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Deep-Dive Analysis of the Best Geothermal Reservoirs for Commercial Development in Alberta: Final Report

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DISCLAIMER

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Definitions

Several terms are used throughout this report that may carry various meanings, depending on the background of the reader. For the purposes of this report, the following terms are defined as follows:

Section: A stacked collection of geological formations that span a prolonged unit of time, i.e. the Cambrian section, or the middle Devonian section

Formation: An individual geological unit with a well-defined age, stratigraphic horizon and rock type, i.e. the Granite Wash formation or the Leduc formation

Brine: The fluid contained with a formation's pore space

Resource: Economically valuable material within a formation, i.e. the thermal energy contained within the brine and the rocks

Reservoir: A regional scale, resource-rich formation

Pool: A localized section of a reservoir that is being investigated for commercial development

Geothermal doublet: A basic geothermal energy production system consisting of a brine production and a brine reinjection well

List of Abbreviations and Symbols

GW	gigawatt
˚C	degrees Celsius
ΔH	change in enthalpy
ΔS	change in entropy
Cp_f	geothermal fluid heat capacity
Cp_r	reservoir rock heat capacity
EJ	exaJoule
ϕ	porosity
γ	thermal recovery factor
η	electricity conversion factor
H_0	dead state enthalpy
H_r	reservoir enthalpy
K	Kelvin
km	kilometer
m	meter
m^3	cubic meters
MJ/m^3K	mega Joules per cubic meter Kelvin; heat capacity
MWe	megawatt of electrical power
M_{wh}	fluid mass at well head
MWt	megawatt of thermal power
ORC	Organic Rankine Cycle
$Q_{r,}$	thermal energy in reservoir
Q_{wh}	thermal energy at wellhead
S_0	dead state entropy
S_r	reservoir entropy
T_0	dead state temperature
T_r	reservoir temperature
V_f	reservoir rock volume
V_r	reservoir fluid volume
W_A	exergy
WCSB	Western Canadian Sedimentary Basin
W_p	exergy available for electricity production

Executive Summary

Geotechnical and hydrogeological data taken from well bore logs and rock cores were used to identify, map, and predict the power production potential of geothermal reservoirs spread across several municipal districts in western Alberta. These districts include the City and County of Grande Prairie, the Municipal District of Greenview, the Town of Hinton and the Tri-council of Clearwater County, Village of Caroline and Town of Rocky Mountain House.

This study provides critical information to stakeholders for catalyzing the growth of an as-yet non-existent geothermal industry in Alberta. On a broader scale, this study provides a case study for quantifying regional scale geothermal resources in sedimentary basins. Although considerable amount of work remains to be done in order to bring a commercial geothermal project to fruition in Alberta, this study conclusively reveals a viable technical and potentially cost competitive geothermal resource base in the Western Canadian Sedimentary Basin.

We analyzed over 65,000 different wells in order to locate potentially water-bearing strata with temperatures ≥100 ˚C in the west-central parts of Alberta. We identified and quantified the resource potential of 22 possible mid-Devonian geothermal pools within our search area. Potential geothermal pools hosted in the Leduc formation were found in all of the municipal districts we investigated. Potential pools in the Swan Hills formation were identified in 3 of the 4 municipal districts investigated, as were potential pools in the Gilwood sandstone. Potential pools in the Granite Wash were found in two municipal districts. A summary of the technical parameters that went into the geologic modeling is found in the table below.

In addition to quantifying the thermal and electrical power potential of specific geothermal pools throughout the 4 municipal districts, this study also investigated 4 end-use scenarios:

- electricity production for a small pilot demonstration facility
- retrofitting of oil and gas wells for district heat use
- geothermal heating for greenhouses
- geothermal heating for timber drying

The major findings from this study are:

- Identification of over 6,100 MWt of thermal power capacity potential for a 30-year production period spread across the study area.
- Quantification of the scale of a geothermal system required to run both a greenhouse (~6 kg/s per hectare with a 60 °C brine) and a standard timber drying kiln (~9 kg/s with a 100 °C brine, for a standard size installation). With repurposed wells, such a system may cost $50-500/kWt. A system with new wells would cost $800-1000/kWt, and would need to be ~10x bigger to justify the expense.
- Identification of over 1,150 MWe of technically recoverable electrical power capacity potential for a 30-year production period. Indicators show that nearly 800MWe would be potentially cost competitive with today's technologies and roughly 80% of this resource is located within the 50km radius around the Town of Hinton.
- Electricity production of Alberta's geothermal resources is at a lower technology readiness level than direct use of heat production. Costs of first adoption of pilot scale binary-cycle geothermal power production in Alberta are ~$12,000-15,000/kWe. These costs are indicative of a pre-commercial technology that still requires technical and cost competitive de-risking. Some factors that may reduce these costs over time are continued exploration using existing oil and gas data, repurposing oil and gas wells as geothermal slim holes and developing and optimizing low and ultra-low temperature heat engines. As the technology matures, we expect these cost to be reduced

to $6,000-$8,000/kWe, which would make geothermal power cost competitive with wind and solar on a kilowatt-hour basis.

- Cost estimates for a 2.5 MWe demonstration plant, based on Albertan environmental conditions, using Albertan design, manufacturing and construction. With new wells, a first-of-its-kind plant of this scale may cost $25-30 million. Initial work indicates that if existing wells can be repurposed to save on drilling costs, this price decreases significantly.
- Cost estimates were developed for refurbishing an under-performing oil and gas well for geothermal heat or electrical power use and for drilling new, full-size geothermal wells in the Alberta economy. The fixed costs for retrofitting a well are ~$150,000, with an additional $40-50 per meter required for new tubing to be installed. The fixed costs for drilling new, full-size geothermal wells estimated to be $1.5 – 2 million per kilometer
- Quantification of the flow rates required to produce 1 MWe of electrical power, as a function of reservoir temperature. Three groups and three methods in this study independently confirmed the flow rates. The flow rates predicted within the study area range from ~40 kg/s to > 200 kg/s per megawatt of electrical power.

By developing our geothermal resources at home, we have the potential to position Albertan companies to be global leaders in basin-hosted geothermal production technology. Exploiting geothermal resources in sedimentary basins is a key aspect of making geothermal energy a major, rather than a niche, renewable power, globally. Due to the ubiquity of oil and gas wells in the Alberta subsurface, we have the potential to save tens of millions of dollars in the upfront costs related to geothermal energy exploration. In addition, if these well can be repurposed for geothermal energy production, the costs savings to the developer by not having to drill new wells for production could be in the tens of billions. Because of the clear technology transfer pathways between the oil and gas and geothermal industries, as well as Alberta's homegrown expertise in drilling and reservoir engineering, Alberta has a significant opportunity to be at the forefront of the development of transformative technology in the geothermal space.

Next steps required to bring geothermal energy to commercial production include building static reservoir models and reservoir production models for the top sites identified in this study, as well as expanded preliminary exploration, similar to that found in this study, for sited all across central and western Alberta. To take of advantage the widespread presence of 60 °C-100 ° water throughout the basin, we also recommend the further development and optimization of low and ultra-low temperature differential heat engines. Additionally further economic modelling is required to show the commercial viability of specific projects, or to determine term the economic variables that will make the technology commercial viable. Finally, a regulatory framework for producing and selling geothermal energy in the province is required.

Town	Reservoir	Temperature (°C)	Depth (m)	Thermal Energy (MWt)	Flow Rate per MWt (kg/s)	Electrical Energy (MWe)	Flow Rate per MWe (kg/s)
Sexsmith	*Leduc*	92±2	3300±83	109	17	15	124
	Swan Hills						
	Granite Wash	120±6	4198±488	176	11	40	48
	Gilwood						
Grande Prairie	*Leduc*	96±3	3389±70	238	16	35	106
	Swan Hills						
	Granite Wash	120±6	4198±488	71	11	16	48
	Gilwood						
Wembley	*Leduc*	112	4256±269	176	12	35	61
	Swan Hills						
	Granite Wash	120±6	4198±488	24	11	5	48
	Gilwood						
Beaverlodge	*Leduc*						
	Swan Hills						
	Granite Wash	120±6	4198±488	71	11	16	48
	Gilwood						
Hythe	*Leduc*						
	Swan Hills						
	Granite Wash	120±6	4198±488	99	11	22	48
	Gilwood						
Valleyview	*Leduc*	75±12	2675±325	597	24	51	282
	Swan Hills	83±6	2825±182	78	20	9	180
	Granite Wash	80±10	3035±175	462	22	46	214
	Gilwood	83±14	3081±367	141	20	16	175
Fox Creek	*Leduc*						
	Swan Hills	90±15	3043±17 6	349	18	46	135
	Granite Wash						
	Gilwood	93±14	3158±164	63	17	9	116
Hinton	*Leduc*	129±13	4513±627	883	10	222	38
	Swan Hills	129±12	4557±486	1558	10	393	38
	Granite Wash						
	Gilwood	119±14	4306±264	69	11	15	50
Rocky Mountain House	*Leduc*	112±11	3608±994	20	12	4	60
	Swan Hills	118±15	4200±690	112	11	24	51
	Granite Wash						
	Gilwood						
Caroline	*Leduc*	96±10	3457±150	592	16	90	102
	Swan Hills	94±10	3788±133	220	16	32	114
	Granite Wash						
	Gilwood	100±8	3861±70	79	15	13	90

1 Introduction

1.1 Project Background and Overview

Geothermal energy production refers to harnessing the latent heat of the earth to provide fuel for human activity. Geothermal energy is a baseload, renewable resource that has the potential to play a role in a global transformation away from fossil fuel based resources. Historically, the development of utility scale geothermal power projects has been restricted to tectonically active areas where high surface heat flow and extensive subsurface fracture networks allow for relatively easy access to hot fluids. These areas are often far away from human activities that require the thermal and electrical power that geothermal energy may provide.

Recent growth in the global geothermal industry has focused on sedimentary basins, many of which contain geothermal resources that are closer to suitable geothermal energy end users. The Western Canadian Sedimentary Basin (WCSB) is a continental scale, alpine foreland basin that underlies many population centers and possesses a large geothermal resource base. The WCSB, which covers most of the Province of Alberta, is best known for its hydrocarbon reservoirs, which include the Athabasca oils sands, as well as over a quadrillion of cubic feet of natural gas and coalbed methane. Prolific development of these hydrocarbon resources has created a robust set of thermodynamic and hydrogeologic subsurface data that can potentially be used to locate and map geothermal resources, as well as quantify the power production capabilities of these resources throughout the basin.

The Department of Earth and Atmospheric Sciences at the University of Alberta undertook this Deep-Dive Analysis of the Best Geothermal Reservoirs for Commercial Development in Alberta in order to catalyze commercial geothermal energy development in the province. We used data from the oil and gas industry to assess the geothermal resource potential of several hot sedimentary aquifers in Alberta, which overlay some of the deepest parts of the WCSB. Five regional municipal governments with high potential for being impacted by exploitation of the WCSB's geothermal resources participated in this project as funding partners. From north to south, these governments are:

1. The County of Grande Prairie
2. The City of Grande Prairie
3. The Municipal District of Greenview
4. The Town of Hinton
5. The Tri-council of Clearwater County, Village of Caroline, Town of Rocky Mountain House

In-kind support for this project in the form of cost estimates, power needs, process flow diagrams were provided by Terrapin Geothermics, Solbird Energy, CES Power and Control and the Iceland School of Energy at Reykjavik University.

The purpose of this study is to provide the participating municipal districts the requisite information for long-term strategic planning towards developing their geothermal resources and to begin the process of commercial development. This information fell into 3 basic categories:

1. The precise location of geothermal reservoirs at depth
2. The thermal and electrical power production capacity of these reservoirs
3. Local options for geothermal power utilization, including cost estimates for various applications

The goal of the study was to incubate a geothermal energy industry in Alberta, leading to commercial production of this resource by 2020.

We began the study by accessing well data for every well in these municipalities that is deeper than 1500 m, as shown in Figure 1.

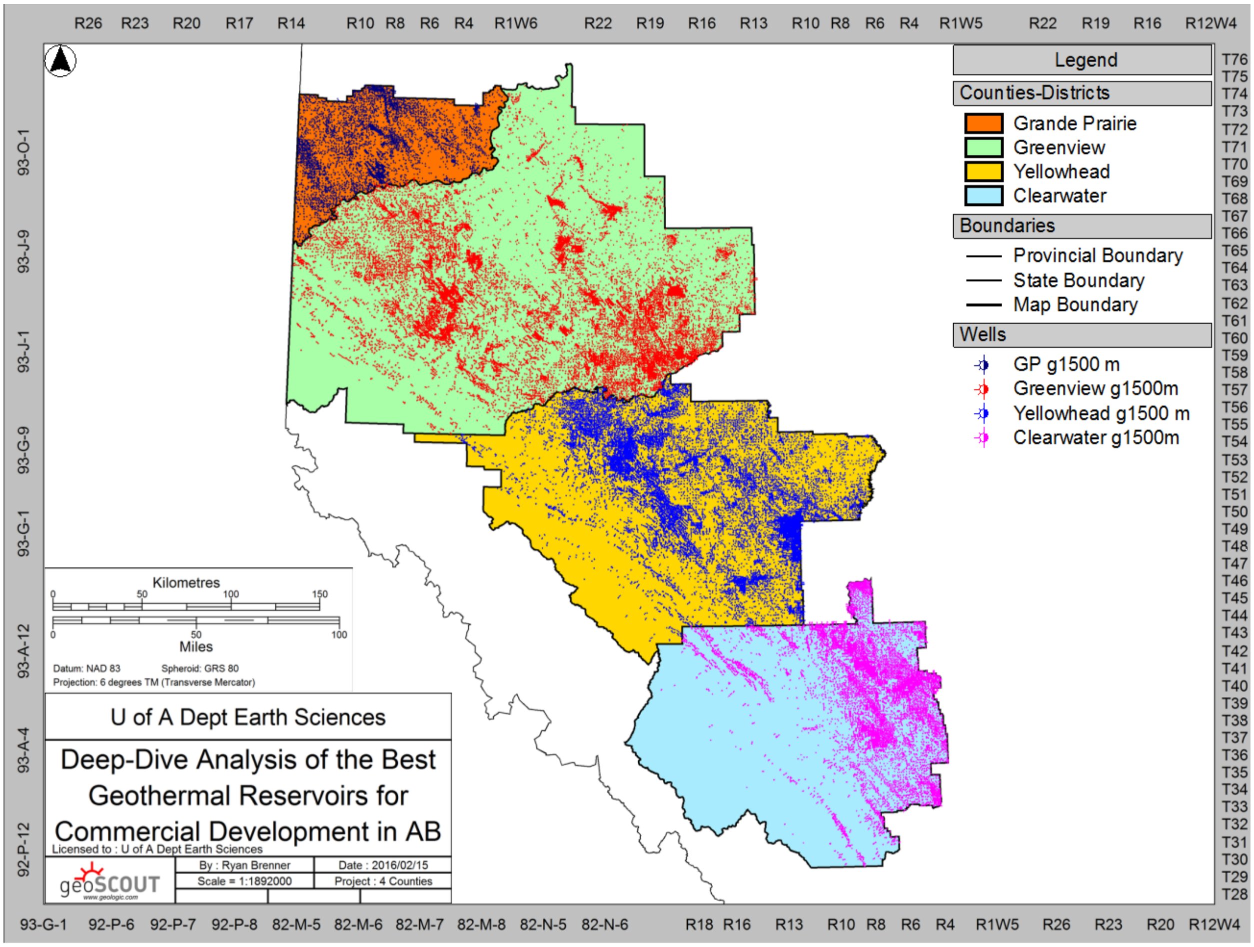

Figure 1 Map of the municipal districts participating in this study, together with every well data point that was used for building the models and developing the volumetric energy assessments

Table 1 shows the breakdown of these wells by depth. Altogether, over 65,000 data points were used to identify the reservoirs most suitable for commercial development.

Table 1 Distribution of wells used in this study by municipal district and well depth

	Number Wells by Municipal District			
Well Depth	*Grande Prairie*	*Greenview*	*Yellowhead*	*Clearwater*
> 1500	5,877	21,354	21,300	12,213
> 2000	4,693	17,395	18,300	10,243
> 2500	1,772	12,528	13,244	5,808
> 3000	253	7,063	7,442	2,449
> 3500	69	1,648	1,737	999
> 4000	19	332	607	401
> 4500	6	108	303	140
> 5000	1	43	30	40
> 5500	0	12	8	8

Temperature is the primary concern in evaluating the technical and commercial viability of a geothermal resource. Commercial use of geothermal energy directly as heat can begin with resource temperatures as low as 50 °C. In Alberta, where average annual air temperatures hover at a balmy 0 °C, utility-scale electricity may be produced from resources with temperatures ≥100 °C. Our search for the most viable resources began by determining the temperature distribution of gas pools throughout the study region. The assumption here is that gas pools lie directly above the water pools, and thus the gas pools provide a window into the conditions found in the underlying aquifers. Figure 2 shows a histogram of all the potential geothermal pools in our study area, categorized by temperature.

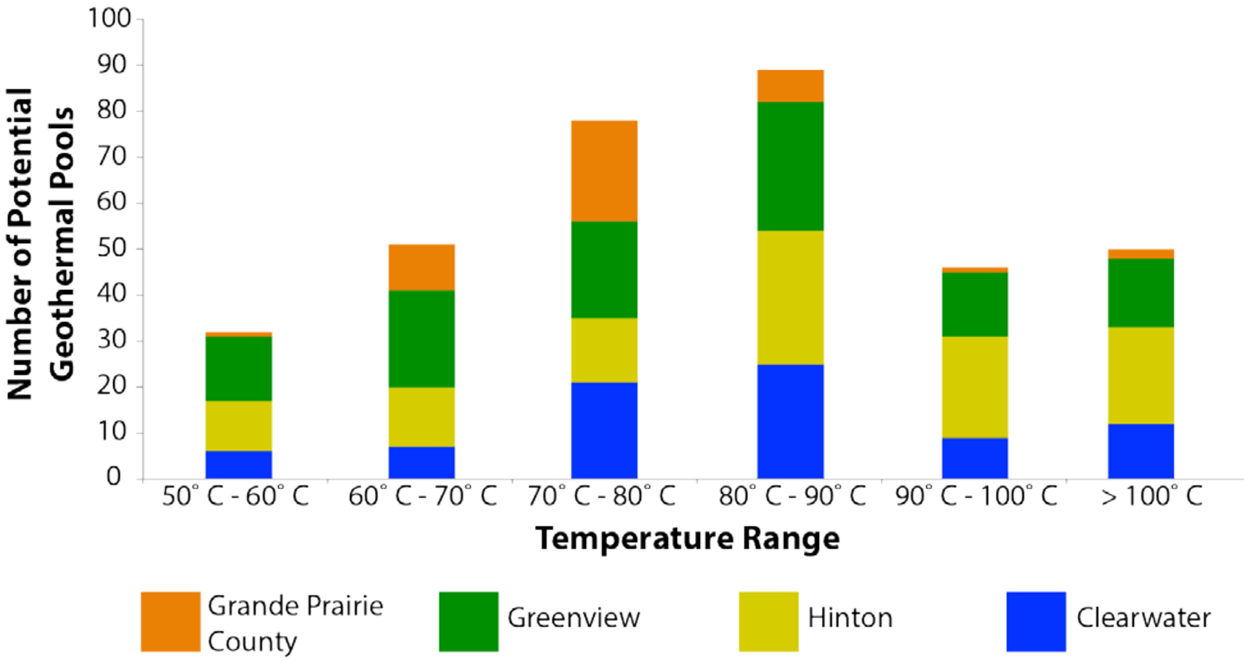

Figure 2 Histogram of identified potential geothermal pools as a function of temperature and municipal location

In the proposal stage of this project, we anticipated identifying 10 geothermal pools that may have the temperatures required for producing electricity. The data revealed that there might be as many as 50 pools in the study area that meet this criterion. Furthermore, an additional 296 pools were identified with temperatures > 50 ˚C. These pools, which contain the majority of Alberta's basin - hosted geothermal resources, are appropriate for direct use of geothermal heat.

In order to maintain the focus of diving deeply, we needed to narrow down the number of ≥100 ˚C pools to choose from for comprehensive evaluation. We chose to start at the bottom of the basin and focus only on Devonian) formations, i.e. formations from 419.2 million years old to 358.2 million years old. Specifically, we looked at all formations below the Ireton as possible geothermal reservoirs. This was a strategic decision made to reduce the total volume of data we needed to manage within the timeframe of this study. Starting at the bottom of the section was a way to insure we targeted the highest temperature reservoirs first. Capping the search below the Ireton formation was an arbitrary decision geared towards keeping the number of pools we investigated close to the expected number identified in the initial project proposal. In the end, we focused on 4 geologic formations that, based on known lithologies and hydrogeologic properties, were deemed to be the most likely water bearing strata. These formations, from the youngest to oldest are:

1. Leduc (carbonate reef)
2. Swan Hills (carbonate reef)
3. Granite Wash (fluvial deltaic sandstone)
4. Gilwood (arkosic sandstone)

Other formations in the study region may also be suitable geothermal reservoirs on a more local basis, but these formations were not investigated in this study. For example, in the interim report, we also briefly discussed several Cambrian formations in the Municipal District of Greenview and Clearwater County. Upon further investigation, however, it became clear that there were not enough data to reliably determine the potential of these formations. Therefore, they are not included in this final report.

The formations mentioned above are the most widespread potential deep aquifers in the study region, and therefore, they have the greatest potential as geothermal reservoirs. Table 3 summarizes the extent of their presence beneath population centers throughout the study region.

Table 2 Locations of the 4 investigated formations beneath 10 population centers within our study area

Municipal District	Population center	Gilwood	Granite Wash	Swan Hills	Leduc
Grande Prairie County	Sexsmith		X		X
	Grande Prairie		X		X
	Wembley		X		X
	Beaverlodge		X		
	Hythe		X		
Municipal District of Greenview	Valleyview	X	X	X	X
	Foxcreek	X		X	
Yellowhead County	Hinton	X		X	X
Clearwater County	Rocky Mountain House			X	X
	Caroline	X		X	X

In total, we identified, mapped and calculated the thermal and electrical power production capacity for 22 potential geothermal pools situated beneath 10 population centers throughout the study region.

A detailed description of the Devonian section of the WCSB underlying western Alberta is found in section 1.2, below. A summary of previous geothermal energy research in the WCSB, found in section 1.3, completes this introductory chapter. Chapter 2 of this report details the methods we used in completing the geotechnical elements of the study, including both the mapping and modeling methods, as well as the volumetric methods used for calculating the bulk thermal and electrical power potential of the reservoirs. Chapter 3 summarizes the results of the geotechnical section of the study, and Chapter 4 details specific options available to the participating municipalities. In Chapter 5, we provide preliminary process flow diagrams, thermodynamic assessments and cost estimates for direct use and electricity generation opportunities available to the participating municipalities. Chapter 6 presents a review of royalty and regulatory issues facing Alberta. The study concludes in Chapter 7 with a summary of the major results and recommendations for further action.

1.2 Devonion Strata beneath the Alberta Foothills

Devonian strata in the Alberta foothills and plains are represented by, from oldest to youngest, the Lower Devonian strata, the Elk Point Group, the Beaverhill Lake Group, the Woodbend Group, the Winterburn Group and the Wabamun Group. Devonian strata make up some of the thickest accumulations of rock in the WCSB and contain world–class hydrocarbon resources. A stratigraphic section of Devonian formations in the Alberta foothills is shown in Figure 3.

The Lower Devonian has been almost entirely eroded away, save for within the Williston Basin (Saskatchewan and Manitoba) and outcrops exposed within the Rocky Mountains (Glass, 1990; Meijer, 1994). These strata were deposited as a result of the second major North American transgression, the Tippecanoe Sequence. The Tippecanoe transgression ended a period of early–Appalachian erosion that deposited siliclastic and carbonate sediments across the North American Craton during the middle Ordovician to the early Devonian (Glass, 1990; Meijer, 1994). This event was followed by a period of erosion during which most of the Lower Devonian in Alberta strata were destroyed. Remnants of the Lower Devonian are nonetheless found in various regions of our study, most notably in the north, in the form of the Granite Wash sandstones (Rottenfusser and Oliver 1977; Meijer, 1994; Dec et al., 1996)

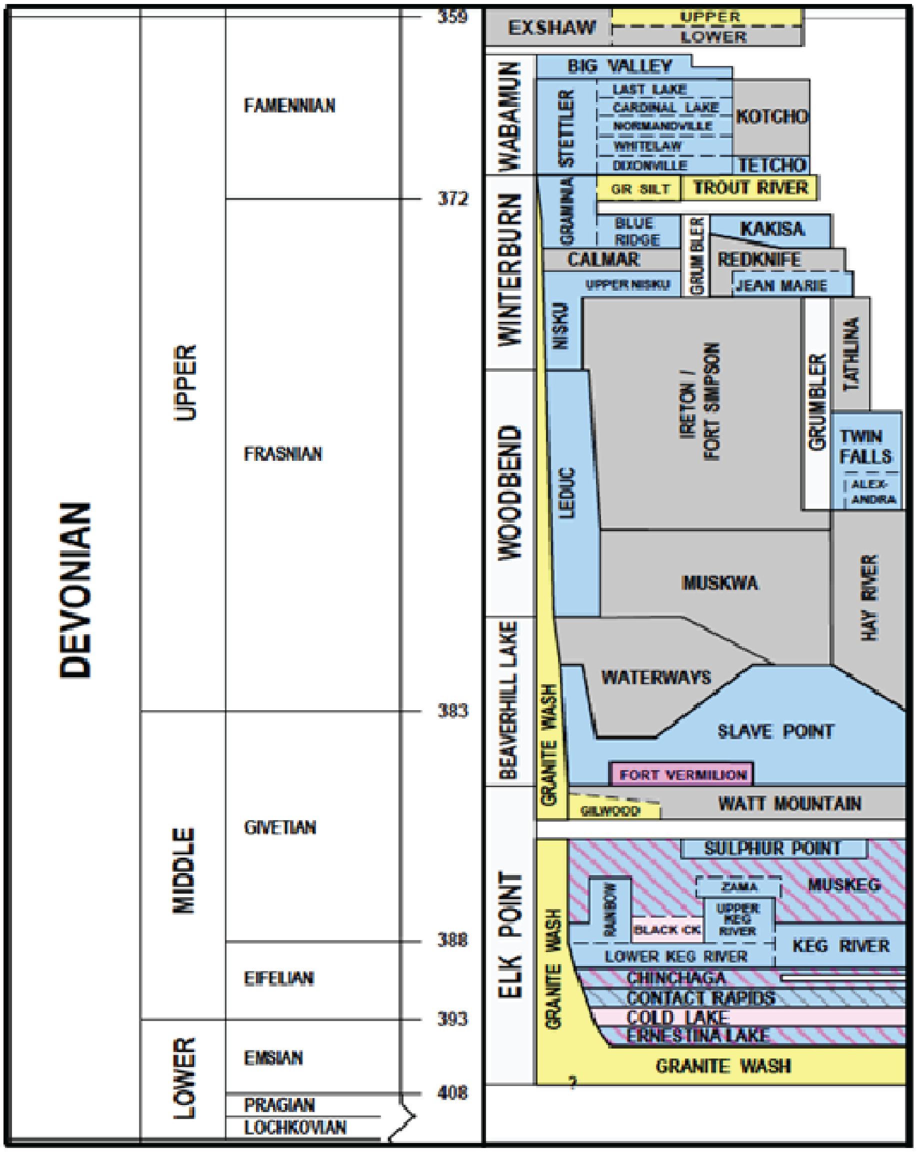

Figure 3 Idealized Devonian stratigraphic columns for our study area in the Alberta foothills (adapted from: Alberta Geological Survey, 2015)

Due to an erosional period at the end of the lower Devonian, the Elk Point Group was deposited on an irregular surface of considerable relief. The Elk Point Group variously overlies Ordovician and Silurian carbonates, Precambrian igneous and metamorphic rocks, and Cambrian clastics and carbonates (James and Leckie, 1988; Glass, 1990.) The initial Elk Point deposit consists of the green shales of the Watt Mountain Formation and the red to green dolomitic mudstones of the Second Red Bed member (Kramers and Lerbekmo, 1967; Rottenfusser and Oliver 1977; Meijer, 1994). Arkosic sandstones of the Gilwood Member (part of the Watt Mountain) were deposited in a fluvial-deltaic complex along the Peace River Arch (Rottenfusser and Oliver 1977). The Gilwood is a promising sandstone reservoir in the southern parts of our study area. The Muskeg, Keg River, Prairie Evaporites and Sulphur Point are all prominent members of the Elk Point Group, although they do not play important roles in this study, either due to their absence from the study area, or their lack of appropriate reservoir properties (Kramers and Lerbekmo, 1967; Meijer, 1994).

