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Combined Reservoir Simulation And Seismic Technology, A New Approach For Modeling CHOPS

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Abstract

Cold Heavy Oil Production with Sand (CHOPS) has become one of the main recovery schemes for developing heavy oil reservoirs in Canada. This became possible with the introduction of progressive cavity pumps, therefore much higher sand cut in viscous heavy oil could be expected from unconsolidated/weakly consolidated formations as opposed to conventional pumps with limited capacity.

In this study, combined reservoir simulation and seismic technology are applied for a heavy oil reservoir situated in Saskatchewan, Canada, for better understanding of the reservoir properties and recovery mechanism. The numerical model was built based on the well log data and several seismic attributes. The integration of seismic attributes improved modeling reservoir heterogeneity, which is a main challenge in modeling sand production.

Firstly, we used geostatistical methods to estimate the initial reservoir porosity, using a seismic survey acquired in 1989. Secondly, sand production was modeled using erosional velocity approach and the model was run based on the oil production. Finally, results of the true porosity derived from simulation were compared against the porosity estimated from the second seismic survey acquired in 2001. This flow provides new tools that validate the simulation model results against the seismic data.

Following this approach the extent and the shape of the enhanced permeability region (wormhole region) for estimated porosity distribution are modeled. The performance of the CHOPS wells is highly dependent on the rate of creation of the high permeability zone around the wells. This method can be used for evaluating future developments of the field such as infill drilling and post CHOPS recovery methods (VAPEX).

Introduction

Cold heavy oil production with sand (CHOPS) is a non-thermal recovery method used in unconsolidated heavy oil reservoirs in Alberta and Saskatchewan, Canada. In this process sand and oil are produced together in order to enhance the oil recovery. This process has proven to be economically successful when vertical wells are used.

Although the process has been mostly developed in western Canada, it was first applied in California. Vonde (1957) reported that with the application of specially designed pumping equipment Husky Oil Co. was producing crude oil as low as 4 °API with sand cuts of up to 70%. The wells were located in the Brooks sand, Cat Canyon field, California. Application of the progressive cavity pumps was a big step in improving oil rate of CHOPS. PCP pumps allowed primary production rates in excess of 150 bbl/d (24 m³/d) oil from wells that were restricted to less than 10 bbl/d (1.5 m³/d) when produced with conventional rod pumps and sand control completion methods.

McCaffrey and Bowman (1991) examined the performance of Amoco's Elk Point and Lindbergh fields in Canada. The program was to investigate the communication between wells using tracer material. Surprisingly the results indicated that wells were connected with a channel system exceeding over 2 km in length that connected up to 12 wells.

There are two main mechanisms involved in unexpectedly high primary oil recovery observed in CHOPS operations. The first one is foamy oil associated with trapping gas evolution from in the heavy oil and the second one is sand production. McCaffrey and Bowman concluded the high productivity of CHOPS operations is related to three main factors:

- Sand production creates an area around the wellbore which provided a larger effective wellbore drainage radius. This could be seen as a high negative skin effect in CHOPS wells.
- Reduction in the in situ oil viscosity of the bitumen, as a result of foamy oil.
- Increasing the porosity of the reservoir by producing sand which leads to creation of high permeability channels (wormholes). This improves the overall permeability of the reservoir.

Sand Production Physics

From geomechanics points of view there are two main mechanisms which could lead to sand production:

- Shear failure, basically related to aggressive drawdown. This means that some plane in the near wellbore region is subjected to a higher shear stress than it can sustain. This may lead to a change of the near wellbore properties of the formation, and to a change in the near wellbore stresses
- Tensile failure, basically related to high production rate. The sand production is then related to fluid drag forces on the grains of the formation. Tensile failure could also be resulted by foamy oil exsolution.

Tremblay and Oldakowski (2002) performed two lab tests to investigate the wormhole growth. They used a sand box to produce oil and sand through a perforation. In first test they only used one perforation. Later on they performed the second test where they used a larger sand pack (80.4 cm long and 29.85 cm diameter) than the one used in previous experiments (36.5 cm long and 10.2 cm diameter). In the second test they also had two production orifices (1.27 cm diameter), rather than the single orifice used in previous experiments (6.9 mm).

The second test validates the first test results. Inside wormholes porosity was increased from the initial value of 36% to 55%. They observed that the wormhole was composed of a central region of loose sand surrounded by concentric bands. Based on the results of these tests they suggest that the diameter of wormholes in field could be as high as 1 m.

Later on K. Oldakowski et al (2002) conducted a series of lab measurements at Alberta Research Council (ARC) to investigate the impact of stress anisotropy on wormhole growth. The results suggest that the wormholes are developed more toward the direction of the lower horizontal stress.

Wong (2003) conducted a series of test to see the impact of the foamy oil and sand production in CHOPS. He studied the effects of the interlocked structure of oil sands, pressure gradient, and gas exsolution on sand production. Using a triaxial cell gave him the opportunity to apply confining stress on the sample. On his test with live oil he observed that sand production before reaching the bubble point in the outlet was not very significant. However as soon as the outlet pressure was about 0.1 MPa below bubble point pressure significant amount of sand and foamy oil was produced.

Wong concluded that the fact that heavy oil behave like cement around sand provides a high shear resistance against the seepage force generated by the fluid flow. However, he argues that the oil sand is very weak in resisting tensile failure under gas exsolution. Therefore he concluded that sand production is in most part due to the tensile stress because of the foamy oil. It should be noted that in Wong laboratory measurements he decreased the pressure very suddenly. The step change in pressure could cause the creation of cavity around the well and. This can bring some uncertainty and it suggests exaggeration of foamy oil impact in his test.

