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2012 J. Geophys. Eng. 9 534

(http://iopscience.iop.org/1742-2140/9/5/534)

J. Geophys. Eng. 9 (2012) 534–548 doi:10.1088/1742-2132/9/5/534

Investigation of the geothermal state of sedimentary basins using oil industry thermal data: case study from Northern Alberta exhibiting the need to systematically remove biased data

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Received 1 April 2012
Accepted for publication 24 July 2012
Published 17 August 2012
Online at stacks.iop.org/JGE/9/534

Abstract
Subsurface temperature data from industrial sources may contain significant biases that greatly reduce their overall quality. However, if these biases can be identified and removed, the data can provide a good preliminary source of information for further studies. In this paper, industrial thermal data from three sources: bottom hole temperatures, annual pool pressure tests and drill stem tests are evaluated to provide an updated view of the subsurface temperatures below the oil sand regions of Northern Alberta. The study highlights some of the potentially large systematic biases inherent in industrial temperature data which affect estimates of geothermal gradient and regional mapping of the geothermal field.

Keywords: geothermal energy, Canadian geothermal, EGS, heat flow

(Some figures may appear in colour only in the online journal)

1. Introduction

In all geothermal studies, the direct measurement of subsurface temperature is the fundamental observation that is used to estimate and constrain models of other thermal parameters such as geothermal gradient, heat flow and total heat available. Unfortunately, such measurements require a borehole to be drilled to the depth of interest, which can easily cost millions of dollars. A much more economical option is to extrapolate the thermal measurements from shallower wells to the greater depths required for geothermal development. However this requires that the thermal data from shallow wells can be considered reliable and free from systematic biases.

This is the situation encountered in geothermal exploration in Northern Alberta where a heat source is sought in the crystalline basement rocks as a possible energy source for oil sand extraction and processing (Majorowicz *et al* 2012). Only one well has been drilled into the crystalline basement rocks. However tens of thousands of shallow wells have been drilled for hydrocarbon exploration and production. In hydrocarbon wells, temperature is a parameter of minor importance and these measurements are rarely made with sufficient care to give high quality data.

Current databases contain large numbers of bottom hole temperature (BHT), annual pool pressure (APP) test temperature and drill stem test (DST) data that have been collected since the 1950s. All of the data used in this paper will be made available in the near future through the Helmholtz Alberta Initiative (HAI) Theme 4. As a general rule in North America, well data including tests, completions, formations, logs, etc are made available to industry by the regulator after a defined period of confidentiality that

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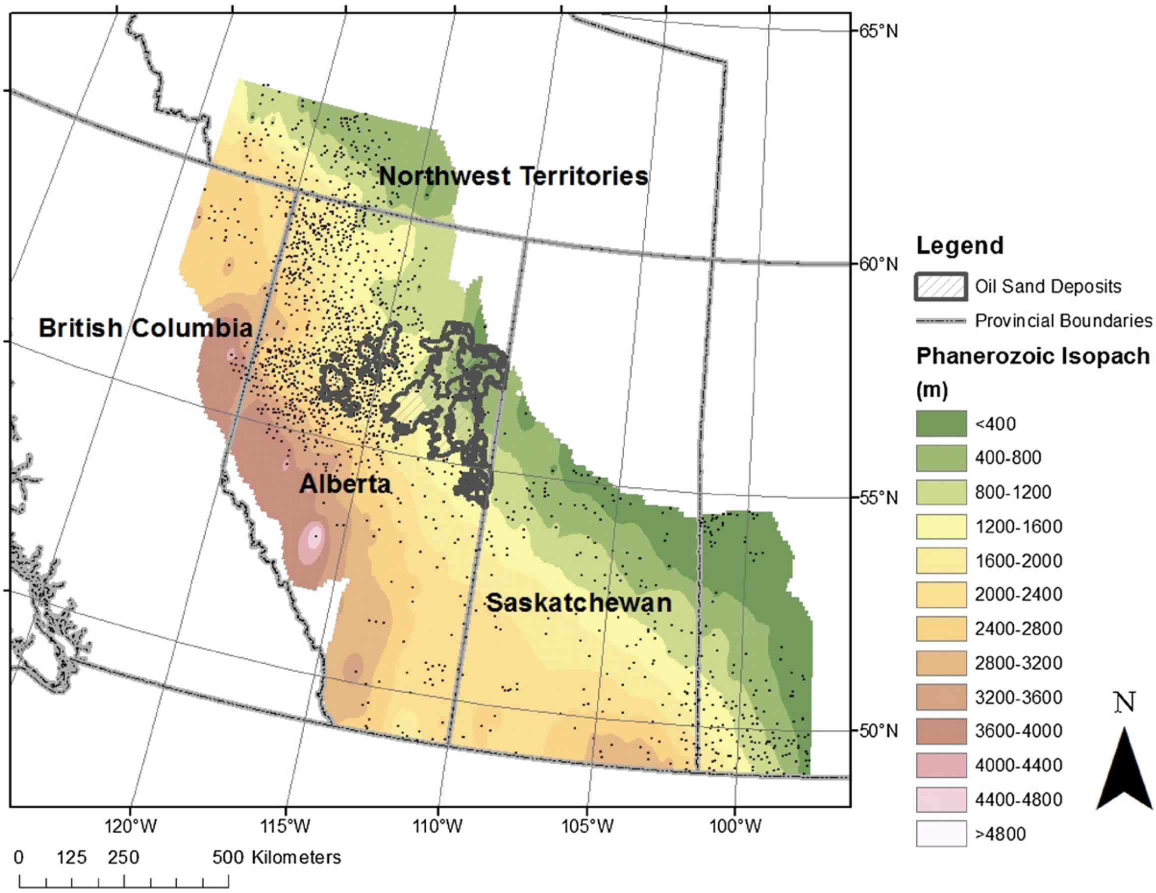


Figure 1. Thickness of the WCSB based on AGS well control data (black dots) modified from Mossop and Shetsen (1994); Burwash *et al* 1994.

ranges from 0 days to infinity. For Alberta, typical time periods of 30 days to a year are common. The data for Alberta are available for search through ACCUMAP at http://www.ihs.com/products/oil-gas-information/analysis-software/accumap/download-well-documents.aspx and IHS, the parent company of ACCUMAP: http://welldocs.ihs.com/login. These data are of variable quality so the greatest challenge in using Alberta industrial data is not in obtaining the data, but rather in assessing the quality and identifying incorrect data. Previous studies using precise continuous temperature logs (Majorowicz *et al* 1999) have identified significant overestimations of temperatures in industrial data in the shallow part of the Western Canadian Sedimentary Basin (WCSB) near Fort McMurray, one of the main target areas of this study.

To classify geothermal systems, Tester *et al* (2006) divided geothermal resources into high- (>150 °C), medium- (50–150 °C) and low- (<50 °C) temperature resources. Low-temperature resources, used for direct heating applications, can be found within the upper 2 km of the WCSB (figure 1) where the basin reaches such a thickness. However, temperatures over 150 °C are needed for power production with enhanced geothermal systems (EGS). Obtaining these temperatures requires drilling to much greater depths and can probably be found only below the base of the WCSB in the underlying crystalline basement rocks. These require predictions based, in most cases, on the available industrial data as shown in examples in figures 2 and 3(*a*) and (*b*). Therefore, the difficulties encountered in geothermal studies of the Alberta basin have not been in lack of data, but in assessing the quality of the data. For this study, these industrial temperature datasets have been compared to (1) a limited number (20) of high precision temperature logs that were made in shallow wells that had been allowed to reach thermal equilibrium (Jessop 1990a, Majorowicz *et al* 1999) and (2) the high precision temperature log measured in 2010–2011 in the 2.35 km deep Anhydride well near Fort McMurray (Majorowicz *et al* 2012). These comparisons have shown that the raw industrial data significantly overestimate geothermal gradients in the Fort McMurray area. The principal study area considered in this paper includes the areas of oil sand deposits, with a 50 km extension in every direction (figure 1). Within the study area, significant variations in geothermal gradients are seen (between 15 and 45 mK m^{-1}; mean = 32 mK m^{-1}; Majorowicz *et al* 2012). The geothermal gradient varies from 20 mK m^{-1} in the southwestern Alberta Rocky Mountain Foothills, to approximately 60 mK m^{-1} in the northwestern corner of Alberta. This variation is controlled by several factors including: (*a*) heat flow reduction by deep groundwater recharge in the Foothills and (*b*) high heat flow due to a high concentration of radiogenic elements, notably in the basement rocks that underlie the WCSB in northwestern Alberta, northeast British Columbia and adjacent regions of the Northwest Territories (Majorowicz and Grasby 2010).

