[PS]West Athabasca Grand Rapids Formation – A New SAGD Play*

M.E. Connelly[1] and Laurie M. Weston Bellman[1]

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[1]Laricina Energy Ltd. & L.M. Weston Bellman (Oil Sands Imaging) (marnie.connelly@laricinaenergy.com), (laurie@oilsandsimaging.com)

Abstract

The majority of Steam-Assisted Gravity Drainage (SAGD) development to date has been concentrated in the Cretaceous McMurray Formation in the Eastern Athabasca fairway of the oil sands deposits of northeastern Alberta, Canada. More recently, operators have identified projects with considerable resource located in shoreface sands of the younger Cretaceous Grand Rapids Formation further west in the Wabasca area (Figure 1).

The Grand Rapids Formation comprises the upper part of the regressive Upper Manville Group (Cant et al., 1997) and consists of multiple thick sandstones hosting 54.5 billion barrels (8678 x 10^6 m^3) of bitumen in place (ERCB, 2009). The uppermost Grand Rapids sand is the largest of the three identified deposits with 33.2 billion barrels (5274 x 10^6 m^3) in place (EUB, 1996). Much of the bitumen resource is underlain by a thin bottom water leg of varying thickness (Peterson et al., 2008).

The complex estuarine depositional environment in which the McMurray sands were deposited resulted in heterogeneous and complex reservoirs. In contrast, the upper Grand Rapids sand is interpreted to have been deposited in a regional marine shoreface setting. Its unique features – broad deposition, clean sand with homogeneous and continuous reservoir pay – increase the predictability and consistency of the reservoir. Laricina Energy Ltd. (Laricina) holds a total of 63 sections (the Germain lease) in the fairway with an estimated 2.5 billion barrels (0.4 x 10^6 m^3) of bitumen in place. Laricina has filed applications for regulatory approval of a commercial demonstration project capable of producing 5000 bbl/day utilizing a variant of SAGD technology which is based on steam and solvents (Figure 2).

In conventional SAGD reservoirs, the horizontal production and injection well pairs are typically placed within the bitumen zone. However, based on laboratory and new simulation studies, Laricina has determined that bitumen recovery in a reservoir with thin associated basal water can be maximized by placing the producer at the base of porosity within the basal water zone (Peterson et al., 2008 and Peterson et al., 2009). The key aspects and concerns in the SAGD development of the Grand Rapids bitumen resource include clearly identifying the porosity base, the bitumen-water contact and any impedance to vertical permeability. To address these issues, a detailed 3D reservoir characterization was required. This presentation will describe the process of integrating core, log and 3D seismic data in the Germain lease to produce a volume of deterministically derived lithology and fluids within the reservoir.

Method

The upper Grand Rapids sand has been a focus of recent drilling and seismic acquisition by Laricina in the Germain lease (T84 R22 W4). Wireline logs and core photos of a type well from the lease is shown in Figure 3. Unlike typical McMurray reservoirs, the upper Grand Rapids sand is homogenous with very rare muddy interbeds. However, the reservoir parameters are similar to the McMurray with bitumen thickness ranging from 10 to 25 meters, average porosity of 34%, bitumen saturations ranging between 65 and 75% and permeability ranging between 1 and 5 Darcy.

Due to the simple nature of this reservoir, a fairly simple set of facies descriptions were established and identified from core. The facies identified were bitumen sand, wet sand, shaley sand, sandy shale, shale and dense or cemented sands. The wet sand facies occurs at the base of the upper Grand Rapids sand, at the base of the bitumen sand interval. Typically, the shale facies are only found above the bitumen sand and below the basal water sand as bounding shales to the sand deposit. Occasional dense or cemented intervals are present within the reservoir sand. These zones are generally very thin, less than 0.5 meters thick and do not correlate between wells. Core and outcrop data suggest that these are limited in areal extent as lateral termination has been encountered in core and these zones are limited to only a few meters in length in outcrop (Figure 4).

