
Geothermal Energy as a Source of Heat for Oil Sands Processing in Northern Alberta, Canada

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ABSTRACT

Geothermal energy has the potential to reduce both the production costs and greenhouse gas emissions associated with oil sands production in the Western Canada sedimentary basin (WCSB) in Northern Alberta. This is currently being investigated through the Helmholtz-Alberta Initiative, which is a research collaboration between the Helmholtz Association of German Research Centres and the University of Alberta. The primary area of interest is in the Athabasca oil sands where the WCSB is relatively thin and the Phanerozoic sedimentary succession is thinning toward the northeast and subcropping onto the Canadian shield. Beneath the Athabasca oil sands, the Precambrian basement is at a depth of 0.5 km (0.31 mi) and can be studied by the analysis of the geophysical logs and core and rock chip samples from a deep 2.4-km (1.49-mi) well drilled into the granitic basement rocks. A second study area is located around Peace River, where the WCSB is about 2 km (1.24 mi) thick, and data from the Phanerozoic section are being analyzed. The research is focused on an evaluation of potential heat sources for oil-sands processing in areas with existing leases. Revised maps of the temperature at the top of the Precambrian basement confirms that temperatures greater than 60°C could be found within the sedimentary strata in the Peace River oil sands area. This temperature will be found in the crystalline Precambrian basement beneath the Athabasca oil sands. Extraction of heat will require the development of engineered geothermal systems with artificial porosity created and fluids circulated at depth. The economics of this process appear favorable, and additional research will define the feasibility of this type of heat production in more detail.

INTRODUCTION

The Athabasca oil sands are one of the largest hydrocarbon deposits on Earth, and about 20% of these deposits are accessible to surface mining. The separation of bitumen from sand requires large quantities of hot

water, which is currently heated by burning natural gas. As a result, oil sands processing accounts for about 6% of Canada's natural gas consumption and incurs significant economic and environmental costs. Bitumen extraction and upgrading processes, as currently executed in the Athabasca region in Alberta, are highly

energy-intensive operations, requiring as much as 2 GJ/bbl of synthetic crude oil (SCO) (Ordorica-Garcia et al., 2008). At current oil sands production levels, this represents 50 million tons of annual CO₂ production. The remaining 80% of oil sand reserves are too deep to mine but can be extracted using in-situ techniques such as steam-assisted gravity drainage (SAGD). This process also requires large quantities of steam to be generated by burning natural gas.

Geothermal energy could potentially supply the heat for both the extraction and processing of oil sands and reduce the associated CO₂ emissions. The primary area of interest is in the Athabasca oil sands, where the sedimentary succession is only a few hundred meters thick and thins toward the northeast. The sedimentary succession is underlain by crystalline basement rocks. A second study area is located around Peace River, where the sedimentary succession is about 2 km (1.24 mi) thick. If temperatures were high enough, then it may be possible to extract this heat from saline aquifers at greater than 60°C within the Western Canada sedimentary basin (WCSB), as proposed by Jessop et al. (1991). However, if heat is to be extracted from less porous sedimentary rocks or crystalline basement rocks, then this would require the development of the engineered geothermal system (EGS), as described by Tester et al. (2006). The EGS involves creating or expanding natural fractures in a rock to enhance the porosity. A fluid (water or CO₂) is then injected and circulated through the fractured rock reservoir to extract heat. Temperatures greater than 80°C are typically needed for EGS electrical power production with organic Rankine cycle (ORC) and may be found in the deep Alberta basin within sedimentary aquifers to the west of oil sands (Majorowicz and Moore, 2008; Majorowicz and Grasby, 2010a). To tap into a resource at such temperatures requires drilling to depths of several kilometers. In Northern Alberta, the thickness of the Phanerozoic sedimentary succession is between 500 and 2400 m (1640 and 7874 ft) in the Athabasca oil sands area and Peace River area, respectively. Therefore, temperatures above 80°C will only be found below the base of sedimentary rocks in the Precambrian crystalline basement, according to the first Alberta basement temperature map of Jones et al. (1985).

This chapter summarizes the present state of knowledge on this topic. It begins with a review of previous thermal studies in Alberta and describes research that has allowed systematic errors in the thermal database to be excluded. We also present some simple cost efficiency calculations. The EGS concept was described in detail by the Massachusetts Institute of Technology (MIT) report, Tester et al. (2006), and the technique was previously referred to as the Hot Dry Rock projects (see Barbier, 2002, for a review). The EGS is being evaluated as a

source of thermal energy for electricity generation. However, as will be shown below, temperatures in Northern Alberta are too low for electricity generation, and the focus is to provide heat for oil sands processing. The idea of using EGS for oil sands processing was first investigated from 2006 to 2008 by an industry consortium (Geopowering the Oilsands [GeoPos]), and we acknowledge the pioneering work of this consortium.

The idea is being investigated in more detail in this chapter as one of the research themes of the Helmholtz-Alberta Initiative (HAI), which is research collaboration between the Helmholtz Association of German Research Centres and the University of Alberta.

CHARACTERIZATION OF GEOTHERMAL CONDITIONS IN NORTHERN ALBERTA

Previous Research

Heat flow (Q) is the fundamental quantity to be understood in geothermal studies. The heat flow measured at the surface of the Earth originates in

- 1) primordial heat from the formation of the Earth, which is mostly transported to the surface through mantle convection and plate tectonic processes. Locally, crustal magma bodies can increase heat flow; and
- 2) heat generated by the radioactive decay of radiogenic elements such as uranium, potassium, and thorium. This occurs mainly in the crystalline rocks of the crust and, to a lesser extent, in the upper mantle.

Heat flow (Q) ranges across Canada from values as low as 20 mW/m² in parts of the Canadian shield to values as high as 90–200 mW/m² in the Canadian Cordillera and Garibaldi volcanic belt, respectively (see Jessop et al., 2005, for heat flow data and Majorowicz and Grasby, 2010b, for the heat flow map of Canada). Heat flow is not commonly measured directly but is obtained from the temperature gradient ($\text{grad}(T)$) in a borehole and laboratory study of the thermal conductivity (k) of the rocks. These quantities are related through

$$Q = k\text{grad}(T) \quad (1)$$

In geothermal exploration, it is required to predict subsurface temperatures. Knowledge of regional heat flow and thermal conductivity are required to predict the geothermal gradient:

$$\text{grad}(T) = Qk^{-1} \quad (2)$$

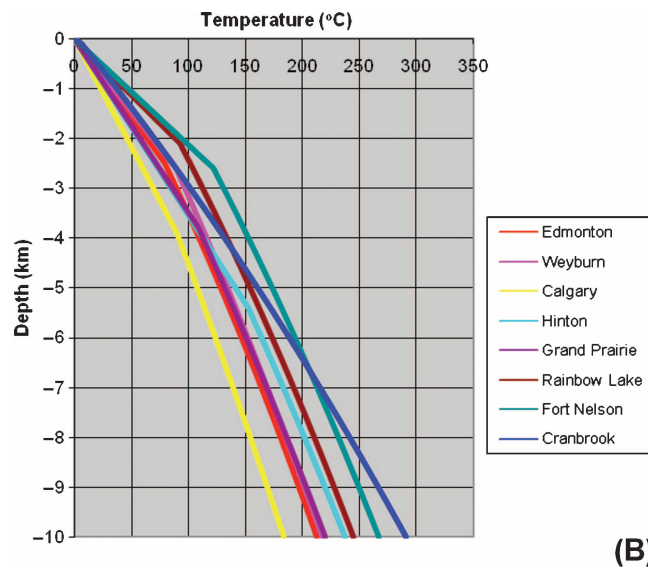
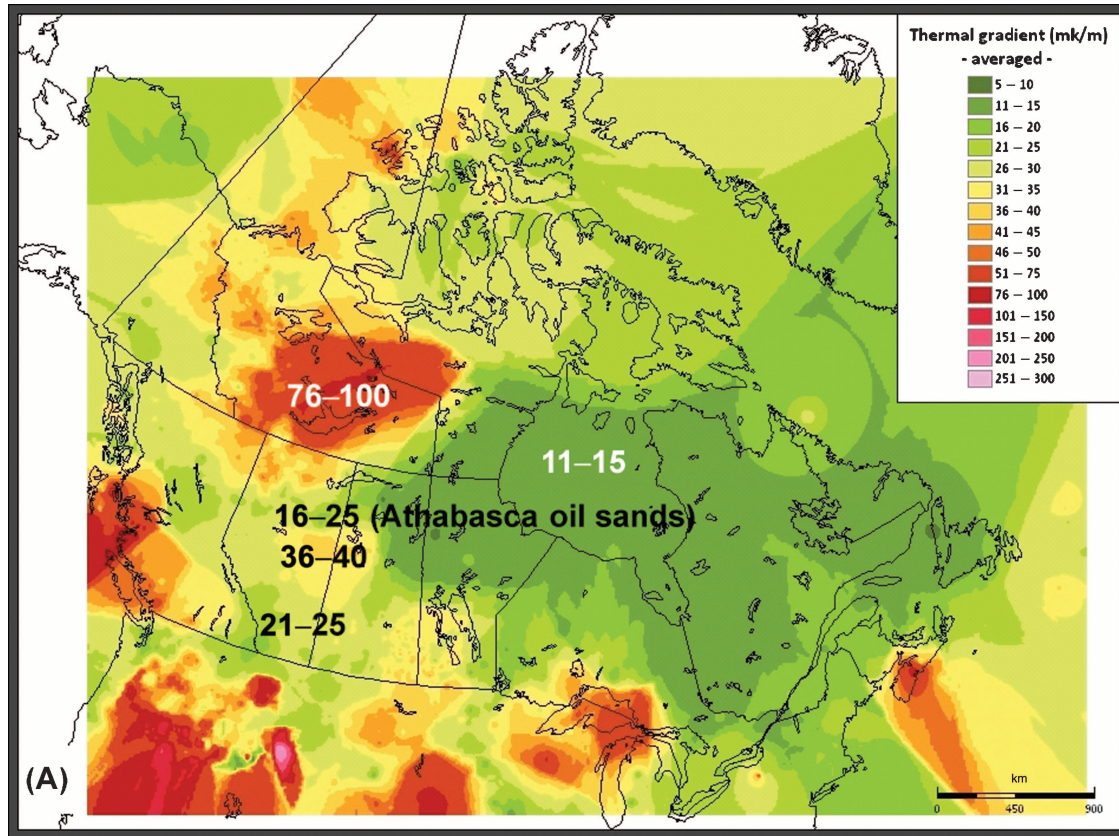


Figure 1. (A) Geothermal gradient (in mK/m) across the northern part of the North American continent (J. Majorowicz, 2010, personal observations) and (B) possible temperatures at locations in the Western Canada sedimentary basin (WCSB) down to 10 km (6 mi) depth (modified from Majorowicz and Grasby, 2010a, b).

which allows the depth to a particular temperature to be predicted. Heat flow (Q) and thermal conductivity (k) are the major controls on thermal gradient in sed-

imentary basins, shield, and orogenic areas across Canada (Figure 1). The thermal gradient characterizes the variation of temperature with depth, assuming that

