2012 Integrated Resource Plan

BC hydro

Chapter

3

Resource Options

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3.1 Introduction

This chapter provides a summary of BC Hydro's assessment of the resource option potential in B.C. and the characteristics or attributes of the resource options. The information on resource options, i.e., the technical, financial, environmental and economic development attributes, is used as an 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.

3.1.1 2010 Resource Options Report

BC Hydro's complete assessment of the potential resource options is presented in the 2010 Resource Options Report (**ROR**) which is attached to the IRP as Appendix 3A. The 2010 ROR looks out 20 to 30 years[1] and considers resource options such as demand-side measures (**DSM**), supply-side generation and transmission resource options that are consistent with the policy and legislated objectives of the B.C. Government, including those specified in the B.C. *Clean Energy Act* (***CEA***). The bulk of the assessment of the 2010 ROR was conducted in 2010, but has been updated to include recent information on the Site C Clean Energy Project (May 2011) and the Interior-to-Lower Mainland (**ILM**) transmission project (November 2011). In the process of assembling data and assessing the potential resource options in B.C., BC Hydro sought input from people with relevant technical expertise and information. A consultation report summarizing this input is contained in Appendix 3A-2 of the IRP.

The resource option information in the 2010 ROR is generally at a level of detail and accuracy that is appropriate for long-term resource planning and portfolio analysis. The level of information is not considered sufficiently accurate to establish the

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

characteristics of site-specific resource options for development or acquisition purposes.

Conducting resource option assessments is an ongoing part of BC Hydro's resource planning work and the information is updated on a regular basis to reflect new findings or to support a particular planning process.

3.1.2 Chapter Structure

Organized by major categories, the following sections summarize the resource options attributes (technical, financial, environmental and economic development – section 3.2) and the resource options potential including DSM (section 3.3), supply-side generation (section 3.4), transmission (section 3.5), and other resources that have potential application in B.C. (section 3.6). The chapter concludes with a short summary of the findings and also provides new information on resource options subsequent to the finalization of the 2010 ROR (section 3.7).

3.2 Resource Options Attributes

Resource options attributes are characteristics that describe a resource option or portfolio and are used to assess its performance in meeting the IRP planning objectives.

A set of technical, financial, environmental and economic development attributes were developed to compare and evaluate the resource options and portfolios. All assessed attributes have varying levels of confidence or uncertainty depending on the level of studies, resource type and resource cost.

3.2.1 Technical Attributes

Technical attributes describe the energy and capacity that each resource option provides and are used to assemble portfolios that meet BC Hydro's energy and capacity reliability planning criteria. The technical attributes considered for each resource option are:

- Dependable generating capacity (**DGC**), which is used for non-intermittent resources and is the amount of megawatts (**MW**) a plant can reliably produce when required, assuming all units are in service;
- Effective load carrying capability (**ELCC**), which is used for intermittent or variable generation resources and is the maximum peak load (MW) 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;
- Installed capacity (MW);
- Firm energy load carrying capability (**FELCC**) is the maximum amount of annual energy that a hydroelectric resource can produce under critical water conditions and is measured in gigawatt-hours per year (**GWh/year**);
- Average annual energy (GWh/year); and
- Monthly per cent of average annual energy.

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

Table 3-1 Generation Reliability Assumptions and Methods

Potential Generation Resources	DGC and ELCC Assumptions and Methods of Determination (MW)	FELCC Assumptions and Methods of Determination (GWh/year)
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: 24 per cent of installed capacity	100 per cent of average annual energy
Wind – Offshore	ELCC: 24 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 & 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[1]	DGC: 1,100 MW	4,700 GWh/year
Pumped Storage	DGC: 100 per cent of installed capacity	N/A
Wave	ELCC: Assumed the same as offshore wind at 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 the same as onshore wind at 24 per cent of installed capacity	Assumed the same as onshore wind at 100 per cent of average annual energy
Resource Smart (Revelstoke Unit 6)	DGC: 470 MW	26 GWh/year
Coal-fired Generation with Carbon Capture and Storage	DGC: 75 per cent of installed capacity	100 per cent of average annual energy

Note: Site C value is based on information filed in May 2011 as part of the Site C Project Description Report.

3.2.2 Financial Attributes

Financial attributes describe the cost of resource options. Financial attributes considered include:

- Unit Energy Cost (**UEC**): reflects the levelized cost[2] of a unit of energy resource option (typically in $/MWh). The values serve as an initial ranking of energy resources in scheduling resources to fill a load/resource gap; and
- Unit Capacity Cost (**UCC**): reflects the levelized cost[3] of a unit of capacity resource option (typically in $/kW-year).

Some key assumptions or methods of determination used to develop the financial attributes include:

- Unless otherwise stated, resource options costs are presented as UECs and UCCs at the point of interconnection (**POI**)[4] and are not attributed with the additional costs of: delivering resources to the Lower Mainland (BC Hydro's major load centre), firming and integrating intermittent resources, nor the costs of meeting potential future greenhouse gas (**GHG**) regulatory requirements. While these are important cost considerations, they are factored in at the portfolio analysis stage described in Chapter 6 of the IRP;
- The UECs and UCCs are presented in constant dollars as of January 1, 2011 ($2011). A two per cent inflation factor is used in instances where it was necessary to inflate dollar values to $2011;
- Weighted average cost of capital – 6 per cent and 8 per cent real cost of capital rates are used in determining UECs. These rates do not presume or prescribe a

[2] Levelized UECs are calculated by taking the present value of the total annual cost of an energy resource and dividing by the present value of its annual average energy benefit. The one exception is for natural gas where the divisor is replaced by the firm energy amount. The reason for this exception is the potential large discrepancy between the physical capability of a natural gas plant and its realistic operations.

[3] Levelized UCCs are calculated by taking the present value of the total annual cost of a capacity resource divided by the resource's dependable capacity.

[4] The costs at POI 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 (linking plant gate area to existing road infrastructure), and transmission interconnection costs.

specific capital structure. The analysis results using the 6 per cent real rate are used in the IRP portfolio analysis; and

- UEC and UCC Methodology – The UEC and UCCs are calculated adopting the annualized cost method, which is unchanged from the 2008 Long-Term Acquisition Plan (**LTAP**).

3.2.3 Environmental Attributes

Environmental attributes provide high level information on the footprint of the resource options. To develop the environmental attributes used in the IRP, BC Hydro retained the services of Kerr Wood Leidal Associates Ltd. (**KWL**), HEMMERA and HB Lanarc.

The environmental 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 facilitates comparison between portfolios of resource options;
- Representative of relevant biophysical resources;
- Based on existing data or easily acquired data; and
- Easy to understand for long-term planning and stakeholder engagement purposes.

The environmental attributes developed were grouped into four environmental categories: land, atmosphere, freshwater and marine and were 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 ($gC/m^2/year$)[5]	hectares (ha) per class	Low (0 to < 69)
			Medium (69 to < 369)
			High (> 369)
	Remoteness – Linear Disturbance Density (km/km^2)	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
Atmosphere	Greenhouse Gas Emissions	tonnes/GWh	Carbon Dioxide equivalent (CO_2e)
	Air Contaminant Emissions	tonnes/GWh	Sulphur Dioxide
			Oxides of Nitrogen
			Carbon Monoxide
			Volatile Organic Compounds
			Fine Particulates: PM[6] 2.5 (reported when data is available)
			Fine Particulates: PM 10 (reported when data is available)
			Fine Particulates: PM Total
			Mercury

[5] $gC/m^2/year$ = grams of carbon per square metre per year; this indicator is a proxy for how much annual vegetation growth occurs in an area per year.

[6] PM = particulate matter.

Environmental Category	Indicator	Unit of Measure	Classifications
Freshwater[7]	Reservoir Aquatic Area[8]	ha	Site C (Pumped Storage and Resource Smart if applicable/available)
	Affected Stream Length[9]	kilometres (km)	Run-of-river and Site C (Pumped Storage and Resource Smart if applicable/available)
	Priority Fish Species (number of priority fish[10] 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[11]	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

These high-level environmental 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.

7 The 2010 ROR developed a fourth freshwater attribute to address the riparian footprint. This attribute was subsequently dropped due to lack of data for potential run-of-river sites and pumped storage which would have made the comparisons ineffectual.

8 "Reservoir Aquatic Area" is an indicator specifically applicable to Site C.

9 "Affected Stream Length" is an indicator applicable to run-of-river projects and Site C.

10 Priority fish are those that have been identified for conservation in the Province of B.C. through the BC Conservation Framework, and then filtered to ensure native species and provincial range data.

11 The 2010 ROR developed a third marine attribute of bathymetry, which is a descriptor of water depth. This attribute was subsequently not reported in the IRP given that it added negligible value compared with the other two marine attributes.

For additional information on the environmental attributes of individual resource options, please refer to Appendix 3A-3 of the IRP. For information on the environmental footprint of resource portfolios, please refer to Chapter 6 of the IRP.

3.2.4 Economic Development Attributes

Economic development attributes describe the contributions that resource options make to the provincial economy. The economic development attributes selected are categorized into three groups: Provincial gross domestic product (**GDP**), employment, and Provincial government revenue and are further broken down into sub-categories described in Table 3-3.

Table 3-3 Economic Development Attributes

Economic Development Category	Sub-Category	Unit of Measure	Classifications
Provincial GDP	Construction/Operation	Dollars ($) and $/year	Direct
			Indirect
			Induced
Employment	Construction/Operation	Jobs[12]	Direct
			Indirect
			Induced
Provincial Government Revenue	Construction/Operation	$ and $/year	Direct
			Indirect
			Induced

For additional information on the economic development attributes of individual resource options, please refer to Appendix 3A-5 of the IRP. For information on the contributions of resource portfolios to economic development, please refer to Chapter 6 of the IRP.

12 "Jobs" is also referred to as person years. This measure reflects the average jobs in the affected industries and may not always be defined as full-time employment. In general, construction jobs are shorter-term and higher in number, whereas operating jobs are longer-term and last for the life expectancy of the project.

3.3 DSM Options Summary

Two sets of demand-side measures (**DSM**) options were developed for the 2010 ROR and IRP: energy-focused options and capacity-focused options. BC Hydro’s traditional DSM initiatives have been energy-focused, with capacity savings treated as an associated benefit. In contrast, the newly introduced capacity-focused options are specifically designed to deliver capacity savings during BC Hydro’s peak load periods on the electrical system through management and control of customers’ electricity demand. Chapter 9 further discusses how these energy and capacity-focused options are applied for developing the the IRP Action Plan recommendations. Within the context of the Recommended Actions, the term ‘rate options’ is synonymous with ‘rate structures’ as discussed in this chapter.

3.3.1 Energy-Focused DSM Options

The energy-focused options utilize a variety of DSM tools and tactics that target changes at the different levels of a strategic framework developed in conjunction with BC Hydro’s Energy Conservation and Efficiency (**EC&E**) Advisory Committee. The three levels of the strategic framework are:

- Individual Level – DSM initiatives are designed to address, overcome or remove five barriers (awareness, availability, accessibility, affordability, and acceptance) to cost-effective energy efficiency;
- Market Level – DSM initiatives are designed to influence market parameters such as price, taxes, financing, codes and standards, municipal development rules, and workforce capacity that influence energy decisions of all consumers; and
- Societal Level – DSM initiatives are designed to effect societal norms and patterns such as urban form, building size, conservation and efficiency norms, and consumption patterns that also influence energy decisions of consumers.

The strategic framework overlays the development of the specific tactics that comprise the energy-focused DSM options and can be summarized by the following five components: codes and standards, conservation rate structures, programs, supporting initiatives and other tactics (market and societal).

- Codes and Standards: Codes and standards target the market level by eliminating inefficient products or building practices from the marketplace. Codes and standards also contribute to and affect societal level changes.
- Conservation Rate Structures: Conservation rate structures target the market level by delivering conservation price signals to customers.
- Programs: Programs target the individual, market and societal levels. Programs influence customer decisions that affect electricity consumption, whether they relate to behaviours, operations or capital assets, and whether they relate to new or existing buildings and equipment. Programs can provide information, incentives, technical support or direct installations to influence customer decisions.
- Supporting Initiatives: Supporting initiatives target the individual level by increasing awareness of energy efficiency opportunities and programs. The market level is targeted by supporting government efforts to change codes and standards. Finally, the societal level is targeted by building a conservation ethic.
- Other Tactics: Market tactics aim to change selected market parameters that influence energy conservation and thereby both increase participation in DSM programs and increase the certainty around achieving expected levels of participation

Five energy-focused DSM options comprised of these components were developed, referred to as Options 1 through 5. Option 2 aligns with BC Hydro’s current DSM Plan and accordingly many of the options are described relative to Option 2.

The five distinct DSM options are each created as integrated packages of DSM tools and tactics. The structure of these DSM options recognizes the fact that these efforts are interrelated and are employed in concert to achieve a particular path of energy savings over time.

The genesis of five DSM options was to respond to the British Columbia Utilities Commission (**BCUC**) directive to BC Hydro (Directive 11, 2008 LTAP) "to address in its next LTAP a methodology for comparing risk-weighted UECs of demand side measures and of physical supply-side resources". Given the interrelated nature of the DSM tools and tactics, it is not possible to isolate the costs and savings of individual tools. However, the creation of five DSM options was designed to give insight into the incremental DSM costs and uncertainties of pursuing additional quantities of energy conservation.

3.3.1.1 Option 1

Option 1 reflects a slowing down of BC Hydro's current DSM Plan, which was developed to meet 66 per cent of the forecasted load growth with DSM.[13] This would meet the minimum amount of DSM per the B.C. Government's *CEA* energy objective of reducing the expected increase in demand for electricity by the year F2021 by at least 66 per cent.

In general, the main difference between Option 1 and Option 2 is at the program level. In Option 1, programs are reduced to 75 per cent of Option 2, except for Voltage Optimization[14] which is kept at 100 per cent. General scaling to 75 per cent is for the purpose of constructing an option for resource planning analysis. If

[13] Option 1 was based on 2010 Load Forecast which did not include Initial LNG and other updates included in the 2011 Load Forecast.

[14] In response to the BCUC decision on the 2008 LTAP, BC Hydro now considers the categorization of Voltage Optimization (VO) as DSM on a case-by-case basis. In the F2012-F2014 Revenue Requirements Application, BC Hydro adopted the following categorization. Where a VO project is implemented at a BC Hydro substation without customer involvement, it is not considered to be DSM. Where a VO project is implemented with the involvement of customers and changes to their facilities or equipment are required, the project is considered to be DSM. This recategorization occurred after the development of the DSM options, which is why they still include VO at BC Hydro substations.

selected, the implementation plan may scale individual programs by different amounts.

All other tactics are similar to those employed in Option 2.

3.3.1.2 Option 2

Option 2 is an updated version of the current DSM Plan that was included in BC Hydro's 2008 LTAP application to the BCUC. Forecast costs and savings have been updated with new information on plan implementation and energy savings opportunities. The key elements of the DSM Plan remain the same as in the 2008 LTAP. This option includes a balanced offering of codes and standards, conservation rate structures, and programs.