A rise in relative sea level initiated the beginning of the Beaverhill Lake Group (Glass, 1990). The Fort Vermillion Formation at the base of this group consists of restricted coastal marine carbonates and evaporites. A further increase in relative sea level deposited widespread open-marine carbonates of the Slave Point Formation, which in turn gave a suitable substrate for the reefs of the Swan Hills Formation (Hemphill et al., 1970; Oldale and Munday, 1994). The Swan Hills Formation contains one of Alberta's most abundant geothermal resources and is found in 3 of the 4 municipal districts in this study. Following the formation of the Swan Hills reefs, the sea again regressed, allowing the shales and argillaceous carbonates of the Waterways Formation to fill in the space between the reefs (Hemphill et al., 1970; Oldale and Munday, 1994).

The Woodbend Group, which overlies the Beaverhill Lake Group, represents a period of relative sea level rise upward from the Cooking Lake, through the Majeau Lake, Leduc and Duvernay formations (Glass, 1990; Switzer et al., 1994). The Cooking Lake Formation is composed of extensive sheet-like shelf carbonates and a deeper – basin filling shale. Majeau Lake contains similar lithofacies, but also contains isolated reef complexes and reefal margins (Andrichuk, 1958; Switzer et al, 1994; Wendte; 1994). The growth of the Leduc Reefs represents the culmination of sea level rise during the deposition of the Beaverhill Lake Group. Leduc reefs are found throughout our study area and, with the Swan Hill reefs, are among Albert's most promising geothermal resources (Jansa and Fischbuch, 1974; Kaufman et al., 1990; Atchley et al., 2006)

Contemporaneously with the formation of the Leduc Reefs, the Duvernay formation was deposited as basin in-filling, dark brown bituminous shale and limestone (Dunn et al., 2012). Similar to the Waterways Formation, the Duvernay basinal sediments were deposited extensively across the entire basin. Eventually an end to the sequence of deepening (and the conclusion of the Woodbend Group) occurred with the deposition of the Ireton Formation consisting of cyclic successions of basin – filling shale (Switzer et al, 1994; Dunn et al., 2012)

The remaining Devonian sequences, i.e. the Winterburn and the Wabamum Groups, were not investigated in this study.

The sedimentary rocks which comprise Alberta's Devonian Strata are of two types: siliclastics and carbonates. Siliclastic formations are formed predominantly from silicate minerals (i.e. quartz, feldspar, micas, clays) that have been physically eroded, transported, re – deposited and lithified. Sandstones and shales are the most common siliclastic rocks. Reservoir quality in siliclastic rocks is defined by the nature of their inter – granular contacts and in – filling cement. Sandstones are generally good reservoirs because their physical composition (i.e. individual sand grains) makes them resistant to compaction. Thus, their primary porosity is often preserved, even when they are found at great depth. We assume that this porosity is water saturated. The relationship between porosity and permeability in sandstones is also fairly well understood in sandstones via the "Klinkenberg" correlation. Therefore, predicting fluid flow behaviour based only on porosity data is reliable over a large area.

Carbonates can form from the chemical precipitation of carbonate – bearing minerals (i.e. limestone) from a body of water, or the accumulation of organically – derived carbonate material (e.g. dead microorganisms; shells) on a substrate. The properties of carbonate rocks vary depending on the environment of their deposition. They can also display significant amounts of secondary porosity, caused either through dolomitization (i.e. calcite changing to dolomite), or karstification (i.e. chemical dissolution in contact with a fluid.) Of the various types of carbonates, reef facies are deemed most favourable for geothermal energy production. Carbonate reefs contain high degrees of both primary and secondary porosity, whereas open marine, shelf and bank carbonates may be severely hydrogeologically restricted. Carbonate reef reservoirs, like sandstones, are generally believed to be water saturated.

Of the formations within these investigated groups, the Leduc (carbonate), Swan Hills (carbonate), Granite Wash (sandstone), and Gilwood (sandstone) are the most widespread and promising geothermal resources. As shown in Table 2, we have identified 22 potential geothermal pools within these formations underlying the population centers underlying our study are. Thus, we studied more than twice the number of pools we sought to investigate during the initial proposal stage of this project.

1.3 Geothermal Research in the Western Canadian Sedimentary Basin

Geothermal research in Canada dates back to Garland and Lennox (1962), who studied heat flow throughout the western Canadian provinces and territories. Majorowicz and Jessop (1981) first studied regional heat flow patterns in the WCSB, specifically. Subsequently, this research has expanded to include thermal conductivity studies throughout the basin (Lam et al., 1985), radiogenic heat production and heat flow from the Precambrian basement underlying the WCSB (Jones and Majorowicz, 1987; Bachu, 1993) and temperature distribution along the Precambrian and various Paleozoic surfaces in WCSB (Jones et al., 1985). Much of this early research was plagued by inconsistencies with the temperature data. Thus, extensive work has been done to correct temperature data for hydrodynamic influences (e.g. Majorowicz et al., 1999), paleoclimatic effects (Majorowicz et al., 2012a) and other biases (Gray et al., 2012). Nieuwenhuis et al, (2015) released a database at the 2015 World Geothermal Congress that is the culmination of the efforts to correct temperature measurements throughout the WCSB.

In addition to the emphasis on temperature corrections, recent geothermal research in the WCBS has focused on exploitation of the basin's geothermal energy for heating and electricity. On behalf of the Geological Survey of Canada, Grasby et al. (2012) performed a country-wide geothermal resource base estimate. Majorowicz et al. (2012b) investigated the possibility of using geothermal energy as heat source for oil-sands upgrading. Weides et al. (2013) looked for potential geothermal resources in Paleozoic strata in the Edmonton, AB metropolitan area (population ~1.16 million). This research led to a further interest in using the basal Cambrian sandstones as a potential electricity producing resource (Weides et al, 2014a). Weides et al, (2014b) also investigated the siliciclastic Granite Wash unit in the Peace River area of Alberta. Heat and electricity from a geothermal source could be used to offset the environmental footprint of in-situ hydrocarbon production in this region. Restricted largely by temperature, both of these formations have marginal electricity producing capabilities in these areas, but are able to provide ample heat for direct use.

This present study is predominantly inspired by the work done by Weides and Majorowicz (2014) that looked at spatial variability in heat flow throughout the entire WCSB. They overlaid the areal extent of known deep basin aquifers with temperature profiles from the surfaces of various geologic periods throughout the Paleo- and Mesozoic. The level of detail in Weides and Majorowicz's (2014) study allowed us to identify specific formations to investigate that have the potential to be exploited for electricity production and are close to either population centers, or areas where there is high industrial power demand. While other studies (e.g. Majorowicz and Grasby, 2010 Grasby et al., 2011, Majorowicz et al., 2012b; Majorowicz and Moore, 2014) have looked at Alberta's geothermal resource base as a diffuse, province-wide commodity. This is the first study that quantifies the power production potential of specific pools within exploitable proximity of possible end users.

2 Methods & Materials

2.1 Regional Reservoir Properties

Using data acquired from GeoSCOUT and the Alberta Energy Regulator and processed with Petrel, Surfer and Voxler, we made geologic models of the Devonian (Woodburn and below) stratigraphic sections underlying our study area. Within this section, we focus on 4 formations that we hypothesized are the most suitable geothermal reservoirs. From youngest to oldest, these formations are:

1. Leduc
2. Swan Hills
3. Granite Wash
4. Gilwood

On a regional basis, we produced a number of contour maps, including depths from the ground surface to the top of the formation, formation isopachs (thicknesses), bottom hole temperatures, potentiometric surfaces and porosity. Table 3 shows the number of data points used to make these maps.

Table 3 Number of data points used for contour mapping of geothermal reservoir properties in the Alberta Foothills.

	Parameter Data Points						
	Total Wells	*Total Vertical Depth*	*Total Vertical Depth to Formation Top*	*Corrected Bottom Hole Temperature*	*Pressure*	*Permeability*	*Porosity*
Leduc	1322	557	557	557	357	402	402
Swan Hills	1708	1708	1695	991	346	736	736
Gilwood	954	936	948	799	80	44	44
Granite Wash	308	308	308	176	63	53	53

Formation tops were identified predominantly by using the GeoSCOUT well tickets. For quality control, we cross-referenced the formation top depths in the GeoSCOUT well tickets with tops identified in the well logs themselves. To assist in this quality control, type-logs for each of the formations in question were obtained from the Alberta Energy Regulator. Temperature contours were made using Nieuwenhuis' (2015; used with permission) data, which contains ~127,000 corrected thermal gradient measurements from wells throughout the entire WCSB. We used the (Horner corrected) bottom hole temperature measurements from wells that terminated in our four potential reservoirs.

Potentiometric surfaces were mapped using drill stem pressure tests. Reservoirs are assumed to be unconfined, and the potentiometric surface is calculated as the difference between the well's total vertical depth and the hydrostatic head of the formation fluid at the given pressure. A brine density of 1150 kg/m^3 was assumed in the hydraulic head calculations. This takes into account changes in water density caused by both elevated salinity and elevated temperature (e.g. Dittman, 1977). This values may be taken as a basin wide average. Potentiometric surfaces are indicator of how much pumping power is required to bring geothermal brine to the surface in a given region.

Porosity measurements were taken from drill cores from the given formations. For situations where more than one measurement was available for a give sequence of core, the value from the deepest part of the core was used. All of the porosity values available to us in this study were made within a gas or oil pool and are not truly representative of the brine saturated parts of the formation. We used the deepest depth porosity values because this is the section of core that is closest to the hydrocarbon/water contact.

2.2 Stratigraphic grids and formation volumes

We used the formation tops (and associated structural elevations) described in Section 2.1 to make maps of the surfaces of each formation at depth. We mapped not only the 4 potential geothermal reservoirs, but all formations between the Ireton and the base of the Devonian. Formation layers were stacked to create a 3-D model of the lower to mid-Devonian section underlying the Alberta foothills.

Once this model was made, we zoomed in on areas within a reasonable distance of a potential geothermal power end-user, i.e. a village, town or city. Table 4 shows the towns that we focused on, along with their populations and the radii around the towns that we modeled. These radii were selected to maximize coverage around a town, while minimizing overlapping, which would lead to redundancies in the volumetric calculations. Thus, areas with towns that are more closely spaced together have smaller search radii accompanying them. The search radii were used to establish the area associated with volumetric energy and power production calculations described in Section 2.3. Formations volumes were calculated by multiplying by the formation thicknesses in these search areas.

Table 4 List of population centers in each municipal district for targeted geothermal reservoir modeling

Municipal District	Town	Population	Modeled Radii (km)
Grande Prairie	Beaverlodge	2,365	10
	Grande Prairie	55,032	10
	Hythe	820	10
	Sexsmith	2,418	10
	Wembley	1,383	10
Greenview	Fox Creek	1,969	25
	Valley View	1,761	37.5
Yellowhead	Hinton	9,640	50
Clearwater	Caroline	501	17.5
	Rocky Mountain House	6,933	17.5

2.3 Volumetric Energy Assessment Equations & Constants

The amount of thermal energy contained in a geothermal pool is a function of the pool's bulk volume (V_b), the pool's porosity (ϕ) the volumetric heat capacities of the pool rock and pore fluid (Cp_r, Cp_f) and the gradient between the pool's temperature (T_r) and an ambient "rejection" temperature (T_0). The values used to define these variables in this study are as shown in Table 5.

The total thermal energy available in a reservoir (Q_r) is defined as:

eqn 1

$$(Q_r) = [(V_n * Cp_{(lm,ss)}) + (V_f * Cp_f)]*(T_r - T_0)$$

A recovery factor (γ) is then applied to the results of eqn 1, to estimate the percentage of the total Q_r that can be recovered at the well head. Many factors go into determining a recovery factor. Williams (2007), offers a detail discussion of this issue and gives a range of 0.1 – 0.25, with higher values being associated with basin-hosted geothermal systems. Nonetheless, we used the conservative value of 0.10 when dealing with localized regions around our population centers.

Table 5 Values and simple equations used for volumetric energy assessment variables.

Variable	Symbol	Unit	Values
Bulk reservoir volume	V_b	m^3	Calculated directly in Petrel models
Porosity	ϕ	factor	Average ± 1 standard deviation from reported core measurements
Net reservoir volume	V_n	m^3	$V_b * (1 - \phi)$
Fluid volume	V_f	m^3	$V_b * \phi$
Sandstone volumetric heat capacity	Cp_{ss}	MJ/m^3K	2.1
Limestone volumetric heat capacity	Cp_{lm}	MJ/m^3K	2.3
Fluid volumetric heat capacity	Cp_f	MJ/m^3K	4.2
Reservoir Temperature	T_r	K	Averages ± 1 standard deviation from drill stem tests and corrected logged bottom hole temperature measurements
Rejection Temperature	T_0	K	273.15

Values for the volumetric heat capacities of sandstones (Cp_{ss}; Gilwood, Granite Wash) and limestones (Cp_{lm}; Swan Hills, Leduc) were taken as average values from the literature (e.g. Robinson, 1988). The volumetric heat capacity of brine was taken from the National Institute of Standards and Technology (NIST; webbook.nist.gov).

Multiplying the total thermal energy Q_r, by the recovery factor, γ, yields the total thermal energy available for production (wellhead thermal energy; Q_{wh}), as shown in equation 2:

eqn 2 $$(Q_{wh}) = \gamma Q_r$$

The mass of fluid required to bring this thermal energy to a wellhead (M_{wh}) is then calculated as the quotient of the wellhead's thermal energy and the fluid's change in enthalpy (ΔH; H_r - H_0) across the temperature gradient, as shown in equations 3 and 4:

eqn 3 $$(H_r; H_0) = (4.2477*T_{(r,0)}) - 1{,}163.5735$$

This equation is a linear regression (r^2=.99) of vapour-saturated liquid water enthalpy values plotted versus temperature taken from a standard steam table. Many steam tables are available online that vary slightly from one to another. We used a free steam table taken from Peace Software, a German engineering firm (http://www.peacesoftware.de/einigewerte/wasser_dampf_e.html)

eqn 4 $$(M_{wh}) = Q_{wh}/\Delta H$$

The wellhead mass is an important variable because it allows us to both quantify thermodynamic losses and parasitic loads, as well as estimate required fluid flow rates per unit power.

By taking entropy loses into account, we arrive at the variable of exergy (W_a), which is a measure of how much energy is present in a geothermal system that can perform thermodynamic work:

eqn 5 $$(W_A) = M_{wh}*(\Delta H - T_0 \Delta S)$$

where ΔS; $(S_r - S_0)$ is the change in entropy between the reservoir temperature and the rejection temperature, as defined by:

eqn 6 $(S_r; S_0) = 3.521E\text{-}08\ T_{(r,0)}^3 - 2.461E\text{-}05T_{(r,0)}^2 + 1.516E\text{-}02T_{(r,0)} + 2.504E\text{-}03$

This equation is a 3rd order polynomial regression (r^2=.99) of vapour-saturated liquid water entropy values plotted versus temperature taken from a standard steam table. Similar to eqn. 3, we used a free steam table taken from Peace Software, a German engineering firm (http://www.peacesoftware.de/einigewerte/wasser_dampf_e.html).

When the exergy (W_A) is multiplied by an electrical utilization factor (η), one arrives at the total amount of energy available for the production of electrical power (W_p)

eqn 7 $(W_p) = \eta W_A$

The results considers electrical utilization factors described by Augustine et al, (2009), which range from ~17 – 40% in our study area, depending on reservoir temperature. Augustine et al. (2009) show sublinear relationship between temperature and utilization factor, with the utilization factor being defined (r^2=0.98) as

eqn 8 $\eta = [(0.3083*T_r)-98.794]/100$

Utilization factors were calculated for each reservoir as a function of their mean measured temperature +/- 1 standard deviation.

Finally, amortizing W_p out over the desired timeframe of power production yields the gross electrical power production (MWe) capacity of the reservoir during the production period.

eqn 9 (MWe)= Wp/years of desired power production

We solved all of these equations as a function of variable temperature and porosity (average ± 1 standard deviation) for each of the four potential geothermal reservoirs identified in this study, as they are found below the municipalities described in Table 2. This study considers the gross thermal and electrical power capacity that a given reservoir may provide over a 30 – year period.

3 Results

3.1 Maps and Models

3.1.1 Regional overview

Wells that were used to identify the top surface depths for the Leduc, Swan Hills, Gilwood and Granite Wash formations are show in Figure 4. Figure 4 also shows the counties and municipal districts covered by the study area. Towns and cities within these municipalities, along with circles representing the areas (Table 2) for the volumetric assessments are also shown.

Wells that were used to identify the top surfaces of the Leduc, Swan Hills, Gilwood and Granite Wash formations are shown in light blue, purple, green and orange, respectively. In some cases, tops for more than one formation are present in the same well. In these cases, only the well from the uppermost formation is visible, as the lower formations are obscured.

The Leduc is the most widespread formation, being present in all four of the municipal districts within the study area. The Swan Hills is also prominent, being present in all but the most northern municipal district (County of Grande Prairie). The Gilwood and Granite Wash sandstones are more locally present, with the Gilwood being found mostly in the central part of the study area and some traces within Clearwater County, and the Granite Wash located only in the far north.

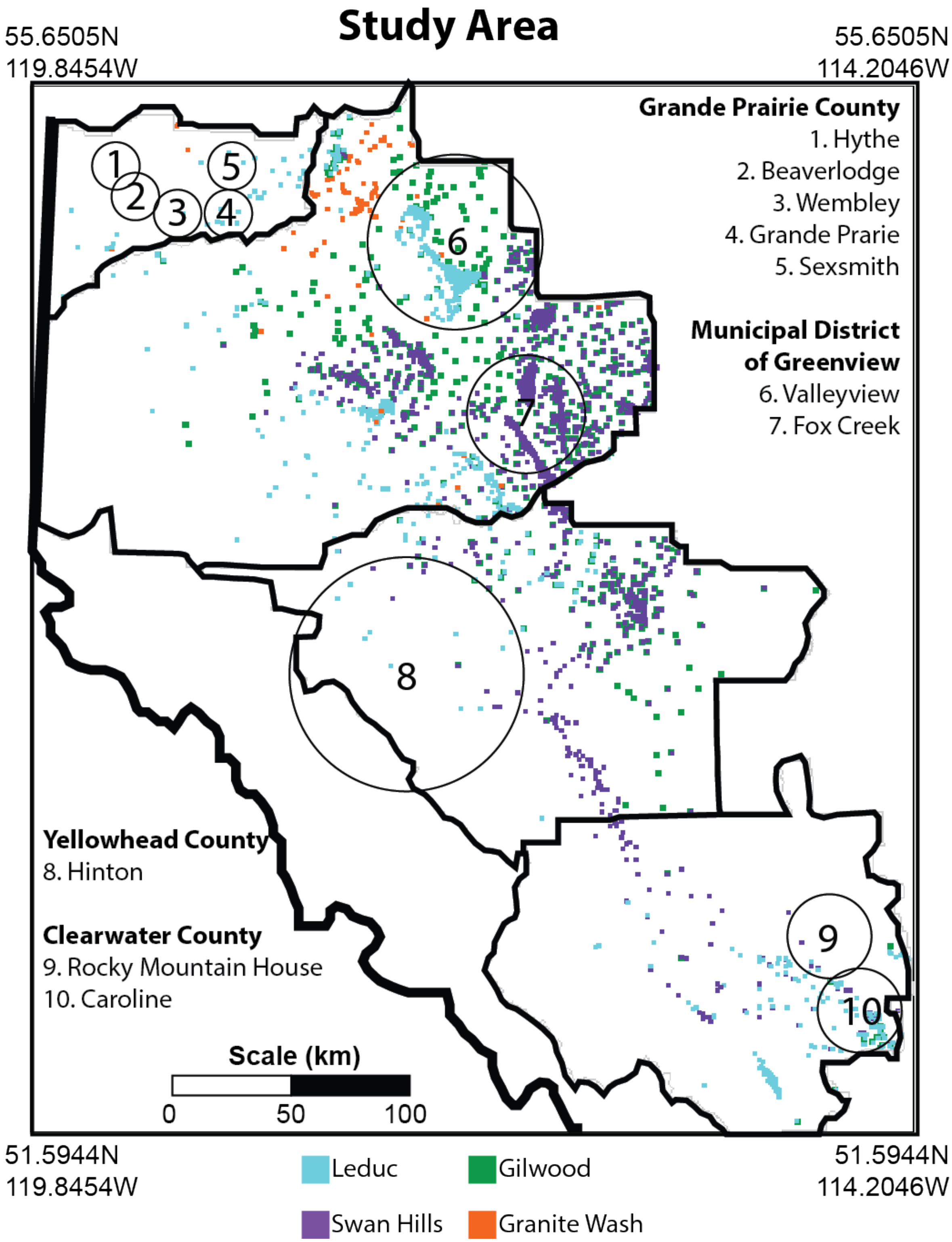

Figure 4 Map of study area showing wells used to identify formation tops, municipal districts contained within the study area, population centers within these districts and the search areas around these centers used in the volumetric assessments

3.1.2 Depth to formation tops

Figure 5 shows the depth to top of each of the 4 formations identified as potential geothermal reservoirs in the study region. Generally speaking, formations deepen to the west-southwest. An exception to this is seen in the far southwest (Clearwater County), where the Leduc, Swan Hills and Gilwood formations abruptly shallow from east to west. This contrast is due to the Rocky Mountain fold and thrust deformation belt extending eastward in the subsurface from the Canadian front ranges. Within the deformation belt, the top of the sequence is reached at as little as ~1000 m. The deformation belt continues northward to the west of the Town of Hinton (8) and does not affect the study area outside of Clearwater County.

In the undeformed basin, the sequence is shallowest in the far northeast of the study area, where the top of the Leduc is reached at ~2000 m. In some places, the Gilwood and the Granite Wash are shallower than the Leduc and Swan Hills due to their extended and intermittent depositional history. The Granite Wash, in particular, was deposited in various locations for most of the early and mid-Devonian and is reached at < 1500 m in the northeast corner of the Municipal District of Greenview. The Leduc, Swan Hills and Gilwood formations are deepest in the area around Hinton (8), where they are reached at depths >4000 m, and in some cases >5000 m. Near Rocky Mountain House (9) and Caroline (10), the Leduc and Swan Hills are reached at depths of 3000-4000 m. Whereas the Gilwood is only sporadically present in Yellowhead and Clearwater counties, the Granite Wash is completely absent from these districts.

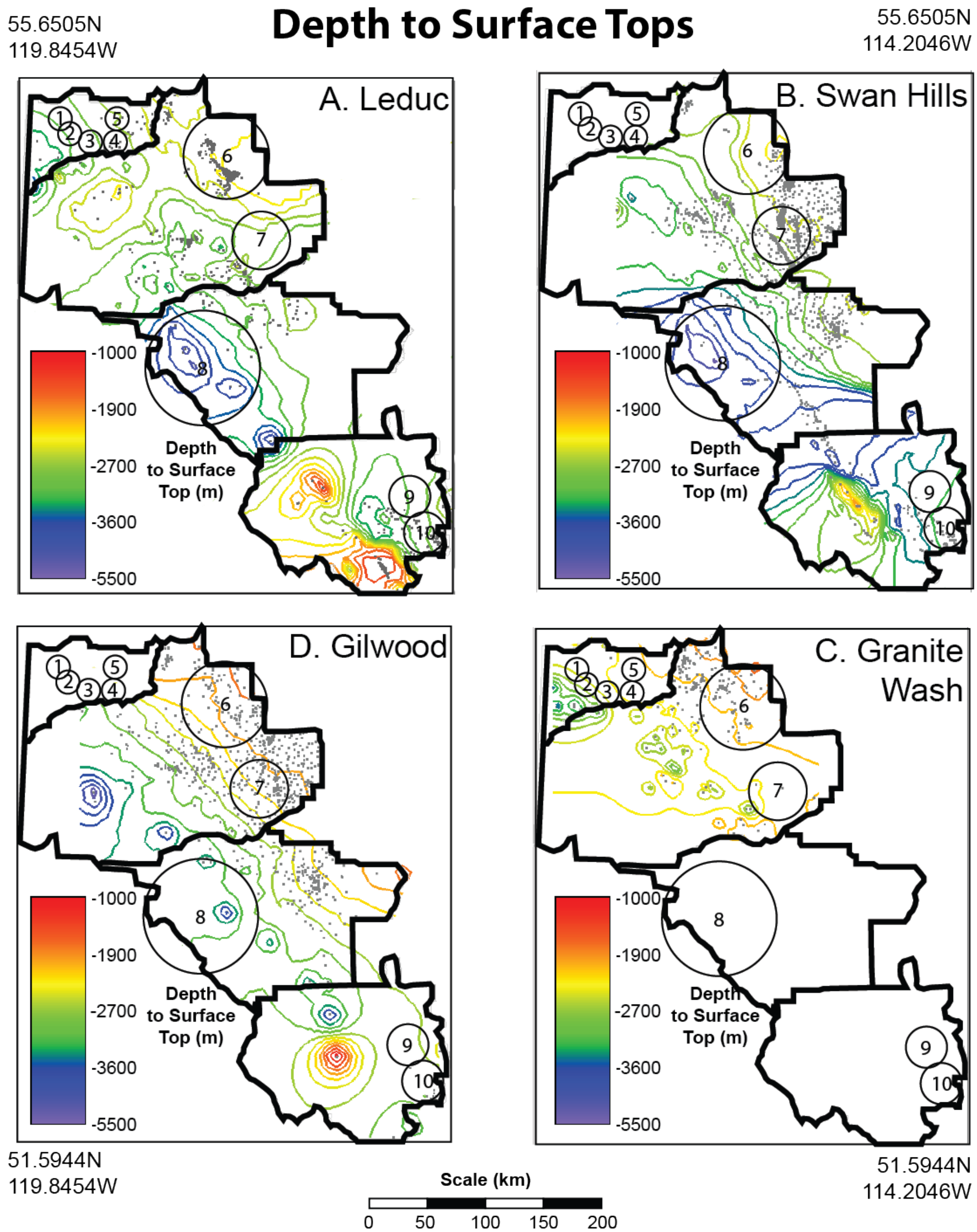

Figure 5 Depth to the top surface of major geothermal reservoirs in Alberta. Clockwise from upper left: A. Leduc, B. Swan Hills, C. Granite Wash and D. Gilwood.

3.1.3 Isopachs

Isopach (formation thickness) maps are shown in Figure 6. Progressively thicker formations are represented by progressively cooler colors (green to violet). A 175 m-300 m NE-SW trending block of the Leduc formation underlies most of the southeast section of Grande Prairie County, including Wembley (3), the City of Grande Prairie (4) and Sexsmith (5). A > 300 m thick section of Leduc fills most of the southwest quadrant of the Valleyview (6) search area. The Leduc does not underlie Fox Creek (7). Near Hinton (8), the Leduc appears as small, isolated deposits, with thicknesses ranging from 100-350 m. A 250-300 m section the Leduc underlies most of Caroline (10). This section skirts the southern margins of the Rocky Mountain House (9) search area.

