncertainty Rating	Cost Uncertainty Rating
Energy and Capacity Options	Option 1	Medium	Medium (-10 per cent / +40 per cent)
	Option 2	Medium	Medium (-10 per cent / +40 per cent)
	Option 3	Medium	Medium (-10 per cent / +40 per cent)
	Option 4	High	Medium/High (-10 per cent / +50 per cent)
	Option 5	High	High (-10 per cent / +60 per cent)
Capacity-Focused Options	Industrial Load Curtailment	Medium	Medium (-10 per cent / +40 per cent)
	Capacity-focused Programs	High	High (-10 per cent / +60 per cent)

4.1.2.2 DSM Environmental and Economic Development Attributes

DSM has little to no environmental impact. As the impacts, if any, are negligible from a long-term resource planning perspective, they were not estimated for the 2013 ROR.

Economic development attributes were updated for energy and capacity Options 1 through 5 for the 2013 ROR.

4.2 Energy and Capacity DSM Options

As discussed earlier, BC Hydro conducted a targeted update of the DSM Options for the 2013 ROR. Specifically, Options 1, 2 and 3 have been updated to reflect new information on the cost and energy savings performance of the DSM tools (programs, codes and standards, conservation rate structures) and supporting initiatives:

As part of the first component of the update, BC Hydro updated the savings potential to reflect new information, including economic/market conditions, customer participation and a reduced 2012 mid-level Load Forecast as compared to the 2010 mid-level Load Forecast. In the 2008 LTAP proceeding, BC Hydro provided evidence that a reduced load forecast impacts DSM economic potential.[4] For example, it is generally acknowledged that industrial DSM participation and energy efficiency will increase during economic growth and decrease in recessionary periods.[5] In addition, different industries have varying economic and technical potential to provide DSM based on specific equipment and processes. For example, forestry likely has greater DSM potential than new oil and gas development or mining.

The second component of the update looked at whether there was an ability to make adjustments to the level of activity in the near term represented by the various DSM options while still retaining the ability to ramp up to meet longer-term targets. As DSM is a flexible resource, it can be reduced in the near-term and ramped up in later years to meet long-term targets. As part of portfolio cost management efforts, BC Hydro is interested in understanding how expenditures could be reduced in the near-term while still retaining the ability to ramp up back to longer-term energy savings targets. Programs and supporting initiatives are more flexible (have more ability to be ramped up or down) in the near-term than codes and standards and conservation rate structures, and therefore adjustments were targeted to programs and supporting initiatives (i.e., in other words, codes and standards and conservation rates were not reduced). BC Hydro explored Options 1, 2 and 3 for the potential to be adjusted in the near term, and revised Option 1 and Option 2 to reflect lower levels of expenditures in the near term. A version of Option 3 with near-term reductions was not included in the analysis. Option 3 would only be selected if needed to fill the resource gap beyond Option 2. If that higher resource

4 Exhibit B 10 in the 2008 LTAP proceeding, section 2.4.2.

5 See, for example, T.Ernst and O.Dancel, “Macroeconomc Impacts on DSM Program Participation”, 2011 ACEEE Summer Study on Energy Efficiency in Industry), page 1-81.

level was required, BC Hydro would not reduce Option 3 expenditures in the near-term due to the deliverability risk in recovering to Option 3 savings levels (uncertainty with the ramp rate assumptions).

As a reference, Table 4-2 below provides a high level description of each option, including how it was modified for the 2013 ROR and how it compares relative to the other options.

Table 4-2 Energy and Capacity DSM Options Comparison

	Option 1	Option 2	Option 3	Option 4	Option 5
Description	**Updated.** A reduction from the current DSM plan (Option 2), delivering DSM savings to reduce the expected increase in demand for electricity by the year 2020 by at least 66 per cent, as called for in the Clean Energy Act (***CEA***).	**Updated.** BC Hydro's current DSM plan. The 2013 ROR Update reflects a reduction from previously planning expenditure levels of $230M in the near term (F2015 to F2016) and then ramps up program activity moderately in F2017 to meet long-term targets. Expenditures are being maintained at a level consistent with the past few years.	**Updated.** Expands programs to the limit of cost-effectiveness, while keeping codes and standards and conservation rate structures the same as in Option 2. Updated to reflect new information since the 2010 ROR.	**Not updated.** Expands the codes and standards and conservation rate structure tools. Initial steps are added towards the tactics reflected in Option 5, with some programs scaled back or wound down as part of the transition.	**Not updated.** Reflects a comprehensive effort to change market parameters and societal norms and patterns in order to save electricity. It contains strong codes and standards and conservation rate structures.

	Option 1	Option 2	Option 3	Option 4	Option 5
Programs	Programs expenditures were further reduced from Option 2 in the near term.	Program expenditures are reduced by ~50 per cent by F2016 and then are moderately increased starting in F2017	Program expenditures are updated to reflect new information since the 2010 ROR.	Relative to Option 3, some programs are wound down earlier because of new codes and standards. Relative to Option 5, there are more incentives for commercial and industrial customers in the early years, because of less aggressive codes and standards activity.	In general, program incentives are eliminated or diminished by F2020 because of more aggressive codes and standards and rate structures. Some program incentives remain where there are cost barriers.

	Option 1	Option 2	Option 3	Option 4	Option 5
Codes & Standards	In the 2010 ROR, Option 1 levels of effort were kept the same as Option 2.	Codes and standards that have been enacted, announced or planned by the federal and provincial governments.	Same as Option 2.	Additional or more aggressive codes and standards are included that are not currently planned by governments. Similar, but less aggressive actions compared to Option 5.	Additional or more aggressive codes and standards are included that are not currently planned by governments. More aggressive than Option 4 in the following areas: 1) residential and commercial retrofit code, 2) residential and commercial building code, 3) earlier introduction of equipment regulations.
Conservation Rate Structures	In the 2010 ROR, Option 1 levels of effort were kept the same as Option 2.	Estimates of future energy savings have been updated to reflect BC Hydro's current long-run marginal cost.	Same as Option 2.	Increased effort from Option 3 as follows: 1) large industrial customers – an increase in the amount of energy consumption that is subject to the higher Tier 2 price; 2) commercial customers - placeholder concept of tying rates to building energy performance.	Levels of effort are higher than Option 3.

	Option 1	Option 2	Option 3	Option 4	Option 5
Supporting Initiatives	Expenditures were further reduced from Option 2 in the near term.	Budget was reduced by ~40 per cent in the near term and then increased in F17.	Updated to reflect new information since the 2010 ROR.	Increased effort targeting market and societal change, resulting in more funding than Option 3.	Levels of effort are higher than Option 4.

4.2.1 Option 1

In the 2010 ROR, Option 1 was developed explicitly to meet 66 per cent of the forecasted load growth with DSM, which would be the minimum required to meet the *CEA* Objective of reducing the expected increase "in demand for electricity by the year F2021 *by at least* 66" per cent [emphasis added]. The planning parameter for the updated Option 1 is similar to those in the 2010 ROR: reduce expected load growth by at least 66 per cent in F2021, and on average for the remaining portion of the planning period (F2022 to F2032). The updated Option 1 targets 6,100 GWh/year of energy savings and 1,200 MW of associated capacity savings by F2021.

At the time of the 2010 ROR, the calculation of the amount of DSM required to reduce the expected increase in demand for electricity by F2021 by at least 66 per cent was based on the 2010 Load Forecast. Based on the 2012 mid-level Load Forecast[6] (the reference forecast for the 2013 IRP), load growth has declined such that a lower level of energy savings is required in F2021 to reduce the expected increase in demand by at least 66 per cent. Accordingly, BC Hydro updated Option 1 with the new load forecast information.

Option 1 also reflects adjustments to near-term expenditures. Specifically, the adjustments to expenditures reflect the lowest level of DSM possible while still being able to ramp up to meet the *CEA* Objective of reducing load growth by at least

[6] Not including load from LNG.

66 per cent in F2021. By F2016, expenditures are reduced to a base level of $100 million. In F2021, energy savings just meet the 66 per cent objective. The level of near-term expenditures is lower than in Option 2. To reach this lower level of expenditures, additional adjustments were made to programs and supporting initiatives in the following areas:

- Residential: Expenditures are reduced by a further 12 per cent by F2016 relative to Option 2 through targeted reductions to a few programs
- Commercial: Program expenditures are reduced by a further 24 per cent by F2016 through limiting participation and reducing program costs for most programs
- Industrial: Relative to the Option 2, program expenditures are reduced by 22 per cent in F2016 and 29 per cent in F2017. These reductions are achieved through lower levels of activity in the load displacement program and other programs.
- Supporting initiatives: an additional 19 per cent by F2016 was made to supporting initiative expenditures

4.2.2 Option 2

In the 2010 ROR, Option 2 was an updated version of the DSM plan that was included in BC Hydro's 2008 LTAP filing with the British Columbia Utilities Commission (**BCUC**). The updated Option 2 target continues to be the 2008 LTAP target, which is 7,800 GWh/year of energy savings and 1,400 MW of associated capacity savings by F2021.

Option 2 was first updated to reflect new information, such as the 2012 mid-level Load Forecast and current economic conditions. This provided a new baseline for the energy savings potential for Option 2.

In addition, BC Hydro wanted to maintain the 2008 LTAP DSM target over the long-term while exploring whether expenditures could be adjusted in the near-term to manage energy portfolio costs. BC Hydro notes that Option 2 was constructed to meet the following parameters: first, reduce expenditures in the near-term (F2014 to F2016) and by doing so, reduce energy savings as well; second, ramp up to generally return to LTAP energy savings levels in F2021; and third, generally remain at the LTAP energy savings levels post F2021 within +/- 10 per cent.[7] The near-term adjustments result in a reduction of $230 million (46 per cent for F2015 and F2016) relative to the DSM plan in the F2012-F2014 Revenue Requirements Application, and approximately $330 million by F2022 in expenditures relative to the update to the Option 2 baseline described above.

With regard to the specific tactics employed in Option 2:

- Codes and standards are those that have been enacted, announced or planned by the federal and provincial governments as summarized in Table 4-3.

[7] Minor variances from LTAP energy savings levels (generally in the order of +/- 10 per cent) can be expected from year to year because of the “lumpiness” of elements in the DSM plan.

Table 4-3 Option 2: Codes and Standards

	Residential	Commercial	Industrial
Equipment	• Incandescent lamps • Standby power • Set-top boxes • External power supplies • Portable and room air conditioners • Battery chargers • Digital television adapters • Windows • Ceiling fans • Torchieres • Electric water heaters	• High intensity discharge lamps and ballasts • Packaged terminal air-conditioners • Ice-cube makers • Large air-conditioners • Traffic and pedestrian lights • Dry transformers • Fluorescent lamps	• Motors
Appliances	• Clothes washers • Refrigerators • Freezers • Dishwashers	• Clothes washers • Refrigeration	
Buildings	• B.C. Building Code • City of Vancouver building bylaw	• B.C. Building Code • City of Vancouver building bylaw	

- Conservation rate structures are those that are in place or planned. These include the Transmission Service Rate (**TSR**) for large industrial customers, the Residential Inclining Block (**RIB**) rate for residential customers, a conservation rate structure for large commercial and small industrial customers in the former Large General Service (**LGS**) rate class, and a conservation rate structure for the Medium General Service (**MGS**) rate class.
- Programs target residential, commercial and industrial customer classes. Programs were the primary lever for determining the near-term adjustments as provided in Table 4-4

1 **Table 4-4 Option 2: Programs**

Program	Near-Term Adjustments
Residential	
Refrigerator Buy-Back	• Reduce market presence in F2014 • Return to market in F2020
Lighting Appliances Electronics	• Combine the programs into a new Retail Program that targets the three product categories on a rotation basis and at a significantly reduced expenditure level
New Home	• Eliminate incentives in early F2015 • Maintain developer education component (through codes and standards) to enhance code compliance and builder/ developer relationship
Smart Meter Infrastructure In-Home Feedback (Web Portal & In-Home Devices)	• Defer in-home display • Continue to support Web Portal
Low Income	• Maintain provision of energy savings kits • Maintain current participation levels in Energy Conservation Assistance Program (**ECAP**), while looking for process improvements
Commercial	
Power Smart Partner and Product Incentive Program (**PIP**)	• Continue with both programs but combine application process and IT infrastructure • Cap incentive funding • Reduce funding for energy study and energy managers. • Eliminate screw-in category and short savings persistence opportunities • Continue existing continuous optimization activities but reduce new participants • Future continuous optimization contract renewals would be offered on a shorter term to maintain flexibility and limit new growth • Defer customer Voltage and VAR Optimization (**VVO**) opportunities
New Construction	• Continue with program but find cost reductions • Eliminate short persistence technologies
Lead By Example	• Reduced employee engagement and re-scoped projects • Maintain policy activities
Industrial	
Power Smart Partner – Transmission	• Screen projects over $1 million; eliminate incentive offer for projects over $5 million • Cap incentive offer • Cap annual incentive funding and energy managers
Power Smart Partner – Distribution	• Eliminate least cost effective end uses and short persistence projects • Cap incentive funding • Increase performance metrics for energy managers
Load Displacement	• Continue with committed projects • Defer new projects to F2019

- Supporting Initiatives expenditures are reduced over the near term to align with program levels of activity. Activities are re-prioritized to focus on understanding the potential for new energy efficient technologies over the longer term.

Option 2 supporting initiatives are summarized in Table 4-5.

Table 4-5 Option 2: Supporting Initiatives

• Public Awareness and Education lays a foundation of general awareness and understanding of the importance of electricity conservation among British Columbians and ultimately to build and sustain a culture of conservation. Community Engagement helps to overcome awareness and acceptance barriers to energy efficiency through community-based social marketing and to capture opportunities to save electricity through changes to local government planning and policy. • Technology Innovation introduces new energy efficient technologies to B.C. and accelerates their commercialization and adoption in the Province. Information Technology supports the successful operation of selected DSM initiatives • Indirect and Portfolio Enabling supports BC Hydro's DSM programs and activities with general management and infrastructure

Finally, the energy savings for revised Option 2 were adjusted for uncertainty.

4.2.3 Option 3

In the 2010 ROR, Option 3 was constructed to target more electricity savings by expanding program efforts, while keeping the level of activity and savings for codes and standards and conservation rate structures consistent with Option 2. Program activities are expanded with increased incentives, advertising or technical support to address customer barriers, thereby increasing customer participation. For the 2013 IRP, Option 3 is based on a similar construct. Program activity is expanded based on allowing program incremental cost-effectiveness to increase beyond BC Hydro's current Long Run Marginal Cost. The updated Option 3 targets 8,300 GWh/year of energy savings and 1,500 MW of associated capacity savings by F2021.

BC Hydro updated Option 3 to reflect new information on program performance in terms of updated assumptions on program costs and energy savings. Energy savings are lower than the 2010 ROR Option 3 because of reduced potential in incremental savings based on new information regarding the cost and energy savings performance of the DSM tools. Codes and standards, and conservation rate structures, reflect the same level of activity as updated Option 2 described above in section 4.2.2.

4.2.4 Options 4 and 5

4.2.4.1 Option 4 Description

Options 4 and 5 were designed in collaboration with BC Hydro's Electricity Conservation and Efficiency Advisory Committee (**EC&E**) and were intended to look at a fundamental shift in BC Hydro's approach to saving electricity. These options place much greater emphasis on tactics that change market parameters and societal norms and patterns that influence electricity consumption and conservation. As new and untested approaches to saving electricity, both Option 4 and Option 5 are subject to considerable uncertainty regarding government, customer and BCUC acceptance and, ultimately, their effectiveness at generating additional cost-effective electricity savings.

BC Hydro did not update Options 4 and 5 at this time because they are currently not technically viable options.

Option 4

DSM Option 4 is founded on new or more aggressive conservation rate structures, and significant government regulation in the form of codes and standards, to generate additional savings. Option 4 targets about 9,500 GWh/year of energy savings and 1,500 MW of associated dependable capacity savings by F2021. Large Industrial customers would be exposed to a much larger degree to marginal cost price signals because the TSR would change from a 90/10 to an 80/20 split between Tier 1 and Tier 2 prices, thereby increasing the amount of energy consumption that is subject to Tier 2 pricing. Each industrial customer would need to meet a government mandated certified plant minimum efficiency level to take advantage of BC Hydro's Heritage hydroelectric lower priced electricity; otherwise, electricity would be supplied at marginal (market-based) rates. Commercial customers would be subject to efficiency-based pricing through either a connection fee tied to building energy performance or an initial baseline rate structure for new buildings. Rate structures may also need to be tied to a house or building's rated energy performance.

Option 5

Option 5 is the most aggressive DSM option considered by BC Hydro. Option 5 targets about 9,600 GWh/year of energy savings and 1,600 MW of associated dependable capacity savings by F2021. This option aims to create a future where buildings are net-zero consumers of electricity with some buildings being net contributors of electricity back to the grid. Energy efficiency and conservation activities are pervasive throughout society and ingrained in a business decision making culture. This shift is reflected through wide-spread district energy systems and micro distributed generation, smaller more efficient housing and building footprints, community densification, distributed workforce and hotelling (shared workspace), best practices in construction and renovation, efficient technology choices and behaviour, and an integrated community perspective (land-use, zoning, multi-use areas). A carbon neutral public sector contributes to the culture shift. All BC Hydro customers would be exposed to marginal cost price signals to a greater extent. For the industrial sector, a market transformation to certified plants occurs, supported with expanded regulation.

Codes & Standards

Table 4-6 summarizes the Option 5 codes and standards changes relative to Option 4. Additional or more aggressive codes and standards are included that are not currently planned by governments.

Table 4-6 Option 5: Codes and Standards Changes

Community	• Residential building code changed to EnerGuide 90 in F2022 and net zero electricity in F2032, requiring distributed generation • Commercial building code strengthened by 15 per cent every five years, reaching net zero electricity in F2032, requiring distributed generation • Residential retrofit code introduced in F2021 and strengthened in F2032, requiring home owners to undertake specific energy saving measures during major renovations • Commercial retrofit code introduced in F2018 and strengthened in F2022, requiring building owners to undertake specific energy saving measures during renovations • Equipment regulations strengthened and broadened to cover additional equipment between F2015 and F2025
Industrial	2020 • New efficiency regulations in place for a selection of equipment • Industrial engineering firms are required to be certified under ISO energy management system standard • System End-Use-Intensity regulation in place 2030 • 75 per cent to 100 per cent of the industrial sectors are regulated to meet efficiency minimums • Efficiency regulations in place for mechanical pulping and hard rock grinding

Conservation Rate Structures

Relative to Option 4, for conservation rate structures, changes are made to deliver even stronger price signals across customer classes.

Table 4-7 summarizes the Option 5 conservation rate structure changes.

Table 4-7 Option 5: Conservation Rate Structure Changes

Residential	Two placeholder concepts are considered for implementation, with modelled savings based on the first concept: • Two-part rate structure similar to the LGS rate assumed to start in F2016, with all customers seeing a marginal cost price signal which includes transmission and distribution costs • Rate structure tied to the efficiency of the home
Commercial	One or more of the following concepts are introduced: • A more aggressive LGS two-part rate • Increased marginal costs to include transmission and distribution costs • Marginal cost based rate for all consumption, with a credit for customers based on their participation in DSM programs • For existing buildings, a rate tied to electricity intensity that is differentiated by sector (kWh/unit) • For new buildings, a rate tied to the building's rated energy performance • Connection fee tied to energy efficiency
Industrial	TSR changed in F2020 (e.g., 80/20 or continuous step). End-Use Intensity rate assumed to start in F2032. Customers must meet Certified Plant minimum efficiency levels to receive the advantage of heritage priced electricity from BC Hydro. Otherwise, electricity is supplied at market-based rates.

Programs

As summarized in Table 4-8, Option 5 includes the following program changes from Option 2.

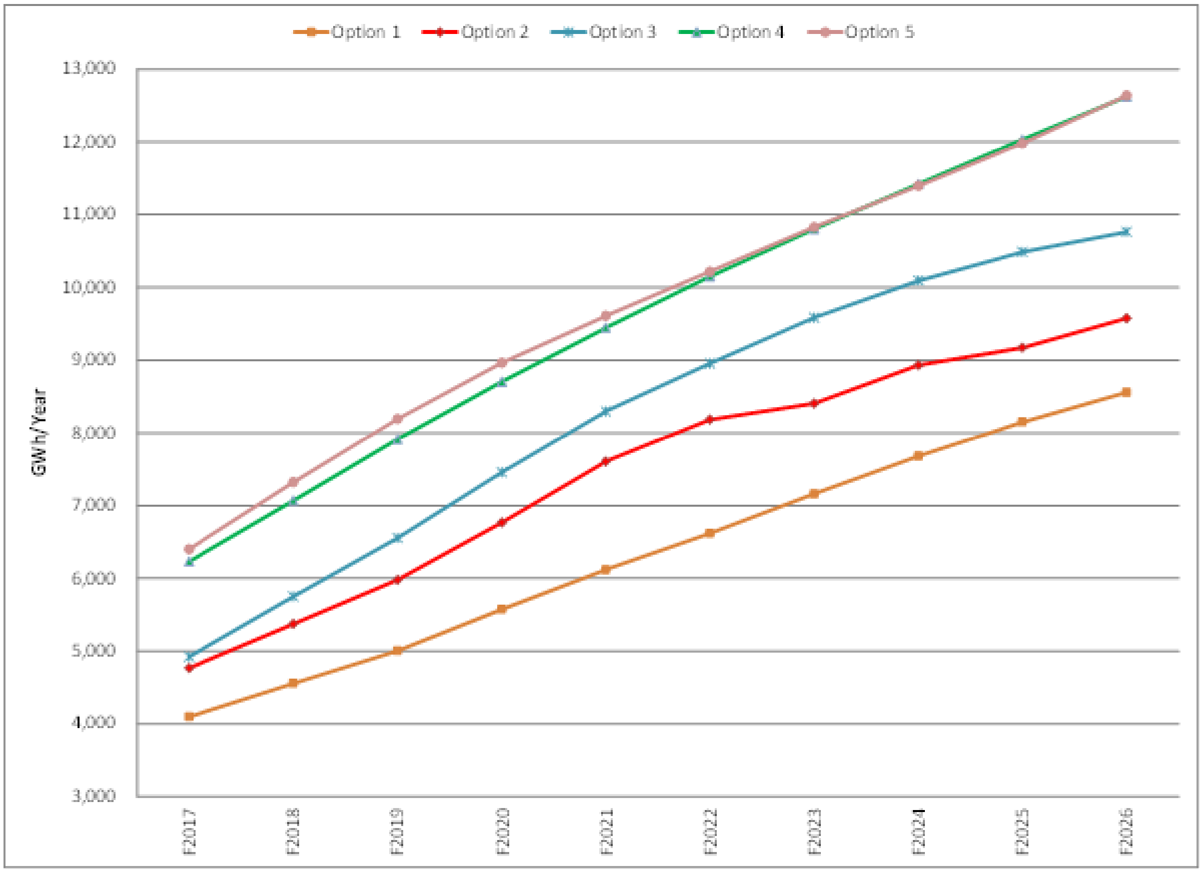
Table 4-8 Option 5: Program Changes

Community	• Program incentives eliminated or diminished around F2020 after two-part rate structures have been in place, at which time customer awareness of the rate structures should be high and a driver of customer energy decisions • Other program activities (e.g., advertising and enabling) are consolidated in F2020 into sector-wide efforts that help customers to respond to the rate structure price signals and focus on capacity building, channel engagement and awareness, and education and advocacy • Selected program incentives are retained to support the shift: – For large capital investments that will continue to face significant up-front capital cost barriers (e.g., new construction, major retrofits, solar photovoltaic, district energy) – For selected higher cost technologies that set the stage for codes and standards (e.g., heat pump clothes dryers) – Broaden direct install programs in residential and commercial
Industrial	• Programs change to integrate with ISO 50001 Energy Management System Standard and Industrial Plant Certification • Basis for program incentives shift from project costs to the value of electricity in F2020, but then diminish over time as rate structures and codes and standards take over as drivers of energy efficiency investments. • Program enabling activities continue.

4.2.5 Electricity Savings and Costs Comparison

Figure 4-1 compares the energy savings obtained from the five energy and capacity DSM options over the time horizon of the analysis.

Figure 4-1 Energy Savings[8]



The associated capacity savings from the energy and capacity DSM options are provided in Figure 4-2.

[8] The energy savings shown for Options 1 through 5 have been adjusted for uncertainty.

Figure 4-2 Associated Capacity Savings[9]

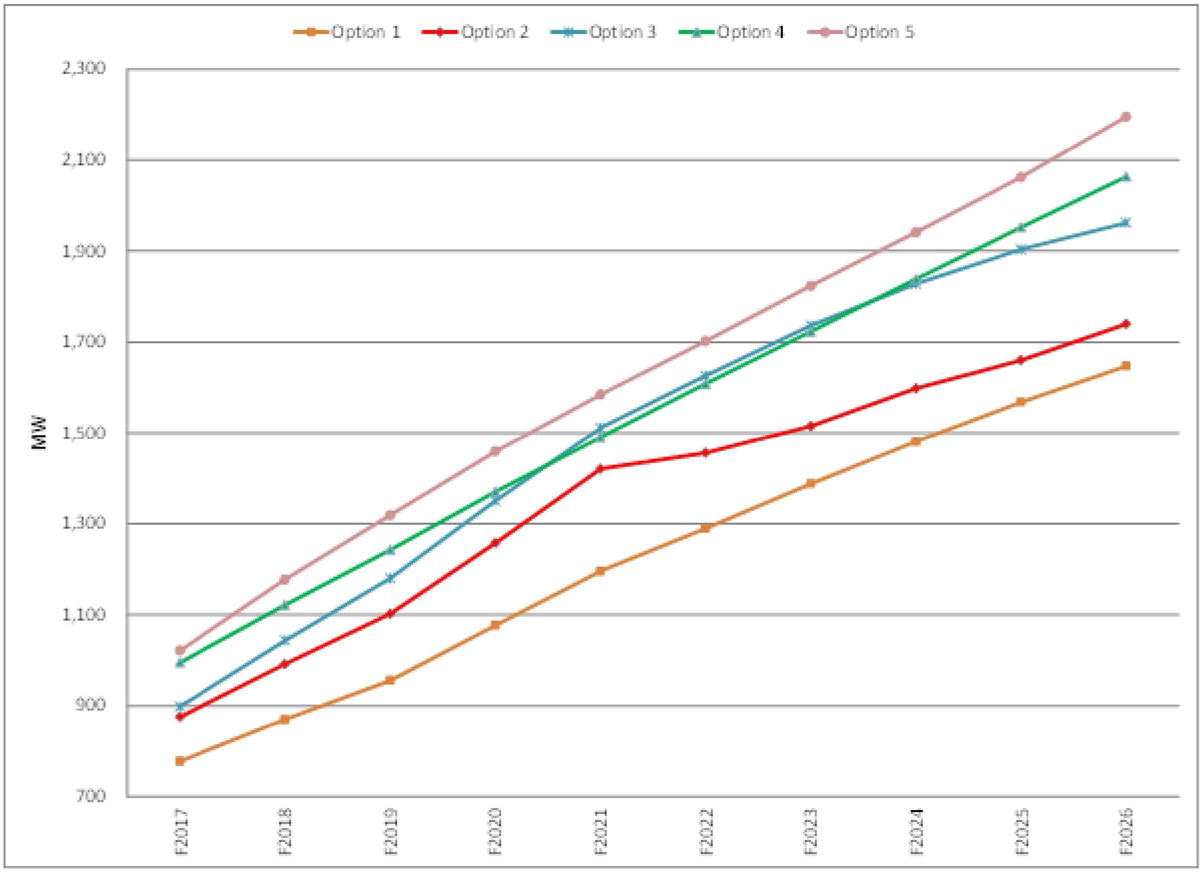


Figure 4-3 and Figure 4-4 show the resource investment TRC and UC in DSM for the various options.

[9] The capacity savings shown for Options 1 through 5 have been adjusted for uncertainty.

1 **Figure 4-3 Total Resource Costs**

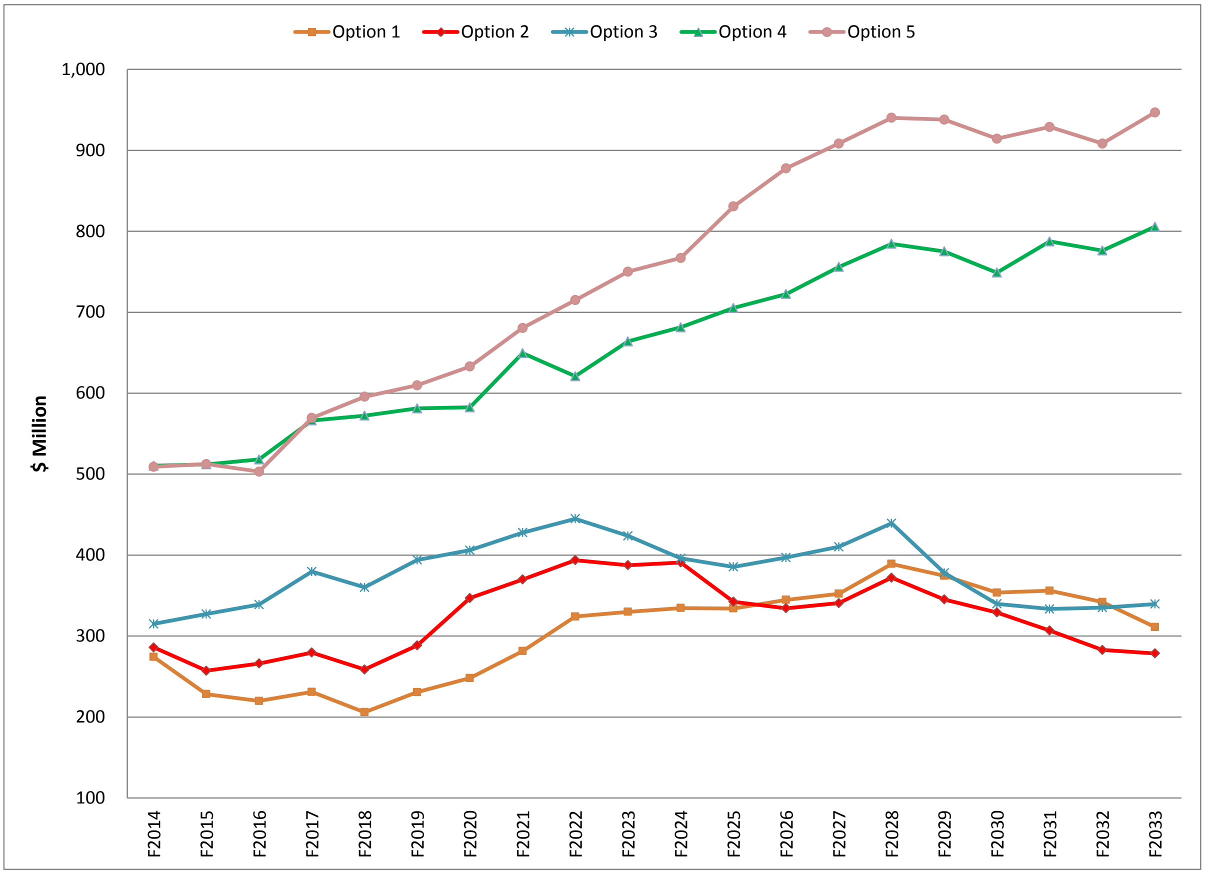
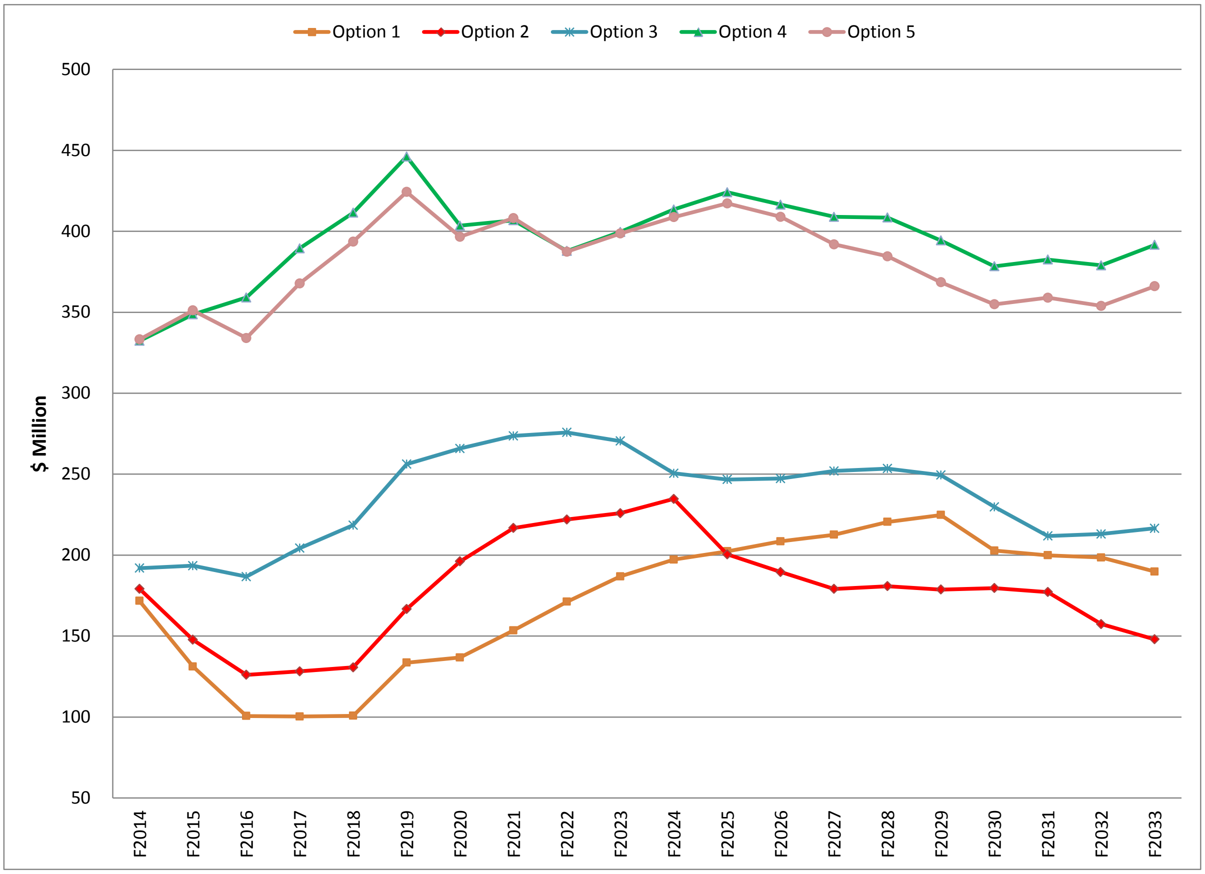


Figure 4-4 Utility Costs



The unit energy costs from TRC and UC perspectives for each of the five energy and capacity DSM options are provided in Table 4-9.

