Ea Energy Analyses

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FINAL REPORT

Cowichan Valley Energy Mapping and Modelling

REPORT 3 – ANALYSIS OF POTENTIALLY APPLICABLE DISTRIBUTED ENERGY OPPORTUNITIES

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Acronyms and abbreviations

AUC – Actual use codes
BAU – Business-as-usual
BC – British Columbia
BCAA – British Columbia Assessment Authority
BIMAT – Biomass Inventory Mapping and Analysis Tool
CEEI – Community Energy & Emissions Inventories
CIBEUS – Commercial and institutional building energy use survey
CRD – Capital Regional District
CVRD – Cowichan Valley Regional District
DEM – Digital elevation model
EE – Energy efficiency
ESHA – European Small Hydropower Association
EOSD – Earth Observation for Sustainable Development of Forests
ESRI – Environmental Systems Resource Institute
GHG – Greenhouse gas
GIS – Geographic Information System
HVAC – High voltage alternating current
JUROL – Jurisdiction and roll number
LIDAR – Light detection and ranging
MSW – Municipal solid waste
NEUD – National energy usage database
NRC – Natural Resources Canada
OCP – Official community plans
O&M – Operation and maintenance
PRISM – Parameter-elevation regressions on independent slopes model
RDF – Refuse derived fuel
RDN – Regional District of Nanaimo
RE – Renewable energy
RMSE – Root mean square area
SSE – (NASA's) Surface meteorology and Solar Energy (dataset)
TaNDM – Tract and neighbourhood data modelling

Contents

1 Introduction

Overall project

The following report is the third in a series of six reports detailing the findings from the Cowichan Valley Energy Mapping and Modelling project that was carried out from April of 2011 to March of 2012 by Ea Energy Analyses in conjunction with Geographic Resource Analysis & Science (GRAS).

The driving force behind the Integrated Energy Mapping and Analysis project was the identification and analysis of a suite of pathways that the Cowichan Valley Regional District (CVRD) can utilise to increase its energy resilience, as well as reduce energy consumption and GHG emissions, with a primary focus on the residential sector. Mapping and analysis undertaken will support provincial energy and GHG reduction targets, and the suite of pathways outlined will address a CVRD internal target that calls for 75% of the region's energy within the residential sector to come from locally sourced renewables by 2050. The target has been developed as a mechanism to meet resilience and climate action target. The maps and findings produced are to be integrated as part of a regional policy framework currently under development.

GIS mapping of renewable potentials

The first task in the project was the production of a series of thematic GIS maps and associated databases of potential renewable energy resources in the CVRD. The renewable energy sources mapped were solar, wind, micro hydro, and biomass (residues and waste). Other sources were also discussed (e.g. geothermal heat) but not mapped due to lack of spatially explicit input data. The task 1 findings are detailed in a report entitled 'GIS Mapping of Potential Renewable Energy sources in the CVRD'.

GIS mapping of regional energy consumption density

The second task in the overall project was the mapping of regional energy consumption density. Combined with the findings from task one, this enables comparison of energy consumption density per area unit with the renewable energy resource availability. In addition, it provides an energy baseline against which future energy planning activities can be evaluated. The mapping of the energy consumption density was divided into categories to correspond with local British Columbia Assessment Authority (BCAA) reporting. The residential subcategories were comprised of single family detached dwellings, single family attached dwellings, apartments, and moveable dwellings. For commercial and industrial end-users the 14 subcategories are also in line with BCAA Assessment as well as the on-going provincial TaNDM project of which the CVRD is a partner. The results of task two are documented in the report 'Energy Consumption and Energy Density Mapping'.

Analysis of potentially applicable distributed energy opportunities

The third task built upon the findings of the previous two and undertook an analysis of potentially applicable distributed energy opportunities. These opportunities were analysed given a number of different parameters, which were decided upon in consultation with the CVRD. The primary output of this task was a series of cost figures for the various technologies, thus allowing comparison on a cents/kWh basis. All of the cost figures from this task have been entered into a tailor made Excel model. This 'technology cost' model is linked to the Excel scenario model utilised in task 4. As a result, as technology costs change, they can be updated accordingly and be reflected in the scenarios. Please note, that the technologies considered at present in the technology cost model are well-proven technologies, available in the market today, even though the output is being used for an analysis of development until 2050. Task 3 results are detailed in this report and both presents an initial screening for various local renewable energies, and provides the CVRD with the means of evaluating the costs and benefits of local energy productions versus imported[1] energy.

Analysis of opportunity costs and issues related to regional energy resilience

Based on the outputs from the above three tasks, a suite of coherent pathways towards the overall target of 75% residential local energy consumption was created, and the costs and benefits for the region were calculated. This was undertaken via a scenario analysis which also highlighted the risks and robustness of the different options within the pathways. In addition to a direct economic comparison between the different pathways, more qualitative issues were described, including potential local employment, environmental benefits and disadvantages, etc.

The main tool utilised in this analysis was a tailor made Excel energy model that includes mechanisms for analysing improvements in the CVRD energy system down to an area level, for example renewable energy in residential buildings, renewable energy generation, and the effects of energy efficiency improvements. For the industrial, commercial, and transport sectors, simple and generic forecasts and input possibilities were included in the model.

The Excel 'technology cost' and 'energy' models are accompanied with a user manual so that planners within the CVRD can become well acquainted with the models and update the figures going forward. In addition, hands on

[1] The term 'imported' here refers to energy imported from outside of the CVRD

instruction as to how to link the Excel model with GIS maps was also provided to both planners and GIS professionals within the CVRD and associated municipal organisations.

Task 4 results are detailed in a report entitled 'Analysis of Opportunity Costs and Issues Related to Regional Energy Resilience'.

GIS mapping of energy consumption projections

Task 5 focused on energy projection mapping to estimate and visualise the energy consumption density and GHG emissions under different scenarios. The scenarios from task 4 were built around the energy consumption density of the residential sector under future land use patterns and rely on different energy source combinations (the suite of pathways). In task 5 the energy usage under the different scenarios were fed back into GIS, thereby giving a visual representation of forecasted residential energy consumption per unit area. The methodology is identical to that used in task 2 where current usage was mapped, whereas the mapping in this task is for future forecasts. The task results are described in the report 'Energy Density Mapping Projections'. In addition, GHG mapping under the various scenarios was also undertaken.

Findings and recommendations

The final and sixth report presents a summary of the findings of project tasks 1-5 and provides a set of recommendations to the CVRD based on the work done and with an eye towards the next steps in the energy planning process of the CVRD.

1.1 Motivation for the study

One of the motivations behind the overall study was to increase the resilience of the CVRD communities to future climate and energy uncertainties by identifying various pathways to increase energy self-sufficiency in the face of global and regional uncertainty related to energy opportunities, identification of energy efficiencies and mechanisms, and identify areas where local energy resources can be found and utilised effectively. Overall this strategy will reduce reliance on imported energy and the aging infrastructure that connects Vancouver Island to the mainland. Investigating future potential scenarios for the CVRD, and Vancouver Island as a whole, makes it possible to illustrate how this infrastructural relationship with the mainland could evolve in years to come.

This work supports the overall development of sustainable communities by:

- Increasing community resilience to price and energy system disruptions,

- Increased economic opportunities both at a macro energy provision scale and the development of local economies which support alternative energy systems and maintenance of those systems,
- Potential economic development by way of community based heat and power facilities which could be owned and operated by the community,
- Identification and exploitation of low cost low impact energy sources,
- Provision of a consistent overall strategic policy and planning framework for community planning,
- Incorporation of clearly defined energy policies in OCP and development permit and growth documents
- Developing early strategies for the development of energy systems and infrastructure programs, particularly with regards to district heat or heat and power programs.

1.2 CVRD overview

Geography

The Cowichan Valley Regional District is located on the southern portion of Vancouver Island in British Columbia, Canada and covers an area of nearly 3,500 km^2. It consists of 9 electoral areas, 4 municipalities, and aboriginal lands, and has a total population of roughly 82,000 people. It is bordered by the Capital Regional District (CRD) to the south, which while roughly 2/3 in size, has a population of approximately 350,000 and is home to the Province's capital, Victoria. To the northeast, the CVRD is bordered by the Nanaimo Regional District (NRD) which has a land area of just over 2,000 km^2 and a population of roughly 140,000. Lastly, to the northwest the CVRD is bordered by the Alberni-Clayoquot Regional District, home to just over 30,000 people spread over a land area of nearly 6,600 km^2.

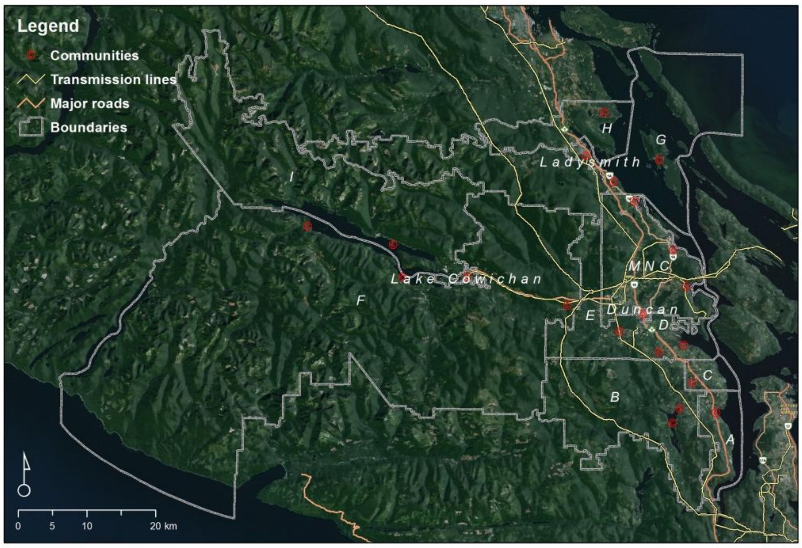

Figure 1: Map of the Cowichan Valley Regional District and its administrative areas (GRAS).

The fact that the vast majority of the population centres within the CVRD are concentrated along the east coast, with very little along the western portion is of great relevance when identifying potential energy generation sources, both with respect to physical access to sites, and proximity to electricity transmission and distribution networks. Figure 1 on the previous page illustrates this.

Energy consumption

Based on 2007 data[2], the CVRD as a whole had an energy demand of nearly 10 PJ or 2.7 TWh (for reference purposes an energy conversion factor is included as appendix 1). As depicted in the figure below, well over half of this went to road transport, slightly over a third to residential buildings, and just under 14% was used by commercial and small-medium industrial buildings.

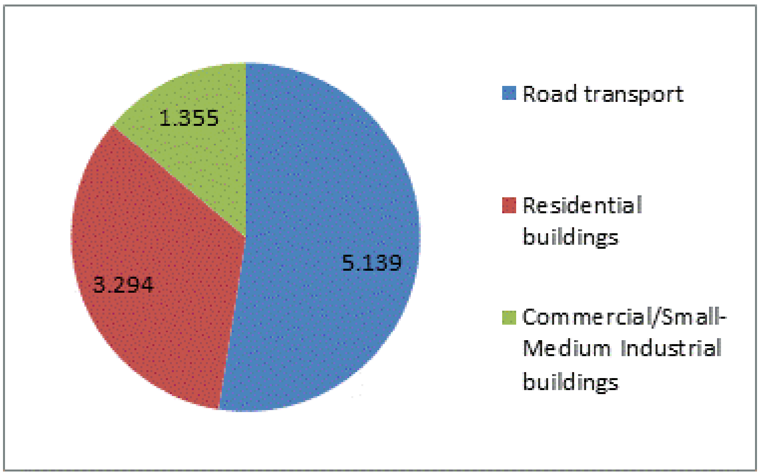

Figure 2: 2007 CVRD total energy consumption by sector (TJ) excluding large industrial users and Indian Reserves (BC Ministry of Environment, 2010).

In terms of fuel use by sector, it is thus not surprising that over 40% of the CVRD's energy needs are met by gasoline and 12% by diesel. Within buildings segment of consumption, the dominant sources are electricity, natural gas, wood, and heating oil. More specific breakdowns of these usages are displayed in the figure below.

[2] Excluding large industrial. Figures are withheld in CEEI publications when there are too few installations, as is the case with large industry in the CVRD.

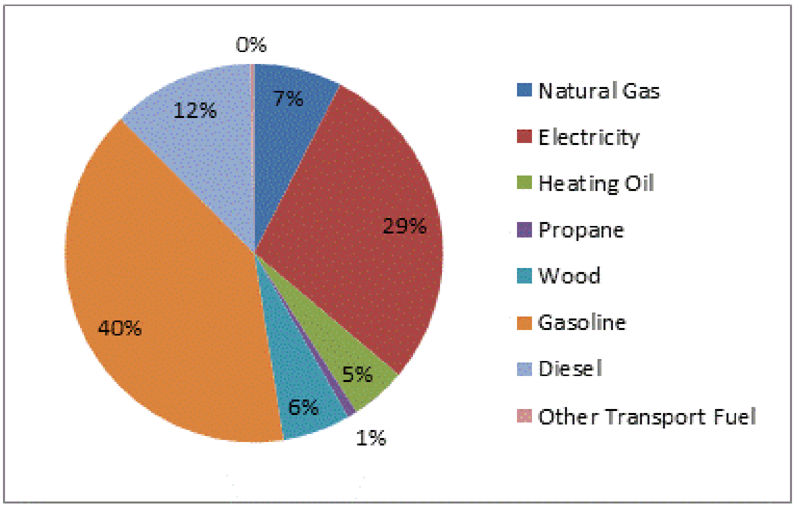

Figure 3: 2007 CVRD total energy consumption by source (TJ) excluding large industrial users and Indian Reserves (BC Ministry of Environment, 2010).

If we look at the residential sector which is the major focus of this project and is depicted in the figure below, the dominant inputs are electricity, wood, heating oil, and natural gas. It is worth noting that roughly 60% of residential dwellings are today heated via direct electric heating (i.e. electric baseboard heating), a phenomenon that is largely explained by the relatively cheap electricity that has historically been available in BC.