In regards to the specific tactics employed in Option 2:

- Codes and standards are those that have been enacted, announced or planned by the federal or provincial governments.
- Conservation rate structures are those that are in place or planned. These include Transmission Service Rate (**TSR**) for large industrial customers, the Residential Inclining Block (**RIB**) rate for residential customers, and a conservation rate structure for large commercial and small industrial customers in the former Large General Service (**LGS**) rate class. A conservation rate structure for small commercial customers in the Small General Service (**SGS**) rate class is planned for introduction in F2018.
- Programs target residential, commercial and industrial customer classes as well as cross-sector programs. Residential programs include programs designed to influence customer behaviour, offerings on lighting, appliances, electronics and programs geared towards new homes and retrofits. Commercial and industrial customer programs include the Power Smart Partner programs, new construction and plant design offers and load displacement.

- Supporting initiatives include public awareness and education, community engagement, codes and standards support, technology innovation, and information technology.
- Market tactics include continuing effort on financing, workforce capacity, channel development, building labelling and industrial plant certification.

3.3.1.3 Option 3

Option 3 targets 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. As a result, program costs also increase to process the higher volume of projects and resulting applications.

The main difference between Option 2 and Option 3 is increased effort and expenditure at the program level. For Option 3, programs are pushed to the limits of cost-effectiveness, defined as the point where marginal costs equal marginal benefits. In this option, program incentives and technical support are increased to address customer barriers and offset the increasing use of more expensive technology. This results in increased customer participation and program processing costs, while improving compliance with codes and standards.

Supporting initiatives remain the same as in Option 2 except for a slight increase in funding to support the expanded program effort.

All other tactics are similar to those employed in Option 2.

3.3.1.4 Option 4

Option 4 builds upon the expanded program effort in Option 3 by adding new or more aggressive codes and standards and conservation rate structures to generate additional savings. These additional tactics go beyond those included in Options 1, 2 and 3 and would be new and untested. As such, it is uncertain whether they would be accepted by government and stakeholders. This option also represents a bridge to Option 5 by including activities and pilot initiatives that would facilitate the market and social transformations targeted by that option. As noted under Option 5, these additional activities and initiatives would be new and untested and it is uncertain to what extent they would succeed in generating additional electricity savings.

Compard to Option 3 for the residential sector, Option 4 entails the same programs, additional reliance on codes and standards and an increase in market and societal tactics such as channel engagement (i.e., working with manufacturers and suppliers to ensure that the latest energy efficient products are available and accessible), workforce capacity building (i.e., increasing the supply of qualified consultants, contractors and installers) and advocacy and awareness regarding energy efficient products and solutions.

Relative to Option 3 for the commercial sector, Option 4 entails the same programs, additional codes and standards, new rate concepts and an increase in market and societal tactics such as channel engagement, workplace capacity and advocacy and awareness.

For the industrial sector, Option 4 entails performance incentives for both transmission and distribution customers (based on level of site or system energy savings) and increased market tactics, such as support for Industrial Plant Certification (utilizing plant baselines, such as GWh/tonne of product) and additional codes and standards.

3.3.1.5 Option 5

Option 5 is the most aggressive DSM option that BC Hydro considered suitable for resource planning purposes. Option 5 includes a fundamental shift in BC Hydro’s approach to saving electricity, one that places much greater emphasis on tactics that change market parameters and societal norms and patterns that influence electricity consumption and conservation. As a new and untested approach to saving electricity, it is subject to considerable uncertainty regarding government and stakeholder acceptance and support and ultimately its effectiveness at generating additional cost-effective electricity savings.

Option 5 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.

For the industrial sector, a market transformation to certified plants occurs, supported with expanded regulation.

3.3.2 Capacity-Focused Options

While the energy-focused DSM options described above generate associated capacity savings, additional capacity savings are achievable through capacity-focused DSM, which specifically targets capacity savings. 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.

For capacity-focused DSM, two options[15] were considered in the IRP. These options composed of building blocks that could be sequentially selected in combination with each other.

[15] 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.

- 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 operational capacity needs in recent years, and customers have delivered as requested.
- 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. 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.

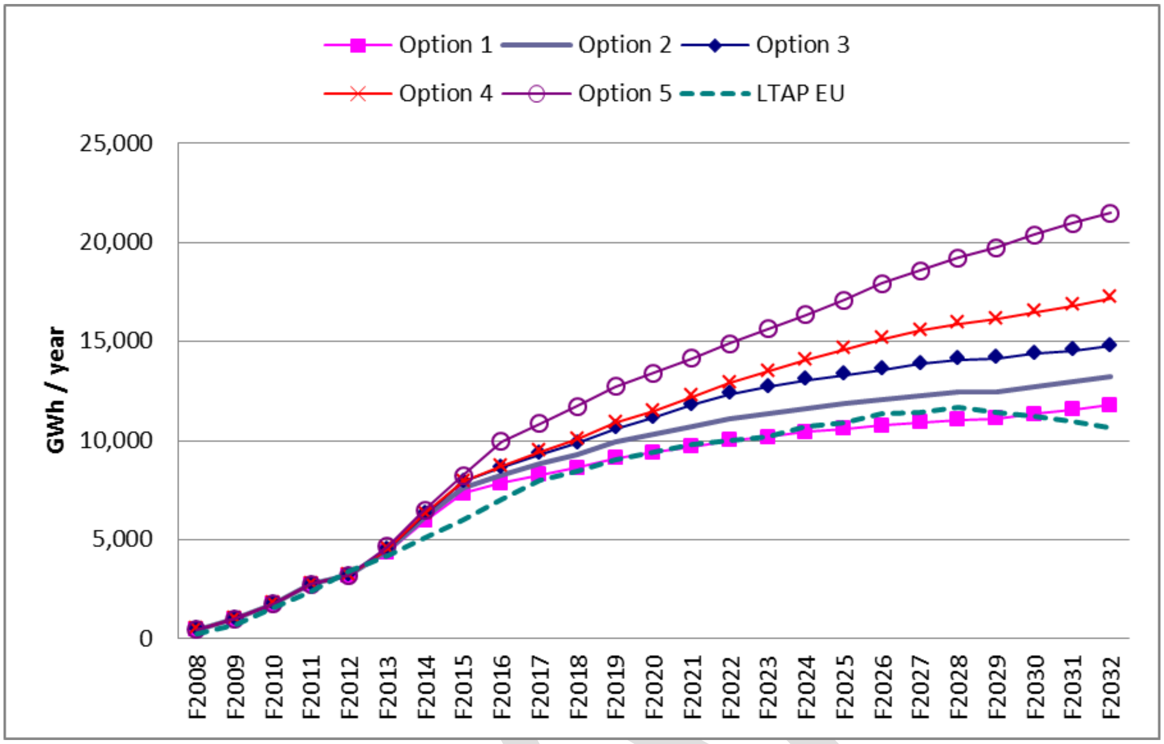
3.3.3 Summary of DSM Options

This section provides a summary and comparison of the energy-focused and capacity-focused DSM options on a cost, energy savings and capacity savings basis.

3.3.3.1 Summary of Energy-Focused DSM Options

Figure 3-1 compares the energy savings obtained from the five energy-focused DSM options over the time horizon of the analysis, along with a curve showing Option A from the Evidentiary Update of the 2008 LTAP.

1 **Figure 3-1 Energy Savings**[16]



2 The associated capacity savings from the energy-focused DSM options are provided
3 in Figure 3-2.

[16] The energy savings for Options 1 through 5 are shown are prior to any risk adjustments.

Figure 3-2 Associated Capacity Savings

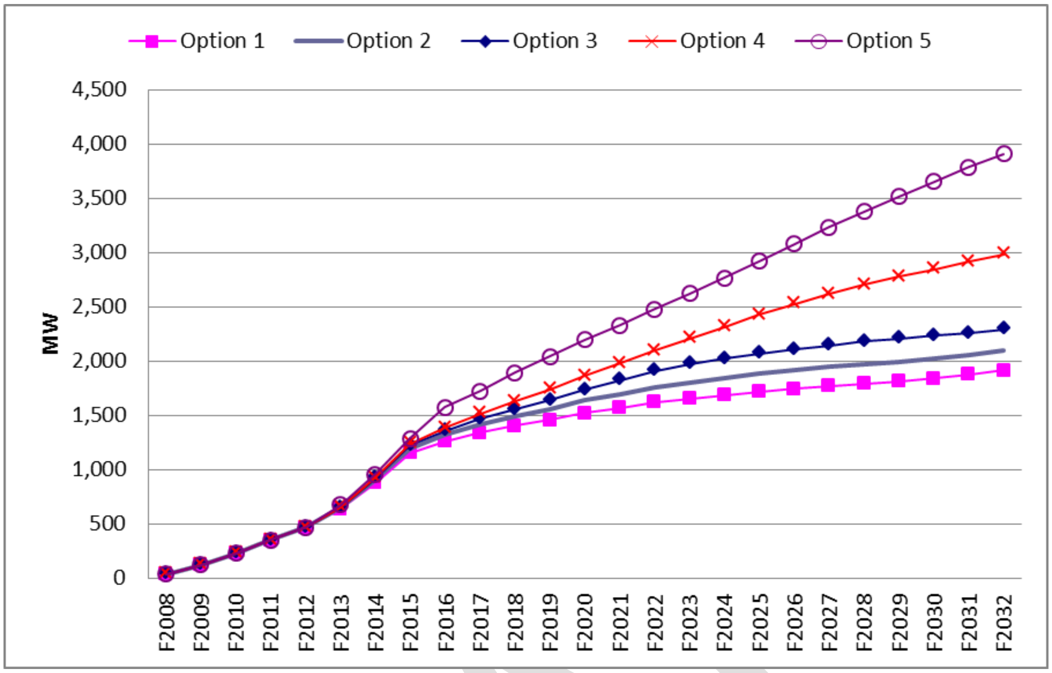
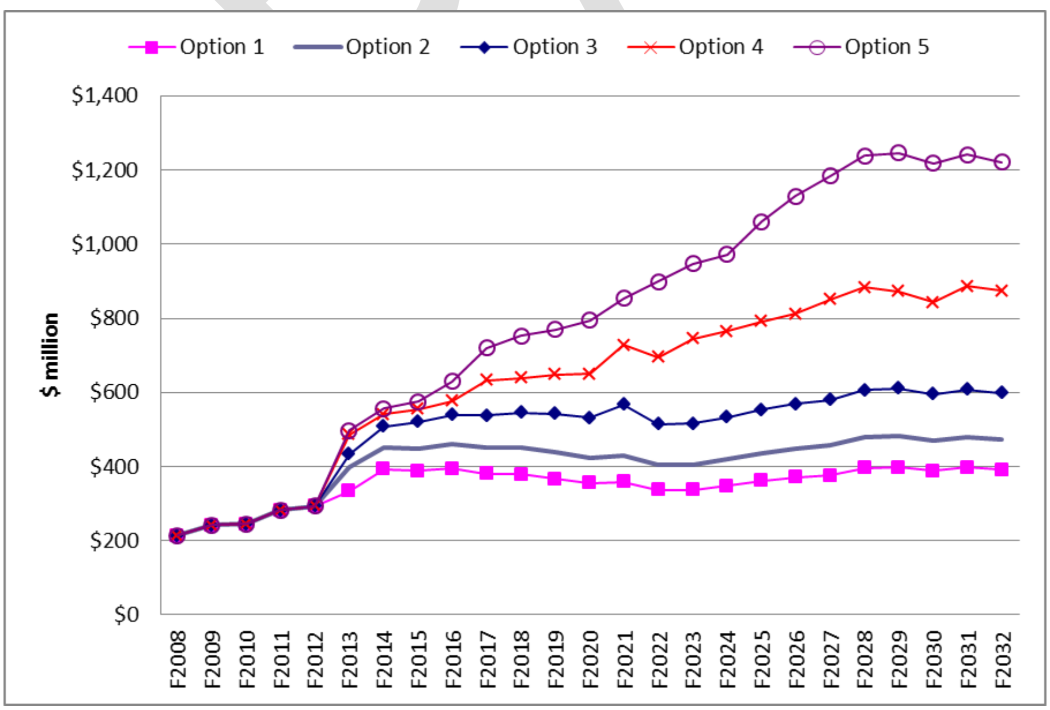


Figure 3-3 shows the societal investment (total resource costs) in DSM for the various options.

Figure 3-3 Total Resource Costs



The unit energy cost from a Total Resource Cost perspective for each of the five energy-focused DSM options is provided in Table 3-4 below.

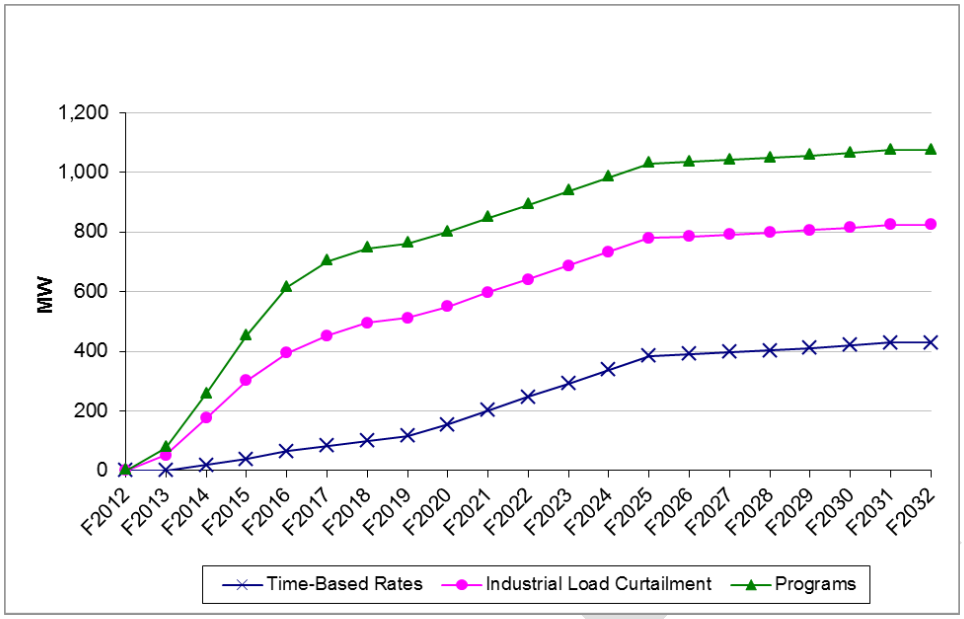
Table 3-4 Total Resource Cost for Energy-Focused DSM

Energy-Focused Option	Total Resource Cost ($/MWh)
1	39
2	41
3	44
4	49
5	49

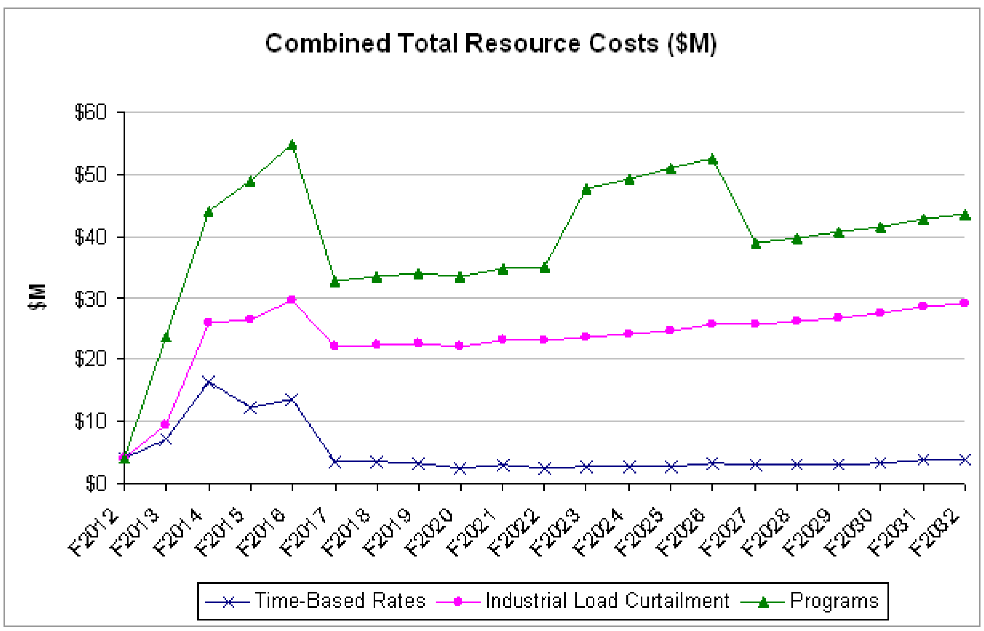
3.3.3.2 Summary of Capacity-Focused DSM Options

The capacity-focused DSM options are summarized in Figure 3-4 and Figure 3-5, including a view of the potential combined capacity savings and Total Resource Costs over the time horizon of the IRP analysis. While the capacity programs are independent, the curves for each option are shown on a cumulative basis to provide an overview of the potential combined savings and costs.