Table 4-9 TRC and UC for Energy and Capacity DSM Options

Energy and capacity Option	TRC ($/MWh)	UC ($/MWh)
1	32	18
2	32	18
3	35	22
4	47	30
5	49	29

4.3 Capacity-Focused DSM Options

While the energy and capacity options described earlier generate associated capacity savings, additional capacity savings are achievable through capacity-focused DSM, which targets capacity savings specifically. BC Hydro did not update the capacity-focused DSM options for the 2013 ROR, but may start to explore them in more detail pending the recommended actions from the IRP.

This list of options represents BC Hydro's first major exploration of capacity-focused DSM, and as a result, experience will need to be gained to increase certainty of the expected electricity savings.

4.3.1 Industrial Load Curtailment

4.3.1.1 Description

Industrial load curtailment targets large customers who agree to curtail load on short notice in return for a financial payment. BC Hydro had a load curtailment offer in place from 2007 to 2010 as an operational contingency in the event of emergency shortages. BC Hydro called on curtailment load twice during that time period and customers curtailed as expected. The load curtailment offer was discontinued to new customers for the 2010/2011 winter season due to a forecast surplus of peak capacity in the BC Hydro system.

In this option, BC Hydro would institute a long-term load curtailment offer and rely on the forecast peak demand reductions for the purpose of resource planning (compared to the previous offer which was utilized to address short-term contingencies). In effect, BC Hydro would scale its system to meet something less than 100 per cent of forecast peak demand and plan to rely on industrial load curtailment on the rare occasions when load exceeded capacity.

BC Hydro also has an industrial Modified Demand Rate as part of the existing TSR which is designed to limit demand during morning and evening peak periods. A redesign of this voluntary Modified Demand Rate is being investigated for its potential to increase capacity savings during the evening peak only.

4.3.1.2 Tactics

For this option, the agreement and financial payment could take a variety of forms (e.g., contract or rates) and a penalty could be applied for non-performance by participating customers.

4.3.2 Capacity-Focused Programs

4.3.2.1 Description

This option comprises a suite of programs that target capacity savings in all three customer sectors. They are designed to provide capacity savings that can be dispatched under utility control. Programs may involve payment for customer equipment and a financial payment for participation in the program. This could complement time-based rates by helping customers to respond to peak and off-peak price signals. In addition, as smart appliances are introduced with the capability to communicate with smart meters, new capacity-focused opportunities are expected.

4.3.2.2 Program Concepts

The key concepts for the capacity-focused residential (Table 4-10), commercial (Table 4-11) and industrial (Table 4-12) programs are outlined below.

Table 4-10 Residential Program Concepts

Water heater control	Equipment provided and installed by utility automatically controls the on/off operation of the water heater. A one-time payment is provided to participants.
Thermostat or switch controlled heat	Equipment provided and installed by utility automatically controls the on/off operation of space heating equipment through a programmable thermostat or switch. A one-time payment is provided to participants.
Switch controlled radiant heat	Equipment incented by utility is purchased and installed and operated during off-peak periods to store heat. Stored heat is extracted and delivered to residence during on-peak times. A one-time payment is provided to participants.

Table 4-11 Commercial Program Concepts

Energy management system load control	Equipment receives a signal from the utility through the smart meter or other communication device that automatically controls the on/off operation of identified end use equipment during curtailment periods. An incentive payment is provided to participants based on proven load control capability.
Lighting control	Equipment provided and installed by utility automatically controls the voltage of power being supplied to the lighting system during curtailment periods. Lighting voltage can be reduced with no apparent reduction in lighting level. An incentive payment is provided to participants based on proven load control capability.
Water heater load control	Equipment provided and installed by utility automatically controls the on/off operation of water heaters during curtailment periods. An incentive payment is provided to participants based on participation.
Thermostat or switch controlled heat	Equipment provided and installed by utility automatically controls the on/off operation of the space heating equipment through a programmable thermostat or switch. An incentive payment is provided to participants based on participation.
Air conditioning load control	Equipment provided and installed by utility automatically controls the on/off operation of air conditioning during curtailment periods. An incentive payment is provided to participants based on participation.

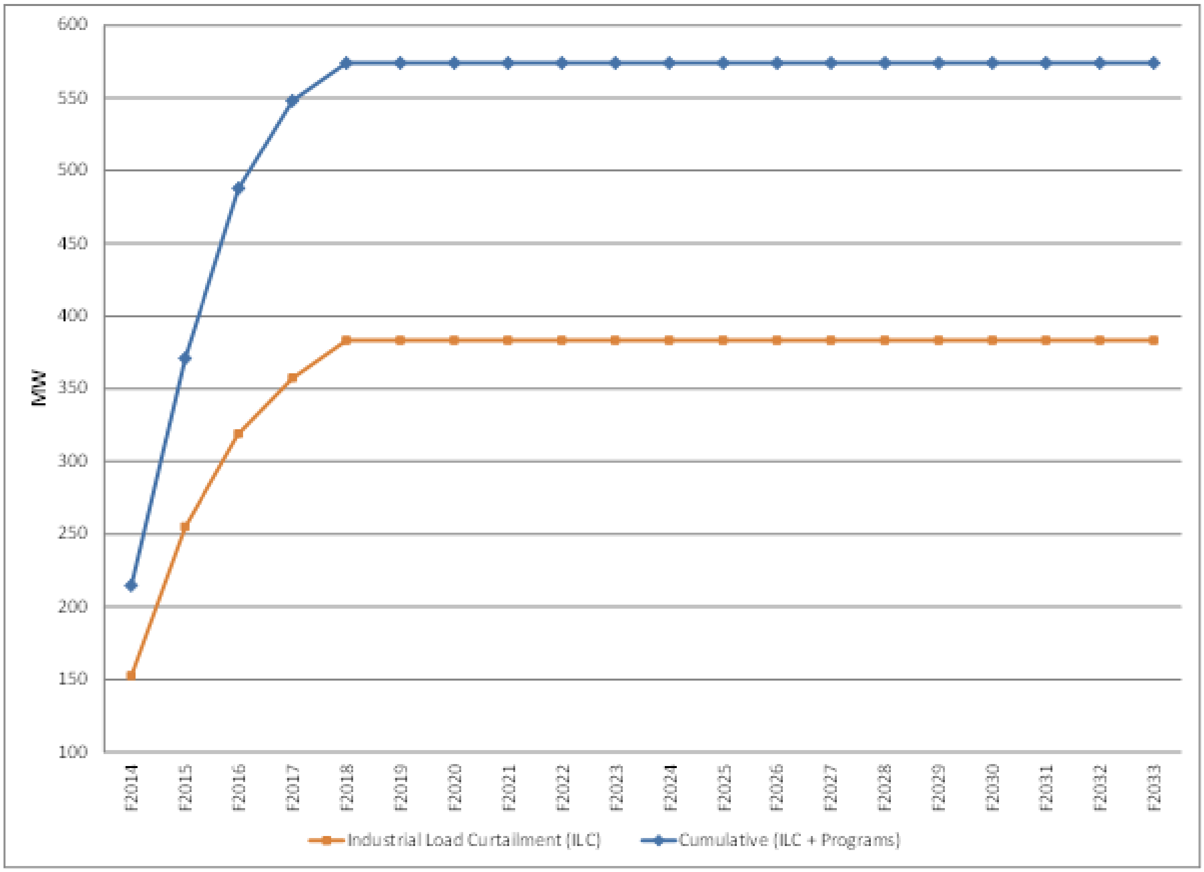
Table 4-12 Industrial Program Concepts

Direct load control for distribution-level customers	Audits and potential incentives are provided to customers to install equipment and participate in offering load curtailment. Target end-uses are customer dependent (e.g., water heating, lighting).

4.3.3 Capacity Savings and Costs Comparison

Figure 4-5 provides a view of the potential combined capacity savings for the capacity-focused options over the time horizon of the analysis. While the capacity programs are independent, the curves for each option are overlaid onto the previous option to provide an overview of the potential combined savings.

Figure 4-5 Combined Capacity Savings (MW)



The unit capacity costs from TRC and UC perspectives for each of the capacity-focused DSM options are provided in Table 4-13.

Table 4-13 TRC and UC for Capacity-Focused DSM Options

Capacity-focused Option	TRC * ($/kw-year)	UC * ($/kw-year)
Industrial Load Curtailment	31	45
Capacity-Focused Programs	55	69

* Includes transmission and distribution loss savings estimates

2013 Resource Options Report Update

Chapter 5

Supply-Side Resource Options

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5.1 Introduction

Supply-side resource options include generation, storage and transmission resources. The following chapter presents an overview of the supply-side resource options and provides the underlying assumptions. The unit energy cost (**UEC**) and unit capacity cost (**UCC**) for the generation resource options in this chapter are presented at the point of interconnection (**POI**).

5.1.1 RODAT & ROMAP Databases

For long-term provincial-level resource planning exercises, potential supply-side data are evaluated in terms of technical, financial, environmental and economic development attributes. The resource options data is captured in the Resource Options Database (**RODAT**) and Resource Options Mapping Database (**ROMAP**):

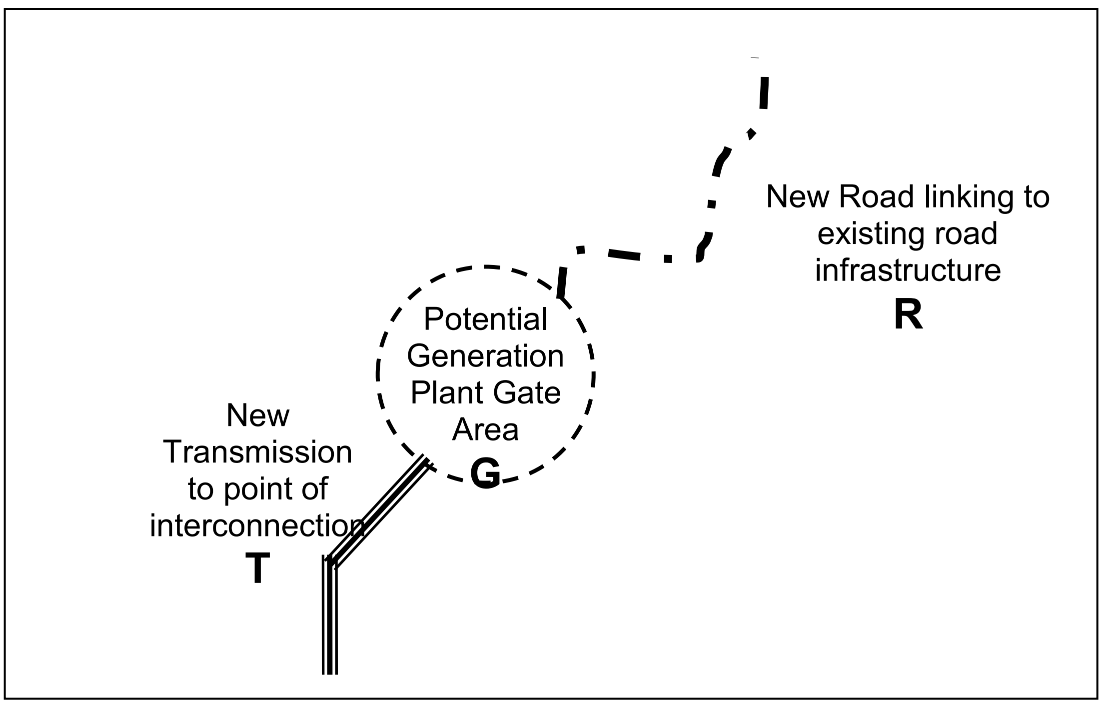
- **RODAT:** Stores technical, financial, environmental and economic development information on the potential resource options and creates summary sheets showing the attributes of each resource options at the project, bundle or cluster levels. The RODAT summary sheets in Appendix 3 present the resource options with UECs less than $200/MWh or UCCs less than $125/kW-yr.
- **ROMAP:** Stores potential resource options data in a Geographical Information System (**GIS**) database that allows the mapping of potential resources, including the new access roads and transmission corridors required to link potential sites to existing infrastructure. ROMAP facilitates the identification of clusters of energy or capacity in relation to the existing landscape features (e.g., water bodies, towns), exclusion areas (e.g., parks, conservancies) and infrastructure (e.g., transmission, road networks). Appendix 5 provides more detailed information on ROMAP.

The databases allow the resource options to be summarized in terms of a project, bundles of projects, and clusters of projects:

- **Project**: A potential project is divided into three components that describe the total resource option at the POI to the electric system. These components are:
  - **Plant gate (G):** Plant gate area containing supply-side generation works and equipment
  - **Road (R) corridor:** Road corridor (length and width) linking plant gate area to existing road infrastructure
  - **Transmission (T) corridor:** Transmission corridor (length and width) linking plant gate area to existing transmission infrastructure

The technical, financial, environmental and economic development attributes of each component of the potential resource options (G, R, T) are evaluated and stored in the databases.

Figure 5-1 Components (G, R, T) of the Resource Options Evaluated to the POI



In this report, as illustrated in Figure 5-1, the technical, financial, environmental and economic development attributes of each resource option are presented at the POI by summing the plant gate (G), new road (R) and new transmission (T) components of each option (i.e., resource option at POI = G + R + T).

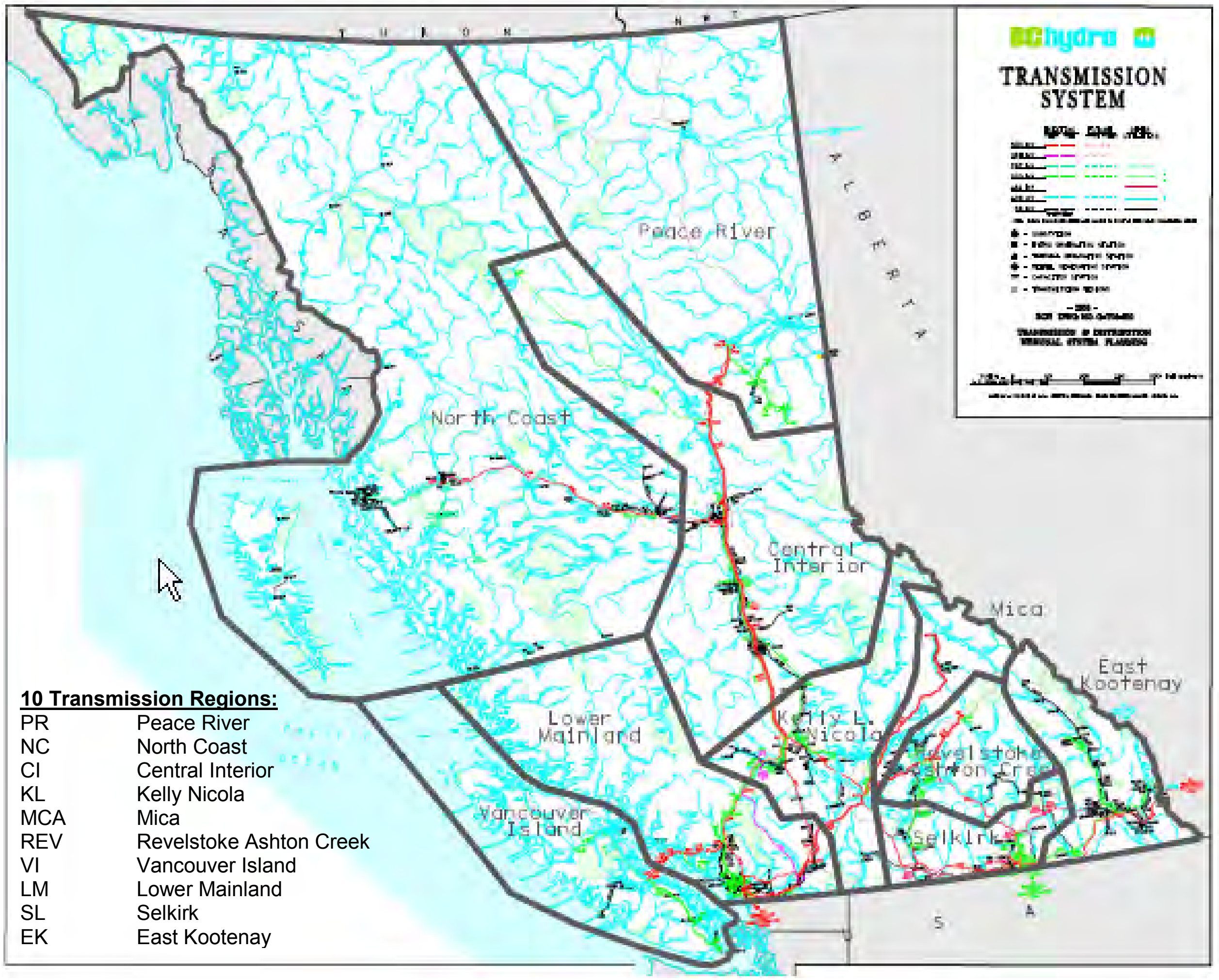
Resource potential can be reported in terms of a specific project, a bundle of projects or a cluster of projects. Bundled and clustered information is defined as follows:

- **Bundle:** a number of potential projects, of a specific resource type, are bundled and sorted according to a region and cost of energy ($/MWh). In some cases, for example run-of-river potential having a large number of small projects, resource potential is presented in terms of bundles and bundles are used as input data for resource planning portfolio analysis.
- **Cluster:** a potential grouping of different generation resource options, within a geographic zone, whose road and transmission components would benefit from economies of scale and shared transmission and road infrastructures. ROMAP stores alternative road and transmission corridors associated with potential projects grouped in clusters. The process of identifying clusters includes mapping resource potential and identifying possible clusters based on energy and capacity densities. The generation resource clusters approach was first introduced in the 2010 Resource Options Report (**ROR**) and considered in the 2012 Draft Integrated Resource Plan (**IRP**).

This report presents data in the form of points or bundles.

Resource options data are reported by transmission region, meaning that though the generation location (G) of a potential resource option is in one transmission region, if the addition of the transmission component (T) interconnects in a different transmission region, the overall project at POI (G + R + T) is reported as being in the zone where interconnection occurs. Figure 5-2 shows a map of the ten transmission regions used in the 2013 ROR Update.

Figure 5-2 Ten Transmission Planning Regions



5.1.2 Resource Options Filters

One of the functional elements of the ROMAP GIS database is that it allows screens to be created to capture areas where resource option development would be severely constrained or prohibited (e.g., exclusion areas, inaccessible areas such as glaciers). These screens are used to establish the resource options considered in the evaluation process by removing potential resource options from consideration.

Three basic filters remove potential resource options from consideration:

(i) A potential resource option may not occur within a legally protected area

(ii) A potential resource option may not occur on a salmon bearing stream

(iii) A resource option may not occur in a zone identified as being a glacier

The potential resource options have been screened using the exclusion framework summarized in Table 5-1.

Table 5-1 Exclusion Zones

Exclusion Zone	Source	Screening Buffer	Screening Criteria ROADS	Screening Criteria POWER LINES	Screening Criteria RESOURCE OPTIONS
Biodiversity Areas	Province of British Columbia, GeoBC, ILMB	No projects within 100 m of exclusion area	None allowed	None allowed	None allowed
Wildlife Management Areas Areas for which administration and control was transferred to the Ministry of Environment via the *Land Act* due to the significance of their wildlife/fish values and designated as Wildlife Management Areas under the *Wildlife Act*	Province of British Columbia, GeoBC, LRDW	No projects within 100 m of exclusion area	None allowed	None allowed	None allowed
Conservancy Areas Conservancy areas designated under the *Park Act* or by the *Protected Areas of British Columbia Act*, whose management and development is constrained by the *Park Act*	Province of British Columbia, GeoBC, LRDW	No projects within 100 m of exclusion area	None allowed	None allowed	None allowed

Exclusion Zone	Source	Screening Buffer	Screening Criteria ROADS	Screening Criteria POWER LINES	Screening Criteria RESOURCE OPTIONS
National Parks	Province of British Columbia, GeoBC, LRDW	No projects within 100 m of exclusion area	None allowed	None allowed	None allowed
Legally Protected Areas Ecological Reserves, Protected Areas, Provincial Parks, Recreation Areas	Province of British Columbia, GeoBC, LRDW	No projects within 100 m of exclusion area	None allowed	None allowed	None allowed
Canadian Forces Bases	CFB Esquimalt (Navy) CFB Comox (Air Force)	No projects within 100 m of exclusion area	None allowed	None allowed	None allowed
Migratory Bird Sanctuaries	Environment Canada	No projects within 100 m of exclusion area	None allowed	None allowed	None allowed
Marine Wildlife Areas (MWAs)[1]		Not applicable	Not applicable	Allow MWA designation not yet made: Database tracks resource options which fall within this area	Allow MWA designation not yet made: Database tracks resource options which fall within this area
National Marine Conservation Areas No electricity generation is permitted		No projects within 100 m of exclusion area	Not applicable	None allowed	None allowed

[1] MWAs are designated by Environment Canada under the *Canada Wildlife Act*. At this time, one site is being considered in British Columbia, the Scott Island Group, located 10 km to 46 km offshore of Cape Scott at the northwestern tip of Vancouver Island. Because of the uncertainty related to the MWA designation in this area, the existing MWA filter "allows" for development in the region and tracks resource options which may fall within the area so that potential resource options can be filtered out, if or, when a designation is made.

Exclusion Zone	Source	Screening Buffer	Screening Criteria ROADS	Screening Criteria POWER LINES	Screening Criteria RESOURCE OPTIONS
Federal Marine Protected Areas (MPA) 1. Bowie Seamount MPA, 180 km offshore of Gwaii Haanas 2. Endeavour Hydrothermal Vent MPA, 250 km offshore of Vancouver Island.		No projects within 100 m of exclusion area	Not applicable	None allowed	None allowed
Provincial MPAs Provincial Park, Conservancy, *Environment and Land Use Act* Protected Areas, Recreation Area (128 are marine taken together) and Ecological Reserves (20 marine, called Marine Ecological Reserves - e.g., Race Rocks)		No projects within 100 m of exclusion area	Not applicable	None allowed	None allowed
Other Exclusion Areas Glaciers	Province of British Columbia, GeoBC, CWB	No projects, roads or power lines within 100 m of exclusion area			

First Nations may have a desire to provide information on areas that they consider are inappropriate for development. Should such information be provided, BC Hydro will convey the information to the government through its consultation reports. At this time, such information is not being reflected in the 2013 ROR Update exclusion zones for the following reasons:

- The 2013 ROR Update is not reviewing individual generation sites,
- The exclusion areas are presently limited to the areas identified as glaciers and areas designated through federal or provincial statutes, and
- The 2013 ROR Update process is not a land use planning exercise.

5.2 Generation Resource Options

5.2.1 Wood Based Biomass – Standing Timber, Road Side and Sawmill Wood Waste

BC Hydro engaged Industrial Forest Services Ltd. for an update to the 2010 modeling study following the same modeling methodology. In the 2013 Update, the UECs are calculated at 7 per cent real cost of capital, and are presented in $2013.

5.2.1.1 Resource Description

Wood based biomass electricity is generated from the combustion or gasification of organic materials as fuels. For the purpose of the 2013 ROR Update, the following categories of fuels are considered:

- **Standing timber** (including Pine Beetle Killed Wood)
- **Roadside debris** (wood already harvested, but left in the forest or road side, some are Pine Beetle Killed Wood)
- **Sawmill wood waste**

British Columbia has significant wood based biomass resources. However, there are many competing uses for these resources. As such, the wood based biomass fuel potentially available for electricity generation may be significantly less than the total available resource fuel.

The majority of forests in B.C. are owned and managed by the Crown. The quantity of wood based biomass fuel that is available for electricity generation is determined (directly or indirectly) by government policies, statutes, regulations and by economics (i.e., harvesting economics and the economics of other competing industries). It is the responsibility of the Ministry of Forests, Lands and Natural Resource Operations to ensure forest sustainability, and to allocate fibre through the setting of annual allowable cuts (**AAC**) and granting of harvesting tenures/licences. After the AAC is set and allocated to users, the actual amount harvested and used for various purposes/industries is largely a matter of the economics of supply and demand. These economic factors include:

- Demand and price for processed wood such as lumber, pulp, paper, wood pellets, plywood, fibre boards, biomass heat and energy
- The location of wood processing facilities relative to the location of the wood supply influences fibre delivery costs

5.2.1.2 Methodology

For the 2010 ROR, BC Hydro engaged a team of consultants from Industrial Forest Services Ltd., together with industry experts, to conduct a modeling study to estimate the long-term wood based biomass energy potential, costs and possible locations of wood based biomass delivery points. That study was overseen by a working group comprised of representatives from BC Hydro, the Ministry of Forests, Lands and Natural Resource Operations and the Ministry of Energy and Mines. Study approach and results were discussed with stakeholders through the ROR process in 2010. This study was updated in 2013 by Industrial Forest Services Ltd following the same modeling methodology.

The modeling study was done primarily using the B.C. Fibre model. This model is a regional fibre forecast and fibre allocation model for B.C. The B.C. Fibre model is well known and accepted in the forest industry. It is used by industrial clients in the B.C. pulp and paper, solid wood and bio-energy sectors to provide strategic guidance. This study modeled B.C. in 13 forestry sub-regions and reported out results for two periods. The first period from year 2013 to 2024 corresponds to the transition and decline in B.C. Interior harvest levels as a result of the Mountain Pine Beetle epidemic. The second period from year 2025 to 2040 represents the subsequent time when a stable mid-term harvest is forecast.

Many assumptions were required to complete this study. The guiding principle was to reflect current knowledge or expectation without speculating future policies, or the demands of new biomass consuming industries.

This study estimated the electricity generation potential and fibre cost from wood based biomass with the following key inputs:

- The government determined AAC
- Changes to the future harvest as a result of the mountain pine beetle epidemic
- Changes to the grade of logs as a result of economic shelf life of dead pine
- The existing sawmill industries and its capacity/ability to utilize the AAC
- The existing residual industry (pulp mills, pellet plants, power plants, board plants) and its capacity to utilize sawmill residues
- The current and future demand of the existing residual industry for non-sawlog grade logs
- The current and future demand of the existing residual industry for road-side logging residues
- The impact on biomass supplies resulting from the development of electricity purchase agreements resulting from the BC Hydro Integrated Power Offer, Bioenergy Phase 1 and Phase 2 Calls for Power, Conifex and Community Based Biomass Call
- The economic drivers of the forest industry including:
  - Lumber prices
  - Pulp selling prices
  - Paper selling prices
  - Can$/US$ exchange

- Housing starts

Within each of the 13 forestry sub-regions in B.C., log supply (sawlog and biomass) was identified and quantified over time based on the above considerations. This was compared to the regional demand for sawlogs and pulplogs. The identification of available biomass for energy production was a large accounting exercise that balanced log/biomass supply against log/biomass demand, and what remained in each region became available for electricity generation.

Once the electricity potential for different regions was determined, possible fibre delivery locations were then identified for each region. Key considerations included the location of existing sawmills, infrastructure and location of available fibre. The cost of biomass delivered to these locations for the three wood based biomass sources was estimated. Generic greenfield biomass power plants and their associated development costs were assumed and used to estimate the cost of projects. The cost of a project together with the cost of delivered biomass fuel are used to estimate the unit energy cost ($/MWh) of the resource.

5.2.1.3 Results

A detailed wood based biomass report is included in Appendix 6. Key observations from the study are listed below:

- The current volume of biomass in the Province (considering all biomass categories in year 2013) that is surplus to existing demand, potentially available for bioenergy production, is about 27 million cubic metres. This is forecasted to decline significantly over the first period and is forecasted to stabilize by 2025 in the second period at about 10 million cubic metres (9.8 TWh equivalent of energy per year). The decline is primarily driven by the decline in the availability of standing timber resulting from reductions to the annual allowable cut as the near term level has been elevated to speed up the consumption of Pine Beetle affected wood. For the purpose of estimate long term energy potential, the results from the second period are considered for long term planning and are summarized in Table 5-2.

- Compared to the results in the 2010 ROR study, the forecasted overall biomass energy potential in the Province for the second period has decreased from 13 TWh to 9.8 TWh. The biggest decrease is the standing timber potential from 8.5 TWh to 6.1 TWh. The potential from sawmill wood waste is dropped by about half from 1.3 TWh to 0.7 TWh, and the potential from roadside debris is about the same from 2.8 TWh to 3.0 TWh. The changes are predominately driven by the reduced long term AAC forecasts as well as increased fibre demand resulting from bioenergy projects developed since the 2010 ROR study.
- There are significant volumes of lower-cost fibre (sawmill woodwaste and roadside woodwaste) potentially available for energy production at approximately 3.7 TWh/year equivalent on a Province-wide basis. Whether the full potential can be realized depends on how closely the economics forecasts of other related industries are to what was modeled, the geographical distribution of the fibre (i.e. whether it is economical to transport to potential power plants), the business strategy plan of the fibre holders and whether the amount of fibre available in any geographical pocket would sustain an economically sized plant.
- The energy potential from standing timber has added uncertainty compared to the lower-cost fibre in that the business strategy of licence and tenure holders and the additional cost and distance to harvest standing timber all contribute to uncertainty
- For the purposes of high level long term planning, the potential from woodwaste, roadside debris and pulp log for each region is aggregated as summarized in Table 5-2 and the cost reported reflects the weighted average. The potential and cost for standing timber are reported separately.

A summary of the technical and financial results for wood based biomass is presented in the Table 5-2.

Table 5-2 Summary of Wood Based Biomass Potential

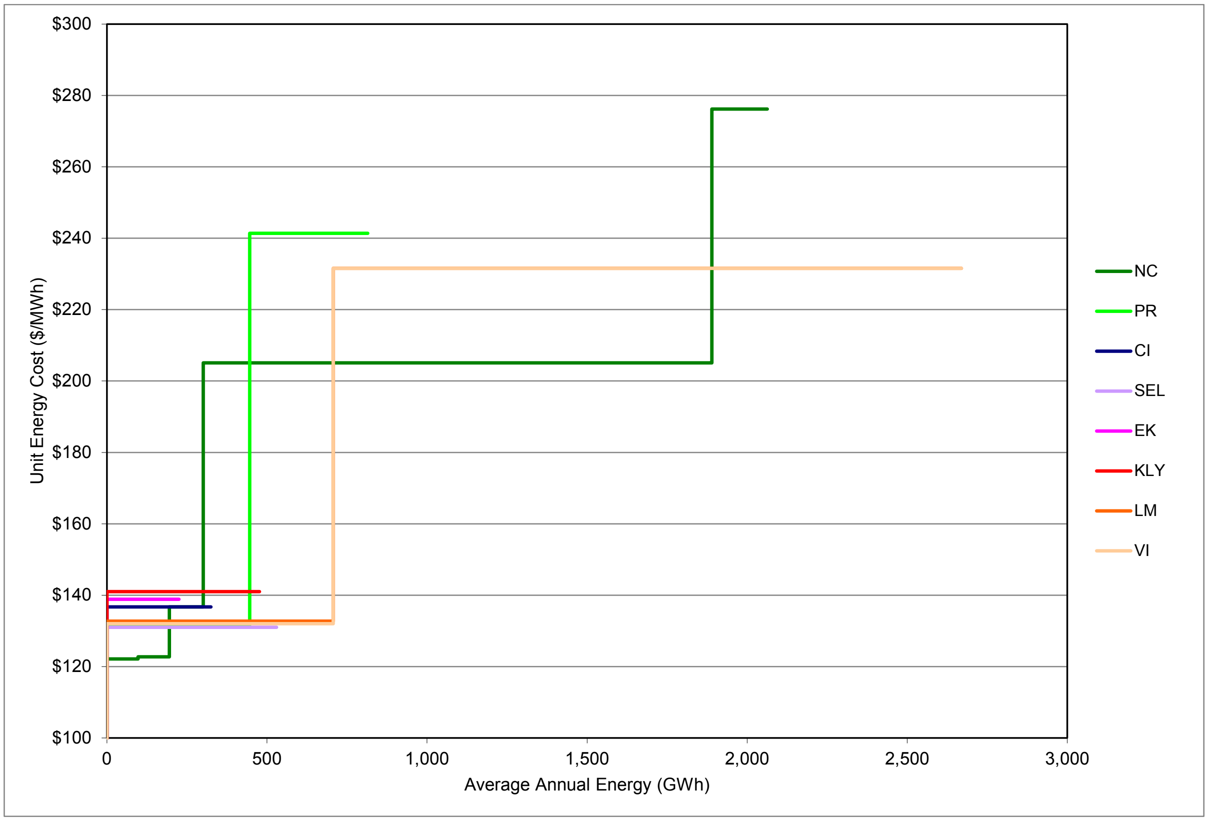
Transmission Region	Number of Projects	Installed Capacity (MW)	DGC (MW)	Annual Energy (GWh/yr)	Annual Firm Energy (GWh/yr)	UEC at POI Range ($2013/MWh)
Standing Timber						
Peace River	1	46	46	368	368	241
North Coast	2	221	221	1,762	1,762	205 - 276
Vancouver Island	1	246	246	1,962	1,962	232
Lower Mainland	1	246	246	1,962	1,962	232
Sub-Total	5	759	759	6,054	6,054	205 - 276
Roadside Debris & Woodwaste						
Peace River	1	56	56	446	446	132
North Coast	3	38	38	301	301	122 - 137
Central Interior	1	41	41	325	325	137
Kelly Nicola	1	60	60	476	476	141
Vancouver Island	1	89	89	707	707	132
Lower Mainland	1	89	89	707	707	133
Selkirk	1	66	66	530	530	131
East Kootenay	1	28	28	225	225	139
Sub-Total	10	467	467	3,718	3,718	122 - 141
Total	**15**	**1,226**	**1,226**	**9,772**	**9,772**	**122 - 276**

* For wood based biomass, this reflects the number of fiber delivery locations considered in the study. The MWs shown reflect the total generation that could be produced given the estimated fuel supply and may be done with multiple plants. In general, there is one fiber delivery location assumed for each forestry sub region unless the potential is small. The boundary of forestry sub regions and transmission regions do not align, as such, there can be more than one fiber delivery location within one transmission region.

The wood based biomass potential may be associated with existing industrial areas (e.g., woodwaste from sawmill sites) or with existing road and transmission infrastructures. A map showing the provincial distribution of the potential wood based biomass resource option is shown in Appendix 5.

The supply curves for the wood based biomass resource potential based on POI costs, by transmission region, are shown in Figure 5-3.

Figure 5-3 Wood Based Biomass POI Supply Curves



5.2.1.4 Environmental and Economic Development Attributes

The environmental attributes of the wood based biomass resources are presented in Appendix 2 and summarized in Appendix 3.

The economic development attributes of the wood based biomass resources are presented in Appendix 4 and summarized in Appendix 3.

5.2.1.5 Seasonality and Intermittence

Wood based biomass resources are a source of firm energy with insignificant seasonality and intermittence.

5.2.1.6 Earliest In-Service Date

General construction period and major capital spending for biomass projects happen over the course of two years. The earliest in-service date (**ISD**) for wood based biomass is assumed to be 2015.

5.2.1.7 Uncertainty

The biggest uncertainty regarding wood based biomass energy potential is long-term fuel availability.

