Petrophysical Reservoir Model of the Beaver Lodge Oil Field, Williams County, North Dakota

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Figure 1: Location of Beaver Lodge Devonian Unit (BLDU)

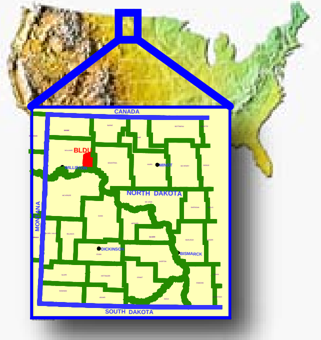


Figure 2: Structural top of the Bakken Formation with the location of wells with formation top data used to create the contour maps.

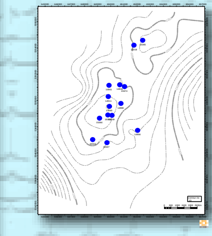
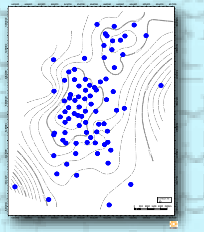


Figure 3: Structural top of the Bakken Formation with the locations of petrophysically modeled wells.



ABSTRACT

Permanent storage of carbon dioxide (CO_2) in mature petroleum reservoirs and saline aquifers has been identified as a potential method to reduce the environmental impacts associated with fossil fuel energy use. The Beaver Lodge oil field is a multiple-pay field located along the north–south-trending Nesson Anticline in Williams County, North Dakota, with the potential of being a sink for CO_2. The structural trap and the shallowing upward carbonate and evaporite sequences of the Duperow Formation in the Beaver Lodge have been identified as a potential target to sequester significant amounts of CO_2. Combining CO_2 sequestration and CO_2-based enhanced oil recovery (EOR) in mature oil and gas reservoirs allows more hydrocarbon to be retrieved than previously possible, which also offsets part or all of the sequestration cost. In order to determine the sequestration and EOR potential of the reservoir, an accurate reservoir model was required. The Beaver Lodge oil field was petrophysically modeled from well data to determine the reservoir characteristics and rock and fluid properties. The petrophysical models were then used to populate the reservoir model with the determined properties through geostatistical methods. Modeling was completed using the industry software Interactive Petrophysics and Petrel. The reservoir model was run to demonstrate production history matching and the potential reservoir response to proposed CO_2 injection.

BEAVER LODGE RESERVOIR

The Beaver Lodge Field is a multiple-pay reservoir field along the north–south-trending Nesson Anticline in eastern Williams County, North Dakota (Figure 1). The Duperow Formation has been the most productive of the hydrocarbon horizons in the Beaver Lodge for the last 57 years. The Duperow has been identified as a potential CO_2 enhanced oil recovery (EOR) site, since the reservoir is mature and is under water flood secondary recovery. The Duperow is a series of shallowing upward carbonate and anhydrite sequences deposited on the shelf of the Elk Point Basin. Primary production is from the subtidal stromatoporoid bank boundstone facies and secondary from the intertidal laminated mudstone facies. The supratidal anhydrite or dolomite beds are the cap rock to the structural trap. In order to accurately calculate potential CO_2 EOR and resulting CO_2 sequestration potential for the Duperow, an accurate property model is necessary for the identification of potential injection sites and injection modeling. Formations above the injection site are modeled to predict possible leakage of CO_2 from the Duperow trap up-section.

METHODS

Data Collection

All well log data were collected from the North Dakota Industrial Commission, Department of Mineral Resources, Oil and Gas Division (NDIC) Web site. Well logs and well files contain almost all data run on each individual well and well core since the early 1950s. Not all data available on the Web site for the Beaver Lodge oil field are used in the creation of the petrophysical modelsl; newer wells measured with a consistent suite of tools were used to maintain consistency and allow well comparisons. Bad hole conditions and cased hole logs were ignored for the model. Eighty-Five wells were used to identify the geologic block model of the formations (Figure 2). Fourteen of the wells had sufficient data and were used for petrophysical modeling (Figure 3).

