[PS]Flow Simulation Model of the Wall Creek Member in the Frontier Formation: Powder River Basin, WY*

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Abstract

The Frontier Formation in the Powder River Basin has been rediscovered for oil and gas potential with the development of long horizontal wells and multi-stage hydraulic fracturing. Over the last decade, the Wall Creek Member of the Frontier Formation has proven to be a successful hydrocarbon-producing target, yet a full understanding of this complex structure has not been achieved. The complexity of the Wall Creek depositional environment has challenged geologists to understand the vertical and lateral heterogeneity of the play; furthermore, the fluid and rock properties have uncertainty and are not well defined. To develop better recovery strategies, an integrated reservoir model using geologic, petrologic, petrophysical, and geophysical data is created to evaluate different scenarios of how the play may occur in the reservoir.

The work started by using a representative horizontal well to create a single-well flow simulation model including properties of the reservoir such as porosity, permeability, relative permeability, capillary pressure, and water saturation. Using the three offset well logs, a 32 feet interval was selected to represent the net pay zone of the Wall Creek Member. The porosity was estimated by averaging the neutron and density porosities, and permeability was established by applying a correlation of porosity and permeability found from the core data. By matching a PVT report from the well, a black oil model was created to represent the reservoir fluid. The production history was matched by modifying the initial fluid saturations and the rock physics parameters such as relative permeability and capillary pressure. As a result, representative fluid and rock physics models were obtained for the reservoir. Sensitivity analysis was conducted to observe the effect of changing reservoir properties and hydraulic fracture properties on production. Well spacing and fracture spacing studies were also performed. Overall, this work allows for a better understanding of what is happening in this reservoir and provides a range of possible production rates for a number of reservoir properties in the field.

One of the most important outcomes from this model is the determination of reasonable fluid and rock physics parameters, which can be used in geologic models that capture the complex small-scale structural heterogeneity observed in outcrops. For the future work, this model will be combined with an outcrop study of Wall Creek heterogeneity to determine the appropriate method to upscale the complex, heterogeneous models to the well scale models. Different geologic scenarios will be evaluated to help determine the best strategy for field development.

Selected Reference

Anna, L.O., T.R. Klett, P.A. Le, and C.P. Anderson, 2010, Total Petroleum Systems and Geologic Assessment of Oil and Gas Resources in the Powder River Basin Province, Wyoming and Montana: U.S. Geological Survey, U.S. Dept. of the Interior, Reston, VA.

Soave, G., 1972, Equilibrium Constants from a Modified Redlich-Kwong Equation of State: Chemical Engineering Science, v. 27/6, p. 1197-1203.

WOGCC, 2016, Wyoming Oil and Gas Conservation Commission: http://wogcc.state.wy.us/. Website accessed November 2017.

Zupanic, J., and M.H. Hofmann, 2016, Stratigraphic Architecture and Facies Distribution Within the Wall Creek Member of the Frontier Formation, Western Powder River Basin, Wyoming: AAPG Annual Convention and Exhibition, Calgary, Alberta, Canada, June 19-22, 2016, Search and Discovery Article #90259 (2016). Website accessed November 2017.

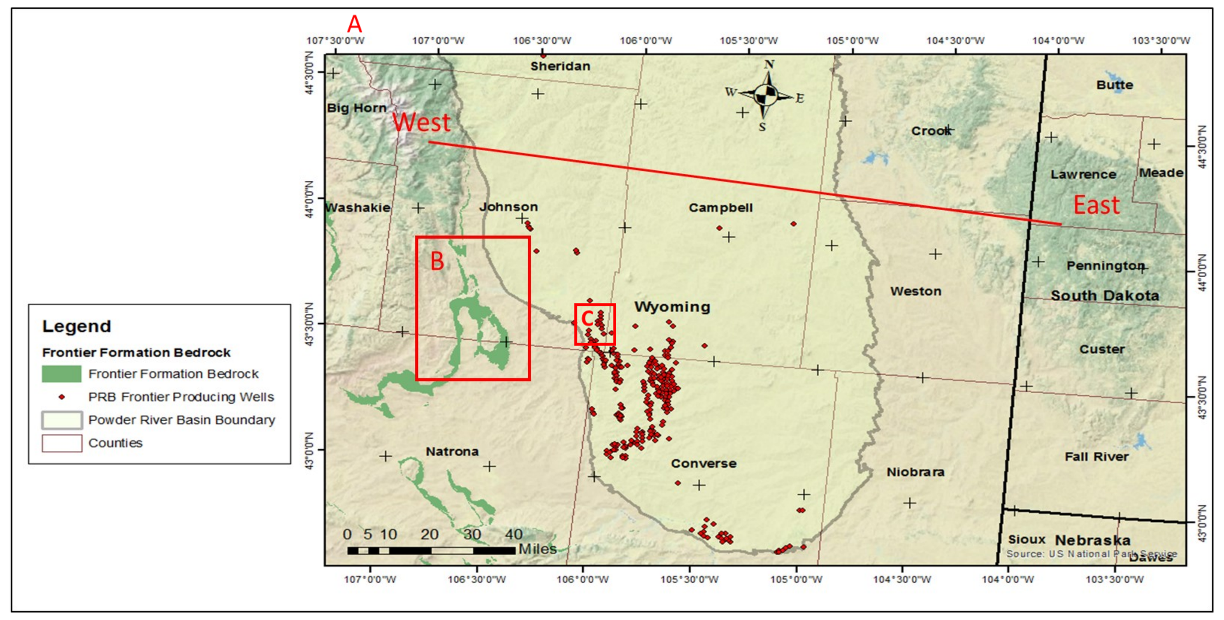

Figure 1: (A) Cross-section of geologic study and location of Frontier outcrop at the surface in Wyoming that associated with Frontier formation in Powder River Basin. (B) Tisdale Mountain Outcrop Study Area. (C) Reservoir Model Study.

The Frontier formation in the Powder River Basin has been re-discovered for oil and gas potential with the development of long horizontal wells and multi-stage hydraulic fracturing. Over the last decade, the Wall Creek member of the Frontier formation has proven to be a successful hydrocarbon-producing target, yet a full understanding of this complex structure has not been achieved.

GEOLOGY

Powder River Basin is an asymmetric basin with near vertical to overturned dips along the western margin and gentle sub-horizontal (basinward) dips along the eastern margin.

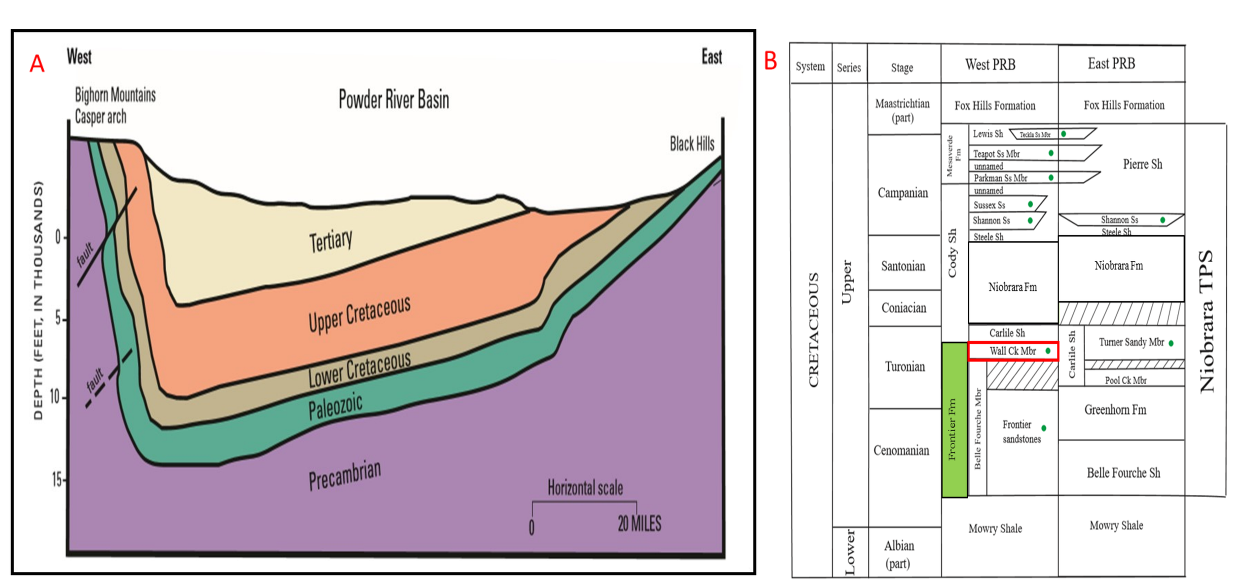

Figure 2: (A) Generalized west-east cross section of Powder River Basin. (B) Stratigraphic column of Upper Cretaceous strata in the Powder River Basin.

