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Using the Movement of Fluids within a Reservoir Over Geological Time to Improve Reservoir Characterization

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While fluids within a reservoir are often thought of as static, in reality they have often moved over geological time. This movement is a result of such factors as the mixing of different hydrocarbon charge, biodegradation, reduction in pressure, chemical reactions such as H_2S production, temperature gradients and water washing. It can happen all over the world. For example, 10 to 20 years oil was commonly considered to be homogeneous within a connected reservoir ago in the Miocene section of the Deepwater Gulf of Mexico. In reality, compositional grading as a result of mixing and equilibration of biogenic gas and low GOR sourced oil is common.

The knowledge of this movement can be a powerful tool for improving reservoir characterization, but has not often been considered. It is particularly useful for predicting compartmentalization, and the 3-D distribution of fluid properties within a reservoir.

This talk will present two extreme examples where understanding this movement was important for improving reservoir characterization. The first is convective mixing of gas in the Sunrise giant gas field and the second is the redistribution of bitumen and water in the Alberta Oil Sands.

Sunrise is a large gas field 900 km^2 in area that is located in the Timor Sea (Fig. 1). There are two main 15 m thick reservoirs (an upper Unit 2 and lower Unit 4) that are separated by an impermeable heterolithic layer. Sunrise is also located near the Timor Trench, which is a subduction zone, so the field is heavily faulted with some large offsets. As a result for the first 10 years after discovery, Sunrise was assumed to have a high-risk of compartmentalization both laterally and vertically.

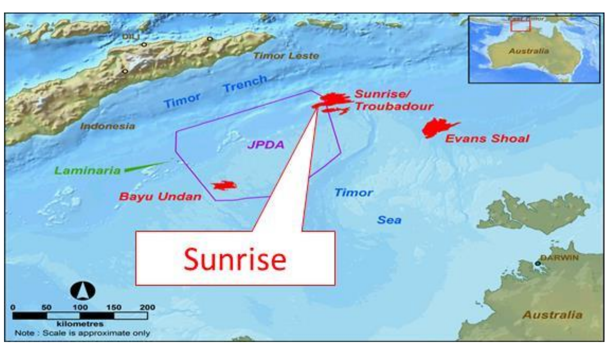

Figure 1: Location map for the Sunrise giant gas field. (James et al., APPEA Journal, 2010)

However, there is something odd in the data. Gases up to 14 km apart in Unit 2 and between Units 2 and 4 were isotopically almost identical indicating connectivity rather than compartmentalization. It would take about 25 million years for these gases to equilibrate by diffusion. However, the field is most likely 1-

2 million and about 12 million years old at a maximum. This begs the question, how did the gases become so well mixed?

There is a hot, radioactive granite underneath Sunrise that is deeper at one end of the field than the other that has created a 30 °C lateral temperature gradient across Sunrise. Could this temperature difference have caused advective mixing of the gases? This potential mixing was examined using simulation. Initial results indicated that mixing to sufficiently equilibrate the gases over a distance of 13 km in Unit 2 would take about 25 million years. This mixing is too slow since it is much longer than the oldest possible age of the field.

As a result, a new geological model was simulated based on conductive faulting that connected Unit 2 and Unit 4. As a result of being located near a subduction zone, there are frequent earthquakes and potential fault movement at Sunrise. Young faults can be conductive because they have not yet filled with quartz cement and they have gaps between both sides of the fault because of irregular fault surfaces. Simulation of the new model indicated that mixing could occur in about 25K years if the conductive faults were about 5 km apart, which is a blink of an eye in geological time (Fig. 2).

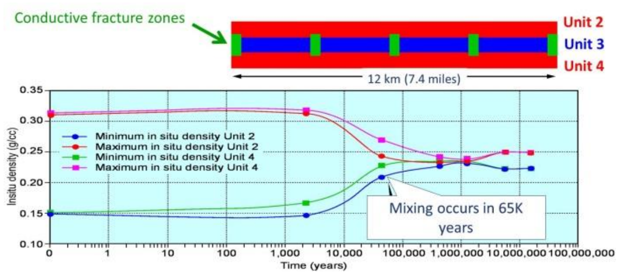

Figure 2: Mixing in Units 2 and 4 when connected by conductive fractures every 5 km. (James et al., APPEA Journal, 2010)

This conductive model suggested by the simulation was confirmed by a re-examination of past well tests and by an interference test carried out on the Sunrise-3 appraisal well. As a result of this work the subsurface model was significantly changed from a high risk of compartmentalization to being well connected vertically and laterally across the entire field.

