Techno-Economic assessment of Geothermal Energy Resources in the Sedimentary Basin in Northeastern British Columbia, Canada

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Contents

1 Highlights

- Demonstrates method to produce geothermal favourability map
- Identifies four areas favourable for geothermal development
- Estimates gross electric power output via probabilistic Volume Method (P90):
- Assesses key financial indicators of geothermal power plants (LCOE, NPV, IRR)
- Indicates favourable sites have gross electric power output (P90) @ LCOE:
    - Horn River: 3.7 MW @ 162 $/MWh_e$
    - Clarke Lake: 44.5 MW @ 166 $/MWh_e$
    - Prophet River: 22.0 MW @ 144 $/MWh_e$
    - Jedney: 7.8 MW @ 156 $/MWh_e$
- Discusses results in comparison to previous studies
- Identifies further research needs:
    - Reduce uncertainty regarding size of geothermal reservoir
    - Estimate achievable brine flow rates
    - Determine the commercial value of heat

2 Executive Summary

This study assesses geothermal energy resources and electricity costs in the Western Canada Sedimentary Basin section located in northeastern British Columbia, Canada. No geothermal power plant exists in Canada to date, and uncertainty regarding the available resource and costs remains high. This study highlights areas of high geothermal favourability, quantifies available electricity production at four locations within the study area and estimates capital costs and key financial indicators for power plants at those locations.

The four locations are Horn River, Clarke Lake, Prophet River and Jedney. These are selected using a favourability map, which takes geological and economic criteria into consideration. Geological criteria are modelled via temperature and indicated aquifer data that point to potential geothermal reservoirs. Economic criteria include distance to electrical infrastructure, distance to towns and small communities and whether a natural gas development is expected at a location.

The amount of available electric power output per unit reservoir area and required brine flow rate are quantified at the four selected locations. Here, the volume method is applied in combination with Monte Carlo simulations. A case study, which uses the area of known natural gas pools as a proxy, computes the size of potential geothermal power plants. **The P90 electric power output of these proxy geothermal power plants is:**

- Horn River: 3.7 MW
- Clarke Lake: 44.5 MW
- Prophet River: 22.0 MW
- Jedney: 7.8 MW

The capital costs of geothermal power plants at the four locations are estimated by scaling price quotes from industry. Price quotes are available for

- a 2.5 MW_e organic Rankine cycle geothermal power plant and
- drilling and completing a 3000 m deep geothermal well.

Key financial indicators are calculated for the geothermal power plants assessed in the case study. Indicators include the Levelized Cost of Energy (LCOE), the Net Present Value (NPV) and the Internal Rate of Return (IRR). LCOE calculations only take electricity production into account (thermal energy production is disregarded). **LCOE values are:**

- Horn River: 162 $/MWh$_e$
- Clarke Lake: 166 $/MWh$_e$
- Prophet River: 144 $/MWh$_e$
- Jedney: 156 $/MWh$_e$

Assessment of NPV and IRR considers revenue from electricity sales and thermal energy sales. Electricity and thermal energy are priced at 110 \$/MWh$_e$ and 2 \$/GJ$_{th}$, respectively. The electricity price is chosen to be equivalent to the base price in BC Hydro's Standing Offer Program. The thermal energy price is the approximate Alberta wholesale price of natural gas averaged over the year preceding this study. Results show positive NPV at a 5 % discount rate, with IRR values ranging from 6 % to 7.8%. The additional benefit of utilizing excess heat (e.g. in greenhouses) is key to making those projects economically viable.

3 Introduction

To date, Canada has no installed geothermal electrical power capacity. In other countries geothermal energy is a relatively low-cost (EIA 2013) and low greenhouse gas emitting (Kristmannsdottir & Armannsson 2003) power source. Geothermal power plants provide high-value baseload power, which is demonstrated by their high capacity factors (Table 6.7.B in EIA 2017a). Capacity factor is the ratio of energy produced over the technological maximum energy production. Variable power sources, e.g. wind and solar, are less valuable to the electricity system because they require backup capacity. Therefore, geothermal energy can help to decarbonize Canada's future energy system.

A key barrier to geothermal development is its high level of uncertainty in terms of cost and available resource (BC Hydro 2013). These uncertainties remain high, despite several studies estimating resource and costs (discussed in Section 4). This uncertainty propagates into long-term electrical energy planning, where recent studies for British Columbia and Alberta (English et al. 2017; Lyseng et al. 2016) have had to rely on geothermal energy cost estimates produced for the USA (EIA 2013). However, USA cost estimates do not reflect the full financial risk associated with developing geothermal energy in western Canada, because the USA has policy mechanisms in place that mitigate risks to project developers. These are, e.g. partial loan forgiveness for failed wells or grants for well development. Such mechanisms do not exist in Canada. Therefore, further research specific to Canada is necessary to better understand the contribution that geothermal energy can make towards meeting future electricity demand growth.

The high-temperature volcanic geology in British Columbia makes this province a focal point of geothermal research in Canada (Grasby et al. 2012). The lower temperature Western Canada Sedimentary Basin (WCSB), especially the section located in northeastern British Columbia, has received less attention. However, this region has been subject to substantial oil and gas development, and a significant database of wells is available from the BC Oil and Gas Commission. This data has been successfully applied to estimate the electric power potential in the Clarke Lake gas field (Walsh 2013). In this study, the database of wells is used to assess the potential electricity production and the cost of geothermal power plants in the British Columbian section of the Western Canada Sedimentary Basin (WCSB). Figure 1 show this project's study area.

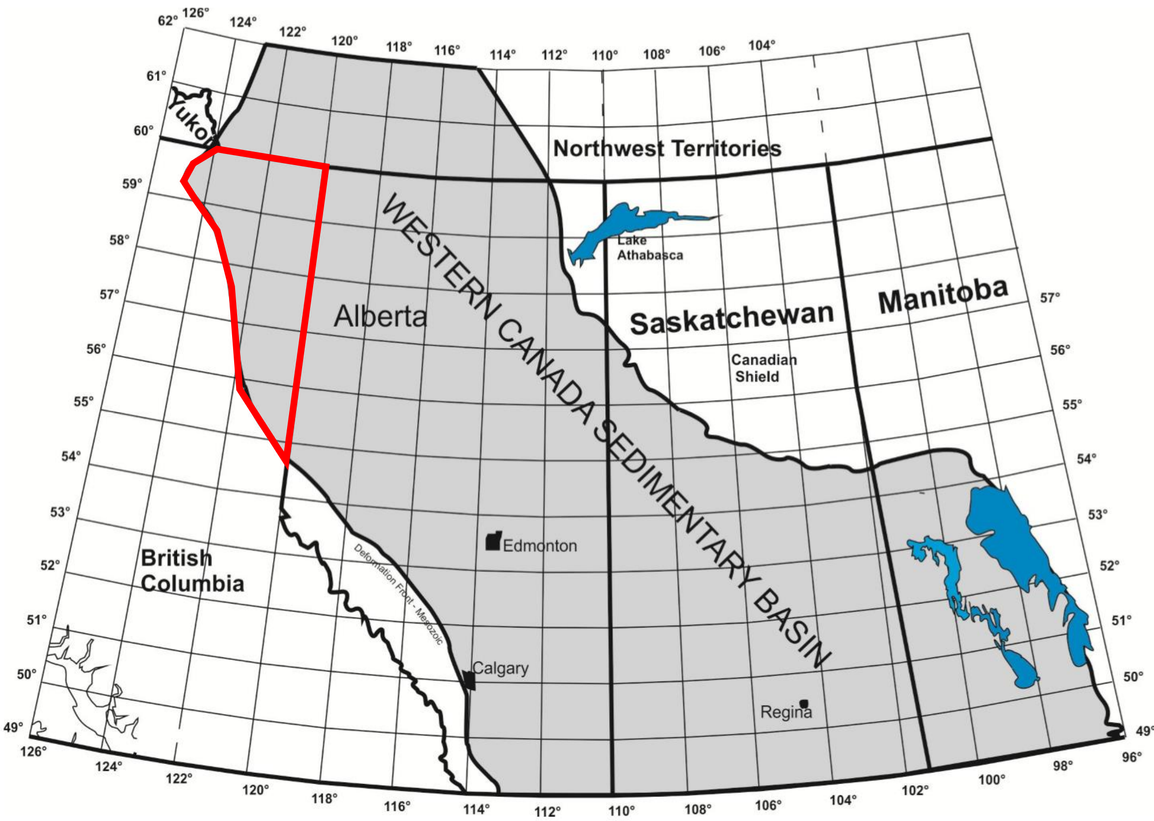

Figure 1 Location of the project area (in red) within the Western Canada Sedimentary Basin (WCSB). Adapted from (Grasby et al. 2012)

This study is divided into three parts. A geothermal favourability map is computed to highlight areas of highest potential for geothermal energy development. The favourability map is a product of several geological and economic layers which are combined in a weighted summation process (ESRI n.d.). Layers include temperature at depth, indicated aquifers and distance to electricity and heat consumers. The favourability map is used to select four sites for further investigation. Here, the available potential electric power output and the required brine flow rates are quantified by applying the volume method (Williams et al. 2008). That section also includes a case study in which the potential size of geothermal power plants at the four sites is illustrated by applying natural gas pool areas as proxy geothermal reservoirs. 'Size' refers to the power output and number of production and injection wells required for each power plant. The capital cost of geothermal power plants is estimated using recent power plant and well drilling cost quotes. Further, the levelized cost of energy is estimated via a cash flow analysis.

4 Background of Geothermal Costs and Resources in British Columbia

This section provides an overview of studies that attempt to quantify the cost and the available resource base of geothermal energy for electricity production in British Columbia. Methods and results differ significantly between studies. For this reason, the uncertainty regarding costs and available resources remains high.

In 2002, BC Hydro identified six sites with the "greatest potential for geothermal development"; all of which are located outside of the WCSB (BC Hydro 2002). The estimated capacity is between 150 MW and 1070 MW, with a levelized cost of energy of 50 $/MWh to 90 $/MWh. That study was extended by Pletka & Finn (2009), who located and quantified geothermal resources in the western United States, British Columbia and Alberta. That study estimated the potential installed capacity and levelized cost of electricity for the 18 most promising sites in British Columbia, two of which were located in the WCSB. The total estimated British Columbian potential installed capacity was 340 MWe at a levelized cost of energy of 100 USD/MWh to 180 USD/MWh. These cost estimates were based on USA experiences, which were multiplied by a factor of 1.3 to adjust for the more challenging environmental conditions of British Columbia. The report does not explain how this multiplication factor was deduced.

In 2014, the Canadian Geothermal Energy Association, an industry organization, reported substantial geothermal resources in the sedimentary basin of northeastern BC (CanGEA 2014). The report quantifies the minimum "technical potential" to be 5,723 MW of installed capacity. However, the applied methodology was developed for enhanced geothermal systems (Beardsmore et al. 2011). The method does not take into account that conventional geothermal power plants (i.e. binary cycle, dry steam and flash steam power plants) require a hydrothermal reservoir in-place.

The latest, most comprehensive techno-economic study of geothermal resources in British Columbia was released by Geoscience BC (2015). Here, a pre-feasibility study was performed on nineteen sites. The eleven most favourable sites were evaluated in detail. Costs were assessed with the Geothermal Electricity Technology Evaluation Model (GETEM). Potential installed capacity was estimated using the volume method (Williams et al. 2008) combined with Monte Carlo simulations to tackle uncertainty in input parameters. This stochastic approach produces probabilistic results. The P90 value states that 90 % of all Monte Carlo iterations reach or exceed the stated value, while the P50 value states that 50 % of results are below and 50 % of results were above the stated value. The median, or P50, total capacity was 626 MW, and the P90 total capacity was 310 MW for the eleven sites. For the P90 capacities, the capital costs ranged between 5,700 $/kW and 13,900 $/kW of installed capacity, while the levelized cost of energy ranged between 117 $/MWh and 398 $/MWh. Two of the eleven sites are located within the WCSB, namely Clarke Lake and Jedney, which have the highest LCOE within the aforementioned range. Their LCOE is 297 $/MWh and 398 $/MWh, respectively.

In spite of this comprehensive study, the uncertainty of LCOE estimates remains high for several reasons. According to the authors, the assumed drilling costs are based on "experiences from 2012" (BC Hydro 2015). However, drilling costs have decreased due to a significant decline in crude oil prices since that year. Drilling costs are a major cost factor in geothermal project development. Additionally, the reservoir temperature used in the cost assessment of Clarke Lake and Jedney was 160°C, which is the lowest temperature applicable in GETEM. However, reservoir temperatures are listed as between 81°C to 123°C at Clarke Lake (Appendix C, Geoscience BC 2015) and 130°C to 149°C at Jedney (Appendix F, Geoscience BC 2015). Additional research to reduce the uncertainty of resource and cost estimates is therefore justified.

5 Geothermal Favourability Map

The geothermal favourability map produced in this section highlight areas where geothermal power plants are most likely feasible within the British Columbian section of WCSB. The map is produced by spatially overlapping criteria that are beneficial to geothermal power development. Areas where geothermal favourability is highest warrant a detailed investigation of available geothermal resources and costs.

Favourability maps are often used to identify potential locations for geothermal energy development (Moghaddam et al. 2014; Kimball 2010; Noorollahi et al. 2008; Coolbaugh et al. 2005; Prol-Ledesma 2000). However, mapping methods vary from study to study. There is no standard approach because different types of available data, different regional scales and different purposes require different methods.

5.1 Methodology

The favourability map is a tool to visually present where geological and economic criteria overlap to create favourable conditions for geothermal power development. The favourability map is produced by overlaying geological and economic data in a geographic information system.

In this study the favourability map is produced via the following steps:

1. Select relevant criteria (Section 5.1.1)
2. Compile data relevant to criteria (Section 5.1.2)
3. Compute input layers from data (Section 5.1.3)
4. Weight and sum input layers (Section 5.1.4)
5. Display favourability map (Section 5.1.5)

These steps are illustrated in Figure 2. First, criteria are selected based on their relevance to geothermal development and whether data is available to represent these criteria. Relevant data is compiled into a format suitable for use in a geographic information system. Input layers are created from relevant data so that each input layer represents one criteria. A two-level weighted summation process is applied to the input layers. Here, weights to input layers are assigned, and the sum of all weighted input layers are computed to produce separate summary layers for geological and economic criteria. The summary layers are again weighted and summed to finally produce the favourability map.

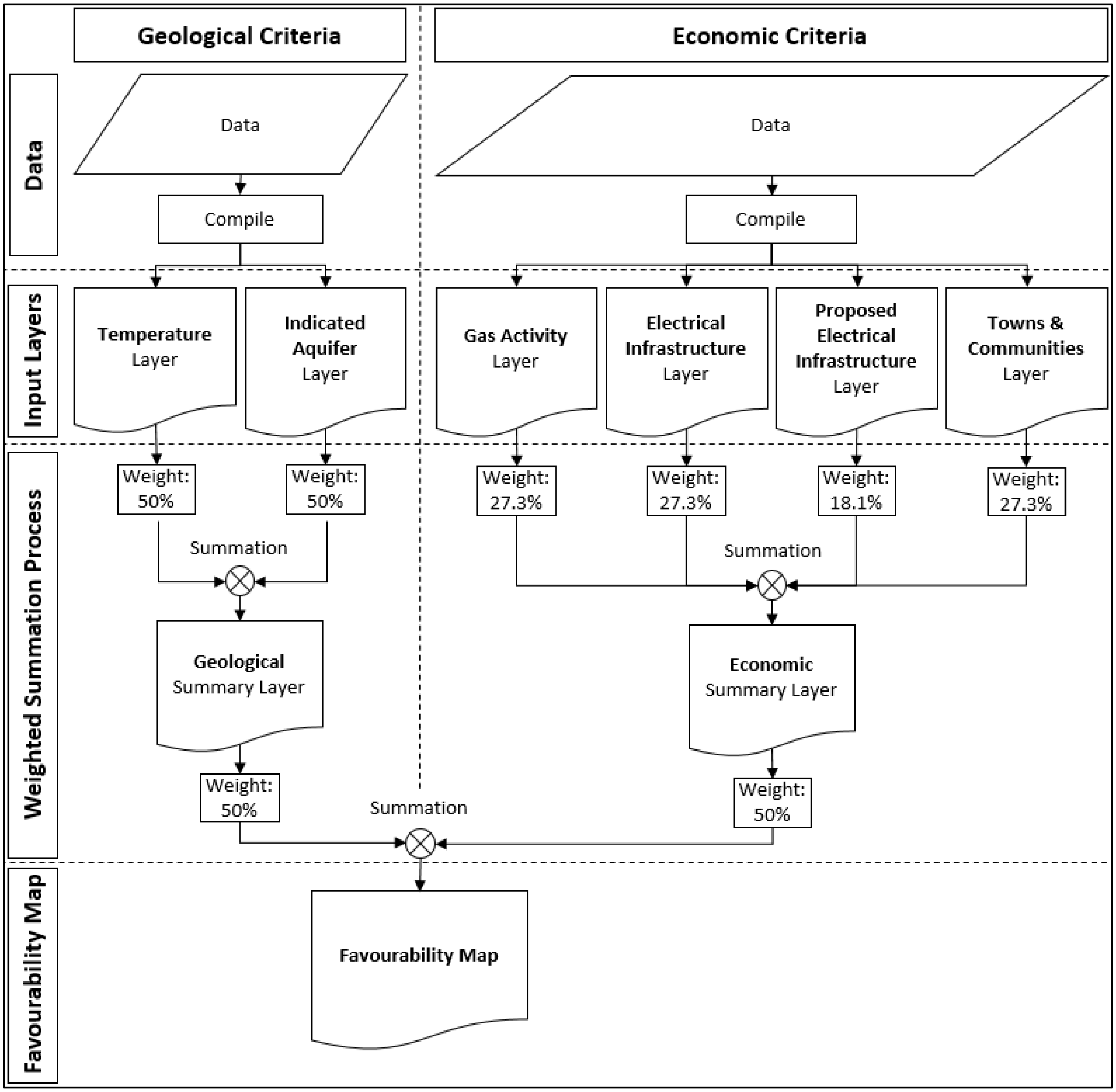

Figure 2 Overview Flowchart of the process to compute the favourability map, employing an adaptation of a two-level Weighted Linear Combination

5.1.1 Criteria Selection

This section describes which criteria are taken into account for compiling the favourability map. Criteria must be relevant for either the geological or economic feasibility of a conventional geothermal power plant to be selected. Each criteria is represented by one input layer (Figure 2). Input layers are named after their criteria. Geological criteria are temperature and indicated aquifer. Economic criteria are gas activity, electrical infrastructure, proposed electrical infrastructure and towns & communities.

5.1.1.1 Geological Criteria

Temperature

The temperature of potential geothermal reservoirs is crucial to geothermal development. Geothermal power production becomes technologically feasible at a temperature difference greater 80 °C between source and sink (Grasby et al. 2012). All else being equal, higher temperatures allow for more electricity production, which results in lower costs per unit electricity.

Indicated Aquifer

Conventional geothermal reservoirs require an aquifer to be in-place in order to allow thermal energy extraction. Furthermore, the reservoir rock must have sufficient hydraulic conductivity to allow the extraction of fluid from the reservoir. Therefore, geological data must indicate the existence of permeable aquifers.

5.1.1.2 Economic Criteria

Gas Activity

Power plants must sell their electricity either to the grid or to local consumers. The natural gas industry is a potential local consumer, because geothermal power may supply natural gas production with low-carbon electricity. In many cases, remote natural gas facilities use a share of their produced gas as “lease fuel” to supply compressors and pumps. An average of 4% of provincial natural gas reserves are attributed to lease fuel in Alberta (Alberta Energy Regulator 2015), which significantly contributes to carbon emissions from the upstream natural gas sector (Navius Research 2016). British Columbia’s recently released Climate Leadership Plan highlights the need to minimize the carbon footprint of the upstream natural gas sector, but recognizes the high cost of extending the electrical grid into areas where future gas developments are expected (Government of British Columbia 2016). Geothermal power may be able to mitigate this cost.

Electrical Infrastructure and Proposed Electrical Infrastructure

Siting a geothermal power plant in close proximity to electrical infrastructure reduces the cost of building transmission lines, which are a major cost factor.