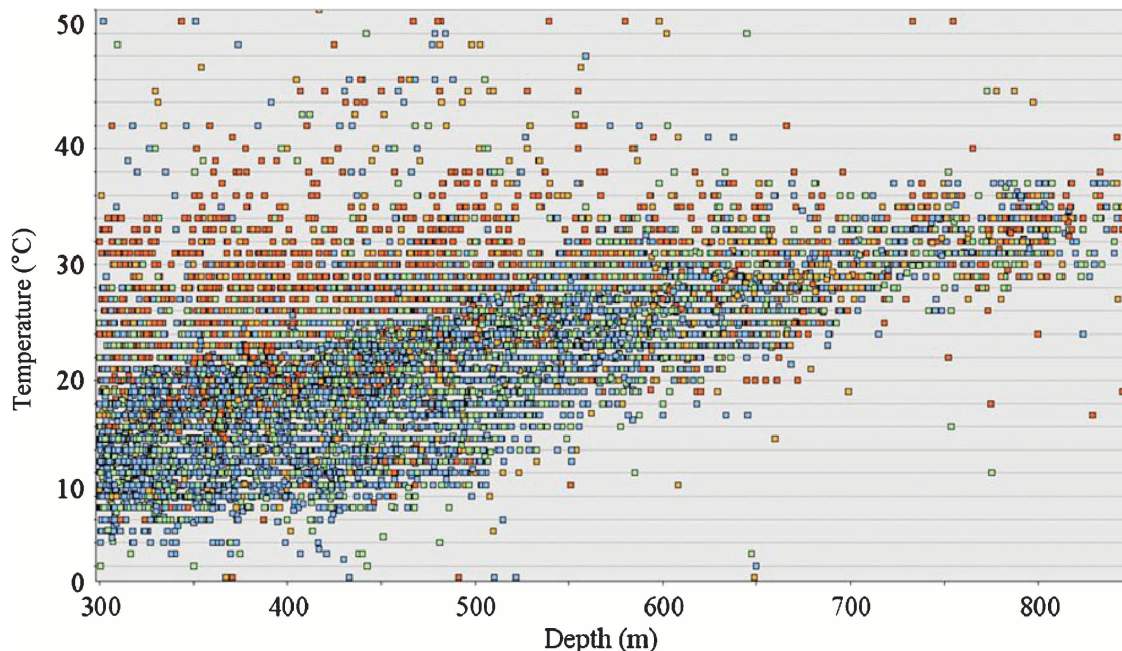


Figure 2. Temperature as a function of depth for wells measured in Northern Alberta from the Energy Resources Conservation Board (ERCB) temperature-pressure annual observations. Measurements made during the summer months are shown in red and are biased toward higher values because of the use of a maximum thermometer.

heat transfer is by conduction. In some areas of recent hydrothermal activity (Garibaldi Mountain area in the Canadian Cordillera) or high hydraulic head (Alberta Foothills), gravity-driven convection of basinal fluids can cause a convective component of heat transfer from the Earth's interior. Note that the thermal conductivity of a rock (k) reflects an average of both the mineral grains and liquids and gases present in the pore space.

In the WCSB, layers of sedimentary rocks overlie the Precambrian crystalline basement. The geothermal gradient ranges from approximately 20 mK/m in the southwestern Alberta Rocky Mountain Foothills to approximately 60 mK/m in the northwestern corner of Alberta. This range is controlled by several factors, including (1) heat flow reduction by deep groundwater recharge in the foothills and (2) high heat flow caused by high concentration of radiogenic elements, notably in the basement rocks that underlie the WCSB in northeast British Columbia and adjacent regions of the Northwest Territories (Majorowicz and Grasby, 2010a).

A large amount of geothermal gradient data in the WCSB comes from well-logging data collected during hydrocarbon exploration and extraction. This includes measurements of bottomhole temperatures (BHT) and drillstem tests (DST). It was found that temperature data collected commercially from wells show a spread

of values in the basin. The analysis of 33,653 BHT measurements from the southern Alberta basin using the moving window (3×3 townships in Dominion system, approximately 27 km \times 27 km [17 \times 17 mi]) for which temperature-depth plots were made (Lam et al., 1985) showed that the standard error of temperature estimates from temperature-versus-depth (T vs. Z) plots ranges from 2 to 15°C. In the study of oil sands areas, this range was found to be 3 to 6°C (the standard error of estimate is given by

$$\sqrt{\left(\sum(y_i - y'_i)\right)/(n - 2)} \quad (3)$$

where n is the number of data points and y'_i gives the regression line of y on z .

Another independent study by Majorowicz et al. (1999) showed that temperature data from the shallower (<1000 m; <3300 ft) part of the basin (including the Athabasca oil sands area) were anomalously high compared to precise temperature-depth logs measured by Majorowicz et al. (1999). The precise temperature logs were measured under equilibrium conditions in the hydrogeological observational wells of Environment Alberta. The observed difference between the commercial data and data obtained in the equilibrium wells was especially large for the shallowest part of

the basin where the sedimentary succession is less than 600 m (1968 ft) thick. This study of thousands of BHT and DST temperatures confirmed the previous finding of Hackbarth (1978) that BHT from geophysical logs are significantly higher than values observed in nearby hydrogeological observational wells. Majorowicz et al. (1999) rejected all the heat flow estimates based on depths less than 1 km (0.6 mi) from their analysis. Unfortunately, this eliminated most of the temperature records from the Athabasca oil sands areas around Fort McMurray where the sedimentary cover is less than 600 m (1968 ft) thick.

INDUSTRIAL TEMPERATURE DATA AND GEOTHERMAL GRADIENT IN THE OIL SANDS: NEW ANALYSIS

The previous discussion highlighted the fact that limited high-quality thermal data are available in Northern Alberta. Such data are needed to determine if low-enthalpy geothermal energy can be used in oil sands extraction and processing. The geothermal gradients and heat flow from Northern Alberta were re-analyzed for the oil sands areas. This analysis shows that the observed systematic trend of geothermal gradient decrease with depth was only partly explainable by thermal conductivity variation. Other sources of bias in the data were identified and removed, as outlined in the succeeding discussion.

Industrial Temperature Data from Oil Sands Area

Existing thermal data from annual well tests and BHT measurements were placed into a geographic information system (GIS) database to allow a more detailed statistical analysis (Gray, 2011). In this most recent analysis of the industrial temperature data, it was found that shallow temperature records taken by maximum thermometers during warmer summer months are inconsistent with those made in the winter months. This was found to be the reason for the scatter observed in shallow thermal gradients. We have found that measurements made during annual observations and reported to the Energy Resources Conservation Board (ERCB) by oil and gas industry systematically overestimate temperatures in the upper few hundred meters, which can be attributed to measurement errors that arise from this incorrect use of maximum temperature thermometers. These instruments do not record variations in temperature with depth. Instead, they measure the maximum temperature recorded during the logging cycle. This causes a problem because with the low-temperature gradients in Alberta, the maxi-

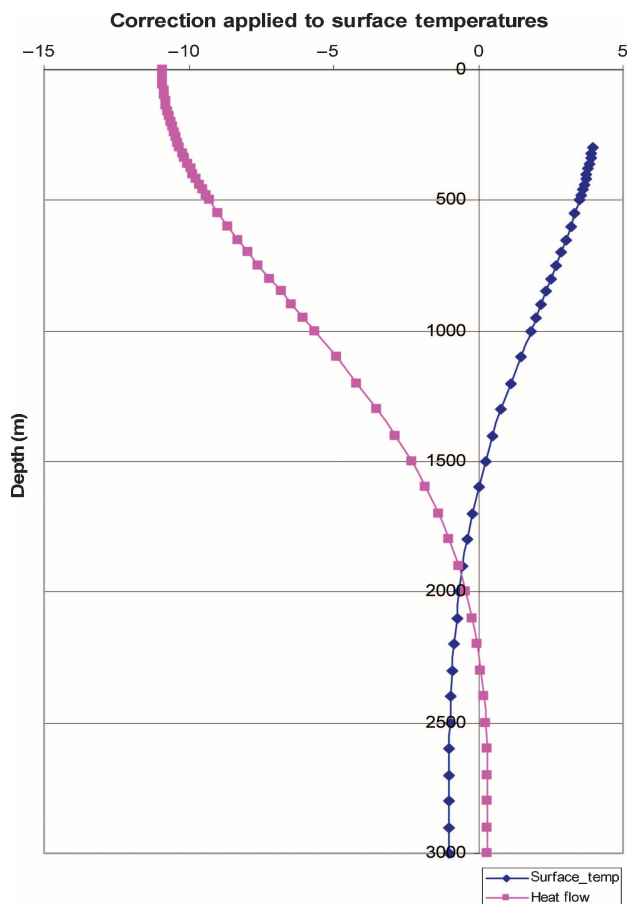


Figure 3. Graph showing the heat flow in mW/m^2 (pink) and surface temperature ($^{\circ}\text{C}$) (blue) corrections applied to this data because of the paleoclimatic effect.

imum recorded temperature on a hot summer day can occur at the surface instead of the bottom of the well. For example, the air temperature could be as high as 30°C , whereas the temperature at the bottom of the hole may be only 10 to 12°C . In this case, a thermometer that is improperly stored will apparently record a BHT that is higher than the true value. This phenomenon is demonstrated in Figure 2, in which temperatures recorded during summer months are shown in red, and exhibit many temperature values much higher than the true geothermal gradient. For this purpose, any well recording a temperature less than 36°C between the months of March and October was removed. The idea is to only keep data from winter months for any wells less than 36°C to prevent any ambiguity as to whether the measured temperature reflects the true gradient or the outside air temperature. This systematic error influences the calculation of geothermal gradients, so only the corrected data set has been used.

Paleoclimatic Correction

Changes in climate over the last few thousand years influence subsurface temperature measurements made in boreholes. This effect was found to be significant at basin depths less than 1500 m (4921 ft) and especially strong in the upper 500 m (1640 ft) beneath the Fort McMurray oil sands region. This effect is the result of

- 1) the Pleistocene–Holocene surface temperature increase of 5 to 6°C that occurred at the end of the Wisconsin glaciation. The magnitude of this surface temperature change has been determined from precise temperature measurements made in a well at Sudbury, Ontario (Perry et al., 2009); and
- 2) the recent climatic warming of 2°C that occurred between the Little Ice Age (~1400–1850) and the present day. This effect has been studied from inversions of precise temperature–depth logs in the Prairie provinces by Majorowicz et al. (2002).

Single temperature records taken at a depth of a few hundred meters comprise most of the thermal measurements in the Athabasca oil sands areas and are closer to being in equilibrium with recent millennial temperature than present climatically elevated temperatures 4°C at present; Majorowicz et al., 2002). In contrast, temperatures measured below a depth of 1500 m (4921 ft) appear to be in equilibrium with surface temperatures from the Wisconsin glaciation, which is about –1°C (Jessop, 1990). This has been accommodated in assigning ground surface mean temperature correction in relationship to default 0°C surface temperature (Figure 3, blue curve).

A paleoclimatic correction for heat flow data has been developed for Northern Alberta and applied to the data. Temperature measurements, including an equilibrium log, are currently being made in the 2.4-km (1.49-mi)-deep Hunt well (Anhydrite Petroleum [AOC] Granite 07-32-089-1-W4) near Fort McMurray to improve the paleoclimatic correction. This is a deep, 2.4-km (1.49-mi) well that was drilled near Fort McMurray in location 7-21-87-10W4 under a project led by Charles Warren Hunt (Anhydrite Petroleum) into the basement rocks (Anhydrite Oil Corporation Granite 07-32-089-1-W4) and is significant because it allows direct observations of the basement thermal regime.

Past temperature ranges have influenced temperature measurements in the depth range of 100 to 2000 m (328–6561 ft). We have removed the paleoclimatic effect of the temperature increase (of 10°C) that occurred at the end of Wisconsin glaciation some 13,000 yr ago and was associated with a transition from subzero temperatures to a warmer Holocene.

Simulation of time changes of the subsurface temperature can be made. This allows the change in subsurface temperature caused by surface forcing to be estimated using the heat conduction equation:

$$C_v \partial T / \partial t = \partial(k[\partial T / \partial z]) / \partial z + A \quad (4)$$

where T is the temperature, k is the thermal conductivity, C_v is the volumetric heat capacity, A is the rate of heat generation per unit volume, z is the depth, and t is the time in a one-dimensional layered geothermal model of the individual sites.

