Look ahead of the bit while drilling: potential impacts and challenges in the McMurray Formation

Siavash Nejadi, Nasser Kazemi, Jordan Curkan, Jean Auriol, Paul Durkin, Stephen Hubbard, Kristopher Innanen, Roman J. Shor, Ian Gates

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Given Name	Surname	Company
Siavash	Nejadi	University of Calgary
Nasser	Kazemi	University of Calgary
Jordan A.	Curkan	University of Calgary
Jean	Auriol	University of Calgary
Paul R.	Durkin	University of Manitoba
Stephen M.	Hubbard	University of Calgary
Kristopher A.	Innanen	University of Calgary
Roman J.	Shor	University of Calgary
Ian D.	Gates	University of Calgary

Abstract

The oil and gas industry, operating and service companies, and academia are actively looking for ways to see ahead of the drillbit while drilling to reduce the risks and costs of the operation and improve the well-placement process. Optimal drilling in the challenging and highly heterogeneous reservoirs, where geological interpretations overlook the high-frequency variations in the rock properties, requires reliable subsurface information from around and ahead of the drillbit. To provide this, we have developed a seismic-while-drilling imaging algorithm based on signal processing, drillstring modeling, and pre-stack wave-equation migration.

To extend the visibility ahead-of-the-bit, we use the drillbit as a seismic source and image the changes in acoustic properties of rocks both around and ahead of the drillbit. The common practice is to build a reverse vertical seismic profile (R-VSP) gathers. Here, we use a blind deconvolution algorithm to estimate the drillbit source signature from the data directly. Alternatively, we can estimate such a signature through drillstring modeling and top-drive measurements (i.e., force and velocity). The drillstring dynamics is modeled by using Riemann's invariants and a backstepping approach. Next, we input the estimated source signature to the pre-stack wave-equation depth imaging workflow. Our simulations show that providing drillbit source signature to the pre-stack wave equation depth migration consistently delivers reliable subsurface images around and ahead of the drillbit.

The output of our workflow is a high-resolution subsurface image that provides vital information in oil sands reservoirs for placement of steam assisted gravity drainage (SAGD) well pairs. Compared to conventional practices, the proposed methodology images around and ahead of the drillbit enabling interactive decision making and optimal well-placement. The key feature of the presented methodology is that instead of cross-correlating the seismic-while-drilling data with the pilot trace and building R-VSP gathers, we use the estimated drillbit source signature and deliver high-resolution pre-stack depth migrated images.

Through numerical modeling, we tested the potential impacts, validity, and challenges of the proposed methodology in drilling horizontal wells in SAGD settings with an emphasis on the McMurray Formation. We further compared the results with the conventional drilling practice. In contrast to existing tools that have limited depth of penetration, interpreting seismic-while-drilling data in real-time

confidently maps key target features ahead of the drillbit. This imaging workflow provides sufficient time to precisely control the borehole trajectory and stay within the desired reservoir zone. Accordingly, it mitigates the risk of intersecting mud-filled channels and lean zones.

Introduction

The Lower Cretaceous McMurray Formation hosts the majority of bitumen in the Athabasca oils sands – the largest known resource of bitumen. This formation is composed of large-scale point bars and other components of meander-belts that are highly heterogeneous (Musial et al., 2012). The repeated erosional cut and fill events within the McMurray Formation have led to multi-stacked channel-belt deposits (Hein and Cotteril, 2013; Horner et al., 2019). Associated point bar deposits are up to 50 m thick, and often exhibit thick packages of massive to cross-stratified sandstones near their base and interbedded sandstones and siltstones upwards, which are referred to as inclined heterolithic strata (IHS) (Thomas et al., 1987). More broadly, channel-belt deposits consist of an amalgam of depositional elements, resulting in complex sedimentary facies relationships, where rock types change both laterally and vertically over short distances (e.g., Hubbard et al., 2011).

Steam-Assisted Gravity Drainage (SAGD) is the most promising in-situ recovery process to produce bitumen resources from Athabasca oil-sands deposits (Butler, 1991; Strobl et al. 1997). SAGD well configurations typically consist of two parallel horizontal wells located at a short distance one above the other. The length of horizontal sections range from 500 to 1000m, and the vertical separation is 5-7m. As the name implies, the key production mechanism in SAGD is gravity. Hence, placing the producing well at high - non-optimal elevations reduces the ultimate recovery factor. Bitumen below the production well cannot be recovered at any significant distance from the well and therefore placement at or near the base of porosity is optimal. Another significant design limitation worth noting is controlling the borehole undulation, with less than 0.5 m unwanted horizontal deviations over its entire length targeted (i.e. 0.5/1000 m).

Geological interpretations of the subsurface, together with engineering design, determine the optimal placement of the horizontal wells. In SAGD systems, the optimal field development requires not only an estimation of gross reservoir thickness but also the distribution of non-reservoir facies and connectivity. Fluvial processes related to point bar formation, intra-point bar erosion, counter-point bar formation, and channel abandonment contribute to the development of heterogeneities within the McMurray Formation (Thomas et al., 1987; Hubbard et al., 2011; Martinius et al., 2017; Yan et al., 2017; Durkin et al., 2017). Bedding architecture and lithologic heterogeneities within different geobodies influence the connected hydrocarbon volume and recovery performance. Mapping inclined heterolithic strata (IHS) of sandwiched sand-shale/siltstone sequences and muddy abandoned channels, where possible, improve the understanding of flow barriers and baffles in the reservoir; that aids in both well placement and advanced well completion design for improved recovery.

The use of three-dimensional (3D) seismic data for detailed subsurface imaging and interpretation is a common practice (e.g., Hubbard et al., 2011; Durkin et al., 2017). 3D seismic data, a high density of wells and extensive cores are used to infer characteristics of sedimentary architecture, including the geometry of point bar elements. The workflow relies on the combination of data types to construct high-resolution geological models of channelized reservoirs, which are the basis of development strategies. The elements of meander-belt deposits at different stratigraphic levels of the reservoir are deterministically modeled and combined with methodologies to infer reservoir rock parameters, such as facies and porosity trends, using seismic attributes (Journel, 2002).

In general, several factors affect the resolution of seismic data. A 360-degree seismic ray path coverage is required to have an ideal and reliable seismic image of the subsurface. The 360-degree coverage guarantees uniform sampling and illumination of the subsurface structure. However, in the field, we only have access to seismic recordings at the surface. The complex stratigraphic architecture, high heterogeneity, low impedance contrast, and sub-seismic features introduce non-uniform illumination and uncertainties in seismic images. In the point-bar deposits of the McMurray Formation, the presence of sub-seismic mudstone drapes potentially impede steam chamber growth (Richardson et al., 1978; Hartkamp-Bakker and Donselaar, 1993). These mudstone drapes cannot be imaged using the surface seismic method. Moreover, the deposits towards the base of the reservoir overlying the sub-Cretaceous unconformity surface are convoluted and show low impedance contrast, which makes detailed imaging of stratigraphic architecture difficult. The small-scale heterogeneities, convoluted layers, and irregular surface topography of the unconformity contribute to stratigraphic complexity and result in a poor seismic response in the region. To reduce the uncertainties inherent in surface seismic recordings, we need to use other sources of information.

