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Reservoir Modeling to Investigate the Impacts of Geological Properties on Steam-Assisted Gravity Drainage (SAGD) at the Orion Project, Lower Cretaceous Clearwater Formation, Alberta*

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Abstract

SAGD is thermally efficient when steam chambers develop uniformly, and cumulative steam-oil ratio (CSOR) is between 2 and 3 or even lower. In contrast, Orion project at Cold Lake did not perform as expected in terms of steam chamber growth and CSOR. Evidences are:

(1) oil production rates (OPRates) range from 4,000 to 6,000 bbls/D, much lower than the predicted 10,000 bbls/D;
(2) average CSOR is 4.4, much higher than the forecasted CSOR; and
(3) abnormal growth of steam chambers were detected by observation wells.

Likely, they are attributed to the impact of reservoir geology. This study aims to understand the impact of geology on steam chamber growth and production performance of SAGD. Steam chamber growth was depicted by temperature profiles. CSORs and OPRates were calculated to quantify the production performance. 3D reservoir models were generated, based on wireline log and core analysis data to illuminate spatial distributions and heterogeneities of petrophysical properties. Results show that impermeable barriers and low-permeability zones were detrimental to steam chamber growth and steam injectivity in Pilot Pad 1. Steam chamber was irregularly shaped by a high-shale-content zone in Pad 103. Low-oil-saturation zone and thin net pay increased the CSORs in Pads 106 and 104, respectively. Dip angles of impermeable barriers are close to zero, imposing a negligible effect on well pad orientation. Identification of the impact of porosity on each well pad was difficult due to lack of porosity variation. The relatively extensive distribution of impermeable barriers, as well as the relatively large area of low oil saturation and thin net-pay, were identified as major geological challenges for Orion project expansion.

Introduction

Orion project at Cold Lake has seven active well pads, including Pilot Pads 1 and 3 and Pads 103 to 107, which produce bitumen from Clearwater Sand. Net pay consists of 23-m, fine- to medium-grained, well sorted shoreface sand.

Previous studies demonstrating the impact of reservoir geology on steam chamber growth and SAGD performance were mainly derived from laboratory experiments, simplistic numerical simulations, and field studies at Athabasca Oil Sands and outside the Canada. This study selected Orion project from Cold Lake that has not been discussed before to understand the impact of geology on steam chamber growth and SAGD performance.

Methodology

Well logs were interpreted using Techlog™ Wellbore Platform in terms of (1) shale content (Gamma Ray method, Neutron-Density method, and Spontaneous Potential method), (2) porosity (Density Porosity method), (3) oil saturation (Archie method), and (4) permeability (Wyllie-Rose method). Then these four parameters were distributed within the reservoir interval to generate 3D reservoir models using Petrel™ E&P Platform.

CSORs and OPRates were calculated to quantify the production performance of each well pad. Observation wells, which monitored the steam chamber growth, provided the temperature profiles to delineate the presence and shape of each steam chamber. Steam temperature is only a function of injection pressure regardless of steam quality (Wang, 2009). Thus, at Orion project, any temperature detected lower than 240 ºC represents absence of steam in the near-wellbore area.

Results

Reservoir models and fence diagrams (Figures 1 and 2) exhibit the spatial distribution and heterogeneity of shale content, porosity, oil saturation, and permeability. Each model covers 4.8 km from west to east and 2.6 km from south to north.

Figure 3 shows CSORs and OPRates versus elapsed time. Pilot Pads 1 and 3 have the lowest CSORs around 3.5, indicating the highest thermal efficiency. Pads 103, 105, and 107 have moderate CSORs around 4.05. Pads 106 and 104 have the highest CSORs around 6.8, representing the lowest thermal efficiency. The low steam injection rates for Pilot Pads 1 and 3 caused bias in terms of OPRates. Except for Pilot Pads 1 and 3, OPRates of other well pads are consistent with CSORs. Thus, Pads 103, 105, and 107 performed better than Pads 104 and 106.

Effect of Impermeable Barrier and Low-Permeability Zone

At Pilot Pad 1, the temperature profiles (Figure 4) show that: (1) steam saturated the reservoir between injector and producer at observation well 4 (OB4), without further upward movement; (2) absence of steam at observation well 2 (OB2); (3) a thick steam chamber was developed at observation well 1 (OB1). Meanwhile, the cross section (Figure 4) reveals that: (1) a laterally continuous impermeable barrier exists just above the well pair at OB4; (2) the injection well at OB2 penetrated a low-permeability zone; (3) the impermeable barrier affecting OB4 pinched-out towards OB1.

Therefore, the upward movement of steam chamber at OB4 was likely impeded by the impermeable barrier. The low-permeability zone at OB2 probably reduced the steam injectivity significantly. In contrast, the steam chamber growth at OB1 was not affected.

Effect of High-Shale-Content Zone

At Pad 103, Figure 5 exhibits two sharp spikes on temperature profile, and a high shale-content zone characterized by a parallelogram pattern. Probably, the steam could not expand through the high-shale-content zone, but instead laterally bypassed this zone, and only saturated the reservoir below and above this zone. Therefore, high-shale-content zone can impair the uniform steam chamber shape.

Effect of Low-Oil-Saturation Zone

Even though steam chambers were well developed at Pad 106 (Figure 6), Pad 106 has the second highest CSOR and the lowest OPRate. Figures 6 and 7 show that the oil saturation decreases from Pad 103 to Pad 106. The average oil saturation is 70% at Pads 103 and 105, and 55% at Pad 106. Therefore, probably the poor production performance of Pad 106 is attributed to the low-oil-saturation zone.