Resource Option	Level of Study	Resource Type Related Uncertainty Rating	Cost Uncertainty Criteria
Roadside debris and sawmill Wood waste	Survey	Medium	Medium (-10 per cent / +40 per cent)
Standing timber	Survey	High	High (-10 per cent / +60 per cent)

5.2.2 Biomass – Biogas (Landfill)

The capital and OMA cost estimates have been increased by about 2 per cent. In the 2013 Update, the UECs are calculated at 7 per cent real cost of capital, and are presented in $2013.

5.2.2.1 Resource Description

Landfill gas (**LFG**) is created when organic waste in a municipal solid waste landfill decomposes under anaerobic conditions. This gas consists of approximately 50 per cent methane (the primary component of natural gas) and 50 per cent carbon dioxide (**CO_2**), as well as a small amount of other organic compounds.

Instead of escaping into the atmosphere, LFG can be captured, converted, and used as an energy source. Additional benefits of capturing the gas include the reduction of odours and other hazards associated with LFG emissions. The combustion of LFG helps prevent methane from migrating into the atmosphere and contributing to global climate change and local smog. The impact of methane as a greenhouse gas is about 21 times that of CO2.

LFG energy projects can convert LFG into useful energy forms such as electricity, steam, heat, vehicle fuel, or pipeline quality gas. The most common are:

- Direct use of medium-grade gas
- Power generation (medium grade)
- Upgrade to vehicle fuel or pipeline-quality gas (high-grade)

Technologies for producing electricity from LFG include internal combustion engines, gas turbines and microturbines.

- The **internal combustion engine (ICE)** is the most commonly used conversion technology in LFG applications, being used in more than 70 per cent of all existing LFG electricity projects. This is mainly due to their relatively low cost, high efficiency, and good size match with the gas output of many landfills. Normally, an ICE is suitable for sites where gas quantity can produce between 800 kW and 3 MW of electricity.
- **Gas turbines** are typically used in larger LFG energy projects, where LFG volumes are sufficient to generate a minimum of 3 MW, and typically more than 5 MW. This technology is competitive in larger LFG electric generation projects because, unlike most ICE systems, gas turbine systems have significant economies of scale. The cost per kW of generating capacity drops as gas turbine size increases, and the electric generation efficiency generally improves as well.
- **Microturbine** technologies are suitable when LFG availability is less than 300 cubic feet/minute (**cfm**), or when LFG has a low methane content (as little as 35 per cent). Microturbines can be added and removed as available gas quantities change. In general, microturbine projects are more expensive on a dollar-per-kW installed capacity basis than ICE projects.

5.2.2.2 Methodology

Power Potential

A 2008 report by Golder Associates[2] provides a thorough study of estimated methane generation, for the period 2012 to 2020, from all operating municipal solid waste (**MSW**) landfill sites under provincial jurisdiction with a disposal rate in 2006 greater than 10,000 tonnes/year. The study uses a simple modified first-order kinetic model to calculate methane production, based on three main factors: waste tonnage disposed each year, ultimate methane yield (**Lo**) and a methane generation rate constant (**k**). The methodology used to estimate methane generation for each landfill site is described in detail in the Golder Report.

The 2010 ROR only examines landfill sites with flow rates greater than 200 cfm, as landfill sites with low-flow rates are not likely to provide sufficient economic incentives for landfill owners to develop LFG projects.

Electricity potential is calculated by multiplying the total LFG heat content (**Btu**) by the heat rate of an electrical generator. Total LFG heat content is obtained by multiplying the heat content per tonne of methane by the average tonnes of methane generated per year. A typical ICE heat rate/efficiency is used to calculate the electricity generation for most of the landfill projects in this study. For landfill sites that have a lower flow rate (less than 300 cfm), a typical microturbine heat rate/efficiency is used.

A capacity factor of 0.9 is assumed in converting the MWh of generation potential into MW of capacity potential. The average annual energy takes into consideration the unit availability. Since LFG is considered relatively reliable, the dependable capacity is assumed to be 95 per cent of the installed capacity. Firm energy is

[2] Inventory of Greenhouse Gas Generation from Landfills in British Columbia, by Golder Associates, 2008. The model was developed as a tool to provide a high-level estimate of LFG generation for inventory purposes and not designed to address differences in site specific landfill waste composition or climatic conditions. More sophisticated LFG generation assessment models may exist that have the potential to produce more precise results based on accurate site specific input data.

assumed to be equal to annual average energy based on the assumption of steady fuel supply.

Cost

There is a wide range of variability in the capital cost of the recovery systems due to variations in site locations, Site Configurations and gas production ranges.

There are two major components of the cost estimates: 1) the capture and flare system (e.g., wells, blowers, flares) and 2) the electricity equipment (e.g., ICEs/gas turbines/microturbines, and gas treatment systems).

Capture and flare system assumptions:

- A typical medium size landfill Site Capture/flare system cost is used to calculate system costs for all projects. The cost is prorated according to LFG flow rate of each landfill site.
- Those landfill sites with existing capture/flare systems are evaluated in more detail. The capital/Operation and Maintenance (**O&M**) costs of these landfill sites are lower due to existing LFG capture systems and generally results in lower costs than LFG projects without existing capture/flare systems.
- Capture and flare system costs are based on information from the U.S. Environmental Protection Agency

Electricity equipment assumptions:

- A typical ICE cost is used to calculate the capital/O&M cost for most of the projects (e.g., $2300/kW times the project capacity)
- A typical microturbine cost is used to calculate the capital/O&M cost for the projects with lower LFG flow rates (e.g., less than 300 cfm)
- Natural gas turbines are not used or evaluated in this study since the project sizes are likely to be less than 4 MW

Main Assumptions:

- The electrical generation facility size is assumed to be constant
- Methane heat content is assumed to be 53.4 MMBtu/tonne CH_4
- ICE heat rate is assumed to be 11.7 MMBtu/MWh
- LFG recovery rate is assumed to be 75 per cent

5.2.2.3 Technical and Financial Results

A summary of the technical and financial results for biogas is presented in Table 5-3.

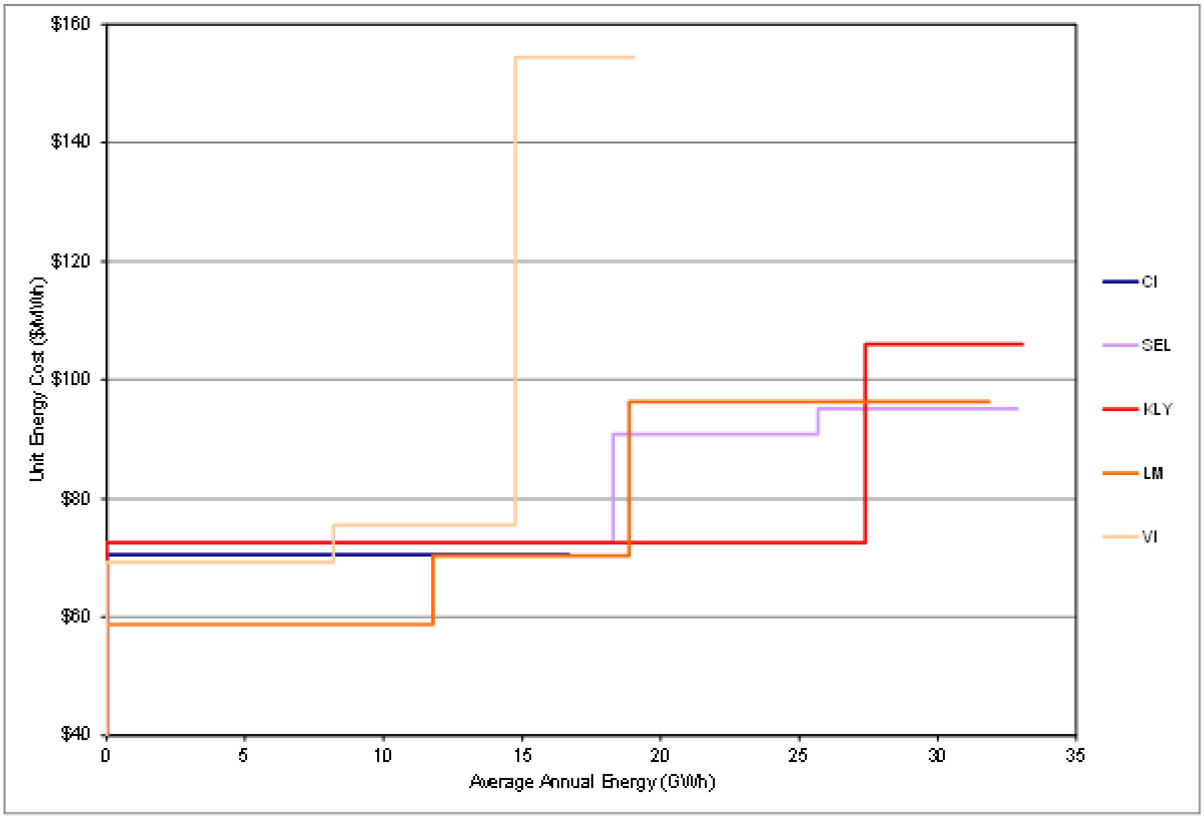
Table 5-3 Summary of Biogas Potential

Transmission Region	Number of Projects	Installed Capacity (MW)	DGC (MW)	Annual Energy (GWh/yr)	Annual Firm Energy (GWh/yr)	UEC at POI Range ($2013/MWh)
Central Interior	1	2	2	17	17	70
Kelly Nicola	2	4	4	33	33	73 - 106
Vancouver Island	3	2	2	19	19	69 - 154
Lower Mainland	3	4	4	32	32	59 - 96
Selkirk	3	4	4	33	33	73 - 95
Total	**12**	**17**	**16**	**134**	**134**	**59 - 154**

A map showing the provincial distribution of the potential biogas resource option is shown in Appendix 5.

The supply curves for biogas resource potential based on POI costs, by transmission region, are shown in Figure 5-4.

Figure 5-4 Biogas POI Supply Curves



5.2.2.4 Environmental and Economic Development Attributes

The environmental attributes of the biogas resources are presented in Appendix 2 and summarized in Appendix 3.

The economic development attributes of the biogas resources are presented in Appendix 4 and summarized in Appendix 3.

5.2.2.5 Earliest In-Service Date

The earliest ISD for biogas is estimated to be 2014.

5.2.2.6 Seasonality and Intermittence

Though there may be variations in biogas release associated with the level of moisture in the landfill, for planning purposes, biogas resources are considered to be a source of firm energy with insignificant seasonality and intermittence.

5.2.2.7 Uncertainty

Resource Option	Level of Study	Resource Type Related Uncertainty Rating	Cost Uncertainty Criteria
Biogas	Pre-feasibility	Medium	High (-10 per cent / +60 per cent)

5.2.3 Biomass – Municipal Solid Waste

For the 2013 ROR Update, the cost assumptions have been updated to 2013 numbers, the UECs are calculated at 7 per cent real cost of capital, and the sizing of the Lower Mainland waste-to-energy **(WTE)** facility has been adjusted to be in line with the size of WTE facility being studied by Metro Vancouver. Tipping fees for the various regional districts are based on the latest available estimates. All other inputs and analysis assumptions are identical to what were used in the 2010 ROR.

5.2.3.1 Resource Description

Biomass - MSW refers to the conversion of MSW into a usable form of energy, such as heat or electricity. This process is commonly referred to as waste-to-energy. For the purpose of this ROR, only conversion of waste into electricity is considered. Four main technologies are available for energy recovery: conventional combustion, gasification, pyrolysis, and plasma arc gasification. Of these four technologies, conventional combustion and gasification are the most commonly used MSW technologies. The following provides a brief description for each of these technologies.

- **Conventional combustion:** Mass burn incineration is the most common form of conventional combustion. Minimal pre-processing of the waste is required for this process. The MSW is sorted to remove oversized and non-combustible items as well as hazardous or explosive materials, and then fed into an incinerator where it is supported on a grate or hearth. Secondary air is added into the combustion chamber to promote combustion. The resulting bottom ash is considered non-hazardous, and is deposited at municipal landfills. Fly ash is captured by air pollution control equipment, and usually requires stabilization before it can be deposited in a municipal landfill. Mass burn incineration is considered to be a proven technology, with over 400 plants in Europe, processing approximately 50 million tonnes of waste per year[3]. A mass burn incineration facility has existed in Burnaby since 2003. This facility processes approximately 280,000 tonnes of MSW per year, and delivers 15 MW of firm capacity. Mass burn facilities can vary in capacity from approximately 36,500 to 365,000 tonnes per year. Typical energy recovery efficiencies for mass burn facilities range from 14 per cent to 27 per cent if the recovered energy is being converted into electricity. Higher energy recovery efficiencies are achieved if heat recovery is taken into account.

- **Standard gasification:** In this process, organic fuel is partially combusted under starved air conditions to generate a synthetic gas, or syngas. The syngas is then cleaned and burned in a second combustion process to produce heat and/or electricity. Standard gasification systems typically require homogenous fuel, and hence extensive pre-processing of the MSW is required which raises costs and requires energy input into the process. Several gasification plants are operating commercially in Japan, with none in Europe or in North America. Gasification plants can range in size from 40,000 to 100,000 tonnes per year[4].
- **Pyrolysis:** Pyrolysis is similar to gasification except for the source of heat. Gasification uses the heat from the waste generated inside the reaction chamber whereas pyrolysis uses an external source of heat to drive the process. There are several facilities using pyrolysis in Japan.
- **Plasma arc gasification:** In this process, waste is transformed into a syngas using extremely high temperatures in an oxygen-starved environment. The high temperatures (from 5,000 to 15,000°C) are due to a thermal plasma field

[3] Management of Municipal Solid Waste in Metro Vancouver – A Comparative Analysis of Options for Management of Waste after Recycling, AECOM Canada Ltd., June 2009.

[4] Waste to Energy: A technical Review of Municipal Solid Waste Thermal Treatment Practices, prepared by Stantec, August 2010.

created by directing an electric current through a low pressure gas stream. Plasma arc gasification has attributes similar to standard gasification. An advantage is that the much higher heat destroys all organic contaminants and vitrifies the slag into a reusable aggregate-like substance. The disadvantage is the higher energy requirements to create and maintain the plasma. There are two pilot projects using plasma technology underway in Canada, but there are currently no commercial scale units operational in Europe or North America.

5.2.3.2 Methodology

A generalized methodology is used for the MSW resource option, whereby the potential is estimated based on fuel source availability. In determining the fuel source availability, an attempt was made to incorporate the 'Zero Waste' philosophy which tries to minimize the amount of waste that has to be landfilled through waste avoidance and diversion. Zero Waste has been adopted or is being considered by a number of regional districts. Since WTE facilities require a guaranteed fuel source, potential WTE facilities were sized conservatively so as to not interfere with efforts to implement waste avoidance and diversion strategies.

To estimate the fuel source availability for individual regional districts, MSW tonnage numbers were obtained from the 2006 B.C. MSW Tracking Report and extrapolated to 2010 numbers based on population growth rates obtained from B.C. Statistics. In this extrapolation, the disposal (i.e., recycling) rates per capita were assumed to remain at 2006 levels since no significant or consistent trends were evident in the 2006 report. For regional districts which did not participate in the 2006 B.C. MSW Tracking Report, data were obtained from regional district waste management plans where available, and again adjusted to 2010 numbers.

For each regional district, a 25-year forecast in MSW tonnage was created by using the B.C. Statistics population forecast for each regional district, as well as assuming that the per capita disposal rate would linearly decrease by 6.7 per cent per year between 2010 and 2015. This decrease in disposal rate is similar to what would be required to increase the diversion rate from 55 per cent to 70 per cent over a five-year period, as planned by Metro Vancouver. The individual MSW tonnage forecasts were then aggregated for each year to form three larger regional entities for which the transport of MSW would not exceed 350 km. The three regions that were considered are:

- **Vancouver Island**, consisting of the regional districts of Alberni Clayoquot, Capital, Comox Strathcona, Cowichan Valley, Nanaimo and Powell River.
- **Lower Mainland**, consisting of the regional districts of Fraser Valley, Metro Vancouver, Squamish Lillooet and Sunshine Coast.
- **Okanagan**, consisting of the regional districts of Central Okanagan, North Okanagan, Okanagan-Similkameen, and Thompson-Nicola.

Finally, to ensure a firm fuel source supply and to potentially allow for more aggressive waste avoidance/reduction strategies, two-thirds of the minimum annual MSW tonnage forecasted over the 25-year period was used to determine the sizing of a WTE facility in each of the three regions.

Based on the approach described above, the MSW fuel potential for each of the three regions was estimated as follows:

Region	MSW (tonne/year)
Vancouver Island	178,000
Lower Mainland	772,300
Okanagan	197,000

It should be noted that Metro Vancouver has gone through an extensive consultation and study process and is presently proposing a 370,000 tonne/year WTE facility[5]. The minimum estimated MSW potential for the Lower Mainland (prior to the one-third reduction) compares well with the forecasted MSW tonnage by Metro

5 http://www.metrovancouver.org/SERVICES/SOLIDWASTE/PLANNING/RECOVER/Pages/Capacity.aspx

Vancouver[6] (1,158,000 versus 1,125,000). The 370,000 tonne/year WTE facility suggested by Metro Vancouver hence represents a more conservatively sized facility than what the estimated available MSW fuel potential would allow. For consistency, Metro Vancouver's proposal for a 370,000 tonne/year WTE facility for the Lower Mainland was adopted for this analysis.

The following assumptions were made:

- At least 100,000 tonnes of MSW are required to make a WTE facility economically feasible
- Each facility will use mass burn combustion technology, and will be optimized for electricity generation
- The analysis does not include utilization of waste heat as this is very location dependent. It is recognized that the exclusion of waste heat utilization results in less cost-effective WTE facilities. The analysis also does not take into account additional electricity savings that would occur due to space heating being offset by waste heat. It is believed, however, that the impacts on DSM savings are of second order.
- Each WTE facility is assumed to be located in-region
- Waste composition and energy conversion efficiency are assumed to be the same for each region. A conversion factor of 0.6 MWh/tonne is used for all facilities.
- Each plant will operate at 100 per cent capacity at all times. Availability is assumed to be 95 per cent (same as Burnaby WTE plant), and 97 per cent is used to determine dependable generating capacity (**DGC**).

[6] Management of Municipal Solid Waste in Metro Vancouver – A Comparative Analysis of Options for Management of Waste After Recycling, prepared by AECOM Canada Ltd., June 2009.

Capital and O&M costs are based on estimates by Ramboll (2007)[7] which have been adjusted to January 1, 2013 numbers, and are modelled as functions of WTE plant size.

WTE Plant Size (tonne/year)	Capital Cost ($/tonne)	O&M Cost ($/tonne)
178,000	1,165	81
370,000	1,034	64
197,000	1,148	75

The following tipping fees were assumed for the three regions: $117/tonne for Vancouver Island, $107/tonne for the Lower Mainland, and $72/tonne for the Okanagan. These numbers were based on the latest tipping fee estimates available for the various regional districts. In addition, it was assumed that 2.8 per cent of the incinerated MSW tonnage would be recovered metal[8], which then could be sold to offset the O&M costs. A scrap metal price of $180/tonne was assumed for this analysis.

5.2.3.3 Technical and Financial Results

A summary of the technical and financial results for MSW are contained in Table 5-4.

[7] Memo to MacViro during the Durham/York Environmental Assessment. Reported in Waste Energy - A Technical Review of Municipal Solid Waste Thermal Treatment Practices – Final Report, prepared by Stantec, August 2010.

[8] Based on metal recovery from the Burnaby Incinerator. Personal communication with Chris Allan, Senior Engineer, Metro Vancouver - Solid Waste Department.

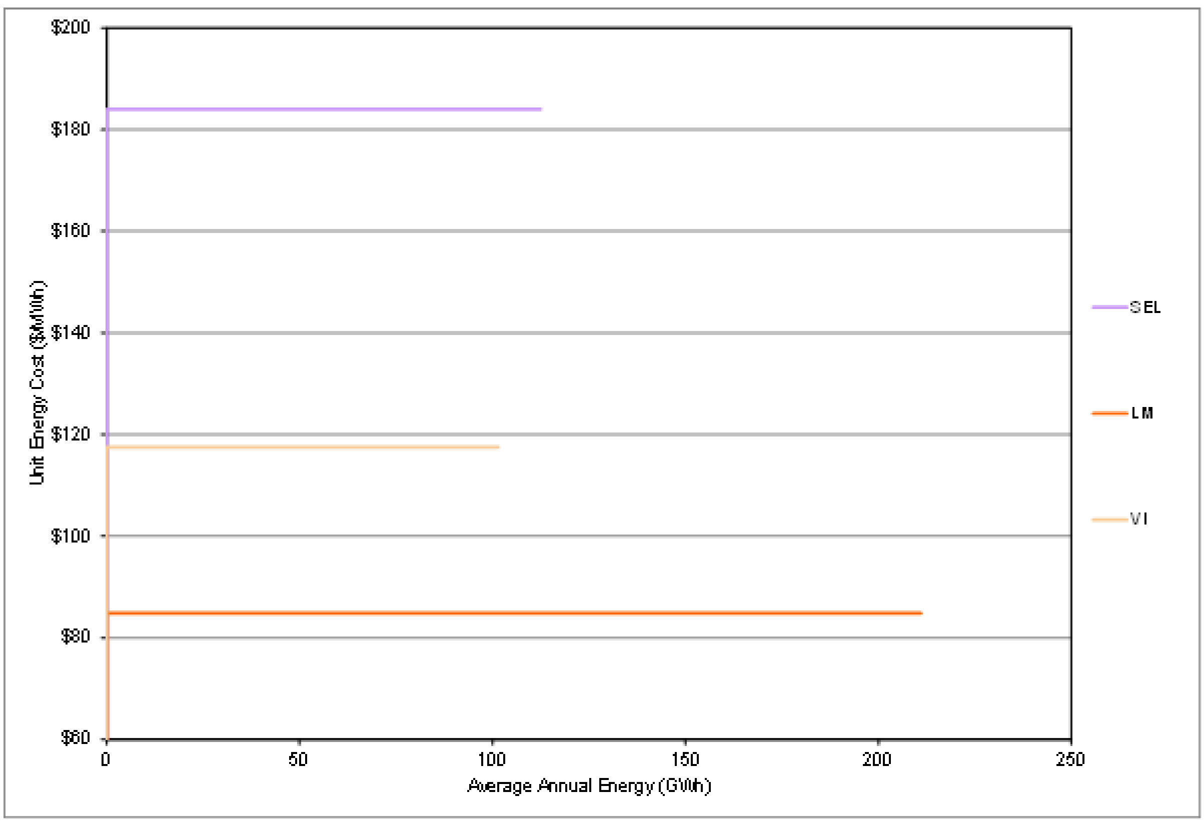
Table 5-4 Summary of MSW Potential

Transmission Region	Number of Projects	Installed Capacity (MW)	DGC (MW)	Annual Energy (GWh/yr)	Annual Firm Energy (GWh/yr)	UEC at POI Range ($2013/MWh)
Vancouver Island	1	12	12	101	101	117
Lower Mainland	1	25	25	211	211	85
Selkirk	1	14	13	112	112	184
Total	**3**	**51**	**50**	**425**	**425**	**85 - 184**

A map showing the provincial distribution of the potential MSW resource option is shown in Appendix 5.

The supply curves for MSW resource potential based on POI costs, by transmission region, are shown in Figure 5-5.

Figure 5-5 Biomass MSW POI Supply Curves



5.2.3.4 Environmental and Economic Development Attributes

The environmental attributes of the biomass MSW resources are presented in Appendix 2 and summarized in Appendix 3.

The economic development attributes of the biomass MSW resources are presented in Appendix 4 and summarized in Appendix 3.

5.2.3.5 Earliest In-Service Date

The earliest ISD for biomass MSW is 2018.

5.2.3.6 Seasonality and Intermittence

Biomass MSW resources are a source of firm energy with insignificant seasonality or intermittence.

5.2.3.7 Uncertainty

Resource Option	Level of Study	Resource Type Related Uncertainty Rating	Cost Uncertainty Criteria
Municipal Solid Waste	Pre-feasibility	Medium	High (-10 per cent / +60 per cent)

5.2.4 Onshore Wind

The onshore wind resource option has been updated to reflect the most recent trends in turbine efficiencies and pricing. The UECs in the 2013 Update are calculated at 7 per cent real cost of capital, and are presented in $2013.

5.2.4.1 Resource Description

Wind power refers to the conversion of kinetic energy from moving air into electricity. Modern utility-scale wind turbines are horizontal axis machines with three rotor blades. The blades convert the linear motion of the wind into rotational energy that then is used to drive a generator. Wind generation facilities can be placed on land or on the substrate in water, either in the ocean or possibly in lakes. The onshore and offshore wind assessments are undertaken separately because of the differences in methodologies used to assess the resource potential as well as differences in the financial cost assumptions.

5.2.4.2 Methodology

For the 2010 Resource Options Report, the onshore wind resource potential and costs were based on the following studies:

- BC Hydro Wind Data Study (DNV Global Energy Concepts Inc., April 2009)
- BC Hydro Wind Data Study Update (DNV Global Energy Concepts Inc., September 2009)
- Updated Capital and O&M Cost Assumptions for Wind Power Development in British Columbia (November 2010, Garrad Hassan) (Appendix 7)

These studies were completed as considerable changes in turbine efficiencies and turbine pricing were taking place. Due to an inherent time delay in capturing current data, these changes were not reflected in the studies provided to BC Hydro. The following updates have been made to capture the more recent trends in turbine efficiencies and pricing:

- **Wind turbine efficiencies:** BC Hydro commissioned DNV-KEMA in May 2012 to provide a wind turbine power curve for International Electrotechnical Commission (**IEC**) Class III wind sites (corresponding to low average wind speeds) and to update the power curves for IEC Class I and II wind sites (corresponding to high and medium average wind speeds, respectively). The three wind power curves were developed by blending wind turbine power curves for a number of recent and current turbine models for each of the three IEC classes. The new power curves were then applied to the modelled wind speeds from the original BC Hydro Wind Data Study to create new hourly generation profiles for each wind project. No changes were assumed for turbine hub heights, installed wind capacity of the individual wind projects or wind farm losses. With the application of the revised power curves, the annual net energy production increased on average by 13 per cent for IEC Class I wind projects, 6 per cent for IEC Class II wind projects, and 18 per cent for IEC Class III wind projects.

- **Wind turbine prices:** Over the past decade, wind turbine prices have undergone considerable changes. Turbine prices steadily increased from 2002 to 2009. Turbine prices peaked in the first half of 2009, but have dropped since then by approximately 20 to 30 per cent. The trends in turbine prices have been detailed in a number of reports. The increase in turbine prices has been attributed to increased material and labour costs, upscaling of turbine size, decline in the U.S. dollar relative to the Euro, increased costs in turbine warranty provisions, and a general increase in turbine manufacturer profitability due in part to a strong demand growth and turbine and component supply shortages. The decline in wind turbine prices since 2009 has coincided with the downturn in the global economic situation. The reduced turbine demand has increased competition among manufacturers, and shifted the turbine market from a seller’s market to a buyer’s market. The current wind turbine prices are forecasted to persist through 2015, but it is uncertain if the low sale margins can be maintained by the manufacturers in the long term. Improved efficiencies in the manufacturing process, continued technical advancements, and potential competition from Chinese turbine manufacturers may help keep turbine prices low in the future. At the same time, resurgence in wind turbine demand, resulting in supply chain pressures similar to those observed between 2004 and 2009, could counter the cost reductions and increase wind turbine prices. In light of these uncertainties, BC Hydro has decreased the wind turbine price by 15 per cent from the original assumption used in the 2010 Resource Options Report.

5.2.4.3 Technical and Financial Results

A summary of the technical and financial results for onshore wind is contained in Table 5-5.

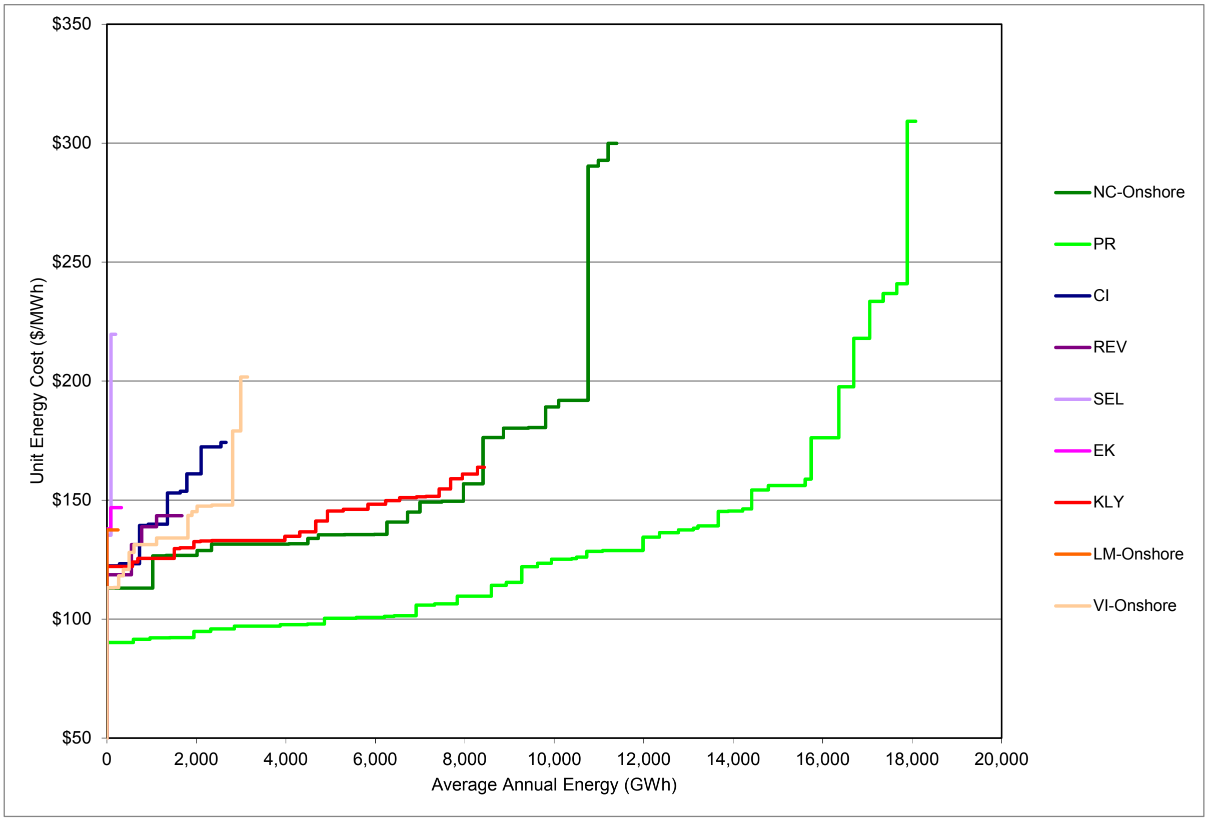
Table 5-5 Summary of Onshore Wind Potential

Transmission Region	Number of Projects	Installed Capacity (MW)	ELCC (MW)	Annual Energy (GWh/yr)	Annual Firm Energy (GWh/yr)	UEC at POI Range ($2013/MWh)
Peace River	45	5,864	1,525	18,083	18,083	90 - 309
North Coast	23	4,085	1,062	11,400	11,400	113 - 300
Central Interior	9	1,049	273	2,660	2,660	122 - 174
Kelly Nicola	22	3,363	874	8,437	8,437	122 - 164
Revelstoke	4	644	167	1,674	1,674	119 - 143
Vancouver Island	13	1,111	289	3,143	3,143	113 - 202
Lower Mainland	1	90	23	249	249	137
Selkirk	2	83	22	194	194	135 - 220
East Kootenay	2	138	36	324	324	138 - 147
Total	**121**	**16,425**	**4,271**	**46,165**	**46,165**	**90 - 309**

A map showing the provincial distribution of the potential onshore wind resource option is shown in Appendix 5.

The supply curves for onshore wind resource potential based on POI costs, by transmission region, are shown in Figure 5-6.

Figure 5-6 Onshore Wind POI Supply Curves



5.2.4.4 Environmental and Economic Development Attributes

The environmental attributes of the onshore wind resource are presented in Appendix 2 and summarized in Appendix 3.

The economic development attributes of the onshore wind resources are presented in Appendix 4 and summarized in Appendix 3.

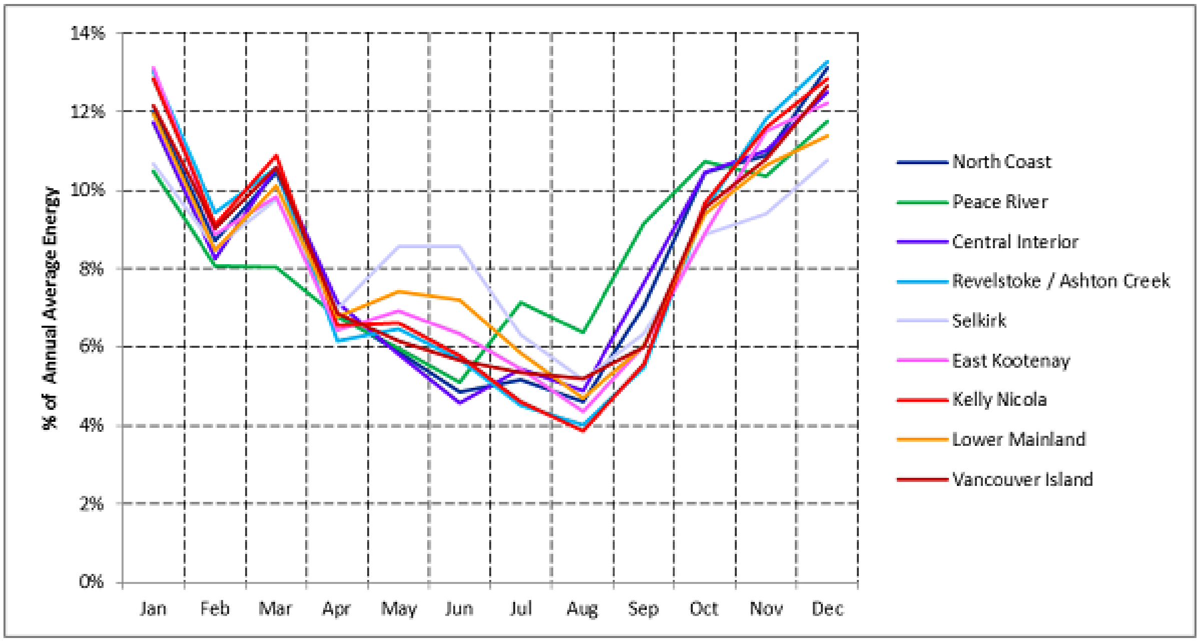
5.2.4.5 Earliest In-Service Date

The earliest ISD for additional onshore wind generation is 2018.

5.2.4.6 Seasonality and Intermittence

The seasonality of onshore wind resources is shown in Figure 5-7 for each of the transmission regions. Onshore wind is considered to be an intermittent resource.

