Sedimentology and Reservoir Characterisation of Specific Play Types in the McMurray Formation, Northeastern Alberta: Implications for *In-Situ* Recovery

Mark Caplan*
Athabasca Oil Sands Corp, Calgary, AB
mcaplan@aosc.com

and

Wayne Fu
Athabasca Oil Sands Corp, Calgary, AB, Canada

Summary

The depositional setting of the McMurray Formation within the main McMurray fairway has been extensively studied by geologists and is well documented in the literature. Most provincial crown land in the easternmost part of the Athabasca Oil Sands Deposit (AOSD) has been leased, and is currently being drilled and geologically characterised with the aim of *in-situ* or mining bitumen extraction, mostly from reservoir channel sand bodies. There are, however, new plays being discovered in the northwestern part of the AOSD, notably in the Ells and Dover areas that represent different depositional environments. Athabasca Oil Sands Corp. (AOSC) is a private oil sands company that holds extensive oil sands assets in this western region of Athabasca (Fig. 1), where it has discovered thick bitumen pay within the McMurray Formation. Other major companies holding rich bitumen leases close-by include the tripartite partnership of Chevron Canada Limited, Shell Canada Limited and Marathon (formerly Western Oil Sands Inc.), as well as TOTAL E&P Canada, and land brokers holding lands for undisclosed clients. Chevron has claimed as much as 7.5 billion barrels of bitumen in-place on their leases which may be exploitable by *in-situ* SAGD methods[1]. Across its leases in the Dover area, AOSC has extensive in-place volumes of bitumen, and plans to develop a 2,000 bpd *in-situ* thermal pilot in 2010, followed by 25,000 to 30,000 bpd tranches commencing 2014[2].

Depositional environments of the McMurray Formation in this region contrast significantly to those reservoirs located within the main fairway to the east. This presentation aims at describing the sedimentology and reservoir characterisation of a small area of the AOSC properties and will compare the reservoir types associated with this new play area to those more traditional channel sand plays found further to the east.

Introduction

Reservoir sands in the western AOSD are located in feeder valleys, within structural lows on the Devonian unconformity surface. These tributary valleys connect to the main Athabasca fairway further to the northeast. In contrast to the main valley, reservoirs in tributary valleys do not occur in the lower or middle McMurray intervals, but occur within the upper McMurray interval. Accommodation space during McMurray times in these tributary valleys was less than in the main valleys to the east, and consequently the McMurray interval is somewhat thinner. Wabiskaw/McMurray shoreface and delta front deposits developed in this area and further to the west. In areas of thicker upper McMurray pay, the reservoir appears to be confined to incised valleys and forms tidally-dominated delta and/or tidal flat fills. The incisions cut into argillaceous middle McMurray delta plain deposits which form the initial fill over the Devonian unconformity in this area. The delta front deposits consist of vertically-stacked, cleaning-upward cycles, each cycle varying from 5 to10 metres in thickness. These cycles reflect a retrogradational parasequence set constituting a transgressive systems tract. Internally, each cycle consists of a cleaning- and coarsening-upward series of wavy-bedded sands passing up into clean, HCS and parallel-laminated sands. Towards the base of each cycle, 8 to 15 centimetres thick, sharp-based, parallel-laminated to HCS and ripple-laminated sand beds grade up into thin, 1 to 2 centimetres thick, bioturbated shales rich in organic detritus that drape rippled sands. These deposits represent episodic deposition in a delta front setting, fed by flood and storm events. Ichnogenera vary from very small, moderate abundances of *Teichichnus, Thalassinoides* and *Planolites* at the base of the lower cycles, to intensely bioturbated intervals dominated by more robust *Rosselia* and *Asterosoma* traces in the upper deltaic cycles. Ichnological and palynological information suggests that these cycles become progressively more marine-influenced upward through the McMurray Formation. The incised valley systems became progressively more inundated with fully marine conditions culminating in a regional marine transgressive, bioturbated, muddy, glauconitic condensed interval prior to development of a regional marine Clearwater shale caprock.