1 **Figure 3-4 Cumulative Capacity Savings**[17]



2 **Figure 3-5 Cumulative Total Resource Costs**[16]



[17] 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.

The unit capacity cost from a Total Resource Cost perspective for the two capacity-focused DSM options is provided in Table 3-5.

Table 3-5 Total Resource Cost for Capacity-Focused DSM

Capacity-Focused Option	Total Resource Cost* ($/kW-year)
Industrial Load Curtailment	32
Capacity-Focused Programs	53

*Note: Includes transmission and distribution loss savings estimates

3.3.4 Additional DSM Information

This section provides new information on the costs, benefits and energy savings associated with the energy-focused DSM options presented in this chapter, but that was not available in time for inclusion in the 2010 ROR. This information has been incorporated into the portfolio analysis contained in Chapter 6 of the IRP.

3.3.4.1 DSM Benefits

In addition to electricity benefits, DSM results in a range of other benefits, including associated capacity benefits, natural gas benefits and non-energy benefits (**NEB**) (e.g., operation and maintenance savings resulting from the installation of an energy efficient measure). Inclusion of these benefits increases the cost-effectiveness of DSM. The demed NEBs and natural gas benefits (used in the analysis of the DSM options in Chapter 6) reflect recent amendments to the Provincial DSM Regulation and are included in BC Hydro's recent section 44.2 application to the BCUC for approval of F2012/F2013 DSM expenditures. As outlined in Chapter 6, the IRP portfolio analysis includes the NEBs and natural gas benefits.

3.3.4.2 DSM Codes and Standards

On March 28, 2012, the Provincial government introduced Bill 32 (*BC Energy and Water Efficiency Act*). This legislation will replace the previous *Energy Efficiency Act* and contains measures to improve standards, streamline enforcement and improve energy performance. Given that Bill 32 was introduced after the DSM resource options were created for the IRP, it was not considered in the development of DSM Options 2, 3, 4 and 5. As described further in Chapter 9, BC Hydro's recommended DSM action plan considers the potential effect of this new legislation.

3.3.4.3 DSM Amortization Period

The DSM amortization period, which aligns DSM costs and benefits over time, has been updated from a 10-year to a 15-year period to reflect the increase in average persistence of DSM program savings. The IRP analysis uses the DSM amortization period to annualize DSM costs so that costs are aligned with realized DSM savings. The IRP portfolio analysis reflects the updated 15-year amortization period.[18]

3.4 Supply-Side Generation Resource Options Summary

There is the potential in B.C. for many different types of supply-side resource options to be developed. As illustrated in Table 3-6 below, a number of different types of resources – such as hydro, wind, biomass and biogas – have been developed or are under development in B.C. by independent power producers (**IPPs**) or customers.

[18] The 15-year amortization period is consistent with BC Hydro's Amended F2012 – F2014 Revenue Requirements Application.

Table 3-6 Supply-Side Energy Projects in B.C.[19]

	In Operation		Under Development	
Project Type	**EPAs**	**Contracted Energy (GWh/year)**	**EPAs**	**Contracted Energy (GWh/year)**
Biogas	4	80	2	10
Biomass	9	2,121	8	1,411
Energy Recovery Generation (Waste Heat)	2	75	1	65
Gas-Fired Thermal	2	3,140	0	0
Municipal Solid Waste	1	131	1	745
Non-Storage Hydro	45	3,426	33	4,706
Storage Hydro	9	4,730	1	139
Wind	2	538	6	1,644
Total	**74**	**14,242**	**52**	**8,720**

This section presents an overview of the supply-side generation resource options that are considered in the IRP portfolio analysis where BC Hydro has been able to develop the resource potential and costs. The identified resource option potential is minimally screened[20] and therefore results in a large volume of potential energy with a wide range of costs, which may or may not be developed in the future. Additional information on BC Hydro's investigations into emerging supply-side resource options is presented in section 3.6.

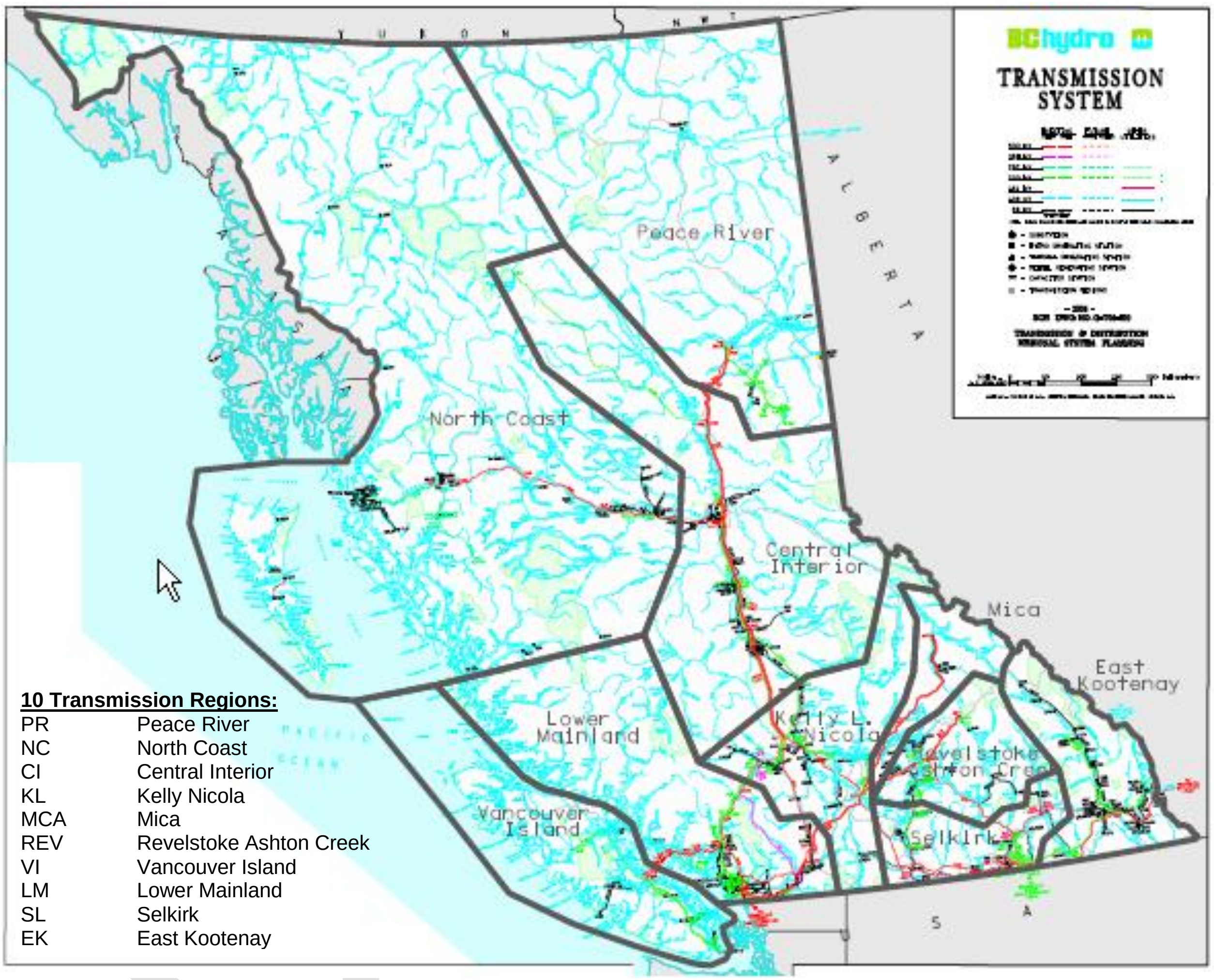
At a high level, this section is organized according to energy and capacity resource options, presented in sections 3.4.1 and 3.4.2 respectively. Technical and financial results are presented for each resource option where UECs and UCCs are shown at the point of interconnection (**POI**). In addition, resource option data are reported by transmission region where the interconnection occurs. Figure 3-6 shows a map of the ten transmission regions used in the 2010 ROR.

19 As of April 1, 2012.

20 Some base level screening was conducted to remove sites from consideration if they were located in an area where there would be legal or regulatory prohibitions e.g., projects located in legally protected areas or situtated on a salmon-bearing stream.

Section 3.4.3 provides summaries of energy and capacity resource potential and costs.

Figure 3-6 BC Hydro's Transmission Planning Regions



3.4.1 Energy Resource Options

3.4.1.1 Wood-Based Biomass

Wood-based biomass electricity is generated from the combustion or gasification of organic materials as fuels. In developing the potential of wood-based biomass, the following categories of fuels were considered:

- Standing timber (including pine beetle-killed wood);

- Roadside wood waste (wood already harvested, but left in the forest or road side, some are pine beetle-killed wood); or
- Sawmill wood waste.

BC Hydro engaged a team of consultants from Industrial Forest Services Ltd., together with industry experts, to conduct a modelling study to estimate the long-term energy potential, costs and possible locations for wood-based biomass projects. Overall, the study found that the amount of standing timber available for fuel was forecast to decline significantly over the next 15 years, but then stabilize thereafter. In addition, the study identified the availability of significant volumes of roadside and sawmill wood waste, but indicated that there was uncertainty regarding the actual potential that could be realized.

A summary of the technical and financial results for wood-based biomass is presented in Table 3-7.

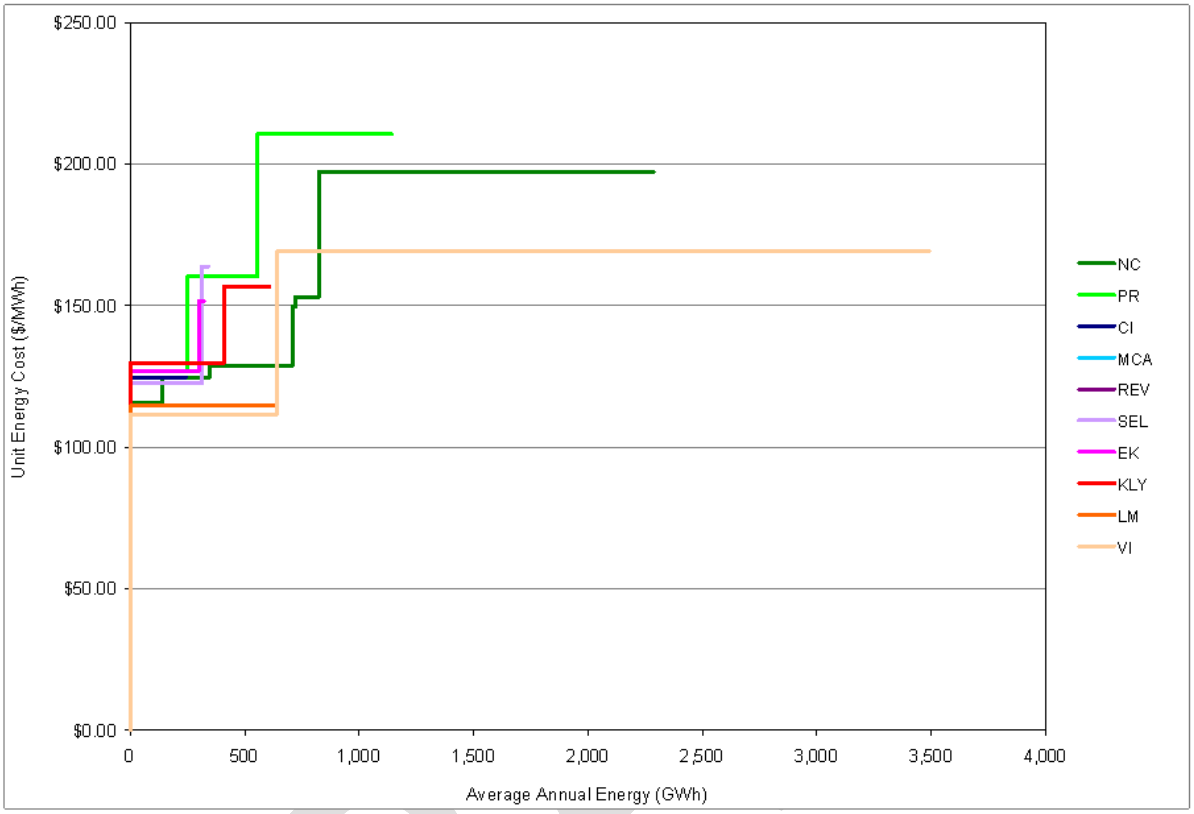
Table 3-7 Summary of Wood-Based Biomass Potential

Transmission Region	Number of Potential Sites*	Installed Capacity (MW)	DGC (MW)	Total Energy (GWh/year)	Firm Energy (GWh/year)	UEC at POI ($2011/MWh)
Standing Timber						
Peace River	2	112	112	892	892	160 - 211
North Coast	4	201	201	1,602	1,602	150 - 855
Kelly Nicola	1	25	25	201	201	157
Vancouver Island	1	358	358	2,850	2,850	169
Lower Mainland	1	358	358	2,850	2,850	169
Selkirk	1	4	4	29	29	164
East Kootenay	1	3	3	23	23	151
Sub-Total	11	1,060	1,060	8,447	8,447	150 - 855
Roadside Debris & Wood Waste						
Peace River	1	31	31	248	248	127
North Coast	3	89	89	707	707	116 - 129
Central Interior	1	31	31	244	244	125
Kelly Nicola	1	51	51	408	408	130
Vancouver Island	1	80	80	641	641	112
Lower Mainland	1	80	80	641	641	115
Selkirk	1	39	39	312	312	123
East Kootenay	1	37	37	298	298	127
Sub-Total	10	439	439	3,499	3,499	112 - 130
Total	**21**	**1,499**	**1,499**	**11,946**	**11,946**	**112 - 855**

* For wood-based biomass, this reflects the number of fiber delivery locations considered in the study. The capacity figures shown reflect the total potential power generation (using multiple plants) based on the estimated fuel supply. 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 a given transmission region.

The supply curves for the wood-based biomass resource potential based on POI costs, by transmission region, are shown in Figure 3-7.

Figure 3-7 Wood-Based Biomass Supply Curves



3.4.1.2 Biomass – Biogas or Landfill Gas

Landfill gas (**LFG**) is created when organic waste in a municipal solid waste (**MSW**) landfill decomposes under anaerobic conditions. LFG can be captured, converted, and used as an energy source to help prevent methane from migrating into the atmosphere and contributing to global climate change.