Conventional SAGD well placement practice includes acquiring data while drilling for optimal placement of the laterals. Measurement-while-drilling (MWD) and logging-while-drilling (LWD) have been adopted to monitor drilling parameters and acquire formation properties, in real-time, and transfer data to the surface. Applications of MWD systems include monitoring and controlling the directional-drilling operation, assistance in detection of abnormal pressure zones, correlation logging, preliminary evaluation of some possible producing zones, monitoring of weight on bit (WOB), and drilling torque at the bit (Dowell et al., 2006). Accurate measurements of depth, inclination, and azimuth are essential for the path determination of horizontal SAGD wells. Among various LWD tools such as Gamma-radiation (GR), nuclear, acoustic, or NMR technologies, LWD resistivity measurements are the principal measurement for geosteering and optimal well placement; the depth of investigation of the LWD resistivity tools is significantly larger than that of any other LWD tools. LWD tools have sensors located immediately above or near the drillbit. Putting these tools at some distance behind the bit still provides an opportunity to first detect, and then avoid drilling into non-reservoir, which is a pseudo-look-ahead capability.

To place the wells in the best possible reservoir section, operators exploit look-ahead monitoring techniques to guide real-time well trajectory adjustment. Industry and academia have researched ways to use noise generated by the drillbit-rock interaction to monitor the rock properties ahead of the drillbit since the 1960s (Poletto and Miranda 2004). The drillbit-rock interaction generates significant P and S waves that are strong enough to bounce several times from the subsurface layer boundaries and be recorded at the surface or in the nearby wells. The methodology that uses the seismic waves generated by the drillbit-rock interaction to image the subsurface structure is called seismic-while-drilling (SWD) imaging. Authors also refer to SWD imaging as an inverse vertical seismic profiling (inverse VSP) (Hardage 1985; Poletto and Miranda 2004). This is because in VSP recordings, the seismic source is at the surface, and the recording devices, i.e., geophones, are placed in the wells. However, in SWD data, the drillbit-rock interaction in the well acts as a seismic source, and the geophones record drillbit noise at the surface.

SWD has some advantages over the LWD and VSP methods. LWD provides images behind the bit; whereas SWD-based algorithms image around and ahead of the bit. Imaging ahead of the bit provides an opportunity to adjust the drilling parameters for improving the rate of penetration (ROP) and updating the well trajectory, which, in turn, ensures staying in the sweet spot, and avoiding risky and non-producible zones. Also, compared to VSP, the SWD method does not interfere with drilling. Accordingly, the drilling crew can drill wells and record drillbit noise simultaneously (Poletto and Miranda 2004). Besides, in SWD, we have the option to record drillbit noise in nearby wells, allowing imaging between wells (i.e., crosswell imaging). Crosswell imaging using SWD gives vital information about the nearby subsurface structures through the development process. In other words, crosswell images improve reservoir characterization and are used to optimize subsequent well pair/pad placement.

We use a new SWD imaging algorithm that provides high-resolution subsurface images. Kazemi et al. (2018) show that if we understand drillbit-rock interactions and can model their seismic radiation patterns, prestack depth imaging of SWD data is possible. To estimate the drillbit signature, Kazemi et al. (2018) used a blind deconvolution method called SMBD (Kazemi and Sacchi, 2014). Recently, Auriol et al. (2019) introduce a methodology that uses drill string modeling and top-drive measurements to model drillbit-rock interaction. These two techniques are used to estimate the drillbit source signature, which is an input to the SWD imaging algorithm developed by Kazemi et al. (2018). Here, we use this algorithm to image around and ahead of the drillbit. Subsequently, we use these images to update reservoir models and consider applications for improving well placement.

The main focus of this study is to present a SWD methodology supported by several case studies inspired from the Surmont Phase 1 SAGD project. We investigate potential applications of look-ahead-of the-bit information for an improved well pad drilling approach. The approach helps to reduce drilling risks and improves 1) the geosteering decisions for individual production well drilling including their vertical placement and 2) the knowledge of geological heterogeneity and reservoir boundaries in well pad design. The computational requirements of the methodology would not constrain its implementation for real-time operational decision making. The methodology provides high-resolution ahead-of-the-bit images of the subsurface that identify reservoir boundaries and highlight geological heterogeneities to be used for real-time decision making.

Methodology

Drillbit-rock interaction generates significant elastic energy in the subsurface. The drillbit energy propagates through or reflects from subsurface layers, and can commonly be recorded at the surface or nearby wells. These wave mods follow the wave equation

$$(\omega^2 \mathbf{s}^2 + \nabla^2)P = f\ \delta(\mathbf{x} - \mathbf{x}_s) \tag{1}$$

where P is pressure wavefield, $\boldsymbol{s}$ is slowness, ω is temporal frequency, f is the drillbit source signature, $\mathbf{x_s}$ is source location, ∇^2 is Laplacian operator, and δ is the Dirac delta function. Solving the wave equation represented in Equation-1 provides the information necessary to generate a subsurface image. To solve Equation-1, we decompose the subsurface slowness and recorded pressure wavefield as follows

$$\mathbf{s}^2 = \mathbf{s}_0^2 + \mathbf{m}, \quad and \quad P = P_0 + \Delta P \tag{2}$$

where $\boldsymbol{s_0}$ is the background slowness, $\mathbf{m}$ is the subsurface image, P_0 is the pressure wavefield satisfying the background medium, and ΔP is the perturbation in the pressure wavefield due to $\mathbf{m}$. Then, by using the Born approximation (Born 1926), we get the subsurface image as

$$\mathbf{m}(\mathbf{x}) = -\sum_{\omega}\sum_{\mathbf{x}_s'}\sum_{\mathbf{x}_r'}(\omega^2 P_0^*(\mathbf{x},\omega;\mathbf{x}_s')\ G_0^*(\mathbf{x}_s',\mathbf{x}_r',\omega;\mathbf{x})\ d(\mathbf{x}_r',\mathbf{x}_s',\omega)) \tag{3}$$

where d is the recorded SWD data at the surface, G_0 is the Green's function that satisfies the wave equation in the background medium, x'_s is source location, x'_r is receiver location, and P_0 is the source-side wavefield. To generate the source-side wavefield, the drillbit source signature is estimated through the exploration of two methodologies. The first method uses a signal processing algorithm and directly estimates the drillbit source signature from the recorded SWD data. In this approach, we use the blind deconvolution method proposed by Kazemi and Sacchi (2014) to estimate the source signature directly from the data (i.e., SMBD algorithm). In the SMBD algorithm, data is modeled as the convolution of drillbit source signature with a reflectivity series