The core facies interpretations were then integrated with the wireline log data for the 3D reservoir characterization analysis. Wireline logs directly (or indirectly) measure P-wave velocity, S-wave velocity and density. From these measured logs, the rock physics attributes lambda (incompressibility) and mu (shear rigidity) can be calculated (Goodway et al., 1997). Cross-plot analysis of these and various other attributes leads to empirical limits and guidelines for lithology and fluid discrimination based on core facies. Figure 5 is a cross-plot of density vs mu*density calculated from well logs in the Grand Rapids zone with the points coloured by core facies. It clearly shows the clustering and separation of different facies in this domain. The relationships between attributes and facies determined from the cross-plots are then used to calibrate and classify the equivalent properties derived from seismic data.

The seismic process involves the use of AVO (amplitude vs offset) analysis to separate the compressional (P-wave) and shear (S-wave) components of the seismic data. The resulting components are used to calculate the physical rock properties through inversion and multiattribute analysis (Russell et al., 1997). When these attributes are classified based on the log and core analysis, the result is a seismic volume transformed to a detailed lithological characterization of the reservoir within the zone of interest. Figure 6 is an example portion of a line through the 3D classified by this method. Gamma ray logs are shown at the two wells intersecting this profile.

The resulting 3D visualization of the lithology and fluid distribution clearly identifies the porosity base of the sand and the bitumen-water contact. This will allow for confident placement of the horizontal well pairs for the SAGD process with the producer placed just above the base of porosity and the injector just above the bitumen-water contact (Peterson et al., 2009). The thin dense sands within the reservoir interval are not able to be resolved in this dataset, however thicker ones such as those in the lower Grand Rapids sand are apparent.

Conclusions

Integration of core, log and seismic data allow for greater understanding of even simple reservoirs like the Grand Rapids. Identifying the presence and location of barriers to vertical permeability, the base of porosity and bottom water thickness allows Laricina geologists and engineers to make decisions regarding important SAGD issues with respect to reservoir development and provides greater confidence in locating horizontal wells in the reservoir.

Acknowledgement

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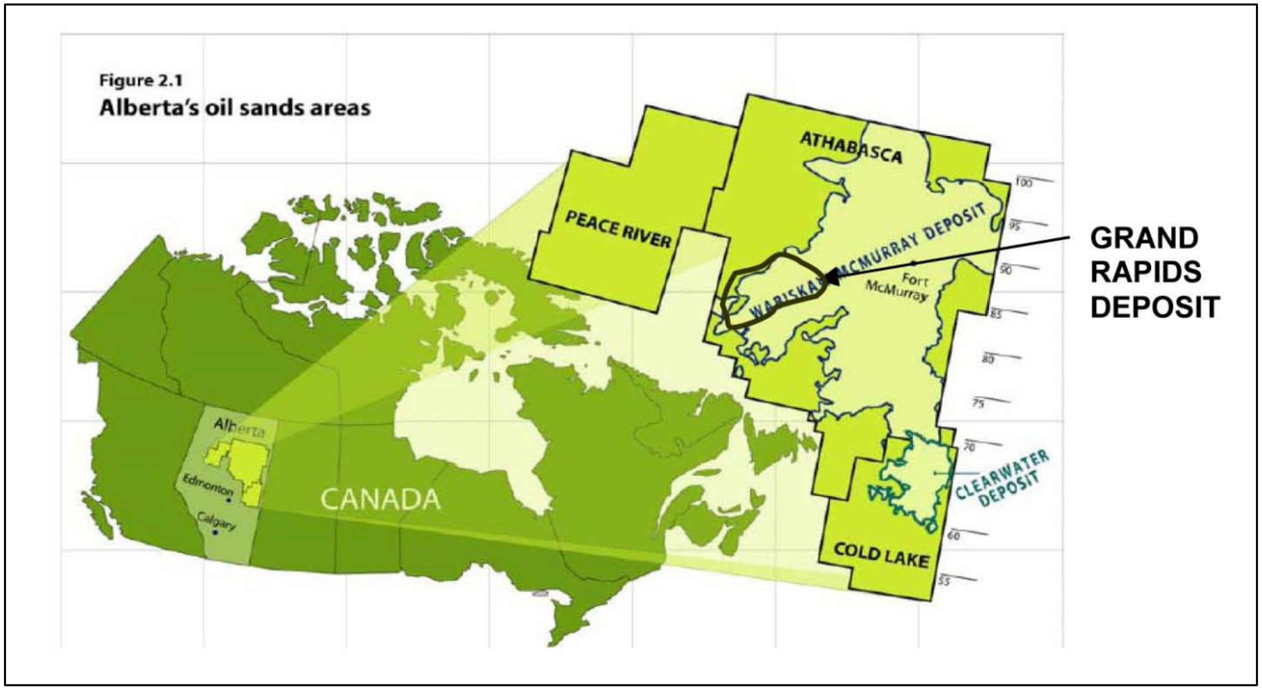

Figure 1. Location of Grand Rapids Oil Sands Deposits, Northeastern Alberta, Canada (modified from ERCB, 2009).

