Using Multiple-Point Statistics for Conditioning a Zama Pinnacle Reef Facies Model to Production History

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Abstract

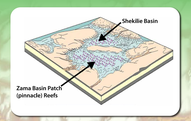
Since October 2005, the Zama oil field in northwestern Alberta, Canada, has been the site of acid gas (approximately 70% carbon dioxide (CO_2) and 30% hydrogen sulfide (H_2S)) injection for the simultaneous purpose of enhanced oil recovery (EOR), H_2S disposal, and CO_2 storage. Injection began in December 2006 and continues through the present at a depth of 4900 feet into the Zama F Pool, which is one of over 800 pinnacle reef structures identified in the Zama Subbasin. To date, over 90,000 tons of acid gas has been injected, with an incremental production of over 50,000 barrels of oil. The primary purpose of this work is to verify and validate stored volumes of CO_2, with the ultimate goal of monetizing carbon credits.

Pinnacle reefs have very complex geologic and facies relationships, and as a result, a thorough understanding of the geology is necessary in order to properly monitor and predict fluid movement in the reservoir. Core-calibrated multimineral petrophysical analysis was performed on well logs, and borehole image logs were used to more accurately identify the different facies and determine each facies' properties along the wellbores. Seismic attribute data interpretations were used to identify the reef versus nonreef facies to aid in the distribution of the facies in the reservoir. These properties were then spatially distributed throughout the reservoir using a combination of multiple-point statistics and object modeling to produce equiprobable reef facies, structure, and volumetric realizations. These equiprobable static realizations were ranked to further use them in dynamic modeling.

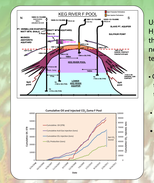
A few selected static and dynamic realizations were further conditioned to obtain a reasonable match between simulated results and historical data. A more realistic depiction of geological and reservoir features using the modeling approaches adopted in this study is expected to provide more reliable dynamic models for simulating long-term behavior and migration of the injected gas. Predictive simulation runs are in progress to predict original oil in place (OOIP), ultimate incremental oil recovery, and ultimate CO_2 storage capacity. Long-term (>100 years) prediction simulations coupled with monitoring data will help in developing a cost-effective monitoring plan for ensuring safe and effective storage of injected acid gas in the depleted F Pool oil reservoir.

Regional Geologic Setting

- Over 800 Devonian-age pinnacle reef structures.
- F Pool is one of the several hydrocarbon-bearing structures.
- Reef structures typically consist of dolomite surrounded and overlain by anhydrite (cap rock) of the Muskeg Formation.
- A large variation in both porosity and permeability is observed in these dolomitized heterogeneous pinnacles, with a decrease to the tops of the reef.
- The principal microfacies include wackestone, packstone, grainstone, floatstone, and rudstone.
- With varying degrees of alteration due to secondary leaching and dolomitization, porosity type varies from intercrystalline to microfracture (Burke, 2009).



Simultaneous CO_2 EOR and Storage



- Uses acid gas (70% CO_2 and 30% H_2S), a by-product derived from the extraction process at a nearby gas-processing plant, for tertiary recovery.
- Cumulative acid gas injected through January 2011: ~90,000 tons
- Net CO_2 stored: ~32,000 tons
- Cumulative oil produced: ~52,000 bbl

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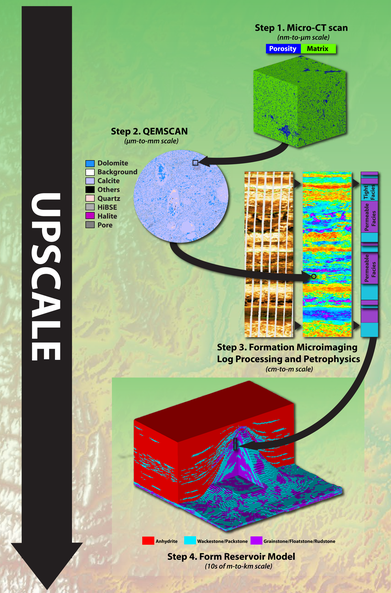
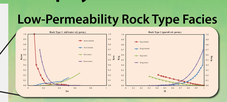
General Modeling Workflow

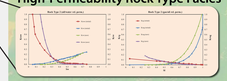


Fluid Inversion Petrophysics

Low-Permeability Rock Type Facies

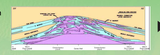


High-Permeability Rock Type Facies



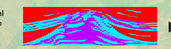
Multiple-Point Statistics and Training Image Production in Schlumberger Petrel®

Seasoned geologists' interpretation of what the internal microfacies heterogeneity might look like.