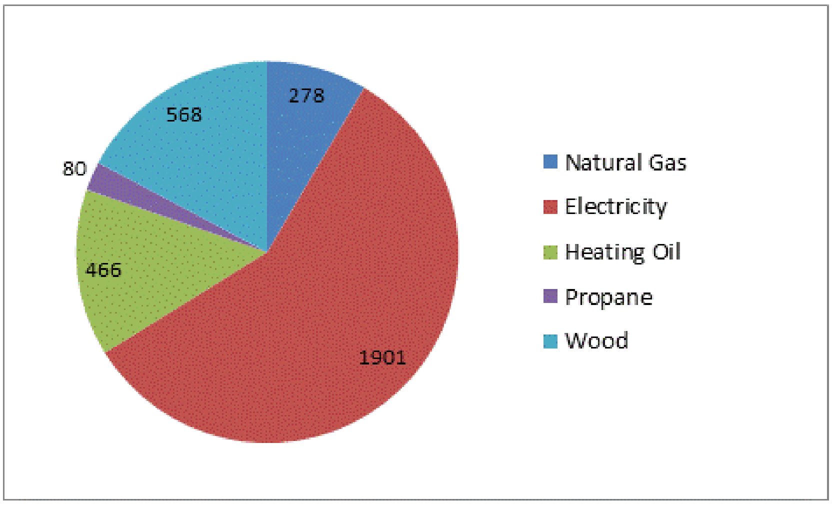

Figure 4: 2007 CVRD residential sector energy use (TJ) (BC Ministry of Environment, 2010).

Vancouver Island energy supply

Vancouver Island as a whole produces less than a third of its electricity consumption, with the remainder being supplied via undersea cables from the mainland. The largest of these connections is referred to as the 'Cheekye-Dunsmuir' which consists of two 500-kV HVAC lines and has an operational capacity of 1,450 MW (the red lines in the figure below). The other major connections are the 'HVDC Pole 2' connection from the Arnott (ARN) terminal station near Ladner on the mainland to the Vancouver Island Terminal (VIT) station located near Duncan with an operational capacity of roughly 240 MW, and the ‘2L129’ connection also from ARN to VIT with an operational capacity of roughly 243 MW. (BC Hydro, 2011) The figure below displays the Vancouver Island transmission system as of October 2007, and as a result the new 2L129 connection is not depicted on the map.

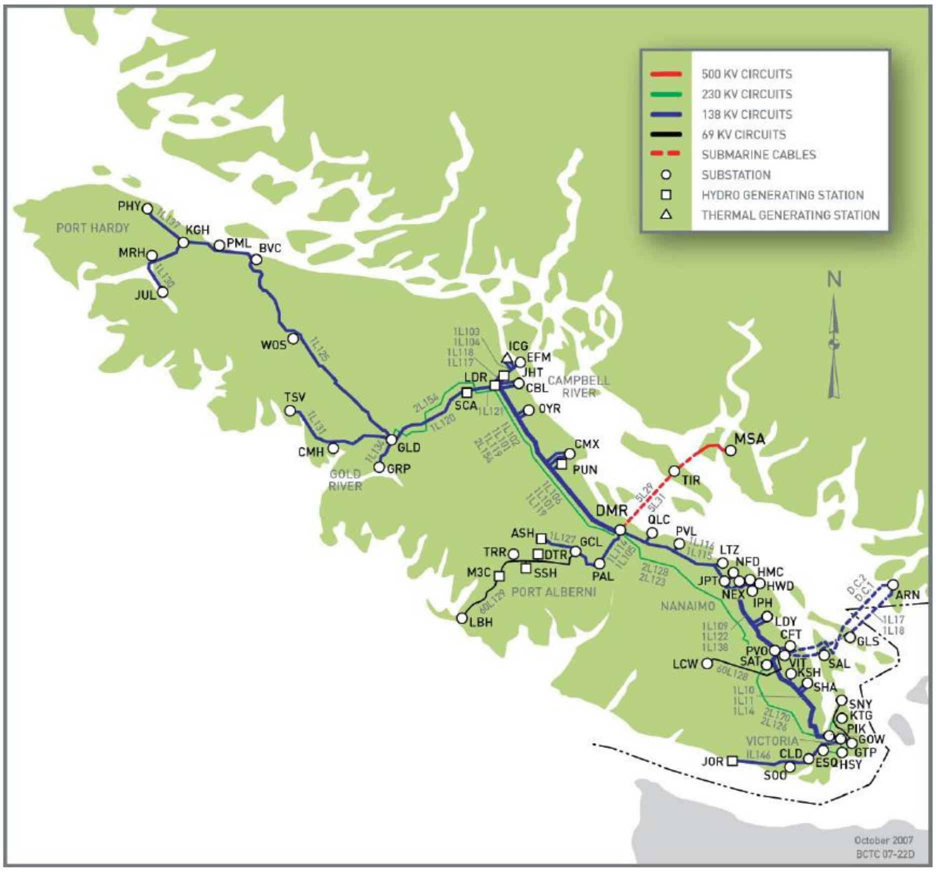

Figure 5: Vancouver Island Transmission network as of October 2007 (BC Hydro, 2007).

The majority of Vancouver Island’s electricity is produced north of the CVRD, with the sole exception being the Jordan River facility located on the southern coast of the island. With the exception of the Elk Falls natural gas fired facility near Campbell River, all the electricity production on Vancouver Island currently comes from hydro, although new wind farm projects are in development in the Northern portion of the island.

CVRD energy supply

The CVRD therefore imports all of its electricity, some of it produced on the northern portion of the island, but a great deal of it is produced on the mainland. In addition all gasoline, diesel, natural gas, heating oil and propane are also imported from outside of the CVRD. As such roughly 95% of the CVRD’s total energy demand is currently imported, with wood being the only local energy source.

GHG emissions

In terms of GHG emissions, the vast majority of the CVRD's GHG emissions can be attributed to road transport. Transport accounted for over 350,000 tonnes of CO_2 equivalent in 2007, or roughly 70% of the CVRD's total (503,000 - excluding large industrial emitters). In this report the term 'CO_2' is used synonymously to CO_2 equivalents.

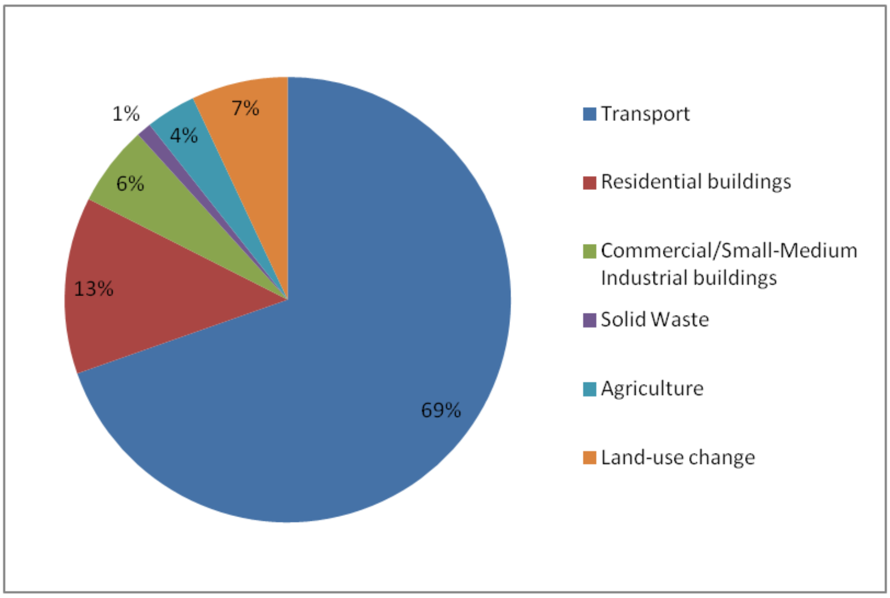

Figure 6: 2007 CVRD GHG emissions according to source excluding large industrial users and Indian Reserves. Total emissions were just over 503,000 tonnes of CO_2 (BC Ministry of Environment, 2010)

When calculating GHG emissions from electricity in British Columbia the CEEI reports utilise a CO_2 intensity of 24.7 g CO_2/kWh, as this represents the average amount of CO_2 found in electricity produced in British Columbia (CEEI, 2010). However, BC also imports and exports electricity, and when this is factored into the equation the average CO_2 intensity of electricity flowing through the power lines is over 3.5 times higher, at roughly 84 g CO_2/kWh (Pembina, 2011). It could be argued that using this latter figure when calculating GHG emissions is a more accurate representation of the actual carbon footprint from the use of electricity in BC. Doing so would increase CVRD residential sector emissions by roughly 50%, but transport related emissions would still be the most dominant source with well over 60% of CVRD emissions.

1.3 Report structure

Each resource has been designated its own chapter, which is presented using the following structure:

1. A backgrounder on the energy resource or technology
2. An analysis of financial data for the resource or technology

3. Where applicable, a link between renewable resources mapping completed in task 1 to specific high potential opportunities, taking into account locational parameters at the site.

1.4 Methodology

For each considered renewable resource, the production and distribution costs are based on a set of assumptions on capital costs, infrastructure maintenance and operation costs, and the efficiency of typical systems. Local parameters such as temperature, proximity factors, site specific resource characteristics, energy prices, and special interest rates are taken into consideration. Cost is expressed in cents/kWh and for GIS mapping purposes estimated on a raster cell basis across the CVRD.

Data

Whenever possible local data has been utilised, however in the case of gaps in CVRD or BC data, these have been supplemented with European data. All cost calculations exclude HST.

Model link

All production and cost figures are contained in the tailor made Excel based 'technology cost model', which is linked to the Excel based 'energy model' utilised in task 4. As production and cost figures change, data can be updated in the 'technology cost model' and be automatically reflected in the scenario results of the 'energy model'.

2 Increased energy efficiency in buildings

EE as a means to high proportion of RE

A strategy to build energy resilience must not only include the provision of renewable energy but also efforts to limit the demand for energy services, as well as the energy efficiency with which this demand is met. The smaller the demand for energy services and the more efficient the consumption of energy, the less energy is needed and the higher the potential share of renewable energy available in the total energy supply. Furthermore, curbing the need for energy services and increasing energy efficiency can help de-couple energy consumption from economic growth.

Building envelope

Heating and cooling of buildings makes up a large portion of total energy traditionally consumed. Any decisions concerning the building envelope impacts the energy consumption for many years to come as buildings typically have a lifetime of 50+ years. The location and positioning of buildings also has an impact on energy consumption and the possibilities for cost-effective sustainable energy supply.

The energy demand for heating and cooling buildings is best addressed at the time of construction. Building regulations were first introduced to ensure sound construction and safety, but have since been expanded to include requirements concerning the energy footprint of buildings. Requirements may relate to specific elements of the construction such as windows or to the entire building as a whole (i.e. the 'energy frame'). The advantage of using an energy frame approach is that it provides flexibility in terms of the overall building design and can be more easily adjusted as more efficient solutions become available. In addition it is also more holistic and looks at the interactions between various building elements. The latter 'energy frame' approach can potentially be more difficult to measure and/or incentivise, and therefore a combination of energy frame and specific requirements may result in the most cost-effective and robust solution.

Capacity building

Training architects and building entrepreneurs in energy efficient design of new buildings can influence choices about energy intensive heating/cooling and the use of artificial lighting. Key topics in this training might include: optimising daylight, solar radiation and natural ventilation, as well as impact decisions about choice of materials and choice of building elements. Study questions might include: building and room orientation in relation to daylight heating/cooling systems, and natural ventilation; segregating overhead lighting in a room into smaller sections, so as to allow that only lights in the darkest parts of a room need be switched on.

Many building design and rating systems currently exist to guide the design and relative ranking of the wide array of choices and trade-offs in building development. The most widely accepted of these are Leadership in Energy and Environmental Design (LEED), Green Build and Green Globe. Specialised expertise can be utilised for specific areas of energy analysis such as envelope design and audits, building commissioning and lighting design.

Civil planners and policy makers also have a role to play, and could make decisions that, for example, position new buildings in areas close to a sustainable energy supply and/or establish development legislation/by-laws that could include requirements concerning choice of energy supply (e.g. a requirement to contract with a nearby district heating system).

At the immediate homeowner level the building inspectors have a substantial role to play both in the maintenance of data (for example the data utilised in the energy model within this project, which will be further detailed in the next report in this series), but most importantly in the direct communication with the public. Building inspectors could also serve an important function as energy auditors to provide additional services and support for the overall transformation of both the existing and future building stock.

With regards to existing building stock, the gradual need for renovation can be used as an opportunity to improve a building's energy footprint. Compared to upgrading the insulation as a stand-alone project, it is for example easier and less costly to improve the insulation of a building while undertaking a roofing renovation.

Educating builders, contractors and architects on the latest building regulations and energy efficient solutions are important to realising the energy efficiency improvement potential of existing buildings.

Costing of energy efficiency

This study did not investigate the costs of improving energy efficiency in buildings, but did include an energy efficiency factor in the scenario analyses so that efficiency gains could be quantified in terms of the potential savings to be generated.[3]

[3] Please consult reports 4 and 5 for more about the energy model and scenario analysis. As a point of departure the assumptions used by the Pembina Institute's 'Green Building Leaders' report regarding

3 Wind generated electricity

3.1 Background

Annual wind energy production depends on wind quality, the rotor area ('swept area'), and the generator capacity. As wind is what is referred to as a 'fluctuating' or 'intermittent' energy source, it is best exploited in combination with other types of renewable energy (such as reservoir hydro power with its storage potential) to achieve optimal overall output in relation to investment.

Turbine type

While various wind turbine models have been utilised since the modern version of this technology was first introduced, the model that has come to dominate the market today is the three-bladed rotor mounted on a horizontal axis. The mechanics of this design operate around a gearbox and asynchronous generator driven by the rotor, whose speed is controlled by pitching or stalling the blades depending on whether a higher or lower speed is needed.

Wind speed

The minimum operational speed required for a traditional horizontal axis turbine is 3-4 meters per second (m/s), the maximum is in the range of 25 m/s, and the optimum speed for power generation is obtained at approximately 8 m/s. Factors influencing wind speed and turbulence include the roughness of the ground surface and the height from ground to turbine hub.