Sand Production Modeling

Main challenges in modeling Cold production raised by high oil flow rates in field which are up to 10 times higher than the flow rates predicted by using Darcy's flow equation. In Addition the oil recovery factor has also been reported to be significantly higher than predicted by Darcy's flow models.

Vardoulakis et al (1996) proposed hydro-erosion model, based on rigid porous media. In this theory mass balance is applied to a three-constituent system consisting of solid, fluid and fluidized solid using homogenization mixture theory. Wang (2003) extended this pure erosion model to include the effect of the deformation of porous media in a consistent manner.

Wang (2003) proposed a coupled geomechanics hydrodynamics model for sand production using Vardoulakis et al approach. Based on his modeling technique when the well is put on production after reaching critical velocity, the erosion process begins. Sand erosion is initiated by degradation of the sand matrix strength and the drag force imposed by fluid pressure gradient. Therefore locally around the wellbore the stress level became higher than the yielding stress and material erosion and stress re-distribution starts. QuikLook software which was used for this study is based on the sand production model proposed by Wang (2003). Please see appendix section for explanations of the erosion model used in this study. The detail of the model is available through TAURUS Reservoir Solutions Ltd website.

Plover Lake Field History

Plover Lake field is a heavy oil reservoir currently operating by Nexen Inc. Plover Lake is situated in the heavy oil belt of Canada that extends over Alberta and Saskatchewan. Oil is produced from the Devonian-Missippian Bakken Formation. This formation is found in NE-SW trending shelf-sand tidal ridges that can be up to 30 m thick, 5 km wide, and 50 km long. Overlying Upper Bakken shales are preferentially preserved between sand ridges. The Bakken Formation is disconformably overlain by Lodgepole Formation carbonates (Mississippian) and/or clastics of the Lower Cretaceous Mannville Group (Mageau et al., 2001). Figure 1 presents the map of study area.

Section 9 from township 35 and range 26 was selected for this study. Oil rate of different wells in this section range from 1 to 5 m³/d prior to installation of PCP pumps. After using PCP pumps oil rates increased 3 to 5 times, the majority of sand production has happened during this period. Unfortunately sand production measurements of individual wells were not available for this study. The cumulative sand production of wells suggests 30% to 60% initial sand cut which drops to 5% as oil rate declines.

The initial seismic survey was performed on this field in 1989. The second seismic survey was done in 2001. Drilling spacing in this area is one well per LSD. Well 04-09 was selected for sand production modeling.

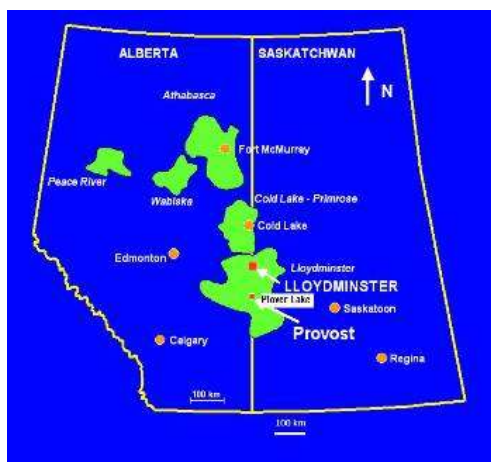


Figure 1. Plover Lake CHOPS operation Map

Methodology

The reservoir simulation part of this study was done using QuikLook simulator. The initial reservoir conditions were described based on the core data and the geological inputs provided by Nexen Inc. The structure of the Bakken Formation was constructed using the seismic survey conducted in 1989 which was tied by well log tops. The depth conversion for the top and base of the reservoir was done using the kriging with external drift (KED) geostatistical approach. The tops from wells (in depth) provided the primary attribute and the seismic time horizons were used as the secondary attribute. Given the complexity of the structure in this area and the presence of sinkholes in this reservoir, this method was very successful to map the top (Upper/Mid Bakken) and the base (Lower Bakken) of the reservoir. Figure 2 present the results of KED for mapping the Upper/Mid Bakken.

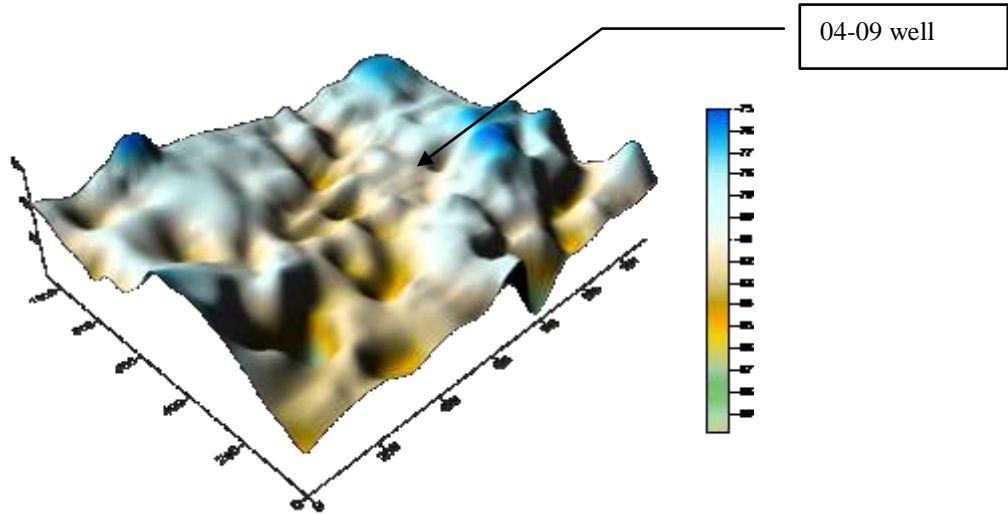


Figure 2. Surface of Upper/Mid Bakken created using KED for well tops and seismic time horizons. Note the presence of sinkholes

The initial porosity of the Bakken formation was calculated using KED with porosity maps, obtained from neural network analysis, as secondary variable. This allows a perfect honouring of the porosity at the well locations. The seismic survey from 1989 is a conventional acquisition. A neural network analysis for porosity used the petrophysical analyzed porosity logs as target logs and six seismic volumes available from AVO and inversion analysis.

