

SCHEDULE 8

ANAHIM LAKE COMMUNITY ELECTRICITY PLAN

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ANAHIM LAKE ELECTRICAL SERVICE AREA COMMUNITY ELECTRICITY PLAN

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EXECUTIVE SUMMARY

This Community Electricity Plan (CEP) explores the energy requirements for the Anahim Lake Electrical Service Area defined by the AHM 25F51 distribution feeder plan, and investigates the potential for various renewable electricity supply options to offset or replace the current diesel based generation. As a secondary objective, information is included on Demand Side Management (DSM) with respect to general opportunities for potential load management through conservation and load displacement.

Electrical power is currently provided by BC Hydro with operations managed by the Non-Integrated Area division. A Diesel Generating Station (DGS), which currently has 6 mobile diesel generators totalling 3.65 MW of capacity (2.65 MW firm), supplies power to a local 25kV distribution grid. The station currently provides approximately 6,400 MWh of electricity annually with a peak winter load of 1.4 MW and an average annual load of approximately 0.8 MW.

Electricity demand is forecasted to increase unless there is a sudden reversal in historic trends due to changes in local industry. Using an annual growth rate of 0.53% results in a 2035 annual load of nearly 7,400 MWh with peak and average annual loads of 1.8 MW and 0.85 MW respectively.

Supply Options

A supply options analysis was conducted to assess the potential for various renewable energy options to replace or offset diesel generation. The screening study yielded a short list of potential options for further analysis.

Firm Sources

The analysis of potential resource capacities suggests two viable firm supply options in addition to the existing diesel generation station, which was used as a benchmark, namely:

- **Biomass** – A high level review was done to assess the potential capacity of a local biomass plant based on available feedstock inventories and provide an “order of magnitude” capital cost estimate based on a survey of previous projects. The study suggests biomass could be cost effective relative to diesel generation and that potential exists for feedstock supply in the quantities required.
- **Small Hydro** – The inventory level study identifies several potential hydro sites with estimated capacities from 10MW to 27MW. Order of magnitude costing estimates suggest capital project costs could be within the 25 year NPV costs of displaced diesel fuel.

Variable Sources

Variable sources were also examined and results suggest one option may be viable for the Service Area, namely:

- **Wind** – The inventory level study determined 2 potential sites where the wind resource was suitable and the distribution distances were not prohibitive. A screening level hybrid system model was run to conclude that, based on the assumptions made, the hybrid system could potentially deliver a lower total cost of energy over 25 years than the current DGS.

An analysis of the potential for a solar installation to make a financial return on the cost of capital showed that the displaced costs of diesel for a low penetration configuration could not offset the capital costs. Although solar energy appears to be more expensive than “base case” diesel and other renewable options studied, the environmental benefits combined with the potential for a Net Metering based DSM initiative warrant maintaining this option for further consideration.

Although the community and potentially larger IPP’s are still interested in grid connection, this option would only be viable if an “anchor project” such as a large IPP or industrial customer were committed to justify the cost of a transmission line from Williams Lake or another transmission tap point. Currently there are no projects that are

far enough along a project approval process or in the right location relative to the Service Area to suggest that grid connection for the Service Area is a viable option in the near future. Grid connection at a future date would enable any “excess” generation from a local supply solution to be sold to the integrated grid. This potential could further improve project economics.

Recommendations

The following recommendations are made based on the findings of this study:

1. Consider local biomass options through the BC Hydro Community Based Biomass Request for Qualifications (RFQ) or similar power acquisition process. The preliminary supply options review presented in this study indicate favourable potential for a firm biomass project to replace the current diesel generation station. The biomass option also reflects local interests. This would enable a switch to a more renewable resource and potentially a lower total cost of energy, while stimulating economic opportunities in the region through the development of a local IPP.
2. Consider a local small hydro project to replace the current diesel generation station. While favourable potential appears to exist for this option, additional analysis will be required with respect to sources and costs.
3. Determine if there is support for a diesel offsetting solution such as a hybrid wind-diesel system. The preliminary screening has shown wind potential to exist and example configurations have shown a potential positive return through the displacement of diesel fuel. The hybrid solution does not necessarily achieve the stated energy goals communicated by the Service Area representatives of achieving maximum sustainability and promoting the use of pine beetle kill, but could achieve a lower cost of energy than the current diesel solution based on the assumptions made. More study is required for this option as wind-diesel systems for mini and microgrids are still a developing area of technical expertise and experience.
4. If support for a hybrid wind-diesel solution has been established, consider deploying wind resource monitoring to verify the assumed wind characteristics used to identify this option as viable. Typically monitoring several points at the selected location for a duration long enough to establish seasonal norms is recommended.

1 INTRODUCTION

The Anahim Lake Electrical Service Area (Service Area) is managed by BC Hydro's Non-Integrated Areas (NIA) division. Power for Anahim Lake is supplied by a Diesel Generating Station (DGS) and distributed via feeder AHM 25F51 and a local 25 kV distribution grid. For prime diesel powered areas such as Anahim Lake, BC Hydro reviews alternative renewable energy solutions which may provide a more sustainable alternative to diesel fuelled generation at a reasonable cost.

A Community Electricity Plan (CEP) has been initiated as a critical step in developing electricity supply solutions in remote communities. Policy Action 28 of the BC Energy Plan: *A Vision for Clean Energy Leadership* (the 2007 Energy Plan) calls upon BC Hydro to prepare a CEP when considering renewal or replacement of diesel generators in Non-Integrated Areas. In this plan, the Provincial Government recognizes the economic and environmental issues associated with reliance on diesel generated electricity in remote communities, and the strong business and social case for pursuing alternatives. BC Hydro will therefore consider all cost effective solutions, including alternative energy and energy efficiency, in its planning for remote communities. CEP's have various meanings and potential scopes but usually involve wide consultation with the community and the establishment of working groups for high level strategic planning on the community's economic, social and environmental goals. For Anahim Lake, there was a narrow focus on evaluating the potential renewable supply options which could replace diesel so that power acquisition processes could be quickly opened up for potential renewable energy projects.

1.1 Purpose

The primary focus of this CEP is to determine if there are enough renewable energy options for the Service Area to justify a power acquisition process to acquire renewable energy. The CEP also identifies ways to manage load growth through conservation and load displacement.

This CEP represents the combined efforts of BC Hydro and Powertech Labs. Powertech Labs Inc. was contracted by BC Hydro to prepare the CEP. The CEP draws on a variety of previous work and is intended to provide a broad overview of the Service Area's energy supply including current generation assets, energy use and cost of energy. Various practical alternative generation and energy conservation options are considered to serve as a planning tool for the both the Service Area residents and BC Hydro.

1.2 Scope

This CEP addresses the supply and use of electric service in the Service Area, as described in the Anahim Lake/Nimpo Lake Distribution Feeder 25F51 Plan. The CEP examines the existing generation assets and forecasted community loads and identifies generation options which could introduce renewable energy generation into the existing distribution grid. Conservation options which support more efficient electricity use in the area are also reviewed.

1.3 Assumptions

The CEP represents a primary planning tool for the identification of energy conservation and supply options but remains a largely qualitative and high level assessment. The primary assumptions for the analysis are:

1. The analysis is conducted based on existing information and available data inputs.
2. The assessment of energy supply and conservation options is limited to a subset identified by the application of standard design principals and guidelines.
3. Quantitative data is stated where possible but often a qualitative assessment will form the basis of specific recommendations.
4. Costs are estimated at a preliminary level and subject to change based on a more detailed costing analysis.
5. Financial calculations assume a 25 year project lifetime and a 6% discount rate.

2 REGIONAL OVERVIEWⁱ

2.1 Geography and Demographics

The Service Area is comprised of the region in and around Anahim Lake and Nimpo Lake. The local population for the region is approximately 1500.

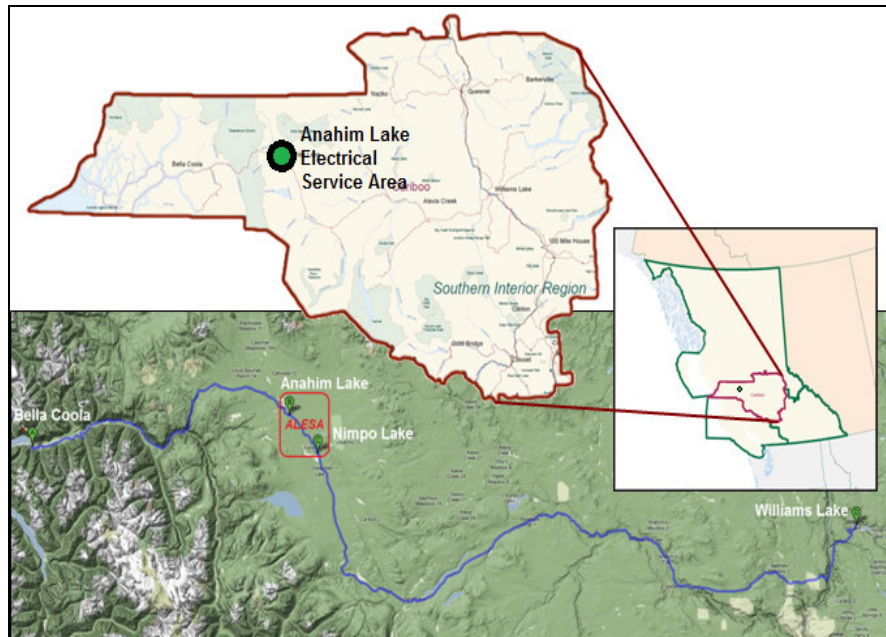


Figure 2.1-1: Anahim Lake Electrical Service Area Location

Anahim Lake Service Area is located in the Cariboo Chilcotin region of British Columbia, on the Bella Coola Highway (Hwy 20), 316 km west of Williams Lake and 135 km east of Bella Coola.

Anahim Lake is situated in the traditional territory of the Ulkatcho First Nation. The Ulkatcho First Nation is the main aboriginal community in the Anahim Lake area. Most of the Ulkatcho members reside on Squinas Reserve #2 adjacent to Anahim Lake.

In addition to local residences, Anahim Lake Village offers a number of businesses and services, including a medical nurse's station, and a school. Anahim Lake is served by a year-round airport with daily flights to Bella Coola and Vancouver.

Nimpo Lake is located on the Bella Coola Highway (Hwy 20), 299 km west of Williams Lake and 17 km southwest of Anahim Lake. Nimpo Lake is primarily residential and offers a number of businesses serving local tourism.

The region is a destination for travellers and offers opportunities for fishing, hiking, canoeing, horseback riding, cross-country skiing and snowmobiling and access to nearby mountains and parks.

Seasonal Temperatures from a nearby weather station at Williams Lake provide an indication of typical conditions in the region. Typical temperatures range from approximately -12.5°C in January to 22°C in August. While temperatures rarely exceed 30°C to 35°C in the summer, occasional extreme winter temperatures drop to -45°C.

Precipitation is typically higher in summertime since the Service Area is located in the rain shadow of the Coast Mountains. Heavy rain or snow falls are rare. A moderate amount of snow is typically present from November to April.