The complexity of the Wall Creek depositional environment has challenged geologists to understand the vertical and lateral heterogeneity of the play; furthermore, the fluid and rock properties have uncertainty and are not well-defined.

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FLOW SIMULATION MODEL OF THE WALL CREEK MEMBER IN THE FRONTIER FORMATION: POWDER RIVER BASIN, WY

Presented by: Tuan Le

RESEARCH GOAL

Advance reservoir characterization understanding in the Frontier Formation in the Powder River Basin. Improve prospect definition and development strategy through a fully integrated outcrop to subsurface reservoir model.

METHODOLOGY

A - Fluid and Rock Physics Models

1/ Reservoir Modeling: Rush State well located in section 36, T42N, R77W in Johnson county, Wyoming.

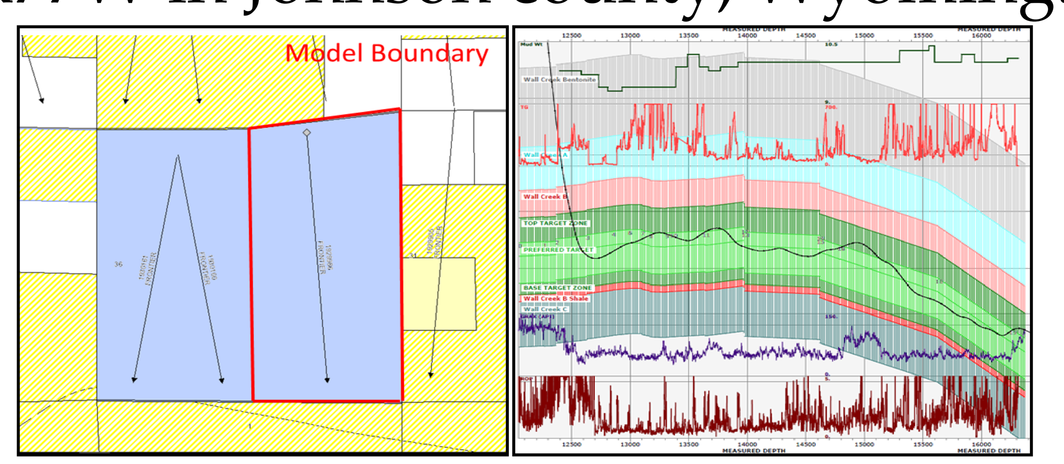

Figure 3: Well location from GIS map (Left) and well deviation from geosteering data (Right).

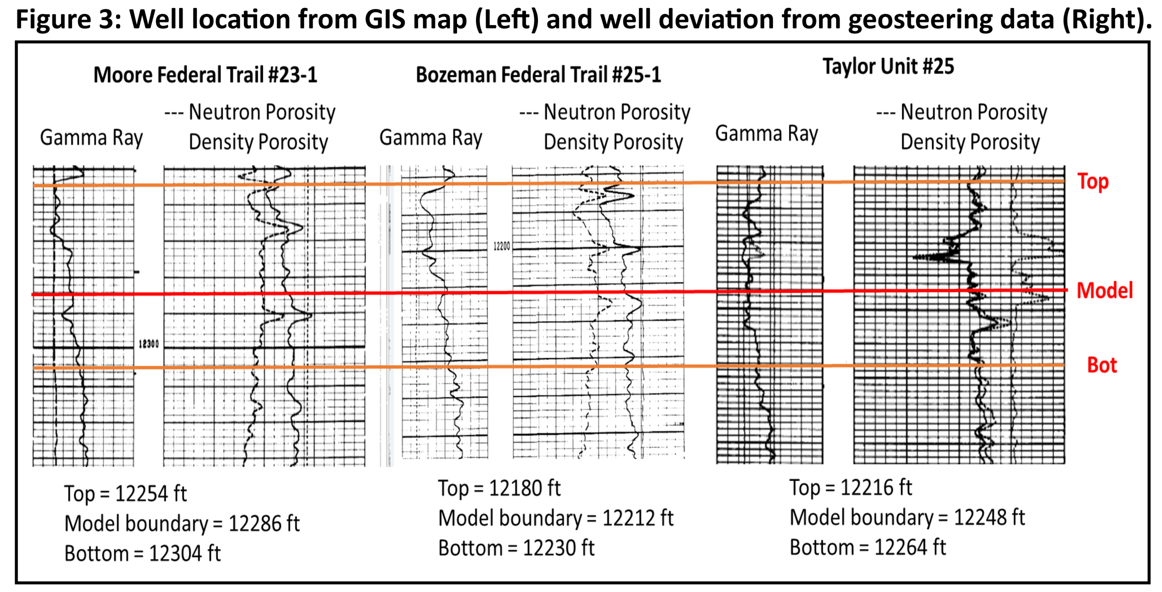

Figure 4: Well log pickings from three wells (50 ft thickness).

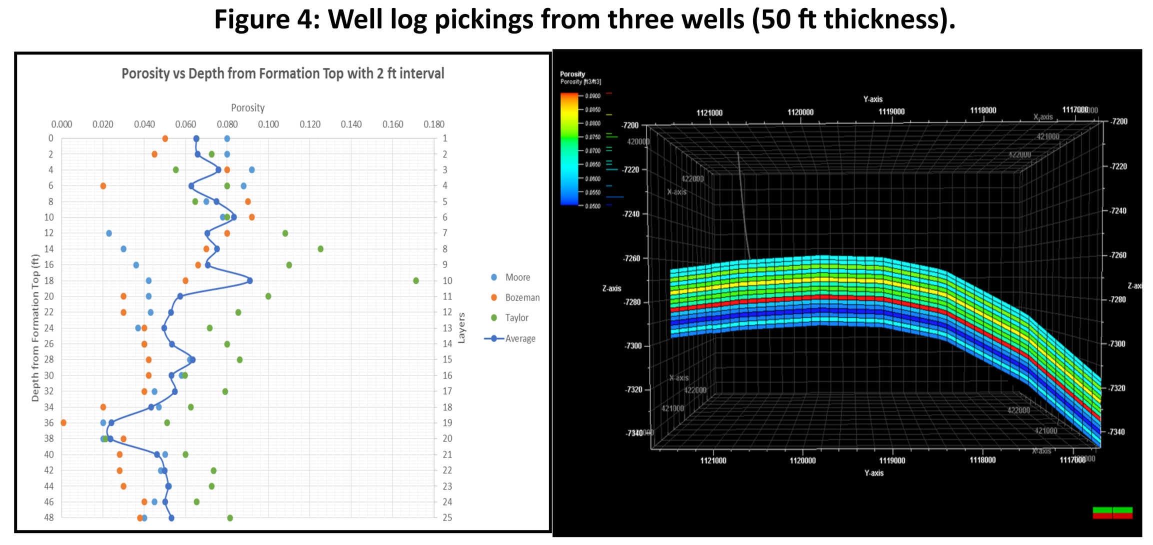

Figure 5: Porosity estimation from well logs and Petrel porosity model (ϕ = 5% - 9.1%).