Proposed electrical infrastructure is not yet operational, but in planning. Since completion of proposed electrical infrastructure cannot be guaranteed, this criteria is treated separately from the (existing) electrical infrastructure criteria. This allows lesser weighting of proposed electrical infrastructure during weighted summation (discussed in Section 5.1.4).

Towns and Communities

Locating geothermal development relatively close to towns and small communities increases economic viability in two ways. First, construction and operating costs may be lower if workers can be housed in a nearby community rather than a remote camp. Secondly, access to excess heat from the geothermal plant presents the opportunity to develop additional economic activity, e.g. a district heating system or greenhouses.

5.1.2 Input Data Compilation

Six criteria that add to geothermal favourability have been selected in the previous section. In this section, input data is compiled to represent the selected criteria. Data for each criteria can have multiple sources, as listed in Table 1.

Table 1 Data sources for favourability map input layers

Criteria	Input Data	Data Provider	Reference
Temperature	Drill-Stem Tests	BC Oil & Gas Commission	Download via AccuMap
	Bottom Hole Temperatures	BC Oil & Gas Commission	Download via AccuMap
Indicated Aquifer	Drill-Stem Tests	BC Oil & Gas Commission	Download via AccuMap
	Natural gas producing well logs	BC Oil & Gas Commission	Download via AccuMap
Gas Activity	Horn River Basin Pools	BC Oil & Gas Commission	(BC Oil and Gas Commission 2014)
	Cordova Embayment	BC Oil & Gas Commission	(BC Oil and Gas Commission 2017b)
	Northern Montney & Heritage Fields	BC Oil & Gas Commission	(BC Oil and Gas Commission 2017a)
Electrical Infrastructure	Substations	BC Hydro	(BC Hydro 2012b)
	Transmission Lines	BC Hydro	From BC Hydro (no longer available)
Proposed Electrical Infrastructure	Substation & Transmission Line	Peace River Regional District	(ATCO Power 2015)
Towns & Communities	Towns & Communities - geographical centers	Google Maps	-

The favourability map is computed using a geographic information system. Hence, all data is geographical, which mean that it contains location information and can be mapped. For example, temperature data contains the geographical coordinates of the measurements in addition to temperature, depth, and other information. Electrical infrastructure data contains geographical locations and the type (transmission line or substation). Data compilation is described in Sections 5.1.2.1 and 5.1.2.2 below. Flowcharts of data compilation and input layer computing are available in the Appendix.

5.1.2.1 Geological Data

Temperature

The temperature of a geothermal reservoir is crucial to geothermal development. For this study, reservoir temperatures are estimated from data recorded in lower middle-Devonian strata of the Elk-Point and Beaverhill Lake Groups (Chapter 10: Mossop & Shetsen 1994). These strata will henceforth be called relevant strata and are chosen for analysis because they a) potentially contain aquifers and b) are located at depths that potentially exhibit temperatures that enable binary-cycle geothermal power plant electricity production (above 80°C).

The source of the temperature data varies in depths (Figure 3). A constant depth temperature layer would contain data recorded in strata from several different eras, since the basin becomes shallower as we move away from the cordilleran deformation front (Figure 3.2 in Chapter 3: Mossop & Shetsen 1994). The depth to the top of relevant strata ranges between approx. 1400 m at the border of British Columbia and Alberta to approximately 4000 m at the base of the cordilleran deformation front.

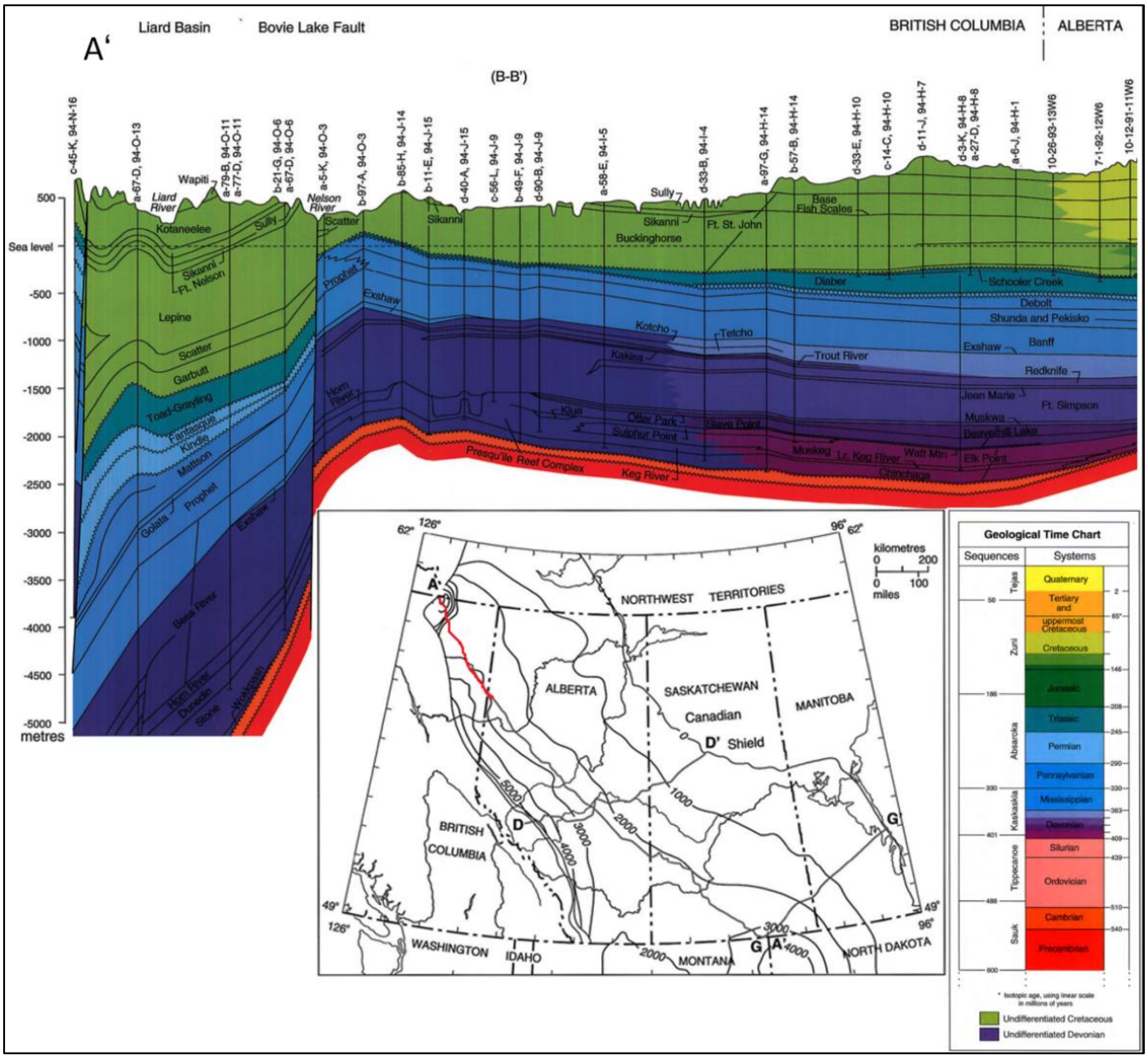

Figure 3 Stratigraphic cross-section of the WCSB in northeast British Columbia. Cross section runs from A' on the left to the British Columbia – Alberta border on the right, along the red line in the map. Adapted from Mossop & Shetsen (1994)*.*

The history of petroleum exploration provides northeastern British Columbia with an immense quantity of temperature data of varying quality. The two main data sources used for this project are temperatures recorded during drill-stem tests (DST), which is a short production test, and bottom hole temperatures (BHT), which are recordings of temperatures at the bottom of a drilled well.

Several strategies for quality control are applied to the temperature data. Over 1780 digitally available BHT measurements from logs collected in relevant strata are used. Deviated and horizontal wells are removed from the data set. Where multiple records exist for a well, only the single highest BHT-record is used. This applies to approximately 30 cases. Depth versus temperature is plotted, and twenty-four wells with anomalously high (>60°C/km) or low (<20°C/km) temperature gradients are manually removed. Approximately 1200 BHT measurements remain. Due to the cooling effect of drilling fluid, BHT measurements were Harrison-corrected (Harrison et al. 1983) in order to avoid underestimation of the resource.

A total of 7425 DST records in northeast British Columbia and Alberta are collected. Data that was recorded in strata younger than relevant strata, or exhibit anomalously high or low temperature gradients, are removed. Approximately 6700 records remain.

The combined set of BHT and DST data is used to compute the temperature input layer (Section 5.1.3.1). Locations of temperature measurements from BHT and DST data are shown in Figure 4.

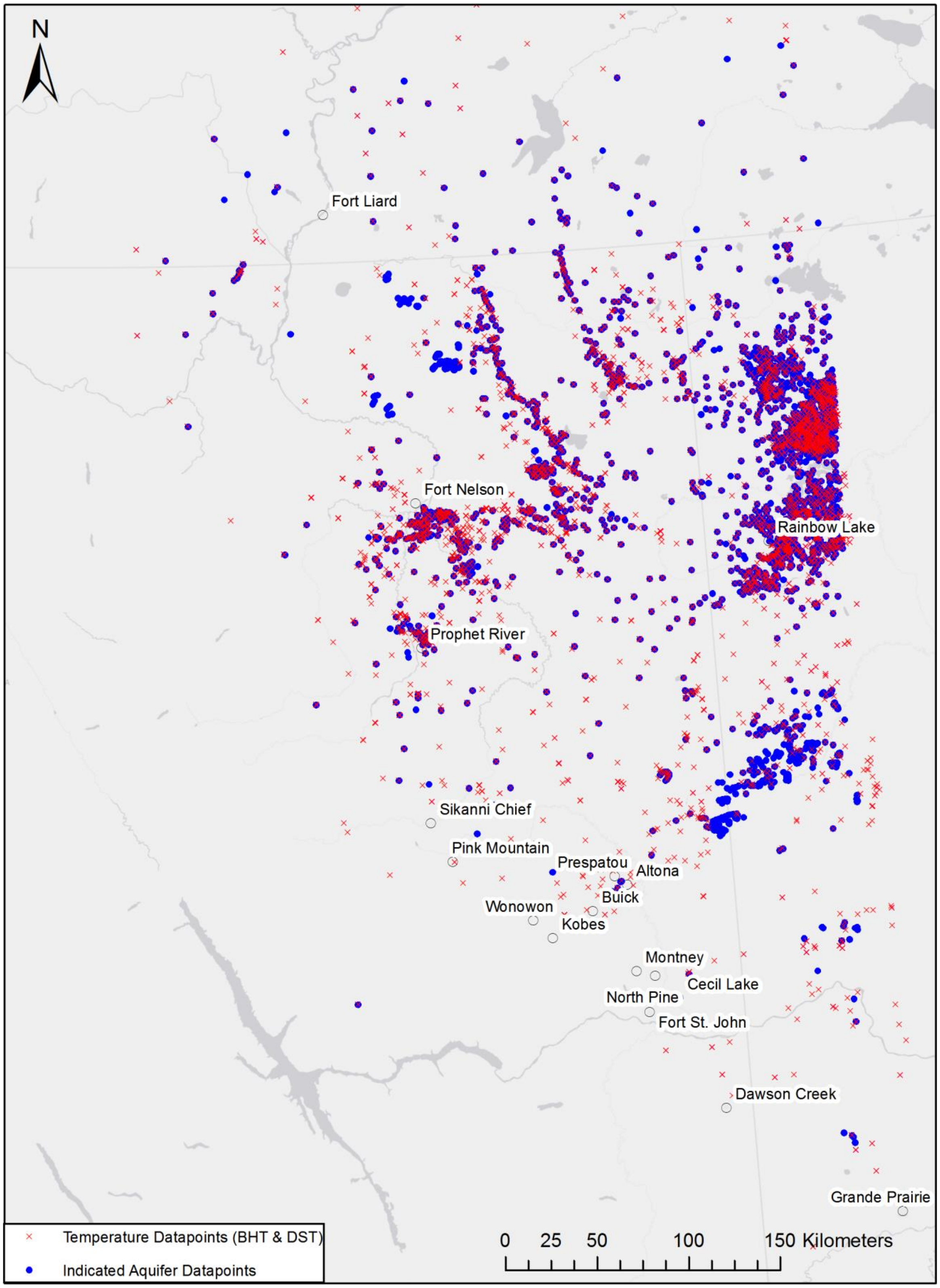

Figure 4 Locations of datapoints taken into account for the Temperature and the Indicated Aquifer Layer

Indicated Aquifers

In order to extract heat from a basin-hosted geothermal reservoir, an aquifer needs to be in place. The available data does not allow locating aquifers with certainty, but data can be used to derive indicators that an aquifer may be present at a certain location. Two types of data recorded in relevant strata of the lower middle-Devonian and Beaverhill Lake Groups are used:

1. Natural Gas producing well records
2. Drill Stem Test logs executed on wells drilled for hydrocarbons

A gross dataset of 3738 natural gas producing well records are obtained. These are filtered to include only wells where data indicates that a) some water was produced and b) production took place over an extended period of time (to exclude failed tests). We assume that some natural permeability exists in a formation if hydrocarbons are produced from a conventional well. Natural gas wells producing from shale formations (Muskwa, Otter Park and Evie) are therefore excluded from further processing, as this rock type usually requires artificial fracturing to enhance hydraulic conductivity. The respective variables and applied filters are listed in Table 2. A total of 2624 data records pass through all filters. The bottom-hole coordinates of these records are used to make the indicated aquifer layer of the favourability map.

Table 2 Filters applied to natural gas producing well records to include only those that indicate an aquifer

Variable	Filter
Average Daily Water Production	> 0 m^3/day
Cumulative Water Production	> 10 m^3
Number of Production Hours	> 0 hours
Producing Zone	Not “Muskwa”, “Otter Park” or “Evie”

The gross drill-stem test dataset includes 6623 records. The records contain a “Blow Description” text field, which aggregates a variety of variables recorded during the test. The format of this text field varies among wells, which makes the automated filtering of records challenging. Therefore, a two-step method of string extraction and filtering is applied, as described in Table 3. First, the position of selected key-words describing a selected characteristic within the text is found via text search. If adjacent words further describing these characteristics include any of those listed in the second column, then the characteristic is considered to indicate a permeable aquifer. However, only DST records that indicate aquifers with at least 2 out of the three keywords (left column) are included in further processing. A total of 3274 DST records pass through the filter, qualitatively indicating permeable aquifers at those bottom-hole coordinates.

Table 3 Qualitative filters applied to DST records. Only records that meet two out of the characteristic descriptions are deemed to indicate a permeable aquifers.

Step 1: Find Key-Word / Characteristic	Step 2: Filter by Description
Blow	Strong
	Good
Recovery	Water
	Salt
	Sulphur
Permeability	Average
	Good
	Excellent
	High

The filtered and combined datasets from natural gas producing wells and drill-stem test records indicate permeable aquifers at 5897 locations, although some of these overlap. A map of their geographical locations is shown in Figure 4. This data is used to produce the indicated aquifer input layer (Section 5.1.3.1).

5.1.2.2 Economic Data

Gas Activity

Gas activity areas are those areas where future natural gas production facilities could be supplied with geothermal power. It is uncertain where natural gas development will occur, but historical sales of petroleum and natural gas rights give some indication. The most recent Oil & Gas Report (Ministry of Natural Gas Development 2016) assesses past development of hydrocarbon extraction activities in key areas in British Columbia's northeast; historical sales of petroleum and gas rights are taken from this document. Future natural gas development is therefore expected in these areas (denoted Gas Activity outlines in Figure 5):

- Northern Montney Field and Heritage Field
  The Northern Montney Field and the Heritage Field show the highest level of gas development activity. Here, the natural gas resource constitutes "wet" gas, which comprises natural gas liquids (condensates), making it a higher value product. Future natural gas development is likely here.

- Horn River Pools A and D of the Muskwa Otter Park Formation
  The Horn River Field has had some development in the past, but resources here are of the slightly lower-grade dry gas kind. For this reason, only pools rather than the entire basin are considered to likely have future natural gas development.

- Cordova Embayment
  The Cordova Embayment has similar resource characteristics to the Horn River basin. However, the area has existing oil and gas infrastructure, making the entire play a likely area for future hydrocarbon development.

These areas are used to compute the gas activity input layer (Section 5.1.3.2).

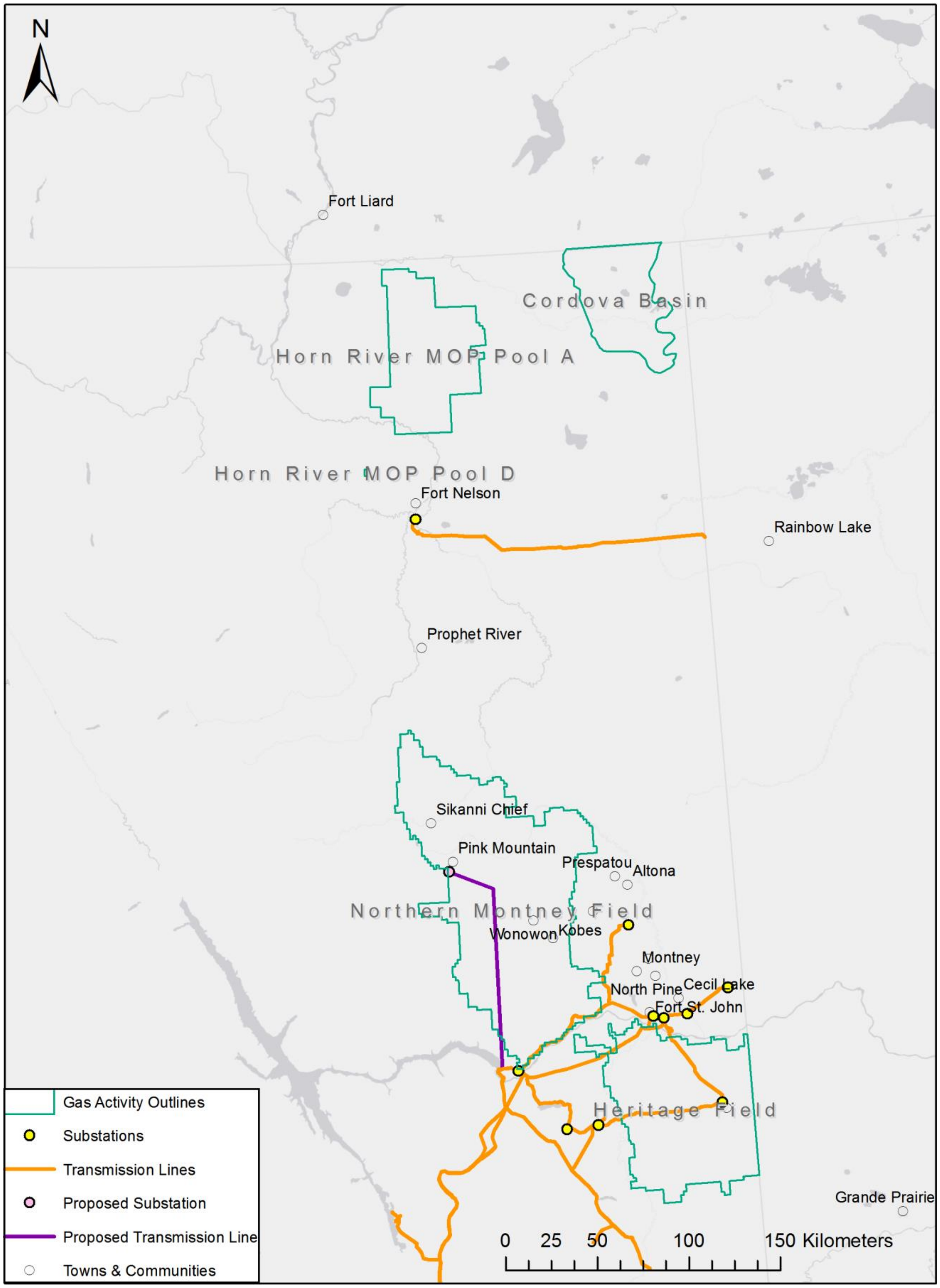

Figure 5 Locations of economic criteria features (MOP: Muswka Otter Park formation)

Electrical Infrastructure and Proposed Electrical Infrastructure

Electrical infrastructure are transmission lines and substations. These provide the opportunity to sell electricity to the grid, which makes their locations beneficial to geothermal development. Substations are generally less expensive to connect to, because they require fewer upgrades than connecting directly to a transmission line.