2.2 Local Governance

The following information pertains to the local forms of government affecting the Service Area.

2.2.1 Cariboo Regional Districtⁱ

The Cariboo Regional District (CRD) is a regional government that functions independently of the provincial government. The CRD consists of 12 electoral areas and four incorporated member municipalities, including Quesnel, Williams Lake, 100 Mile House, and Wells. The Cariboo Regional District presently provides fire protection, recreation, library, waste management and utility systems to an estimated population of 65,659 residents, based on the 2001 population census.

2.2.2 Ulkatcho

Ulkatcho First Nation is a Dakelh First Nations government and a member of the Carrier Chilcotin Tribal Council. The Ulkatcho have 931 members and 21 Reserves in the Anahim Lake area. The Ulkatcho administration offices, health center, band-operated school and store are located in Anahim Lake.

Ulkatcho is not involved in the BC Treaty process. The Province and Ulkatcho have a forestry agreement to support Ulkatcho economic development goals and address pine beetle forestry infestation.

2.3 Economic Overview

The major regional industries are forestry and tourism. The region has a number of inns and resorts, offering wilderness, sport fishing and hunting excursions. In the summer of 2006, a series of industry economic considerations forced the West Chilcotin Forest Products lumber mill in Anahim Lake to suspend operations.

2.3.1 West Chilcotin Forest Products Ltd.

West Chilcotin Forest Products Ltd (WCFP) was formed as a joint venture incorporating the business interests of Ulkatcho and Carrier Lumber Ltd. The WCFP mill was shut down in 2006. Previously, the mill produced lumber and white wood chips for use in wood pulp production. With the onset of the pine beetle in regional forests, WCFP has been exploring ways to utilize waste wood for electrical generation through biomass options. WCFP advocates that a biomass energy project will provide additional economic opportunities for the region while reducing greenhouse gas emissions associated with the decay in regional pine beetle afflicted forests.

2.3.2 Regional Economic Projects/Proposals

While there have been no recent public announcements of new developments within the Service Area region, there are other projects being considered in the Cariboo and Coastal regions between Bella Coola and Williams Lake. The status of these projects is considered as increased regional electrical demand may impact future interconnection opportunities for the Service Area.

2.3.2.1 Prosperity Gold/Copper Project

Developer: Taseko Mines Ltd.

Status: Proposed

Proposed development of a large gold/copper deposit 125 km SW of Williams Lake (192 km by road). Preliminary figures suggest an operation employing 350 people and milling 66,000 tonnes/ day over a 20-year mine life with reserves of 744 million tons. Construction of a 125 km 230kV power transmission line and access roads will also be included in the construction. Pre-feasibility study was completed by Kilborn Engineering Pacific Ltd. The project involves proposed construction of a 125 kilometre transmission line corridor from Dog Creek on the BC Hydro grid to Prosperity Mine site. The project's review is proceeding under the BC Environmental Assessment Act and a federal review panel.

2.3.2.2 Gibraltar Copper Mine Expansion

Developer: Taseko Mines Ltd.

Status: Active (Construction started Fall 2006)

Upgrade and expansion of the concentrator facility to increase production from 70 million pounds to 100 million pounds of copper per year by 2008. Phase 1, the addition of a SAG mill, has completed.

2.3.2.3 Bella Coola Rock Project

Developer: Bella Coola Rock Corporation

Status: On Hold

Proposed aggregate quarry approx 2 km from Bella Coola. The mining permit has been approved and construction will commence when market conditions are suitable.

2.3.2.4 Williams Lake Arena and Events Centre

Developer: City of Williams Lake

Status: On Hold

Proposed arena and events centre would include facilities to host sports, entertainment, trade shows and community events. The Chiefs Development Group has been selected to develop the project. Project is on hold while the City seeks funding from senior government.

3 ENERGY SUPPLY

3.1 Current Regional Supply

There are four other electrical generation facilities in the region providing primary or backup power to the non-integrated areas of Bella Bella and Bella Coola, which are also served by BC Hydro.

1. Boralex Ocean Falls (IPP)

Location: Bella Bella
Type: Hydro
Installed Capacity: 14 MW

3. BC Hydro Ah-Sin-Heek

Location: Bella Coola
Type: Diesel and Fuel Cell
Installed Capacity: 7 MW

2. BC Hydro Bella Bella

Location: Bella Bella
Type: Diesel
Installed Capacity: 6 MW

4. BC Hydro Clayton Falls

Location: Bella Coola
Type: Hydro
Installed Capacity: 2 MW

3.2 Current Local Supply

The Service Area is currently administered by BC Hydro's Non-Integrated Areas (NIA) division. The local AHM 25F51 distribution grid extends from Anahim Lake to Nimpo Lake approximately 15km to the south.

The BC Hydro DGS consists of 6 mobile diesel generation units with a total installed capacity of 3.65MW and a firm capacityⁱⁱⁱ of 2.65MW. The installation also includes an outdoor sub-station, controls building, office/workshop and bermed fuel storage area containing 3 vertical 8000 gal fuel storage tanks and auxiliary equipment for a total usable stored fuel volume of 72,360 Litres.

Table 3-1: Service Area DGS Assets

Genset No.	BCH Mobile Generator	Prime (kW)	CAT Genset Model
1	M098G1	600	D398B
2	M112G1	600	D398B
3	M164G1	1,000	3516
4	M166G1	850	3512
5	M168G1	300	3406
6	M168G2	300	3406

The generation station has a current Gross Heat Rate of 3.66 kWh per Litre of diesel fuel and a Net Heat Rate of approximately 3.39 kWh/L^{iv}. Generators are configured for automatic loading parallel operation. Units will come on-line or off-line depending on genset availability and the load condition. Unit dispatch attempts to keep the generators operating at their rated load to maintain fuel efficiency while maintaining sufficient spinning reserve to meet load fluctuations.

The local substation feeds one 25 kV feeder (AHM 25F51) which consists of 23 km of 3-phase line and 82 km of single phase line.

As of September 2008 there were 555 customer accounts representing:

- 405 Residential (non-heating) accounts
- 29 Residential (heating) accounts
- 101 General (under 35kW) accounts
- 7 General (over 35kW) accounts
- 11 Street lighting accounts
- 2 BC Hydro (for own use) accounts

3.3 Use of Alternate Fuels

A residential End-Use Survey^v obtained from BC Hydro’s Power Smart division provided a summary of the types of fuels used as sources of energy for each house engaged in the survey. While the survey was not explicitly quantitative, compilation of the 40 returned surveys showed the following general observations about the use of alternate fuels:

- The main residential space heating source is wood (53% of the households)
- Other types of space heating are propane, electricity, oil, natural gas and diesel
- Water heating is mostly electricity (about 60% of the houses), as well as propane and natural gas, with few houses on wood and oil
- During the period of 2 years preceding the survey date (2008), 15% of customers changed or modified their space heating system by adding electric baseboard heaters, portable electric heaters, and electric fireplace.

3.4 Environmental Impacts

The current Service Area power generation station consumes between 120,000 and 250,000 litres of diesel fuel each month to produce approximately 500 MWhr/month or 6,400 MWhr/year. An annual consumption of 1.9 million litres was reported for the period of June 2008 to May 2009. The annual consumption is responsible for approximately 5,000 Metric Tons of CO₂ emissions per year^{vi}. A comprehensive environmental management plan and appropriate containment around fuel storage, delivery and transfer points are in place to manage environmental risks associated with the diesel fuel supply.

3.5 Current Service Load Demand

As of May 2009, the Service Area represented an average annual load of approximately 0.815 MW with a winter peak load of 1.4 MW and a total annual energy demand of 6,375 MWh.

The breakdown of the load can be summarized by the types of BC Hydro accounts currently offered within the Service Area. The pie chart (Figure 3.5-1 below) shows the percentage contribution from each type of account.

The bulk of the demand is from residential loads (47%) followed by commercial loads under 35kW (29%). Only 17% of the demand is from large commercial loads greater than 35kW and 7% from residential heating only accounts. Small loads less than 0.3% of the total demand are attributed to street lighting and BC Hydro’s own utility loads.

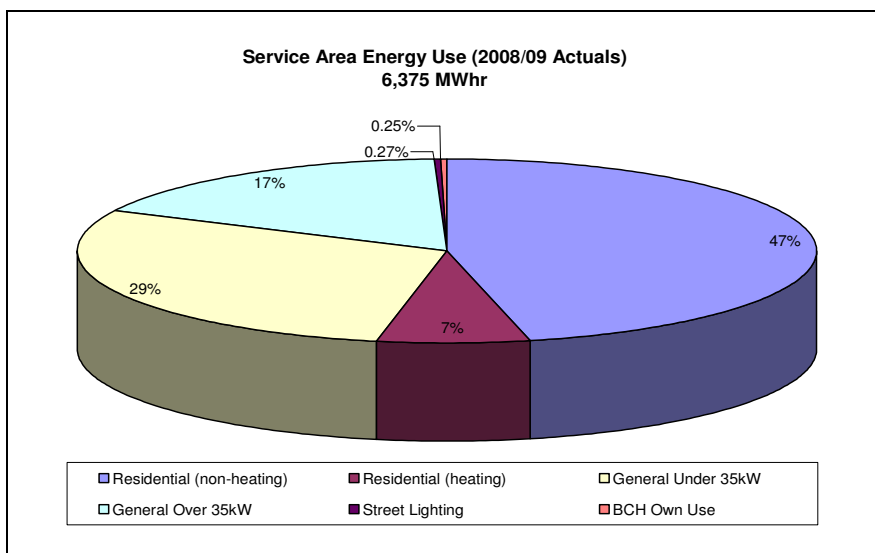
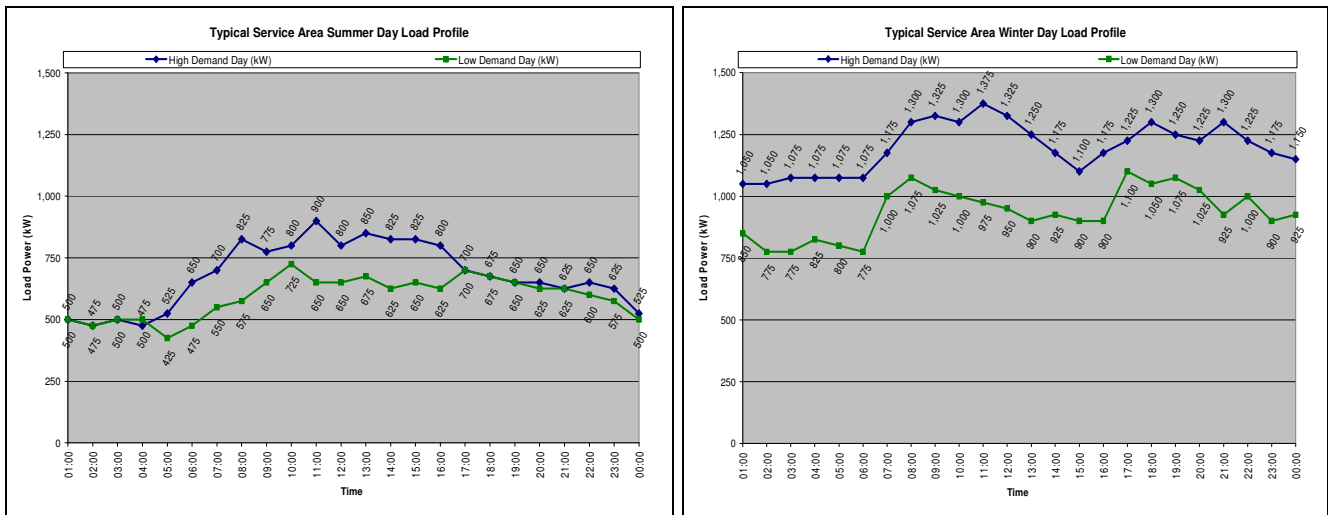


Figure 3.5-1: Breakdown of Service Area BC Hydro Customer Accounts

The extremes of the load are represented by daily profiles comprising maximum and minimum load samples collected over a month interval during both peak summer and winter periods. The profiles show the load ranging annually from approximately 425kW to 1.4MW (Figure 3.5-2).