Figure 5-7 Normalized Monthly Onshore Wind Energy Profiles by Transmission Region



5.2.4.7 Uncertainty

Resource Option	Level of Study	Resource Type Related Uncertainty Rating	Cost Uncertainty Criteria
Onshore Wind	Pre-feasibility	Low	Medium (-10 per cent / +40 per cent)

5.2.5 Offshore Wind

For this ROR, the turbine nameplate capacity for the offshore wind resource option has been increased to reflect the current global trend in offshore wind turbine sizing, as well as an updated power curve has been applied to estimate the annual energy production. In the 2013 Update, UECs are calculated at 7 per cent real cost of capital; all other cost assumptions are identical to what were used in the 2010 ROR, and cost estimates are presented in $2013.

5.2.5.1 Resource Description

The following section evaluates the potential to generate electricity with offshore wind turbines located in ocean substrate depths of up to 40 m.

5.2.5.2 Methodology

The analysis is based on averaged wind speeds at 80 m hub height from the Canadian Wind Atlas, and gridded bathymetric data provided by the Canadian Hydrological Services. Modelled wind speeds from the Canadian Wind Atlas were compared to long-term wind speed estimates based on actual offshore observations. As a result of this comparison, the modelled wind speeds of the Canadian Wind Atlas were adjusted upward by 0.6 m/s.

To identify potential project locations, the following criteria were used:

- 80-m wind speeds ≥ 8 m/s
- Water depth ≤ 40 m
- Area size of project ≥ 14.5 km2. This equates to a minimum project size of 83.5 MW, based on a turbine nameplate capacity of 3.6 MW, and a turbine density of 1.6 turbines/km2

A GIS analysis was performed to delineate the potential project areas, and for each project, the percentage of area for three water depth intervals (0 m to 20 m, 20 m to 30 m, and 30 m to 40 m) was determined. In the delineation process, the maximum project area size was limited to 83 km^2 (or 478 MW), and projects greater than 83 km^2 were split into smaller projects. In addition, a buffer zone of 14 km along the dominant wind direction and 5 km perpendicular to the dominant wind direction was implemented. Screens for legally protected areas were applied as described in Table 5-1.

To estimate the installed capacity and the annual energy production, the following assumptions were made:

- Turbine density of 1.6 turbines/km2
- Generic IEC Class I turbine with a nameplate capacity of 3.6 MW

- Power curve for a generic IEC Class I turbine, assuming an air density of 1.25 kg/m3
- Total (excluding transmission) loss factor of 18.5 per cent
- Weibull distribution with a shape factor of 2.0

The average annual energy was determined using the same methodology as applied in the BC Hydro Wind Data Study Update. Representative costs for offshore wind projects as a function of water depth were provided by Garrad Hassan (Appendix 7), and water depth was taken into account in the UEC calculations. It should be noted that the cost estimates provided by Garrad Hassan assume a certain level of constructability. Factors such as seabed substrate or wave heights, which can have impacts on costs, have not been considered.

5.2.5.3 Technical and Financial Results

A summary of the technical and financial results for offshore wind are contained in Table 5-6.

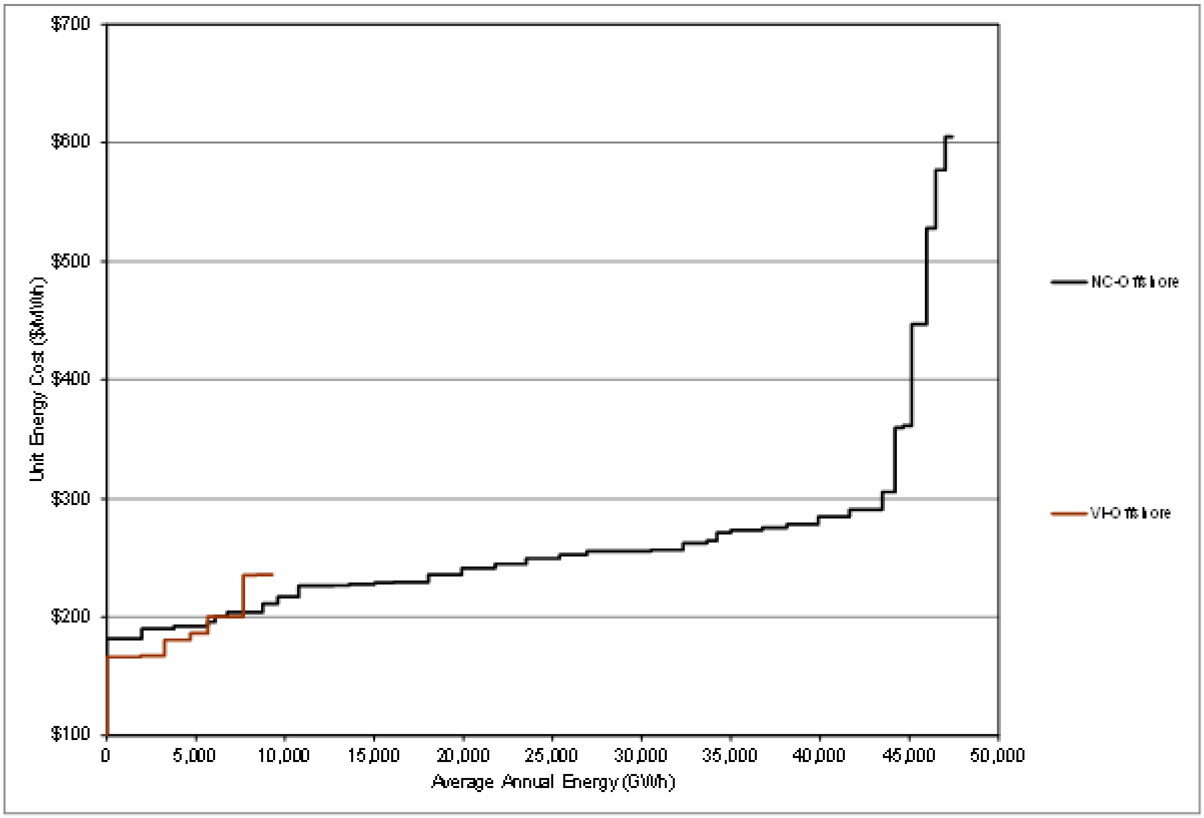
Table 5-6 Summary of Offshore Wind Potential

Transmission Region	Number of Projects	Installed Capacity (MW)	ELCC (MW)	Annual Energy (GWh/yr)	Annual Firm Energy (GWh/yr)	UEC at POI Range ($2013/MWh)
North Coast	36	12,319	3,203	47,397	47,397	182 - 605
Vancouver Island	7	2,369	616	9,303	9,303	166 - 236
Total	**43**	**14,688**	**3,819**	**56,700**	**56,700**	**166 - 605**

A map showing the provincial distribution of the potential offshore wind resource option is shown in Appendix 5.

The supply curves for offshore wind resource potential based on POI costs, by transmission region, are shown in Figure 5-8.

Figure 5-8 Offshore Wind POI Supply Curves



5.2.5.4 Environmental and Economic Development Attributes

The environmental attributes of the offshore wind resources are presented in Appendix 2 and summarized in Appendix 3.

The economic development attributes of the offshore wind resources are presented in Appendix 4 and summarized in Appendix 3.

5.2.5.5 Earliest In-Service Date

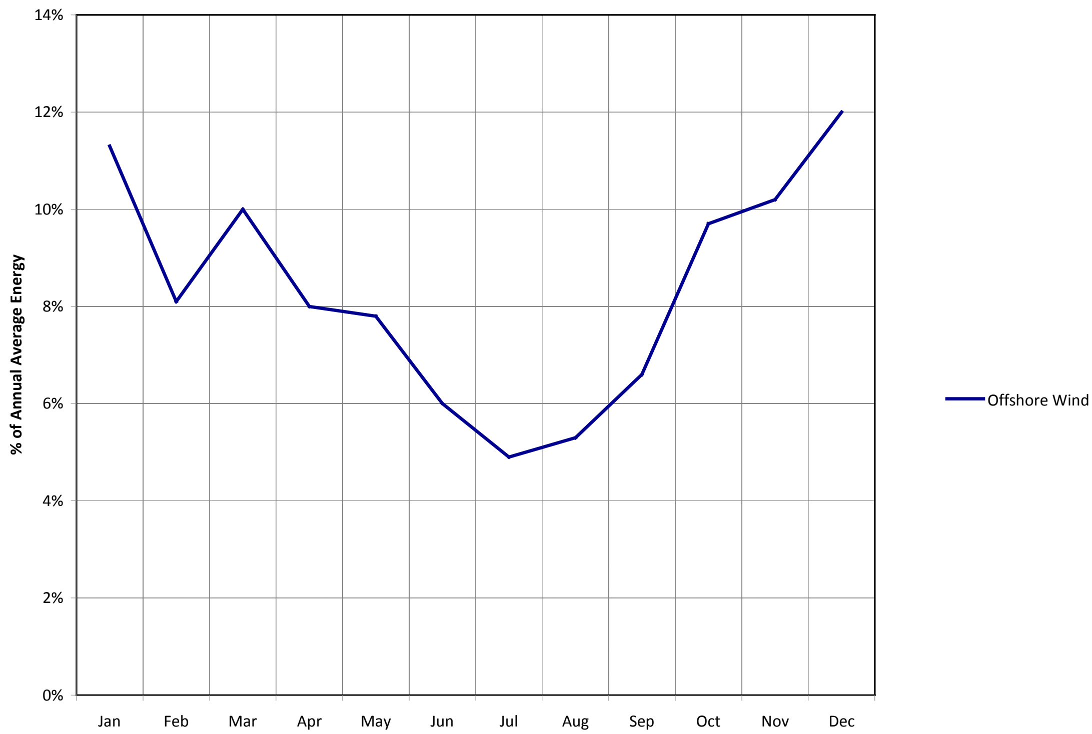
The earliest ISD for additional offshore wind generation is 2019.

5.2.5.6 Seasonality and Intermittence

As presented in Figure 5-9, the offshore wind generation potential is assumed to possess the same seasonal characteristics as the offshore project modelled in the

BC Hydro Wind Data Study. Offshore wind is considered to be an intermittent resource.

Figure 5-9 Normalized Monthly Offshore Wind Energy Profile



5.2.5.7 Uncertainty

Resource Option	Level of Study	Resource Type Related Uncertainty Rating	Cost Uncertainty Criteria
Offshore Wind	Pre-feasibility	Medium	High (-10 per cent / +60 per cent)

5.2.6 Geothermal Potential

The cost parameters used in the 2010 ROR are adjusted to account for the challenging geographical conditions of B.C. sites and the higher risk of failed wells for B.C. greenfield sites. In the 2013 Update, the UECs are calculated at 7 per cent real cost of capital, and are presented in $2013.

The cost estimates presented in the 2010 ROR were based on the GeothermEx assessment. For the 2013 ROR Update, BC Hydro reviewed a number of external studies to develop its cost assessment. Cost parameters were first assigned based on a high-level review of published costs for new geothermal projects globally, and then adjusted to account for: 1) the challenging geographical conditions of B.C. sites (i.e., higher equipment deployment costs due to the remoteness and difficult terrain); and 2) the higher risk of failed wells for B.C. greenfield sites relative to expansion projects of well-understood geothermal reservoirs (i.e., higher drilling costs due to B.C.'s resources not being previously characterized through exploration and development). It should be noted that even with these adjustments, given the high risks and challenges associated with the three stages of the development of geothermal resources – and in particular production and re-injection drilling – the estimates shown may not actually result in operational facilities.

5.2.6.1 Resource Description

Geothermal energy systems draw on natural heat from within the Earth's crust to drive conventional power generation technologies. The primary source of geothermal energy is radioactive decay occurring deep within the Earth, supplemented by residual heat from the Earth's formation and heat generated by the Earth's gravitational forces pulling dense materials into the Earth's core.

The majority of existing geothermal power plants draw energy from reservoirs of gaseous or liquid water in permeable rock located at depths of up to 3,500 m. These hydrothermal reservoirs, which are subdivided into vapour and liquid-dominated resources depending on whether primarily steam or liquid water is present, are the result of heat transfer to local aquifers from geologically active high-temperature belts located relatively close to the Earth's surface. To date, most geothermal plants have been sited in areas with high subsurface temperatures, high rock permeability, and a naturally occurring water-steam resource.

For electric power production from new conventional hydrothermal resources, geothermal reservoirs are tapped by drilling production wells, typically greater than 15 cm in diameter and up to 6,500 m in depth. Several production wells spaced 200 m to 500 m apart, each having net capacities of 2 MW to 10 MW, are connected by steam lines to a central power plant. Condensate from the power plants is distributed to injection wells, returning the fluid volume to the underground reservoir. Existing conventional hydrothermal operations that supply electrical power in the western United States typically vary in size from 10 MW to 260 MW.

For reservoirs filled with naturally occurring pressurized dry steam, a simple direct-steam power plant consists of pipes directly connecting the production wells to a turbine to generate electricity. Turbine exhaust is usually run through a condenser, turning the steam into liquid that is returned to the reservoir in injection wells. No dry steam resources have been found in Canada, and are thought to be rare outside of the geyser formations in the southern U.S.

For high-temperature (above 180°C) fluid-dominated reservoirs, a flash-steam power plant uses an intermediary vessel to vaporize a portion of the reservoir fluid drawn up from the production well before it is dried and passed through a conventional steam turbine at the power house. The un-vaporized liquid, also known as brine, is combined with the condensate from the turbine and re-injected into the reservoir. Some flash plants can repeat the vaporizing stage and introduce steam into a low pressure turbine in order to extract more energy before it is returned to the reservoir.

For moderate temperature systems (120°C to 170°C), binary-cycle power plants are used, whereby the geothermal fluid produced is put through a heat exchanger in which a secondary working fluid with a low boiling temperature, such as iso-butane, benzene or propane, is vaporized. The gaseous working fluid is passed through a specially designed turbine to generate electricity, liquefied in a condenser, and returned to the heat exchanger to again vaporize when heated by new geothermal fluids. Spent geothermal fluid is commonly returned into reservoir through injection wells.

Beyond conventional hydrothermal resources, three other types of geothermal resources are often considered suitable for power generation. Co-produced fluids refer to the hot water that accompanies oil and gas produced from deep wells in hydrocarbon fields. Collecting and passing the hot fluid through a binary-cycle power plant may be relatively inexpensive by piggybacking on existing infrastructure and eliminating the need for new drilling. The oil and gas development in Northeast B.C. has resulted in many deep but relatively slim wells, as well as some data on the temperature and flow of geothermal fluids. The potential for co-produced fluids or binary geothermal generation in Northeast B.C. is being currently assessed. Co-produced fluids will not be considered in the 2013 ROR Update pending completion of the Northeast B.C. resource assessment. Also accompanying some oil and gas operations in sedimentary basins are geo-pressured fluids composed of hot pressurized brine containing dissolved methane. The heat and the pressure in the fluids can be used to drive electrical generation equipment, while piggybacking on the existing oil and gas infrastructure to make development of geo-pressured resources cost-effective. The presence of geo-pressured fluid resources is unknown in B.C., and hence it is not considered at this time.

Finally, Hot Dry Rock (**HDR**) resources are found in areas offering sufficient heat for power generation but lacking an in situ water-steam supply and/or permeability of the geology. HDR is the most abundant and widely distributed geothermal resource, but bringing to the surface the heat energy locked in rock formations up to 10 km deep involves subsurface fracturing of impermeable rock, followed by the pumping of surface water or groundwater into the fractured area to create an artificial reservoir. Once the artificial reservoir has been proven sufficiently porous to allow water to permeate the rock structure and to absorb heat, and at the same time to retain a sufficient volume of heated water without it dissipating into the earth, pumped surface or ground water can then be delivered to a binary-cycle power plant via a production well. The Enhanced Geothermal Systems (**EGS**) required to tapping into HDR resources are currently in the early phases of development. Due to the largely speculative timeline for the technical viability of HDR-based systems, they were not considered in this report.

For reasons stated above, only conventional hydrothermal resources using flash or binary technologies are considered within the scope for the assessment in the 2013 ROR Update. Nonetheless, it bears mentioning that there may be potentially significant co-produced fluid and HDR resources in B.C. that could increase the potential geothermal resource base of British Columbia.

5.2.6.2 Methodology

There have been historical efforts to collect data on the hydrothermal resource potential in B.C. – notably at Mount Meager by the National Geothermal Energy Program and subsequent private developers. The Geological Survey of Canada published the Geothermal Energy Resource Potential of Canada in 2011 to summarize data collection and analysis from the 48 years of geothermal research led by the National Geothermal Energy Program. The primary conclusion of the report states: "Canada's in-place geothermal power exceeds one million times Canada's current electrical consumption. However, only a fraction of this total potential could be developed."

B.C.'s geothermal potential is illustrated in the map "Geothermal Resources of British Columbia" (Fairbank and Faulkner 1992) that integrates the known elements of the B.C. resource. The map indicates 18 general areas of low, moderate and high temperature geothermal potential throughout the province. These areas include the Garibaldi Volcanic Belt, Pemberton Belt, Harrison Lake area, Okanagan Valley, Low Arrow Lake area, Kootenay Lake area, Southern Rocky Mountain Trench, Upper Arrow Lake area, Valemount area, Hudson's Hope area, Northeast British Columbia Thermal Anomaly, Liard River area, the Stikine Volcanic Belt, Mount Edziza area, Lakelse Lake, Gardener Canal area, King Island area and the Anahim Volcanic Belt.

A summary of the research to date is articulated in the Geothermal Potential of the Cordillera (Jessop 2008): "The geothermal resource base is very large, but the difference between the resource base and the usable resource is also very large."

The electric power generation potential from a usable resource depends on the thermal energy present in the reservoir, the amount of thermal energy that can be extracted from the reservoir at the wellhead, and the efficiency with which that wellhead thermal energy can be converted to electric power. The challenge in the resource assessment lies in quantifying the size and thermal energy of a reservoir as well as the constraints on extracting that thermal energy. In B.C., there has been relatively little targeted geothermal exploration to confirm the thermal properties of geothermal reservoirs or understand the constraints on bringing hot fluid from the reservoir to the surface.

Estimates of the near-term geothermal generation potential in B.C. have been conducted by GeothermEx, a U.S. based geothermal consultancy, as part of the Western Renewable Energy Zones (**WREZ**) project. As per the WREZ report:

> The methodology used to estimate the geothermal generation potential has relied on volumetric estimation of heat in place wherever sufficient information was available to justify this approach. In brief, the heat-in-place approach entails estimation of the area, thickness, and average temperature of the geothermal resource. Recovery factors that are based on industry experience are applied to estimate the proportion of heat that can be recovered as electrical energy over an assumed project life of 30 years. Uncertainty in the input parameters is handled by a probabilistic approach that yields a range of possible generation values and associated probabilities. The modal value of the probability distribution is considered the "most likely value" of generation potential for the project concerned.
>
> Where there is insufficient resource information to apply the heat-in-place method, estimates of generation potential have been made by analogy to better-known projects in similar geologic environments. If the only public information about a project is that it contains geothermal leases or has been the

> subject of a geological reconnaissance study, the project size has been estimated at a minimum size of 10 MW (gross). Larger estimates of capacity can be justified even in the absence of published resource data if there is evidence of active geothermal development efforts. (For) British Columbia, capacities of 50 MW (gross) have been estimated (for some sites) based on potentially favourable geologic conditions, even in the absence of current development efforts.

The GeothermEx assessment identified 18 discrete project locations and assigned an electricity generation potential as per the above methodology. High quality resources were assumed to be developed with flash-steam power plants, whereas medium quality resources were assumed to be developed by binary-cycle power plants. Cost parameters were assigned to these technology types based on a high level review of published costs for new geothermal projects globally, adjusted to account for the challenging geographical conditions of B.C. sites and the higher risk of failed wells for B.C. greenfield sites relative to expansion projects of well-understood geothermal reservoirs.

The WREZ methodology is a conservative estimate for B.C. because it includes only the ‘discovered’ resources and does not include more speculative “undiscovered” resources for which insufficient heat or flow data are currently available.

5.2.6.3 Technical and Financial Results

A summary of the technical and financial results for the geothermal resource option is contained in Table 5-7.

Table 5-7 Summary of Geothermal Potential

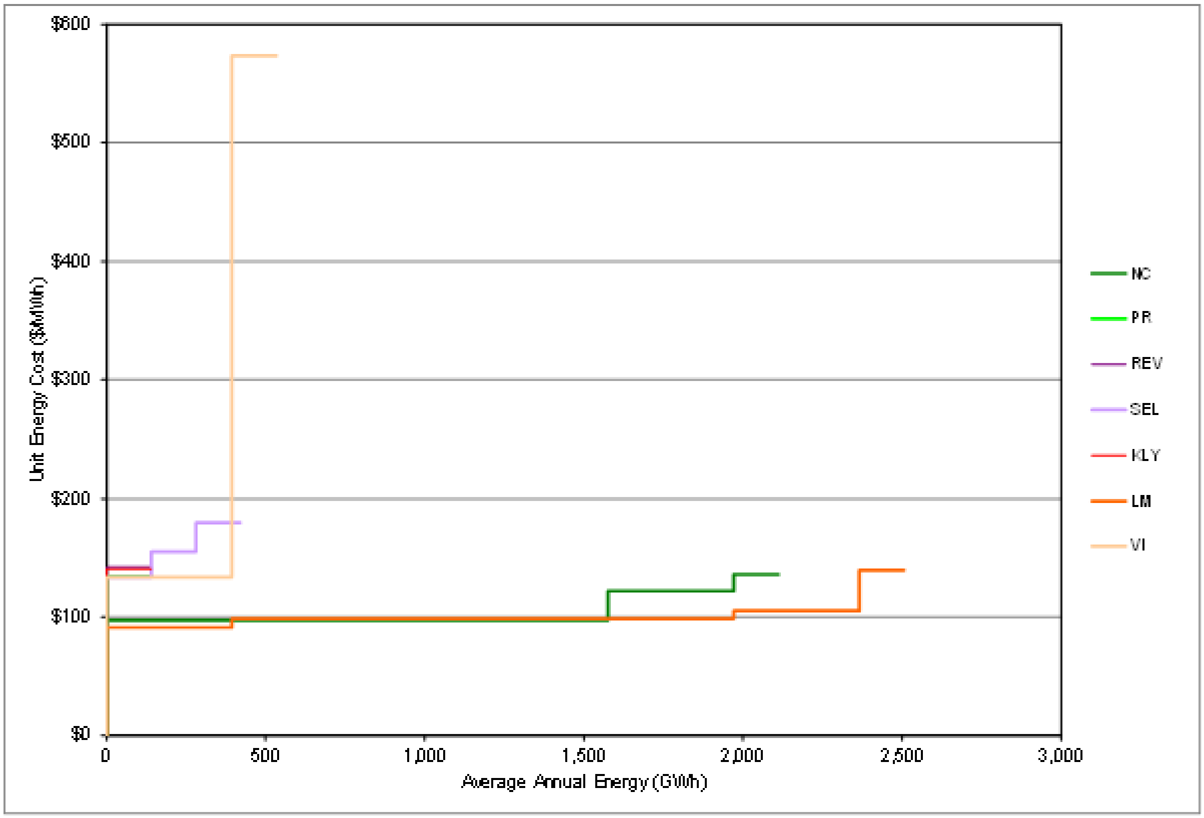
Transmission Region	Number of Projects	Installed Capacity (MW)	DGC (MW)	Annual Energy (GWh/yr)	Annual Firm Energy (GWh/yr)	UEC at POI Range ($2013/MWh)
Peace River	1	20	20	140	140	134
North Coast	3	270	270	2,111	2,111	97 - 136
Kelly Nicola	1	20	20	140	140	141
Revelstoke	1	20	20	140	140	142
Vancouver Island	2	70	70	534	534	134 - 573
Lower Mainland	5	320	320	2,505	2,505	91 - 139
Selkirk	3	60	60	420	420	134 - 179
Total	**16**	**780**	**780**	**5,992**	**5,992**	**91 - 573**

Note: Summary table excludes two sites that are technically inaccessible (e.g., within a protected area, or exceeds technical criteria established for road or transmission access).

A map showing the provincial distribution of the potential resource option is shown in Appendix 5.

The supply curves for geothermal resource potential based on POI costs, by transmission region, are shown in Figure 5-10.

1 **Figure 5-10 Geothermal POI Supply Curves**



2 ### *5.2.6.4 Environmental and Economic Development Attributes*

3 The environmental attributes of the geothermal resources are presented in
4 Appendix 2 and summarized in Appendix 3.

5 The economic development attributes of the geothermal resources are presented in
6 Appendix 4 and summarized in Appendix 3.

7 ### *5.2.6.5 Earliest In-Service Date*

8 The earliest ISD for geothermal is estimated to be 2017 for sites that have had
9 significant previous investigation efforts. For other sites, the earliest ISD is assumed
10 to be 2019.

5.2.6.6 Seasonality and Intermittence

For resource planning purposed, geothermal resources are considered to be a source of firm energy without significant seasonality or intermittence.

5.2.6.7 Uncertainty

There are risks associated with the confirmation of potential and development of geothermal resources. The development of geothermal resources proceeds in three stages, and at each stage there are risks and challenges to overcome. In the confirmation stage, a potential geothermal reservoir is surveyed and mapped through geological survey techniques and slim-hole drilling. If the results of the confirmation stage are encouraging, the project can proceed to the drilling or feasibility study stage, in which deep production wells are drilled to establish the parameters of the geothermal reservoir, identify the sustainable flow rates from the reservoir, and estimate the financial feasibility of the project. If the drilling or feasibility stage establishes a financial foundation for the project, the construction stage can begin. In the final construction stage, the surface collection systems, generation equipment and interconnection facilities are built. The challenges that must be overcome in each stage in the B.C. context are:

- Confirmation stage:
  - Proponent must secure tenure to the land and acquire necessary permits for early stage reconnaissance. In B.C., the tenure process requires applicants to request a parcel of land be put up for tenure and must win the rights through a sealed bid auction. The uncertainty related to the auction process is a disincentive for some geothermal developers to invest efforts to investigate new potential sites. Since 2002, the Province has awarded geothermal permits to 12 locations and there is only one active geothermal lease at South Meager Creek.
  - Drilling of three to ten slim-holes may cost from $0.5 million to $5 million, with no guarantee of identifying a viable geothermal resource

- Drilling or feasibility stage:
  - Flow rates through the production wells may not be sufficient to drive power production, although some of these 'dry' wells can be used as injection wells. The probability of drilling a 'dry' well is considerably higher for greenfield sites relative to expansion projects, increasing the risk and cost.
  - The heat flow from the reservoir may not be sustainable over the lifetime of a prospective power project if the heat within the reservoir cannot be replenished quickly enough
  - The drilling program is expensive (more than $5 million per well drilled) with no guarantee of a financially viable project
- Construction stage:
  - Some of the B.C. geothermal resources are located in remote areas or associated with land conservancies, making permitting of the necessary infrastructure challenging in some instances

Resource Option	Level of Study	Resource Type Related Uncertainty Rating	Cost Uncertainty Criteria
Geothermal	Survey, except Meager Creek which is Feasibility	High	High (-10 per cent / +60 per cent)

5.2.7 Run-of-River

There are no fundamental methodology changes in the 2013 Run-of-River (**RoR**) updates, but the potential estimation and cost estimation are updated to reflect the revision provided by Kerr Wood Leidal Associated Ltd. (**KWL**). These revisions are documented in the memorandum attached to Appendix 8-A. In the 2013 Update, the UECs are calculated at 7 per cent real cost of capital, and are presented in $2013.

5.2.7.1 Resource Description

A RoR hydroelectricity generation facility diverts a portion of natural stream flows and uses the natural drop in elevation of a river to generate electricity. RoR projects divert some of a river's flow for power generation and leave the remaining flow in the original stream for environmental and social purposes. A weir (i.e., a structure smaller than a dam used for storage hydro) is required to divert flows into the penstocks that lead to the power generation facilities. A RoR project does not require a large impoundment of water.

Currently there are 45 RoR facilities with a total installed capacity of 846 MW, generating an average 3,470 GWh/year of energy in B.C., and there are additional 32 contracted RoR projects with a total installed capacity of 1,332 MW and average generation of 4,429 GWh/year waiting to be built.

5.2.7.2 Methodology

The 2013 RoR updates maintain the same methodology as in the 2010 ROR. The 2010 RoR resource options review was undertaken in collaboration with an external consulting firm KWL, who updated the November 2007 KWL Run-of-river Hydroelectric Resource Assessment study. The study used a GIS Rapid Hydro Assessment Model developed by KWL tool to assess the energy, capacity and cost of selected potential run-of-river generating sites. The updates include:

- An update to the areas and reaches of streams excluded from the analysis that are considered undevelopable such as: legally protected areas, glaciers, reaches of streams that are used by salmon, and existing and committed project locations
- Development of a new RoR hydropower inventory for B.C. using a revised / improved optimization methodology that more closely corresponds to hydroelectric projects presently being proposed and developed in B.C.
- A revised estimate of project costs based on updated cost data in 2011 dollars

An analysis was performed to create a high-level inventory of estimated RoR power potential for B.C. using a hydropower assessment model, topographic and hydrologic GIS data. Gross power potential was evaluated at ~100 m length of stream based on the estimated head and design flow. The design flow was estimated as one-and-a-half times the mean annual discharge (**MAD**), an increase from the 2007 design flow. The MAD was estimated in GIS from the annual runoff data developed by the Province (1998) and the head was estimated for penstocks ranging in length from 500 m to 5,000 m in 500 m increments using the Provincial digital elevation model data. The resulting output consists of over 10 million data points representing potential power plant points-of-diversion complete with flow, head and power estimations.

Site Screening/Constraints

This raw dataset of potential power sites was screened for:

- Legally protected areas including newly designated areas
- Reaches of streams supporting salmon species (observations)
- Glaciers identified in new Provincial glacier datasets
- Stream reaches related to identified Provincial topographic digital elevation model errors
- Stream reaches that correspond to projects that have existing or committed (not operating) hydroelectric developments with electricity purchase agreements (**EPAs**)

Site Optimization - Updated Methodology

The screened dataset underwent an optimization routine that selects the largest project in a given stream reach with the updated optimization methodology.

In 2007, the site optimization and selection methodology found the greatest power per unit length of penstock and found the steepest drop for a given reach of a stream. As an example, if there were two steep drops nearby, the larger of the two was selected. The MAD was used for design flow.

The methodology from the 2007 work is a good start for identifying potential sites, but often developers will design a larger project to optimize the cost effectiveness of the project and extract as much capacity and energy as they can from a location, since there are many costs that are less sensitive to the size of the project and comprise a large portion of the costs (such as access roads and power lines). This generally results in a project that extends beyond the steepest drop in a reach of the stream and a design flow typically 50 per cent greater than what would have been estimated in 2007.

Both the old (2007) and new (2010) methodologies consider the steepest section of the stream, however the 2010 methodology generally selected a larger project with the steepest section encompassed by the new potential project. The new optimization results in a change to the project layout size (length of diverted stream and head) and a higher design flow. It selects the largest project on a given stream which is optimized to find the greatest change in gross power over the change in penstock length. This effectively finds the steepest drop of a stream reach and also includes nearby steep channel sections and nearby steep drops in the total length of the penstock. In addition to this, a larger design flow was used (150 per cent of MAD).

The 2010 methodology resulted in an estimated project size (capacity and energy) that is believed to be a closer representation of what might be developed for that reach of stream. In many cases it results in more capacity and energy and often with lower UECs than using the methodology applied in the 2007 study.

Energy Estimates

Regional hydrology analysis was carried out to develop an estimate of energy production. This involved data from a statistical analysis of Water Survey of Canada (**WSC**) hydrologic data, and used GIS capabilities to distribute the resulting statistics to the proposed project locations. Annual energy production, firm energy and dependable capacity, were estimated based on flow duration curves. Minimum flow releases for fish were assumed to be 15 per cent of mean annual flow. Flow duration curves were selected for each potential site based on regional WSC gauges in their hydrologic zone.

Average annual energy was estimated based on the total quantity of energy that could be generated annually, on average, based on the flow duration curve for the entire period of record for the selected WSC gauge at each potential site. Firm energy was estimated as the total quantity of energy that is generated in the lowest flow year (October to September) in the period of record for the selected WSC gauge at each potential site. The dependable capacity was estimated from the monthly flow duration curves as capacity that can be generated 85 per cent of time in December and January.

The seasonal energy profile was based on monthly capacity factors derived from monthly flow duration curves for regional WSC hydrometric stations to estimate energy production by month.

The FELCC and ELCC of the potential sites were determined by BC Hydro using models dealing with the loss of load analysis.

Cost Estimation

In the 2010 Report, resource costs were estimated in 2011 dollars using information from constructed project costs, contractors' and manufacturers' quotes and engineering judgement. In the 2013 Update, resource costs are adjusted for inflationary impact and are presented in $2013. This information was used to develop a series of cost curves (such as penstock, intake and powerhouse civil works, generating equipment, transmission) to estimate costs for each potential site based on key project parameters such as project capacity (MW). A least-cost path routing method was used to estimate the cost of roads and power lines to existing infrastructure.

Costs are composed of capital costs and annual costs. Capital costs include costs such as penstock, civil work, generation equipment, construction camp and transportation etc. Annual costs include such as OMA costs, water rental costs, property taxes and land allowance costs.

The UEC was estimated for each potential site based on the estimated capital and annual costs, annual energy production, project life, and discount rate.

Estimated earliest ISDs vary based on project size and the estimated number of years required for licensing, design, and construction.

Details of the 2013 RoR resource options update are presented in Appendix 8.

5.2.7.3 Technical and Financial Results

A summary of the technical and financial results for the RoR resource option is contained in Table 5-8.