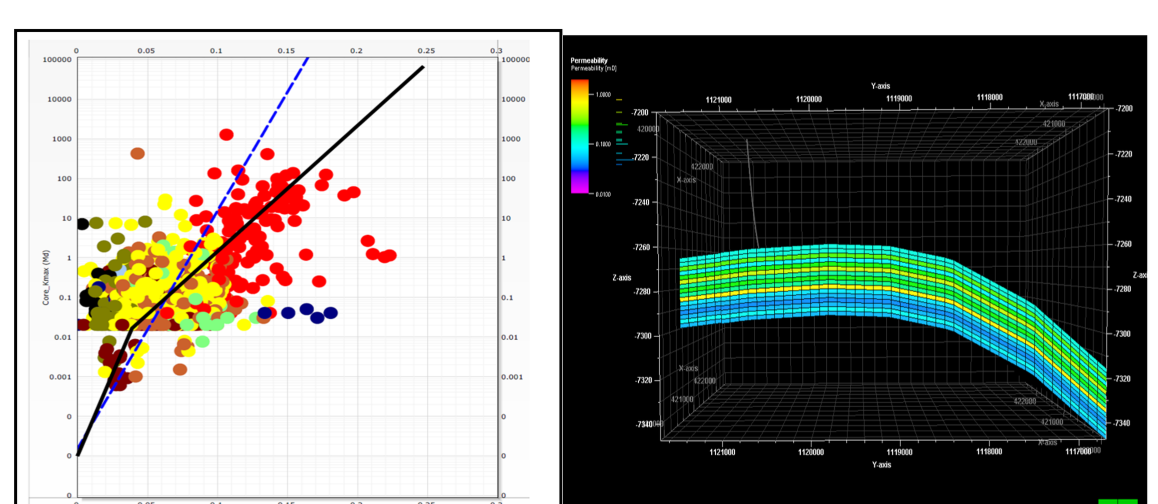

Figure 6: Permeability estimations from Porosity-Permeability cross plot and Petrel permeability model (K = 0.0382 md—0.7806 md).

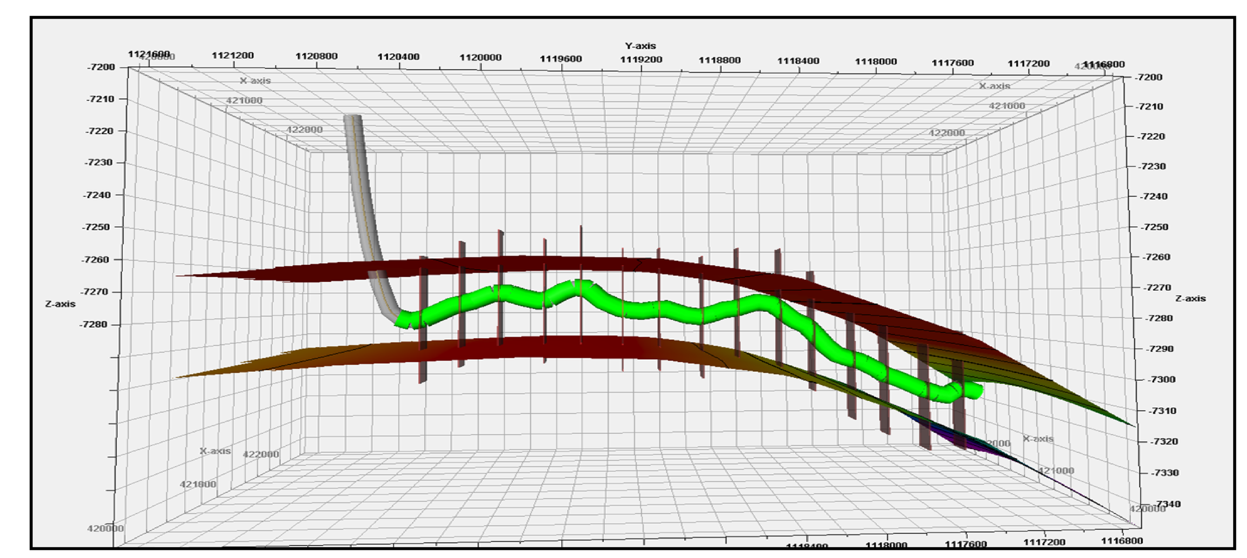

Figure 7: Completion model including sliding sleeve completion and 15 frac stages with 50 feet high and 100 feet half length for each fracture.

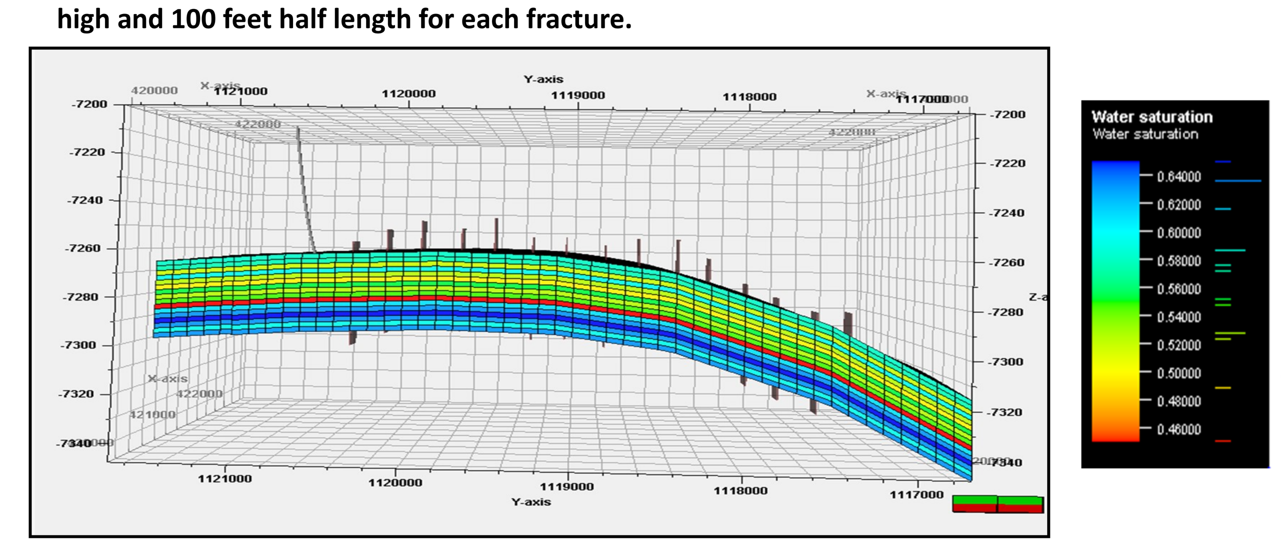

Figure 8: Petrel water saturation distribution model using porosity dependent (Sw = 45% - 65%).

2/ Fluid model: Using PVTi software from Schlumberger simulation to match the PVT.

- Use trial-error inputting different parameter for Soave-Redlich-Kwong EOS:

. EOS parameter: Ω_A, Ω_B, Acentric factor, Vshift, Binary interaction coefficient and other regression variables.

. Different weights for each properties to limit the changes while matching different properties.

. Properties matching: Relative volume, density, viscosity, B_o, B_g, gas-oil ratio.