Geographical data on existing transmission lines and substations was made available for this study from BC Hydro. This data is used to compute the electrical infrastructure input layer (Section 5.1.3.2). Transmission lines feature a voltage of 60 kV and above. Lower voltage distribution lines are not taken into account, because their geographical data is not publicly available.

Within the study area, a new transmission line is currently in the planning process. This line would connect the Bennet Dam to Pink Mountain, 120 km to the north. We assume that a substation will be located at the northern end of the proposed transmission line. This information is used to compute the proposed electrical infrastructure input layer (Section 5.1.3.2).

The locations of existing and proposed transmission lines and substations are shown in Figure 5.

Towns and Communities

Towns and communities provide the opportunity to sell heat and develop further economic activities such as greenhouses, district heating system or aquaponics. Towns and communities were identified using Google Earth's search function as well as satellite imagery. The geographical center of each town and community is used to compute the towns and communities input layer. Locations of towns and communities are shown in Figure 5.

5.1.3 Input Layer Computing

There are six input layers, one for each criteria. The format of input data varies, e.g. temperature data is in point form with a temperature value attached, towns are point locations, gas activity areas are areas (polygons). Input layers are the result of harmonizing this data (i.e. applying a transformation function to each dataset). Harmonizing the data is necessary to allow comparing the value that different criteria add to geothermal favourability.

Input layers are computed to a gridded format that allows representation of input data. Each grid cell contains one normalized decimal value from 0 to 1. The value is a measure of the geothermal favourability of the respective criteria at that location. For example, in the temperature input layer a grid cell that contains a value close to 1 has a higher reservoir temperature than another cell with a value close to 0. In the towns & communities layer a value close to 1 represents a location close to a town or community, a cell with a value close to 0 is further away from a town or community.

Input layers are normalized on a scale from 0 to 1 because criteria need to be mathematically comparable to one another (Voogd 1983). Temperature, for example, is measured in units of degrees Celsius, while the proximity to a town or community is measured in meters. Therefore, a transformation is applied, so that input layer values range from 0 (unfavourable) to 1 (favourable). The values will henceforth be called 'scores'. Scores are assigned in three different ways:

1. Linearly between maximum and minimum value (e.g. temperature)
2. Linearly decreasing with distance from a feature (e.g. distance from transmission lines)

3. Binary – 1 or 0 (e.g. location within or outside of a gas activity area)

Input layer compilation is described in detail in the following sections. Flowcharts of data compilation and input layer computing are available in the Appendix.

5.1.3.1 Geological Factors

Temperature

Temperature data is in point form because it is was recorded at specific natural gas wells (Figure 4). A temperature map is produced by interpolating between measurements and applying spatial averaging (Figure 6). This map presents the temperature at the top of relevant strata that potentially contain geothermal reservoirs. The depth varies between 1400 m at the maps northeastern edge to about 4000 m at the cordilleran deformation front (Figure 3.2 in Chapter 3: Mossop & Shetsen 1994). The map is cropped along the British Columbia – Alberta border and along 80 °C contour. The latter is the minimum temperature that technically allows electricity production. The temperatures range between 80°C to 146°C. The map is in grid format with 100 m x 100 m grid cells, each containing a temperature value.

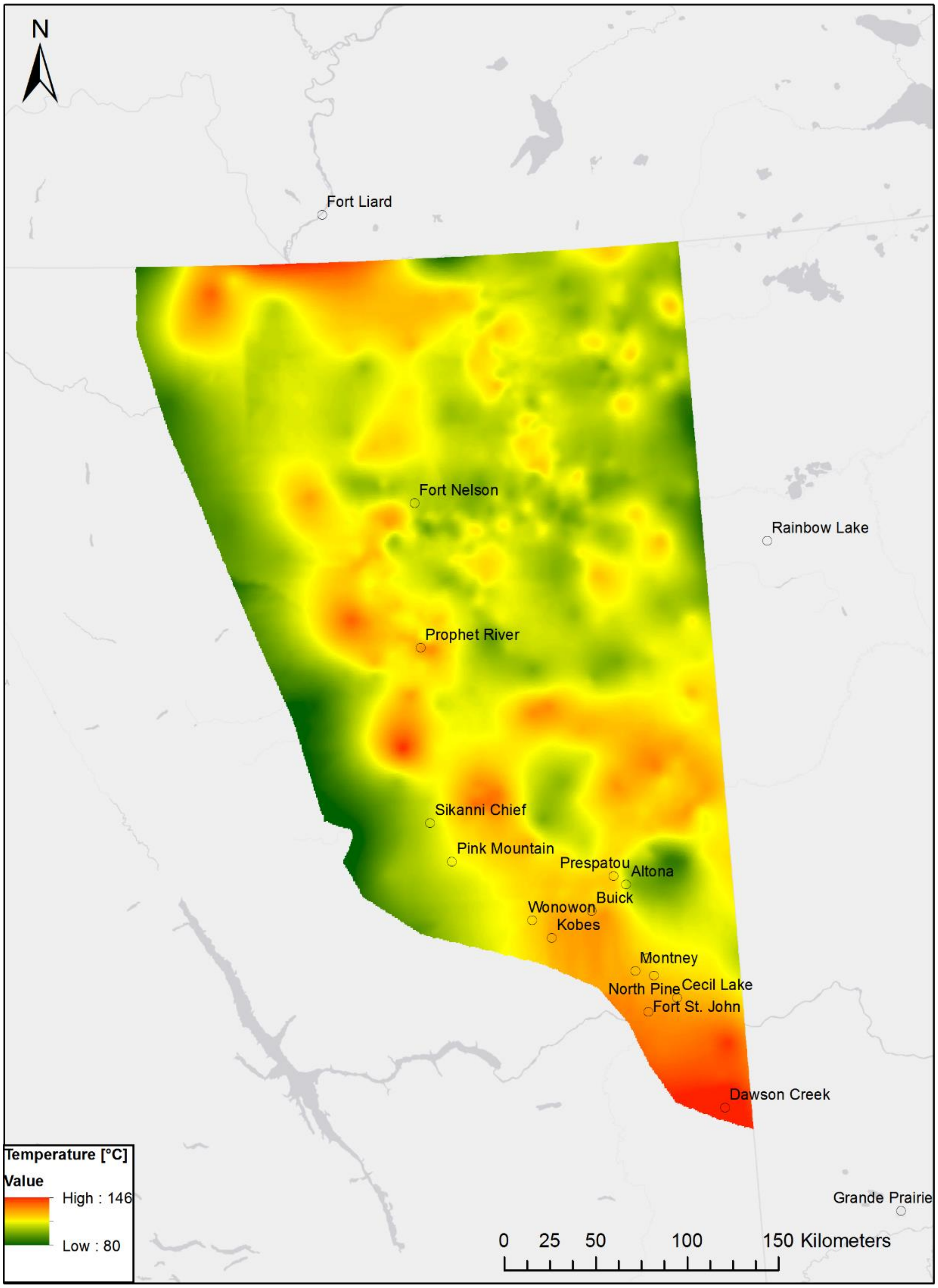

Figure 6 Temperature map at the top of relevant strata

The temperature layer is produced from the temperature map by normalizing the temperature values. The scores are computed linearly from a score of 0 at 80°C to a score of 1 at 146°C, as shown in Figure 7. A score of 0 for a temperature of 80 °C is appropriate, because the thermal efficiency of a power plant is so low at this temperature that feasibility is unlikely.

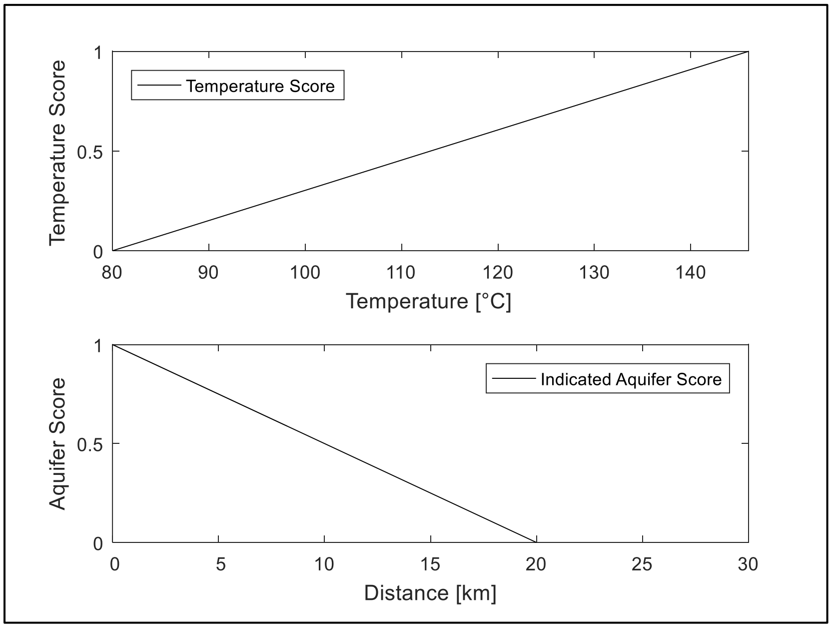

Figure 7 Scores assigned to the temperature layer and the indicated aquifer layer

<u>Indicated Aquifers</u>

The indicated aquifer input data identify point locations where drill-stem tests and wells drilled for hydrocarbons indicate some water at depth. We assume that the existence of a geothermal reservoir is likely at such a point location, but the chance of finding a reservoir decreases with distance from that location. The indicated aquifer layer is computed from these locations by computing the distance between every point within the project area to the closest indicated permeable aquifer, up to a distance of 20 km. A grid cell located on an indicated aquifer has a score of 1 and a grid cell located 20 km or more away from an indicated aquifer has a score of 0, as shown in Figure 7. The decline of scores with distance is linear.

The sensitivity of the favourability map to several different indicated aquifer scoring methods was evaluated within the context of this study. These included varying maximum distances and exponential, rather than linear, declining scores. While these changes had some effect on the overall result, those areas with highest favourability did not see a significant change. We therefore deem the method described above to be sufficient to identify those areas with the highest geothermal potential.

5.1.3.2 Economic Factors

<u>Gas Activity</u>

The gas activity data comprise areas where natural gas infrastructure might be developed in the future and might be electrified with geothermal power. The scores of this layer are binary. The score is 1 if a cell falls within a gas activity area and 0 if it is located outside of a gas activity area.

Electrical Infrastructure and Proposed Electrical Infrastructure

Electrical infrastructure and proposed electrical infrastructure data comprise, respectively, existing and planned transmission lines and substations. Separate input layers are computed from the existing and planned infrastructure data. While the method for assigning scores for both layers is identical, each layer is weighted separately in order to reflect the uncertainty of completion for the proposed transmission line to Pink Mountain. Weighting is discussed in Section 5.1.4.

Scores are assigned based on the distance from transmission lines or substations. First, the distance between every point within the project area to the closest transmission line is computed, up to a distance of 10 km. The process is repeated for substations, up to a distance of 20 km. The higher maximum distance for substations reflects the lower cost attributed to connecting a power plant to a substation as opposed to a transmission line. Since transmission lines feature a voltage of 60 kV or above, an additional substation would need to be constructed in order to connect to a transmission line. This study assumes that costs for a substation are approximately equivalent to the cost of about 10 km of feeder line (Windustry 2003). Thus, proximity to a substation is therefore valued double that of proximity to a transmission line. These scores are attributed to both layers by normalizing the distances linearly, as shown in Figure 8.

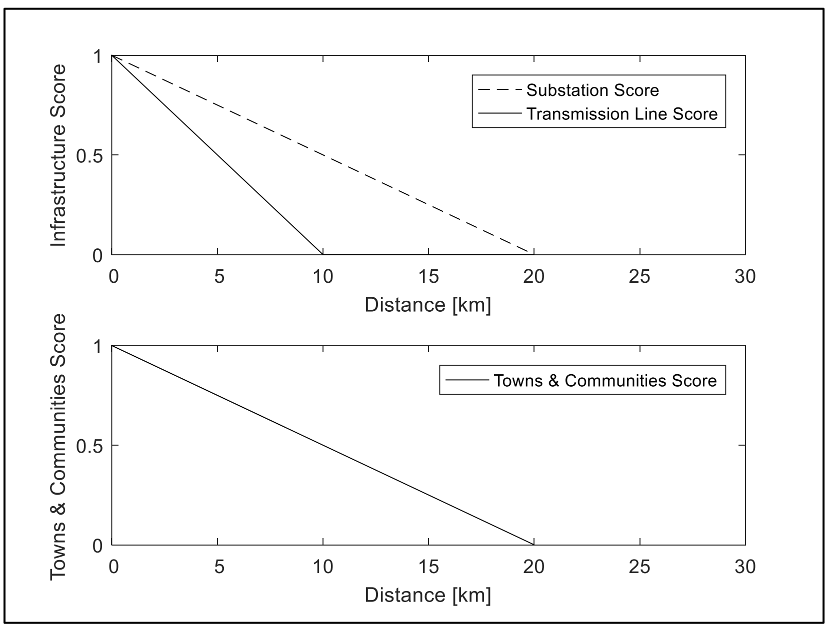

Figure 8 Scores assigned to the Infrastructure Layer and the Towns & Communities Layer

Where a point lies within a radius of 20 km of a substation and within 10 km of a transmission line, the higher score is attributed to that point, as shown in (Equation 1).

$$\text{Infrastructure } Score = Max \begin{cases} 1 - \dfrac{Distance\ to\ Substation}{20\ km} \\ 1 - \dfrac{Distance\ to\ Transmission\ Line}{10\ km} \end{cases} \qquad \textit{(Equation 1)}$$

We assume that the power plant can be connected to any point along a transmission line, or preferably, to a substation. A geothermal power plant might be feasible in the WCSB within an approximate capacity range of 5 MW to 70 MW, based on previous work at Clarke Lake (Walsh 2013). Connecting a power plant of this size to the electrical grid requires detailed modelling to assess available line capacity. Such modelling is outside of the scope of this study.

Towns and Communities

Towns and communities input data are the geographical town centers, which represent the possibility to sell excess heat from the power plant. Scores are assigned via the distance from geographical centers. The distance between every point within the project area to the closest town or community is compiled, up to a distance of 20 km. We consider 20 km to be the approximate distance up to which heat transport from the geothermal plant to the town might be possible, which is within the range of values found in the literature (International District Heating Association 1983; Ulloa 2007; Danfoss 2014). Scores decline linearly with distance. The center of a town or community has a score of 1, while a cell located 20 km or more outside of a town or community has a score of 0 (Figure 8).

5.1.4 Weighted Summation

Weighted summation is a method to compute a single output layer (which is the favourability map) from the six input layers. Input layers are grids where each grid cell represents a 100m x 100m square of the study area. The favourability map has the same format. Each cell value in the favourability map is a mathematical function of the six input layer cell values at the matching location. The function used to aggregate layers is an adaptation of a Weighted Linear Combination (Nyerges & Jankowski 2009; Malczewski 2000), which we call weighted summation. Literature provides multiple ways to weight and aggregate input layers, but Greene et al. (2011) provide a decision tree for how to select the appropriate method. This method was selected due to its relative simplicity when dealing with a small number of input criteria.

This study employs a two-level weighted summation (Figure 2 on Page 10), in order to allow separate weighting of geological and economic input criteria. Here, each input layer is assigned a weight. All weighted cell values of matching locations are summed to compute the output layer. This process is first applied to the *Temperature* and the *Indicated Aquifer Layers* to compute a *Geological Summary Layer*. It is then applied to the *Gas Activity, Electrical Infrastructure, Proposed Electrical Infrastructure* and the *Towns & Communities Layer* to compute the *Economic Summary Layer*. Finally, the favourability map is computed from both summary layers.

This process is implemented in a geographic information system as map algebra. An example is illustrated in Figure 9, using the *Temperature* and *Indicated Aquifer Layers*. Only nine grid cells are depicted in each layer for simplicity. The grids are spatially matched, e.g. the top left cell in the temperature grid represents data referring to the same location as the top left cell in the indicated aquifer grid. The grid cells in the Data Source column contain input data in its original scale, which is normalized to a scale between 0 and 1 in the Input Layer column. The weighted summation process multiplies the value of each cell by the weight, which is 0.5 for both layers here. The spatially matched cell values (e.g. top left cell-value from one grid plus top left cell-value from the other grid) are added and placed in the corresponding cell in the new grid shown in the Geological Summary Layer column.

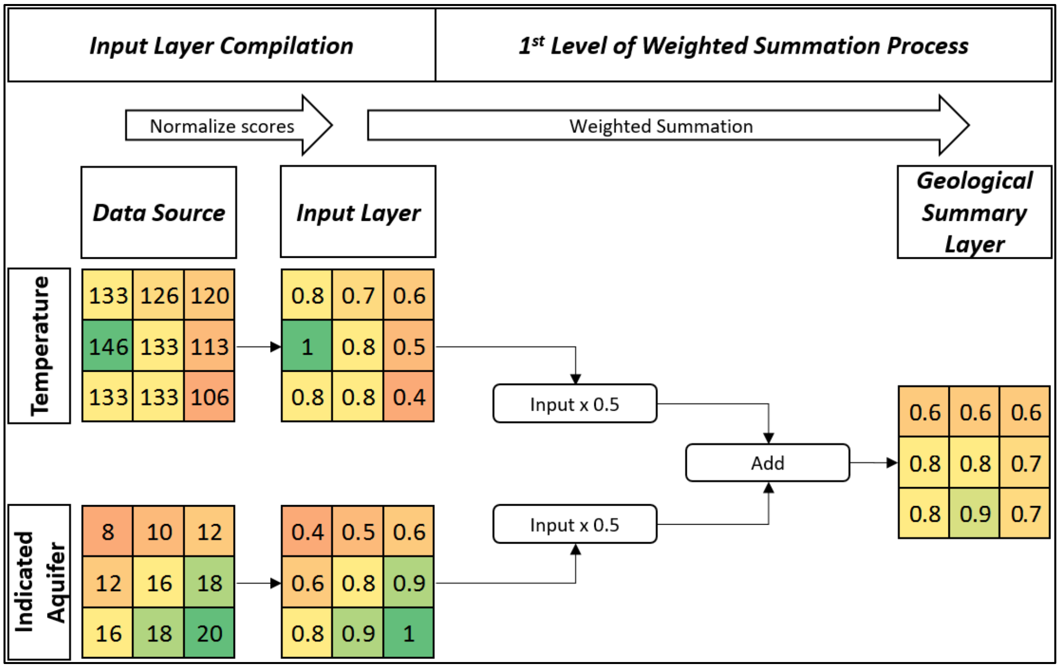

Figure 9 Illustration of the map algebra applied to compute the Geological Summary Layer

The weight of a criterion signifies its importance to the favourability of a geothermal power plant development. There are several methods for finding the appropriate weight for each layer, as discussed by Malczewski (2000), Malczewski (2007) and Greene et al. (2011). In this study, importance values for each criterion are directly assigned on a scale from 0 to 10 (Table 4). Weights are based on author experience, and are somewhat subjective. Importance values are then normalized by summing all importance values and dividing each by the total. Weights correspond to the normalized importance values. The sum of all normalized weights adds up to 1, like the input layers. Therefore, the favourability map also features scores within a range from 0 to 1.

Table 4 Importance values assigned to each input and summary layer with its corresponding weight

Level	Layer	Importance	Weight
1st Level	**Geological Summary Layer**	**Importance**	**Weight**
	Temperature	10	0.500
	Indicated Aquifer	10	0.500
	Economic Summary Layer	**Importance**	**Weight**
	Gas Activity	6	0.273
	Electrical Infrastructure	6	0.273
	Proposed Electrical Infrastructure	4	0.182
	Towns & Communities	6	0.273
2nd Level	**Favourability Map**	**Importance**	**Weight**
	Geological Summary Layer	10	0.5
	Economic Summary Layer	10	0.5

Importance	Description
10	essential
8	strong importance
6	important
4	less important
2	negligible
0	no importance
9, 7, 5, 3, 1	intermediate values

Manually assigned importance values

Calculated weight

Importance values are assigned with the following justifications:

Temperature and *Indicated Aquifers* are of “essential” importance because a geothermal reservoir must feature high temperature and an aquifer in-place to allow exploitation. *Gas Activity*, *Electrical Infrastructure* and the *Towns & Communities* are “important” because they represent the opportunity to sell electricity or heat, but no single criteria is essential. *Proposed Electrical Infrastructure* is considered “less important”, since completion of the proposed transmission line is uncertain. The *Geological* and *Economic Summary* criteria are both “essential”, because both factors need to be in place to allow geothermal power plant development. A power plant must be geologically feasible to be technically feasible, but it must also be economical to build and operate.

