Resource Options Update Launch Workshop, September 14, 2010 Handout

Draft Summaries of Assumptions and Methodology

BC Hydro periodically updates its information on potential resource options in BC for electricity planning purposes. Data on different resource options has been used as an input to electricity planning exercises and to support BC Hydro analytical work.

BC Hydro is embarking on the next comprehensive update of its resource options data in preparation for the 2011 Integrated Resource Plan and other planning efforts. Through the update, BC Hydro is seeking to understand the future potential availability of different electricity resources in B.C. over the next 20 years.

BC Hydro invites input from individuals and organizations on the methodology and data to ensure its validity and accuracy. Updated data will be used to inform future electricity planning efforts where the benefits, risks and trade-offs associated with different portfolios of resources are examined.

The summaries contained within this document were handed out during the break-out portion of the Resource Options Update Launch Workshop on September 14, 2010. These break-out sessions provided attendees with a brief overview of the assumptions made and draft assessment methodology for each resource option being examined. Attendees were given some time for questions and then asked to sign up to be included in subsequent discussions on the resource options.

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Table of Contents

1. Distributed Generation

1.1 Description

1.1.1 Distributed Generation with a focus on the Customer

In 2008, BC Hydro started to examine the prospect of additional Distributed Generation (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 demand or supply –side or a combination of both. How a customer pursues DG will be 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 our customers based on the factors noted below:

- Increased customer and public engagement in the provision of energy (due to a heightened reliance on electricity and increased expectations for reliability).
- The evolution of generation technologies as well as the development of smart grids and smart meters (the Smart Metering and Infrastructure Program is a critical enabler of DG for BC Hydro).
- The commitment of governments, citizens and businesses to solve climate change.
- Utilities recognizing that smaller and regionally distributed types of projects can provide many benefits.

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 are already in place, including:

- approximately 90 projects are in service under BC Hydro's net metering program (projects up to 50 KW)
- Several projects have been awarded Energy Purchase Agreements (EPAs) in previous and existing calls such as the Customer Based-Generation and Bioenergy Phase 1
- Standing Offer Program (SOP) has been implemented for opportunities <10MW
- Some DSM programs encompass DG (e.g. load displacement & sustainable communities)

The role of these existing programs is being assessed in terms of how they can be adapted or replicated to advance DG in BC.

The goals of the DG strategy are to:

- develop an overarching set of principles to guide BC Hydro's pursuit of DG
- identify other programs/business models that may be required to meet customer needs & requirements
- test new concepts (business models and technologies) through demonstration projects
- create a comprehensive, simple suite of programs to enable DG

Benefits of Distributed Generation

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

For utilities, DG offers benefits such as avoided 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 promote a sustainable energy future for BC. The use of renewable DG technologies (the focus of BC Hydro's strategy) also provides environmental benefits though reduced GHG emissions.

1.1.2 DG Technical Potential Data & Methodology

For the purposes of developing an overarching strategy for DG, a high level technical potential and market potential forecasted out over 20 years was developed. The high level technical potential was derived based on publicly available resource statistics, existing BC Hydro customer data, inputs from BC Hydro's LTAP, customer interviews and assumptions based on industry experience.

A Top Down approach was used for the Commercial, Industrial and Government sectors. The DG Team looked at the number of customers and electricity usage by segment (e.g. Pulp & Paper, Sawmills, etc). They then assumed a typical configuration and technology for a DG project that would be consistent across the sector, applied further assumptions around likelihood of participation and calculated the potential for such projects to offset their current requirements from BC Hydro.

For the Agricultural and Municipal sectors (e.g. landfills, animal waste, MSW, etc), the DG team employed a Bottom Up approach. The number and size of facilities around the province were determined using public statistical information. Assumptions around minimum viable facility size for a DG project and the BTU potential of various fuels were used to determine the potential for each of the sectors.

An analysis for the Residential sector was not undertaken at this time.

1.1.3 DG Update Needs

BC Hydro is continuing to pursue DG opportunities. To date, the DG team is working on advancing six demonstration projects across Commercial, Industrial, Municipal, and Residential and First Nation customer segments. Each of these projects would not have been viable under existing processes, and each is exploring a creative way of acquiring new energy savings or new generation by taking a more holistic approach to the customer, taking into consideration: system benefits, the role of innovation for both supply and demand opportunities; displacement of load; transferability of technology and economic development.

For the purposes of the 2011 IRP, BC Hydro will not be explicitly including DG as a resource option in itself. To some extent, DG is implicitly included in defined resource options and BC Hydro does incorporate an allowance for incremental Standing Offer Program energy in the supply/demand balance. Further decisions regarding potential future customer offer(s) resulting from CEA direction and BC hydro corporate initiatives are required before explicit forecasts of DG potential can be developed.

Under this IRP process, the majority of resource types that lend themselves to characterization under DG such as: small hydro, small wind, biogas, and MSW, have already included in the resource option breakdown. However there are several resource types that have not been included in the IRP, these are Combined Heat and Power (CHP) and waste heat opportunities. Our research has indicated that these resource types could be viable under a DG program or offer. Generally, these types of resources would be pursued by Industrial, Commercial, Municipal and Government sectors.

1.2.1 Challenges

DG is not the same as a traditional resource option, rather it is an acquisition process whereby BC Hydro can acquire new electricity savings or new/incremental generation from customer's wishing to pursue DG related projects. The data that was collected as part of the DG Strategy was done for different purposes and there is a danger that by including DG as a resource option we will be double counting resources that have already been accounted for in the IRP process. Since DG can be acquired through supply and demand models, this also creates an opportunity for double counting.

DG from BC Hydro's perspective is similar to other acquisition processes such as net metering, the Standing Offer Program and the upcoming Feed in Tariff. It is yet another process through which BC Hydro is advancing small scale generation.

1.2.2 Proposed Timeline for subsequent Meetings

At this time no additional input is being sought from participants as the majority of resource types that lend themselves to characterization under DG (for example run-of-river hydro, wind, biogas, and MSW) will be reviewed and updated in their respective resource option categories.

1. Biogas-Landfill gas

1.1 Resource Description

1.1.1. Landfill Gas (LFG) Resource

Landfill gas (LFG) is created when organic waste in a municipal solid waste landfill decomposes under anaerobic condition. This gas consists of about 50 percent methane (the primary component of natural gas), about 50 percent carbon dioxide (CO_2), and a small amount of other organic compounds.

Instead of being allowed to escape into the air, LFG can be captured, converted, and used as an energy source. Using LFG helps to reduce odours and other hazards associated with LFG emissions. Because methane has about 21 times the contribution of GHG effects compared to CO_2, using LFG also helps prevent methane from migrating into the atmosphere and contributing to local smog and global climate change.

In particular, LFG energy projects:

- Reduce emissions of greenhouse gases that contribute to global climate change.
- Offset the use of non-clean resources, such as coal, oil, and natural gas.
- Help improve local air quality.
- Provide revenues for landfills and energy cost savings for users of LFG energy.
- Create jobs and economic benefits for communities and businesses.

The goal of a landfill gas (LFG) energy project is to convert LFG into a useful energy form, such as electricity, steam, heat, vehicle fuel, or pipeline quality gas. The most prevalent are:

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

In Canada, most existing projects are either direct use (heating) application or electrical generation facilities.

Direct use of medium-grade gas and electricity generation is a common application of LFG. A heating application may be a better option if there is a nearby end user. If there is no nearby energy user, electricity generation may prove to be the best option. In the 2010 ROU, we only focus on the electricity application.

1.1.2. Technology for LFG Electricity Projects

Technologies for producing electricity from LFG include internal combustion engines, gas turbines, or microturbines [Ref. 1].

The internal combustion engine (ICE) - is the most commonly used conversion technology in LFG applications; more than 70 percent of all existing LFG electricity projects use them. 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 800kw-3MW 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.

Microturbines - In general, microturbine project costs are more expensive on a dollar-per- kW installed capacity basis than ICE projects. Microturbine technologies are suitable when LFG availability is less than 300 cubic feet/minute (cfm), or when LFG has a lower methane content (as little as 35%). Microturbines can be added and removed as available gas quantities change.

1.1.3. Biogas-LFG Data Availability

- Based on the 2008 LTAP and more recent regional studies [Ref. 2], 12 potential landfill gas projects have been indentified in BC. The electricity potential of each project ranges from 0.6MW- 3MW. The total potential is 18MW of capacity and 148 GWh of energy.
- Data on capital and OMA costs are updated using information from the U.S Environmental Protection Agency [Ref. 1].
- Data on landfill gas generation potential are updated with information from the 2008 Golder Associates report entitled “Inventory of Greenhouse Gas Generation from Landfills In British Columbia” [Ref. 2].

1.1.4. Biogas-LFG Data Update Needs

- New potential landfill sites
- Landfill gas generation potential update
- Landfill sites extension with new closure year
- Landfill sites with existing capture/flare system update
- Detailed cost Information

1.2 Methodology

1.2.1 Biogas-LFG Resource Option Assessment Methodology

<u>To calculate the power potential</u>

The 2008 Golder Report [Ref. 2] provides a thorough study of estimated methane generation between 2012-2020 from all operating MSW landfill sites under provincial jurisdiction that have a disposal rate greater than 10 000 tonnes/year in 2006. The study used 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 methane generation rate constant (k). The methodology used to obtain methane generation projection for each landfill site is described in detail in the Golder Report [Ref. 2].

The 2010 ROU only examines the relatively larger landfill sites (flow rate grater than 200 cfm) as landfill sites with low flow rates are not likely to provide enough economic incentive for landfill owners to develop LFG projects.

Electricity potential is calculated by multiplying the total LFG heat content (Btu) by the heat rate of electrical generator. Total LFG heat content is obtained by multiplying the heat content per ton of methane by the average tons 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 consideration of unit availability during a year. Since LFG is considered relatively reliable, the dependable capacity is assumed to be 95% of the installed capacity. Firm energy is assumed to be equal to annual average energy based on the assumption of steady fuel supply.

To calculate the Cost

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

Each potential project has three basic components: a gas collection system and backup flare; a gas treatment system; and an electricity facility.

There are two major components to the cost estimates: (1) the capture and flare system (e.g. wells, blowers, flare, gas treatment system) and (2) the electricity equipment (e.g. ICE, gas turbine, microturbine).

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 system are evaluated in more detail. The capital/OMA costs of these landfill sites are given a discount based on current LFG existing capture levels [Ref. 3] and generally results in lower costs than LFG project without exiting capture/flare system.
- Capture and flare system costs are based on [Ref. 1].