The thickest section of the Swan Hills reefs runs along the southeast margins of the Valleyview (6) search area, where it is nearly 400 m thick. This section occurs throughout most of the eastern part of the Municipal District of Greenview and underlies the northeast quadrant of the Fox Creek (7) search area, where it thins to < 300 m throughout most of the rest of the search area. A ~ 250 m thick dome of the Swan Hills fills most of the northeast quadrant of the Hinton (8) search area. This dome thins slightly to the northeast and pinches out entirely to the southwest, on the border of the town itself. A 50-100 m section of the Swan Hills underlies most of central Clearwater County, including much of both the Rocky Mountain House (9) and Caroline (10) search areas.

The Granite Wash formation is found exclusively in the northernmost part of the search area. A nearly 200 m thick dome of the Granite Wash is found beneath the Grande Prairie City-Sexsmith corridor, which thins to ~100 m across most of the western part of the Grande Prairie County, all the way to Hythe. The section pinches out to the way west to Hythe, but tapers off to the north and south, nonetheless underlying all of the population centers in the county. The Granite Wash covers to northern and central parts of the Municipal District of Greenview with a 10-50 m thick layer. A 10-20 km wide NE-SW trending slice, ~100-200m thick, runs directly across the center of the Valleyview search area. Another thick, approaching 300 m, section of the Granite Wash is also found in a ~5-10 km dome directly in the center of the Municipal District of Greenview.

The Gilwood sandstone is distributed as a thin (< 50 m) layer throughout the north, east and central sections of the study area. This thin layer completely underlies Valleyview (6), Fox Creek (7) and Caroline (10). In the far east of the Caroline search area, the Gilwood is nearly 100 m thick. A NE-SW wedge of the Gilwood appears in the northeast quadrant of the Hinton (8) search areas, where it thickens to a ~70 m on the north and northeast edges of the town. The Gilwood is not found in Grande Prairie County, although a thick (>100 m) dome of it occurs to the south in a relatively uninhabited section of the Municipal District of Greenview.

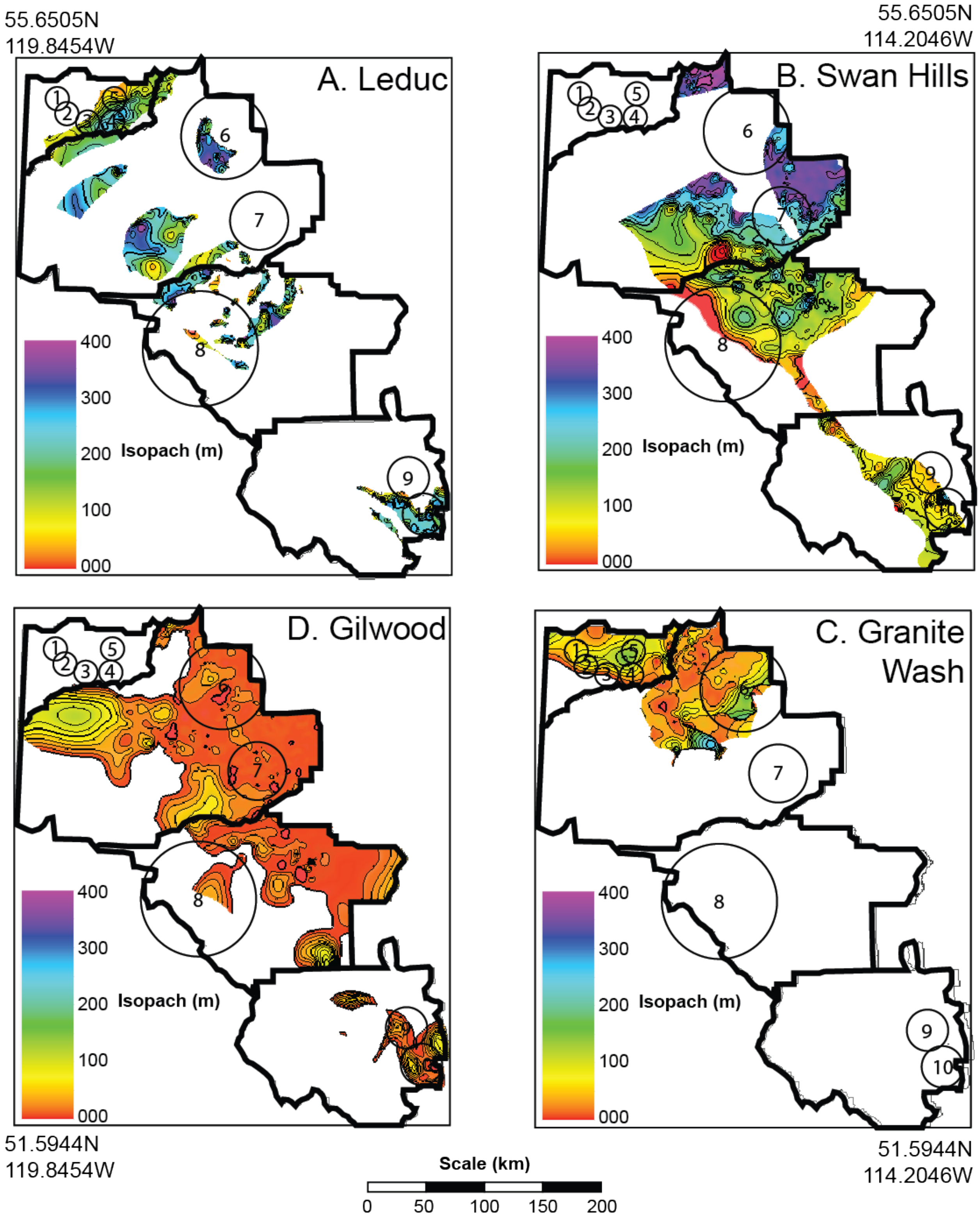

Figure 6 Isopach (formation thickness) maps of major geothermal reservoirs in Alberta. Clockwise from upper left: A. Leduc, B. Swan Hills, C. Granite Wash and D. Gilwood.

3.1.4 Temperature

Contour maps of the temperature distributions within the four formations involved in this study is shown in Figure 7. Temperatures increase sub-linearly with depth, which is indicative of a fairly constant regional geothermal gradient. A thermal inversion can be seen at the base of the stratigraphic section near Hinton (8), where the Gilwood is 10-20 °C cooler than the overlying Swan Hills and Leduc formations. Similarly, the Leduc is slightly warmer than the Swan Hills in this location, despite its situation above the Swan Hills. In the far southwest of the study area (Clearwater County), the influence of the deformation front can again be seen. Here, temperatures in the Leduc and Swan Hills abruptly drop as one moves from east to west out of the undeformed basin. This is due to the stratigraphic section's shallower depth in the deformed belt, as shown in Figure 4.

The coolest temperatures in the study areas are found in the far northeast, where temperatures in the Leduc and Granite Wash are < 70 °C. In this location, the Gilwood and Swan Hills range from 80 °C to just below 100 °C. Temperatures increase to the West and south as the basin deepens towards the mountain front. Temperatures > 100 °C can be in all formations underlying Fox Creek (7), Hinton (8), Rocky Mountain House (9) and Caroline (10). Beneath Valleyview (6), > 100 °C temperatures are reached in the southwest sections of the search area in the Gilwood and Granite Wash. In Grande Prairie County, > 100 °C temperature are reached in the Leduc below Wembley (3) and the western edge of Grande Prairie City (4), as well as in the Granite Wash underlying Hythe (1), Beaverlodge (2) and Wembley (3).

The warmest temperatures in the study region are found in the Hinton (8) search area. Here, temperatures in the Gilwood are > 120 °C, and temperatures in the Leduc and Swan Hills exceed 140 °C. On the northern edge of the town of Hinton, temperatures > 150 °C can be found in the Leduc formation. Other areas with high temperatures (i.e. > 120 °C) can be found in the western parts of the Municipal District of Greenview, which is largely uninhabited. The Granite Wash formation in the western part of Grande Prairie County may also approach 120 °C

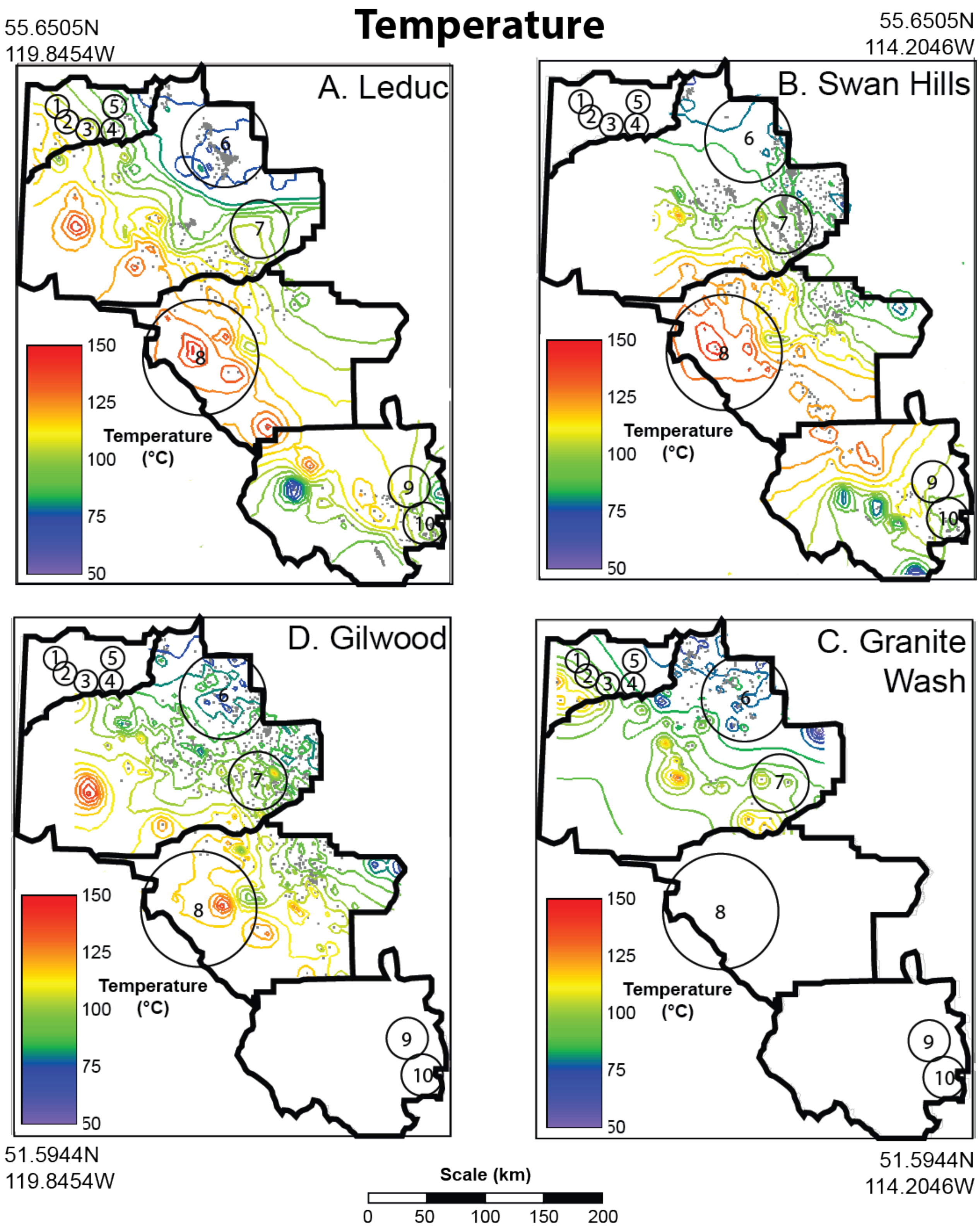

Figure 7 Temperature distribution maps of major geothermal reservoirs in Alberta. Clockwise from upper left: A. Leduc, B. Swan Hills, C. Granite Wash and D. Gilwood.

3.1.5 Potentiometric Surfaces

Contour map of potentiometric surfaces throughout the study area are shown in Figure 8. In the image, warm colors (green to red) represent over-pressured formations, where pore pressure is high enough to bring formation fluid to the surface without additional pumping power. Cool colors (violet to green) represent under-pressured formations, where pumping will be required to bring fluid to the surface. Drill stem pressure data are less abundant than temperature or depth data, and thus the potentiometric surface maps involve substantially more interpolation than the previous figures. Further investigation of reservoir pressures, and by extension, potentiometric surfaces, are required to accurately predict the flow rates reservoirs may be able to sustain, as well as the pumping power required to achieve the necessary brine flow rates.

Pressure in the Leduc and Swan Hills formations tend to drop from north to south across the study area. Near Wembley (3), Grande Prairie City (4) and Sexsmith, the potentiometric surface in the Leduc is ~ 100 m above ground level. The pressure increases to > 300 m underneath the Valleyview (6) search area. Here, the potentiometric surface of Swan Hills formation fluids is ~ 100 m above ground level. Further to the south, underneath Fox Creek (7), the Swan Hills' potentiometric surface approaches 400 m above the surface. North of Hinton (8), the Swan Hills is highly over pressured, with one measurement showing a potentiometric surface of > 1000 m above ground level. In contrast, the Leduc formation in the Hinton (8) area is strongly under pressured, with the potential metric surface falling > 500 m below the ground surface. Similar conditions can be found in the Leduc and Swan Hills in the southern most portions of the study area. i.e. Rocky Mountain (9) and Caroline (10).

Both the Gilwood and the Granite Wash are over pressured throughout the study area, where data are available. Beneath Valleyview, both of these formations have potentiometric surfaces > 200 m above the ground level. In some locations around Fox Creek (7), the Gilwood's potentiometric surface is > 750 m above the ground level. No pressure data are available for either of the sandstone formations in Grande Prairie County.

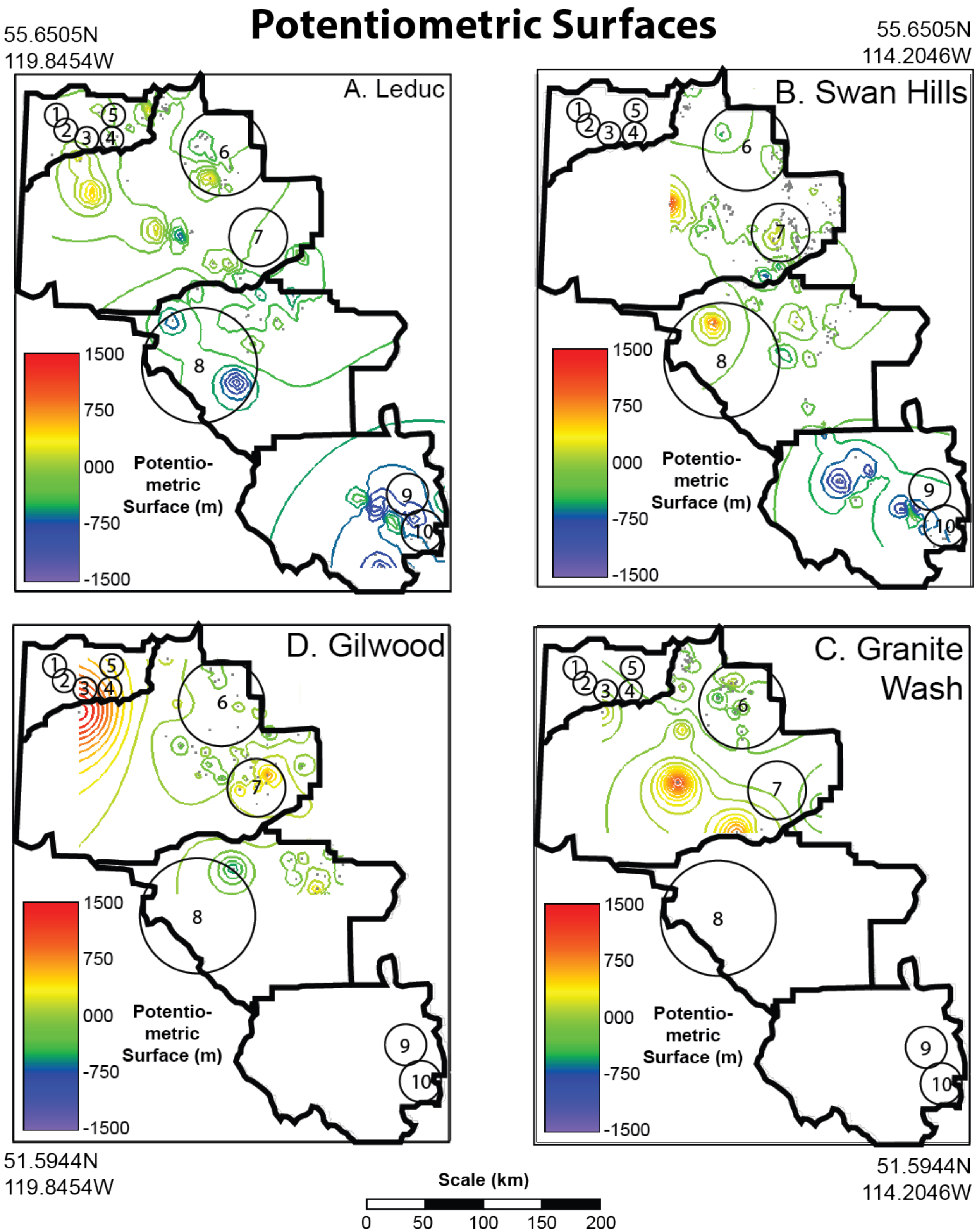

Figure 8 Potentiometric surfaces of major geothermal reservoirs in Alberta. Clockwise from upper left: A. Leduc, B. Swan Hills, C. Granite Wash and D. Gilwood.

3.1.6 Porosity

Figure 9 shows a contour map of regional porosity distribution within the four formations under investigation. Porosity is an important variable in volumetric calculations, which require both a net reservoir volume and brine volume. Porosity is an indicator of the presence of an aquifer. Because the heat capacity of brine is approximately twice that of the reservoir rock, increased pore space, which is presumably saturated with brine, increases the over all thermal energy content of the reservoir. High porosity is also generally correlated with high permeability, which is essential for maintaining brine circulation during plant operations. A rigorous study of reservoir permeabilities was beyond the scope of this study.

Porosity values from the study area are sparse. The highest porosities are found in the Gilwood formation underlying Valleyview (6). Here, several cores have porosities approaching 25 %. The Granite Wash also has a well with a similar porosity measurement just outside the northeast corner of the Valleyview search area. The rest of the sandstone (Gilwood and Granite Wash) porosity measurements fell in the 5-8 % range. The carbonates (Leduc and Swan Hills) have similar porosity values (i.e 5-8 %). Some exceptions to this are seen in uninhabited areas of the Municipal District of Greenview and the Yellohead County, where the porosity is 10–20 %.

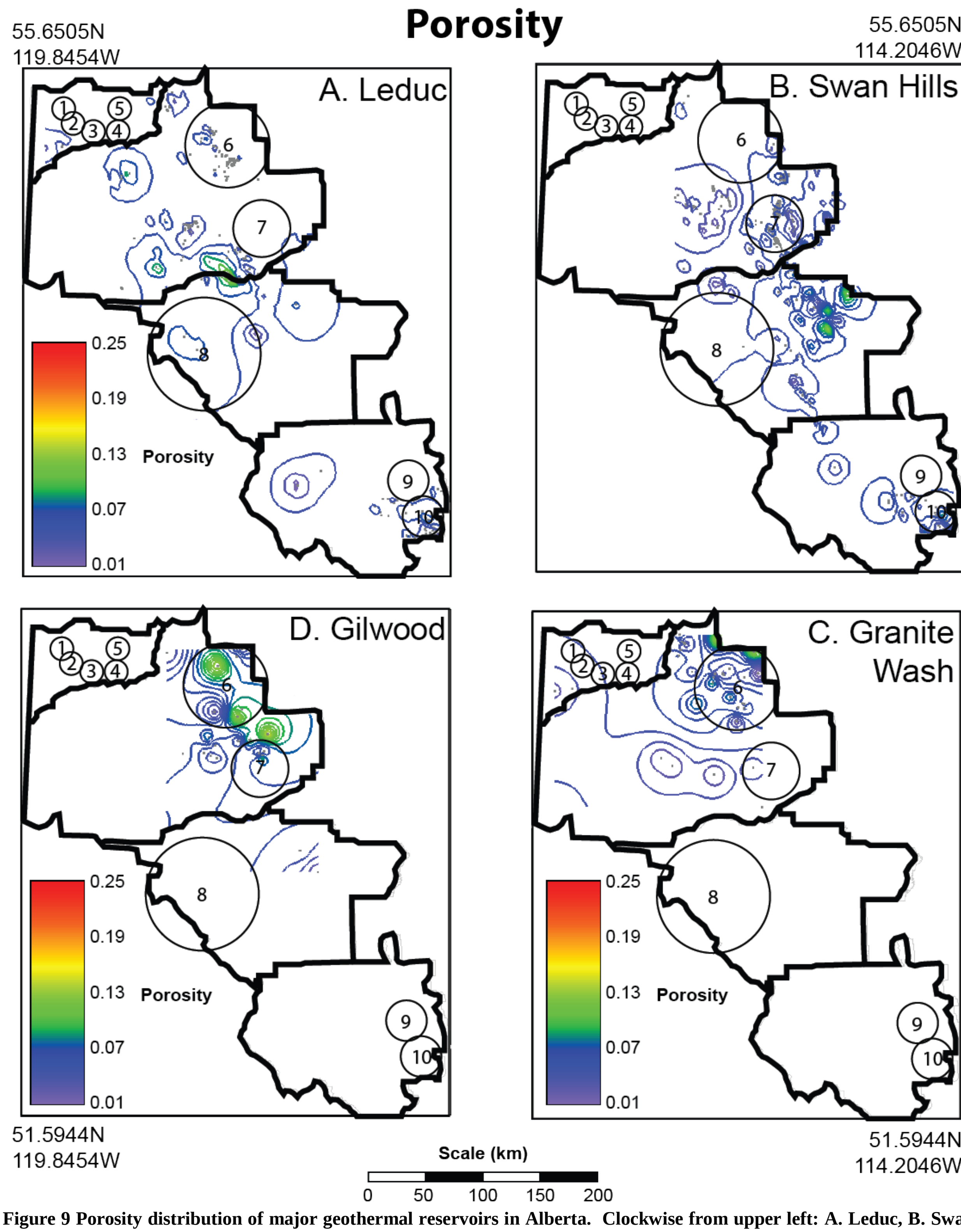

Figure 9 Porosity distribution of major geothermal reservoirs in Alberta. Clockwise from upper left: A. Leduc, B. Swan Hills, C. Granite Wash and D. Gilwood.

3.2 Volumetric Power Potential Calculations

The isopachs shown in Figure 6 were multiplied by the search areas shown in Table 2 to obtain the bulk formation volumes underlying the investigated population centers. The bulk formations volumes, along with the mean (+/- 1 standard deviation) formation temperature and porosity, were used to perform the volumetric method described in Section 2. In order to provide a more accurate volumetric assessment, only data from wells contained within the targeted municipal boundaries were used. Figure 10 shows the mean gross thermal and electricity power production potential for a 30-year operating period in each of the municipal districts involved in this study.

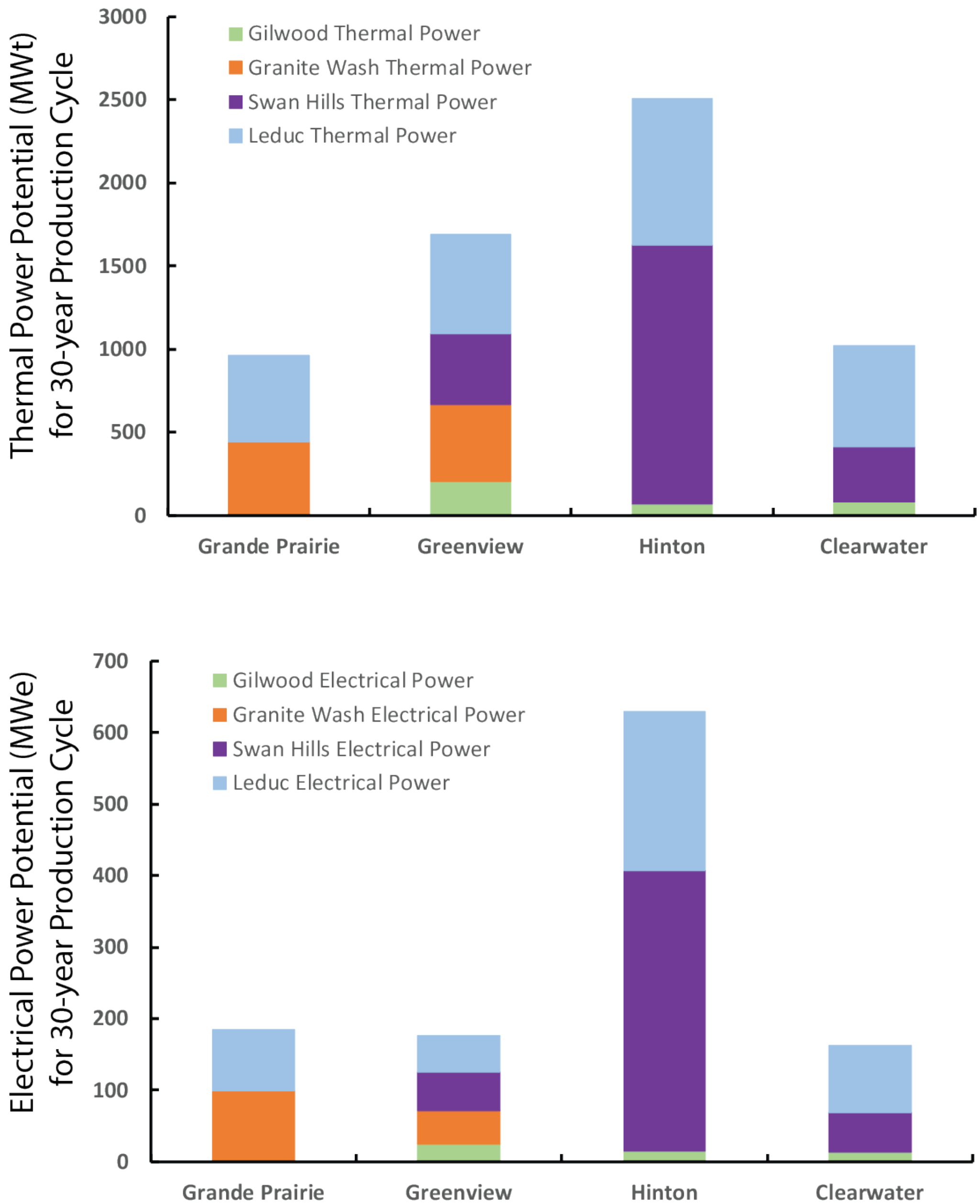

Figure 10 Column charts showing the total thermal power capacity (A.) and total electrical power capacity (B.) for the different formations and municipalities targeted in this study.

Nearly 6,200 MWt of potential thermal power for a 30-year production period was identified within the search areas. Over ¾ of this potential capacity is found in the Leduc and Swan Hills formations. The Swan Hills formation in the vicinity of Hinton alone contains over 1,500 MWt of potential capacity. The Granite Wash formation has a thermal power potential of ~900 MWt for a 30-year production period, and the Gilwood may contain ~350 MWt. These are mean values from a range that considers the mean +/- one standard deviation of temperature and porosity found within the individual search areas.

Using the range of utilization factors described by Augustine et al. (2009; eqn. 8), the electrical power potential was calculated as a function of the reservoirs' temperature and exergy. The thermal energy contained in these reservoirs has a mean electrical power production potential of ~1,150 MWe for a 30-year production period. Over 80% of this potential is found in the Leduc and Swan Hills formations, and over 50% of that is found in the area around Hinton. The Granite Wash and the Gilwood formations contribute ~15 MWe and ~53 MWe, respectively, to the overall electrical power production potential during a 30-year production period.