This change had a significant impact on the proposed development plan by reducing the number of producing wells and changing their optimal locations. The subsea flow line layout was also changed.

We will now examine the second example from the Alberta Oil Sands. Eighty to 110 million years ago the Alberta oil sands was originally a conventional oil field. Fowler et al. (2004) estimated that the original oil charge was 25° to 30° API (Fowler et al., 2004). More recently, Adams et al. (2013), cited by Fustic et al. (2013) estimated it to be 30^0 API. Biodegradation has reduced much of this oil to bitumen with an API gravity ranging from 6 to 10 degrees and a viscosity ranging from hundreds of thousands to millions of cP. The bitumen is almost a solid at reservoir conditions.

However, an inspection of a plot of water saturation (Sw) vs. porosity shows that there is something odd compared to a conventional analogue (Fig. 3). Why is the McMurray Sw so high, particularly when it is such a high-quality, quartz-rich reservoir that has 30 to 40% porosity and is multi Darcy in permeability?

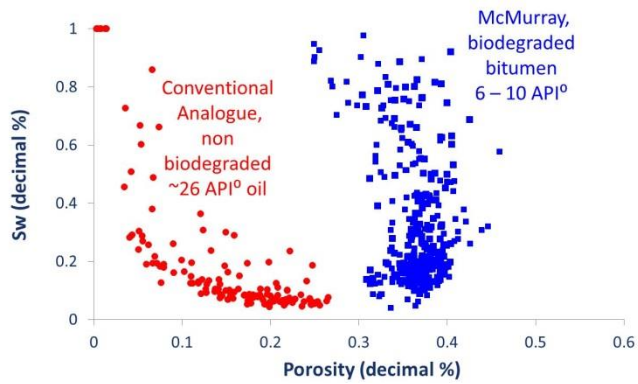

Figure 3: Sw vs. porosity for a McMurray field compared to a conventional analogue. (©2014 Society of Petroleum Engineers Ref: James (2014))

In contrast, the conventional analogue has as totally different distribution of Sw (Fig. 3). While lower porosity, it has a similar depositional environment, is quartz rich and has multi-Darcy permeability. As porosity and reservoir quality goes up, Sw goes down. The significance difference between the conventional analogue and the McMurray is the hydrocarbon density. The conventional analogue has a non biodegraded oil with a 30 API gravity and a density of about 700 kg/m^3 so it is much lighter than the formation water density. In contrast the McMurray bitumen has a density that is very close to that of the McMurray formation water.

When the McMurray was first charged with the lighter oil, there were strong buoyant forces. However, over time with biodegradation and reduction in density contrast, buoyant forces have become small and capillary forces much stronger, relatively. This change will have caused the bitumen and formation water to redistribute. The transition zone will have been pulled up into the reservoir so that there is some water mobility everywhere within the McMurray. This water mobility has been confirmed by the presence of isotopes that show the formation water is on the order of hundreds to thousands of years old whereas the oil is about 80 to 110 million years old.

Biodegradation also produced large amounts of methane that will have “bubbled” up to through the oil column because of its low density. If the methane gets trapped, it will form a temporary gas cap. However, over time the biodegradation rate will slow down as the oil becomes increasingly biodegraded and the rate of gas production will drop. Hence if a trap is leaky, then the gas will eventually deplete. The water will preferentially fill the depleted trap because it has a viscosity of 0.5 cP compared to bitumen with a viscosity of hundreds of K to millions of cP (Fustic et al., 2013).

Interestingly, simulation shows that over a million years capillary pressure will pull the water in the depleted gas cap down forming an upside down transition zone, which is actually found in field data. In conclusion the redistribution of water and bitumen over time as a result of biodegradation, capillary pressure and buoyant forces is important to understand the high water saturations of the McMurray formation and the background water mobility found throughout the McMurray.

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