Table 5-8 Summary of Run-of-river Potential

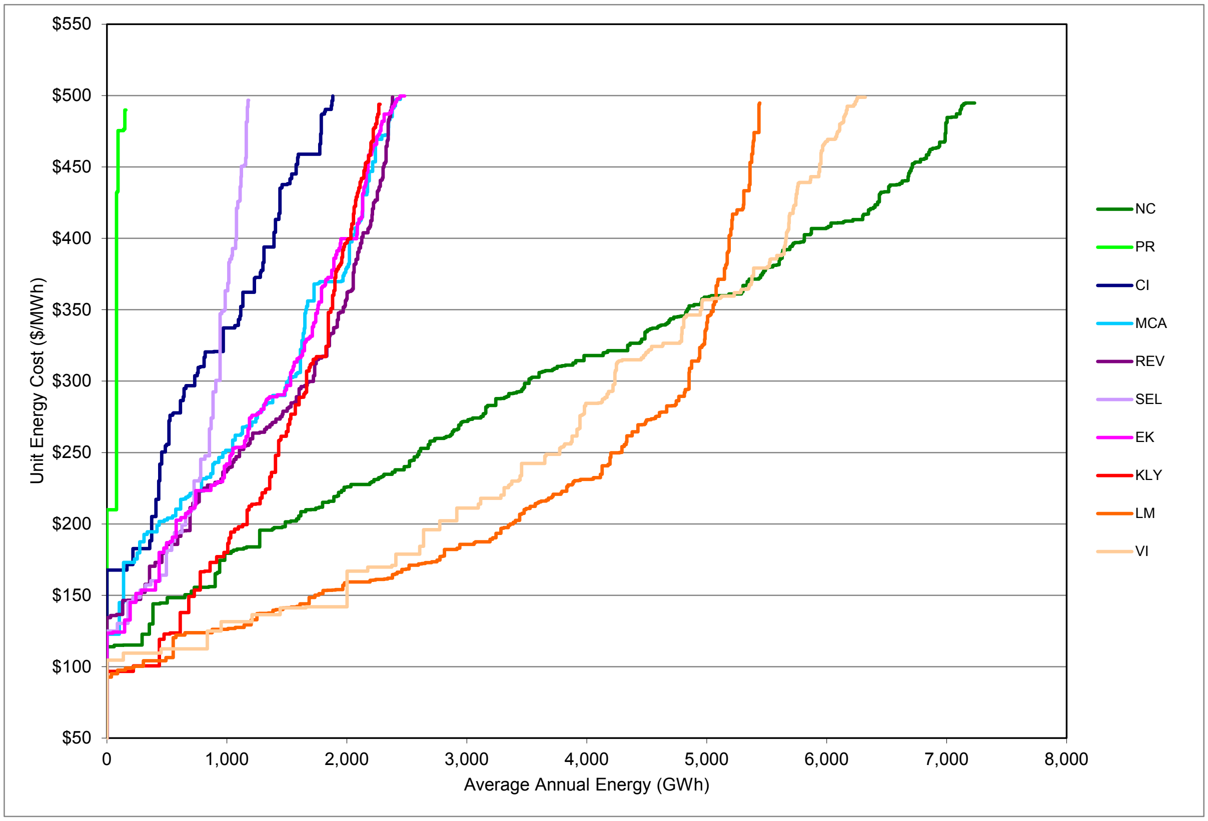
Transmission Region	Number of Projects	Installed Capacity (MW)	ELCC (MW)	Annual Energy (GWh/year)	Annual Firm Energy (GWh/year)	UEC at POI Range ($2013/MWh)
Peace River	6	55	2	158	88	210-490
North Coast	260	2027	226	7,232	5,786	114-495
Central Interior	62	616	43	1,950	1,597	168-500
Kelly Nicola	101	783	31	2,277	1,809	97-494
Mica	101	786	32	2,452	1,928	123-499
Revelstoke	123	828	32	2,383	1,648	134-499
Vancouver Island	163	1,754	420	6,322	4,802	105-499
Lower Mainland	173	1,551	310	5,443	4,189	93-495
Selkirk	44	405	13	1,182	835	125-497
East Kootenay	136	773	41	2,481	1,861	124-500
Total	**1,169**	**9,579**	**1,149**	**31,880**	**24,543**	**93-500**

Note: The table presents results for run-of-river resources under $500/MWh.

A map showing the provincial distribution of the potential RoR resource option is shown in Appendix 5.

The supply curves for RoR resource potential based on POI costs, by transmission region, are shown in Figure 5-11.

1 **Figure 5-11 Run-of-river POI Supply Curves**



2 Note: This figure presents results for run-of-river resources under $500/MWh.

3 *5.2.7.4 Environmental and Economic Development Attributes*

4 The environmental attributes of the RoR resource bundles are presented in
5 Appendix 2 and summarized in Appendix 3.

6 The economic development attributes of the RoR resource bundles are presented in
7 Appendix 4 and summarized in Appendix 3.

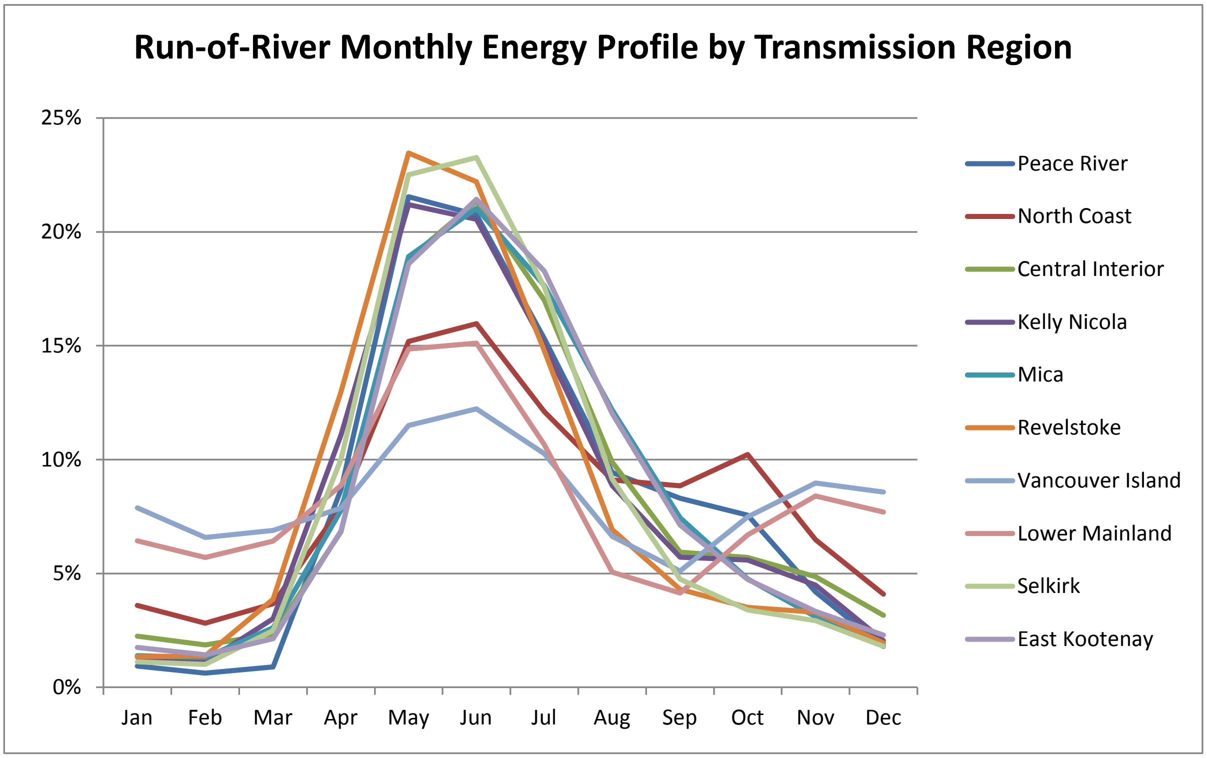
8 *5.2.7.5 Earliest In-Service Date*

9 The earliest ISD for additional RoR generation is estimated to be 2017.

5.2.7.6 Seasonality and Intermittence

The seasonality of the potential RoR resources is shown in Figure 5-12. The RoR energy profiles are reported by transmission region once interconnection requirements are considered.

Figure 5-12 Normalized Monthly Run-of-river Energy Profiles by Transmission Region



Note: This figure presents results for run-of-river resources under $500/MWh.

RoR resource options have seasonal characteristics in that much of the power generation potential is in the freshet period, when the BC Hydro system may already be operating under generation constraints.

5.2.7.7 Uncertainty

Resource Option	Level of Study	Resource Type Related Uncertainty Rating	Cost Uncertainty Criteria
Run-of-river	Survey	Low	Medium (-10 per cent / +40 per cent)

5.2.8 Pumped Storage

Several North Coast Pumped Storage sites identified after the 2010 ROR are included in this 2013 ROR Update. The fixed OMA costs have been changed to reflect changes in maintenance costs of different types of Pumped Storage facilities (freshwater, saltwater, etc.). In the 2013 Update, the UCCs are calculated at a 7 per cent real cost of capital (except for the Mica site where a value of 5 per cent is used reflecting BC Hydro’s ownership), and are presented in $2013.

5.2.8.1 Resource Description

Pumped Storage (**PS**) units use electricity from the grid, typically during light load hours, to pump water from a lower elevation reservoir to an upper elevation reservoir. The water is then released during peak demand hours to generate electricity. Reversible turbine/generator assemblies or separate pumps and turbines are used in PS facilities. PS units are a net consumer of electricity due to the inherent inefficiencies in the pumping-generating cycle resulting in an ability to recover only approximately 70 per cent of the energy used during pumping. However, the ability to store water and release it during times of system need makes PS a useful capacity resource. PS units can respond quickly to variations in system demand and can provide ancillary services such as voltage regulation.

There are over 100 GW of PS installed worldwide and it is the most widespread energy storage system in use on power networks. However, there are no commercial PS facilities in British Columbia. Of the installed worldwide capacity, the majority utilize freshwater and surface reservoirs, although facilities that use an ocean as a lower reservoir also exist. The use of underground caverns as a lower reservoir has also been explored.

5.2.8.2 Methodology

BC Hydro engaged Knight Piésold to identify greenfield PS potential in the Lower Mainland, Vancouver Island, and North Coast regions. The study investigated potential greenfield conventional facilities that use freshwater and surface reservoirs, as well as unconventional facilities such as those that use seawater. The study identified technical and economic parameters of potential sites at a conceptual level.

Hatch Ltd. was engaged to assess the cost of installing a pump-turbine or a pump at Mica Generating Station, building upon the work presented in the Hatch study on Mica in 2008.

The PS reports are presented in Appendix 9.

5.2.8.3 Technical and Financial Results

A summary of the technical and financial results for the PS resource option is contained in Table 5-9. As PS is considered a capacity option, only the UCCs are shown.

Table 5-9 Summary of Pumped Storage Potential

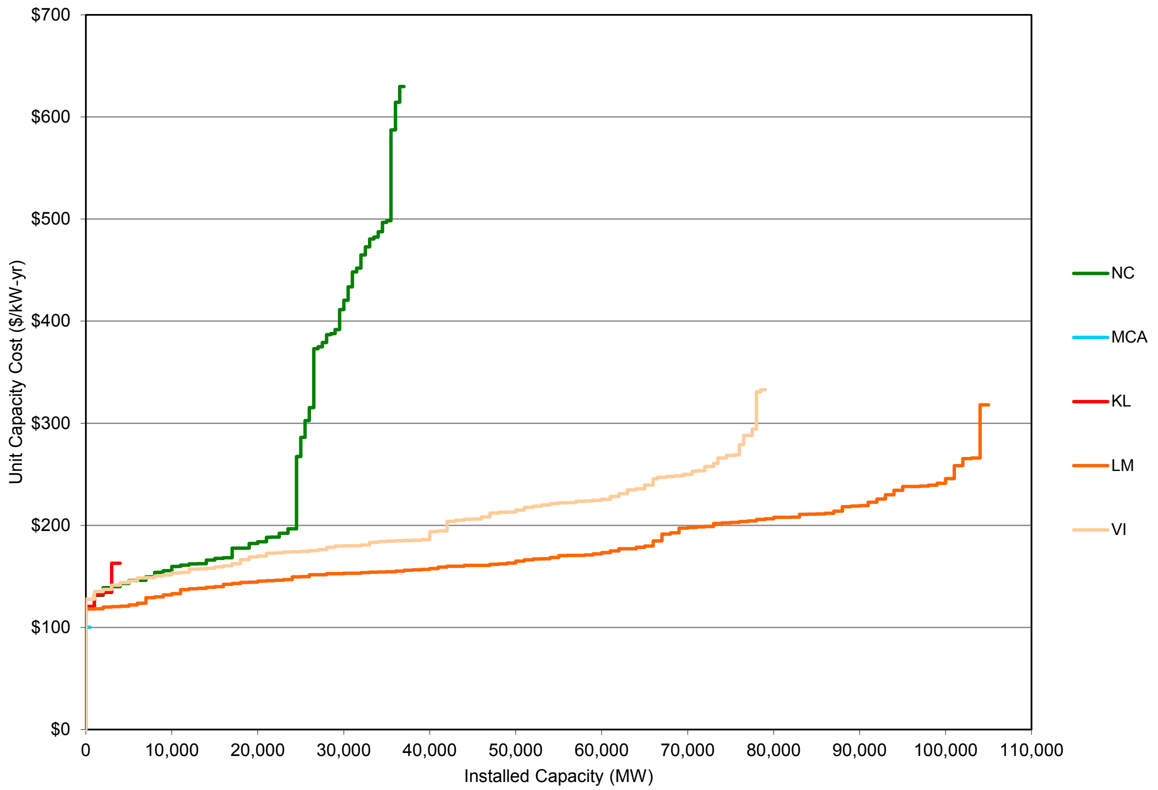
Transmission Region	Number of Projects	Installed Capacity (MW)	DGC (MW)	UCC at POI Range ($2013/kW·year)
Kelly Nicola	4	4,000	4,000	121 – 163
Mica	1	500	465	100 *
Vancouver Island	84	79,000	79,000	128 – 333
Lower Mainland	105	105,000	105,000	118 – 318
North Coast	50	37,000	37,000	119 – 630 *
Total	**244**	**225,500**	**225,465**	**100 – 630**

Notes:
1. UCCs for pumped storage include fixed costs only.
2. Mica Pumped Storage UCC is calculated at 5 per cent real cost of capital.
3. North Coast UCCs are at plant gate; transmission and road access cost components are not included.

A map showing the distribution of the potential PS resource option (excluding the North Coast potential) is shown in Appendix 5.

The supply curves for PS potential in the transmission regions investigated, based on POI costs, are shown in Figure 5-13.

Figure 5-13 Pumped Storage POI Supply Curves



5.2.8.4 Environmental and Economic Development Attributes

The environmental attributes of the PS resource option are presented in Appendix 2 and summarized in Appendix 3. The environmental impact of reservoir drawdowns has not been characterized due to data limitations.

The economic development attributes of the PS resource option are presented in Appendix 4 and summarized in Appendix 3.

5.2.8.5 Earliest In-Service Date

The earliest ISD for the Mica PS option is 2019. The earliest ISD for pumped storage is 2021 for the Lower Mainland/Vancouver Island/North Coast greenfield pumped storage sites.

5.2.8.6 Seasonality and Intermittence

There are no seasonality or intermittence issues related to the PS resource option.

5.2.8.7 Uncertainty

Resource Option	Level of Study	Resource Type Related Uncertainty Rating	Cost Uncertainty Criteria
Pumped Storage Greenfield	Survey	High	High (-10 per cent / +60 per cent)
Pumped Storage – Mica	Pre-Feasibility	Medium	High (-10 per cent / +60 per cent)

5.2.9 Large Hydro - Site C

Site C is updated based on the information provided in the Site C Environmental Impact Statement (**EIS**) submission filed in January 2013. The UEC is calculated at 5 per cent real cost of capital, and are presented in $2013.

5.2.9.1 Resource Description

The 2010 *Clean Energy Act* (***CEA***) prohibits electricity generation projects with storage in excess of prescribed capabilities, and explicitly excludes 11 large hydro projects. As a result, for the 2010 ROR, the only project considered as a potential large hydro resource option is the project commonly known as Site C.

The Site C Clean Energy Project (**Site C**) is a proposed third dam and hydroelectric generating station on the Peace River in northeast B.C. Site C would be located downstream from the existing Williston Reservoir and two existing BC Hydro generating facilities (G.M. Shrum and Peace Canyon). It would include an earthfill dam, approximately 1,050 m in length, and 60 m high above the river bed. The reservoir would be 83 km long and would be, on average, two to three times the width of the current river. It would have relatively little fluctuation in water levels, with a proposed maximum normal operating range of 1.8 m. Site C would provide approximately 1,100 MW of dependable capacity, and produce more than 4,700 GWh/year of firm energy (5,100 GWh/year average).

As the third dam and generating station on the Peace River, Site C would gain significant efficiencies by taking advantage of water already stored in the Williston Reservoir upstream to generate electricity. As a result, Site C would generate about 35 per cent of the electricity produced at the W.A.C. Bennett Dam, with only 5 per cent of the reservoir area. Site C would be a publicly owned heritage asset, with a significant upfront capital cost, low operating costs and a long life of more than 100 years.

BC Hydro recently submitted a Site C EIS with federal and provincial regulatory agencies. The EIS describes the project rationale, its potential effects — including environmental, social, economic, heritage and health — and proposed measures to avoid or mitigate adverse effects. It also includes the benefits Site C would provide to customers, Aboriginal groups, northern communities, and the province. The complete EIS can be found on the regulatory agencies' websites at: www.eao.gov.bc.ca or www.ceaa.gc.ca. Additional information on Site C is available at: www.bchydro.com/sitec.

5.2.9.2 Methodology

The data in this report is based on the updated project design and cost estimate and is consistent with the information provided in the Site C EIS submission filed in January 2013.

5.2.9.3 Technical and Financial Attributes

Table 5-10 summarizes the technical and financial characteristics of Site C.

Table 5-10 Site C Summary

Transmission Region	Number of Projects	Installed Capacity (MW)	DGC (MW)	Annual Energy (GWh/year)	Annual Firm Energy (GWh/year)	UEC at POI Range ($2013/MWh)
Peace River	1	1,100	1,100	5,100	4,700	83

Note: Based on capital cost of $7.9 billion. The UEC in the table above includes sunk costs. For portfolio analysis sunk costs to March 31, 2013 are removed, which reduces the UEC to $76/MWh in 2011$. UEC value is presented using a 5 per cent real cost of capital. The Site C UEC at the previous 6 per cent real cost of capital is $95/MWh.

A map showing the location of Site C is presented in Appendix 5.

5.2.9.4 Environmental and Economic Development Attributes

The environmental attributes of the Site C resource option are presented in Appendix 2 and summarized in Appendix 3.

The economic development attributes of the Site C resource option are presented in Appendix 4 and summarized in Appendix 3.

The environmental and economic development attributes for the Site C project use a similar methodology to other projects investigated as part of the 2010 ROR. These attributes do not represent the detailed effects of the project. Rather the high-level environmental footprints and economic development attributes are used for comparison of resource options across provincial-scale portfolios, and act as proxies for more detailed environmental, social, and heritage effects of potential projects. The detailed effects of the Site C project on environmental, heritage, social, economic and health resources are evaluated as part of the environmental assessment (**EA**) process, according to the methodologies required by the Site C Environmental Impact Statement Guidelines.

5.2.9.5 Earliest In-Service Date

The Site C project requires environmental certification and other regulatory permits and approvals before it can proceed to construction. In addition, the Crown has a duty to consult and, where appropriate, accommodate Aboriginal groups. The Site C project schedule is based on the regulatory process established as part of the joint

B.C./Canada agreement for a cooperative environmental assessment process, and the project construction schedule. The forecast ISD for the Site C Clean Energy Project is fiscal 2023 for the first generating unit, with all units in service in fiscal 2024.

5.2.9.6 Seasonality and Intermittence

There are no seasonality or intermittence issues with Site C. It is expected that the generation flexibility associated with large hydro will help mitigate intermittence issues associated with other resource options.

5.2.9.7 Uncertainty

Resource Option	Level of Study	Resource Type Related Uncertainty Rating	Cost Uncertainty Criteria
Site C	Feasibility	Medium	Low-Medium*

Note: The Site C cost estimate is a Class 3 cost estimate as defined by the Association for the Advancement of Cost Engineering (**AACE**). From the AACE classification, "Typical accuracy ranges for Class 3 estimates are -10 per cent to -20 per cent on the low side, and +10 per cent to +30 per cent on the high side, depending on the technological complexity of the project, appropriate reference information, and other risks (after inclusion of an appropriate contingency determination)."

5.2.10 Resource Smart

BC Hydro is pursuing the advancement of two capacity Resource Smart projects: G.M. Shrum Units 1-5 Capacity Increase (referred to as **GMS Units 1-5 Capacity Increase**) and Revelstoke Unit 6. In the 2013 Update, the UCCs are calculated at 5 per cent real cost of capital, and are presented in $2013.

5.2.10.1 Resource Description

There is some opportunity to modestly increase the energy and/or capacity within BC Hydro's existing fleet of 30 hydroelectric Heritage assets. These opportunities are commonly referred to as Resource Smart opportunities.

Energy and/or capacity increases can be realized as stand-alone investments planned specifically to satisfy an energy and/or capacity need identified through the long range planning process, or the opportunities can be realized at the time of reliability refurbishment or replacement investments associated with the major generating components. The capability of all of the major generating components (generator, turbine, unit transformer, circuit breaker, exciter, governor, water passage) and auxiliary equipment have to be able to facilitate the increased energy and capacity requirements so in some cases it can take a long time to fully realize the uprated potential of the Heritage assets if combined with reliability improvements.

In recent years, BC Hydro has implemented or is implementing a number of such opportunities. Examples already included in BC Hydro's resource stack as committed resources are:

- The addition of one unit (500 MW) at Revelstoke Generating Station in the B.C. Interior (Revelstoke Unit 5, in-service in F2011)
- The addition of two units (appropriately 500 MWs each) at Mica Generating Station in the B.C. Interior (Mica Units 5 and 6 are expected to be in-service in F2015 and F2016, respectively).
- Increasing the capacity of Units 6 to 8 at the GMS Generating Station, providing additional capacity of approximately 90 MW (in-service in F2013) on the Peace River
- Replacing the runners at Ruskin Generating Station in the Lower Mainland, adding approximately 9 MW of additional capacity and 28 GWh/year of energy
- Replacement of the G1 and G2 generator stators at the Cheakamus Generating Station in the Lower Mainland and increase the dependable capacity of each unit by approximately 20 MW each with expected in-service date of September 2017 for Unit 1 and March 2018 for Unit 2
- The Identification phase of a generator stator reliability improvement capital project is underway with potential to add approximately 4 MW to each of Units 5 and 6 at the Bridge River Generating Station

- The Identification Phase of a capital project to explore the feasibility, impacts, and energy capability associated with the dredging of Grohmann Narrows in the Kootenay region

The largest remaining Resource Smart projects identified in terms of additional dependable capacity are:

- GMS Units 1-5 Capacity Increase, which entails upgrades to GMS units 1 to 5 turbines with more efficient turbines to provide up to 220 MW of dependable capacity when all 5 units are rewound
- Revelstoke Unit 6, which entails installation of a sixth unit at Revelstoke with an installed capacity of 500 MW and estimated 488 MW of dependable capacity

5.2.10.2 Methodology

The GMS Units 1-5 Capacity Increase is based on conceptual level estimates and Revelstoke Unit 6 is updated with the most recent project information.

5.2.10.3 Technical and Financial Attributes

A summary of the technical and financial results for the Resource Smart options are contained in Table 5-11.

Table 5-11 Summary of Resource Smart Potential

Transmission Region	Number of Projects	Installed Capacity (MW)	DGC (MW)	Annual Energy (GWh/year)	Annual Firm Energy (GWh/year)	UCC at POI Range ($2013/kW-year)
Peace River	1	220	220	TBD	TBD	35
Revelstoke	1	500	488	26	26	50

Note:
Peace River numbers are based on conceptual level estimates. The installed capacity and DGC will be in the range of 185 MW to 220 MW.

A map showing the distribution of the potential Resource Smart resource option is shown in Appendix 5.

5.2.10.4 Environmental and Economic Development Attributes

The environmental attributes are presented in Appendix 2 and summarized in Appendix 3. As this option does not result in a new footprint, a limited number of attributes are summarized in the RODAT sheets.

The economic development attributes are presented in Appendix 4 and summarized in Appendix 3.

5.2.10.5 Earliest In-Service Date

The earliest ISD for GMS Units 1-5 Capacity Increase project is F2021. The earliest ISD for the Revelstoke Unit 6 project is F2021.

5.2.10.6 Seasonality and Intermittence

There are no seasonality or intermittence issues with Resource Smart projects.

5.2.10.7 Uncertainty

Resource Option	Level of Study	Resource Type Related Uncertainty Rating	Cost Uncertainty Criteria
GMS Units 1-5 Capacity Increase	Feasibility	Low	High (-35 per cent / +100 per cent)
Revelstoke Unit 6	Feasibility	Low	Medium (-10 per cent / +40 per cent)

5.2.11 Natural Gas-Fired Generation and Cogeneration

The capital cost for the 100 MW simple cycle gas turbine (**SCGT**) is increased to reflect recent increases in gas turbine costs. The co-generation resource option is characterized using a representative project. All other inputs and analysis assumptions are identical to what were used in the 2010 ROR. In the 2013 Update, the UECs for the combined cycle gas turbines (**CCGT**) and UCCs for SCGT are calculated at 7 per cent real cost of capital, and are presented in $2013.

5.2.11.1 Resource Description

Natural gas-fired generators produce electricity using the heat released by the combustion of natural gas. SCGT and CCGT are the most commonly employed technologies. Conversion efficiencies are typically 35 to 40 per cent for SCGT machines, and 50 to 60 per cent for CCGT machines.

Co-generation of both heat and electricity using natural gas as a fuel is another form of natural gas-fired generation. Cogeneration involves electricity production using reciprocating engines or turbines and a steam/thermal host to use the excess heat produced from the generation process. Resource potential is limited by the availability of steam/thermal hosts such as greenhouses, hospitals, universities and industrial facilities that use steam or heat. By using waste heat in a process that requires heating, the efficiency of cogeneration plants is 90 per cent or greater.

Gas-fired generation has several advantages:

- It is a proven technology with low construction cost risk and high operational reliability
- Generators are available in a range of sizes and configurations, and are capable of supplying large-scale, dependable capacity and firm energy
- The plants can be sited close to load centres and can be especially useful in serving transmission constrained regions
- Operation of the generators may be displaced when economic energy (e.g., secondary hydroelectric energy) is available at prices lower than the cost of gas

The primary disadvantages of gas-fired generation include:

- Production of greenhouse gases (**GHG**) and other air pollutants
- Natural gas prices can be volatile posing significant cost uncertainty

The development of any gas-fired generation in B.C. would need to be within the allowance made for non-clean resources in the B.C. *CEA*, except for any generators built to serve Liquefied Natural Gas (**LNG**) facilities. The *CEA* states that no more than 7 per cent of total electricity generation in the province can come from non-clean sources.

5.2.11.2 Methodology

BC Hydro undertook an in-house update of the cost of some selected gas-fired units. The main alternatives that are expected to be relevant for resource planning purposes are a 100 MW SCGT option that can serve as a capacity resource and 50 MW, 250 MW, and 500 MW CCGT's that can provide both firm energy and capacity.

5.2.11.3 Technical and Financial Results

A summary of the technical and financial results for the gas-fired generation resource options are contained in Table 5-12 and Table 5-13.

Table 5-12 Summary of CCGT and Small Cogeneration Natural Gas-Fired Generation Potential

Resource Option	Number of Projects	Installed Capacity (MW)	DGC (MW)	Annual Energy (GWh/year)	Annual Firm Energy (GWh/year)	UEC at POI Range ($2013/MWh)
50 MW CCGT in Kelly/Nicola	1	56	49	300	386	92
250 MW CCGT in Kelly/Nicola	1	263	236	1,450	1,861	62
500 MW CCGT in Kelly/Nicola	1	530	479	2,940	3,776	58
Small Cogeneration	1	10	10	80	80	74

Notes:

1. Representative project used to characterize the resource option.
2. UECs are based on natural gas price estimates from BC Hydro's 2013 Market Scenario 1, and do not include the cost of GHG offsets or the B.C. carbon tax.

As SCGTs are considered to be capacity options, the UCCs are shown in Table 5-13.

Table 5-13 Summary of the SCGT Natural Gas Fired Generation Potential

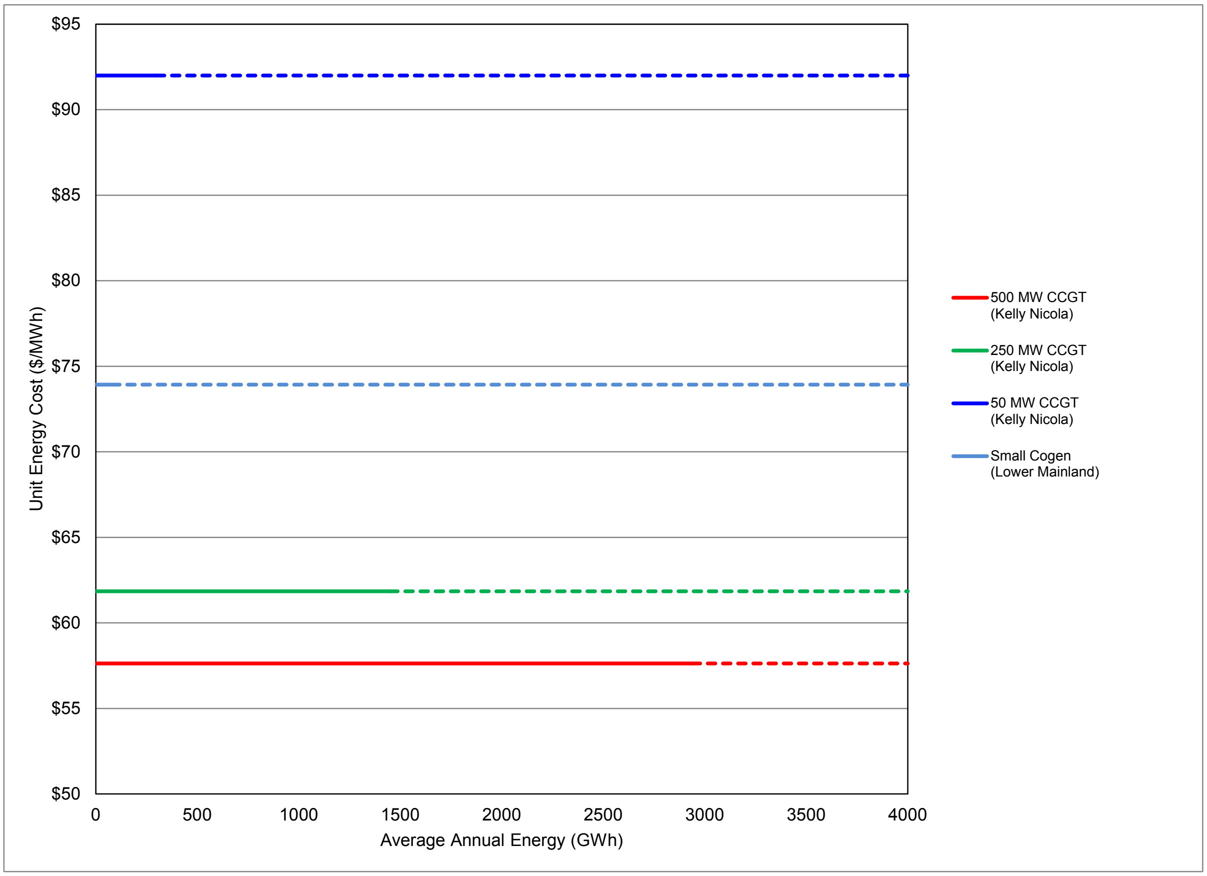
Transmission Region	Number of Projects	Installed Capacity (MW)	DGC (MW)	UCC at POI Range ($2013/kW·year)
100 MW SCGT in Kelly/Nicola	1	103	98	84
100 MW SCGT on Vancouver Island	1	103	101	180

Notes:
1. Representative project used to characterize the resource option.
2. Unit capacity costs for SCGTs include fixed costs only.

A map showing representative locations of potential gas-fired generation resource options is shown in Appendix 5.

The supply curves for the CCGT and small cogeneration resource options, based on POI costs, are shown in Figure 5-14.

Figure 5-14 CCGT and Small Cogeneration POI Supply Curves*



* The solid line indicates the energy contribution of a single representative project. A dotted line indicates additional potential.

5.2.11.4 Environmental and Economic Development Attributes

The environmental attributes of the natural gas-fired generation and small gas cogeneration project options are presented in Appendix 2 and summarized in Appendix 3.

The economic development attributes are presented in Appendix 4 and summarized in Appendix 3.

5.2.11.5 Earliest In-Service Date

The earliest ISD for gas-fired resource options is 2017.

5.2.11.6 Seasonality and Intermittence

There is no seasonality or intermittence issues associated with gas-fired resource options.

5.2.11.7 Uncertainty

Resource Option	Level of Study	Resource Type Related Uncertainty Rating	Cost Uncertainty Criteria
Natural Gas	Pre-Feasibility	Medium	High (-10 per cent / +60 per cent)
Co-generation	Survey	Low	Medium (-10 per cent / +40 per cent)

5.2.12 Coal-Fired Generation with Carbon Capture and Sequestration

All inputs and analysis assumptions are identical to what were used in the 2010 ROR. In the 2013 Update, the UEC is recalculated at 7 per cent real cost of capital, and is presented in $2013.

5.2.12.1 Resource Description

In traditional coal-fired power generation, coal is milled to a fine powder allowing it to burn more quickly. The powdered coal is blown into the combustion chamber of a boiler where it is burnt at high temperatures. The hot gases and heat energy produced convert water into steam that is used to generate electricity. Integrated Gasification Combined Cycle (**IGCC**) plants are a newer generation of coal power generation technology. In an IGCC plant, the coal is first gasified to produce a synthetic gas (**syngas**). Syngas is burned in a combined cycle generator to produce electricity. The steam turbine also uses steam created in cooling syngas which contributes to the higher efficiency of IGCC plants, potentially in the 60 per cent range.

In B.C., Policy Action No. 20 of the 2007 BC Energy Plan stipulates that coal-fired generation must meet a zero GHG emission standard “through a combination of ‘clean coal’ fired generation technology, carbon sequestration and offset for any residual GHG emission". While 'Clean Coal' technology in the form of IGCC is now becoming available, technology that allows the carbon dioxide to be captured from the plant and stored through sequestration, allowing coal-fired generation to have 'near zero' GHG emissions is still evolving and is not presently viable on a large commercial scale. According to the Electric Power Research Institute (**EPRI 2007**)[9], coal-fired plants with 90 per cent CO_2 emission capture and storage could be commercially available by 2022 (Appendix 10).

5.2.12.2 Methodology

BC Hydro relied upon reports prepared by Powertech Labs Inc. in 2009 (Appendix 10) and a 2007 National Energy Technology Laboratory report[10].

5.2.12.3 Technical and Financial Results

A summary of the technical and financial results for the coal-fired generation with carbon capture and sequestration (**CCS**) resource option is contained in Table 5-14.