5.1.5 Favourability Map

The favourability map is a result of overlaying six criteria that make geothermal power plant development feasible (Figure 10). Each criteria is represented by appropriate input data. Data is harmonized into input layers to allow mathematical computation.

The map uses a colour scale to represent favourability scores. The scores range from 0 to 0.61, denoting that there is no location where all favourability criteria overlap (this location would have a score of 1). In order to highlight those areas where geothermal favourability is highest, the map shows only areas where scores are in the top 10 %, 20% and 30 % ranges. Each 10 % represent one of ten equal intervals from 0 to 0.61.

Favourability scores are relative to one another. High favourability scores highlight locations that warrant a more detailed assessment. On their own, however, the scores do not attest to the feasibility of a geothermal power plant at a particular location. A higher favourability score merely indicates that relevant criteria overlap at that location, leading to a higher likelihood of a geothermal power plant being feasible.

Locations considered for further economic assessment are encircled in red and discussed in the following section.

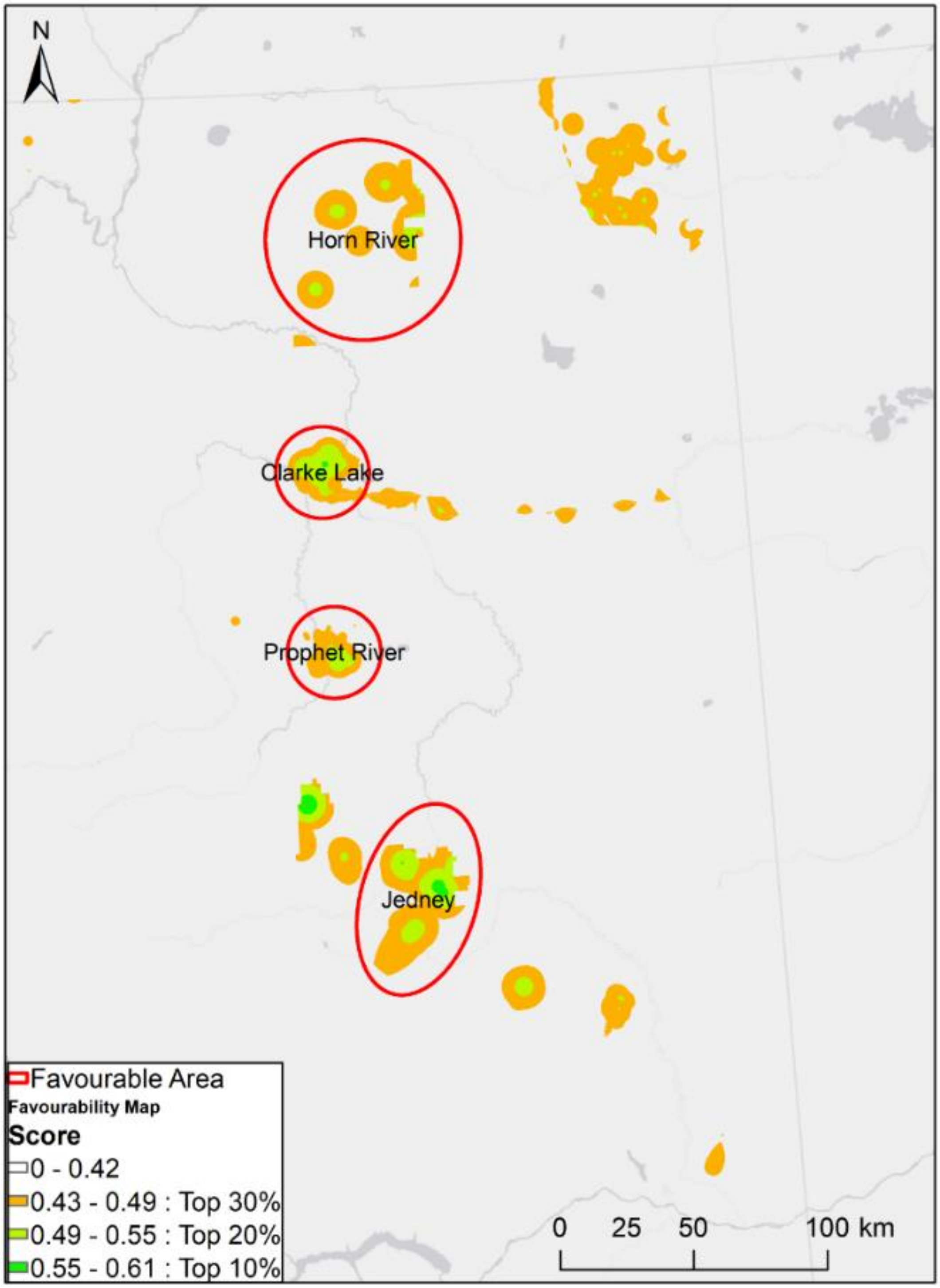

Figure 10 Geothermal Favourability Map of the sedimentary basin in northeastern British Columbia. Red ellipses indicate areas that warrant further economic assessment. (Projection: Albers, Datum: NAD 83)

5.2 Results & Discussion

The purpose of the favourability map is to identify locations that warrant analysis of geothermal resource and costs. We chose four favourable areas: Horn River, Clarke Lake, Prophet River and Jedney

(Figure 10). These names refer to larger areas, not exact geographical coordinates. Each site is representative of its location, meaning that it is characterized by different features, e.g. distances to electrical infrastructure or close proximity to a town.

Horn River is located to the north of Fort Nelson, close to the border between British Columbia and the Northwest Territories. Here, several partly connected patches show favourability due to gas activity paired with relatively high temperatures. Currently, no transmission expansion is expected into this region. Upstream natural gas electrification is a possible long-term demand.

The Clarke Lake favourable area is located in proximity to an existing substation and the town of Fort Nelson. The Clarke Lake and Milo gas fields have been a focal point for hydrocarbon extraction, making a large amount of geological data available here. Both gas fields have been subject to previous geothermal assessments (Arianpoo 2009; Walsh 2013; Geoscience BC 2015).

Prophet River features relatively high temperatures and a large amount of data from hydrocarbon activity. Furthermore, Prophet River is connected via an electrical distribution line to Fort Nelson. This distribution line has not been taken into account within this favourability mapping process, because comprehensive distribution line location data is not publicly available. However, this line might have the capability to export power from a geothermal power plant, although this might require an upgrade of the line.

Jedney contains the largest connected patch of high geothermal favourability. Favourability in this area is attributed to the overlap of relatively high temperature, the proximity to several small communities and its location within the Northern Montney Gas Field. Another smaller patch of high geothermal favourability is located to the west of the Jedney area. This area is not selected for further analysis because it features similar characteristics to Jedney.

Within the Cordova embayment several smaller patches indicate favourability. These, however, are not connected and are further apart than those in the Horn River area. Several smaller patches of geothermal favourability within the top 30 % interval are located along the Fort Nelson – Rainbow Lake transmission line. These patches are not connected and temperature is generally relatively low along the transmission line. Another area around Prespatou and Altona indicates high geothermal favourability. Here, indicators of permeable aquifers are relatively scarce. These areas do not warrant further evaluation.

Four areas within northeastern British Columbia have been selected for further analysis of available resource and cost. This is discussed in the following chapters.

6 Resource Quantification

The geothermal resource potential in favourable areas is analyzed in this chapter. This data is then used estimate size (i.e. the installed capacity and the number of production and injection wells) and the costs of geothermal power plants. The data can also be used for estimating the contribution that geothermal energy can make to decarbonize the Canadian energy system, although such an analysis is not part of this study.

The available resource is quantified in terms of gross electric power output per unit geothermal reservoir area. The result is dependent on reservoir area, because the data available for this study does not allow reservoir area approximation. Gross power output constitutes the capacity of the generator. Net power output constitutes export from the power plant, where parasitic loads caused by pumps, fans and other plant infrastructure have been subtracted from the gross value. Additionally, the required brine flow rate per megawatt installed capacity and number of production wells is estimated.

6.1 Modelling of Electric Power Output and Brine Flow rates – The Volume Method

The Volume Method (Williams et al. 2008) is applied to estimate the geothermal resource. The model assumes a fixed heat resource within a known volume of geothermal reservoir. Inputting several parameters like reservoir temperature and heat capacity estimates the reservoir energy content. Relating this heat reservoir to the heat sink at the surface computes the available electric work. Dividing by the project lifetime (30 years) results in the potential electric power output.

The Volume Method is modelled as follows:

The reservoir thermal energy Q_R is calculated as

$$Q_R = [(1 - \phi)(\rho_R C_R) + \phi(\rho_F C_F)]A_R D_R (T_R - T_0) \qquad \textit{(Equation 2)}$$

where ϕ is the porosity of the reservoir rock, ρ_R is the density of the reservoir rock, C_R is the specific heat capacity of the reservoir rock, ρ_F is the density of the reservoir fluid, C_F is the specific heat capacity of the reservoir fluid, A_R is the reservoir area, D_R is the reservoir thickness, T_R is the reservoir temperature and T_0 is the rejection temperature. The rejection temperature is the temperature of the heat sink. For air-cooled systems, the rejection temperature can be approximated with the annual average ambient air temperature.

Only a fraction of the reservoir thermal energy can be extracted. Thus, a recovery factor (r_g) is applied to estimate the thermal energy that can be harnessed at the wellhead (Q_{WH}).

$$Q_{WH} = Q_R r_g \qquad \textit{(Equation 3)}$$

The enthalpy is the energy content in the geothermal fluid. The difference between the enthalpies of the geothermal fluid (Δh) at the wellhead (h_{WH}) and at rejection (h_0) must be determined. The enthalpy is temperature and state dependant. The geothermal fluid is assumed to be saturated liquid water at reservoir and rejection temperature.

$$\Delta h = h_{WH} - h_0 \qquad \textit{(Equation 4)}$$

The thermal energy at the wellhead (Q_{WH}) and the difference between the enthalpies of the geothermal fluid (Δh) are used to determine the total mass of geothermal fluid that needs to be extracted through the well head (m_{WH}).

$$m_{WH} = \frac{Q_{WH}}{\Delta h} \qquad \textit{(Equation 5)}$$

The amount of energy in a thermal reservoir that can be converted to useful work through transfer to a reference environment is called exergy. Here, the energy reservoir is the geothermal reservoir while the reference environment is the ambient air above ground. The amount of energy that is rejected when performing work is referred to as entropy. The amount of available exergy (W_A), is defined as

$$W_A = m_{WH}[\Delta h - T_0(s_{WH} - s_0)] \qquad \textit{(Equation 6)}$$

where m_{WH} is the mass of geothermal fluid at the well head, T_0 is the rejection temperature, s_{WH} is the specific entropy of the geothermal fluid at reservoir temperature and s_0 is the specific entropy of the geothermal fluid at rejection temperature.

Only a fraction of the available exergy can be converted to electric energy. The amount of electric energy (W_e) that can potentially be produced depends on the utilization efficiency (η_u) of the geothermal power plant and is defined as follows.

$$W_e = W_A \eta_u \qquad \textit{(Equation 7)}$$

W_e is a measure of the total amount of electric energy that can be produced over the lifetime of the power plant. Dividing the total electric energy by the lifetime (l) yields the rated power (P) of the generator, i.e. the gross potential electric power output.

$$P = \frac{W_e}{l} \qquad \textit{(Equation 8)}$$

Reservoir area is not assessed within this study, because the available data does not allow this estimation. Therefore, electrical power output results are presented per square kilometer of geothermal reservoir area (Section 6.3.1). Power output per reservoir area is calculated by applying a placeholder reservoir area to the model (Equation 2: A_R). The power output (Equation 8: P) is then divided by the placeholder reservoir area to calculate the power output per unit reservoir area. The size of the placeholder reservoir area does not impact this result.

The required brine flow rate ($\dot{m}_b$) is the rate at which brine must be continuously extracted from the reservoir over the lifetime of the project to produce the gross electric power output (P). Thus, the required brine flow rate will transport all of the recoverable heat energy to the well head within that lifetime. This metric serves as a guidance as to the amount of brine that must be extracted (by however many wells are necessary to sustain that flowrate) in order to achieve the desired power output. The required brine flow rate does not imply any achievable brine flow rate from a single geothermal well.

$$\dot{m}_b = \frac{m_{WH}}{l} \qquad \textit{(Equation 9)}$$

The Volume Method is based on the assumption that a geothermal reservoir comprises a finite heat resource without thermal recharge. Some work suggests that heat flow in the WCSB is controlled primarily by conduction of heat from the Precambrian basement, rather than by convection via groundwater flow (Bachu & Burwash 1994). In this case, thermal recharge can be neglected as conductive recharge is negligible on a human lifespan timescale (Barbier 2002). Other studies suggest, however, that groundwater flow may have some influence on the geothermal regime (Majorowicz et al.

1999). In this case, thermal recharge might occur, making the volume method a conservative estimate. Assuming a finite heat resource is therefore deemed reasonable for this study.

6.2 Model Inputs

Assumptions and sources for estimating model parameters are described below. Where there is uncertainty about the correct parameter value, a probability distributions is used. A Monte Carlo simulation with 100,000 iterations is performed with the Microsoft Excel Add-In “@Risk 7.5” by Palisade Corporation. Results are also presented as distributions of possible values. Input parameters differ by favourable site. Therefore, four separate Monte Carlo simulations are performed, one for each favourable site. Uncertainties regarding temperature, thickness, recovery factor and porosity of the reservoir are handled via a Monte Carlo simulation. Results are therefore presented as a range of likely values.

6.2.1 Reservoir Volume Factor – Reservoir Area

The reservoir volume is the volume of the heat reservoir from which geothermal brine can be drawn. The reservoir volume is the product of reservoir area (discussed here) and reservoir thickness (discussed in Section 6.2.2).

In this study, reservoir area and thickness are determined separately, rather than determining a combined value for reservoir volume. This is because determining reservoir volume requires thorough geological and geophysical analysis. Williams et al. (2008) note that reservoir volumes “are derived from production histories, drilling results, chemical tracer tests, and exploratory geological and geophysical investigations” in their latest assessment of geothermal resources in the USA.

The data available for this study is insufficient to assess reservoir volume (but data to assess reservoir thickness is available). For this reason, results are presented as electrical power output per square kilometer of geothermal reservoir area (Section 6.3.1). However, the potential size of geothermal power plants is estimated in a case study, which uses natural gas pool areas as proxy geothermal reservoir areas (Section 6.4).

6.2.2 Reservoir Volume Factor – Reservoir Thickness

The reservoir volume is the volume of the heat reservoir from which geothermal brine can be drawn. The reservoir volume is the product of reservoir area (discussed in Section 6.2.1) and reservoir thickness (discussed here).

Reservoir thicknesses are derived from stratigraphic cross sections compiled for several wells in northeastern British Columbia by Ibrahimbas & Walsh (2005). The cross sections cover most of the area under investigation (Figure 11).

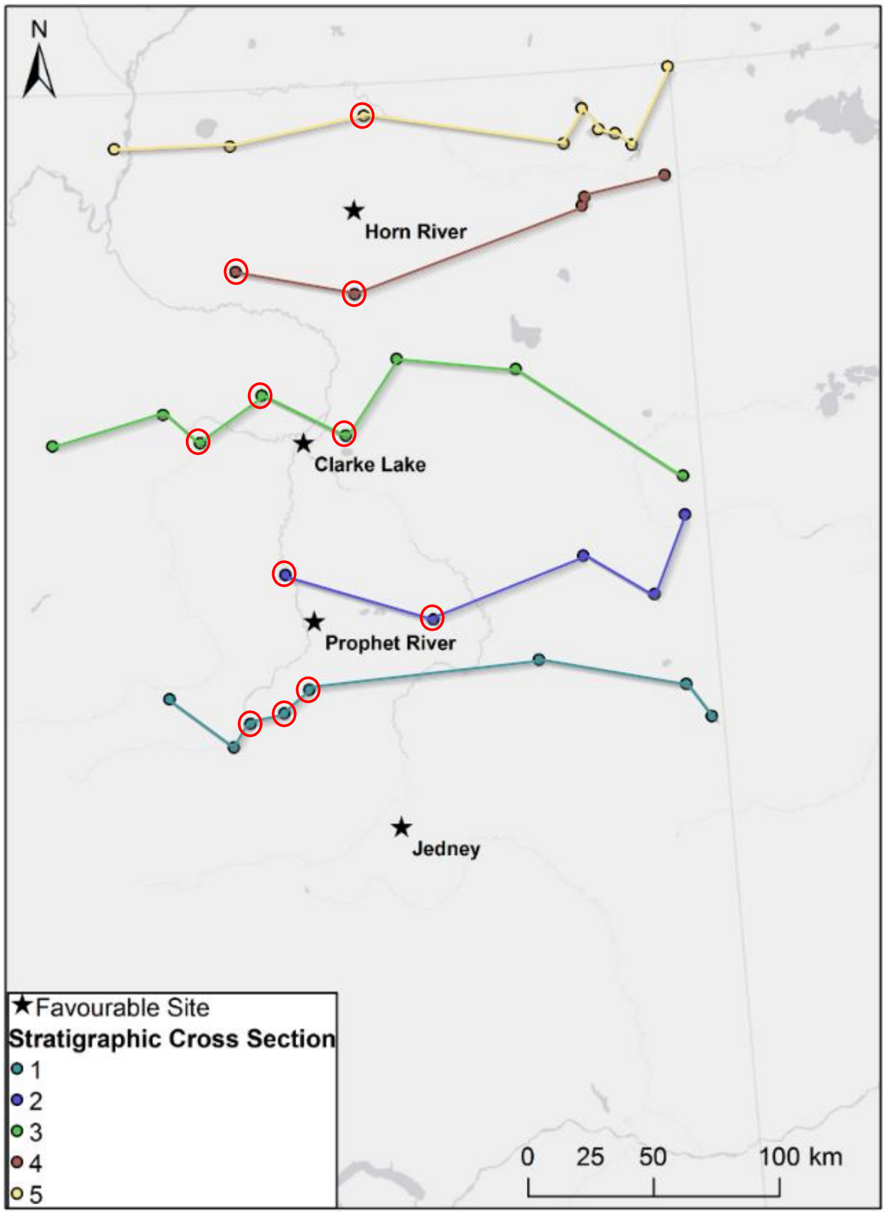

Figure 11 Location of stratigraphic cross sections used for reservoir thickness estimation. Well locations highlighted in red are used for reservoir thickness estimation. Cross sections were compiled by Ibrahimbas & Walsh (2005).

For each favourable area, the three geographically closest wells to the centre of the favourable area (denoted by the star in Figure 11) are used to compute reservoir thicknesses. The reservoir thickness is the sum of the thicknesses of permeable strata between the Beaverhill Lake Group rocks and the Precambrian surface. Where a well does not penetrate the Precambrian surface, only strata penetrated by the well are considered.

Figure 12 shows how reservoir thickness is assessed. For this study, the following formations are assumed to contain geothermal reservoirs: Slave Point, Sulphur Point, Keg River, Lower Keg River, Upper Keg River, Wokkpash, Stone, and Upper Chinchaga (where dolomitized). Well logs indicate the vertical depths, so the depth of the interface between formations can be approximated within several meters of accuracy. The red arrows illustrate the thickness of each permeable layer. The sum of all permeable layer thicknesses produce the reservoir thickness for that well.

Within the Monte Carlo simulation, the reservoir thicknesses are selected from a triangular probability distribution. The minimum thickness is smallest thickness value of the three wells closest to a favourable site, while the maximum thickness is the largest value. The most likely value is the average between the minimum and maximum values. The thickness of a well that is neither found to be a maximum nor a minimum is disregarded.

The wells used to assess reservoir thickness are listed in Table 5.