Effect of Thin Net Pay

Pad 104 has the highest CSOR and the lowest OPRate. The reservoir isopach map (Figure 8) shows that Pad 104 is located within a thin net pay with the average thickness of 18 m. This thickness may not be sufficient to allow gravity to act as an adequate driving mechanism. Therefore, probably the significant loss in thickness is the primary factor leading to the highest CSOR and lowest OPRate.

Effect of Porosity

Figure 9 shows that the porosity is relatively homogeneous through the entire study area, without any obvious variation trend. Therefore, it is unable to identify the impact of porosity on each well pad in this case.

Effect of Dip Angle of Impermeable Barriers

When encountering dipping impermeable barriers, steam chambers grow updip preferentially. To characterize the dip angles of impermeable barriers, this study used a novel method: pseudo-borehole imaging (PBI). PBIs were created by circle-shaped (10-m radius) cross sections intersecting the permeability model to mimic the borehole imaging tools. Figure 10 illustrates the dip angles of impermeable barriers. Its highest inclination is 1° and average inclination is 0.6°, indicating that the impermeable barriers are almost horizontal. Therefore, dip angle of impermeable barriers has a negligible effect.

Challenges for Orion Project Expansion

Using 0.2 Darcy as a permeability cut-off, the filtered model shows that impermeable barriers have relatively extensive distribution and relatively poor continuity. They can prevent the upward growth of steam chamber and make the SAGD-able interval thinner than the mapped net pay.

The southeastern extensive area has low oil saturation (Figure 7), which is lower than 55%. The expansion of Orion project to the southeastern part may not be economically promising. The reservoir isopach map (Figure 8) shows that the southern area has thin net pay with the thickness lower than 18 m, which is not economical for the SAGD expansion.

Conclusions

Impermeable barriers, low-permeability zones, high-shale-content zones, low-oil-saturation zones, and thin net pay are the most critical geological parameters influencing the steam chamber growth and SAGD performance in Orion project. Impermeable barriers may dictate the thickness of SAGD-able intervals and impair the vertical extension of the steam chambers. Low-permeability zones may reduce the steam injectivity and even cause the absence of steam chambers. High-shale-content zones had an impact on Pad 103 where the steam could only bypass these zones and the steam chamber was irregularly shaped. Low-oil-saturation zones may result in a poor production performance even though the steam chambers developed successfully. Thin net pay is the dominant factor causing the highest CSOR and lowest OPRate at Pad 104. The dip angle of impermeable barriers did not have any effect on steam chamber growth. The porosity is relatively homogeneous and quite high throughout the study area. Lack of the porosity variation makes it hard to identify the impact of porosity. Relatively widespread impermeable barriers and low-permeability zones, and relatively large area of low oil saturation have been identified as major challenges for the Orion project expansion to the unexploited area.

Reference Cited

Wang, H.Y., 2009, Application of temperature observation wells during SAGD operations in a medium deep bitumen reservoir: Journal of Canadian Petroleum Technology, v. 48/11, p. 11-15. Website accessed September 7, 2016, http://dx.doi.org/10.2118/130439-PA.