Scale

Stand-alone wind turbines, or turbines in wind parks, can produce electricity at a number of scales, i.e., household, institutional, regional, etc. The size of a wind turbine is determined by the size of its generator. Thus a 2,000 kW turbine (more commonly referred to as a 2 MW turbine) has a 2,000 kW generator, meaning that its peak output at any point in time is 2,000 kW. Wind turbines can be categorised by the following sizes[4]:

Large – 800-4,000 kW
Small – 5-500 kW
Household – 5-25 kW
Micro – 0.5-1.5 kW

However it is worth noting that turbine size continues to increase, particularly offshore turbines.

renovation rates, % annual tear downs, and annual average improvements to meet building code were applied to the base scenario assumptions.

[4] "Technology Data for Energy Plants", Danish Energy Agency and Energinet.dk, June 2010

Due to the resolution of data, site compounding factors, and the relatively high electricity production cost associated with smaller wind turbines, within the CVRD project the focus was on a regional scale, i.e. larger wind turbines that feed into the electricity grid.

Siting

Onshore

Onshore wind turbines can be sited individually, in small clusters, or in large groups (i.e. wind parks). In an onshore scenario, the turbines are typically placed on the ground but in some cases small wind turbines can also be mounted on roofs. Roof mounted wind turbines can result in noise and vibration, which may cause problems for building users. As such roof-mounted wind turbines are not widely used.

Offshore

Siting wind turbines offshore in shallow water (coastal areas) or further out at sea can be a means to overcoming a lack of suitable onshore sites due to high ground level roughness. Most often off-shore wind turbines are grouped together in wind parks with a joint grid connection to the shore.

Moving from land to water, however, would increase capital costs to build the necessary foundation and explains why larger turbines are often used in offshore systems. The following table shows how foundation costs increase with increased water depth. Foundation costs may constitute 25% of the total structure cost while the turbine cost is roughly 50% (DEA 2010).

Water depth (m)	10	20	30	40
Foundation costs (EUR/W)	0.43	0.66	1.0-1.1	1.4-1.9
(CAD/W)	0.60	0.92	1.4-1.5	1.5-2.7

Table 1: Foundation costs (DEA 2007). Applied conversion rate: 1 EUR = 1.4 CAD).

Other siting considerations

Other important considerations when looking at siting of onshore wind turbines include: distance to buildings and roads, noise, flickering light/shadow due to the moving blades, and aesthetic visual impact. In the siting of offshore wind turbines concerns also exist regarding disturbances to the environment. Apart from the disturbance resulting from the construction phase, appropriate siting can ensure minimal negative impacts on the marine environment. In fact, some studies have even indicated that there are positive ecological effects related to offshore parks, including the establishment of new species and fauna communities, and new types of habitats with greater biodiversity (Lindeboom et al. 2011).

Risk of bird collision for both onshore and offshore turbines has been discussed at length, but a study by Risoe National Laboratory for Sustainable

Energy (Lemming et al. 2009) showed that bird death due to collision is less than one bird per year and thus not a major concern.

Public acceptance

Another aspect to be considered in any wind project is public acceptance. As with all other major public construction work, a hearing process is typically called for, but to strengthen public acceptance of a project stakeholder involvement can help identify appropriate locations for the wind turbines. In addition, applying a joint ownership model can help increase local support for wind projects.

3.2 Financial analysis

Onshore wind

Wind turbines are usually optimised to extract the maximum share of the energy at wind speeds of around 8 m/s. Below 4 m/s a wind turbine will seldom produce any energy. The CVRD has a number of areas with wind regimes of 4 m/s and lower, but the CVRD's best wind regimes have annual average wind speeds of 6-8 m/s at 80 metres above ground level.

Capacity factor

The capacity factor of a wind turbine is defined as the potential annual electricity generation as a share of the maximum possible generation. A 2 MW turbine could generate 8,760*2 = 17,520 MWh/year, if operated at the rated power (rated power is another term for the size of the wind turbine's generator) throughout the 8,760 hours of a year. With a capacity factor of 30%, the turbine will in reality generate 17,520*0.30 = 5,256 MWh/year.

For annual average wind speeds in the range of 5-9 m/s, there is an almost linear relationship between the average wind speed at hub height and the capacity factor, (EWEA 2009):

Capacity factor (%) = 16 + (wind speed – 5) * 6

Average annual wind speed at hub height	Capacity factor (%)
5	16
6	22
7	28
8	34
9	40

Table 2: Capacity factor according to wind speed (EWEA 2009)

It should be noted, however, that these values can only be taken as a generic rule-of-thumb. For a specific site, a thorough wind resource assessment is required.

Investment costs

The investment cost of a modern wind farm, consisting of 2-3 MW wind turbines, is approximately (DEA, 2010)[5]:

Year of installation	Investment cost (million CAD per MW)
2010	1.96
2030	1.68
2050	1.62

Table 3: Investment cost of a modern wind farm, consisting of 2-3 MW wind turbines (DEA, 2010)

Assuming that the entire investment is loan-financed with an interest rate of 5% per year and 25-year amortization, these investments costs translate into the following annual capital costs:

Year of installation	Capital cost (CAD per MW per year)	Operation and maintenance costs (cents/kWh)
2010	139,067	1.82
2030	119,200	1.61
2050	115,227	1.54

Table 4: Annual capital costs and operation and maintenance costs for a modern onshore wind farm (DEA, 2010).

Operations and maintenance

The O&M cost data are taken from the same publication as investment cost data. The total generation cost (excluding grid connection costs) equals:

Capital cost / Annual generation + O&M cost

Total generation cost

Based on this equation, the total generation cost of wind electricity can be calculated as a function of annual average wind speed at hub height and time:

Average annual wind speed (m/s)	Total generation costs (cents/kWh)		
	2010	2030	2050
5	11.74	10.11	9.76
6	9.04	7.80	7.52
7	7.49	6.47	6.24
8	6.49	5.61	5.41
9	5.79	5.01	4.83
BC Hydro electricity price[6]	8.27	11.93	13.10

Table 5: Cost of onshore wind as a function of annual average wind speed at hub height. The BC Hydro average electricity price is included for reference purposes, but unlike the wind costs, it includes transmission, distribution, and flat fees.

[5] Prices were converted to Canadian dollars using an exchange rate of 1 EUR = 1.4 CAD.

[6] Based on a weighted average. Under the Residential Conservation Rate, customers pay 6.67 cents per kWh for the first 1,350 kWh they use over an average two-month billing period. Above that amount, customers pay 9.62 cents per kWh for the balance of the electricity used during the billing period. Assuming a 35% increase from 2010 to 2020, a 9% increase from 2020 to 2030 and a 5% increase from 2030 to 2040 and 2040 to 2050. https://www.bchydro.com/youraccount/content/residential_bill.jsp

As an example, for 2010 and a wind speed of 7 m/s the generation cost is calculated as follows:

Capital cost / (operating hours * capacity factor) + O&M costs =

139,067 / (8,760*0.28) + 18.2 = 7.49 cents/kWh

Onshore cost summary

It is anticipated that generation costs for onshore wind will decrease for all wind speeds over the next 40 years. However, as it is the wind speed at the individual site that is the most important variable it is not possible to pinpoint a particular point in time when offshore wind in general becomes financially viable. With high enough wind speeds some projects will already be viable today, while others with lower wind speeds will become increasingly more economically attractive as costs decrease.

Offshore wind

Calculating the total generation cost of an offshore wind turbine system follows the same approach as for an onshore wind turbine system.

Capacity factor

For annual average wind speeds in the range of 7-11 m/s, the relationship between the average wind speed and the capacity factor can still be approximated by a linear function, although slightly different (EWEA, 2009):

Capacity factor (%) = 31 + (wind speed – 7) * 3.9

Investment and O&M costs

The investment cost of a typical offshore wind farm, consisting of 3-10 MW wind turbines and including landfall costs, is represented in the table below and depicts a gradual reduction in cost over time (DEA, 2010):

Year of installation	Investment cost (million CAD per MW)
2010	3.78
2030	3.08
2050	2.80

Table 6: Investment cost of an offshore wind farm, consisting of 3-10 MW wind turbines.

Assuming that the entire investment is loan-financed with an interest rate of 5% per year and 25-year amortization, these investments translate into the annual capital costs in Table 7. The table also includes the offshore O&M costs (DEA, 2010):

Year of installation	Capital cost (CAD per MW per year)	Operation and maintenance costs (cents/kWh)
2010	268,200	2.52
2030	218,534	2.10
2050	198,667	1.96

Table 7: Annual capital costs and operation and maintenance costs for an offshore wind farm.

Total generation costs

The total generation cost (excluding grid connection costs) equals:

Capital cost / Annual generation + O&M cost

Based on this equation, the total generation cost of wind power, as a function of annual average wind speed at hub height and time, is:

Average annual wind speed (m/s)	Total generation costs (cents/kWh)		
	2010	2030	2050
7	12,40	10.15	9.28
8	11.29	9.25	8.46
9	10.41	8.53	7.81
10	9.69	7.94	7.27
11	9.09	7.45	6.83
BC Hydro electricity price[7]	8.27	11.93	13.10

Table 8: Cost of offshore wind as a function of annual average wind speed at hub height. The BC Hydro average electricity price is included for reference purposes, but unlike the wind costs, it includes transmission, distribution, and flat fees.

Offshore cost summary

As was the case for onshore wind, it is anticipated that average generation costs for offshore wind will also decrease for all wind speeds over the next 40 years. However, even with offshore winds speeds that are 2 m/s or more higher than those found onshore, offshore wind costs are expected to be higher than those for onshore. It must be noted that these are generalised expectations, and individual siting and wind speed investigation is even more critical for offshore parks where aspects such as water depth, floor bed composition, shipping conditions, etc., can vary greatly from project to project.

3.3 Link to GIS maps

The wind energy costs in the technology cost model are also used as inputs to create GIS maps of the geographical costs. The cost of exploiting wind energy is comprised of electricity costs, grid extension costs and distribution costs.

Generation cost

In order to calculate the per kWh cost of wind power on a geographical basis, the first inputs were the average cost of onshore and offshore wind power from different wind speeds calculated in the technology model (and presented in the section above). The average costs for onshore wind for example are displayed in Figure 7 below.

[7] Based on a weighted average. Under the Residential Conservation Rate, customers pay 6.67 cents per kWh for the first 1,350 kWh they use over an average two-month billing period. Above that amount, customers pay 9.62 cents per kWh for the balance of the electricity used during the billing period. Assuming a 35% increase from 2010 to 2020, a 9% increase from 2020 to 2030 and a 5% increase from 2030 to 2040 and 2040 to 2050. https://www.bchydro.com/youraccount/content/residential_bill.jsp

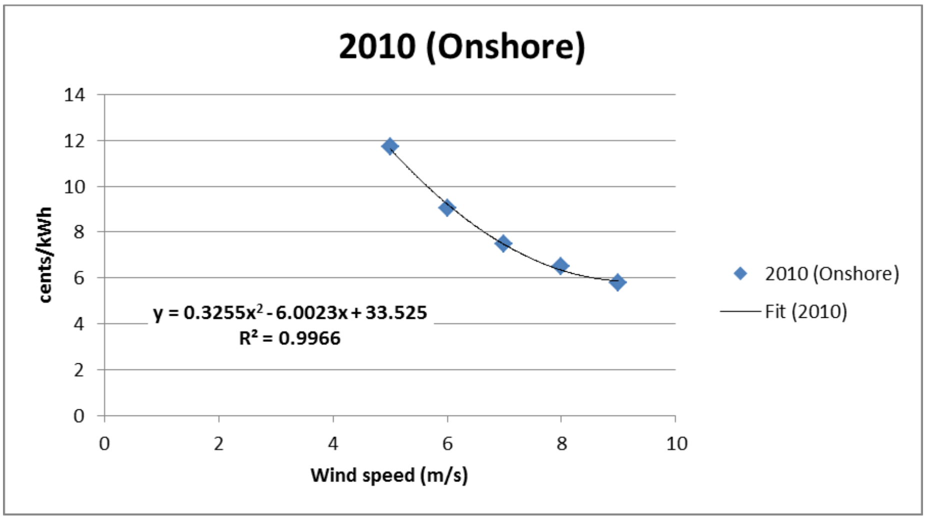

Figure 7: Cost of onshore wind power in 2010 as function of wind speed (a similar figure exists for offshore wind).

Grid extension

Exploitation of wind energy will in almost all cases require a grid extension in order to connect new wind parks with an existing grid. Therefore, the technology cost model has a built-in assumption that the generation of wind energy happens at an average distance of 15 km (onshore) and 30 km (offshore) from the grid. Thus, for each km greater/less than 15 or 30 km, the grid extension costs (cents/km/kWh) need to be added or subtracted. To address such nuances, a distance to grid surface was calculated in GIS and for each km exceeding a distance of 15 km (onshore) or 30 km (offshore) we added 0.022 and 0.056 cents/kWh for onshore and offshore grid connections, respectively. Similar values were subtracted for grid distances less than the 15 km and 30 km.

Total cost

The total wind energy cost was calculated by summing electricity cost, grid extension cost and distribution cost (2 cents/kWh) – cf. Figure 8).

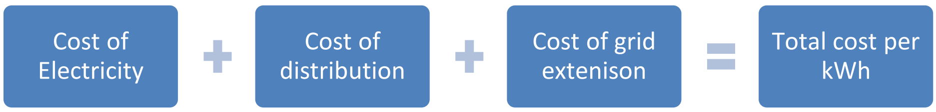

Figure 8: Schematic illustration of the wind energy cost calculation.

Figure 9 and Figure 10 show the cost mapping results for onshore and offshore systems, respectively.