In case of a simple model of a single ice age followed by warmer period (e.g., 10°C [50°F] temperature increase), the temperature at depth z was shown by Jessop (1990) to be

$$T = T_{\text{Spresent}} + \text{grad}(T) * z + \delta T [\text{erf}(z/2\sqrt{st_1}) - \text{erf}(z/2\sqrt{st_2})] \quad (5)$$

where T_{Spresent} is the present average surface temperature; $\text{grad}(T)$ is the thermal gradient; t_1 and t_2 are times of the end and beginning of the ice age; δT is temperature step, and it is negative for an ice age; and s is the thermal diffusivity of the ground.

This effect is caused by a negative heat flux from the surface forcing. Jessop (1990) described the physical basis of this effect, and Majorowicz and Wybraniec (2011) describe additional details of the specific correction method used. Upon completion of the temperature log from the Hunt well, these corrections will be revised.

The effect of the surface temperature correction on the measured thermal data is shown in Figure 4. In the uncorrected data, the geothermal gradient at shallow depths is centered at approximately 40 mK/m, whereas deep geothermal gradient is centered at approximately 30 mK/m. However, after applying the correction, the shallow and deep gradients converge at 35 mK/m.

A red trend line shows the correct removal of the systematic trend. The mean thermal gradients were computed for both the corrected and uncorrected data. The values for the shallow (300–800 m; 984–2624 ft) and deep data (>800 m; >2624 ft) are as follows:

| grad(T) | corrected | uncorrected |
|-------------|-----------|-------------|
| shallow | 31.6 mK/m | 40.2 mK/m |
| deep | 30.2 mK/m | 30.4 mK/m |

We can therefore take the mean temperature gradient in the Phanerozoic sedimentary succession beneath the Athabasca oil sands to be some 32 mK/m.

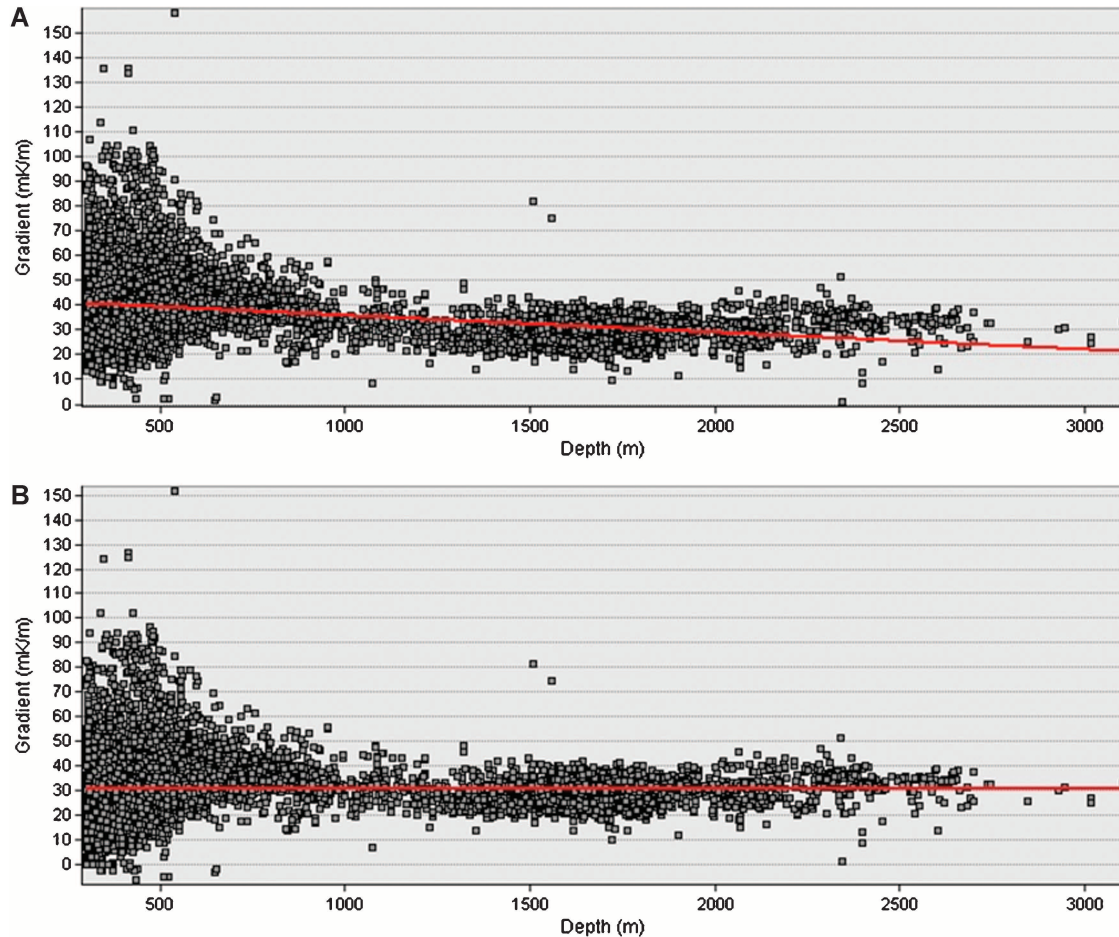


Figure 4. Graph showing the thermal gradient before (A) and after (B) the surface temperature correction.

Temperature at the Phanerozoic–Precambrian Basement Interface

The corrected geothermal gradient data were then used to construct a map of temperatures at the base of the sedimentary sequence (top of the Precambrian crystalline basement rocks). This only used wells deeper than at least 50% of the Phanerozoic sedimentary thickness. This is important in the context of geothermal exploration because it allows us to determine if the requisite temperatures will be found in sedimentary or crystalline rocks.

The map in Figure 5 shows that temperatures greater than 60°C might be found within the Phanerozoic sedimentary sequence in the Peace River oil sands area (cf. Figure 5A, B). In contrast, beneath the Athabasca oil sands, these temperatures will be encountered at depths of about 3 km (1.8 mi) in the Precambrian basement rocks.

Heat extraction from the sedimentary sequence is simpler than from crystalline rocks because fluids to transport the heat are naturally present and porosity is

generally higher. Thus, if heat is to be extracted from within the sedimentary rocks of the WCSB, then aquifer temperatures of 15 to 20°C in the Athabasca region and 60 to 70°C around Peace River could be expected. Note that thermal gradients in the thin sedimentary layer are higher than in the basement rocks because of the so-called thermal blanket effect. The estimated effective thermal conductivity of the sedimentary rocks is 1.4 to 2.4 W/m K, whereas in the Athabasca region, it is clear that the crystalline basement rocks have higher thermal conductivities (2–4 W/m K). This will result in a lower thermal gradient in the basement compared to the sedimentary rocks.

Estimated Heat Flow from Industrial Data

Estimating heat flow requires estimates of both the thermal gradient and the thermal conductivity over the same depth interval. Estimates of thermal gradient have been greatly improved through recognition that many

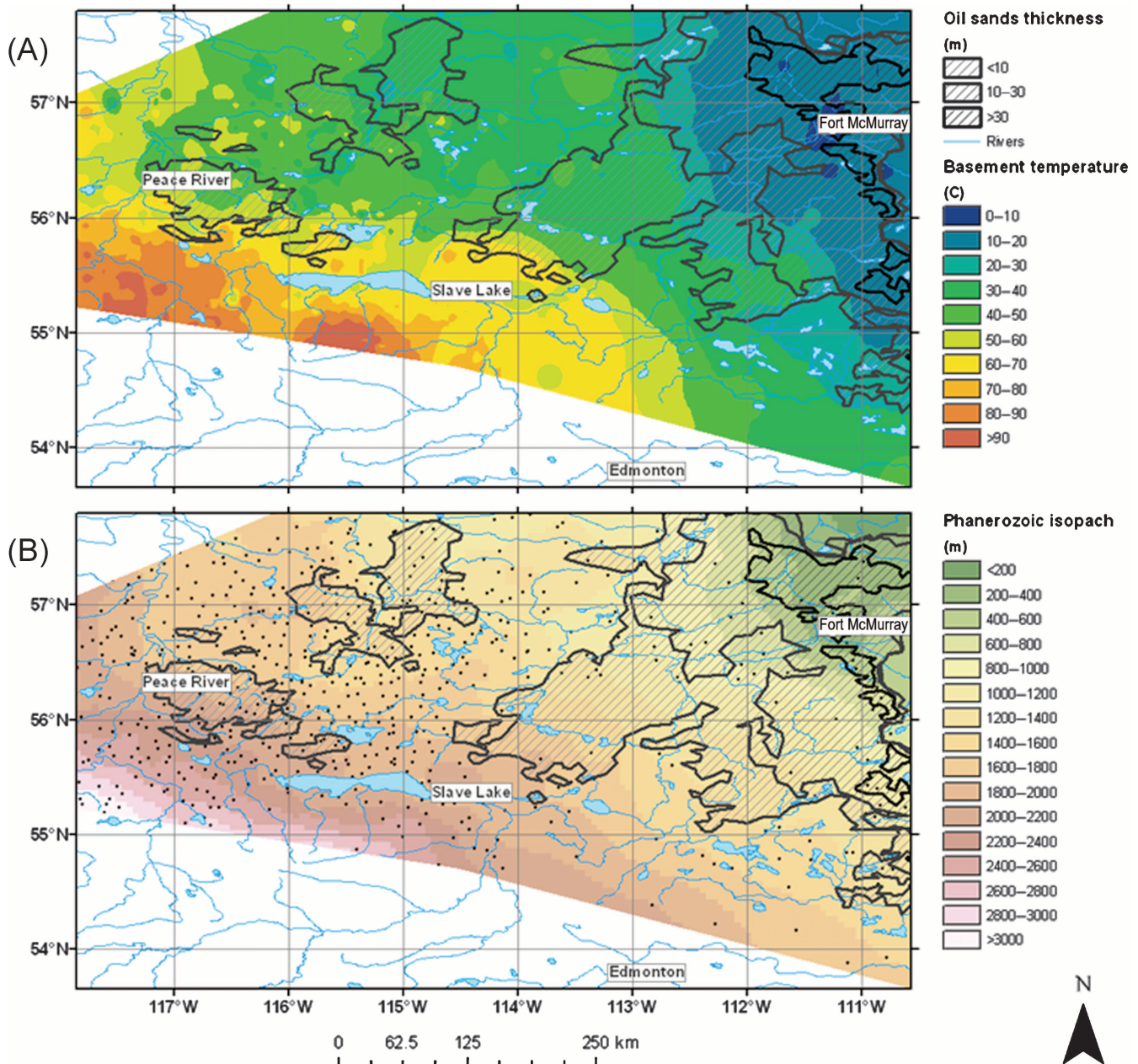


Figure 5. (A) Map of estimated temperature at the top of the Precambrian basement (in °C). Oil sands area boundaries and thickness are shown. (B) Precambrian basement depth (Phanerozoic thickness).

previously collected data points incorporated systematic errors (described above).