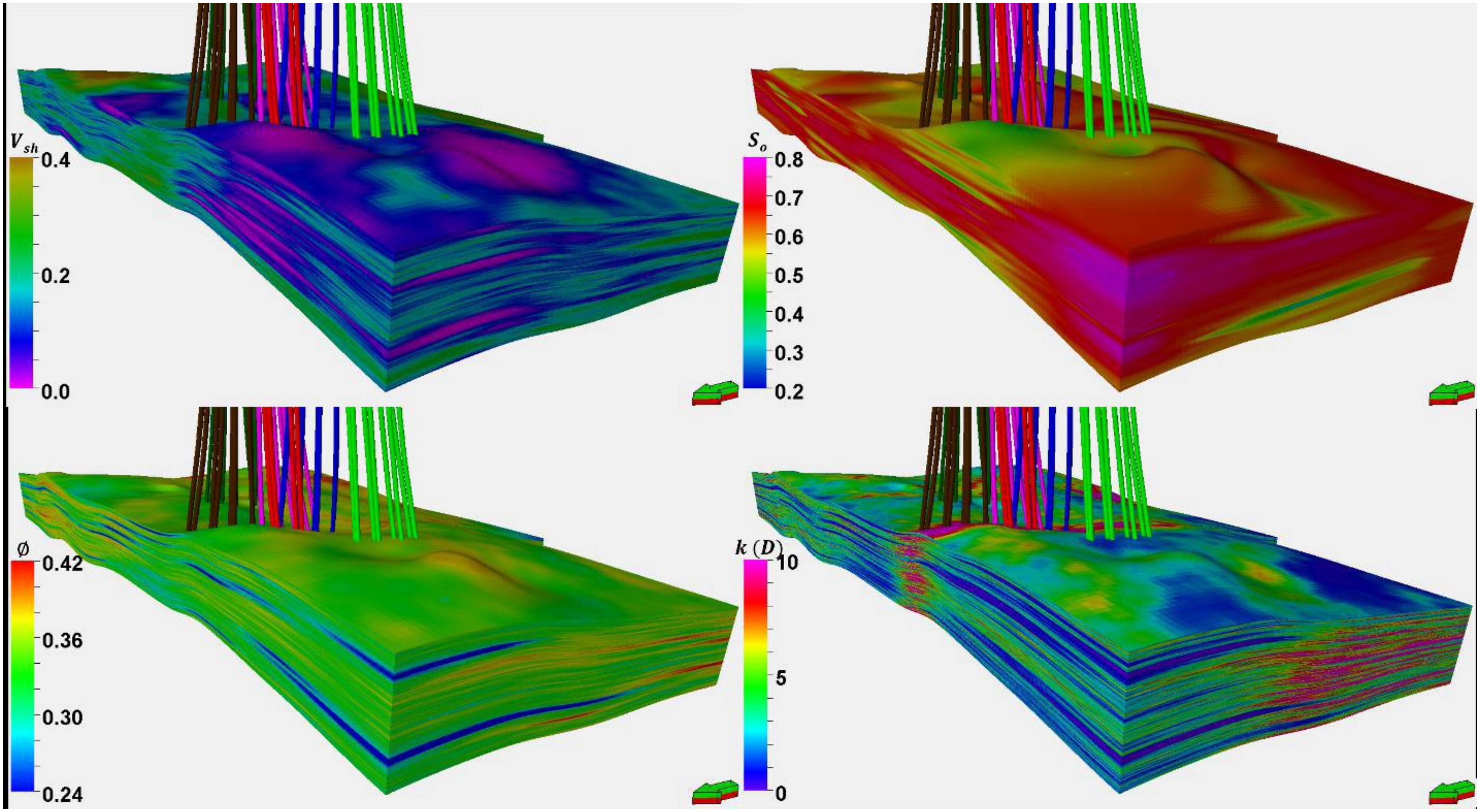

Figure 1. 3D reservoir models: shale content model, oil saturation model, porosity model, and permeability model.

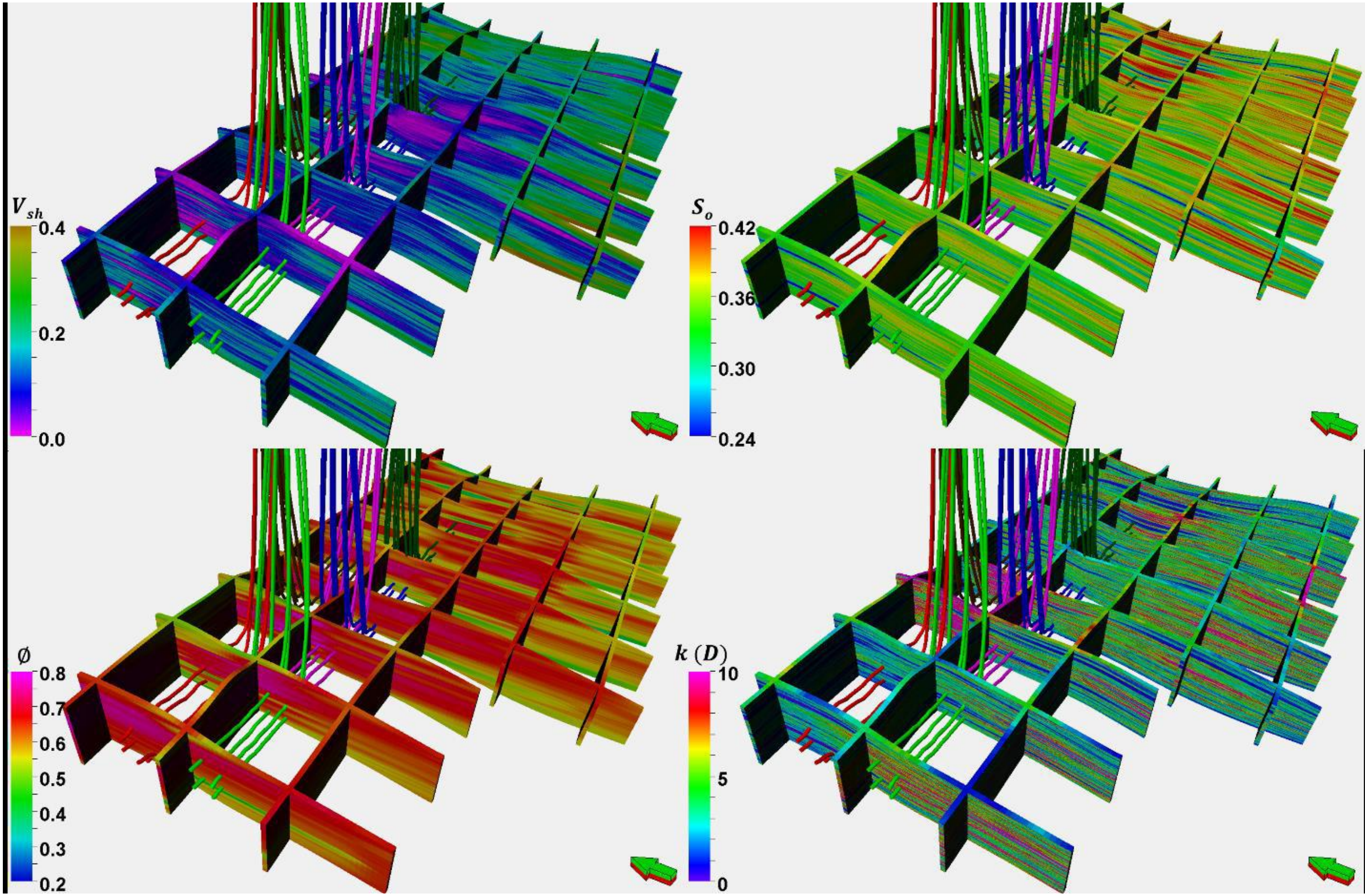

Figure 2. Fence diagrams showing the spatial distribution and heterogeneity of reservoir properties.

