Challenges When Predicting Reservoir Quality in the Subsalt K2/K2-North Field, Green Canyon, Gulf of Mexico

Todd J. Greene¹, Brian E. O’Neill², Richard E. Drumheller², Todd Butaud², and Arnold Rodriguez²

¹Department of Geological and Environmental Sciences, California State University – Chico, 400 W. 1st St., Chico, California 95929
²Anadarko Petroleum Corporation, 1201 Lake Robbins Dr., The Woodlands, Texas 77308

ABSTRACT

Accurately modeling reservoir quality in Miocene deepwater reservoirs in the K2/K2-North Field, Green Canyon, Gulf of Mexico, presents many challenges for planning primary and secondary oil recovery. An overlying thick salt canopy prevents adequate seismic imaging at reservoir levels, structural complexities make correlating sand packages difficult, and well spacing is sufficiently large that correlating intra-reservoir surfaces is problematic. Borrowing from successful methodologies developed for seismically better-imaged deepwater reservoirs in the eastern Gulf of Mexico, we utilize well-log, core, and pressure data to calibrate petrophysical properties to individual depositional facies towards the ultimate purpose of predicting reservoir quality in areas which lack core and/or well control.

First, based on detailed sedimentologic descriptions for the cored intervals, grain-size analyses, whole core x-ray scans, well-log patterns, and correlations, we identified four main reservoir facies within two principal Miocene intervals: channel-bypass, thick-bedded amalgamated sheets (axial and marginal), and thin-bedded layered sheets. Second, to distribute facies within time-correlative packages, we used depositional models based on Gulf of Mexico shallow-seismic analogs of distributary channel complexes. While the lower Miocene interval characteristics are more akin to confined, proximal portions of a frontal splay, the middle Miocene interval contains characteristics of the more unconfined medial portions.

Third, using whole core data, we examined a wide range of petrophysical attributes to recognize unique combinations of petrophysical properties for each key reservoir facies. This provided valuable insight for choosing log-based curves used for identifying facies within uncored wells.

To date, pressure transient analysis of production data from the two main intervals are consistent with our facies interpretations. The more sheet-like interval shows few barriers while the more channelized interval suggests a higher degree of complexity.

The resulting improved facies classification scheme has provided a more useful basis for routine reservoir modeling and field management.
INTRODUCTION

The K2/K2-North Field (Green Canyon [GC] 518/562) is located approximately 175 mi (280 km) offshore, south of New Orleans, Louisiana, in greater than 4000 ft (1200 m) of water depth (Fig. 1). Current oil and gas production flows through the Marco Polo TLP (tension leg platform) in Green Canyon Block 608 utilizing an 8.5-mi (13.5-km) flow-line and subsea tieback production system. A thick salt canopy (10,000-15,000 ft thick; 3-3.5 km thick) separates the Marco Polo minibasin from the subsalt K2/K2-North Field (Fig. 2). Located within a quasi-polygonal network of salt stocks, feeders, welds, and canopies, the K2/K2-North Field has a complex geologic history and petroleum system that is best described by Mount et al. (2006). Other on-trend oil fields that share a similar complex history include Genghis Khan (GC 652) and Timon (Mount et al., 2006) (Fig. 1). To date, the K2/K2-North Field contains 19 wells (including sidetrack and bypass boreholes) drilled into Miocene subsalt reservoirs. After two years of primary production, secondary oil recovery was deemed the best strategy to maximize returns in the most cost efficient manner.

Effective reservoir management is critical during secondary oil recovery. Therefore, when creating an integrated geologically-based reservoir model, it is important to capture any reservoir heterogeneity suggested by the data. For example, in the lower Miocene interval, geochemical data, pressure transient analysis, and log signature all suggest some degree of reservoir heterogeneity. In addition, vertical compartmentalization can also be expected; pressure transient analysis shows two distinct zones in the lower Miocene reservoir.

Although 3-D seismic data blanket the area and provide excellent structural information for the K2/K2-North Field, seismic attributes cannot provide any reservoir-scale detail due to negative effects caused by the thick overlying salt canopy. Therefore, to populate a reservoir model with representative flow properties (e.g., porosity and permeability), information on reservoir architecture, distribution, and quality were derived from a nearly complete suite of well logs, numerous sidewall cores, and two whole cores through most of the reservoir intervals. This presents considerable challenges when reservoir quality sands cover very large areas and the well control is concentrated only locally near the updip limits of the field.