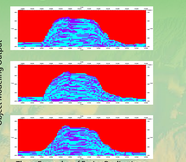
Rasterization.

Fitting rasterized image to actual reef structure and imported into Petrel.



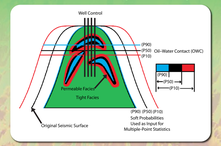
Training Image Workflow

Multiple-Point Statistics and Object Modeling Output

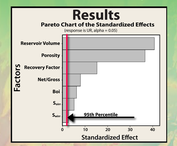


Three Examples of Facies Realizations

Uncertainty Analysis for Ultimate Recovery



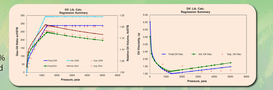
Results



PVT Modeling in Winprop®

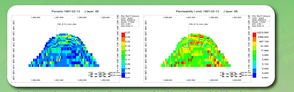
PVT (pressure, volume, and temperature) Modeling

- 11-component Peng–Robinson (P–R) equation of state (EOS) PVT model for compositional simulations.
- A good agreement between simulated and experimental minimum miscibility pressures (MMPs) simulated MMPs were 4.1% higher and 5.5% lower than the measured values for pure CO_2 and acid gas (80% CO_2 + 20% H_2S) mixture) with initial recombined live oil.

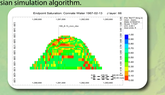


Initial Conditions (dynamic simulation model in CMG-GEM®)

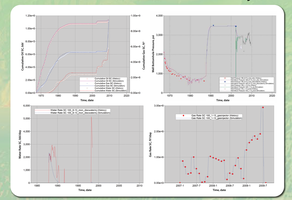
- OOIP = 3.9 million stock tank barrels (MMSTB (material balance-based calculation)).
- Initial reservoir pressure = 2095 psi.
- Reservoir temperature = 160°F.
- Saturation pressure = 1275 psi.
- Initial gas/oil ratio = 284 scf/stb.
- API gravity = 35.2°.
- 1.1 MMSTB (28% of OOIP) of oil was produced during a 20-year period (1967–1987) of primary depletion aided by bottom aquifer influx through a single well.
- Pressure and production behavior indicates the presence of weak bottom aquifer support.



Porosity and permeability realizations populated into the model using the sequential Gaussian simulation algorithm.

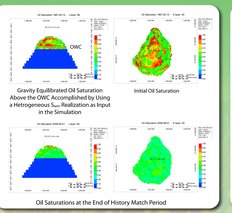


History Matching



The P10 OOIP (4.45 MMSTB) realization was selected for performing history matching. Both sets of relative permeability (oil–water and gas–oil) curves for tight reservoir (Rock Type 1) and good reservoir rocks (Rock Type 2) were modified to achieve a satisfactory history match. In addition to the modeled reef structure below the OWC, a small numerical aquifer with no leakage option was also added at the bottom of the structure for improving simulated pressure response.

Results



Summary

- Multiple-point statistics algorithm and object modeling workflow were successfully used for characterizing and modeling complex oil-producing carbonate pinnacle reef structure.
- A good agreement between the historical data (production, gas injection, and pressure) and simulated results was obtained with minimal reconditioning of both static and dynamic models.

Next Steps

- Further history matching with other static realizations and predictive dynamic simulations are in progress to evaluate the potential for maximizing incremental oil recovery through optimum well locations and injection–production strategies to study the long-term behavior of acid gas plumes and to predict ultimate CO_2 storage capacity.
- The workflow adopted in the project will be used to evaluate more pinnacle reefs in the Zama Subbasin.

Bibliography

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