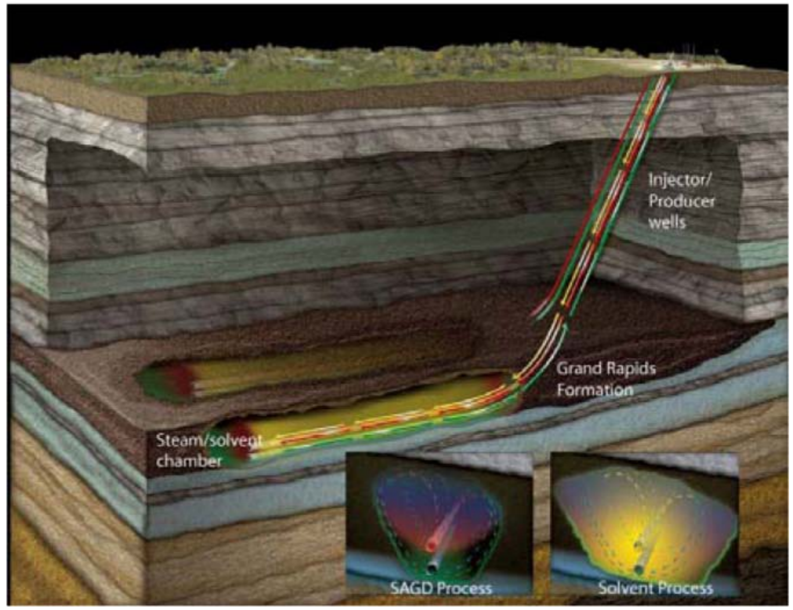

Figure 2. Schematic of SAGD and Solvent SAGD Process.