The total thickness of the Bakken Formation was divided into three equal layers for modeling. Well 04-09 was perforated in the first two layers of the model. The grid size of 5m by 5 m was used to model drainage area of 400m by 400 m of the 04-09 well. Based on the well log data and core permeability a relationship between permeability and porosity was derived. Figure 3 presents the cross plot of permeability and porosity at 04-09 well location. The permeability values of the simulation model were calculated using this relationship and porosity values estimated from KED method explained above.

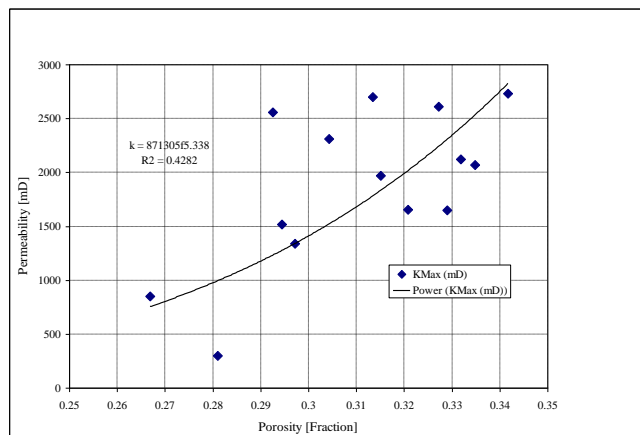


Figure 3. Cross plot of permeability and porosity derived from core data

Initial reservoir pressure of Bakken Formation was estimated to be 6,000 kPa based on a DST test in the 08-09 well. The reservoir was initially undersaturated. The bubble point pressure of reservoir was 6000 kPa, therefore no gas cap was initially considered.

Table 1 presents the PVT properties of the reservoir fluid used in reservoir simulation. The gas properties were estimated by Satnding (Z factor) and Call et al correlations (gas viscosity), respectively, using gas specific gravity of 0.66.

Table 1. PVT properties assumed for Plover Lake oil

Pressure (kPa)	GOR (m3/m3)	Bo	Oil Viscosity (Cp)
200	0.221	1.00100	1820.0
1500	2.502	1.00555	1701.7
2500	4.257	1.00905	1610.7
3500	6.012	1.01255	1519.7
4500	7.767	1.01605	1428.7
5500	9.522	1.01955	1337.7
6000	10.400	1.02130	1292.2
6500	10.400	1.02305	1246.7
7500	10.400	1.02655	1155.7

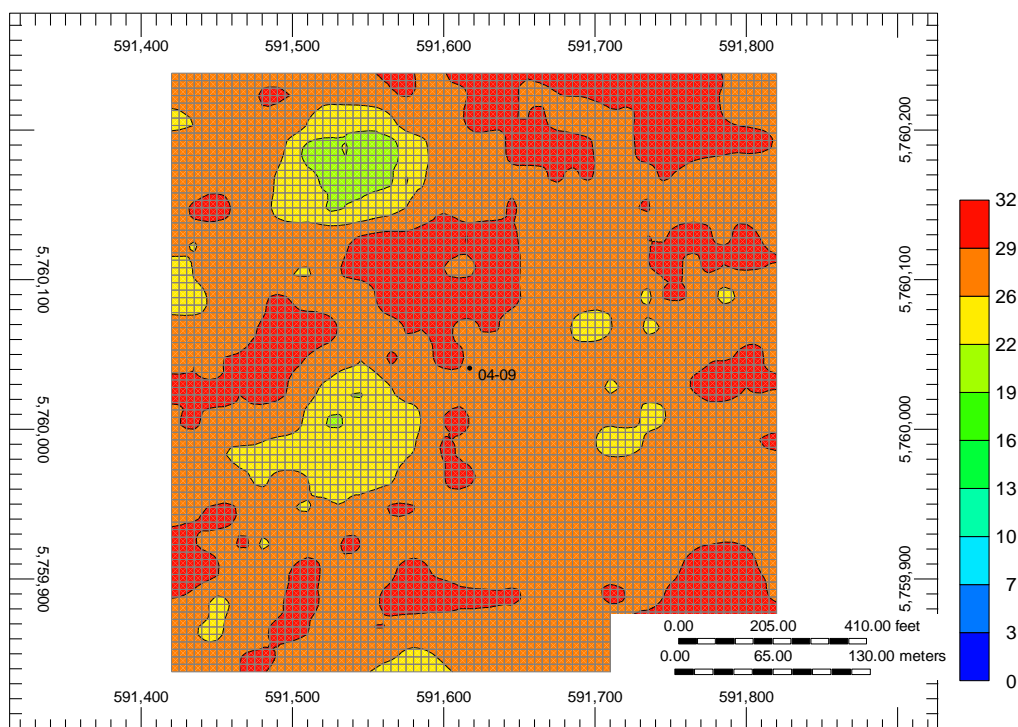


Figure 4. Initial porosity map estimated from KED method

The reservoir simulation model was run for two cases. In the first case no sand production was considered in modeling. The simulator was driven based on the produced oil and the minimum bottomhole pressure of 500 kPa (representing pump off condition).