Table 5 Reservoir thickness values used for favourable sites

Site	Unique Well Identifier (UWI)	Total Thickness [m]	Min or Max for Site
Prophet River	00/B-092-D/094-I-04/0	260	max
	00/A-011-D/094-J-07/4	258	
	00/D-011-F/094-G-15/0	221	min
Clarke Lake	00/B-089-E/094-J-15/0	428	max
	00/C-094-L/094-J-09/0	319	
	00/B-094-L/094-J-11/0	162	min
Horn River	00/B-021-G/094-O-06/0	225	max
	00/A-006-C/094-O-08/0	164	
	00/A-065-G/094-O-16/0	108	min
Jedney	00/A-025-D/094-G-15/2	410	max
	00/A-083-J/094-G-11/0	333	
	00/D-011-F/094-G-15/0	221	min

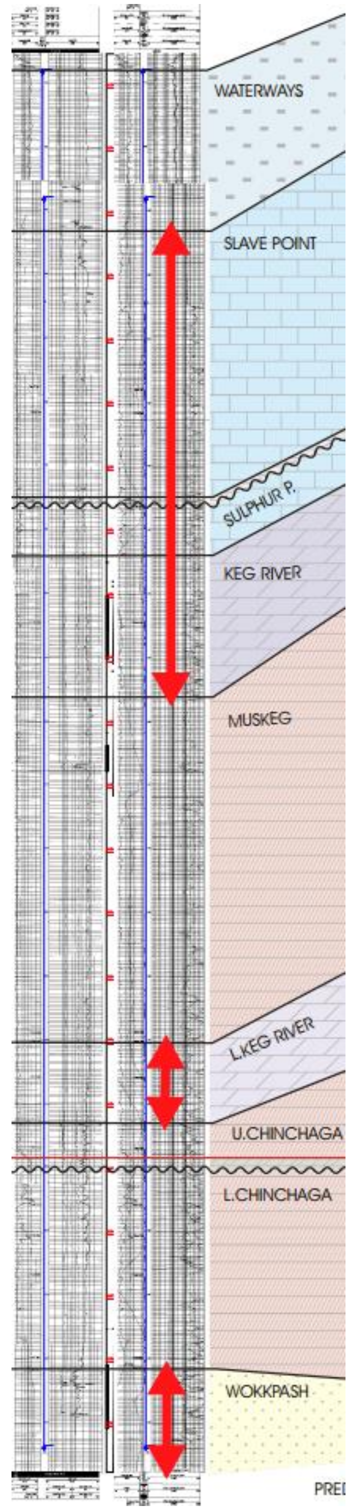

Figure 12 Example of reservoir thickness assessment for well 00/A-011-D/094-J-07/4. Red arrows indicate strata considered permeable for thickness estimate.

6.2.3 Reservoir Temperature

The reservoir temperature is the temperature of the brine that is the heat source for the geothermal power plant. The temperature data used as an input to the Volume Method is the same data that has been used previously to compute the temperature layer of the favourability map. The temperature data compilation is described in Section 5.1.2.1. Data sources are temperatures recorded during drill-stem tests (DST) and Harrison corrected (Harrison et al. 1983) bottom-hole temperatures (BHT) recorded in natural gas wells.

For each of the four favourable areas, the mean and standard deviation of temperatures are computed from all data points that are

1) located within a defined area (Favourable Area w. Top 30 % Score in Figure 13) and
2) were recorded at a minimum depth.

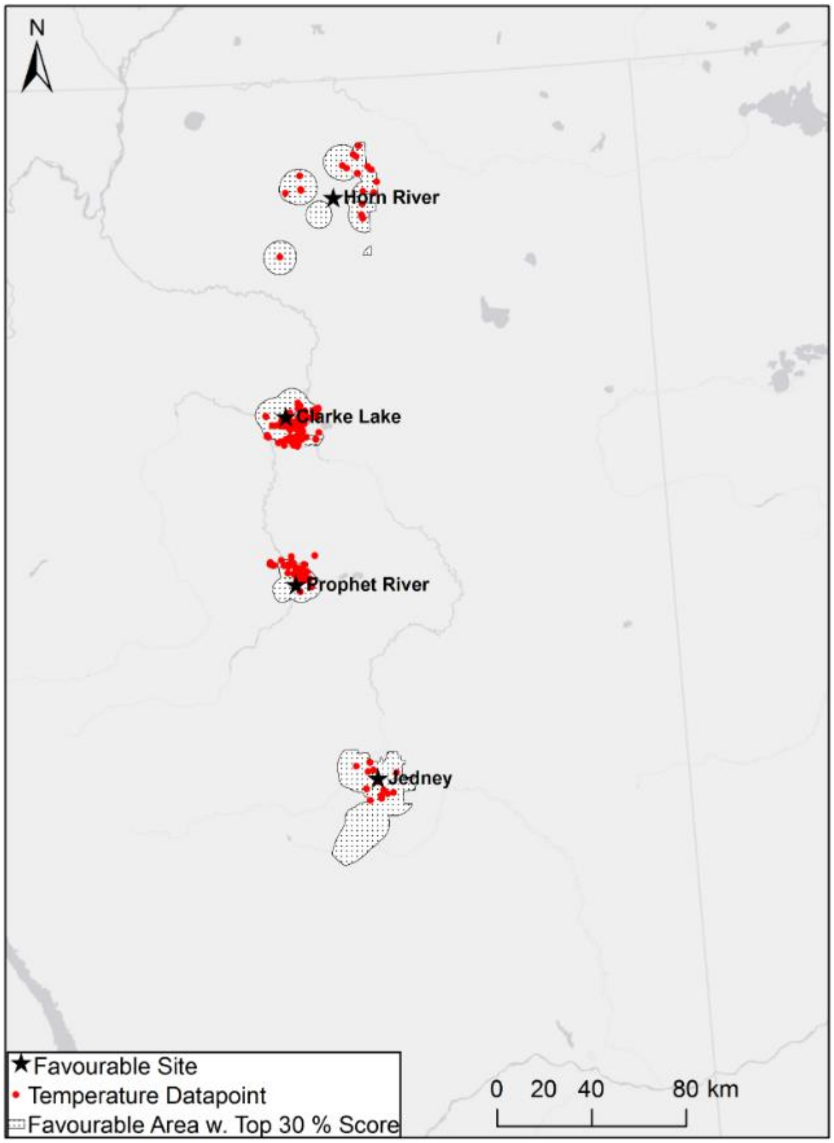

Figure 13 Location of temperature measurements from BHT and DST records used for temperature probability parameters

The temperature records shown in Figure 13 are further filtered by depth. To pass through the filter, temperatures must have been recorded at least as deep as the minimum depth of the top of the youngest permeable formation considered for reservoir thickness. Minimum depths, number of records passing through the depth filter, and resulting temperature distribution parameters are listed in Table 6.

Table 6 Reservoir temperature data used to compute reservoir temperature distribution and resulting distribution parameters

Favourable Site	**Horn River**	**Clarke Lake**	**Prophet River**	**Jedney**
Minimum Depth of Record	2,430 m	1,935 m	2,230 m	2,825 m
Number of Records	21	107	46	16
Mean Temperature [°C]	129.6	111.1	125.6	142.8
Standard Deviation of Temperature [°C]	13.3	19.3	18.6	19.9

Within the Monte Carlo simulation, the reservoir temperatures for each favourable site are selected from triangular probability distributions around the mean ± 1 standard deviation (Figure 14). A triangular distribution is chosen over a normal distribution to avoid computing very low (and very high) temperatures, which are infeasible for electricity production with a binary cycle power plant.

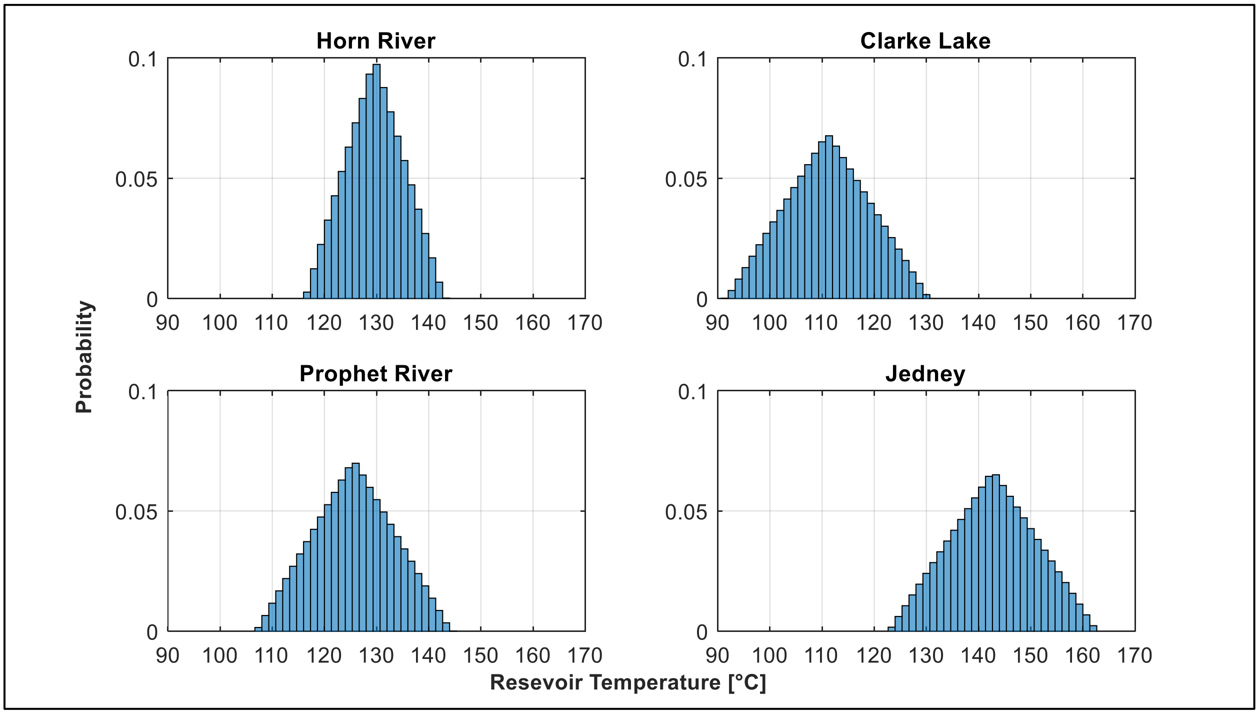

Figure 14 Triangular temperature distributions used in Monte Carlo simulations

6.2.4 Reservoir Porosity

Studies in southwestern Alberta (Lam & Jones 1985) and central Alberta (Weides et al. 2013) show porosity of the Slave Point formation to be between 6 and 20 % and 0.3 to 15 %, respectively. Furthermore, average porosity of the Slave Point formation in British Columbia was accessed via AccuMap and found to range between 1% and 9 %, with approximately 3 % being the most common value. Porosity values for older formations could not be found for use in this study.

Within the volumetric assessment, the porosity values are selected from a triangular distribution between 0 and 20 %, with a most likely value of 3 % (Figure 15). The high minimum and maximum value ensure coverage of the full range of observed values, while the relatively low most likely value of 3 % ensures a conservative estimate.

It is important to note that porosity in the Volume Method only has a minor impact on resulting power output. A higher porosity changes the fraction of volume filled with brine, which has a higher heat capacity than rock. Porosity values do not impact required brine flow rate results.

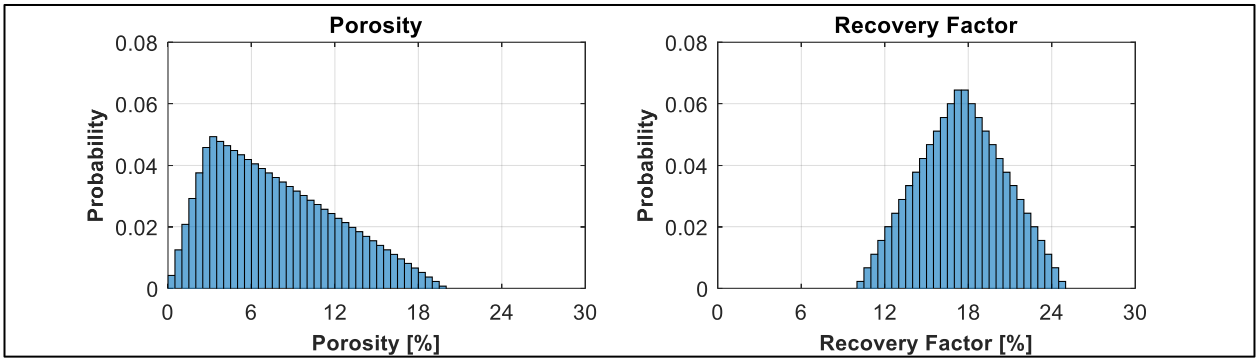

Figure 15 Triangular Porosity and Recovery Factor distributions used in Monte Carlo simulations

6.2.5 Reservoir Recovery Factor

The recovery factor is the amount of heat energy that can be extracted from the reservoir. A discussion of recovery factor is available in Williams (2007). Within the Monte Carlo simulation, the recovery factor is selected from a triangular distribution with a minimum value of 10 % and a maximum value of 25 %, which represent the lower and upper bound cited by Williams (2007). The most likely value selected here is the arithmetic mean at 17.5 % (Figure 15).

6.2.6 Reservoir Heat Capacity

The volumetric heat capacity is a measure of thermal energy stored in a medium per unit temperature and volume. The reservoir contains two media: rock and brine. Brine is assumed to fill the porous fraction of the reservoir volume, while rock fills the non-porous fraction.

All reservoir rock is assumed to be dolomite with a volumetric heat capacity of 2663 kJ/m^{3}K. This value is the product of the specific heat capacity 0.928 kJ/kgK (Krupka et al. 1985) and the density 2870 kg/m^3 (Gardner et al. 1974) of dolomite.

The heat capacity for the geothermal brine is assumed equivalent to that of pure water, which is approximately 4200 kJ/m^{3}K. This is a product of the specific heat capacity of 4200 kJ/kgK and the density of 1000 kg/m^3.

6.2.7 Utilization Efficiency

The utilization efficiency is the percentage of thermal energy that can be converted to electric energy while considering thermodynamic irreversibilities in the power plant (e.g. losses in heat exchangers, parasitic load of air-cooled condensers). Optimal utilization efficiency of binary cycle geothermal power plants are modelled by Augustine et al. (2009) for brine temperatures between 100 °C and 200 °C (Figure 16). The authors distinguish between subcritical and supercritical power plant efficiencies. Supercritical power plants operate above the critical pressure of the working fluid. This higher pressure results in a higher efficiency over subcritical plants, but the more complex design also leads to higher capital costs. Therefore, the utilization efficiency values used in each Monte Carlo iteration of the volumetric assessment are linearly interpolated from subcritical power plant data.

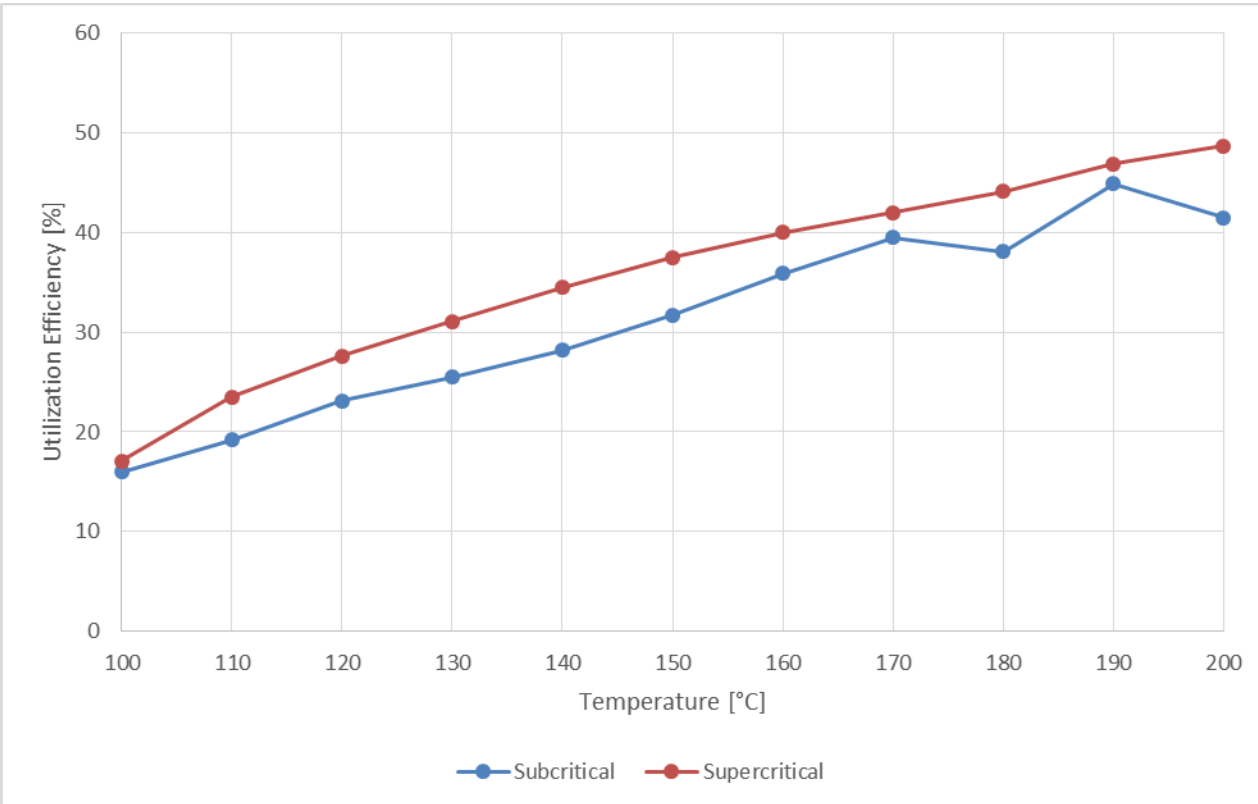

Figure 16 Optimal utilization efficiencies of sub- and supercritical binary cycle geothermal power plants. Graph based on data by Augustine (2014)*.*

6.2.8 Rejection Temperature

The rejection temperature for all favourable sites is 0 °C. This is approximately equivalent to the annual average air temperature at Fort Nelson (-0.4 °C) from 1981 – 2010 (Government of Canada 2017).

6.2.9 Entropy and Enthalpy

Specific enthalpy and specific entropy of the geothermal brine is assumed to be that of liquid water. In order to avoid precipitation of dissolved solids from the brine, phase change must be avoided. This can be achieved by maintaining brine pressure above saturation pressure at all times throughout the cycle, from brine production to brine injection. Therefore, enthalpy and entropy values are equivalent to those of saturated liquid water at reservoir temperature and rejection temperature. Enthalpy and entropy are linearly interpolated from H_2O saturation temperature tables published at www.thermofluids.com (Bhattacharjee n.d.).

6.3 Results

The Monte Carlo simulations compute 100,000 results for each favourable site. Results are sorted into 50 equally wide bins, plotted as histograms and treated as probability distributions. Key percentile values as well as the modes (most likely values) are listed separately for use in economic calculations at a later stage.

6.3.1 Potentially Available Electric Power Output

Histograms of potentially available electric power output per unit area (MWe/km^2) for each favourable site are shown in Figure 17. A curve fitting analysis shows that probabilities follow a Gamma distribution. The horizontal axis depicts the potential electrical power output per unit area, while the vertical axis depicts the probability with which results fall into a specific bin. The vertical axis values of all bins add up to 1.

