Alberta's Western Canada Sedimentary Basin's First Electrical Geothermal Project

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Keywords

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ABSTRACT

In Canada's western provinces, the Western Canada Sedimentary Basin (WCSB) is known to have warm to hot brines in large extractable volumes from permeable, hydrocarbon bearing units. In Alberta's north-western region the Municipal District of Greenview (MDGV) has been actively supporting preliminary resource investigations within its lands. These investigations have been to determine if there is an economically viable resource under the MDGV and, in particular, a new Heavy Industrial District (HID) planned for a large tract of land south of the city of Grande Prairie. The industrial park, referred to as the Tri-Municipal Industrial Park (TMIP), will utilize both electrical and thermal energy produced by the project. The research suggests that temperatures above 120°C are attainable at depths from 3,500 m and below. The target formations at these depths are under the Beaverhill Lake Group and are comprised of the Swan Hills, Granite Wash, Gilwood and the basement unconformity. Importantly, the targets are below the hydrocarbon and shale-rich Duvernay Formation. Only two wells within the TMIP have been drilled to basement and only a handful of wells are drilled below the Duvernay Formation. There is limited flow test data on the target formations but extrapolating from similar target formations elsewhere, it is anticipated that flow rates in 7-inch pipe will exceed 30 l/s. Fluid chemistry modelling of existing analytical data suggests that there will be no major issues with mixing of formation waters and injection into the Leduc Formation is a possibility.

1. Introduction

The Municipal District of Greenview (MDGV), located in northwestern Alberta, Canada, has a significant energy resource in the form of heat within the oil and gas reservoirs currently being tapped by wells drilled within the MDGV for hydrocarbon production. There have been more than 60,000 wells drilled within the MDGV since the 1950s. Many of these wells tap deep aquifers (formations that produce fluids such as water and hydrocarbons) of warm water in addition to oil and gas resources. This warm water is a source of thermal energy that can be used for electrical generation and direct use applications, particularly given the large temperature variation between the resource and the mean annual temperature (ΔT). The low mean annual temperature means a significant number of heating degree days, so even a low temperature resource has sufficient energy content to offset the heating needs of citizens and industry.

The project was funded by the MDGV in response to a request for proposals from Canada's Federal Department of Natural Resources (NRCan). The funding was through the "Emerging Renewable Energy Program" (ERPP) which sought to provide support to projects with the potential to produce 8MWe. In 2018, a project in Saskatchewan, proposed by DEEP Energy Inc., was funded through the program and DEEP's first well was drilled in December 2018.

Underlying the MDGV are hot sedimentary aquifers (HSAs) that form part of the Western Canada Sedimentary Basin (WCSB). These aquifers show promise for heat extraction using several different approaches. Given the large number of drilled oil and gas wells in the region, there is a possibility that co-produced fluids can be extracted and utilized in parallel with oil and gas production using the existing drilled infrastructure. However, the diameter of the well liners in oil and gas production zones (4 ½ or 5 ½ inches and sometimes 7 inches) do not provide sufficient mass flow for economic production of geothermal fluids.

In addition to the narrow well bore diameters, upper well casing sizes are often too narrow to accommodate the high capacity pumps needed for electrical generation from low temperature, gas-rich fluids (i.e. fluids below <170°C). Pumping the well diminishes the decompression cooling, but many of the wells represent older infrastructure. However, because there are so many wells, the use of abandoned, orphaned, or wells that have been in service for long periods of time, has been reviewed. These wells can potentially have wellbore integrity issues. Re-entering and reusing wells must be done with caution and appropriate well integrity testing carried out to ensure that the cement and casing integrity are adequate for the desired use. Re-entering wells for the purpose of flow testing and bottomhole temperature (BHT) measurements will be an important aspect of the exploration phase of this project.

Extensive analysis was undertaken to review the historic BHTs. It was found that older measurements suggested a much higher gradient than more modern wells. Despite the uncertainty of the BHTs, evidence strongly suggests that BHTs will exceed 120°C at 4000 m and flow rates in wide diameter wellbores could exceed 50 liters/sec (l/s), but are more likely to be 30 l/s. The project anticipates that production from large-diameter, purpose-drilled geothermal wells will exceed 1 MWe power generation with parallel MWth generation for direct use. Once reservoir conditions are better known following testing it will be possible to refine the development options and economics of the project.

It should be emphasized that any produced geothermal fluid can be used for either indirect utilization (to generate power), or direct utilization purposes (heating commercial-scale buildings, greenhouses, district heating, providing waters for spas and swimming pools, lumber drying, etc.). The ERPP development fund was established to promote the generation of electricity from renewable sources and did not take into account the energy potential from projects accessing thermal energy from HSAs. However, for the MDGV, the thermal energy potential is very important for their plan to offset greenhouse gas use in a new Heavy Industrial District (HID) south of the city of Grand Prairie. Formulated as the Tri-Municipal Industrial Partnership (TMIP) the Municipality plans on providing future tenants of the park with green electrical and thermal energy. It will take further testing and exploration to identify zones with sufficient brine flow and temperatures to produce electricity, but there are unquestionably sufficient resources within the TMIP area to serve as a stable, direct use energy source for many of the commercial and industrial applications planned for the area.

2. Tri-Municipal Industrial Partnership Heavy Industrial District

The MDGV chose to focus the geothermal development project on an under-development industrial park south of Grande Prairie. The Tri-Municipal Industrial Partnership (TMIP) Heavy Industrial District (HID) (Figure 1) is a partnership between the MDGV, the City of Grande Prairie and the County of Grande Prairie and will require significant electrical and thermal energy. The TMIP will focus on attracting specific heavy industrial users that directly benefit from co-location with a hydrocarbon source and infrastructure (road, pipeline, and rail). Tenants of the District will benefit from access to green electricity and thermal energy provided by the MDGV.

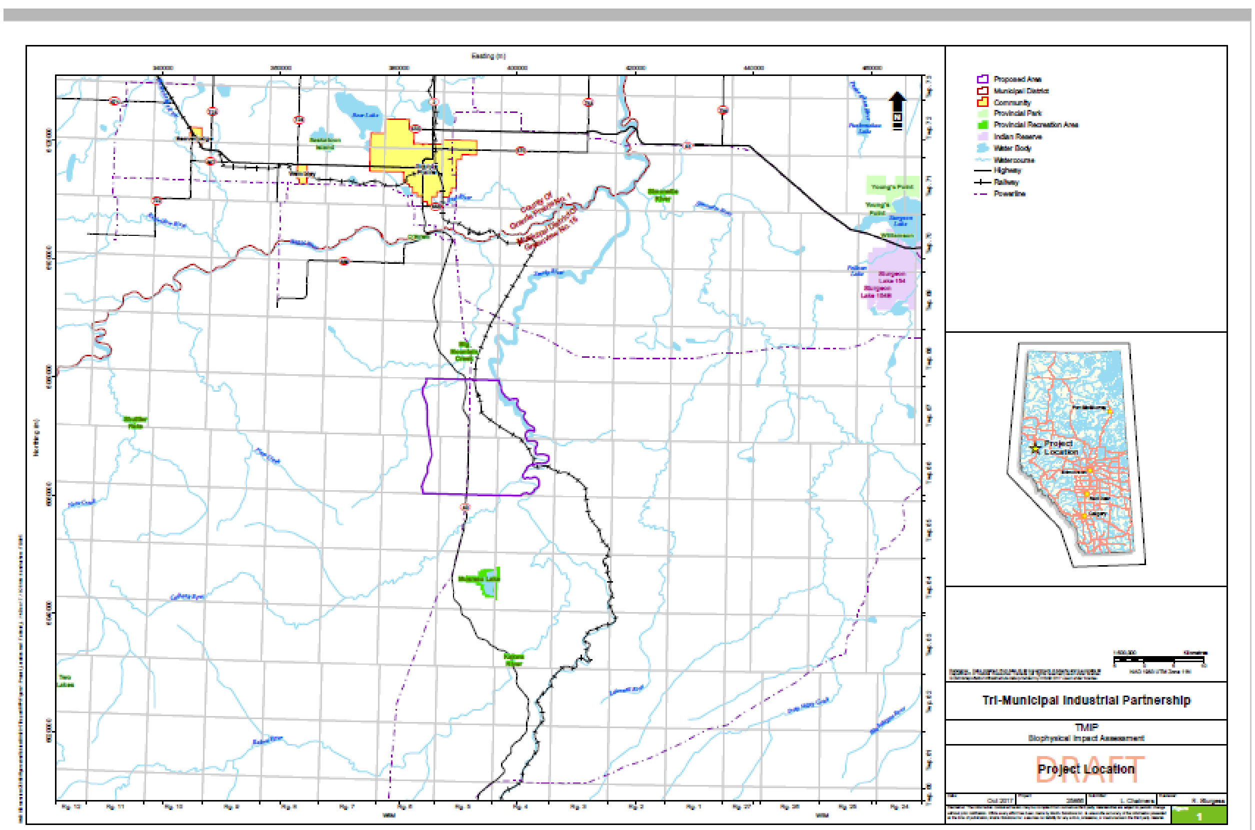

Figure 1: Regional Base Map of Tri-Municipal Industrial Partnership (purple outline) south of the City of Grand Prairie (yellow block) within the boundaries of the MDGV.