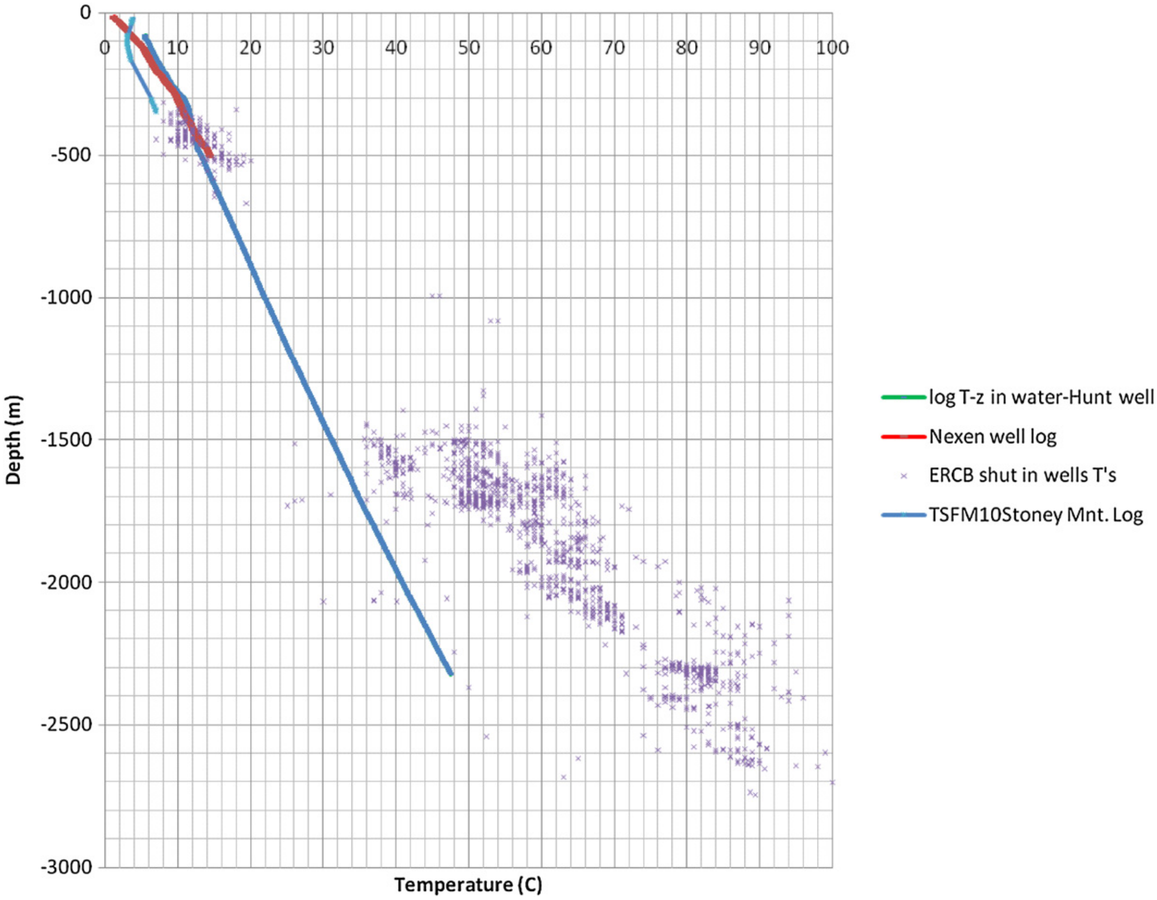


Figure 2. The only available > 2 km deep high precision continuous log of temperature–depth in Alberta from the 2.35 km Anhydride Petroleum 7-32-89-10 (Hunt) well near Fort McMurray (Majorowicz *et al* 2012) and precise logs < 0.6 km temperature logs in sedimentary cover in the Nexen well (2-32-84-07W4) and Stoney Mnt–TSFM10 well (location is 111.272 °N 56.385 °N) near Fort McMurray (Majorowicz *et al* 1999). These logs are compared versus industrial temperature data from the wider region as shown in figures 3(*a*)–(*c*). Note: the comparison shows that the blanketing effect of the deeper basin and its higher heat flow give a much higher temperature at depth and that it is a much better prospect for geothermal energy.

The main purpose of this paper is to produce a preliminary estimate of the thermal conditions in the crust beneath regions of oil sand extraction between Fort McMurray and Peace River (see figure 3 for location). This is done in the context of the larger area of the central-northern Alberta basin. The main variables of interest are the geothermal gradient of the Western Canada Sedimentary Basin (WCSB). Additionally, this paper seeks to highlight some of the systematic biases that have been identified in industrial temperature data. These, as we will show later in this paper have seriously influenced previous studies of geothermal gradients within the basin by overestimating thermal gradient and heat flow in the shallow part of the WCSB basin.

2. Regional geology

Much of Alberta is covered by the northeastward thinning wedge of sedimentary rocks of the WCSB which overlies the Precambrian basement rocks (Burwash *et al* 1994, Mossop and Shetsen 1994). This basin reaches a maximum thickness of 6000 m in the foothills of the Rocky Mountains and terminates to the northeast where the Precambrian basement outcrops as the Canadian Shield. There are two distinct sedimentary successions within the basin. The lower succession was deposited on the passive margin between the Early Cambrian and Jurassic as epeiric sea clastics and carbonates (Wright *et al* 1994). The upper succession was deposited in a foreland basin between the late Jurassic and Paleocene as mountains formed in the Laramide orogeny were eroded. The upper succession is dominated by westerly sourced siliciclastic rocks. Within our study area the unconformity between the WCSB and the Precambrian craton is characterized by a major structural high, known as the Peace River Arch which trends to the northeast (Wright *et al* 1994). Below the WCSB the basement rocks of the North American Craton are composed of various accreted terranes of Archean to Proterozoic age. These have been mapped using magnetic and gravity data and samples from the limited number of drill-holes that have reached the basement (Burwash *et al* 1994).

3. Previous geothermal studies

The first analysis of regional geothermal patterns in the Alberta basin used a limited number of industrial measurements of BHT (Anglin and Beck 1965). This was extended by Majorowicz and Jessop (1981) who used additional

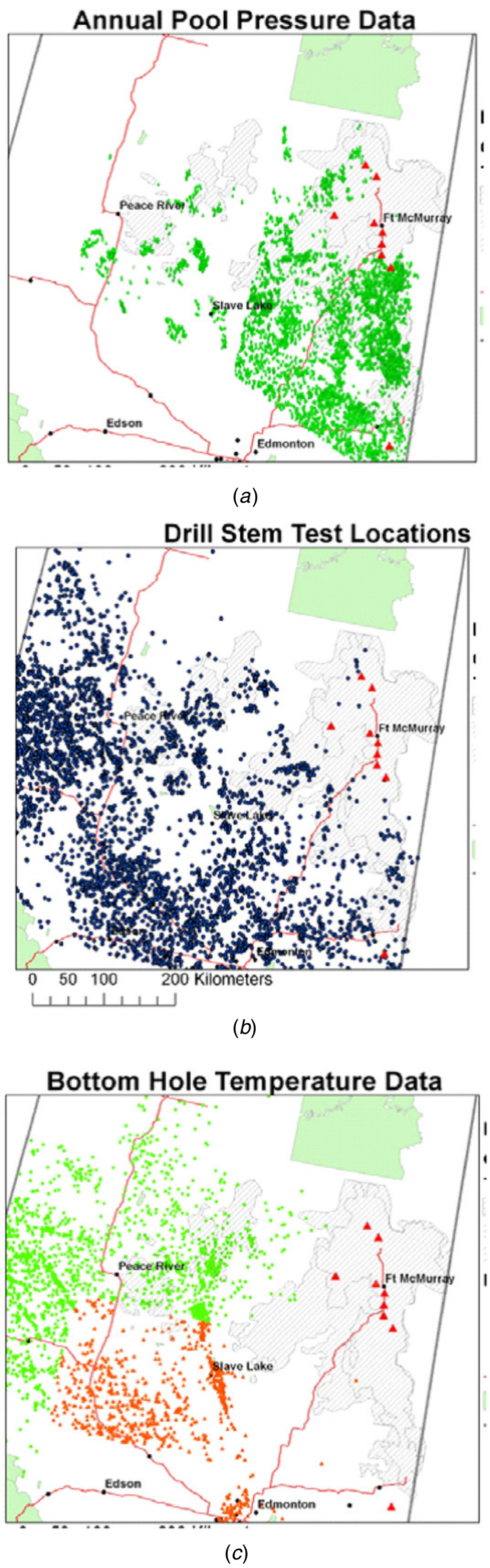


Figure 3. Locations of wells used after the erroneous data was culled and corrected, resulting in higher quality data for BHT (*a*), APP (*b*) and DST (*c*) data. Red triangles indicate locations of precise temperature logs (PSWs). In the BHT data, orange points indicate data corrected by the so-called 'Horner' method (Lachenbruch and Brewer 1959) while green points were corrected by the Harrison *et al* (1983) method.

selected BHT and DST temperature measurements from the American Association Petroleum Geologists (AAPG) geothermal database and Alberta Government Energy Resources Conservation Board open file annual pressure test (APP) temperature data from shut-in wells. A much larger industrial temperature database (BHTs) was collected by Walter Jones at the University of Alberta and used to give improved estimates of regional heat flow patterns (Lam and Jones 1984, Lam *et al* 1985, Jones 1991, Jones *et al* 1985, Majorowicz *et al* 1985). A specific focus was given to direct geothermal energy potential in Western Canada (e.g. WCSB) (Jones *et al* 1985, Majorowicz *et al* 1985). In addition, shallow geothermal energy (Majorowicz *et al* 2009) and EGS potential in all of Canada were investigated by Majorowicz and Grasby (2010).