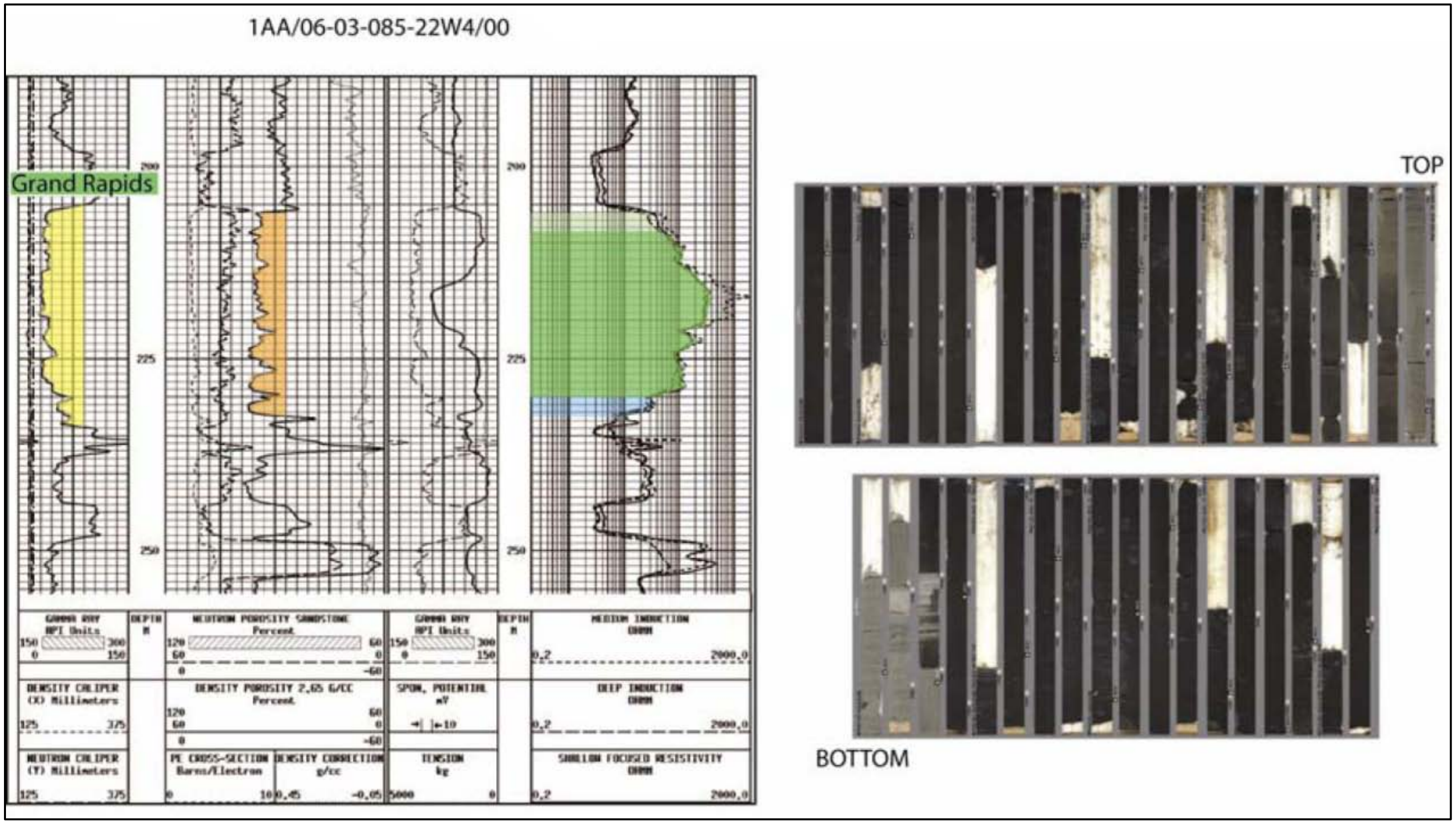

Figure 3. Germain area Upper Grand Rapids Type Well – 1AA/06-03-085-22W4M. Note: the white areas in the core photo are empty core sleeves.

Figure 4. Outcrop and core evidence of lateral discontinuity of cemented zones.

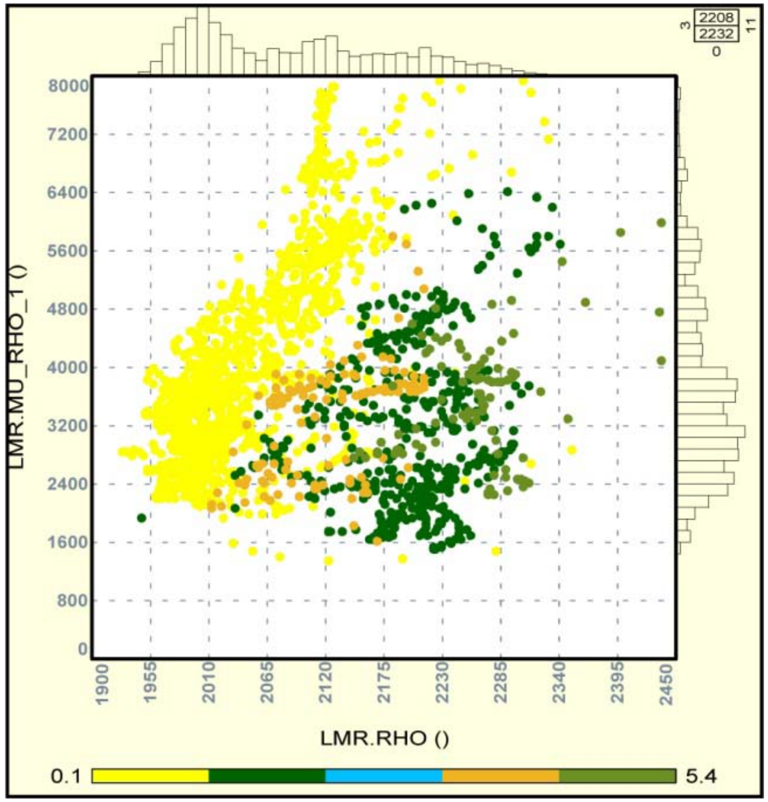

Figure 5. Log density versus mu*rho with points coloured by core facies (sand-yellow, shale-dark green, shaley sand-orange, sandy shale-olive green, dense sands-blue).

