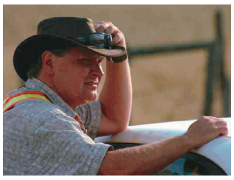
Heavy and Bituminous Oils: Can Alberta Save the World?



Douglas R. Schmitt
Institute for Geophysical Research
Department of Physics
University of Alberta,
Edmonton
Alberta, Canada

E-mail:
doug.schmitt@gmail.com

Abstract

The oil sands deposits of Alberta represent a significant fraction of the world's current reserves. The viscosity of these oils however requires special enhanced oil recovery techniques to be applied. Both capital and operational costs are significant for these methods. Remote monitoring of the production process holds substantial opportunity for the geophysical community. In this contribution, I describe the heavy oil deposits and the methods of enhanced production, discuss briefly some of the issues of rock physics that would contribute to monitoring of such a resource, and show some examples of seismic data obtained in such regions. Although geophysics shows promise for monitoring, there is a great deal of work that must be done to convince other geoscientists of its value.

Introduction

Canada's bituminous oil sand deposits have likely been in place since the mid-Cretaceous, and were used by Canada's First Nations to seal birch bark canoes. The deposits were first seen by Europeans in 1788, and have already been supplying upwards of 30% of Canada's total petroleum production.

Despite this, it was only in 2003 that their size was officially noticed outside of Canada. At the end of that year, The Oil and Gas Journal revealed in its annual report on global petroleum supplies and consumption (Radler, 2003), a large ~20% jump over those of 2002 in overall global reserves by simply including the bituminous oil sands of Canada in its estimates.

This jump also lifted Canada's reserve standing from near 5 Gbbl (772 x 10^6 m^3)[1] to 180 Gbbl (28.6 x 10^9 m^3), a number exceeded only by the presumed 260 Gbbl (41.3 x 10 ^{9}) of Saudi Arabia and surpassing those of all the other Middle Eastern countries.

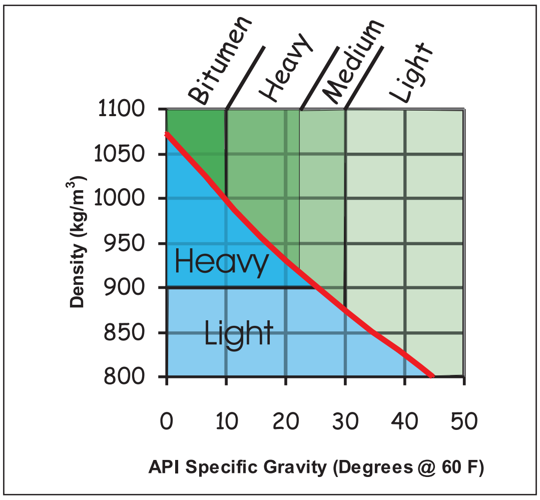


Fig. 1. Relationships between Canadian government (in kg/m^3) along vertical axis and the American Petroleum Institute (in 'degrees' API) along the horizontal axis; classifications of crude oils on the basis of density.

The size of these deposits had long been recognised (see, for example, Mossop, (1980) for additional background information and a review of the geological studies prior to that time) but had not been included prior to 2003, primarily because of the difficulties involved in producing such highly viscous oils.

The development of a variety of both surface mining and *in situ* recovery technologies however has reached the point of being economic, even before the rapid rise in the price of oil in the last year. Three other factors, the flattening of global conventional light oil reserves, the growth of consumption in Asia, and the political stability of Canada relative to other major producing areas are currently driving the startup of a large number of projects. Through the decade ending in 2004, CDN$29 billion has already been invested in oil sands projects with an estimated sum of $79.5 billion of direct- and $16.5 billion of sustaining- capital to be spent potentially in this coming decade (Alberta Economic Development, 2005).

Clearly, this is a large investment for Alberta, Canada and perhaps even the entire world. Here I give a brief background to the developments now taking place in Alberta, then shift the focus towards the role of geophysics in the development of this resource.

World hydrocarbon supplies

One simple characterisation of oils is based on its mass density. Generally, as mass density increases, the proportions of long-chain hydrocarbons (> C16 to C20) becomes larger in the oil. Different classifications exist but it is useful to compare those of the Canadian government (based on kg/m^3) to those of the American Petroleum Institute specific gravity (° API)[2]. In Canada, only the terms heavy (> 900 kg/m^3) and light (< 900 kg/m^3) are employed while the API provides four classifications from bitumen to light (Figure 1). Chemically, aside from the lengthening of hydrocarbons, bitumen is deficient in hydrogen, relative to lighter oils. Aside from the issues in production, this heavy material was economically undesirable as it must be upgraded by the addition of hydrogen to make a lighter and more valuable synthetic crude. Other problems arise due to relatively high sulphur

---

[1] m^3 ~ 6.29 barrels.

[2] The API values are a measure dependent on the relative density of the fluid of interest ρ to that of water ρ_w both taken at a temperature of 60° F (15.56° C) according to API° = $141.5\rho_w/\rho$ -131.5. Water has an API° = 10.

content of approximately 5% and small but not insignificant concentrations of metals such as titanium, tungsten, and iron. This bitumen and heavy oil is essentially the residue from a lighter oil that has lost its lighter fractions in part by bacterial degradation.

It is worthwhile to briefly look at some of the societal factors that are influencing the growth of the oil sands development. Including both light and intermediate oils that are produced by conventional techniques, the distribution of global reserves according to type shows that both heavy oil and bitumen account for approximately half of the established reserves[3] of 2234 Gbbl[4] (Figure 2a). An interesting pattern appears when the distribution of these various reserves is examined by region, (Figure 2b-d) revealing large inequalities. Essentially, the bulk of the conventional, heavy, and bitumen reserves are located in three regions, being respectively: the Middle East, South America (principally Venezuela), and North America (principally Canada).