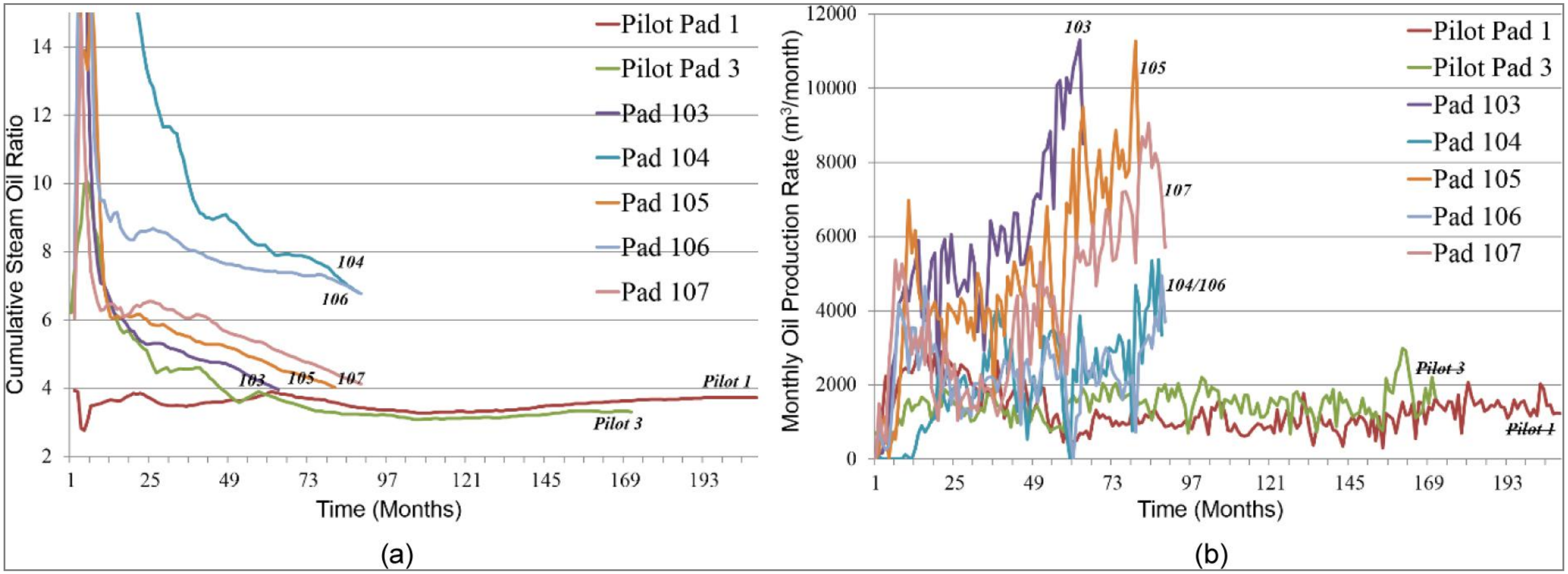

Figure 3. (a) CSORs; (b) OPRates of well pads versus elapsed time.