Electricity equipment assumptions:

- A typical ICE cost is used to calculate the capital/OMA cost for most of the projects (e.g 2300$/KW times the project capacity) [Ref. 1].
- A typical Microturbine cost is used to calculate the capital/OMA cost for the projects with lower LFG flow rate (e.g less than 300 cfm).
- Natural gas turbines are not used/evaluated in this study since the size of the projects 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/ton CH4 [Ref. 4].
- ICE heat rate is assumed to be 11.7MMBtu/MWh.
- LFG recovery rate is assumed to be 75% [Ref. 4].

1.2.2 Biogas in the 2008 LTAP

- The current methodology used for calculating the potential LFG production (modified first order kinetic model) is similar to the one used for the 2008 LTAP.
- For the 2008 LTAP, both LFG production potential and cost estimates were based on the 2002 Environment Canada report. For the 2010 ROU, the methodology used to estimate LFG production potential is from the 2008 Golder Report [Ref. 2] and the cost reference is from USEPA [Ref. 1].

1.2.3 Constraints

- Supply for landfill from MSW resources may be potentially impacted if some MSW is transferred as resources of incinerators.
- The UEC cost provides a guide line of LFG project and only for preliminary study; however, a more accurate cost can depend on each landfill site condition.

1.2.4 References

1 - U.S Environmental Protection Agency web-site;
2 - Inventory of Greenhouse Gas Generation from Landfills In British Columbia", by Golder Associates, 2008;
3 - An Inventory of Landfill Gas Recovery and Utilization in Canada 2006 & 2007, by The Greenhouse Gas Division of Environment Canada, January 2009

4 - Environment Canada publication Strategic Assessment of the Additional Potential for Landfill gas Recovery and Utilization in Canada – Environment Canada, June 2002.

1.2.5 Proposed Timeline for Subsequent Meetings

One subsequent meeting is proposed to discuss the potential/cost based on interest and availability of stakeholders on September 28th 2010 (subject to change based on inputs and interests).

1.4 Draft Results

1. Biomass – Municipal Solid Waste (MSW)

1.1 Resource Description

1.1.1 Biomass - MSW Technologies

Biomass – MSW refers to the conversion of municipal solid waste (MSW) into a useable form of energy, such as heat or electricity. This process is commonly referred to as Waste to Energy (WTE). For the purpose of this resource options update, 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[1]. 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% to 27% 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, but not in Europe or in North America. Gasification plants can range in size from 40,000 to 100,000 tonnes per year[1].

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 5000 to 15 000 °C) are due to a thermal plasma field 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 should destroy 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.

1.1.2 Biomass – MSW Data Availability

Several sources of information are available that can be used to determine fuel source availability, conversion factors and financial cost assumptions. These include:

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

- **Annual MSW Tracking Reports** are published by the **BC Ministry of Environment (BCMOE)**, based on data supplied by regional districts. The primary objective of the tracking process is to monitor the amount of MSW landfilled or incinerated within each regional district and the province as a whole. The last report was published in 2006.

- **BC Statistics** provides population forecasts for all regional districts.

- **Solid Waste Management Plans** for individual regional districts can be used to supplement missing data in the BCMOE MSW tracking reports.

- **Stantec** prepared a report for BCMOE, titled "Waste to Energy – A Technical Review of Municipal Solid Waste Thermal Treatment Practices" (August 2010). This report provides an overview of Waste-to-Energy technologies as well as financial cost assumptions.

- **AECOM Canada Ltd.** prepared a report for Metro Vancouver, titled "Management of Municipal Solid Waste in Metro Vancouver – A Comparative Analysis of Options for Management of Waste after Recycling" (June 2009). This report provides an overview of Waste-to-Energy technologies as well as financial cost assumptions.

- **KPMG Letter** dated January 26, 2010, "Metro Vancouver's Draft Solid Waste Management Plan", provides financial cost assumptions.

1.1.3 Biomass - MSW Data Update Needs

The primary needs for the Biomass - MSW resource options update are to validate the methodology approach, and assumptions made for available fuel sources as well as energy recovery efficiencies and financial costs.

1.2 Methodology

1.2.1 Biomass – MSW Resource Option Assessment Methodology

A generalized methodology is proposed for the Biomass – MSW resource option, whereby the potential will be estimated based on fuel source availability. MSW tonnage numbers obtained from the 2006 BC Municipal Solid Waste Tracking Report will be extrapolated to 2010 numbers based on population growth obtained from BC Statistics. In this extrapolation, the disposal (i.e. recycling) rate per capita are assumed to remain at 2006 levels since no significant or consistent trends are evident in the 2006 report. For regional districts which did not participate in the 2006 MSW survey, data will be obtained from regional district waste management plans (where available) and adjusted to 2010 numbers. The tonnage per year of MSW from the regional districts will then be aggregated to form larger regional entities (e.g. Lower Mainland, Vancouver Island, Okanagan) for which the transport of MSW would not exceed 350 km. Finally, to determine the tonnage of MSW available for regional WTE facilities, only a percentage of the aggregated MSW tonnage is considered available so as not to interfere with the preferred strategies of waste management, namely waste avoidance and waste reduction.

In addition, the following assumptions will be made:

- At least 200,000 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. Utilization of waste heat will not be considered as this would require detailed location information.
- Each WTE facility is assumed to be located in-region.
- Waste composition and energy conversion efficiency is assumed to be the same for each region.
- Each plant will operate at 100% capacity at all times.
- For the Lower Mainland region, the sizing of a WTE facility will be based on recommendations by Metro Vancouver which is currently considering an additional mass burn incineration facility.

The average annual energy will be determined using the capacity of each facility (tonnes per year), and assumptions of MSW caloric value and energy recovery efficiencies.

The firm energy expected from each facility will be the same as the average annual energy, consistent with other thermal resource options.

The average annual energy and firm annual energy will be combined with the expected costs of a WTE facility to develop the plant gate average and firm Unit Energy Costs for the Biomass – MSW resource.

The dependable capacity will be assumed to be 100% of installed capacity.

No seasonality or intermittency is assumed for Biomass – MSW resources.

An outstanding issue remains between the Biomass – MSW and the Biomass – Biogas resource options in that both resource options compete for some of the same fuel. This will be addressed in the stakeholder meetings.

1.2.2 Biomass - MSW Resource in the 2008 LTAP

The Biomass – MSW resource was last updated for the 2008 LTAP. Three projects with a total installed capacity of 53.4 MW were identified based on existing proposals and/or studies. These included a 6.4 MW WTE facility in Kamloops, a 7 MW expansion of the existing WTE facility in Burnaby, and a 40 MW MSW cogeneration project near Nanaimo.

1.2.3 Constraints

Public opposition of WTE facilities due to environmental and health concerns could provide significant barriers for WTE facilities to proceed. This is not taken into account in this assessment. Also, it is assumed that any environmental and/or government permits are achievable.

1.2.4 References

MOE Annual Tracking Reports: http://www.env.gov.bc.ca/epd/epdpa/mpp/reduction.htm

BC Statistics: http://www.bcstats.gov.bc.ca/data/pop/pop/dynamic/PopulationStatistics/SelectRegionType.asp?category=Census

Stantec Report: http://www.env.gov.bc.ca/epd/epdpa/mpp/pdfs/BCMOE-WTE-Emissions-final.pdf

AECOM Canada Ltd. Report: http://www.metrovancouver.org/services/solidwaste/planning/Thenextsteps/SDD_3_AECOM_FULL_REPORT.pdf

KPMG Letter: http://www.belkorp.com/default.asp?mode=portfolio&id=52

1.2.5 Proposed Timeline for Subsequent Meetings

A meeting is proposed with the stakeholders to review the methodology, and the assumptions made for fuel source availability, energy recovery efficiencies and financial costs for the Biomass – MSW resource option. A preliminary date/time for this meeting has been set for September 23rd at 10:00 AM PDT. Stakeholders will be able to participate in person or by teleconferencing. A second meeting may be scheduled based on feedback from the first meeting.

1. Wood based biomass

1.1 Resource Description

1.1.1 Biomass Technology

Biomass Energy means electricity generated from the combustion or gasification of organic materials. Wood based biomass addressed in this document is one of the three categories of biomass considered in the Resource Options Update/ Integrated Resource Plan. The other two categories are municipal solid waste and biogas generated from municipal landfills, which are addressed in separate documents.

BC Hydro considered three sources of relatively abundant wood-based biomass in this Resource Options Update:

- Standing timber (including Pine Beetle Kill)
- Roadside debris (wood already cut, but left in the forest/road side)
- Sawmill wood waste

British Columbia has significant wood based biomass resources. However, unlike other resource options, wood based biomass is a resource with many competing uses and electricity generation may be a lower value use in British Columbia. As such, the wood based biomass energy potential for electricity generation may be significantly less than that which could be supported by the available fuel resource.

The majority of forests in BC 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 Forest and Range (MoFR) to ensure forest sustainability and to allocate fiber through the setting of annual allowable cuts (AAC) and granting of harvesting tenures/licences. After the AAC has been 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; and

- The location of wood processing facilities relative to the location of the wood supply which influences fibre delivery costs.

The biggest uncertainty regarding wood based biomass energy potential is long-term fuel availability. Other than that, wood based biomass energy is generally considered a dependable resource with firm energy the same as the average annual energy, and the dependable capacity the same as its installed capacity.

Wood based biomass energy is a well established energy sector in B.C.. The general construction period is one to three years.

1.1.2 Biomass Data Availability

In the 2008 LTAP, BC Hydro, through biomass stakeholder engagement sessions, identified the wood-based biomass potential to be 3760 GWh/470 MW. This was broken down into 800 GWh of woodwaste at $104/MWh, 1360 GWh of standing timber at $158/MWh and 1600 GWh of roadside debris at $132/MWh.

Subsequent to the LTAP, some biomass energy has been purchased by BC Hydro through the BioEnergy Phase 1 call and Integrated Power Offer. Additional biomass project information has also been gathered through Request for Expression of Interest for Fort Nelson and BioEnergy Phase 2.

1.1.3 Biomass Data Update Needs

The primary needs for the resource options update for wood based biomass (from participants) is to seek comments on the approach and relevant data to inform or update the estimate of resource potential, cost and location. To aid the calculation of economic attributes, BC Hydro is also seeking input on detailed cost breakdowns for biomass projects. The objective of the update is to obtain the best available data that can feed into the analysis for the Integrated Resource Plan.

1.2 Methodology

1.2.1 Biomass Resource Option Assessment Methodology

In the 2008 LTAP, wood based biomass potential was identified through stakeholder engagement sessions. For this resource options update, BC Hydro has engaged a team of consultants (Rob Schuetz) from Industrial Forest Services Ltd. together with Jim Girvan and Murray Hall to conduct a modeling study to estimate the long-term availability potential, cost and most logical locations of wood based biomass power plants. This study is overseen by a working group comprising of representatives from BC Hydro, MoFR and Ministry of Energy Mines and Petroleum Resources (MEMPR).

