[PS]Characterization of a Low Gas Pressure Reservoir: Beluga Formation, South Ninilchik Gas Field, Cook Inlet, Alaska*

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Abstract

The Beluga Formation is considered an under-developed prospect located in the South Ninilchik gas field within the Cook Inlet basin. The target sands in this stacked fluvial braided stream deposit are laterally discontinuous, mixed with volcanic materials and interbedded with thin coal streaks. This high degree of stratigraphic variability, coupled with low gas pressure affecting porosity and permeability quantification, and complex mineralogy creates a challenging task for geological and petrophysical interpretation of this unconventional gas play.

Logging-while-drilling (LWD) evaluation included azimuthal density images, nuclear magnetic resonance (NMR), neutron, density and acoustic logs. The azimuthal density image log provided detailed visualization of the structure of this fluvial system and was used to identify the different depositional facies within the Beluga Formation. Porosity, permeability and gas saturation were computed based on the NMR and density porosity. NMR data was also used to delineate grain size distribution.

Five depositional facies have been identified and at least three different grain size distributions have been modeled for the Beluga Formation. Due to low-pressure gas affecting the hydrogen index, pay and high-permeability zones were identified using the crossover of density and NMR porosity, similar to density and neutron cross-over, but is more reliable because NMR porosity is independent of mineralogy. The permeability and saturation values computed from the NMR data enhanced the prediction capability for the production intervals. The relationship between the LWD logs and the identified depositional facies, grain size distribution and pay zones show a direct correlation to the producing intervals verified by the percentage of gas flow per zone observed on the production log.

This integrated approach in characterizing the Beluga formation utilizing LWD logs, depositional facies and grain size modeling proven with production data, provided a better characterization of this unconventional reservoir. The implications of this study on the future optimal reservoir drainage strategy are significant, as the results provide a framework for understanding future well evaluation within the reservoir.

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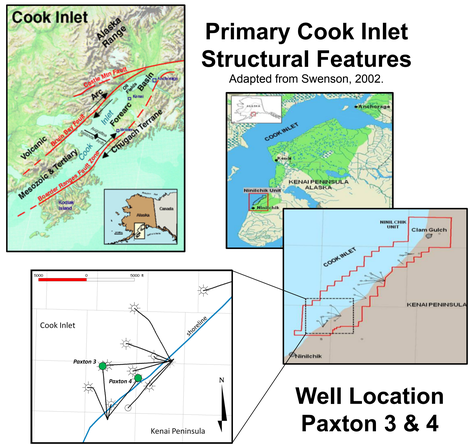
Geologic Setting

Cook Inlet fore-arc basin, south central Alaska

- Underexplored basin, fluvial reservoirs
- Historical basin-wide production
  - 1.3 billion bbls oil, 7.75 Tcf gas

Ninilchik Gas Field

- Discovered in 2000, NE-SW trending anticlinal structure
- Cumulative production of > 100 Bcf biogenic gas
- Miocene-age Beluga reservoirs



Primary Cook Inlet Structural Features

Adapted from Swenson, 2002.

Well Location Paxton 3 & 4

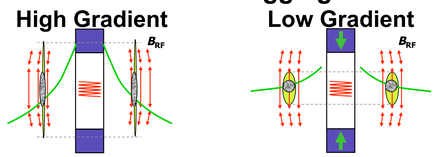
Petrophysical Challenges

- Significant clay content and volcanic material affect GR signature
- Lithology differentiation: gas-bearing Beluga sands inter-bedded with silt, clay and coal; typically commingled
- Presence of heavy minerals
- Pay identification
- Permeability estimate

Formation Evaluation Program for Paxton 3 & 4

- LWD low-gradient magnetic resonance
- LWD Quad Combo (GR, neutron, density, acoustic log)
- Post-completion production logs