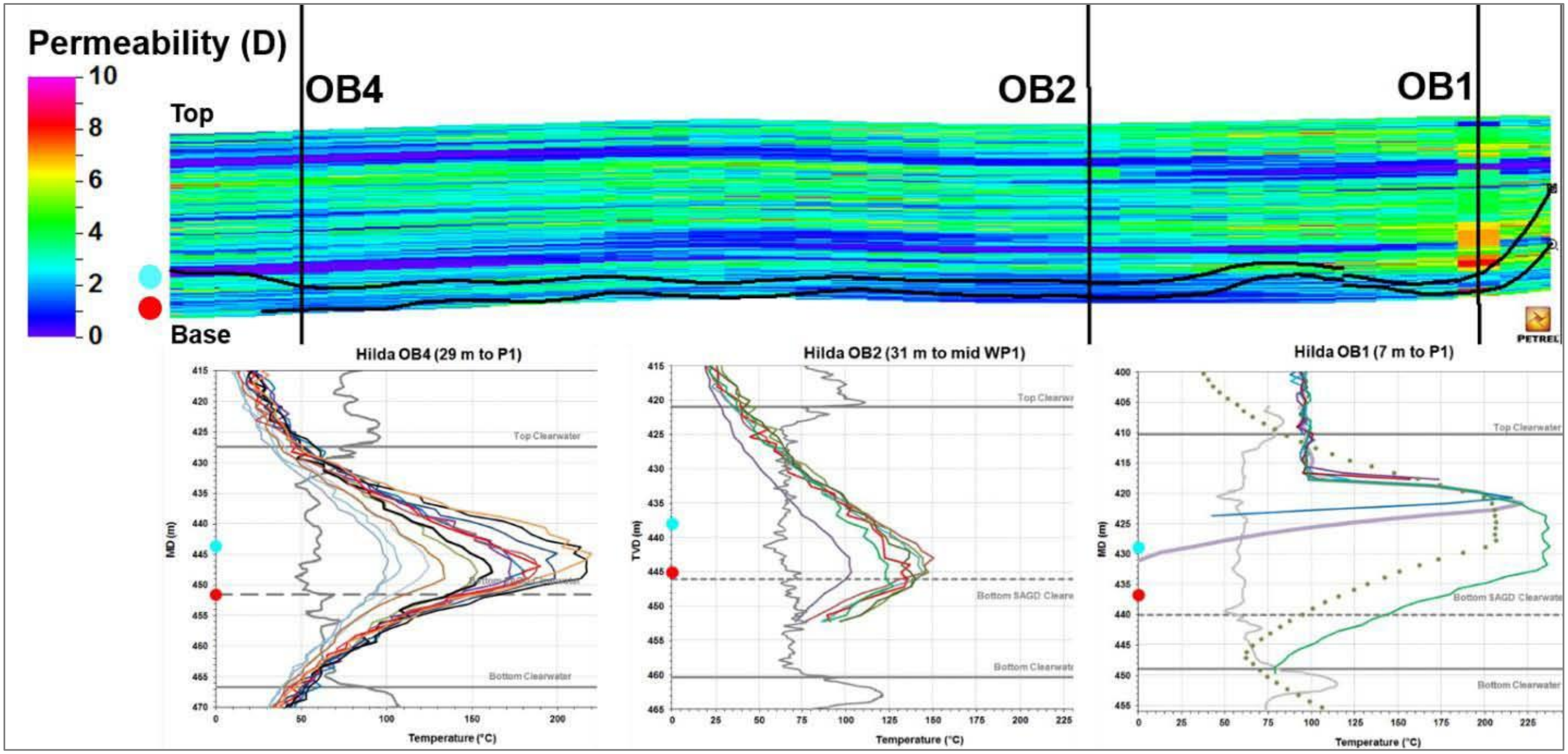

Figure 4. Cross section showing the impermeable barriers and low-permeability zones at Pilot Pad 1, integrated with temperature profiles of three observation wells.

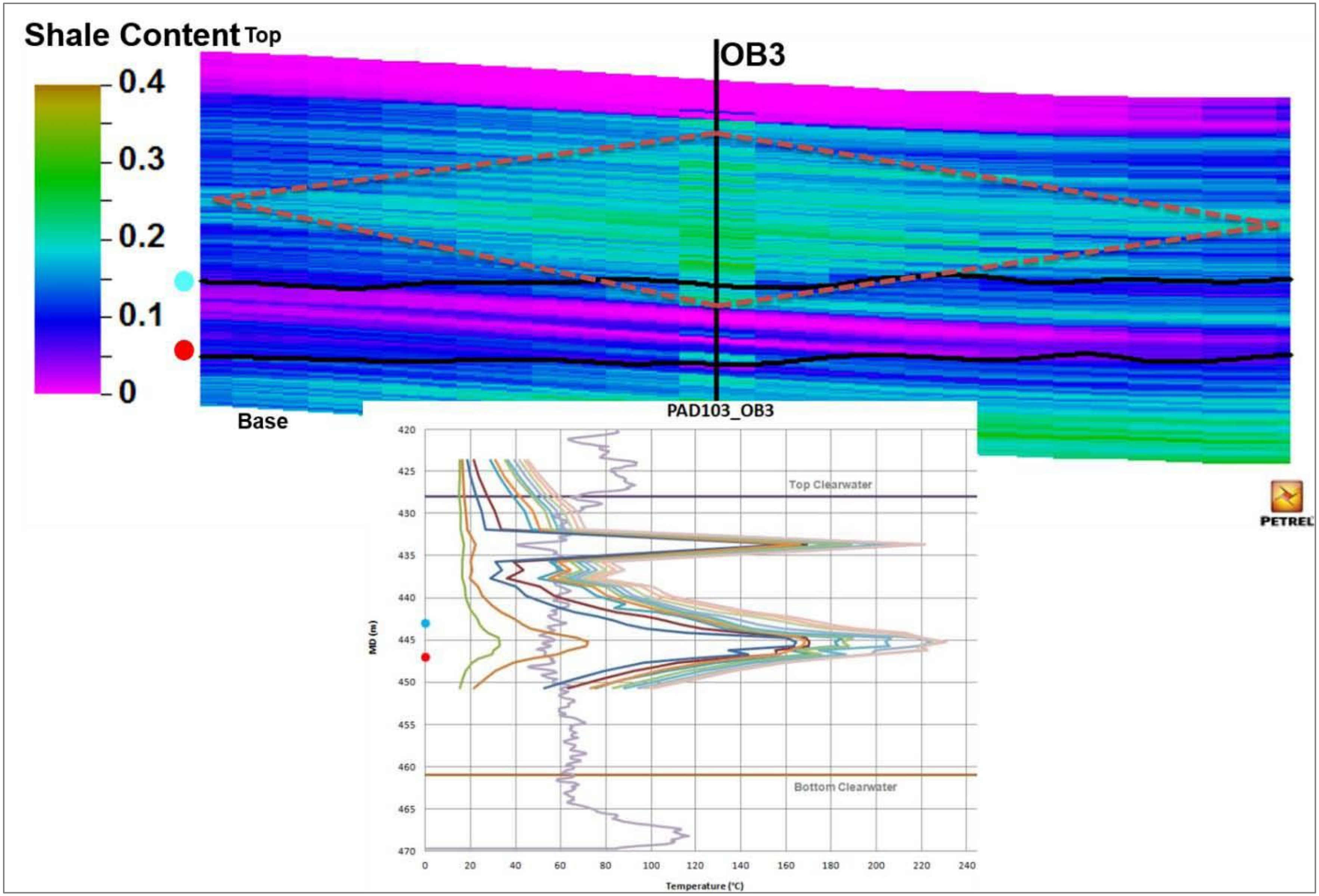

Figure 5. Cross section showing the high-shale-content zone at Pad 103, integrated with temperature profile of one observation well.