The modeling study will be done primarily using the BC Fibre model. This model is a regional fibre forecast and fibre allocation model for BC. It is well known and accepted in the forest industry (for the purpose of this study, BC is divided into 12 regions). International Wood Markets recently used this model to complete a fibre availability study and produced the publication: *Impact and Outlook of BC Timber Availability and Wood Products Production, March 2010*.

The study initiated by BC Hydro will estimate the electricity potential and fibre cost from wood based biomass by considering the following:

- The government determined annual allowable cut (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 agreement contracts resulting from the BC Hydro Integrated Power Offer and the Bioenergy Phase 1 Call; and
- The economic drivers of the forest industry including:
    - Lumber prices
    - Pulp selling prices
    - Paper selling prices
    - Can$/US$ exchange
    - US and Japanese Housing Starts

Once the electricity potential for different regions is determined, logical locations for developing biomass power plants will be identified while considering features such as location of existing sawmills, infrastructure and location of available fibre. The cost of biomass delivered to these locations for each of the three wood based biomass sources will be estimated. Lastly, generic greenfield biomass power plants from 10 MW to 60 MW and their associated development cost will be assumed to yield an estimate of unit energy cost ($/MWh).

Many assumptions are required to complete this study. The guiding principle is to reflect current knowledge or expectation without guessing at future policies, or the demands of new biomass consuming industries. For this consultant study, BC Hydro is working closely with the MoFR and the MEMPR to ensure that the assumptions (especially policy assumptions and the forecast change in AAC) are reasonably aligned with government viewpoints. In general, this study utilizes three broad categories of assumptions as described below.

(A) Forest Management Unit Fibre Supply

There are broad assumptions on four sources of fibre supply:

1) Log availability for all industries is constrained by the annual allowable cut, which is determined by the Provincial Chief Forester every five years. As this BC Hydro study will be a 30-year forecast, assumptions on the future AACs that have yet to be determined must be made for each of the timber supply areas, tree farms, woodlots and community forests within BC. Log availability by quality (grade) is further estimated based on the impact of the mountain pine beetle on log quality and the transition from sawlog to pulplog as time since death increases. The transition is determined using information provided and verified by the sawmilling industry. Reference :Lazlo Orbay Quantifying Lumber Value Recovery from Beetle killed trees 2006 FERIC
2) Roadside residue is constrained by both the AAC and by the annual operating rates of the forest industry. The quantities of roadside residue that result from harvesting within each forest management area are estimated with general input from FP Innovations' BIOS model.
3) Sawmill residues quantities by type (sawdust, planer shavings, bark and wood chips) are estimated over time based upon each sawmill and plywood mill's operating capacity and estimated future run rates. This information has been collected by the three experts (Industrial Forest Services Ltd.), each of the team members having over 25 years of experience within the forest industry.
4) Log, roadside and residue supply is constrained based upon the region that the supply exists. The review examines 12 geographic regions that cover BC. Although some transfers of logs and sawmill residues occurs between regions, generally this is minimal. The transfers of logs between regions however are noted based on historic information collected by the consultants.

(B) Existing Forest Industry Fibre Demand

The assumptions on fibre demand are based upon the following information:

1) Sawmill and plywood plant capacity for log utilization is based upon their operating rates that were experienced in 2006 (basically the last "good" year for lumber demand.)
2) Pulpmill and pellet plant capacity is based on industry intelligence on historic operating rates and plant size.
3) Future demand is broadly based on assumptions that are global in nature reflecting lumber demand, US housing starts, exchange rates, and the overall health of the economy. These assumptions will be generally based upon public forecasts made by economic financial analyst (e.g. RBC, International Wood Markets, Salmon Brothers, RISI).
4) Pulpmills, pellet plants and board mills will target sawmill residuals first as this is lower cost fibre than roadside debris or standing timber.
5) Only after sawmill residues are exhausted will the existing forest industry target the unused low-grade logs that exist within the framework of the AAC and are not being utilized by sawmills.

(C) Rationalization of Wood Based Biomass Supply for electricity generation

The primary assumptions with respect to this investigation are the following:

1) The existing forest industry has access to available fibre first, and what is left over is available for electricity generation.
2) In the coming years, the industry is expected to face:
   a) a declining AAC as a result of the pine beetle epidemic
   b) declining sawlog supply as a result of the deterioration of pine

c) a gradual increase in demand for lumber
d) the inability to satisfy traditional sawmill run rates due to a decline in sawlog supply
e) a reduction in sawmill residues as a result of a decrease in lumber production
f) a decrease in roadside residues as this ties to the annual harvest
g) a temporary increase in non-sawlog grade logs that are dispersed among sawlogs.

3) Within each of the 12 regions in BC, log supply (sawlog and biomass) is identified and quantified over time. This is compared to the regional demand for sawlogs and pulplogs. The identification of available biomass thus becomes a very large accounting exercise that balances log/biomass supply against log/biomass demand and what remains in each region is what is available for electricity generation.

1.2.2 Biomass Study Constraints:

The potential for bioenergy from wood-based biomass estimated by the study is subject to the assumptions made for the future. For example, the demand and economics of competitive industries can deviate from the forecast assumption. New wood biomass consuming industries may be developed in the future competing for the resource. Furthermore, policy can change and forest fire may significantly reduce biomass inventory. Lastly as a second order effect, change in gas price may change sawmills' decisions to redirect their waste wood to internal uses. All these speak to the uncertain nature of biomass availability for electricity generation.

1.2.3 References

References that will be used in the study are documented in the assumptions described in the methodology section above.

1.2.4 Proposed Timeline for subsequent Meetings

It is proposed that comments on the assumptions or this approach be submitted in an email to Kathy Lee at Kathy.lee@bchydro.com and copied to Nadja Holowaty at Nadja.holowaty@bchydro.com no later than September 21. It is also proposed that a meeting with the Biomass Resource stakeholders to review preliminary results be in the week of October 4th.

1. Coal-fired Generation Facilities

1.1 Resource Description

1.1.1 Coal-fired Generation

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 temperature. The hot gases and heat energy produced converts water into steam that is used to drive a steam turbine and generate electricity. Integrated Gasification Combined Cycle (IGCC) plants are a newer generation of coal power generation technology. In an IGCC, 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% range.

In British Columbia, policy action No. 20 of the 2007 Energy Plan stipulates that coal-fired generation must meet a zero greenhouse gas (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 are 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 commercial scale. According to EPRI (2007), coal-fired plants with 90% CO_2 emission capture and storage could be commercially available by 2022.

1.1.2 Data Availability

Recent BC Hydro studies have focused on advancements in Carbon Capture and Sequestration (CCS) given the requirement for carbon emissions from coal plants to be sequestered.

1.1.3 Data Update Needs

The primary data need for the resource options is to monitor advancements in CCS technology.

1.2 Methodology

1.2.1 Coal Generation Assessment Methodology

BC Hydro will rely on reports prepared by Powertech Labs Inc. in 2008 and 2009 to assess the state of CCS technology. The reports are listed in the References section.

1.2.2 Coal Generation Resources in the 2008 LTAP

Appendix F2 of the 2008 LTAP provided an overview of the status of the Coal with CCS technology. Conventional coal generation resources were not characterized in the Resource Options Report that was part of the 2008 LTAP.

1.2.3 Constraints

As described previously, CCS technology that is presently not viable on a commercial scale is a constraining factor in the development of coal-fired power generation.

1.2.4 References

EPRI, 2007. “CO_2 Capture and Storage” Electrical Power Research Institute Journal.

Powertech Labs Inc. 2008 “Clean Coal Power generation by CO2 sequestration” 2008 LTAP Appendix F2.

Powertech Labs Inc. 2009 Memo. “Coal with Carbon Capture and Sequestration for Long Term Transmission Inquiry”.

1.2.5 Proposed Timeline for subsequent Meetings

Meetings can be scheduled based on stakeholder interest to discuss the coal resource option update.

1. Energy Storage

1.1 Resource Description

1.1.1 Energy Storage Technologies

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 many reasons for installing additional storage at all levels of the power system including: the ability to defer capital expenditure on transmission or distribution assets, increased longevity of assets through reduced peak load, decreased reliance on importing power at peak, provision of ancillary services such as voltage and frequency regulation, provision of reactive power and peak shifting for intermittent renewable supply.

From the perspective of this assessment, energy storage can function as a resource option for BC Hydro in two different ways:

- Firming of intermittent renewable resources
- Reducing peak load

In both cases, storage is a pure capacity option and net user of energy. Energy storage sources are charged using “cheap” (off-peak) or “excess” (unplanned renewable) energy from the system and discharged as required. All storage technologies have varying degrees of energy efficiency loss and environmental impact; valuation of benefit must take these into account.

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%. To date this technology has been implemented in large facilities using underground caverns. Recently the technology has been explored for use with intermittent and seasonal renewable energy sources to store “excess” energy as it is produced. Smaller scale, above ground CAES systems are currently being assessed for economic viability. Since BC Hydro does not have a large amount of thermal energy, potential future applications are limited. However firming renewable energy sources and improving efficiencies of Combined Heat and Power (CHP) plants are possible applications.

- **Pumped Hydro Storage** is well established commercially as a means to store energy. The concept is the same as that used in hydroelectric power plants; potential energy is stored as a head of water. The water is pumped up to a reservoir store and released as required. Similar to CAES, pumped hydro storage has recently been explored for use with intermittent or seasonal energy sources to store “excess” energy as it is produced. In addition, pumped hydro may have value in buying “cheap” electricity to pump and selling when the market value is high. Pumped storage is a net energy consumer with an efficiency of approximately 70%. This technology option is included as a separate category due to the level of knowledge and commercial availability in British Columbia. (See Pumped Storage Resource Option Assessment Document)

- **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 today’s 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. Applications include providing smoothing for solar photovoltaic and wind energy sources, voltage and frequency regulation services. Flywheels can have efficiencies as high as 90%. Potential future application for the BC Hydro system is dependent on the penetration of intermittent renewables.