The second model was used to match the production history of the 04-09 well in the Plover Lake reservoir. Table 2 is a summary of the sand production parameters used for matching the oil rate of the 04-09 well. The relationship between dimensionless porosity (relative change in porosity) and permeability multiplier is presented in Figure 5.

Table 2. Sand production Parameters

Parameter	Value assigned
Initial fluidized sand saturation	0.08
Maximum porosity	0.65
Velocity coefficient Water	1.00
Velocity coefficient Oil	1.00
Velocity coefficient Gas	0.00
Critical velocity for onset of sand production (m/S)	0.00
Sand slip coefficient	1.00
Initial erosion coefficient (1/m)	5.00
Initial deposition coefficient (1/m)	0.00
Critical fluidized sand saturation	0.15
Time scale exponent n	0.50

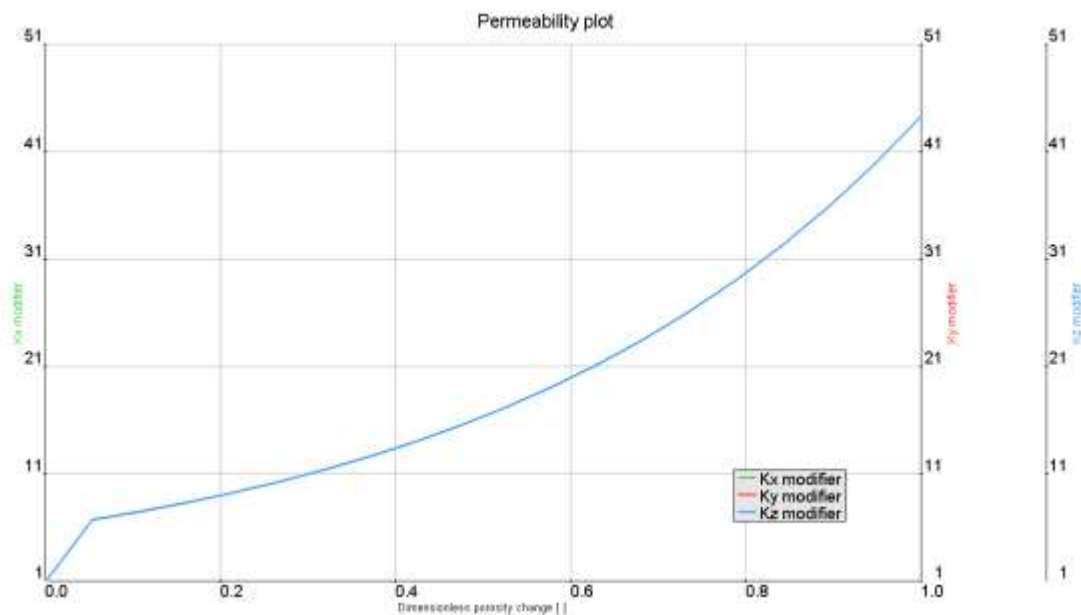


Figure 5. Relationship between dimensionless porosity and permeability multiplier (same modifier was used for all directions)

The following Figures 6 to 9 present the results of the two models. Figures 6 and 7 present the oil rate and the cumulative oil production of the two models respectively. The models results are compared against the actual production history of the 04-09 well. Examination of this plot shows that, without considering sand production, we were not able to honor the oil production rate. This is due to the productivity of well being much less than the case which considers sand production.