3.3 Flow Rates per Megawatt of Thermal and Electrical Power

The final metric we analysed was the flow rate required to produce 1 megawatt of gross thermal (MWt) and electrical (MWe) power from any given reservoir and location. This number was derived by dividing the mass-at-well head calculated in the volumetric method (eqn. 4) by the total power production potential (eqn. 9). To convert back to thermal power production potential, we multiplied the results of eqn. 9 by the utilization factor (eqn. 8). Figure 11 shows a scatterplot of calculated flow rates per megawatt of power production for each of the formations and localities in the study area.

In Hinton, the Swan Hills flow rate (purple) is slightly obscured by the Leduc plot (light blue). Flow rates required to produce 1 MWt of power range from <10 kg/s in the Swan Hills and Leduc formations near Hinton to >20 kg/s in the Leduc formation by Valleyview. All of the formations by Valleyview require flow rates > 20 kg/s to produce 1 MWt of gross thermal power. The Leduc formation in the northeast part of Grande Prairie County, as well as the Leduc and Swan Hills near Fox Creek and the Leduc, Swan Hills and Gilwood near Caroline have required flow rates ranging from 10 kg/s to 20 kg/s. Only one value (~11 kg/s) was calculated for the Granite Wash sandstone in Grande Prairie County, because only one porosity value (0.028 +/- 0.008) was available for this formation throughout the county.

Flow rates required for producing 1 MWe of gross electrical power range from ~38 kg/s in the Swan Hills and Leduc formations to nearly 300 kg/s in the Leduc formation beneath Valleyview. All of the formations beneath Valleyview require flow rates > 175 kg/s to produce 1 MWe of gross electrical power. It is likely that these flow rates will make electricity production in this area economically unrealistic, as too many wells would be required. The Leduc formation in Sexsmith, Grande Prairie and Caroline, as well as the Gilwood and Swan Hills beneath Fox Creek and the Swan Hills beneath Caroline all require flow rates of 100-150 kg/s for 1 MWe of gross electrical power. These flow rates may be attainable with few enough wells to make a project economically viable. Areas where required flow rates for 1 MWe of gross electrical power are <100 kg/s are considered good targets for commercial electricity production. These areas include all of the reservoirs beneath Hinton, the Granite Wash formation throughout Grande Prairie County, the Swan Hill formation beneath Rocky Mountain House, and the Leduc formation beneath Rocky Mountain House and Wembley.

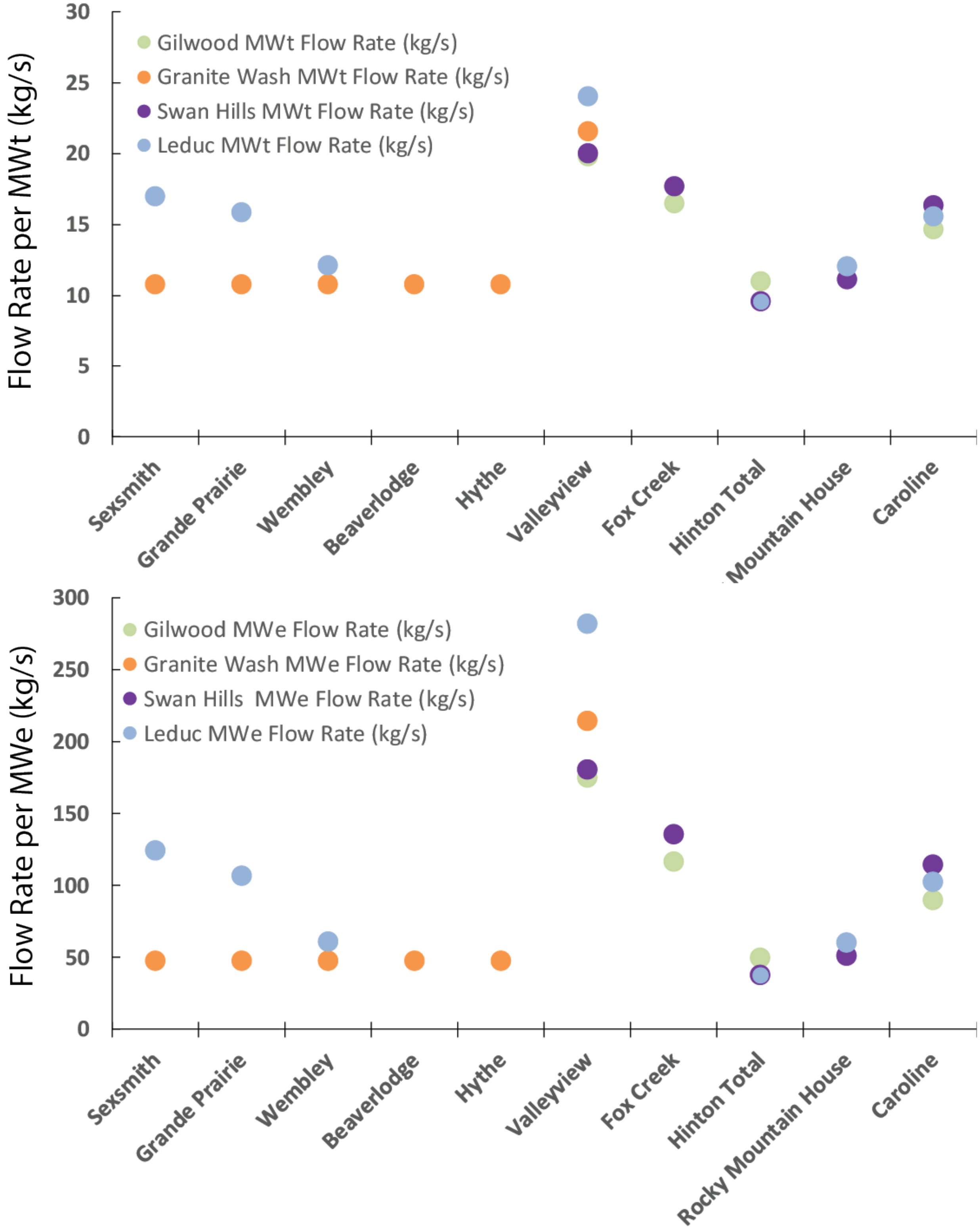

Figure 11 Flow rate (kg/s) required to produce 1 MW of gross thermal and electrical power

3.4 Discussion

We identified over 6,100 MWt of thermal power available to domestic, commercial and industrial end-users throughout the study region for a 30-year production period. This equates to an electrical power potential of ~1,150 MWe. This is enough to meet more than 20% of Alberta's mandate of ~5,000 MWe of renewable power being brought online by 2030.

This estimate must be tempered with practical concerns. The first concern is the quality of the resource. In some places, for example Valleyview, none of the reservoir temperatures are hot enough to reliably produce electricity with existing binary cycle technology. Even if such an ultra-low temperature differential engine was available, the flow rates needed to produce any meaningful power (i.e. >175 kg/s) would require too many wells, making any electricity generation economically untenable. Areas that require flow rates of 100 – 150 kg/s to produce 1 MWe of electrical power present a more promising case for electricity production. Here, technology may be available to convert the thermal energy to electrical power, but local electricity markets and specific projects will determine whether or not commercial development is viable. Areas with flow rates < 100 kg/s required to produce 1 MWe of gross electrical power are considered good targets for commercial development. Using these guidelines, ~800 MWe of economically recoverable electrical power potential was identified, more than 75% of which was found near Hinton. An additional ~225 MWe of electrical power potential may also be available in the areas around Sexsmith, Grande Prairie City, Fox Creek and Caroline. The resource in Valleyview, while not hot enough for electricity production, may still provide ample thermal energy for direct heating. Thus, the first order estimate of 6,100 MWt of gross thermal power potential does not require much revision.

Along with the temperature of the resource, and by proxy the flow rates required per unit power, another major concern is the reservoirs' hydrogeologic properties. This study only investigated porosity as a means to understand the volumetric properties of the formations. We gleaned little information regarding the reservoirs' abilities to sustain the required flow rates for electricity production. What information we were able to attain was taken from gas pools, not water pools, which, for the sake of this study, were assumed to directly underlie the gas pools.

Another salient hydrogeologic consideration is the thickness of the producing unit. Both of the carbonate units investigated in this study (i.e Leduc and Swan Hills) have ample thickness for producing from vertical wells. Production from the Gilwood or Granite wash formations, where thickness is generally <100m, will require deviated wells. A full investigation of the hydrogeologic properties necessary to model flow in these reservoirs was beyond the scope of this study. For the moment it remains unclear which well paths, completions and reservoir stimulations may be necessary to generate the required flow rates.

Finally, further study of the hydrodynamic properties of the brine, in concert with refining the data regarding the brine's hydraulic head, is required for calculating the net power potential. We identified both under-pressured and over-pressured reservoirs throughout the study region. Both situations contain unique pumping challenges that will affect the net power output. The area around Hinton, where most of the high potential resource is located, had sparse pressure data. A well in the Swan Hills ~45 km north of Hinton is over-pressured, potentially by several hundred meters of head. Two wells on a NW-SE trend on either side of Hinton show the Leduc being under-pressured by the same amount. Understanding the pumping power required to circulate the geothermal fluid is essential to determining the net power, and thus the commercial viability, of a project.

4 Regional Reports

4.1 Grande Prairie City and County

Grande Prairie was the northern – most municipal district we investigated, with sponsorship from both the city and county of Grande Prairie. The city of Grande Prairie covers ~72.8 km^2 of land area and has ~55,000 residents. The entire county covers ~5,863 km^2 of land area and contains an additional ~20,500 residents. Beyond the city itself, population centers investigated in the county include Sexsmith (pop. ~2,500), Hythe (pop. ~850), Beaverlodge (pop. ~2,800) and Wembley (pop. ~1,400). A three dimensional projection of Grande Prairie's geothermal reservoirs underlying these population centers is shown in Figure 12. Please note that the z-axis of Figure 12 represents structural elevation in meters below sea level, not the total vertical depths of the formations. Structural elevations are required for the 3D mapping because they normalize the depth below the surface to a constant datum, in this case, sea level. For total vertical depth maps of these formations, please see Figure 5 in Chapter 3.

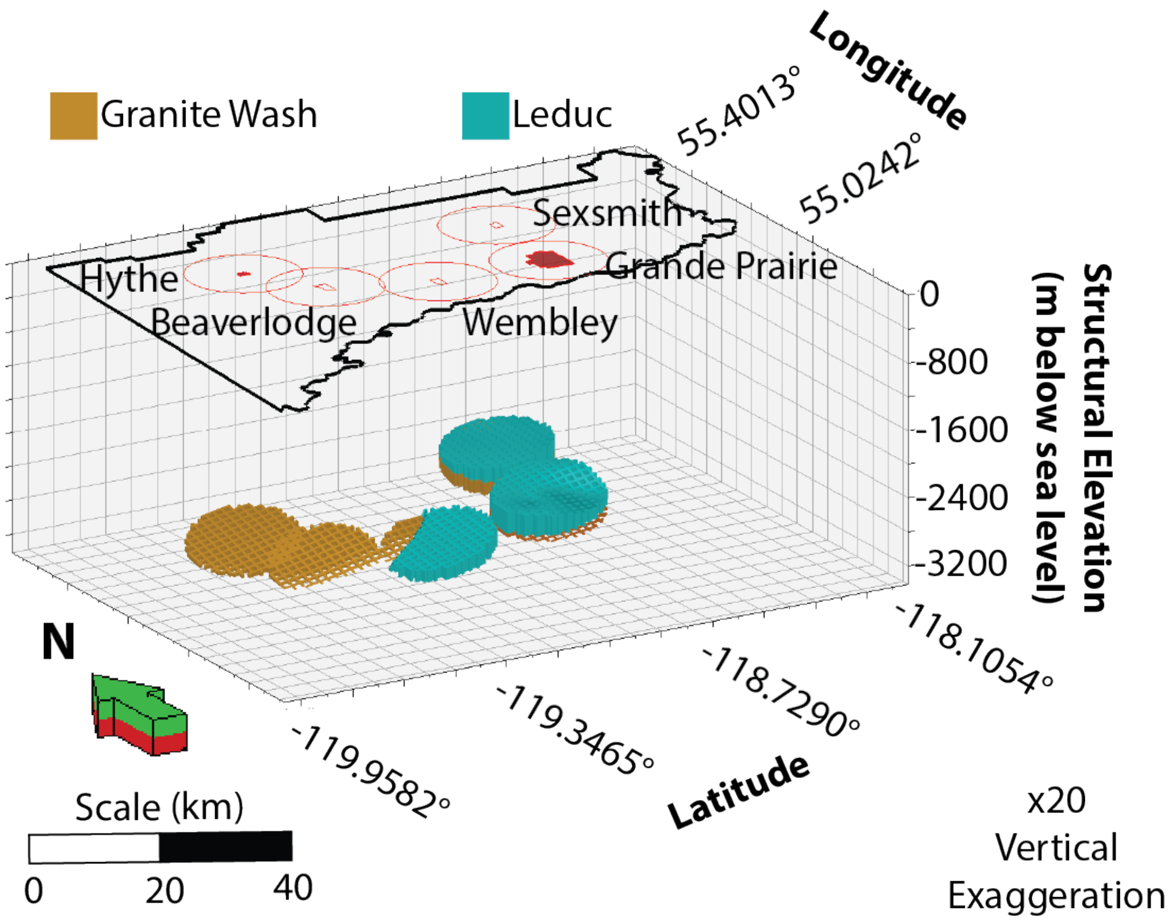

Figure 12 3D Stratigraphic grids of potential geothermal reservoirs underlying population centers in Grande Prairie County. Note that the z-axis (depth) represents structural elevation (meters below sea level) and not total vertical depth.

The two most prominent geothermal reservoirs found in this region are the Leduc carbonate reef and the Granite Wash sandstones.

As shown in Chapter 3, Figure 6a, the Leduc cuts across the county in a SW – NE (bottom left to top right) trend. The formation is more extensive in the northeast, where it underlies practically the whole county. To the southwest, the Leduc becomes laterally far less extensive and only underlies the southern margins of the county. Neither Hythe nor Beaverlodge appear to overlie the Leduc Formation. Figure 6c, shows the Granite Wash Formation underlying approximately 2/3rds of Grande Prairie County. This formation was not identified in the south-western section of the county. The Granite Wash appears to completely underlie the city of Grande Prairie, Hythe and Beaverlodge. It skirts the only northern edge of Wembley, limiting its volume near this town. Table 6 shows the values that were used in the volumetric power potential calculations for each of the population centers in Grande Prairie County.

Table 6 Values used in volumetric power potential assessments for population centers in Grande Prairie County

		Sexsmith	**Grande Prairie**	**Wembley**	**Beaverlodge**	**Hythe**
Volume (m^3)	*Leduc*	3.11E+10	6.35E+10	3.58E+10		
	Granite Wash	3.51E+10	1.42E+10	4.77E+09	1.41E+10	1.97E+10
Depth (m)	*Leduc*	3300±83	3389±70	4256±269		
	Granite Wash	4198±488	4198±488	4198±488	4198±488	4198±488
Temperature (°C)	*Leduc*	91.7±2.3	95.56±3.41	112		
	Granite Wash	120.2±5.7	120.2±5.7	120.2±5.7	120.2±5.7	120.2±5.7
Porosity	*Leduc*	0.028±0.008	0.028±0.008	0.028±0.008	0.028±0.008	0.028±0.008
	Granite Wash	0.044±0.023	0.044±0.023	0.044±0.023		

Only one reliable temperature and porosity datum was found for the Granite Wash formation in Grande Prairie County. Thus, their values are constant throughout the table. The top of the Granite Wash is reached at ~3500 m in the northeast part of the county near Sexsmith and is at least 4700 m deep in the southwest of the county by Beaverlodge. The Leduc is reached at less than3500 m near both Sexsmith and Grande Prairie City. In the area around Wembley, the top of the Leduc is generally deeper than 4000 m.

Figure 13 shows the mean thermal and electrical power production potentials for each of the population centers in Grande Prairie County, calculated using the range of values shown in Table 6. In total, we identified nearly ~960 MWt of thermal power production potential in the county, roughly 1/3rd of which is found in the Grande Prairie City search area. The towns of Wembley and Sexsmith both also contain over 200 MWt of thermal power potential. Beaverlodge and Hythe, which are underlain only by the Granite Wash formation, each contain less than 100 MWt of thermal power production potential.

This thermal power equates to roughly 185 MWe of electrical power potential across the county. Temperatures in the Leduc formation beneath Sexsmith and Grande Prairie city, however, may not be high enough to reliably produce electricity with existing technology. Removing these reservoirs from the calculation yields an electrical power potential of ~135 MWe. The largest single reservoir is the Granite Wash beneath Sexsmith, which potentially could produce ~40 MWe of electrical power during a 30-year production period. The next largest reservoir, with a potential of ~35 MWe, is the Leduc underlying Wembley. As is the case for all of the areas described herein, the capacity would be achieved through several small plants, rather than one central facility.

Given Grande Prairie County's population of < 100,000, there is enough electricity power potential in the Granite Wash formation to provide for all of the domestic needs the county's residents. Producing this power, especially in the western part of the county, may be challenging, because the Granite Wash formation is thin. Beneath Sexsmith and Grande Prairie City, however, the Granite Wash is likely thick enough to be exploited with vertical wells. Among these two cities alone, the Granite Wash has an electrical power production potential of ~57 MWe

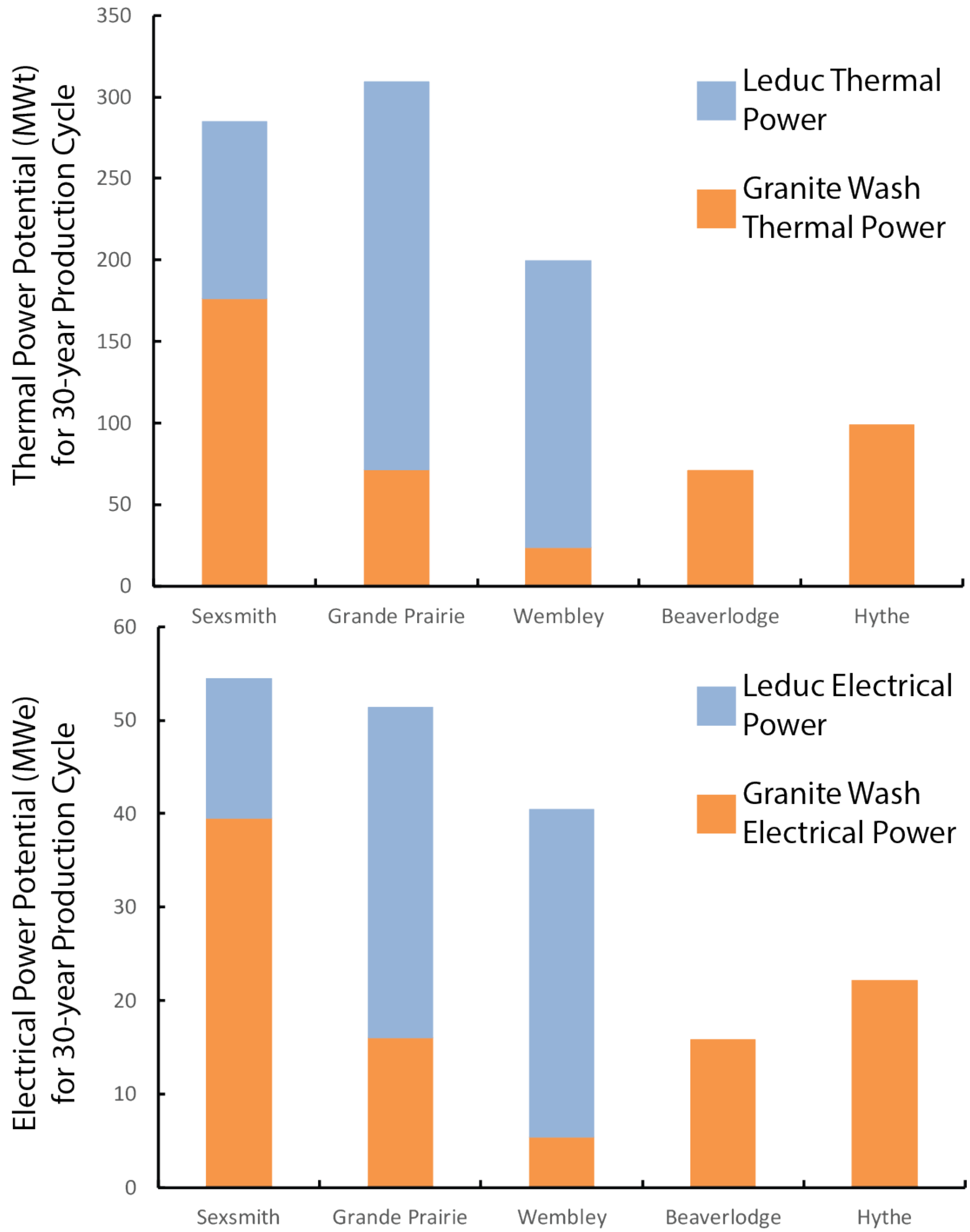

Figure 13 Mean thermal and electrical power production potential for the Granite Wash and Leduc formations underlying population centers in Grande Prairie County

Although the Leduc formation beneath Sexsmith and Grande Prairie City may not be hot enough to produce electricity, they contain ample thermal energy for direct heating applications. This heat can be used for residential and commercial district heating, industrial process heat, agriculture development, snow melting and recreation (e.g. swimming pools).

4.2 Municipal District of Greenview #16

The Municipal District of Greenview covers a land area of ~33,000 km^2, with a population of ~13,500. About 45% of this population (~4,300) lives in Grande Cache. Due to its location west of the deformation belt, however, we were unable to investigate the area immediately surrounding Grande Cache. We did investigate a 75 km diameter around Valleyview (population ~1,750) and a 50 km diameter around Fox Creek (population ~2,000). A three dimensional projection of the geothermal reservoirs underlying these population centers is shown in Figure 14. Please note that the z-axis of Figure 14 represents structural elevation in meters below sea level, not the total vertical depths of the formations. Structural elevations are required for the 3D mapping because they normalize the depth below the surface to a constant datum, in this case, sea level. For total vertical depth maps of these formations, please see Figure 5 in Chapter 3.

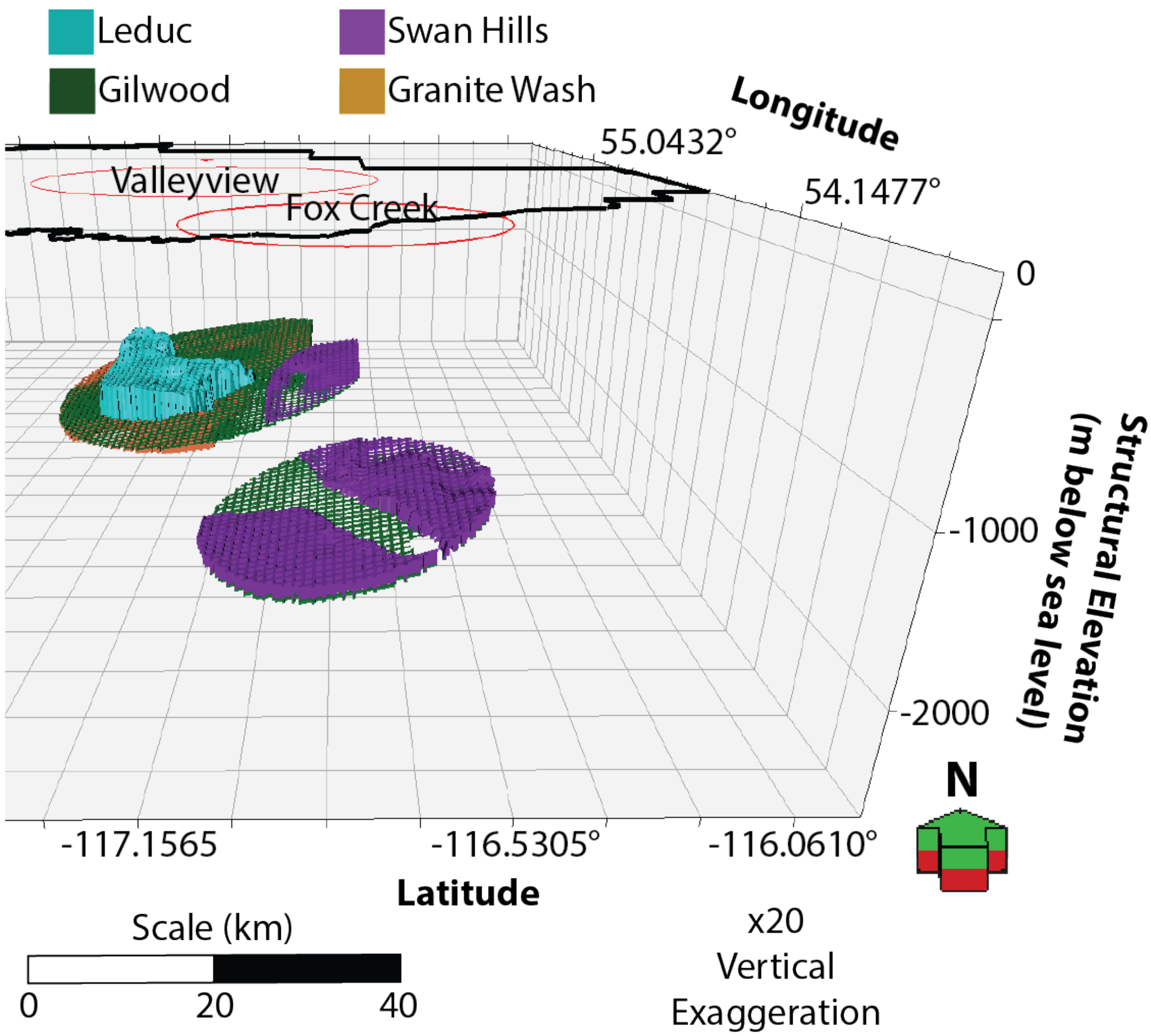

Figure 14 Stratigraphic grids of potential geothermal reservoirs underlying population centers in the Municipal District of Greenview. Note that the z-axis (depth) represents structural elevation (meters below sea level) and not total vertical depth.

All 4 of the formations investigated in this study underlie Valleyview. The Gilwood and Granite Wash form thin layers that basically cover the entire search area. The Swan Hills appears as a 275-375 m reef margin on the southeast section of the search areas. A less than 300 m thick section of the Leduc underlies practically the entire southwest quadrant of the Valleyview search area. Only the Swan Hills and the Gilwood are found beneath Fox Creek. Here, the Gilwood forms a thin layer, 10s of meters thick, underlying the entire area. The Swan Hills appears as two 200-300 m thick shelves to the northeast and southwest of the town, but does not appear to underlie the town itself.

Table 7 shows the values that were used in the volumetric power potential calculations for each of the population centers in the Municipal District Greenview.

Table 7 Values used in volumetric power potential assessments for population centers in the Municipal District of Greenview

	Town	Valleyview	Fox Creek
Volume (m^3)	*Leduc*	2.4E+11	
	Swan Hills	2.62E+10	1.04E+11
	Granite Wash	1.80E+11	
	Gilwood	5.01E+10	1.87E+10
Depth (m)	*Leduc*	2675±325	
	Swan Hills	2825±182	3043±17 6
	Granite Wash	3035±175	
	Gilwood	3081±367	3158±164
Temperature (°C)	*Leduc*	75±12	
	Swan Hills	83±6	90±15
	Granite Wash	80±10	
	Gilwood	83±14	93±14
Porosity	*Leduc*	0.05±0.03	
	Swan Hills	0.05±0.05	0.05±0.04
	Granite Wash	0.06±0.03	
	Gilwood	0.06±0.05	0.06±0.02

Within our study area, the investigated formations are shallowest in the Municipal District of Greenview. Beneath Valleyview, the Leduc and the Swan Hills are both reached at depths of <3000m. Both of the sandstone units (Granite Wash and Gilwood) are reached at depths of ~3000 m. Beneath Fox Creek, the Gilwood and the Swan Hills are reached at depths of ~3050 m and ~3150 m, respectively. These are the only two formations present in this area. In the interim report, Cambrian formations were also discussed. Due to a lack of reliable data, however, we were unable to confirm the stratigraphy of the Cambrian section in this area. While the Cambrian section is potentially up to 500 m thick to the southeast of Fox Creek, we do no know of where the potential water-bearing strata are. Therefore, a more detailed analysis of Cambrian geothermal resources beneath Fox Creek would require additional exploration.