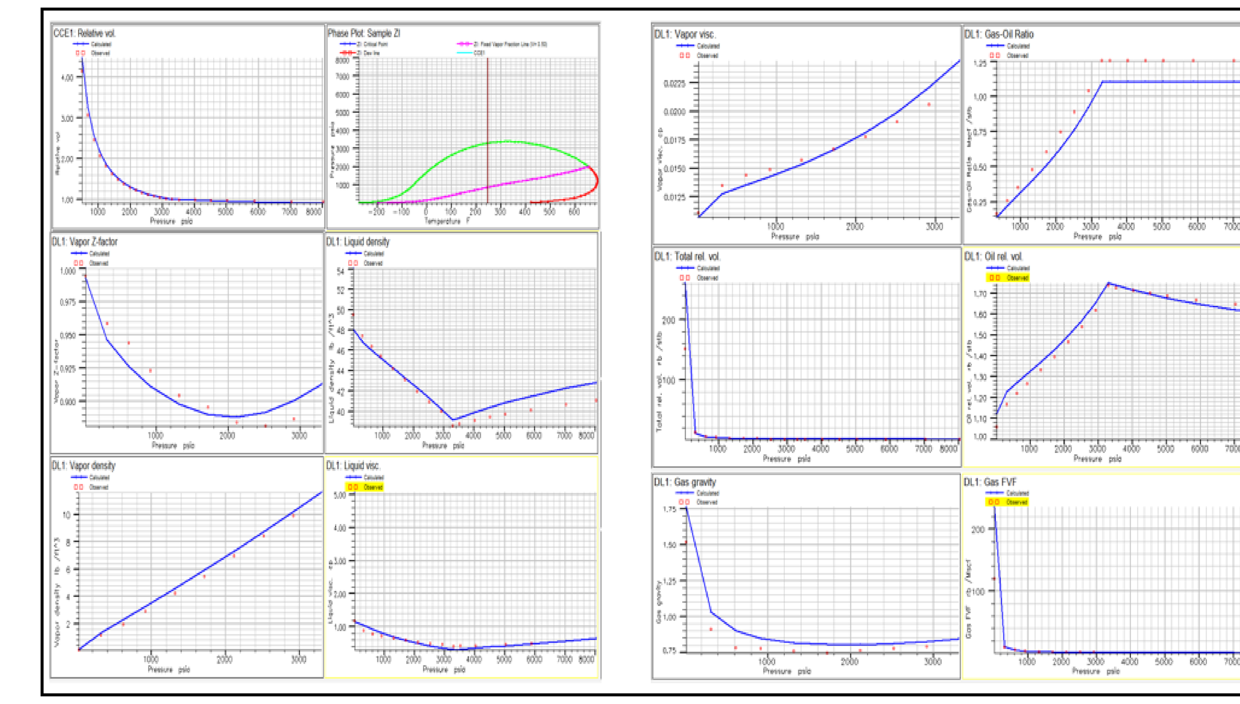

Figure 9: PVT Matching using PVTi software from Schlumberger simulation that applied Soave-Redlich-Kwong equation of state.

3/ Logarithmic Grid Refinement (LGR): Using tartan grid to apply LGR into each hydraulic fracture: 25 grid cells in I direction with average cell size of 100 feet and LGR around frac with 10 divisions with minimum distance of 2 feet in J direction. Total grid cells = 49,728 cells.

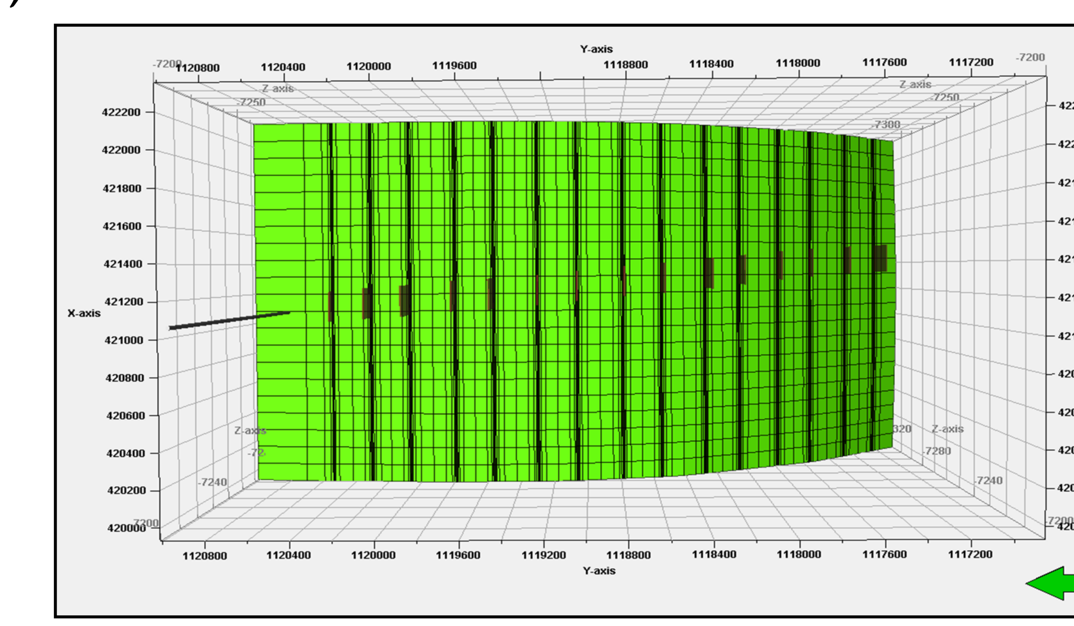

Figure 10: Base LGR reservoir model for history matching.

4/ History Matching Procedures:

- Modify relative permeability curves to match the production.

- Initialize the reservoir condition according to the report such as pressure, water saturation, gas-oil ratio, capillary pressure, water salinity.

- Remove drilling/frac fluid at beginning of production for better matching.

- Run the model from May 2014 through Sep 2016.

- Constrain the model matching to the historical oil rate.

- Match gas rates, water rates, and estimated bottom hole pressure.

- Construct field analysis using base model properties.

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5/ Results:

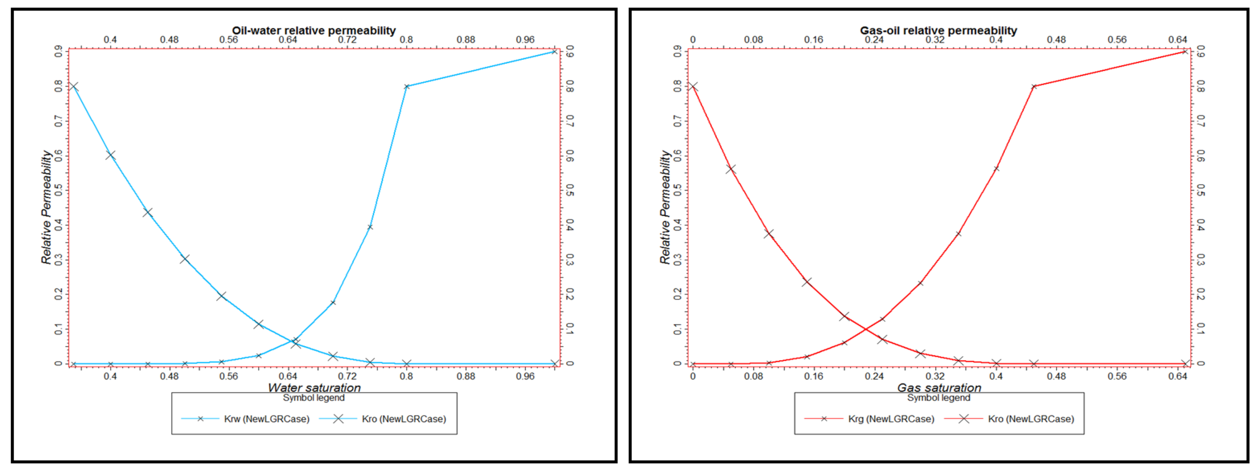


Figure 11: Modification of rock physics for oil, water and gas relative permeability to achieve the historical production matching. (Sorw = 0.2, Sorg = 0.2, Swcr = 0.35, Sgcr = 0.05).