The MDGV is working with the Alberta Ministry of Environment and Parks (AEP) to create a 25-year plan to provide a land use, infrastructure, and policy framework that will attract future industrial activities to the plan area, thus reducing the risk of industrial sprawl. Additionally, the area is directly linked to the City of Grande Prairie, and thus to the City of Edmonton, accounting for part of the CANAMEX Trade Corridor (Canada-Mexico trade corridor) linking the region to international markets.

Near the TMIP District, there is a nearby development called Grovedale, the MDGV has made the statement that all future residential, commercial, industrial, and institutional new construction or renovations should incorporate systems for generating renewable energy, such as solar panels, geothermal heating (ground-based and deep, low temperature geothermal), or wind turbines (Grovedale Area Structure Plan 2018). They have also made the declaration that individual ground-based geothermal heating systems are encouraged for residential structures. For commercial, industrial, and institutional uses there should be a District Energy Sharing System that could be expanded to residential structures based on the outcomes of feasibility studies.

These publicly stated values for Grovedale made by the MDGV reflect their desire to create a more sustainable industrial park. Although the MD has not called the development an eco-industrial their aims are similar. By definition, an eco-industrial park (EIP) is an industrial park that aims to achieve sustainable development by cooperating with other businesses and the local community to reduce waste and pollution and share resources such as information, materials, water, energy, infrastructure, and natural resources. https://en.wikipedia.org/wiki/Eco-industrial_park. It is the sharing of green, sustainable, base-load (firm) electricity and thermal energy that is driving the MDGV to consider geothermal energy for both electrical and thermal applications within the district.

Early in 2018, the MDGV engaged Terrapin Geothermics to develop a proposal for electrical and thermal energy generation based on previous work done in the area of Fox Creek (Hickson et al., 2018). Coincidently, Canada’s federal government, through Natural Resources Canada (NRCan) announced a grant program entitled “Emerging Renewable Power Program” (ERPP). Under this program Canada’s federal government is providing up to $200 million dollars to expand the portfolio of commercially viable renewable energy sources available to provinces and territories as they work to reduce GHG emissions from their electricity sectors (NRCan 2018). The funding submission for the ERPP was completed in 2018 and updated in early 2019 in order to provide a substantive impetus for the planning of the TMIP district in terms of providing the site with green energy and a path to sustainability.

3. Energy Resource Assessment Parameters

3.1 Target strata

Subsurface data was extracted from datasets acquired from hydrocarbon drilling operations and tests of wells drilled within the TMIP, additional wells outside the study area, and previously written reports and documents. There are 3011 wells within the mapped area; 2051 of these wells are single-operation wells with unique data sets. Of these, there are 603 inactive and 1538 active wells (Figure 2). Active wells include wells where the latest reported status implies any type of operation from pumping and flowing to testing and drilling. Inactive wells include wells that are abandoned, closed, canceled, and/or junked. None of the wells discussed in this paper have been visited in the field.

To prioritize the research, geological and individual well fluid production, were reviewed using the pertinent existing geological and geothermal research studies. The most recent (other than Terrapin's own work) was conducted by the University of Alberta (Banks 2017). This work built on the detailed earlier studies of Gray et al. 2012, Weides et al. 2014 and others. These studies identified the Leduc, Swan Hills, Gilwood and Granite Wash formations (all Devonian age) as prospective geothermal resources underlying the MDGV. In addition to these aquifers, the unconformity between the overlying sedimentary sequence and the metamorphic basement rocks may be an important aquifer. In other areas it is reported as altered and permeable (R. Eccles, personal communication, October 2018).

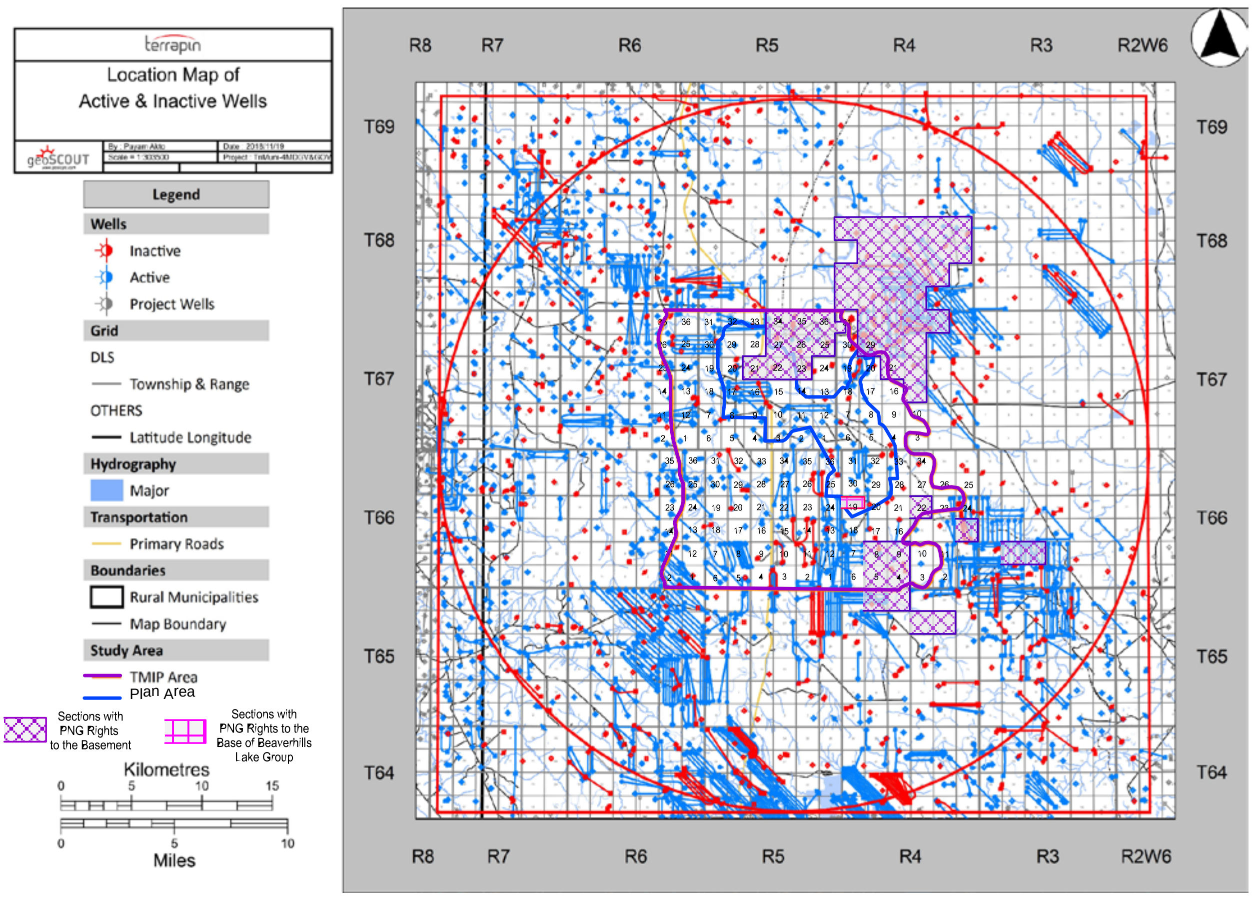

Figure 2: Tri-Municipal area divided into four quadrants (separated along the township and range boundaries). Wellheads and tracks are shown for the 1538 active wells (blue) and the 603 inactive wells (red). Details of the wells were obtained using GeoScout from publicly available wells data accessed through Alberta Energy data repository.)