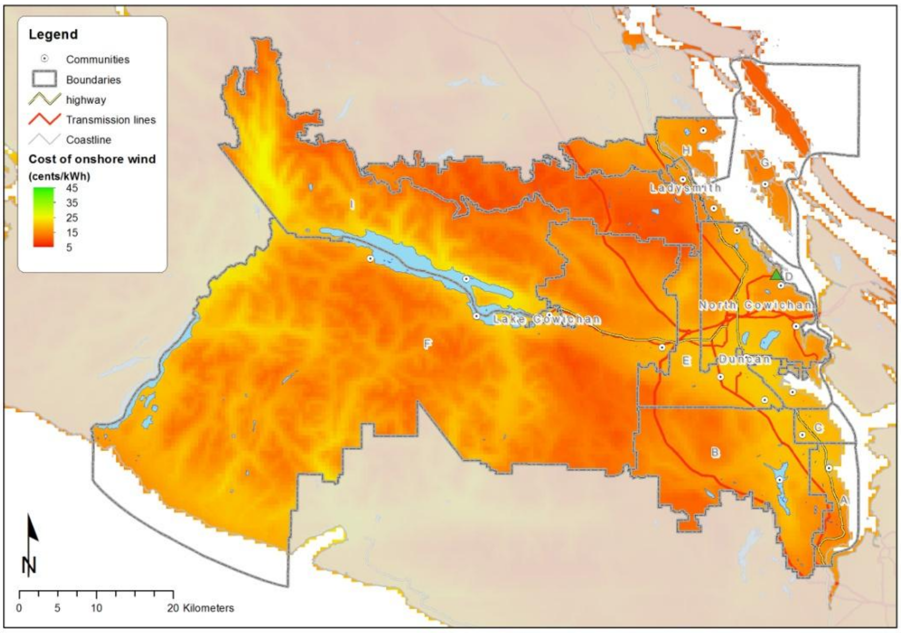

Figure 9: Cost of supply (cents/kW) for onshore wind 2010.

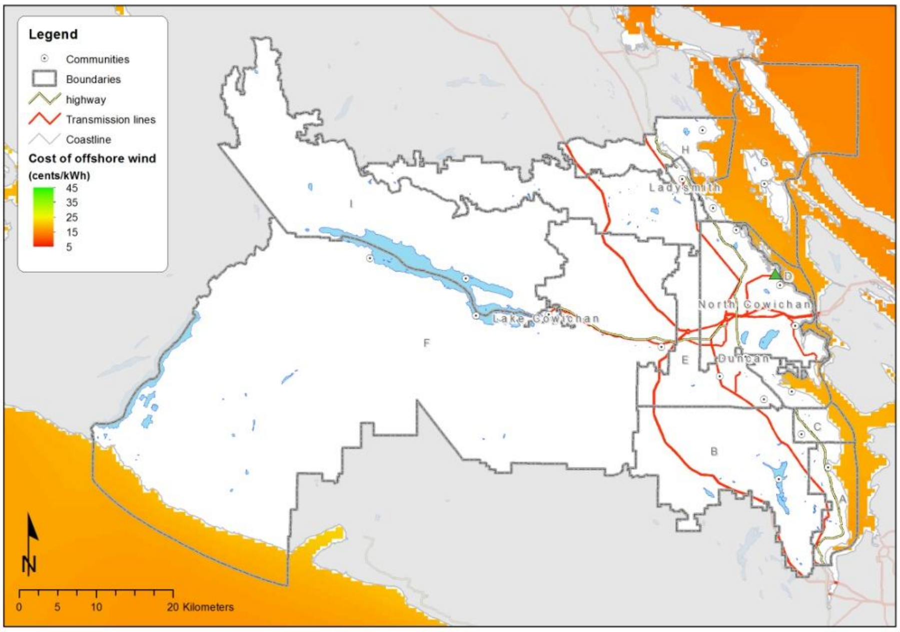

Figure 10: Cost of supply (cents/kW) for offshore wind 2010.

Summary

The above two figures highlight the fact that due to greater variation in local topography, there is greater variance in the cost data for onshore wind. However, as also represented in the two figures, for the CVRD the cost of onshore wind is lower than the cost of offshore wind. Indicated by the dark red colour, the lowest cost areas are near Ladysmith in Electoral Area G, and as such these areas could warrant closer examination.

4 Small-scale hydro

4.1 Background

The basic principle of hydropower is to transform the potential energy of water into mechanical energy available at a turbine shaft and then afterwards into electricity through a generator. The greater the height and the more water flowing through the turbine, the more electricity can be generated.

The dividing line for categorisation of small-scale and large-scale hydro differs from country to country, but according to the European Small Hydropower Association (ESHA), it generally ranges from 10 to 30 MW. A capacity of up to 10 MW total for small-scale is becoming the generally accepted norm by ESHA, the European Commission and the International Union of Producers and Distributors of Electricity (UNIPEDE). Small-scale hydropower may be further categorized into mini, micro (e.g. below 300-400 kW) and pico (e.g. below 5 kW).

Small-scale hydropower is normally the run-of-river design (as opposed to conventional large-scale hydro, which is generally dam based). As such, small-scale hydropower does not significantly interfere with river flows. There are two main differences run-of-river and conventional hydro. Firstly, in run-of-river there is no water storage or damming, other than the limited amount required to submerge the intake pipe. Second, there is no alteration of downstream flows, since all diverted water is returned to the stream below the powerhouse.

4.2 Financial analysis

In general terms, small-scale hydro costs increase as head decreases and as size decreases. However, the investment cost of small run-of-river hydropower is site specific and consequently wide-ranging, with a factor of 5-10 between the most expensive and the cheapest options. As a result, in order to produce a realistic estimate of the costs of hydro generation, the characteristics of specific sites must be known. As the initial resource screening conducted by GRAS did not reveal many promising sites within the CVRD, the focus of the study shifted to other more potentially relevant technologies. Consequently, generic cost values for small-scale hydro opportunities have been applied in the energy model for use in the business-as-usual scenario. The assumptions are as follows:

- The investment cost is extremely site specific, with the most cost-intensive options being at least 4 times more expensive than the cheapest ones.
- IEA's Renewable Energy Costs and Benefits for Society website[8] estimates the investment cost for planning purposes at 3.5 M$/MW.
- Estimated O&M costs from the same source are: $70,000 /MW/year.

The resulting cost figures applied in the scenario analyses for the business-as-usual scenario are presented below. Assuming that the CVRD would start with the 'lowest hanging fruits', the cost is expected to increase slightly over the years. However, these costs are based on the cost assumptions outlined above, and after the initial screening undertaken by GRAS (see report 1 for a more complete description of this screening process), it does not appear that there are many sites that can generate electricity at the costs noted below.

Costs (cents/kWh)	2010	2030	2050
Cost of small-scale hydro plant	5.00	6.00	8.00
Cost of net infrastructure	1.00	1.00	1.00
Cost distribution	2.00	2.00	2.00
Total cost	8.00	9.00	11.00

Table 9: Cost of small-scale hydro power (cents/kWh).

The graph below illustrates that given an ideal site, small-scale hydro's production cost is competitive with BC Hydro's end-user electricity price. However, given that the CVRD did not appear to have many promising sites, it is unlikely that CVRD small-scale production costs would be in this range.

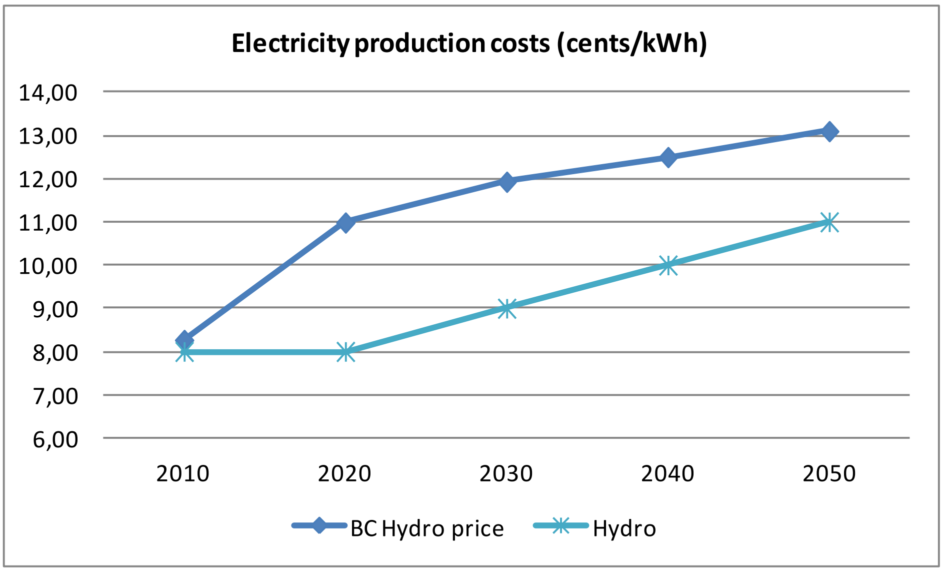

Figure 11: Comparison of BC Hydro electricity end user price and small-scale hydro power based electricity production cost from a suitable site (cents/kWh).

[8] www.recabs.org

4.3 Link to GIS maps

Given the site specific nature of micro hydro production costs, the generic costing used above did not warrant a costing map as this would imply a level of detail that is not supported by the data available. In this regard, as higher resolution data becomes available, further analysis of potential sites could be warranted.

5 Heat pumps

5.1 Background

Heat pump technology applies the same principles as used with refrigerators, where, utilising a compressor, energy is moved from a cold environment to a warm environment. With a refrigerator this is done via an electrically powered heat pump that transfers heat from inside the fridge to the coils on the back of the fridge, thus leaving the inside cool and the outside coils much warmer.

Heat pump systems exploit the energy stored in the ambient environment (air, top soil, ground, rock, lake, river, or sea), waste water, industrial effluent, or the exhaust air from a ventilation system. Heat pumps can be used for small-scale heat production in, for example, homes or for large-scale heat production to service district heating. This chapter will elaborate on the use of heat pumps for residential heating.

5.2 Heat pump system types

The three main types of heat pumps are geo-exchange systems (i.e. liquid-to-water systems), air-to-water systems, and air-to-air systems. The two first require a waterborne heating/cooling system such as floor heating or radiator systems, while the latter can rely on a duct-based heating system.

Geo-exchange systems

Geo-exchange heat pumps – also referred to as 'ground source heat pumps' – collect heat from the ground (or if in cooling mode deposit heat) and circulate this heat in the house via a water-based heating system, thus providing both heating and hot water.[9] Figure 12 on the following page displays a diagram of a typical geo-exchange system.

The temperature of the shallow ground or water from which the heat is collected is fairly constant year round. Though not overly problematic, there is some seasonality to the underground temperatures due to more solar energy being absorbed in the summer and less in the winter. These variations lag several months behind the seasons, meaning that there is more heat to be harvested in fall, and least in the late winter/early spring.

[9] A distinction is made between ground source heat pumps (geo-exchange) and geothermal heat pumps. Ground source heat pumps exploit the solar heat accumulated in the top soil while the geothermal heat pumps exploit the energy within the earth deep in the ground and are used for large scale production since it is quite costly to locate a conductive layer and drill the necessary holes.

The heat extraction from the ground is usually undertaken via a horizontal heat exchanger, which, depending on frost conditions, is buried 0.6 – 1.5 meters underground (this heat exchanger is essentially a buried tube that runs back and forth horizontally). Ensuring that it is correctly sized and placed at the optimal depth is important for the overall and long-term efficiency of the system. In some instances, when due to rocks or other restrictions it is not possible to utilise horizontal pipes, more expensive vertical tubes are used instead. Due to the underground heat exchanger, geo-exchange heat pumps are the most expensive in terms of installation and upfront cost.

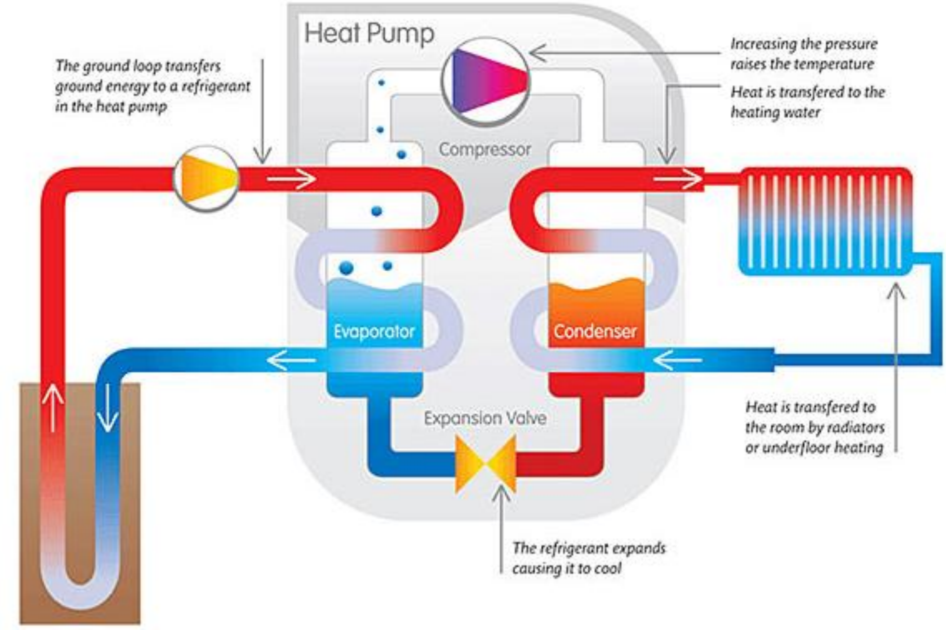

Figure 12: Diagram of a heat pump (www.digtheheat.com).

Air-to-water systems

Air-to-water heat pumps use the ambient air as the heat source and deliver heat to a water-based heating system. As the air shows greater seasonal temperature variations, the efficiency is lower compared to geo-exchange. The main advantage is lower installation cost.

Air-to-air systems

Air-to-air heat pumps also use the ambient air as heat source but deliver heat to the indoor air using a fan. In houses with ventilation systems, the heat can be delivered to the ventilation system, ensuring heat coverage in all rooms. Alternatively there are different options to ensure heating in all rooms:

- Installation of more than one air-to-air heat pump.
- Installation of a multi-split system which allows connecting several indoor units to one outdoor unit.
- Installation of additional electric heating panels.