$$\mathbf{d}_j = \mathbf{F}\,\mathbf{r}_j + \mathbf{n}_j \qquad j = 1, \ldots J, \tag{4}$$

where $\mathbf{F}$ is the convolution matrix built from the drillbit source signature f, r_j and n_j are the reflectivity series and noise term in channel j. Kazemi and Sacchi (2014) found the smallest common factor between the channels by solving an inverse problem where the solution fits the heterogeneous system of equations and provides a sparse reflectivity series. Then, the byproduct of the algorithm is the drillbit source signature. The SMBD algorithm estimates the smallest common factor between all of the channels in the SWD data by solving a heterogeneous system of equations. Let's convolve the data of channel *p* with the reflectivity of channel *q* and the data of channel *q* with the reflectivity of channel *p*. After some algebraic manipulations, we get

$$\mathbf{D}_p\mathbf{r}_q - \mathbf{D}_q\mathbf{r}_p = \mathbf{N}_p\mathbf{r}_q - \mathbf{N}_q\mathbf{r}_p \tag{5}$$

where $\mathbf{D_p}$ and $\mathbf{N_p}$ are the convolutional matrices built from d_p and n_p, respectively. After using all of the combinations similar to Equation-5 between all of the channels, we end up having a heterogeneous system of equations

$$\mathbf{A}\,\mathbf{x} = \mathbf{e} \tag{6}$$

where

$$\mathbf{A} = \begin{pmatrix} \mathbf{D}_2 & -\mathbf{D}_1 & & & & & \\ \mathbf{D}_3 & & -\mathbf{D}_1 & & & & \\ \mathbf{D}_4 & & & -\mathbf{D}_1 & & & \\ \vdots & & & & \ddots & & \\ & \mathbf{D}_3 & -\mathbf{D}_2 & & & & \\ & \mathbf{D}_4 & & -\mathbf{D}_2 & & & \\ & \vdots & & & \ddots & & \\ & & & & \mathbf{D}_J & & -\mathbf{D}_{J-2} \\ & & & & & \mathbf{D}_J & -\mathbf{D}_{J-1} \end{pmatrix} \tag{7}$$

and

$$\mathbf{x} = [\mathbf{r}_1, \mathbf{r}_2, \mathbf{r}_3, \dots, \mathbf{r}_J]^T \tag{8}$$

The term **e** is the concatenation of vectors similar to the right-hand side of Equation-6. To find the reflectivity series that fit the heterogeneous system of equations represented in Equation-6, SMBD solves the following cost function

$$\hat{\mathbf{x}} = \underset{\mathbf{x}}{\operatorname{argmin}} \quad \frac{1}{2}||\mathbf{A}\,\mathbf{x}||_2^2 + \lambda\sum_i(\sqrt{x_i^2+\epsilon^2}-\epsilon), \quad \text{subject to} \quad \mathbf{x}^T\mathbf{x} = 1 \tag{9}$$

where λ is a regularization parameter, and ε is a small number. The regularization term in the cost function is the Huber norm that promotes sparsity in the final solution. After finding the sparse reflectivity series, the drillbit source signature is estimated by a least-squares matching filter in the frequency domain that matches the data to the reflectivity series. Interested readers are referred to Kazemi et al. (2018) for the details of the application of the SMBD algorithm in estimating the drillbit source signature and SWD imaging.

The second approach for estimating the drillbit source signature relies on drill string modeling and top-drive measurements (Auriol et al., 2019). These authors showed that through modeling the drillstring dynamics and measuring the top-drive force and velocity time series, it is possible to estimate the drillbit source signature. They also use the estimated drillbit source signature in combination with the SWD data to estimate the velocity of rocks that are interacting with the drill.

In this paper, we assume that the drillbit generates significant energy that can reflect several times from the layer boundaries and can be recorded at the surface or nearby wells. However, in situations where the drillbit does not generate significant noise, we should consider using a controlled source in the well. In both cases, i.e., using dillbit as a source or a controlled source, if the elastic energy reaches the surface or nearby wells, our proposed workflow is valid and provides high-resolution subsurface images.

Case Studies

This section presents different case studies, where the look-ahead-while-drilling could potentially improve SAGD well placement. The main objective is to assess value creation as a result of using SWD to sequential geosteering decisions. We illustrate the application of the proposed methodology in various geological settings inspired by Surmont Phase 1 developments.

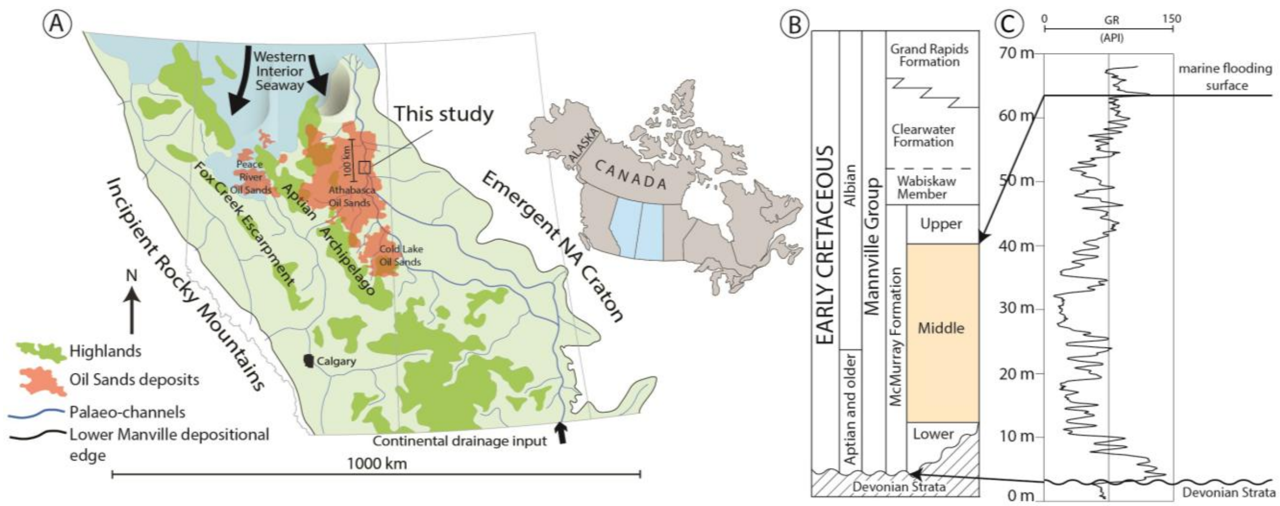

Figure 1 - A) Paleogeographic reconstruction of the Early Cretaceous Western Canada Sedimentary Basin (WCSB), including the location of the ancient meander belt deposit of this study. B) Stratigraphic setting of the McMurray Formation in the lower Mannville Group. C) Simplified stratigraphic column for the McMurray Formation, which unconformably overlies Devonian carbonate strata in the study area and Gamma-radiation (GR) log through the entire McMurray Formation. (Modified from Hubbard et al., 2011, and Durkin et al., 2017)

The Surmont Lease study area in the Athabasca Oil Sands is located ~70 km southeast of the city of Fort McMurray, Alberta, Canada (Figure-1A). A typical vertical profile of the McMurray Formation in the focused project area shows an overall fining upward sequence composed of a series of upward fining cycles. It consists of a thick meander-belt deposit underlain by one or more incompletely preserved channel belt deposits. In the study area, a thin regionally deposited fine-grained sandstone and siltstone cover the upper meander-belt deposit. The top of the reservoir (cap rock) is a regionally correlatable marine flooding surface at the base of the Wabiskaw Member, which serves as the stratigraphic datum (Figure-1B, C).