Comparing McMurray Geological Play Types

There appear to be several types of reservoir plays in the McMurray Formation. They reflect different depositional environments that were formed by contrasting hydrodynamic processes, and resulted in significant internal sedimentological differences and consequent contrasts in reservoir quality (Table 1). The standard McMurray reservoirs are ribbon-shaped, meandering, tidally-influenced channel sands, the basic building blocks of which are crescent-shaped, sandy point bar deposits. These channel sands are often vertically and laterally amalgamated to form meandering channel sand complexes, with significant internal reservoir and lithological heterogeneities. In some cases, reservoir architecture is controlled by the dimensions and geometry of point bar deposits comprising these meandering channel systems. Three-dimensional seismic information is required in order to image these point bar architectural elements. A dense drilling pattern of delineation wells is also necessary to predict the geometry of point bar reservoir architectural elements as well as the occurrence and position of single or compound channel mud plugs and muddy vertical accreting fills. Tidal processes associated with channel development is responsible for the introduction of much clay material into the system, forming the inclined heterolithic stratification (IHS), which is identified in many *in-situ* projects located in the main fairway. Individual channel sands are generally on the order of 5-10 metres thick and less than a few hundred metres in width. In order to generate channel reservoirs of significant thickness and width, it is necessary that channel sands be vertically stacked and laterally amalgamated into compound reservoir sands. This occurs in the main fairway due to generation of sufficient accommodation space resulting in multiple vertically-stacked channel sands. Reservoir quality deteriorates upwards within individual channel bodies, as well as within the overall McMurray channel fill succession. Vertical contrasts in reservoir quality result in significant vertical permeability contrasts which may lead to impacts in the development and growth of steam chambers.

In contrast to channel reservoir plays, the deltaic play types located further to the west exhibit very different reservoir characteristics. As with channel reservoirs, the deltaic lobes require multiple stacking of these geobodies in order to attain a vertical reservoir thickness sufficient to meet *in-situ* net pay thickness cut-off requirements. This can occur in confined containers such as infilling of a narrow incised valley by deltaic sand bodies, or where deltaic lobes emanate from a fixed point source setting. Individual deltaic cycles tend to clean-upward. Reservoir quality is best developed in areas proximal to a sediment source. In general, reservoir quality improves vertically through an individual deltaic cycle. There is also a tendency for reservoir quality to deteriorate laterally from the delta centre to its margins. This may also result in increased reservoir compartmentalisation toward the edges of isolated deltaic lobes. In some instances, deltaic lobes are laterally amalgamated at the same stratigraphic interval, forming widespread sand sheets. It has also been recognised that each deltaic cycle contains a feeder channel, consisting of medium-grained, sharp-based, cross-bedded sand, which is interpreted as a distributary channel. These channels are narrow and can often be elusive to identify.

Reservoir Characteristics of McMurray Formation

Deltaic bodies of the McMurray Formation comprise an amalgamated thickness of over 35 metres. Reservoir quality within these thick sand bodies is quite uniform in both a vertical and lateral sense. These sands display very good porosities and bitumen saturations, low clay volumes and a high NTG. Although average bitumen saturation appears somewhat lower than channel sands to the east, lateral continuity of reservoir quality is high compared with the more conventional channel sand plays. These reservoirs cover many sections of land and do not contain mud plugs, making this reservoir play favourable to *in-situ* exploitation.

Reservoir Parameters	Channel Reservoirs	Deltaic Reservoirs
Porosity	Excellent	Excellent
Bitumen Saturation	Excellent	Good-Excellent
NTG	Moderate-Good	Good
Thickness	Excellent (if amalgamated reservoir sands)	Good
Reservoir Width	Poor-Moderate	Good
Reservoir Heterogeneity	High	Low-Moderate