These Devonian-aged subsurface formations are comprised of limestone, shale and various other types of sediments deposited between 419.2 and 358.2 million years ago. Various formations within the Devonian stratigraphic sequence were found to have characteristics that make them suitable for geothermal fluid production (cf. Banks 2017; Gray et al. 2012; Weides et al. 2014). These formations are also major oil and gas plays (Hickson et al. 2018a)

The TMIP is to the south of the Peace River Arch (Figures 3 and 4) a significant uplifted basement structure that influenced the deposition of sediments in the WCSB during the Devonian.

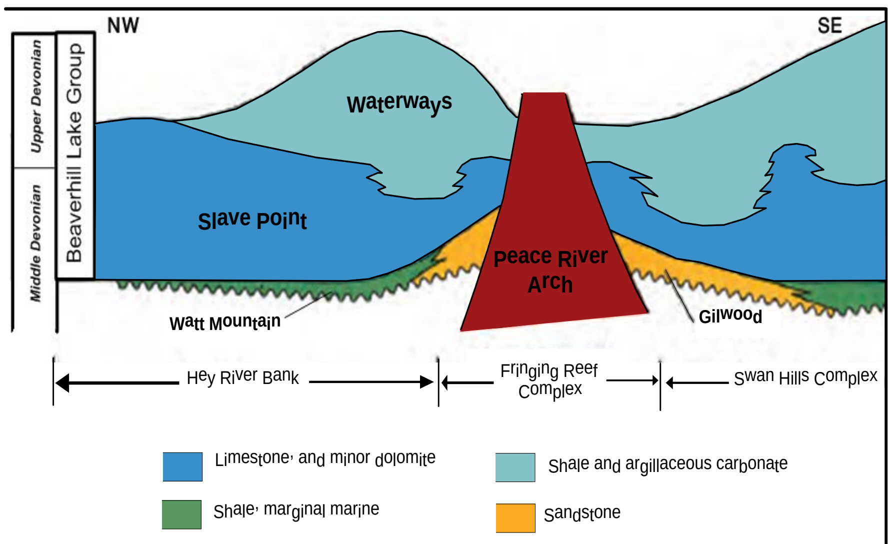

Figure 3: Schematic strata showing the location of the Peace River Arch and the overlying Devonian strata. The bedrock interface and the Watt Mountain and Gilwood formations are the prime targets for fluid production for geothermal purposes. The Duvernay is stratigraphically above the Beaverhill Group.

Devonian strata are also the source of an important hydrocarbon play in strata named the Duvernay Formation. The Duvernay Formation has a high hydrocarbon potential (up to 11% total organic carbon) and low water production. It is fracked to liberate the hydrocarbons and is currently one of the most commercially important oil and gas plays in Alberta.

For geothermal energy production, these younger hydrocarbon-rich formations (made up of shales and dense argillaceous limestones) do not flow geothermally significant quantities of water. In fact, they are noted as tight formations needing fracturing in order to flow the hydrocarbons. However, they overlie rocks of the Beaverhill Lake Group (Devonian-aged) (Figure 3). It is these underlying rocks that show potential for temperatures and water production sufficient to commercially produce electricity (Bank, J. 2017; Gray et al. 2012; Hickson et al. 2018a, b and c; Majorowicz and Grasby 2010; Weides and Majorowicz 2014; Weides et al. 2014).

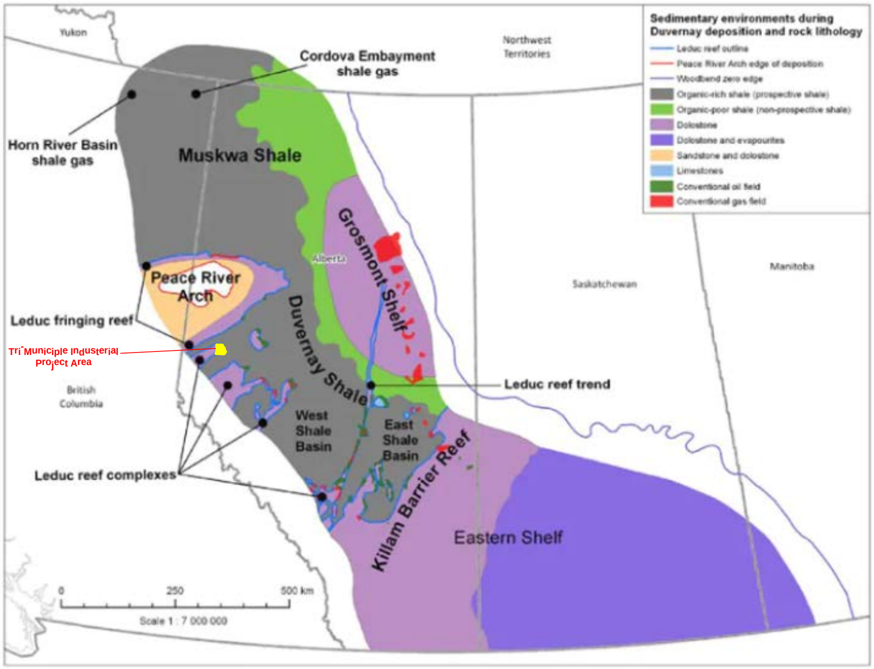

Figure 4: Lithological deposits of the Duvernay Formation overlie much of Alberta. In the area of the TMIP the deposits are tight, hydrocarbon-rich shale suitable for secondary recovery technology.

High water production is known in the region. An example is the Kaybob Field (to the southeast of the TMIP), where hydrocarbon production is focused on older Devonian-aged strata (Field et al. 1970).

Table 1: Characteristics of drilled wells in the TMIP area below the Duvernay Formation. (Susp = Suspended; Drild = drilled; Abnd = abandoned; Act WTR Disp=active water disposal well; preCamb=Precambrian; mtn=mountain; grn_wash=Granite Wash; bvrhl_lk=Beaverhill Lake; CNRL=Canadian Natural Resources Ltd.; Rsrcs=Resources; Enrg Srvcs=Energy Services)

Well ID	Well Status	TVD (m)	BH Temp. (°C)	Formation@ Depth	On Prod YYYY/MM/DD	Prod./Inject. Formation	Cum WTR Prod. (m3)	Cum WTR Inject. (m3)	Current Operator Name
100/10-08-067-05W6/00	Susp Gas	3766.1	234	Leduc	1970-06-22	Gething	3,045	-	CNRL
100/11-22-067-05W6/00	Drild& Abnd	3908.5	210	preCamb	-	-	-	-	BP Cda Enrg Grp ULC
100/10-25-067-05W6/00	Abnd Zone Gas	3525.9	164	Leduc	1965-11-01	Wabamun	0		CNRL
100/05-18-066-04W6/00	Abandoned	4164	114	Gilwood	-	-	-	-	Paramount Rsrcs Ltd
100/14-19-066-04W6/00	Act WTR Disp	4046	111	preCamb	2003-06-25	bvrhl_lk	4,049	194,929	Paramount Rsrcs Ltd
100/16-25-066-05W6/00	Cased	3988.8	106	Watt_mtn	-	-	-	-	Paramount Rsrcs Ltd
100/10-20-067-05W6/00	Abnd Zone	3639.3	101	Leduc	-	-	-	-	Suncor Enrg Inc(2)
100/09-20-066-04W6/00	Drild& Abnd	4043.8	-	grn_wash	-	-	-	-	Suncor Enrg Inc(2)
100/06-08-067-05W6/00	Act WTR Disp	3982.4	-	Leduc	-	Leduc	-	689,604	Secure Enrg Srvcs Inc
100/07-20-067-05W6/00	Act WTR Disp	3661.4	-	Leduc	-	Leduc	-	929,140	Secure Enrg Srvcs Inc

3.2 Bottomhole Temperatures

Bottomhole temperatures are taken in oil and gas wells when the wells are finished to their target formation (TD target or total depth). Like geothermal wells, oil and gas wells are drilled with drilling fluid ("mud") The use of drilling fluids cools the well. For oil and gas wells there little to no equilibration time before the BHT is measured. This means that at best, the BHT is a few degrees cooler than the actual formation temperature, or at worst may be many tens of degrees different. A number of scientists have worked on methodologies (cf. Deming 1989; Gray et al. 2012; Majorowicz and Grasby 2010; Weides and Majorowicz 2014; Weides et al. 2014) to determine the actual BHT in oil and gas field drilled wells. The resulting work points to inconsistencies in the temperature data, data gaps, and in some cases wrongly recorded temperatures, but in other cases tantalizingly consistent high temperatures over a broad area.