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

In developing the LFG resource potential, BC Hydro reviewed a report by Golder.[21]

A summary of the technical and financial results for biogas is presented in Table 3-8.

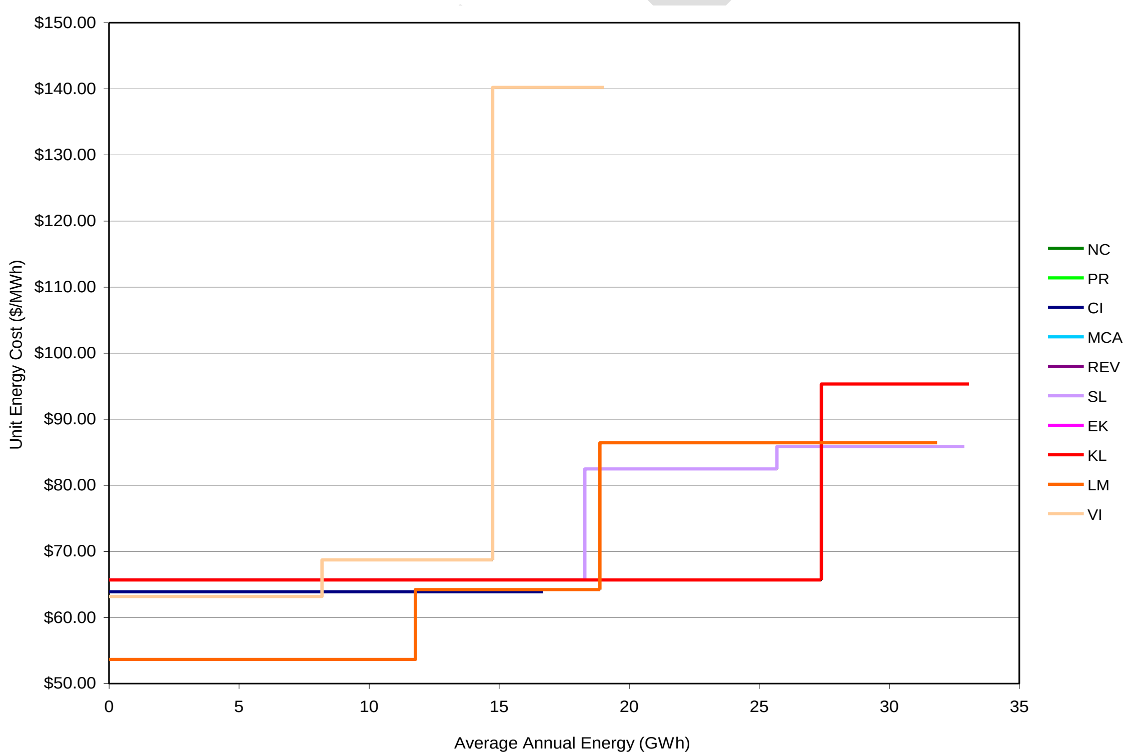
[21] "Inventory of Greenhouse Gas Generation from Landfills in British Columbia", by Golder Associates, 2008.

Table 3-8 Summary of Biogas Potential

Transmission Region	Number of Potential Sites	Installed Capacity (MW)	DGC (MW)	Total Energy (GWh/year)	Firm Energy (GWh/year)	UEC at POI ($2011/MWh)
Central Interior	1	2	2	17	17	64
Kelly Nicola	2	4	4	33	33	66 - 95
Vancouver Island	3	2	2	19	19	63 - 140
Lower Mainland	3	4	4	32	32	54 - 86
Selkirk	3	4	4	33	33	66 - 86
Total	**12**	**17**	**16**	**134**	**134**	**54 - 140**

The supply curves for biogas resource potential based on POI costs, by transmission region, are shown in Figure 3-8.

Figure 3-8 Biogas Supply Curves



3.4.1.3 Biomass – Municipal Solid Waste

MSW biomass refers to the conversion of municipal solid waste into a usable form of energy, such as electricity. Conventional combustion and gasification are the most commonly used MSW technologies.

The MSW resource option potential is estimated based on fuel source availability, where an attempt was made to incorporate the "Zero Waste" philosophy that endeavours to minimize the amount of waste going to landfills by employing waste avoidance and diversion strategies.

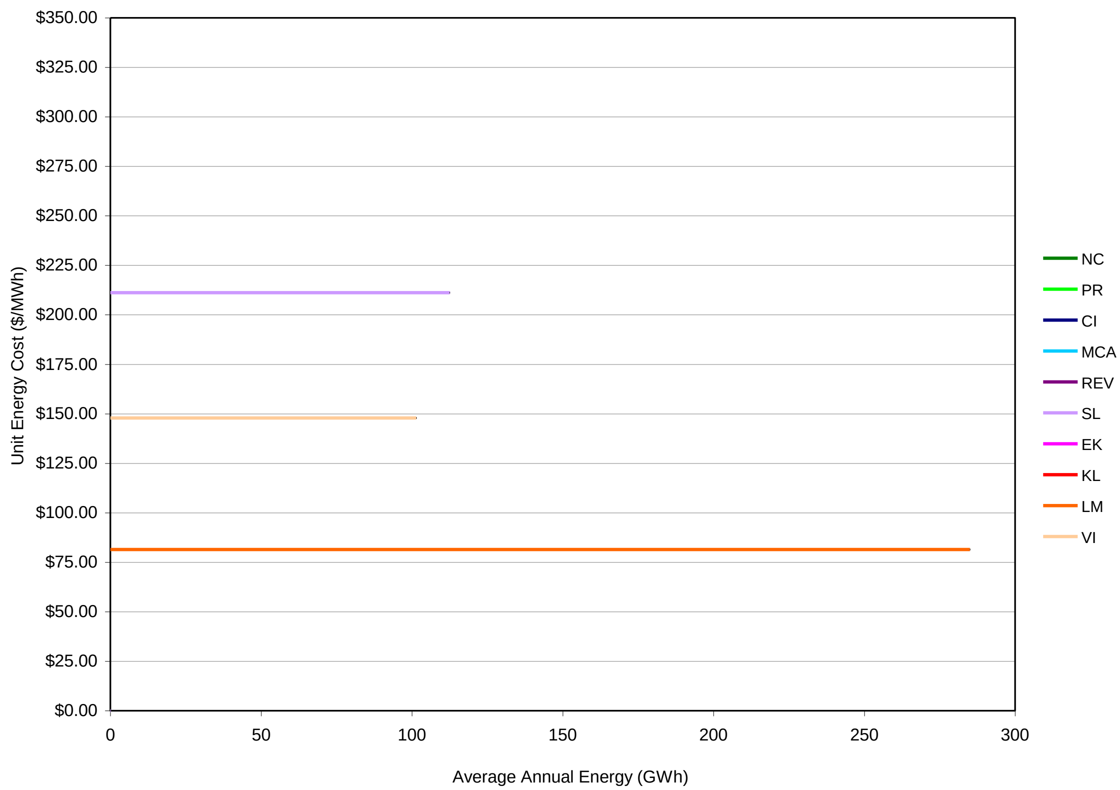
A summary of the technical and financial results for MSW is contained in Table 3-9.

Table 3-9 Summary of MSW Biomass Potential

Transmission Region	Number of Potential Sites	Installed Capacity (MW)	DGC (MW)	Total Energy (GWh/year)	Firm Energy (GWh/year)	UEC at POI ($2011/MWh)
Vancouver Island	1	12	12	101	101	148
Lower Mainland	1	34	33	285	285	81
Selkirk	1	14	13	112	112	211
Total	**3**	**60**	**58**	**499**	**499**	**81 - 211**

The supply curves for MSW resource potential based on POI costs, by transmission region, are shown in Figure 3-9.

Figure 3-9 MSW Biomass Supply Curves



3.4.1.4 Onshore Wind

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.

BC Hydro engaged DNV Global Energy Concepts Inc. to complete the Wind Data Study and Wind Data Study Update to obtain detailed information on the wind resource potential in B.C. and engaged Garrad Hassan to update the onshore wind costs.

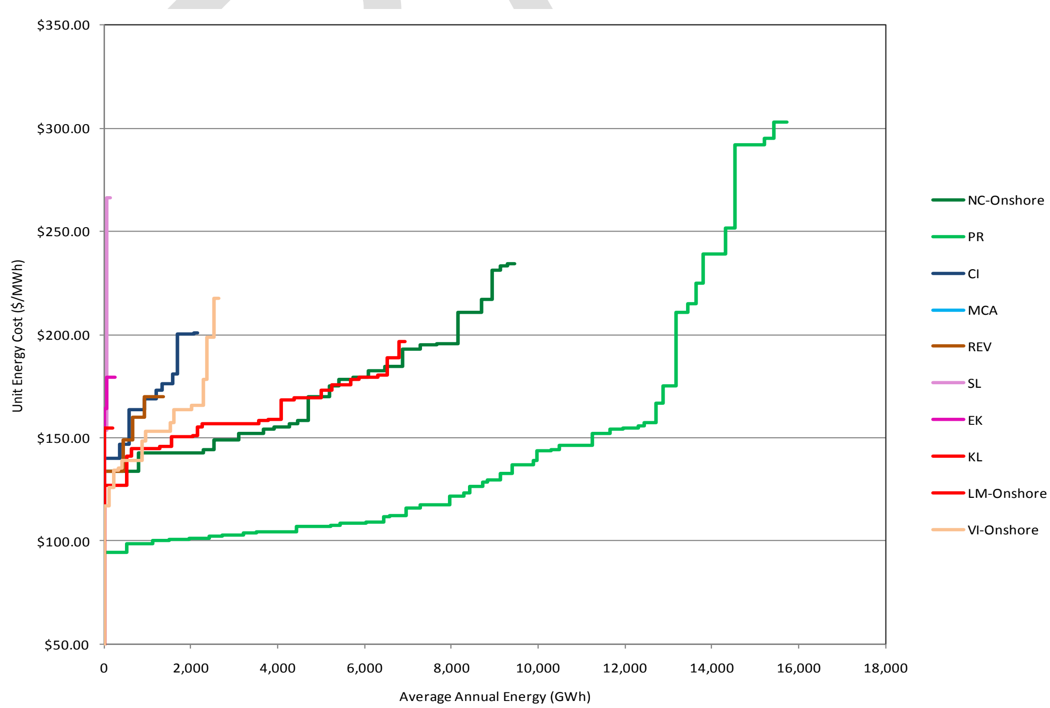
A summary of the technical and financial results for onshore wind is contained in Table 3-10.

Table 3-10 Summary of Onshore Wind Potential

Transmission Region	Number of Potential Sites	Installed Capacity (MW)	ELCC (MW)	Total Energy (GWh/year)	Firm Energy (GWh/year)	UEC at POI ($2011/MWh)
Peace River	45	5,864	1,407	15,717	15,717	95 - 303
North Coast	23	4,085	980	9,463	9,463	134 - 234
Central Interior	9	1,049	252	2,151	2,151	140 - 201
Kelly Nicola	22	3,363	807	6,917	6,917	127 - 197
Revelstoke	4	644	155	1,372	1,372	134 - 170
Vancouver Island	13	1,111	267	2,651	2,651	117 - 218
Lower Mainland	1	90	22	207	207	155
Selkirk	2	83	20	154	154	154 - 266
East Kootenay	2	138	33	252	252	164 - 180
Total	**121**	**16,425**	**3,942**	**38,885**	**38,885**	**95 – 303**

The supply curves for onshore wind resource potential based on POI costs, by transmission region, are shown in Figure 3-10.

Figure 3-10 Onshore Wind Supply Curves



3.4.1.5 Offshore Wind

In addition to onshore wind potential, BC Hydro also examined the potential of offshore wind turbines located in ocean substrate depths of up to 40 m. 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.

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. Garrad Hassan provided representative costs for offshore wind projects as a function of water depth.

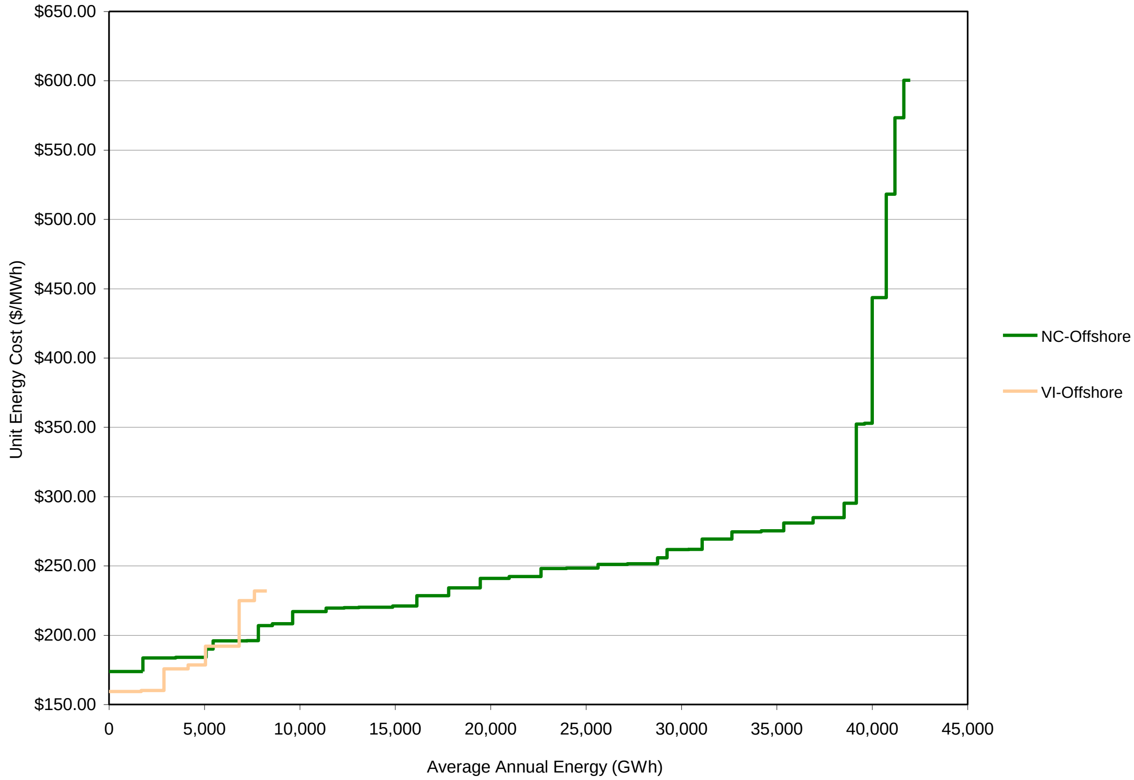
A summary of the technical and financial results for offshore wind are contained in Table 3-11.

Table 3-11 Summary of Offshore Wind Potential

Transmission Region	Number of Potential Sites	Installed Capacity (MW)	ELCC (MW)	Total Energy (GWh/year)	Firm Energy (GWh/year)	UEC at POI ($2011/MWh)
North Coast	36	12,873	3,090	41,991	41,991	174 - 600
Vancouver Island	7	2,466	592	8,270	8,270	159 - 232
Total	**43**	**15,339**	**3,681**	**50,261**	**50,261**	**159 - 600**

The supply curves for offshore wind resource potential based on POI costs, by transmission region, are shown in Figure 3-11.

Figure 3-11 Offshore Wind Supply Curves



3.4.1.6 Run-of-River Hydroelectricity

A run-of-river (**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.