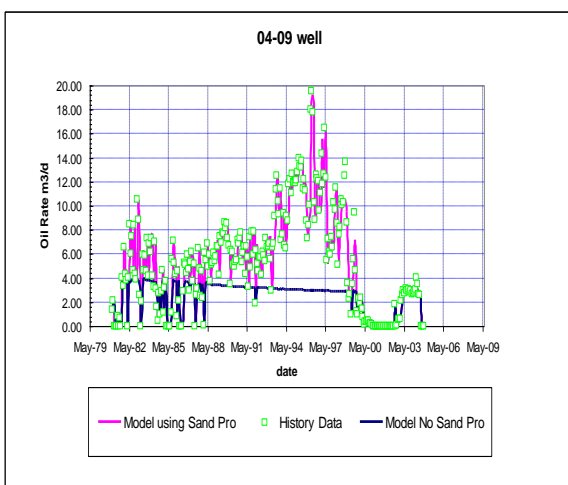


Figure 6. History match of oil rate

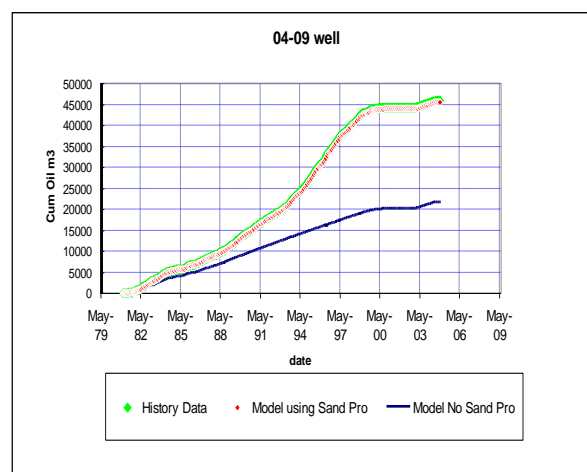


Figure 7. History match of cumulative oil production

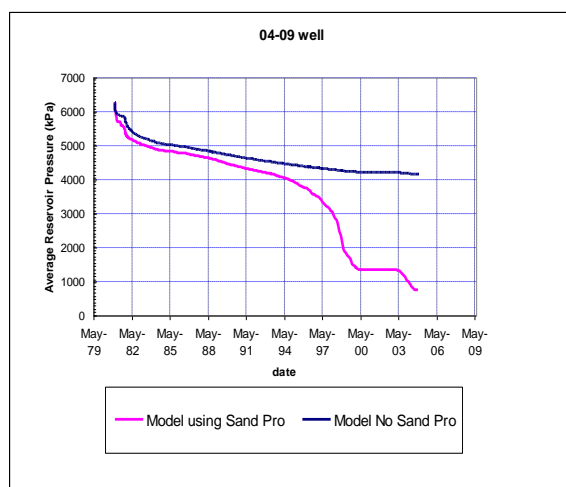


Figure 8. Average reservoir pressure

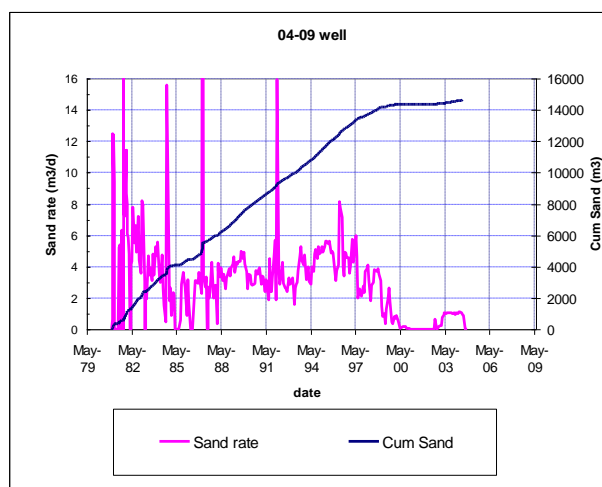


Figure 9. Sand production and cumulative sand production

Figure 8 presents the simulated average reservoir pressure for the two models. A recent pressure survey (2007) in this well suggests that the reservoir pressure is about 500 to 700 kPa. The average reservoir pressure of the model which does not consider sand production is substantially higher than the case with sand production. This is due to lower oil and gas production in this model. Examination of this plot suggests that after installation of the PCP pump and aggressive drawdown against the Bakken Formation average pressure declines significantly. After analyzing the results it was concluded that by lowering bottomhole pressure a significant amount of gas is coming out of solution. The gas is produced and the reservoir pressure decreases consequently. The sand production and cumulative sand production of the model is presented in Figure 9.

Discussion

The second seismic survey (2001) was processed using similar processing flow. The porosity map of the Bakken Formation was estimated from neural network analysis. The porosity logs for 14 wells on the seismic 3D were used together with several seismic attributes (such as AVO attributes and seismic inversion volumes) to derive a non-linear relation that was applied on the whole 3D, creating a set of pseudo-wells at each seismic trace. For the 2001 survey we did not use KED to constrain the porosity map to match the well log values since the porosity within the reservoir was altered. Specially, around the wellbores the porosity increased as a result of sand production. The results of the second seismic survey are presented in Figure 10.

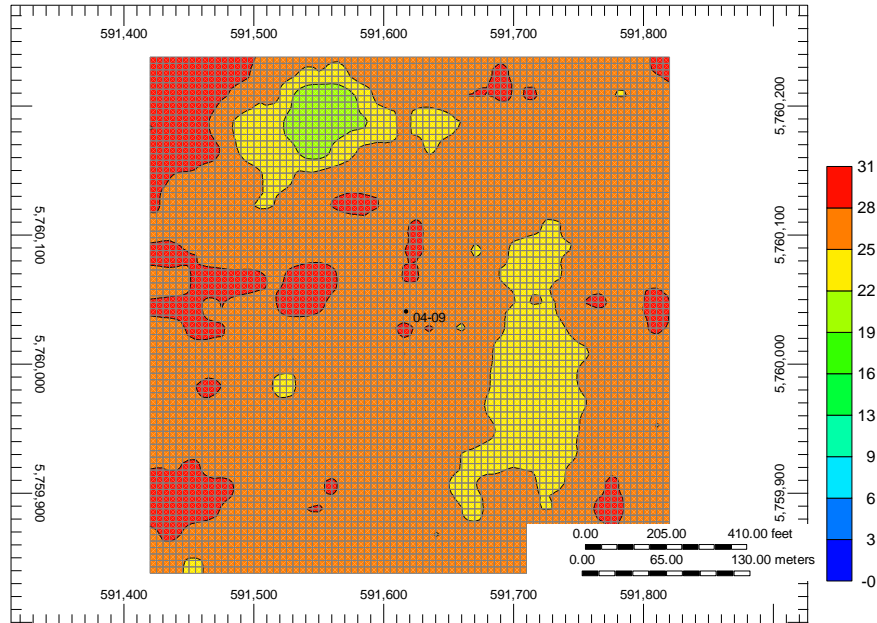


Figure 10. Porosity of the Bakken Formation estimated by 2001 seismic survey

The dynamic porosity of the Bakken Formation was subtracted from the initial porosity to investigate the changes in the reservoir porosity. The simulated difference porosity for different layers of the reservoir is presented in Figures 12, 14, and 16. The difference porosity maps are compared with initial permeability maps shown on Figures 11, 13 and 15. It is clear that most of the change in porosity happened in the lower layers. In addition, the areas with higher porosity and lower structure experienced more porosity change. The change in porosity is an indication of the presence of wormholes in those blocks.