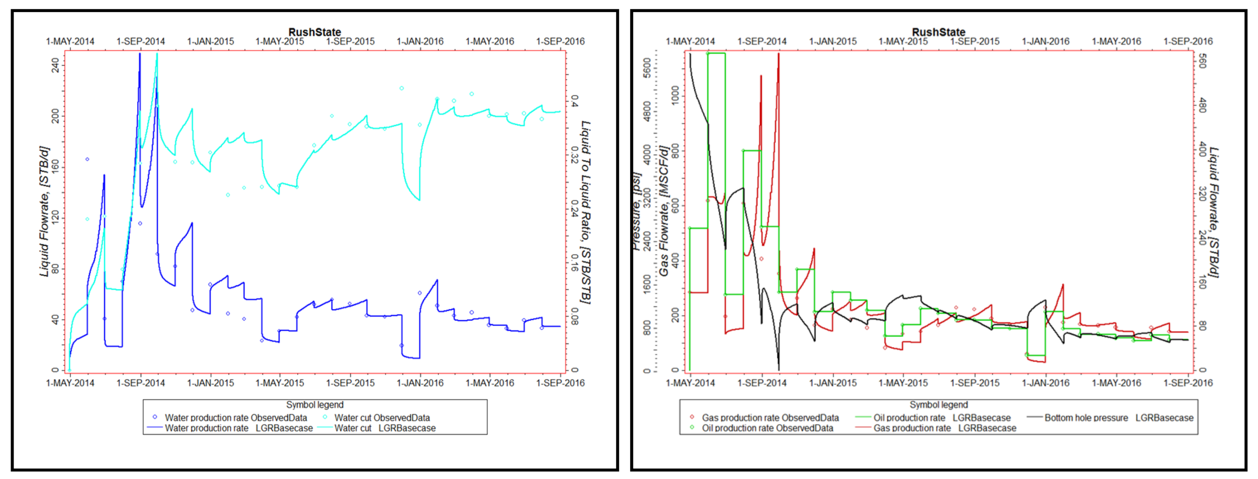
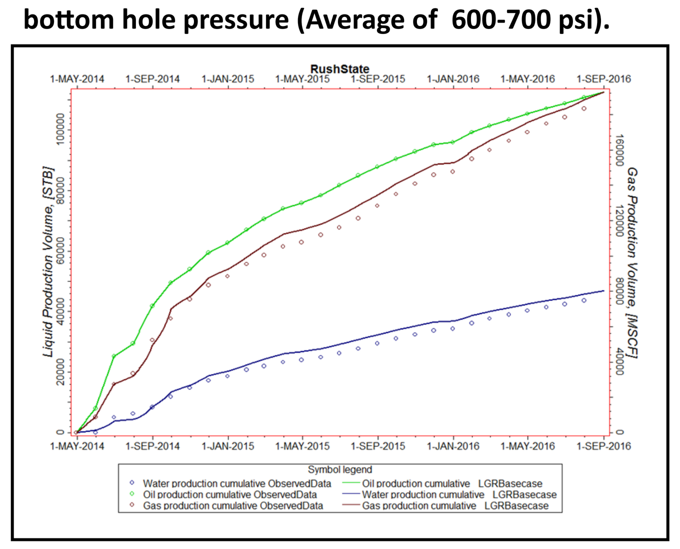


Figure 12: History matching results for oil, gas, water production and water cut with reasonable bottom hole pressure (Average of 600-700 psi).



- From the history data in 09/01/2016
  - Cumulative Oil Production = 112,539 STB
  - Cumulative Gas Production = 191,347MSCF
  - Cumulative Water Production = 45,927 STB
- From the model in 09/01/2016
  - Cumulative Oil Production = 112,539 STB
  - Cumulative Gas Production = 192,678 MSCF
  - Cumulative Water Production = 46,816 STB

Figure 13: History matching results of cumulative production of oil, gas, and water.

B - Sensitivity Analysis

1/ Procedures:

- Model is rerun with bottom hole pressure constraints obtained from history matching.
- Model Parameters:

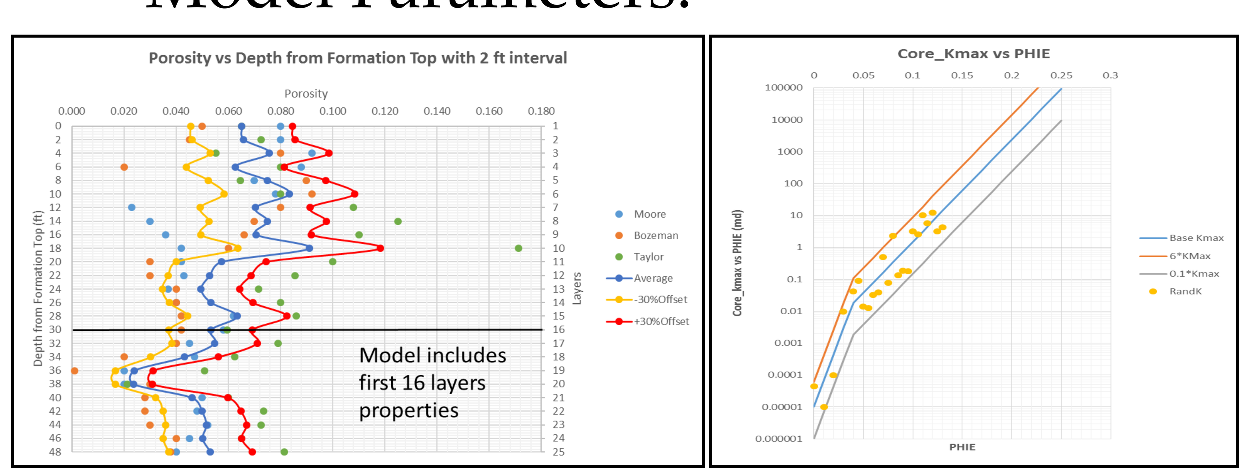


Figure 14: Sensitivity analysis for min and max porosity and permeability of model.

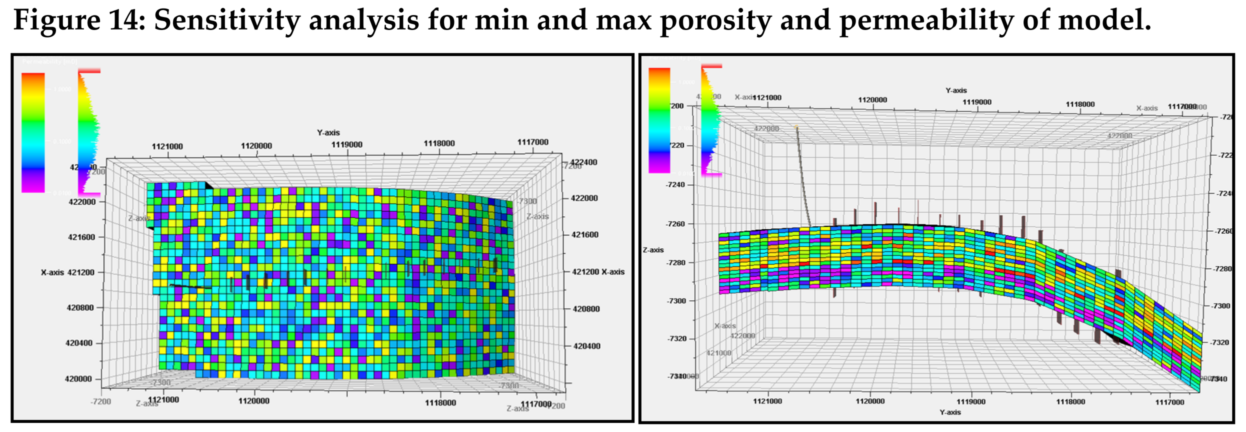


Figure 15: Sensitivity analysis for random distributed permeability of model.