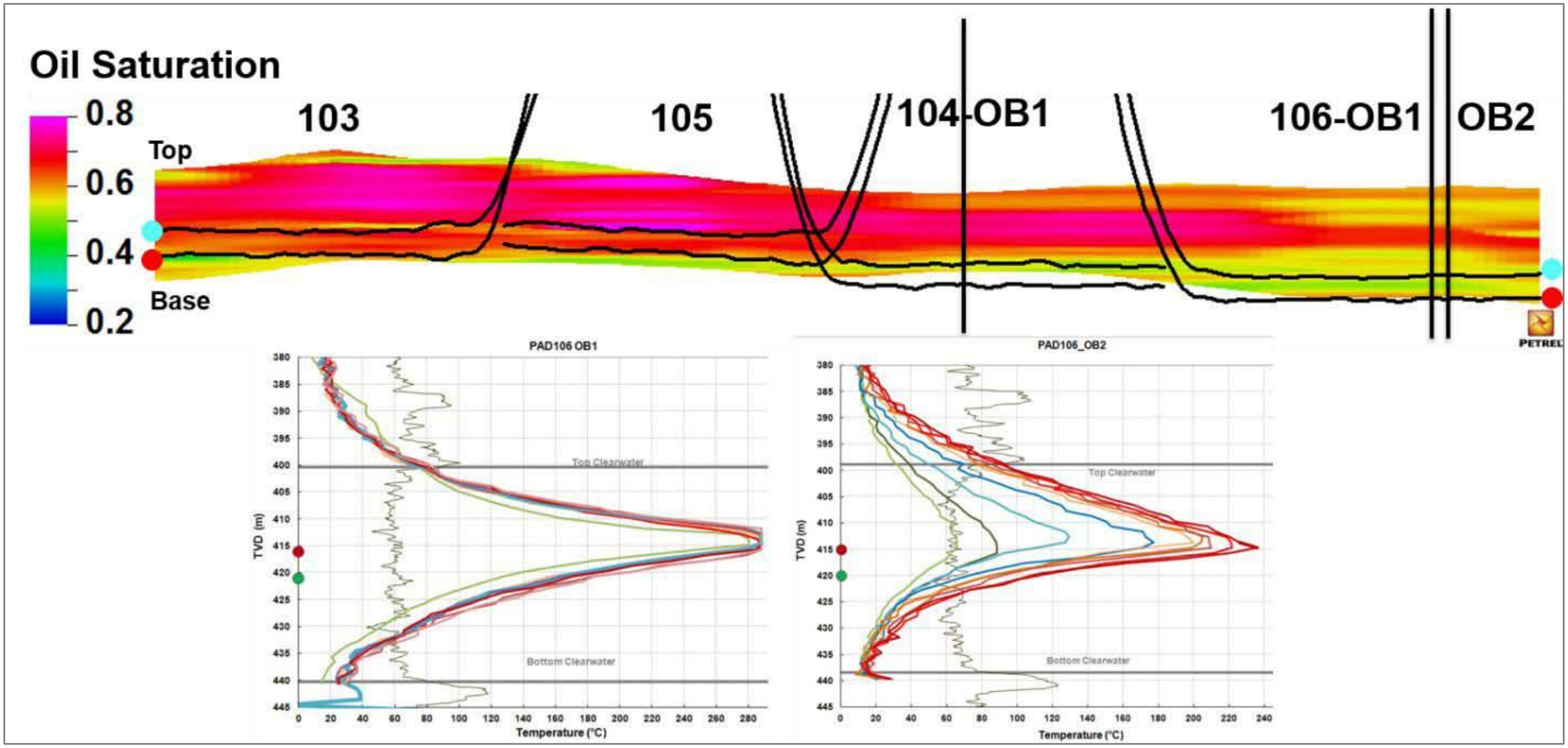

Figure 6. Cross section showing the variation of oil saturation from Pad 103 to Pad 106, integrated with temperature profiles of two observation wells.