The next step was to compare the porosity difference maps against the porosity difference map estimated by time lapsed seismic. Figure 17 presents the porosity difference map estimated by time lapsed seismic. No direct correlation between the porosity values estimated from seismic and simulation was observed. However a closer look at the gas saturation map showed a reasonable correlation between the gas saturation and the porosity values estimated from seismic. The gas saturation map is presented in Figure 18. Moreover, the porosity changes estimated by time lapsed seismic occurred at the top areas of the structure that shows the presence of a secondary gas cap.

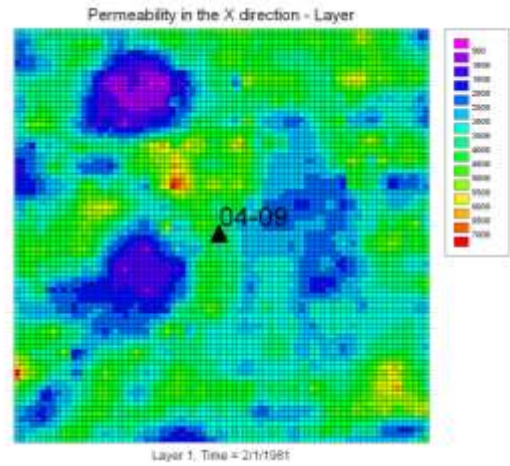


Figure 11. Initial permeability map of the first layer

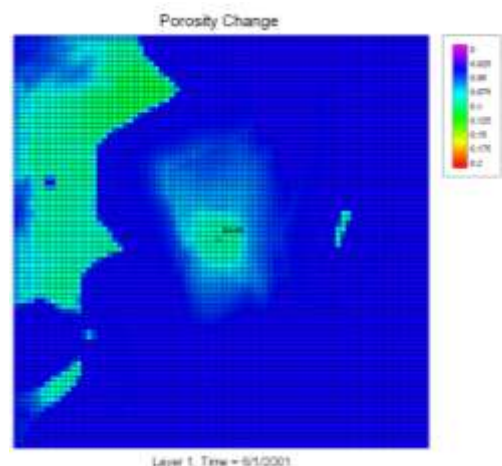


Figure 12. Porosity change of the first layer

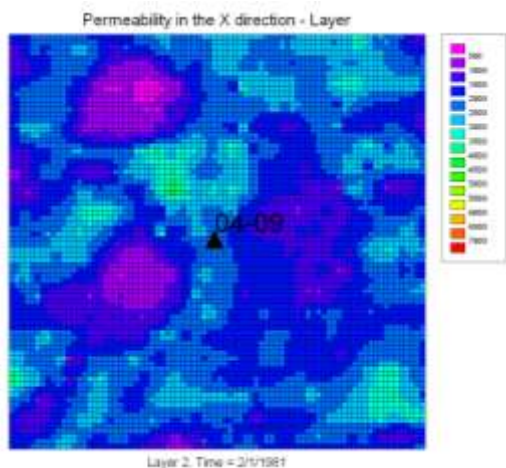


Figure 13. Initial permeability map of the second layer

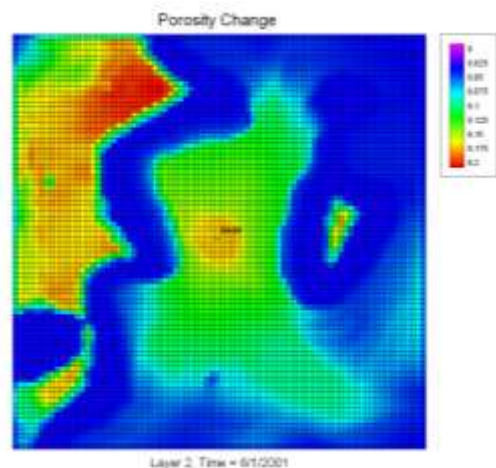


Figure 14. Porosity change of the second layer

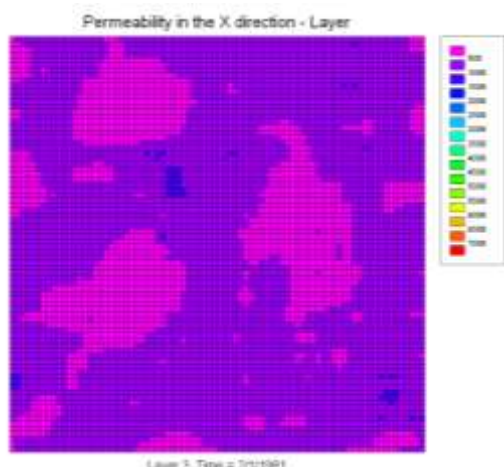


Figure 15. Initial permeability map of the third layer

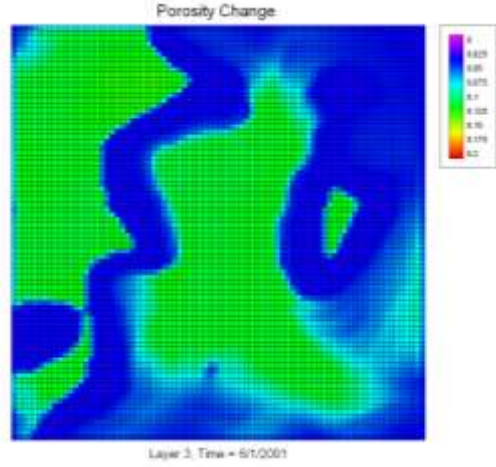


Figure 16. Porosity change of the third layer

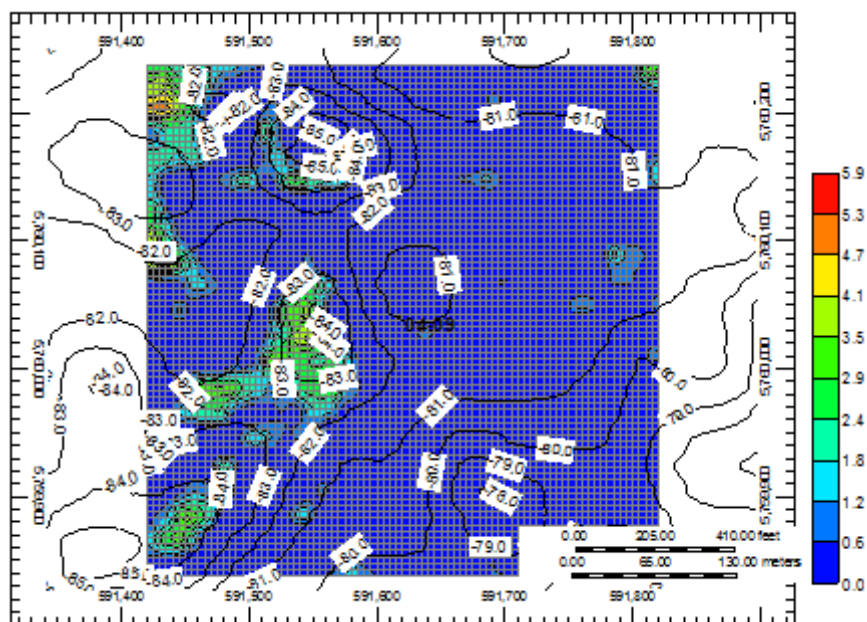


Figure 17. Porosity change map estimated by time lapsed seismic

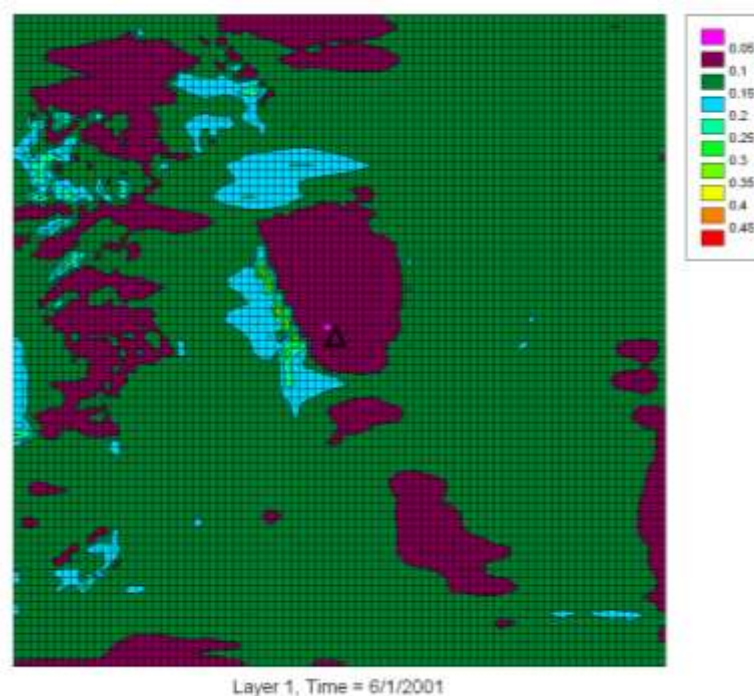


Figure 18. Gas saturation map

Conclusions

By using seismic attributes and geostatistic method (KED), a more accurate structure map was generated for reservoir simulation. Given the complexity of the structure in this area and the presence of sinkholes in this reservoir, this method was very successful to map the top (Upper/Mid Bakken) and the base (Lower Bakken) of the reservoir.