Interactive Petrophysics

Interactive Petrophysics (IP) is well log analysis software that allows petrophysical models and physical properties to be calculated from well data. Using gamma ray, neutron, density, resistivity, and photoelectric (PE) curves (Figure 4), IP is able to calculate porosity (effective and total), water saturation, resistivity of water, and lithology. These calculations are vital to the creation of a three-dimensional property model that can then be scaled up and used for reservoir fluid modeling. The logs were initially split into zones with consistent curve signals. These breaks corresponded to formation tops in most cases. The Bakken Formation was split into three zones, upper, middle, and lower, because of the larger difference between the middle sand and the upper and lower organic-rich shale. The Three Forks, Birdbear, and Duperow Formations were identified by consistent gamma, neutron, and density signals for the entire thickness of each formation that appears in all interpreted logs. After the identification of the zones, clay volumes were calculated by statistical methods (Figure 5). Histograms for the gamma, neutron, and resistivity curves were used to identify the clean and clayey values for each curve (Figure 6). The neutron/density cross-plot helped to identify clay volume based on the overall lithology estimated from values from the PE curve (Figure 7). The porosity and water saturation models (Figure 8) are calculated from the PE histograms (Figure 9), neutron/density (Figure 10), density/sonic, and neutron/sonic cross plots. Saturation of water is formulated from resistivity/porosity cross plots and the Archie Equation. Together all the curves result in effective porosity, total porosity, bound water saturation, and free water saturation, which are useful in the reservoir model that is required to model CO_2 movement in the reservoir. In order to calculate the permeability of the formations, a correlation between the porosity and permeability for offset well core analysis data is used. Core data were used from seven offset wells to correlate the matrix porosity and matrix permeability. Fractures were ignored for this initial correlation. The core data found were all collected from the lower portion of the Duperow Formation, and it was assumed that the carbonates above the Duperow were of similar characteristics. This assumption was also used for the clastic Bakken Formation since there is a large carbonate component in the middle sandy layer. The upper and lower shale layers were assumed to have no matrix porosity or matrix permeability. Limestone and dolostone lithologies were found to have separate trends, and two correlation curves were calculated:

$$\log(K_{Lime}) = 24.3988\phi - 2.01413 \quad \text{[Eq. 1]}$$

$$\log(K_{Dolo}) = 14.0169\phi - 1.62785 \quad \text{[Eq. 2]}$$

where K is permeability and ϕ is porosity (Figure 11). Correlations are of nonfractured samples above 0.02 md permeability to remove fracture and secondary porosity and lab measuring limits.

Petrel

Petrel is a finite difference modeling program that was used to make a three-dimensional geologic block model of the formations from eighty-five wells with formation top data (Figure 12). Formation top elevations were assumed correct from NDIC unless well log verification was possible to make adjustments. The well data were then input into the model to check formation tops and also assign marker horizons in the zones between the formation tops. A total of 15 horizons were identified in the field between the top of the Bakken Formation and the base of the Duperow Formation (Figure 13). Each zone between the horizons was then split into layers with an average thickness of 1.3 m, totaling 188 layers. This model was then populated with the well properties calculated with IP. The horizontal grid size for the model was 100 m by 100 m for all zones and horizons. The model has over 3.5 million cells and covers an area of 190 km^2 with a thickness of about 250 m. Properties were populated across the model using the Sequential Gaussian Simulation. A range of 3000 m in the horizontal and 2 m in the vertical was used for the spherical variogram to populate the lithology fraction, effective porosity, and water saturation (Figure 14–16). The populated lithology fraction was normalized for each cell to ensure that each cell totals one. The permeability was then populated from correlation curves based on the ratio between limestone and dolostone (i.e., cells with limestone fraction greater than dolostone use Equation 1 to calculate permeability).

Figure 4: Original well log data for NDIC well15365 with gamma ray, caliper, resistivity (DeepRes, MedRes), density, neutron, and photoelectric (PEF) curves.