- **Batteries** come in many different chemistries generally falling into two distinct categories: traditional and flow. Traditional 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. Traditional battery technologies that are available include Sodium Sulphur (NaS), Lithium ion (Li-ion), Advanced Lead Acid and Metal Air. Of these, the Metal Air technology is the most promising from a cost and environmental perspective however a utility scale rechargeable option is not yet commercially available. Li-ion, advanced lead acid and NaS have efficiencies in the range of 85-90%. NaS is the most advanced commercially but is most appropriate for applications larger than 1MW. Li-ion is becoming much more available for utility applications due to the large amount of research into car battery technology and an expected over capacity in production. Li-ion batteries are expected to reduce in price and be easily scaled to meet many different utility applications. Advanced lead acid is cheaper than the others but requires a large footprint and has a shorter cycle life. Flow battery technologies such as Vanadium redux and Zinc Bromine are commercially available for small applications. They can be scaled up but have a large footprint due to the need for high volume storage tanks.

- **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%) which makes them unattractive for most applications.

Energy storage has been installed in a number of off-grid locations in BC for the purposes of storing "excess" energy generated by renewable energy sources. BC Hydro has a field test system at Bella Coola, incorporating a hydrogen fuel cell (100kW) and zinc bromine flow batteries (4 x 50kW) to store off-peak energy from the hydroelectric facility. Off-grid small-commercial and residential systems use commercially available lead acid batteries to store off-peak energy generated by either renewable or non-renewable sources.

BC Hydro, in partnership with Natural Resources Canada (NRCan), has initiated a project to install 2MW of battery storage to support the substation at Golden. This resource is expected to be in service late 2011 and will perform peak shaving as well as provide back-up power for the community of Field.

Outside of BC, battery energy storage installations have been implemented in the US, Japan and Europe. Compressed air installations have been implemented in Germany and the US. Flywheel installations are currently being implemented in the US.

1.1.2 Energy Storage Technology Data Availability

There are many sources of information on the available technologies including vendors, associations, consultants, other utilities, academia and research groups. A few of the key sources are:

- **The Energy Storage Association (ESA)**: provides an overview of the technology options, general functions, deployment status, efficiency and costs. http://www.electricitystorage.org/ESA/home/

- **Electric Power Research Institute (EPRI)**: conducting research into costs of implementation of energy storage systems and value proposition. Tracking new project installations in North America as a result of stimulus funding. Testing new energy storage technologies and units. http://my.epri.com/portal/server.pt?

1.1.3 Energy Storage Technology Data Update Needs

The primary need for the resource options update is to validate the approach, data and methodology applied to the energy storage option. Additional information on actual installation costs and performance that could be used to validate cost and performance assumptions would be useful.

1.2 Methodology

1.2.1 Energy Storage Resource Option Assessment Methodology

The methodology considers energy storage as a commodity that can be provided by the most appropriate available technology. Storage blocks are defined by capacity dependent on a functional application at a point in the value chain of the utility. There are 4 categories of storage block defined:

- **100MW block for system support**

This type of storage can be used in blocks of 100MW, up to 1000MW, for system support in the following areas:

- Integrating renewables as distributed generation
- Dependable capacity
- Firm energy
- Peak shaving
- “Spinning reserve”

The storage could be provided by CAES, pumped hydro, batteries or fuel cell systems. CAES requires an appropriate geologic formation or large scale containment and is generally used to improve the efficiency of Natural Gas turbine thermal plants. Hydrogen fuel cell storage systems may be appropriate for seasonal storage if other more efficient options are not readily available. Battery storage technologies are considered too expensive and/or immature to deliver this level of storage.

Pumped hydro storage is considered most appropriate for this block size and is covered by the Pumped Storage Resource Option Assessment Document.

- **1MW block for substation support**

This type of storage can be used in blocks of 1MW, up to 10MW, for substation support in the following areas:

- Integrating renewables as distributed generation
- Peak shaving at the substation level
- Improving reliability for customers through islanding
- Microgrid support

This level of storage is most appropriately provided by battery. It is assumed that a Li-ion, Advanced lead acid, NaS, ZnBr, or Vanadium redox energy storage system is used. Costs, efficiencies and life-cycles are averaged across the current known performance of the technologies. [Source: EPRI]

- **25kW block for community level support**

This type of storage can be used in blocks of 25kW, up to 100kW, for community level support in the following areas:

- Integrating residential renewables
- Individual or aggregate peak shaving
- Integrating electric vehicle charging
- Improving power quality and reliability for customers

This level of storage is most appropriately provided by a battery. It is assumed that a Li-ion energy storage system is used. Costs, efficiencies and life-cycles are based on the current known performance of the technology. [Source: EPRI]

- **5kW block or residential support**

This type of storage can be used in blocks of 5kW and aggregated based on number of residential customers with storage installed. Storage at this level can be:

- Utility controlled
- Customer controlled (Demand Side Management)

The storage in individual or aggregate form can be used to:

- Integrate residential renewables
- Individual or aggregate peak shaving
- Integrating electric vehicle charging
- Improving power quality and reliability for customers
- Individual or aggregate demand response

This level of storage is most appropriately provided by a battery. It is assumed that a Li-ion energy storage system is used. Costs, efficiencies and life-cycles are based on the current known performance of the technology. [Source: EPRI]

1.2.2 Energy Storage Resource In the 2008 LTAP

Energy Storage was not included in the 2008 LTAP.

1.2.3 Constraints

CAES and pumped hydro are constrained by geologic formations and conditions. In addition, CAES systems are generally used in conjunction with Gas Turbine thermal plants to enhance efficiencies and this is not applicable to BC. All other energy storage options are constrained only by the availability of the technology, integration into the grid network and cost of implementation.

It is also assumed that any environmental and/or government permits are achievable.

1.2.4 References

Grid-scale Energy Storage: Technologies and Forecasts through 2015 (John Kluza, GTM Research, 2009)

Energy Storage Market Opportunities: Application Value Analysis and Technology Gap Assessment (EPRI Technical Update, 2009)

Energy Storage for the Electricity Grid: Benefits and Market Potential Assessment Guide (Sandia, 2010)

Electric Energy Storage Technology Options: Primer on Applications, Costs and Benefits (Rastler, EPRI, 2009)

Energy Storage Systems for Communities, CADER conference 2010 (Rastler, EPRI, 2010)
http://www.cader.org/documents2010/DanRastler20100429.pdf

Electricity Storage in the Grid: An Update on Where We are Today, IEEE-USA Annual Meeting 2009 (Bradford Roberts, 2009)
http://www.ieeeusa.org/calendar/conferences/annualmeeting/2009/program/Presentations/IEEE-USA%20Storage%20Presentation.pdf

1.2.5 Proposed Timeline for subsequent Meetings

Subsequent meetings will be scheduled based upon feedback from this meeting.

1. Geothermal

1.1 Resource Description

1.1.1 Geothermal Power Technologies

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 overwhelming majority of existing geothermal power plants draw energy from reservoirs of gaseous or liquid water in permeable rock located at depths ranging up to 3000 m. These hydrothermal reservoirs, which are subdivided into vapor- 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 hydrothermal resources, geothermal reservoirs are tapped by drilling production wells, typically greater than 15 centimetres in diameter and up to 3000 metres in depth. Several wells spaced 200 to 500 metres 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 geothermal 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 Geysers formation in the south US.

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 once 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 return to the reservoir.

For moderate temperature systems (120°C to 170°C), **Binary-cycle power plants** are used, where 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 heating by new geothermal fluids. Spent geothermal fluid is commonly re-injected.

Beyond conventional hydrothermal resources, three other types of geothermal resources are often considered suitable for power generation. **Co-produced fluids** refers to the hot water that accompanies oil and gas produced from the 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. For the most part, the magnitude of the flow volumes or actual temperatures of the co-produced fluids in BC hydrocarbon fields is unknown. For some areas where these values are known, the pooled temperature of co-produced fluid is too low to be considered for energy production. For these reasons, co-produced fluids will not be considered further in this review. Also accompanying some oil and gas operations in sedimentary basins are **Geopressured 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 geopressured resources cost-effective. The presence of geopressured fluid resources is unknown in BC, and it is not thought at this time, that they will be considered further in the review.

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. They are 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 proved sufficiently porous to allow water to permeate the rock structure and absorb heat, the pumped surface or ground water can then delivered to a binary-cycle power plant via a production well. The Enhanced Geothermal Systems to tap 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 will not be considered in this report.

For reasons stated above, only conventional hydrothermal resources using flash- or binary technologies are considered in scope for this resource assessment. Nonetheless, it bears mentioning that there is a likelihood of significant co-produced fluid and HDR resources in BC that would greatly increase the theoretical geothermal resource base.

1.1.2 Geothermal Power Technology Data Availability

There is to date no commercial geothermal electricity projects in BC, however, there have been long-standing efforts to collect data on the promising hydrothermal resource base in BC. The investigations and accumulated data are summarized in the Geological Survey of Canada's Review of National Geothermal Energy Program Phase 2 – Geothermal Potential of the Cordillera. In total, the existing work to understand the geothermal resource in BC includes:

- Estimates of heat generation and heat content
- Bottom Hole Temperature (BHT) reading from oil and gas explorations
- Estimates of Depth-Temperature profiles
- Estimates of thermal conductivity and heat flow
- Limited temperature data from geothermal-specific bore holes

There has been a long history of interest in the geothermal potential at Mount Meager. It was one of the focuses of the National Geothermal Energy Program and of subsequent private development, and as a result there has been more research conducted in this area than for other areas in British Columbia.

While there is not yet a study that provides a firm estimate of geothermal potential, an overview of the province's geothermal potential is illustrated in the map "Geothermal Resources of British Columbia" (Fairbank and Faulkner 1992) that integrates the known elements of the BC 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, Valem-ount 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 good summary of the research to date is well articulated in this Geological Survey's report: "The geothermal resource base is very large, but the difference between the resource base and the usable resource is also very large."

A 2008 workshop hosted by the BC Ministry of Energy, Mines and Petroleum resources gathered experts in the field to discuss the geoscience requirements to facilitate geothermal energy development in BC and to understand the usable resource. The workshop suggested the following geoscience investigations:

- Establishment of a national or western Canadian map and comprehensive assessment of geothermal potential.
- Establishment and standardization of databases with basic information from existing sources
- Investigation, development, or compilation of new geoscience maps and knowledge bases
- Accurate digital map of hot spring locations
- Initiation of geophysics and geology studies to understand crustal dynamics and geothermal reservoirs
- Establishment and maintenance of a regional seismic network; regional GPS and InSAR studies; a neotectonics atlas of the Cordillera with fault ages and types; regional strain information; radiometric ages and geochemistry of young volcanics; crustal thickness; geophysical surveys; airborne electromagnetics; heat flow; temperature gradient data; alteration; structural geology; etc

1.1.3 Geothermal power Technology Data Update Needs

Stakeholders are requested to provide input into the long-term total extractable energy that can be produced from areas of geothermal favourability, beyond the discrete projects identified in near-term project inventory described below.