High quality 3D seismic time-slices provide geometric constraints on the uppermost depositional elements of the McMurray Formation (Durkin et al., 2017). It captures the 3D representation of different geobodies, including distinctive point bar and counter-point bar elements, side bars, and abandoned channel fills. In this seismically-constrained meander-belt deposit, we deterministically model the individual architectural elements; these stationary zones constrain parameter estimations in the property modeling phase (Nejadi et al., 2019).

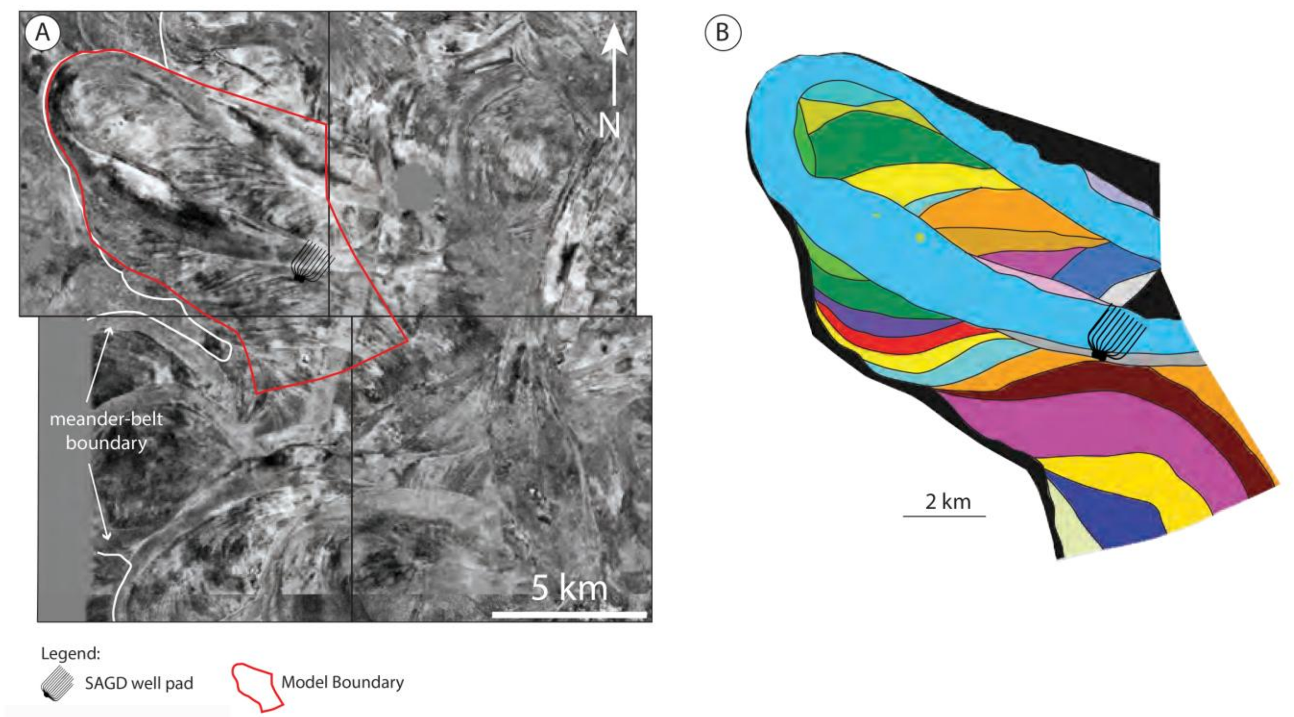

Figure 2 - A) 3D seismic-amplitude stratal slice and B) zone model of the seismically constrained youngest meander-belt deposit in the focused study area. (Modified from Durkin et al., 2017)

The optimal SAGD development requires not only an estimation of the gross oil-sand reservoir thickness, but also internal imaging of the reservoir, including the distribution of non-reservoir facies. Current best practice for SAGD well pad placement is to place the production well near the base of the pay zone. Development areas are selected according to various criteria including: net continuous bitumen; top gas and water, lean zones; cap rock thickness; and surface constraints including proximity to the central processing facility.

In our study area, the base of the pay zone is the base of high porosity bitumen saturated sandstone facies, which is below the seismically-constrained youngest meander deposit. Typically, petrophysical well logs show that porosity and bitumen saturation is highest at these depths; in the absence of vertical flow barriers and baffles, it is a sweet spot for well pair placement. However, the lack of lithologic contrast and resolution of seismic data limits the interpretation of depositional elements at these depths. The amalgamation of sandy meander belt deposits makes correlations difficult and adds to the complexity of reservoir characterization. Mapping mudstone-filled abandoned channels and muddy IHS areas of the lower channel belt deposit(s) are critical to horizontal well pair placement. These impermeable elements block vertical steam chamber growth and limit depletion from the thick, overlying bitumen-saturated point bar deposits. Similarly, drilling and placing the wells inside these poor quality elements affect productivity or injectivity, leading to a partial loss of the drilled lateral length. Wireline well logs, core descriptions, and stratigraphic dip analysis are used to infer the distribution of channel elements in the underlying deposits (Fustic et al., 2007). This limited source of data incurs uncertainty in interpreting depositional elements and spatial distribution of reservoir vs. non-reservoir facies.

Below the base of the meander-belt strata and above the sub-Cretaceous unconformity, the McMurray Formation is characterized by smaller upward fining fluvial channel deposits that are encased in fine-grained deposits including floodplain, paleosol and lacustrine units. These smaller channels - less than 10 m thick and 100-150m wide - are related to relatively localized paleodrainages that incised Devonian strata. Imaging this amalgam of non-reservoir units - between the base of porosity and top of unconformity - is equally crucial to optimal well placement and field development planning.

Case A: Producer partially drilled in non-reservoir facies, reservoir boundary

This case examines the downsides of placing a horizontal producer in a suboptimal location. The producer is placed near the base of the pay zone to maximize recovery, but is partially drilled into a mudstone-filled channel associated with the lower meander-belt deposit. The proximity of the mudstone-filled channel to the highly reflective Devonian Unconformity challenges the precise interpretation and estimation of the three-dimensional distribution of this non-reservoir rock.