Table 1: Comparison of reservoir play types

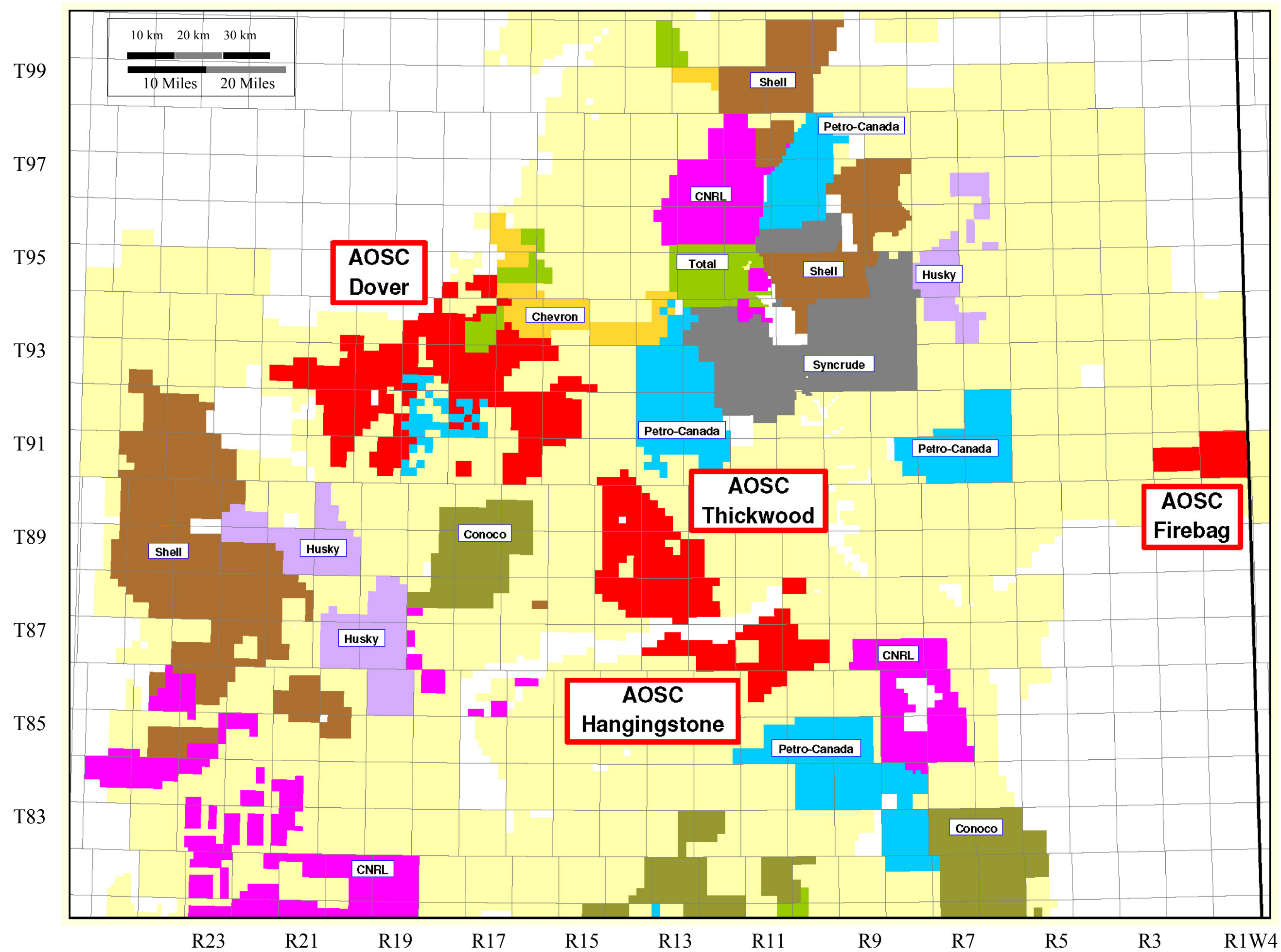

Figure 1: Athabasca Oil Sands Corp. oil sands land holdings (displayed in red)

Acknowledgements

We would like to thank AOSC management for allowing us to release this information. This presentation would not have been possible without technical contributions from the following people: Kerrie Bann, Graham Dolby, Al Gordon, Emeline Lamond, Garett Nykipilo, Mimi Reichenbach, Chris Sato, Chris Taggart, and many others.

References

1. Daily Oil Bulletin, March 2nd, 2006. Chevron To Develop Athabasca Oilsands In Situ Project
2. Daily Oil Bulletin, January, 16th, 2008. After Raising $401 Million, Another New Player Joins Oilsands Drilling Boom.