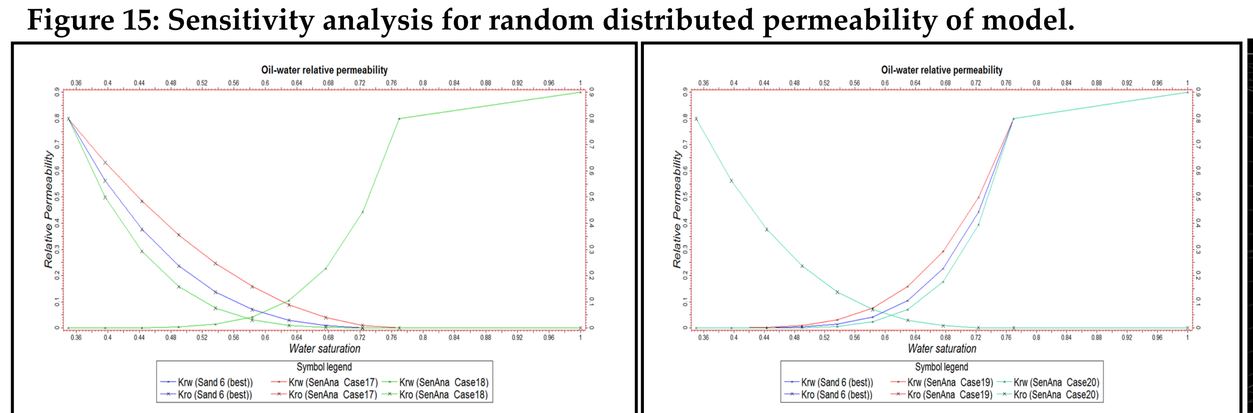


Figure 16: Sensitivity analysis for Corey Exponent of oil and water for rock physics.

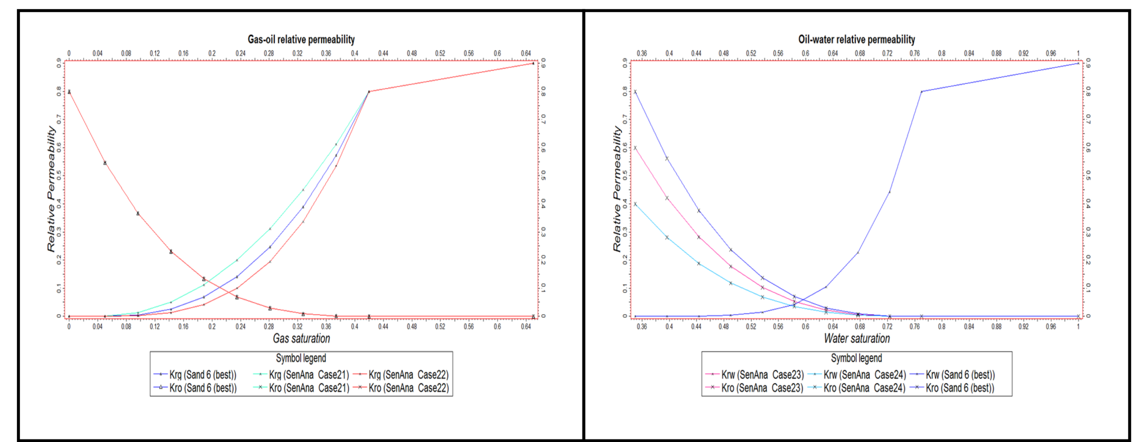


Figure 17: Sensitivity analysis for Corey exponent of gas and Kro at Somax of rock physics.

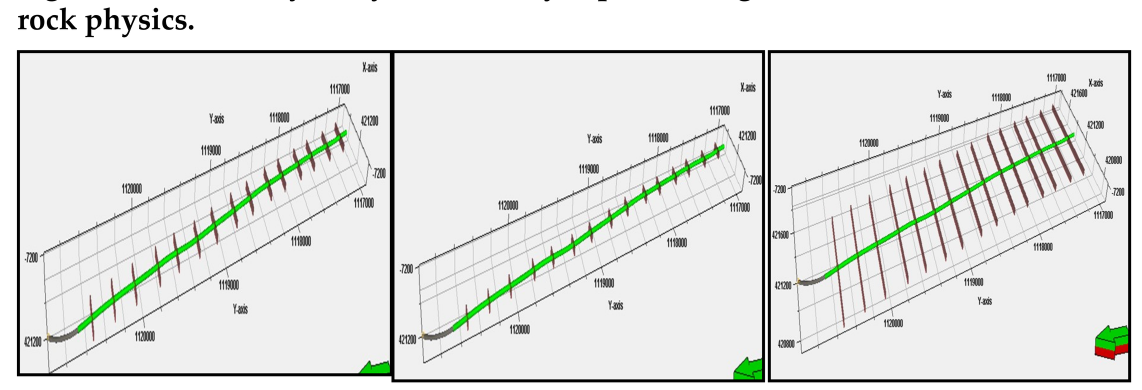


Figure 18: Sensitivity analysis for hydraulic fracture half-length of 100 feet, 50 feet, 200 feet for a single horizontal well of model.

2/ Results:

- Permeability/porosity have largest impact on production.
- Random distributed permeability shows no significant difference.
- Relative permeability parameters are suitable for history matching purpose.
- Half length of hydraulic fracture has no big impact. 100 feet half length is good for simulation purpose.

C - Well Analysis

1/ Procedures: Applying LGR with 75 grid cells in I direction with average cell size of 25 feet and 10 division with minimum distance of 2 feet in J direction.

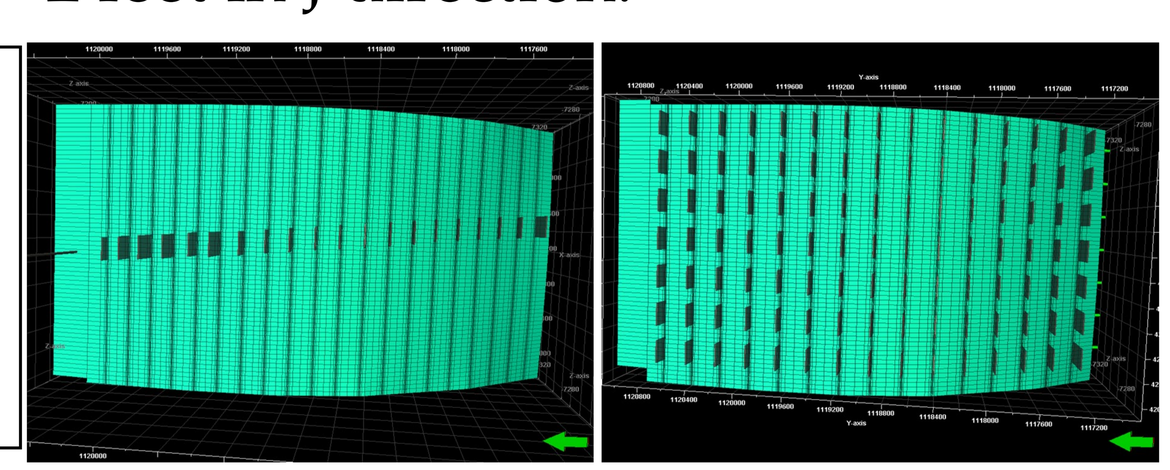


Figure 19: Example of LGR application for hydraulic fracture in frac spacing (Left) and well spacing analysis (Right).