Estimates of thermal conductivity can be made from net rock analysis of the sedimentary rocks present in a well. An average thermal conductivity can best be estimated from the lithology, porosity, and thickness of geologic units recorded in the well. The average rock conductivity was assigned from measured k averages

for different sedimentary rock types from the Alberta basin from previous studies at University of Alberta Geothermal Laboratory (Beach et al., 1987). These have been corrected for temperature-depth dependence using the method of Chapman et al. (1984) with the equation

$$K_{ij} = K_{i,20^{\circ}\text{C}} \left[\frac{293}{T_j} + 273 \right] \quad (6)$$

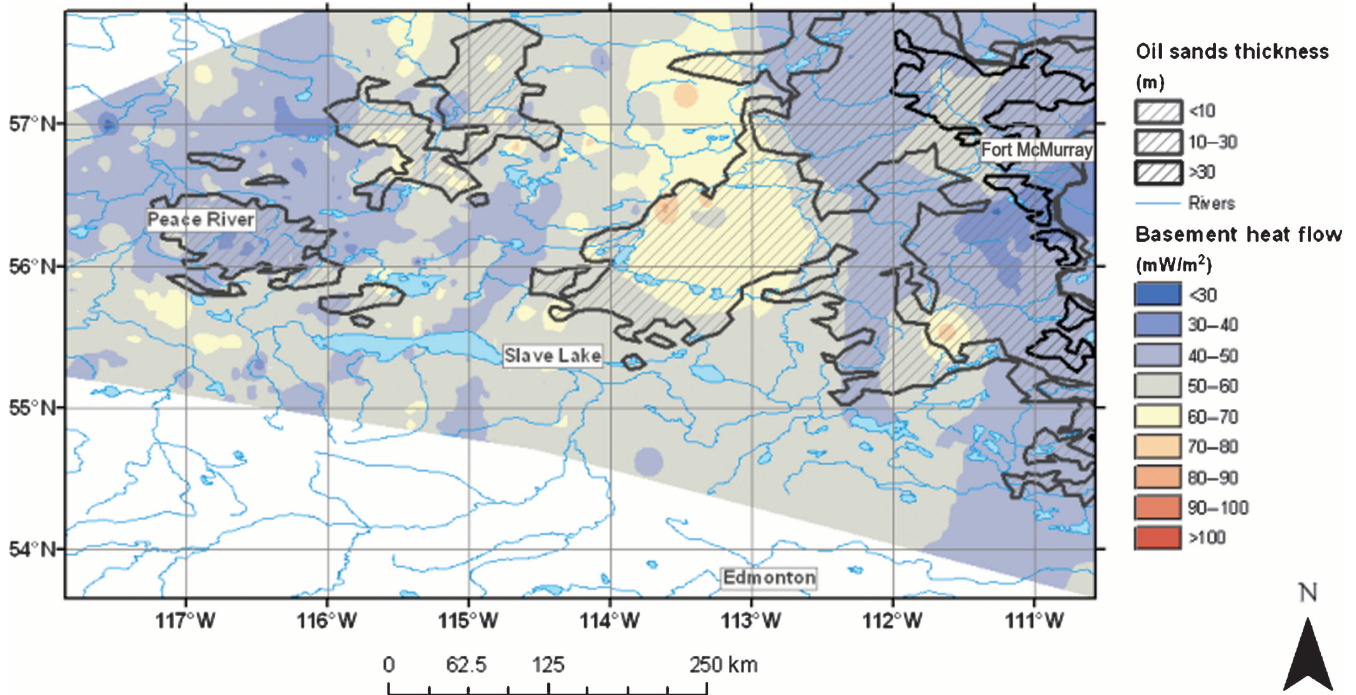


Figure 6. New heat flow map estimated from industrial temperature data and estimates of thermal conductivity from net rock and porosity and average rock thermal conductivities. Contours are in mW/m^2 . Oil sands thickness is shown by diagonally lined patterns.

where T is temperature in $^{\circ}\text{C}$ and; $K_{i,20^{\circ}\text{C}}$ is the rock conductivity measured under laboratory conditions.

The temperature variation of the thermal conductivity of water is represented for T less than 137°C by the equation

$$K_w = 0.56 + 1.88E(-03)T - 7.23E(-06)T^2 \quad (7)$$

where K_w is conductivity of water, and T is temperature in degrees Celsius.

A revised heat flow map (Figure 6) was compiled from (1) the corrected thermal gradient data and (2) the estimated thermal conductivity of the Phanerozoic sedimentary sequence. These results were constrained by thermal measurements made in the 2400-m (7874-ft)-deep Hunt well. The map shows that the heat flow in the major oil sands areas (Athabasca and Peace River) is in the 40 to 50 mW/m^2 range. Values in excess of 60 mW/m^2 are observed in the Cold Lake area. Heat flow values greater than 70 mW/m^2 are observed in the region 112–113°W, 56–57°N, in the western part of the Athabasca oil sands region, which is part of a larger zone of high heat flow trending southeast to northwest. Another region of anomalous heat flow is found in the region 113.5–115.5°W, 57–58.5°N, and apparently aligned with the boundary between the Taltson magmatic zone and the

Buffalo Head terrain, two crustal blocks in the Precambrian basement beneath the sedimentary basin (Ross et al., 1991). This boundary is characterized by high heat generation averages of $3.5 \mu\text{W}/\text{m}^3$ ($N = 15$ number of data) and $3 \mu\text{W}/\text{m}^3$ ($N = 261$) (Jessop, 1992). The alignment of the highest heat flow zone with the boundary between these two ancient units within the Precambrian basement may be related to a wide collision zone, with higher concentrations of heat-generating elements formed by vertical redistribution of radiogenic elements. This phenomenon was previously proposed by Drury (1985) for other areas of the Canadian shield such as the Churchill-Superior boundary zone. It could be applied to geothermal exploration in Northern Alberta if additional data collection can show that the high heat flow zone is caused by high levels of radiogenic heat generation from U, Th, and K.

HEAT FLOW-HEAT GENERATION IN THE HUNT WELL (FORT MCMURRAY)

Having considered the regional variation of heat flow and thermal gradient, we will now consider a more detailed study of these parameters around the Hunt well in Fort McMurray.



Figure 7. Photograph of the Hunt well core at the Energy Resources Conservation Board (ERCB) Core Research Center in Calgary. Core in each of the slats is approximately 0.75 m (2.46 ft) (photo by J. Majorowicz, October 2010).

Thermal Conductivity of Northern Alberta Basement Rocks

The most reliable heat flow estimates for the Athabasca oil sands area are based on thermal measurements in the 2.34-km (1.45-mi)-deep Hunt well where equilibrium temperature logs have been recorded. The thermal conductivity (k) of the basement rocks was determined from granitic core samples recovered at depths of 2330 to 2342 m (7644–7683 ft). Granitoid core samples from the Hunt well (see Figure 7) have been obtained both from the well owner (Charles Warren Hunt) and from the ERCB Core Research Laboratories in Calgary. The samples obtained from the owner are larger (>10 cm [>4 in.] in length) than those from ERCB (1–2 cm; 0.4–0.8 in.). Preliminary mineralogical assessments of these samples have been made using both x-ray diffraction (XRD) and thin-section methods.

Core samples were sent to the Geophysical Institute of the Czech Academy of Sciences for measurement of thermal conductivities using the nondestructive laser optical method developed by Popov et al. (2003). The three largest core samples measured at the geothermics laboratory of the Geophysical Institute of the Czech Academy of Sciences showed that thermal conductivity measurements on the base of the samples gave lower thermal conductivity and diffusivity values than measurements made on the larger faces or on larger samples. This effect is caused by the relatively small dimensions of the surface and the vicinity of the sample boundaries, which prevents effective diffusion of the heat pulse. Thermal conductivity values mea-

sured on the larger and smaller walls along the drill core axis for two samples (samples 1 and 2) showed a consistent thermal conductivity of 2 W/m K. Sample 3 appeared relatively inhomogeneous and showed thermal conductivity values within the range of 2.38 to 4.44 W/m K along the laser beam path. The differences can be explained by the composition of measured samples, which are characterized by a large variability in the quartz content (24–47%). The thermal conductivity of quartz is relatively high (7.69 W/m K; Jessop, 1990) compared with plagioclase (1.5–2.3 W/m K) and K-feldspar (2.37 W/m K), which are other major minerals in these samples.

Knowledge of the mineral composition can be combined with measurements of the thermal conductivity of each mineral that can be used to predict the thermal conductivity of the whole rock using the geometric model of Jessop (1990), which states that

$$K = \exp\left[\sum_{r=1}^n \Phi_r \ln(K_r)\right] \quad (8)$$

where K is thermal conductivity, Φ_r is the volume fraction of the r th mineral, and K_r is the thermal conductivity measurement of the r th mineral made in the laboratory.

The values listed above predict a thermal conductivity of almost 3 W/m K, which is higher than the values determined for the Hunt well core plugs by the laser method. This is still the case if low-end values such as 1.5 W/m K are used for the thermal conductivity of plagioclase that are used in the calculation. The range of thermal conductivities reported for plagioclase is 1.5–2.35 W/m K, according to table 5 in Jessop (1990). The calculated value is also higher than most of the thermal conductivity measurements made on the 26 core plugs at the Geological Survey of Alberta with the heat impulse method (Mathias-1) that was about 2.72 W/m K, SD = 0.2 W/m K. In summary, the value of thermal conductivity for the Hunt well granites mean value of 2.72 W/m K obtained for the 26 plugs using heat impulse method is assumed to be correct.

The geothermal gradient in the granites of the Hunt well at depths of 2191 to 2342 m (7188–7683 ft) is calculated to be 22 mK/m. Using the thermal conductivity values of 2.72 W/m K derived above, this predicts a heat flow near 60 mW/m², which compares to a national average of 64 mW/m² ± 16 mW/m² (1 σ) for Canada that was calculated by Majorowicz and Grasby (2010b). The range of Hunt well heat flow estimate based on the measured average 2.72 W/m K (59.8 mW/m²) is higher than the cratonic Canadian mean value of 42 mW/m² ± 9 mW/m² (Jessop, 1992).

Table 1. Results of U, Th, K abundances (ppm) in the Hunt well from core analysis (upper five) results and means from two spectral gamma logs for the upper (sediments) and lower (granites) part of the well interval (see text for explanation).

| Sample | K (wt. %) | Th (ppm) | U (ppm) | 9.52 cU | 2.56 cTh | 3.48 cK | A ($\mu\text{W}/\text{m}^3$) |
|----------------------------------------------------------------------|-----------|----------|---------|---------|----------|---------|--------------------------------|
| HW1B | 1.13 | 8.46 | 0.54 | 5.16 | 21.66 | 3.92 | 0.78 |
| HW2B | 1.02 | 0.38 | 0.22 | 2.05 | 0.971 | 3.56 | 0.17 |
| HW3B | 0.82 | 0.20 | 0.27 | 2.56 | 0.51 | 2.84 | 0.15 |
| University of Alberta– GeoForschungsZentrum spectral (granite) | 2.85 | 33.53 | 1.71 | 16.28 | 85.84 | 9.92 | 3.19 |
| Loncar spectral (sediments) | 0.36 | 1.8 | 1.9 | 17.23 | 4.81 | 1.25 | 0.58 |

Heat Generation

As described above, heat is generated within the crystalline rocks of the crust. Higher concentrations of U, Th, and K will be associated with elevated heat flow and can be considered targets for geothermal exploration. The Hunt well samples allow models of heat generation to be verified by mineralogical analysis. The heat generation (A) can be calculated from abundances of the radiogenic isotopes of uranium (cU), thorium (cTh), and potassium 40 (cK40) using the equation of Bucker and Rybach (1996):

$$A = 10^{-5} \rho (9.52cU + 2.56cTh + 3.48cK), \text{ in } \mu\text{W}/\text{m}^3 \quad (9)$$

where concentrations are in parts per million (ppm), and ρ is the rock density.