5.3 Heat pump system aspects

Efficiency

The efficiency of a heat pump is defined as the 'coefficient of performance' (COP): the ratio of heat delivered, to energy required to power the compressor. A rough estimate for the COP of heat pumps operated in a temperate climate is 3. A COP of 3 means that for every 1 unit of energy input to the compressor, three units of energy are then released in the form of heating or cooling. The energy input for a heat pump compressor is typically electricity or natural gas. The following analysis has been completed assuming the compressor is powered by electricity.

A heat pump essentially collects heat from a source in one area (i.e. ground, air, water, etc.) and pumps it to another area (i.e. interior of a home). As such, the larger the temperature difference between these two areas, the more 'work' the pump has to do, and therefore the more inefficient it becomes (lower COP value). Of the various heat sources available to feed into a heat pump the most commonly used for residential heating is solar heat stored in the earth or ambient air. Therefore for heating purposes a relatively high exterior temperature source is desirable. Likewise, within the house, colder temperature dispersion technologies (i.e. in floor heating systems) are desirable. Due to variations in the outdoor temperature (and/or perhaps in the desired indoor temperature) the COP of a heat pump system is not constant, and when comparing systems it is important that the same standards are applied.

Factors affecting performance

According to the IEA Heat Pump Centre, heat pump performance in buildings is affected by a number of factors:

- the annual heating and/or cooling demand and maximum peak loads;
- the temperatures of the heat source and heat distribution system;
- the auxiliary energy consumption (pumps, fans, etc.);
- the technical standard of the heat pump;
- the size of the heat pump in relation to the heat demand and the operating characteristics of the heat pump;

the heat pump control system. To optimize system operation, water-based heat pump should usually not be sized to meet the entire building heating/cooling demand. Instead only 80-85% of demand should be met by the heat pump and the remaining peak load demand be met by a supplementary energy source. If the heat pump is designed to cover the entire heat load, the system will operate at partial load most of the time and the efficiency will be lower.

Air sourced systems

The lifetime of air-to-water and air-to-air systems are affected by the salt content of the ambient air as they are mounted outside the building. Another concern can be the outdoor noise level, however newer heat pumps are becoming increasingly quiet thus rendering this less of a concern than it has been in the past.

Hot water production

For hot water production liquid/water and air/water systems can be used. The hot water produced must be 55°C due to risk of legionella at lower temperatures. This means that the output temperature of the heat pump must be 60-65°C which is higher than most heat pumps can deliver. Here a supplementary heat source is required.

5.4 Financial analysis

In the following section the cost assumptions in the business-as-usual scenario of the technology cost model for geo-exchange and air-to-air systems for a single family home are presented. These two systems are selected as they appear to be the most relevant heat pump options in the CVRD.

Geo-exchange

The supply cost of a geo-exchange system in the business-as-usual scenario has been estimated in the following manner, using a detached single-family home as an example:

- A detached single-family home is assumed to have a demand of 14,030 kWh/year for space heating and hot water.
- Based on a local supplier, the investment cost of a geo-exchange system is assumed to be 27,500 CAD. Assuming that the investment is loan-financed with an interest rate of 5% per year and 20 years amortization, the initial investment converts to a capital cost of 2,207 CAD/year equivalent to 15.73 cents/kWh heat demand.
- An operation and maintenance (O&M) cost of 0.30 cents/kWh heat demand is assumed. This gives a combined capital and O&M cost of 16.03 cents/kWh heat demand.
- The heat pump is assumed to have an annual average COP (delivered heat divided by consumed electricity) of 3.5. Thus 4,009 kWh of electricity is required to produce 14,030 kWh of heat. Assuming an electricity tariff of 8.27 cents/kWh in 2010, the total electricity cost is 2.36 cents/kWh heat demand.
- Thus, total annual costs add up to 2,580 CAD equivalent to 18.39 cents/kWh heat demand.

The table below presents the variation in investment cost, heat demand, and resulting total supply cost across the different types of dwellings.

	Investment (CAD)	O&M (cents/ kWh)	Heat demand (kWh/year)	Total costs (cents/kWh)
Single-family, detached, existing	27,500	0.30	14,030	18.39
Single-family, detached, new	24,750	0.30	14,030	16.82
Single-family attached, existing	22,000	0.30	6,360	30.17
Single-family attached, new	19,800	0.30	6.360	27.64
Apartment, existing	13,750	0.30	3,565	33.61
Apartment, new	12.375	0.30	3,565	30.52
Moveable dwelling, existing	19,250	0.30	6,900	25.05
Moveable dwelling, new	17,325	0.30	6,900	22.81

Table 10: Geo-exchange systems – Applied assumptions regarding costs and heat demand by type of building.

Air-to-air

An air-to-air heat pump system for a typical single-family home (160 m^2) costs somewhere between 7,200 and 10,000 CAD. Assuming a COP of 2.5 and using the same approach as above for geo-exchange systems (except 17.5 years economic life), the total annual cost becomes 1,377 CAD/year equivalent to 9.81 cents/kWh heat demand for an existing single-family detached house.

	Investment (CAD)	O&M (cents /kWh)	Heat demand (kWh/year)	Total costs (cents/kWh)
Single-family, detached, existing	10,000	0.30	14,030	9.81
Single-family, detached, new	9,000	0.30	14,030	9.19
Single-family attached, existing	8.000	0.30	6,360	14.56
Single-family attached, new	7,200	0.30	6,360	13.46
Apartment, existing	5,000	0.30	3,565	15.82
Apartment, new	4,500	0.30	3,565	14.60
Moveable dwelling, existing	7,000	0.30	6,900	12.44
Moveable dwelling, new	6,300	0.30	6,900	11.56

Table 11: Air-to-air systems – Applied assumptions regarding costs and heat demand by type of building.

As can be seen below, the cost of geo-exchange systems is higher than air-to-air systems. It should be kept in mind that all of these figures are approximations, and actual on site costs can vary substantially according to site specific parameters.

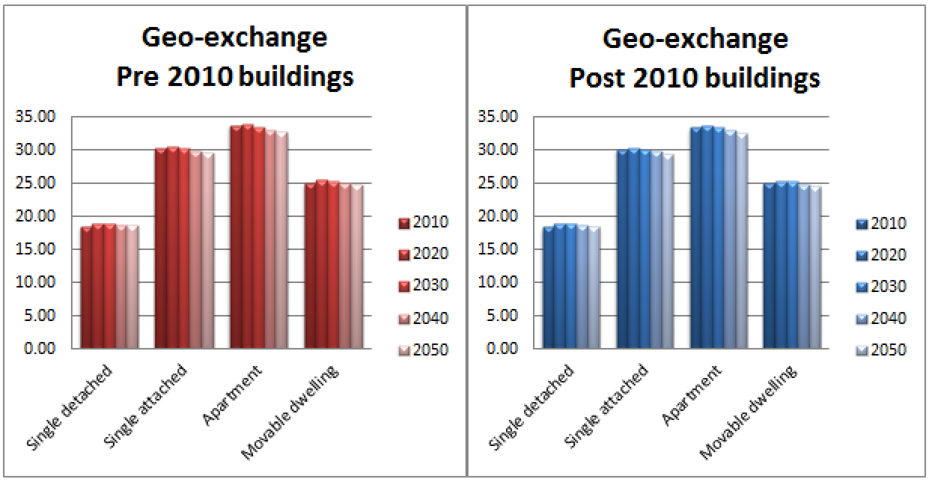

Figure 13: Heat pump (ground) - Cost of supply (cents/kWh) for pre-2010 and post-2010 buildings.

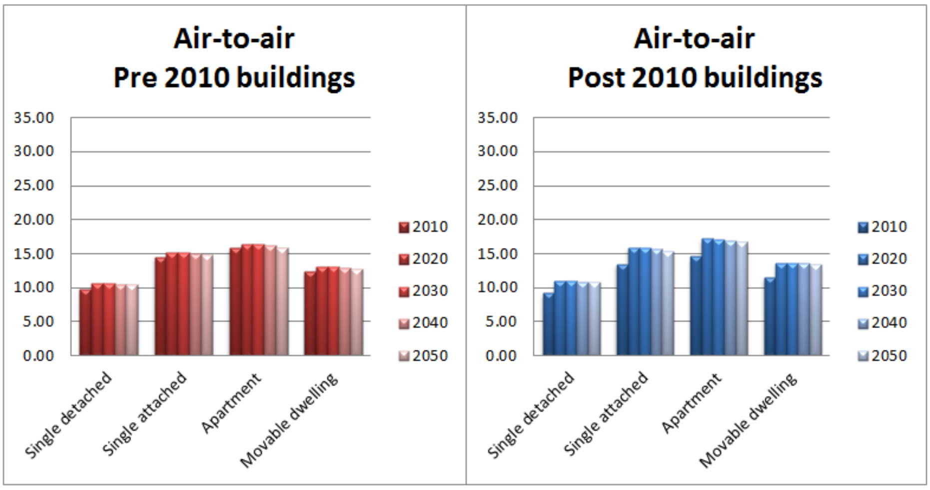

Figure 14: Heat pump (air) – Cost of supply (cents/kWh) for pre-2010 and post-2010 buildings.

5.5 Link to GIS maps

The cost of heat pumps varies significantly with dwelling type. As a result, the cost surface mapping analysis only took into account existing housing stock, where an appropriate distinction between the various types can be made. In order to do so all residential records from BCAA (+Indian reserves) were extracted and linked to their respective parcels.

Energy source	Heat pump (ground)	Heat pump (air)
Single detached	19.1	9.12
Single attached	35.33	15.04
Apartments	38.37	20.20
Moveable dwelling	27.52	12.18

Table 12: Average cost (cents/kWh) of various heating types for different dwelling types.

Lastly, a grid layer for each of the two energy sources is created from the polygon parcel layer and with cell values representing the average cost of each of the two types of heat pumps.

The generation cost varies very little depending on geographic variation. Therefore the two maps below show no difference in the distribution of the two heat pump types, only in the cost, with the air-to-air heat pumps being significantly cheaper than the geo-exchange systems.

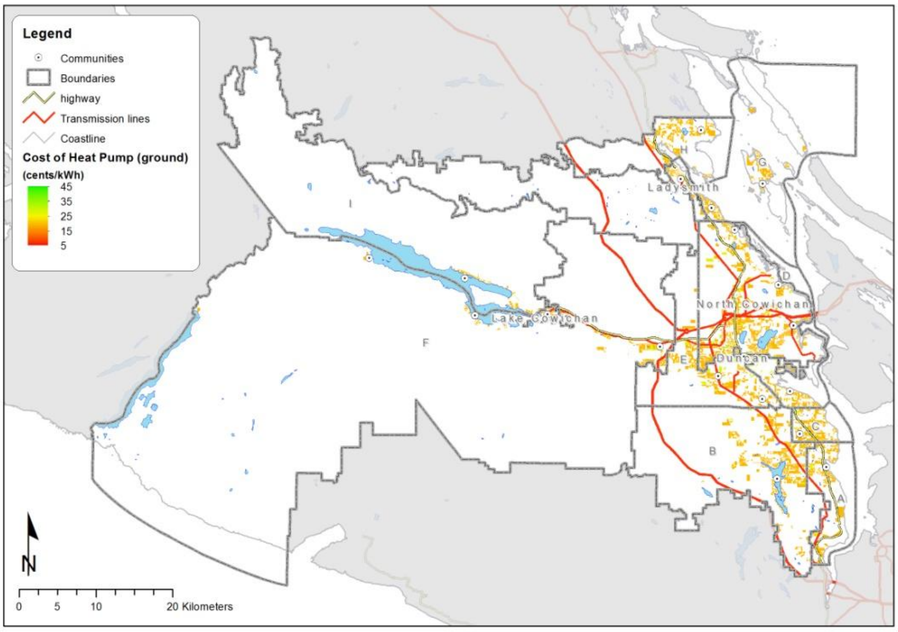

Figure 15: Cost of supply (cents/kW) for geo-exchange 2010.

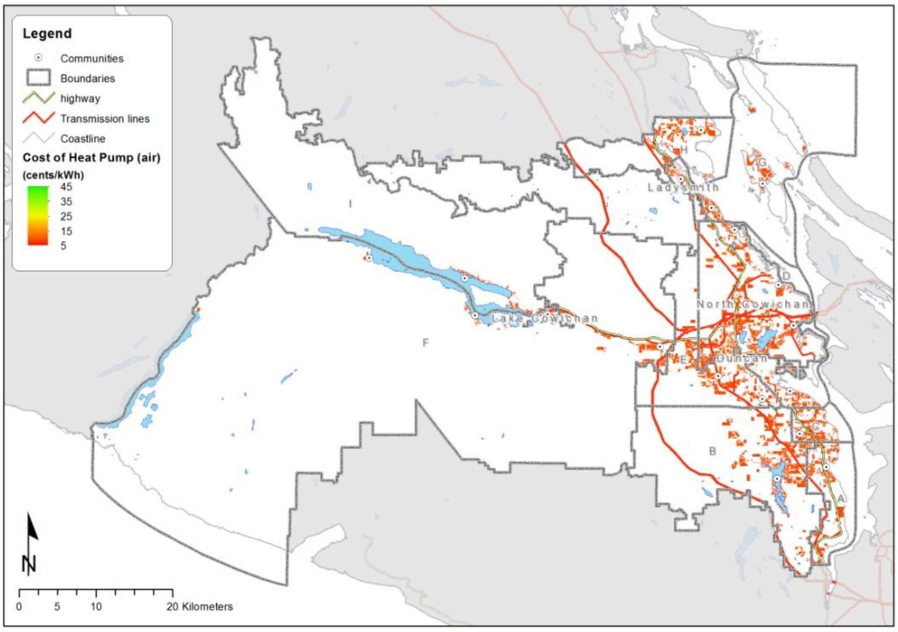

Figure 16: Cost of supply (cents/kW) for air-to-air heat pumps 2010.

6 Solar energy

6.1 Background

Solar energy technologies are manifold. In spite of solar energy having been exploited for centuries new technologies are still being invented and commercialised and old technologies improved.

Solar hot water

Most associate solar hot water systems with systems placed on the roof of a house where they generate hot water for household use. A solar hot water system uses solar collectors to heat a liquid, and a large variety of types and sizes exist. Solar hot water systems may also be used as a source of energy for district heating systems.