Table 2: Corrected bottomhole temperatures of wells in the Devonian strata within the TMIP area.

Formation @ TD	# of Wells	# of Wells with BHT	Temperature Range (°C)	Average T. (°C)	Depth Range (m)
Wabamun G.	24	10	70-196	112.1	3880.5-4179.4
Winterburn G.	3	1	70	70	3125-4416.1
Ireton F.	2	2	188-205	196.5	3304.9-4162.3
Leduc F.	11	4	101-234	179.2	3248.1-4564.1
Watt Mountain F.	4	1	106	106	3740.2-4388.6
Gilwood M.	3	1	114	114	3810.3-4164
Granite Wash F.	1	0	UKWN	UKWN	3739.6-4106.9

The most common method for correcting the BHTs measured in sedimentary aquifers is the Horner Correction. According to Peters and Nelson (2009), the standard deviation of Horner-corrected BHTs is ±8°C in shallow wells, while it can be up to 30°C in deep formations. In this study, a modification of the Horner Correction method was used by conservatively adding 4-8°C to the measured BHTs according to the depth. The BHTs were corrected by adding 4^{o}C for all depths shallower than 1 km, 5^{o}C for all depths between 1 km and 2 km, 6^{o}C for all depths between 2 km and 3 km, 7^{o}C for all depths between 3 km and 4 km, and finally, 8^{o}C for all depths 4 km and greater.

For plotting BHTs and creating the temperature gradient plots, the average thermal gradient of each measurement (BHT / (Depth in kilometer)) was used. Scattered BHTs were removed from the calculations based on 1049 wells. In total, 38 BHTs were removed from the data set and the results tabulated by formation (Table 2).

The data set includes measured temperatures from the 1950s to the present day. According to Gray et. al. (2012), digital thermometers became more commonly used in the WCSB post-1999. After this they were widely used to record temperatures through drill-stem tests, though it was not until 2000 that seasonal effects were no longer seen in BHT measurements. In order to further test the validity of the data, BHTs for wells were potted separately by age (Figures 6 and 7).

3.3 Temperature Gradients

Once the BHT data was cleaned, temperature gradients were calculated for the area. It was immediately apparent that these data showed two different gradients. There were 431 wells measured in the time frame 1956 - 1999 and 435 wells measured between 2000 and 2018. The age-filtered data has been plotted as two separate graphs (Figures 6 and 7). Figure 6 presents those wells older than 2000 (1956 -1999) and Figure 7 those wells 2000 and younger (2018) and within the TMIP area. There are no scattered BHT measurements after 2000 (Figure 7), but the pre-2000 data shows two distinct gradient populations; 30.3°C/km and 60.1°C/km (Figure 6). In addition to these populations, 38 data points were excluded due to inconsistencies or poor data quality. Using only the 2000 – 2018 data a gradient of 30.7°C/km was calculated and used to plot the formation temperatures at 3000 m and 4000 m (Figure 9). Based on the calculated gradients, temperatures above 130°C are expected at 4000 m. This depth is also below the Duvernay Formation and within the target formations.

The corrected BHTs are plotted in Figure 8, using only the 2000 – 2018 data sets. This is considered a conservative representation of the temperatures at depth. Until higher temperatures suggested by the older data set are confirmed by testing, these more conservative temperatures will be used for development planning.

3.4 Depth-to-Top-of-Formation Map

Each stratigraphic unit has unique characteristics that identifies it from units above and below. In addition to permeability and porosity, these characteristics include contained hydrocarbons and water. The subsurface units are not flat-lying as can be ascertained from the distribution of the strata around the Peace River Arch (Figures 3 and 4). Over geological time uplift and faulting have modified the surface of each unit (Alberta Energy Regulator 2016). As with geothermal wells, when drilling an oil and gas well, rock chip samples (cuttings) and cores are collected and interpreted by the on-site geologist as to the type of rock represented by the cuttings and the stratigraphic unit they belong to. It is through analysis of these cores and cuttings that a picture of the subsurface can be drawn.

The Peace River Arch (geographically evident in the form of the Swan Hills, Figures 3 and 4) is an example of an uplifted area where the stratigraphic units thin as they approach the arch due to erosion. By mapping the depth of the top (and bottom) of each unit in the subsurface a contour map of the extent and depth of each rock layer (stratigraphic unit) can be determined (Figure 9; Alberta Energy Regulator 2016). This gives a picture of what the environment of deposition might have been as well as what has happened to the rock unit since its deposition. These are important parameters to understand in order to determine if the rock unit will make a good reservoir rock. In addition to depositional and formational porosity, rocks that have been affected by fractures and faulting can have secondary permeability and porosity.

Figure 9 helps to identify any trends (structures) taking place at the surface of each formation. The contour map created for the tops of the formations that underly the Duvernay Formation (Beaver Hill and older) shows a distinct subsidence area in the SE quadrant and overall, the formation dips to the SSW (gets deeper) consistent with the work of AGS 2017 3-D modelling completed for the area. From these types of maps, it is possible to determine if a unit is suddenly terminated, as for example against a fault, or if the unit is dipping deeper and deeper into the subsurface as can be seen with the data shown. These maps are very important for targeting wells as they help predict where each formation will be encountered in the subsurface when drill site specific information is limited or non-existent.