Heat generation can also be studied by well-log measurements of the intensity of radiation caused by radioactive decay. Rybach (1976, 1986) developed an empirical relationship between rock radioactivity measurements and heat generation determinations on corresponding rock samples, which can be used for indirect heat generation estimates from gamma logs. The Rybach (1986) relationship is of general use as standard gamma-ray (GR) units (American Petroleum Institute [API]). The empirical relationship GR (API units) versus A ($\mu\text{W}/\text{m}^3$) has been further developed and revised in the equation of Bucker and Rybach (1996):

$$A = 0.0158(\text{GR [API]} - 0.8) \quad (10)$$

Gamma Ray (Total Count)–based Heat Generation Determination

To apply this to the Hunt well, a gamma log was collected in the well from the surface to a depth of 2334 m

(7657 ft). The production gamma ray (PGR) tool made by Sondex measures the naturally occurring radiation that is emitted by various formations to determine lithology. Gamma rays are detected by a sodium iodide scintillation crystal, amplified and counted with an appropriate telemetry tool. The detector is temperature compensated to minimize drift from the photomultiplier tube. When calibrated, the difference between background and calibrator levels establishes a ratio between raw counts and API units based on API calibration pits for GR, allowing a calibrated display to be presented on the log in API units.

The log measured by Loncar on December 9, 2010, showed a mean total GR intensity of 124.2 API, which is the value affected by 1000 m (3280 ft) casing and tubing between the surface and the well's bottom. This value is lower than the gamma level (API) based on stacked GR logs done right after the well drilling and recent (July 2011) logging done by University of Alberta–GeoForschungsZentrum Potsdam in a well with no production tubing. The mean total GR intensity is 173.2 API.

This GR mean level allows to predict a heat generation value, $A = 2.72 \mu\text{W}/\text{m}^3$ from the empirical equation given above (Bucker and Rybach, 1996; equation 10). Note that the radiation level and heat generation ($0.28 \mu\text{W}/\text{m}^3$) in the sedimentary rocks are much lower than in the granites.

Gamma-ray Spectrometry (U, Th, and K)–based Heat Generation Determination

Determination of U, Th, and K radiogenic isotopes content can be done with GR spectrometry, which gives better determination of heat generation than preliminary estimates from just measuring the total gamma intensity. Recently (July 2011), gamma-ray spectrometry measurements using U, Th, and K channels were made in the Hunt well, from 0.5 to 1.8 km (0.31–1.12 mi) by the University of Alberta–GeoForschungsZentrum team.

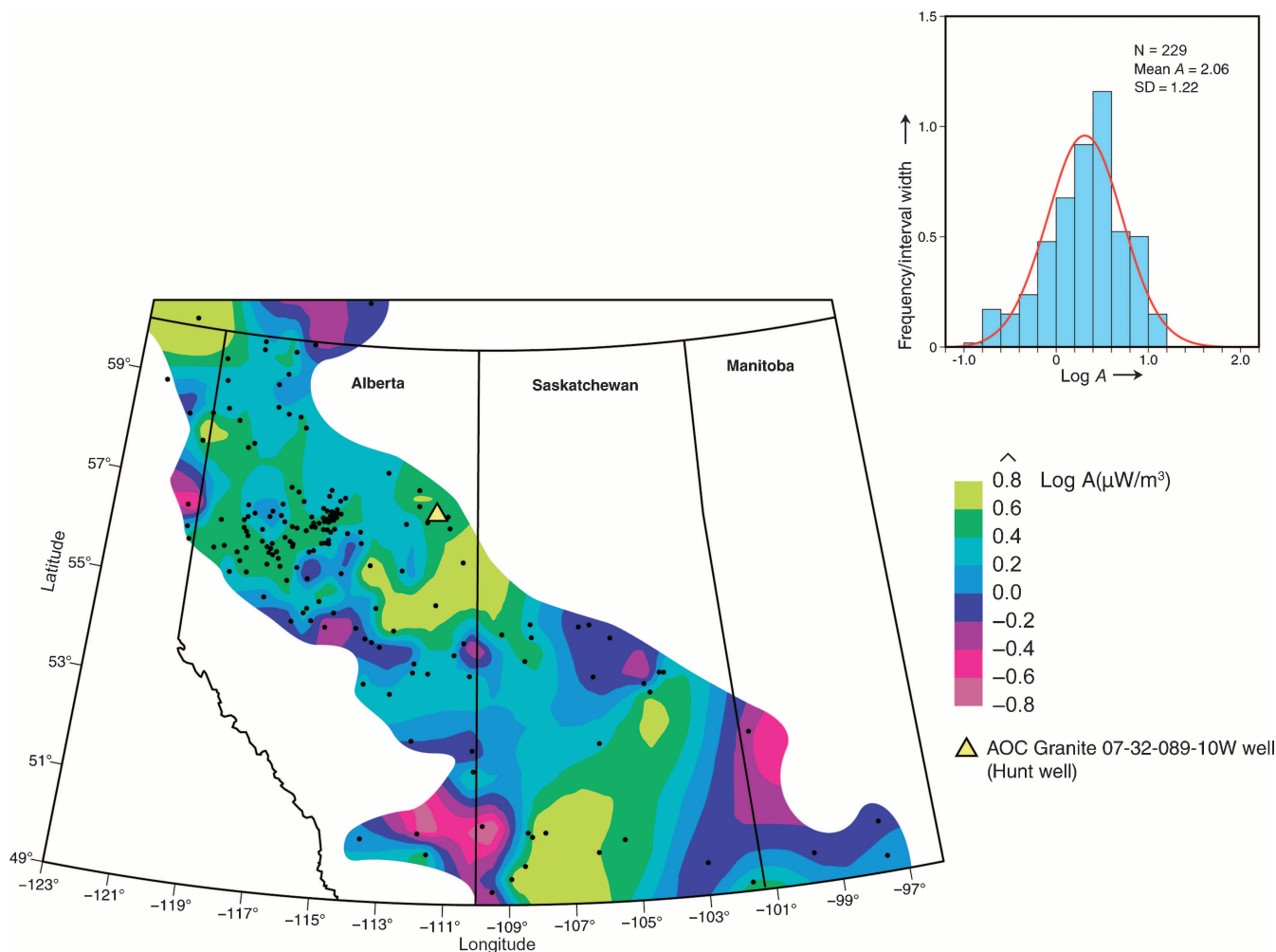


Figure 8. Location of the Hunt well (estimated $\log A = 0.6 \mu\text{W}/\text{m}^3$) versus update of the heat generation map of $\log A$, where A is heat generation in $\mu\text{W}/\text{m}^3$. The insert shows log-normal distribution of $\log A$ (modified from Jones and Majorowicz, 1987).

Mean concentrations of U (1.71 ppm), Th (33.53 ppm), and K (2.85%) were calculated from recorded logs. Mean heat generation was computed from these spectral gamma results and gives high value ($3.2 \mu\text{W}/\text{m}^3$, as detailed in Table 1). A much higher value was calculated from two gamma-ray spectrometry logs done previously (December by commercial logging by Loncar, who used a different probe [Three Rivers Ltd]). Their runs give higher levels of U and a heat generation near $3.7 \mu\text{W}/\text{m}^3$.

Laboratory Geochemical Method Core Sample Analysis-based Heat Generation Determination

The concentrations of heat-producing elements have also been determined by geochemical techniques for a limited number of core samples from the Hunt well

(Table 1). The analytical technique used for determining these elemental concentrations is a modification of the technique described in detail in Cooper et al. (2008). In brief, finely ground rock powders were prepared from the core samples and were dissolved in a combination of hydrofluoric and nitric acid in Savillex beakers. The resulting solutions were analyzed on a Perkin-Elmer Elan 6000 quadrupole inductively coupled plasma mass spectrometer (ICP-MS) in the Department of Earth and Atmospheric Sciences at the University of Alberta. As determined by replicate dissolutions of the Hunt well samples and dissolutions of international rock standards, the K, U, and Th analyses of the core samples are believed to be accurate and precise to better than 10% relative of the reported concentrations.

All three analyzed samples (HW1B, HW2B, HW3B) were taken from the very bottom of the first Hunt well

Table 2. Results of heat generation from Burwash and Burwash (1989).*

| Lsd | Section | Township | Range | Meridian | Heat Generation A ($\mu\text{W}/\text{m}^3$) | Resulting Heat Flow Q (mW/m^2) |
|-----|---------|----------|-------|----------|------------------------------------------------|--------------------------------------------------|
| 7 | 8 | 83 | 3 | w4 | 5.12 | 82.152 |
| 10 | 23 | 87 | 22 | w4 | 2.26 | 54.696 |
| 2 | 32 | 89 | 12 | w4 | 3.3 | 64.68 |
| 13 | 31 | 96 | 6 | w4 | 1.31 | 45.576 |
| 2 | 2 | 80 | 6 | w4 | 1.17 | 44.232 |
| 5 | 34 | 78 | 6 | w4 | 0.8 | 40.68 |
| 10 | 10 | 66 | 6 | w4 | 2.61 | 58.056 |
| | | | | Mean | 2.37 | 55.72 |

*U, Th, and K abundances and expected heat flow from Q-versus-A relationship in the area of northeastern Alberta wells. Lsd = legal subdivision.

at the 2342-m (7683-ft) level. The analyses indicate concentrations of K (0.82–1.13 wt. %), U (0.22–0.54 ppm), and Th (0.2–8.46 ppm) that are markedly lower than average concentrations of these elements deduced from gamma-ray spectrometry at the larger 0.5- to 1.8-km (0.31–1.12-mi) interval above. Although the geochemically determined concentrations are likely to be more accurate than those determined by well-logging techniques, it is not clear if the geochemical results reported for individual samples from the bottom of the Hunt well (2342 m; 7683 ft) are representative of the concentrations of heat-producing elements in the well as a whole. In particular, the gamma-ray spectrometric logs were taken from the top of the Precambrian to 1800-m (5905-ft) depth, and it is possible that this larger depth interval is characterized by different rock types with different K, U, and Th concentrations than those present in 1-m (3.3-ft) core at the bottom of the first well. To test this idea, we intend to expand our geochemical database through analysis of additional core and rock

chip samples recovered from different depths in the well.

Comparison of New Heat Generation Determination with Previous Work Data for the Area

The study of Burwash and Cumming (1976) has provided the data on uranium and thorium concentrations for 182 samples from the Precambrian basement of the Churchill province in Alberta and Saskatchewan and the Superior province in eastern Saskatchewan and Manitoba. The measurements were made by the delayed neutron activation method. Mapping of the heat generation trends across the WCSB was reported by Jones and Majorowicz (1987), using the Burwash and Cumming data set plus additional data from the Peace River area (total of 229 samples). Burwash and Burwash (1989) and Bachu and Burwash (1991) did further analysis and mapping for Alberta and the WCSB, respectively.

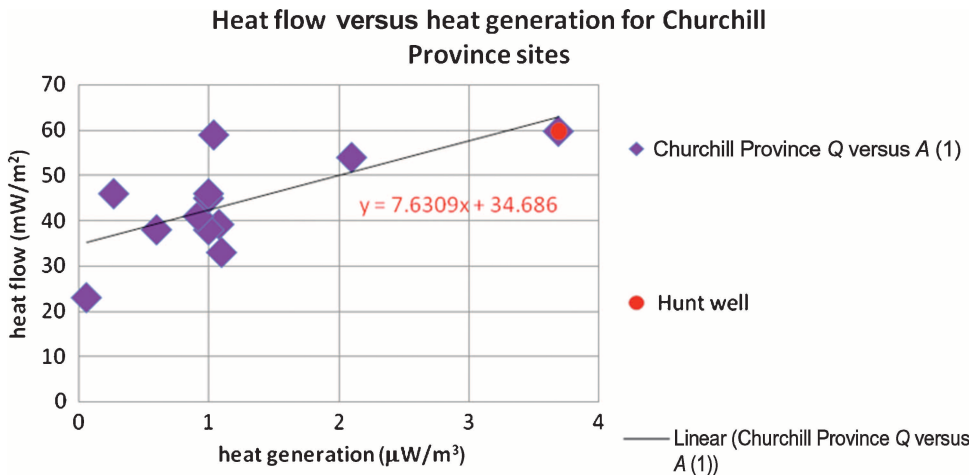


Figure 9. Heat flow versus radiogenic heat generation of the Precambrian rocks in the Churchill Province. Heat generation and heat flow estimates for the Fort McMurray area are used: $A = 3.7 \mu\text{W}/\text{m}^3$, $Q = 60 \text{ mW}/\text{m}^2$.