These profiles are assumed to represent the typical Service Area load characteristics and will scale from the summer profile to the winter profile in accordance to the ambient temperature. This assumption will be used to create an annual profile in subsequent analyses of supply and energy conservation options for the Service Area.

Daily distributions are relatively stable with only moderate load peaks (i.e. differences in peak loads to minimum or average load for the same interval). This is typical of larger communities with predominantly residential service loads.



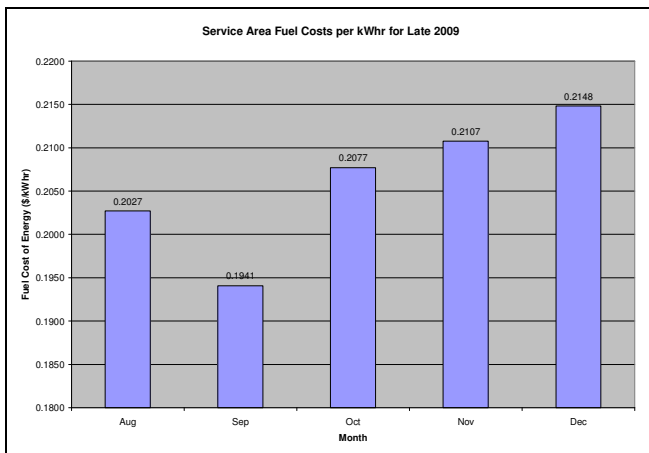
a) Summer Profile

b) Winter Profile

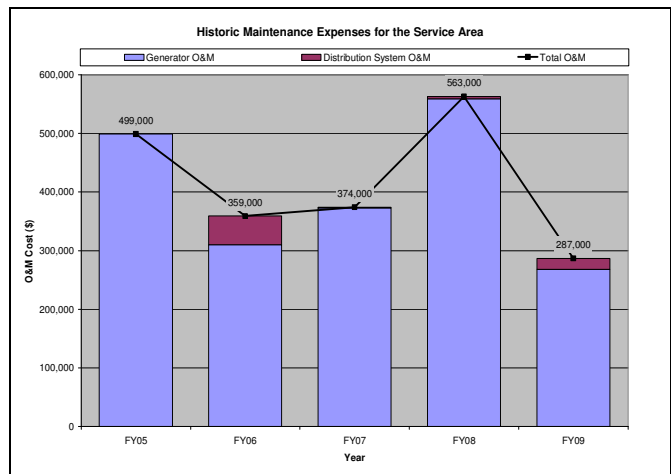
Figure 3.5-2: Daily Service Area Load Profiles

3.6 Current Costs

Internal fuel use and cost data for the Service Area recorded over the period of August through December, 2009 (Figure 3.6-1a) shows direct fuel only costs to be approximately \$0.215/kWhr by the end of 2009^{vii}. Assuming the remaining data is approximately symmetric over the balance of the year, an annual fuel cost of energy is approximately \$0.21/kWh. This corresponds to a total landed diesel fuel cost of \$0.71/L.



a) Select 2009 Monthly Fuel Costs



b) Historic annual O&M Costs

Figure 3.6-1: Service Area Cost of Energy Components

Maintenance costs include equipment maintenance, repair and upgrades as well as general administration costs. Additional maintenance is also required for the distribution system. The graph (Figure 3.6-1b) shows the maintenance expenses incurred for the Service Area over the past 5 years. Although costs fluctuate from year to year due to particular maintenance events occurring at different times, the average 5 year maintenance cost for the diesel generation station is approximately \$415k. It should be noted that this estimate represents a particular snapshot of O&M costs over a short duration within the overall service life of the equipment. The result is therefore only an approximation of levelized annual O&M costs. Assuming this nominal maintenance cost of \$415k/yr, for the 2009 year net generation of 6,378 MWh, maintenance costs represent \$0.065/kWh.

Table 3-2: Summary of Unit Energy Cost Costs

Cost Type	2009 Unit Cost(\$/kWh)
Diesel Fuel	0.210
Maintenance and Admin	0.065
Total	0.275

Based on the estimated \$0.21/kWh for diesel fuel only, the current cost of energy for the Service Area is approximately \$0.275/kWh.

3.7 Regional Electricity Proposals

There are two electrical generation projects currently proposed for the region.

3.7.1 Hanceville Biomass Project

Developer: Western Biomass Power Corp. and Tsilhqot'in National Government (TNG)
Status: Proposed

Proposal submitted to the Bioenergy Call for Power for a 60 MW Biomass plant located in Hanceville near the Sigurdson Brothers Mill. Western Biomass Power intends to build a forest-based biomass-fired thermal electric power plant using mountain pine beetle-killed trees harvested from existing TNG forest tenures and wood waste from logging operations.

3.7.2 Nascall Hydro-Electric

Developer: Primex Investments Ltd
Status: Pre-application

Proposed hydroelectric project of 71 MW located on the Nascall river, currently in the pre-application phase requiring an Environmental Assessment. In the Project Definition document, Nascall includes the installation of a 57 km transmission line from the facility to Bella Coola, and a 49 km transmission line linking the Bella Coola power line to the Anahim Lake power line.

3.7.3 Local Proposal: WCFP-Pristine Biomass Project^{viii}

In 2007, Ulkatcho supported an MOU between WCFP and Pristine Power to form a renewable power partnership and develop an innovative biomass facility. The project was a partnership of Pristine Power, Carrier Lumber and the Ulkatcho First Nation and proposed using beetle-damaged wood, mill residue and wood waste to be converted into a local source of clean, renewable energy for the service area. Under the MOU, the partnership would generate up to 10 megawatts (MW) of clean power at the WCFP mill. The mill would receive approximately 3.5MW while the communities would receive roughly 2MW, eliminating the reliance on diesel for electric power generation. Remaining electricity would be sold into the BC Hydro grid via a proposed grid extension to the WCFP biomass generation site.

The project was expected to improve local air quality by facilitating the shut down of the mill's two beehive burners and eliminate a diesel generation set and the consumption of more than 3.5 million litres of diesel fuel annually and reduce greenhouse gas emissions by over 10,000 tonnes per year. The project was also expected to provide economic benefits to the community through an Energy Purchase Agreement (EPA) with BC Hydro. The project did not result in an EPA in Phase One of BC Hydro's Bioenergy Call for Power.

4 GROWTH FORECASTS

The following sections present growth forecasts based on BC Hydro’s approved methodology for load forecasting in the non-integrated areas and January 2010 data.

4.1 Local Community Growth

While specific community data and population trends were not part of the scope for this CEP, BC Hydro has provided some short-term forecast data suggesting the anticipated growth in customer accounts.

The graph below shows that the only short-term account growth anticipated is in the number of residential non-heating accounts. These “non-heating” residential accounts represent the standard household service provided under the residential Zone II tariff. Growth in this category is expected to range from approximately 0.25% to 0.5% annually over the four years of forecast considered or by five accounts over four years (Figure 4.1-1).

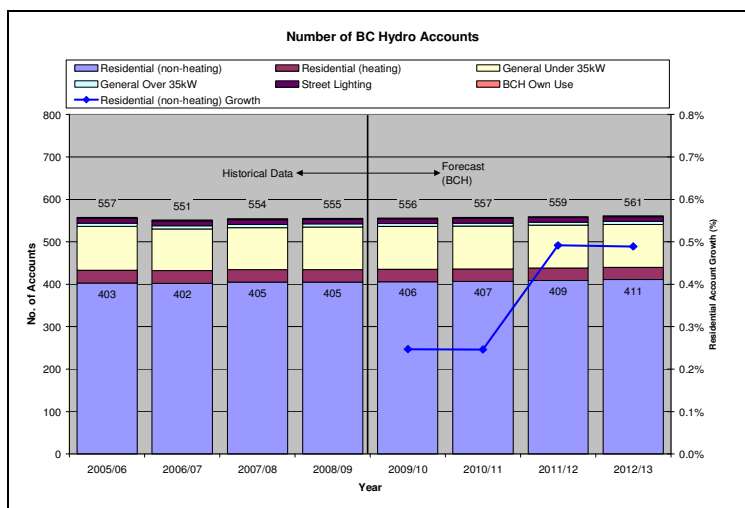


Figure 4.1-1: Short Term BC Hydro Service Area Account Growth Forecast

4.2 Local Electricity Demand Forecast

Historic data for the Service Area shows an increasing demand with some year to year variation (Figure 4.2-1). A short increase in growth followed by a slight decrease in demand was seen between 2002 and 2005 with a stabilization trend in recent years. The annual compound growth for the last 10 years was just under 1%.

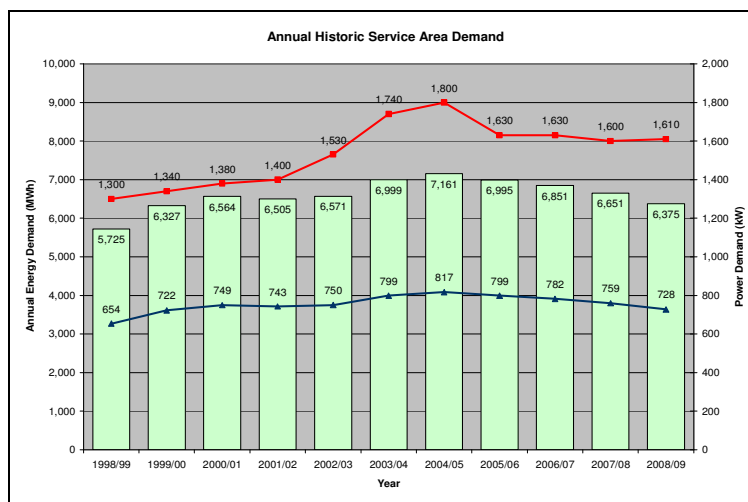


Figure 4.2-1: Historic Demand and Peak Power for the Service Area

BC Hydro’s forecast data provided an estimation of anticipated community loads through to year 2029/30. Based on this data, the forecast was extrapolated to a 25 year forecast ending in year 2035/36 using the average growth rate from 2019/20 to 2029/30 of 0.65%.