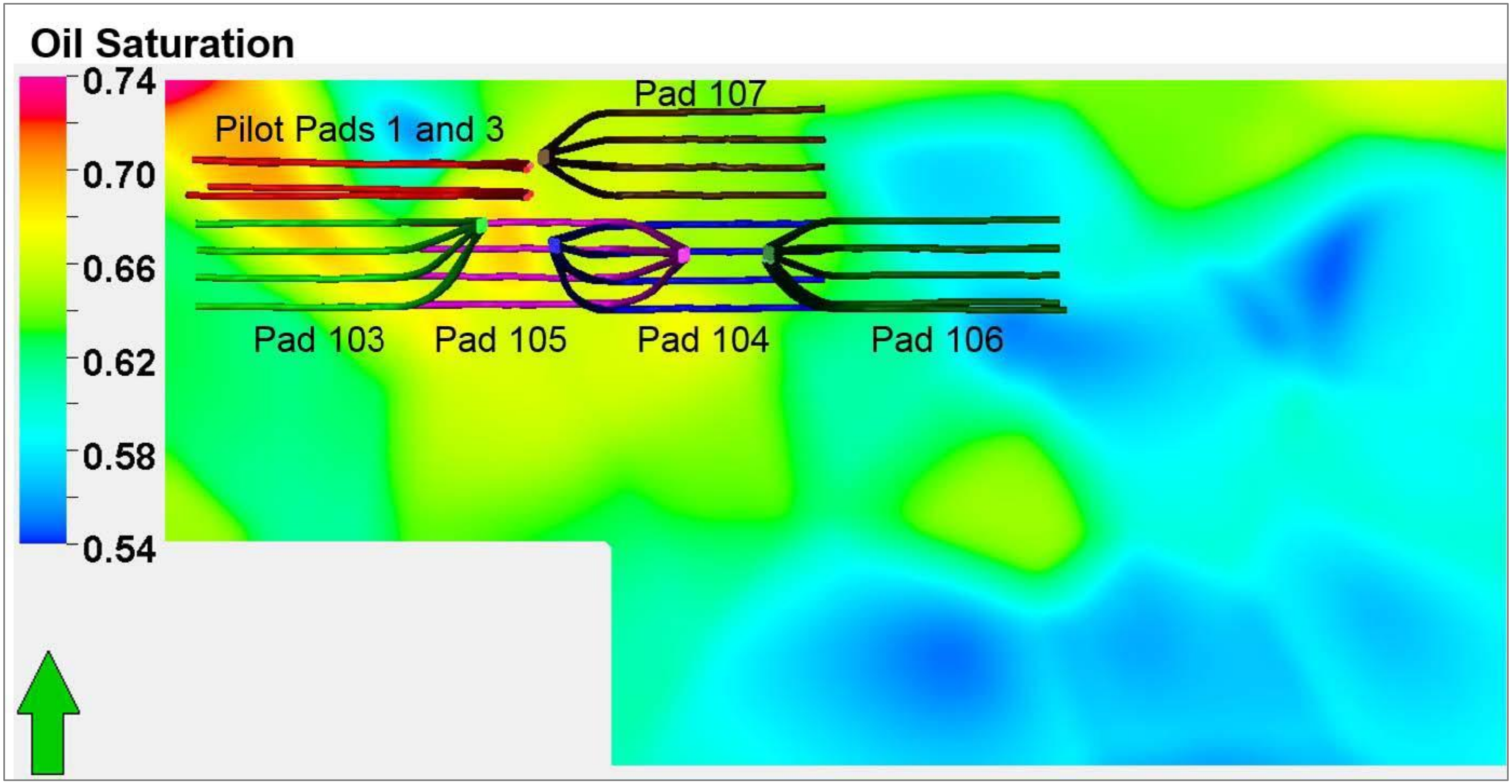

Figure 7. Map showing the variation of oil saturation in the project area.