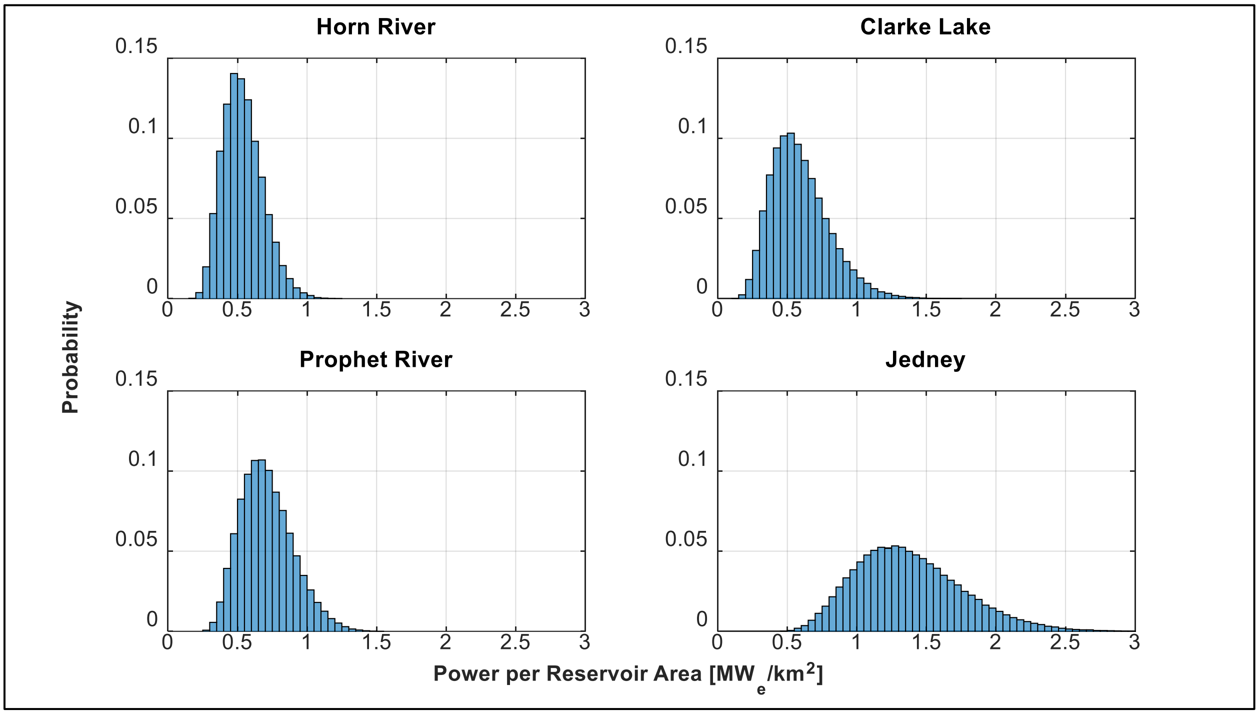

Figure 17 Probabilities of potential electric power output per unit reservoir area

Key parameters of each distribution are listed in Table 7. The P90 value states that 90 % of all Monte Carlo iterations reach or exceed the stated value, while the P50 value states that 50 % of results are below and 50 % of results were above the stated value. The mode (or most likely value) states the center value of the bin with the highest probability of occurrence.

Table 7 Potentially available electric power output per unit area for each favourable site. All values are in megawatt per square kilometer [MW$_e$/km^2].

Favourable Site	Horn River	Clarke Lake	Prophet River	Jedney
P90	0.3650	0.3507	0.4821	0.9167
P50	0.5251	0.5629	0.6911	1.3379
Mode	0.4750	0.5250	0.6750	1.275

6.3.2 Required Brine Flow Rate

Histograms of required brine flow rates for each favourable site are shown in Figure 18. The horizontal axis depicts the flow rate in kilograms per second that is required to produce one megawatt of electric power. The vertical axis depicts the probability with which results fall into a specific bin. The total vertical axis value of all bins sum to 1.

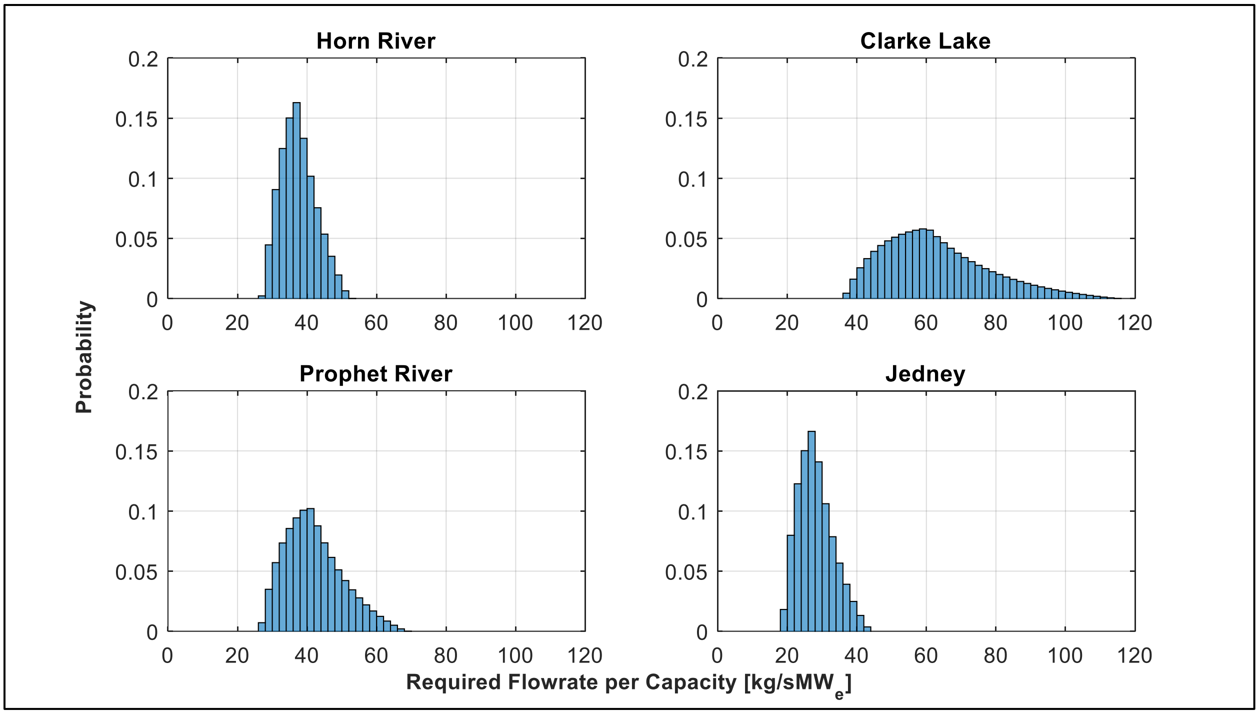

Figure 18 Probabilities of required brine flow rate per megawatt of installed electric capacity

Key parameters of each distribution are listed in Table 8. Generally, renewable energy projects are valuated using the P90 resource assessment values, in order to ensure a high degree of certainty. However, results shown here are required flow rates, rather than flow rates deduced from geological or geophysical analysis. Using the P10 value in economic assessments is therefore deemed the conservative approach. Therefore, the P90, P50, and the P10 value is listed.

Table 8 Required brine flow rates per megawatt installed capacity. All values are in kg/s per MW.

Favourable Site	Horn River	Clarke Lake	Prophet River	Jedney
P90	31.3	45.1	32	22
P50	37.1	60.5	40.9	27.6
P10	44.5	84.5	53.7	35.2
Mode	37.0	59.0	41.0	27.0

6.3.3 Sensitivity Analysis

The potentially available electric power output and required brine flow rate (result values) are sensitive to the stochastic model parameters. The stochastic parameters are the thickness, temperature, porosity and recovery factor of the reservoir. Sensitivity is defined as the magnitude of change in the result value with a given change in an input value. The sensitivity differs between stochastic parameters. The sensitivity also differs between result values.

The sensitivity analysis for each input value is performed in @Risk 7.5 as follows:

1. All 100,000 iterations of the Monte Carlo simulation are sorted in ascending order by the input value being analyzed.

2. The iterations are binned into 20 bins, so that each bin contains 5000 iterations.
3. The mean of the output values in each bin is computed.

The first bin contains the lowest fifth percentile input value. This percentile of input values corresponds to a mean output value. This process allows ignoring all but one input value, because the other input values in each of the 20 bins are still distributed according to their input distribution.

As an example, the results of the sensitivity analysis for Jedney are shown in Figure 19. The sensitivity of results from the other favourable sites are similar to those found in Jedney.

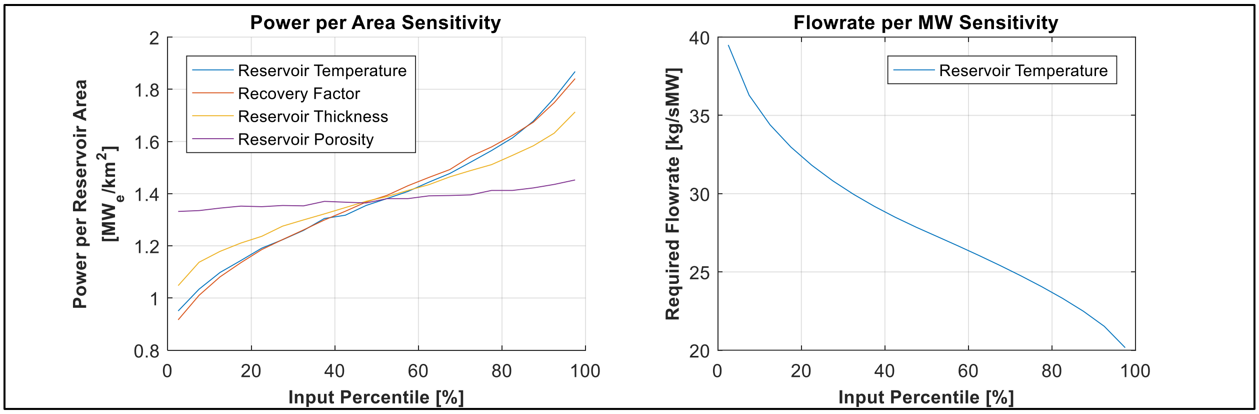

Figure 19 Sensitivity of Jedney model results to stochastic model parameters

Reservoir Temperature and Recovery Factor have a significant impact on the power output per reservoir area. Reservoir Thickness is less significant. The reservoir porosity has only a minor impact on the power per reservoir area. The required flow rate is significantly impacted by reservoir temperature. This is the only parameter that impacts required flow rate.

6.4 Case Study – Geothermal Power Plant Sizes

This case study illustrates the size of geothermal power plants at each favourable site. Here, 'size' refers to the gross electric power output and the number of production wells required to enable that power output.

Proxy geothermal reservoir areas are used to estimate power plant sizes, because the data available to the authors is not sufficient to estimate actual geothermal reservoir areas. Proxy reservoir areas are derived from natural gas pools in the Slave Point formation (Table 9). The BC Oil and Gas Commission (2016) identifies several gas pools for Clarke Lake, Prophet River and Jedney and provides their perimeters as geographical data for download. The pool areas are calculated using the outermost outline of each pool. Each gas pool is part of a larger gas field, which is also listed in Table 9 to specify the gas pools used for this case study. The total gas pool area is the sum of all individual gas pools that are in close proximity to each favourable site. Gas pools are not available for Horn River. Here, a conservative value is chosen by the authors.

Table 9 Total gas pool areas are used as proxy geothermal reservoir areas to estimate power plant sizes

Favourable Site	Horn River	Clarke Lake	Prophet River	Jedney
Gas Pools (Gas Field)	-	Slave Point A (Clarke Lake)	Slave Point A, B, C, H, I, J, L, M, N, O, P (Adsett)	Slave Point A, B, C (Bubbles) Slave Point B, C (Bubbles North)
Total Gas Pool Area = Proxy Geothermal Reservoir Area [km²]	10	127	45.7	8.5

The electric power output for geothermal power plants are calculated using the potential electric power output per unit reservoir area presented in Table 7, multiplied by the proxy geothermal reservoir area of Table 9. Results are shown in Table 10.

Table 10 Electric power output for geothermal power plants. All values are in megawatt [MW_e].

Favourable Site	Horn River	Clarke Lake	Prophet River	Jedney
P90	3.7	44.5	22.0	7.8
P50	5.3	71.5	31.6	11.4
Mode	4.8	66.7	30.8	10.8

Example calculations for the number of production wells required to supply the geothermal power plants are shown in Table 11. The number of production wells is dependent on three variables:

a) the electric power output
b) the required brine flow rate per megawatt
c) the achievable brine flow rate per production well

Values for a) and b) are presented in Table 10 and Table 8, respectively. The achievable brine flow rate is assessed by Lam & Jones (1985), who use DST data from the Hinton-Edson area in southwestern Alberta to infer flow rates in excess of 30 l/s. Although that study only assesses formations of Upper Devonian age, and that study does not clearly state whether 30 l/s is the achievable flow rate from a single well, other studies concerning the sedimentary basin in Alberta have also assumed that a flow rate of 30 kg/s per well might be achievable (Majorowicz & Moore 2014; Majorowicz & Grasby 2014). Another study assessing Clarke Lake and Jedney and assumes achievable flow rates of 100 kg/s per production well (Geoscience BC 2015). The number of required production wells is calculated for both flow rates of 30 kg/s and 100 kg/s per well, in order to allow comparison to previous studies.

Table 11 Number of production wells required to supply geothermal power plants with electric power output P90 and required flow rate per megawatt P50. Values are rounded up to the nearest whole number.

Favourable Site	Horn River	Clarke Lake	Prophet River	Jedney
at 30 kg/s per well	5	90	31	8
at 100 kg/s per well	2	27	10	3

6.5 Discussion

In this chapter, the potential electric power output per unit reservoir area and the required brine flow rate per megawatt installed capacity were assessed. A case study applied natural gas pool areas as proxy geothermal reservoirs in order to estimate the size of potential geothermal power plants. The sensitivity analysis shows that power output is sensitive to changes in temperature, recovery factor and thickness of the geothermal reservoir. Changes in reservoir porosity have a minor impact on results.

The Horn River and Clarke Lake favourable areas show the lowest power output per reservoir area, where P50 values are 0.5251 MW_e/km^2 and 0.5629 MW_e/km^2, respectively. Results for Prophet River are slightly higher. Jedney has the highest power output per reservoir area where the P50 value is 1.3379 MW_e/km^2. The values for Clarke Lake and Jedney are similar to values found by Geoscience BC (2015), where the P50 is 0.7 MW_e/km^2 and 1.3 MW_e/km^2, respectively. Previous studies of Horn River and Prophet River are not available for comparison.

Jedney features the widest distribution of power output per reservoir area, which means that uncertainty is highest here. Required flow rates are lowest in Jedney and highest in Clarke Lake. Clarke Lake also features the widest distribution of required flow rates per megawatt capacity. A higher required flow rate implies that a larger number of wells need to be drilled in order to achieve a given power output. This, in turn, implies higher capital costs.

The power output values assessed in the case study are within range of those found in other studies. The case study shows that the possible P50 geothermal power output is 71.5 MW at Clarke Lake and 11.4 MW at Jedney. The P50 value at Clarke Lake is 34 MW in the assessment by Walsh (2013) and 37.4 MW in the assessment by Geoscience BC (2015). In Jedney the P50 value assessed by Geoscience BC (2015) is 24.7 MW.

It is important to note that the case study may overestimate or underestimate the electrical power output. Power output is dependent on reservoir area and reservoir thickness. On the one hand, the reservoir thickness is assessed across several potentially permeable formations (see Chapter 6.2.2), but the proxy reservoir areas used in this case study are based on gas pool areas of the Slave Point formation. This may cause overestimation of the resource, because this approach assumes that the geothermal reservoir area extends beyond the Slave Point formation into all formations included in the reservoir thickness assessment. On the other hand, the gas pool area may be significantly smaller than the area of an aquifer, because buoyant gas may be confined to a relatively small trap underlain by a larger aquifer. Therefore, the sizes of geothermal power plants assessed in the case study are only indicative. To reduce uncertainty of results, future research is required (e.g. interpret drill-stem test and seismic prospecting data to confirm available geothermal reservoir volumes).

7 Economic Analysis

In this chapter, the capital costs and key financial indicators for geothermal power plants in each favourable area are assessed. The capital cost includes the cost of the power plant, cost of well development and grid connection. The financial indicators include the Levelized Cost of Energy (LCOE), the Net Present Value (NPV), and the Internal Rate of Return (IRR).

Several economic models specific to geothermal energy assessments are reviewed in Section 7.2 below, but found not to be applicable to the work in this study. Therefore, a simple model is developed to conduct the analysis. This model is applied to each favourable area.

Results from this analysis are to be taken as representative values for the respective favourable area, rather than exact costs at a particular location. All dollar values in this section denote Canadian Dollars, unless stated otherwise.

7.1 Background of economic analysis of geothermal power plants.

Two of the four favourable areas have been investigated techno-economically in previous work (Geoscience BC 2015). Clarke Lake was estimated to have a net power output of 13.8 MW at a LCOE of 297 $/MWh. A Jedney area power plant was assessed to produce a net 9.2 MW at 398 $/MWh. The economic parameters of both of these sites were assessed using the Geothermal Energy Technology Evaluation Model (GETEM). The GETEM files for Clarke Lake and Jedney were reviewed and show that the brine temperature used in both cases is 160 °C, rather than the 115°C for Clarke Lake and 149°C for Jedney listed in Appendix C of that study. Cost assessments are therefore based on inconsistent reservoir temperatures.

Majorowicz & Moore (2014) estimate costs of geothermal heat for direct-use (not electricity production) and compare costs to fossil fuel alternatives. They assume operating lifetimes of up to 30 years, 80 % well drilling success rate and flow rates between 10 and 80 kg/s. The latter are based on data from formations of Mississippian and Upper Devonian age. Flow rates of up to 194 kg/s were found in the Elkton formation. The study shows that geothermal cost competitiveness is heavily dependent on the achievable brine flow rate per well.

Lam & Jones (1985) study the Hinton-Edson area in northeastern Alberta to analyze porosity and derive possible flow rates and potentiometric surfaces for aquifers in the Upper Devonian to Upper Cretaceous formations. Unfortunately, flow rates for the Slave Point formation and older are not included in the assessment. Nevertheless, the study shows that porous regions extend laterally over a distance of several kilometres.

Majorowicz & Grasby (2014) estimate costs for geothermal power and heat from hydrothermal and enhanced geothermal systems north of 59°N latitude. Here, bottom-hole temperatures are used to compute a map of drilling depths required to reach 120°C temperature. A constant water flow rate of 30 kg/s is assumed feasible, which leads to electricity costs between 0.84 and 0.50 $/kWh and thermal energy costs of 0.10 $/kWh.

Augustine (2014) uses GETEM and a sedimentary reservoir model to compute power plant costs for various reservoir depths, temperatures, productivity indices and flow rates. That study focuses on the distance between production and injection well required to sustain a constant reservoir temperature over the 30 year lifetime.

7.2 Other Economic Models Reviewed

Several economic analysis models specific to geothermal energy assessments are reviewed in order to confirm their applicability to this study. These models are:

- Geothermal Energy Technology Evaluation Model (GETEM)
- Cost of Renewable Energy Spreadsheet Tool (CREST)
- Renewable Energy Technology Screen (RETScreen)

In summary, none of these models were found to be applicable to this study for reasons discussed below. Economic analysis is therefore performed using a simple economic model discussed in Section 7.3.

7.2.1 Geothermal Energy Technology Evaluation Model (GETEM)

The Geothermal Energy Technology Evaluation Model (GETEM) was developed by the US Department of Energy to assess

- the Levelized Costs of Energy,
- major cost contributors and
- how technology improvements might impact costs of geothermal power plants (Entingh & Mines 2006).

Although GETEM was not designed to assess individual projects, Nathwani & Mines (2015) come to the conclusion that “it can be used to provide preliminary estimates of potential project viability.”

GETEM is implemented in Microsoft Excel and the latest available version is dated 29 August 2012, denoted “beta”. This model was applied by Geoscience BC (2015) to economically assess Clarke Lake and Jedney. However, the model requires a minimum brine temperature of 160°C, which is above the reservoir temperature range found in this study (Table 6). GETEM is therefore not suitable for economic analysis of most geothermal energy project in the WCSB, where very few temperature records produced by the oil and gas industry reach 160°C.

7.2.2 Cost of Renewable Energy Spreadsheet Tool (CREST)

The Cost of Renewable Energy Spreadsheet Tool (CREST) was developed by the National Renewable Energy Laboratory (NREL) of the US Department of Energy. A model specific to analyzing geothermal power projects is available in version 1.4. This cash flow model allows adjusting complexity, but is designed specifically for projects located in the USA. Several inputs, such as tax incentives and depreciation options do not apply in Canada. Further, CREST requires detailed inputs for financing options such as debt term length or debt service coverage ratio. This model is therefore too detailed for application in this high-level study.

7.2.3 Renewable Energy Technology Screen (RETScreen)

The Renewable Energy Technology Screen (RETScreen) is developed by Natural Resources Canada (NRCan). The latest “Expert” edition is a standalone software. The model can assess a wide range of renewable energy and energy efficiency projects. However, assessment of geothermal energy projects is limited to steam-dominated reservoirs. In this study, all reservoirs are within a temperature range that precludes flash-steam power plants. Hence, the RETScreen model cannot be used to assess geothermal power plants in the WCSB.