Despite the recent WCFP mill closure and short term decrease in community population, the annual energy growth estimates assume a long term perspective leading to a moderate yet steady growth. The forecast growth rate averages 0.53% over 25 years as shown below (Figure 4.2-2). Load reductions associated with Demand Side Management (DSM) Programs and conservation and efficiency improvements on the load side are not included in this forecast

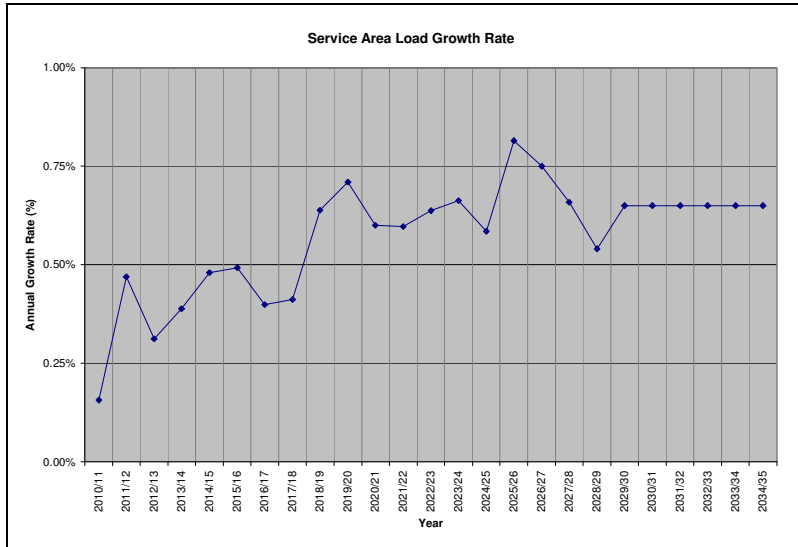


Figure 4.2-2: Service Area Demand Growth Rate 25 Year Forecast

The demand and power forecasts (Figure 4.2-3 and Table 3-1) estimate that over the next 25 years, the loads may increase to:

- Total Annual Energy Demand:.....7,350 MWhr
- Average Annual Power:.....0.84 MW
- Peak Annual Power:.....1.780 MW

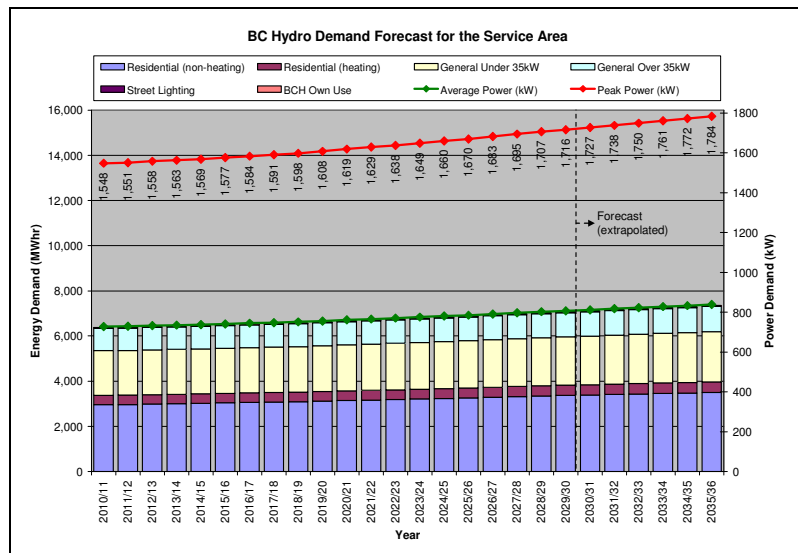


Figure 4.2-3: Service Area Demand and Power Growth 25 Year Forecast

Table 4-1: Service Area Demand Forecast Data

Year	Gross Gen (MWh)	Net Gen (MWh)	Average Power (kW)	Peak Power (kW)
2010	6,895	6,378	728	1,548
2011	6,906	6,388	729	1,551
2012	6,938	6,418	733	1,558
2013	6,960	6,438	735	1,563
2014	6,987	6,463	738	1,569
2015	7,021	6,494	741	1,577
2016	7,055	6,526	745	1,584
2017	7,083	6,552	748	1,591
2018	7,112	6,579	751	1,598
2019	7,158	6,621	756	1,608
2020	7,209	6,668	761	1,619
2021	7,252	6,708	766	1,629
2022	7,295	6,748	770	1,638
2023	7,342	6,791	775	1,649
2024	7,390	6,836	780	1,660
2025	7,434	6,876	785	1,670
2026	7,494	6,932	791	1,683
2027	7,550	6,984	797	1,695
2028	7,600	7,030	803	1,707
2029	7,641	7,068	807	1,716
2030	7,691	7,114	812	1,727
2031	7,741	7,160	817	1,738
2032	7,791	7,207	823	1,750
2033	7,842	7,254	828	1,761
2034	7,893	7,301	833	1,772
2035	7,944	7,348	839	1,784

Forecasts and growth estimates do not include information about future commercial and economic opportunities in the region due to the uncertainty of these ventures. They also do not include DSM reductions in load.

The growth will impact the demand categories differently as shown below in Figure 4.2-4:

Increases:

- Residential (non-heating) may increase from 47% to 49%
- General Under 35kW may increase from 29% to 30%
- Street Lighting may increase from 0.27% to 0.31%

Decreases:

- Residential (heating) may decrease from 7% to 6%
- General Over 35kW may decrease from 17% to 15%

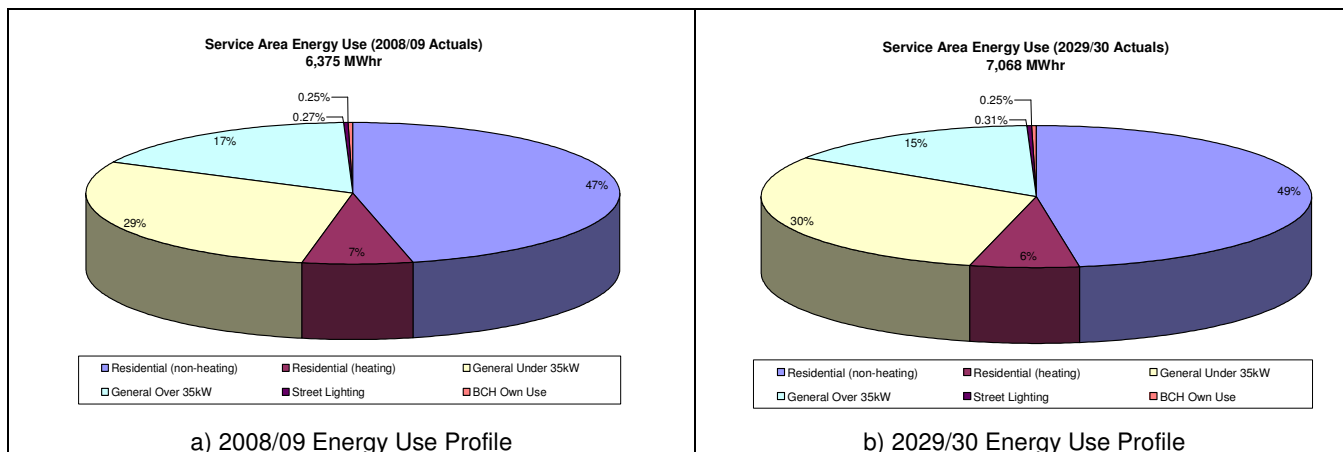


Figure 4.2-4: Service Area BC Hydro Account Growth Forecast by Sector

5 SUPPLY OPTIONS

The following sections present an overview of power generation options and technologies with potential for deployment in the Service Area. Potential options are considered for the community supply using specific community attributes and a design tool-box approach based on prior research and experience. A trade-off analysis is performed at a high level.

5.1 Supply Options Screening for the Service Area

The following table (Table 5-1) represents the type of load which characterizes the Service Area:

Table 5-1: Load Characteristics and Target System Attributes

Load Range	Target System Attributes
500 kW to 2MW	<ul style="list-style-type: none"> • Target medium or greater penetration of renewable energy. • Larger scale renewable sources requiring moderate distribution can be considered. • Potential for energy storage for peak shaving and grid stabilization applications. • Load can justify capital project for renewable firm power. • Efficiency gains in generation will have significant impacts on energy costs. • Opportunities for net metering of distributed renewables as DSM option.

The community size can support significant development of renewable power options. This includes renewable firm power and variable supply options which can be sized for significant penetration and offset of prime diesel. DSM options can be broadened to include residential distributed generation to reduce net system loads.

Based on these assumptions, a number of supply options suitable for a 0.5 MW to 2 MW community load were identified.

Table 5-2: Summary Table of Qualitative Resource Screening

	Supply Option	Summary of Qualitative Assessment	Potential Candidate
Firm	Diesel Electric	<ul style="list-style-type: none"> • This is the incumbent baseline generation system and needs to be considered in a detailed analysis. 	Yes
	Grid Interconnection	<ul style="list-style-type: none"> • Previous work has been commissioned to explore this option and therefore should be considered in the evaluation of potential options. 	Yes
	Small Hydro	<ul style="list-style-type: none"> • Small hydro generation is in-line with the community's values for renewable clean power. • Small hydro scales well to the Service Area load. • The attributes and load range of the Service Area suggests that there is a potential economic case for a small hydro project. • A preliminary resource screen raised concerns that suitable river flows and elevation drops may not be within a practical radius of the community and may warrant further investigation 	Yes
	Geothermal	<ul style="list-style-type: none"> • Geothermal generation is in-line with the community's values for renewable clean power. • Despite being a large load for a remote community, the near 1 MW load is low for typical geothermal plant developments and may have challenges in presenting an economic case. • A preliminary resource screening of geothermal potential showed limited potential within a 100km radius. 	No
	Micro Turbines	<ul style="list-style-type: none"> • Micro turbines were considered to have little advantage over the existing diesel generation assets unless fuelled with a renewable waste gas stream, land fill gas or syngas. • This technology could be considered for electrical generation in the context of a biomass process to derive the feedstock. 	No
	Biomass	<ul style="list-style-type: none"> • Biomass generation is in-line with the community's values for renewable clean power. • Previous interest has been expressed in this option and should be considered in greater detail. 	Yes

	Supply Option	Summary of Qualitative Assessment	Potential Candidate
Variable	Wind Power	<ul style="list-style-type: none"> This technology has the potential to offset significant diesel fuel and could present an economic case for a wind farm development. The wind option is a renewable clean technology which is consistent with community values. A very preliminary resource screening using modeled wind data showed reasonable annual wind capacity and potentially suitable locations within close proximity to the Service Area. No wind monitoring is in place. 	Yes
	Hydro-Kinetic	<ul style="list-style-type: none"> Hydro kinetic (or in-stream) devices offer the potential to offset diesel with a clean renewable resource. The renewable clean technology is consistent with community values. A preliminary resource survey showed a selection of streams and rivers in the Anahim Lake region. Because the technology requires no significant elevation drop (or head), it may be a good fit for the interior plateau region. To date the technology is at an early stage of development and is essentially a demonstration technology. Limited generation component options are presently available. This option may want to be considered 	Yes
	Solar	<ul style="list-style-type: none"> Solar electric and solar hot water are clean renewable technologies and consistent with community values. Solar power was identified as a DSM option for end use load reduction. 	Yes

5.2 Potential Supply Options

5.2.1 Diesel Electric Generation

Electric generators driven by diesel engines are used widely to provide base-load and back-up power to remote communities. A well established supply chain and fuelling infrastructure, combined with BC Hydro expertise in managing these systems, makes the diesel generators an attractive option since it is a well established and proven means of reliable power generation.