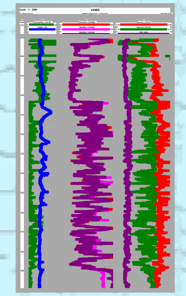


Figure 5: Volume of clay curve (Vcl) calculated from well log data analyzed in histogram or cross-plot form. Zones are picked based on similar log expression and closely correspond to formation boundaries.

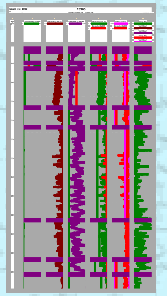


Figure 6: Gamma ray histogram for Zone 12 (Duperow Formation). Clean and clayey lines picked based on the distribution of the histogram. The adjustment of the red and green lines converts the gamma ray curve to percent volume of clay. Neutron and resistivity curves are converted in the same manner and observed for agreement.

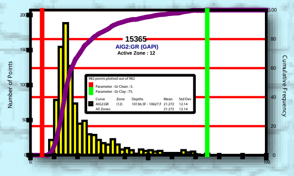


Figure 7: Neutron density cross-plot compared to the lines for sandstone, limestone, and dolostone porosity. Note anhydrite and clay plots near and below the dolostone line.

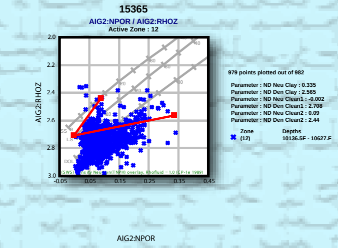


Figure 8: Porosity and water saturation model curves calculated by histogram and cross-plots. A four-mineral solver is used to calculate the lithology curves from the interpreted well log data.

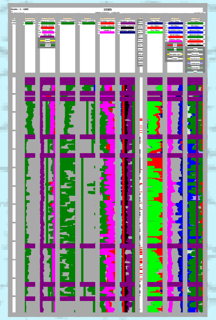


Figure 9: Photoelectric histogram for Zone 12 (Duperow Formation). The mean value of 4.4 is between calcite (3) and dolomite (5) and is interpreted as mostly carbonate for the zone.

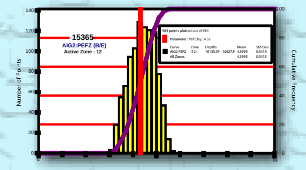


Figure 10: Neutron density cross-plot used to distinguish wet and dry clay boundaries.

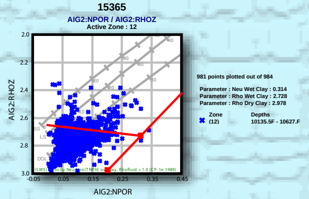


Figure 11: Porosity and permeability correlations for limestone (gray) and dolostone (pink) based on core analysis in well files. Fractured samples and samples measured near lab equipment accuracy have been filtered out of the data set.

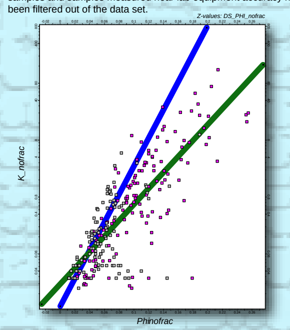


Figure 12: Three-dimensional block model of the Beaver Lodge oil Field from the top of the Bakken to the base of the Duperow. 10 times vertical exaggeration.

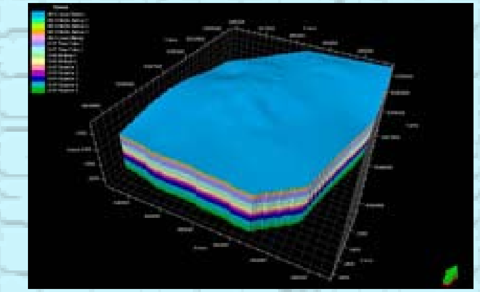


Figure 13: Well log correlation between wells 15062, 15249, and 15365 to identify similar zones for the three-dimensional model. Zones were selected as formation boundaries and markers identifiable by the gamma ray and photoelectric curves.