2/ Results:

a/ Well Spacing Analysis: Fully developing the half-section reservoir.

- Redesign well for analysis purpose.
- Run with bottom hole pressure constraint of 500 psi.

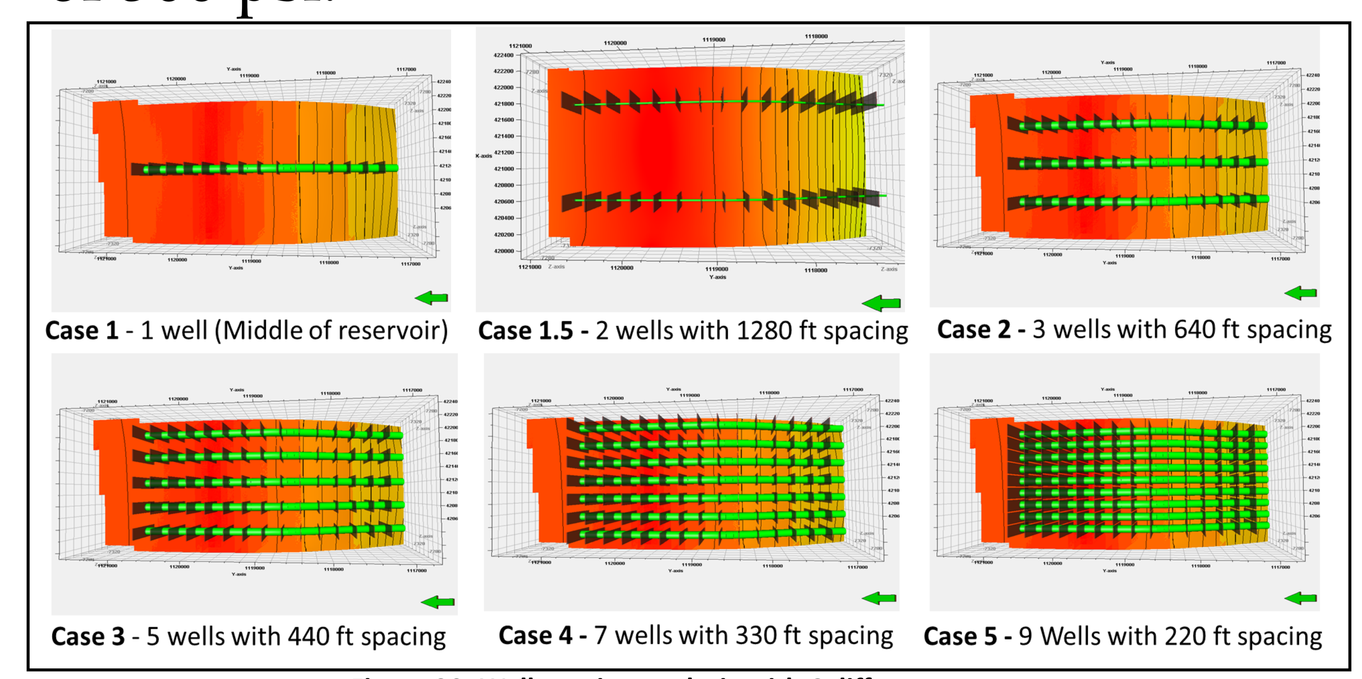


Figure 20: Well spacing analysis with 6 different cases.

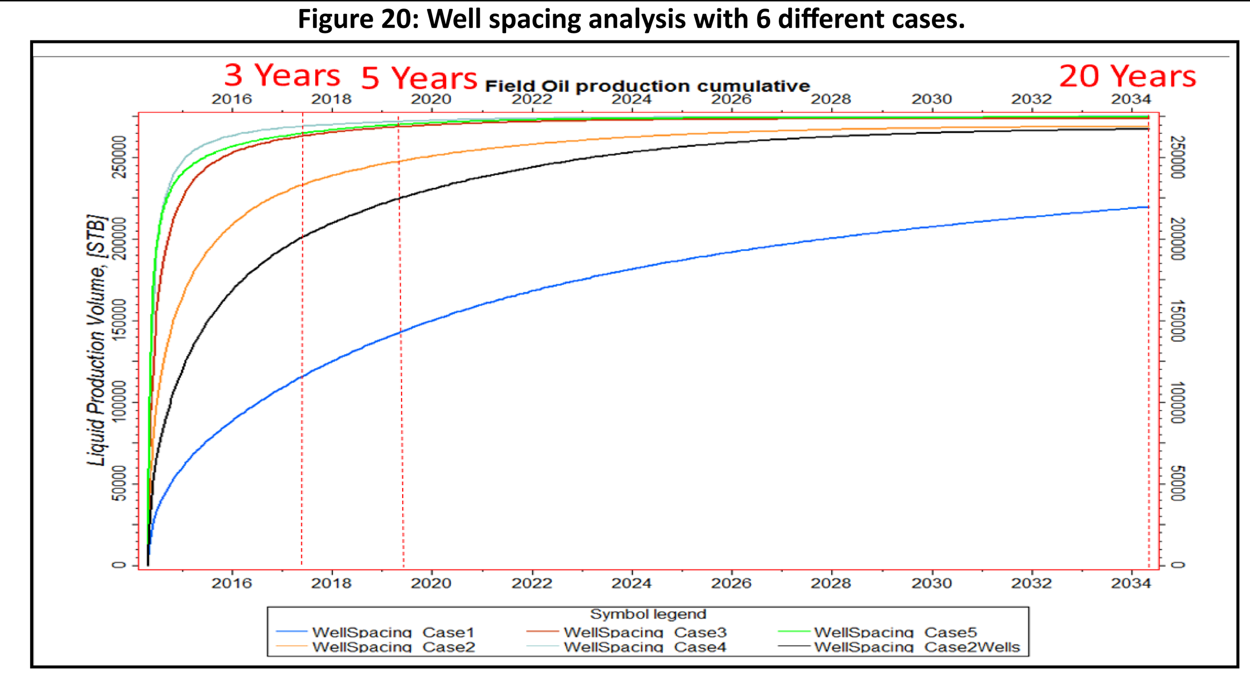


Figure 21: Cumulative oil production with 6 different cases of well spacing analysis.

3 Year Production	5 Year Production	20 Year Production
Case 1: 114,534 STB	Case 1: 142,658 STB	Case 1: 219,646 STB
Case 1.5: 199,812 STB	Case 1.5: 224,780 STB	Case 1.5: 267,294 STB
Case 2: 232,410 STB	Case 2: 247,700 STB	Case 2: 269,039 STB
Case 3: 262,783 STB	Case 3: 268,721 STB	Case 3: 273,871 STB
Case 4: 268,873 STB	Case 4: 271,976 STB	Case 4: 274,996 STB
Case 5: 264,492 STB	Case 5: 270,080 STB	Case 5: 274,557 STB

Table 1: Cumulative oil production in 3, 5, and 20 years of well spacing analysis.

- In long term, the reservoir should be developed at a well spacing of 1280 feet between the wells. Only 1-2% additional recovery with tighter well spacing are seen.
- In short term, significant incremental recoveries are shown in Cases 1 to 3, but project economics will ultimately determine optimal well spacing.

b/ Frac Spacing Analysis: Optimizing the number of frac stages for better recovery.