Solar electricity

Solar electricity is generated by photovoltaic or mirrors cells that are exposed to sunlight. The output of a photovoltaic system depends on the geographical location and the orientation of the photovoltaic cells. The orientation is described by the angle relative to the direction to Equator (azimuth) and the angle relative to horizontal level (pitch). Various types and models exist and their capacity spans from very small to high MW capacity. Small systems can provide a basic amount of electricity to remote areas that are not grid connected for powering items such as pumps, lighting, or charging batteries. Concentrated solar power plants operate at a larger scale. They are large production plants that need almost perfect sun condition and use mirrors to concentrate the rays of the sun on a fluid that vaporises and drives a turbine to generate electricity.

6.2 Financial GIS analysis

Solar hot water

A comparison of costs between pre-2010 and post-2010 dwellings shows that overall the cost of applying solar hot water is higher for post-2010 dwellings. This is due to the fact that post-2010 dwellings are more efficient and use less energy. In addition, the model inputs result in substantial cost differences between single detached dwellings and the other building types. However, the quotes received from CVRD suppliers differed significantly from other data sources, highlighting the need to further investigate input data for this particular energy source.

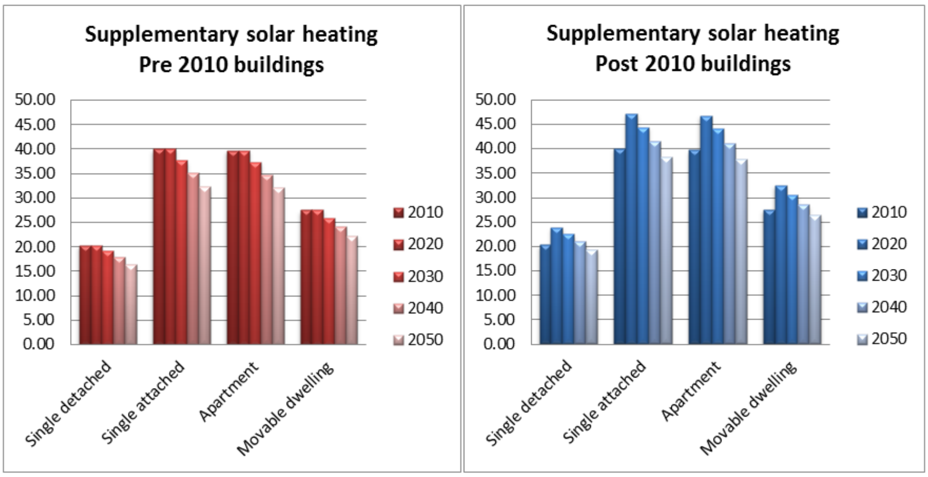

Figure 17: Solar heating (supplementary) - Cost of supply (cents/kWh) for pre-210 and post-2010 buildings.

Solar electricity

The table below shows the assumed financial feasibility of grid-connected photovoltaic (PV) systems:

Aspect	Unit	2010	2030	2050
Electricity generation	kWh/kW	1,000	1,000	1,000
Specific investment, total system	CAD/kW	4,830	2,450	1,330
Capital costs (5% interest, 30 years)	cents/kWh	31.42	15.94	8.65
O&M costs	cents/kWh	4.48	2.52	1.68
Total generation cost	cents/kWh	35.90	18.46	10.33

Table 13: Generation costs for grid connected photovoltaic systems.

Due to high upfront investment costs, the cost of PV based electricity production is quite high compared to the BC Hydro electricity price and remains higher until well after 2040. As such, the CVRD should continue to monitor PV electricity production costs, however it is unlikely that small-scale PV will be cost competitive with other renewables such as wind within the next 10-15 years.

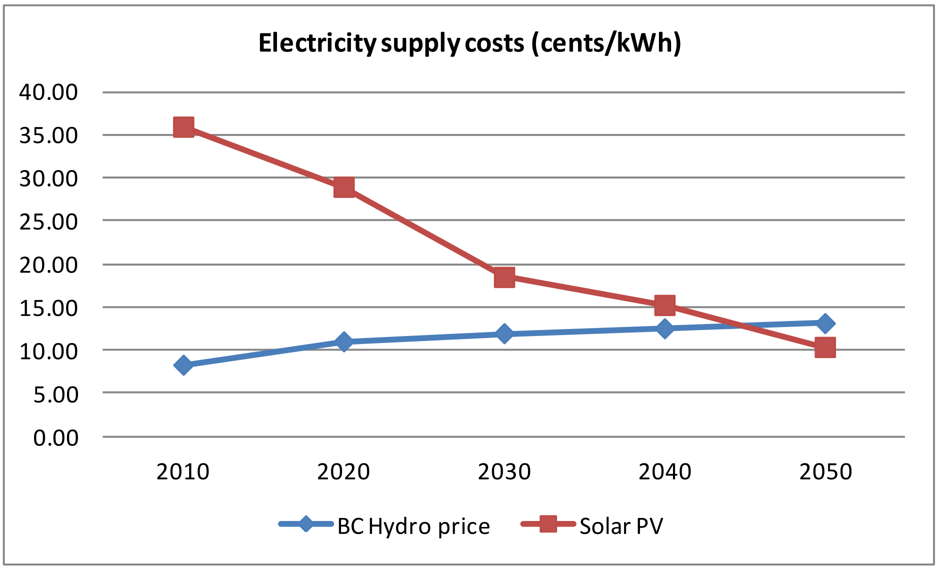

Figure 18: Comparison of BC Hydro electricity price and PV based electricity supply cost keeping in mind that the BC Hydro price includes transmission, distribution and flat fees (cents/kWh).

6.3 Link to maps

Solar heating

The cost of solar heating based on the current input data varies significantly with housing type. As a result, the cost surface mapping analysis considered only existing housing stock, where an appropriate distinction between the various types could be achieved. All residential records were first extracted from BCAA and Cowichan Tribes and linked to their respective parcels. Finally, a grid layer was created from the polygon parcel layer, where cell values represent the average cost of solar heating.

Single detached	Single attached	Apartments	Moveable dwelling
21.23	41.77	41.48	28.81

Table 14: Average cost (cents/kWh) of solar heating for different dwelling types.

The geographic variation is insignificant compared with the large uncertainties regarding the economic feasibility of solar heating systems, and therefore the figure below shows a very uniform price level.

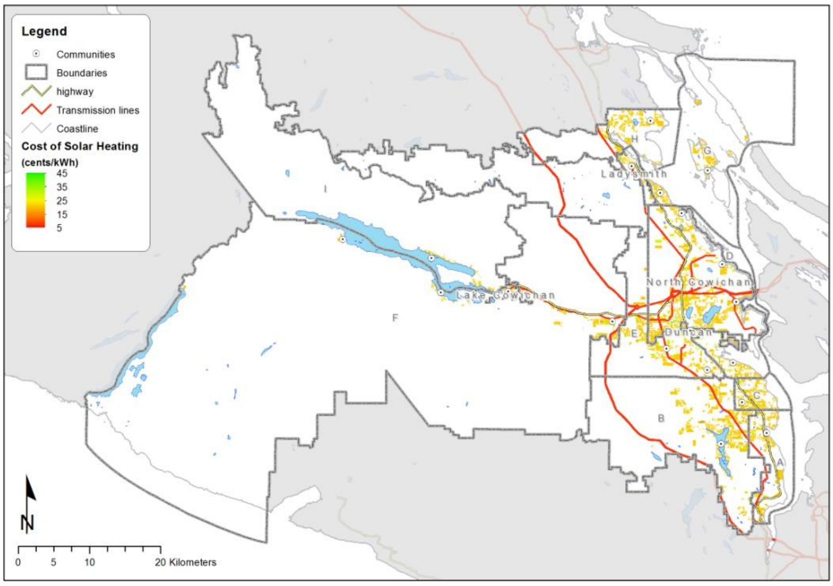

Figure 19: Cost of supply (cents/kW) for solar heating 2010.

Solar electricity

The exploitation of solar PV is deemed possible only where buildings are or will be present. Official community plans (OCPs) were thus used to demarcate the areas where solar PV could be considered for the region. The OCP polygon demarcation was subsequently converted to a grid and the average cost of solar PV (i.e. 35.90 cents/kWh) was assigned to each grid cell.

As the figure below illustrates, the cost of solar PV for the end-user is clearly much higher than the BC Hydro electricity price (8.27 cents/kWh).

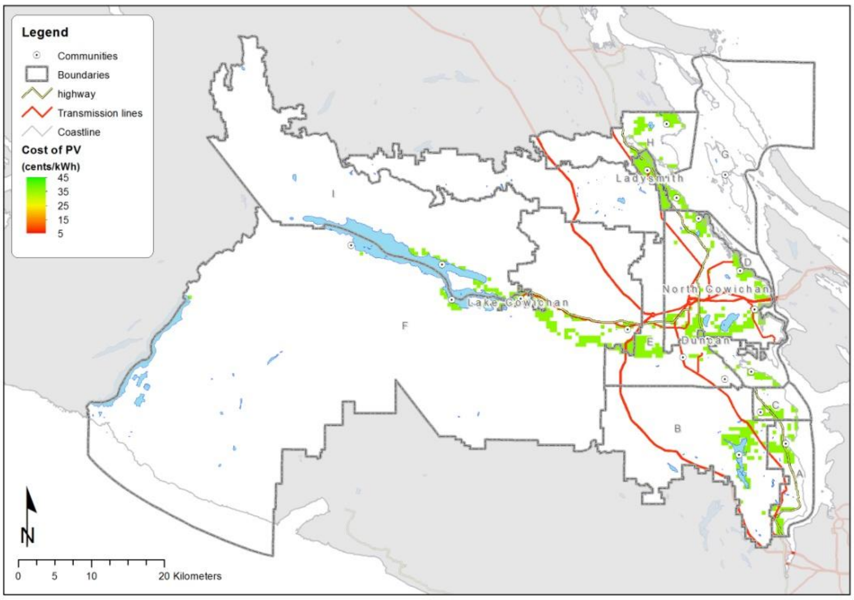

Figure 20: Cost of supply (cents/kW) for PV 2010.

7 Biomass

7.1 Background

Biomass covers a wide range of biomass types and possible applications. The main types of biomass that can be used for electricity or heat production are:

- Firewood
- Wood chips
- Straw
- Wood pellets
- Energy crops (i.e. willow, elephant grass, etc.)
- Biogas (based on organic waste, animal manure or energy crops).

Biomass can be used centrally for electricity and/or heat production. Biomass can also be used for heating purposes in smaller boilers or stoves (e.g. for residential homes or industrial processes).

Firewood

In residential homes firewood can be used for direct heating if burned in wood stoves. While energy efficiency can be up to 80-90% for more advanced stoves, the heat generated is generally not distributed evenly within the house and may require additional heat sources to heat other rooms and hot water. This inadequacy reduces the total efficiency of the heating system. More advanced stoves can be integrated with a waterborne heating system, thus enabling heating of the entire house and the hot water use.

Wood chips and straw

Wood chips can be used in both small and large combined heat and power (CHP) plants, or for heat-only production in boilers for district heating. Smaller CHP plants (up to approximately 150 MW input capacity) and heat-only-boilers are grate-fired where the wood chips are fed onto a moving grate. Electricity production from such plants is done with a steam turbine. Straw can be used in the same grate fired technologies, but will lead to higher emissions of NO_x and particulates, increased ash, and larger concerns regarding corrosion and slag deposits. For larger CHP plants, fluidized-bed technology can be applied, where wood chips will be blown into the boiler with an air stream and a sand mixture, which improves heat transfer and combustion.

Wood pellets

Like wood chips, wood pellets can be used in CHP plants or heat-only-boilers. Wood pellets have a lower water content compared to wood chips which can result in better combustion. Combustion of wood pellets is carried out by using pulverized combustion. Temperatures and efficiency for pulverized fuel

CHP are higher compared to grate fired plants, and investment costs are lower per MW electricity. On the other hand, wood pellets are a more costly fuel, and total production cost will depend on the local options for biomass production.

For residential heating, wood pellets can be used in wood pellet stoves, either as free-standing versions similar to classic wood stoves or connected to a waterborne heating system. Wood pellet stoves are easier to operate and require less maintenance compared to wood stoves.

Biogas

Biogas can be produced from an anaerobic process using animal manure, organic waste, or energy crops. Subsequently biogas can be used for electricity and heat production in CHP plants, used in gas engines or gas turbines, or as feedstock for commercial-scale greenhouses. Biogas can also be used in transport, and given that the vast majority of the CVRD's future GHG emissions will come from the transport sector, this could be an interesting option going forward.

7.2 Financial analysis – Wood chips

Forest residues are of particular interest in the CVRD and as such the financial analysis focuses on this resource. In interviews with local forestry companies it was revealed that wood chips delivered at roadside (from short to medium distances to the road) incur a transport cost of roughly 25 CAD/tonne, or 30-35 CAD/tonne in the case of transport to harbour. With a moisture content of 45% (slightly dried), the lower heating value is 7.7 GJ/tonne[10]. Based on a price of 35 CAD/tonne for transported wood chips, the cost is 4.5 CAD/GJ[11].

CHP

For CHP to be financially attractive, it must be undertaken on a large scale. As such, heat production alone (as opposed to district heating and electricity production) is the better choice when dealing with smaller scale applications. It is difficult to determine the exact point at which CHP is the better choice, however it is typically around 5-15 MW electric capacity. In this range the electric efficiency is about 29%, and the heat efficiency roughly 77%. With this ratio between electricity and heat production, a plant of 4.5 MW electric power capacity would have a heat generating capacity of 12 MJ/s[12]. With a capacity factor of 45% this plant would generate 170,000 GJ (47,300 MWh) of heat per year, roughly equivalent to the demand of 3,500 single-family

[10] 2.1 MWh/tonne
[11] 16 CAD/MWh = 1.63 cents/kWh
[12] Heat capacity is expressed in MJ/s, while electric capacity is expressed in MW, however in energy terms they are equal.

detached dwellings. In addition, it would produce approximately 18,000 MWh of electricity. These calculations are displayed in the table below.