In the studies mentioned above, forced convection of groundwater originating in the Rocky Mountain Foothills was initially viewed as the dominant process controlling the thermal regime of the basin. This was due mainly to two observations. The first was the lack of any significant correlation between estimated heat flow (Majorowicz and Jessop 1981) and measured U, Th, K concentrations (Burwash 1979, Beach *et al* 1987, Jones and Majorowicz 1987) in areas of high and low hydraulic head. Second, several high heat flow anomalies were identified along the shallow eastern margin of the basin. Another study using industrial temperature data in a foreland basin, the Raton Basin of Colorado, has also concluded that basin-scale groundwater circulation is more important than conduction (Dingwall and Blackwell 2011) based on similar results.

However, using independent hydrogeological and geothermal data, Bachu and Burwash (1994) and Bachu (1991, 1993) found flow rates of formations to be too weak to significantly affect the subsurface temperatures. Additionally, Majorowicz *et al* (1999) identified significant overestimation of Alberta industrial well logs from shallow depths (<1000 m) compared to hydrogeological observation wells confirming similar findings by Hackbarth (1978). Both studies concluded that data shallower than 1000 m should be rejected from future studies. Unfortunately for this study, Fort McMurray, which is one of the key regions of interest, overlies only 500 m of sedimentary rock. Therefore no thermal data exists below a depth of 1000 m in this region with the exception of the Anhydride Petroleum 7-32-89-10 (Hunt) well which has been drilled to a depth of 2370 m (Majorowicz *et al* 2012). In light of these more recent studies, conduction was interpreted to be the dominant mechanism by Majorowicz *et al* (1999, 2012).

The most widely used thermal model for the WCSB is the atlas of the WCSB produced by the Alberta Geological Survey in 1994. It was compiled from 1473 BHT measurements, each of which reached the basement, and was manually verified (Mossop and Shetsen 1994, Bachu and Burwash (1994)). It also includes shallow (<1000 m) temperature records from the shallower portion of the WCSB. This map features unusually high geothermal gradients along the shallow margin of the basin. The most recent map of heat flow in Canada, completed by Majorowicz and Grasby (2010), suggests that heat flow values in the WCSB range from 40–80 mW m^{-2}.

4. Temperature data from wells—data editing and corrections

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.

Three industrial temperature datasets were used for this study, APP tests, DSTs and BHTs. The locations are shown in figures 3(*a*)–(*c*) respectively. Each of these datasets were compared to 20 shallow temperature logs collected from around Fort McMurray by Majorowicz *et al* (1999) and recently taken temperature logs in the 2370 m Hunt well near Fort McMurray (figure 2) were incorporated into this study as constraints to corrected industrial temperature data. Each of these datasets contained tens of thousands of entries from wells within our study area. However, the following discussion will illustrate that much of this data could not be used for the purpose of determining subsurface temperatures.

Any systematic biases that may be present within the datasets must be identified, and removed. The first, and most significant, bias in the data was identified in the shallow pool pressure data and it stems from the use of maximum reading thermometers. During the logging of a low-temperature well, an improperly handled maximum thermometer may record the air temperature at the surface and never encounter a higher temperature within the well. Due to this problem, many shallow measurements taken during the summer months are much higher than the actual temperature at the bottom of the borehole.

4.1. APP tests

APP tests (figure 3(*a*)) are required by the Energy Resource Conservation Board (ERCB) to monitor the pressure and production of oil and gas reservoirs within Alberta. Therefore, there is extensive APP data coverage in Alberta. APP tests required a well to be shut in for several days before the test can be carried out so for that reason the well is able to return to equilibrium with the wall-rock temperature. The time needed will depend on a number of parameters including the depth.

While the testing and reporting procedure for these tests are very rigorous, temperature is of minor concern to the goals of the tests and is only used for calibration of instruments (ERCB 2010). Therefore, while temperature data is available, there has never been any quality control or quality assurance standards in place. Up until the late 1980s to early 1990s, analogue maximum temperature reading thermometers were the industry standard. Today digital instruments are much more common. These measurements are preferred because they take their measurements *in situ* at the depth of interest instead of recording the maximum temperature encountered.

For the study described in this paper, the ERCB released the APP data for just the oil sand region of Northern Alberta. Therefore this is the most spatially limited dataset of the three available, covering the oil sand areas, plus 50 km in every direction. Spatial resolution is also very limited for this dataset in the western half of the basin and large areas containing oil sand deposits are missing data. On the other hand, data coverage in the eastern part of the basin is better than coverage from either BHTs or DSTs.

All three data sets are potentially prone to this error but it is very well defined in the shallow pool test data. Figures 4(*a*)–(*c*) show this effect quite clearly as the shallow annual pool test dataset contains hundreds of measurements made during summer months that are significantly higher than measurements taken during winter months. This error can yield geothermal gradients as much as five times the true value. Furthermore, these erroneous summer measurements are at odds with the precise shallow wells (PSWs) that were reported by Majorowicz *et al* (2009).

Further evidence that this error is also due to the use of maximum temperature thermometers is that the number of overestimated summer measurements decreases progressively for more recent time after 1980. Digital recording thermistors were first introduced in the early 1980s, but were still quite rare for a decade. Throughout the 1990s, digital equipment became more popular until it was the industry standard. This is shown in figure 5 as data from before the 1980s was riddled with the seasonal effect and it is not until 2000 that the seasonal effect is no longer seen. At greater depths, where the borehole temperature is greater than 30 °C, the seasonal effect is no longer relevant and for our data this depth is approximately 1200 m. In conclusion, it is also worth noting that maximum temperature thermometers are still being used today, but certainly by 2000 the seasonal effect was largely eliminated and only data from after 2000 or at depths greater than 900 m are used in this study.

4.2. Drill stem tests

DSTs were used to assess the productivity of a formation by opening it to atmospheric pressures and measuring the rate at which formation pressure drops and formation fluids flow. DSTs are rich sources of information about reservoir and fluid properties if they are successful. However, they are expensive and therefore less abundant than the other two types of tests.

Temperatures measured in DSTs are a direct measurement of pore fluid temperature and therefore do not need to equilibrate with the temperature of the well bore. For this reason, as long as the test is carried out successfully, the temperature can be considered more reliable than a BHT measurement. However, there are many reasons why a DST may fail and different types of problems will have different and unpredictable effects on the resulting temperature measurement. Furthermore, a reservoir that has been producing for many years or decades will cool off as cooler formation waters are re-injected into the wells. In this case, DSTs from old reservoirs will underestimate the true temperature at that depth. Technically speaking, it is possible to manually evaluate each test on a case-by-case basis to identify erroneous tests. However, to do so would be extremely time consuming and so for this study data were imported without editing from the ACCUMAP database.

The DST data is spatially extensive and displays good coverage of the Peace River area and areas south of the oil