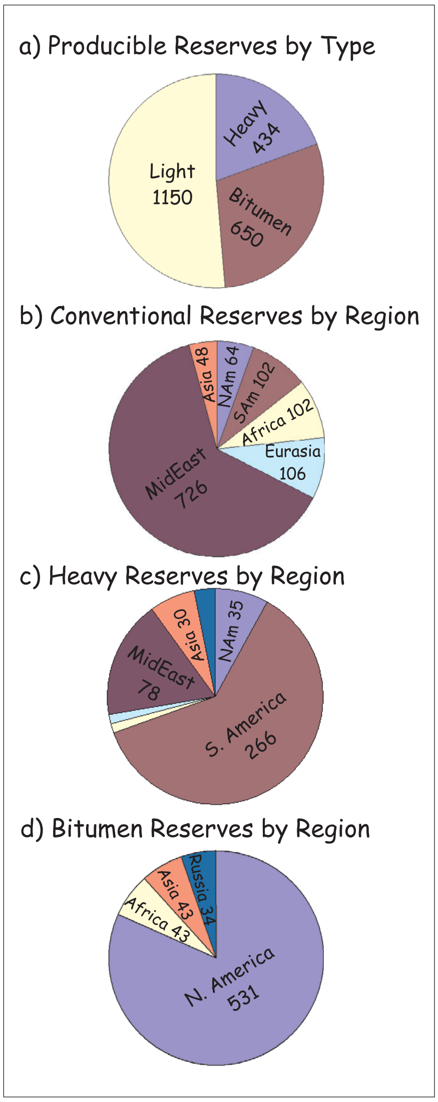


Fig. 2. Summary of currently recoverable petroleum reserves according to a) type of reserve, and the regional distributions of b) conventional (light), c) heavy, and d) bituminous oils. Numbers represent reserves in units of BBO (Billion (109) Barrels of Oil, 1 Barrel = 158.984 litres by volume). The statistics quoted are derived from the Meyer and Attasi, 2003.

Consumption patterns by region (Figure 3) also highlight important trends. After actually reaching a minimum in the early 1980s, consumption has generally increased in all areas and today is about 0.08 Gbbl/day (29.2 Gbbl/year). The growth in consumption has not been rapid in the developed world generally. However, both China's and India's needs have nearly doubled in the decade ending in 2003 and this growth is expected to continue as the economies of these two large nations expand. This consumption growth is occurring in a situation in which it is becoming increasingly difficult to maintain and increase production of conventional light and intermediate oils, and is placing a strain on global supplies that, in part, have led to the rapid increase in the price of oil since 2003. Indeed, an oversimplified face value examination of the numbers above would suggest that the current global reserves would be depleted in less than a century.

Geology of the Oil Sands

There are three major oil sand accumulations in Alberta: the Peace River, the Cold Lake, and the Athabasca deposits; the locations of which are highlighted in Figure 4. The areas are distinguished primarily on the basis of differences in the geology, the geography, and the oil content. These areas cover upwards of 60,000 km^2, an area roughly equivalent to that of Tasmania. The Athabasca (sometimes referred to the Athabasca-Wabiska deposits) are the largest. AEUB say established reserves are 177 Gbbl (28.1 x 10^9 m^3) with the definition of established being those reserves that are producible given current technology. Estimates of the reserves that are but ultimately recoverable is 332 Gbbl (52.8 x 10^9 m^3). The initial total oil in place, however is a staggering 1,700 Gbbl (270 x 10^9 m^3) with some estimates of the ultimate oil in place (National Energy Board, 2004) even going as high as 2520 Gbbl (400 x10^9 m^3). It is currently unknown how much could eventually be obtained.

The geology of the three oil sand regions differs, but in many ways can be similarly summarised. It is useful to first briefly examine the overall geological structure of Alberta, (Figure 5) which begins in British Columbia in the Rocky Mountains. The tectonic history of the basin essentially consists of two parts (Price, 1994). First, from the later Proterozoic to the late Jurassic the western edge of North America essentially consisted of passive margin sedimentation, primarily sourced from the east. The second is characterised as the foreland basin stage that incorporated passively deposited supracrustal sediments that were detached from the metamorphic basement and thrust to the east from the late Jurassic to

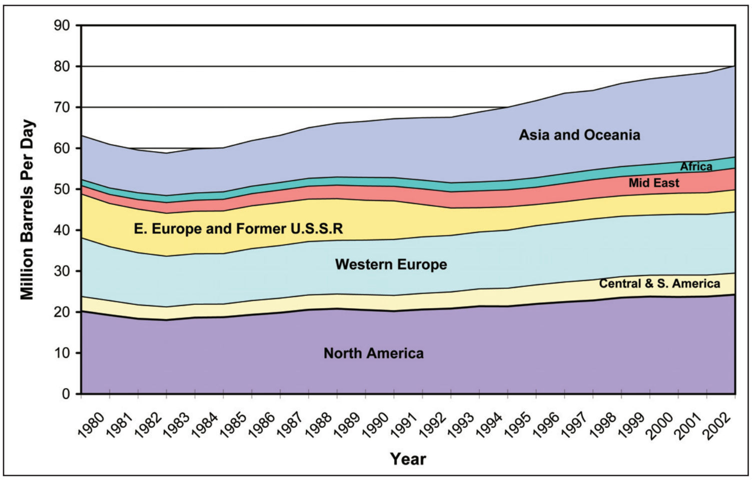


Fig. 3. Summary of daily consumption of petroleum in Millions of Barrels per Day for various regions, data from U.S. DOE (2005).

---

[3] The careful reader will note some inconsistencies in the volumes given to the various reserves. These arise due to differences in the criteria employed by different reporting agencies in deriving their final statistics; in all cases the original source of the information used here is given. This author is not qualified nor prepared to defend any of these statistics, and indeed, as reserve devaluations continue to come to light in the media and in recent books, one may question actually who is able to do this difficult prognostication.

[4] 1 BBO = Billion barrels of oil = 159 x 10^6 m^3 = 1 Gbbl = 10^9 barrels.