Table 5-14 Summary of Coal-Fired Generation with CCS Potential

Transmission Region	Number of Projects	Installed Capacity (MW)	DGC (MW)	Annual Energy (GWh/year)	Annual Firm Energy (GWh/year)	UEC at POI Range ($2013/MWh)
Peace River	1*	745	556	3,896	3,896	88

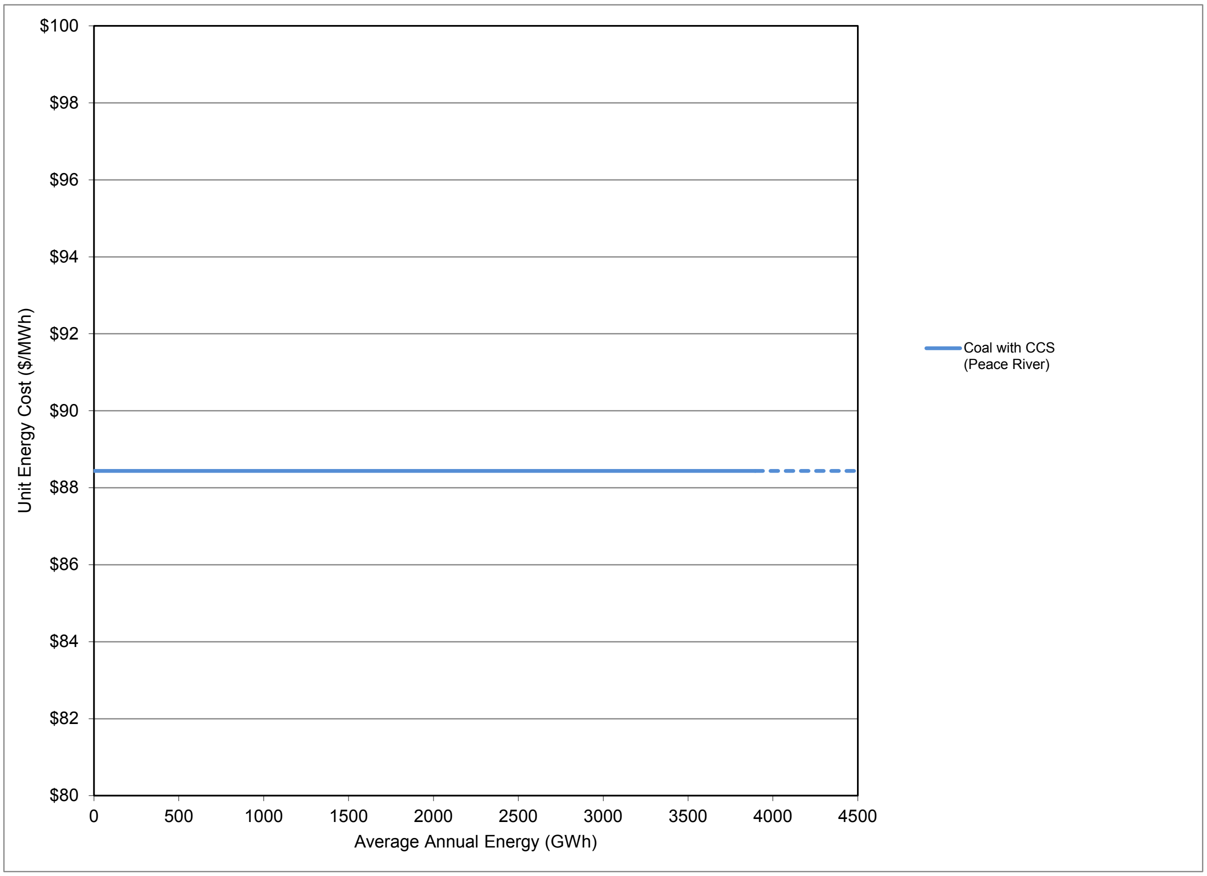
* Representative project used to characterize the resource option.
The dependable capacity was discounted to account for the energy used up by the CCS process.
Coal-fired generation with CCS is an emerging technology. There is significant uncertainty around the cost estimates provided.

Appendix 5 presents a map of the potential location assumed for the coal-fired generation resource option in the 2013 ROR Update.

The supply curve for the coal-fired generation with CCS resource option, based on POI costs, is shown in Figure 5-15.

9 Fall 2007, EPRI Journal, Pathways to Sustainable Power in Carbon-Constrained Future, page 4-13.
10 Cost and Performance Baseline for Fossil Energy Plants, Volume 1: Bituminous Coal and Natural Gas to Electricity Final Report, Revision 1, August 2007.

Figure 5-15 Coal-Fired Generation with CCS POI Supply Curve*



* The solid line indicates the energy contribution of a single representative project. A dotted line indicates additional potential.

5.2.12.4 Environmental and Economic Development Attributes

The environmental attributes of the coal-fired generation with CCS resource option are presented in Appendix 2 and summarized in Appendix 3.

The economic development attributes are presented in Appendix 4 and summarized in Appendix 3.

5.2.12.5 Earliest In-Service Date

The earliest ISD for coal-fired generation with CCS in British Columbia is estimated to be 2030.

5.2.12.6 Seasonality and Intermittence

There are no seasonality or intermittence issues with the coal-fired generation with CCS resource option.

5.2.12.7 Uncertainty

Resource Option	Level of Study	Resource Type Related Uncertainty Rating	Cost Uncertainty Criteria
Coal-fired Generation with CCS	Survey	High	High (-10 per cent / +60 per cent)

5.2.13 Wave

All inputs and analysis assumptions are identical to what were used in the 2010 ROR. In the 2013 Update, the UECs are recalculated at 7 per cent real cost of capital, and are presented in $2013.

5.2.13.1 Resource Description

Wave energy is generated by winds blowing over the surface of the ocean. Because ocean waves are a product of the complex interactions among variable local winds, occasional storms or the effects of distant sea conditions, wave energy is a complex and variable phenomenon. The character of the ocean wave state is often summarized in terms of wave height, period, direction and spectral distribution parameters. The wave energy resource is usually characterized by the wave power level, which is the flux of energy per unit length of wave crest (kW/m) that is a function of the square of the wave height and period.

The strong winds within the band from 40 to 60 degrees latitude as well as the circumpolar storms contribute to a good potential wave energy resource on the Pacific coast of B.C. and Alaska. In the deep waters of the open Pacific, the wave energy resource is large and consistent over distances on the order of a few hundred kilometres. As waves approach the shore through waters of decreasing depth, waves are modified by complex refraction and diffraction. Wave energy is also dissipated as waves approach shore due to friction with the ocean bottom. As a result, wave energy in shallower water can vary significantly over distances of less than 1 km, and interactions with the shoreline and local bathymetry can create localized wave energy ‘hot spots’.

There are five generic approaches to capturing the wave energy resource, each at the early stages of commercial development and each with potential application in B.C.

- **Attenuator:** Floating multiple-segment device that is arranged and moored in-line with the principal wave direction. Wave crests run along the length of the attenuator, causing flexing between joints. The flexing extracts kinetic energy through hydraulic pumps or similar mechanical-electrical converters.
- **Point Absorber:** A floating device which absorbs kinetic energy through its movement in the waves, akin to a bobbing fishing lure. The power generated from the device’s motion is then converted into electricity using a hydraulic or electromechanical power conversion system.
- **Oscillating Wave Surge Converter:** This type of device typically consists of a vertical plate which extracts energy from the ocean waves by moving in a horizontal direction.
- **Oscillating Water Column:** This type of device consists of a hollow structure that has an open bottom. The wave action inside the column drives the air-column above it. An air-turbine can then be used to convert the air-pressure differential into electricity.
- **Overtopping Device:** This device typically consists of an enclosed basin into which waves overtop using a ramp. The water inside the enclosed is elevated over the sea-level, creating a low hydraulic head which is converted into electricity using a low-head Kaplan turbine.

There are currently no wave energy projects deployed in B.C. waters. However, two wave energy projects have received partial funding from federal and/or provincial funding agencies: a near-shore multi-MW point absorber demonstration to be located near Ucluelet, and a point absorber demonstration unit that will reduce the use of diesel-fuelled generation in a B.C. remote community. Globally, wave energy remains in its infancy, with single units or small arrays in demonstration underway in some European jurisdictions.

5.2.13.2 Methodology

With the available data indicating a fairly homogenous resource[11], it is not practical to predict a specific location for wave energy project development. However, as of 2010 there has been a demonstrated private sector development interest in 16 discrete sites on the B.C. Coast through the application for and granting of Investigate Use Permits and Tenure for wave energy development to the B.C. Integrated Land Management Bureau. These 16 sites are found clustered around the central and northern coasts of Vancouver Island. There are no current applications or granted tenures on the highly-energetic western coast of Haida Gwaii, but owing to the strength of the resource, it is assumed that a development interest may emerge near Haida Gwaii.

For the purposes of this report, an assumption has been made that these 16 applied or granted tenure sites as well as a speculative cluster of sites on the west coast of Haida Gwaii represent the developable wave energy resource over the 20-year time horizon. The total theoretical energy for these projects is calculated as the product of the length of the wave energy development perpendicular to the dominant wave direction, which has been estimated based on the GIS map of the Integrated Land Management Bureau (**ILMB**) tenure database, and the incoming wave power for the site from the Canadian Hydraulic Centre (**CHC**)[12] report. The extractable wave energy is related to the theoretical wave energy, but is limited by geographical, environmental and technical considerations. For the purposes of the 2013 ROR, it

[11] The near-shore wave energy resource is thought to show much greater variation due to influences of the local bathymetry, but this data is not available at the present time.
[12] CHC, Inventory of Canada's Marine Renewable Energy Resources, April 2006.

was assumed that an array of generic wave energy capture devices are notionally deployed along the length of sites perpendicular to the dominant wave direction and a simple correlation between incoming wave energy and energy production based on published device power curves was used to calculate energy production potential at each site.

The costs associated with these wave energy projects have been estimated based on the cost projections from the UK Carbon Trust report[13].

5.2.13.3 Technical and Financial Results

A summary of the technical and financial results for the wave resource option is contained in Table 5-15.

Table 5-15 Summary of Wave Potential

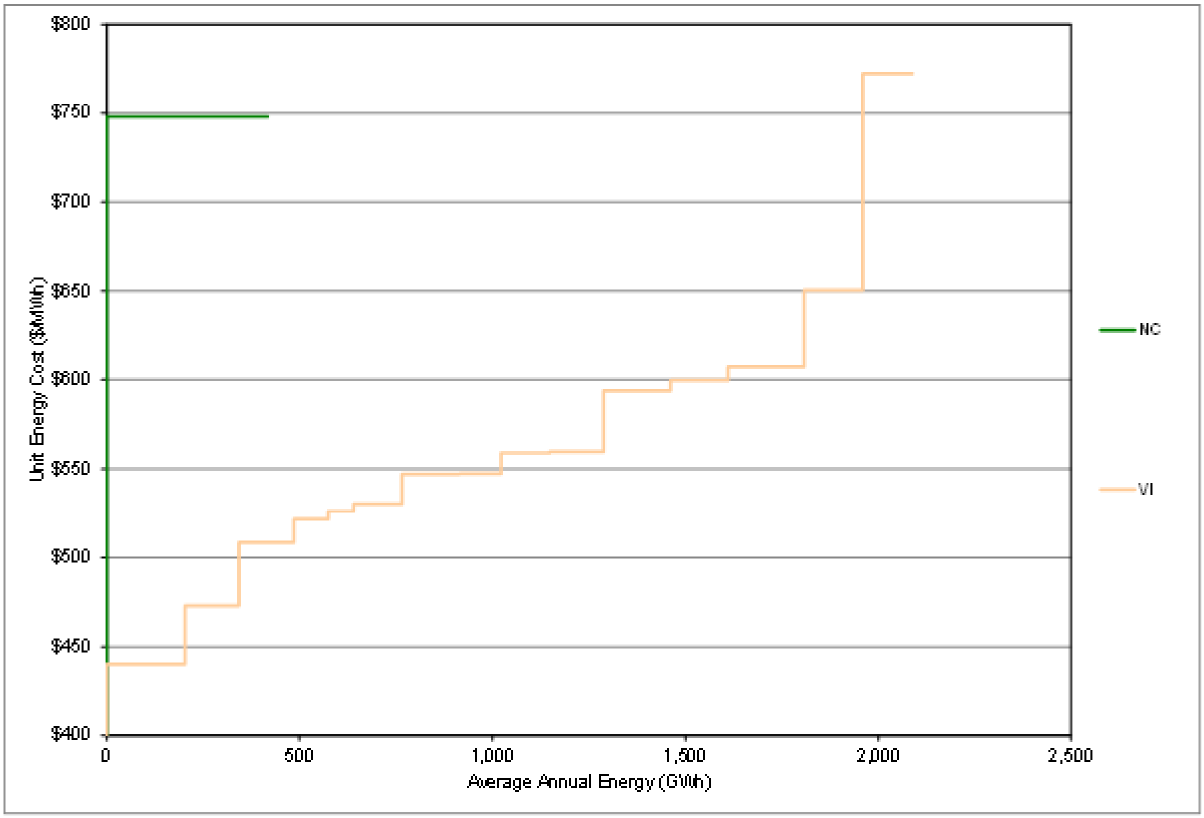
Transmission Region	Number of Projects	Installed Capacity (MW)	ELCC (MW)	Annual Energy (GWh/year)	Annual Firm Energy (GWh/year)	UEC at POI Range ($2013/MWh)
North Coast	1	143	34	418	418	748
Vancouver Island	15	936	225	2,088	2,088	440-772
Total	**16**	**1,078**	**259**	**2,506**	**2,506**	**440-772**

A map showing the distribution of the potential wave resource option is shown in Appendix 5.

The supply curves for the wave resource potential, based on POI costs, are shown in Figure 5-16.

[13] Future Marine Energy, Results of the Marine Energy Challenge: Cost Competitiveness and Growth of Wave and Tidal Stream Energy, Carbon Trust, January 2006.

Figure 5-16 Wave POI Supply Curves



5.2.13.4 Environmental and Economic Development Attributes

The environmental attributes of the wave resource option are presented in Appendix 2.

The economic development attributes are presented in Appendix 4.

5.2.13.5 Earliest In-Service Date

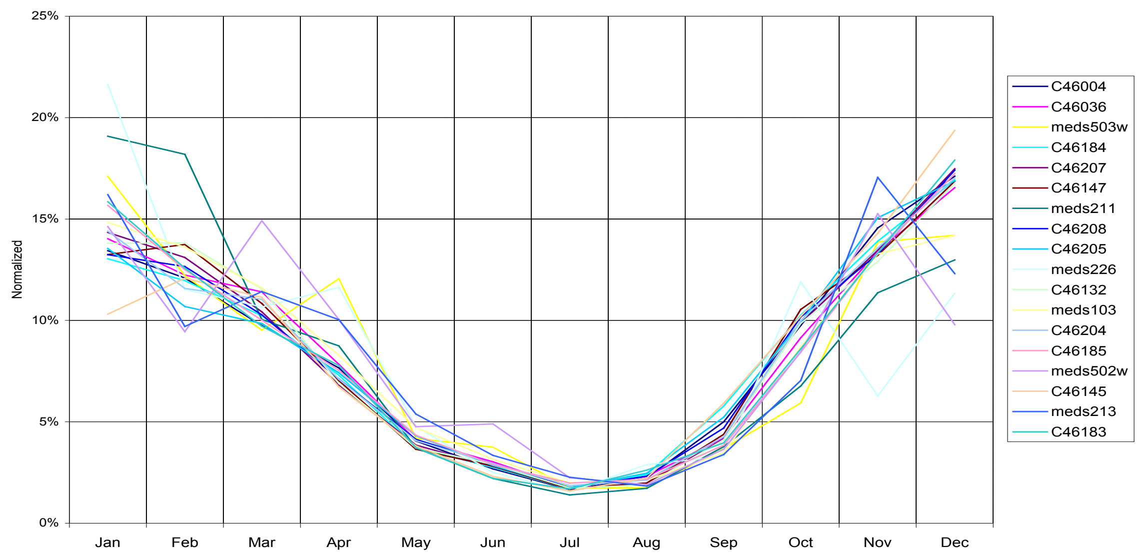
The earliest ISD for the wave resource option is 2024.

5.2.13.6 Seasonality and Intermittence

For wave energy, the seasonality and intermittence is fundamentally similar to that of offshore wind. There is significant day-to-day variability in wave energy resources in a manner similar to wind energy. There is a pronounced seasonal variability for wave energy with a strong peak in the winter months coincident with the BC Hydro system peak.

In terms of understanding the seasonality and intermittence of ocean energy, BC Hydro is appreciative of the submission of Ocean Renewable Energy Group (**OREG**) (Appendix 11). BC Hydro reproduced a graph from OREG that provides the monthly energy profile of wave power at measured and modeled locations off the B.C. coast as shown in Figure 5-17 below.

Figure 5-17 Monthly Energy Profile – Wave Potential



5.2.13.7 Uncertainty

Resource Option	Level of Study	Resource Type Related Uncertainty Rating	Cost Uncertainty Criteria
Wave	Survey	High	High (-10 per cent / +60 per cent)

5.2.14 Tidal

All inputs and analysis assumptions are identical to what were used in the 2010 ROR. In the 2013 Update, the UECs are recalculated at 7 per cent real cost of capital, and are presented in $2013.

5.2.14.1 Resource Description

Tidal energy refers to the kinetic energy available in the flow of water driven by the rotation of the Earth in the gravitational fields of the sun and the moon. Tides generally repeat themselves at a regular 24-hour 50-minute interval. However, complex interactions with the gravitational pulls of sun and moon can cause irregularities in the magnitude of the tides. Tidal energy is variable from one hour to the next, but can be precisely predicted years into the future.

Tidal energy can be captured in two different ways: tidal barrages and tidal current systems. Tidal barrages involve the construction of a dam in estuaries with a large tidal range to impound water during high tide and exploit the potential energy in the height difference between high and low tides. Tidal barrage is not considered a viable prospect in B.C. This report will focus exclusively on tidal current systems.

Tidal current systems, similar to wind energy systems, capture the kinetic energy in fast flowing tidal currents to drive a generator. The electrical generation potential is proportional to the cube of the tidal current velocity, and devices are typically located in areas where the tidal current is accelerated through a narrow channel.

There are three fundamental designs of tidal current systems:

- **Horizontal axis turbines:** the axis of a rotor is horizontal, parallel to the flow of the tidal current
- **Vertical axis turbines:** the axis of the rotor is vertical, perpendicular to the tidal current

- **Oscillating hydrofoil:** A hydrofoil is attached to an oscillating arm in the shape of a whale tail. The tidal current flowing across the hydrofoil results in a lift such that the arm swings back and forth across the tidal flow. This motion can then drive fluid in a hydraulic system to be converted into electricity.

There are two notable tidal current projects in B.C. Demonstration of a small tidal device at Race Rocks, provided power to the Pearson College ecological education and research centre, reducing the need for diesel-powered generation. A planned tidal current demonstration at Canoe Pass near Campbell River has received federal and provincial funding to install two-times 250 kW vertical axis turbines connected to the BC Hydro grid.

5.2.14.2 Methodology

The CHC report identifies the individual sites in B.C. with a mean annual tidal flow velocity sufficient to justify a theoretical tidal energy project. For these sites, the theoretical tidal energy resource is calculated based on the cube of the tidal flow velocity. The actual extractable energy at these sites is related to the theoretical energy resource, but is limited by geographical and environmental considerations unique to the site, and by technological constraints related to the efficiency of the tidal devices. For the purposes of this ROR, it was assumed that the combined geographical, environmental and technical considerations would limit the tidal energy extraction to 20 per cent of the theoretical tidal energy available at each of the sites identified in the CHC report. It is recognized that the geographies and environmental considerations at the individual sites may permit more or less than 20 per cent of the theoretical energy to be extracted, but specific evaluations are beyond the scope of this study.

The simple sum of the extractable energy from all sites identified in the CHC report may be an over-estimate of the total extractable resource owing to the dynamic interactions within the B.C. Coastal system. The 2002 Triton study[14] suggests that a mean 600 MW can be extracted from the B.C. Coastal system with modest reductions in tidal flows or environmental impacts. The 600 MW figure represents maximum energy that can be extracted from the system, of which approximately 33 per cent can be converted into electricity after accounting for inefficiencies in the tidal generation technologies. In order to estimate within an order of magnitude the total extractable energy from the B.C. system, only the larger sites with an estimated theoretical energy potential of at least 75 MW was included in the ROR, with a threshold of not more than mean 600 MW extracted from the entire system. In essence, this calculation assumes a maximum of 20 per cent of the available kinetic energy is extracted from each potential site, of which one-third is converted into electricity. A capacity factor is estimated for each site based on the average tidal velocity in order to estimate installed capacity.

Owing to the early state of commercial development, there is no real-world experience with the capital and long-term operating costs associated with tidal power at the commercial scale. In 2006, the UK Carbon Trust assessed the future costs and potential growth of marine renewables based on the results of their $4.8 million, 18-month long Marine Energy Challenge. The Carbon Trust report represents an unbiased assessment of generic tidal energy costs at the commercial scale.

5.2.14.3 Technical and Financial Results

A summary of the technical and financial results for the tidal resource option is contained in Table 5-16.

[14] Green Energy Study for British Columbia, Phase 2: Mainland, Tidal Current Energy, October 2002, prepared for BC Hydro Engineering, by Triton Consultants.

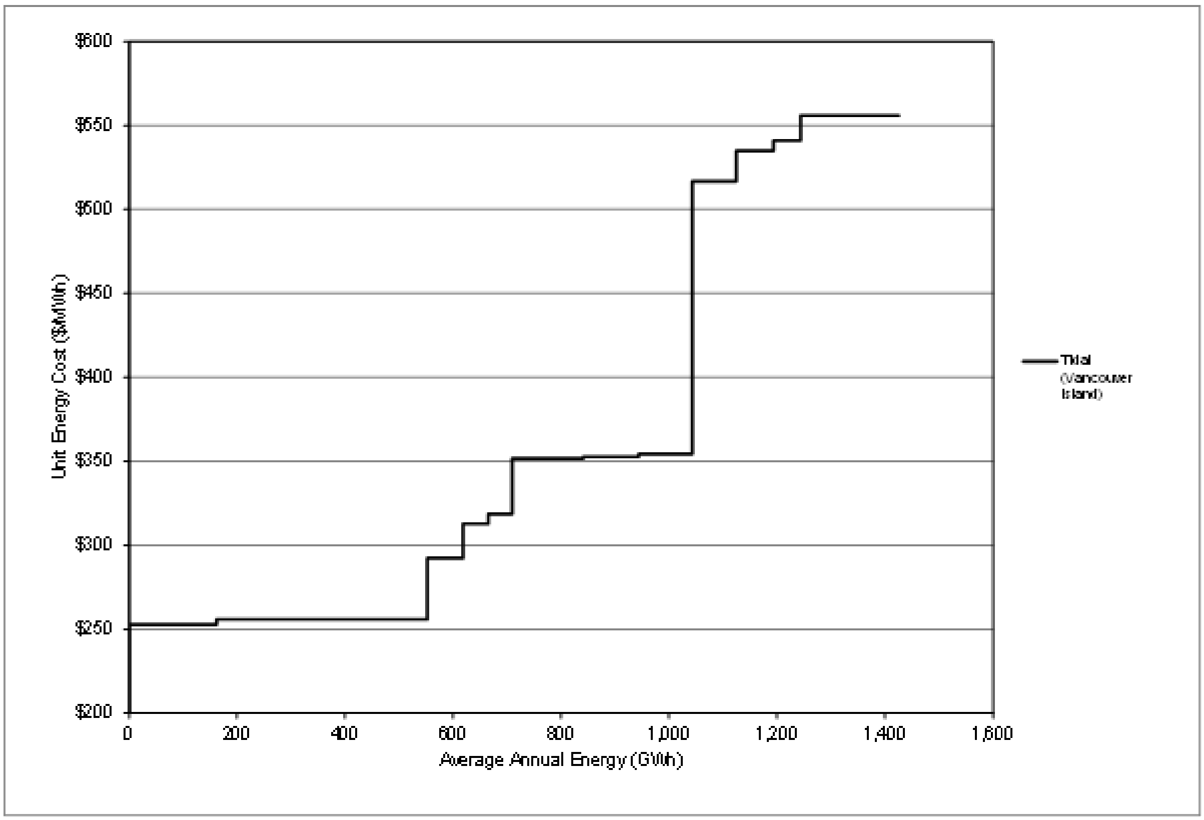
Table 5-16 Summary of Tidal Potential

Transmission Region	Number of Projects	Installed Capacity (MW)	ELCC (MW)	Annual Energy (GWh/year)	Annual Firm Energy (GWh/year)	UEC at POI Range ($2013/MWh)
Vancouver Island	12	617	247	1,426	1,426	253-556
Total	**12**	**617**	**247**	**1,426**	**1,426**	**253-556**

A map showing the distribution of the potential tidal resource option is shown in Appendix 5.

The supply curve for the tidal resource option, based on POI costs, is shown in Figure 5-18.

Figure 5-18 Tidal POI Supply Curve



5.2.14.4 Environmental and Economic Development Attributes

The environmental attributes of the tidal resource option are presented in Appendix 2.

The economic development attributes of the tidal resource option are presented in Appendix 4.

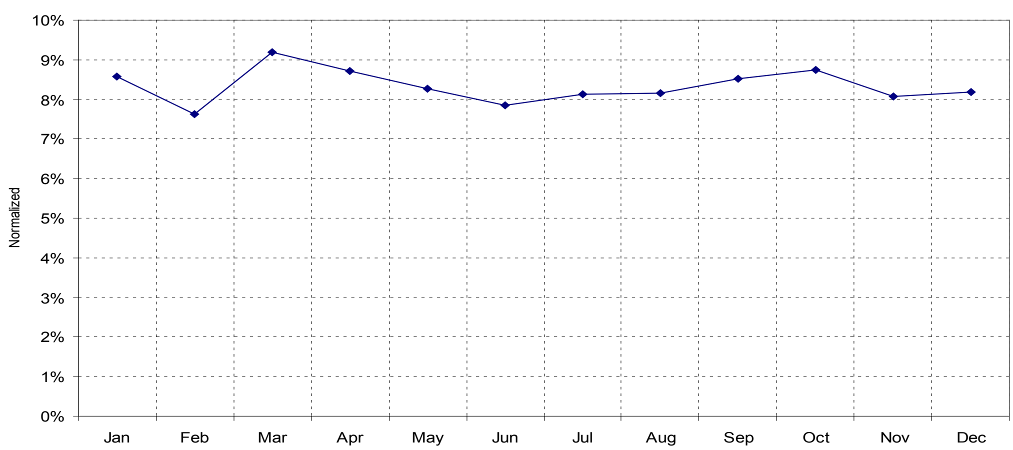
5.2.14.5 Earliest In-Service Date

The earliest ISD for the tidal resource option is 2024.

5.2.14.6 Seasonality and Intermittence

There are no major seasonal trends associated with the tidal resource option. There are predictable intermittency issue associated with the tides given the rise and fall of tides. A monthly energy profile is presented in Figure 5-19.

Figure 5-19 Monthly Energy Profile – Tidal Potential (Discovery Passage)



5.2.14.7 Uncertainty

Resource Option	Level of Study	Resource Type Related Uncertainty Rating	Cost Uncertainty Criteria
Tidal	Survey	High	High (-10 per cent / +60 per cent)

5.2.15 Hydrokinetic

An analysis of the achievable hydrokinetic generation potential in BC is not possible due to the absence of data describing the raw resource or the expected locations, sizes and costs of hydrokinetic development projects.

Resource Description

Hydrokinetic energy – also called “river in-stream” or “river current” energy – refers to the kinetic energy from flowing water in rivers. Hydrokinetic energy systems convert the kinetic energy in free-flowing rivers into electricity without the use of dams or diversions. Unlike conventional hydroelectric systems, hydrokinetic systems do not require a hydraulic head, depending rather on the swift moving river similar to tidal current or wind energy systems.

Hydrokinetic electrical generation potential is proportional to the cube of the river current velocity, and devices are typically located in areas with fast river currents and substantial flow volumes for significant portions of the year.

There are three fundamental turbine designs:

- **Horizontal axis turbines:** the axis of a rotor is horizontal, parallel to the flow of the river current
- **Vertical axis turbines:** the axis of the rotor is vertical, perpendicular to the river current.
- **Paddlewheels:** the axis of the rotor perpendicular to the river current and often above the surface of the water

There are currently no active hydrokinetic demonstration projects in B.C.

5.2.15.1 Methodology

Due to the limited data availability and the absence of a rigorous resource estimate, an assessment of hydrokinetic energy potential in B.C. cannot be presented in this report. Hydrokinetic resources may be updated in subsequent resource estimates following the completion of a National Resources Canada (**NRCan**) study to assess the hydrokinetic resource potential in Canada.

5.2.16 Storage Technologies

The commercial readiness for various storage technologies are updated based on EPRI's 2012 report.

5.2.16.1 Resource Description

Energy storage is now recognised as a key component to future grid asset management and operations. BC Hydro is fortunate in having an abundance of storage in the form of hydro reservoirs. However, there are several possible reasons for installing additional storage at all levels of the power system including the:

- Potential to defer capital expenditure on transmission or distribution assets
- Potential to increase the longevity of assets through reduced peak load
- Potential to decrease any reliance on importing power at peak
- Potential provision of ancillary services such as voltage and frequency regulation
- Support of intermittent energy supply

Recent advances and focus in development of energy storage have focused on a variety of technologies for a variety of functions within the electrical grid system:

Compressed Air Energy Storage (**CAES**) has been used to improve the efficiency of natural gas turbines, compressing the air off-peak and releasing it into the combustion cycle during peak. Compressed air can improve the efficiency of the combustion cycle by as much as 40 per cent. To date this technology has been implemented in large facilities using underground caverns. The technology has been explored for use with intermittent and seasonal renewable energy sources to store energy that is generated but not immediately used to serve load. Smaller scale, above ground CAES systems are currently being assessed for economic viability.

Pumped storage is well established commercially as a means to store energy. This resource option is addressed in section 5.2.8 of this report.

Capacitors store energy in the form of electric charge. As such it can be released very rapidly, which is why these types of systems are used as voltage regulators on transmission and distribution grids. Generally capacitors are used for short bursts of power and are not useful for applications in which energy is required to be discharged over periods of time longer than a few seconds. Advances in capacitors have focused on increasing their energy density. However, these types of devices are still in the early stages of development.

Flywheels store energy as inertia or mechanical energy. To date they have been used for reactive power applications with their ability to produce short intense bursts of power. Flywheels can have efficiencies as high as 90 per cent.

Batteries come in many different chemistries generally falling into two distinct categories: solid state and flow. Solid state batteries are contained, do not require pumps or other moving parts and rely on the closure of a conducting loop to allow a flow of electrons that either charge or discharge the battery. Flow batteries rely on chemicals that are pumped through a membrane and require periodic refreshing.

Solid state battery technologies that are available include Sodium Sulphur (**NaS**), Lithium ion (**Li-ion**), Advanced Lead Acid and Metal Air.

Hydrogen Fuel Cell Storage Systems combine electrolysers with fuel cells to create a means to store electricity. These types of systems have been implemented in some cases where a large excess of energy is needed to be stored (e.g., excess wind energy) however the current systems suffer from a very poor round-trip efficiency (< 40 per cent) which makes them unattractive for most applications.

Figure 5-20 summarizes the range of applications of existing storage technologies.

Figure 5-20 Range of Application of existing Storage Technologies

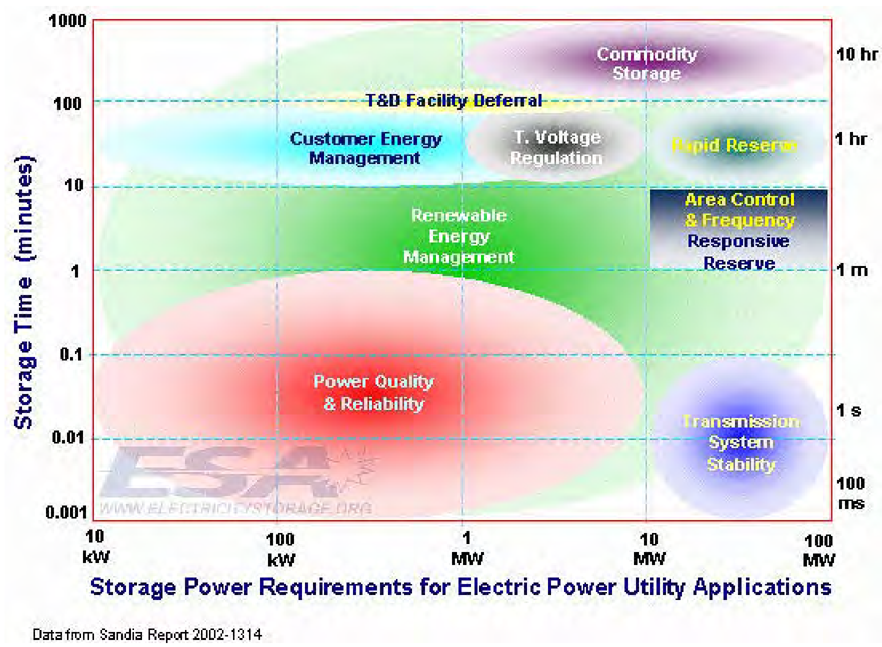


Table 5-17 summarises the different storage technologies and their respective commercial readiness.

Table 5-17 Summary of Storage Technologies and Applications

Storage Technology	Function	Commercial Readiness[15]
CAES	Bulk storage for intermittent renewables	Commercial
Pumped storage	Bulk storage for intermittent renewables	Commercial
Flywheel	Smoothing of fluctuating intermittent renewables, frequency and voltage regulation	Commercial
Capacitors	Frequency and voltage regulation	Commercial at small scale and for high power, low energy applications. Not available for high energy applications
Batteries	Distributed energy storage for peak shaving and islanding. Voltage regulation and storage for small scale renewables.	
NaS		Commercial
Li-ion		Early Commercial
Adv. Lead Acid		Demonstration
Metal-Air		R&D
Zinc Bromine		Demonstration
Vanadium redux		Demonstration
Fuel cell systems	Storage for medium to large scale renewables	Early Commercial

5.2.16.2 Methodology

Pumped storage is the only storage resource option that is considered to be within scope for long-term system planning purposes. The pumped storage resource option is described in section 5.2.8 of the 2013 ROR Update. At this time, no further assessment of storage options has been undertaken.

[15] Commercial readiness reported as per EPRI “Electricity Energy Storage Technology Options”, 2012

5.2.17 Solar

The cost assumptions are updated to reflect the most recent trends seen at the utility-scale PV plants. In the 2013 Update, the UECs are calculated at 7 per cent real cost of capital, and are presented in $2013.

5.2.17.1 Resource Description

Solar power, where electricity can be generated from the energy within the sun rays, can be categorized into two main categories: Concentrating Solar Power (**CSP**) and Photovoltaic (**PV**).

PV is the other branch of solar power. It converts solar energy directly into direct-current (**DC**) electricity. Unlike CSP which requires high direct irradiation, PV can operate under direct or diffuse solar irradiation. Typically, each module can provide up to 50 to 200 Watts. This technology is small relative to CSP, and is available not only from a utility perspective, but can also be available in residential[16] and commercial scale. The two broad categories are crystalline silicon (**c-Si**) and thin films.

With silicon being one of the most abundant elements on earth and the c-Si technology fairly mature, it makes up approximately 85 per cent of the global PV market today. Current c-Si has a conversion efficiency of 15 to 20 per cent, best among commercially available technologies.