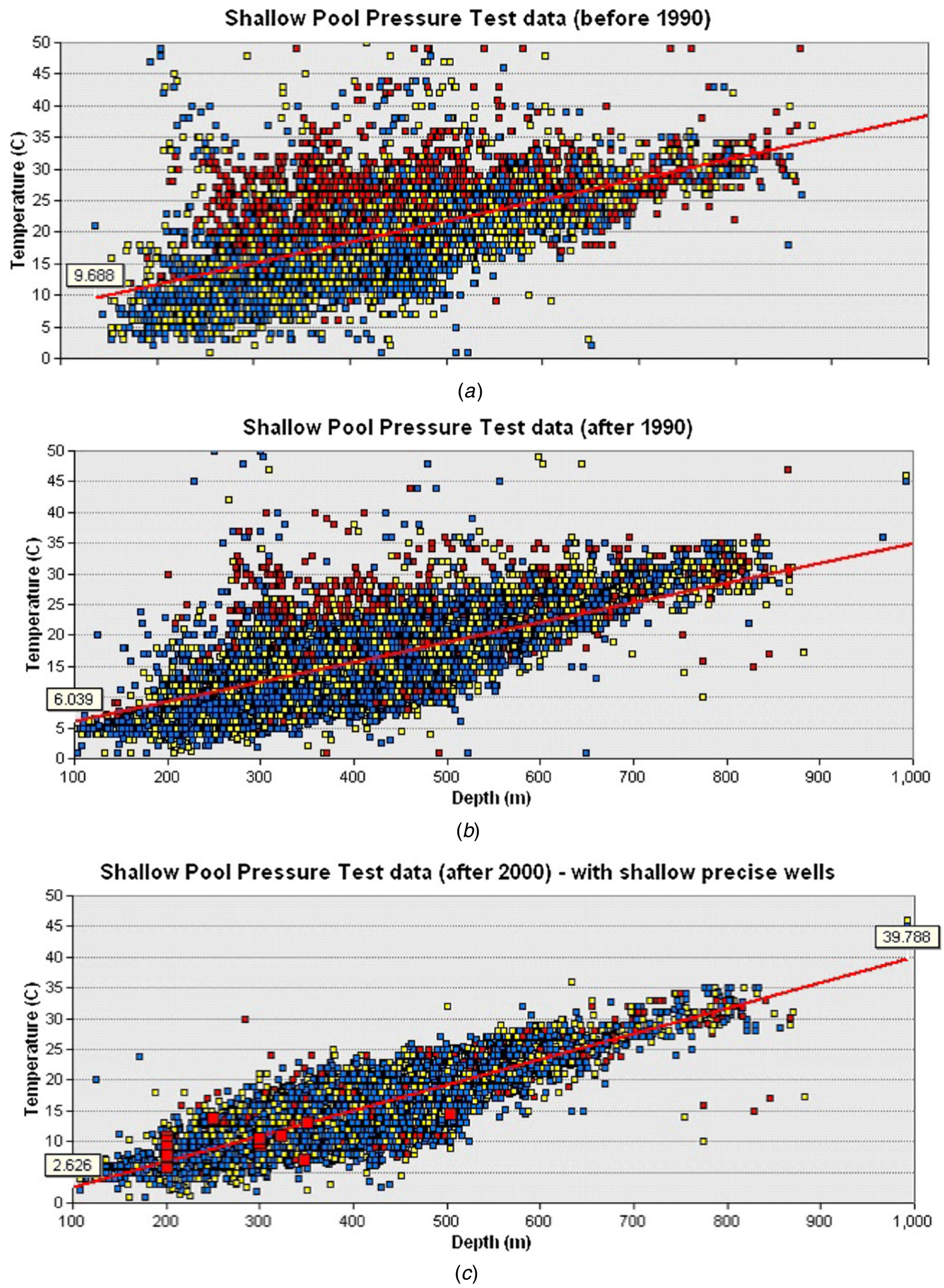


Figure 4. (*a*)–(*c*) Illustration of the seasonal effect on shallow APP data. Red, yellow and blue dots are measurements taken during summer (May–Aug), transitional (Mar, Apr, Sep, Oct) and winter (Nov–Feb) months, respectively. Data are grouped in three figures: (*a*) before 1990 AD, (*b*) after 1990 AD and after 2000 AD (*c*). The newest data, more recent than 2000, show the least seasonal bias and closest agreement with the PSWs (large red squares).

sand deposits. However, the eastern deposits, especially around Fort McMurray, have limited data coverage meaning that a direct comparison with our precise temperature wells is not possible.

After the seasonal effect was identified in the shallow pool test data (figure 4), we looked for it in the DST data as well. The effect does not seem to be significant in this dataset, as can be seen in figures 5(*a*)–(*c*), but there does seem to be a large improvement in data precision since the 1990s. Data from before 1990 was extremely noisy and shows a higher overall gradient than data from after 1990. Unlike the APP data, however, the spread of the data does not significantly improve between 1990 and 2000. The number of measurements available after 2000 is also quite small so removing data between 1990 and 2000 would severely limit the DST data coverage.

The change in DST data quality through time was further investigated by grouping the data into 1-, 2-, 3-, 4- and 5-year intervals and plotting the mean and standard deviation of the geothermal gradients within those intervals in figures 6(*a*) and

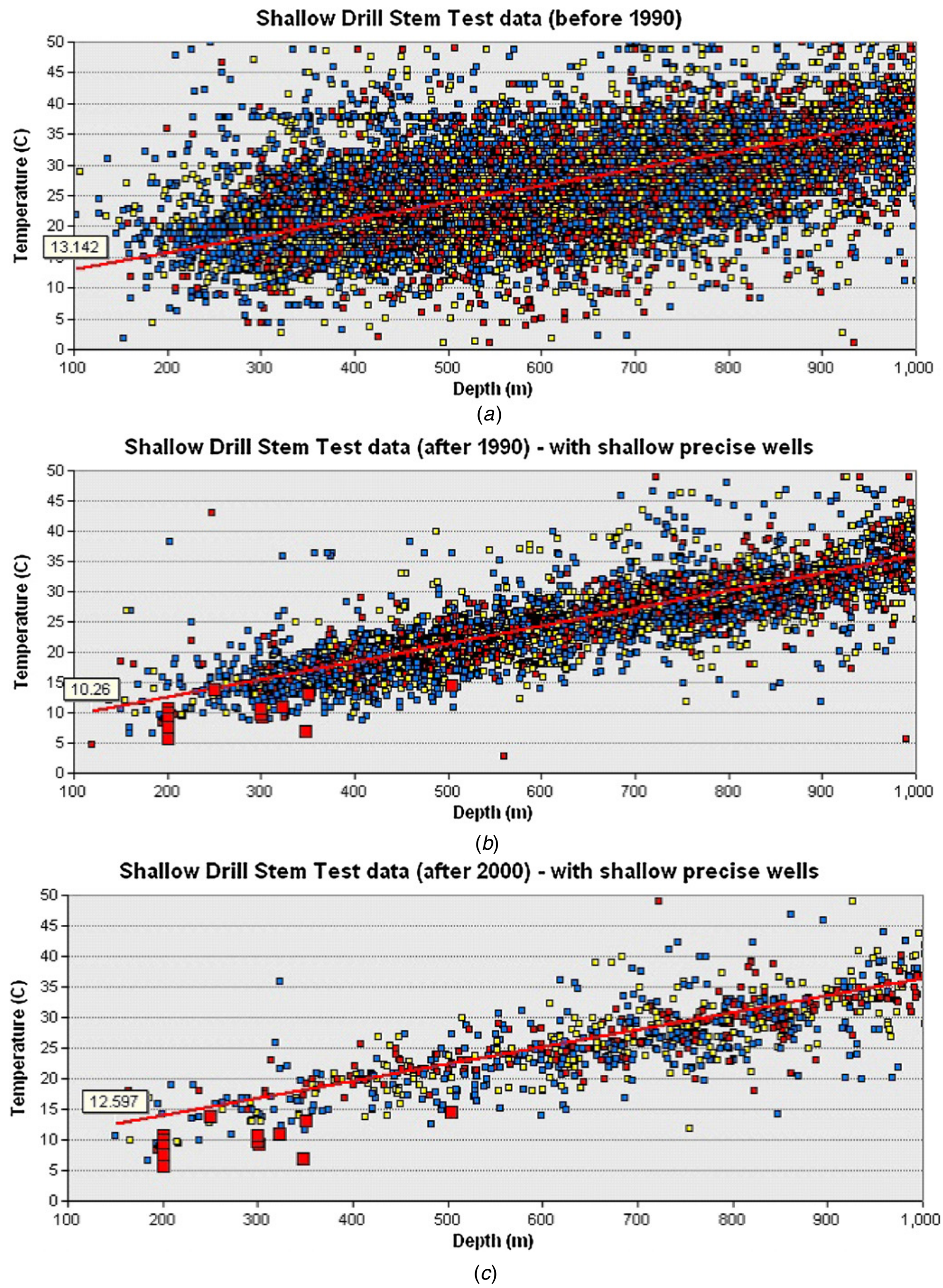


Figure 5. (*a*)–(*c*) Illustration of the seasonal effect on shallow DST data. Red, yellow and blue dots are measurements taken during summer (May–Aug), transitional (Mar, Apr, Sep, Oct) and winter (Nov–Feb) months, respectively. Unlike the APP data, old DST data do not show a seasonal bias but have very high scatter. Data are grouped in three figures: (*a*) before 1990 AD, (*b*) after 1990 AD and after 2000 AD (*c*). There is also not the significant improvement in data quality between 1990 and 2000 that was seen in APP data. Overestimation compared to PSWs (large red squares) could be due to a lack of sampling around Fort McMurray.

(*b*). With the DST data, a significant decrease in the average gradient observed occurred in the 1970s and a decrease in standard deviation of the gradients happened in the mid to late 1980s. Therefore 1990 was deemed as the appropriate cutoff because it had a much lower mean and standard deviation of gradients than older data. Data from between 1990 and 2000 do not appear to be of lesser quality than data newer than 2000, so they were not excluded in the DST dataset.