Generating capacity	MJ/s (heat)	2	12	50
Total efficiency	%	103	106	106
Heat efficiency	%	78	77	77
Electric efficiency	%	25	29	29
Capacity factor	%	45	45	45
Annual heat production	GJ	28,382	170,294	709,560
Assumed heat demand per unit	GJ	50.0	50.0	50.0
Number of residential units supplied		568	3406	14191
Annual fuel consumption	GJ	36,387	221,161	921,506
Specific investment	Mio. CAD per MJ/s	2.199	1.898	1.371
Interest rate	%	2.0	2.0	2.0
Lifetime	years	20	25	30
Capital cost	CAD/year	268,933	1,166,708	3,060,549
Fuel price	CAD/GJ	4.6	4.6	4.6
Annual fuel cost	CAD/year	165,735	1,007,324	4,197,184
O&M	CAD per MJ/s per year	107,737	23,397	23,397
Total O&M	CAD/year	215,474	280,765	1,169,855
Total annual costs	CAD/year	650,142	2,454,798	8,427,588
Price of electricity	CAD/Mwh_{el}	102.25	102.25	62.65
Electricity production	MWh	2,527	17,816	74,232
Income electricity sale	CAD/year	258,378	1,821,665	4,650,961
Cost of heat at plant gate	**CAD/GJ**	**13.8**	**3.7**	**5.3**
	cents/kWh	**4.97**	**1.34**	**1.92**

Table 15: Costing aspects for wood chip-fired CHP boilers in 2010.

Heat only

Meanwhile, if the plant is designed to solely produce heat, typical calculations for a wood chip-fired boiler plant are displayed below.

Generating capacity:	MJ/s	1	10	50
Thermal efficiency	%	102	**103**	106
Capacity factor	%	45	**45**	45
Annual heat production	**GJ**	**14,191**	**141,912**	**709,560**
Annual fuel consumption	GJ	13,913	**137,779**	669,396
Specific investment	Mio. CAD per MJ/s	0.998	**0.891**	0.416
Capital cost (2% per year, 20 years)	CAD/year	61,047	**456,491**	928,272
Fuel price	CAD/GJ	4.6	**4.6**	4.6
Annual fuel cost	CAD/year	63,369	**627,540**	3,048,898
O&M	CAD per MJ/s per year	40,852	**37,851**	24,511
Total O&M	CAD/year	40,852	**378,506**	1,225,560
Total annual costs	CAD/year	165,268	**1,462,538**	5,202,730
Cost of heat at plant gate	**CAD/GJ**	**11.6**	**10.3**	**7.3**
	cents/kWh	**4.19**	**3.71**	**2.64**

Table 16: Costing aspects for wood chip-fired boilers in 2010.

The technology for both heat only boilers and CHP wood chip plants is mature, and it is unlikely that they will experience significant price reductions in the years to come.

Wood chips summary

The CVRD has a unique opportunity for wood-based district energy specifically in and surrounding the City of Duncan where key facilities such as the Island Savings Centre, Cowichan Aquatic Centre, the regional hospital, and Cowichan Secondary School are all located within a stone's throw of each other. In addition, this area supports large concentrations of commercial and seniors care facilities. As such the area encompasses a mix of concentrated large energy users with the potential to use a plentiful supply of local waste wood to meet their energy demands.

7.3 Other potentials

Liquid biomass – Sewage

The wastewater treatment plant for North Cowichan and Duncan, which currently treats sewage from about 35,000 households, is currently located on Cowichan Tribes Reserve Land. On average, about 50 kg of faeces per year is produced per person (Heinonen-Tanski and van Wijk-Sijbesma 2004). If utilised to produce biogas, this amount of faecal material could produce 1.6 GWh of energy in the form of biogas (Gell 2011).[13] Due to time constraints, a cost analysis for biogas production was not carried out in this project, but it is an interesting option given the energy potential and raw input supply. In addition to potential energy supply, there are also additional environmental benefits associated with processing liquid biomass, which while not encompassed in this report, should also be identified and evaluated.

[13] 'Cowichan Tribes Energy Action Plan - First Steps', March 2011

8 Municipal solid waste

8.1 Background

Municipal solid waste (MSW) can be utilised as an energy resource in a number of ways. When considering exploiting MSW for energy purposes, however, it should be kept in mind that sustainability targets often include reducing the amount of waste produced, recycling, and composting which altogether result in a smaller amount of waste available for energy purposes and a change in the organic fraction.

Waste combustion

The most common treatment of MSW for energy use is combustion in heat-only-boilers or CHP plants. Combustion of MSW is more complicated compared to other solid fuels, as MSW is more difficult to handle, the heating value is lower, and there are more concerns with emissions, ash and slag deposits.

Refuse derived fuel

Certain fractions of MSW can be treated to produce 'refuse derived fuel' (RDF), which mainly consists of chopped wood, plastic, paper, and cardboard. RDF is a dry fuel with a higher heating value (up to 20 GJ/tonne) and is suitable for co-firing in larger fossil fired plants, such as coal-fired CHP plants.

Gasification

Thermal gasification processes can produce syngases, which can be used in gas engines or gas turbines. However, the commercial breakthrough for gasification techniques remains to be achieved and MSW is more complicated as a fuel in this respect (compared to other biomasses), since it is less homogeneous and contains more water.

Biogas

Organic waste can be used to produce biogas in an anaerobic process. In order to be able to use MSW for this process the organic fraction needs to be separated from the non-organic fraction either by sorting at source or by establishing 'mechanical biological treatment' facilities for sorting the MSW into different fractions. The output from mechanical biological treatment can be partly recycled (metal, paper, plastic, glass), processed further to produce RDF, or used in biogas plants.

8.2 Financial analysis – Waste incineration

As was noted above, CHP needs to operate at a large scale as its financial viability depends largely on how much heat can be sold at what price. This is also the case with MSW based CHP. Thus with its 25,000 to 30,000 tonnes of annual MSW, the CVRD is likely best served engaging in discussions with the

RDN (ca. 60,000+ tonnes of MSW) and/or the CRD (ca. 150,000 tonnes) to build and operate a common facility (AECOM 2011).

Tri-Regional District Solid Waste Study

In May of 2011, AECOM released a study that investigated the possibility of a tri-regional facility. The study found that after organics management and recycling have been maximized, when combining the solid waste from the three districts (CVRD, RDN and CRD), there is roughly 225,000 tonnes per year that need to be treated and/or disposed, of which 200,000 tonnes could be treated by a waste-to-energy facility.

The study analysed mass burn, gasification, and plasma gasification technologies. Mass burn was confirmed as the most proven, reliable and lowest cost technology. The optimum size for such a plant is about 3 times larger than the 200,000 tonnes that are available in the 3 districts considered, and as such a 4th option for the placement of the facility in Gold River where additional waste would be utilised was also incorporated. The costs for such a facility based on its location are displayed in the table below. As a reference point, the CVRD waste is currently disposed at a landfill in South Central Washington where the tipping fee is 135 CAD/tonne, while the RDN and CRD per tonne tipping fees are currently 107 CAD and 100 CAD respectively.

Location	Facility costs (CAD/t)	Transportation costs (CAD/t)	Total costs (CAD/t)
CRD	84	21	105
CVRD	84	31	116
RDN	84	30	115
Gold River	42	68	111

Table 17: Estimated treatment costs (CAD/tonne) for mass burn at different locations.

The reason for the Gold River option having much lower facility costs, whilst having much higher transport costs (as depicted in the table above), is that it is 3 times larger than the other 200,000 tonne facilities, but located outside the region.

The above analysis was undertaken with a 50% district heating uptake in the RDN and CVRD and an unspecified uptake in the CRD. Results indicate that the RDN would be better suited to district heating off take, and with an 80% uptake, the cost would be reduced to roughly 107 CAD/tonne. Meanwhile, the study was uncertain regarding the potential for district heating off take in the CRD, and with zero uptake there, costs were estimated to be 119 CAD/tonne. These variances based on the amount of heat that can be sold indicate how important this parameter is.

Heat production costs

The above discussion compared the total cost of disposing of MSW based on different locations and amount of district heating uptake. However, within this report the focus is instead on what the heat production cost is. Based on local figures, cost estimates from the Danish Energy Agency's Technology Data for energy plants, and incomes from tipping fees and electricity production, the cost of heat at the plant gate given is outlined in the table below.

Low heating value	**GJ/tonne**	**11.5**
Volume of waste	tonnes/year	140,000
Total efficiency	%	97
Heat efficiency	%	71
Electric efficiency	%	26
Capacity factor	%	90
Waste incineration capacity	tonnes/hour	18
Power generating capacity	MW	15
Heat generating capacity	MJ/s	40
Power generation	GWh/year	116
Heat generation	TJ/year	1,143
Share of district heat sold	%	15
Assumed heat demand per unit	GJ	50.0
Number of units supplied		3,429
Investment cost[14]	Mio. CAD/MW	16.8
Investment cost	Mio. CAD	248
Plant lifetime	Years	25
Interest rate[15]	%	5
Capital costs (% per year, 25 years)	Mio. CAD/year	17.6
O&M	CAD/tonne	60
O&M	Mio. CAD/year	8.4
Total annual costs	Mio. CAD/year	26.0
Tipping fee[16]	CAD/tonne	95
Annual tipping income	Mio. CAD/year	13.3
Electricity tariff	CAD/MWh	102.25
Annual electricity income	Mio. CAD/year	11.9
Required Return on investment[17]	%	1
Required Return on investment	Mio. CAD/year	2.5
Required Heat Income	Mio. CAD/year	3.3
Resulting Heat tariff at plant gate	CAD/GJ	19.1
Resulting Heat tariff at plant gate	**cents/kWh**	**6.9**

Table 18: Waste incineration plant aspects and resulting heat cost at plant gate.

[14] This figure is significantly higher than that utilised by the AECOM study.
[15] If owned and operated by the CVRD, the interest rate could perhaps be around 2%, which due to the large capital investment would drastically reduce the heat cost.
[16] Have assumed a tipping fee lower than the current tipping fee so that both waste and heat customers benefit from the establishment of the plant
[17] Assuming a very low required rate of return if the facility is owned by the CVRD

The costs depicted in the final row of the table are at the plant gate, and therefore the costs of distributing the heat to end-users must be added to this figure. This distribution cost will be analysed in the following chapter.

8.3 Non-cost related factors

Non-cost related aspects should also be kept in mind when considering MSW, for example noise, odour and visual impacts are all aspects that can affect the political feasibility of a project.

9 District heating

9.1 Background

District heating is based on central heat production and distribution of this heat to consumers through a pipe system. District heating offers the opportunity to utilise different sources of central heat production, which are potentially more efficient, flexible, and cheaper for the consumer when compared to individual heat production. However, the infrastructure cost for the distribution system and the heat losses in the distribution system need to be taken into account.

Consumption density

A crucial factor for the cost-effectiveness of district heating is the energy density in the supply area in terms of heat consumption per customer and distance between customers. The higher the energy density, the better the efficiency and the economy of the system. When establishing a district heating system it is desirable to connect as many customers as possible. To facilitate this connection density, bylaws can be instituted to require or incentivise hook up to ensure the overall system economy. Furthermore, infrastructure establishment for district heating can be considerably cheaper with new developments than with existing built-up areas. That being said, retrofitting existing areas is not insurmountable as illustrated by numerous European examples.

Heat distribution is usually carried out by using hot water or steam. Steam has a higher production and distribution cost, but can be an advantage for industrial customers due to the higher temperature. In larger district heating systems, the distribution system can consist of both a high pressure (approx. 25 bar) transmission system and a lower pressure (approx. 6 bar) distribution system. A typical temperature for water distributions systems is between 70 °C and 100 °C. Losses in the distribution system vary between 10 and 25% depending on distance between customers and the pipe insulation. Research and development regarding low temperature district heating is currently being undertaken. Low temperature district heating (water temperature around 50°C) offers lower losses in the distribution system and potentially higher production efficiency (e.g. for large heat pumps). However, the heating systems at the end-user need to be able to run at lower temperatures, such as floor heating in newer low energy homes.

User installations

End-users are required to have a waterborne heat system in order to be able to utilise district heating. Waterborne systems can be retrofitted in existing houses, but the total installation cost will rise. As such, in addition to the central heating system and distribution net, an end-user installation is needed.

Both indirect systems (heat exchanger transfers heat from the district heating system to the in-house system) and direct systems for direct use of the district heating exist. The advantage of indirect system is the decoupling from the main system and thereby lower vulnerability between the two systems. However, direct systems can operate at lower temperatures in the distribution system, as there is no need for a temperature difference in the heat exchanger.

Heat production

The advantage of district heating is in the central nature of heat production. Central production units offer a lower investment cost (per MW heat) compared to individual technologies) and a lower operating cost. Heat production to district heating can be delivered from:

- Industrial waste heat,
- CHP production, and
- Heat-only production (fuel fired boilers, heat pumps, geothermal heat).

Heat production from industrial waste heat can offer a way to utilise heat that would otherwise have no use. As a result the heat production costs are low, and it can provide additional revenues for industry. One potential drawback is that incentives to make efficient technologies at the industrial site might be affected if waste heat can be sold to the district heating system at a high price.

CHP production offers the opportunity to use the waste heat generated when producing electricity, thereby raising the total efficiency of CHP to around 90% instead of 40% (for e.g. natural gas fired electricity production). The technology used for CHP production will, among other things, depend on the size of the district heating system. For large systems (heat production capacity > 200 MW), coal fired power plants can be used while biomass or natural gas fired plants are more relevant for smaller systems. The focus of this study due is on smaller plants. MSW fired CHP plants are also an option for central heat production. CHP plants have a higher investment cost compared to heat-only technologies, but a lower operating cost due to the electricity sales. CHP plants need a high capacity factor (or more simply put, high utilisation rate) to recover the investment costs.

Heat-only technologies are usually used as backup capacity and for peak load production. Boilers can be fossil fuel fired (natural gas, oil) or biomass fired (wood chips, wood pellets). In some cases (depending on the electricity system) electric boilers can be an option for heat-only production due to low investment costs and the option to produce heat when the electricity price is low. Large heat pumps can also be used for heat-only production but need longer operation times due to the higher investment cost. Other options for heat-only production are solar heat (where the investment cost is considerably lower than for individual solar heat installations) or geothermal heat production.