Figure-3 shows a cross-section that encounters a horizontal well pair. Different colors highlight the inner architectural elements of the reservoir. The log example alongside both injector and producer show typical Gamma-radiation log responses for common sedimentary rock types; cool colors correspond to the high GR values. The presented model is constructed for the most likely interpretation of the reservoir, as this is thought to be the most likely outcome and most useful and realistic for field development purposes. For optimal field development planning, we recommend performing sensitivity studies and evaluating the uncertainty in both deterministic and stochastic modeling, although such studies are beyond the scope of this paper.

The length of the producer is 860 m. Approximately the last 140 m of the lateral section shows a high GR value, highlighting suboptimal well placement and drilling of non-reservoir facies (mudstone). The corresponding injector is drilled according to the producible length of the producer and is 140 m shorter than the designed length and pad average.

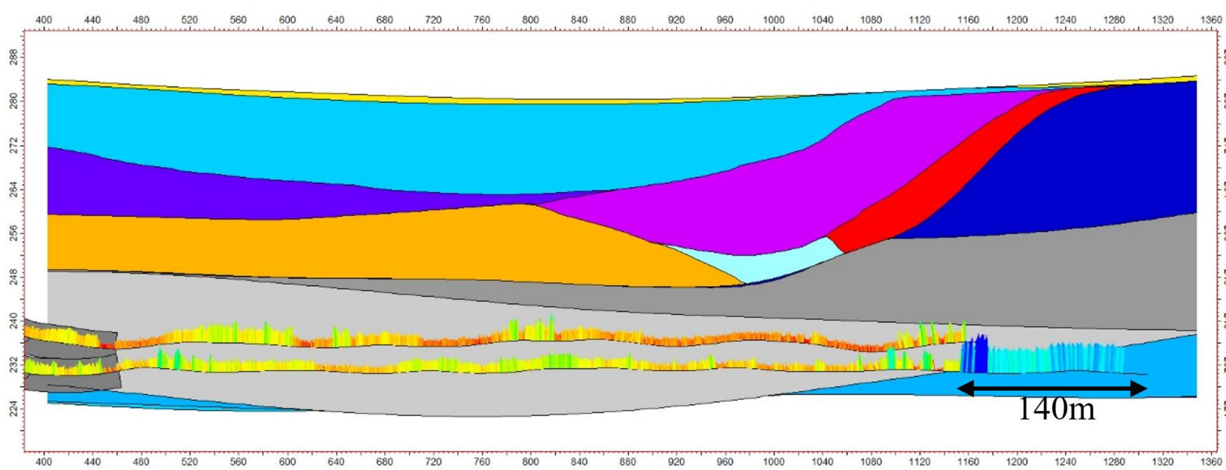

Figure 3 - Vertical reservoir cross section along Case A well pair. Different colors show the zone model and and the log show Gamma-radiation along the laterals. The horizontal scale is 1:2800, and the vertical exaggeration is 4.5.

Figure-4A displays the production data for this well pair. The average monthly oil production is roughly 1,400 m^3 with a cumulative steam oil ratio (cSOR) of 3.6 m^3/m^3. This well pair has a lower oil production rate and a higher cSOR compared to other well pairs in the same pad, which is attributable to the shorter producible length and the smaller drainage volume as a result of proximity to the reservoir boundary (mudstone-filled channel or edge of the belts). Table-1 compares the production data with other case studies; the data for the pad average is also included as the baseline to highlight the difference between superior and low performing cases.

Figure-5 shows the overlay of subsurface velocity profile and high-resolution SWD image corresponding to the cross-section represented in Figure-3. As clear, the mudstone boundary is remarkably imaged with the proposed SWD imaging algorithm. To generate the SWD image, we numerically simulated 15 equally spaced drillbit sources in the vertical section of the producer's well. Moreover, we considered that there is a vertical well on the right-hand side of the cross-section. Hence, we recorded the numerically simulated pressure wavefields at the right-hand side vertical well. By doing so, we show that the subsurface image of cross well SWD data could efficiently reveal the mudstone and reservoir boundary. Accordingly, the high-resolution SWD image is a vital source of information for optimal well placement and avoiding risky zones. In this case, where the horizontal producer reaches and penetrates the reservoir boundary, the optimal geosteering solution, in practice, is not steering the horizontal well above the non-reservoir zone. Whereas, SWD interpretations provide improved images of the boundary well in advance (Figure-5), with sufficient time to make a decision and steer the well to the sides or as the best choice, not to drill beyond a certain measured depth - in the mud. In practice, this application saves rig time and minimizes drilling costs; incurred expenses for inefficient 140 m dilling cover the cumulative costs of seismic-while-drilling.