1.2 Methodology

1.2.1 Geothermal Power Resource Option Assessment Methodology

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 BC, there is little publicly available data to empirically and confidently define 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 BC have been conducted by GeothermEx, a US-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, and medium quality resources developed by binary-cycle power plants. Costs and performance parameters were assigned to these technology types based on costs of recent US plants, adjusted to accommodate the relative lack of experience in the Canadian jurisdiction and the challenging geographical conditions of the BC sites.

The WREZ methodology is a conservative estimate for BC 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, but superficial heat gradient modelling suggest may be viable. Input from stakeholders as to the location and size of the undiscovered resources in BC will be incorporated into this assessment. Undiscovered resources have a longer development timeline and should be considered more uncertain than the development of discovered resources.

1.2.2 Geothermal Power in the 2008 LTAP

The 2008 LTAP assessment of Geothermal power was consistent with the WREZ methodology described above.

1.2.3 Constraints

Sites that are found within existing park, protected areas or eco-reserves will be excluded from this assessment

1.2.4 References

- BC Geothermal Directory, published by BC MEMPR http://www.empr.gov.bc.ca/OG/oilandgas/GeothermalGeoscience/Documents/BCGeothermalDirectory.pdf
- Geological Survey of Canada's Review of National Geothermal Energy Program Phase 2 – Geothermal Potential of the Cordillera, A. Jessop, 2008. http://geopub.nrcan.gc.ca/moreinfo_e.php?id=225917
- Geothermal resources of British Columbia, Fairbanks & Faulkner, 1992. http://www.em.gov.bc.ca/dl/GeoTherm/GeoThermRes_small.pdf

1.2.5 Proposed Timeline for Subsequent Meetings

Proposed conference call on total extractable resources from favourable regions to be scheduled based on interest and availability of stakeholders.

1. Natural Gas-fired Generation Facilities

1.1 Resource Description

1.1.1 Natural Gas-fired Generation

Gas-fired units generate electricity using the heat released by the combustion of natural gas. Simple cycle and combined cycle gas turbines (SCGTs and CCGTs) are the most commonly employed technologies. Conversion efficiencies are typically 35-40% for SCGT machines, and 50% for CCGT machines.

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

The primary disadvantages of natural gas generation include:
- Gas units emit greenhouse gases and other pollutants such as NOx;
- Natural gas prices can be very volatile posing significant cost uncertainty, particularly when base load operation is required;

The development of any gas-fired generation in BC would need to be within the allowance made for non-clean resources in the BC Clean Energy Act. The Act states that no more than 7% of total electricity generation in the province can come from non-clean sources.

1.1.2 Data Availability

Several studies related to gas-fired generation have been commissioned by BC Hydro in the past. The most recent study was carried out for the 2008 LTAP. AMEC· Americas Limited (AMEC) prepared prefeasibility-level capital and operating cost estimates of a nominal 100MW simple cycle power generating plant for peaking duty. In addition, AMEC updated the capital and operating costs for the units that were included in a previous AMEC planning report prepared in 2006. The plants considered in the update were:
• Simple cycle 47MW gas turbine power plant
• Combined cycle 60MW gas turbine power plant
• Combined cycle 250MW gas turbine power plant, and
• Combined cycle 500MW gas turbine power.

1.1.3 Data Update Needs

The primary data need for the current resource options update is to obtain up-to-date cost and performance data regarding widely-used utility scale gas-fired generation units.

1.2 Methodology

1.2.1 Natural Gas-fired Generation Assessment Methodology

BC Hydro will carry out an in-house update of the cost and performance characteristics of some selected gas-fired units. The main alternatives that are expected to be relevant for BC Hydro's integrated resource planning process are:

- SCGT unit sizes of 47, 100 and 170 MW, and
- CCGT unit sizes of 250 and 500 MW.

1.2.2 Natural Gas-fired Generation Resources in the 2008 LTAP

Natural gas-fired generation resource options data identified in the 2008 LTAP were based on information from the above-mentioned study carried out by AMEC Americas. The 2008 LTAP also included information on various options for Burrard, but this information is not being updated due to recent government policy directions restricting the use and future role of Burrard.

1.2.3 Constraints

Gas-fired generation is a mature technology. There are no technological constraints other than the need for adequate gas supply, cooling water supply and proximity to the transmission grid. In some cases, such as in the Fraser Valley airshed, siting of natural gas-fired generators may be precluded due to public concerns with respect to regional air quality.

1.2.4 References

BC Hydro, 2008 "Gas-fired Combustion Turbine Power Plant Costs and Performance Updates" Report prepared by AMEC Americas. AMEC 157842.

Gas Turbine World. 2010. GTW Handbook.

1.2.5 Proposed Timeline for subsequent Meetings

Interested stakeholders will be updated via e-mail as BC Hydro carries out the evaluation of gas-fired generation resource options. Additionally, meetings can be scheduled based on stakeholder interest to discuss the resource option update.

1. Pumped Storage Hydroelectric Facilities

1.1 Resource Description

1.1.1 Pumped Storage Hydro

Pumped Storage (PS) hydro units use electricity from the grid 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. Pumped Storage units are a net consumer of electricity due to inefficiencies in the pumping-generating cycle and only around 70% of the energy used during pumping can be recovered. However, the ability to store water and release it during times of system need makes PS a useful source of capacity. Pumped storage hydro units can also respond to variations in system demand very quickly and can provide ancillary services such as voltage regulation.

There is over 90 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, a majority utilize freshwater and surface reservoirs. Facilities that use an ocean as a lower reservoir also exist. The use of underground caverns as a lower reservoir has also been explored.

1.1.2 Pumped Storage Hydro Data Availability

A few studies related to PS have been commissioned by BC Hydro in the past.

BC Hydro report 888 (1977) identified 80 potential PS sites in the Lower Mainland and Vancouver Island region. Conceptual layout drawings and cost estimates for 4 of these sites are presented. The study concluded that 1000 MW plants would be developed at these sites. The cost estimates for these 4 sites were subsequently updated in 1993 and presented in BC Hydro report H2645 (1993).

BC Hydro Engineering report PSE379 (2001) included an appendix report by Klohn-Crippen Consultants that reviewed pumped storage sites on Vancouver Island. The review used the sites identified in the 1977 study as a starting point and then screened the list to 7 sites for more detailed investigation. The most promising sites were at Shawnigan Lake, Comox Lake, and Campbell River which together could provide total of 500 MW of capacity.

A Powertech report on “Evaluation of the Jorvic Sewage Reclaim Pipeline at the Jordan River Hydroelectric Project” (2007) and BC Hydro memo on “Jordan River Pumped Storage” (2007) provided an overview level assessment of pumped storage opportunities using BC Hydro’s existing reservoir system on the Jordan River and comments on the potential for Greenfield sites in the Jordan River watershed. The study concluded that there is low potential for development of pumped storage hydroelectric projects using the existing reservoir systems based on technical constraints (e.g. low head, low storage capacity).

In 2008, Hatch Energy carried out a study on the potential for installing pump-turbines at BC Hydro’s Mica generating station. The study looked at installing pump-turbines at empty bays at the generating station reserved for the future Mica 5-6 units. It also looked at the possibility of locating pumps in a separate pumphouse or in a new bay. The study concluded that installing pump-turbines at the empty bays instead of the turbines planned under the Mica 5-6 project would result in a loss of capacity available to the system. A more detailed assessment of a separate pumphouse was included in the Hatch report.

BC Hydro has also received input from Independent Power Producers (IPPs) with potential PS sites in the Lower Mainland. Generic technical and financial details of these sites were presented in BC Hydro’s 2008 Long Term Acquisition Plan – Appendix F11.

1.1.3 Pumped Storage Hydro Data Update Needs

The primary data need for the resource options update is to obtain up-to-date information regarding PS potential, particularly in the generation and transmission constrained Lower Mainland and Vancouver Island region.

1.2 Methodology

1.2.1 Pump Storage Hydro Resource Option Assessment Methodology

BC Hydro has engaged a consultant to identify Greenfield PS potential in the Lower Mainland region. The study will look at conventional facilities that use freshwater and surface reservoirs as well as unconventional facilities such as those that use seawater. The study will identify technical and economic parameters of potential sites at a conceptual level.

A consultant will also be engaged to assess the cost of installing a pump-turbine or a pump at Mica Generating Station continuing on with the work presented in the Hatch Energy study on Mica in 2008.

1.2.2 Pump Storage Hydro Resource In the 2008 LTAP

The 2008 LTAP presented PS potential identified based on input from Independent Power Producers, the 2007 Powertech and 2007 BC Hydro engineering reports and potential identified in the BC Hydro study carried out in 2001, as referenced above.

1.2.3 Constraints

PS is a mature technology. The need for two reservoirs with a suitable length to head ratio is a constraining factor.

1.2.4 References

BC Hydro, 1977 “Pumped Storage in British Columbia, Preliminary Engineering Assessment” Hydroelectric Design Division, Report No. 888. December 1977.

BC Hydro, 1993. “Pumped Storage in British Columbia”, Hydroelectric Design Division, Report No. H2645. March 1993.

BC Hydro, 2001. “Green Energy Study for British Columbia, Phase 1: Vancouver Island”, Green and Alternative Energy Division, Report No. PSE379. September 2001.

Powertech, 2007. “Evaluation of the Jorvic Sewage Reclaim Pipeline at the Jordan River Hydroelectric Project”.

BC Hydro, 2007. “Jordan River Pumped Storage”. Memo No. GENMIS08-NRGPLN.

Hatch Energy, 2008. “Installation of Pump-turbines at Mica Generating Station”. Pre-feasibility study.

BC Hydro, 2008. “2008 Long-Term Acquisition Plan Application. Appendix F-1 Resource Options Database (RODAT) sheets - Pumped Storage Opportunities for Lower Mainland and Pumped Storage Opportunities for Vancouver Island”.

1.2.5 Proposed Timeline for subsequent Meetings

BC Hydro will be providing regular updates on the consultant study to identify Greenfield PS potential in the Lower Mainland / Vancouver Island region as well as on the Mica pump-storage study, to interested stakeholders. Meetings can be scheduled as necessary to discuss information on specific potential sites.

1. Hydrokinetic

1.1 Resource Description

1.1.1 Hydrokinetic Power Technologies

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 will be typically located in areas with fast river currents and substantial flow volumes for significant portions of the year.

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 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 demonstrations in BC.

1.1.2 Hydrokinetic Power Technology Data Availability

Hydrokinetic energy potential is proportional to the cube of velocity of the river current. There are two databases maintained by Environment Canada that contain river current velocity measures collected from long-standing river gauge sites and discrete hydrometric field tests: HYDAT and the Canada Water Survey Measurement Database. In comparison to the large number and long stretches of potential stream and river sites, there is little data available to provide an accurate picture of river velocities in BC.