The idea of developing lower cost PV alternatives leads to thin films. Thin films, accounting for most of the remaining PV market, are made of extremely thin layers of photosensitive materials on backing such as glass, stainless steel or plastic. As this technology evolves in search for higher efficiency, semiconductor compounds such as Cadmium Telluride (**CdTe**) and Copper-Indium-Gallium-Diselenide (**CIGS**) are being used. Although thin films have lower materials costs and higher production

[16] Under Rate Schedule 1289 – Net Metering Service, customers with their own generation facilities (up to 50 kW from clean or renewable resources) that produce more than they consume receive a credit from BC Hydro that goes to their account and can be applied against future consumption charges. As of July 2012, there are 168 BC Hydro Net Metering projects in operation, including 149 solar projects.

efficiency, they are offset by lower efficiencies relative to c-Si. Among the current types of thin film technologies, the conversion efficiency ranges from 10 to 15 per cent. As well, the potential health and safety concerns that Cadmium introduces may discourage increased adoption of this technology.

In order to achieve higher performance, a third type of PV is being considered. Similar to the idea of concentrating sunlight to an area like in the CSP, concentrated photovoltaic (**CPV**) technology uses optics such as lenses or curved mirrors to concentrate a large amount of sunlight onto a small area of solar PV cells. Making up less than one per cent of the PV market, CPV has the potential to reach over 30 per cent conversion efficiency. Further research and development are required to bring the high cost lower.

Concentrating solar power is a technology where with the use of mirrors, it concentrates a large area of sunlight onto a small area. This concentrated light will heat a fluid where the steam produced will then drive a turbine and generates power. In addition, it has the capability for storing heat in insulated containers for usage at a later date. Here are four types of CSP:

Parabolic Troughs: have large mirrors that shaped like a “U”, and concentrate light onto a receiver pipe along the inside of the curved surface. The solar radiation will heat the fluid inside the pipe, where the steam is then used to generate electricity in a conventional steam generator. It is made to follow the sun during the daylight hours by tracking along a single axis. The collector is aligned North-South and track the sun as it moves from East to West in order to maximize the collection of energy. The parabolic troughs are the most widely commercially deployed CSP plant.

Linear Fresnel: uses long rows of flat or slightly curved mirrors to capture solar radiation and concentrate them onto a linear receiver tube. Advantage of linear CSP is it uses cheaper flat glass mirrors, and requires less steel and concrete as the metal support structure is lighter. However, it is less efficient than parabolic troughs.

Solar Tower: utilize a large number of flat solar tracking mirrors called heliostats which concentrate the solar radiation on a receiver at the top of a tower. A heat transfer fluid, which can be water, oil or even molten salt[17], contained in the receiver is used to create steam which spins a conventional turbine that drives an electricity generator. Power towers are more cost effective, offering higher efficiency and better energy storage capability among the CSP technologies.

Dish-Stirling: utilize a large parabolic solar dish that focuses the solar radiation onto a receiver located at the focal point. The dish is usually coupled with a Stirling engine. Although this technology can achieve the highest efficiency among all CSP technologies, it is still at the demonstration stage and the cost of mass producing this product remains uncertain.

Direct Normal Irradiance (**DNI**), the amount of solar radiation from the direction of the sun, is often used to determine whether the location is suitable for CSP. IEA indicated that arid or semi-arid regions between latitude 15° to 40° north or south have the optimal location required to acquire good amount of DNI. According to their CSP roadmap published in 2010, CSP developers typically set a bottom threshold of DNI levels of 1,900 kWh/m^2/year to 2,100 kWh/m^2/year. Below that, photovoltaic are assumed to have a competitive advantage.

5.2.17.2 Methodology

Due to the various options within CSP and PV, finding one investment, operation and maintenance costs that can be applied to all technologies will be difficult. Aside from material costs, other costs depend on the availability of sunlight, whether the facility has storage capacity and the size of the plant. For example, solar tower, in general, has higher costs than the parabolic troughs; however, its higher efficiency can help in lowering the overall investment costs. According to the

[17] Molten salt raises the potential operating temperature to between 550 to 650 Celsius, enough to allow higher efficiency supercritical steam cycles. In addition, it provides an efficient, low-cost medium in which to store thermal energy.

Black & Veatch's (**B&V**) Cost Report[18], the total capital cost for a trough CSP with storage is $7,060/kW while a tower CSP with storage comes to $7,040 kW. Due to these high costs and the geographic location in B.C., CSP is deemed to be non-competitive relative to other resources.

When considering cost and data in the rest of the section, the focus will be on c-Si. The solar resource assessment and figures assessed in this section is a non-tracking utility PV with a 5 MW install size. Solar isolation data from NRCan was used to identify the best solar location in ten different areas through the province. The monthly PV potentials were obtained from the NRCan database. Based on information found in B&V Cost Report, the total capital cost for a utility-scale PV plant is approximately $2,830/kW, with O&M costs assumed to be $50/kW-yr. The modules and inverters are considered equipment cost, making up 57 per cent of the total. The at-gate construction, which includes the structures as well as the balance-of-system (i.e., wirings, switches, support racks) are 36 per cent while sunk costs like engineering, procurement, construction management services and owner's cost make up the final 7 per cent.

Seasonality was addressed using the monthly profile from NRCan database.

Project lead time for permitting is estimated to be three years, with the construction lead time adding an additional year.

5.2.17.3 Technical and Financial Results

A summary of the technical and financial results for the solar resource option are contained in Table 5-18.

[18] Black and Veatch Cost and Performance Data for Power Generation Technologies Report (February 2012)

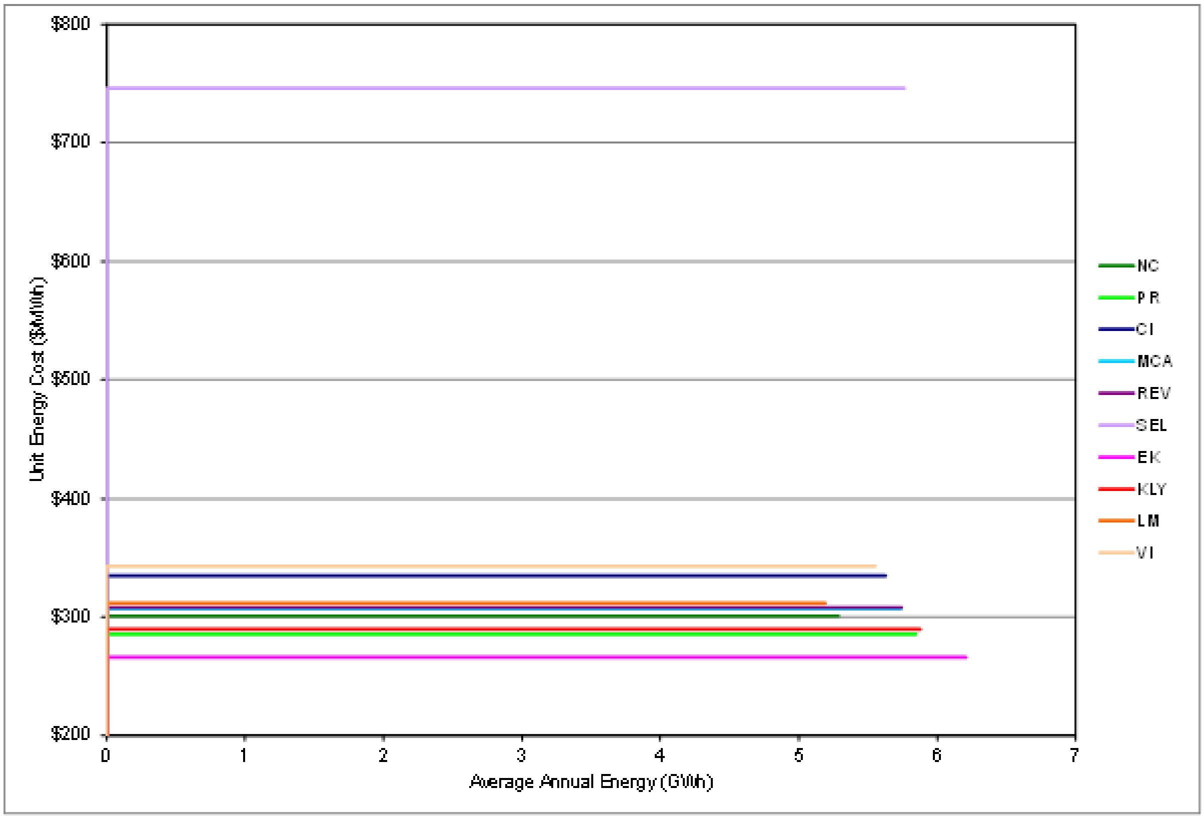
Table 5-18 Summary of Solar Potential

Transmission Region	Number of Projects	Installed Capacity (MW)	ELCC (MW)	Annual Energy (GWh/year)	Annual Firm Energy (GWh/year)	UEC at POI Range ($2013/MWh)
Peace River	1	5	1	6	6	286
North Coast	1	5	1	5	5	301
Central Interior	1	5	1	6	6	335
Kelly Nicola	1	5	1	6	6	290
Mica	1	5	1	6	6	307
Revelstoke	1	5	1	6	6	308
Vancouver Island	1	5	1	6	6	343
Lower Mainland	1	5	1	5	5	312
Selkirk	1	5	1	6	6	746
East Kootenay	1	5	1	6	6	266
Total	**10**	**50**	**12**	**57**	**57**	**266 - 746**

A map showing the distribution of the potential solar resource option is shown in Appendix 5.

The supply curves for the solar resource potential based on POI costs, by transmission region, are shown in Figure 5-21.

Figure 5-21 Solar POI Supply Curves



5.2.17.4 Environmental and Economic Development Attributes

The environmental attributes of the solar resource option are presented in Appendix 2.

The economic development attributes of the solar resource option are presented in Appendix 4.

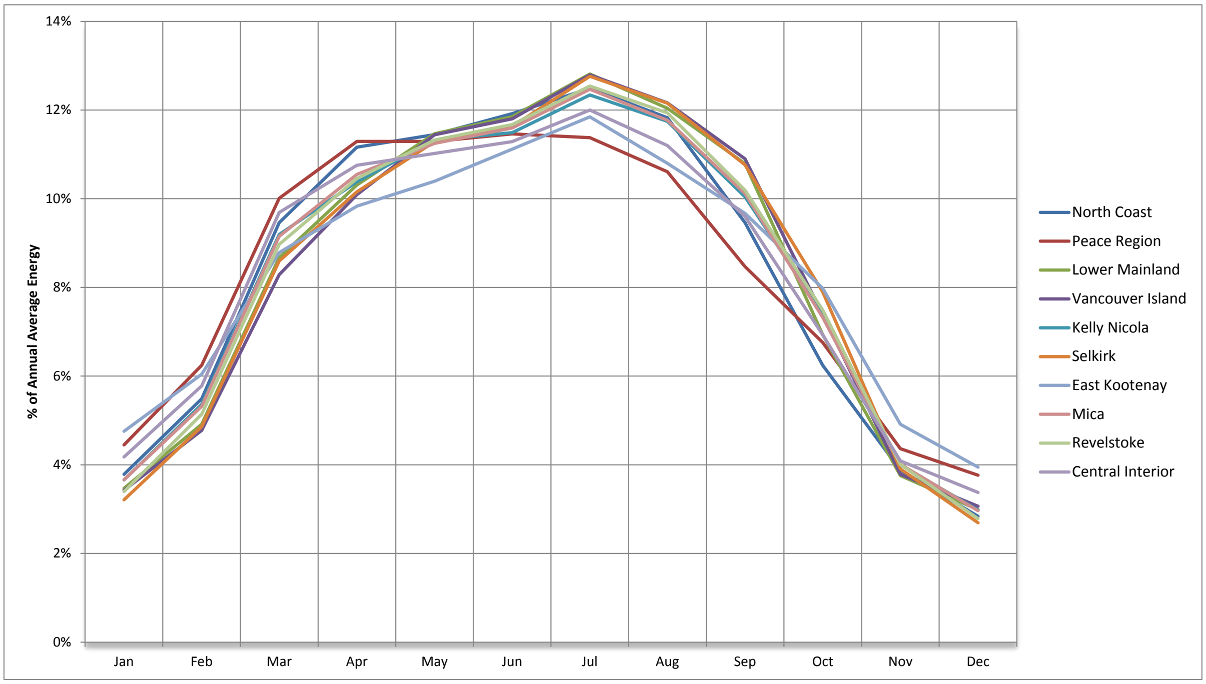
5.2.17.5 Earliest In-Service Date

The earliest ISD for the solar resource option is 2017.

5.2.17.6 Seasonality and Intermittence

The seasonality of solar resources is shown in Figure 5-22 for each of the transmission regions.

Figure 5-22 Normalized Monthly Solar Energy Profiles by Transmission Region



In order to concentrate the sunlight in the CSP technology, it needs unobstructed sunshine, measured in DNI, under clear sky condition. On the other hand, PV technology can use both direct and diffuse solar radiation. In B.C., solar power generation is intermittent, pending on the location, the amount of PV potential and fluctuation in cloudiness.

5.2.17.7 Uncertainty

Resource Option	Level of Study	Resource Type Related Uncertainty Rating	Cost Uncertainty Criteria
Solar	Survey	Low	Medium (-10 per cent / +40 per cent)

5.2.18 Miscellaneous Distributed Generation

5.2.18.1 Resource Description

In 2008, BC Hydro began formalizing, in consultation with key stakeholders, a Distributed Generation (**DG**) strategy to explore potential DG across its customer base. For the purposes of this initiative, BC Hydro defined DG as:

> An approach whereby smaller-scale generation of electricity is located close to the load it is intended to serve, often located at customer sites. It can be contrasted to the traditional model of larger-scale and centralized electricity generation that is located a substantial distance away from load.

DG can be either a demand side or supply side resource, or a combination of both. How a customer pursues DG is based on several factors including: the customer's profile and objectives, the specific project, the technology and generation potential, and the cost and value to BC Hydro.

BC Hydro undertook the development of a strategic process including pilot projects to help advance DG projects with its customers to better understand the market potential for DG, and recognizing the need to design an efficient and cost-effective process for potential projects given BC Hydro's current suite of power acquisition offers. While DG is not a new concept for BC Hydro or its customers, BC Hydro believes that additional DG potential exists and could be explored. A number of DG-related programs and projects have been completed or are already in place, including:

- Approximately 250 projects are in service under BC Hydro's net metering program (projects up to 50 kW)
- 2001 40GWh RFP
- 2002 Customer Based-Generation Call
- 2006 Open Call for Power
- 2009 Bioenergy Phase 1 Call

- 2010 community-Based Biomass Call
- 2011 Bioenergy Phase 2 Call
- Standing Offer Program up to 15 MW
- 2009-2012 Integrated Power Offer

Based on feedback received during the development of the Net Metering Evaluation Report No. 3 posted at https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/independent-power-producers-calls-for-power/net-metering/net-metering-evaluation-report-april2013.pdf, coupled with BC Hydro's review of our current DG processes, BC Hydro has identified gaps between its existing processes and developed an approach on how to bridge those gaps with a seamless suite of offers that span demand-side and supply-side opportunities.

Next steps include increasing the Net Metering cap from 50 kW to 100 kW for commercial, institutional, industrial, municipal and First Nation customers; provided there will be no adverse cost impacts on non-participating ratepayers; and begin the design of a streamlined acquisition process that supports small-scale DG projects (50 kW to 1 MW) under the umbrella of the Standing Offer Program.

Benefits of Distributed Generation

From the customer's viewpoint, DG may offer energy independence, new choices of electricity supply, enhanced power reliability and improved quality.

For utilities, DG may offer benefits such as the potential to avoid transmission and distribution system upgrade costs, reduced line losses, and the freeing up of system capacity to address non-distributed load growth.

On a provincial scale, DG may contribute to self-sufficiency, encourage diversity in sectors such as forestry and agriculture, create efficiencies with commercial, industrial, municipal and residential customers, and advance near commercial and emerging technologies and applications with customers.

5.2.18.2 Methodology

Same as 2010 ROR, for the purposes of the 2013 ROR Update, DG potential is not presented as a separate resource option. DG potential is captured within the demand-side management potential and the supply-side resource options, as presented in sections 4 and 5 of the report.

5.2.19 Other Capacity Options

The Canadian Entitlement is the Canadian portion of the potential for additional electricity produced in the Columbia River in the western U.S. as a result of the Columbia River Treaty ratified in 1964. The Province owns the Canadian Entitlement and Powerex markets the energy under an agreement with the Province. While the Province receives the financial benefits of the Canadian Entitlement, BC Hydro has access to the physical product (energy and capacity) and can use it as a source of limited supply. As this supply is not “solely from electricity facilities within the Province”, given the self-sufficiency requirement in the *CEA*, the Canadian Entitlement is not a source of dependable capacity in the long term, and therefore, the role of the Canadian Entitlement is limited as a bridging or contingency resource option.

5.2.20 Nuclear

Nuclear has not been included in the 2013 ROR Update as Policy Action No. 23 of the B.C. Government’s 2007 BC Energy Plan provides that the B.C. Government “rejects nuclear power as a strategy to meet British Columbia’s energy needs”. This is reiterated in B.C. *CEA*, which specifies the objective of not using nuclear power.

5.2.21 Generation Resource Potential Results Summary

The inventory of potential supply-side resource options at the POI is summarized by transmission region in Table 5-19.

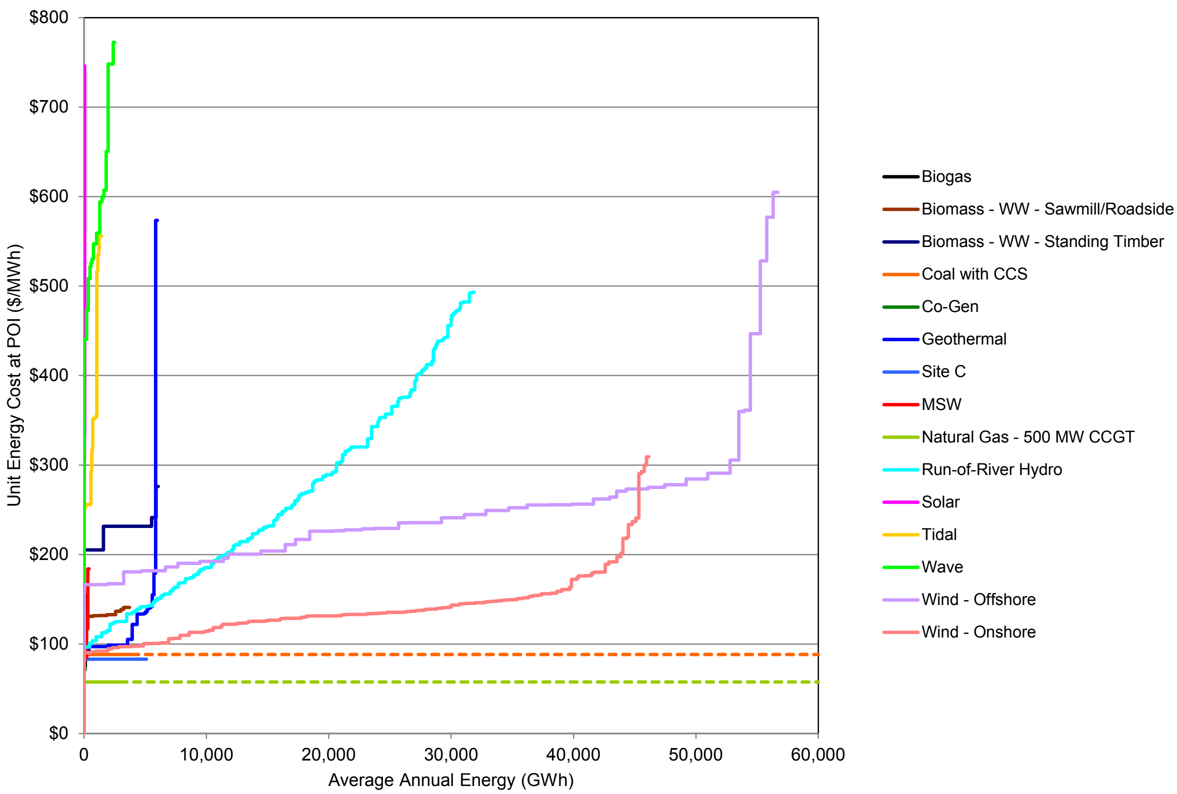
Table 5-19 Inventory of Supply-Side Generation Resource Potential by Transmission Region

Resource Type		Peace River	North Coast	Central Interior	Kelly Nicola	Mica	Revelstoke Ashton Creek	Vancouver Island	Lower Mainland	Selkirk	East Kootenay	Total
		Transmission Regions										
Woodbased Biomass	DGC (MW)	102	259	41	60	-	-	335	335	66	28	1,226
	Firm Egy. (GWh/yr)	815	2,063	325	476	-	-	2,669	2,669	530	225	9,772
Biogas Biomass	DGC (MW)	-	-	2	4	-	-	2	4	4	-	16
	Firm Egy. (GWh/yr)	-	-	17	33	-	-	19	32	33	-	134
MSW Biomass	DGC (MW)	-	-	-	-	-	-	12	25	13	-	50
	Firm Egy. (GWh/yr)	-	-	-	-	-	-	101	211	112	-	425
Onshore Wind	ELCC (MW)	1,525	1,062	273	874	-	167	289	23	22	36	4,271
	Firm Egy. (GWh/yr)	18,083	11,400	2,660	8,437	-	1,674	3,143	249	194	324	46,165
Offshore Wind	ELCC (MW)	-	3,203	-	-	-	-	616	-	-	-	3,819
	Firm Egy. (GWh/yr)	-	47,397	-	-	-	-	9,303	-	-	-	56,700
Geothermal	DGC (MW)	20	270	-	20	-	20	70	320	60	-	780
	Firm Egy. (GWh/yr)	140	2,111	-	140	-	140	534	2,505	420	-	5,992
Run of River	ELCC (MW)	2	226	43	31	32	32	420	310	13	41	1,149
	Firm Egy. (GWh/yr)	88	5,786	1,597	1,809	1,928	1,648	4,802	4,189	835	1,861	24,543
Pumped Storage	DGC (MW)	-	37,000	-	4,000	465	-	79,000	105,000	-	-	225,465
	Firm Egy. (GWh/yr)	-	-	-	-	-	-	-	-	-	-	-
Site C	DGC (MW)	1,100	-	-	-	-	-	-	-	-	-	1,100
	Firm Egy. (GWh/yr)	4,700	-	-	-	-	-	-	-	-	-	4,700
Resource Smart (Rev 6)	DGC (MW)	-	-	-	-	-	488	-	-	-	-	488
	Firm Egy. (GWh/yr)	-	-	-	-	-	26	-	-	-	-	26
Natural Gas-fired	DGC (MW)	-	-	-	862	-	-	101	10	-	-	973
	Firm Egy. (GWh/yr)	-	-	-	6,177	-	-	159	80	-	-	6,416
Coal-Fired with CCS	DGC (MW)	556	-	-	-	-	-	-	-	-	-	556
	Firm Egy. (GWh/yr)	3,896	-	-	-	-	-	-	-	-	-	3,896
Wave	ELCC (MW)	-	34	-	-	-	-	225	-	-	-	259
	Firm Egy. (GWh/yr)	-	418	-	-	-	-	2,088	-	-	-	2,506
Tidal	ELCC (MW)	-	-	-	-	-	-	247	-	-	-	247
	Firm Egy. (GWh/yr)	-	-	-	-	-	-	1,426	-	-	-	1,426
Solar	ELCC (MW)	1	1	1	1	1	1	1	1	1	1	12
	Firm Egy. (GWh/yr)	6	5	6	6	6	6	6	5	6	6	57
Total Dependable Capacity and ELCC (MW)		3,306	42,056	359	5,852	498	708	81,317	106,028	180	106	240,410
Total Firm Energy (GWh/yr)		27,728	69,180	4,604	17,079	1,934	3,495	24,250	9,941	2,130	2,416	162,756

Notes: 1. The RoR values represent the potentials with UEC under $500/MWh.
2. Site C data presented in this table is based on information provided in the Site C EIS submission filed in January 2013.
3. Representative projects were used to characterize the natural gas-fired and coal-fired generation resource options.

In order to facilitate a high-level comparison of costs for the inventory of generation resource potential, Figure 5-23 provides an overview of the base UECs at POI.

Figure 5-23 Supply-Side Generation Resource Potential Supply Curve Summary – Base UECs $/MWh at POI



Notes:

1. Representative projects were used to characterize the natural gas-fired and coal-fired resource options. Dotted lines indicate additional potential.
2. The Site C values presented in this figure are based on information provided in the Site C EIS submission filed in January 2013.
3. The run-of-river results shown above have been summarized for resources with a UEC under $500/MWh.

A more detailed overview of base UECs at POI under $200/MWh, and a summary of the uncertainties associated with the data are presented in Table 5-20.

Table 5-20 Supply-Side Generation Resource Potential – UEC Values at POI below $200/MWh

Resource Type	Project Name	Transmission Region	Average Annual Energy (GWh)	UEC @ 7% Real ($2013/MWh)	Level of Study	Resource Type Uncertainty	Cost Uncertainty
Biogas	Bailey	LM	12	59	Pre-feasibility	Medium	High
Biogas	Comox Valley	VI	8	69	Pre-feasibility	Medium	High
Biogas	Foothills Blvd	CI	17	70	Pre-feasibility	Medium	High
Biogas	Minnie's Pit	LM	7	70	Pre-feasibility	Medium	High
Biogas	Cache Creek	KL	27	73	Pre-feasibility	Medium	High
Biogas	Glenmore	SL	18	73	Pre-feasibility	Medium	High
Biogas	Alberni valley	VI	7	75	Pre-feasibility	Medium	High
Biogas	Greater Vernon	SL	7	91	Pre-feasibility	Medium	High
Biogas	Campbell Mtn	SL	7	95	Pre-feasibility	Medium	High
Biogas	Ecowaste	LM	13	96	Pre-feasibility	Medium	High
Biogas	Mission Flats	KL	6	106	Pre-feasibility	Medium	High
Biogas	Campbell River	VI	4	154	Pre-feasibility	Medium	High
Biomass WW - RSD/SMW	WBBio_WPR	NC	97	122	Survey	Medium	Medium
Biomass WW - RSD/SMW	WBBio_EPR	NC	98	123	Survey	Medium	Medium
Biomass WW - RSD/SMW	WBBio_WK	SL	530	131	Survey	Medium	Medium
Biomass WW - RSD/SMW	WBBio_SP	PR	446	132	Survey	Medium	Medium
Biomass WW - RSD/SMW	WBBio_VI	VI	707	132	Survey	Medium	Medium
Biomass WW - RSD/SMW	WBBio_LM	LM	707	133	Survey	Medium	Medium

Resource Type	Project Name	Transmission Region	Average Annual Energy (GWh)	UEC @ 7% Real ($2013/MWh)	Level of Study	Resource Type Uncertainty	Cost Uncertainty
Biomass WW - RSD/SMW	WBBio_MAC	CI	325	137	Survey	Medium	Medium
Biomass WW - RSD/SMW	WBBio_PG	NC	106	137	Survey	Medium	Medium
Biomass WW - RSD/SMW	WBBio_EK	EK	225	139	Survey	Medium	Medium
Biomass WW - RSD/SMW	WBBio_KM	KL	476	141	Survey	Medium	Medium
Coal-fired generation with CCS	750 MW Integrated Gasification Combined Cycle	PR	3,896	88	Survey	High	High
Co-gen	Small Co-generation projects	LM	80	74	Survey	Low	Medium
Geothermal	Mt. Garibaldi	LM	394	91	Survey	High	High
Geothermal	Mt. Edziza	NC	1,577	97	Survey	High	High
Geothermal	Pebble Creek	LM	788	99	Survey	High	High
Geothermal	South Meager Creek	LM	788	99	Feasibility	High	High
Geothermal	Mt. Cayley	LM	394	105	Survey	High	High
Geothermal	Hoodoo Mountain	NC	394	122	Survey	High	High
Geothermal	Mt. Silverthrone	VI	394	134	Survey	High	High
Geothermal	Kootenay Lake	SL	140	134	Survey	High	High
Geothermal	Hudson's Hope	PR	140	134	Survey	High	High
Geothermal	Lakelse Lake	NC	140	136	Survey	High	High
Geothermal	Harrison Hot Springs	LM	140	139	Survey	High	High
Geothermal	Canoe Creek/ Valemont	KL	140	141	Survey	High	High
Geothermal	Upper Arrow Lake	REV	140	142	Survey	High	High

Resource Type	Project Name	Transmission Region	Average Annual Energy (GWh)	UEC @ 7% Real ($2013/MWh)	Level of Study	Resource Type Uncertainty	Cost Uncertainty
Geothermal	Lower Arrow Lake	SL	140	155	Survey	High	High
Geothermal	Okanagan Valley	SL	140	179	Survey	High	High
Large Hydro - Site C	Site C Clean Energy Project	PR	5,100	83 *	Feasibility	Medium	Medium
MSW	MSW2_LM	LM	211	85	Pre-feasibility	Medium	High
MSW	MSW1_VI	VI	101	117	Pre-feasibility	Medium	High
MSW	MSW3_SE	SL	112	184	Pre-feasibility	Medium	High
Natural Gas	500 MW Combined Cycle Gas Turbine	KL	2,940	58	Pre-feasibility	Medium	High
Natural Gas	250 MW Combined Cycle Gas Turbine	KL	1,450	62	Pre-feasibility	Medium	High
Natural Gas	50 MW Combined Cycle Gas Turbine	KL	300	92	Pre-feasibility	Medium	High
Run of River Hydro	ROR_80-100_LM	LM	224	97	Survey	Low	Medium
Run of River Hydro	ROR_90-100_KN	KL	220	97	Survey	Low	Medium
Run of River Hydro	ROR_100-110_KN	KL	217	101	Survey	Low	Medium
Run of River Hydro	ROR_100-110_LM	LM	329	104	Survey	Low	Medium
Run of River Hydro	ROR_100-110_VI	VI	450	108	Survey	Low	Medium
Run of River Hydro	ROR_110-120_VI	VI	386	113	Survey	Low	Medium
Run of River Hydro	ROR_110-120_NC	NC	135	115	Survey	Low	Medium

Resource Type	Project Name	Transmission Region	Average Annual Energy (GWh)	UEC @ 7% Real ($2013/MWh)	Level of Study	Resource Type Uncertainty	Cost Uncertainty
Run of River Hydro	ROR_110-120_BQL	NC	158	115	Survey	Low	Medium
Run of River Hydro	ROR_110-130_KN	KL	173	122	Survey	Low	Medium
Run of River Hydro	ROR_120-130_MCA	MCA	104	123	Survey	Low	Medium
Run of River Hydro	ROR_120-130_EK	EK	147	124	Survey	Low	Medium
Run of River Hydro	ROR_120-130_VI	VI	116	125	Survey	Low	Medium
Run of River Hydro	ROR_120-130_SE	SL	88	125	Survey	Low	Medium
Run of River Hydro	ROR_120-140_NC	NC	90	125	Survey	Low	Medium
Run of River Hydro	ROR_120-130_LM	LM	649	125	Survey	Low	Medium
Run of River Hydro	ROR_130-140_VI	VI	492	134	Survey	Low	Medium
Run of River Hydro	ROR_120-140_REV	REV	131	136	Survey	Low	Medium
Run of River Hydro	ROR_130-140_LM	LM	206	137	Survey	Low	Medium
Run of River Hydro	ROR_130-150_EK	EK	94	139	Survey	Low	Medium
Run of River Hydro	ROR_130-150_SE	SL	189	139	Survey	Low	Medium
Run of River Hydro	ROR_140-150_VI	VI	558	142	Survey	Low	Medium

Resource Type	Project Name	Transmission Region	Average Annual Energy (GWh)	UEC @ 7% Real ($2013/MWh)	Level of Study	Resource Type Uncertainty	Cost Uncertainty
Run of River Hydro	ROR_130-150_KN	KL	117	142	Survey	Low	Medium
Run of River Hydro	ROR_140-150_LM	LM	326	143	Survey	Low	Medium
Run of River Hydro	ROR_140-160_MCA	MCA	35	145	Survey	Low	Medium
Run of River Hydro	ROR_140-150_REV	REV	149	147	Survey	Low	Medium
Run of River Hydro	ROR_140-160_BQL	NC	199	149	Survey	Low	Medium
Run of River Hydro	ROR_140-160_NC	NC	319	151	Survey	Low	Medium
Run of River Hydro	ROR_150-170_EK	EK	193	154	Survey	Low	Medium
Run of River Hydro	ROR_150-160_REV	REV	75	155	Survey	Low	Medium
Run of River Hydro	ROR_150-160_LM	LM	461	156	Survey	Low	Medium
Run of River Hydro	ROR_150-170_SE	SL	218	159	Survey	Low	Medium
Run of River Hydro	ROR_150-170_KN	KL	131	162	Survey	Low	Medium
Run of River Hydro	ROR_160-170_LM	LM	325	164	Survey	Low	Medium
Run of River Hydro	ROR_160-170_CI	CI	167	168	Survey	Low	Medium
Run of River Hydro	ROR_160-170_VI	VI	374	168	Survey	Low	Medium

Resource Type	Project Name	Transmission Region	Average Annual Energy (GWh)	UEC @ 7% Real ($2013/MWh)	Level of Study	Resource Type Uncertainty	Cost Uncertainty
Run of River Hydro	ROR_170-180_CI	CI	49	172	Survey	Low	Medium
Run of River Hydro	ROR_170-180_LM	LM	295	173	Survey	Low	Medium
Run of River Hydro	ROR_160-180_NC	NC	90	174	Survey	Low	Medium
Run of River Hydro	ROR_160-180_REV	REV	142	174	Survey	Low	Medium
Run of River Hydro	ROR_160-180_MCA	MCA	134	174	Survey	Low	Medium
Run of River Hydro	ROR_170-190_KN	KL	158	177	Survey	Low	Medium
Run of River Hydro	ROR_170-180_VI	VI	232	178	Survey	Low	Medium
Run of River Hydro	ROR_170-190_BQL	NC	154	181	Survey	Low	Medium
Run of River Hydro	ROR_180-190_CI	CI	156	183	Survey	Low	Medium
Run of River Hydro	ROR_170-190_SE	SL	68	184	Survey	Low	Medium
Run of River Hydro	ROR_170-190_EK	EK	111	184	Survey	Low	Medium
Run of River Hydro	ROR_180-190_LM	LM	401	185	Survey	Low	Medium
Run of River Hydro	ROR_180-200_NC	NC	166	186	Survey	Low	Medium
Run of River Hydro	ROR_180-200_REV	REV	195	190	Survey	Low	Medium