Input into reservoir models comes from a variety of sources including structure and fault maps, geometry of stratigraphic surfaces, and facies distribution. In this paper, we describe how facies were identified in both the cored and non-cored intervals, and how those facies guided our depositional model for the lower Miocene and upper Miocene intervals.

METHODOLOGY

Core-Based Depositional Facies Identification

Obtaining whole core through the reservoir interval provides the best chance to capture the largest range of facies in the reservoir. Because our goal is to populate a reservoir model with facies that can be defined and mapped spatially, our facies types are depositional facies rather than simple lithofacies. Therefore, our facies identification begins with detailed sedimentologic core description while simultaneously building a process-based depositional model.

Our descriptions of lithology, sedimentary trends, structures, visual grain size, and bed thickness patterns are integrated with log data over the cored interval as well as any available core data. This includes laser particle grain-size analyses (LPSA), x-ray (CT) scan images of whole core and plugs, core gamma-ray log, scanning electron microscope (SEM) images, and thin-section photomicrographs from core plugs sampled at every one-ft interval. In general, each facies type should contain unique porosity/permeability ranges with minor overlap from other facies types. While not always possible, facies intervals should also be thick enough and petrophysically distinct enough to be recognizable in wireline logs and of sufficient scale to establish mappable units within the field.
Figure 1. Location map of the K2/K2-North – Marco Polo – Genghis Khan fields in the Green Canyon protraction area, Gulf of Mexico (modified after Mount et al., 2006). Entire map area is overlain by allochthonous salt canopy being fed in part from the K2 and Genghis Khan salt stocks (pink areas). Marco Polo Field is located in a suprasalt minibasin. As reported by Mount et al. (2006), the dark green area represents the proven limit of highest-known oil (HKO) to lowest-known oil (LKO). The intermediate green area represents reserve potential updip of HKO. The light green area represents potential upside downdip of LKO. Dashed lines indicate flow lines from the subsalt K2/K2-North and Genghis Khan fields to the Marco Polo TLP.
Log Analysis

Formation Evaluation

Wells drilled in the K2/K2-North Field provide a comprehensive suite of wireline and logging while drilling (LWD) curves that generally include gamma ray, resistivity, neutron, density, sonic, and less commonly nuclear magnetic resonance and oil-based imaging logs. Editing and log processing techniques were consistently applied to all well-log data. Formation pressures were acquired via wireline and LWD tools, to help establish fluid pressure gradients; wireline fluid samples were acquired during pressure testing to attain fluid properties.

Key reservoir parameters computed from the logs include clay volume, porosity, water saturation (Sw), and permeability. Fluid data and extensive core data acquired in the field help constrain key log-analysis input parameters (i.e., grain density, Archie parameters, fluid density, and clay properties). Depth-adjusted core data also allows a more direct comparison to log-based computations of porosity, water saturation, clay volume, and permeability. The comprehensive core data set allows us to examine a wide range of evaluation methods for the field and determine which methods provide the most consistent and representative results. It is critical (especially for the purpose of reservoir modeling) to maintain a consistent formation evaluation methodology for each well in the field.
Rock Typing

The goal of rock typing in this study is to classify and evaluate reservoir-quality data derived from core, toward the ultimate purpose of predicting reservoir properties in portions of the reservoir lacking core and/or well control. Rock type classification helps develop reservoir models populated with reasonable ranges of reservoir properties. Several different approaches to rock typing and facies characterization were employed for the K2/K2-North study which can be classified (similar to Rushing et al., 2008) in three different levels: (1) hydraulic rock types aimed at characterizing fluid flow characteristics, pore geometry, and reservoir performance (flow and storage capacity) by using porosity-permeability relationships, as in the reservoir quality index of Amaefule et al. (1993), and more detailed pore geometry characteristics according to Pittman (1992); (2) depositional rock types that define the large-scale mappable sedimentologic facies that make up the overall depositional model for the reservoir; and (3) petrophysical rock typing, which was used in this study to include a wide range of detailed petrophysical data (petrologic analysis, core properties, fluid properties) as a means of understanding the relationship between hydraulic rock types and larger scale depositional rock types.

Electrofacies Analysis

Electrofacies were described by Serra and Abbott (1980) as the set of log responses that characterizes a bed and permit it to be distinguished from the others. We attempt to characterize depositional rock types via multivariate analysis of several key log curves, with the intention of identifying depositional facies in wells lacking conventional core. Our methodology is not purely an electrofacies approach; in addition to typical log curves, we utilize a bed-description curve (described in greater detail below) as one of the key input parameters in the multivariate analysis.