Due to the shallow depths of the investigated formations in the Municipal District of Greenview, the temperatures in the formations may not be high enough for reliably producing electricity. This case is especially true around Valleyview, where the mean temperatures in the formations are not much higher than 80 °C. Both formations beneath Fox Creek have mean temperatures ~90 °C, which, given Alberta's cold climate, may be considered a marginal electricity producing resource. In both cases, one standard deviation of the mean higher would put the resource above 100 °C. These hotter wells are found to the southwest of the town of Fox Creek.

Figure 15 shows the mean thermal and electrical power production potentials for each of the population centers in the Municipal District of Greenview, calculated using the range of values shown in Table 7. In total, we identified nearly 1,700 MWt of thermal power production potential in the municipal district. Over 75% of this thermal resource is situated beneath Valleyview. This phenomenon is partially due to the fact that the Valleyview search diameter was 25 km larger than the Fox Creek area.

This thermal power equates to roughly 175 MWe of electrical power potential across the municipal district. Due to the lower temperature of the resource near Valleyview, however, it is unlikely that electricity can be reliably produced from the thermal energy. In the area around Fox Creek, ~50 MWe of electrical power may be available. Even in this area, however, the electricity producing capabilities of the resource are marginal, albeit improving to the southwest.

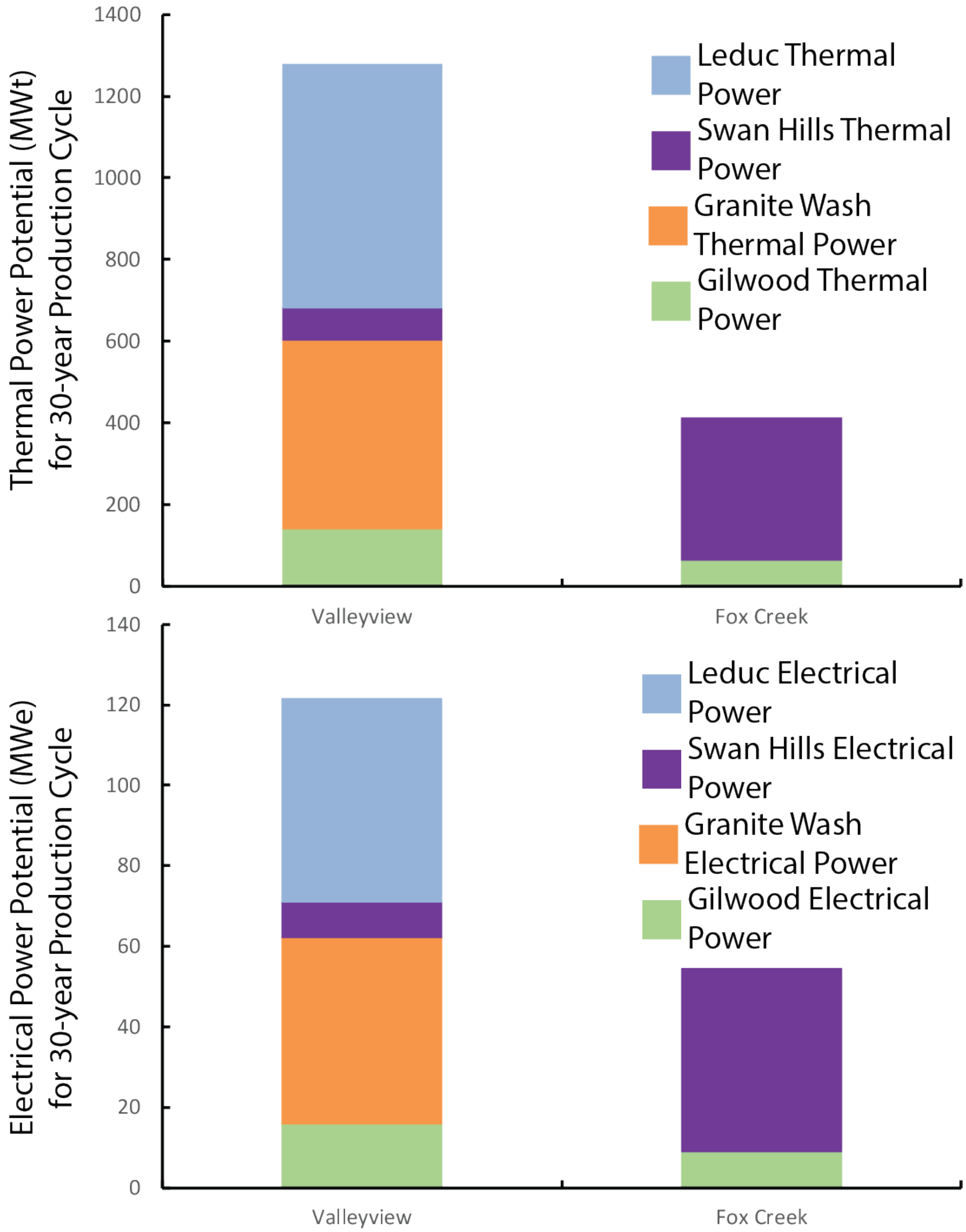

Figure 15 Mean thermal and electrical power production potential for potential geothermal reservoirs underlying population centers in the Municipal District of Greenview

Despite the lack of temperatures required for producing electricity beneath Fox Creek and Valleyview, ample thermal energy is available for various residential, commercial and industrial purposes. New residential developments and work camps in the area could benefit from a constant, non-combustion based source of heat. Producing geothermal brine from the area around Fox Creek may have the added benefit of reducing induced seismicity in the area.

While not investigated in this study, the area around Grande Cache most likely possesses a large, high grade geothermal resource base. The basin is deep in this area, perhaps > 6000 m in places. Additionally, the town’s situation over deformed strata, coupled with it is proximity to the mountain front, mean that hot fluid from the mid-crust have ample flow conduits to reach shallow depths. This process would elevate the local geothermal gradient, potentially creating formation fluids hot enough to power a traditional steam turbine, as opposed to a binary cycle turbine. Further exploration to determine the geothermal resource potential in this area is recommended.

4.3 Hinton & Western Yellowhead County

Geothermal exploration in Yellowhead County was funded entirely by the Town of Hinton, population ~10,000. We focused on a 50 km radius around the town. This radius was selected because it included the area around Obed, where an electrical tie in station was recently constructed. Data in the immediate vicinity of Hinton was sparse, which also led to the increased search radius. Due to the issues associated with mapping within the deformation belt (sparse data; tenuous correlations), we were not able to map beneath the west side of the town. Figure 16 shows a stratigraphic grid of potential geothermal reservoirs found within 50 km of Hinton. Please note that the z-axis of Figure 16 represents structural elevation in meters below sea level, not the total vertical depths of the formations. Structural elevations are required for the 3D mapping because they normalize the depth below the surface to a constant datum, in this case, sea level. For total vertical depth maps of these formations, please see Figure 5 in Chapter 3.

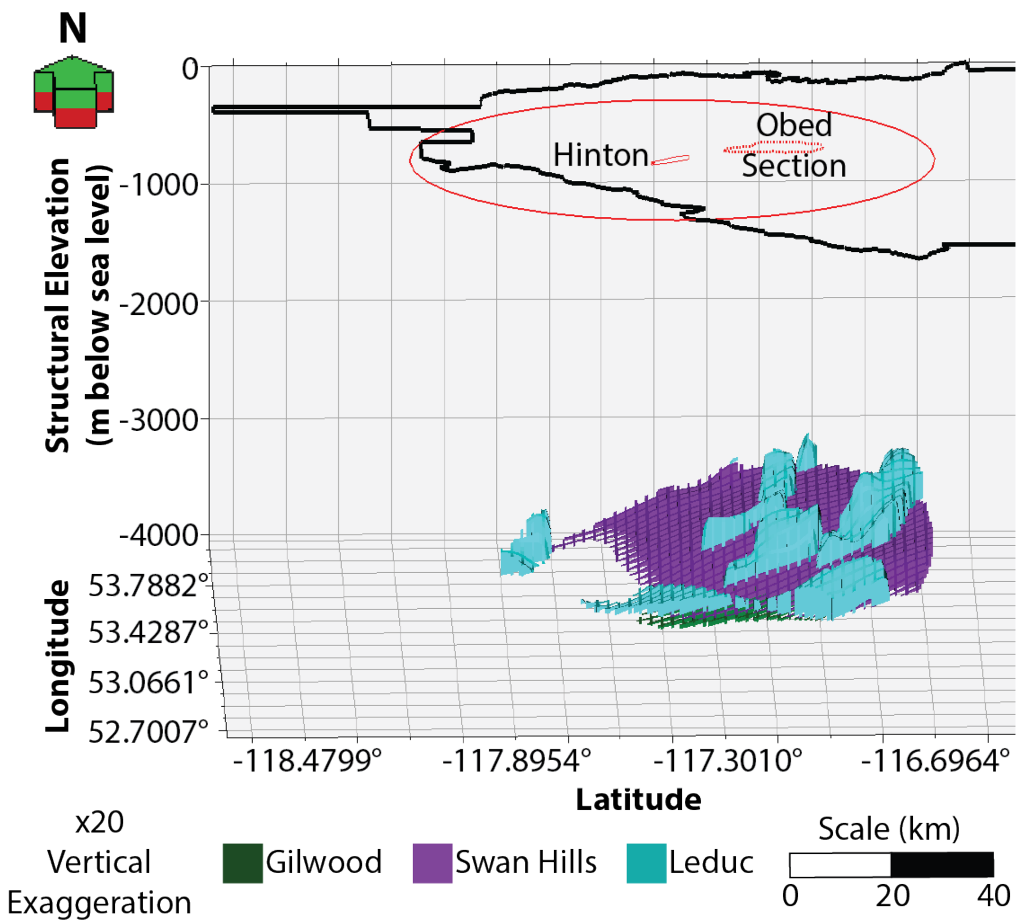

Figure 16 Stratigraphic grids of potential geothermal reservoirs underlying the Town of Hinton in Yellowhead County. Note that the z-axis (depth) represents structural elevation (meters below sea level) and not total vertical depth.

Three potential geothermal reservoirs were found in Yellowhead County's Devonian strata: the Gilwood, the Swan Hills and the Leduc. The Gilwood appears as 30-40 km wide tongue that is ~50 m thick on the northeast edge of the city and gradually tapers out over a distance of 40-50 km to the northeast. The Swan Hills is present as a sharply southwest dipping reef margin that fills most of the eastern half of the Hinton search area as a broad dome. The center of the dome, which is in the immediate vicinity of the Yellowhead highway about 20-25 km Northeast of Hinton, is nearly 300 m thick at its center. The Leduc formation forms isolated pods of reef deposits, often directly overlying the Swan Hills. One such reef appears to sit directly on top of the center of the Swan Hills dome. Here, the Leduc formations is also approaching 300 m thick. Another significant Leduc deposit occurs in a thin sliver running parallel to the deformation front (NW-SE) just along the northeast edge of the city. The section of the Leduc is thickest (>300 m) about 45 km southeast of the Town of Hinton. It tapers to about 100 m thick beneath the city and pinches out about 20 km to the northwest.

In Hinton, we made a volumetric assessment for the entire area, as we did for the other municipal districts, and we did a separate calculation for the section where the Leduc is deposited directly on top of the thick part of the Swan Hills dome. Due it its proximity to the coal mine, we deemed this area the "Obed Section." Table 8 shows the values that were used in the volumetric power potential calculations for both the Obed section and the entire Hinton search area.

Table 8 Values used in volumetric power potential assessments for the Obed section and the entire Hinton search area

	Town	Obed Section	Hinton Total
Volume (m^3)	*Leduc*	2.1E+10	1.39E+11
	Swan Hills	9.7E+09	2.50E+11
	Gilwood		1.39E+10
Depth (m)	*Leduc*	4240±459	4513±627
	Swan Hills	4484±440	4557±486
	Gilwood		4306±264
Temperature (°C)	*Leduc*	134±6	129±13
	Swan Hills	138±8	129±12
	Gilwood		119±14
Porosity	*Leduc*	0.068±0.046	0.068±0.046
	Swan Hills	0.046	0.046
	Gilwood		0.034±0.018

The formations found in the area around Hinton are both the hottest and the deepest reservoirs in the entire study region. All of the formations are reached at an average depth between 4200 and 4500 m. Mean temperatures throughout the area at least 120 °C. Temperatures in the Obed section, where the Leduc is reached at ~4240 depth, are >135 °C. In addition to high temperatures, the Leduc formation also has the highest mean porosity of any of the reservoirs investigated in this study. Only one porosity value for the Swan Hills formation, which is the average for the entire study region, was available. The Gilwood formation, which is found as a relatively thin (<50M) wedge trending from the outskirts of Hinton to the northeast is slightly cooler, shallower and less porous than either the Leduc or the Swan Hills formations in the area.

Figure 17 shows the mean thermal and electrical power production potentials for both the Obed section and the entire 50 km search diameter around Hinton, calculated using the range of values shown in Table 8. In total, we identified ~2,500 MWt of thermal power production potential within 50 km of the Town of Hinton. Over 60% of this thermal resource is contained in the Swan Hills formation. The Obed section alone contains just over 200 MWt of thermal power production potential, with nearly 70% of it contained in the Leduc formation. These values equate to an electrical power production capacity of ~57 MWe for the Obed Section and ~630 MWe for the entire Hinton area. Again, about 60% of the electrical power potential is found within the Swan Hills formation. The Gilwood, which only has significant thickness on the northeast border of the city, has a thermal and electrical power production capacities of ~69 MWt and 15 MWe, respectively.

The area around Hinton is clearly the best target for large-scale geothermal electricity production in Alberta. For comparison purposes, the Keephills 3 coal power plan has a capacity of 450MW. The electrical power potential identified in this area would be enough to replace this capacity through the development of multiple distributed geothermal facilities. The Obed section alone contains enough electrical power potential to fuel the residential and commercial needs of a city three times the size of Hinton. Geothermal power developed from these resources can supply clean, baseload electricity to provincial and national parks in the region. In addition, thermal power from these resources can be used to support the already existing timber industry in the area, as well as fueling a year-round agriculture industry through geothermal heated greenhouses.

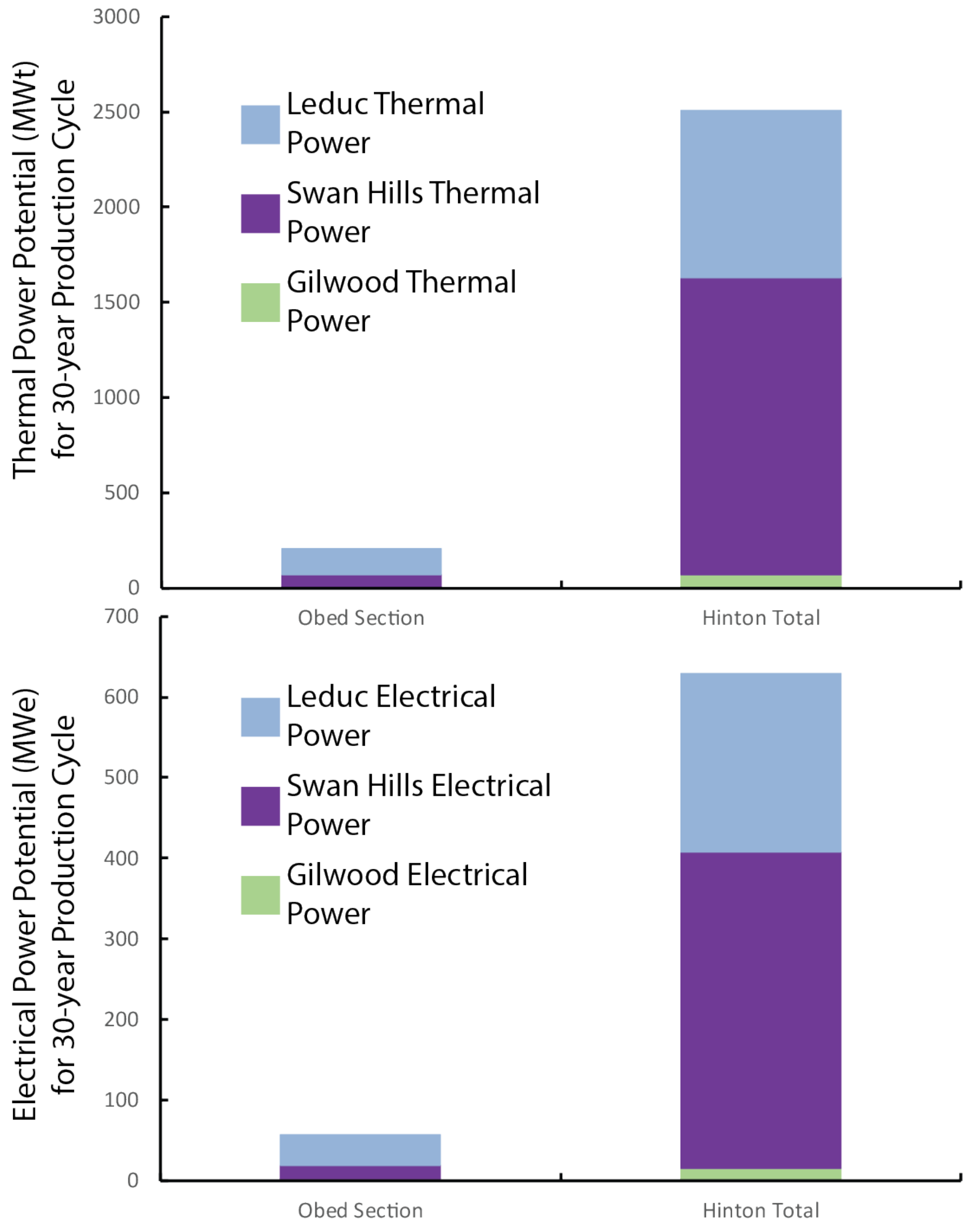

Figure 17 Mean thermal and electrical power production potential for potential geothermal reservoirs underlying the Town of Hinton, including the Obed section to the northeast of the city

4.4 Clearwater County

Clearwater County was the southern – most municipal district we investigated, with sponsorship from the Tri – Council of Clearwater County, Village of Caroline and the Town of Rocky Mountain House. Altogether, this represents about 12,300 residents, more than half of whom live in Rocky Mountain House. We investigated areas around Rocky Mountain House (35 km search diameter) and Caroline (35 km diameter). Figure 18 shows a stratigraphic grids of potential geothermal reservoirs found within 17.5 km of both of these localities. Please note that the z-axis of Figure 18 represents structural elevation in meters below sea level, not the total vertical depths of the formations. Structural elevations are required for the 3D mapping because they normalize the depth below the surface to a constant datum, in this case, sea level. For total vertical depth maps of these formations, please see Figure 5 in Chapter 3.

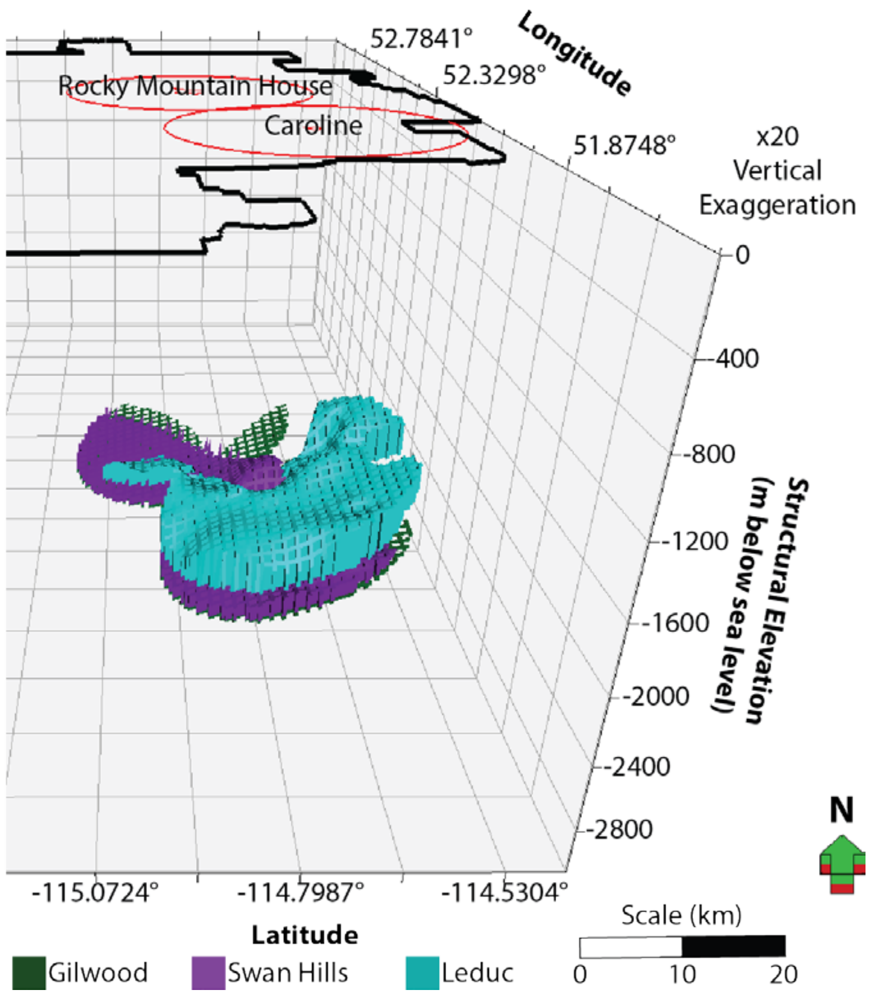

Figure 18 Stratigraphic grids of potential geothermal reservoirs underlying population centers in the Clearwater County. Note that the z-axis (depth) represents structural elevation (meters below sea level) and not total vertical depth.

The Gilwood, Swan Hills and Leduc were all identified as potential geothermal reservoirs in Clearwater County. While it appears as though all three formations underlie both population centers, only one well in the Rocky Mountain House area penetrates the Gilwood, at depth of ~1950m. There was no temperature or porosity measurement associated with this well. Therefore, the presences of the Gilwood beneath Rocky Mountain House is mostly inferred, and a volumetric assessment for this formation beneath Rocky Mountain House was not performed. Beneath Caroline, the Gilwood forms two distinct domes, one to the west and one to the northeast of the village. Both domes have a maximum thickness of ~100 m, and they taper towards each other to a thickness of ~25 m beneath the Village. The Swan Hills in the region appears as a 75-125 m thick deposit that underlies both population centers. The Leduc appears as a thick (~275 m) deposit throughout most the Caroline search area, with the exception of the area directly north of the village. The Leduc only skirts the southwest margins of the Rocky Mountain House search area, where it appears to be <50 m thick. Table 9 shows the values that were used in the volumetric power potential calculations for the population centers in Clearwater County.

Table 9 Values used in volumetric power potential assessments for population centers in Clearwater County

	Town	Rocky Mountain House	Caroline
Volume (m^3)	*Leduc*	4.17E+9	1.52E+11
	Swan Hills	2.09E+09	5.99E+10
	Gilwood		2.06E+10
Depth (m)	*Leduc*	3608±994	3457±150
	Swan Hills	4200±690	3788±133
	Gilwood		3861±70
Temperature (°C)	*Leduc*	112±11	96.5±10
	Swan Hills	118±15	94±10
	Gilwood		100±8
Porosity	*Leduc*	0.05±0.024	0.066±0.054
	Swan Hills	0.042±0.022	0.062±0.05
	Gilwood		0.068±0.1

Both the Swan Hills and the Leduc formations beneath Rocky Mountain House have sufficient temperatures for electricity production. The mean temperature in the Gilwood beneath Caroline is also just over 100 °C, the minimum temperature we consider sufficient for electricity generation. Both the Swan Hills and Leduc formation beneath Caroline have mean temperatures in the upper 90s, placing them just on the boundary between marginal and sufficient temperature for electricity production. In all cases, porosities found throughout Clearwater County were generally higher than those found elsewhere. Porosity measurements from the Gilwood, however, varied considerably, with the standard deviation being greater than the mean. This effect results from one porosity measurement being > 20% and the remainder (3) being < 1%. With the exception of the Swan Hills formation beneath Rocky Mountain House, which is reached at a depth of ~4200 m, all the potential geothermal reservoirs we investigated in Clearwater County are reached at depths <4000 m.

As shown in Figure 19, we identified just over 1,000 MWt of thermal power production potential underlying the two investigated population centers in Clearwater County. A little more than half of this potential is found in the Leduc formation underlying Caroline. The Gilwood contributes less than 10% of this total, with the rest being supplied by the Swan Hills, predominantly beneath Caroline.

This thermal power potential equates to a mean electrical power potential of ~160 MWe. While most of this potential is found in the Leduc beneath Caroline, the temperature of the resource in that location is marginal for electricity production. The higher grade resources beneath Rocky Mountain House contain nearly 30 MWe of electrical power potential, which is enough to fuel the domestic and commercial needs of the entire county. An additional high grade resource may be found in the Gilwood beneath Caroline. Within the search area, the Gilwood's mean electrical power production potential is ~13 MWe. This is mostly contained in the dome to the southwest of Caroline. The dome to the east of Caroline, lies largely outside of the search area and straddles the boundary with Red Deer County. This particular section of the Gilwood is a promising area for future exploration.

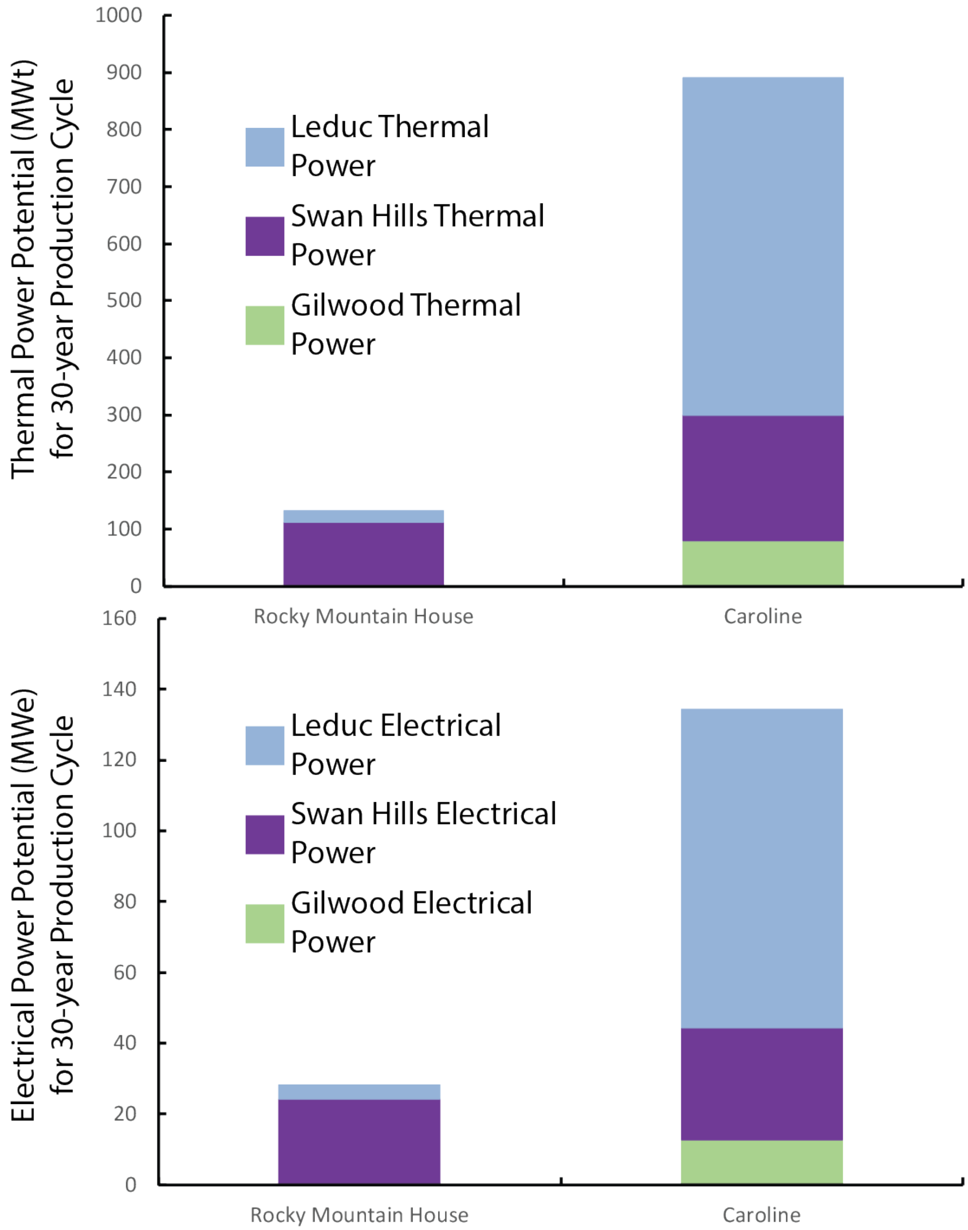

Figure 19 Mean thermal and electrical power production potential for potential geothermal reservoirs underlying the Rocky Mountain House and the Village of Caroline in Clearwater County

Clearwater County has the same standard set of opportunities (i.e. traditional electricity generation, various direct heating uses) for geothermal energy development that are available to all of the communities participating in this study. Additionally, the Caroline gas field in Clearwater County provides a unique opportunity to convert a diminishing gas field into a productive geothermal field. Many of the wells in this field are in the process of being shut in due to high water cuts in the gas flow. This water flow could be maximized by retrofitting these wells. The flow could then be used to potentially produce electricity through the development of low-temperature geothermal engines or through direct use options discussed in greater detail below.