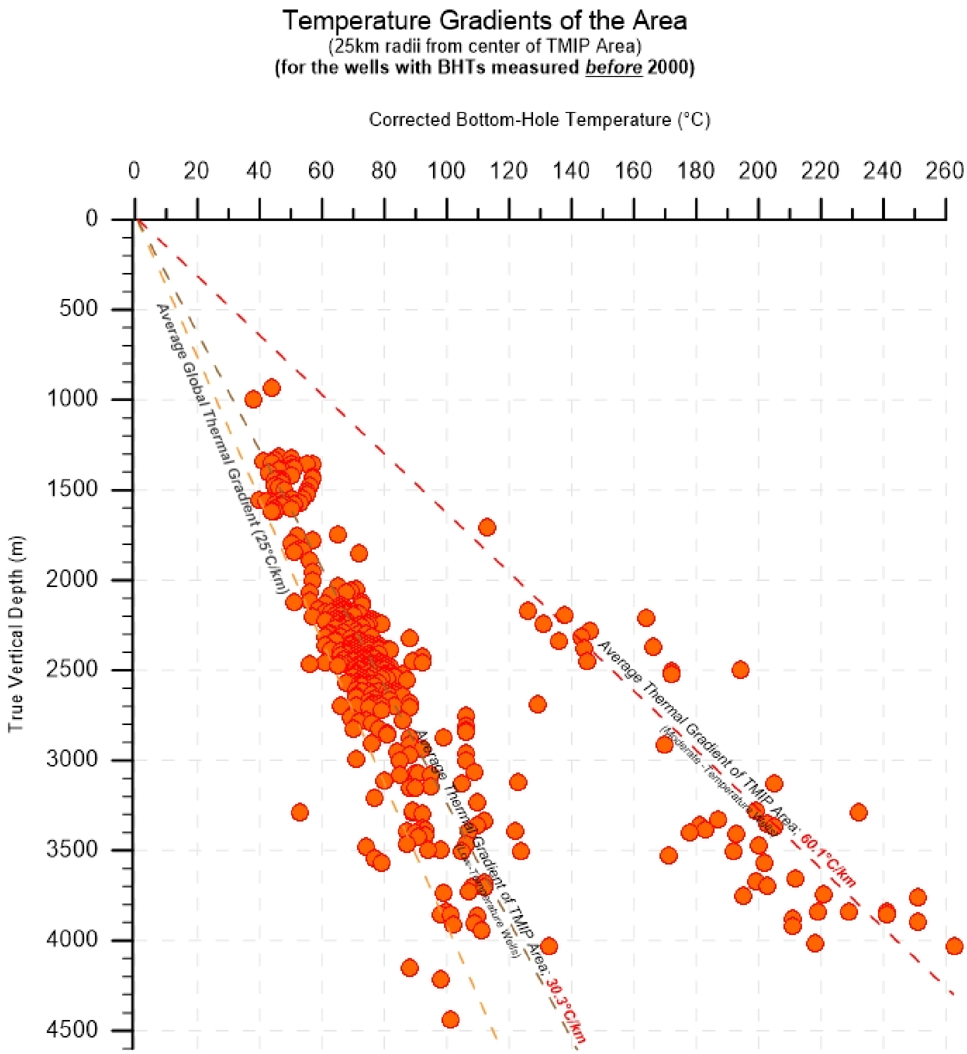

Figure 6: Temperature gradients calculated from corrected BHT ("Horner Correction" Peters and Nelson 2009) for wells within a radius of 25 km of the TMIP mapped area measured before 2000 (1956-1999). These data show two distinct temperature gradient lines (60.1°C/km and 30.3 °C/km). Before plotting, thirty-eight spurious BHTs were removed from the data set due to data issues (N=390 wells). (TVD is not m.a.s.l., but from ground elevation. Golden Software Grapher 8 software linear power lines "best fit" algorithm was used to calculate the gradients.)

Other than the depocenter in the SE quadrant and the rising surface in the northern sections of the TMIP, there is little detailed information as to the subsurface topography. An analysis of existing seismic and other geophysical data would also help to identify structure and fractures in the subsurface in a similar manner to that done by Alberta Energy Regulator 2016. Microseismicity could also be useful to improve the understanding of the subsurface. Fractures are potential conduits for convective heat transfer (Lowell, 1975) from deep crustal levels to shallower depth. There is an apparent, but not conclusive, coincidence of wells with high BHTs with regional fractures (Hickson et al. 2018b and 2018c)

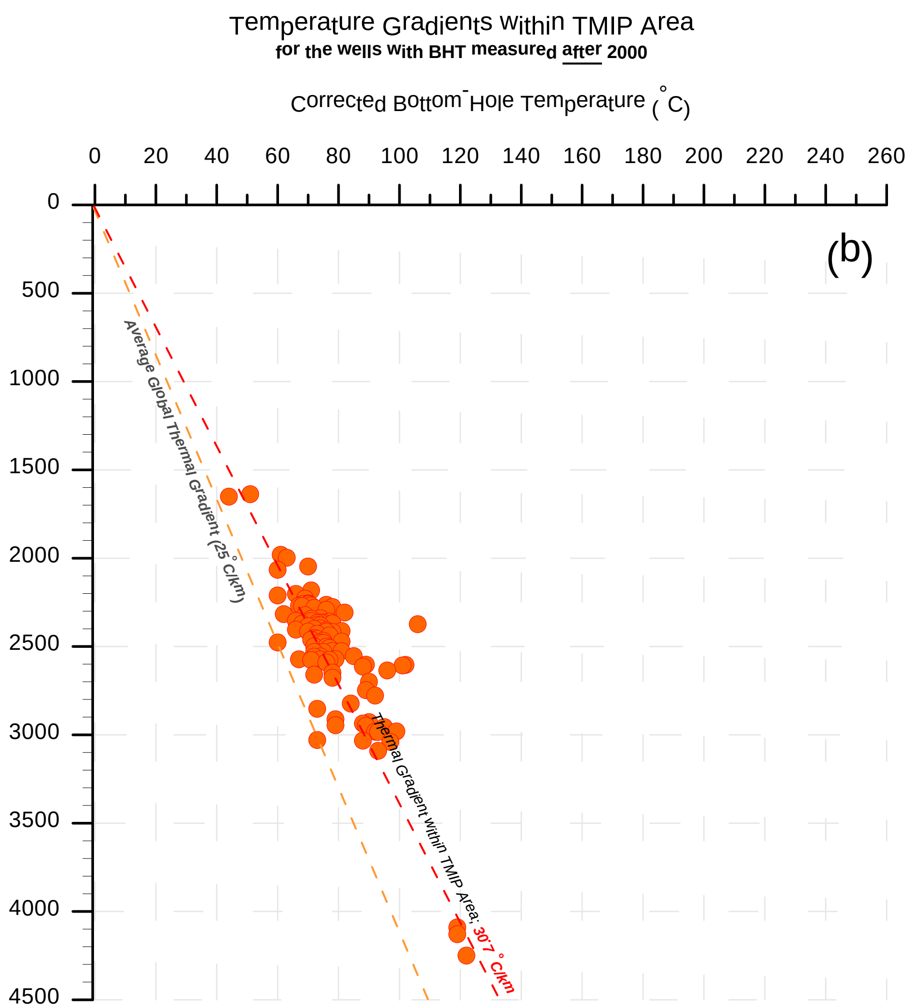

Figure 7: Using only wells within the TMIP area and which were measured after the year 2000, gives a gradient of 30.7°C/km (N=104 wells). The three data points from the deep wells helps confirm the higher than global average gradient (TVD is not m.a.s.l., but from ground elevation. Golden Software Grapher 8 software linear power lines "best fit" algorithm was used to calculate the gradients.)