The 2010 ROR for run-of-river resources was undertaken in collaboration with KWL (an external consultant). The study used a Geographical Information System (**GIS**) tool to assess the energy, capacity and cost of selected potential RoR generating sites.

A summary of the technical and financial results for the RoR resource option is contained in Table 3-12.

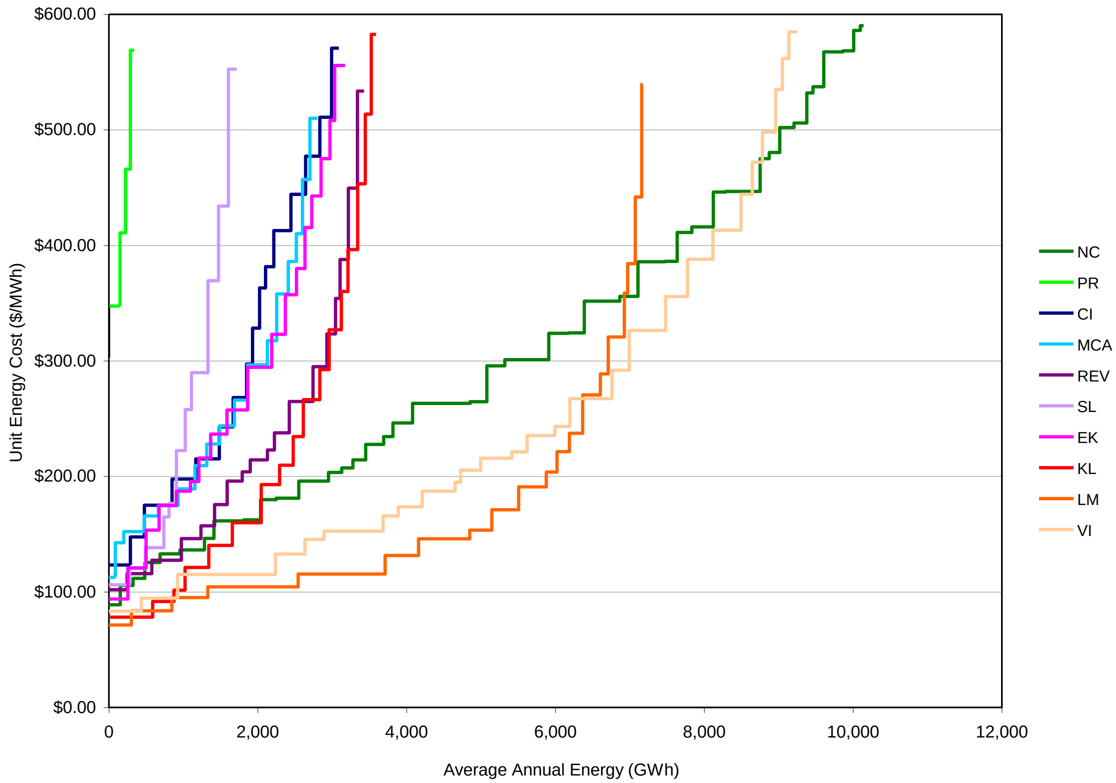
Table 3-12 Summary of Run-of-River Potential

Transmission Region	Number of Potential Sites	Installed Capacity (MW)	ELCC (MW)	Total Energy (GWh/year)	Firm Energy (GWh/year)	UEC at POI ($2011/MWh)
Peace River	32	115	1	342	294	303 - 600
North Coast	434	2,778	137	10,140	8,267	79- 600
Central Interior	122	849	40	3,089	2,489	122- 589
Kelly Nicola	179	978	51	3,588	2,815	78 - 600
Mica	128	808	22	2,802	2,474	111- 566
Revelstoke	192	972	34	3,428	2,991	90- 577
Vancouver Island	320	2,274	512	9,248	6,903	83 - 598
Lower Mainland	206	1,684	255	7,174	5,436	66- 578
Selkirk	90	525	9	1,718	1,479	103- 596
East Kootenay	213	970	13	3,173	2,733	89 - 598
Total	**1,916**	**11,950**	**1,074**	**44,703**	**35,880**	**66- 600**

Note: The table presents results for run-of-river resources under $600/MWh.

The supply curves for RoR resource potential based on POI costs, by transmission region, are shown in Figure 3-12.

Figure 3-12 Run-of-River Supply Curves



Note: This figure presents results for run-of-river resources under $600/MWh.

3.4.1.7 Large Hydro – Site C

In accordance with sections 10 and 11 of the *CEA*, BC Hydro is prohibited from developing electricity generation projects on specified streams (per Schedule 2 of *CEA*). In addition, no government approvals may be issued to BC Hydro or anyone else in respect of projects for electricity generation on a stream with a storage capability in excess of prescribed storage limits (as of the date of the IRP, no regulation prescribing storage capability has been issued). As a result, the only project considered in the IRP as a potential large hydro resource option is Site C, which is expressly excluded from the CEA's definition of 'prohibited projects'.

The Site C Clean Energy Project (**Site C**) is a proposed third dam and hydroelectric generating station on the Peace River in northeastern B.C. Site C would be located downstream from the existing Williston Reservoir and the 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 of average energy).

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 upstream Williston Reservoir 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 five percent 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.

The data in this report is based on the updated project design and cost estimate from the Project Description Report as filed with federal and provincial regulatory agencies in May 2011 to initiate the Environmental Assessment of Site C.

Table 3-13 summarizes the technical and financial characteristics of Site C.

Table 3-13 Site C Summary

Transmission Region	Number of Potential Sites	Installed Capacity (MW)	DGC (MW)	Total Energy (GWh/year)	Firm Energy (GWh/year)	UEC at POI ($2011/MWh)
Peace River	1	1,100	1,100	5,100	4,700	95

Note: Based on capital cost of $7.9 billion as per updated cost estimate filed in May 2011 as part of the Site C Project Description Report.

3.4.1.8 Geothermal

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.

Geothermal electricity can be produced based on conventional or unconventional resources. Conventional resources are in the form of steam or, much more commonly, hot water; while unconventional resources are found in rock that is hot but essentially dry, and commonly called hot dry rock (**HDR**) resources. Only conventional hydrothermal resources using flash or binary technologies are considered within BC Hydro's resource option assessment. There may be potentially significant co-produced fluid and HDR resources in B.C. that could increase the potential geothermal resource base of B.C.

There are no commercial geothermal electricity projects in B.C. at this time. From the 2010 ROR, BC Hydro understands that there are some challenges with geothermal development in B.C. related to the risk/reward of making significant upfront capital investment at the early exploration and initial production drilling stages. As a potentially low cost and high capacity value generation resources, combined with the significant need for future capacity resources, BC Hydro is proposing to undertake necessary activities to review and assess the viability of geothermal generation in B.C. as outlined in Chapter 6.

BC Hydro has reviewed a number of external studies to develop its assessment of geothermal potential.

A summary of the technical and financial results for the geothermal resource option is contained in Table 3-14.

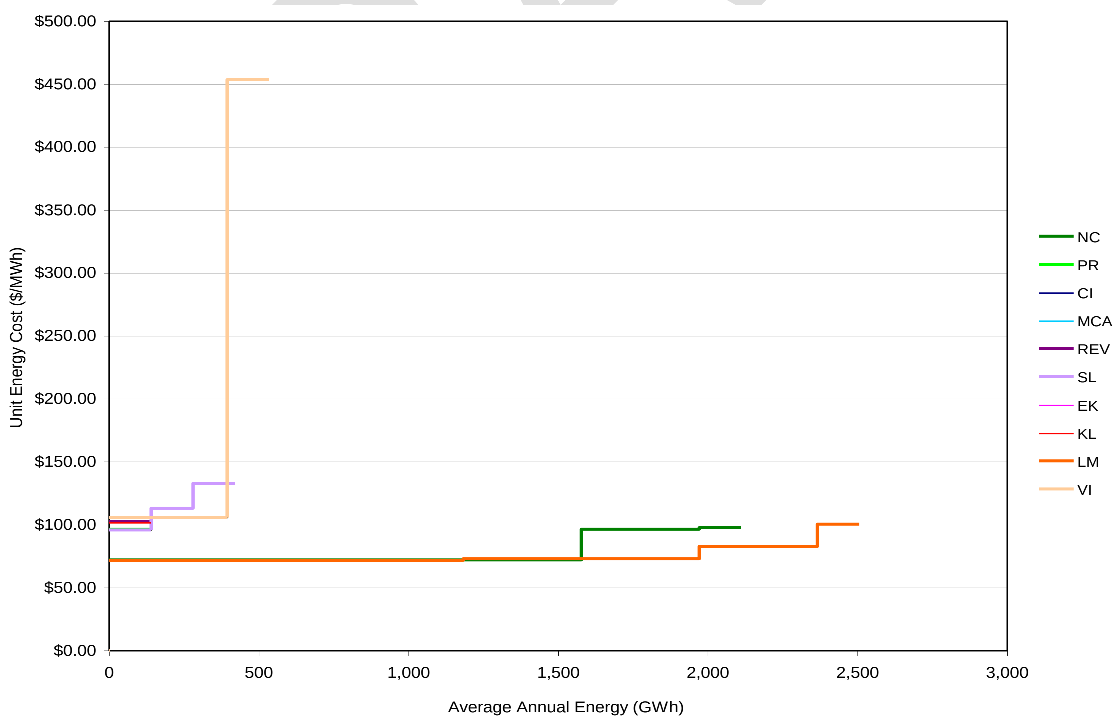
Table 3-14 Summary of Geothermal Potential

Transmission Region	Number of Potential Sites	Installed Capacity (MW)	DGC (MW)	Total Energy (GWh/year)	Firm Energy (GWh/year)	UEC at POI ($2011/MWh)
Peace River	1	20	20	140	140	96
North Coast	3	270	270	2,111	2,111	72 - 98
Kelly Nicola	1	20	20	140	140	102
Revelstoke	1	20	20	140	140	103
Vancouver Island	2	70	70	534	534	106 - 454
Lower Mainland	5	320	320	2,505	2,505	71 - 101
Selkirk	3	60	60	420	420	96 - 133
Total	**16**	**780**	**780**	**5,992**	**5,992**	**71 - 454**

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).

The supply curves for geothermal resource potential based on POI costs, by transmission region, are shown in Figure 3-13.

Figure 3-13 Geothermal Supply Curves



3.4.1.9 Natural Gas-Fired Generation and Cogeneration

Gas-fired units generate electricity using the heat released by the combustion of natural gas. Combined cycle gas turbines (**CCGT**) are the most commonly employed technologies. Conversion efficiencies are typically 50 per cent for CCGT machines.

The development of any gas-fired generation project in B.C. would need to be within the allowance made for non-clean resources in the *CEA*. The *CEA* provides a 93 per cent target for electricity generation from clean or renewable resources.

BC Hydro undertook an in-house update of the cost and performance characteristics of three representative gas-fired generation units located in Kelly Nicola: 50 MW, 250 MW, and 500 MW CCGT. BC Hydro also undertook an in-house update for potential cogeneration units in the Lower Mainland. Cogeneration is the simultaneous production of electrical and thermal energy from a single fuel. The efficiency of cogeneration plants is 90 per cent or greater.

A summary of the technical and financial results for the gas-fired generation resource options is contained in Table 3-15.

Table 3-15 Summary of CCGT and Small Cogeneration Gas-Fired Generation Potential

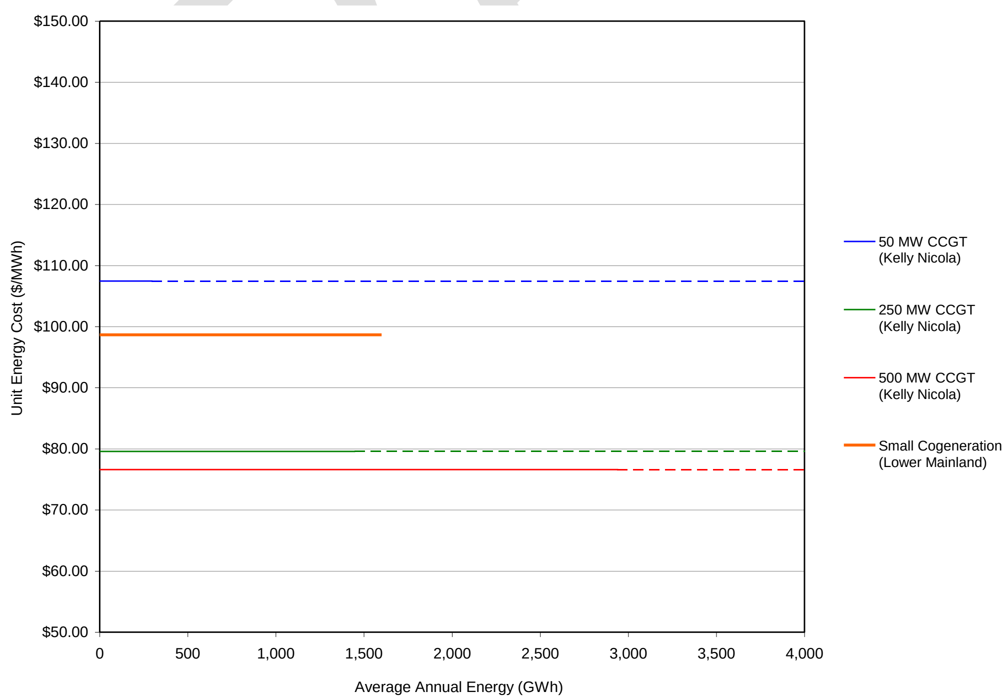
Resource Option	Number of Potential Sites	Installed Capacity (MW)	DGC (MW)	Total Energy (GWh/year)	Firm Energy (GWh/year)	UEC at POI ($2011/MWh)
50 MW CCGT in Kelly Nicola	1	56	49	300	386	107
250 MW CCGT in Kelly Nicola	1	263	236	1,450	1,861	80
500 MW CCGT in Kelly Nicola	1	530	479	2,940	3,776	77
Small Cogeneration in Lower Mainland	20	200	200	1,600	1,600	99

Notes:

1. Representative project used to characterize the resource option.
2. Gas-fired generation options are based on natural gas price estimates for the 2015-2039 period using the "Medium" gas price forecast of $7.34/GJ, which was assigned highest likelihood at the time of 2010 ROR. More updated gas price forecasts and likelihoods are provided in Chapter 6, with the associated impact on impacts on portfolio analysuis results being addressed in Chapters 5 and 6.

The supply curves for the CCGT and small cogeneration resource options, based on POI costs, are shown in Figure 3-14.

Figure 3-14 CCGT and Small Cogeneration Supply Curves



Note: A dotted line indicates additional potential.

3.4.1.10 Coal-Fired Generation with Carbon Capture and Sequestration

Policy Action No. 20 of the 2007 Energy Plan stipulates that coal-fired generation in B.C. 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 Integrated Gasification Combined Cycle (**IGCC**) is now becoming available, technology that allows plant-generated carbon dioxide to be captured and stored through sequestration is still evolving and is not presently viable on a large-scale commercial scale. According to the Electric Power Research Institute (**EPRI**)[22], coal-fired generation plants with 90 per cent CO_2 emission capture and storage could be commercially available by 2022.

In developing the potential of coal-fired generation with carbon capture and sequestration (**CCS**) resource option, BC Hydro relied upon reports prepared by Powertech Labs Inc. in 2009 and a 2007 National Energy Technology Laboratory report[23].