7.3 Economic Model

The purpose of the economic analysis is to estimate the capital costs and compute key financial indicators for a proxy geothermal power plant at each favourable site. Financial indicators are the Levelized Cost of Energy (LCOE), Net Present Value (NPV) and the Internal Rate of Return (IRR). As three publicly available economic assessment models were reviewed and found inapplicable to this study, a simple economic model is outlined in the following sections.

7.3.1 Capital Costs

The capital costs are the total cost of building a geothermal power plant, building transmission and grid connections, and drilling and casing the production and injection wells. Capital costs are based on price quotes from industry, for

- a 2.5 MW geothermal power plant (reference plant) and
- a quote for well drilling and completion.

Price quotes are discussed in Section 7.4.1. Capital costs items are scaled linearly to reflect different power plant sizes at each favourable site. Well drilling and completion costs are scaled linearly with depth, because resource depth varies between favourable sites. Both of these assumptions likely overestimate the costs for larger power plants and shallower geothermal reservoirs because costs do not scale linearly. The calculated costs are therefore conservative estimates. Cost of transmission is available on a per km basis from BC Hydro (see Section 7.4.1).

The capital costs are calculated as follows:

$$C_C = C_{Ref}\frac{P_e}{P_{Ref}} + C_W(D_R + B_R)N_W + C_T X_T + C_I \qquad \textit{(Equation 10)}$$

C_C: *Capital Costs* ($)

C_{Ref}: *Total cost of reference power plant components* ($)

P_e: *Electric capacity of power plant* (kW_e)

P_{Ref}: *Electric capacity of price quoted power plant* $= 2500\ kW_e$

C_W: *Cost of well drilling and completion per meter depth* ($/m)

D_R: *Depth of reservoir top* (m)

B_R: *Reservoir thickness* (m)

N_W: *Total number of wells*

C_T: *Cost of transmission per kilometer* ($/km)

X_T: *Transmission distance* (km)

C_I: *Cost of interconnection* ($)

Capital costs are considered overnight costs, which means all capital costs are incurred in year zero. Capital costs are not discounted in financial indicator calculations.

The total number of wells is the sum of the number of production and injection wells. We assume that each injection well can service two production wells. The number of wells is calculated via the required brine flow rate and the assumed brine flow rate per well. The calculated number of production and injection wells is each rounded up to the nearest integer value (whole number). The term to the left of the plus sign signifies the number of production wells. The term to the right of the plus sign signifies the number of injection wells:

$$N_W = RoundUp(P_e \frac{\dot{m}_b}{\dot{m}_W}) + RoundUp(P_e \frac{\dot{m}_b}{2\dot{m}_W}) \quad \text{(Equation 11)}$$

N_W: *Total number of wells*

P_e: *Electric capacity of power plant* (kW_e)

$\dot{m}_b$: *Required brine flowrate* (kg/skW_e)

$\dot{m}_W$: *Brine flowrate per well* (kg/s)

$RoundUp(x)$: *function to round x up to the nearest integer value*

7.3.2 Levelized Cost of Energy

The Levelized Cost of Energy (LCOE) is the cost at which electricity is produced throughout the lifetime of the project. LCOE allows comparing different electricity generating options with one another. Any power plant technology can be compared via LCOE. However, LCOE should not be the only metric of comparison, because it does not capture the value of firm power from baseload generators, as opposed to variable power from wind and solar power plants.

LCOE are the total discounted project cost divided by the total discounted electricity sold over the project lifetime. Only electrical energy is considered in the LCOE. Thermal energy production is disregarded. The method to calculate LCOE is based on work by the International Energy Agency & Nuclear Energy Agency (2015):

$$LCOE = \frac{C_C + \sum_{t=1}^{n} \frac{C_{O\&M} P_e}{(1+r)^t}}{\sum_{t=1}^{n} \frac{E}{(1+r)^t}} \quad \text{(Equation 12)}$$

$LCOE$: *Levelized cost of energy (\$/kWh$_e$)*

C_C: *Capital costs (\$)*

$C_{O\&M}$: *Operation and Maintenance costs (\$/kW$_e$))*

P_e: *Electric capacity of power plant* (kW_e)

E: *Annual net electricity production (kWh$_e$)*

r: *Discount rate*

n: *Project lifetime in years (30 years)*

The annual net electricity production is the electricity produced and sold in each year of operation:

$$E = P_e F L h \qquad \text{(Equation 13)}$$

E: *Annual net electricity production* (kWh_e)

P_e: *Electric capacity of power plant* (kW_e)

F: *Capacity Factor*

L: *Net parasitic load factor*

h: *hours per year = 8760 h*

The capacity factor accounts for power plant downtime. The net parasitic load factor accounts for internal electricity use. Electricity consumed internally by e.g. pumps and cooling fans cannot be sold externally.

7.3.3 Net Present Value

The Net Present Value (NPV) is the difference between all discounted costs and revenues. A positive NPV is financially beneficial, while a negative NPV is a financial loss to the investor. The NPV of competing investments can be compared to decide which project has greater financial return.

$$NPV = -C_C + \sum_{t=0}^{n} \frac{(R_e + R_{th} - C_{O\&M} P_e)}{(1+r)^t} \qquad \text{(Equation 14)}$$

NPV: *Net Present Value* ($)

C_C: *Capital costs* ($)

R_e: *Annual revenue from electricity sales* ($)

R_{th}: *Annual revenue from heat sales* ($)

$C_{O\&M}$: *Annual Operation and maintenance costs per electric installed capacity* ($/$kW_e$)

P_e: *Electric capacity of power plant* (kW_e)

r: *Discount rate*

n: *Project lifetime in years (30 years)*

Annual revenues from electricity sales are:

$$R_e = C_e E \qquad \textit{(Equation 15)}$$

R_e: *Annual revenue from electricity sales* (\$)

C_e: *Price of electricity (\$/kWh$_e$)*

E: *Annual net electricity production (kWh$_e$)*

Excess heat is available for sale from the brine exiting the power plant. This heat could be sold to a district heating system, for example. Annual revenues from heat sales are:

$$R_{th} = C_{th} P_{th} F h \qquad \textit{(Equation 16)}$$

R_{th}: *Annual revenue from heat sales* (\$)

C_{th}: *Price of heat (\$/kWh$_{th}$)*

P_{th}: $Thermal\ capacity\ of\ power\ plant\ (kW_{th})$

F: *Capacity Factor*

h: *hours per year = 8760 h*

The thermal capacity used here is the thermal power that can be extracted from the brine between

- the temperature at which the brine exits the power plant and
- the minimum useful temperature for a district heating system.

This minimum useful temperature is considered 60°C, which is a typical operating temperature for a district heating system. The thermal capacity is a function of the brine enthalpies at those temperatures:

$$P_{th} = P_e \dot{m}_b \left(H_{P,exit} - H_{min}\right) \qquad \textit{(Equation 17)}$$

P_{th}: $Thermal\ capacity\ of\ power\ plant\ (kW_{th})$

P_e: $Electric\ capacity\ of\ power\ plant\ (kW_e)$

$\dot{m}_b$: $Required\ brine\ flowrate\ (kg/skW_e)$

$H_{P,exit}$: $Enthalpy\ of\ brine\ exiting\ the\ power\ plant\ (kJ/kg)$

H_{min}: $Enthalpy\ of\ brine\ at\ minimum\ useful\ temperature\ of\ 60°C\ (kJ/kg)$

The temperature of the brine exiting the power plant is dependent on the energy extracted from the brine in the power plant. The extracted energy is deduced by estimating the thermal power that is transferred from the brine to the working fluid of the Rankine cycle.

$$H_{P,exit} = H_R - \frac{\dot{Q}_{th}}{\dot{m}_b}$$ *(Equation 18)*

$H_{P,exit}$: *Enthalpy of brine exiting the power plant* (kJ/kg)

H_R: *Enthalpy of brine at reservoir temperature* (kJ/kg)

$\dot{Q}_{th}$: *Thermal power transferred to working fluid* ((kW_{th})

$\dot{m}_b$: *Brine flowrate* (kg/s)

The brine enthalpy is a function of temperature. H_R and H_{min} enthalpy is linearly interpolated between values published in thermodynamic property tables (Bhattacharjee n.d.). Brine is considered saturated liquid water. For example, the specific enthalpy of saturated liquid water at 60 °C (H_{min}) is 251 kJ/kg.

The thermal power transferred to the working fluid depends on the thermal efficiency of the Rankine cycle. The assumed efficiency is 30%, which is typical value for Rankine cycles (Cengel & Boles 2002).

The thermal power transferred to the working fluid is:

$$\dot{Q}_{th} = \frac{P_e}{\eta_{th}}$$ *(Equation 19)*

$\dot{Q}_{th}$: *Thermal power transferred to working fluid* ((kW_{th})

P_e: *Electric capacity of power plant* (kW_e)

η_{th}: *Thermal efficiency of Rankine cycle (30%)*

7.3.4 Internal Rate of Return

The Internal Rate of Return (IRR) is a measure of financial project viability. It is equal to the discount rate at which the NPV becomes zero. When the IRR is larger than the weighted average cost of capital (WACC) then the project is financially viable. When the IRR is smaller than the WACC then the project is not financially viable.

The IRR is computed by solving the following equation for r:

$$NPV = 0 = -C_C + \sum_{t=0}^{n} \frac{(R_e + R_{th} - C_{O\&M}P_e)}{(1+r)^t}$$ *(Equation 20)*

NPV: *Net Present Value* (\$)

C_C: *Capital costs (\$)*

R_e: *Annual revenue from electricity sales* (\$)

R_{th}: *Annual revenue from heat sales* (\$)

$C_{O\&M}$: *Annual Operation and maintenance costs per electric installed capacity (\$/kW$_e$)*

P_e: *Electric capacity of power plant* (kW_e)

r: *Discount rate*

n: *Project lifetime in years (30 years)*

7.4 Model Inputs

7.4.1 Capital Costs

The capital costs are the total cost of building a geothermal power plant, building transmission and grid connection, and drilling and casing the production and injection wells. Capital costs for proxy geothermal power plants are assessed for each favourable site. All values used for capital cost calculations are listed in Table 12.

Table 12 Values used in capital cost calculation

Item	Symbol	Value	Source
Reference plant cost	C_{Ref}	12,002,951 $	See Table 13
Reference plant capacity	P_{Ref}	2500 kW	See Table 13
Power plant capacity	P_e	Horn River: 3700 kW Clarke Lake: 15000 kW Prophet River: 15000 kW Jedney: 7800 kW	Table 10: P90 1) 1) Table 10: P90
Well drilling and casing	C_W	2000 $/m	Terrapin Geothermics (see below)
Depth of reservoir top	D_R	Horn River: 2430 m Clarke Lake: 1935 m Prophet River: 2230 m Jedney: 2825 m	Table 6: Minimum depth of record
Reservoir thickness	B_R	Horn River: 225 m Clarke Lake: 428 m Prophet River: 260 m Jedney: 410 m	Table 5: Max
Required brine flow rate	$\dot{m}_b$	Horn River: 0.0371 kg/skW Clarke Lake: 0.0605 kg/skW Prophet River: 0.0409 kg/skW Jedney: 0.0276 kg/skW	Table 8: P50
Brine flow rate per well	$\dot{m}_W$	100 kg/s & 30 kg/s per well	Table 11
Cost of transmission	C_T	84,800 $/km	(BC Hydro 2012a)
Transmission distance	X_T	10 km	Assumption
Cost of interconnection	C_I	1.5 M$	(BC Hydro 2012a)

1) The assessed power plant capacities are taken from the case study (Section 6.4). However, power plant sizes are limited to 15 MW to allow comparison to power plants eligible under BC Hydro's Standing Offer Program.

CES Power and Control supplied a price quote for a 2.5 MW_e Organic Rankine Cycle Power geothermal power plant. Costs are listed in Table 13. The variable C_{Ref} (Equation 10) is the total power plant cost.

Table 13 Price quote by CES Power and Control for a 2.5 MW_e geothermal power plant

No.	Power Plant Costs	Cost [$]
1	Project Management	349,200
2	Engineering Design	852,000
3	Site Construction Equipment	21,600
4	Civil and Site Preparation	444,000
5	Concrete	21,600
6	Structural Steel	60,000
7	Buildings	46,800
8	ORC Equipment	6,155,600
9	Piping	784,800
10	Electrical	2,619,351
11	Instrumentation	420,000
12	Startup / Commissioning	109,200
13	Special / Other	118,800
	Total power plant cost	**12,002,951**

The cost of drilling and well completion for a geothermal well with conventional casing design (20”-13-3/8”-9-5/8”-7”) drilled to a depth of 3000 m was quoted by Terrapin Geothermics at $5,000,000 - $6,000,000. This study uses 2000 $/m for variable C_W (Equation 10) to linearly scale costs to actual resource depths. This is a conservative estimate, because costs may scale exponentially with drilling depths and all favourable areas but Jedney comprise a resource shallower than 3000 m.

Transmission costs are costs for constructing new transmission lines. Interconnection costs are costs of connecting transmission lines to a substation. Costs for transmission C_T and interconnection C_I are taken from BC Hydro (2012a). According to that document, transmission costs are 84,800 $/km for a 25 kV transmission line built on level terrain. That value is used here. The transmission distance X_T is assumed to be 10 km for all projects, because exact power plant locations are unknown. Interconnection costs depend on the lowest available voltage at a substation. This study uses an interconnection cost of 1.5 M$.

7.4.2 Levelized Cost of Energy, Net Present Value, Internal Rate of Return

All values used to calculate LCOE, NPV and IRR are listed in Table 14.

Table 14 Values used in LCOE, NPV and IRR calculation

Item	Symbol	Value	Source
Operation & Maintenance Costs	$C_{O\&M}$	100 $/kW$_e$	(EIA 2013)
Capital Costs	C_C	See Table 15	(Equation 10)
Power plant capacity	P_e	Horn River: 3700 kW Clarke Lake: 15000 kW Prophet River: 15000 kW Jedney: 7800 kW	See Table 10: P90 1) 1) See Table 10: P90
Discount rate	r	5 %	(Geoscience BC 2015)
Capacity factor	F	95 %	(Geoscience BC 2015)
Net parasitic load factor	L	75 %	(Geoscience BC 2015)
Price of electricity	C_e	0.11 $/kWh$_e$	BC Hydro Standing Offer Program
Price of thermal energy	C_{th}	2 $/GJ = 0.0072 $/kWh$_{th}$	Approx. average Alberta wholesale natural gas price from 01 Feb 2016 to 31 Jan 2017 (NGX 2017)
Required brine flow rate	$\dot{m}_b$	Horn River: 0.0371 kg/skW Clarke Lake: 0.0605 kg/skW Prophet River: 0.0409 kg/skW Jedney: 0.0276 kg/skW	See Table 8: P50
Enthalpy of brine @ 60°C	H_{min}	251 kJ/kg	(Bhattacharjee n.d.)
Enthalpy of brine @ reservoir temperature	H_R	Horn River: 547 kJ/kg Clarke Lake: 468 kJ/kg Prophet River: 530 kJ/kg Jedney: 603 kJ/kg	(Bhattacharjee n.d.) and Table 6: Reservoir mean temperature
Thermal efficiency of Rankine cycle	η_{th}	30 %	Typical value (Cengel & Boles 2002)

1) The assessed power plant capacities are taken from the case study (Section 6.4). However, power plant sizes are limited to 15 MW to allow comparison to power plants eligible under BC Hydro's Standing Offer Program.

Operation and Maintenance costs for binary cycle geothermal power plants are published by EIA (2013). The power plant capacities are those assessed in the case study (Section 6.4), up to a maximum of 15 MW to allow comparison to power plants eligible under BC Hydro's Standing Offer Program (SOP). For the same reason, the price of electricity is chosen to be 0.11 $/kWh$_e$, which is the base price in the SOP. The price of thermal energy is the approximate average Alberta wholesale natural gas price from 01 Feb 2016 to 31 Jan 2017 (NGX 2017), assuming a thermal efficiency of 100%. This is justified by the need of geothermal heat prices to be competitive to alternatives. The discount rate of 5 % is equivalent to the discount rate used in (Geoscience BC 2015), to allow comparison between results. The discount rate is a measure of the diminishing future value of money.

The economic assessment assumes that the P50 brine flow rate (Table 8) is necessary to supply geothermal power plants. The minimum useful temperature for a district heating system is based on author experience. This value is the usual set-point for domestic hot water tanks.

7.5 Results & Discussion

The LCOE for proxy power plants at the four favourable sites ranges from 144 to 166 $\$/\mathrm{MWh_e}$ at assumed flow rates of 100 kg/s per production well (Table 15). These values are significantly smaller than values assessed for Clarke Lake and Jedney in Geoscience BC (2015), which were 297 $\$/\mathrm{MWh_e}$ and 398 $\$/\mathrm{MWh_e}$, under equivalent brine flow rate assumptions. LCOE values are highly sensitive to the discount rate. In this study, a 5% discount rate was used. When increasing the discount rate to 7%, the LCOE of Clarke Lake increases to 202 $\$/\mathrm{MWh_e}$. The LCOE disregards thermal energy and only considers electric energy production. The capital costs per unit gross electric capacity range from 12,262 $\$/\mathrm{kW_e}$ to 14,410 $\$/\mathrm{kW_e}$, which is approximately equivalent to values found in Geoscience BC (2015). In that study, the capital costs were 11,100 $\$/\mathrm{kW_e}$ and 13,900 $\$/\mathrm{kW_e}$ for Clarke Lake and Jedney, respectively.

Table 15 Results of computing Capital costs, LCOE, NPV and IRR for a proxy geothermal power plant in each favourable area.

Technical Parameters	**Unit**	**Horn River**	**Clarke Lake**	**Prophet River**	**Jedney**	
Gross electric capacity	kW_e	3,700	15,000	15,000	7,800	
Thermal capacity	kW_{th}	28,249	146,980	120,951	49,716	
Net annual electricity production	GWh_e	23.1	93.6	93.6	48.7	
Annual heat production >60°C	GWh_{th}	235.1	1223.2	1006.6	413.7	
Number of production wells	-	2	10	7	3	Production flow rate: **100 kg/s per well**
Number of injection wells	-	1	5	4	2	
Financial Indicators						
Capital costs	Million $	52.0	216.1	183.9	104.5	
Capital costs per capacity	$\$/kW_e$	14,047	14,410	12,262	13,397	
LCOE	$\$/kWh_e$	0.162	0.166	0.144	0.156	
NPV	Million $	7.4	54.5	62.7	11.6	
IRR	**%**	6.2	7.1	7.8	6.0	
Technical Parameters						
Number of production wells	-	5	31	21	8	Production flow rate: **30 kg/s per well**
Number of injection wells	-	3	16	11	4	
Financial Indicators						
Capital costs	Million $	105.1	518.6	393.1	195.1	
Capital costs per capacity	$\$/kW_e$	28,398	34,574	26,206	25,010	
LCOE	$\$/kWh_e$	0.312	0.376	0.289	0.277	
NPV	Million $	71.7	362.6	356.0	127.6	
IRR	**%**	10.4	10.5	12.0	10.2	

The LCOE and capital cost estimates presented here are for relatively small scale pilot projects with significant potential for cost reductions. Scaling the 2.5 MW ORC geothermal power plant price quote to assess larger projects likely overestimates costs, because costs for larger power plants don't scale linearly. Furthermore, using a price quote for drilling and completing a geothermal well with a depth of 3000 m likely overestimates costs for shallower geothermal reservoirs. The US Energy Information Administration estimates capital costs of 4,362 $\mathrm{US\$/kW_e}$ for binary geothermal power plants in the US with a capacity of 50 MW_e (EIA 2013) and an LCOE of 44 US$/$MWh_e$ (EIA 2017b). Similar costs may be achieved through developing larger projects, sharing transmission capacity between projects and allowing industry to develop experience in geothermal well drilling.

Deployment of pilot-scale geothermal energy projects will likely require policy support. The IRR values range from 6 % to 7.8% and NPV is positive in all four cases for a discount rate of 5 % because calculations include revenue from both thermal energy and electric energy sales. Here, the electricity sales price is assumed to be equivalent to the base price paid in BC Hydro's Standing Offer Program of 0.11 $/$kWh_e$, which is below the LCOE of all projects. Therefore, financial viability requires either a higher price paid for electricity or additional revenue from heat sales. Thermal energy production likely exceeds heat demand in Horn River, Prophet River and Jedney. However, an abundant, low greenhouse gas emitting and relatively inexpensive heat source presents economic opportunities, e.g. growing food in greenhouses or aquacultures.