4.3. Bottom hole temperatures

BHTs (figure 3 (*c*)) are the most abundant tests available because they are cheap and can be carried out at the same time as other well-logging operations. The BHT tests used for this study were compiled in the 1980s by Jones *et al* (1985) during the University of Alberta geothermal program. The data were assembled for Alberta in three separate studies: Lam *et al* (1985), Lam and Jones (1984) and Jones *et al* (1985). They

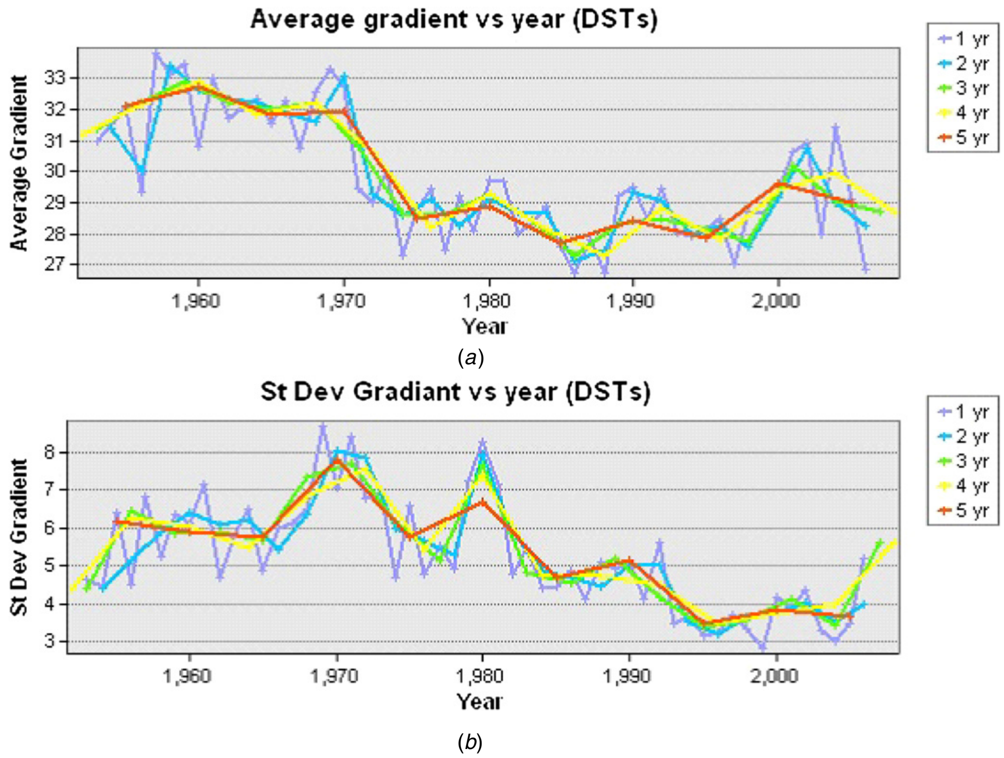


Figure 6. (*a*) and (*b*) Changes in DST data quality with time in years (1950 and on). Measurements have been grouped into 1-, 2-, 3-, 4- and 5-year intervals to help identify possible trends. A significant decrease in the average gradient measured (*a*) occurred in the early 1970s and a drop in the standard deviation of gradients measured (*b*) occurred in the early 1990s. These changes likely correspond to changes in the quality of DST practices and 1990 was chosen as the cut-off of good quality DST data.

were also collected by the University of Alberta group in the Williston basin (Jones 1991).

BHTs are measured at the end of drilling during the logging run by lowering a probe repeatedly into the hole and measuring the temperature of the fluid within the borehole. The temperature recorded at the bottom of the formation is assumed to be the highest temperature encountered in the logging run. During drilling, the circulation of cool drilling fluids will lower the temperature of the borehole and surrounding wall rocks so the temperature of the borehole rises slowly from the temperature of the drilling mud to the true temperature at that depth. To account for this effect, the common practice in the geothermal industry is to use Horner plots for estimating static reservoir temperature from temperature buildup data (temperatures recorded versus time since well fluid circulation process ceased). In this method, the buildup temperature is plotted against the logarithm of dimensionless Horner time, $(tp + \mathrm{d}t)/\mathrm{d}t$, where tp is the circulation time before shut-in and $\mathrm{d}t$ is the build-up time. The data points are then fitted to a straight line, which is extrapolated to infinite $\mathrm{d}t$ (a dimensionless Horner time of equilibration with the reservoir temperature). The extrapolated temperature corresponding to this point is taken as the true reservoir temperature. This method is based on the 'line source solution' to the diffusivity equation on describing the radial conductive heat flow (Lachenbruch and Brewer 1959). The latest method has been developed by Kutasov and Eppelbaum (2011). It has recently been shown that in deep and super-deep wells, the temperature of the drilling fluid (at a given depth) depends on the current vertical depth, on drilling technology (flow rate, well design, fluid properties, penetration rate, etc), geothermal gradient and thermal properties of the formation.

Unfortunately, only a small portion of the data (south of Township 80, east of the fifth meridian) contain the information required to be able to use the Horner plot correction (see figure 8). The remaining data were corrected with the Harrison *et al* (1983) correction employed by the Heat Flow Map of North America (Blackwell and Richards 2004a, 2004b). Harrison *et al* (1983) based their calibration of BHT data measured in Oklahoma, using mostly DST measurements as a benchmark. The exact BHT correction equation used (Harrison *et al* 1983), is

$$T_{\mathrm{cf}} = -16.512 + 0.0183xz - 2.345 \times 10^{-6}z^2 \qquad (1)$$

where T_{cf} values are subtracted or added to the original BHT values, and z is the depth (m).

Like APP tests, analogue thermometers were used until the 1980s to record the maximum temperature encountered during the logging run. The maximum temperature was assumed to have been recorded at the bottom of the hole. However, in a shallow well the surface air temperature in summer can exceed the BHT. Comparison between BHT data and precise temperature logs from the WCSB wells showed that reasonable agreement exists when BHTs statistically corrected (Jessop 1990a)

The BHT data used for this study (figure 7) was compiled by Lam and Jones (1984). In this study, 55 246 BHT values were collected from 28 260 petroleum exploration well logs

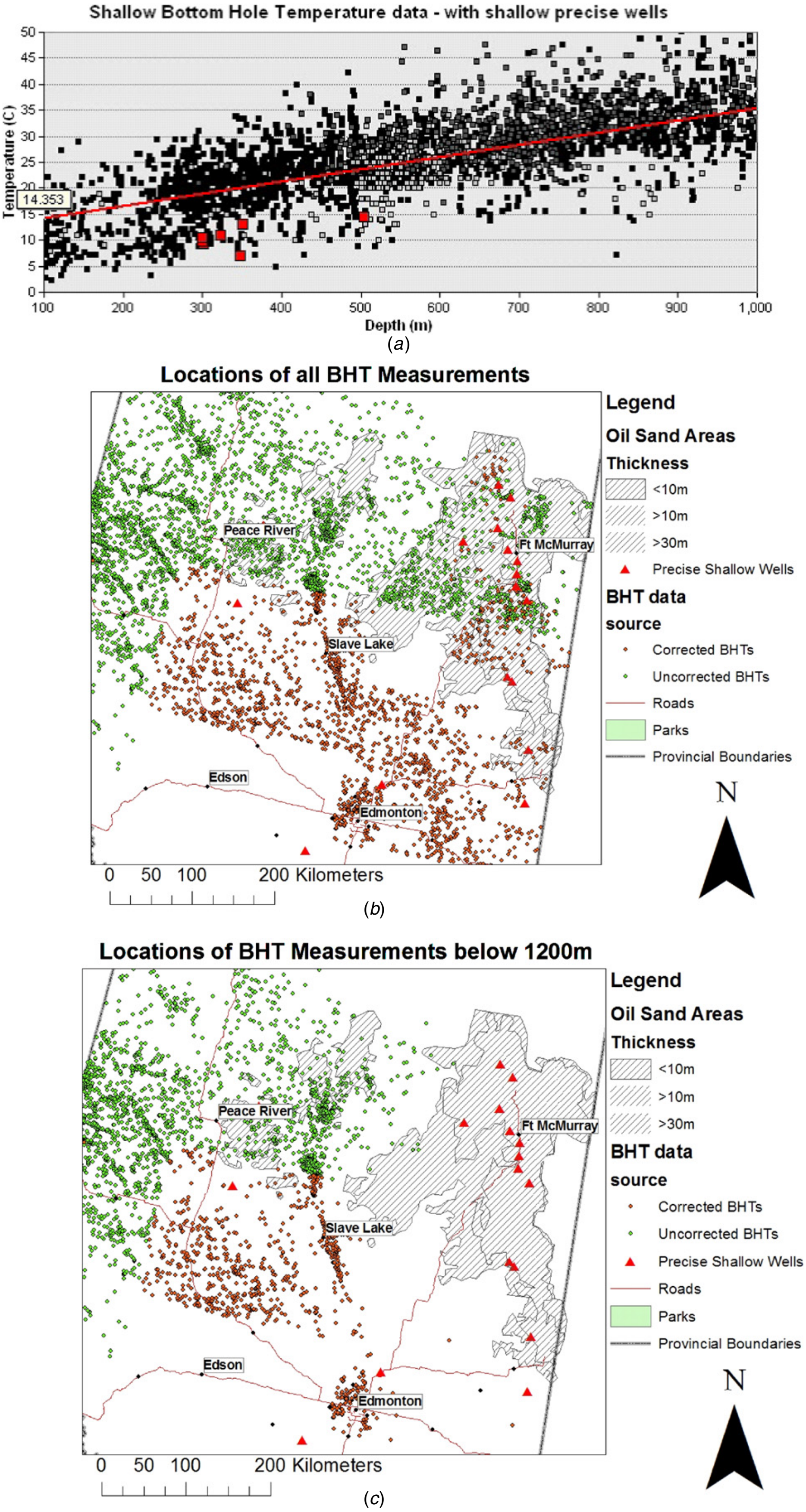


Figure 7. Shallow BHT data versus depth showing the seasonal effect (*a*). Average gradient of temperature is 36.97 mK m^{-1}. Maps show the data before (*b*) and after (*c*) removing data below 1200 m.