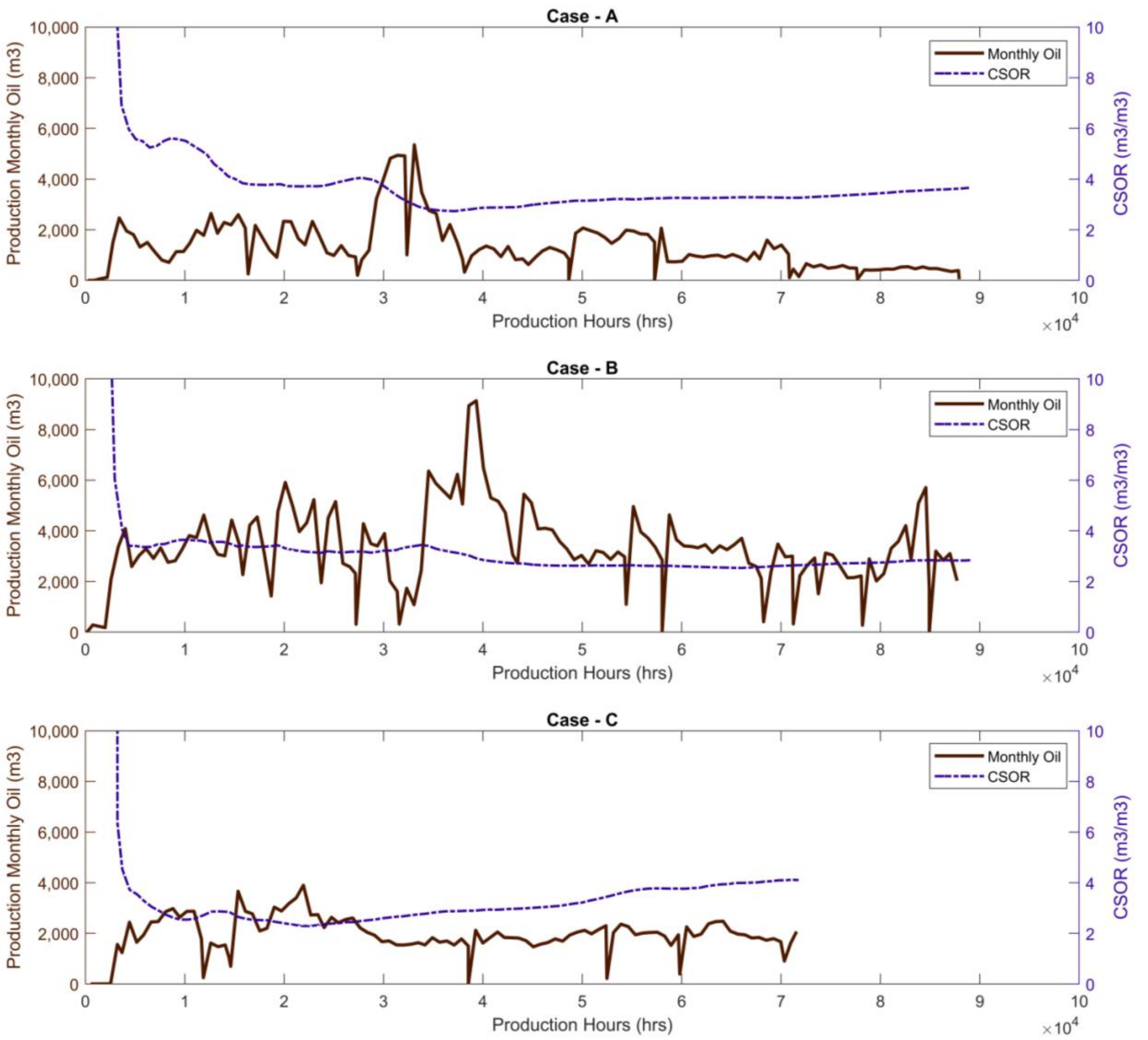

Figure 4 - Oil production and cumulative steam oil ratio for different case studies.

Table 1 - Well data, average monthly oil production, and cumulative steam oil ratio for different case studies compared with the pad average.

Case	Producer Length	Injector Length (m)	Monthly Oil (m^3)	CSOR (m^3/m^3)
A	850 (140m Mudstone)	710	1,400	3.6
B	860	860	3,600	2.8
C	840 (463m IHS)	840	2,100	4.1
Pad Average	850	850	2,700	3.4

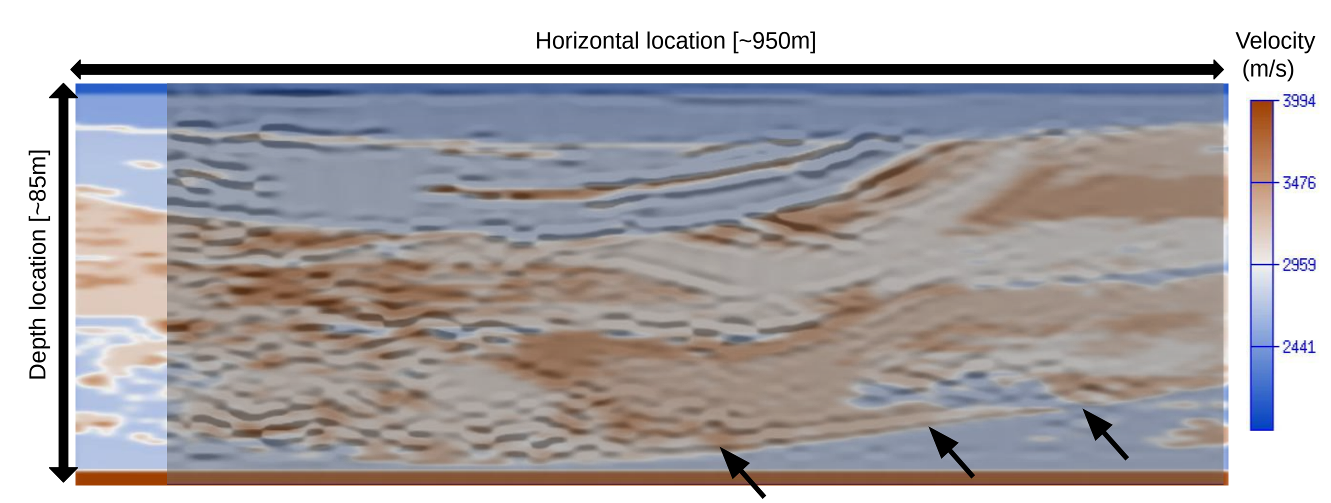

Figure 5 - Overlay of subsurface velocity profile and high-resolution SWD image corresponding to the cross-section represented in Figure-3. Black arrows show the mudstone boundary.

Case B: Optimal drilling and well placement

This case presents the optimal well placement with little or no loss of producible length of the horizontal wells (Figure-6). The producer is placed near the base of porosity and both injector and producer are drilled in reservoir facies with good porosity and high bitumen saturation. The production performance of this well pair is well above the pad average and is one of the best well pairs in the pad (Figure-4B). The average monthly oil production is 3,600 m^3 with cSOR of 2.8 m^3/m^3 (Table-1).

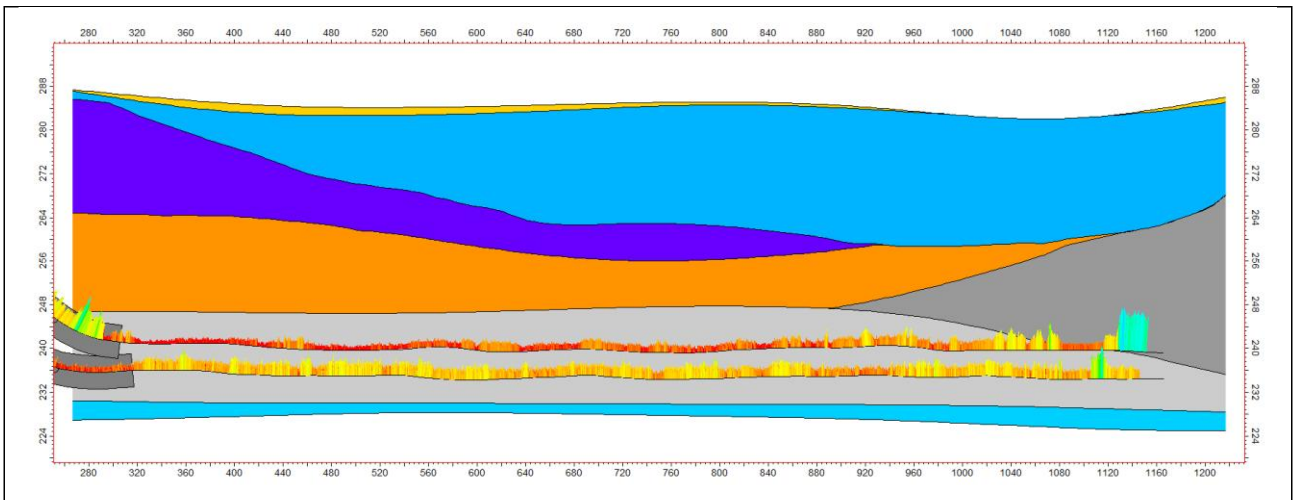

Figure 6 - Vertical reservoir cross section along case B well pair. Different colors show the zone model and the logs show Gamma-radiation along the laterals. The horizontal scale is 1:2800, and the vertical exaggeration is 4.5.