A summary of the technical and financial results for the coal-fired generation with CCS resource option is contained in Table 3-16.

Table 3-16 Summary of Coal-Fired Generation with CCS Potential

Transmission Region	Number of Potential Sites	Installed Capacity (MW)	DGC (MW)	Total Energy (GWh/year)	Firm Energy (GWh/year)	UEC at POI Range ($2011/MWh)
Peace River	1*	745	556	3,896	3,896	81

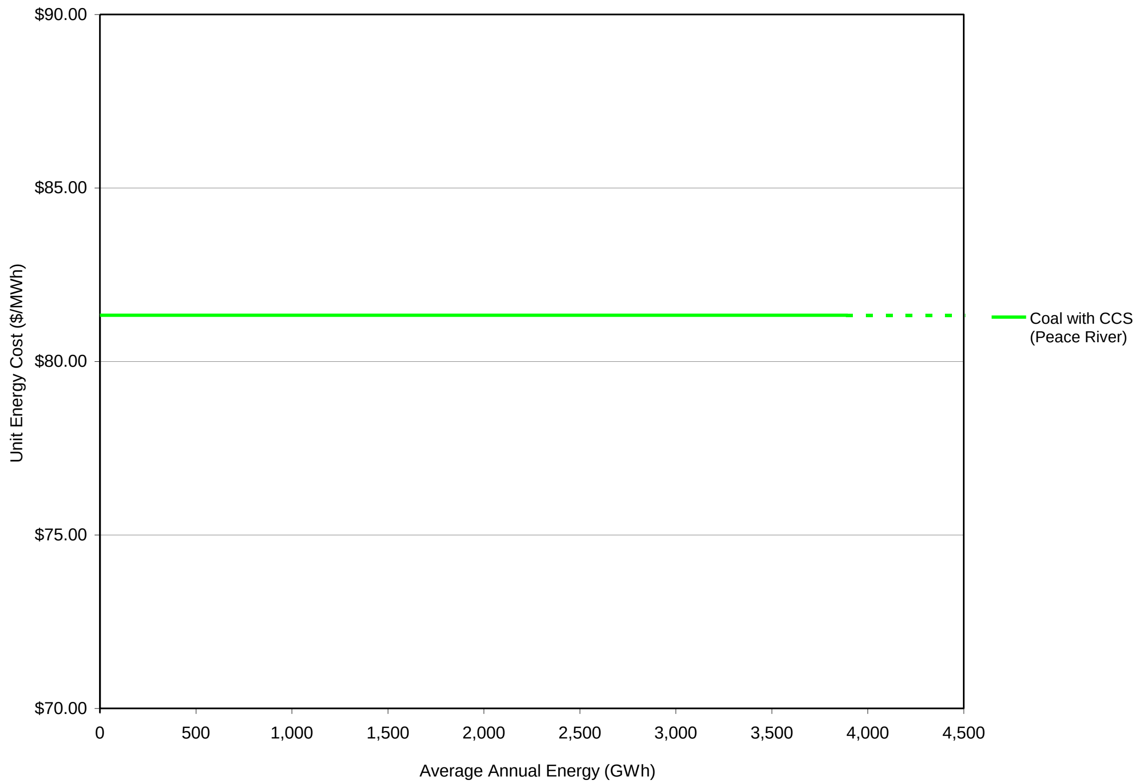
* Representative project used to characterize the resource option.

The supply curve for the coal-fired generation with CCS resource option, based on POI costs, is shown in Figure 3-15.

[22] Fall 2007, EPRI Journal, “Pathways to Sustainable Power in Carbon-Constrained Future”, page 4-13.

[23] “Cost and Performance Baseline for Fossil Energy Plants, Volume 1: Bituminous Coal and Natural Gas to Electricity Final Report”, Revision 1, August 2007.

Figure 3-15 Coal-Fired Generation with CCS Supply Curve



Note: A dotted line indicates additional potential.

3.4.1.11 Wave

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. Currently, there are five generic approaches to capturing the wave energy resource, all of which are at the early stages of commercial development and with potential application in B.C. There are currently no wave energy projects in B.C. waters, although two demonstration projects have received support from provincial and federal innovative clean energy funding agencies.

BC Hydro relied on information in 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**)[24] report to develop the total theoretical wave energy. The costs associated with these wave energy projects have been estimated based on the cost projections from the U.K.-based Carbon Trust report[25].

A summary of the technical and financial results for the wave resource option is contained in Table 3-17.

Table 3-17 Summary of Wave Potential

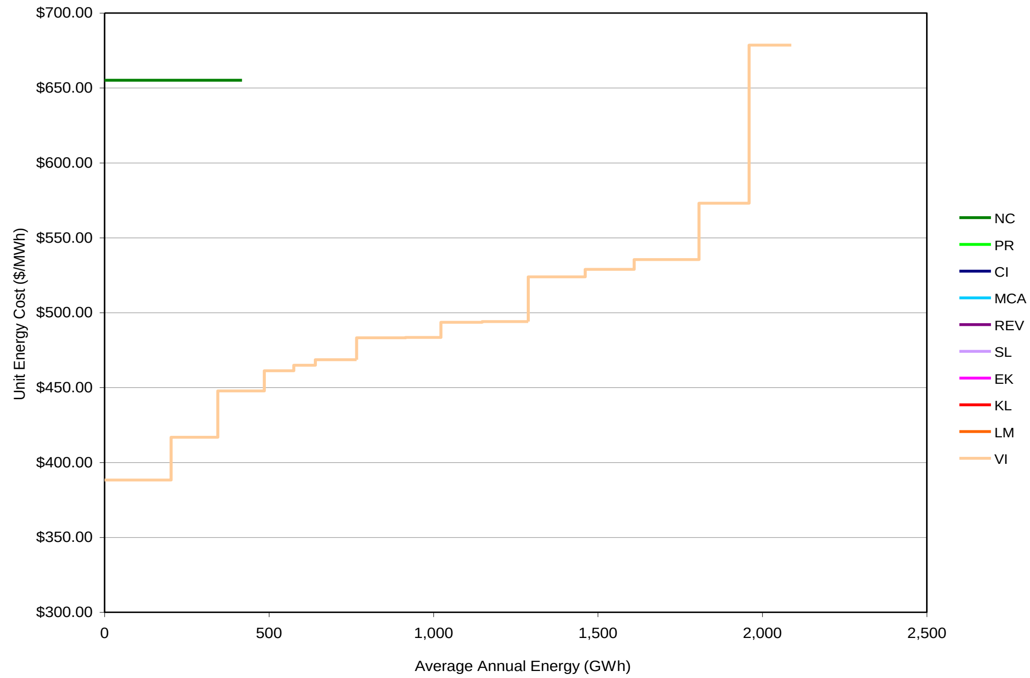
Transmission Region	Number of Potential Sites	Installed Capacity (MW)	ELCC (MW)	Total Energy (GWh/year)	Firm Energy (GWh/year)	UEC at POI ($2011/MWh)
North Coast	1	143	34	418	418	655
Vancouver Island	15	936	225	2,088	2,088	388 - 679
Total	**16**	**1,078**	**259**	**2,506**	**2,506**	**388 - 679**

The supply curves for the wave resource potential, based on POI costs, are shown in Figure 3-16.

24 CHC, Inventory of Canada's Marine Renewable Energy Resources, April 2006.

25 Future Marine Energy, Results of the Marine Energy Challenge: Cost competitiveness and growth of Wave and tidal stream energy, Carbon Trust, January 2006.

Figure 3-16 Wave Supply Curves



3.4.1.12 Tidal

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. Tidal energy is variable from one hour to the next, but can be accurately predicted several years into the future.

Tidal energy can be captured in two different ways – tidal barrages and tidal current systems. Tidal barrage is not considered a realistic prospect in B.C. due to its needs of a dam construction and its negative estuary ecosystem impact. This assessment focuses exclusively on tidal current systems. There are no commercial tidal current projects in B.C., although there are two demonstration projects underway.

Owing to the early state of commercial development, there is little real-world experience with the costs associated with tidal power on a commercial scale. BC Hydro relied on the Carbon Trust report to assess the costs of tidal development.

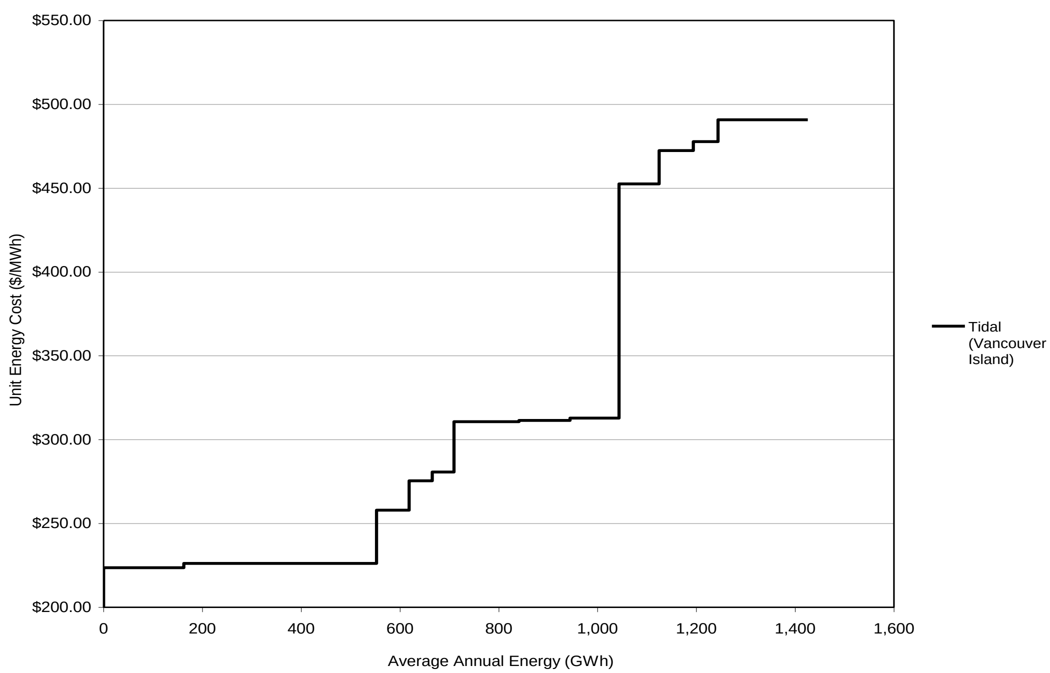
A summary of the technical and financial results for the tidal resource option is contained in Table 3-18.

Table 3-18 Summary of Tidal Potential

Transmission Region	Number of Potential Sites	Installed Capacity (MW)	ELCC (MW)	Total Energy (GWh/year)	Firm Energy (GWh/year)	UEC at POI ($2011/MWh)
Vancouver Island	12	617	247	1,426	1,426	224 - 491
Total	**12**	**617**	**247**	**1,426**	**1,426**	**224 - 491**

The supply curve for the tidal resource option, based on POI costs, is shown in Figure 3-17.

Figure 3-17 Tidal Supply Curve



3.4.1.13 Solar

Solar power is generated from sunlight and can be achieved directly using photovoltaic cells (crystalline silicon or thin film) or indirectly by using Concentrating Solar Power (**CSP**) technologies. Both the photovoltaic and CSP technologies are commercially proven. Globally the costs have achieved dramatic decline and are projected to continue, but are not expected to become cost-competitive in Canadian jurisdictions over the next 10 years in the absence of price support.

There are no known commercial solar power installations in British Columbia. However, there are several distributed generation installations on the customer side of the meter.

The solar resource option assessment focuses on utility-scale photovoltaic systems given the ability to modularly increase the size of the solar power installation size over time and thereby managing capital investment risk. CSP technologies are not included due to thier large upfront capital investment as utility-scale CSP plants typically require a large-scale implementation.

The solar resource option assessment examined commercial installations on the utility side of the meter with commercial scale solar installations sized at 5 MW.

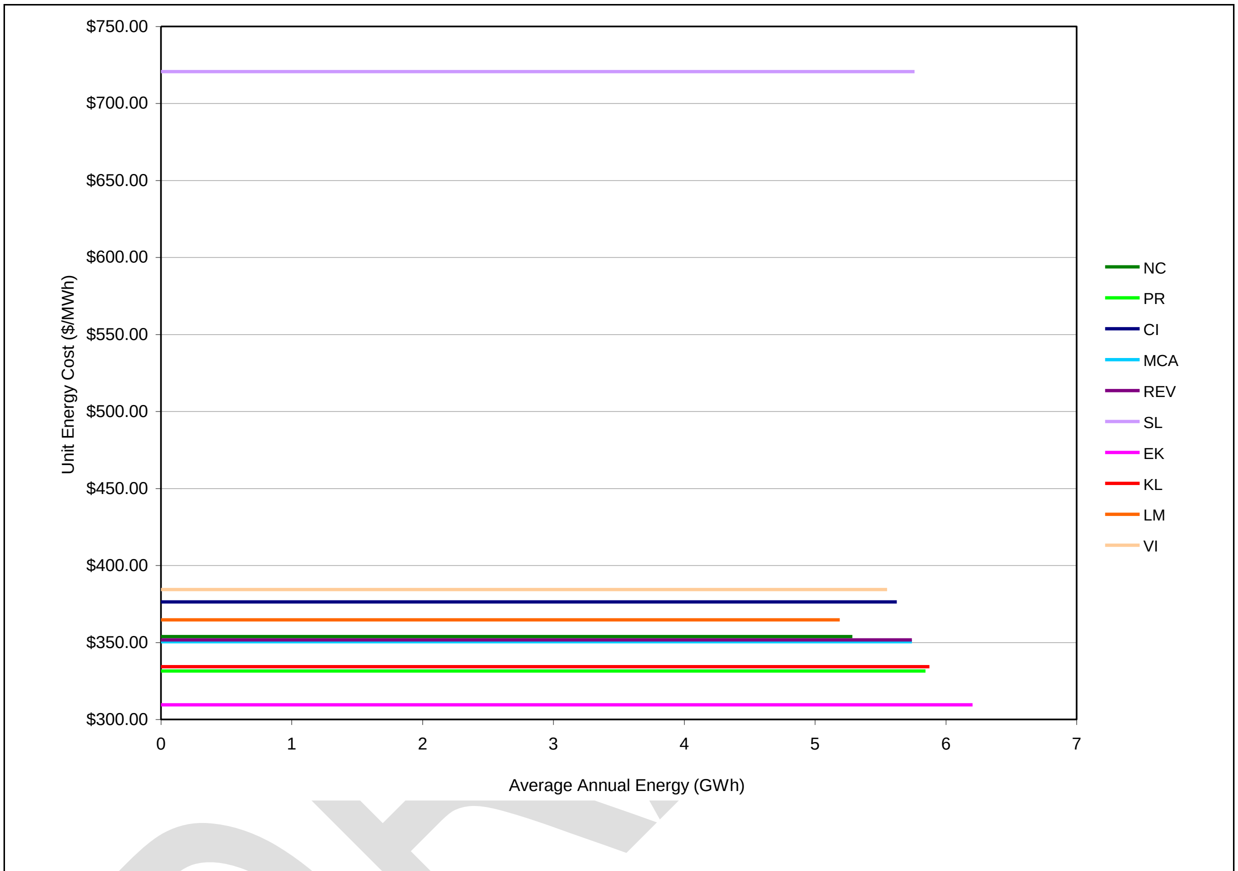
A summary of the technical and financial results for the solar resource option is contained in Table 3-19.