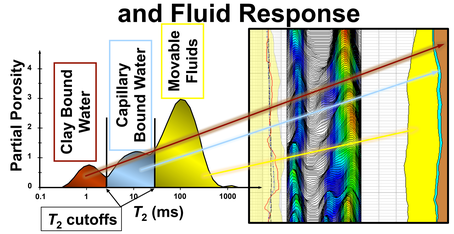
LWD NMR Logging



Diffusion Effect Vibration Intolerant

No Diffusion Effect Vibration Tolerant

Magnetic Resonance T_2 Distribution and Fluid Response



NMR/Density Solution

Fluids parameter were taken at reservoir conditions

- Pressure gradient ~0.44 psi/ft
- Temperature ~87 ° - 98° F

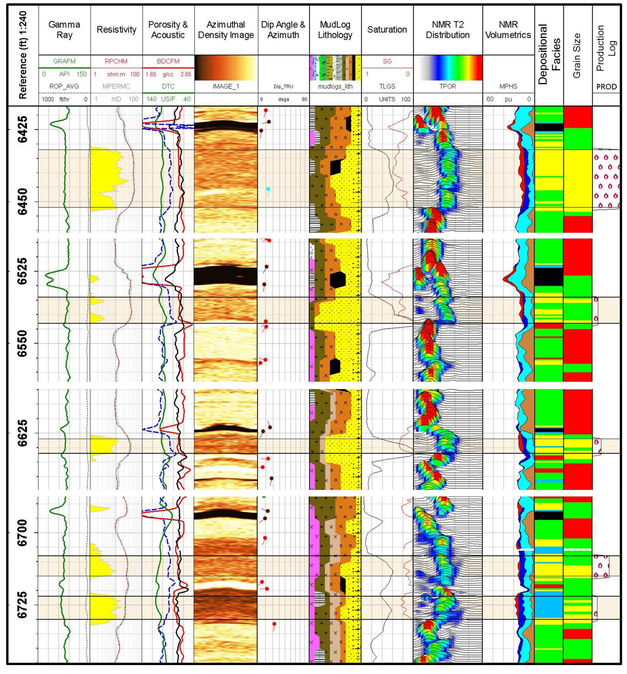
$$\rho_l = 1\,g/c^3 \qquad \rho_g = 0.07\,g/c^3 \qquad (HI)_l = 1 \qquad (HI)_g = 0.2$$

$$\phi = \frac{(\rho_{ma}-\rho_b)((HI)_l-(HI)_g)+(\rho_l-\rho_g)\phi_{NMR}}{(\rho_{ma}-\rho_l)((HI)_l-(HI)_g)+(\rho_l-\rho_g)(HI)_l} \qquad S_g = \frac{(HI)_l-\left(\frac{\phi_{NMR}}{\phi}\right)}{(HI)_l-(HI)_g}$$

- Coates-Timur permeability model is used to compute a log of absolute permeability from NMR log with C=10, m=4, n=2.
- Azimuthal density image was used to identify 5 depositional facies: sandstone, shaly sandstone, sandy shale, shale, and coal.
- NMR T2 distribution array was used to identify 3 different grain sizes: sand, silt, and clay.

RESULTS & CONCLUSION

Paxton 3



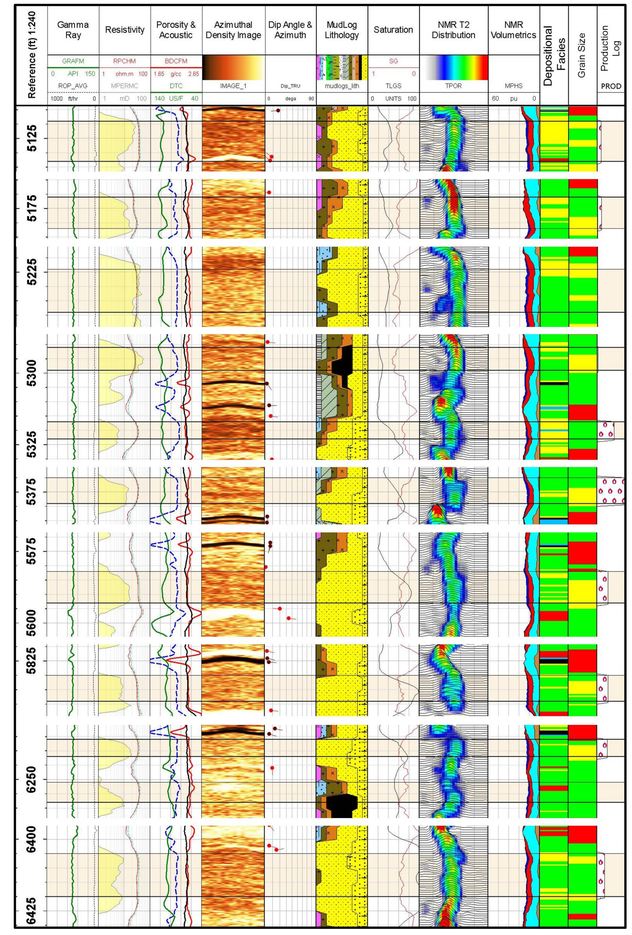
MudLog Lithologies

Sand, Sandstone, Coal, Tuffaceous Siltstone, Tuffaceous Sandstone, Tuffaceous Claystone, Siltstone, Tuff, Shale, Clay, Claystone, Conglomeratic Sand, Conglomerate, Calcareous Tuff, Carbonaceous Material, Shell Fragments, Carbonaceous Shale, Cmtd Contam

Depositional Facies
Black = Coal
Red = Shale
Blue = Sandy Shale
Green = Shaly Sandstone
Yellow = Sandstone

Grain Size
Red = Clay
Green = Silt
Yellow = Sand

Paxton 4



- Combined density and low-gradient NMR log data help determine porosity and reduce permeability uncertainty in this low-pressure gas reservoir
- Five depositional facies and three grain size distributions have been modeled and show a good correlation with the identified pay zones from density-NMR method
- Paxton 3 produces gas from 5 stacked pay zones and Paxton 4 produces gas from 11 stacked pay zones
- NMR gas saturation correlates with pay zones and the gas flow percentage from the production log
- Integrated petrophysical interpretation is necessary for understanding this unconventional gas play

Reference:

Swenson, R., 2002, Introduction to Tertiary tectonics and sedimentation in the Cook Inlet basin, *in* Dallegge, T.,compiler, Geology and hydrocarbon systems of the Cook Inlet basin, Alaska: AAPG Pacific Regional Conference, May 23–24, 2002, Anchorage, Alaska, p. 11–20.