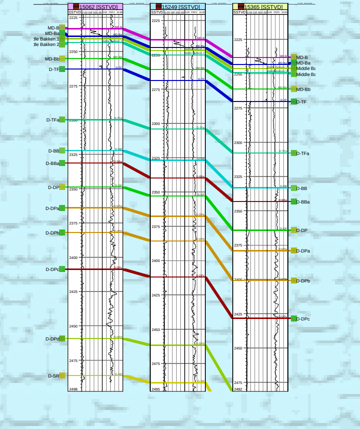


Figure 14: Porosity distributed to cells of the model by sequential Gaussian simulation using a spherical variogram with a 3000-m horizontal range and a 2-m vertical range.

Figure 15: West to east cross section of the distributed porosity model. 10 times vertical exaggeration.

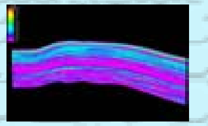


Figure 16: North to south cross section of the distributed porosity model. 10 times vertical exaggeration.

Figure 17: Modeled bottom hole pressure, production volume, and injection volume for well 2487. Note unrealistic pressures after the start of injection in 1997

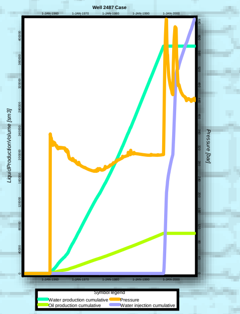
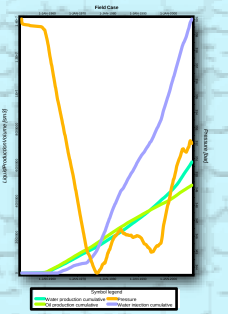


Figure 18: Modeled bottom hole pressure, production volume, and injection volume for all wells in Duperow Formation. Model pressures much greater than observed



RESERVOIR SIMULATION

The Duperow and Birdbear Formations were upscaled to allow for reservoir simulation. The upscaled model consisted of about 260,000 cells, and lithologic properties were averaged from the geologic property model. The monthly production and injection data from July 7, 1951, to September 1, 2007, for all wells perforated in the Duperow Formation were used to calculate daily production and injection rates. The model was then run to provide a history match to observe bottom hole pressures in the reservoir. The individual wells in the model did not behave similarly to observed data; pressures during the injection phase were much greater than the original 370-bar reservoir limit. This is most likely due to the a lack of fracture and secondary porosity and permeability in the model. In well 2487, the bottom hole pressure after injection reaches more than 600 bar, much larger than safe injection pressure (Figure 17). If this injection pressure was allowed in the actual reservoir, unintentional fracture ofthe reservoir or cap rock could occur. Overall field pressure was maintained at a higher pressure than the observed, but lower than original reservoir pressure (Figure 18). With the lack of history matching between the reservoir and the model, injection modeling of CO_2 is invalid for this reservoir model. Further petrophysical modeling of fracture or secondary porosity and permeability is necessary prior to attempting CO_2 EOR or CO_2 sequestration modeling.

CONCLUSION

Using IP, consistent petrophysical models were created for 14 wells utilizing well log data. The petrophysical models calculated the total and effective porosity and the water saturation for the Bakken, Three Forks, Birdbear, and Duperow Formations. The petrophysical values were then inputed in a 3.5-million-cell geologic block model of the oil field and distributed through Sequential Gaussian Simulation to populate the cells not intersecting well data. Matrix permeability was distributed to the cells by lithologic and porosity correlation. Fracture and secondary porosity and permeability is not currently known and not accounted for in this model. The reservoir simulation was unable to produce an accurate history match, most likely due to the lack of fracture and secondary porosity and permeability in model. The low permeability values of the model make correlation difficult and available data does not provide information on the fracture patterns or apertures. Further data collection is required to increase the accuracy of the model. This field is no longer the focus of possible CO_2 injection testing. There is no future work planned at this time, and the reservoir model will not be improved past current completion. However, the methodology behind the Beaver Lodge model will be applied to the future injection field.

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