The extractable energy from the hydrokinetic energy potential at a given site is related to the cross-sectional area that is effectively 'swept' by the hydrokinetic device. An estimate of the potential swept area of a hydrokinetic device requires an understanding of the geometry of the river below the water surface. There are three datasets that provide some surface and sub-surface level information of rivers in BC: the National Hydro Network database, the Canadian Digital Elevation dataset, and the Soil Landscapes of Canada dataset. These datasets by themselves give very little visibility into the detailed geometry of the river channels, however they may be a starting point to build estimates of river geometry in BC.

A 2006 study by Verdant Power Canada for NRCan provided an overview of the cost and performance of some emerging hydrokinetic energy systems. The technology overview indicated a fairly wide diversity of turbine sizes, efficiencies and costs, which is to be expected considering the early stage of technical development.

An estimate of the total hydrokinetic energy potential in Canada was conducted by the UMA group in 1980. Owing to data limitations mentioned above, a crude estimate of Canada's largest rivers suggest the Fraser River could be used to provide 380 GWh / yr of hydrokinetic energy.

1.1.3 Hydrokinetic power Technology Data Update Needs

There is currently no assessment of the hydrokinetic potential in BC. NRCan is currently undertaking a review of hydrokinetic estimation methodologies and has proposed an assessment of the national potential for hydrokinetic energy. BC Hydro will participate in this project, subject to participation from other Canadian jurisdictions, and will use the results to inform future resource assessments.

1.2 Methodology

1.2.1 Hydrokinetic Power Resource Option Assessment Methodology

Due to the limited data availability and the absence of a rigorous resource estimate, an assessment of hydrokinetic energy potential in BC cannot be presented in this assessment. Hydrokinetic resources will be updated in subsequent resource estimates following the completion of the proposed NRCan study to assess the hydrokinetic resource potential in Canada.

1.2.2 Hydrokinetic Power in the 2008 LTAP

Hydrokinetic energy was not included in the 2008 LTAP

1.2.3 References

- Technology Evaluation of Existing and Emerging Technologies: Water Current Turbines for River Applications, Verdant Power Canada for NRCan, 2006 http://www.oreg.ca/web_documents/verdant_river_turbines_report.pdf
- Assessment of Canada's Hydrokinetic Power Potential: Phase I Report, Canadian Hydraulics Centre, 2010

1.2.5 Proposed Timeline for Subsequent Meetings

Subsequent meetings will be scheduled based upon feedback from this meeting.

2010 Resource Options Update
TIDAL ENERGY RESOURCE OPTION ASSESSMENT

INTRODUCTION

1. Resource Type – Tidal

1.1 Resource Description

1.1.1 Tidal Power Technologies

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. The environmental impacts of the dam infrastructure and changes to the estuary ecosystem are significant and there are no realistic prospects for a tidal barrage system in BC. This report will focus exclusively on tidal current systems.

Tidal current systems, similar to wind energy systems, capture the kinetic energy is fast flowing tidal currents to drive a generator. The electrical generation potential is proportional to the cube of the tidal current velocity, and devices will be 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 BC. A small device demonstration has been underway for several years at Race Rocks, where a 65 kW Clean Current horizontal axis turbine has 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 2 X 250 kW vertical axis turbines that will be connected to the BC Hydro grid.

The largest tidal current demonstration in Canada is located in Nova Scotia's Bay of Fundy, which will host three multi-MW class tidal current turbines to verify their viability in one of the strongest tidal current environments in the world.

1.1.2 Tidal Power Technology Data Availability

Data on the tidal current resource in BC is derived from two primary sources:

- Tidal Current Energy study, by Triton Consultants for BC Hydro, 2002
- Inventory of Canada's Marine Renewable Resources, by the Canadian Hydraulics Centre (CHC) and Triton Consultants, 2006

Both sources use computational models to understand the complex interactions between the tidal constituents and the local bathymetry to identify discrete locations on the BC coast where current velocities and flow volumes are sufficient to drive a tidal current system. The theoretical energy available at these priority locations is calculated.

Both of these studies provide a good high level view of the locations on the BC coast where high tidal current velocities may be found. However, there are several limitations in using this data to identify viable energy production sites or in seeking to calculate a realizable energy production potential in the province:

- The coarseness of the computational model is unable to capture the detailed local flow structure at locations of interest. Detailed site modelling and in-situ velocity measurement are necessary in order to properly site and size a tidal energy project.
- It is uncertain how much of the theoretical available energy can be captured by a tidal energy system. Theoretical efficiency limits of energy extraction by turbines from fast-moving water are well understood, however practical limitations of energy extraction based on actual turbine and array designs, as well as concerns of environmental impacts due to changes in tidal patterns are not at all understood.
- Important questions remain about what happens to tidal flow and velocities in both local and distant locations when tidal energy is extracted at any location within the BC tidal system. The maximum extractable energy available on the BC coast may be significantly less that the simple sum of energy available at the discrete locations identified in these reports. The question of how much energy can be extracted from the BC tidal system before tidal flow velocities are reduced to unacceptable levels requires more detailed modelling of the BC coastal system.

1.1.3 Tidal power Technology Data Update Needs

A further discussion is planned in October through the Ocean Renewable Energy Group of how to develop a dynamic model of the BC tidal system that will account for changes in tidal flow as energy is extracted.

1.2 Methodology

1.2.1 Tidal Power Resource Option Assessment Methodology

The CHC report identifies the individual sites in BC 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 resource options update, it will be assumed that the combined geographical, environmental and technical considerations would limit the tidal energy extraction to 15% of the theoretical tidal energy available at each of the sites identified in the CHC report. Although it is clear that a 15% estimate of extractable energy is crude, it is consistent with other tidal energy studies completed in other jurisdictions[1]. It is recognized that the geographies and environmental considerations at the individual sites may permit more or less than 15% of the theoretical energy to be extracted, but specific evaluations is 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 BC Coastal system. The Triton study in 2002 suggests that a mean 600 MW can be extracted from the BC 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 30% can be converted into electricity after accounting for inefficiencies in the tidal generation technologies. In order to estimate within an order of

[1] EPRI, "North American Tidal Flow Power Feasibility Demonstration Project", 2006

magnitude the total extractable energy from the BC system, only the larger sites with an estimated extractable energy of at least 50 MW will be included in the ROR, with a threshold of not more than mean 600 MW extracted from the entire system.

Owing to the early state of commercial development, there is no real-world experience with the costs associated with tidal power at the commercial scale. While some efforts have been made to survey technology developers on their projected costs, these projections are unverified by disinterested third parties or by real-world experience. In 2006, the UK Carbon Trust assessed the future costs and potential growth of marine renewables based on the results of their $4.8M, 18-month long Marine Energy Challenge. The Carbon Trust report represents a disinterested parties' assessment of generic tidal energy costs at the commercial scale.

1.2.2 Tidal Power in the 2008 LTAP

Tidal power was not included in the 2008 LTAP.

1.2.3 Constraints

Currently, the Province of BC has made clear the tenure requirements for development of tidal energy sites. However, the complex management of the ocean environment remains largely in its infancy and it is unclear what legal or regulatory limitations will ultimately be imposed on tidal energy development. For the purposes of this review, no restraints have been included to limit the locations of tidal energy projects.

1.2.4 References

- Tidal Current Energy study, by Triton Consultants for BC Hydro, 2002 http://web.me.com/michaeltarbotton1/Triton/download/environment3928.pdf
- Inventory of Canada's Marine Renewable Resources, by the Canadian Hydraulics Centre (CHC) and Triton Consultants, 2006 http://canmetenergy-canmetenergie.nrcan-rncan.gc.ca/fichier.php/codectec/En/2009-053/2009-053_RP-CAS_404-DEPLOI_e.pdf
- Future Marine Energy, by the UK Carbon Trust, 2006 http://www.carbontrust.co.uk/ Publications/pages/PublicationDetail.aspx?id=CTC601

1.2.5 Proposed Timeline for Subsequent Meetings

Subsequent meetings will be scheduled based upon feedback from this meeting. BC Hydro will continue to work with government, industry and academic stakeholders to address the fundamental uncertainties of tidal energy resource extraction cited above.

2010 Resource Options Update
Wave Energy Resource Option Assessment

1. Wave

1.1 Resource Description

1.1.1 Wave Power Technologies

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 summarizes 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 BC 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 though 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 BC:

- 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 BC waters, however two wave energy projects have received partial funding from federal and/or provincial funding agencies: a near-shore multi-megawatt 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 BC remote community. Globally, wave energy remains in its infancy, with single units or small arrays in demonstration underway in some leading European jurisdictions.

1.1.2 Wave Power Technology Data Availability

The Canadian Hydraulics Centre's 2006 Inventory of Canada's Marine Renewable Energy Resources ("CHC Report") describes the efforts to-date to analyze and quantify the wave energy resource in Canada:

In the late 1970's the National Research Council Canada (NRC) investigated methods to determine wave energy flux from buoy measurements (Mansard, 1978), and quantified the wave energy resource at sites near Tofino B.C. and Logy Bay Nfld. (Baird and Mogridge, 1976). During 1991-1993, Transport Canada funded the development and published a Wind and Wave Climate Atlas of Canada in four volumes, each focusing on a different geographic region. These reports presented detailed information on wind speeds, wave heights and wave periods, but no information was given on wave energy flux or power. Allievi and Bhuyan (1994) analysed data from eleven buoys for a single year (1991) to estimate wave power in deep water off the coast of British Columbia; however, their results are inconsistent with other studies. Very recently, Cornett (2005) presented results from a preliminary analysis of wave buoy measurements from over 60 sites in the NE Pacific and the NW Atlantic near Canada.

The CHC report builds upon Cornett's work by integrating direct wave measurements from multiple sites in the deep and near-shore BC coast with a wind-wave model of the North-East Pacific ocean. The CHC report presents a summary of the wave power in the deep and near-shore BC Coast and includes a representation of the monthly variability of the resource. As the discussion above indicates, this coarse-level analysis may be a good indication of the wave energy resource in deep water, though the uncertainty in the estimate increases for near-shore sites in the absence of more detailed modelling or on-site wave monitoring.

Unlike tidal energy – which is found in density sufficient for economic development only in specific locations – a strong wave energy resource can be found along much of the BC coast. The analysis suggests that there is a fairly homogenous resource averaging 36 – 42 kW / m in the deep waters offshore of Vancouver Island and Haida Gwaii. It is difficult to predict the precise locations of future wave energy development based on the existing resource map.