Diesel-electric systems are also attractive due to their flexibility and dispatchability. Relative to other supply options, it is convenient to supply and install a diesel system of moderate capital cost that is capable of reliably meeting a community's electricity needs. Disadvantages of diesel systems include operating costs which can vary significantly on an annual basis, dependence on imported fuel and exposure to the associated price volatility, emission of noise, air pollutants and greenhouse gasses and the potential for fuel spills (although extensive containment minimizes this risk).

A hybrid system could target medium penetration of renewable energy as a diesel-hybrid. A 20% to 35% penetration of variable energy sources is a reasonable target but hybrid systems for micro and mini grids are still an area of developing technical expertise and experience. Maintaining grid stability and power quality on a small, diesel based mini grid can be very technically challenging when "peaky" renewables have very large power supply swings. Careful technical review is vital for these projects.

Benefits of off-setting diesel can be high. As an example, 25% of annual diesel consumption for the Service Area represents about 471 kL of fuel or \$335,000 at current diesel fuel costs. This amounts to a \$6.5 M net present value of fuel savings assuming a real discount rate of 6% over 25 years (Figure 5.2-1).

An alternate firm source or high penetration system (60% to 100% renewable fraction) with a relatively stable output (such as small-hydro) may present more opportunities to lower the total cost of energy and reduce reliance on diesel. The net present value of the maximum displaced diesel generation "fuel only" costs would be approximately \$25.6 million^{ix} (Figure 5.2-1).

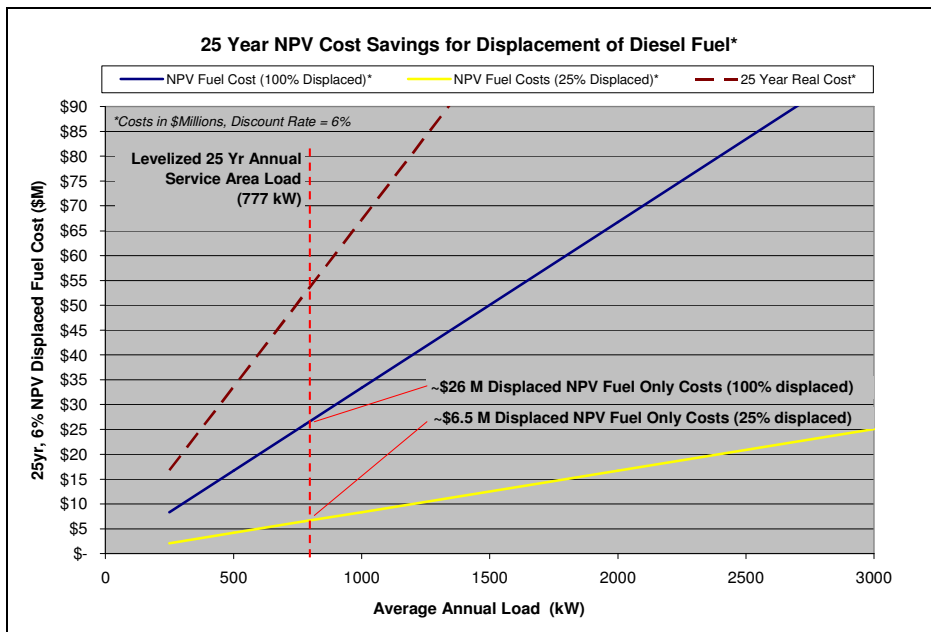


Figure 5.2-1: Summary of Potential Displaced Fuel Costs

Co-generation (or Combined Heat and Power; CHP) also presents a means for increasing the overall fuel efficiency of the power station. Waste heat from the generators could be used to provide an alternate source of space or hot water heating. In the context of the Service Area, a district heating approach is likely not an option at the present time. Co-generation, however, may be considered for further study if there is a particular community building or a small number of community buildings in close proximity to the diesel generation station that could benefit from a source of waste heat.

5.2.2 Grid Interconnection

BC Hydro’s NIAs are typically a long distance from the integrated transmission and distribution system and extensions for the relatively small loads are not economic. Despite this, there remains a significant interest in grid extension in the region.

Grid interconnection options have been considered in previous studies for the Service Area. Both a distribution study and subsequent transmission study were undertaken exploring options to extend the grid from Williams Lake 200 km to the west. The following summarizes the results of these studies^x:

Distribution Interconnection to Williams Lake

A 10 year Long Range Proposal Plan was prepared by BC Hydro Distribution Planning to investigate distribution options for connecting Anahim Lake and WCFP to the BC Hydro grid along Highway 20 on the west side of Williams Lake. The Distribution Study found that there are no technically feasible distribution options for the connection of Anahim Lake Service Area to the BC Hydro grid at distribution voltage (25 kV).

The basis for this conclusion is that the existing William Lake feeder (WLM 25F57) is already very long and an extension to Anahim Lake would further decrease the reliability of the 300 plus kilometres of total feeder length. In addition, given the limitations on the existing feeder capacity, it would also leave little or no room for significant load growth along the Highway 20 corridor including Anahim Lake.

Transmission Interconnection to Williams Lake

In 2009, BCTC completed a conceptual study to identify transmission requirements to connect Anahim Lake to the integrated transmission system via the substation in Williams Lake and a route along the Highway 20 corridor. For the purpose of the study, the load was assumed to be 7 MW (to account for potential local operations such as the mill) and located 250 km away from Williams Lake substation (WLM). WLM currently has two voltage levels, 66kV and 25kV. A new station for a more desirable transmission voltage of 138kV in WLM

would cost about \$20M which is uneconomical for the supply of a relatively small load demand. Therefore, 66kV was chosen as the voltage level for the transmission extension analysis.

The transmission study concluded that a 66kV line about 250 km from Williams Lake to Anahim Lake was technically feasible. An-order-of-magnitude costing estimate for the line alone was expected to be about \$60 million (+100/-50%) in 2009 direct dollars. The lead time to build the line would be 2 to 4 years depending on various stakeholder engagements. The cost of line termination at Williams Lake, Anahim Lake and the 66kV/25kV station at Anahim Lake would be covered by cost variance of +100/-50% of the total cost of the line. A next level study would be required to confirm these high level estimates of approximately \$250k/km and whether or not a 138 kV line is a better option.

Distribution Interconnection to Vanderhoof

The concept of a grid connection linking Anahim Lake to Vanderhoof was recently introduced as a possible alternative to interconnection to Williams Lake. The connection could potentially support electricity from local biomass projects as well as the electrical needs of three mine projects in the proposal phase.

The CEP does not examine this option, due to the uncertainty of the three Silverquest Resources Ltd. mine proposals. Furthermore, the proposed route would involve extensive consultation and regulatory requirements and could take up to ten years or more to implement and would also require large capital investment.

5.2.3 Small Hydro Generation

The Service Area is situated on an inland plateau. Nearby elevation includes the Rainbow Mountains located in Tweedsmuir Park to the west, the Itcha Ilgatchuz mountains to the east and Far Mountain to the North. Prominent water systems drain from Tweedsmuir Park towards Anahim Lake but much of the elevation drop occurs within park boundaries. The region is well known for its lakes and rivers but little flow data is available in any proximity to the Service Area.

The following maps (Figure 5.2-2) show the location of the nearest Water Survey Canada (WSC) hydrometric stations (green tear drops) near potential sources of elevation; 08FC003 – Dean River below Tanswanket Creek, 08FB006 – Atnarko River near the mouth, 08FB007 – Bella Coola River above Burnt Bridge Creek and 08FB004 – Salloomt River near Hagenborg.

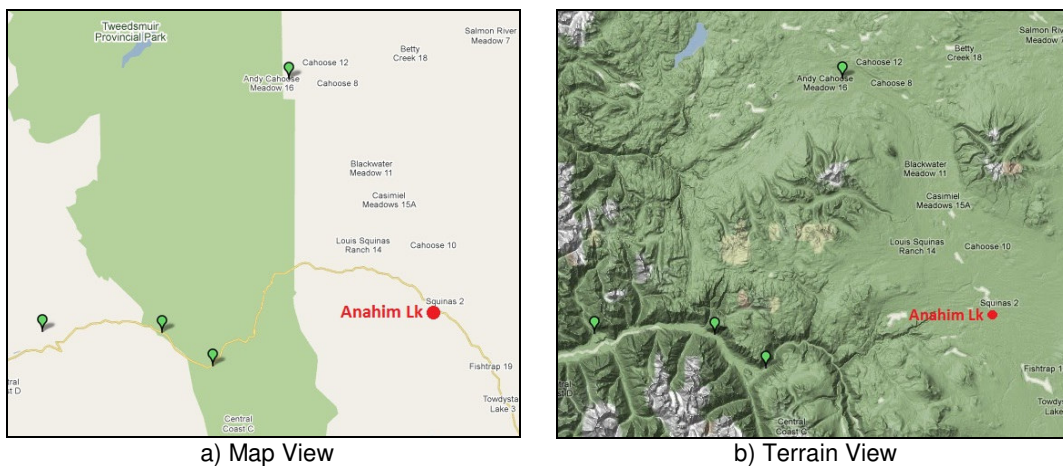


Figure 5.2-2: WSC Hydrometric Stations Near the Service Area

To date, insufficient data has been gathered to provide a basis for identifying potential small hydro projects within a reasonable distribution range. GIS modeling or ground surveying would be required to identify local hydro potential in any detail.

In 2007, BC Hydro and Kerr Wood Leidal Consulting Engineers (KWL) conducted a study titled “Run-of-River Hydroelectric Resource Assessment for British Columbia”. This study performed a comprehensive mapping of hydroelectric potentials using an assessment tool developed in house by KWL. The tool input topographic and

hydrologic GIS data to interpolate flows in un-metered rivers and streams. Although the study was intended as an inventory level assessment, results can be used to investigate, at a high level, the hydro electric potential near the Service Area.

The KWL study shows that there is local potential for run-of-river projects in the Service Area region. The sites identified all show potential for well over 2MW and 7,500 MWh per year. While this inventory level study highlights potential run-of-river hydro opportunities, extensive studies would be further required to validate the physical and economic viability of the identified projects.

Integration into the local isolated grid would also require further consideration of dump loads and potential system designs. Other local power consumers may also be interested in purchasing power and could therefore potentially justify a plant size with additional capacity resulting in lower annual energy costs.