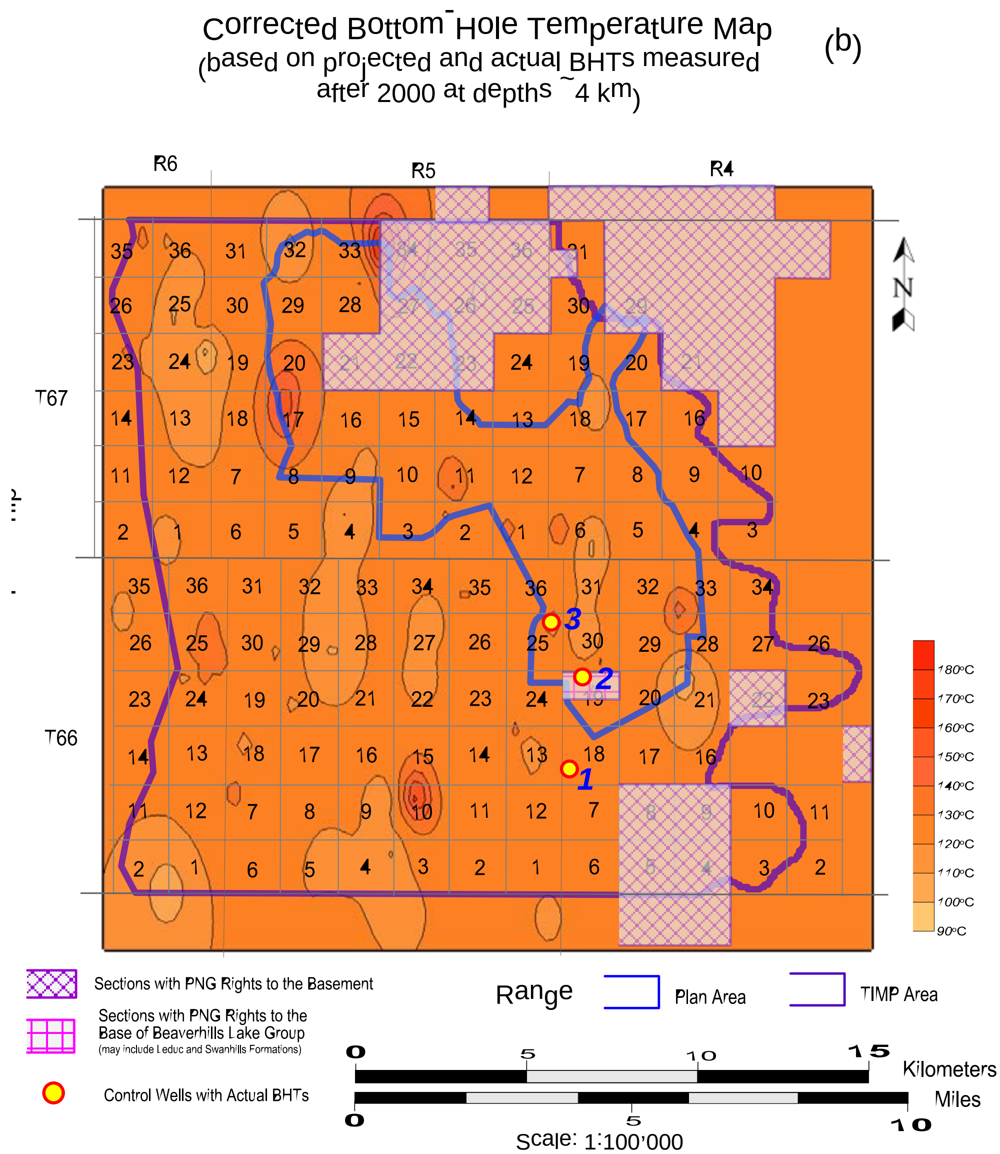

Figure 8: Temperature isothermal contour map of the TMIP plotted using only the post- year 2000 data. The projected temperatures at 4000 m (b) are shown. Numbers refer to wells in control data set. (Isothermal contours were calculated using Grapher *Inverse Distance to a Power* gridding method)

3.5 Gross Thickness (Isopach) Map

The thickness of each unit in a well is determined by identifying where the next identifiable unit starts. This information gives the gross thickness of a unit. These unit thicknesses are plotted on a map as an area of equal thickness or isopachs. Figure 10 is an isopach map for the TMIP area and shows the variation in the thickness of the sub-Duvernay formations. Only a few wells have penetrated below the Duvernay (Figure 9). Like oil and gas exploration, a thick resource is preferred in geothermal resource extraction to ensure long-term production from a reservoir.

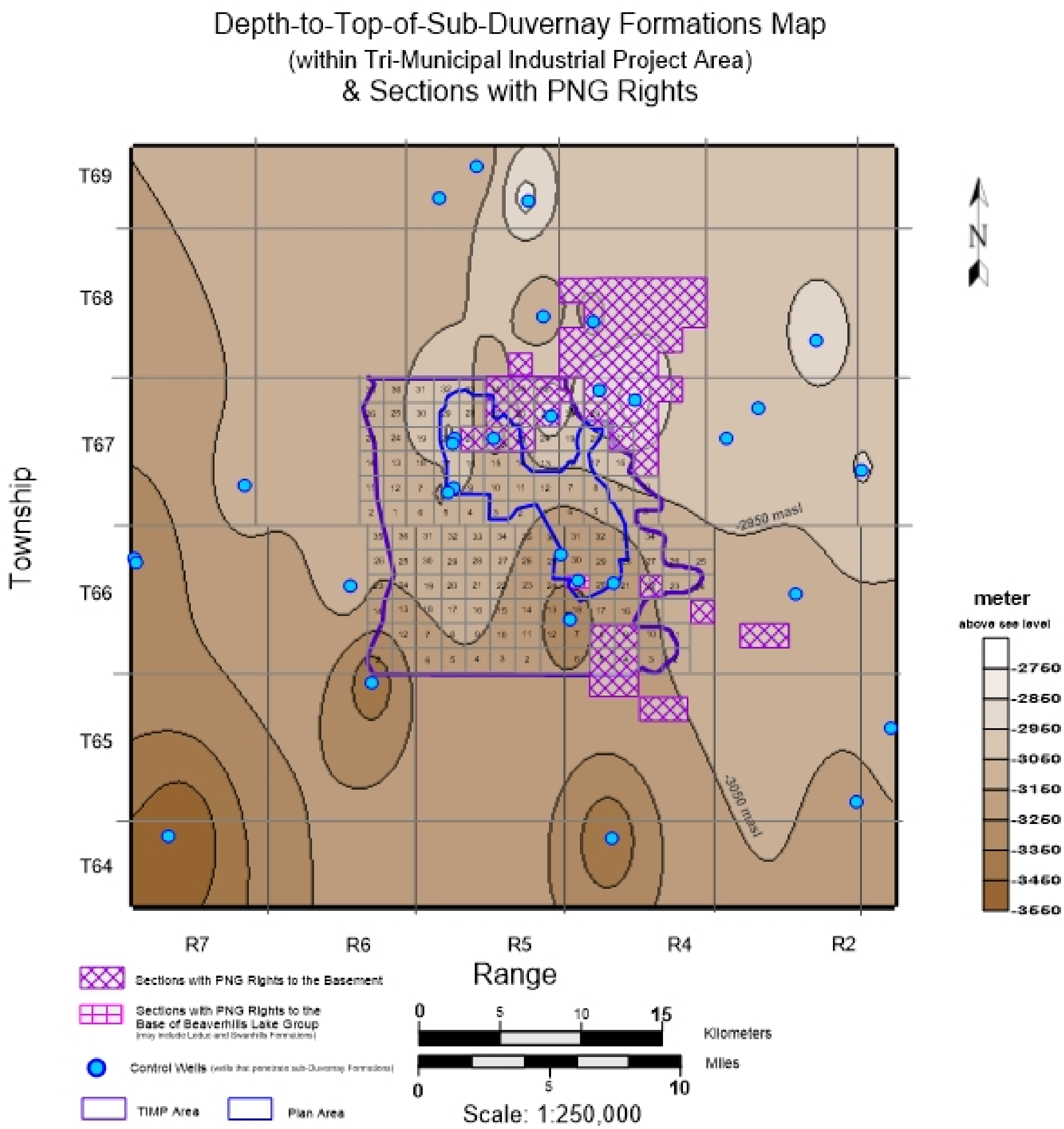

Figure 9: Depth to sub-Duvernay formations (mapped on the Beaverhill Lake Group).Wells shown in blue penetrate below the Duvernay and dominate the isopachs. Contour interval is 100 m. Map is based on data taken from drilling and geology records available in GeoSCOUT using Golden Software Grapher 8.

As already stated, the major oil and gas play in this area is the Duvernay. Other plays have been important at testing the sub-Duvernay strata, but in fact few wells penetrate below the Duvernay in the TMIP area. Only two wells within the TMIP area have penetrated to bedrock (Figure 10). For this reason, the thicknesses shown in Figure 10 are minimum thicknesses. It is possible that with analysis of seismic data from the area, that the depth to bedrock could be plotted and a better estimate of the sub-Duvernay strata obtained. However, this was beyond the scope of the report. Additionally, detailed analysis of the seismic data may determine if the deep “basin” in the SE quadrant (Figure 10) is fault controlled and how it relates to the stratigraphic thickening seen to the NE. It should be noted that this is also coincident with a thickening of the subsurface formations (Figure 10), so could represent a localized basin in the basement, infilled with sediments older than the Duvernay.

In some wells, the Duvernay Formation is absent but when it occurred it is usually overlying Beaverhill Lake Group. So, the Beaverhill Lake Group was regarded as the top of formations in wells with or without Duvernay. In total, 21 wells drilled the top of the Devonian formations, while none of the wells have hit the target geothermal formations; all have at least one potentially productive formation. The thickness of aquifers underlaying the Duvernay Formation ranges between 100-150 m, but in general, the Devonian Stratum is thick, averaging 700 m. The four potential formations (Leduc, Swan Hills, Granite Wash, Gilwood) have thicknesses that range between 300-450 m. The Leduc is the thickest formation in this group and has large water flows. Additionally, potential for large water flows from the basement unconformity is anticipated, but unknown without further exploration and testing.

3.6 Porosity and Permeability

In this study, the porosity values are taken from measurements conducted on drill cores (including sidewall cores) in the laboratory the results of which are accessed through the databases in GeoSCOUT. In some cases, there is additional information gathered from wireline logging of the formations. When no drilling core data is available for the studied wells, logging curves gathered from sonic/neutron measurements can provide helpful indications of relative permeability. Even though the laboratory measurements on drilling cores and logging surveys in the wells had a hydrocarbon reservoir focus, the porosity and permeability values can be regarded as representative of the water-saturated parts of the formation and thus can pertain to geothermal fluids within the formation.