Permeability Algorithms

Another phase of rock typing involved comparing facies-specific petrophysical parameters to reservoir quality indices toward the goal of developing facies-based permeability transforms to predict permeability in uncored wells. The use of data-mining software allowed us to quickly compare a wide range of petrophysical attributes to core permeability for each depositional facies. This provided insight for developing algorithms for computing permeability using a combination of log curves.

FACIES

First, the sedimentologic reasoning for creating a unique facies type is described. Second, the log-based analysis that calibrates wireline log signatures to core and assigns facies to non-cored intervals is introduced.

Depositional Facies Identified in Core

We identified four main depositional facies and one grouped non-reservoir facies. Whole cores taken from two of the K2/K2-North Field wells provide material from both the lower and middle Miocene reservoirs (Fig. 1).

Channel Bypass Facies

The Channel Bypass Facies (Fig. 3A) appears least frequently, although it is best quality facies observed in all of the cored material. It contains variable-bedded, medium-fine-grained, well-sorted sands with common cross-beds and plane-bedded zones. Mud rip-up clasts (0.5-1 in [1-2 cm]) are common and they are often aligned
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(FACING PAGE) Figure 3. Representative facies from the cored wells. For each core description section, the depth track tick marks are one-ft apart. Each core photo shows two ft of section from the boxed area in the core description. The core photos show a standard light photo on the left side and an ultraviolet light photo on the right side. Grain size abbreviations: m = medium-grained; f = fine-grained; vf = very fine-grained; silt = silt; and md = mud. (A) Channel Bypass Facies; (B) Amalgamated Sheets – Axial Facies; (C) Amalgamated Sheets – Marginal Facies; and (D) Layered Sheets Facies.

along cross-bedded surfaces (Fig. 3A). Indications of flow bypass include scoured surfaces and top boundary surfaces defined by well-sorted medium-grained sands sharply overlain by silty mudstone. Sandy injections, soft-sediment deformation, and water-escape features are also present.

We interpret these deposits to represent confined, high-energy flows that have largely bypassed this area leaving behind the coarsest, best sorted material. Flows were either building or sustaining energy and did not deposit the bulk of their load at the cored site.

Amalgamated Sheets – Axial Facies

The Amalgamated Sheet – Axial Facies (Fig. 3B) is the most common facies in the blocky sand-rich reservoir intervals. It contains thick-bedded fine-grained sands but grain size can reach to medium grained. High-density turbidites with massive, structureless beds (S3 division of Lowe, 1982) persist throughout the facies with common internal sand-on-sand amalgamation surfaces, occasional dish structures, and frequent faint plane-bedded intervals. Grain size and sorting remains uniform throughout but abrupt upward-fining does occur at bed tops. Scour surfaces are less frequent than the Channel Bypass Facies and rare mud rip-up clasts and carbonaceous debris are randomly dispersed.

We interpret these deposits to have originated from the axis of high-energy flows that decelerated rapidly leading to concentrated suspension-related fallout of the coarsest material (Lowe, 1982; Postma, 1986). The sheet-like geometry is a product of a lower degree of flow confinement than the Channel Bypass Facies. The Amalgamated Sheet – Axial Facies most likely grades laterally into the Amalgamated Sheets – Marginal Facies.

Amalgamated Sheets – Marginal Facies

This facies is characterized by thin-bedded, fine-to-very-fine-grained sands that gradually fine upwards (Fig. 3C). Moderately-sorted, low-density turbidites predominate with common massive (Ta), plane-bedded (Tb), rippled (Tc), and silty suspension deposits (Td). The Ta beds often display dish structures and amalgamation surfaces. There are rare scour surfaces and very rare mud rip-up clasts.

We interpret this facies to represent the off-axis equivalent to the high-density Amalgamated Sheet – Axial Facies. There are many characteristics suggesting waning-flow conditions with little flow bypass. Alternatively, this facies could also be considered as proximal levees to the Channel Bypass Facies. If this is the case, there would be little connectivity to the Amalgamated Sheet – Axial Facies, though it could laterally grade into the Layered Sheets Facies discussed below.

Layered Sheets Facies

The Layered Sheets Facies (Fig. 3D) contains the lowest net-to-gross values. They are typical low-density turbidites with upward-fining moderately-to-poorly sorted fine-to-very-fine-grained sands containing rippled beds (Tc), silty suspension deposits (Td), and probable hemipelagic background deposits (Te). Any indications of erosion, bypass, or scouring are rare to non-existent.