It is interesting to highlight that the very last few meters (20 m) of the injector penetrates an element of the upper meander-belt. This element is a separate, older unit not related to the modeled point bar deposit, with high IHS and mudstone facies proportions. As a result, the GR response near the end of this injector is characterized by high values, which correspond to non-reservoir facies. Again, this demonstrates the need for detailed reservoir characterization and precise interpretation of point bar elements including the three-dimensional geometry and fill of channel bodies prior to field development planning in SAGD settings.

Case C: Producer is partially drilled in Paleosols/Basal Shales

In this case, we discuss a scenario where portions of the horizontal producer is placed in non-reservoir rocks (Figure-7). Consider non-uniform 3D seismic resolution and a pad size of 1000 x 1000 m^2;

typically 10 vertical cored or logged stratigraphic wells are drilled in such pads. This leads to an average vertical well spacing (sampling) of 10 hectares/well. That is sufficient to map flat structures like the base meander-belt, but introduces significant uncertainty in 1) interpreting depositional elements and 2) estimating reservoir boundaries, as defined by the edge of the belts.

As mentioned, optimal horizontal well placement in a SAGD setting necessitates placing the producer well as close as possible above the base of bitumen. A detailed map (<1 m uncertainty) of the highs and lows on the undulatory unconformity surface, facies variations, as well as basal water distribution is needed. In this example, because of poor vertical well sampling and low-resolution 3D seismic data near the base of the reservoir, the vertical position of the producer is suboptimal with approximately the first half of the producer is drilled in mudstone and IHS strata. This has significantly affected the production performance of the well pair. The average monthly oil production of this well pair is 2,100 m^3 and cSOR is 4.1 m^3/m^3, which is quite poor compared to the pad average (Figure-4C).

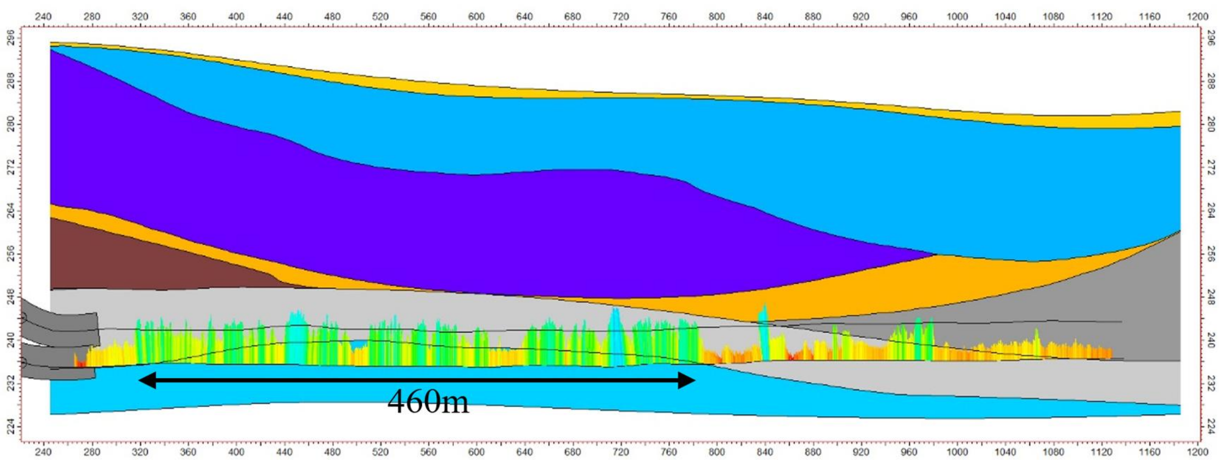

Figure 7 - Vertical reservoir cross section along case C well pair. Different colors show the zone model and and the log show Gamma-radiation along the laterals. The horizontal scale is 1:2800, and the vertical exaggeration is 4.5.

The real-time SWD data potentially images the surface on top of non-reservoir basal shales, and it provides valuable information to support decision making, steering the well, and adjusting the landing point of the horizontal section.

Added value

There have been limited reports on the application of SWD in SAGD developments. The excessive costs of acquisition and interpretation need to be clearly justified in order to convince operators of its benefits. Several reports (e.g. Chemali, 2011) clarify the benefits of SWD and its successful application in deep water and subsalt drilling environments. A discussion of missed or wasted resources during SAGD developments, considering both the cost of data acquisition and time spent on design and data interpretation, is not available at this time. In our case studies, we presented certain environments where look-ahead-of-the-bit information could drastically improve SAGD well placement, and ultimately, well deliverability. The production performance of adjacent well pairs shows the added value of optimal well placement and the potentials of SWD data.

A key design criterion in SAGD well placement is the target depth of the producer's horizontal track. Generally, horizontal wells are drilled using sparse vertical well sampling and surface seismic data. These sources of data have quite large uncertainty near the base of the pay zone, and as a result, laterals may not be optimally placed with regards to target petrophysical properties (Case C), and in some cases, even miss the desired target altogether (Case A). SWD can help to reduce this uncertainty by providing reflective information in real-time. Operators can update subsurface images and lessen the risks while the well is being drilled into the target zone.

Ahead-of-the-bit information helps geosteering engineers to mitigate the risks of drilling in unwanted zones without disturbing drilling operations. It provides indications of reflecting horizons/rocks and helps to detect non-reservoir facies. This supports both drilling and well completion design decisions. Ahead-of-the-bit information is highly valuable to optimize casing landing point for horizontal SAGD wells placement. Besides, the detailed and high-quality rock type information provides invaluable constraints to enhance engineering designs and optimize completion equipment (e.g. Nejadi et al., 2018).

Figure-8 shows a seismic depth section of the meander belt in the study area. As discussed and illustrated in different case studies, in the area used for this study, the horizontal well pairs are often placed between the base of the upper meander-belt deposit and top Devonian strata. Seismic profiles at these depths show non-uniform resolution rendering geological interpretations, yielding a challenging task. Due to the strong reflectance at the contact between poorly consolidated sediments of the McMurray Formation and competent underlying Devonian limestones, the surface seismic resolution is relatively poor up to 10 m above the unconformity.