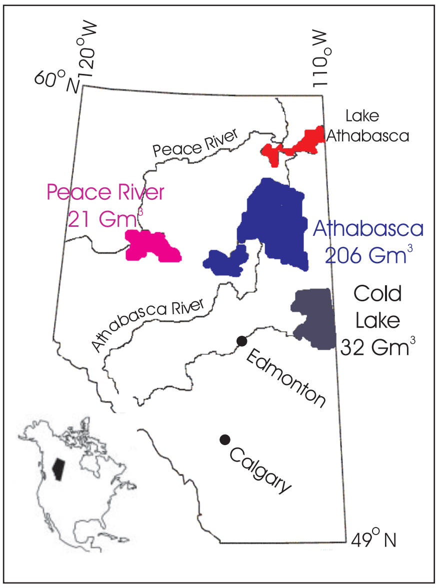


Fig. 4. Map of Alberta indicating the three regions in which concentrations of bituminous sands lie with the estimated reserves of each in Gm^3. Summary map based on that available from the Alberta Department of Energy (2004). Volumes of bitumen are estimates of that existing in place according to the Alberta Energy and Utilities Board (2004) based on analysis of well log and other information. The total area of Alberta is 660,000 km^2, for comparison New South Wales has just over 800,000 km^2.

the early Eocene. The load of these thickened thrust sheets induced flexure of the lithosphere, bending the crust to produce a basin, which subsequently filled with Mesozoic siliclastic sediments primarily of Cretaceous age. The first ranges of the Rocky Mountains are thrust sheets of a fold and a thrust belt, formed during the late Cretaceous and early Tertiary Laramide orogeny.

Within this overall framework, and using the Athabasca reservoir as representative, the host sands were deposited on top of a major angular unconformity that truncates Paleozoic limestones and calcareous shales. Valleys were established in the carbonates by a major river system running from south to north. After the sea levels rose in the early Cretaceous, the valleys were subsequently filled with a series of earlier fluvial and estuarine deposits and later marginal-marine sediments. As might be expected, the finer structure of the sands is similar to that of sand bars in a meandering river system that features numerous sandbars and crosscutting channel complexes (see Pemberton and James, 1997 for detailed discussions). This deposition occurred in the Lower Cretaceous of Aptian to Albian age (~120 to 100 Ma) in a formation regionally referred to as the Mannville Group. It must be noted that some of the resource may also be found in the older Paleozoic carbonates, particularly in the Peace River region.

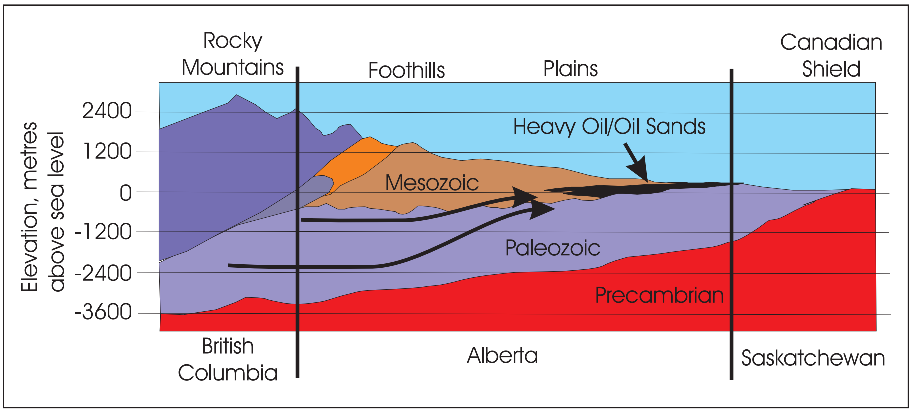


Fig. 5. Illustrative geological cross section of Alberta, this cross section runs from west to east following along the Athabasca River and continuing NE past the Athabasca oil sand region in Figure 4. Black arrows represent migration paths of the oil from the west to the east.

The source rocks, the timing, and the migration mechanisms for the bitumen remains controversial. Such a large deposit will attract attention as well as unconventional explanations attempting to explain where the oil came from. For example, one theory maintains that both the sand and the oil resulted from a large terrestrial 'gastrobleme', which conveniently spewed forth the sands and then the oil[5]. More conventional theories are perhaps less dramatic but still retain a good deal of mystery. Generally, it is believed that the oil migrated to the east from the west across the basin (Figure 5) with a number of workers suggesting the generation and migration was roughly contemporaneous with the late Cretaceous – early Tertiary Laramide orogeny mentioned above. A variety of shales with ages from the Mesozoic to the Paleozoic have also been suggested (see Riediger *et al.*, 2000 for a brief background to this discussion). However, recent geochemical studies using a new Re-Os dating technique on the bitumens (Selby and Creaser, 2005) have been carried out. The work suggests 112 ± 5.3 Ma as the date for the generation and migration of the oils, which is contemporaneous with the deposition of the final host sands. This early date precludes generation of the oil during the Laramide orogeny and points the source towards older and more voluminous Paleozoic source rocks. This scenario is consistent with both the unconsolidated nature of the oil sands (cementation being further hampered by the oil) and the large degree of biodegradation of the original oil, the residue of which is bitumen. It is also more consistent with numerical flow and hydrological studies (Adams *et al.*, 2004).

Characteristics of the oil sand materials

The best sands have a number of favorable petrophysical characteristics (e.g. Mossop, 1980). The sand typically consists of moderately sorted, fine grained (62.5 to 250 μm) grains, of which 95% are quartz with less frequent feldspars, micas, and clays. As might be expected for such a material, the absolute permeability is high although the bitumen itself is essentially immobile due to its viscosity. Shale stringers however lie within the deposits and can restrict the flow of fluids. The sorting allows for high porosities from 25% to 35%. The high porosity is also the result insufficient mineral cementation indicative of the shallow burial depth and lack of diagenetic modification that these sands experienced. As such, the material is unconsolidated and defined as sand, not sandstone.

Workers have long been concerned about the microscopic distribution of the fluids within the pore space as this has direct implications on how the oil is produced. One longstanding model of this fluid distribution (Figure 7) suggests that the bitumen should be kept apart from the mineral grains by thin layers of water along surfaces and by pendicular menisci at grain contacts (Takamura, 1982; Ofosuasiedu *et al.*, 1992). Preferential wetting in smaller pore spaces keeps the matrix material water wet. There is some evidence however that

---

[5] This theory that has actually led to drilling of the metamorphic basement in the Athabasca region in search of an even larger potential reservoir believed to lie at depths of 6 km., unfortunately the funding for this endeavor only allowed for a much shorter wellbore and the theory yet remains untested.

this model may not be completely accurate. Zajic *et al.* (1981) examined a frozen oil sand using transmission electron microscopy with resolutions of 10 nm but saw no evidence at this scale for a thin layer of water. Czarnecki *et al.* (2005) has also questioned the water wetting assumptions, which can be traced to some early conjectures in the 1920s that suggest a lack of serious supporting evidence but have since been repeated in the literature. This may be an important consideration in future rock physics studies as the distribution of fluids controls the effective fluid properties, the complexity of the electrical conduction networks within the rock, and the cohesive surface forces between adjacent mineral grains.