5.2.4 Biomass Generation

In order to determine the feasibility of a biomass project in the Service Area and the size of such a system, a biomass inventory of the area is required to determine whether the resource can be harvested in a sustainable manner.

The Ministry of Forests and Range estimates that as of 2008 the cumulative area of provincial Crown forest affected by pine beetle damage to some degree (red-attack and grey-attack) was about 14.5 million hectares, cumulating to a total of 620 million cubic metres of timber that have been affected since the current infestation began (see Figure 5.2-3). From 2004 to 2006, the average annual pine harvest (total volume cut) in BC has been about 42 million m³ per year^{xi}. The effected region is shown in the figure below.

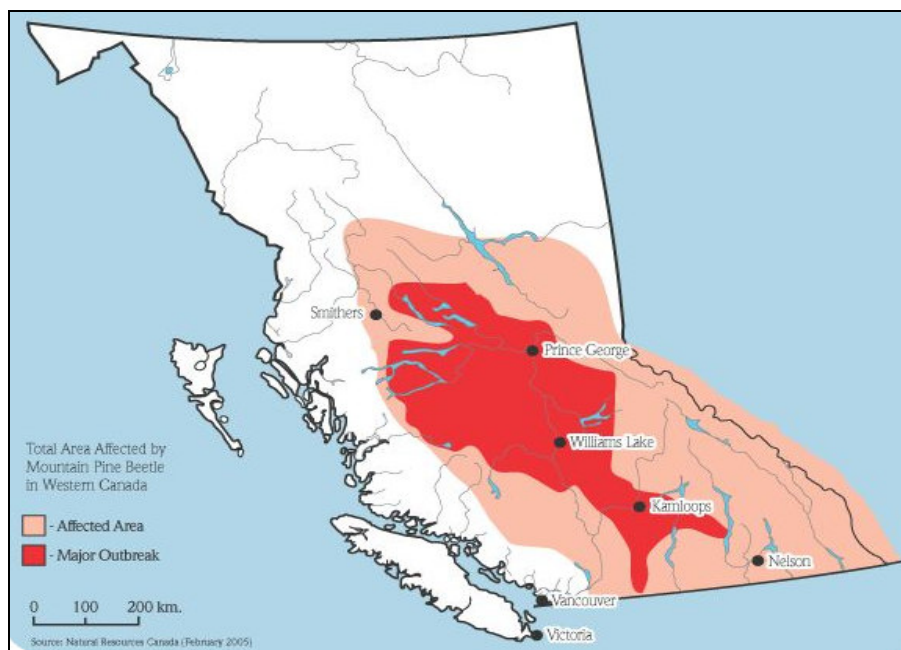


Figure 5.2-3: Pine Beetle Affected Areas in BC

If the WCFP mill re-started, the amount of available biomass feedstock can increase significantly in the Service Area. Also, wood waste from existing logging operations could be used as feedstock for a biomass plant.

From the table below (Table 5-3), it appears that there may be sufficient woody feedstock available in the Anahim Lake Service Area for a biomass power plant of up to 20 MW in size. Based on this and the fact that there have so far been two biomass project proposals submitted in the Cariboo-Chilcotin area, it is reasonable to assume that the biomass feedstock availability is sufficient to merit a more detailed investigation of the feasibility of a biomass project in the area.

Table 5-3: Service Area Biomass Feedstock Potentials

Resource	Potential Bio-fuel Production	Equivalent Biomass Capacity
West Chilcotin Forest Products (WCFP)	Approx 70 million FBM annually (or 0.165 million cubic meters of lumber); Plant produces 11,600 tonnes of sawdust per year	The sawdust from WCFP is enough to produce 6,900 MWh/yr or power a 0.8 MW biomass plant <i>NOTE: This mill is not currently in operation.</i>
Local sawmill residues	A typical BC sawmill will process about 470,000 m ³ of wood per year producing 33,000 tonnes of sawdust and 20,000 tonnes of bark A large BC sawmill (1 million m ³ of wood processed per yr) produces about 70,000 tonnes of sawdust and 40,000 tonnes of bark ^{xii}	Enough wood fuel to power a 3 – 7 MW biomass plant
Pine beetle wood available in the area for harvesting	Using Williams Lake data, we can assume that in the Anahim Lake area, about 1,500 m ³ of pine beetle wood can be harvested per day, or about 300,000 – 500,000 m ³ per year	Enough wood fuel to power a 5 to 15 MW plant
Wood waste from logging operations	As a reference data point, the Tsilhqot'in National Govt which encompasses several communities in the in the Cariboo-Chilcotin region, reported that in 2006, 700,000 m ³ of wood waste was produced in logging operations. We can assume a fraction of this wood waste (50,000 m ³) is available annually for the Anahim Lake area	Enough wood fuel to power a 1 MW plant

5.2.4.1 Transportation of Feedstock

For the Anahim Lake area, the only available transportation option is Highway 20 which runs between Williams Lake and Bella Coola. All logging roads can be accessed by logging trucks.

For biomass power applications, the maximum truck transport distance is generally considered to be around 100 km^{xiii} to merit economic feasibility. But transportation is only 25% of the delivered cost of wood, with actual harvesting operation, or tree-to-roadside costs accounting for most of the cost. This means that reducing transport costs may only have a minor effect on overall process economics, depending on haul distance. All components of feedstock costs such as licensing, harvesting and transportation costs, as well as treatment and processing costs should be considered in order to determine the cost-effectiveness of the use of feedstock.

Infrastructure requirements to cheaply transport pine beetle wood are a challenge in the BC interior. The transportation and processing of pine beetle wood may be more expensive, as conventional methods may need modification (example: conventional open logging trucks may be unsuitable for transporting older and brittle beetle-wood). Also, 70% of the available feedstock is typically only accessible through 'bush roads', which are not suitable to chip trucks. The option of setting up small, mobile plants at harvesting sites to process the pine beetle wood therefore presents a significant logistical challenge for the removal of chips. A most feasible option is to set up a processing plant in or near a town with available electricity.

5.2.4.2 Cost of Biomass Generation

Based on the 25 year forecasted Service Area annual peak load of almost 2MW and demand of 7,500 MWh, an order of magnitude estimate for a biomass project suitable for the Service Area would range from:

- \$5 M to \$12 M in capital costs
- \$800 K to \$1.1 M in annual operating costs

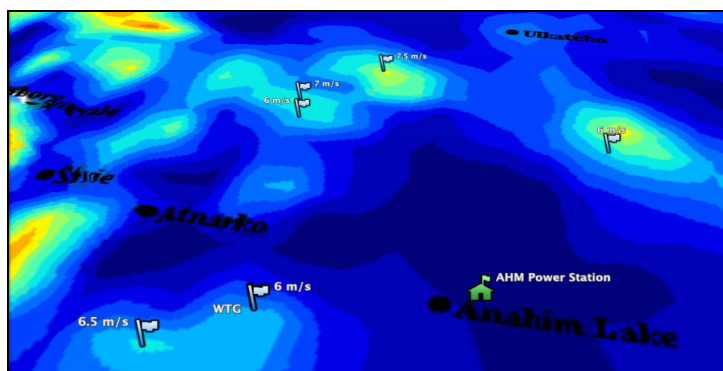
Table 5-4: Biomass Generation Cost Estimates

Cost Type	Typical Estimated Cost
Wood Fuel Cost (total delivered, chipped price) ^{xiv}	\$30/m ³ or \$102/MWh ^{xv} (whole-tree chipping on site); and \$40/m ³ or \$136/MWh (hauling logs and “in bush” chipping)
Installed Capital Cost ^{xvi}	Direct combustion (steam cycle) \$2,500 per kW
	Gasification-combustion \$3,000 per kW
	Pyrolysis-to-turbine \$3,000-\$5,600 per kW
O&M ^{xvii}	\$5.05 per MWh

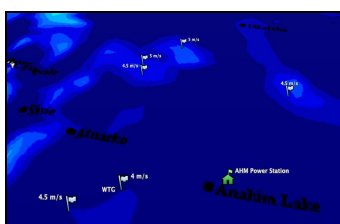
The estimated costs (Table 5-4 above) show the potential for biomass to reduce current annual operating cost of the DGS. At the preliminary screening level, the operating and capital cost estimates indicate that a biomass project may be viable and cost effective for the loads represented by the Service Area.

5.2.5 Wind Power

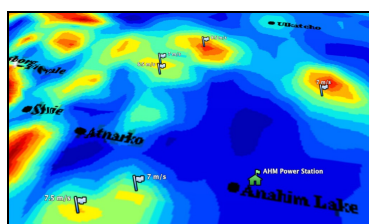
A preliminary evaluation of the wind resource for the Service Area is based on model data from the Canadian Wind Energy Atlas (Figure 5.2-4).



a) Annual Wind Potential



b) Summer Wind Potential



c) Winter Wind Potential

Figure 5.2-4: Modeled Wind Data for the Service area Region

Using the wind data overlaid on topographic information, several sites were identified as potential locations for wind harvest (Figure 5.2-5 below). Potential sites can be seen to range in annual wind speed from 4 m/s to 8.5 m/s. Two locations were selected for further analysis, based on their wind speeds, distance to interconnection and proximity to an existing access road for financial viability.

Distribution of power from the wind site to the power station will account for a significant part of the project cost, so the individual sites were assessed for proximity and access for interconnection to the Anahim Lake power station. The area surrounding the Service area has a small distribution network, with both the northern-most and southern-most points being considered as interconnection points for the turbine sites.

5.2.5.1 Wind Site 1

The first potential turbine location is approximately 1 km from the nearest road up an elevation of approximately 200m. Site 1 is well suited for either a single large turbine, or an array of turbines aligned on the prominent ridge. The road network then can lead back to the southern-most point of the distribution feeder line, which

simplifies potential interconnection to the site. The total distribution line length required would be 24.5 km, including the 1 km run to the nearest road.

Relevant Details of the site are:

- Nominal Elevation1845 m
- Winter Average Wind Speed8.05 m/s
- Summer Average Wind Speed3.75 m/s
- Mean Annual Wind Speed6.22 m/s
- Distance to AHM Interconnection24.5 km (including 1 km over sloped terrain)

5.2.5.2 Wind Site 2

The second potential turbine location is approximately 1.5 km from the nearest road up an elevation of approximately 100m. Site 2 could be suited for either a single large turbine, or an array of turbines aligned on the prominent ridge. The road network then can lead back to the northern-most point of the distribution feeder line, providing a closer point of interconnection. The total distribution line length required would be 18.5 km, including the 1.5 km run to the nearest road. Although the wind resource is slightly lower for Site 2, it has a total distribution line that is 6 km less than Site 1 which can account for significant capital costs associated with distribution.