5 Pathways to Commercialization

5.1 Overview

Previous chapters in this report detailed our geothermal resource base assessment for the Alberta foothills. The Deep Dive also compiled information concerning geothermal technology and commercial development relevant to moving projects forward. The areas we investigated were:

1. Cost estimates for major geothermal power plant components
2. Geothermal energy end-use options
3. Royalty structures in successful geothermal energy producing nations

This section of the report was performed by a consortium of industry and academic partners, external to the University of Alberta, as in-kind contributions to the Deep Dive. A list of the contributors and the areas they investigated are found in Table 10.

Table 10 List of project in-kind partners and their thematic contributions

Contributor	Topic
Terrapin Geothermics Inc.	Royality review; drilling costs; timber industry information
CES Power and Control	Organic Rankine Cycle (ORC) Modeling; 2.5 MWe ORC price quote
Iceland School of Energy; Reykjavik University	Organic Rankine Cycle (ORC) Modeling; global ORC cost review
Solbird Energy Inc.	Geothermal greenhouse thermodynamic and economic models; Greenhouse and timber kiln heating schematics

This chapter summarizes the findings and key points of each of these individual reports. The reports themselves are found in their entirety in the appendix. The reports contributed by these partners should provide guidance to the participating municipalities in support of their strategic planning activities. They are meant to inform public officials and provide frameworks for moving conversations forward on a community level. They are not meant to function as comprehensive technological or economic pre-feasibility studies.

5.2 Costs of major geothermal power plant components

5.2.1 Drilling Costs

Geothermal power plants consist of 5 major pieces of infrastructure:

1. Wells
2. Pumps
3. Heat exchangers & piping
4. Turbines
5. Electrical transmission equipment

The riskiest investment is in the wells, without which there is no direct confirmation of a reservoir's viability. The wells are required to circulate geothermal fluids from the deep subsurface. The wells are primarily what distinguishes a geothermal power station from any other type turbine-using power plant.

It is common practice for geothermal developers to drill "slim hole" test wells to prove a resource before proceeding to full scale geothermal well drilling. A geothermal slim hole is broadly similar to a conventional gas well in terms of diameter and completions. Practically speaking, any gas well in our study area could be retrofitted to serve as a geothermal slim hole. The requirements for serving this purpose are significantly lower than the requirements for repurposing a gas well for full-time brine circulation as a geothermal producer or an injector.

Based on costs taken from the PSAC 2017 Well Cost Study (PSAC, 2016), we estimate the fixed costs of retrofitting a gas well for use as a geothermal slim hole to be ~$75,000 per well. This includes the costs of installing new wellhead equipment, adding a packer to seal off the current producing zone and perforating an area for a new production zone in the geothermal pool. Table 11 summarizes these fixed costs. In additional to these fixed costs, a new liner would need to be installed in the well. The PSAC study estimates $37/m for well lining. Thus, a 4,500 m well retrofit would require an additional ~$166,500 in new lining. Retrofitting a 4,500 m gas well as a geothermal slim hole is nearly an order of magnitude cheaper than drilling a new one

Table 11 Estimated material costs for repurposing a 4,500 m gas well as a geothermal slim hole

Item	Unit Cost	Units	Cost
Overhead well-retrofit	$6,000/per well	1	$6,000
Well head equipment	$18,000/per well	1	$18,000
Packer	$10,200	1	$10,200
Perforation	$34,000	1	$34,000
Well liner	37/meter	4500	$166,500
Subtotal			$234,700
Contingency	20%		$46,940
TOTAL			$281,640

Costs for drilling a full size geothermal well will vary with specific local conditions. Through Terrapin Geothermics Inc., we obtained a rule-of-thumb price quote for a full size geothermal well from Cougar Drilling. Cougar Drilling is both active locally in oil and gas drilling and globally as a geothermal driller. They estimate a cost of $5-6,000,000 for a 3,000 m geothermal well with a 20” surfacing casing that telescopes down to a 7” production casing. These costs may not increase linearly per meter past 3,000 m. A 4,000 m well may cost closer to $9,000,000 than $8,000,000, depending on local conditions.

5.2.2 Surface infrastructure

Surface infrastructure for a geothermal power plant includes pumps, heat exchangers, turbines and power distribution equipment. Pumps include brine production and injection pumps, ORC working fluid pumps, coolant pumps and district heating fluid distribution pumps. Power distribution equipment means thermal piping in the case of a direct-use geothermal system and electricity generation and transmission equipment in the case of an electricity producing geothermal plant.

The costs for a 2.5 MWe ORC, which could be run on a simple doublet, were provided by CES Power and Control, an Edmonton based company that builds small scale generation facilities for a variety of industrial purposes. A summary of these costs are provided in Table 12. The full class-C cost estimate may be found in Appendix A. For the modular designed surface plant, they estimate a cost of ~$12,000,000. Coupled with two $9,000,000 wells, the total cost of a 2.5 MWe pilot plant may be ~$30,000,000, or $12,000/kWe. This is considerably higher than the ~$3,000/kWe global average, a figure provided to us by the Iceland School of Energy (Appendix C2). The global average, however, considers mature technology and not a first-of-its-kind adoption. Nominal public subsidies could make geothermal cost competitive with solar and wind in Alberta, due to its baseload capacity factor. While the capital cost of solar capacity may cost 7-10 times less than the capital cost of geothermal capacity (e.g. Lazard, 2016), a geothermal system has 4-5 times the capacity factor.

Table 12 Estimated costs for a 2.5 MWe Organic Rankine Cycle geothermal power plant

TASK DESCRIPTION	Total
Project Management	$349,200.00
Engineering Design	$852,000.00
Site Construction Equipment	$21,600.00
Civil and Site Preparation	$444,000.00
Concrete	$21,600.00
Structural Steel	$60,000.00
Buildings	$46,800.00
ORC Equipment	$6,155,600.00
Piping	$784,800.00
Electrical	$2,619,350.80
Instrumentation	$420,000.00
Startup / Commissioning	$109,200.00
Special / Other	$118,800.00
Grand Total:	**$12,002,950.80**

A direct use geothermal plant would be significantly cheaper than an electrical power plant. The cost of the electricity generation and transmission equipment in the above scenario is ~$8,700,000. The construction and heat exchange infrastructure is ~$3,300,000. In addition to this equipment, a heating fluid pump and pipes are required. Costs for the pump are estimated to be ~$115,000 (Appendix A2). Costs for the thermal piping are taken from the PSAC well cost report and are estimated to be $22/m. An 11 km district heating network, such as the one serving the Munich-suburb of Unterhaching, would cost $242,000. The thermal power required for district heating system is dependent on application. In section 5.3, below, we describe the thermal requirements for tomato greenhouses and timber kilns, as examples.

5.3 Geothermal end-use options

5.3.1 Direct Use

Geothermal energy can be used directly as heat or converted to electrical power. Geothermal resources as cool as 40 °C can be exploited for thermal power. Direct-use applications for geothermal heat are available throughout our entire study region. Common end-uses for geothermal heat include:

1. Domestic and commercial space heating
2. Industrial process heat
3. Greenhouse and nursery heating
4. Timber and grain drying
5. Snow melting
6. Balynology (spas and public baths)

For this report, we looked closely at opportunities for geothermal applications in the agriculture and timber industries. Solbird Inc., an Edmonton based micro-renewable and ground source heat pump installation company, reviewed the economics and thermodynamics of a geothermal heated tomato greenhouse facility. Terrapin Geothermics Inc. networked with the forestry and timber industries on our behalf. They provided us with dimensions and operating conditions of a typical timber kiln, as well as the thermal load such a facility requires.

As of 2013, Alberta had ~127,000 m^2 of greenhouses, representing 5.5% of Canada's greenhouse market. A 1 hectare tomato greenhouse operation would require 45,000 GJ/year of heating. This equates to a constant thermal power requirement of ~1.5 MWt/hct. Considering an average annual air temperature of 0

°C in Alberta, this requirement would be met with a flow rate of ~6 kg/s for a 60 °C brine flow. An 80 °C brine would meet this requirement with a 4.5 kg/s flow rate. These flow rates are low; a one hectare tomato greenhouse may be undersized even for a simple doublet (production and injection well) system. These flow rates are low enough to seriously consider the use of refurbished gas wells for long term production and injection, given the typical spacing of the wells and the land requirements of the greenhouses. Furthermore, these temperatures are available as a low-grade geothermal resource throughout the Western Canadian Sedimentary Basin. In fact, it is likely that any agricultural land west of the Edmonton-Calgary corridor has access to a greenhouse-grade geothermal resource in least one geologic horizon.

Currently, over 80% of greenhouses in Alberta are heated with natural gas. Due to natural gas price fluctuations, the cost of heating a hectare size tomato greenhouse with natural gas has fluctuated from below $80,000 year in 2016 to nearly $180,000 in 2014, as shown in Figure 20. With the implementation of Alberta's new carbon tax, higher heating costs maybe expected.

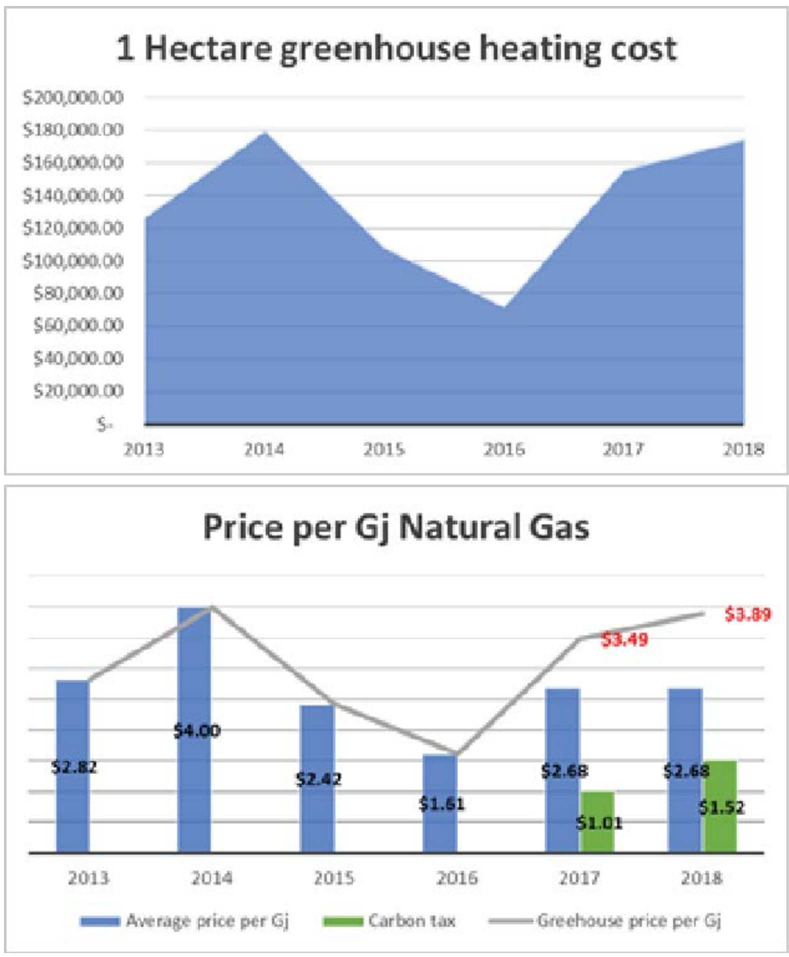

Figure 20 Price fluctuations in greenhouse heating costs as function of natural gas prices from 2-13-2018

A single hectare tomato greenhouse would take decades to pay back the investment of a geothermal doublet, and the doublet would likely be far oversized for the greenhouse. The economics of a new doublet specifically for greenhouses make sense at ~5 hectares. Retrofitting existing wells for brine circulation, however, appears to be an excellent investment, where feasible. Greenhouse heat may also be provided by using the waste heat from a geothermal power plant, which is often still > 80 °C. This would essentially be free heat for the greenhouses, with practically no capital expense. Furthermore, this would add a diversified income stream for the power plant operator, making the economics of the whole project more favourable.

A qualitative process flow diagram for a geothermal-fueled greenhouse installation is found in Figure 21.

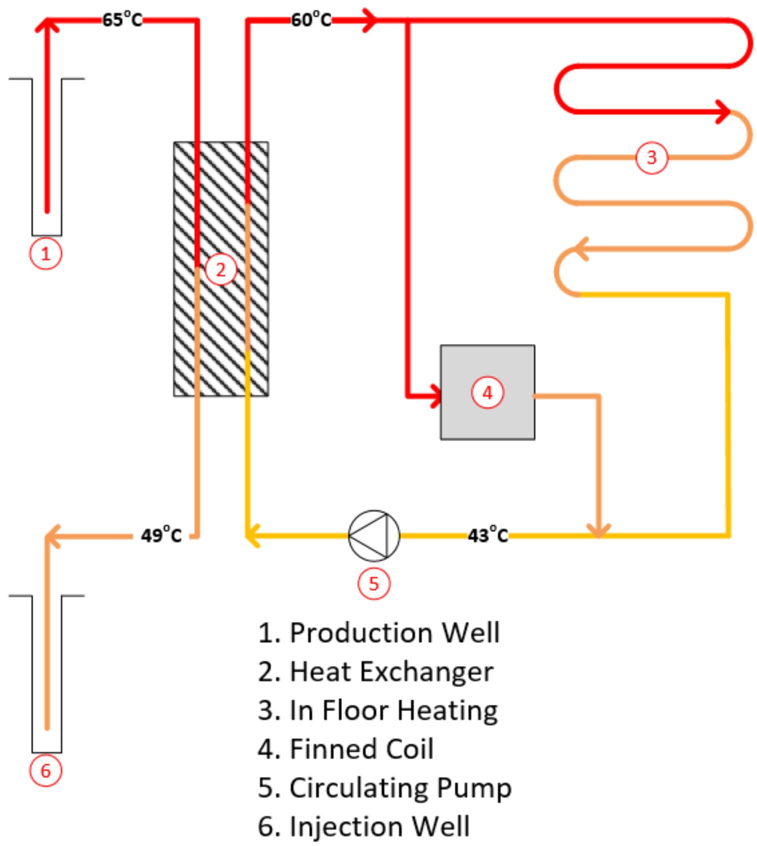

Figure 21 (adapted from Boyd, 2008) Schematic diagram for a geothermal-fueled greenhouse installation. Thermal energy from a produced brine (1) is transferred to a working fluid at the surface (2), which is then circulated through heating coils in the floor of the greenhouses (3). The working fluid is circulated throughout the system, including through a regenerator (4) with a pump (5) in a closed loop. Cooled brine is then reinjected into the subsurface (6).

Another significant direct use geothermal opportunity in Alberta are timber drying kilns. A typical drying kiln is an enormous box where 100 °C air constantly circulated. A typical kiln may be ~97,000 m^3 and require 11 million btu/hour of heat. This equates to a constant thermal power load of ~3.3 MWt. Considering the volatility of the natural case market and the coming impacts of Alberta's carbon tax using a geothermal source, rather than natural gas, for timber drying may be economically sensible, especially if coupled with power generation and/or retrofitted oil and gas wells.

A qualitative process flow diagram for a geothermal heated timber kiln is shown in Figure 22.

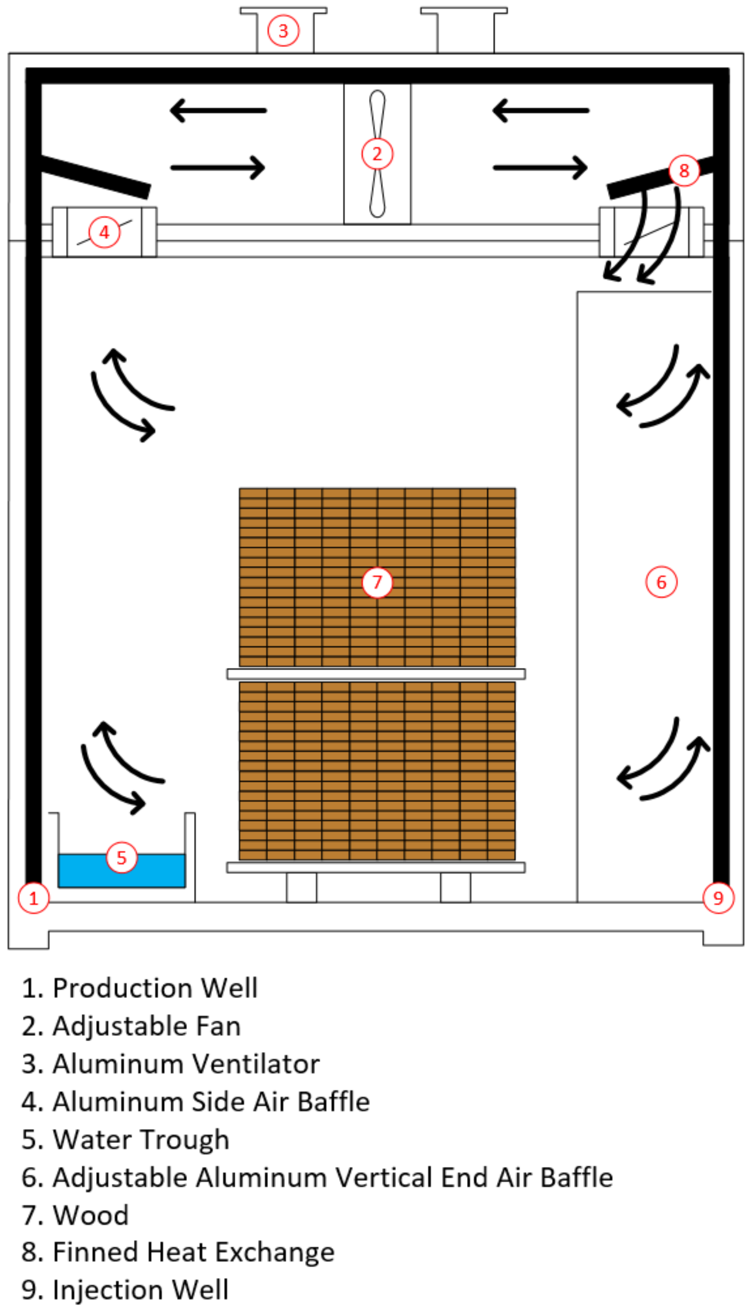

Figure 22 (adapted from Scott and Lund, 1998) Schematic diagram for a geothermal-fueled timber kiln. The kiln is essentially a large hall, where thermal energy from produced brine (1) heats ambient air (3) that is circulated through the hall with a large, adjustable fan (2). Even air flow throughout the facility is maintained with a series of baffles and fins (4, 6). Heat is transferred from the brine to the air with finned heat exchangers (7) near the air intake, and the humidity is maintained with a water tank (5). The cooled brine is reinjected into the subsurface (9).

Existing timber drying facilities in Alberta can be evaluated on a case by case basis for the feasibility of retrofitting them with a geothermal source. New timber drying facilities may be strategically located to take advantage of available geothermal resources.

5.3.2 Electricity production.

Electricity production from geothermal resources in the Western Canadian Sedimentary Basin will be employ binary cycle technology. In a binary cycle geothermal plant, the heat content from the geothermal resource is transferred to a low boiling point "working fluid," whose vapour subsequently drives a turbine as water steam would drive a steam turbine. The working fluid is then re-condensed through a chiller before going through the cycle again. The working fluid stays in a closed loop in the surface plant, and the geothermal brine stays in a semi-closed loop between the surface plant and the reservoir. The most common type of binary cycle engine employed in the geothermal industry is the Organic Rankine Cycle (ORC) engine, a schematic diagram of which is shown in Figure 23.

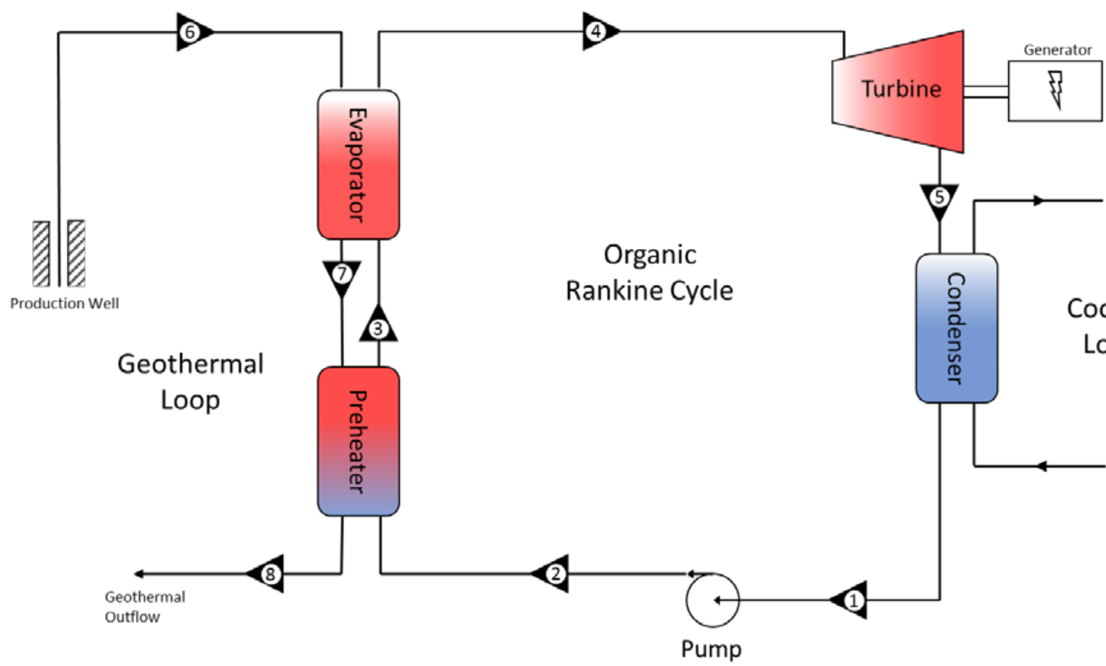

Figure 23 Process flow diagram of an Organic Rankine Cycle power plant, showing the working fluid loop (1-5) and the geothermal brine loop (6-8.) The working fluid loop begins with cool refrigerant (1) that is pumped from the condenser to the preheater (2). The pre-warmed working fluid (3) is then moved to the evaporator, where it boils (4), driving a turbine. After volume expansion within the turbine, the working fluid is then returned to the condenser (6), where the cycle begins again. In the geothermal brine loop, formation fluid is pumped from depth to the evaporator (6), where it boils the working fluid. Residual heat from the brine (7) is used to preheat the working fluid coming into the evaporator. The cooled brine is then injected back into the subsurface (8).

A team of engineers from CES Power and Control and an engineer from Iceland School of Engineering (Reykjavik University) both submitted thermodynamic models of ORCs under various operating conditions. These reports are found in Appendix C. CES Power and Control analyzed the performance of air-cooled ORCs with brine inlet temperatures of 140 °C and 120 °C and flow rates of 50 kg/s and 30 kg/s. A summary of their results are shown in Table 13, below. With a 140 °C inlet temperature, a flow rate of ~37 kg/s is required to achieve 1 MWe of net electrical production. With a 120 °C inlet temperature, a flow rate of 69-71 kg/s is required. This calculated flow rates are in good agreement with the flow rates calculated in the volumetric assessments discussed in Chapter 3 (Section 3.3; Figure 11).

Table 13 Performance summary of Organic Rankine Cycle engines at two different brine inlet temperatures and flow rates.

Brine Temp. [°C]	Flow Rate of Brine [kg/s]	Gross Electrical Work Output [kW]	Flow Rate of Working Fluid [kg/s]	Pump Power Required [kW]	Fan Motor Power [kW]	Net Electrical Work Output [kW]	Overall Eff. [%]	Flow Rate for 1 MWe (kg/s)
140	50	1798	60.37	164	140	1345	9.04	37
140	30	1079	36.22	98	83	803	9.00	37
120	50	1063	40.28	109	93	724	7.41	69
120	30	638	24.17	66	56	423	7.21	71

In addition to the models created by CES Power and Control, a master's engineering student at the Iceland School of Engineering (Reykjavik University) studied various working fluids in ORCs with both 135 °C and 105 °C brine inlet temperatures. He studied efficiency of the working fluids under different degrees of brine cooling. Figure 24 shows the optimal results for the different inlet and outlet brine conditions.