Production technologies

To provide a background for geophysical discussions that will occur later, it is also important to reveal how these oils are produced. Essentially the very high viscosity of heavy oils and bitumens makes producing them difficult. Indeed the bitumen is immobile under conditions existing naturally within the earth and considerable production methodologies are required. The problem boils down to reducing the viscosity of the bitumen and heavy oils so that they flow through the porous rock. This may be done by injecting solvents but the most popular methods have lowered the viscosity by heating the formation. The viscosity of such liquids is highly sensitive to temperature (Figure 6) and changes by many orders of magnitude over a range from 0 to 300° C. Natural *in situ* temperatures fall in a range of approximately 10° C and the oils move very slowly.

This problem is overcome by a variety of strategies, principally by heating the reservoir. It is interesting to note that some of the first suggestions for heating the oils during the 1950s relied on the use of peaceful nuclear explosions. Fortunately, this suggestion was not implemented. Since then, production methods have essentially fallen into two categories:

1. Surface strip mining of oil sand 'ore' and processing for removal of the oil, and
2. *In situ* enhanced recovery techniques.

A large fraction of Canada's total oil production is currently derived from the upgraded synthetic crude, which is produced at just two mines operated by Syncrude Canada Ltd. and Suncor Energy Inc. These mines straddle the Athabasca River north of Fort McMurray, Alberta. The oil sands are relatively shallow at these locations and allow for the economical removal of the overburden and extraction of ore. Typical daily production from these two mines and the associated upgrading facilities is approximately 380,000 bbl/day (~ 60,000 m^3).

It is estimated however that approximately 10% of the bitumen deposits could be accessed by these surface strip mining methods. *In situ* recovery techniques must be used to get at the bulk of the deposits. It is this *in situ* recovery that may be of the most interest and opportunity to the geophysics community. First, current exploration of the resource is conservatively carried out by drilling, which is expensive and provides relatively low resolution. Geophysical techniques can be used to assist by helping to locate the thickest and richest oil sand materials. Due to the shallow nature of the deposits, electromagnetic airborne techniques (e.g. Cristall *et al.*, 2004) and electrical resistivity tomography (e.g., Kellett and Maris, 2005) have been applied to find the best deposits. High resolution seismic techniques (e.g. Siewert *et al.,* 1998) have shown promise for delineating finer details of the complex fluvial and estuarine sedimentary structure (e.g. Langenberg *et al*., 2002).

There are a number of *in situ* technologies that have been developed to produce the heavy oils and bitumens that range from cold heavy oil production to steam assisted gravity drainage. A recent and more detailed review was recently provided by Butler and Yee (2002). However a few of the more popular methods are presented and some examples of geophysical observations related to monitoring such processes are given.

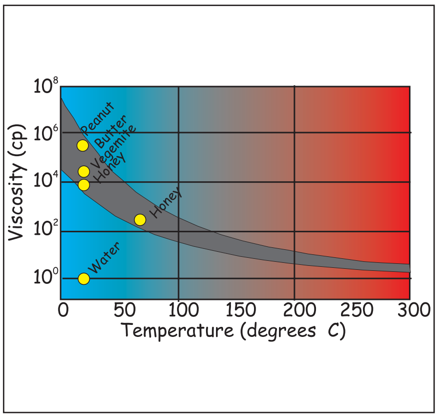


Fig. 6. Temperature dependence of Alberta heavy oils and bitumens versus temperature. Ranges of viscosity values fall within the gray zone. The lower bound and upper bounds are typical of Lloydminster heavy oils and Athabasca bitumen, respectively. For comparison, the viscosities of a number of food products recognizable in Australia are shown by the yellow filled circles, most are given at 20 °C.

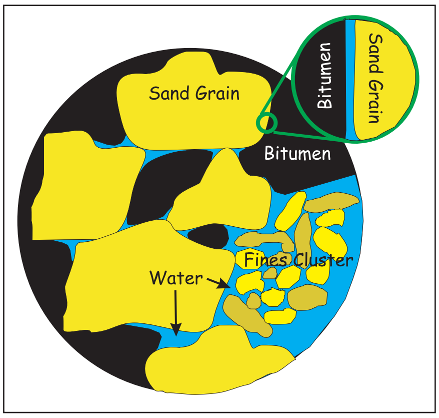


Fig. 7. Conventional model of the distribution of fluids within the oil sands. Blue, black, and yellow represent water, bitumen, and mineral grains, respectively. (after Czarnecki et al., 2005).

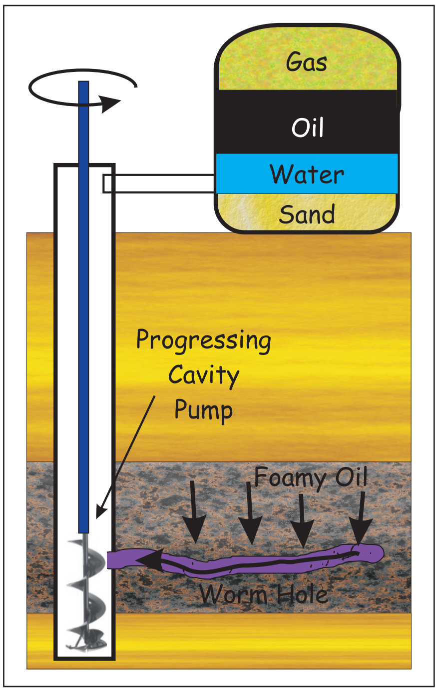


Fig. 8. Cartoon illustrating the 'cold production' method of heavy oil production. A progressing cavity pump returns a mixture of sand and fluids to the surface. The pump is essentially an auger that continuously removes material from the bottom of the wellbore.