Table 3-19 Summary of Solar Potential

Transmission Region	Number of Potential Sites	Installed Capacity (MW)	ELCC (MW)	Total Energy (GWh/year)	Firm Energy (GWh/year)	UEC at POI ($2011/MWh)
Peace River	1	5	1	6	6	331
North Coast	1	5	1	5	5	354
Central Interior	1	5	1	6	6	376
Kelly Nicola	1	5	1	6	6	334
Mica	1	5	1	6	6	351
Revelstoke	1	5	1	6	6	352
Vancouver Island	1	5	1	6	6	384
Lower Mainland	1	5	1	5	5	365
Selkirk	1	5	1	6	6	721
East Kootenay	1	5	1	6	6	310
Total	**10**	**50**	**12**	**57**	**57**	**310 - 721**

The supply curves for the solar resource potential based on POI costs, by transmission region, are shown in Figure 3-18.

Figure 3-18 Solar Supply Curves



3.4.1.14 Nuclear

Nuclear has not been investigated as a resource option given that Policy Action No. 23 of the 2007 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 section 2(o) of the *CEA*, which specifies that B.C.'s energy objectives must be achieved without the use of nuclear power.

3.4.2 Capacity Resource Options

3.4.2.1 Pumped Storage

Pumped Storage (**PS**) hydro 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 inherent inefficiencies in the pumping-generating cycle which result in recovery of about only 70 per cent of the energy used.

The ability to store water and release it during times of system need makes PS a useful capacity resource. PS hydro units can respond quickly to variations in system demand and can provide ancillary services such as voltage regulation. PS is the most widespread energy storage system in use on power networks with over 90,000 MW installed worldwide. However, there are no commercial PS facilities in British Columbia.

BC Hydro engaged Knight Piésold Ltd. to identify greenfield PS potential in the Lower Mainland and Vancouver Island regions, and engaged Hatch Ltd. to assess the cost of installing a pump-turbine or a pump at Mica Generating Station.

A summary of the technical and financial results for the PS resource option is contained in Table 3-20. As PS is considered a capacity option, only the UCC is shown.

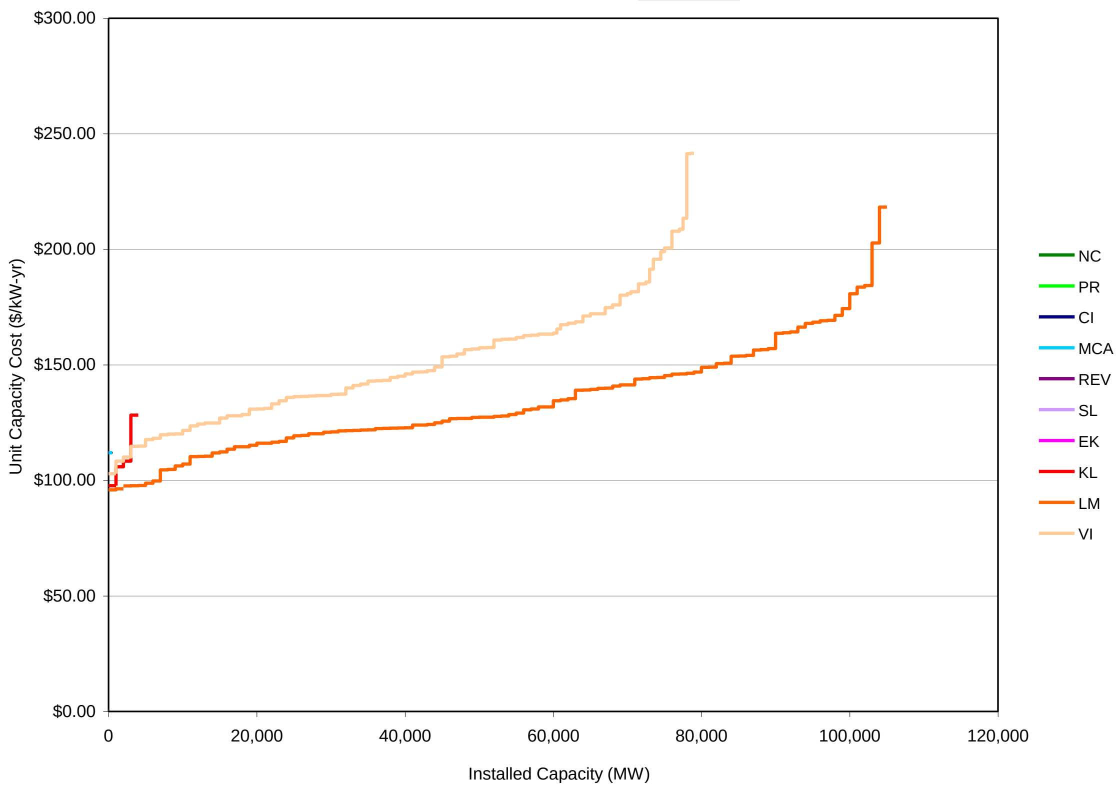
Table 3-20 Summary of Pumped Storage Potential

Transmission Region	Number of Potential Sites	Installed Capacity (MW)	DGC (MW)	UCC at POI ($2011/kW·year)
Kelly Nicola	4	4,000	4,000	98 - 128
Mica	1	500	465	112
Vancouver Island	84	79,000	79,000	103 - 242
Lower Mainland	105	105,000	105,000	96 - 218
Total	**194**	**188,500**	**188,465**	**96 - 242**

Note: UCCs for pumped storage include fixed costs only.

The supply curves for PS potential in the transmission regions investigated, based on POI costs, are shown in Figure 3-19.

Figure 3-19 Pumped Storage Supply Curves



3.4.2.2 Natural Gas SCGT

Gas-fired units generate electricity using the heat released by the combustion of natural gas. In terms of capacity resources, simple cycle gas turbines (**SCGT**) are the most commonly employed technology. Conversion efficiencies are typically 35-40 per cent for SCGT machines.

The development of any gas-fired generation in B.C. would need to be within the allowance made for non-clean resources in the *CEA*. The *CEA* provides a target of generating 93 per cent electricity from clean or renewable resources.

BC Hydro undertook an in-house update of the cost and performance characteristics of two representative gas-fired units: 100 MW SCGT in Kelly Nicola and 100 MW SCGT on Vancouver Island.

The UCCs for the two representative SCGTs are shown in Table 3-21.

Table 3-21 Summary of the SCGT Natural Gas Fired Generation Potential

Transmission Region	Number of Potential Sites	Installed Capacity (MW)	DGC (MW)	UCC at POI ($2011/kW·year)
100 MW SCGT in Kelly Nicola	1	103	98	70
100 MW SCGT on Vancouver Island	1	103	101	162

Notes: Unit capacity costs for SCGTs include fixed costs only.

3.4.2.3 Resource Smart

BC Hydro's Resource Smart program, introduced in the late 1980s, promotes the identification, study and implementation of projects that provide cost-effective energy and capacity gains at existing BC Hydro facilities. BC Hydro evaluates the generating components of its hydroelectric and thermal generating stations with a desire to replace or refurbish those assets that are estimated to be at the end of their useful life, or have shown reliability or safety problems.

Looking forward, BC Hydro is planning for the installation of a sixth generating unit at Revelstoke with an installed capacity of 500 MW. The Revelstoke Unit 6 project cost was updated by inflating the costs used in the 2008 LTAP.

A summary of the technical and financial results for the Resource Smart options is contained in Table 3-22.

Table 3-22 Summary of Resource Smart Potential

Transmission Region	Number of Projects	Installed Capacity (MW)	DGC (MW)	Total Energy (GWh/year)	Firm Energy (GWh/year)	UCC at POI ($2011/kW-year)
Revelstoke	1	500	470	26	26	55

3.4.2.4 Other Capacity Options

The Canadian Entitlement (**CE**) is the Canadian portion of the additional electricity produced in the Columbia River in the western U.S. as a result of provisions of the Columbia River Treaty ratified in 1964. BC Hydro has access to the capacity associated with the CE. However, this capacity is not "solely from electricity facilities within the Province". Given the self-sufficiency requirement in the *CEA*, the CE is not a suitable source of dependable capacity in the long term, and therefore, the role of the CE is limited as a bridging or contingency resource option.

3.4.3 Summary of Supply-Side Generation Resource Options

In the prior sections, the UECs of supply-side resources are shown based on POI. Here for comparison purposes, the UECs are presented as adjusted to reflect the cost of resources delivered to the Lower Mainland, which is BC Hydro's major load centre. The results are summarized in Table 3-23 and Figure 3-20.

For comparison, BC Hydro's current reference energy price is set at $129/MWh in $2011 based on the weighted-average levelized and adjusted firm energy price from the Clean Power Call.

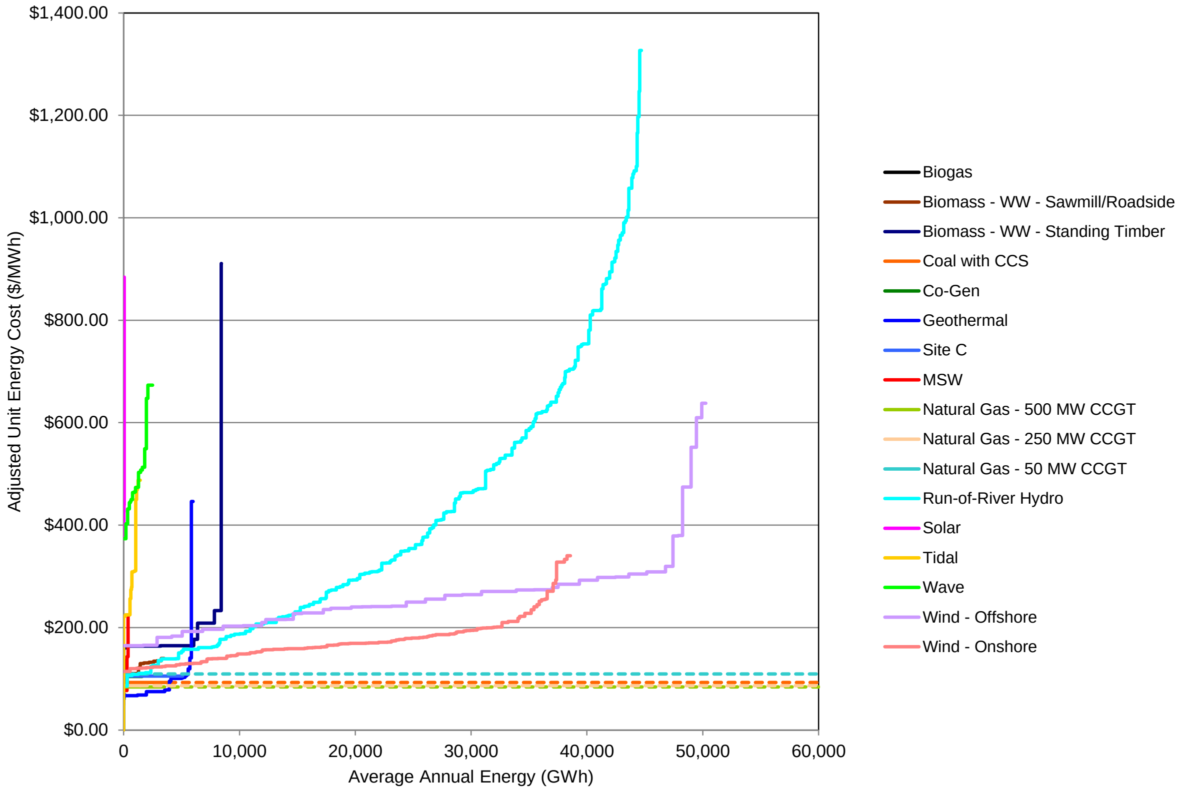
Table 3-23 UECs of Energy Resource Supply Options

Energy Resource	Total FELCC Energy (GWh/year)	Total DGC or ELCC Capacity (MW)	UEC at POI @ 6% Real ($2011/MWh)	Adjusted Firm UEC[2] @ 6% Real ($2011/MWh)
Biomass – Wood Based	11,946	1,499	112 – 855	107 – 911
Biomass – Biogas	134	16	54 – 140	49 – 135
Biomass – Municipal Solid Waste	499	58	81 – 211	77 – 225
Wind – Onshore	38,885	3,942	95 – 303	114 – 340
Wind – Offshore	50,261	3,681	159 - 600	165 – 638
Geothermal	5,992	780	71 – 454	67 – 446
Run-of-River	35,880	1,074	66 – 600	86 – 1,327
Site C[3]	4,700	1,100	95	104
CCGT and Cogeneration[4]	7,623	964	77 – 107	84 – 109
Coal-fired Generation with CCS	3,896	556	81	93
Wave	2,506	259	388 – 679	373 – 673
Tidal	1,426	247	224 – 491	222 – 488
Solar	57	12	310 – 721	376 – 884

Notes:

1. The resource 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 higher estimated costs.
2. The details of how the cost adjusters were developed and applied are provided in Appendix 3A-34 of the IRP. The cost estimates as shown are results of survey-level assessment, therefore should not be inferred as feasibility indicators of low cost projects in future power acquisition processes.
3. The Site C values presented in this table are based on information filed in May 2011 as part of the Site C Project Description Report.
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 3-20 Energy Resource Option Supply Curves

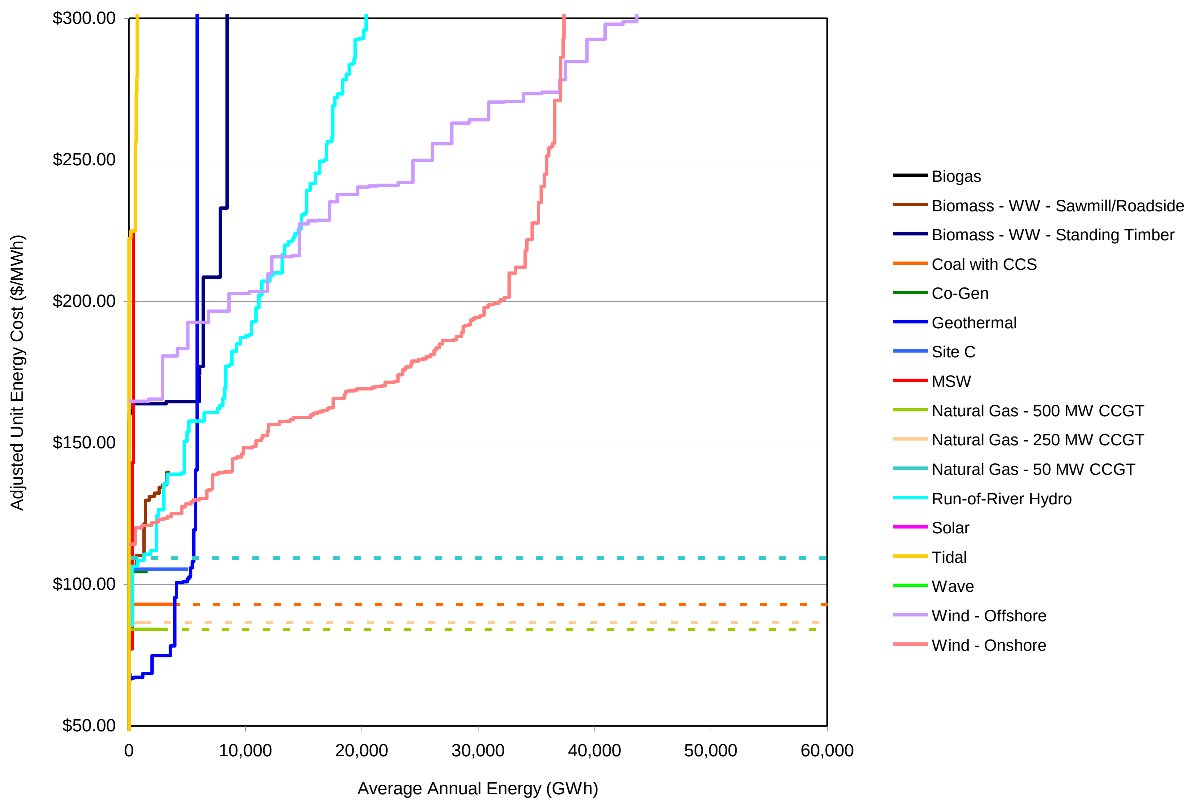


Notes:

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 higher estimated costs.
2. The Site C values presented in this table are based on information filed in May 2011 as part of the Site C Project Description Report.
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.