The latter study presented additional heat generation values for the WCSB and increased the database to 240 samples.

Bachu and Burwash (1991) also presented U , Th , and K concentrations and heat generation values for samples obtained in wells drilled during the construction of the Slave River hydroelectric project to the north of our study area but did not list precise sample locations. The mean value based on 12 samples from 12 wells was $2.955 \mu\text{W}/\text{m}^3$, with the range 0.42 to $5.94 \mu\text{W}/\text{m}^3$. The Th/U ratio had a mean value of 3.09 .

The mean value $A = 2.06$ (SD 1.22) $\mu\text{W}/\text{m}^3$ for the WCSB basement (Jones and Majorowicz, 1987) is larger than the radiogenic heat generation values reported for the Superior (approximately $1.2 \mu\text{W}/\text{m}^3$; Jessop and Lewis, 1978) and Churchill cratons (approximately $0.7 \mu\text{W}/\text{m}^3$, Drury, 1985, and $1.05 \mu\text{W}/\text{m}^3$, this work; see Figure 9 compilation) provinces. When equal log A contour intervals were used to map the basement heat generation (Jones and Majorowicz, 1987), three large zones of relatively high heat generation were found. One coincides with the Peace River Arch basement structure, and one coincides with the Athabasca axis defined by Darnley (1981) (Figure 8).

The mean value of A for northeastern Alberta in the vicinity of our study area (Table 2) is $2.37 \mu\text{W}/\text{m}^3$ (minimum and maximum are 0.8 and $5.12 \mu\text{W}/\text{m}^3$, respectively), as compiled from the Burwash and Burwash (1989) data.

Estimates of heat generation made in the Hunt well using a spectral gamma log of GeoForschungsZentrum and Loncar were 3.2 to $3.7 \mu\text{W}/\text{m}^3$, respectively. These values are high, but the previous discussion shows that they are well within the range of values previously reported from northeastern Alberta. These values are part of a region of high heat generation called the Athabasca axis high by Jones and Majorowicz (1987).

The Th/U ratio for the Hunt well is based on GeoForschungsZentrum spectral log data and is uncommonly high, near 16 . It is a much higher Th/U ratio (3.09) found in Wood Buffalo basement core samples by Bachu and Burwash (1991). Note that the Th/U ratio of the Hunt granite by spectral log is uncommonly high and shows very a unique character of rocks that went through metasomatism there. The empirical relationship holds for normal Th/U ratios of about 4.0 and lacks calibration points in the high heat production range (L. Rybach, 2011, personal communication).

Heat Flow–Heat Generation Relationship

The heat flow–heat generation relationship for the Precambrian Churchill province has been studied (Figure 9). This includes the preliminary results of the

Hunt well in Fort McMurray and the Rumpel Lake well (Drury, 1985) to the northeast of the Athabasca oil sands. Other Churchill Province data have been taken from the compilation of Jessop (1990). These data suggest a correlation ($R > 0.63$) with a reduced (see below for explanation) heat flow of $Q_r = 35 \text{ mW}/\text{m}^2$ under the upper crustal layer some 8 km (5 mi) thick (see Jessop, 1990, for details on heat flow versus heat generation and heat generation models for the crust). This result is close to the WCSB cratonic values of Jessop (1992), $Q_r = 33 \pm 3 \text{ mW}/\text{m}^2$ and $D = 10 \pm 4 \text{ km}$ ($6.2 \pm 2.5 \text{ mi}$). The cratonic numbers were used to calculate geotherms for the cratonic area of western and northern Canada by Majorowicz and Grasby (2010a) (see Figure 1 inset).

The dependence of heat flow on heat generation established for the Churchill province shows that the search for basement rocks with high heat generation is a priority for further study of high heat prospects for geothermal energy.

The statistical relationship between heat flow (Q) and heat generation (A) (Figure 8) is of the form

$$Q = Q_r + DAo \quad (11)$$

In this model, crustal radiogenic heat generation occurs in a layer with thickness D . Q_r is known as the reduced heat flow, which is the heat flow into this layer, caused by the heat flow input from the lower crust and upper mantle below a depth D . The heat generation model proposed by Lachenbruch and Sass (1977) for the crust assumes exponential decrease of heat generation with depth (equation below). It takes the form

$$A = A_o \exp(-z D^{-1}) \quad (12)$$

where A is the heat generation, A_o is the surface heat generation, z is the depth, and D is the thickness (heat generation occurs in a layer with thickness D).

This model explains the statistical relationship between Q and A in many locations worldwide (Drury, 1986). It has been used here to explain the statistical relationship between heat flow and heat generation for the Churchill province. It can be applied to the Hunt well using the estimates of A , Q , and D (Figure 10).

HIGH-TEMPERATURE GEOTHERMAL RESOURCE IN THE OIL SANDS AREAS?

Based on the results of the Hunt well temperature logs that were recorded with a platinum thermometer

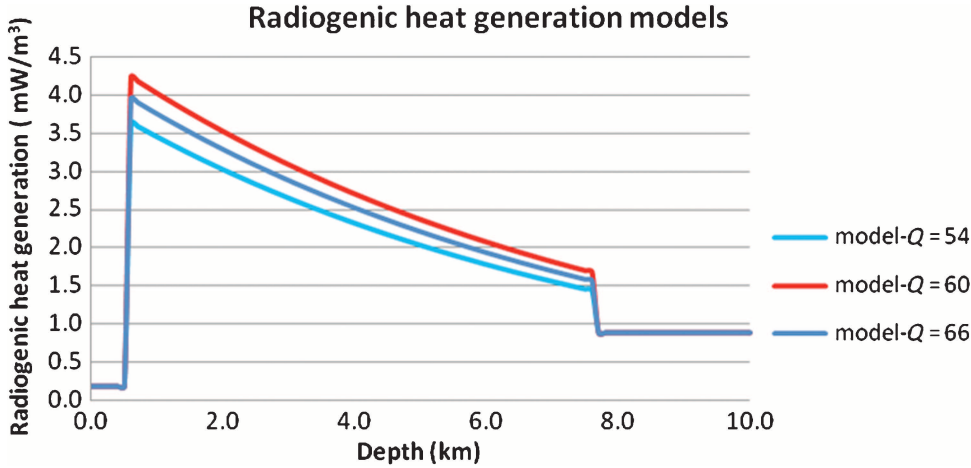


Figure 10. Radiogenic heat generation–depth exponential decay model derived from Churchill Province heat flow versus heat generation statistical relationship (Figure 7) for values of Q (mW/m^2), D (km), and A ($\mu\text{W}/\text{m}^3$). Three models are used to illustrate the temperature–depth variations (Figure 13) for the Fort McMurray Precambrian rocks, Churchill Province.

probe Sondex in 2008 and 2010 (Figure 11), we can refine estimates of subsurface temperature beneath the Athabasca oil sands. The base of the Phanerozoic sedimentary succession is at a depth of 500 m (1640 ft), with a temperature of 11°C at the top of the Precambrian basement. Such low temperature at the bottom of the basin precludes the use of a direct heat geothermal project in the area. However, such heat source could be used with geothermal heat exchange with the aid of heat pumps.

The thermal data from the Hunt well suggest that in the area of the Athabasca oil sands, reaching the temperatures needed for geothermal energy production will require drilling into crystalline rocks. Downward extrapolation of the thermal gradient measured (Figure 12) in the deep part of the crystalline basement ($22 \text{ mK}/\text{m}$) well below the potential influence of the glacial–post-glacial downward heat flow influence predicts that a temperature of 80°C would be found at a depth of about 4 km (2.5 mi). The variations of temperatures (T) as a function of depth (z) can be predicted for a range of likely heat flows in the area from the equation

$$T(z) = T_o + (Q/K + A_oDK^{-1})z + (A_oD^2K^{-1}) \times \{1 - \exp(-z/D)\}, \quad (13)$$

where T_o is the mean equilibrium surface temperature and K is the thermal conductivity.

The observed curvature of the temperature–depth range in Figure 13 is a result of the decrease in thermal gradient with increasing depth. This is caused by the decrease in heat generation with depth, as described by the model of Lachenbruch and Sass (1977). Heat generation A below depth D is assumed to be $0.9 \text{ mW}/\text{m}^3$ for the midcrustal depths (Figure 10).

The model described above is clearly a simplification; however, it satisfies the heat flow–versus–heat

generation relationship that was based on the idea of heat flow provinces (see Lachenbruch and Sass, 1977; Drury, 1986, for further discussion of the model). The other model used to explain the relationship of Q versus A is the simple step model, which is also called the Roy model (Roy et al., 1968):

$$A(z) = A_o \ 0zD \quad (14)$$

In both cases, heat flow will decrease with depth as

$$Q_z = Q_o - \int Adz, \quad (15)$$

where Q_o is the surface heat flow. Temperatures of 120 to 150°C would be found at depths of 6.4 to 8.4 km (4.0–5.2 mi) and, in principle, could be used to generate electricity with the ORC. This is likely uneconomic because Tester et al. (2006) estimated that a depth of



Figure 11. Preparing for temperature logging of the Hunt well after filling the well with water in December 2010.

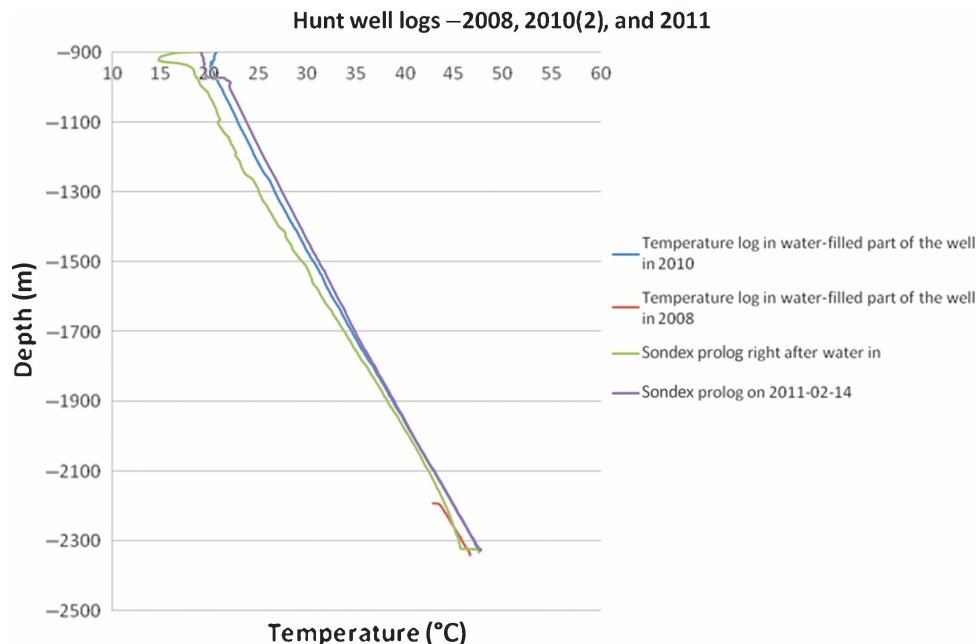


Figure 12. Variation of temperature as a function of depth in the Hunt well. The red curve shows the measured temperatures in the water-filled part of the well in 2008. Recent temperature log (blue curve) was done on December 12, 2010, three days after the well was filled with water and stabilized at the 928-m (3043-ft) level. The well was filled completely on December 9. A total of 51 to 52 m³ (1800–1835 ft³) of water pumped into the well. The fluid levels were as follows: December 9, 897 m (2942 ft); December 10, 917 m (3007 ft); and December 12, 928 m (3043 ft).