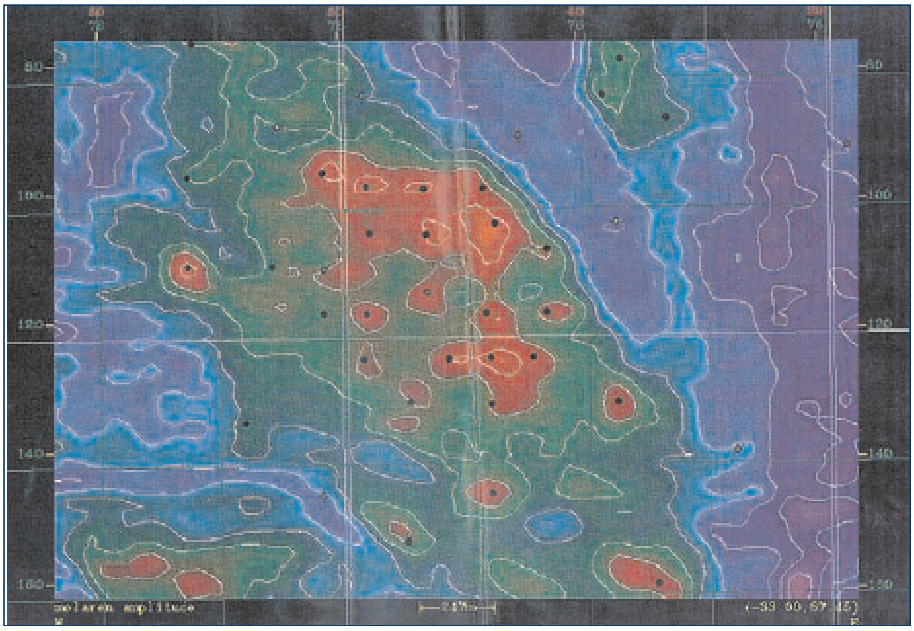


Fig. 9. Seismic amplitude map obtained over a cold production zone showing high returned amplitudes in the vicinity of the producing wells (indicated by dark circles). Map from Lines et al., 2003 courtesy of the Society of Exploration Geophysicists via their fair use policy.

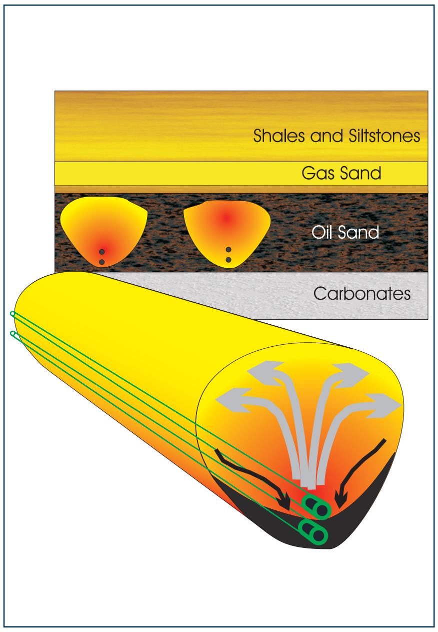


Fig. 10. Conceptual model of steam assisted gravity drainage technique. Steam is injected via the upper horizontal wellbore to heat the bitumen which then runs down along the sides of the steam zone to be produced in the lower horizontal wellbore. The steam zone extends along the length of the horizontal wells. A bank of such horizontal well pairs will typically be developed in order to access as large a proportion of the reservoir as possible. The geological structure shown is representative of the Athabasca situation.

- ***Cold heavy oil production*** (CHOP) is a method of producing heavy oils inexpensively without the addition of expensive enhanced recovery techniques although this method leaves more than 85% of the oil in the formation. In this method, vertical wellbores are drilled into the heavy oil sand reservoir and material is extracted with a special progressing cavity pump that consists of an auger screw (Figure 8). The screw or stator is the only moving part and is made of a tough synthetic elastomer that resists wear. The reason such wear resistance is desired is because cold production requires that sand also be produced with oil, water, and gas. Where exactly within the reservoir the sand comes from and how it assists the production of the oil is not completely understood. One model that appears to reasonably predict production histories is the creation of wormholes in the reservoir. These wormholes, which have been produced in laboratory situations, are essentially long cavities that progressively extend away from the producing wellbore while sand and fluids are removed. The wormholes are additionally valuable in that they produce a large effective surface area to the wellbore that allows for more effective production (*e.g.* Tremblay and Oldakowski, 2004).

Direct geophysical detection of the wormholes is unlikely as their dimensions are much smaller than seismic wavelengths (*e.g.* Chen *et al*., 2004). However, during production the pore fluid pressure (*i.e.* reservoir pressure) is drawn down by 50%, or more. The pressure drops below the bubble point and gas exsolves from the mixture to produce bubbles. The exoslution process maintains pressure within the reservoir and promotes the production of fluids and sand. Recent theoretical and experimental work by the Alberta Research Council (Lillico *et al*., 2001) suggests that initially large numbers of micron scale bubbles are nucleated. It is the reductions in the overall fluid compressibility, caused by nucleation of these bubbles that is likely to be responsible for strong changes in seismic amplitudes in the immediate vicinity of cold production wells (e.g. Lines *et al.,* 2003), as shown in the seismic amplitude map (Figure 9) of Mayo (1996).

- ***Steam assisted gravity drainage*** (SAGD) is a horizontal well steam injection technology developed in Canada in the past 20 years. This technique has become popular for *in situ* production in heavy oil and bitumen reservoirs. In SAGD, two parallel and horizontal wellbores are drilled one on top of the other, separated by approximately 2 m. The lower bore is near the bottom of the oil containing sands. At the beginning of this process, high quality steam is injected into both wellbores until the viscous oils between them are sufficiently mobile to enable good communication. At this point, injection continues only from the top well. Engineering models suggest that a steam chamber begins to grow both laterally away from the wellbore (at rates ~ 5 cm/day) and vertically within the oil sand. The growth of this steam zone occurs by the displacement of the now hot and lower viscosity oil which flows down along the sides of the chamber to its bottom (Figure 10). The pooled oil is then recovered through the lower wellbore with production rates of 100 m^3/day and estimated recovery rates of 50%.