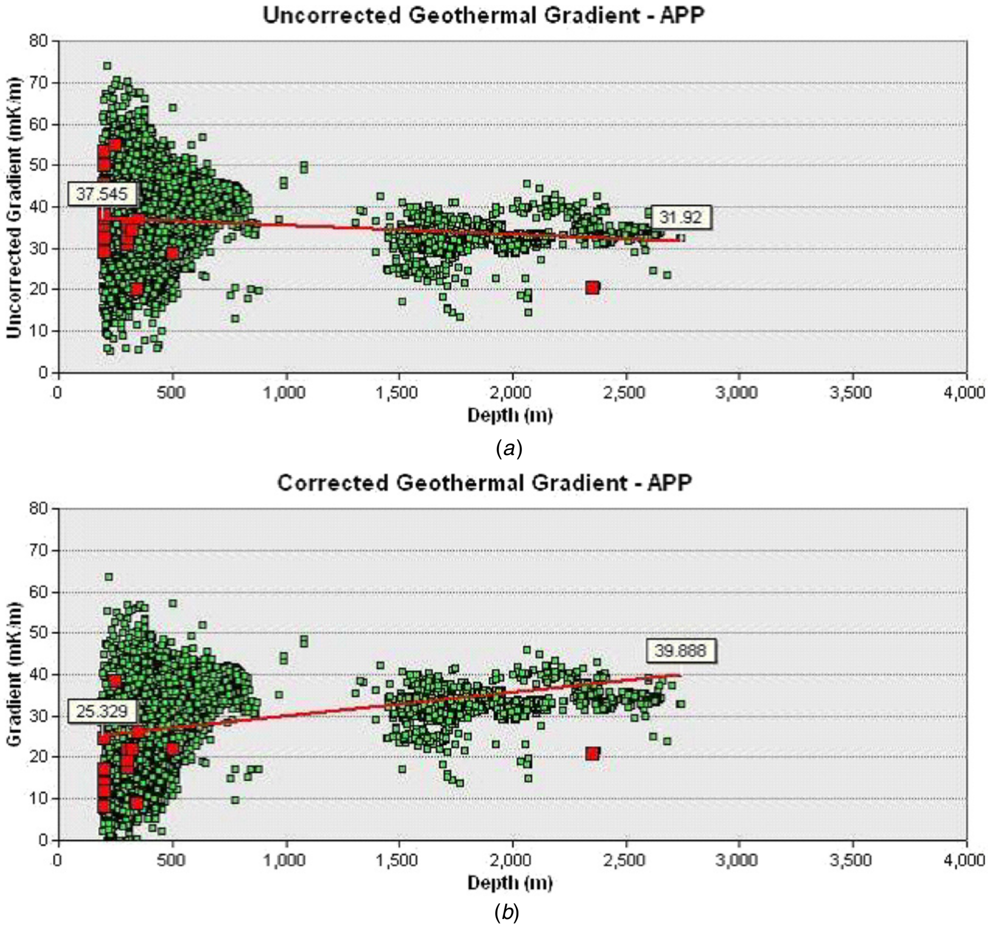


Figure 8. (*a*) and (*b*) Effect of the surface temperature correction of APP data. Shallow data is strongly skewed towards lower gradients due to a low gradient region around Fort McMurray. Like DST data, the uncorrected data (*a*) shows a decreasing trend with increasing depth. In the corrected data, however, the skewed shallow data causes the linear fit to be increasing instead of flattened (*b*).

in Alberta. This dataset is the most problematic of the three since the data was collected before 1980 so they were collected before the introduction of the first digital thermistors. Additionally, the authors were not aware of the seasonal effect at the time of compilation and so the test date was also not recorded. The shallow BHT data are certainly affected by the seasonal affect since temperatures above 20 °C are common at depths of 300–400 m (figure 7). In comparison to the PSWs of Majorowicz *et al* (2009), the shallow BHT data is significantly higher in the same areas as discussed further in Majorowicz *et al* (1999). There is little that can be done about the shallow BHT data without information of the test date. Therefore, shallow BHT data will be omitted completely and will only be used in the deep basin. The cut-off chosen was 1200 m because at that depth temperatures are consistently above 30 °C and therefore the surface air temperature cannot influence them.

To our knowledge, this is the first time that this systematic bias has been identified in industrial temperature data, especially in geothermal studies. There is an indication that the problem of maximum temperature thermometers has been known for quite some time, especially in the petroleum industry (Ibrahim 2000).

However, many current geothermal studies, including the Geothermal Map of North America (see Blackwell and Richards (2004a, 2004b) for a description of the methodology) that employs industrial temperature data simply eliminate shallow data. The problem with such an approach is twofold.

(1) The vast amount of valuable data are wasted and for the large areas of shallow sedimentary succession we have lost coverage, especially in asymmetric basins such as the WCSB and Raton Basin.
(2) Choosing a cut-off depth that is too shallow to try and compensate for the first effect can be too arbitrary.

With the gradients seen in the WCSB, subsurface temperatures only exceeded local summertime surface air temperatures at depths of 1200 m (figure 7). At depths shallower than this cut-off, it is ambiguous which temperature the measurement is referring to. This ambiguity can be reduced using knowledge of the test date. However, there is an abundance of digitally measured temperature measurements available today so it seems more appropriate to only use measurements taken in the last decade.

5. Comparison of different datasets

In comparing the PSW with the shallow data from each set, the APP data appears to be in best agreement as several

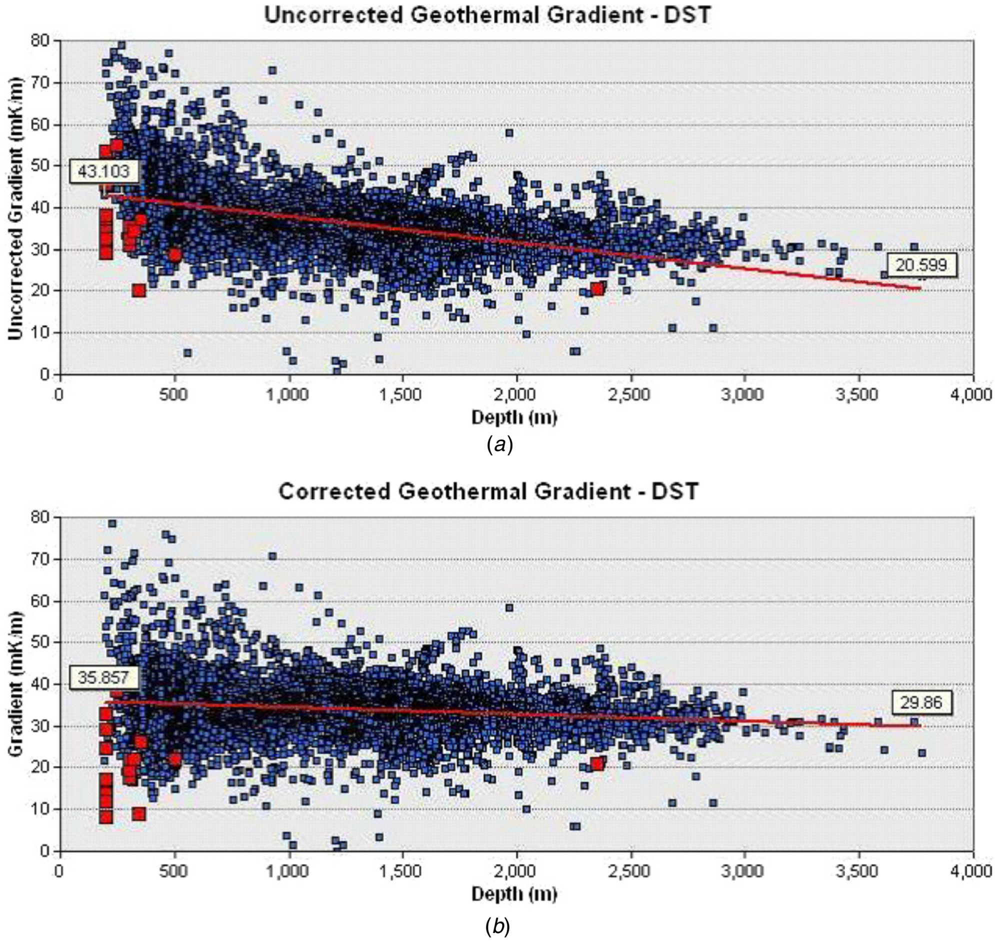


Figure 9. (*a*) and (*b*) Effect of the surface temperature correction of DST data plotted with PSWs (red). Uncorrected data (*a*) shows a strongly decreasing trend with increasing depth. This trend has been largely flattened out in the corrected data (*b*).