7 km (4.34 mi) for the 150°C isotherm represents the limit for economic electricity generation with EGS.

ECONOMICS OF USING GEOTHERMAL HEAT IN OIL SANDS PROCESSING

Direct Heating of Water

Two major incentives for using geothermal energy in oil sands extraction and processing exist: (1) the cost of natural gas and (2) the reduction in greenhouse gas emissions. Oil sands extraction and processing could benefit from scalable, reliable heat sources for heating water and generating steam. Most of this energy is currently provided by burning natural hydrocarbons and supplemented by heat recovery techniques such as cogeneration (Rosen, 2008; Natural Resources Canada’s Office of Energy Efficiency, 2006). In the case of in-situ oil sands operations, low-grade geothermal heat would reduce the overall natural gas demand, with the advantage of limited degradation in thermal content by recycling the thermal fluids instead of extracting them.

This idea of using geothermal heat for oil sands processing was previously suggested by M. Moore (2006, personal communication). The industry consortium, GeoPower in the Oil Sands (GeoPos, established in 2007), also suggested that geothermal heat can compete economically with burning natural gas.

In this chapter, we present the following simplified calculation to study the economic feasibility by

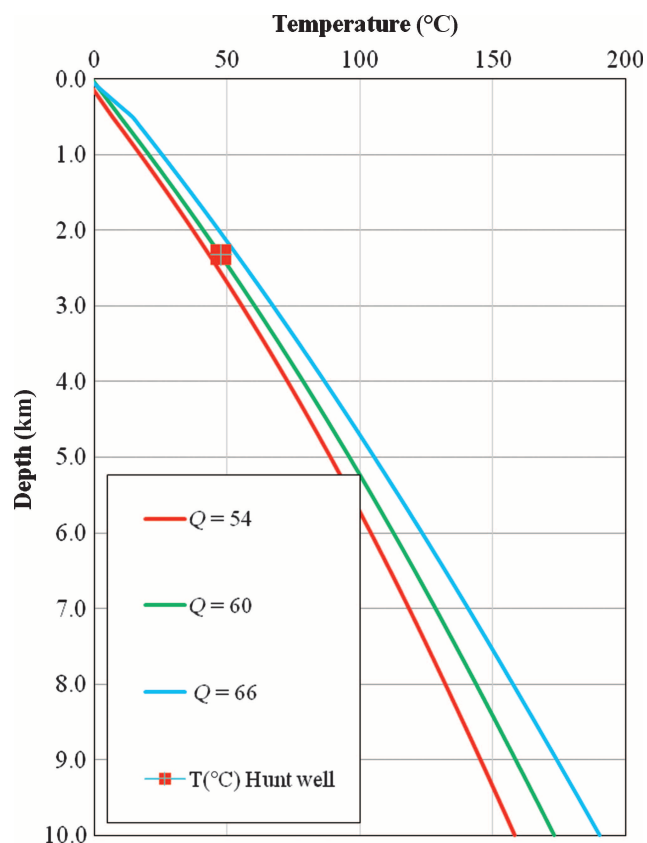


Figure 13. Temperature-depth predictions to 10 km (6 mi) for the Fort McMurray area.

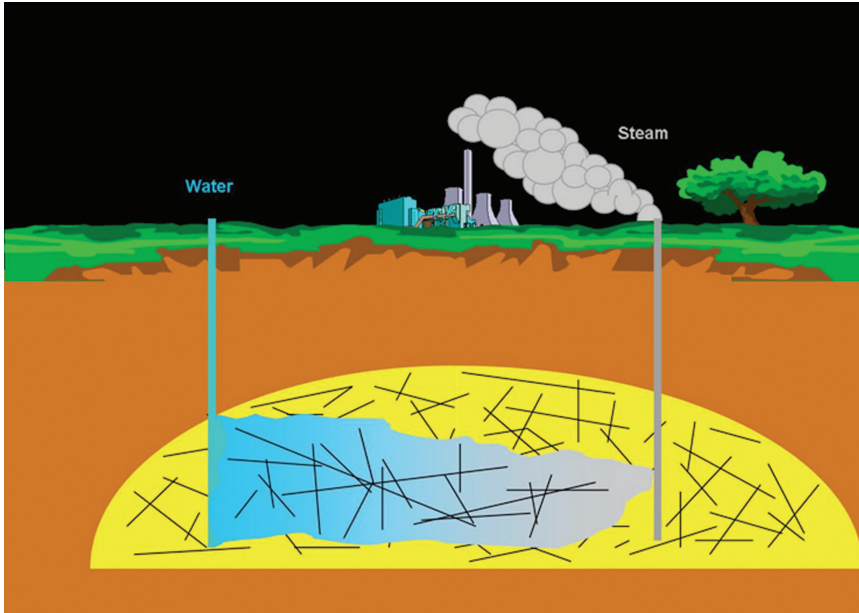


Figure 14. Conceptual model of heat extraction from the artificially fractured crystalline rock flooded with surface water and extracted by a production well as hot water or steam (this is depth and temperature dependent).

considering a fractured system using production and injection wells (Figure 14). The calculations illustrated in Figure 15 make the following assumptions:

- 1) Drilling a well doublet to 6 km (3.7 mi) would cost approximately \$30 million based on Tester et al. (2006);
- 2) Water is circulated through a fractured granite reservoir, and the flow rate is sustained for 10 yr;
- 3) Water from the geothermal loop is used to heat water for oil sand processing and heats it by 60°C.

The cost of heating water for oil sands processing was calculated based on these assumptions and is shown in Figure 15. At a flow rate of 50 L/s, the cost of geothermal heat can be seen to be comparable with the cost of burning natural gas (\$3–6/GJ at 50% boiler efficiency). This flow rate has been sustained at some geothermal projects such as Soultz and can be considered realistic.

The HAI will investigate the energy economics of this idea in greater detail using detailed numerical modeling. The ability of a fractured rock reservoir to sustain a flow rate of 50 L/s, with a temperature increase of 50 to 60°C, will be critically examined. Another critical issue to be understood is what type of fracture density could be created at the depth range of 4 to 5 km (2.5–3.1 mi). Detailed petrophysical studies will provide data from basement rocks beneath the Athabasca oil sands to address this issue and see under what conditions hydraulic fracturing would be effective or economic. The heat flow studies will also be used in these numerical studies.

The figures presented below suggest that geothermal heating is, in principle, economic. Both (1) increases in natural gas prices and (2) explicit carbon mitigation costs can only make geothermal systems even more competitive. This situation will be further improved with advances in drilling technology and cost reduction.

Is Electricity Generation Feasible?

The use of hot water for the production of electrical power from EGS would require the use of ORC turbines that have efficiency in the range of 8 to 12%

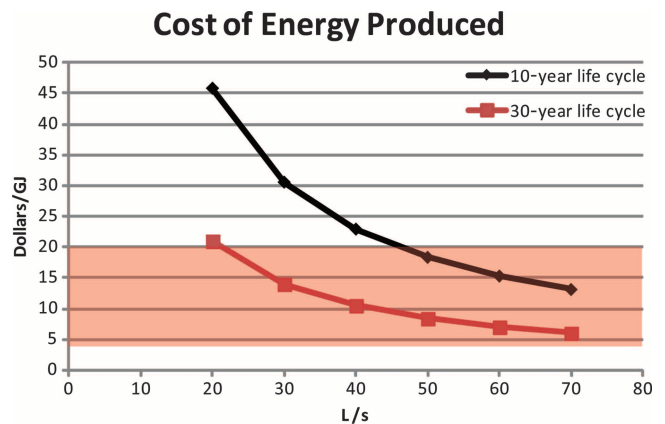


Figure 15. Cost of heating water by 60°C in an EGS as a function of flow rate. Heat is extracted by circulating water through a fractured granite reservoir with a triplet of wells that is sustained for 10 to 30 yr. Cost of using natural gas (\$2–10 per GJ at 50% efficiency) is shown by a transparent area [orange].

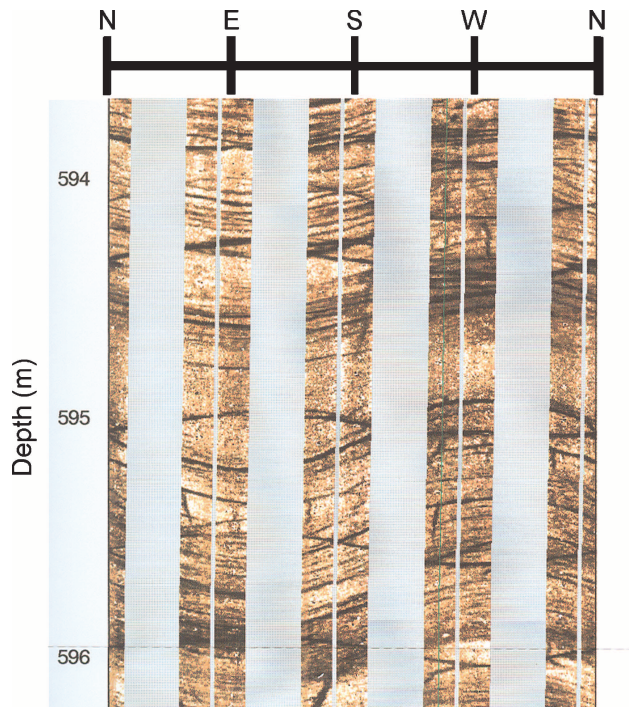


Figure 16. Image logs [Formation Micrologger (FMI)] of fractures in Precambrian granite in the upper part of the Hunt well. Core lengths are approximately 0.75 m (2.46 ft). Fractures are indicated by the bold, dark, straight, and wavy lines on the images.

(Tester et al., 2006). The costs of this type of heat production were estimated using the following assumptions:

- 1) no exploration or technical risks and costs;
- 2) efficiency of ORC = 10%;
- 3) flow rate of 50 L/s per two production wells;
- 4) temperature range = 150 to 50°C.

For a triplet well system (one injector and two producers), these assumptions predict that the overnight cost of electricity will reach some \$22 million/MW of installed capacity in the Peace River oil sands area where 150°C can be reached at 6-km (3.7-mi) depth. In the Athabasca area, the thermal blanket of low-conductivity sediments is only a few hundred meters thick, and the expected temperature gain with depth in crystalline rocks is some 22 mK/m. It is very unlikely that direct electricity generation using geothermal energy could be economic.

In summary, whereas electricity generation may be uneconomic, direct heat extraction may be economic. This process has a thermal efficiency of 50 to 80% and would require drilling to about 4 to 6 km (2.5–3.7 mi). This process would be feasible, providing the crystalline basement rocks that can be fractured to produce a res-

ervoir. Because hot water can only be transmitted over a distance of some tens of kilometers, this reinforces the need to focus geothermal investigations close to the locations where oil sands production (surface or in situ) will occur in the foreseeable future.

EVALUATION OF GEOTHERMAL POTENTIAL IN NORTHERN ALBERTA: FUTURE STUDIES

In addition to questions about the availability of heat, which were discussed above, successful geothermal energy production requires the ability to extract heat from rocks at depth. This heat extraction process is limited by the degree to which fractures can be created at depth. This is controlled by the stress state in the Earth, the type and strength of the rock, and the degree of natural jointing and fracturing. Consequently, several approaches are being used as part of the HAI to determine optimal locations and strategies for geothermal heat production in Northern Alberta. New thermal, geological, and geophysical data sets will be collected in 2011 and will be reported in a separate publication. Here, we summarize some of the research themes.