Heat storage

An important measure to ensure flexibility of central heat production is heat storage. Heat storage is used to handle demand variations and to optimise CHP production, so that electricity production can take place when the electricity price is high, regardless of whether the accompanying heat production is in demand at that time Heat storage to handle demand variations can be used for shorter periods (hours and days) or longer periods (e.g. to store solar heat production during summer time for use during colder months). Compared to other measures of energy storage, heat storage is relatively cheap.

9.2 Financial analysis

The cost of a new district heating network depends much on local circumstances, and requires a site specific assessment to be accurate. It is assumed in the modelled business-as-usual scenario that the district heat delivered to the consumer is based on a generating capacity of 10 MJ/s or greater; that the average distribution cost starts at 6.6 cents/kWh in 2010; and that it increases to 7.2 cents/kWh in 2050, due to reduced heating demand resulting from dwelling energy efficiency improvements.[18] It must be repeated, however, that distribution costs are extremely site specific and can vary tremendously depending on the size and type of system. Therefore these values serve as very general figures.

The distribution cost must be added to the heating cost 'at plant gate' for the various heat production options, which gives the total heat price at the end-user. An overview of these costs is displayed below.

[18] This average distribution value of 6.6 cents is based on Danish figures.

Cents/kWh	2010			2050		
Heat Source	**Cost**	**Dist.**	**Total**	**Cost**	**Dist.**	**Total**
Wood chips CHP	1.3	6.6	**7.9**	4.0	7.4	**11.4**
Wood chips Heat	3.7	6.6	**10.3**	6.2	7.4	**13.6**
MSW CHP	6.9	6.6	**13.5**	4.7	7.4	**12.1**

Table 19: District heating costs at the end-user in 2010 and 2050 according to production type. Distribution costs can vary substantially from generalised figures.

9.3 Link to GIS maps

District heating is possible in areas with high energy consumption. High energy consuming areas were mapped using a local neighbourhood function in ArcGIS. First, the centroid of each energy consuming parcel was extracted and valued according to its energy usage. Hereafter, a point statistics function was used to calculate summarized energy usage from point features that fall in the neighbourhood around each output raster cell.

The outcome is a map of relative energy density that clearly divides the CVRD into hot-spots (i.e. high energy usage) and cold-spots (i.e. low energy usage). The hot spot areas were delineated and used as the mask defining areas where district heating could be a viable option. The delineated hot-spots were subsequently converted to a grid, with the average cost of district heating (i.e. 10.3 cents/kWh) assigned to each grid cell.

Figure 21 below illustrates that district heating is viable in 12 areas.

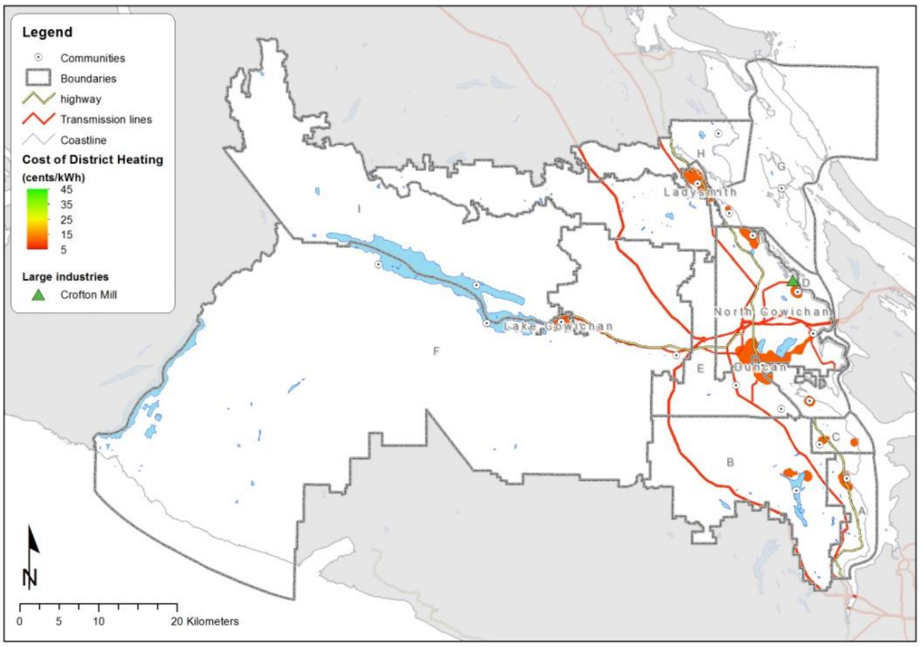

Figure 21: Cost of supply (cents/kW) for district heating 2010.

10 Summary

This report combined the resource screening from the previous report with a cost investigation of the various RE technologies deemed most relevant in the CVRD. The primary aim has been to determine the end-user costs of the various production technologies, thus allowing comparison on a cents/kWh basis, which can then serve as inputs to the scenario modelling in task 4.

10.1 Electricity

Figure 22 presents the residential end-user electricity cost of from the various electricity production technologies in the business-as-usual scenario, including an assumed distribution cost.

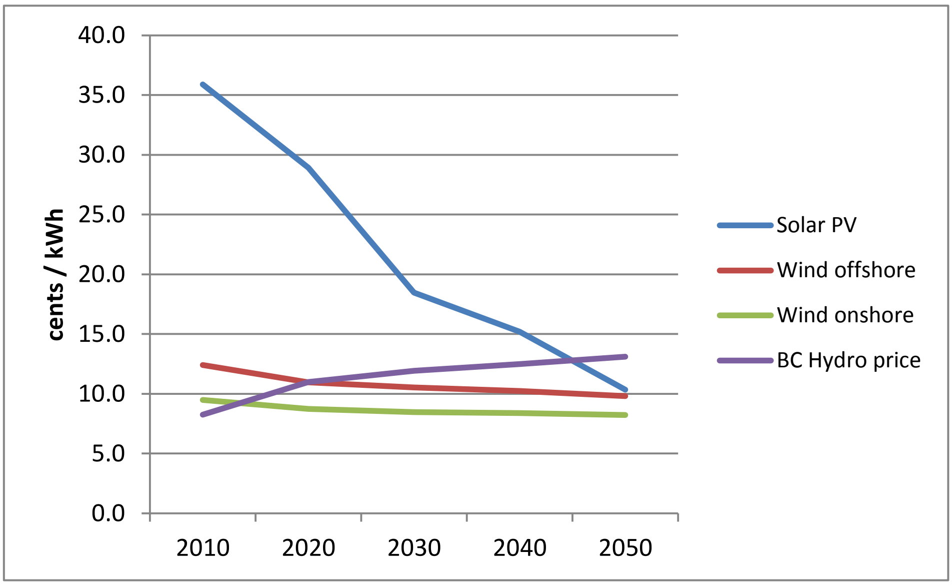

Figure 22: Cost of electricity supplied to residential end-users. Costs for mini hydro are not included as they are extremely site specific. From the end-users viewpoint electricity costs from CHP plants are assumed equal to the BC Hydro electricity price, with the price variation from the accompanying heat production occurring on the heat side.

End-user electricity costs from CHP plants are assumed to be the same as from BC hydro. As such, there is no separate line in Figure 22 for electricity costs from CHP. The cost variation for the modelled CHP plants therefore occurs on the heat side of the CHP production, and these heat costs are shown separately in Figure 23. The cost of electricity based on mini hydro is not included, as the cost is extremely site specific and the lack of potentially adequate sites in the CVRD would mislead the reader to believe that it is a viable option at this cost.

The electricity production costs show that solar PV is significantly higher at present compared to other electricity production technologies and is, in fact, a factor 4 higher than the 2010 BC Hydro electricity price. However, this cost is anticipated to fall drastically over the period up to 2050. The cost of onshore wind is already competitive with the BC hydro price and falls slightly, while the cost of offshore wind also falls gradually through to 2050.

Recommendations

Based on our findings, and given a desire for renewable electricity produced within the CVRD, it is recommended that the CVRD further investigate concrete potential wind projects within the region. Small-scale grid connected PV electricity production is not anticipated to be cost competitive with onshore (or offshore) wind for many years, and therefore it is recommended that (on a cost basis) it not be prioritised at this point.[19] However, PV costs have fallen dramatically in recent years and their cost development should therefore be monitored going forward.

10.2 Heat

Based on data and assumptions regarding fuel prices, technologies, and anticipated development, Figure 23 shows the cost of heating (cents/kWh) supplied to residential end-users according to heating option.

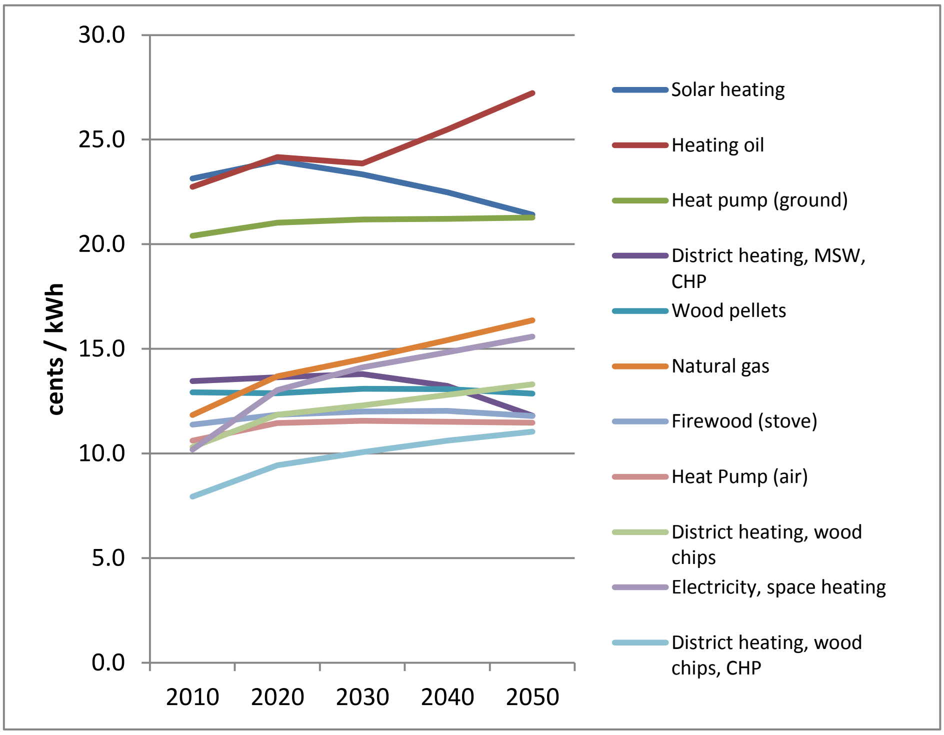

Figure 23: Cost of heat supplied to residential end-users. The cost is a weighted average according to residential dwelling type and whether it is an existing or new unit. District heating costs in particular are very site specific, and could therefore vary greatly.

[19] As an off-grid RE option, PV is a significantly more cost competitive technology.

The most expensive heating technologies throughout the period 2010-2050 remain solar heating, heating oil, and geo-exchange.[20] The cost of heat based on natural gas, electricity, wood chip-based district heating, and wood chip-based CHP district heating increase significantly over the period due to rising fuel costs. Meanwhile, the cost of MSW-based CHP district heating decreases over the period as the value of the electricity by-product increases. Lastly, the heat supply cost of firewood stoves, wood pellets, and air-to-air heat pumps remains fairly stable and relatively low.

Recommendations

Based on these findings, it is recommended that the CVRD further investigate concrete district heating projects within the region. The costs of implementing a district heating distribution network can vary greatly, but under good conditions can provide the lowest cost heat solution. It is also recommended that air-to-air heat pumps be promoted, especially in areas where district heating is not likely to be an option.

A particular focus on the replacement of oil and natural gas furnaces is recommended, as these technologies have both a high carbon footprint, and due to anticipated fuel cost increases, will become increasingly more expensive for the end-users.

On a lifecycle basis, as electricity prices increase, air-to-air heat pumps will become increasingly more cost-effective than electric baseboard heating, while at the same time providing the added benefit of reducing electricity consumption by roughly 2/3. However, relative to air-to-air heat pumps, electric baseboard systems have relatively low upfront costs, but much higher electricity costs. As such, an effective promotion of air-to-air heat pumps should provide consumers with knowledge of the long-term cost savings associated with air-to-air heat pumps, and, if possible, access to low cost financing, thus reducing the upfront costs.

With respect to end-users that are not connected to the electricity grid, a switch from oil or propane furnaces to wood pellets would result in both cost and GHG emission savings.

[20] Geo-exchange heat costs are site specific depending on potential heat sources, heat demand, etc., and therefore could vary greatly. Meanwhile, quotes for solar water heating systems varied widely, so these costs should be viewed with caution and further investigated.

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12 Appendices

Energy conversion factors

As a reference for the reader, the table below gives an overview of the various energy related terms and units that are utilised throughout the report.

Aspect	Symbol	Name	Value
Energy quantity Generally used to measure heat values	J	joule	1
	kJ	kilojoule	10^{3}
	MJ	megajoule	10^{6}
	GJ	gigajoule	10^{9}
	TJ	terajoule	10^{12}
	PJ	petajoule	10^{15}
Power Generally used to measure the output of a plant or device	W	watt	1
	kW	kilowatt	10^{3}
	MW	megawatt	10^{6}
	GW	gigawatt	10^{9}
	TW	terawatt	10^{12}
Energy quantity Generally used to measure the amount of electricity	Wh	watt hour	1
	kWh	kilowatt hour	10^{3}
	MWh	megawatt hour	10^{6}
	GWh	gigawatt hour	10^{9}
	TWh	terawatt hour	10^{12}
Conversion factors:	1 Wh	3,600 J	
	1 kWh	3.6 MJ	
	1 MWh	3.6 GJ	
	1 GWh	3.6 TJ	
	1 cent/kWh	10 CAD/MWh	