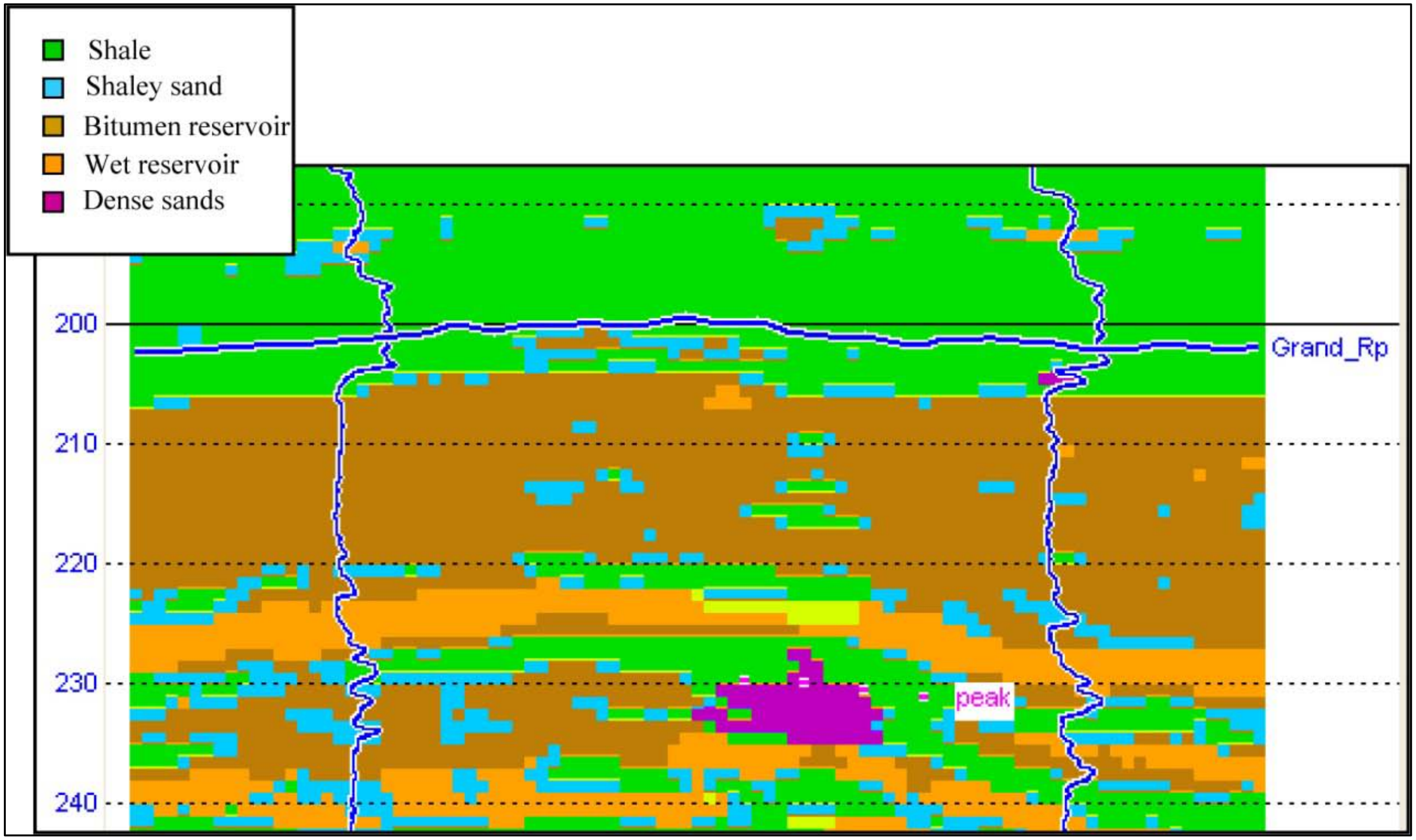

Figure 6. 3D profile through two wells in the project area. The colours represent lithology and fluids.