We interpret the Layered Sheet Facies to represent inter-channel (distal levees) or distal lobe/sheet deposits. These deposits were off-axis to higher energy flows or they represent a period of low sediment supply to the area.
Non-Reservoir Facies

The remaining portions of the core are grouped in the Non-Reservoir Facies. Common features include contorted, folded, sheared, and faulted silty mudstone that we interpret to be part of a mass transport complex (MTC). Other features include hemipelagic shale, calcium-carbonate cemented intervals, and dispersed carbo-
naceos debris.

Log-Based Facies

Rock Typing

Similar to the observations of Rushing et al. (2008), our experience with sandstone/shale sequences is that specific depositional facies can include a range of hydraulic rock types. For this reason we use depositional facies as our primary rock typing method, with the hydraulic rock types playing a subordinate role in the model building. Once rock types are established, core data are organized and collated in conjunction with well log curves and log curve products. We used data-mining software (designed to handle multivariate data sets) to fa-
cilitate the detailed petrophysical rock typing, organize the vast array of petrophysical data, and to identify quickly key data trends. This particular step not only provides insight on the relationship of depositional facies to hydraulic rock types, but also provides a means of screening potential input candidates for use in electrofacies analysis.

Fuzzy Logic

After considering several multivariate statistical techniques, we chose to use the fuzzy logic method (as de-
scribed by Cuddy, 2000). In contrast to more traditional statistical techniques, fuzzy logic pattern recognition does not rely on bivalent logic where membership to a given set is either true or false. Instead, fuzzy logic sets lack crisp boundaries and thus can deal with partial membership and variable degrees of membership for a given set (Fig. 4). This is ideally suited to the deepwater depositional facies encountered in the K2/K2-North Field reservoirs, since many of the facies share similar attributes. We have found that a combination of key log input curves can accurately identify depositional facies originally described through detailed core descriptions.

While the fuzzy logic technique proves to be very satisfactory in identifying depositional facies in both cores and uncored wells, we only consider it as an initial means of facies identification to establishing a general depositional framework. At this point, we interrogate and revise these facies picks using a wider range of data that will typically include mud log grain size, percussion sidewall data, thin sections, interwell correlations, and image logs. This final stage involves close collaboration of the project sedimentologist, geologic modeler, and petro-
physicist. This last step establishes depositional facies intervals for each well, and serves as the framework for the 3D depositional model.

Permeability Algorithms

We were able to develop a generalized empirical algorithm for computing permeability (independent of fa-
cies type), as well as facies-specific permeability transforms. Both methods, when judged based on comparison to depth-adjusted core data, generate very good results (Fig. 5). The generalized method is particularly useful because we can estimate permeability for a given interval almost immediately after logging.

Depositional Model

By choosing to not use a purely stochastic model, we elected to use our depositional model to guide how we distribute reservoir quality parameters in the reservoir model. Based on core and log information, regional paleo-
Due to the higher degree of flow confinement and lateral heterogeneity in the lower Miocene interval, we interpret a more proximal position within a frontal splay where we expect more flow-bypass, confined channels, and rapid lateral lithologic changes. By contrast, due to the lateral continuity and the more unconfined flow character of the middle Miocene interval, we interpret a medial position within a frontal splay where we expect less lateral changes, a higher net-to-gross, and greater lithologic homogeneity. To date, limited production data have confirmed a higher degree of complexity in the lower Miocene reservoir, as well as a more connected, laterally continuous reservoir in the upper Miocene interval.
SUMMARY

The K2/K2-North Field provides an excellent case study on the challenges of creating a reservoir model in the subsalt environment. Reservoir-scale seismic resolution is not high enough to help with depositional geometry, wells are concentrated in a relatively small area along the updip boundary of the field, and well-to-well spacing is too large to correlate internal stratigraphic surfaces. Nevertheless, based on log analysis, core data, pressure transient analysis, and shallow seismic analogs, we interpret a deepwater frontal splay environment both the lower Miocene and the middle Miocene reservoir intervals. Through multiple iterations of log-based facies identification and core data analysis, we were able to assign ranges of rock-quality properties to both cored and non-cored portions of the wells. As we develop a 3D depositional model that includes non-drilled portions of the reservoir, we will be able to populate a fully integrated reservoir model to better manage the K2/K2-North Field secondary oil recovery efforts.

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REFERENCES CITED