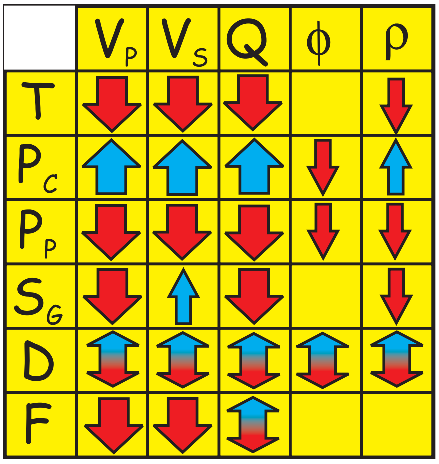
There are a number of variations on this theme (Butler and Yee, 2002). Methane gas may be injected in order to provide a region of low thermal conductivity at the top of the steam zone and reduce heat loss. This technique is referred to as steam and gas push (SAGP). In another technique that is now undergoing preliminary field trials and is referred to as vapor extraction (VAPEX), light hydrocarbon solvents such as ethane and propane are injected instead of steam. These solvents also reduce oil viscosity and allow it to flow in a manner similar to SAGD. This method is intended for reservoirs that are too thin for application of SAGD, which is inefficient in such situations due to the conductive heat losses. Another process which has been employed on a large scale is cyclic steam stimulation (CSS). This process takes place from banks of deviated and vertical wells and involves injecting steam into the formation, at pressures approaching the lithostat. The heat from this injected steam and hot water is then allowed to diffuse into the formation, which heats the oil and lowers the viscosity. After a suitable period, the same wells are then turned onto production with the presumption that the heated oil will flow back to the well.

Geophysical monitoring

The *in situ* technologies for producing heavy oils and bitumens require large capital investments and have high ongoing operational costs. Despite the high economic input, there is often no guarantee that a given project will necessarily meet its initial expectations. A number of difficulties can arise in developing such a reservoir. A major problem can arise in well completion where the liquid access ports in the steel casings can collapse, restricting the flow of fluids both in and out of the wellbore. This can cause substantial sections of the reservoir to be bypassed. Nature herself is not always amenable to simplified models of the subsurface. There can be both barriers to permeability that deny the steam access to sections of the reservoir and other lean or barren zones of high permeability that can steal the costly steam by routing it away from where is was intended to go. These problems can be difficult to detect as the tools available to the production engineer typically remain limited to history-matching of the fluid injection and production history. Concerns are raised only if these fluid histories substantially miss the initial expectations.

Issues related to the common solutions of history-matching aside, there are few tools that allow technical problems within the wellbore to be located or even detected. Determining the consequences of geological complexity in the three dimensional world away from the wellbore can be even more difficult to understand. Geophysical techniques have the potential to provide additional information away from the wellbore that could highlight both technical and geological problems. This has been long recognised and the pioneering seismic monitoring projects began in the oil sands in the mid-1980s (see Schmitt, 2004 for a listing of this work). These early studies demonstrated that the changes induced by enhanced oil recovery methods were substantial and could be detected using geophysical methods. Typically, the seismic reflectivity of the disturbed zones is greatly enhanced for a variety of reasons.

Injection of steam and the formation of a steam chamber can dramatically effect physical properties, particularly at the low effective confining stress of the shallow Athabasca oil sands. There are many changes occurring in the reservoir during such types of production and have been reviewed previously (Schmitt, 2004). Briefly however, the conditions of temperature (T), confining stress (P_C), pore fluid pressure (P_P), gas saturation state (S_g), and geomechanical damage (D) (e.g. Chalaturnyk and Li, 2004) are continuously evolving spatially and temporally. These extrinsic variables will influence the instrinsic physical properties of P-wave and S-wave velocities (V_P and V_S, respectively), the bulk density ρ, the porosity ϕ, and the quality factor Q (i.e. the inverse attenuation). The influence table (Figure 11), revised from Schmitt (2004), outlines the linkages between the extrinsic conditions and the intrinsic properties. This revised table also now includes the frequency F at which observations are made as it is likely that oil sands materials behave anelastically (Solano, 2004). This table represents more



	V_P	V_S	Q	ϕ	ρ
T	↓	↓	↓		↓
P_C	↑	↑	↑	↓	↑
P_P	↓	↓	↓	↓	↓
S_G	↓	↑	↓		↓
D	↕	↕	↕	↕	↕
F	↓	↓	↕		

Fig. 11. Influence table showing the expected responses in the intrinsic physical properties (V_P = compressional wave velocity, V_S = shear wave velocity, ϕ = porosity, Q = quality factor, ρ = bulk density) of the material dependent on the variations in the extrinsic reservoir conditions (T = temperature, P_C = confining stress or pressure, P_P = pore fluid pressure, S_g = gas saturation, D = geomechanical damage, F = frequency of elastic waves). The directions of the arrows in the cells indicate whether the intrinsic property is expected to increase (blue upward pointing arrow) or decrease (red downward pointing arrow) with a corresponding increase in the magnitude of the extrinsic condition.

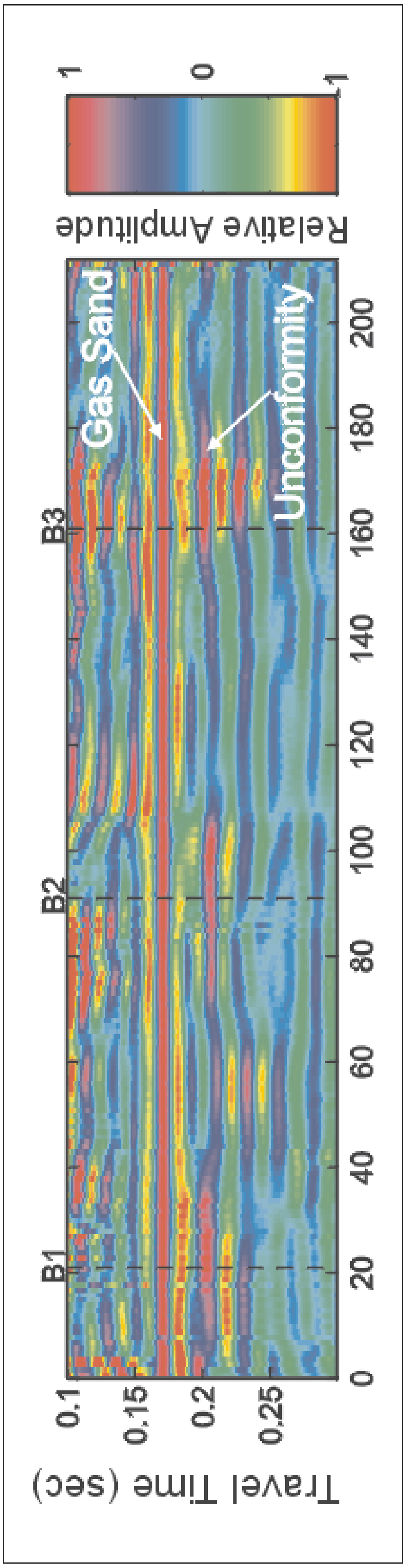


Fig. 12. Example of high resolution seismic profile acquired perpendicular to three SAGD well pairs in an Athabasca reservoir from Schmitt, 1999, courtesy of the Society of Exploration Geophysicists via their fair use policy. A close CMP spacing of 1 m is used in this study.