Developing a Regional Stress Model for Northern Alberta

All prior EGS studies have shown that most of the artificially created fractures are reactivations of existing fractures (Tester et al., 2006). Thus, it is important to map the orientation of existing fractures. Image logs from several wells, including the Hunt well, are being analyzed to measure the spatial density and orientation of preexisting fractures.

The state of crustal stress is key to the development of EGS resources because this is the fundamental factor influencing fluid flow through existing fracture patterns and controlling the creation and orientation of artificially induced hydraulic fractures. Stress directions are being analyzed across Northern Alberta to determine the best locations and orientations for fracturing the rocks. Stress directions can be inferred through the analyses of borehole failure patterns particularly with the development of borehole breakouts that are manifest as a lengthening of the borehole axis in the direction of the least horizontal compression. Borehole breakout analysis was first implemented in Alberta by Bell and Gough (1979), and several subsequent analyses have already been conducted. This work is currently being expanded using public domain-oriented caliper logs. This work is also being followed up with studies of drilling-induced core fractures (Figure 16)

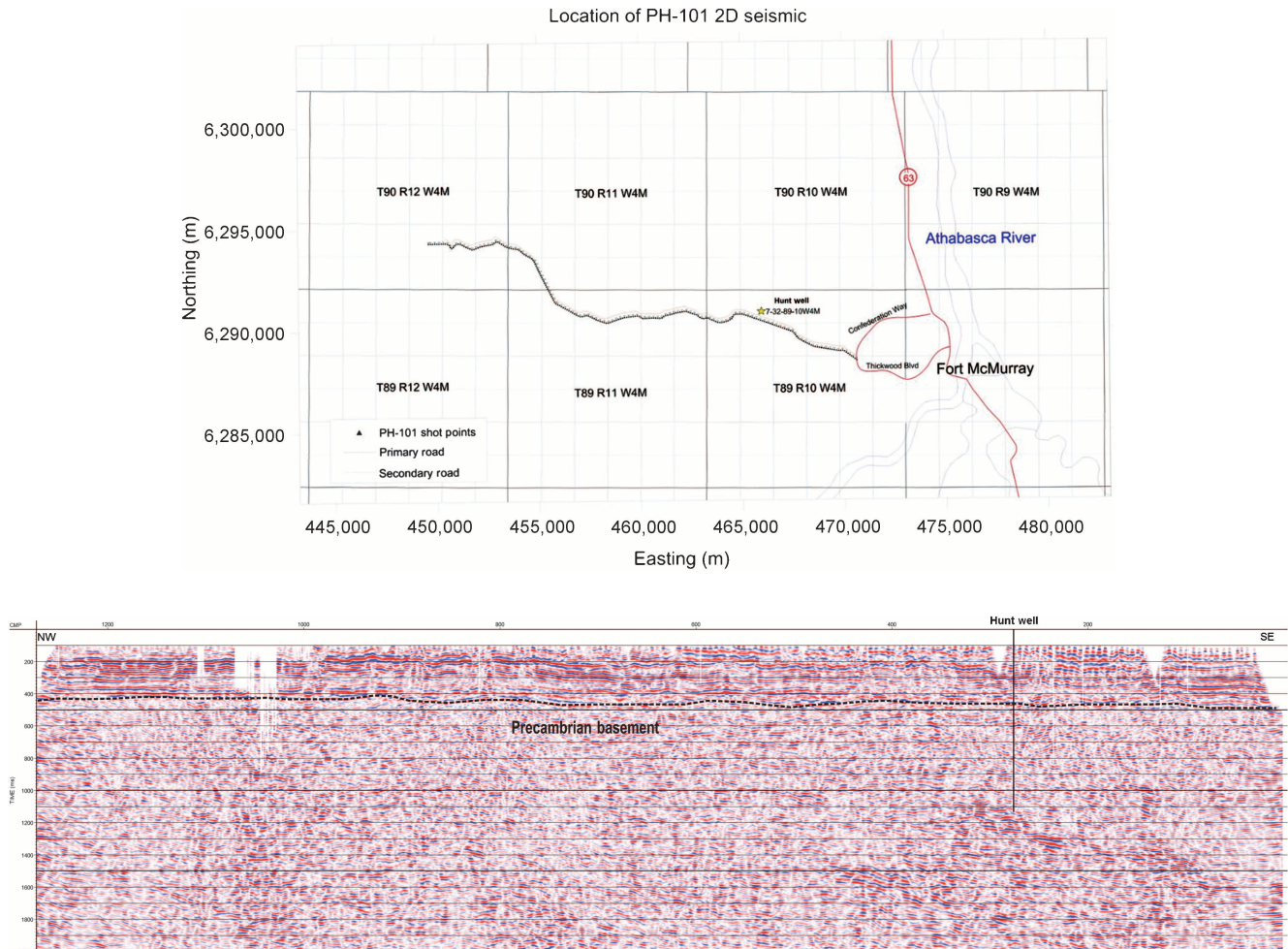


Figure 17. (A) Location of the regional seismic line crossing the location of the Hunt well. (B) Two-dimensional seismic line. Note dipping reflections in the basement in the Hunt well location. These intercept the deeper part of the well and could be interpreted as shear regime features in the granite below the Hunt well location.

that can constrain the relative magnitudes of the principal stresses (Li and Schmitt, 1998). Initial evidence exists from the study of the Hunt well logs and reflections in a nearby seismic section (Figure 17A, B) for a major set of eastward-dipping fractures. Additional evidence for the presence of major fractures comes from the rapid drop in water levels in the Hunt well. The well was filled in December 2010, and the water level dropped to 0.9 km (0.54 mi) in a matter of hours. This was followed by an additional drop of 70 m (230 ft) over the next five weeks. We interpret this observation as an evidence of deep cracks opening under pressure. It is favorable for the development of the EGS because it suggests that (1) regional stress and (2) the orientation of preexisting fractures are favorable for the creation of a network of artificial fractures. It should also be noted that zones of open fractures may not be good locations for EGS. These fractures commonly

result in permanent fluid loss from the geothermal reservoir.

Reservoir simulation (described above) is being used to determine how much heat can be extracted from the metamorphic basement rocks in Northern Alberta. Geologic models for the region are being revised, both for the crystalline basement and overlying sedimentary basin.

Temperature Dependence of Magnetic Susceptibility of Oil Sands Samples as a Means of Constraining Mineralogy In situ

Downhole magnetic susceptibility and temperature measurements could potentially provide useful in-situ estimates of the content of paramagnetic versus diamagnetic minerals in oil sands samples through the Athabasca

(shallow, low-temperature) and Peace River (deeper, higher temperature) areas. A purely diamagnetic mineral such as quartz should show no temperature dependence of magnetic susceptibility and, therefore, will show no variation with depth. Paramagnetic minerals (e.g., clays such as illite or chlorite), however, should show a decrease in magnetic susceptibility according to the Curie law

$$M/B = C/T \quad (16)$$

where M is the magnetization, B is the applied field, M/B is the magnetic susceptibility, C is a mineral-specific Curie constant, and T is the temperature.

Systematic decreases in magnetic susceptibility with temperature (and depth) may help to identify the presence of these paramagnetic minerals in situ. The greater decrease in magnetic susceptibility with temperature, the greater the amount of these minerals. Of course, there may be situations where a decrease in magnetic susceptibility is merely caused by changes in lithology, but a systematic decrease over a large interval is more likely to point to a relatively constant mineralogical composition with the decreases resulting from the temperature dependence of paramagnetic minerals. An example of the temperature dependence of magnetic susceptibility for an oil sand sample with 95% quartz and 5% illite is given in Figure 18.

Surface Geophysical Surveys

Geophysical data are also being used in a regional characterization of the structure of the crystalline basement and sedimentary basin. This work is being conducted on several directions, beginning with the analysis of existing, freely available magnetic and gravity data. It is anticipated that proprietary high-resolution aeromagnetic images will assist in mapping faults and other

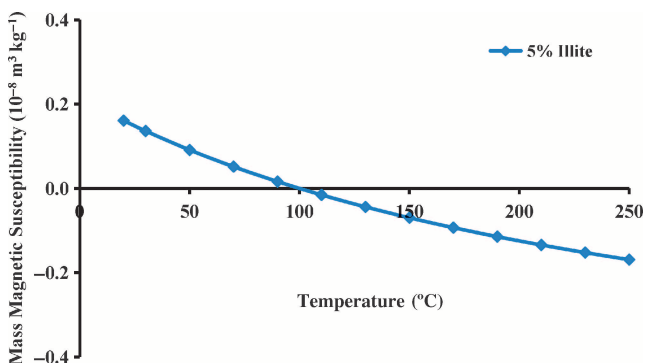


Figure 18. An example of the temperature dependence of magnetic susceptibility for an oil sands sample with 95% quartz and 5% illite.

lineaments within the crystalline basement that might define zones of enhanced fracture density. The amplitudes of the spatial magnetic field variations may also give indirect evidence for changes in the concentration of the radiogenic elements that generate heat. A significant amount of legacy seismic data exists in the region, and this is currently being reprocessed to map structures within both the sedimentary rocks and crystalline basement. One important question to be examined is how displacements within the basement have controlled sedimentation patterns and deformation within the overlying sedimentary sequence.

The Hunt well provides further opportunities to link surface geophysical observations to conditions at depth within the crystalline basement rocks. Additional logging data will be collected within the Hunt well and will include the use of image logs to supplement those already recorded. The goal of this study will be to characterize the distribution and orientation of existing stress and fractures. It will also characterize present-day natural fluid flow and identify the reason for the rapid fluid loss. Additional legacy seismic data have been obtained in the vicinity of the Hunt well, and this is being reprocessed. A borehole seismic survey will be used to investigate possible relationships between the distribution of in-situ fractures and seismic anisotropy. Such seismic anisotropy would be an important exploration tool in the context of EGS because it could allow surface detection of subsurface stress and fracture patterns. Magnetotelluric data will also be collected to image zones of fracturing and would be sensitive to the presence of fluids in these fractures.

In the various geophysical studies described above, it must be stressed that it is not clear if regions of significant fracturing would be target locations for EGS or locations to avoid. When fluids are injected to extract heat, it is commonly observed that the fractures cause major fluid loss.

CONCLUSIONS

Potential sources of geothermal heat have been identified beneath areas currently leased for oil sands extraction. This includes

- 1) the area within the Precambrian basement rocks beneath the Athabasca oil sands north of Fort McMurray;
- 2) the WCSB in the Peace River area.

In the area of the Athabasca oil sands, the removal of paleoclimatic effects suggests that the geothermal gradient in the crystalline basement is 22 mK/m.

Modeling of available thermal data (including thermal conductivity and heat production) predicts a temperature of 80°C at 4.1 km (2.46 mi) and 120°C at 6.5 km (3.9 mi). The studies at the Hunt well provide a suggestion for the Athabasca oil sands that the temperatures needed for effective geothermal energy production will require drilling into crystalline rocks.

Successful geothermal energy production will require the effective extraction of heat from crystalline rocks at depths of 4 to 6 km (2.5–3.7 mi). This heat extraction process is limited by the degree to which artificial fractures can be created at depth. All prior EGS studies have shown that most of the artificially created fractures are reactivations of existing fractures. Therefore, the initial evidence from the study of the existing log seismic section near the location of the Hunt well that deep eastward reflections that are seen in the basement intercept fractures seen in the well is an encouraging sign for the future of geothermal energy in the area. The noticed rapid loss of water from the Hunt well can be interpreted as evidence of water filling deep cracks that have opened under pressure. These observations of open fractures are encouraging for the EGS potential of Northern Alberta.

Although the order-of-magnitude estimates suggest that this type of heat generation could potentially be economic, additional research is needed to fully investigate the feasibility of heat production using geothermal energy as a heat source for the extraction and processing of the Athabasca and Peace River oil sands.

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