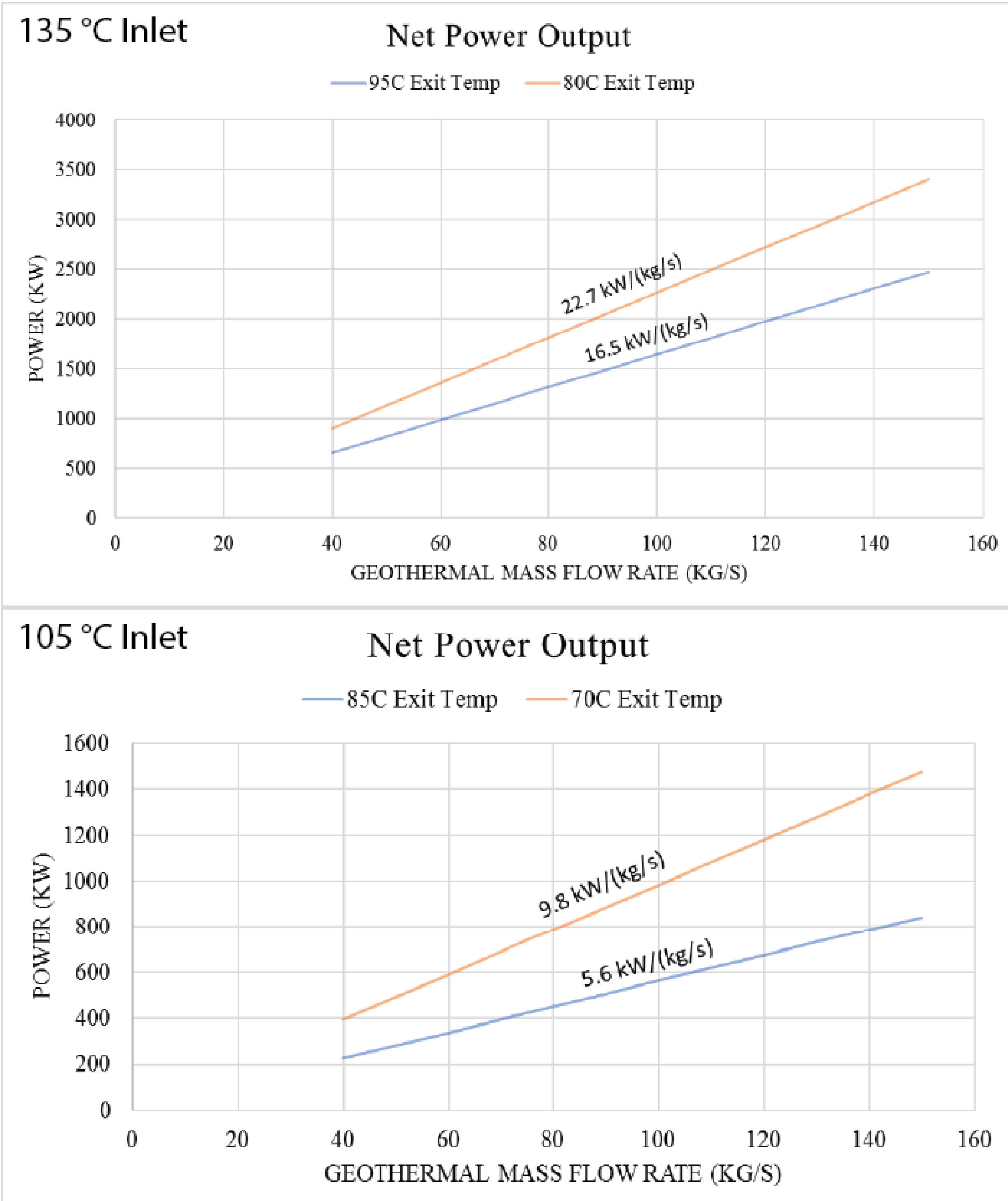

Figure 24 Net power output for an ORC with a 135 °C (top) and 105 °C (bottom) inlet temperature at 2 different brine temperature gradients

These results are also in good agreement with both the model from CES Power and Control and the volumetric calculations described in Chapter 3 (Section 3.3; Figure 11). Based on the results from these three different calculations, we expect simple doublets throughout our study area to be able to produce 1-2 MWe of net electrical power.

5.4 Geothermal Regulations in Alberta

Alberta currently has no regulatory framework in place for developing geothermal resources.

British Columbia is the only Canadian province with explicit geothermal legislation. For reference, the Geothermal Resource Act for British Columbia may be found here:

http://www.bclaws.ca/civix/document/id/complete/statreg/96171_01

In addition to work being done in Alberta on this issue, geothermal development regulations are also being contemplated in Saskatchewan, as well as the Yukon and Northwest Territories

Geothermal regulatory frameworks focus on answering several key questions, including:

- What is the definition of geothermal resource in Alberta?
- Who owns Alberta's geothermal resources?
- Can geothermal resources be regulated in a manner similar to mineral resources, water resources, or hydrocarbon resources, or does a new category of resource need to be developed?
- What are the processes for obtaining geothermal exploration and production leases?
- What environmental protections need to be in place for allowing geothermal drilling and production?

Since this study began in February 2016, the Government of Alberta has assigned a task force through the Ministry of Energy to look into these issues. A rigorous jurisdictional review of geothermal regulations around the world is not necessary in this report, as it will be undertaken by the Ministry of Energy task force. Researchers at the University of Alberta will continue assist the Government of Alberta in this process. Developing a regulatory framework for geothermal energy development in Alberta will take years and will involve deliberation by provincial officials in consultation with industry, municipal and residential stakeholders.

5.5 Environmental Impacts

While geothermal energy is classified as a renewable resource in Alberta and Canada, it is not without its environmental impacts. Most of geothermal energy development's carbon footprint is in the plant construction, including drilling and infrastructure manufacturing. Environmental impacts during geothermal power production include noise pollution, trace gas emissions, water consumption and mineral precipitant management.

While detailed environmental impact assessments must be performed on a case-by-case basis. The Geothermal Energy Association (geo-energy.org, 2017) keeps statics on the performance geothermal plants compared to other renewable and non-renewable power sources in regards to several key environmental metrics, including emissions per MWh of generated energy, land use footprint and water consumption.

No statistics are available for emissions from binary cycle geothermal plants. In theory, a binary cycle plant should have no emissions, because the working fluid is in a closed loop, and the geothermal brine is reinjected into the subsurface. The brine flow, however, will include some reservoir gas, including CO_2, methane, nitrogen, NO_x and SO_x. Gas may also be exolved as the brine depressurizes at the surface. Typically, these gases would be separated at the well head and vented to the atmosphere. Because gas entrained in the brine flow reduces the overall heat capacity of the fluid, developers would seek to have

<10% by volume gas in the brine. Thus, gas emissions from binary cycle power plant would still be negligible.

Geothermal power plants use approximately three times less land per GWh (404 acres/GWh) of produced energy than wind turbines (~1300 acres/GWh) and nearly eight times less land area than solar photovoltaic (~320 acres/GWh). During its entire life cycle, a binary cycle geothermal power plant may use anywhere from 0.32-1.08 liters of water per kWh of energy produced. This compares unfavourably to wind (~0.04 l/kWh) and solar (0.28-0.76 l/kWh). Most of water consumed by binary cycle geothermal power plant is cooling water. Alberta's low annual ambient air temperature, however, make the use of air-cooled plants more feasible here than in many other locations around the globe. The use of air-cooled plant would place geothermal energy's water use footprint on par with that of wind and solar energy.

All statistics cited above may be found at: http://geo-energy.org/geo_basics_environment.aspx

6 Conclusions

6.1 Technical Development

From the technical perspective, we have now identified the top sites in west-central Alberta for geothermal energy development. Detailed reservoir and production models for these sites, along with slim hole wells drilled into the reservoirs will be required to move this research out of a computer and into the field for a pilot and demonstration-scale technology demonstration.

Commercial opportunities for direct-use exploitation of the resources identified in this study exist throughout the study area. Although, commercially proven technology currently exists that would allow for electricity production from the hotter reservoirs identified in this study, the lack of local expertise and knowledge means that electricity production of Alberta's geothermal resources is at a lower technology readiness level than in other jurisdictions. Resources at the lower temperature end (80-100 °C) of what we identified in this study require the development and/or optimization of low and ultra-low temperature differential heat engines to be considered potential electricity producing resources. The relatively cold (~0 °C) annual average air temperature in Alberta gives the province a strategic advantage in the deployment of this type of technology, which also leads to the potential economic conversion of other waste heat streams into electricity and a significant global export opportunity. Technology development opportunities for direct use geothermal heating exist in optimization of surface and down hole heat exchangers, as well as retrofitting of forced-air heating systems to accept a geothermal input source.

In addition to technology development, we also recommend deeper research into the sites identified in this study, as well as broader exploration through western Alberta. Deeper research includes using well logs and seismic lines to further define the properties of geothermal pools and model long term brine circulation in proposed development areas. Additional exploration targets include the Devonian section beneath Grande Cache, Cambrian sections beneath Fox Creek and Caroline and the deep basin in the far north of the province by Rainbow Lake and High Level. Any location west of the Edmonton-Calgary corridor is suitable exploration site for direct use of geothermal energy. In particular, the area between the southwest margins of Edmonton and the northwest margins of Red Deer is particularly favourable for direct use applications. Additionally, there are direct-use geothermal resources at shallower depths than what we explored here throughout western Alberta.

6.2 Cost Competitive Outlook

Regarding cost competitiveness, we estimate the capital cost for first Alberta adoption of binary-cycle geothermal power technology to be $12,000 - $15,000/kWe, for a pilot scale project. These costs are indicative of a pre-commercial technology that still requires technical and project development de-risking. If we compare these costs with the wind and solar capital costs within the US, we see they are ~10x less expensive (Lazard, 2016). However, another important factor to consider is the capacity factor, i.e. how often a power plant will produce electricity, keeping in mind that the capacity for wind and solar depends greatly on geographical location, generally speaking a wind farm has a capacity factor of roughly 30%, solar farms 15% and geothermal power plant 95%. Therefore, a kWh of geothermal energy from a pilot scale geothermal project is estimated to be ~2x as expensive as wind or solar. Both of these comparisons carry the imperative caveat that wind and solar are fully commercial technologies that have benefitted from extensive research and public subsidies. Geothermal electricity production in Alberta is at a very early project development level compared to wind and solar. This is not because the technical components aren't commercially available but rather because the integrated geothermal system which includes exploration, reservoir modelling, drilling, etc that are needed to access the underground heat source and delivery it for heat use or electricity generation has never been done in Alberta. The fact that pilot-scale capital costs of geothermal electrical power are 'only' about twice as expensive as full-scale wind and solar on a kWh basis should be seen as an encouraging starting point. As the project development within the province matures, the capital costs of geothermal electricity power need to be reduced to $6,000 - $8,000/kWe to compete with wind and solar on a kWe basis and $4,000-$6,000/ kWe to meet global averages (Lazard, 2016). Specific measures that may need to be taken to achieve these cost reductions are:

- Continued use of existing oil and gas exploration data, including well logs and seismic profiles, to reduce the risk of drilling dry wells
- Repurposing existing oil and gas wells as geothermal slim holes for advanced exploration, reservoir productivity testing and, where possible, full-scale brine production and injection
- Scaling up from pilot scale (1-2.5 MWe) to full field development (> 10 MWe)
- Creating a local manufacturing base for geothermal power plant components, including geothermal well casings, heat exchangers and organic Rankin cycle generators
- Developing and optimizing low and ultra-low temperature differential heat engines

In contrast with electricity production, which requires further technical and economic de-risking, direct use of geothermal energy for various heating purposes is commercially viable technology in the current economic environment. A simple geothermal doublet in Alberta may produce anywhere from 2.5 MWt (at 60 °C and 10 kg/s flow) to 21 MWt (at 100 °C and 50 kg/s flow) of thermal power, considering a 90% efficiency. If this doublet is comprised of repurposed oil and gas wells, the capital costs of a direct use geothermal system may range from $50-500/kWt. The geothermal system for the 1 hectare tomato greenhouse discussed in Section 5.3.1, for example, may have a capital expense of up to $750,000, if a suitable well pair can be found. If this greenhouse were to be heated with natural gas, it would require ~42,500 GJ/year. Using the 10-year average gas price (~3.93/GJ; Alberta Energy Regulator, 2017); this amounts to a ~$165,000/year in fuel expenses alone. The fuel cost savings provided by the geothermal system would pay for the system itself in < 5 years. These costs savings would be accompanied by a CO_2 emissions reduction of ~2,380 tons per year (56kg/GJ; Natural Resources Canada Archives, 2017), representing an additional ~$70,000 in savings a year.

If new wells are required for a district heating system, the capital cost will be considerably more expensive. It is harder to estimate these costs because a detailed design study for any given project may show that is it cheaper to drill several narrow diameter wells than two full size geothermal wells, for which we have price estimates here. Justifying the capital expense of drilling new wells for a direct use geothermal system will require that the project be considerably larger than the 1.5 MWt greenhouse or the 3.3 MWt timber kiln contemplated here. A 10 hectare greenhouse complex run off of full size geothermal production and injection wells may have a capital cost of $800-1000/kWt, for a total cost of $12-15 million. Using the metrics discussed in the previous paragraph, this complex would require ~1,650,000/year in fuel costs and be subject to an additional ~$700,000 in carbon taxes, at current rates. For a large direct use project such as this, the fuel cost savings provided by the geothermal system would pay for the system in < 10 years. This analysis does not consider projected increases in gas prices or the Alberta carbon tax.

6.3 Recommendations

Considering a 30-year production period, west-central Alberta contains >6,000 MWt of thermal power potential and >800 MWe of technically and potentially cost competitively recoverable electrical power potential. This could provide up to 16% of the Government of Alberta's targeted renewable energy capacity by 2030. This is a substantial renewable energy resource that must play an important role in Alberta's energy transition. Whereas electricity production from this resource requires further technical and economic de-risking, a process that may take some years, direct-use of Alberta's geothermal resources for heating purposes are commercially viable immediately.

To reduce the technical risk, we recommend using direct use geothermal projects to de-risk the project development of electricity production projects. Direct-use projects are both technically and economically safer, because they require lower temperatures, lower flow rates, and shallower wells. Refurbished oil and gas wells may be used in demonstration-scale direct-use projects at a fraction of the cost of drilling the new wells required by an electrical power plant. Focusing on direct use in the near-term (1-3 years) will allow scientists and engineers to observe firsthand the behaviour of a producing geothermal pool without the risk of integrating with an electrical power plant. Knowledge gained through the development and operation of direct-use geothermal systems can then inform best practices for developing geothermal electrical power stations. The construction of pilot-scale geothermal power plants is an intermediate, i.e. 3-5 year, goal.

Currently no regulatory framework exists for geothermal energy development in Alberta. To enable project development of geothermal resources will require clear and concise policy and regulations.

This study provides significant support geothermal energy has an important role to play in Alberta's energy transition. In support of the conclusions and recommendations of this study, the University of Alberta is planning a major investment in expanding our geothermal energy research activities throughout western Canada. Our goal is to see operating direct use geothermal systems in Alberta within 1-3 years, a pilot scale electrical power plant brought online in 3-5 years and a mature industry developing by 2030, providing clean, baseload load heat and power to Albertans.

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Appendix A1: Drilling Cost Statement

Dr. Jonathan Banks
4-02 ESB
University of Alberta
Edmonton, AB
T6G 2E3

Re: Geothermal Well Drilling Cost Estimates

Dr. Banks,

As per our recent conversations, we're forwarding along some preliminary estimates on drilling costs we've been able to develop in conjunction with some of Terrapin's industry partners including Cougar Drilling and PTAC.

A typical geothermal well at a depth of 3,000m with conventional casing design (20"-13-3/8"-9-5/8"-7") is around $5,000,000 - $6,000,000. Not knowing the pressure or temperature, one can assume that the cost could be minimum of around $2,000+ per meter of the well. It goes without saying that there would be variations in this number depending on the current level of drilling activity, the location of the drilling activity and the complexity of the operation, but these numbers should provide reasonable starting points for your models.

Kind regards,

Sean Collins
President
Terrapin Geothermics

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Appendix A2: Class C cost estimate for a 2.5 MWe Organic Rankine Cycle geothermal power plant

Design Build - Class C Estimate

2.5MW Geothermal Power Generation Plant

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March 3rd, 2017

Attn: Jonathan Banks

CES Power & Control is pleased to provide the following Class C estimate to cover the Design Build of the 2.5MW geothermal power generation plant project.

The following breakdown illustrate a brief description of all task of this project and associate cost including equipment, material and labor.

If any additional information is necessary to evaluate this proposal, feel free to contact any of our team representative outline below.

TASK DESCRIPTION	**Total**
Project Management	$349,200.00
Engineering Design	$852,000.00
Site Construction Equipment	$21,600.00
Civil and Site Preparation	$444,000.00
Concrete	$21,600.00
Structural Steel	$60,000.00
Buildings	$46,800.00
ORC Equipment	$6,155,600.00
Piping	$784,800.00
Electrical	$2,619,350.80
Instrumentation	$420,000.00
Startup / Commissioning	$109,200.00
Special / Other	$118,800.00
Grand Total:	**$12,002,950.80**

***Note. GST is not included in the price**

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Bid clarification

- Performance or labor and material bond are not included in this proposal.
- Price does not include submersible pump system.
- Price include brine reinjection pump system.
- Price is based on 5 day work week (Monday – Friday), 8 hr. /day. No extra overtime is accounted for.
- Pricing is based on supplied preliminary information.
- Material pricing is subject to commodity price increase.

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Project organization list

- Stephan Humphreys – Senior Estimating Manager
- Ryan Tuff – Lead Project Engineer
- Katrina Wilson – Project Engineer
- Charles L'Ecuyer – President / CEO

If any questions or concerns on this proposal, please feel free to contact one of our team representative.

Regards,

Stephan Humphreys
Lead Estimator / Project Manager

s.humphreys@CESwest.ca

Appendix B1: Report on geothermal fueled tomato greenhouses

Introduction

This report has been developed for Dr. Jonathan Banks, Research Associate at the University of Alberta.
The purpose of this report is to test the feasibility of merging direct heat geothermal technology with commercial scale greenhouses in Alberta.

Research

Based on research conducted by the Alberta Government department of Agriculture and Forestry, (Laate, "*The Economics of Production and Marketing of Greenhouse Crops in Alberta*", 2013), and through collaboration with local greenhouse and energy experts, this report will go through the current energy demands that tomato greenhouses require in 2017. Once energy demands have been established, this report will outline potential energy savings that can be realized through a geothermal heating system.

From Government of Alberta findings, there was a total of 127,500 square meters of commercial greenhouses operating in the province of Alberta in 2010 (Figure 1, Laate, 2013). These greenhouses account for only 5.5% of the total greenhouses in Canada as of 2010. Approximately 41% of the total greenhouses in Canada operate in the Medicine Hat area, the second most populated greenhouse location is Red Deer at 16%. The locations of these greenhouses will play a substantial part in determining the feasibility of a geothermal direct heat system (Laate, 2013).

Survey Region	Industry Area (m^2)	Size of Operation (Sq. M.)				Number of Greenhouses by Region
		< 1,000	1,000 to 2,000	2,001 to 4,000	>4,000	
Fort McMurray	2,788	0	0	2	0	2
Grande Prairie	87,361	11	6	0	11	28
Whitecourt	25,619	4	11	11	2	28
Edmonton	124,535	17	17	4	9	47
Bonnyville	88,290	6	6	4	4	21
Lloydminster	26,022	9	4	6	0	19
Red Deer	189,550	19	13	9	24	64
Calgary	144,052	9	6	9	6	30
Medicine Hat	492,565	2	0	15	58	75
Lethbridge	32,528	2	2	4	4	13
Total Operations	**1,213,311**	**79**	**66**	**64**	**118**	**328**
Percent of Operations	**-**	**24**	**20**	**20**	**36**	**100**

Source: A Profile of the Greenhouse Industry in Alberta in 2010

Figure 1: Number of Greenhouse Operations by Size and Regions in Alberta, 2010 (Laate, 2013)

As of 2010, approximately 79% of all greenhouses in Alberta were heated with natural gas furnaces (Figure 2, Alberta Agriculture and Forestry, 2013). Out of the 328 greenhouses that reported, only 2% used a renewable resource, bio fuel (Figure 2, Alberta Agriculture and Forestry, 2013).

Systems	Responses	Percent of Responses
Natural Gas Furnace	300	79
Hot Water	131	30
Steam	17	4
In-floor heating	19	4
Propane Furnace	17	4
Soil Heating	19	4
Electric	9	2
Stove Pipe Heater	17	4
Coal Deckker	47	12
Bio-therm	2	1

Source: Profile of the Greenhouse Industry in Alberta, 2010 **N = 328**

Figure 2: Type of Heating system Used in Greenhouses, 2010 (Laate, 2013)

	Fuel Type					
Region	Natural Gas	Coal	Wood	Oil/Propane	Electric	Total by Region
Fort McMurray	0	2	0	2	0	4
Grande Prairie	26	2	4	4	4	41
Whitecourt	28	4	2	0	0	34
Edmonton	39	11	0	2	0	51
Bonnyville	17	0	2	4	2	26
Lloydminster	19	0	0	0	0	19
Red Deer	56	13	0	2	2	73
Calgary	30	4	0	2	0	36
Medicine Hat	73	9	0	0	0	81
Lethbridge	13	2	0	0	0	15
TOTAL	300	47	9	17	9	382
Percent of Growers	**79**	**12**	**2**	**4**	**2**	**100**

Source: Profile of the Greenhouse Industry in Alberta, 2010 **N = 328**

Figure 3: Type of Fuel used in Greenhouse Operations in Alberta, 2010 (Laate, 2013)

As per 2013, the average commercial tomato producing greenhouses used a total of $12.73 per square meter for heating. (Laate, 2013) Based on a total of 196,859 square meters of tomato greenhouses in Alberta in 2010, the average cost for heating these buildings was $2,506,015.07 per year.

Extrapolating the average cost of natural gas in Alberta from 2013 (Alberta Energy, http://www.energy.alberta.ca/NaturalGas/1322.asp) to present and analyzing this with the average cost of heating a greenhouse in Alberta, it has been determined that the average greenhouse needs approximately 4.5 GJ of natural gas per sq. m. per year. The price of natural gas since 2013 has been very volatile, seeing swings of over 100% from one year to the next, or in the case of a small 1 hectare greenhouse, over $70,000 in variable cost fluctuation on heating.
Based on Government of Alberta findings (Laate, 2013), the average commercial tomato greenhouse generates a revenue of approximately $107.88 per sq. m./year and has a production cost of $94.54 per sq. m./year. This leaves a margin of $13.34 per sq. m./year. Of the operating cost, heating costs contribute up to 13% of the total. Any increases to the price of natural gas can quickly turn the economics of a greenhouse into the red.

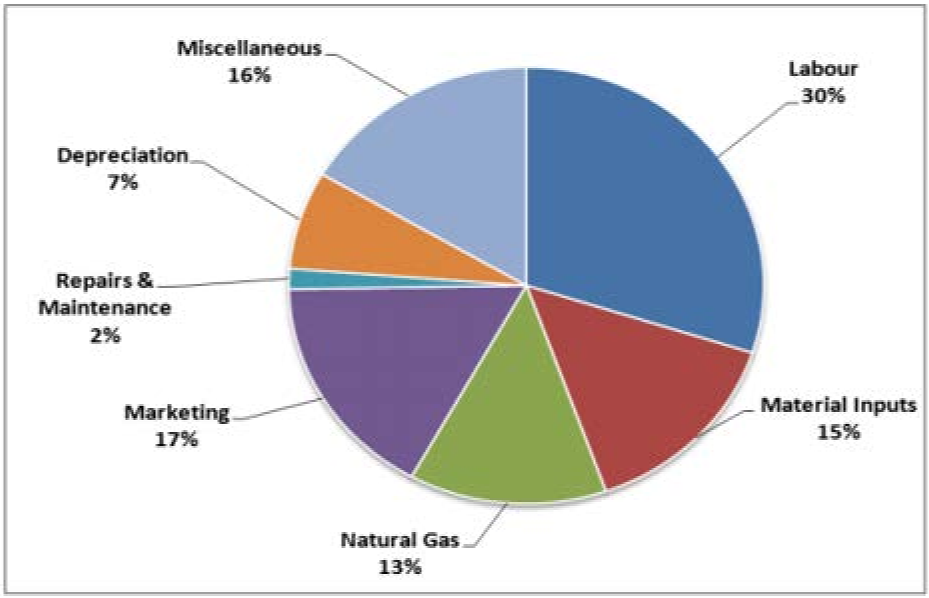

Figure 4: Breakdown of Greenhouse Tomato Production Costs in Alberta, 2011 (Laate, 2013)

Using the previous information, along with the gas prices over the last 4 years and present/future carbon tax, the following graph (Figure 5) outlines the average cost to heat a 1 hectare greenhouse in Alberta. The average greenhouse in Alberta will also incur costs associate with heating equipment at approximately $38.89 per sq. m.

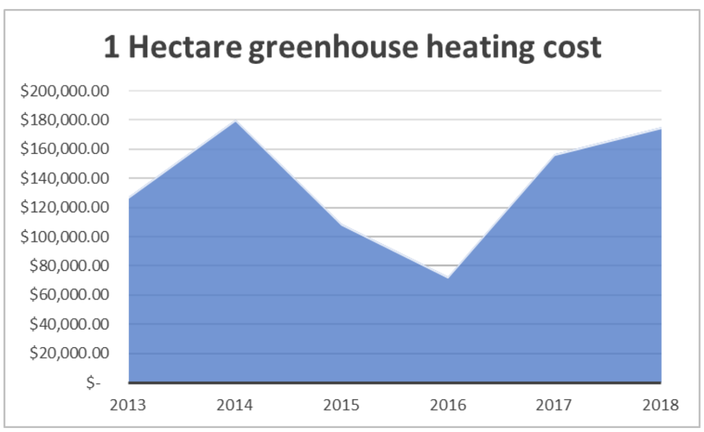

Figure 5: Average Cost to Heat a 1 Hectare Greenhouse in Alberta

The agriculture industry is not greatly affected by the Alberta carbon tax implemented in 2016. Agriculture is given up to an 80% tax exemption on carbon tax related to fuels. This 80% tax exemption is represented within this report and calculations (Figure 6).

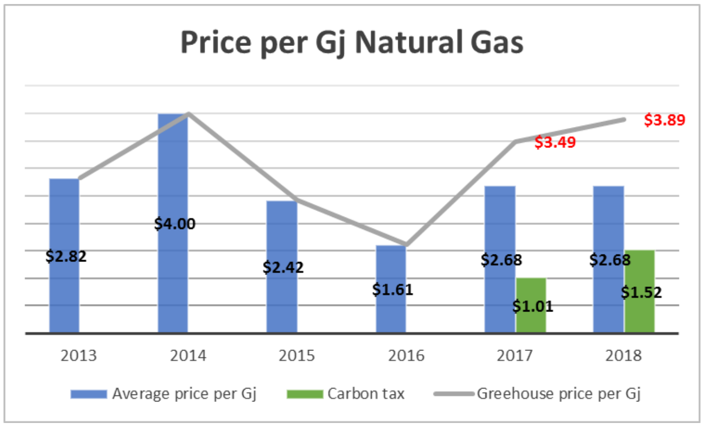

Figure 6: Price per GJ of Natural Gas with Relation to Alberta Carbon Tax Exemptions

Conclusion

From research into greenhouses in Alberta and market analysis of vegetables and energy, a renewable energy heating system could save the average 1 Hectare greenhouse over $180,000 per year in heating costs (Simard, M., and Neyes, R.).
With an average heating load of 4.5 GJ per sq. m. per year and a fixed cost of $38.89 per sq. m. for equipment, the economics for renewable energy heating are promising.
Using these numbers, a 1 hectare greenhouse requires a heating load of approximately 4,500 GJ and has a fixed heating equipment cost of $388,900. With a push to curb our agricultural energy requirements in Alberta through the Growing Forward 2 program, it seems that the agriculture carbon tax exemption may only be a bridge to help this industry make the jump to renewables and energy efficiency.

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Subject Matter Experts//Personal Communications:
Matthew Simard, Alternative Energy Technologist and Journeyman Electrician
Robert R. Neys, B. Sc and Master Gardener

Appendix B2: Statement regarding timber kiln opportunities

Dr. Jonathan Banks
4-02 ESB
University of Alberta
Edmonton, AB
T6G 2E3

Re: Timber Drying Economics and Industrial Interest

Dr. Banks,

Terrapin Geothermics has been exploring the preliminary economic viability of geothermal timber drying and the overall interest in this technology from the forest products industry. This work has shown strong initial interest, with several productive meetings taking place with the senior executives throughout Alberta's forest products industry.

Throughout these conversations, a few key findings emerged. The first was that the heating demand for timber kilns is quite significant with some facilities quoting a heating demand of over 11 million BTU's per hour. This quote was given for a facility with dimensions of 24' x 48' x 84', creating a total kiln air volume of 96,768 cubic feet. A second theme that emerged was the sense that affordable, reliable, "green" heat could play a role as a significant variable for industry partners contemplating future builds. For kilns that are using natural gas combustion for heating, there also appears to be a viable case for retrofitting these facilities for geothermal heating, particularly when modeling the impact $30-$50/tonne carbon pricing will have on natural gas costs in the future. It is worth nothing that facilities that are currently producing their input heat via hog fuel would demonstrate poor economics for retrofit use as their current input fuel costs are very low.