of the PSWs lie on the best fit line (figure 8). The DST data does not provide as good of a fit with the PSWs and yields slightly higher average temperatures (1–7 °C) at the same depths (figure 9). It is not clear if this is due to a systematic error with the data or due to the poor coverage of the Fort McMurray area. The shallow BHT data certainly shows the least agreement with the PSWs (figure 7). Despite very good coverage in the area, shallow BHTs are as much as 20 °C higher than PSWs in the same area. This adds more justification to removing shallow BHT data from this study (figure 10).

After removing the older, lower quality data from these data sets, there remains good spatial resolution of the oil sand areas. Figures 3(*a*)–(*c*) show the remaining data in each set relative to the oil sand areas, and the PSWs. None of the data sets show good coverage of the Fort McMurray area but the APP data has the most data in the shallow basin with some DST data in the area and no BHT data at all. In the southern area, around Cold Lake, APP and DST data both have good coverage. In the Peace River region, to the west, BHTs have the best coverage, DSTs also have good coverage but the APP data appears in clusters leaving large gaps.

A recently measured (February, July 2011) precise thermal log in the deep Anhydride Petroleum 7-32-89-10 (Hunt) well near Fort McMurray (Majorowicz *et al* 2012) covers the depth interval between 0.1 and 2.35 km (figure 2). Within this well, at a depth of 0.5 km, is the Phanerozoic–Precambrian unconformity. Above this unconformity are Phanerozoic sedimentary rocks with low effective thermal conductivity (harmonic mean = 2 W mK^{-1}) and below it are Precambrian crystalline rocks with high thermal conductivity (∼3 W mK^{-1}). For the shallow part the corrected (seasonal correction) APP data from the Fort McMurray area are in reasonably good agreement with the precise thermal log (figure 2). For the deep basin, the APP data are much higher than precise temperatures from the deep part of the temperature log in granite of the Fort McMurray area. Since industrial temperatures are only collected from within the WCSB, any data from a depth greater than 500 m is taken from an area in the deeper part of the basin (west of the Anhydride Petroleum 7-32-89-10 (Hunt)). At depths of 2000–2500 m, the industrial data shows higher geothermal gradients (∼30–35 mK m^{-1}) compared to the Anhydrite well (∼20 mK m^{-1}). Whether this difference is caused by a difference in heat flow or thermal conductivity is outside the scope of this paper.

6. Paleoclimatic corrections

It is well established that temperature-depth profiles are not linear. Climatic fluctuations will affect the ground surface

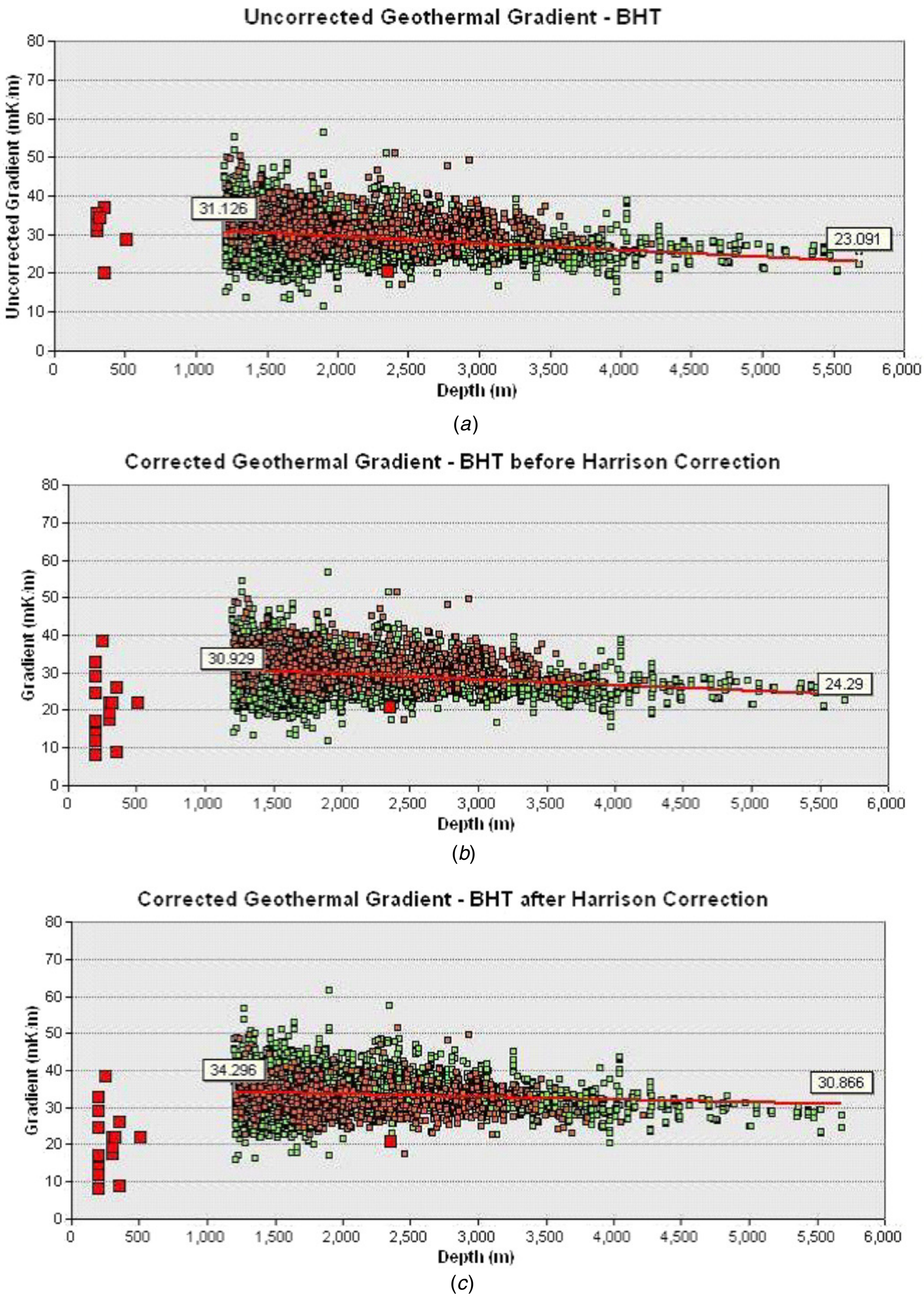
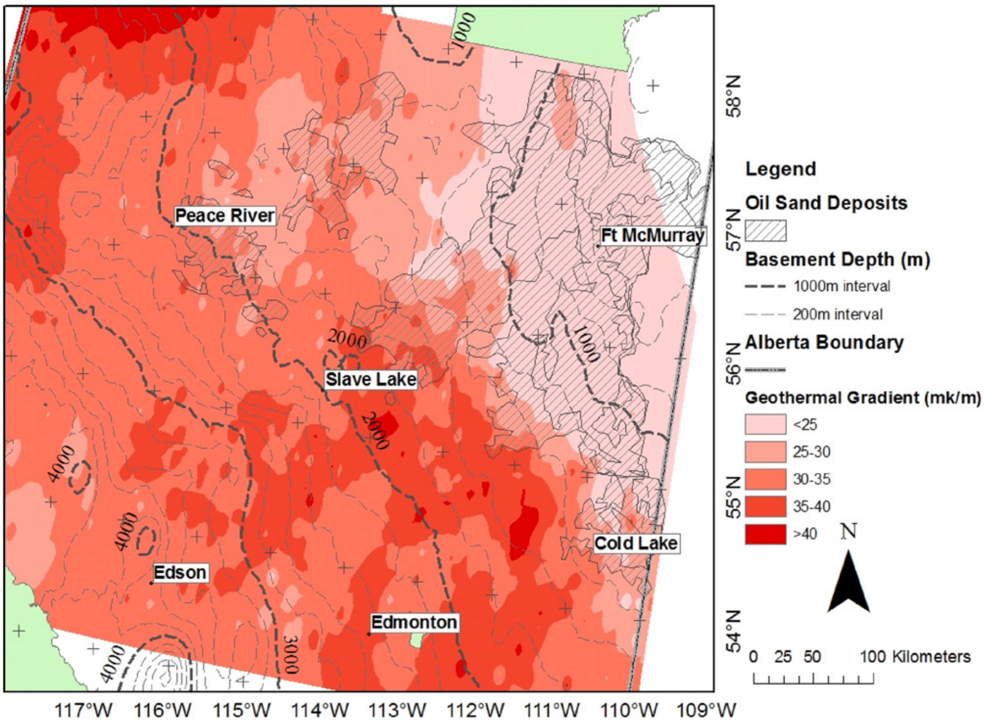