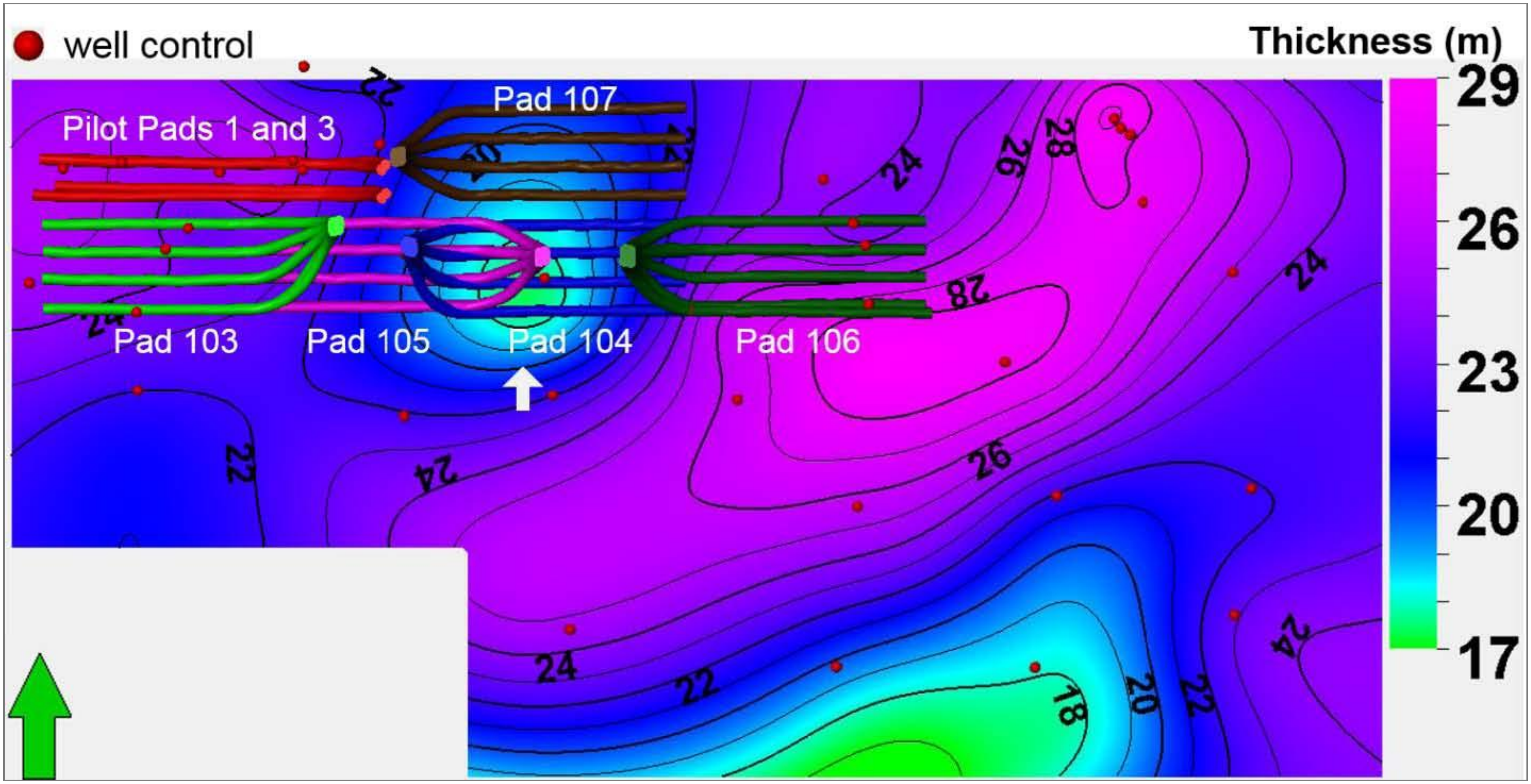

Figure 8. Isopach map showing the distribution of net-pay thickness in the project area.

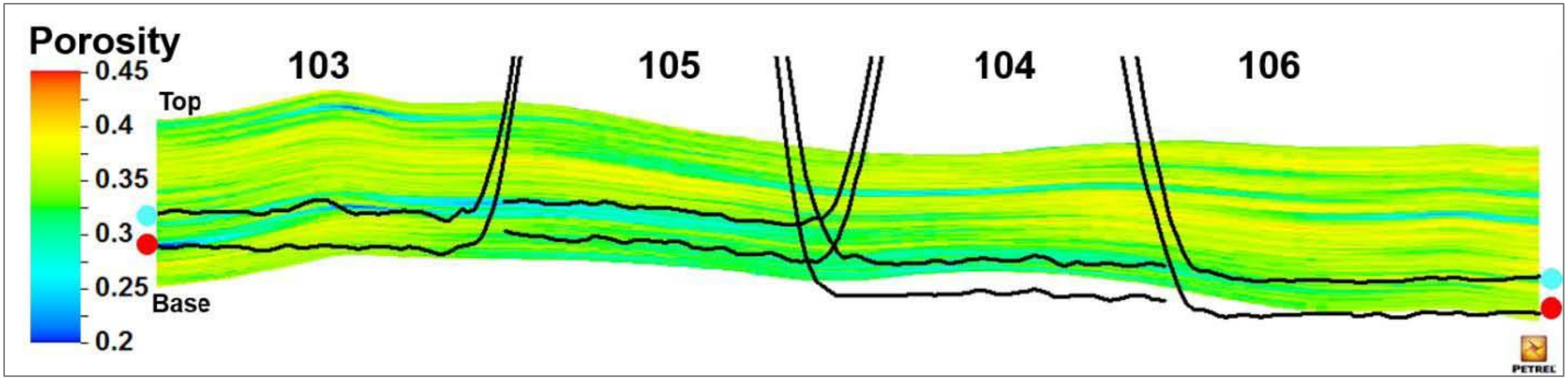

Figure 9. Cross section showing the variation of porosity from Pad 103 to Pad 106.

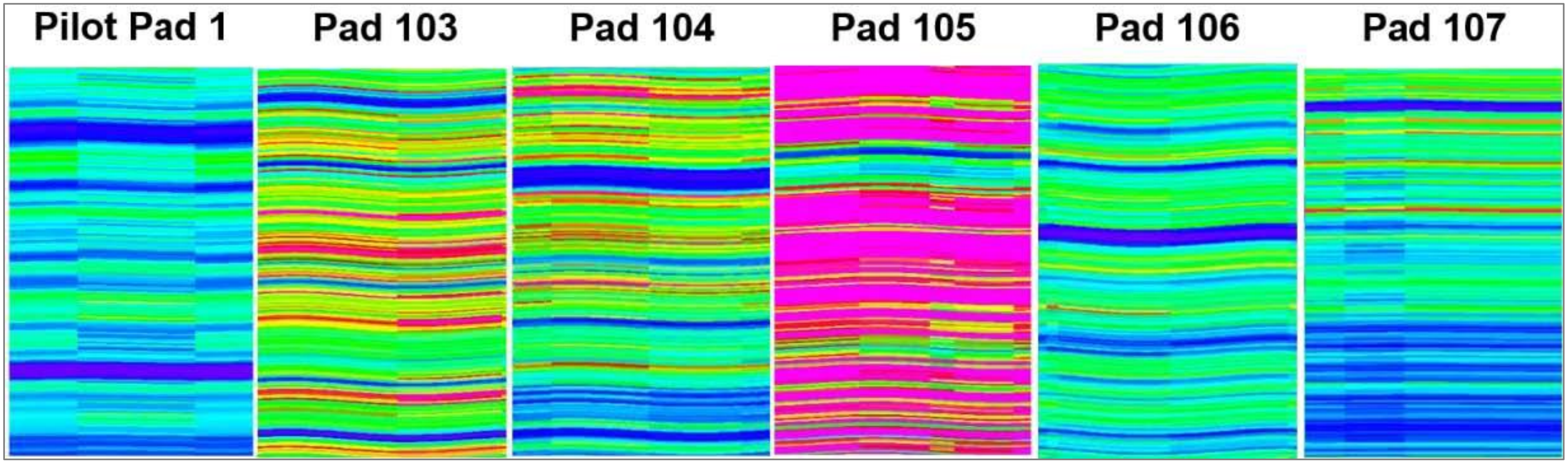

Figure 10. Pseudo-borehole imaging showing the dip angle of impermeable barrier at each well pad.