For ease of viewing, the lower left portion of Figure 3-20 with adjusted UECs less than $300/MWh is provided at a larger scale in Figure 3-21.

Figure 3-21 Energy Resource Option Supply Curves with Adjusted Firm UEC Less Than $300/MWh



The UCC of the supply-side capacity resource options are summarized in Table 3-24.

Table 3-24 UCCs of Capacity Resource Supply Options

Resource Type	Capacity Options	Dependable Capacity (MW)	UCC @ 6% Real ($2011/kW-year)
Resource Smart	Revelstoke Unit 6	470	55
Natural Gas – SCGT	Various Locations	98 or 101	70 or 162
Pumped Storage	Various Locations	1,000	96 – 100

Notes:
1. SCGT and Pumped Storage fuel costs are not included.
2. Revelstoke Unit 6 values based on the 2008 LTAP escalated to $2011.
3. Two SCGT representative projects are used to characterize the gas-fired generation resource option.
4. Presentation of Pumped Storage data is limited to results below $100/kW-year.
5. UCCs are shown at the point of interconnection.

During the process to develop the 2010 ROR, there was strong public interest to access the 2010 resource options database presented in GIS format. To meet the increasing requests, BC Hydro posted the 2010 Resource Options Geometric Locations & Associated Attribute information at http://www.bchydro.com/etc/medialib/internet/documents/planning_regulatory/iep_ltap/2012q1/gis_romap_dataset.Par.0001.File.gis_romap_dataset_20120224.zip.

3.5 Transmission Options Summary

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 *CEA* requires that BC Hydro identify long-term transmission requirements in its IRP planning process.

3.5.1 Bulk Transmission Options

To achieve the *CEA* mandate, BC Hydro reviewed the transmission options required to remove congestion from various sections of BC Hydro's bulk transmission network over a 30-year transmission resource planning horizon. A list of resource options for addressing congestion on the bulk transmission system is summarized in Table 3-25

Table 3-25 Bulk Transmission Resource Options

Item No.	Upgrade Option Description	Lead Time (Years)	$2011 Direct Cost ($ million)	Incremental Capacity (MW)
	North Interior			
TO-01	New 500 kV, 50 per cent series compensated transmission circuit 5L8 between GMS and Williston.	8	373.2	1,470
TO-02	New 500 kV, 50 per cent series compensated transmission circuit 5L14 between Williston and Kelly Lake.	8	327.9	2,120
TO-03	New +/-500 kV HVDC bipole transmission circuit between Peace River and Lower Mainland – Phase 1.	8	1,425.3	1,000

Item No.	Upgrade Option Description	Lead Time (Years)	$2011 Direct Cost ($ million)	Incremental Capacity (MW)
TO-04	New +/-500 kV HVDC bipole transmission circuit between Peace River and Lower Mainland – Phase 2.	8	237.2	1,000
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	57.2	360 (CI-KLY/NIC) and 300 (PR-CI)
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	55.0	390 (CI-KLY/NIC) and 330 (PR-CI)
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	62.6	650 (CI-KLY/NIC) and 580 (PR-CI)
	North Coast			
TO-08	New 500 kV circuit Williston-Glenannan-Telkwa-Skeena parallel to the existing 5L61 - 5L62 and 5L63 lines.	8	991.5	400
TO-09	50 per cent series compensation of the WSN-GLN 500 kV line 5L63 (or 5L61 or 5L62).	3	31.8	133
TO-21	A new 449 km long +/-500 kV HVDC bipole transmission circuit between WSN and SKA.	8	1,049.2	2,000
	South Interior			
TO-10	New 500 kV, 50 per cent series compensated transmission circuit 5L97 between Selkirk and Vaseaux Lake.	8	217.9	750
TO-11	New 500 kV, 50 per cent series compensated transmission circuit 5L99 between Vaseaux Lake and Nicola.	8	188.7	750

Item No.	Upgrade Option Description	Lead Time (Years)	$2011 Direct Cost ($ million)	Incremental Capacity (MW)
TO-12	50 per cent series compensation of the 500 kV lines 5L91 and 5L98.	3	59.4	133 (SEL-KLY/NIC) and 147 (SEL-REV/ACK)
TO-13	50 per cent series compensation of 500 kV lines 5L71 and 5L72.	Committed in 2014	44.2	624
TO-14	50 per cent series compensation of 500 kV lines 5L76, 5L79, and 5L96.	3	58.0	112
TO-19	50 per cent series compensation of 500 kV line 5L92 SEL-CBK.	3	30.0	150
TO-20	A new 500 kV line between SEL and CBK. To define this line, information from Section 5 Inquiry for a new 500 kV line from SEL to Alberta border (287 km, TTC = 1550 MW) is utilized. The new CBK-SEL 500 kV line will be 180 km long.	8	625.8	1,550
	Interior to Lower Mainland			
TO-15	New 500 kV, 50 per cent series compensated transmission circuit 5L83 between Nicola and Meridian.	Committed in 2015	585.5	1,550
TO-16	New 500 kV, 50 per cent series compensated transmission circuit 5L46 between Kelly Lake and Cheekye.	8	495.3	1,384
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	9.7	570
	Lower Mainland to Vancouver Island			
TO-18	New 230 kV transmission circuit 2L124 between Arnott and Vancouver Island terminal.	6	221.2	600

Note: TO-15 information is based on a progress report for the ILM project filed with BCUC in November 2011.

3.5.2 Transmission Expansion and Regional Transmission Projects

The main focus of the IRP process is to identify major bulk transmission upgrades and transmission facilities required for interconnecting new resources to the grid. However, some BC Hydro transmission projects are being advanced to alleviate regional transmission constraints or for transmission expansion purposes. These projects are captured in the discussion on regional planning issues and constraints identified in section 2.5 of the IRP.

3.5.3 Transmission for Export

As set out in the *CEA*, the IRP is required to provide a description of the expected export demand for electricity from B.C. clean or renewable resources and the extent to which BC Hydro has arranged for contracts for the export of electricity and the transmission or other services necessary to facilitate those exports. While the main components of export analysis are set out in Chapter 7, this section describes the transmission options considered for export purposes.

Existing transmission congestion along the I-5 corridor in the Pacific Northwest makes a new transmission path from eastern part of B.C. to Mid-Columbia and California more viable than other options. Therefore, the Selkirk (**SEL**) substation is used as a modelling hub for collecting B.C.'s excess energy and transferring it to U.S. markets.

For modelling purposes, 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-to-Devil's Gap transmission path is configured with one or two 500 kV transmission circuit(s).

The SEL-to-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 proposed CNC line would transfer up to 3,000 MW power from B.C.-based power facilities to Northern California and would include a double circuit 500 kV high-voltage alternating current (**HVAC**) line from SEL to Devil's Gap substation and to the North East Oregon

(**NEO**) substation plus a +/- 500 kV HVDC bipole from NEO to the Collinsville substation near San Francisco.

3.6 Other Resource Options

In addition to the resource options potential identified in section 3.3, 3.4 and 3.5 of this chapter, BC Hydro is doing additional work to advance other resource options. The work ranges from monitoring the commercial readiness of technologies and/or assessments of resource potential to investigating market barriers to the development of certain resource options and identifying whether there is a role for BC Hydro to play in alleviating these barriers. Appendix 3D presents more details of the BC Hydro's Corporate Technology Roadmap.

3.6.1 Distributed Generation

For the purposes of this work, BC Hydro defines distributed generation (**DG**) as:

> An approach whereby smaller-scale generation of electricity is located close to the load it is intended to serve and can be located at customer sites, and is usually connected to the distribution system. 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. While no formal assessment of DG potential was conducted for the 2010 ROR, some of the potential considered within DSM and the supply-side resource options would qualify as DG.

Based on customer and stakeholder interest, BC Hydro has examined potential DG opportunities across its customer base and a number of DG-related programs and projects are already in place, including:

- Over 200 projects are in service under BC Hydro's Net Metering program (projects up to 50 kW);
- Completed agreements with several pilot projects;

- Several projects have been awarded electricity purchase agreements in calls such as the Customer Based-Generation and Bioenergy Phase 1 calls;
- A Standing Offer Program has been implemented for clean power projects sized at 15 MW or less; and
- An industrial load displacement program within the current DSM Plan.

To support the development of new small-scale DG projects, BC Hydro is examining the practices of other jurisdictions; analyzing its existing acquisition programs and processes to ensure appropriate alignment between various project thresholds; and identifying possible barriers and their removal, BC Hydro is also currently assessing the role of these existing initiatives and whether they fully capture all cost-effective DG opportunities in B.C. More information on this is provided in section 9.4.3 of the IRP.

3.6.2 Evolving Generation Technology

3.6.2.1 Hydrokinetic

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.

BC Hydro is monitoring the development of these technologies and assessments of resource potential. Hydrokinetic resources may be updated in subsequent resource option estimates following the completion of the proposed National Resources Canada (**NRCan**) study to assess the hydrokinetic resource potential in Canada.

BC Hydro has worked with technology suppliers to host a field test of vertical-axis hydrokinetic devices in a controlled environment downstream of its Duncan Dam. There are currently no active hydrokinetic demonstration projects in B.C.

3.6.2.2 Storage Technologies

Energy storage is now recognised as a key component to future grid asset management and operations. Recent advances in the development of energy storage have focused on numerous technologies for a variety of functions within the electrical grid system. Besides pumped storage, other technologies include compressed air energy storage, capacitors, flywheels, batteries, and hydrogen fuel cell storage systems.

BC Hydro is monitoring the development of these technologies and more information on their commercial status can be found in Appendix 3A of the IRP. BC Hydro is advancing a demonstration of advanced batteries to improve system reliability with support from the federal government's Clean Energy Fund, as well as evaluation of community-scale energy storage technologies in test environments. None of these technologies are considered to be within the scope of the 20-year IRP planning horizon.

3.6.3 Emerging Transmission Technology

3.6.3.1 Advanced Conductors

BC Hydro currently relies on a network of overhead, subterranean and submarine aluminum-steel composite cables to conduct power at high voltage from generating stations to the load centres. BC Hydro monitors research developments for advanced conductor technologies which seek to utilize emerging materials to increase the conductivity and/or strength of transmission cables. These advances have the potential to reduce transmission system costs and energy losses.

One of the areas being investigated is High-Temperature Superconductors (**HTS**) which are materials that lose all resistance to electrical conduction at temperatures above the boiling point of nitrogen. HTS cables consist of brittle HTS filaments wound around flexible tubes through which pressurized liquid nitrogen is pumped for cooling. HTS transmission cables are currently in demonstration in several North American and Asian jurisdictions.

Carbon nano-tubes are another material with potential for application in advanced transmission cables. Carbon nano-tubes – a type of tubular fullerene molecule – have extremely high conductivity and tensile strength characteristics, offering improved performance over conventional cable materials. Carbon nano-tubes are currently available for industrial applications, but the cost per unit weight is prohibitive for application to transmission cables. Research is underway to develop low cost manufacturing techniques.

3.6.3.2 Real-Time Condition Assessment and Control

The term "Smart Grid" describes the integration of power system management and communications that enable monitoring and automatic optimization of interconnected elements of the grid. Within the context of the transmission system, which already exhibits many of the attributes of a Smart Grid, there are advanced monitoring and control technologies becoming available that allow operation of transmission networks to the limits of design capacity in a safe and reliable manner. A variety of commercially available sensors can be deployed on transmission lines and sub-station infrastructure to monitor the operation of assets and detect abnormal conditions. BC Hydro is working to deploy advanced sensors and the integration of the collected data into control systems as part of its Smart Grid initiative.

3.6.3.3 Advanced Stations

Advances in information technology, communication infrastructure and power system technologies are driving innovations towards next-generation stations that transform voltages and manage power flow with greater control and with a smaller physical footprint. The main power apparatus in a next-generation station, such as circuit breakers and transformers, will be smaller and elements such as busbars, insulators and ground grids will be more densely packaged. The sensors and communication modules will be embedded in the power apparatus and primary high voltage measurements will utilize high-accuracy optical devices with direct digital outputs. This will allow new approaches for monitoring, control and protection including reduced wiring, reliable and accurate filtering of data, improved data security, self-diagnosis of problems, and industry standard approaches for information exchange. The systems will be modular, allowing low cost expansion capabilities. Next-generation stations are currently in the demonstration and early deployment stage of development. BC Hydro is currently investigating the use of solid state power electronics for use in intelligent transformers, as well as exploring new communication protocols for use in smart sub-stations.

3.7 Conclusion

This chapter has summarized the findings of the 2010 ROR, which is used as a key input to the IRP portfolio analysis. In comparison to past resource options assessments, the 2010 ROR is a comprehensive effort and provides additional information on:

- Potential energy for wood-based biomass, offshore wind and solar resource options;
- Potential capacity for pumped storage in the Lower Mainland and Vancouver Island areas;
- Revisions to the small hydro energy potential;
- Updated bulk transmission options; and
- Environmental and economic development attributes.

At the time of completing the 2010 ROR, an overall finding was that there were generally higher costs to developing new resource options primarily due to increased construction and material costs.

3.7.1 New Information

Subsequent to the completion of the 2010 ROR, some new information has emerged that was not available in time for inclusion in the IRP, as described below.

The costs of wind energy have dropped over the past three years due to wind turbine price drops and turbine efficiency improvements. BC Hydro is working with the wind industry to understand and evaluate these developments. As part of BC Hydro's ongoing efforts to assess resource option potential and costs, wind costs may be updated in future resource options assessments after completing this review. At the same time, BC Hydro will evaluate whether other resource options have been affected by these market developments and whether other cost updates are required.

Given the potential for significant load growth in the North Coast region, BC Hydro engaged Knight Piésold to conduct a screening assessment of greenfield pumped storage potential in the North Coast region. This information is provided in Appendix 3E.

In January 2011, Powerex and Pacific Gas & Electric (**PG&E**) signed a term sheet in in pursuit of an anchor-tenant energy transaction for the CNC transmission line. Since then, there has been an absence of secured energy deals in the market thereby making the new transmission line a more risky undertaking. Accordingly, the CNC partners have abandoned the CNC project for the foreseeable future. Further details on the CNC project are contained in Chapter 7.

On December 8, 2011, the B.C. Government issued Ministerial Order No. M335 amending the DSM Regulation, B.C. Reg. 228/2011. In addition to amending certain defined terms, the DSM Regulation amendments made substantial changes to the Total Resource Cost test which have increased the cost-effectiveness of DSM.