- Run with bottom hole pressure constraint of 500 psi.

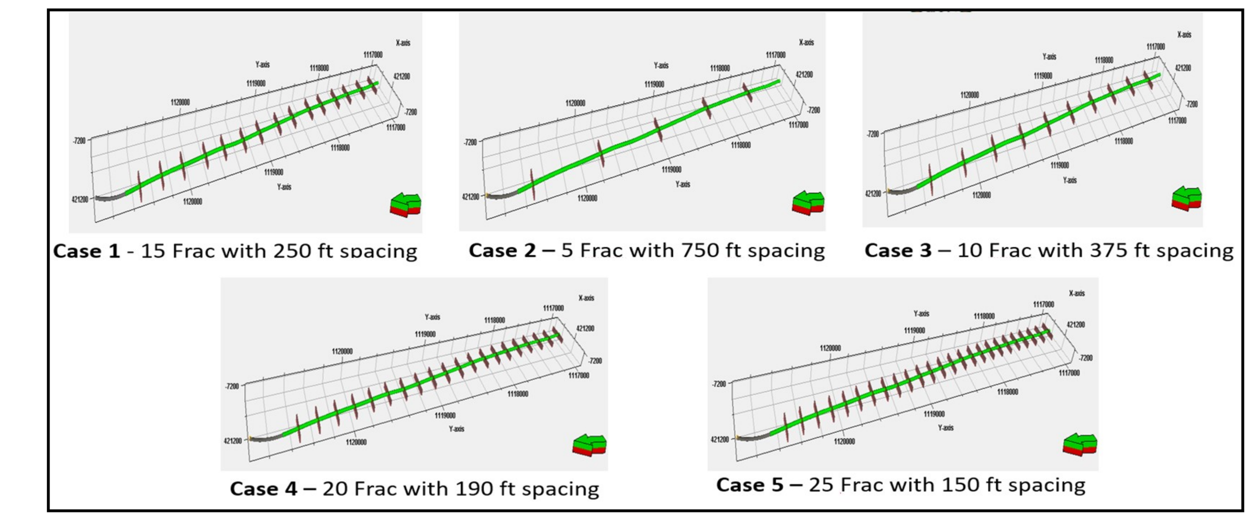


Figure 22: Frac spacing analysis with 5 different cases.

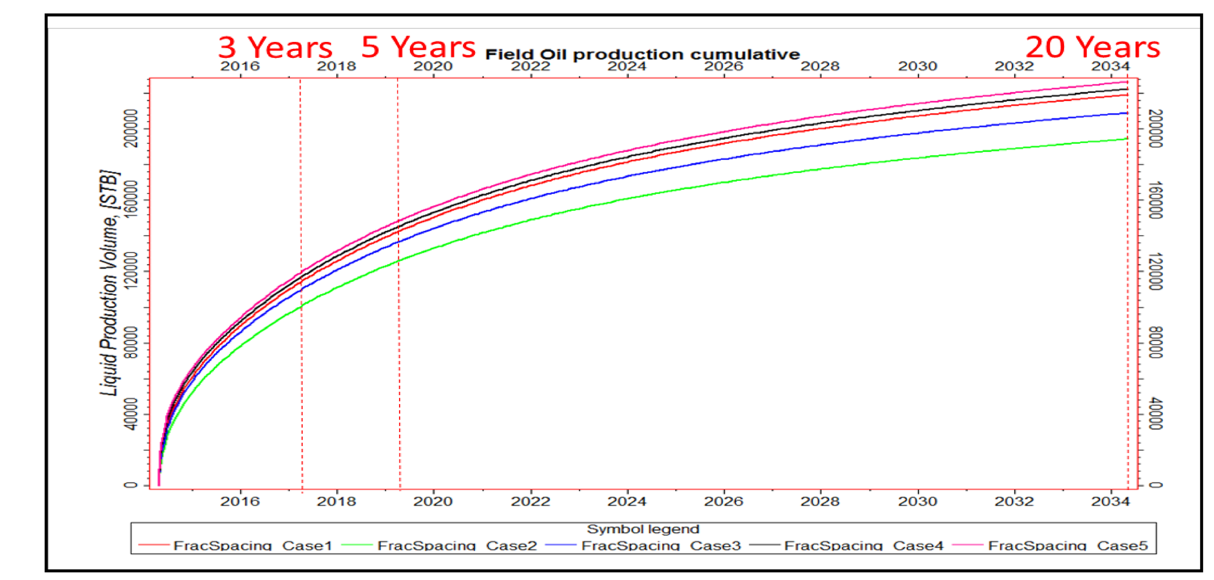
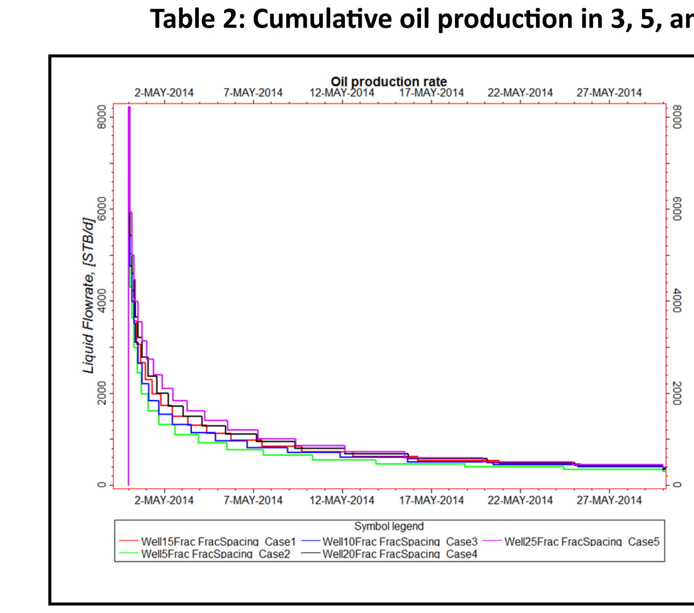


Figure 23: Cumulative oil production with 5 different cases of frac spacing analysis.

3 Year Production	5 Year Production	20 Year Production
Case 1: 115,563 STB (0%)	Case 1: 143,260 STB (0%)	Case 1: 219,219 STB (0%)
Case 2: 101,676 STB (-12.8%)	Case 2: 126,605 STB (-12.3%)	Case 2: 194,406 STB (-12%)
Case 3: 111,051 STB (-4.00%)	Case 3: 137,348 STB (-4.22%)	Case 3: 208,991 STB (-4.78%)
Case 4: 118,169 STB (+2.23%)	Case 4: 145,984 STB (+1.87%)	Case 4: 222,348 STB (+1.40%)
Case 5: 120,869 STB (+4.48%)	Case 5: 149,149 STB (+4.00%)	Case 5: 226,417 STB (+3.20%)

Table 2: Cumulative oil production in 3, 5, and 20 years of frac spacing analysis.



Frac Spacing Analysis
Case 1: 15 frac = 6,814 STB/day
Case 2: 5 frac = 5,479 STB/day
Case 3: 10 frac = 6,287 STB/day
Case 4: 20 frac = 7,470 STB/day
Case 5: 25 frac = 8215 STB/day

Increasing the frac stages improving the initial production; however, the declination rates become faster.

Figure 24: Initial production rate of each frac spacing case.

- Higher number of hydraulic fracture stages improves the total production at the early years. 15-20 stages are the optimum number for frac spacing.

FUTURE WORK

- Integrate fluid and rock physics model with high definition geocellular model from UM for upscaling reservoir model.
- Conduct sensitivity study and performance prediction.
- Analyze a variety of technologies for maximizing oil recovery.