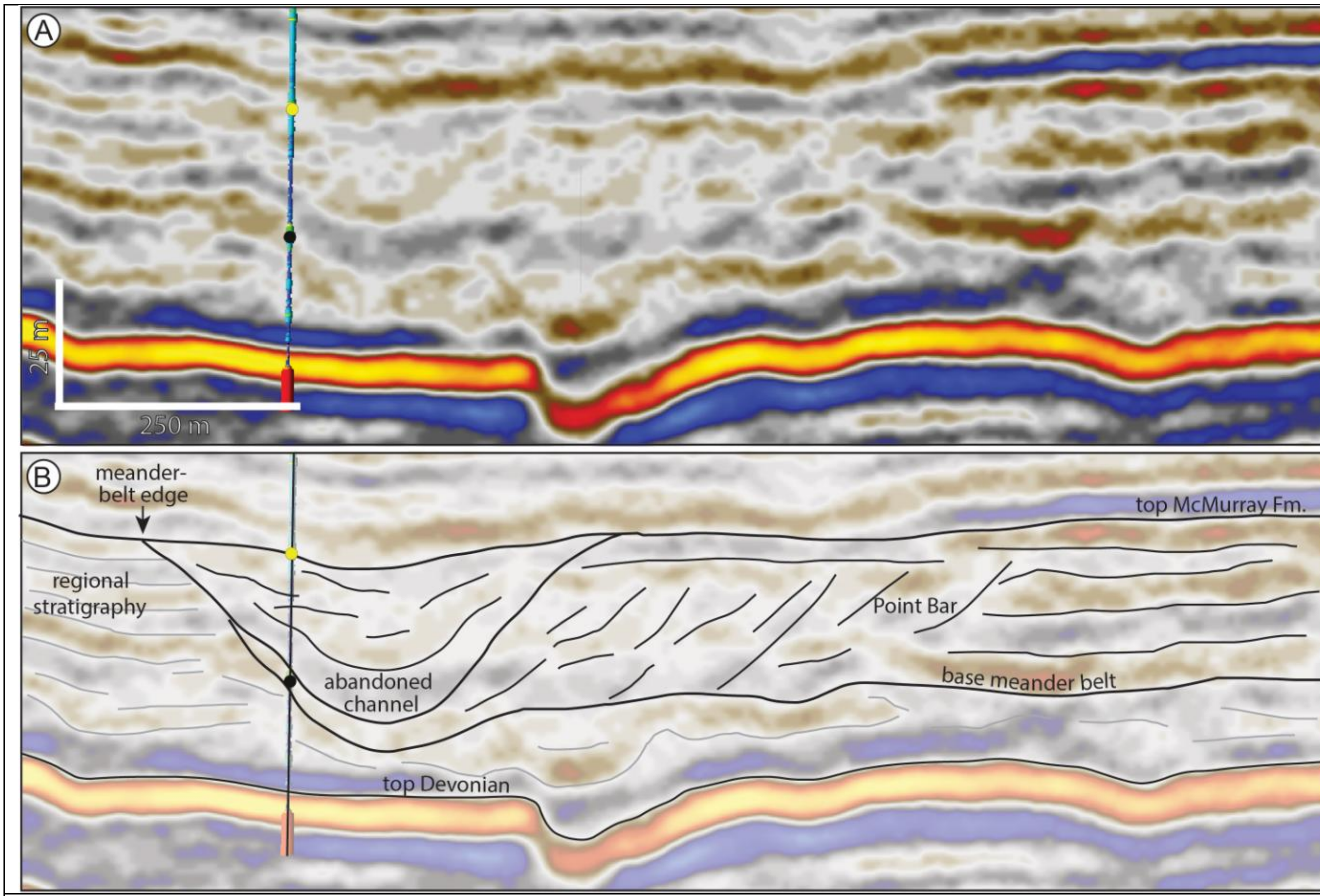

Figure 8 – A) Seismic-time cross section of the McMurray Formation in the study area. B) Line trace showing the elements of meander-belt deposits at different stratigraphic levels. 3D seismic resolution is relatively poor up to 10 m above the unconformity. (Modified from Durkin et al., 2017)

In the case of non-challenging SAGD development areas with flat structures near the base, seismic-while-drilling information will provide detailed images of the inner elements of the deposit, resulting in reduced uncertainties in reservoir characterization step. The operator may use detailed geological models to fine-tune the well pair orientations in the future pads and place the pads perpendicular to the point bar packages - accretion surfaces and maximize productivity (Su et al., 2017).

Multi-Well Pad Drilling

Multi-well pad drilling reduces both time and costs by allowing for shared construction, equipment, and facilities, reducing the surface footprint while minimizing rig moving expenses. It further provides an opportunity for continuous process improvement. In this paper, we propose improvements to well placement strategies that can enhance production efficiency in the context of multi-well pad drilling. This approach fine-tunes the placement of horizontal wells with the help of drilling and subsurface data obtained in real-time while drilling previous laterals. A result may be that the sequence of lateral drilling may be modified as data is collected through the batch drilling process.

The sequence starts with drilling the first lateral in the best-characterized, less uncertain part of the pad that inherently implements the best knowledge of the subsurface. Subsurface images are updated while drilling the horizontal wells. The real-time information reduces uncertainties and updates the current understanding of the presence, scale, and continuity of low-quality facies. This approach follows the idea of just-in-time well placement and design, which is to specify the next horizontal well, in the drilling sequence, according to the risks and uncertainties, instead of a pre-defined order using *a priori* knowledge. The selection criteria and placement of the next laterals are modified in real-time using the lessons learned from the previous drilling. Our proposed workflow challenges the practice of merely skidding the rig over a few meters and drilling the next lateral in a pre-designed manner that solely relies on sparse vertical well sampling and three-dimensional seismic with non-uniform resolution in the depths of lateral placement.

Conclusions

This paper discussed the value of look-ahead-of-the-bit information to multi-well pad drilling in SAGD settings. We use a novel SWD imaging algorithm that provides high-resolution subsurface images. Imaging ahead of the bit provides an opportunity to adjust the drilling parameters, updating the well trajectory and improves 1) well placement and 2) drilling performance. The approach consists of estimating the drillbit source signature and using it as an input to the SWD imaging algorithm. Later on, we use these images to update reservoir models and improve well placement. Implementation of SWD information in the context of SAGD well pad drilling in the presence of poor three-dimensional seismic quality and geological uncertainty demonstrates reasonable improvement in optimal well placement.

Application of SWD information potentially addresses the problem inherent in horizontal producer placement, and minimizes risks of drilling in non-reservoir facies; it implements an improved image of the subsurface and reduces the uncertainties in reservoir size, distances to the boundary, and formation properties. In addition to improved well placement, the near-real-time updated subsurface images provide sufficient time to fine-tune downhole well completion designs.

Nomenclature

Symbols

δ: Dirac delta function

ϵ: Small number in Huber norm for approximation the L_1 norm

ω: Angular frequency

λ: Regularization parameter

∇^2: Laplacian operator

d: Seismic data

e: Noise term in SMBD

f: Seismic source function

m: subsurface model

n: Noise in the data

r: Subsurface reflectivity

s: Slowness

A: Channels combination matrix for SMBD

D: Convolution matrix of seismic data, d

G: Green's function

J: Maximum number of channels per shot gather

N: Convolution matrix of noise

P: Pressure wavefield

Subscripts

i: Channel index

j: Channel index

p: Channel index

q: Channel index

Superscripts

T: Transpose

*: Conjugate transpose

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