KED helped for the initial estimation of the reservoir simulation parameters, e.g. porosity. The porosity map obtained from KED honour both the seismic data and the well log data. The seismic attributes are more sensitive to the change in gas saturation rather than change in porosity. This was validated through this study using Plover Lake time lapsed data.

The hydro-erosion method was successfully applied to match the Cold Heavy Oil Production with Sand (CHOPS) in the Plover Lake reservoir. This was not possible using a static model without considering sand production. The presence of the wormholes and their positive impact on CHOPS wells oil rate was modeled successfully. This method could predict the wormholes growth as a result of aggressive drawdown against the formation. In general, grid blocks with higher porosity and lower structure experienced more porosity change (higher wormholes density).

The application of this technique allows us to optimize the CHOPS operation. The results of history matched model could be used for developing post CHOPS operations to improve the ultimate recovery factor from the reservoir. It is crucial to understand the impact of the high permeability channels (wormholes) on the sweep efficiency of different post CHOPS Improved Oil Recovery method (IOR) such as VAPEX or thermal methods.

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Appendix:

For modeling hydro-erosion a Representative Elementary Volume (REV) is considered. There are five phases involved in the REV:

1. Solid grains (s),
2. Fluidized solids (fs),
3. Fluid (f),
4. Water (w)
5. Gas (g)

Using mixing law, volume fraction, porosity and saturation of each phase, the volume V of the REV reflects the individual phase's contribution presents in the REV. For each phase, mass balance, equilibrium, and erosion mechanical equations can be derived. The set of governing equations are summarized as following.