Relevant Details of the site are:

- Nominal Elevation1660 m
- Winter Average Wind Speed7.47 m/s
- Summer Average Wind Speed3.75 m/s
- Mean Annual Wind Speed5.97 m/s
- Distance to AHM Interconnection18.5 km (including 1.5 km over sloped terrain)

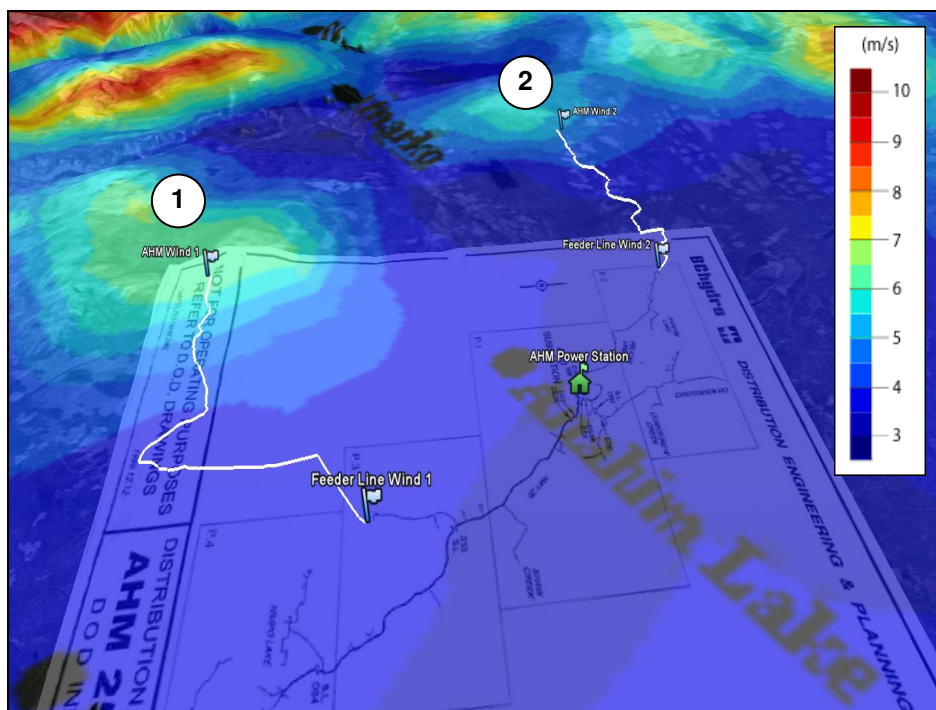


Figure 5.2-5: Potential Wind Sites Near the Service Area

Using the HOMER^{xviii} tool From Homer Energy, an analysis was conducted to evaluate potential turbine configurations able to yield a low to medium penetration of wind energy into the current annual Service Area load (approximately 20% to 40%).

Suitable turbines were selected based on matching performance specifications with the wind characteristics at the particular sites. Potential turbine configurations to be evaluated at both Sites 1 and 2 include:

- a) Up to 5x 100 kW Northwind 100 turbines
- b) Up to 5x 250 kW Fuhrlander 250 turbines
- c) Up to 3x 1,650 kW Vestas V82

Because the model does not allow for escalations of fuel cost or load over the analysis duration, levelized values were used as inputs for fuel cost, diesel generation station maintenance and total annual demand^{xix}.

Assumptions made for this analysis were:

- Cost Amortization Period..... 25 years
- Discount Rate6%
- Levelized Cost of Fuel.....\$0.999 per L
- Levelized Annual Load 6,803 MWh
- Levelized Annual DGS Maintenance\$537,000
- 1,650 kW Turbine Capital Cost\$4,000,000
- 1,650 kW Turbine O&M Cost (per year).....\$12,500
- 250 kW Turbine Capital Cost\$765,000
- 250 kW Turbine O&M Cost (per year).....\$7,000
- 100 kW Turbine Capital Cost\$440,000
- 100 kW Turbine O&M Cost (per year).....\$5,000
- Transmission Costs (along roadway).....\$60,000/km
- Transmission Costs (mountain terrain, includes roads and clearing)\$160,000/km
- Target wind penetration (renewable fraction) ~20% to 30%

The high level HOMER analysis indicates that both potential wind turbine locations will be able to provide a reasonable penetration level, a reduction in diesel fuel and a potential lower cost of energy than the current DGS.

5.2.6 Hydro-Kinetic

There is a rich network of streams and rivers around the Service Area which could present potential for diesel offsetting through hydro-kinetic power generation. Figure 5.2-6 shows the local hydrologic water networks and monitoring stations in the region^{xx}, however, insufficient stream flow data in the area is available to consider a wide variety of options in any detail.

generated during the peak summer months. Unlike wind energy in the area, the solar resource is lower in the winter season when electrical loads are highest.

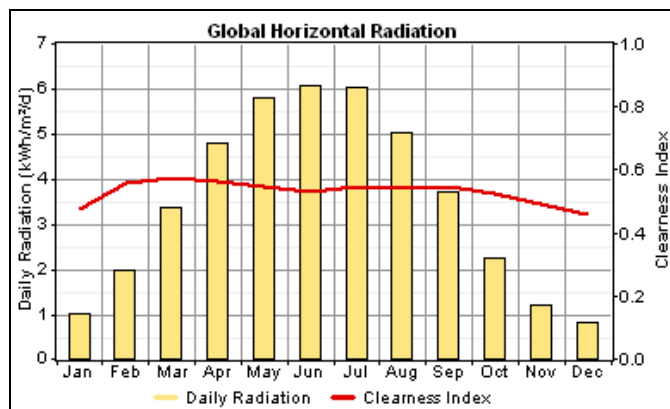


Figure 5.2-7: Solar Insolation and Clearness Index for the Service Area

Typical installed cost for a small residential solar PV system (500W to 1.5 kW), comprised of solar panels, mounting, grid-tie inverter, wiring and installation is approximately \$4,000 to \$15,000.

Using the HOMER^{xxii} tool, an analysis was conducted to evaluate potential solar configurations able to yield a low to medium penetration of solar energy into the current annual Service Area load

For the purpose of this analysis, up to 175kW of combined solar PV is assumed as representing approximately 25% maximum penetration into current summer loads. Due to the modularity of these systems, the total capacity will be assumed to be distributed among a number of houses in the community as individual 1kW residential systems, with the option of interconnection on the residential side of the AC lines so that customers could take advantage of net metering programs in exchange for installation on their properties.

Assumptions made for this analysis were:

- Cost Amortization Period..... 25 years
- Discount Rate 6%

- Levelized Cost of Fuel.....\$0.999 per L
- Levelized Annual Load 6,803 MWh
- Levelized Annual DGS Maintenance\$537,000

- PV System Cost (incl. PV, mounting, wiring, interconnection and install)\$6,300/kW
- Power Converter Cost.....\$650/kW

- Target solar penetration (renewable fraction)25% of summer load

The high level HOMER analysis indicates that for a reasonable sized solar PV installation, the displaced costs of diesel could not offset the initial capital investment. Solar PV and solar thermal energy may be best utilized as a residential DSM strategy, where added incentive is provided through net metering, which provides revenue to the customer when they are a net exporter to the grid.

5.3 Supply Options Analysis

The discussions presented on individual supply options in the previous sections shows that some options may have potential to provide an alternate source of energy in the Service Area while others do not technically or economically seem feasible.

The following summary and assessment (Table 5-6) ranks the options according to the following categories:

- Y** = Yes.....the option is considered viable for the Service Area based on the screening
- C** = Conditional.....the option is not considered viable for the Service Area but could become viable based on other considerations

Table 5-6: Summary of Key Supply Options Findings

	Supply Option	Summary of Key Findings	Other Considerations	Viability
Firm	Diesel Electric	<ul style="list-style-type: none"> Current energy solution Reasonably inexpensive energy, simple to deploy and operate and has proven reliability. Despite moderate energy cost, power is still sold to Zone II customers at subsidized rates. Combustion of fossil fuels resulting in approximately 5000 tons of CO₂ emissions (too small to be a single reportable emitter under Provincial legislation). Diesel generation remains a viable supply option for the Service Area. 	<ul style="list-style-type: none"> Despite the cost effectiveness and reliability, BC Hydro's long term goal is to reduce the environmental footprint of operations. 	Y
	Small Hydro	<ul style="list-style-type: none"> Potential for small hydro run-of-river projects near the Service Area was identified based on an inventory level study. 5 top sites were investigated and found to suggest potentials from 10MW to 27MW. Transmission distances for potential projects range from 12km to 40km. At the preliminary screening level, these cost estimates indicate that a hydro project may be viable for the loads represented by the Service Area. 	<ul style="list-style-type: none"> The desktop level study would need to move to a more detailed exploration of potential small hydro sites, seasonal monitoring of potential river flows and a more detailed design and costing analysis to be undertaken prior to pursuing a small hydro development project. 	Y
	Biomass	<ul style="list-style-type: none"> Of the many biomass conversion technologies, there are several that are suitable for the Service Area loads such as Anaerobic Digestion, Entropic Cycle, Gasification and Pyrolysis. Not all of the potential technologies, however, would be cost effective for the given loads or suitable for the local available feedstock. The region likely represents a sufficient supply of local biomass feedstock to meet the Service Area needs; regional estimate is approximately 5MW to 25MW equivalent capacity. A survey of existing BC biomass facilities suggests potential Service Area project capital costs to range from \$5M to \$12M and operating costs from \$800K to \$ 1M per year. At the preliminary screening level, these cost estimates indicate that a biomass project may be viable for the loads represented by the Service Area. 	<ul style="list-style-type: none"> A more detailed design and costing analysis to be undertaken before a firm assessment of project viability could be made. A large biomass project could also strengthen the case for grid interconnection if significant quantities of power derived from local renewable feedstock could be exported. 	Y

	Supply Option	Summary of Key Findings	Other Considerations	Viability
Variable	Wind Power	<ul style="list-style-type: none"> A wind resource assessment showed good wind potential in 2 sites within reasonable distribution distances from the local AHM 25F51 Service Area grid. Wind speeds at these sites were estimated to range from 3.75m/s to 8m/s. A high level energy model was used to predict the performance of various turbine configurations suggesting that each site had the potential to yield lower overall energy costs through the offsetting of diesel fuel. A single 1.65MW turbine or an array of smaller 250kW turbines were determined to be promising configurations. Displaced diesel fuel potential was assessed up to 650,000L per year. At the preliminary screening level, this analysis indicates that a hybrid wind-diesel project may be viable for the loads represented by the Service Area. 	<ul style="list-style-type: none"> High level modeled wind data estimates were used. For design considerations past the initial pre-feasibility study, typically on-location wind monitoring would be required to verify the wind potential. 	Y
	Hydro-Kinetic	<ul style="list-style-type: none"> An assessment of available hydro-kinetic resources for in-stream generation was limited by the availability of relevant data. Evaluation of the nearby Dean River showed little potential for steady power generation. Hydro-kinetic systems and devices are still in earlier pre-commercial stages of development and are best suited for pilot programs. 	<ul style="list-style-type: none"> Hydro-kinetic power generation may remain of interest and could be considered as a variable power option only if there is interest in further exploration of suitable streams and in pursuing a demonstration project of this nature. 	C
	Solar	<ul style="list-style-type: none"> Solar capacities of up to 175kW were evaluated and found to not lower the total cost of energy based on the cost assumptions made. Reduced diesel consumption has a compelling environmental benefit despite lack of substantial cost savings over the DGS. 	<ul style="list-style-type: none"> There may still be potential for residential level installations and may be considered as part of a broader DSM initiative. 	C

This summary suggests that:

- Biomass, diesel and small hydro represent the potential firm, cost effective supply options for the Service Area loads.
- Wind power represents a potential viable non-firm source to offset fuel use.
- Solar photovoltaic generation, while not necessarily viable under the current assumptions, may present other compelling benefits and when considered in the context of a broader DSM program may have the potential for positive environmental impacts and reduced energy costs.
- Hydro-Kinetic generation, while not necessarily viable based on available data, may warrant further consideration if there is interest in more exploration of suitable streams and in pursuing a demonstration project of this nature.