A challenge for the study was that within the TMIP area only three wells have porosity data. These data show the Leduc F. has an average porosity of 2-10%, but widening the study showed log data for Leduc F. wells had the potential to be porous up to 20%. The only well that had a porosity log in the mapped area, 100/11-30-066-07W6/00, is located 25 km away from center of TMIP area. These results suggest the Leduc F. could be ranked as high and “good” to “very good” when encountered in the TMIP.

Additionally, from wireline log data outside the TMIP area, the porosity of the Swan Hills F. is very high and forms a very porous reservoir, particularly at measured depths below 3190 m. Data gathered for the study, showed the Swan Hills F. has an average porosity of 13%, while in some sections it approaches an excellent porosity of 16%. In addition to the good porosity, with the formation’s thickness and high borehole temperatures it can be concluded that this formation is a good candidate for geothermal fluid production.

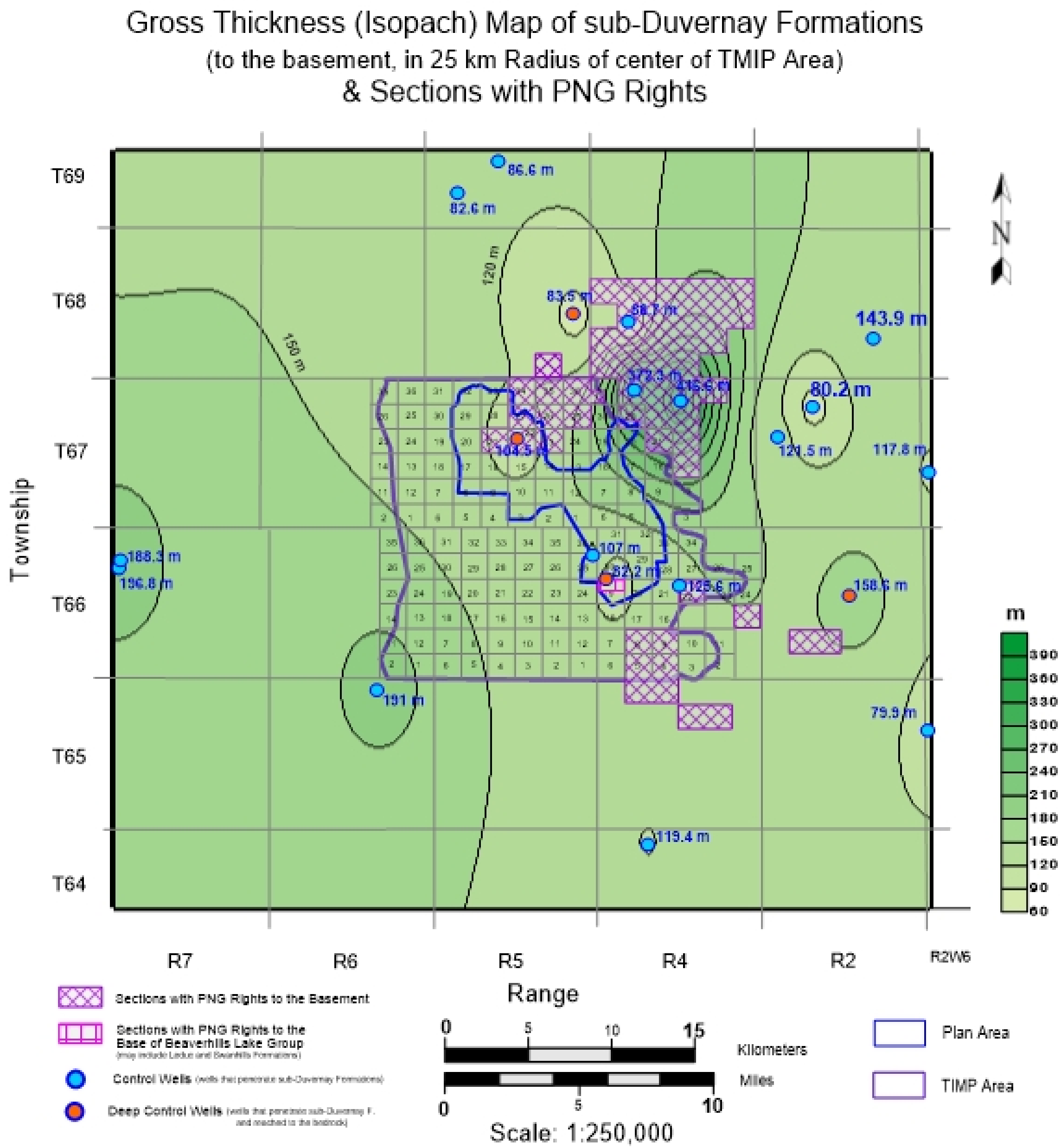

Figure 10: Gross thickness (isopach) map of the sub-Duvernay Formations. The Swan Hills Formation is composed of Pinnacle reefs, thus the consistency of the thickness may not be as indicated. Individual information from each hole has been "smoothed" between data points. Map is based on data taken from drilling and geology records available in GeoSCOUT using Golden Software Grapher 8. (Appendix C). Also shown are the Petroleum and Natural Gas right (PNG) in the area.

In addition to existing studies of the Devonian strata, the log and core data that Terrapin studied confirm that the Leduc and Granite Wash formations can be regarded as excellent target reservoirs for new drilling and potentially for re-drilling and re-completion operations. Data from outside the TMIP indicate that the highly permeable Swan Hills F. could also be a suitable target but may not be present in all areas.

3.7 Water Production and disposal

Water production and achievable brine flow rates

As most of the oil and gas pools contain water produced with the hydrocarbon, this produced water can also be a good indicator of the water content of the formation, its permeability, its water productivity, and the flow intensity of the wells. A challenge for geothermal energy production in the TMIP area is the lack of flow tests from the target formations. As noted previously, these formations are deeper and contain less hydrocarbons than overlying formations, such as the Duvernay. Mass flow is a critical factor in economical production of geothermal energy and can be a more important variable than the temperature.

A recent publication (Palmer-Wilson et al. 2018) provided detailed analysis of geothermal energy production from British Columbia's portion of the WCSB. In their calculations they showed the viability of projects with the following flow rates: Horn River: 0.0371 kg/s per kW; Clarke Lake: 0.0605 kg/s per kW; Prophet River: 0.0409 kg/s per kW and Jedney: 0.0276 kg/s per kW. They point out that a weakness in the results in the lack of site-specific brine flow data

In Alberta, work in the Hinton-Edson area yielded similar encouraging results from the Devonian sections. Water recovered mainly from the Leduc Formation in the central region and from the Beaverhill Lake Group in the Edson area yielded flow rates of more than 400 m^3/h (>100 l/s) and a number of wells yielded flows of more than 30 l/s (Lam and Jones 1985). Other studies concerning the sedimentary basin in Alberta have also assumed that a flow rate of 30 kg/s per well might be achievable (Majorowicz and Moore 2014; Majorowicz and Grasby 2014). Another study assessing Clarke Lake and Jedney areas, British Columbia, assumes achievable flow rates of 100 kg/s per production well (Renaud et al. 2018)

Currently the only example of well production measurements in Canada applicable to geothermal development are measurements from the Clarke Lake field in British Columbia. Here the Middle Devonian Slave Point Formation has dolomitized zones that show high permeability. Two gas wells were flow tested by Petro-Canada for approximately a year. The wells produced 2800 m^3/day (33 kg/s) with a deliverability of 0.75 (m^3/d)/kPa (Walsh 2013). The Slave Point Formation is part of the Beaverhill Lake Group in the TMIP area (Figure 7), but has not been flow tested, nor has the presence of dolomitization been noted, although penetration of this unit is limited.

The limited information from the target formations within the TMIP makes it difficult to conclude what flow rates might be achievable, but data cited above from other areas is suggestive of the potential to have flows of sufficient volume to achieve economic success at the expected temperatures of the deeper aquifers. In the case of the TMIP area, the BHTs of geothermal production wells are expected to be 120°C or higher at a depth of 4000 m (Figure 9).