Owing to the early state of commercial development, there is no real-world experience with the costs associated with wave power at the commercial scale. Further, there is no current consensus on the technical approach to wave energy conversion, and the various technical approaches have different cost and performance characteristics. While some efforts have been made to survey technology developers on their projected costs, these projections are unverified by disinterested third parties or by real-world experience. In 2006, the UK Carbon Trust assessed the future costs and potential growth of marine renewables based on the results of their $4.8M, 18-month long Marine Energy Challenge. The Carbon Trust report represents a disinterested parties' assessment of generic wave energy costs at the commercial scale.

1.1.3 Wave power Technology Data Update Needs

Stakeholders comments regarding wave power at the commercial scale are requested. The objective of the update is to obtain the best available data.

1.2 Methodology

1.2.1 Wave Power Resource Option Assessment Methodology

With the available data indicating a fairly homogenous resource[1], it is not practical to predict a specific location for wave energy project development. However, there has been a demonstrated private sector development interest in 16 discrete sites on the BC Coast through the application for and granting of Investigate Use Permits and Tenure for wave energy development to the BC 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, as 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 ILMB tenure database, and the incoming wave power for the site from the CHC 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 this resource options report, it was assumed that the combined geographical, environmental and technical considerations would limit the wave energy extraction to 15% of the theoretical tidal energy available at each of the sites identified in the CHC report, consistent with other wave energy studies completed in other jurisdictions[2].

The costs of these wave energy projects has been estimated based on the cost projections from the UK Carbon Trust report.

1.2.2 Wave Power in the 2008 LTAP

Wave power was not included in the 2008 LTAP

1.2.3

1.2.4 References

- Inventory of Canada's Marine Renewable Resources, by the Canadian Hydraulics Centre (CHC) and Triton Consultants, 2006 http://canmetenergy-canmetenergie.nrcan-rncan.gc.ca/fichier.php/codectec/En/2009-053/2009-053_RP-CAS_404-DEPLOI_e.pdf
- Future Marine Energy, by the UK Carbon Trust, 2006 http://www.carbontrust.co.uk/ Publications/pages/PublicationDetail.aspx?id=CTC601

1.2.5 Proposed Timeline for Subsequent Meetings

Subsequent meetings will be scheduled based upon feedback from this meeting.

[1] 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.

[2] EPRI, "Offshore wave power feasibility demonstration project", 2005

1 Run Of River Hydro (ROR)

1.1 Resource description

1.1.1 Run of River Technology Description and Utilization in British Columbia

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. Such 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 dams used for storage hydro) is required to divert flows into the penstocks that lead to the power generation facilities. A run-of-river project does not require a large impoundment of water.

Currently there are 38 ROR facilities with a total installed capacity of 779 MW generating on average 3286 GWh annually in BC.

BC Hydro awarded 35 new contracts for ROR with the total installed capacity of 1004 MW and average annual generation of 3987 GWh in the Clean Power Call and those facilities are supposed to be in service by 2016.

1.1.2 Run of River Data Availability

In 2007, BC Hydro commissioned Kerr Wood Leidal (KWL) to perform a Run-of-River Hydroelectric Resource Assessment for British Columbia. The report produced by KWL identified over 8000 potential sites with an estimated potential installed capacity of 12 000 MW and annual energy of approximately 50 000 GWh/year.

1.1.3 Run of River Data Update Needs

For the 2010 Resource Options Update (ROU), the ROR potential will be re-evaluated. KWL will update its 2007 assumptions and methodology, and will reassess ROR potential in the province, including potential sites, energy, capacity, and costs for each project. BC Hydro is seeking input on assumptions and overall methodology.

1.2 Methodology

1.2.1 Run of River Resource Option Assessment Methodology

The 2010 run-of-river resource options review will be undertaken in collaboration with KWL and will update the November 2007 KWL Run-of-River Hydroelectric Resource Assessment study (Ref. 1). The study will use a GIS tool to assess the energy, capacity and cost of selected potential run-of-river generating sites. The following section describes the proposed assumptions and methodology.

The specific updates to be included in the 2010 version of this GIS based study include:

- An update to the areas and reaches of streams excluded from the analysis that are considered undevelopable such as: legally protected areas, reaches of streams that are used by salmon, glaciers, and existing and committed project locations.

- Development of a new run-of-river hydropower inventory for BC using a revised / improved optimization methodology developed in 2007 by KWL, that more closely corresponds to hydroelectric projects presently being proposed and developed in BC.

- An estimate of project costs based on updated cost data in 2011 dollars.

Run-of-River Resource Option Assessment Methodology

An analysis will be performed to create a high-level inventory of estimated run-of-river power potential for British Columbia.

Using KWL's Rapid Hydropower Assessment Model (RHAM), topographic and hydrologic GIS data, gross power potential will be evaluated at ~100 m length of stream based on the estimated head and the design flow. The design flow will be estimated as 1.5 times the mean annual discharge (MAD), an increase from the 2007 design flow. The MAD has been estimated in GIS from the annual runoff data developed by the Province (1998) and the head has been estimated for penstocks ranging in length from 500 m to 5000 m in 500 m increments using the Provincial digital elevation model data. The resulting output will 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 will be screened for:

- Legally protected areas including newly designated areas.
- Reaches of streams including those newly identified as having salmon species presence (observations).
- Glaciers identified in new Provincial glacier datasets.
- Stream reaches related to identified Provincial topographic digital elevation model (DEM) 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 will then undergo an optimization routine that selects the largest project in a given stream reach from optimizing the project size (at each ~ 100 m stream section).

This will include the application of new optimization methodology that more closely compares with hydroelectric projects that are presently being proposed and developed in BC.

In 2007, the site optimization and selection methodology found the greatest power per unit length of penstock and effectively 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 mean annual discharge (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 are 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% greater than what would have been estimated in 2007. In 2010, the new optimization and site selection methodology will attempt to align more closely with what a developer might design and construct.

Both the old (2007) and new (2010) methodologies consider the steepest section of the stream, however the 2010 methodology will generally select a larger project with the steepest section encompassed by the new potential project. The new optimization will result in both a change to the project layout size (length of diverted stream and head) and a higher design flow. It will select 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 will be used (150% of MAD).

The 2010 methodology will result in an estimated project size (capacity & energy) that is a closer representation of what an IPP might develop for that reach of stream. In many cases it will result in more capacity and energy and often with lower unit electricity costs (UEC) than a project that is only located within the steepest drop of a stream.

It is hopeful that the new methodology will result in an updated dataset that is more representative of British Columbia's ROR hydroelectric potential.

Energy Estimates

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

Average annual energy will be 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 a potential site. Firm energy will be 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 a potential site. The dependable capacity will be estimated from the monthly flow duration curves as capacity that can be generated 85% of time in December and January.

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

The Firm Energy Load Carrying Capability (FELCC) and Effective Load Carrying Capability (ELCC) of the potential sites will be determined by BC Hydro using models dealing with the loss of load analysis. The details are provided in the 2008 LTAP Appendix F12.

Costs Estimation

Costs will be estimated in 2011 dollars using information from constructed project costs, contractors' and manufacturers' quotes and engineering judgement. This information will be used to develop a series of cost curves (such as civil works, transmission, generating equipment) to estimate costs for each potential site based on key project parameters such as project capacity (MW). A least-cost path routing method will be used to estimate the cost of roads and power lines to existing infrastructure.

Unit energy costs will be estimated for each potential site based on the estimated capital and annual costs, annual energy production, project life, and discount rate.

Earliest in-service dates will vary based on project size and the estimated number of years required for licensing, design, and construction.

1.2.2 Run of River in the 2008 LTAP

Appendix F5 of the 2008 LTAP presents the 2007 KWL ROR report.

1.2.3 Constraints

The screening of potential sites is described in section 1.2.1 above.

1.2.4 References

Ref. 1: Run-of-River Hydroelectric Resource Assessment for British Columbia, Final Report, November 2007, KWL.

Ref. 2: 2008 LTAP, BC Hydro, 2009.

1.2.5 Proposed Timeline for Subsequent Meetings

Two meetings, one on September 20 and another on September 27, are proposed by BC Hydro to discuss the assumptions, methodology, preliminary inputs and results. The time and location will be provided to the interested participants.

1. Solar

1.1 Resource Description

1.1.1 Solar Power Technologies

Solar power is generated from sunlight and can be achieved directly using photovoltaic (PV) cells or indirectly by using Concentrating Solar Power (CSP) technologies. PV cells transform solar radiation directly into electricity using the properties of the compounds on the surface of the PV cells and their interaction with solar radiation. CSP technologies generate electricity indirectly by concentrating sunlight with reflective mirrors and using the thermal energy to drive conventional thermal power generation technologies. Both the photovoltaic and CSP technologies are commercially proven.

PV systems can use many different compounds within the solar cells to convert solar radiation directly into electricity. The various compounds have ranges of costs and solar radiation conversion efficiencies. Silicon was one of the first materials used to make PV cells and continues to dominate the commercial solar cell market. A variety of silicon called crystalline silicon(c-Si) is the most common form used. Recently, thin film PV cells have been developed that are physically much thinner than C-Si PV cells. These thin film PV cells are lower in cost but also generally have lower solar radiation conversion efficiencies than c-Si PC cells. The most common compound used in thin film PV cells is cadmium telluride (CdTe). Although PV cells are sealed, Cadmium is a toxic material and is often raised as an issue with thin film solar PV cells.

PV systems can also utilize concentrated solar radiation. These systems can achieve higher solar radiation conversion efficiency levels but are generally hampered by higher costs and technical challenges.

Several CSP technologies exist that include linear CSP, solar tower CSP and dish/engine CSP systems.

Linear CSP systems use large mirrors to capture solar radiation and concentrate it onto a linear receiver tube. The receiver contains a fluid that is used to create superheated steam that spins a turbine driving an electricity generator. Linear CSP technology using solar troughs are the predominant CSP technology.

Solar tower CSP systems use 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 contained in the receiver is used to create steam which spins a conventional steam turbine that drives an electricity generator.

Dish/engine CSP technology relies on a concentrating solar dish that focuses the solar radiation on a power conversion unit at the dish's focus point. The power conversion unit contains the thermal receiver and also the engine/generator. The dish is mounted on a device that tracks the sun.

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 (See Section 1.2.4 for references).