Based on our conversations with industry, our understanding of the technical inputs required for timber drying and the information provided by your Deep Dive Analysis, we are cautiously optimistic that a market exists to demonstrate geothermal timber drying in Alberta. This also presents a unique investment attraction pathway for municipalities looking to specifically attract forest product manufactures to their region.

Kind regards,

Sean Collins
President
Terrapin Geothermics

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Appendix C1: Summary of Organic Rankine Cycle process flow modelimg
(full model contained in separate .xlsx file)

The Organic Rankine Cycle (ORC) operates on the same principle as a steam-powered turbine generator power plant, but instead of water it uses a refrigerant which boils at a lower temperature. This lower boiling point allows for lower temperature heat sources to be utilized. The common refrigerant R134a was selected as the working fluid due to its ideal thermodynamic properties together with considerations for health, safety, environmental impact, and cost.

In this analysis the ORC converts geothermal energy contained in brine into electrical energy. The inlet brine temperatures considered are 120°C or 140°C. The brine is considered to be exiting the ground at flow rates of 30kg/s or 50kg/s. Three different cases were evaluated for each temperature and flow rate: Rated (winter ambient air temperature of -20°C), Operating (typical average ambient air temperature of 1.7°C), and Nominal (summer ambient air temperature of 20°C). The net power production and the overall efficiency of the plant was calculated for each of these cases.

The ORC pressurizes R134a and then boils it in heat exchangers before sending the vapour to a turbine which reduces the pressure and creates power to drive an electrical generator. The maximum pressure, (P_{max}) and minimum pressure (P_{min}) the turbine operates between is dependent on the type of working fluid and ambient temperature, as well as considerations of material strength and cost. Iterations with different P_{max} and P_{min} were done to ensure maximum energy conversion efficiency with reasonable equipment costs. Maximum efficiencies were obtained by setting P_{max} = 2.5MPa for all cases, while P_{min} was determined to be 0.2MPa, 0.45MPa, and 0.8MPa for the Rated, Operating, and Nominal cases, respectively.

The vapour from the turbine must be condensed back into a liquid in order to be pumped back up to the boiler pressure, thereby completing the cycle. For the condensing process air cooled heat exchangers (ACHEs) were used. ACHEs use fans to pass ambient air across tubes wherein the R134a is condensed. ACHEs are cost effective when the ambient temperature is moderate or cool and preferred when water consumption should be minimized.

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It is possible to produce up to 1.8 MW of power to export to the grid with this plant design, which assumes conservative equipment performance. The overall efficiency ranges from a low of ~2% in the middle of a hot summer day and a high of ~13% on a very cold day in winter. The efficiency changes so drastically with the outside temperature because of how much easier it is to condense the R134a when it is cold outside. Condensing at a lower temperature reduces the backpressure on the turbine which increases its performance, resulting in more electricity generated. Condensing on a hot day also requires considerably more fan power by moving a larger volume of air to remove the waste heat from the ORC cycle.

The following equations characterize the plant performance:

$$Power\ Production = Generator\ Output - Pumping\ Power - Fan\ Power - \ Parasitic\ Loads$$

$$Overall\ Efficiency\ = \frac{Power\ Production}{Heat\ Transfered\ into\ the\ ORC\ from\ the\ Brine}$$

Appendix C2: Optimization study for Organic Rankine Cycle engines in geothermal systems

Deep Dive Analysis: Binary Power Plant Model for Prospective Geothermal Wells

Casey Lavigne

Iceland School of Energy
Reykjavik University

March 6, 2017

Abstract

A basic model was created in EES for a prospective geothermal binary power plant. Various working fluids were evaluated for efficiency in an Organic Rankine Cycle under the constraints of geothermal exit temperature and saturated vapour at the turbine inlet. The temperature and pressure of the first reservoir model was 135°C and 45 MPa respectively. At a geothermal exit temperature of 95°C, the highest efficiency was determined to be 11.4%, leading to a specific net power of 16.5 kW/(kg/s). The lower geothermal exit temperature of 80°C led to an efficiency of 9.9% with a corresponding net power output of 22.7 kW/(kg/s).

A second well with reservoir conditions of 105°C and 25 MPa was also modelled. The highest efficiency found for an exit temperature of 85°C was calculated to be 9.1%, yielding a specific net power output of 5.6 kW/(kg/s). A lower geothermal exit temperature of 70°C resulted in a cycle efficiency of 6.7% and net power output of 9.8 kW/(kg/s).

Literature review yielded a plant cost estimate of $2.93 MUSD based on an average of specific investment costs. Drilling costs have a potential to make up an additional 30-100% investment depending on the knowledge of the field.

Further analysis is recommended, including comprehensive cooling design and superheating allowance, to potentially increase the efficiency of the modelled ORC.

---

1. Introduction

A deep-dive analysis was performed by the University of Alberta in partnership with Alberta Innovates and multiple municipalities around Alberta to assess the potential for geothermal exploitation of reservoirs near those municipalities. The researchers mapped the lithological structures at various locations, constructed preliminary reservoir models, and estimated total reservoir energy storage.

As a complement to this analysis, basic power plant modelling was performed to estimate potential steady state electricity production from a prospective geothermal binary system. Using two different well conditions, cycle efficiency and corresponding power output was determined for an organic rankine cycle (ORC) using various working fluids.

2. Methodology

The binary power plant cycle was modelled using Engineering Equation Solver (EES). EES is a program that can solve large systems of non-linear algebraic and differential equations. Its use is amplified by its extensive library of thermodynamic fluid properties.

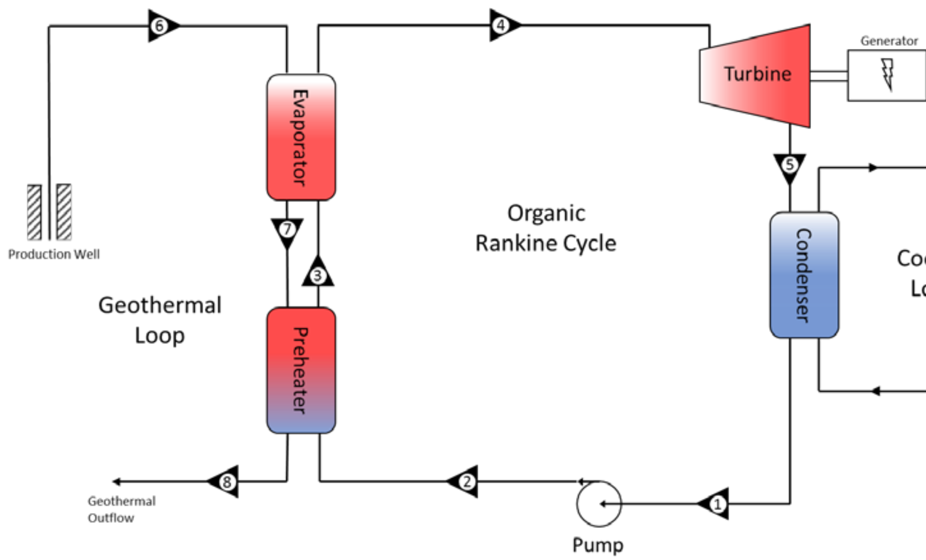

Figure A. Schematic of geothermal binary system used for modelling

In this analysis, EES was used to set up a system of thermodynamic equations to describe the binary power plant model and subsequently solve for those thermodynamic states which optimized the heat transfer from the geothermal fluid to the working fluid in the ORC. See Figure 1 for a schematic of the cycle as modelling in EES.

2.1. Optimization

Due to the expedient nature of the analysis, heat exchanger design was not used to as a factor in the optimization. Instead, the energy input was calculated from the difference between reservoir temperature and conservative geothermal outflow temperatures, with the implication that different-sized heat exchangers would be used for each outflow temperature. The energy transfer to the working fluid was controlled by the specification of a pinch point. The pinch point of a heat exchanger is a measure of its efficiency and is the smallest temperature difference between the two fluids that can be achieved at any point in the heat exchanger.

The output of the evaporator was restricted to saturated vapor state, i.e. no superheating was considered. With these constraints, the model was then optimized for efficiency by varying evaporator pressure while allowing the model to adjust the binary mass flow rate accordingly. For most working fluids, the optimization arrived at the maximum pressure allowed by the constraints of the model, namely the pinch point and saturated vapour specifications.

3. Assumptions

3.1. Geothermal Fluid

The output from two wells, representing two different reservoirs, was to be modelled. As specified by the project lead, the temperature and pressure conditions of the two reservoirs were 135°C and 45 MPa (450 bar) for Well 1 and 105°C and 25 MPa (250 bar) for Well 2. The input pressure for Well 1 was decreased to 400 bar to account for likely heat exchanger pressure limitations. A drop in pressure due to piping friction would be very low relative to the reservoir pressures and would have little effect on the specific heat capacity, therefore, no piping pressure losses were considered.

3.2. Working Fluid Selection

Several working fluids, common in binary use, were evaluated in the models. Aside from R134a, all fluids considered are retrograde, or “dry”, fluids that have a positive-sloping vapour saturation curve (DiPippo, 2012). Cycles that utilize dry fluids are in no danger of condensation during the expansion through the turbine, which can lead to turbine failure and/or additional maintenance. The fluids used in this model are n-butane, isobutane, n-pentane, isopentane, toluene, and R134a.

3.3. Condenser

There are two general categories of condensers, defined by the medium used for cooling. Water-cooled systems can be once-through, meaning that the water gains heat from the working fluid through a heat exchanger and then exits the system, or they can be set up as a closed loop wherein the exit water is cooled in a cooling tower and then reenters the heat exchanger. Closed-loop water-cooled systems and air-cooled systems both require fan-driven cooling towers, increasing the parasitic load on the system and decreasing the cycle efficiency (Mendrinos, Kontoleontos, & Karytsas, 2006). The decision between cooling systems is largely determined by regional environmental conditions, such as average and seasonal ambient air temperatures, humidity, and availability of water supply.

Due to region and relative small size of plant, a once-through water-cooled system is implied for this model. A conservative condenser temperature leads to a negligible cooling water pumping power for a basic model such as this.

3.4. Preheater and Evaporator

The initial state of the ORC is saturated liquid from the condenser. The saturated liquid is then pumped to pressure equivalent to that the of evaporator and sent through the preheater and evaporator to exit as a fully saturated vapour (quality = 1). There is potential for a higher cycle efficiency by lowering the evaporator pressure and adding a superheater, however, this was not considered for this model (DiPippo, 2012).

Efficiency of the preheater is specified by a pinch point temperature, typically in the range of 3-10°C (Marcuccilli & Thiolet, 2010). As a reasonable compromise between prospective exchanger efficiency and corresponding cost, a pinch point temperature of 5°C is used for this analysis.

Many binary systems have a minimum geothermal exit temperature of 60°C or higher to avoid silica deposition. Silica content is expected to of negligible concentration in the water of the model reservoirs, therefore, there was no geochemically-imposed limit on the heat transfer from the geothermal water.

3.5. Efficiencies

Typical values used in literature are used for the efficiencies of the ORC pump, motor, turbine, and generator. A value of 95% is used for the efficiency of both the motor and the generator (Mendrinos, Kontoleontos, & Karytsas, 2006). Pump efficiency was defined as 80% as per Frick et al. (2015) and 85% was used for the turbine efficiency as per Dickson & Fanell (2003).

4. Results

4.1. Well 1

Model inputs of Well 1 were 135°C and 400 bar. The model was run at various evaporator pressures for each working fluid for geothermal exit temperatures of 80°C and 95°C.

4.1.1. Cycle Efficiency

The hydrocarbon fluids performed similarly for both geothermal exit temperatures. The highest efficiency was found at the highest allowable evaporator pressure, considering a minimum pinch point of 5°C, for all fluids except R134a which found a maximum efficiency at an intermediate pressure. The resultant cycle efficiency at various evaporator pressures is shown in Figure 2 and Figure 3 for both exit temperatures.

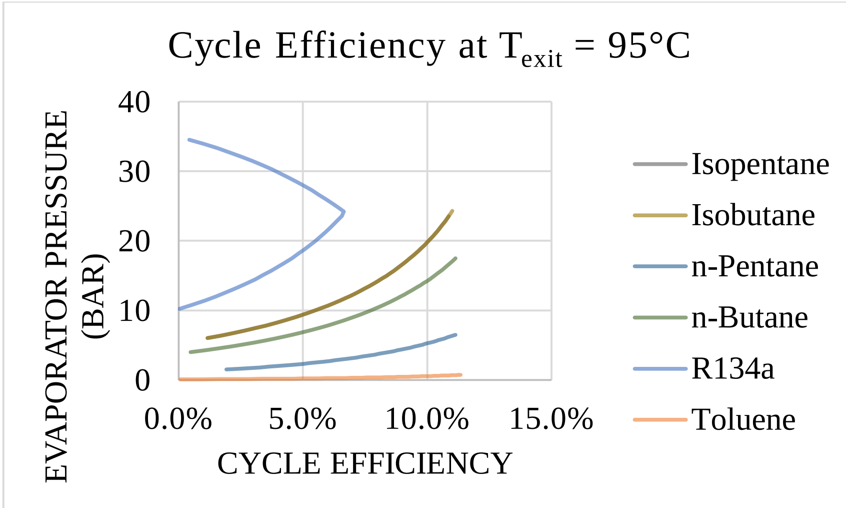

Figure B. Efficiencies of working fluids at different evaporator pressures for exit temp of 95C

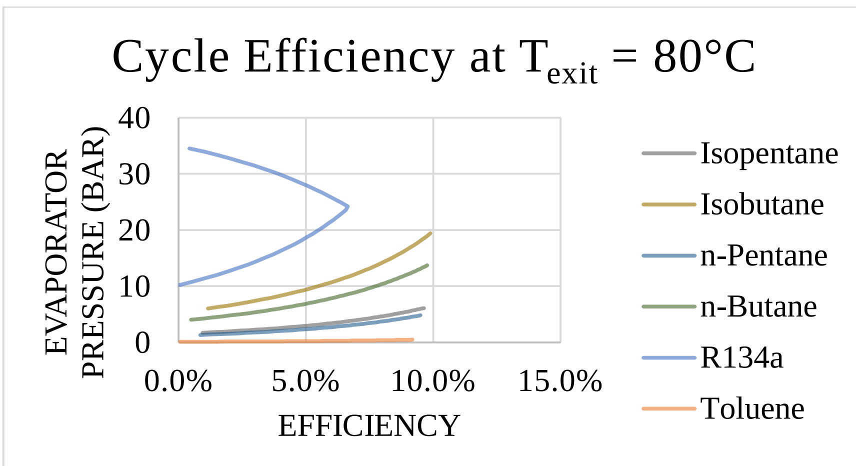

Figure C. Efficiencies of working fluids at different evaporator pressures for exit temp of 80C

Due to the fact that no superheating is considered in the model, the cycle efficiency decreases as exit temperature decreases. As shown in Figure 4, the highest efficiency shown was 11.4% for exit temperature of 95°C and 9.9% at an 80°C exit temperature.

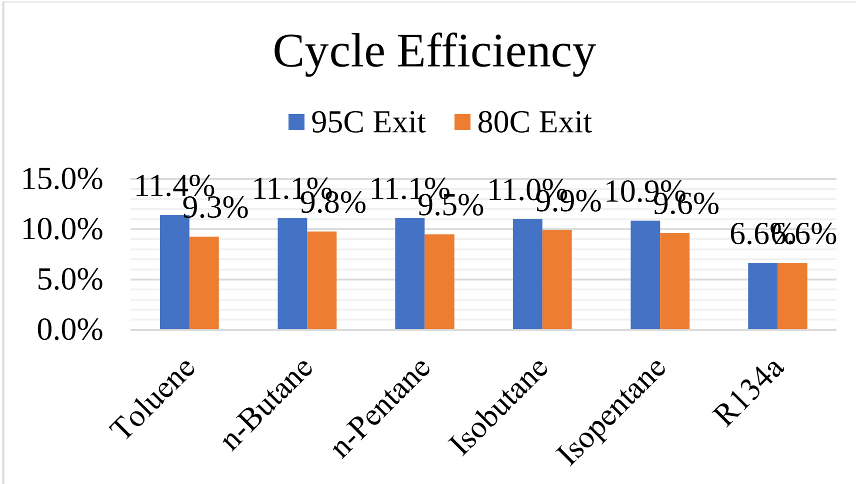

Figure D. Cycle efficiencies for all working fluids at both exits temperatures for Well 1

4.1.2. Power

Using the energy input from the geothermal fluid at each exit temperature, a net power output per unit mass flow rate can be calculated for the maximum efficiency of each working fluid. Figure 5 shows the net power output of the most efficient working fluid for a range of geothermal mass flow rates. The most efficient working fluids can supply 1 MW of power at low geothermal mass flow rates and in excess of 2.2 MW at 100 kg/s.

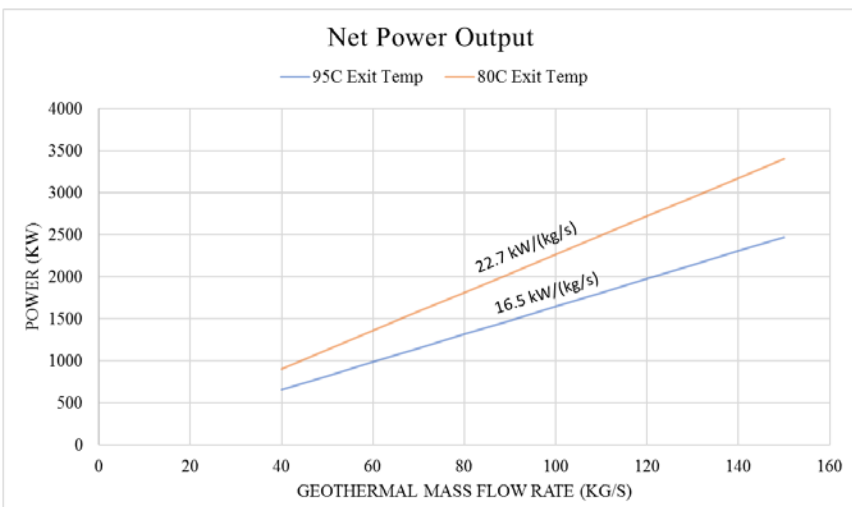

Figure E. Power output of binary model for a range of geothermal mass flow rates

4.2. Well 2

Model inputs of Well 1 were 105°C and 250 bar. The model was run at various evaporator pressures for each working fluid for geothermal exit temperatures of 70°C and 85°C.

4.2.1. Cycle Efficiency

The hydrocarbon fluids again performed similarly for both geothermal exit temperatures. The highest efficiency was found at the highest allowable evaporator pressure, considering a minimum pinch point of 5°C, for all fluids except R134a which experienced a decrease in efficiency just before its maximum evaporator pressure. The resultant cycle efficiency at various evaporator pressures is shown in Figure 6 and Figure 7 for both exit temperatures.

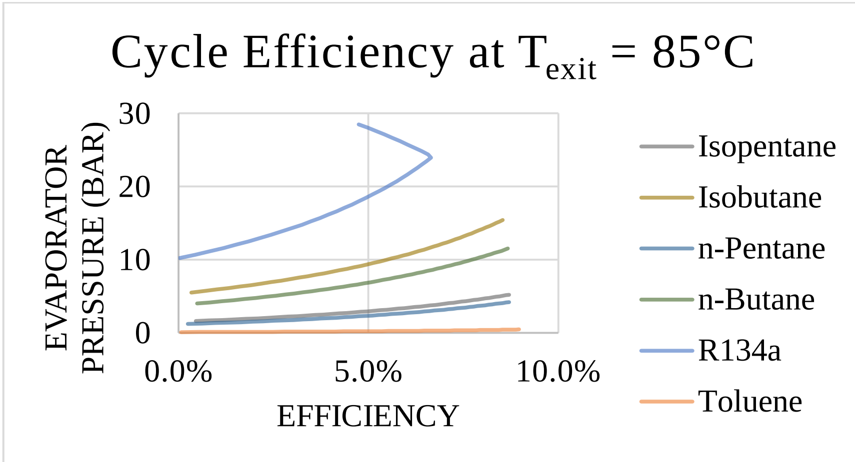

Figure F. Efficiencies of working fluids at different evaporator pressures for exit temp of 85C for Well 2

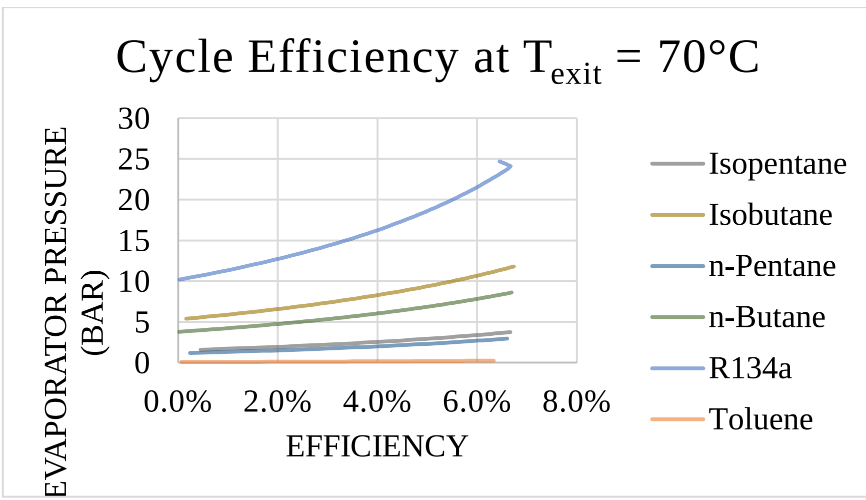

Figure G. Efficiencies of working fluids at different evaporator pressures for exit temp of 70C for Well 2

Due to the fact that no superheating is considered in the model, the cycle efficiency decreases as exit temperature decreases. As shown in Figure 8, the highest efficiency shown was 9.1% for exit temperature of 85°C and 6.7% at a 70°C exit temperature.

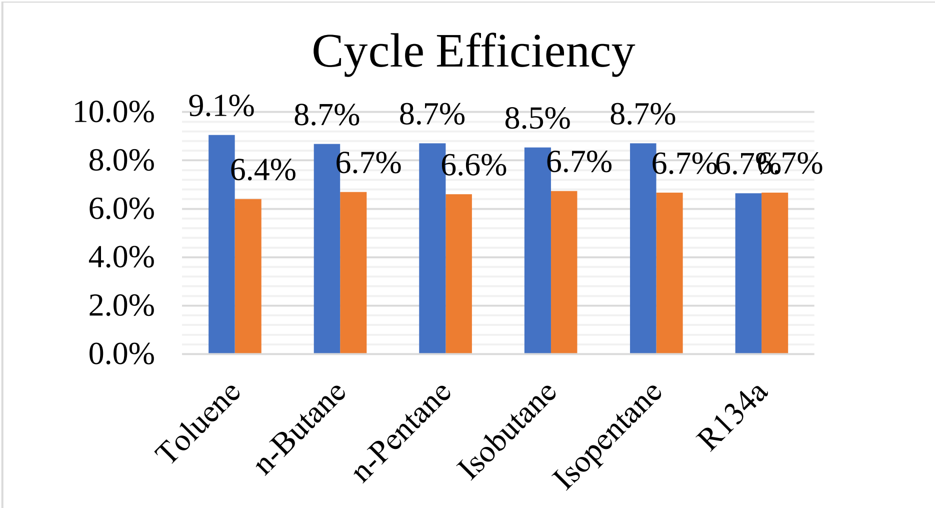

Figure H. Cycle efficiences for all working fluids at both exits temperatures for Well 2

4.2.2. Power

Using the energy input from the geothermal fluid at each exit temperature, a net power output out per unit mass flow rate can be calculated for the maximum efficiency of each working fluid. Figure 9 shows the net power output of the most efficient working fluid for a range of geothermal mass flow rates. The most efficient working fluids can supply 1 MW of power at a geothermal mass flow rate of 100 kg/s with a 70°C exit temperature.

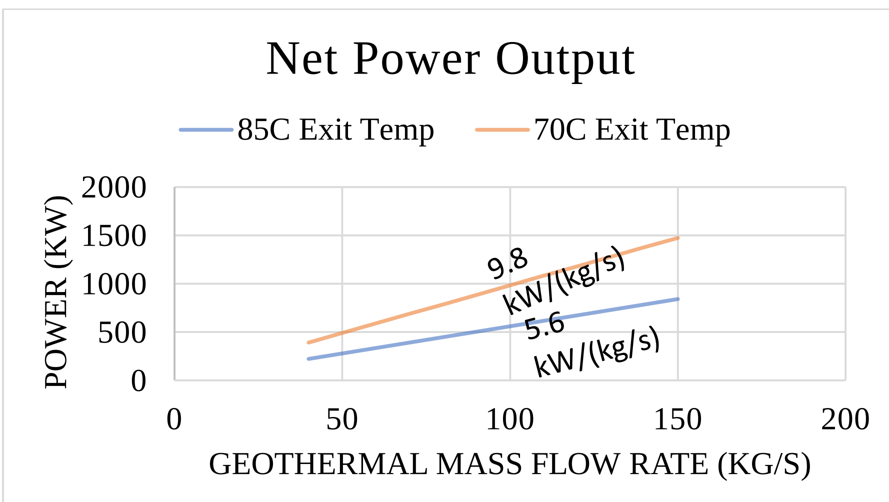

Figure I. Power output of binary model for a range of geothermal mass flow rates

5. Further Optimization

The model developed for the deep-dive analysis was basic in nature in accordance with the current reservoir output estimates. However, more detail can be added to the model to derive less conservative and potentially more accurate results. These additional optimizations:

- Superheating – A superheater can be modelled to potentially increase the net power output at lower evaporator pressures and lower working fluid mass flow rates.

- Condenser Design – The cooling system can be further refined in both choice of system and design of heat exchanger to potentially lower the condenser temperature and allow a larger pressure drop through the turbine, resulting in a higher power output.

- Supercritical Operation – Some binary systems have been able to achieve more efficient heat transfer by operating in the supercritical zone of the working fluid (Marcuccilli & Thiolet, 2010).

- Advanced Binary Cycles – The binary cycle efficiency could be increased by modifying the cycle simply to include a recuperator, or further complexity could be added by introducing a high and low pressure combined cycle (DiPippo, 2012).

6. Cost

A general literature review was completed to estimate the specific cost of a binary system. Some ranges have a cost spread up to 100% (see Table 1 for summary), with an average value of $2925 USD/kW. Therefore, the estimate for a 1 MW binary plant would require an approximate investment of $2.93 MUSD.

Table A. Specific binary system plant costs from literature

Specific Plant Cost (USD/kW)	Source
2000 - 4000	Roos et al. (2013)
2000 - 3750	Jung et al. (2014)
3750 (3000 EUR)	Quoilin et al. (2013)

Note this encompasses plant cost only, not drilling costs which are a significant portion of the investment costs involved in developing a geothermal field. Table 2 provides drilling costs in known and unknown fields as described by one report. As expected, the cost and standard deviation is higher for drilling in unknown fields due to a lower success rate.

Table B. Expected specific cost of drilling for a geothermal power plant (Stefansson, 2002)

Drilling Cost	Expectation Value (USD/kW)	Range with standard deviation (USD/kW)
Known Field	1170	1130 - 1949
Unknown Field	1805	1402 - 3119

7. Conclusion

This report detailed the findings of the optimization of a geothermal binary power plant utilizing an ORC to produce electric power. Several working fluids were used in the EES model to determine a maximum efficiency for a given geothermal fluid exit temperature. It was determined that the two reservoir conditions could conservatively produce 1-3 MW in an ORC, and likely more, depending on number of wells and well flow rates. Also, the estimated power outputs would likely increase with an optimization which allows for superheating of the working fluid.

While the electric generation efficiencies are low relative to fossil-fueled power plants, it is of less concern as the fuel in geothermal project is free and renewable. Also, a binary power plant such as the one modelled can act as an enterprising cooling mechanism for a direct use heating system. The usage of the geothermal exit water (at temperatures between 70°C and 95°C) in downstream applications can greatly increase the efficiency of the overall system.

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