Future research needs to address several issues to further assess the viability of geothermal energy projects in northeastern British Columbia. Determining the commercial value of heat produced from low greenhouse gas emitting sources will allow estimating the required policy support that might leverage private investment. Additionally, the seasonal change of power and heat production should be considered in future research. This study assumes a constant temperature of the heat sink (reference temperature) of 0 °C, which is the approximate average annual air temperature in Fort Nelson. Since this temperature varies throughout the year, the power and heat output of a geothermal power plant may vary as well. A more detailed analysis of transmission requirements, which depend on the exact location of the power plant, the terrain and the availability of grid connection infrastructure can further reduce uncertainty in cost estimates.

8 Literature

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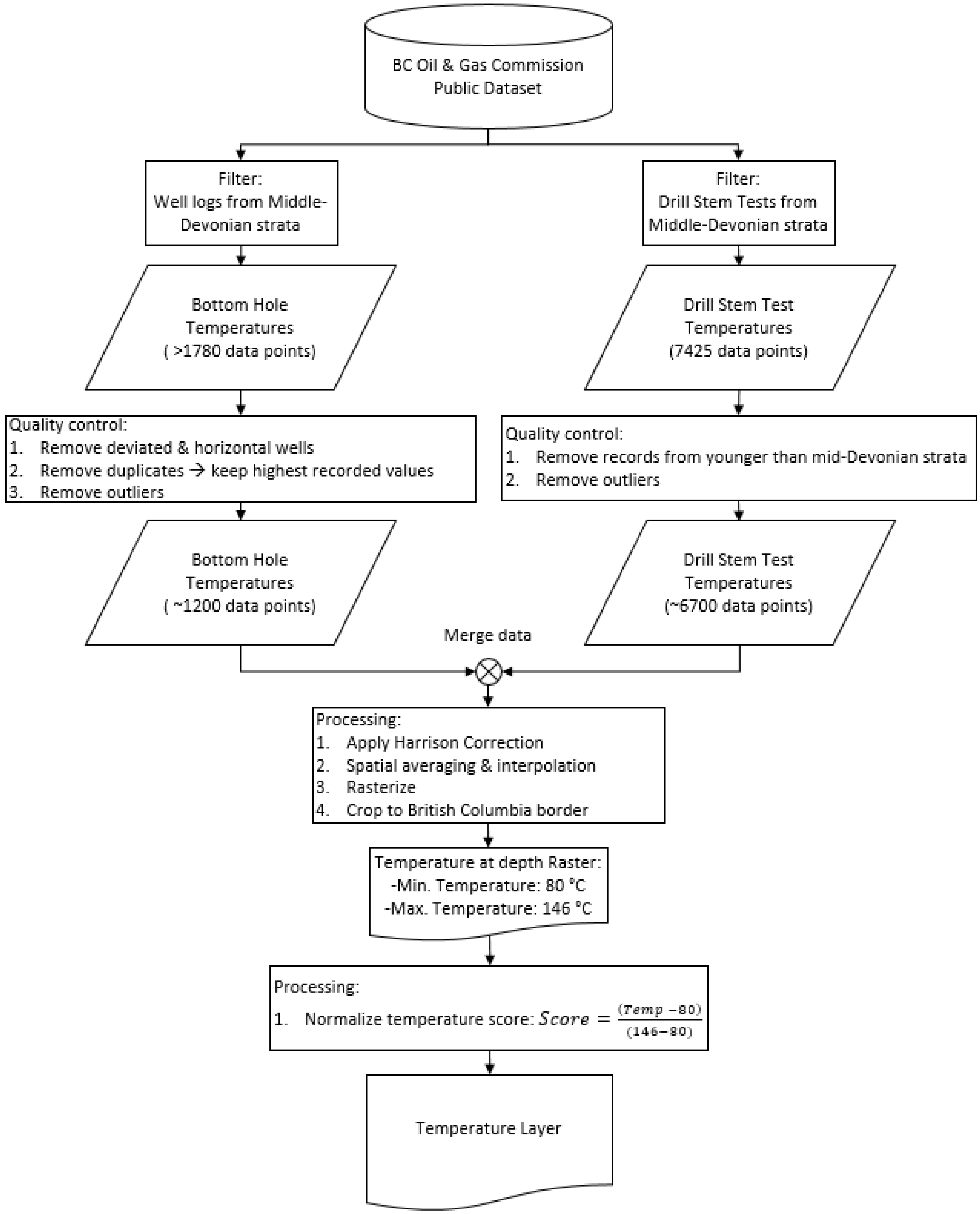
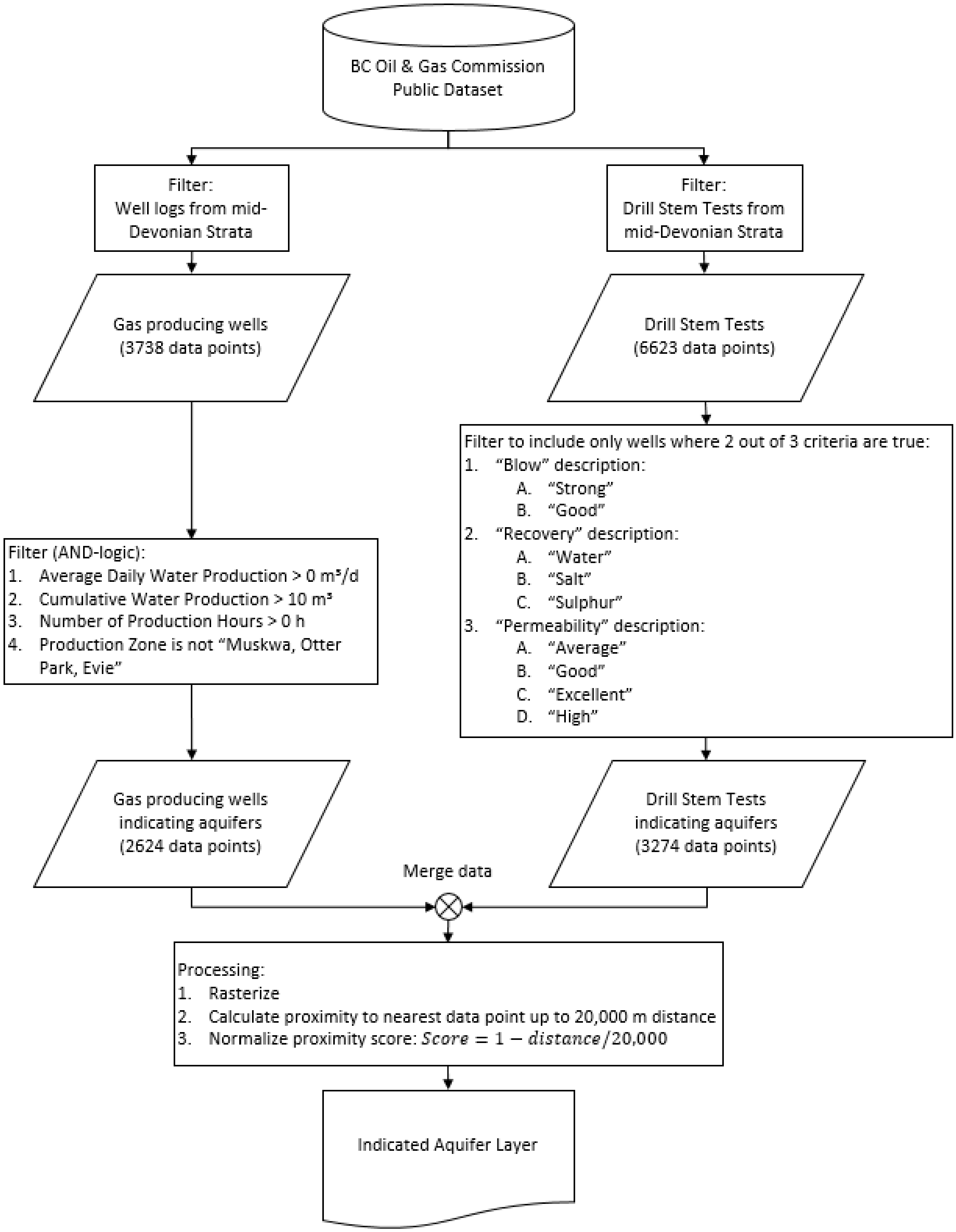
9 Appendix

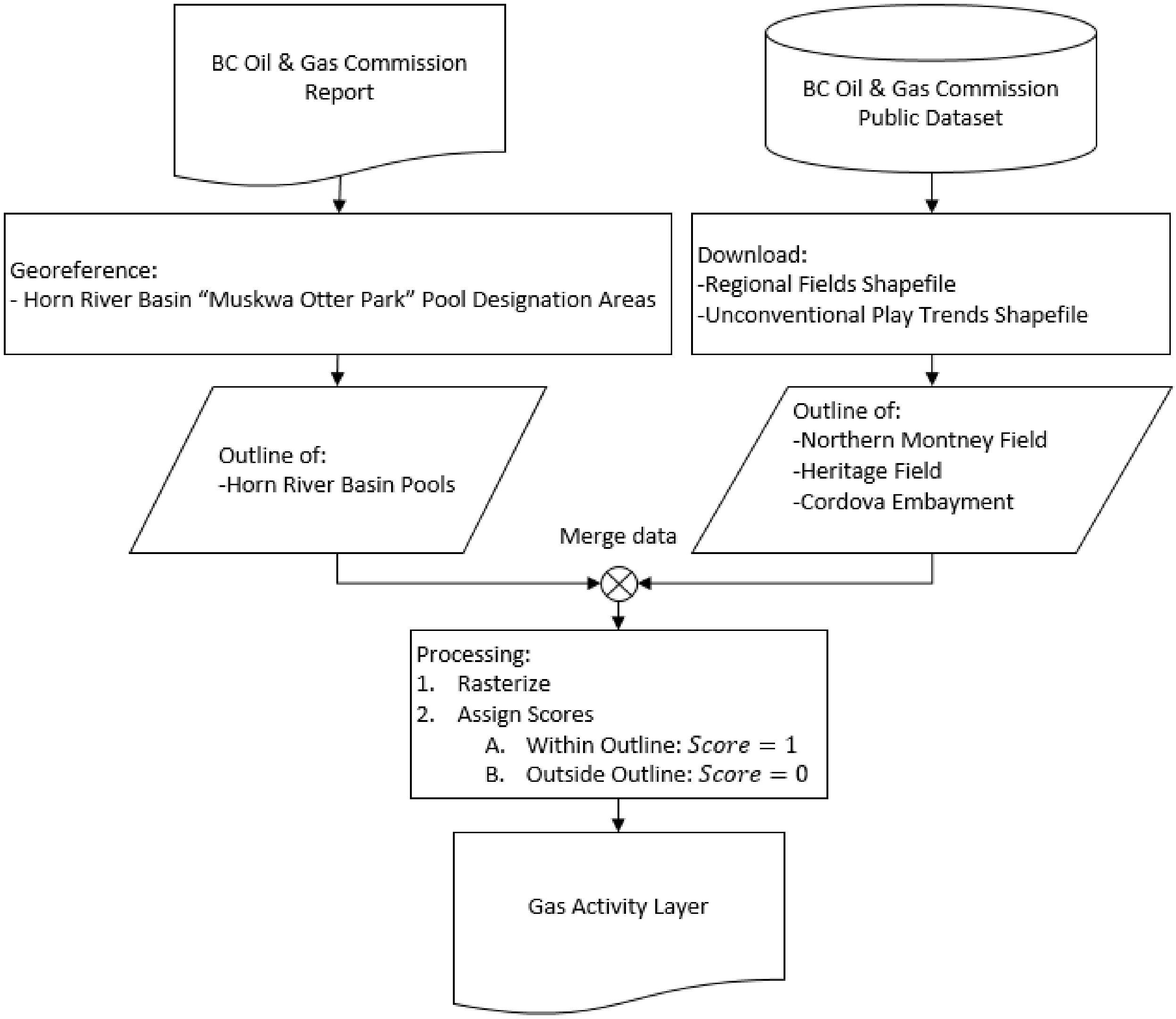
Appendix 1 Flowchart: Temperature Layer



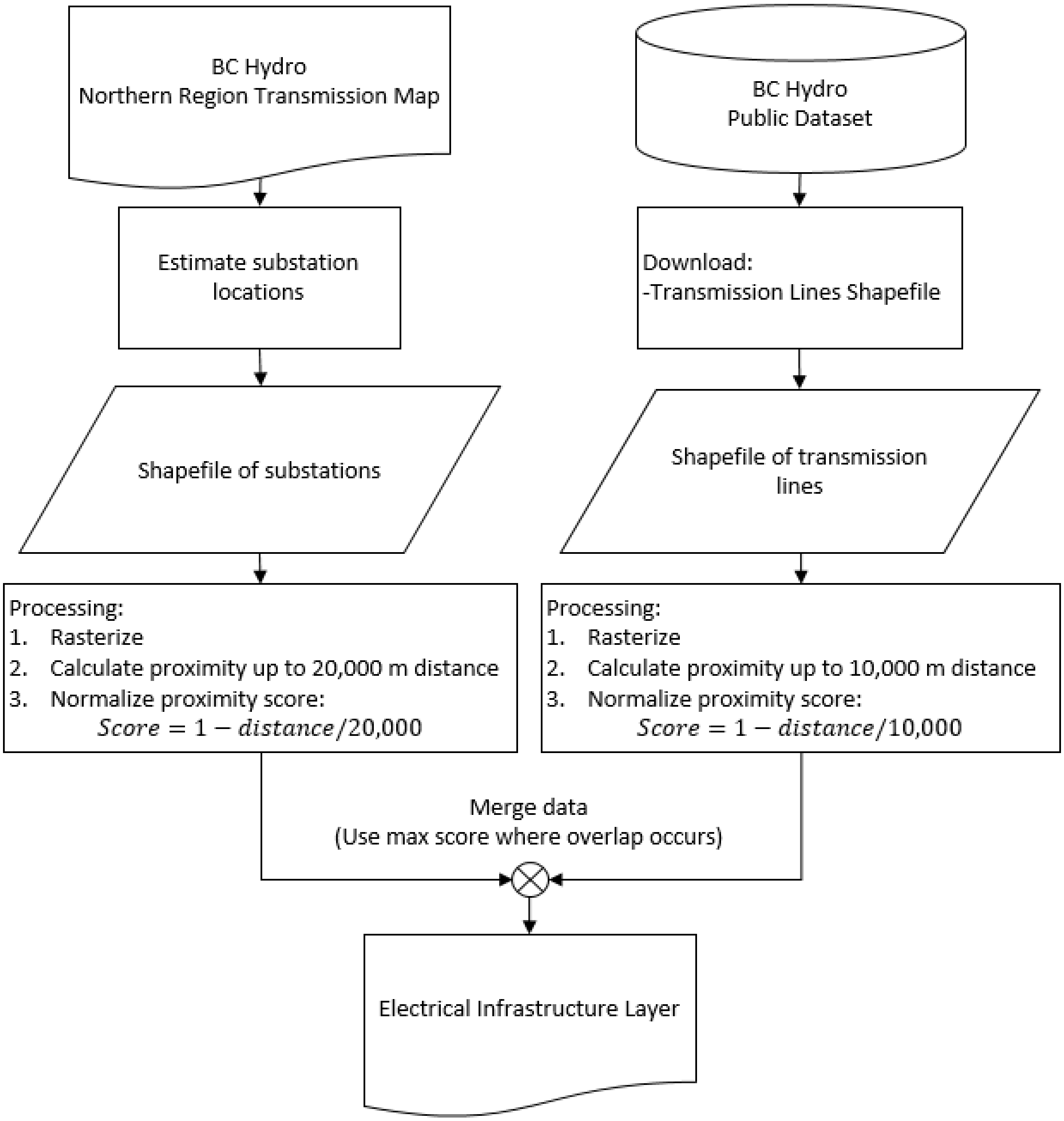
Appendix 2 Flowchart: Indicated Aquifer Layer



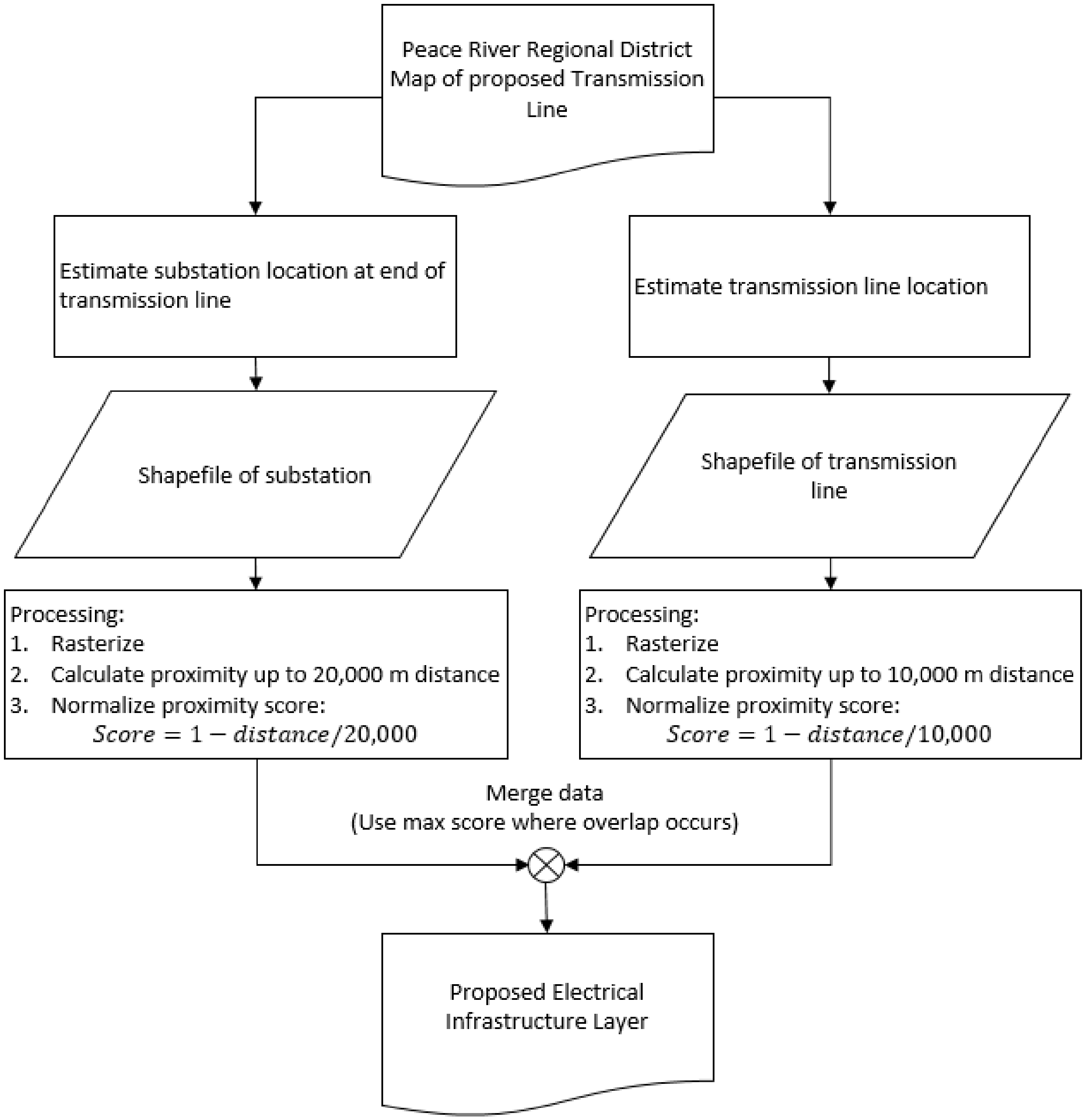
Appendix 3 Flowchart: Gas Activity Layer



Appendix 4 Flowchart: Electrical Infrastructure Layer



Appendix 5 Flowchart: Proposed Electrical Infrastructure Layer



Appendix 6 Flowchart: Towns and Communities Layer