or less the behavior of the intrinsic properties due to changes in the extrinsic conditions. However, current understanding is far from being able to provide a reliable model for what the changes in such unconsolidated materials might be during production and further work is necessary.

Seismic monitoring over such production zones also differs from normal geophysical exploration in that the scales of the former are usually much smaller. Typical spacings between pairs of horizontal wellbores, for example, are less than 100 m and the wellbores extend for upwards of 1,000 m. As such, standard exploration seismic exploration techniques, while certainly useful, may not provide optimal spatial resolution.

View of workers directly mining oil sand along the Athabasca River, although the source of the lantern slide is unknown, the material obtained was likely for use in paving roads in Edmonton in 1915. The oil sand lies immediately above the hard carbonate shelf. This image is freely available from Library and Archives Canada.

My group has been involved with a series of 2D time lapse profiling for an Athabasca reservoir in the last few years. Figure 12 is an example of a profile acquired perpendicularly across three horizontal wellbore pairs (B1, B2, and B3), near the bottom of the reservoir at a depth of about 150 m (Schmitt, 1999). Large amplitude anomalies are associated with each of the three pairs and are presumably caused by the changes in the reservoir due to steaming. At the time the data was acquired, connection between the three different zones, as evidenced by temperature monitoring from observations wells, was just being established and the temperatures between the wells remained substantially cooler. This profile has been repeated 11 times since 1995 taking care to ensure that the source and receiver positions were unchanged between surveys. The results of this work will be forthcoming[6]. However, it is worth commenting that seismic response is not necessarily symmetrical with respect to the wellbores; suggesting that movement of fluids may not exactly occur in a uniform fashion. This should not be surprising given the complex nature of sedimentary structures within the reservoir (McGillivray *et al.,* 2005); but such suggestions are not necessarily met with enthusiasm by reservoir simulators who prefer a simpler earth[7].

Directions for the future

These are exciting times for the Alberta geophysical community; the oil sands provide an opportunity to carry out good science with a direct practical application. However, much work remains to be carried out. This work is not only directly technical, but in my humble opinion the community may need some shift in its operating paradigm from one of exploration, in which careful imaging of the geological structure has been paramount, to one that may be more quantitative such that the geophysical observations can be translated more precisely to the needs of production geologists and engineers. Only when this is done will we be able to convince them of the value of time-lapse monitoring in locating, for example, bypassed resources.

Aside from the production methodologies already mentioned, one future area of research that is now being discussed is that of '*in situ* upgrading' in which some portion of the refining process is actually carried out as part of the production. This is currently only a concept, but it is likely that such processes will be substantially more complex than simply injecting steam. One could easily speculate that such production strategies would make seismic monitoring even more desirable. The client community, which will come more from the refining side of chemical engineering, understand the value of process monitoring and are likely to be receptive to any technology that can assist them towards these goals.

Finally, Alberta's oil sand resource is large and as production from the heavy oils, and bitumens increase they will have an important impact. The subtitle to this paper: 'Can Alberta Save the World' suggested to me by David Denham must be put in context of the overall global demands. As mentioned earlier, global requirements in 2003 were closing in on ***30 Gbbl (4.6 X 10^9 m^3) per year.*** This means that even if we were able to squeeze every last drop of the highest estimate of the ultimate in-place hydrocarbons in the oil sands given above, the world-wide community would consume it in less than a decade. Clearly, we will soon have to seriously begin to seek additional supplementary sources of energy with conservation being one component of an overall strategy, as even our giant reserves cannot last forever.

Acknowledgements

Our research is currently supported by NSERC via the discovery and collaborative research grants programs and by the Canada Research Chairs program. Past support has come from the Seismic Heavy Oil Consortium, the COURSE program of the Alberta Energy Research Institute, and the Alberta Oil Sands and Technology Research Authority. The author wishes to thank Ian Jackson of the Research School of Earth Sciences at the Australian National University for sponsoring his visit to Australia, and for the motivation to include frequency into Figure 11. Although many have contributed to our work, special recognition must go to Jay Haverstock, Mike Lazorek, Len Tober, Marek Welz, and C. Dean Rokosh whose enthusiasm kept difficult field programs going.

---

[6] A 'movie' of these 11 seismic frames may be accessed from my webpage www-geo.phys.ualberta.ca/~doug

[7] The author has been informed that the seismic observations collected in the field must be in serious error as they did not agree with a particular computer generated reservoir simulation!

References

Alberta Department of Energy, 2004, Oil Resources Map, accessed September, 2005 at (http://www.energy.gov.ab.ca/docs/oil/pdfs/oil_resources_Map.pdf.

Adams, J. J., Rostron B. J., and Medoza C. A, 2004, Coupled fluid flow, heat and mass transport, and erosion in the Alberta basin: implications for the origin of the Athabasca oil sands: Can. J. Earth Sci., **41**, 1077-1095.

Alberta Economic Development, 2005, Oil Sands Industry Update, biennial updated report accessed Sept. 2005 at http://www.alberta-canada.com/oandg/files/pdf/oilsands_spring2005.pdf.

Alberta Energy and Utilities Board, 2004, Statistical Series (ST) 2004-98: Alberta's Reserves 2003 and Supply/Demand Outlook 2004-2013, accessed Sept, 2005 at http://www.eub.gov.ab.ca/BBS/products/publications/statseries/ST98.htm.