The above summary outlines the potential viability of each supply option in the context of the Service Area. Other factors, however, will also influence supply choices, such as:

- Social impacts
- Environmental impacts
- Risks

Based on the objectives of this particular CEP, these considerations will not be explicitly considered by means of a qualitative or qualitative analysis.

Grid connection, although not supportable based on current loads in the area, could in the future enable any “excess” generation from a local supply solution to be sold to the integrated grid. This potential could further improve project economics for some of the alternatives listed above.

6 RECOMMENDATIONS

Based on the findings of this study, the following recommendations, listed in priority order, are suggested for consideration.

1. Consider local biomass options through the BC Hydro Community Based Biomass Request for Qualifications (RFQ) or similar power acquisition process. The preliminary supply options assessment presented in this study indicate favourable potential for a firm biomass project to replace the current diesel generation station. The biomass option also reflects local interests. This would enable a switch to a more renewable resource and potentially a lower total cost of energy, while stimulating economic opportunities in the region through the development of a local IPP.
2. Consider a local small hydro project to replace the current diesel generation station. While favourable potential appears to exist for this option, additional analysis will be required with respect to sources and costs.
3. Determine if there is support for a diesel offsetting solution such as a hybrid wind-diesel system. The preliminary screening has shown wind potential to exist and example configurations have shown a potential positive return through the displacement of diesel fuel. The hybrid solution does not necessarily achieve the stated energy goals communicated by the Service Area representatives of achieving maximum sustainability and promoting the use of pine beetle kill, but could achieve a lower cost of energy than the current diesel solution based on the assumptions made. More study is definitely required for this option as wind-diesel systems for mini and microgrids are still a developing area of technical expertise and experience.
4. If support for a hybrid wind-diesel solution has been established, consider deploying wind resource monitoring to verify the assumed wind characteristics used to identify this option as viable. Typically monitoring several points at the selected location for a duration long enough to establish seasonal norms is recommended.

APPENDIX A

Demand Side Management (DSM)

This section explores the potential for electrical energy savings for the Anahim Lake Service Area across a range of potential measures with a focus on energy conservation and fuel switching.

Energy Conservation Measures

BC Hydro Power Smart programs cover a wide variety of energy efficiency and conservation measures. Incentives for energy-efficient products (e.g. lighting, appliances, etc.) and building retrofit incentives (e.g. for insulation upgrades) are examples of energy efficiency initiatives.

A spreadsheet model developed by The Sheltair Group¹ was used to estimate residential energy saving opportunities. The model makes use of HOT2000² housing archetypes; because no specific household information was available, the model was configured with parameters typical of small remote communities.

The baseline case in the Sheltair model predicted residential electricity consumption to be 2,975 MWh which closely matches the actual 2008/09 residential loads. A second scenario incorporated the following energy savings measures which were available in the spreadsheet model:

Measure	Cost of Incentive
• Air leakage sealing	Full
• Single to Double Pane Window Upgrade.....	Full
• Programmable Thermostat.....	Full
• Energy Star Refrigerators and Televisions	Incremental
• Low-Flow Shower Heads/Faucets	Full
• Pipe Insulation.....	Full
• Higher usage of CFLs	Full

End-use	Baseline Consumption (kWhr/yr)			Consumption with DSM Measures (kWhr/yr)		
	Electric	Non-electric	Total	Electric	Non-electric	Total
Space heating	827,000	17,055,000	17,882,000	712,000	14,683,000	15,395,000
Domestic Hot water	701,000	1,192,000	1,893,000	676,000	1,192,000	1,868,000
Appliances	1,447,000	0	1,447,000	1,035,000	0	1,035,000
Total	2,975,000	18,247,000	21,222,000	2,423,000	15,875,000	18,298,000
Potential Savings	-	-	-	18.5%	13.0%	14.0%

The DSM tool estimated the total community cost of the suggested energy efficiency measures at \$1,670,000 or an average of \$4,000 per home. From a customer perspective, the resulting electrical savings yield a total annual residential rate savings of \$40,000³, or an average of \$100 per household. The potential savings to BC Hydro however are much greater since it bears the majority of the cost of service. BC Hydro's annual savings

¹ www.sheltair.com

² HOT2000 is software designed by Natural Resources Canada to estimate annual dwelling energy consumption.

³ Assuming Residential Service Rate for Zone II of \$0.0684 per kWh

would be approximately \$120,000⁴, with a greenhouse gas (GHG) abatement of approximately 350,000 kg CO₂ equivalent.⁵

Fuel Switching

Fuel switching refers to the customer’s ability to choose from a variety of fuel sources to heat their home. The key distinction is between heating with either electricity or alternate fuels such as propane, wood, or oil. The conversion efficiency for producing heat directly from fuel is on the order of 80% to 85% as compared to the 25% to 28% efficiency of converting fuel energy first to electricity. However, this efficiency difference is not always reflected in the price customers pay for their energy.

Due to its geographical location, the Anahim Lake Electrical Service Area experiences a lengthy heating season. Currently, most heating in this area is provided from the direct combustion of fuels such as wood or propane, but there is potential for these loads to switch to electricity in the future. The Service Area has had electricity service provided from BC Hydro since at least 1998 and is beyond the initial post electrification stage where the risk of fuel switching to electricity are highest. The risk of further changes is therefore low, but should be considered. The results of the Sheltaire analysis summarized in the table above estimate the total residential non-electric space heat load to be approximately 17,055 MWh per year or 42 MWh per house per year. This total non-electric energy consumption represents a potential liability for BC Hydro should residents choose to switch these heating loads to electricity.

DSM Discussion

The table below provides an overview of the screening level assessment of DSM options.

	DSM Measure	Potential Benefit (unbundled)	Other Considerations
Energy Conservation	Energy Efficiency	<ul style="list-style-type: none"> Potential to save 550,000 kWhr annually \$40,000 annual potential cost savings to customer (\$100 per household) \$120,000 annual potential cost savings to BC Hydro based on displaced fuel 	<ul style="list-style-type: none"> Estimated cost for implementing the measures is approximately \$1,670,000 or an average of \$4,000 per home
Load Displacement	Fuel Switching	<ul style="list-style-type: none"> The continued use of wood and propane as heating fuels represents 17,055 MWhrs of avoided electricity consumption Avoided demand totals \$330,000 in avoided fuel costs 	<ul style="list-style-type: none"> The potential liability to BC Hydro for non-electric heat is approximately 17,055 MWhr annually or \$3.6M.

It should be noted that each estimate of potential energy savings is stated as an unbundled value (i.e. independent of other measures). Once DSM measures are combined, the combined benefits do not necessarily amount to the sum of individual potentials. The current study has identified opportunities for energy efficiency and risks related to fuel switching in residential buildings. Next steps for BC Hydro should include:

- Further development of BC Hydro’s DSM incentives for NIA communities.
- Obtaining a more detailed and extensive survey of community loads and residential statistics on existing appliances, lighting, heating devices, and building envelope
- Continued emphasis on the use of wood and alternate fuels for residential heating.

⁴ Assuming a diesel generation cost (fuel only) of \$0.215 per kWh

⁵ Calculated based on IPCC guidelines: 2,778 g-carbon/L-diesel, oxidation factor of 0.99. Gross Heat Rate for Anahim Lake taken to be 3.66 kWh/L.

ENDNOTES

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- ⁱ Community Information Sources:
- BC Hydro: Correspondence with NIA personnel
 - Cariboo Regional District: <http://www.cariboord.bc.ca/>
 - Anahim Lake Resort: <http://www.anahimlakeresort.com/anahim.htm#area>
 - Province of British Columbia: <http://www.britishcolumbia.com/regions/towns/?townid=3529>
- ⁱⁱ www.cariboord.bc.ca
- ⁱⁱⁱ Firm power calculated as the total installed capacity not including the largest generator.
- ^{iv} Based on reported system losses of 7.5% in FY08.
- ^v "2008 Tables for NIA Anahim Lake", BC Hydro Power Smart.
- ^{vi} CO₂ calculated based on IPCC guidelines: 2,778 g-carbon/L-diesel and an assumed oxidation factor of 0.99.
- ^{vii} BCH Fuel consumption and fuel cost data: "AHMdataajk'100129.pdf" courtesy of Alan King.
- ^{viii} WCFP Newsletter, December 20, 2007: <http://www.wcforestproducts.com/WCFP-Newsletter.html>
- ^{ix} 25 year energy costs assume a 2.15% annual fuel price inflation and a 6% real discount rate.
- ^x "Phase 1 Distributions Options for Anahim Lake", BC Hydro Engineering, May 2007
- ^{xi} "Anahim Lake Transmission Interconnection Conceptual Study – Draft", BCTC, December 10, 2009
- ^{xii} "An information guide on pursuing biomass energy opportunities and technologies in BC", 2008
- ^{xiii} "An Information Guide on Pursuing Biomass Energy Opportunities and Technologies in BC", Report 2008.
- ^{xiiii} Concawe 2002, p.13
- ^{xv} Based on costs to harvest and haul lodge pole pine in the Prince George region of BC (source: NRCan Bioenergy options for woody feedstock report).
- ^{xvi} Assuming 30,000 cubic meters of wood residue is consumed per MW per year
- ^{xvii} Using costing information for the construction of the Saginaw Chippewa Soaring Eagle Resort 5 MW Wood-fired Steam CHP Plant; and An Information Guide on Pursuing Biomass Energy Opportunities and Technologies in BC, 2008, By BIOCAP
- ^{xviii} Same as above and Feedstock Availability and Power Costs Associated with Using BC's Beetle Infested Pine, 2005, Report prepared for BIOCAP Canada Foundation.
- ^{xix} Hybrid Optimization Model for Electric Renewables (HOMER) - modelling and analysis tool developed by the National Renewable Energy Laboratory (NREL) and distributed by HOMER Energy LLC.
- ^{xx} Levelized energy costs were derived from the current costs stated in Section 3.6, the demand forecast, and 2% inflation on O&M and fuel delivery costs and a 6% real discount rate.
- ^{xxi} Hydrologic Maps adapted from Environment Canada.
- ^{xxii} <http://eosweb.larc.nasa.gov/sse/>
- ^{xxiii} Hybrid Optimization Model for Electric Renewables (HOMER) - modelling and analysis tool developed by the National Renewable Energy Laboratory (NREL) and distributed by HOMER Energy LLC.