Resource Type	Project Name	Transmission Region	Average Annual Energy (GWh)	UEC @ 7% Real ($2013/MWh)	Level of Study	Resource Type Uncertainty	Cost Uncertainty
Run of River Hydro	ROR_180-200_MCA	MCA	162	193	Survey	Low	Medium
Run of River Hydro	ROR_180-200_VI	VI	168	194	Survey	Low	Medium
Run of River Hydro	ROR_190-200_BQL	NC	174	196	Survey	Low	Medium
Run of River Hydro	ROR_190-210_KN	KL	168	198	Survey	Low	Medium
Run of River Hydro	ROR_190-210_LM	LM	264	199	Survey	Low	Medium
Run of River Hydro	ROR_190-210_SE	SL	143	200	Survey	Low	Medium
Wind - Offshore	Wind_OBC24-1	VI	1892	166	Pre-feasibility	Medium	High
Wind - Offshore	Wind_OBC25-1	VI	1347	167	Pre-feasibility	Medium	High
Wind - Offshore	Wind_OBC28	VI	1442	181	Pre-feasibility	Medium	High
Wind - Offshore	Wind_OBC8-1	NC	1967	182	Pre-feasibility	Medium	High
Wind - Offshore	Wind_OBC29	VI	1014	186	Pre-feasibility	Medium	High
Wind - Offshore	Wind_OBC7-1	NC	1812	190	Pre-feasibility	Medium	High
Wind - Offshore	Wind_OBC14-1	NC	1911	192	Pre-feasibility	Medium	High
Wind - Offshore	Wind_OBC3	NC	403	196	Pre-feasibility	Medium	High
Wind - Onshore	Wind_PC28	PR	591	90	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_PC21	PR	371	92	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_PC19	PR	441	92	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_PC13	PR	541	92	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_PC16	PR	377	95	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_PC14	PR	527	96	Pre-feasibility	Low	Medium

Resource Type	Project Name	Transmission Region	Average Annual Energy (GWh)	UEC @ 7% Real ($2013/MWh)	Level of Study	Resource Type Uncertainty	Cost Uncertainty
Wind - Onshore	Wind_PC10	PR	1,023	97	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_PC20	PR	609	98	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_PC15	PR	382	98	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_PC09	PR	713	100	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_PC11	PR	473	101	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_PC41	PR	155	101	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_PC42	PR	219	101	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_PC18	PR	486	101	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_PC26	PR	416	106	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_PC48	PR	505	106	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_PC06	PR	761	110	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_NC09	NC	1,025	113	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_VI12	VI	151	113	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_VI14	VI	113	113	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_PC27	PR	333	114	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_PC40	PR	350	115	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_VI13	VI	105	118	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_SI12	REV	545	119	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_VI15	VI	126	121	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_PC05	PR	353	122	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_SI23	KL	569	122	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_NC10	CI	280	122	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_PC25	CI	450	123	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_PC12	PR	308	123	Pre-feasibility	Low	Medium

Resource Type	Project Name	Transmission Region	Average Annual Energy (GWh)	UEC @ 7% Real ($2013/MWh)	Level of Study	Resource Type Uncertainty	Cost Uncertainty
Wind - Onshore	Wind_SI20	KL	122	124	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_PC17	PR	315	125	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_PC43	PR	139	125	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_PC47	PR	108	125	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_SI15	KL	814	126	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_PC37	PR	231	126	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_BC20	NC	294	127	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_BC22	NC	697	127	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_VI08	VI	113	128	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_PC04	PR	349	128	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_PC34	PR	906	129	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_NC07	NC	322	129	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_SI22	KL	126	130	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_SI10	KL	313	130	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_SI14	REV	232	131	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_VI07	VI	502	131	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_NC01	NC	1729	132	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_BC18	NC	426	132	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_SI19	KL	148	133	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_SI04	KL	253	133	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_SI16	KL	1632	133	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_NC12	NC	230	134	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_VI05	VI	703	134	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_PC32	PR	368	134	Pre-feasibility	Low	Medium

Resource Type	Project Name	Transmission Region	Average Annual Energy (GWh)	UEC @ 7% Real ($2013/MWh)	Level of Study	Resource Type Uncertainty	Cost Uncertainty
Wind - Onshore	Wind_SI18	KL	335	135	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_SI32	SL	89	135	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_BC21	NC	589	135	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_NC02	NC	666	136	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_BC19	NC	279	136	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_PC36	PR	425	136	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_SI05	KL	355	137	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_SI27	LM	249	137	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_PC38	PR	330	138	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_SI37	EK	87	138	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_PC44	PR	105	138	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_SI11	REV	330	139	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_PC01	PR	455	139	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_NC11	CI	195	139	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_BC25	CI	426	140	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_NC08	NC	463	141	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_SI28	KL	261	141	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_SI13	REV	567	143	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_VI10	VI	89	144	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_BC23	NC	278	145	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_VI11	VI	112	145	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_PC03	PR	222	145	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_SI03	KL	355	145	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_PC07	PR	325	145	Pre-feasibility	Low	Medium

Resource Type	Project Name	Transmission Region	Average Annual Energy (GWh)	UEC @ 7% Real ($2013/MWh)	Level of Study	Resource Type Uncertainty	Cost Uncertainty
Wind - Onshore	Wind_SI01	KL	553	146	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_PC29	PR	201	146	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_SI38	EK	237	147	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_VI06	VI	333	147	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_VI02	VI	467	148	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_SI30	KL	396	148	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_BC08	NC	490	149	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_BC13	NC	481	150	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_SI29	KL	314	150	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_BC26	KL	376	151	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_SI09	KL	212	151	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_SI06	KL	294	152	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_PC24	CI	285	153	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_PC23	CI	150	154	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_PC02	PR	371	154	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_SI08	KL	256	155	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_BC17	PR	824	156	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_BC09	NC	438	157	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_PC08	PR	130	159	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_SI26	KL	263	159	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_SI31	KL	340	161	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_BC24	CI	321	161	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_SI02	KL	151	164	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_PC22	CI	442	172	Pre-feasibility	Low	Medium

Resource Type	Project Name	Transmission Region	Average Annual Energy (GWh)	UEC @ 7% Real ($2013/MWh)	Level of Study	Resource Type Uncertainty	Cost Uncertainty
Wind - Onshore	Wind_PC45	CI	111	174	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_BC15	PR	623	176	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_BC10	NC	458	176	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_VI04	VI	178	179	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_NC06	NC	554	180	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_BC11	NC	386	181	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_BC12	NC	290	189	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_NC05	NC	660	192	Pre-feasibility	Low	Medium
Wind - Onshore	Wind_BC07	PR	333	198	Pre-feasibility	Low	Medium

Notes:

1. Resource options presented alphabetically and values rounded to the nearest integer.
2. Representative projects were used to characterize the natural gas-fired and coal-fired generation resource options.
3. UECs for natural gas-fired options are based on natural gas price estimates from BC Hydro's 2013 Market Scenario 1.
4. The Site C values presented in this table are based on information provided in the Site C EIS submission filed in January 2013, and the UEC is calculated assuming 5 per cent real cost of capital.
5. For presentation purposes, the bundling results have been limited to results below $200/MWh.

The inventory of energy resource potential, by resource type, is summarized in Table 5-21 as follows:

Table 5-21 Summary of Supply-Side Energy Resource Potential by Resource Type – UEC Values at POI

Energy Resource	Total Annual Energy (GWh/year)	Total Dependable Generation Capacity (MW)	UEC @ 7% real cost of capital, at POI ($2013/MWh)
Biomass – Wood Based	9,772	1,226	122 – 276
Biomass – Biogas	134	16	59 – 154
Biomass – MSW	425	50	85 – 184
Wind – Onshore	46,165	4,271	90 – 309
Wind – Offshore	56,700	3,819	166 – 605
Geothermal	5,992	780	91 – 573
Run-of-river	31,880	1,149	93 – 500
Large Hydro - Site C	5,100	1,100	83 *
CCGT and Cogeneration	4,770	774	60 – 94
Coal with CCS	3,896	556	88
Wave	2,506	259	440 – 772
Tidal	1,426	247	253 – 556
Solar	57	12	266 – 746

Notes:

1. Representative projects were used to characterize the natural gas-fired and coal-fired generation resource options.
2. The Site C values presented in this table are based on information provided in the Site C EIS submission filed in January 2013 using estimates of annual energy of 5,100 GWh/year, dependable capacity of 1,100 MW and base UEC (at 5 per cent real) at POI of $80/MWh in 2011$ based on capital cost of $7.9 billion.
3. The run-of-river results shown above have been summarized for resources with a UEC under $500/MWh.

The supply-side capacity options inventory is summarized in Table 5-22 as follows:

Table 5-22 Summary of Supply-Side Capacity Resource Potential – UCC at POI Summary

Resource Type	Capacity Option	Transmission Region	Dependable Capacity (MW)	UCC @ 7% real cost of capital, at POI ($2013/kW·year)
Resource Smart	GMS Units 1-5 Capacity Increase	PR	220	35 *
Resource Smart	Revelstoke Unit 6	REV	488	50 *
Natural Gas-fired Generation	SCGT at Kelly/Nicola	KL	98	84
Pumped Storage	PS at Mica Generating Station	MCA	465	100 *
Pumped Storage	Kenyon – Stave	LM	1,000	118
Pumped Storage	Upper Deserted - Un-named	LM	1,000	118
Pumped Storage	Upper Vancouver - Lower Vancouver	LM	1,000	120
Pumped Storage	Upper Vancouver - Lower Misery	LM	1,000	120
Pumped Storage	Haynon - Chochiwa	KL	1,000	121
Pumped Storage	Burwell - Seymour	LM	1,000	121
Pumped Storage	Blinch – Stave	LM	1,000	122
Pumped Storage	Palisade - Seymour	LM	1,000	124

Notes:
1. GMS Units 1-5 Capacity Increase numbers are based on conceptual level estimates.
2. SCGT and Pumped Storage only include fixed costs.
3. UCCs for GMS Units 1-5 Capacity Increase, Revelstoke Unit 6, and PS at Mica Generating Station are calculated assuming 5 per cent real cost of capital.
4. A SCGT representative project is used to characterize the Natural Gas resource option.
5. Presentation of PS data is limited to results below $125/kW-year.

As discussed in section 5.2.19, BC Hydro also has access to the capacity associated with the CE and this capacity is relied upon as a contingency resource, not a long-term planning option.

5.3 Bulk Transmission Resource Options

To be able to serve customers with electricity, BC Hydro must both connect the generation resources to the electric system and deliver that electricity to customers through the transmission system. In addition, the B.C. CEA requires that BC Hydro identify long-term transmission requirements in the long-term system resource planning process.

To achieve this mandate BC Hydro has reviewed the transmission options required to remove congestion from various sections of BC Hydro's bulk transmission network. In the next section, transmission congestion is described and existing transmission limits are specified. Following that, a list of options for addressing congestion is provided.

5.3.1 Transmission Paths, Cut-Planes, and Congestion

Figure 5-24 provides an overview of the BC Hydro's transmission system, paths and cut-planes. A transmission path consists of one or several transmission lines which transfer power between two regions. Cut-planes are imaginary lines that cut through one or more transmission paths to identify transmission bottlenecks of an integrated network. When the expected flow on a cut-plane exceeds its thermal, voltage stability, or transient stability limits, the cut-plane is constrained and requires incremental capacity. In this diagram the red lines indicate the existing 500 kV transmission lines, the green lines indicate the 230 kV transmission lines, the blue lines indicate the 138 kV transmission lines and the black lines cutting across the red transmission lines are the cut-planes indicating the areas of congestion for which the basket of transmission resource options were identified. The direction of the arrows indicates the typical direction of power flow, i.e., the transfer of power from the supply side of the cut-plane towards its load side.

Figure 5-24 Overview of Transmission System and Cut-Planes

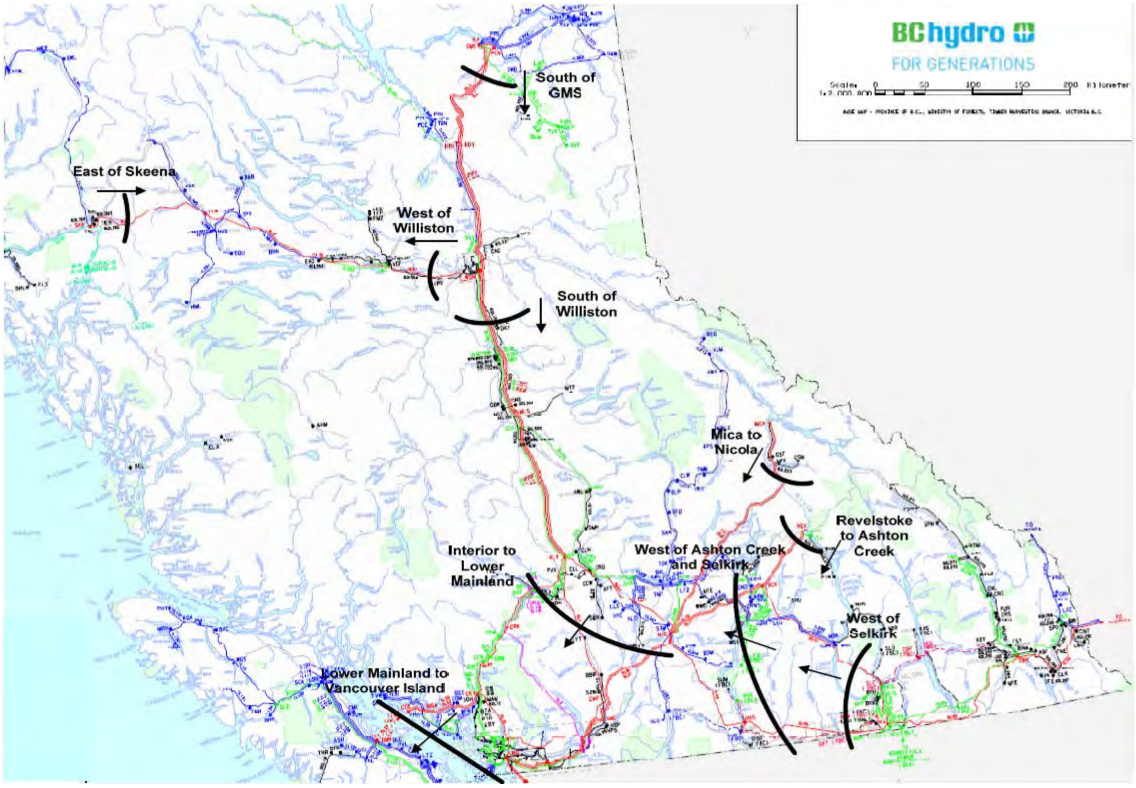


Table 5-23 outlines total transfer capability (**TTC**) and the limiting constraint for each one of the BC Hydro's bulk transmission cut-planes.

Table 5-23 Cut-Plane Capacities

No.	Cut-plane	TTC (MW) 2010/2011	Limiting Load Condition	Limiting Constraint
1	South of GMS	3590	Heavy Winter	Voltage Stability
		3620	Light Winter	Voltage Stability
2	South of Williston	3060	Heavy Winter	Voltage Stability
		3340	Light Winter	Voltage Stability
3	East of Skeena	1000	Light Summer	Transient Stability
4	West of Williston	695	Heavy Winter	Voltage Stability
5	West of Selkirk	1910	Heavy Winter	Voltage Stability
		2320	Heavy Summer	Voltage Stability
6	West of Ashton Creek/Selkirk	3270	Heavy Winter	Voltage Stability
		4020	Heavy Summer	Voltage Stability
7	Mica to Nicola	1650	All Seasons	Voltage Stability
8	Revelstoke to Ashton Creek	3000	Winter	Thermal Limits
		2060	Summer	Thermal Limits
9	Interior to Lower Mainland	~ 5000	All Seasons	Thermal Limits
10	Lower Mainland to Vancouver Island	2000	Winter	Thermal Limits
		1900	*Summer*	Thermal Limits

5.3.2 Bulk Transmission Options

Table 5-24 identifies transmission options that BC Hydro is considering over a 30-year transmission resource planning horizon. In this table, each transmission option includes a brief description, a construction lead time, a direct capital cost, an expected added capacity and the applicable line length. Some transmission reinforcements enhance transfer capacity of more than one transmission cut-plane. For these transmission options, all impacted cut-planes and their respective incremental transmission capacities are identified. All cost estimates are in 2013 dollars and do not include overhead and interest during construction.

Table 5-24 also includes transmission projects which are at various phases of their completion. These projects include new Nicola – Meridian 500 kV line 5L83 and series compensation of 500 kV circuits 5L71 and 5L72. Both of these projects will be modelled in future resource planning load/resource scenarios at their respective ISDs. Table 5-24 is not inclusive of all possible solutions but captures the ones that have been previously reviewed. In the analysis phase of the resource planning process, BC Hydro intends to remove potential bulk transmission constraints by modeling the incremental transfer capacities that appropriate transmission options provide.

Scope, schedule, and cost of the listed transmission options are approximate. More accurate information would be prepared as a particular option becomes necessary.

Table 5-24 Transmission Reinforcement Options Considered in Long-Term Resource Planning

Item No.	Upgrade Option Description	Lead Time (Years)	2013 Direct Cost ($Million)	Incremental Capacity (MW)	Line Length (km)
	North Interior				
TO-01	New 500 kV, 50 per cent series compensated transmission circuit 5L8 between GMS and Williston.	8	388.3	1470	278
TO-02	New 500 kV, 50 per cent series compensated transmission circuit 5L14 between Williston and Kelly Lake.	8	341.1	2120	330
TO-03	New +/-500 kV HVDC bipole transmission circuit between Peace River and Lower Mainland - Phase 1.	8	1,482.9	1000	928
TO-04	New +/-500 kV HVDC bipole transmission circuit between Peace River and Lower Mainland - Phase 2.	8	246.8	1000	N/A
TO-05	Series compensation upgrade at Kennedy from 50 per cent to 65 per cent on GMS to Williston 500 kV lines 5L1, 5L2, 5L3 and 5L7 with thermal upgrades to 3000A rating.	3	59.5	360 (CI-KLY/NIC) and 300 (PR-CI)	N/A
TO-06	Series compensation upgrade at McLeese from 50 per cent to 65 per cent on Williston to Kelly 500 kV lines 5L11, 5L12 and 5L13 with thermal upgrades to 3000A rating.	3	57.2	390 (CI-KLY/NIC) and 330 (PR-CI)	N/A

Item No.	Upgrade Option Description	Lead Time (Years)	2013 Direct Cost ($Million)	Incremental Capacity (MW)	Line Length (km)
TO-07	500 kV Shunt compensation: At Williston add one 300 MVAr SVC and two 250 MVAr switchable capacitor banks. At Kelly Lake add one 250 MVAr shunt capacitor.	3	65.1	650 (CI-KLY/NIC) and 580 (PR-CI)	N/A
	North Coast				
TO-08	New 500 kV circuit Williston-Glenannan-Telkwa-Skeena parallel to the existing 5L61 - 5L62 and 5L63 lines.	8	1,031.6	970	449
TO-09	Series compensation of the WSN-SKA 500 kV lines 5L61, 5L62 and 5L63 plus voltage support and transformation addition in the existing BC Hydro substations.	3	142.3	580	N/A
TO-21	A new +/-500 kV HVDC bipole transmission circuit between WSN and SKA.	8	1,091.6	2000	449
	South Interior				
TO-10	New 500 kV, 50 per cent series compensated transmission circuit 5L97 between Selkirk and Vaseaux Lake.	8	226.7	750	163
TO-11	New 500 kV, 50 per cent series compensated transmission circuit 5L99 between Vaseaux Lake and Nicola.	8	196.3	750	138
TO-12	50 per cent series compensation of the 500 kV lines 5L91 and 5L98.	3	61.8	133 (SEL-KLY/NIC) and 147 (SEL-REV/ACK)	N/A
TO-13	50 per cent series compensation of 500 kV lines 5L71 and 5L72.	Committed in 2014	46.0	950	N/A
TO-14	50 per cent series compensation of 500 kV lines 5L76, 5L79, and 5L96.	3	60.3	112	N/A
TO-19	50 per cent Series compensation of 500 kV line 5L92 SEL-CBK.	3	31.2	150	N/A

Item No.	Upgrade Option Description	Lead Time (Years)	2013 Direct Cost ($Million)	Incremental Capacity (MW)	Line Length (km)
TO-20	A new 500 kV line between Selkirk and Cranbrook parallel to the existing 500 kV line 5L92.	8	651.1	1550	180
	Interior to Lower Mainland				
TO-15	New 500 kV, 50 per cent series compensated transmission circuit 5L83 between Nicola and Meridian.	Committed in 2015	609.2	1550	247
TO-16	New 500 kV, 50 per cent series compensated transmission circuit 5L46 between Kelly Lake and Cheekye.	8	656.7	1384	197
TO-17	500 kV and 230 kV shunt compensation: At Meridian 230 kV add two 110 MVAr capacitor banks At Nicola 500 kV add one 250 MVAr capacitor bank.	3	10.1	570	N/A
	Lower Mainland to Vancouver Island				
TO-18	New 230 kV transmission circuit 2L124 between Arnott and Vancouver Island terminal.	6	230.1	600	67

Note: TO-15 presented in this table is based on information filed with BCUC in November 2011.

5.3.3 Transmission Expansion Projects

Not all BC Hydro transmission projects are driven by the elimination of transmission congestion. Some of the ongoing and under review projects are to expand the existing network to supply electricity to remote communities, to benefit from potential resources in the remote areas, and to improve trade opportunities.

BC Hydro’s transmission planning process includes one transmission expansion project known as the Northwest Transmission Line (**NTL**). The NTL is a 344 km, 287 kV circuit from Skeena substation (near Terrace) to a new substation to be built near Bob Quinn Lake. It is designed to provide power to remote northwest parts of the province and to facilitate connection of new generation resources to the grid. The expected ISD for this project is spring 2014.

The Northeast Transmission Line (**NETL**) is an example of the current transmission expansion studies. In the NETL studies, BC Hydro assessed supply of significant load growth in the Fort Nelson and the Horn River Basin (**HRB**) regions, driven by prospects for natural gas production-related activities. The studies are based on forecasts for natural gas production and associated raw gas treatment and gas processing facilities, resulting in an electricity demand in the range of 350 MW to 1100 MW.

The studies looked at interconnecting the Fort Nelson/HRB regions to the BC Hydro integrated system, through a new 550 km transmission interconnection running from GMS to Fort Nelson/HRB. Given the distances and the wide range of load expectations, the voltages examined were 230 kV and 500 kV. A 500-kV transmission interconnection would facilitate integration of up to 1500 MW of wind power projects in the Hackney Hills area (about 100 km north of GMS), as well as up to 300 MW of natural gas production-related and other loads in the same vicinity.

The studies also examined supplying load growth in the Fort Nelson/HRB regions through local gas-fired generation using a variety of gas turbine technologies and configurations. Co-generation alternatives, involving production of both electricity and heat (steam) for gas processing purposes were included.

5.3.4 Regional Transmission Projects

The main focus of the integrated resource planning process is to identify major bulk transmission upgrades and transmission facilities required for interconnecting new resources to the grid. As such, the ongoing planning work to accommodate the growing regional demand at sub-transmission and distribution voltages is not covered in this process. Details of regional transmission projects are published through the capital planning process.

One example of the regional transmission projects is Dawson Creek / Chetwynd Area Transmission project (**DCAT**). This project, which received a Certificate of Public Convenience and Necessity (**CPCN**) from the BCUC in April 2013, is driven by the rapid load growth in Dawson Creek area and would build a new 60 km, 230 kV double circuit from the future Sundance substation (19 km east of Chetwynd) to Bear Mountain Terminal (**BMT**) near Dawson Creek. Another 12 km of 230 kV double circuit transmission lines would connect the expanded Dawson Creek Substation to BMT. The expected project in-service date is June 2015.

The conceptual second phase of the DCAT project is known as the Peace Region Electrical Supply (**PRES**) project, previously known as GDAT (GMS to Dawson Creek Area Transmission). This includes BC Hydro's plan for the reliable supply of additional new loads in the South Peace region. DCAT's CPCN is considered a prerequisite for the PRES project.

Details of regional transmission projects are published through the capital planning process.

5.3.5 Transmission for Export

BC Hydro is exploring the opportunity to create new transmission capacity between B.C. and power markets in the Mid-C and California. This effort will enable trading of B.C.'s surplus energy. In addition, it will allow BC Hydro, IPPs, and energy traders to have access to the U.S. markets.

BC Hydro considers the resource planning process to be an appropriate platform for assessing different levels of power export. It is recognized that the existing transmission congestion along the I-5 corridor on the Pacific North West makes a new transmission path from eastern part of B.C. to Mid-C and California more viable than other options. The Selkirk substation (**SEL**) is viewed as a suitable modeling hub for collecting B.C.'s excess energy and transferring it to the U.S.

In modeling, a generic 500 kV single tower transmission path from SEL to Devil's Gap Substation near Spokane in Washington State is considered as the new transmission link between B.C. and U.S. Depending on the level of power transfer to the U.S., the SEL – Devil's Gap transmission path is configured with one or two 500 kV transmission circuit(s).

The SEL – Devil's Gap circuit fits within the scope of a future hybrid transmission path from eastern B.C. to northern California. This transmission path is also known as the Canada-Northwest-California (**CNC**) project. The CNC transfers up to 3,000 MW power from B.C.'s renewable resources to Northern California and includes a double circuit 500 kV high-voltage alternating current (**HVAC**) line from SEL to Devil's Gap Substation to North East Oregon Substation (**NEO**) and a +/-500 kV HVDC bipole from NEO to Collinsville Substation near San Francisco. The CNC partners have abandoned the CNC project for the foreseeable future.

Any investment in the expansion of the transmission network for exporting power to the US will depend on a strong demand for importing BC's clean energy. Until such demand is proven, expansion of the BC's transmission tie-lines remains conceptual.

5.3.6 Transmission for Interconnecting Individual New Resources

In the resource options review phase of the planning process, the cost of interconnecting individual new resources to the existing transmission grid is estimated. The cost breakdown includes: the cost of the power line, the cost of the new sectionalizing substation for interconnecting the power line to an existing BC Hydro high voltage line[19], and the cost of termination and possible voltage transformation at an existing BC Hydro substation.

To assess the cost of the power line, transmission voltage level needs to be known. For each new generation resource the transmission voltage level is determined based on the rated output of generating plant and its distance from the nearest BC Hydro transmission facility. Table 5-25 provides the estimated per kilometre cost of overhead lines and submarine cables. Table 5-26 and Table 5-27 are generic estimates of interconnecting substation cost and transformation cost in 2011 dollars.

[19] In the Resource Options phase of the IRP process, a new substation is considered only for interconnecting 25 kV, 69 kV, 138 kV, 230 kV and 287 kV power lines to the existing lines with similar voltages.

Table 5-25 Unit Cost of Power Lines

New Power Line Voltage (kV)	Cost ($/km), $2011			
	Average Overhead Line Slope (0-15 per cent)	Average Overhead Line Slope (16-30 per cent)	Average Overhead Line Slope (>30 per cent)	Submarine Cable
25	84,800	169,600	254,400	500,000
69	106,000	212,000	318,000	1,000,000
138	159,000	318,000	477,000	3,600,000
230	265,000	530,000	795,000	5,300,000
500	530,000	1,060,000	1,590,000	7,100,000

Table 5-26 Interconnection Substation Cost

New Power Line Voltage (kV)	Interconnecting Substation Cost ($2011, millions)
25	1.5 (0.4 for tapping an existing line)
69	7.5
138	9.5
230 (or 287)	10.5

Table 5-27 Voltage Transformation Cost

New Generation Power Line Voltage (kV)	Transformation Cost ($2011, millions)						
	25 and 35	69	138	230	287	360	500
25	0	1.5	1.5	1.5	1.5		
69		0	7.5	7.5	7.5	7.5	
138			0	12	12	15	18
230				0	0	13.5	16.5
500							0

Notes:

1. In absence of information, the sectionalizing substation cost was used.
2. There was no transformation cost assumed since the power line would likely be built at 287, which would be a similar cost to a 230 kV.

5.4 Comparison to the 2010 ROR

There is no fundamental methodology change in the 2013 ROR Update, but the information obtained in the 2010 ROR was reviewed for material changes to availabilities or costs. BC Hydro resources and those resource options bid into previous acquisitions processes by IPPs have been reviewed and updated.

In addition, the UECs and UCCs have been updated for all resource options using BC Hydro's updated Weight Average Cost of Capital to reflect long-term forecasts of project borrowing costs and the lower financing costs available in the markets. In the 2013 Update, BC Hydro-owned projects utilized a 5 per cent real cost of capital; third party developed projects utilized a 7 per cent real cost of capital.

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Chapter 6

Unit Energy Cost Adjustment

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6.1 Introduction

In Chapter 5, the unit energy costs (**UECs**) for each generation resource option at the point of interconnection (**POI**) are shown. These UECs represent the estimated overall cost of both non-firm and firm energy, and are based on the sum of three component-costs: costs within plant gate, road costs, and transmission interconnection costs.

In the past (2006 Integrated Electricity Plan and 2008 Long-Term Acquisition Plan), concerns were raised by stakeholders and participants that it is difficult to compare these UECs of resource options with diverse characteristics located in different areas of the province.

In order to facilitate a high level comparison of costs across resource types and to reflect the cost of resources delivered to the Lower Mainland (the load centre of the BC Hydro system), a cost adjustment process has been applied. The cost adjustment process assumes that the non-firm energy is valued at the market price from BC Hydro's 2013 market scenario 1 and adjustments are then made to each resource option's firm UEC in order to reflect the cost of delivering firm energy to the Lower Mainland and the value of the resource option in meeting BC Hydro system needs. This process intends to reflect the value and impact the various resource options would have in a supply portfolio, and is similar to the approach taken in bid evaluation during the Clean Power Call processes. In addition, a 5 per cent soft cost adder, which is chosen based on BC Hydro's experience, is applied to reflect the fact that implementing these resource options would entail soft cost expenditures such as environmental assessment, First nation, and stakeholder engagement costs, etc.

6.2 Adjustments

The adjustments applied to each resource option type are summarized as follows:

- 5 per cent Soft Cost Adder

- Freshet Firm Energy Adjustment
- 3 x 12 Time-of-Delivery Price Adjustment
- Cost of Incremental Firm Transmission
- Line Losses Adjustment
- Green House Gases (**GHG**) Offset Costs
- Capacity Credit
- Wind Integration Cost

A 2 per cent inflation factor was used in instances where it was necessary to inflate dollar values to $2013.

The adjusters are integrated with the base UECs to enable a high level comparison across resource types.

It must be noted that these cost adjusters do not reflect the resource option risks and uncertainties (e.g., level of study, resource type uncertainty, earliest in service date, cost uncertainties) or the resource option network upgrade costs (i.e., the cost of interconnecting resource options to the bulk transmission system).

6.3 Summary of Adjusted Firm Unit Energy Costs

Table 6-1 and Figure 6-1 present UECs that have been adjusted to reflect potential costs to BC Hydro customers on an adjusted firm energy price basis using a process similar to the Clean Power Call bid evaluation process.

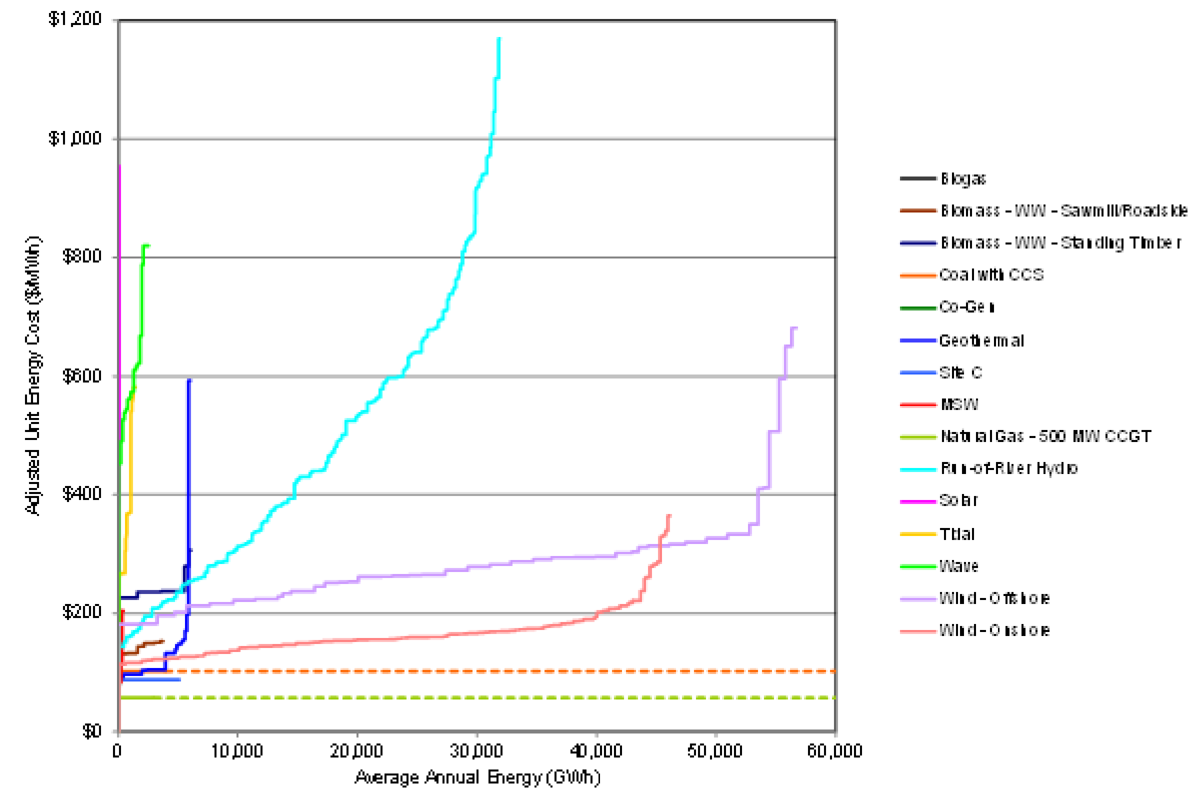
Details of how these adjusters were developed and applied are contained in Appendix 12.

Table 6-1 Summary of Supply-Side Energy Resource Options Potential – UEC at POI and Adjusted Firm UEC Values

Energy Resource	Total FELCC Energy (GWh/year)	Total DGC or ELCC Capacity (MW)	UEC at POI @ 7% Real ($2013/MWh)	Adjusted Firm UEC @ 7% Real ($2013/MWh)
Biomass – Wood Based	9,772	1,226	122 – 276	132 – 306
Biomass – Biogas	134	16	59 – 154	56 – 156
Biomass – MSW	425	50	85 – 184	83 – 204
Wind – Onshore	46,165	4,271	90 – 309	115 – 365
Wind – Offshore	56,700	3,819	166 – 605	182 – 681
Geothermal	5,992	780	91 – 573	90 – 593
Run-of-river	24,543	1,149	97 – 493	143 – 1,170
Site C	4,700	1,100	83	88
CCGT and Cogeneration	6,103	774	58 – 92	57 – 86
Coal-fired Generation with CCS	3,896	556	88	103
Wave	2,506	259	440 – 772	453 – 820
Tidal	1,426	247	253 – 556	264 – 581
Solar	57	12	266 – 746	341 – 954

Note: The Site C values presented in this table are based on information provided in the Site C Environmental Impact Statement (**EIS**) submission filed in January 2013, and the UEC is calculated assuming 5 per cent real discount rate.

Figure 6-1 Resource Potential Supply Curve Summary – Adjusted Firm UEC Values ($/MWh)



Notes:

1. Representative projects were used to characterize the natural gas-fired and coal-fired generation resource options. Dotted lines indicate additional potential.
2. The Site C values presented in this figure are based on information provided in the Site C EIS submission filed in January 2013.