Butler, R. M., and Yee, C. T., 2002, Progress in the *in situ* recovery of heavy oils and bitumen: J. Can. Petrol. Tech., **41**, 31-40.

Chalaturnyk, R. J, and Li P., 2004, When is it important to consider geomechanics in SAGD operations?: J. Can. Petrol. Tech., **43**, 53-61.

Chen, S., Lines, L., and Daley, P., 2004, Foamy oil and wormhole footprints in heavy oil cold production reservoirs: Recorder, **29**(8), 49-51.

Cristall, J., Farquharson C., and Oldenburg D., 2004, Airborne electromagnetic inversion applied to oil sands: expanded abstract, Can. Soc. Expl. Geophys. Annual Meeting.

Czarnecki, J., Radoev B., Schramm L. L., and Slavchev R., 2005, On the nature of Athabasca oil sands: Adv. Colloid and Interface Sci., **114**, 53-60,.

Kellett, R. L., and Maris, V., 2005, Imaging electrically resistive oilsand channels in northeast Alberta, Canada, accessed Sept. 2005 at http://www.komex.com/Geophysics/projects/papers/ERT_oilsand3.pdf.

Langenberg, C. W, Hein F. J., Lawton D., and Cunningham J., 2002, Seismic modeling of fluvial-estuarine deposits in the Athabasca oil sands using ray-tracing techniques, Steepbank River area, northeastern Alberta: Bull. Can. Petr. Geol., **50**, 178-204.

Lillico, D. A., Babchin, A. J., Jossy, W. E., Sawatzky, R. P., and Yuan, J. Y. 2001, Gas bubble nucleation kinetics in a live heavy oil: Colloids and Surfaces A – Physiochemical and Engineering Aspects, **192**, 25-38.

Lines, L., Chen S., Daley P. F, Embleton J., and Mayo L., 2003, Seismic pursuit of wormholes: The Leading Edge, **22**, 459-461.

McGillivray, P., 2005, Microseismic and Time-lapse Seismic Monitoring of a Heavy Oil Extraction Process at Peace River, Canada: Recorder, **30**(1), 5-9.

Mayo, L., 1996, Seismic monitoring of foamy heavy oil, Lloydminster, western Canada: 66th Ann. Internat. Mtg: Soc. of Expl. Geophys., 2091-2094.

Meyer, R.F., and Attanasi, E. D., 2003, Heavy oil and natural bitumen – strategic petroleum resources, United States Geological Survey, Fact Sheet 70-03, accessed Sept. 2005, at http://pubs.usgs.gov/fs/fs070-03/fs070-03.html.

Mossop, G. D., 1980, Geology of the Athabasca oil sands: Science, **207**, 145-152.

National Energy Board, 2004, Canada's Oil Sands: Opportunties and Challenges to 2015, and Energy Market Assessment – May 2004, accessed Sept. 2005, http://www.neb-one.gc.ca/Publications/index_e.htm.

Ofosuasiedu, K., Hughes, R., Price D., and. Rutherford J. P, 1992, SEM AIA study of the size distribution and mineral-content of Athabasca oil sand and its coke residues: Energy Sources, **14**, 95-105.

Pemberton, S. G., and D. P. James (eds), 1997, Petroleum Geology of the Cretaceous Mannville Group, Western Canada: Can. Soc. Petrol. Geol., Memoir 18.

Price, R., 1994, Cordilleran tectonics and evolution of the Western Canada Sedimentary basin, *in* Geological Atlas of the Western Canada Sedimentary Basin, G. D. Mossop and I. Shetson (comp.), Canadian Society of Petroleum Geologists and Alberta Research Council, Calgary, Alberta, accessed Sept. 2005 at http://www.ags.gov.ab.ca/publications/ATLAS_WWW/ATLAS.shtml.

Radler, M., 2003, World wide reserves increase as production holds steady, Oil and Gas Journal, **100** (52), 113-145.

Riediger, C., Ness, S., Fowler M., and Akpulat T., 2000, Timing of oil migration, Paleozoic and Cretaceous bitumen and heavy oil deposits, eastern Alberta, expanded abstract: Can. Soc. Expl. Geophys. Annual conference, accessed Sept. 2005 at http://www.cseg.ca/conferences/2000/2000abstracts/819.PDF,.

Schmitt, D. R., 1999, Seismic attributes for monitoring of a shallow heated heavy oil reservoir: A case study: Geophysics, **65**, 368-377.

Schmitt, D. R., 2004, Oil sands and geophysics, CSEG Recorder, **29**(11), 5-11.

Siewert, A., Millington G., and Wilkinson K., 1998, High Fidelity Vibratory Seismic "HFVS" Application for Shallow Heavy Oil Sand targets – Kearl Oil Sands Mine 2D Survey and Cold Lake 3D Survey Alberta: Extended Abstract, Geotriad Conference, Calgary.

Selby, D., and Creaser R. A., 2005, Direct radiometric dating of hydrocarbon deposits using Rhenium-Osmium isotopes: Science, **308**, 1293-1295.

Solano, G. E., 2004, Zero offset VSP data processing and attenuation estimates in the oil sands: Dept. of Physics, University of Alberta, Edmonton, Alberta.

Takamura, K., 1982, Microscopic structure of Athabasca oil sand: Can. J. Chem. Eng., **60**, 538-545.

Tremblay, B., and K. Oldakowski, 2002, Wormhole growth and interaction in a large sand pack: J. Petr. Sci. and Eng., **34**, 13-32.

U.S. Dept. of Energy, International Energy Annual 2003, 2005, accessed Sept. 2005 at http://www.eia.doe.gov/iea/wec.html, released in spreadsheet format, July, 2005.

Zajic, J. E., Cooper D. G., Marshall J. A., and Gerson D. F., 1981, Microstructure of Athabasca bituminous sand by freeze-fracture preparation and transmission electron microscopy: Fuel, **60**, 619-623.

Some other resources, recent short article in Wired magazine http://wired-vig.wired.com/wired/archive/12.07/oil.html, the Athabasca Regional Issues Working Group has a website (http://www.oilsands.cc/about_us/default.asp) that bring forth issues from the energy industries perspective related to the rapid development of the oil sands region. The Lloydminster Oilfield Technical Society has sponsored a highly informative website discussing numerous issues related to heavy oil production (http://www.lloydminsterheavyoil.com/).