There is a good possibility of achieving flow rates in the 30 l/s or higher within the TMIP, but only well testing will confirm if these flow rates are achievable.

Water disposal

In addition to indications of the potential of specific formation to produce water, formations can also take waste water. The study area contains several waste water disposal wells and there are 29 active waste water wells, five suspended waste water wells, and five abandoned waste water wells in the 50 k radii area around the TMIP area. These wells provide guidance on the best formations to dispose of water.

Of the water wells in the region, three wells are disposing water into Devonian Strata. One well uses the Beaverhill Group and two wells use the Leduc Formation. Other wells are disposing water into shallower formations. Two of the wells inject water at between 3,796 m and 3,989 m depth and the two Leduc formation wells inject approximately 38.5 m^3/hr and 45 m^3/hr, (equivalent to 10.7 l/s and 12.5 l/s respectively from wells 7” diameter casing with the exception of one well with 5 ½” casing).

Water disposal regulations and restrictions mean that disposal capacity is at a premium in the region. Work will be required to negotiate with current operators in order to determine if there is disposal capacity in wells in proximity to the geothermal development. If this is not an option, then suspended wells could be considered for re-working into disposal wells. Failing these options, disposal well requirements will need to be evaluated.

Two water disposal wells within the TMIP dispose water at 3,796 m and 3,989 m into the Leduc F. The geothermal reservoir targets are deeper, (below the Leduc - Gilwood and Granite Wash), but these significant water floods must be taken into consideration for their potential to cool the aquifers below. According to Ferguson and Ufondu (2017), water injection may lower the formation temperatures around the injection well for a distance of 800 m.

4. Technical Uncertainties

4.1 Hydrogeology of the Formations

Our study has identified several subsurface formations with indications of sufficient porosity and permeability to facilitate the steady flow of water into the well bore. However, even within the same geological formation such as the targeted Granite Wash or Swan Hills formations, there can be varied permeability based on location. Many interdisciplinary considerations such as fluid chemistry, attributes of the produced fluids and biological activity of the hydrocarbons needs to be measured and integrated into the analysis. Further in-field studies that verify the permeability and porosity of the target formations in the candidate wells will need to be conducted via pressure and injection tests.

4.2 Geochemistry of Well Fluids

The chemical makeup of the fluids in the well is extremely important. Downhole fluids with challenging chemistry can cause corrosion, scaling, and gas issues that can quickly cause havoc to the infrastructure needed to turn geothermal heat into usable energy. In addition, a major health and safety concern is that many wells in the MDGV produce sour gas (i.e. gas high in hydrogen sulfide (H_2S))). Techniques for the mitigation and prevention of HS escape are well known by the drilling and hydrocarbon industries in Alberta. A review and analysis of the geochemical properties of the fluids has been completed (Shevalier 2018). This work addressed both the potential for scaling and corrosion from produced brines as well as the impact of injection of the spent brine into the subsurface. Production waters for Gilwood and Granite wash do not show any tendency to form any minerals. Swan Hills water does show potential to form calcite and siderite minerals, and Leduc water does show potential to form calcite. Depending on the amount of mixing taking place (volume of disposal water), precipitation is likely to occur when disposing Swan Hills, Gilwood and Granite Wash into the Leduc Formation and with declining water temperature, scaling of calcium carbonate is likely to occur. However, scaling and precipitation can be abated by chemical treatment.

4.3 Fluid Temperature at Wellhead

Although there is data on the bottomhole temperature in all the studied formations and for many existing wells, there are no temperature readings at the wellhead on the surface. If the fluid being produced from the wells was pure saline water, then the high heat capacity of water would retain most of the heat from the hot sedimentary basin to the surface. However, in the high-pressure environment within the formations, there are gases that are in liquid state within the downhole fluid. Once this fluid rises to the surface and pressure drops, decompression cooling occurs due to adiabatic expansion of the produced fluid on the way to the surface. Pumping methods which can reduce this pressure drop and the resulting decompression cooling need to be studied. BHTs measured in wells prior to the year 2000 need to be re-measured to determine if they are erroneous or if they represent wells that have tapped into localized high temperature zones. The size of the wellbore diameter required dependent on BHT and flow rates needs to be calculated when more conclusive results are determined.

4.5 Fluid Flow Rates to the Surface

Without conducting additional technical analysis, it is uncertain as to what flow rates will be found at the surface. Most of the wells are not free-flowing and decompression cooling leads to low wellhead temperatures. In order to overcome the temperature drop, a downhole pump must be used. The small diameter of many oil and gas wells limits the ability to install downhole pumps of the size typically used in the geothermal industry, however some small diameter pumps are available.

Fluid flow rates to the surface have been reported in several papers and vary widely; volumes of up to 100 kg/s from a single well have been reported. Testing of existing wells and purpose-drilled exploration wells will be required before mass flow rates can be determined from the TMIP area.

Additional aspects that must be taken into consideration include the pressure of the formation, estimated withdrawal rates that would be sustainable over a 20-30 year period, the type of the pump, the size of pump, and the parasitic load of the pump. The fluid flow rates are a key consideration and input when it comes to fully assessing the electricity generation potential or heat supply from each well. The production rate (liters/second) of each well will dictate how and if existing wells can be effectively used to produce geothermal fluids. The conclusion of this study is that purpose-drilled geothermal wells will be required in order to harvest the heat energy of the field.

4.6 Reinjection of Production Fluids

Another issue closely linked to the fluid flow rates from the targeted Devonian formations to the surface, is the reinjection of the produced fluids back into the ground for disposal and to maintain pressure within the formation to assist sustainable fluid production to the surface. Many geothermal energy projects in other regions did not reinject their production fluids and eventually experienced major drawdown in fluid flow rates from their production wells due to reduced pressure. However, the quantity of water available within the formations may alleviate the necessity of injecting back into the production formation. Further hydrological testing and modelling will be required.

If disposal is considered into the Leduc Formation, the chemistry of the produced fluid will be important to determine any subsurface issues related to mixing of the formation waters. According to the calculations of Shevalier (2018) for the mixing of Swan Hills and Leduc waters the system is initially oversaturated with respect to calcite and remains so during the mixing of the waters. When the Swan Hills and Leduc mixing ratio reaches 12.5%-87.5% the system becomes oversaturated with respect to dolomite, aragonite, and magnesite. For the Granite Wash - Leduc waters the system is initially oversaturated with respect to calcite. When the Granite Wash - Leduc mixing ratio reaches 10.0% the system becomes undersaturated with respect calcite. For the Gilwood - Leduc waters the system is initially oversaturated with respect to calcite. The system becomes undersaturated with respect to calcite when the mixing ratio reaches 7.5%.

The total flow rates from the production wells will dictate how many reinjection wells will be needed. Growing data suggests that high pressure injection rates in some areas can cause earthquakes and efforts will need to be taken to try and avoid this potential issue.

4.7 Conversion Technology Selection

Once the geothermal resource is better understood through on-site tests and surveys, the final decisions for technology selection for power conversion will need to be made to ensure that the technology selected is the most suitable for the project.

5. Exploration Planning and Well Targeting

At the conclusion of the study several priority areas were chosen for further investigations. This process required the analysis and spatial integration of the following information:

1. Predicted temperature at 3000 to 4000 m depth from post2000 year BHT data
2. Depth to sub-Duvernay strata – target is for the shallowest drilling depth
3. Thickness of sub-Duvernay strata – thickest possible sequence of strata
4. Porosity and permeability – these are not available from within the target area

5. Depth to bedrock – shallowest possible depth – depth is not reliable based on 2 data points
6. Predicted flow rates in target formations – highest possible flow rates from sub-Duvernay strata
7. Distance from injection wells – minimum of one km distance from injection well regardless of formation.

Due to the age of the field there has to be deep depleted reservoirs. Drilling deeper than these reservoirs will possibly encounter drilling problems (lost circulation, sloughing hole, etc.). The drilling histories of the deepest, newest wells will be reviewed prior to developing a drilling program. The locations where multiple favourable indices coincide should become the exploration targets. Unfortunately, in the TMIP area not all the favourable indices coincide in one section. The final location will most likely be determined by factors related to land position and sub-surface PNG and mineral rights.

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