1.1.2 Solar Power Technology Data Availability

There are several available sources of information that can be used to determine solar radiation and solar insulation that include:

- **The Canadian Forest Service** (CFS) in collaboration with the **CAMNET Energy Technology Center Photovoltaic Systems Group** has developed a solar insolation model based on 1974-1993 (CERES, **Environment Canada**) monthly mean daily global insolation data from 144 meteorological stations across Canada. Data from an additional 8 stations in Alaska (U.S. National Solar Radiation Database, 1961-1990) is also used to improve the models in that region. Insolation values were interpolated over the country in a regular grid (grid size: 300 arc seconds ~10 km). The models used are based on position (longitude, latitude) and precipitation (used as a surrogate for cloudiness). This data source can provide monthly PV Potential (kWh/kW), Mean Daily Global Insolation measured as MJ/m2 and also measured as kWh/m2. These data parameters are available for varying slants of PV cell surfaces and also include parameters for solar tracking device impacts.

- **NASA Solar Radiation Database** is available that provides over 200 meteorological and solar parameters, on any global coordinates entered over a 22 year period.

- **Energy Mines, and Resource Canada** developed a Canadian solar map in 1984 that can provide some limited information. This source of information consists of two maps of Canada: one shows solar radiation and its variability recorded on a horizontal surface, the other shows solar radiation recorded on inclined surfaces. The data is primarily for the period 1956 to 1978 and is available for December, June, April and October monthly periods.

The costs of solar PV systems were obtained from suppliers for representative sized PV systems. These costs will be validated using recent project examples.

1.1.3 Solar Power Technology Data Update Needs

The primary needs for the resource options update is to validate the approach, data and methodology applied to the solar resource option. Additional information on actual installation costs and performance that could be used to validate cost and performance assumptions would be useful. Also, any time series data on actual performance of solar installations in the province would help inform the analysis of solar resource option performance characteristics.

1.2 Methodology

1.2.1 Solar Resource Option Assessment Methodology

The solar resource option assessment will focus on utility scale PV systems. Of the various solar power technologies, PV cells are expected to be the most likely to be pursued in British Columbia given the ability to modularly increase the size of the solar power installation size over time, requiring smaller initial capital investment.

CSP technologies are not included in the solar resource assessment as these technologies typically require large upfront capital investments as the CSP plants require a large scale implementation.

The solar resource option assessment will examine commercial installations on the utility side of the meter with commercial scale solar installations sized at 500kW and solar farm scale installations sized at 1MW and 5MW.

The CFS/CAMNET solar insolation data will be used to identify the best solar location in each of the transmission regions that will be used in the Integrated Resource Plan (IRP). At each of these locations, a generic solar PV installation of varying sizes will be modelled. The monthly solar insolation values will be obtained from the CFS database. The average annual energy that can be obtained from this solar radiation will be modelled based on a modern PV cell design using C-Si technology.

The firm energy expected from a solar resource will be determined based on internal BC Hydro modeling of the solar resource in conjunction with the BC Hydro system.

This average annual energy and the firm annual energy will be combined with the expected costs of a solar project to develop the plant gate average and firm Unit Energy Costs for the solar resource.

Two approaches are being considered to determine the effective load carrying capability (ELCC) for the solar resource option. These are:

- A methodology developed by the National Renewable Energy Laboratory (NREL) in the U.S that involves using the ratio of summer to winter peak load and a formula to derive the ELCC; and
- Time series values of the solar power output from the generic PV installations will be used to perform a loss of load analysis (LOLA) and derivation of the ELCC.

Seasonality will be addressed using the average monthly energy production profiles based on the period of record in the datasets used.

Project lead time for permitting will be assumed to be 1 year and construction lead time will be assumed to be 1 year.

1.2.2 Solar Resource In the 2008 LTAP

Solar was not included in the 2008 LTAP.

1.2.3 Constraints

Land availability is a constraint with solar installations. For this analysis, it is assumed that a suitable location can be found in the vicinity of the identified location. Solar resources can utilize land-fill areas that are full, abandoned mining locations or abandoned air fields, for example.

It is also assumed that any environmental and/or government permits are achievable.

1.2.4 References

Canadian Forest Service/CAMNET Solar Maps: https://glfc.cfsnet.nfis.org/mapserver/pv/index_e.php

NASA Solar Radiation Database: http://eosweb.larc.nasa.gov/sse/

SolarBC Map of Installations in British Columbia: http://www.solarbc.ca/view-installations-across-bc

Day4 Energy Inc. installations (including some in British Columbia): http://www.day4energy.com/EN/installations.htm

1.2.5 Proposed Timeline for subsequent Meetings

It is proposed that one meeting be held with the Solar Resource stakeholders to review data, methodology and preliminary results. A second meeting would be scheduled based upon feedback from the first meeting.

1. Onshore/Offshore Wind

1.1 Resource Description

1.1.1 Onshore/Offshore Wind Technologies and Utilization in British Columbia

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.

With approximately 159 GW of wind installed globally (2009), and 3,472 MW installed in Canada (2010), both onshore and offshore wind are considered mature technologies. As of October 2009, a 102 MW wind plant has been operational in BC. Including wind plants under construction, and wind projects that have received Energy Purchase Agreements in the Clean Power Call, 782 MW of wind are expected to be operational in BC by 2015.

1.1.2 Onshore/Offshore Wind Data Availability

Several studies have been commissioned by BC Hydro recently to obtain detailed information on the wind resource potential and costs in BC:

- In February 2008, **Garrad Hassan** conducted a study titled '**Assessment of the Energy Potential and Estimated Costs of Wind Energy in British Columbia**'. This report presented a high-level assessment of the potential energy that could likely be harnessed by wind power in BC and the likely cost ranges of wind power for different regions of the province.
- The **BC Hydro Wind Data Study** was completed by **DNV Global Energy Concepts Inc.** in April 2009. This study provided ten years of 10-minute power production data and thirty years of monthly wind power production data for 104 potential wind generation plants across British Columbia. This study was initially completed for BC Hydro's wind integration study. Due to modelling costs and objectives of the integration study, the study was limited to areas where significant wind energy development would likely occur, covering approximately two-thirds of the province.
- In September 2009, the **BC Hydro Wind Data Study Update** was undertaken by **DNV Global Energy Concepts Inc**. to complete the coverage of the province and estimate the wind development potential in regions not covered in the BC Hydro Wind Data Study.

1.1.3 Onshore/Offshore Wind Data Update Needs

Stakeholders are requested to provide comments on the overall methodology for the wind resource option assessment, and in particular to comment on the data and modelling assumptions used to assess the offshore wind potential for BC.

1.2 Methodology

For the 2011 IRP, the offshore wind potential will be evaluated for BC, and the cost assumptions used to determine the unit energy cost for both onshore and offshore wind will be updated. In the BC Hydro Wind Data Study, bathymetry (i.e. water depth information) was not included as a project criterion, and hence only existing offshore Investigative Use Permits (IUPs) were considered for theoretical projects. For the 2011 IRP, a study is proposed to assess the off-shore wind potential in BC in more detail, based on information of bathymetry as well as wind speed. The cost assumptions used to determine the most recent unit energy costs for wind are based on the 2008 Garrad Hassan study with some refinements to interconnection costs. Due to potential changes in the market conditions since 2008, the cost assumptions for onshore/offshore wind will be updated. Garrad Hassan has been retained to complete this cost update.

1.2.1 Offshore Wind Resource Option Assessment Methodology

In this analysis, water depth information provided by the Canadian Hydrographic Service and average wind speeds based on the Canadian Wind Atlas will be used to identify offshore areas suitable for wind development.

The following criteria will be used to identify areas suitable for offshore wind potential:

- Water depth less than 30 m. Although future wind plants may be built in waters deeper than 30 m, or using floating turbine technology, 30 m represents the limit for offshore wind plants that are currently being built.
- Average wind speed at 80 m hub height greater than 7.0 m/s. A cut-off of 6 m/s was used in the BC Hydro Wind Data Study for onshore wind. A greater wind speed cut-off is chosen for offshore wind, recognizing that offshore wind plants are more expensive to build and maintain than onshore wind plants.
- A minimum wind plant size of 100 MW, based on economic feasibility.

To delineate potential offshore project areas, a GIS analysis will be performed using the bathymetry data, wind speed map, and the minimum size criterion. The installed capacity for each project area will be determined using a 3 MW turbine and a turbine density assumption of 2.3 turbines/km^2 (based on a 4D by 15D turbine layout). In certain areas of coastal BC, particularly the Hecate Strait, very large swaths of water may be identified for offshore wind development. Taking into account that there are physical limits as to how many turbines can be placed in an area due to wake effects within wind plants as well as impacts from neighbouring wind plants, the installed capacity of each project will be limited to 500 MW, and a 20 km buffer zone will be placed around each offshore project. Parks and other protected marine areas are not being considered for the initial screening of projects, but will be added at a later stage.

The net capacity factor estimation will be based on the same methodology used in the BC Hydro Wind Data Study Update. The average annual energy will then be determined for each project using the installed capacity and the net capacity factor.

Due to the lack of time series data, the seasonality profiles for the offshore wind projects will be assumed to be the same as the offshore wind project modelled in the BC Hydro Wind Data Study. Similarly, the firm energy and ELCC for these projects will be prorated using the same factors found with that one offshore project.

To calculate the unit energy costs, the updated cost assumptions will be applied to project specific information from this study, including turbine size, number of turbines and net capacity factors.

To determine the earliest in-service date for offshore wind projects, a project lead time of 2 years is assumed for permitting, and 3 years is assumed for construction, resulting in a total lead time of 5 years.

1.2.2 Onshore/Offshore Wind Resource In the 2008 LTAP

For the 2008 LTAP, the resource option for onshore/offshore wind was based on the Garrad Hassan study.

1.2.3 Constraints

Wind is an established renewable energy technology. Public concerns over aesthetics and environmental and health effects may limit wind farm development.

1.2.4 References

Garrad Hassan Study:
http://www.bchydro.com/etc/medialib/internet/documents/info/pdf/rou_wind_garrad_hassan_report.Par.0001.File.rou_wind_garrad_hassan_report.pdf

BC Hydro Wind Data Study:
http://www.bchydro.com/etc/medialib/internet/documents/environment/winddata/pdf/wind_data_study_report_may1_2009.Par.0001.File.bch_wind_data_study_may1_09.pdf

BC Hydro Wind Data Study Update:
http://www.bchydro.com/planning_regulatory/energy_technologies/wind_energy/wind_data_study.html

Canadian Wind Atlas: http://www.windatlas.ca/en/maps.php

1.2.5 Proposed Timeline for subsequent Meetings

A meeting is proposed for September 24th at 1:00 PM PDT to discuss the overall methodology for the wind resource option assessment, and in particular review the modelling assumptions made for the offshore wind resource potential analysis. Preliminary results for the offshore wind resource assessment will be presented. The meeting will take place at BC Hydro. Stakeholders will be able to participate either in person or by teleconferencing.