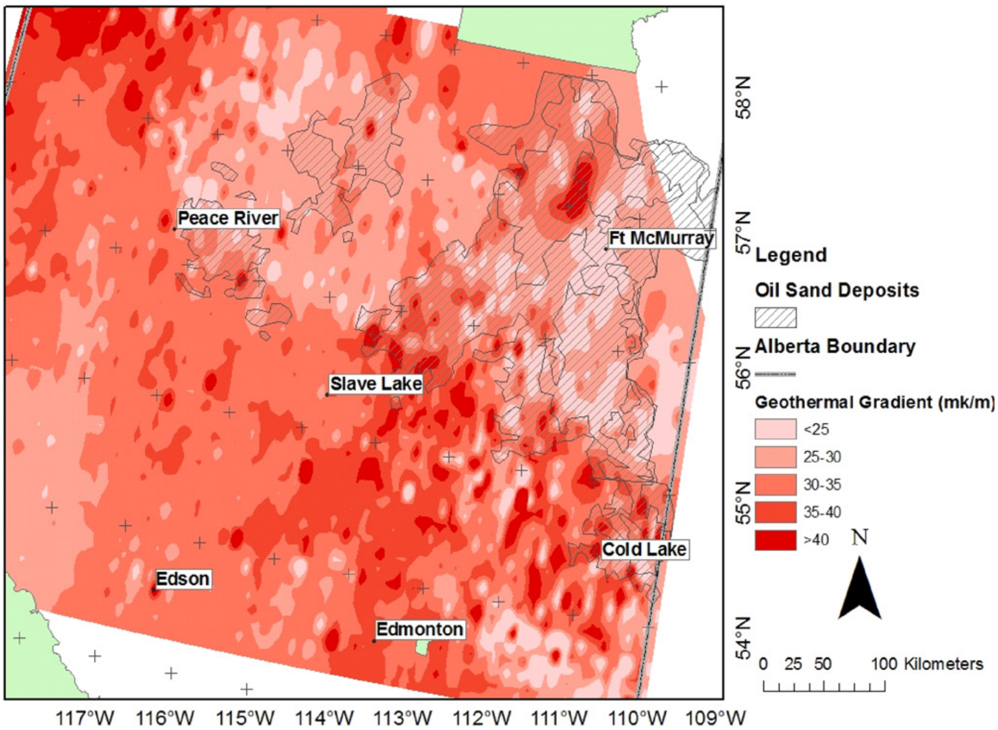
Figure 10. Effect of the surface temperature and Harrison corrections of BHT data. In uncorrected data (*a*), there is a strong decreasing trend with depth. Upon applying the surface temperature correction (*b*), the Horner corrected (orange) and uncorrected (green) both appear to be somewhat levelled out but the uncorrected data are still lower than the Horner corrected data. After applying the Harrison correction (*c*) the green and orange points are much more similar and the decreasing trend is much less pronounced.

temperature and send 'pulses' of heat flow downwards into the subsurface at a rate controlled by the thermal diffusivity of the rocks. In the case of glacial–postglacial temperature increase (some 10 °C) this will cause an increase of geothermal gradient with depth as observed in the equilibrium thermal log in the Anhydride Petroleum 7-32-89-10 (Hunt) well (Majorowicz *et al* 2012).

In the Northern Hemisphere, glaciation has significantly distorted subsurface heat flow to depths of over 1000 m (Gosnold *et al* 2005, Jessop 1971, 1990b, Majorowicz and Wybraniec 2010). For this reason, in calculations of geothermal gradients, the present ground surface temperature cannot be used because it will overestimate gradients at shallow depths and underestimate gradients at greater depths. Instead, inversions of continuous temperature logs are used to derive ground surface temperature histories of a region. The inversion used for this study is based on a well measured in Sudbury, Ontario (Perry *et al* 2009). The Anhydride Petroleum 7-32-89-10 (Hunt) well log shows a similar change in geothermal gradient with depth to the Sudbury well and



(*a*)



(*b*)

Figure 11. (*a*) and (*b*) Final geothermal gradient map (*a*) after all corrections and culling compared to the original raw data set (*b*), showing a vast improvement in data quality and identification of a previously unresolved region of low geothermal gradient around Fort McMurray. The topography of the Precambrian basement is labelled in metres.

has been attributed to a +10 °C change in surface temperature since the latest Ice Age (Majorowicz *et al* 2012).

The results of this correction varied with each data set. In theory, an uncorrected dataset should have anomalously high gradients at shallow depth and a slight negative slope in gradients at greater depths. Figures 8–10 show the uncorrected and corrected gradients for each dataset. The correction of the DST data (figure 9) certainly seems to be most successful with the uncorrected data showing a trend of decreasing gradient with depth. After the correction, this decrease is much less pronounced.

The success of the correction on the APP data is much less apparent due to the high variability of the shallow data (figure 8). While the gradients of deeper data are largely unaffected, corrected gradients of the shallow data are much lower than the uncorrected gradients. Therefore, the linear trend of the corrected gradient shows a significant increase in gradient with depth. It will be shown later in this paper that there is significant spatial variation in gradients in the study area so this positive trend is interpreted to be due to regional variations rather than a problem with the correction itself.

7. Geothermal gradient

After removing the large errors present in each database, a much more reasonable model of subsurface temperatures was created. Figure 11 shows the inverse distance weighted (IDW) map of corrected geothermal gradients for all of the datasets combined (figures 3(*a*) and (*b*)) as well as the IDW map of the original, raw data (figure 11(*b*)). For all these maps, areas more than 50 km from the closest data point have been removed to reduce edge effects caused by extrapolation of un-sampled areas.

Both maps show a similar overall pattern. However, the refined corrected data shows much less variability and a well defined region of low geothermal gradient around Fort McMurray which is much less apparent in the raw data. This overprinting has resulted in apparently high heat flow and high geothermal gradients in the region surrounding Fort McMurray in the geothermal gradient map of the WCSB contained in the Alberta Geological Survey Atlas of the WCSB (Bachu and Burwash 1994).

8. Conclusions and recommendations

Our results show that each of the three independent temperature datasets contained its own biases and quality issues. In all cases, recent data is of much higher quality than older data and this can be easily attributed to advances in the instruments used for measuring temperature.

The APP data was judged to be the best quality data based on the minimum required shut-in time before measurement and was confirmed by qualitative observations as well as comparison to PSWs in the same area.

DSTs were judged to be second best because they directly measure the temperature of the formation fluids and so they do not require re-equilibration with the borehole. These data slightly overestimated PSWs but there was poor DST data coverage in that area and it was also found to be a location of low gradients. DSTs also showed good agreement with APP data on small-scale variations in gradient such as to the northeast of Edmonton.

BHT data was found to be worst because they were compiled during the 1980s and the different regions of data had to be corrected differently because of the information available. The shallow BHTs also showed significant overestimation compared to PSWs. Even after removing shallow BHTs, they were found to show less agreement with the DST data than the APP data. Many of the main features in other datasets were still observed in BHT data and it covered areas that the other datasets did not so the data was still considered useful.

When using shallow industrial temperature data, older (pre-2000) measurements should be treated with care to avoid creating anomalies due to analogue measuring equipment. Additionally, the surface temperature warming since Holocene glaciation can lead to a distortion in interpolated gradients from point measurements up to depths of 1000 m. This effect is probably most important in regions with extensive glacial histories such as Canada and northern Europe. The shallow geothermal gradients need to be corrected for the paleoclimatic effect. The correction can be derived from deep (>2 km) wells with precise temperature log and measured thermal conductivities.

The geothermal gradient map after cleaning and correcting temperature data sets has an average gradient of 30 mK m^{-1} and features two main anomalies: the Fort McMurray Low and the Northwest Alberta High. The Fort McMurray Low features gradients below 20 mK m^{-1} and a sharp western contact (see figure 11).

Acknowledgments

The authors thank both referees and Alan Jessop for their helpful reviews. Professor Ben Rostron at the University of Alberta is thanked for help with the DST and APT data access. This research was funded through the Helmholtz Alberta Initiative by the Government of Alberta using Ecotrust funds. We also recognize the pioneering work of Dr Alan Jessop (GSC) and Professor Walter Jones at the University of Alberta in using industrial temperature data to develop a regional geothermal database for Western Canada.

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