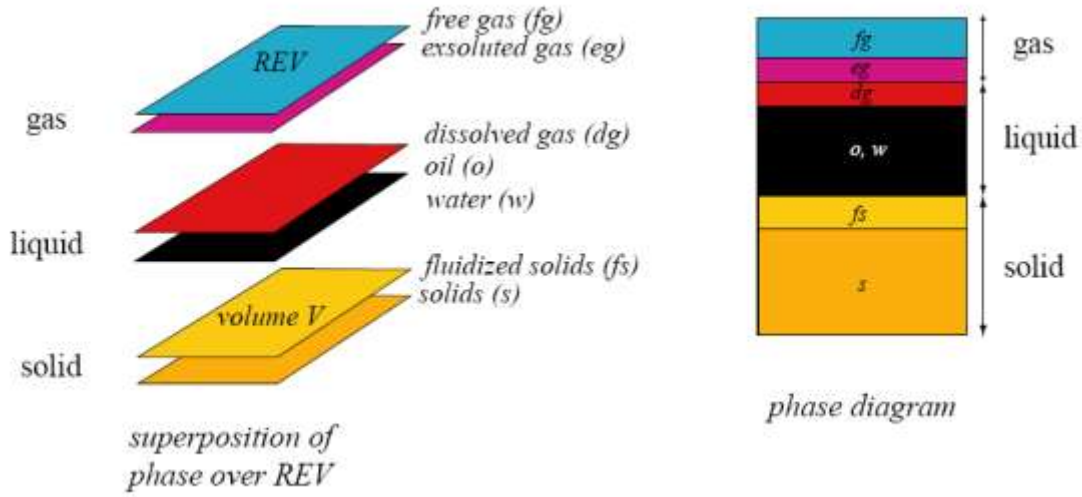


Figure 19. Schematic of different phase's involved in hydro-erosion modeling using REV approach Wang (2003)

$$\nabla \cdot \left[\frac{v_o}{B_o} + \frac{S_o \phi \dot{U}_s}{B_o} \right] + \frac{\partial}{\partial t} \left[\frac{\phi S_o}{B_o} \right] = 0 \quad (1)$$

$$\nabla \cdot \left[\frac{v_g}{B_g} + \frac{S_g \phi \dot{U}_s}{B_o} + \frac{RSv_o}{B_o} + \frac{R_s S_o \phi \dot{U}_s}{B_o} \right] + \frac{\partial}{\partial t} \left[\frac{\phi S_g}{B_g} + \frac{\phi S_o R_s}{B_o} \right] = 0 \quad (2)$$

$$\nabla \cdot \left[\frac{v_w}{B_w} + \frac{S_w \phi \dot{U}_s}{B_w} \right] + \frac{\partial}{\partial t} \left[\frac{\phi S_w}{B_w} \right] = 0 \quad (3)$$

$$-\frac{\partial \phi}{\partial t} + \nabla \cdot [(1 - \phi) \dot{U}_s] + \frac{\dot{m}}{\rho_s} = 0 \quad (4)$$

$$-\frac{\partial[\phi(S_{fs}-1)]}{\partial t} + \nabla \cdot [\eta_{slip} S_{fs} v_m + (1-\phi + S_{fs}) \dot{U}_s] = 0 \quad (5)$$

Where;

ϕ = porosity,

S_i =saturations,

B_i = the formation volume factors, $= i$

V_i = volumetric velocity of each phase ($i=o, g, w, f, s$),

R_s = the solution gas oil ratio,

\dot{U}_s = the volume-weighted velocity of deforming solid skeleton.

$\frac{\dot{m}}{\rho_s}$ = the source or sink term to account for the local rate of solid loss or gain per unit volume due to erosion.

η_{slip} = a constant between 0 and 1 to account for the slippage between sand and viscous fluid. $\eta_{slip} = 0$ means sand particles are eroded from sand matrix but would not flow with fluid, while 1 means that there are no slippage between sand particles and fluid sand particle velocity is equal to fluid mixture velocity.

Equations 1 to 3 are the mass balance for oil, gas and water relatively. Equations 4 and 5 are the erosion mechanical equations. Term $\frac{\dot{m}}{\rho_s}$ in equation 4 is related to the erosion model using the constitutive law derived from inverse filtration theory by following equations:

$$\begin{aligned} \frac{\dot{m}}{\rho_s} &= \lambda(\phi_{\max} - \phi) S_{fs} \left(1 - \frac{S_{fs}}{S_{fsc}} \right) \|V_m\| \quad \text{if } \|V_m\| \geq \|V_m^{Cr}\| \\ \frac{\dot{m}}{\rho_s} &= 0 \quad \text{if } \|V_m\| < \|V_m^{Cr}\| \end{aligned} \quad (6)$$

V_m^{Cr} is in the above equation presents the critical average velocity of mixture below which no sand production occurs. Maximum possible porosity ϕ_{\max} is the value which no erosion is occurred above this value. The critical fluidized sand saturation S_{fscr} prevents all the mass from being eroded. V_m is the average velocity in the REV. V_m is depending on the wettability (capillary forces), and saturation of each phase in REV. λ is the erosion coefficient.

Computation Method:

An iterative coupled model was used for modeling sand production. The steps of this method are presented below:

- Solving 3D, 3 phase reservoir simulation model to obtain the pressure, saturation and velocity of each phase in all blocks
- Check for erosion through equation 6
- Update porosity values by mass balance equations
- Update permeability values based on change in porosity
- Update Viscosity of different blocks
- Resolve reservoir simulation model with updated parameters and repeat until convergence criteria is met
- Move on to the next time step

Nomenclature

ϕ = porosity

S_i = saturations

B_i = the formation volume factors ($i=o, g, w$)

V_i = volumetric velocity of each phase ($i=o, g, w, fs$)

R_s = the solution gas oil ratio

\dot{U}_s = the volume-weighted velocity of deforming solid skeleton

$\frac{\dot{m}}{\rho_s}$ = the source or sink term

η_{slip} = slippage coefficient

V_m^{Cr} = critical average velocity

V_m = average velocity

λ = erosion coefficient