Introduction

Giant Hydrocarbon Reservoirs of the World: From Rocks to Reservoir Characterization and Modeling

P. M. Harris
Chevron Energy Technology Company, San Ramon, California, U.S.A.

L. J. Weber
ExxonMobil Exploration Company, Houston, Texas, U.S.A.

INTRODUCTION

The SEPM/AAPG core workshop “Giant Hydrocarbon Reservoirs of the World: From Rocks to Reservoir Characterization and Modeling” and this companion publication are an attempt to assemble information on giant (>500 MOEB recoverable reserves) reservoirs that is of value to a wide audience. Various examples and methods of reservoir characterization, development, and modeling practices are documented in this volume. Although far from exhaustive, this compilation includes a wide range of reservoirs when examined from any perspective, i.e., location, geology, production history, and characterization. Figure 1 shows the geographic distribution of the reservoir examples that are included in this volume.

A good understanding of geologic variability in time and space is a prerequisite for any successful reservoir description. Geologic and engineering data obtained from core are fundamental building blocks in reservoir characterization. A common goal is to describe the reservoir in sufficient detail to identify remaining hydrocarbons and then to produce these reserves efficiently. To this end, a focus in this volume centers on aspects of geologic modeling as they relate to heterogeneity in facies, which typically controls variability in porosity, permeability, and fluid saturations.

It is our goal that the technical content of the chapters presented here result in discussion directed toward

- fundamental concepts and methods of reservoir characterization, which include accurate representation of internal and external reservoir geology, precise and quantitative description, and level of detail that satisfies simulation capabilities
- an understanding of the scales of rock heterogeneity and its effect on petrophysical and engineering properties and their relationships to fluid flow and hydrocarbon recovery
- improved methods of reservoir description and development through application of high-resolution sequence and seismic stratigraphy and seismic visualization techniques
- identifying alternative approaches to more effective reservoir management practices

The reservoir examples described in this volume (1) explore historical and alternative approaches to reservoir description, characterization, and management and (2) examine appropriate levels and timing of data gathering, technology applications, evaluation techniques, risk assessment, and management practices in various stages in the life of individual development projects.
The giant reservoirs of this volume account for approximately 0.5 trillion bbl recoverable hydrocarbons. Reservoir examples are both carbonate and siliciclastic, and collectively, they account for a wide range of variability in reservoir parameters (e.g., gross rock volume, net-to-gross, porosity, and permeability). Most of the reservoirs in this volume occur outside the United States and Canada, and until now, core from many of these reservoirs have not been widely observed.

Enhanced recovery of hydrocarbons requires a critical understanding of reservoir heterogeneity by both geoscientists and engineers. Spatial heterogeneity that affects fluid flow occurs over all scales of investigation from the intrawell, interwell, reservoir, and basin scales of examination. We feel that the giant fields discussed herein address issues important to reservoir description, characterization, and management from both geologic and engineering perspectives.

**SUMMARY OF RESERVOIR EXAMPLES**

**Caspian Basin**

Kenter, Harris, Collins, Weber, Kuanysheva, and Fischer discuss the central platform part of the Tengiz field in “Late Visean to Bashkirian Platform Cyclicity in the Central Tengiz Buildup (Precaspian Basin): Depositional Evolution and Reservoir Development.” The Tengiz buildup, an intensely cored and studied isolated carbonate platform in the Precaspian Basin, contains a succession of shallow-water deposits ranging from Famennian to Bashkirian in age. The upper Visean, Serpukhovian, and Bashkirian form the main hydrocarbon-bearing interval in the platform. Depositional cycles (high-frequency sequences) in this interval are several to tens of meters thick for the Visean and Serpukhovian, and decimeter to meter scale for the Bashkirian. Visean and Serpukhovian cycles are generally easy to correlate from well to well over several kilometers distance, whereas Bashkirian cycles are incomplete and are more difficult to correlate. The distribution of reservoir rock types in the central platform is determined by burial diagenetic modification of an earlier reservoir system that includes meteoric alteration and porosity enhancement below major sequence boundaries and reduced dissolution along higher order sequence boundaries associated with the presence of volcanic ash. The lateral continuity of tight layers at sequence boundaries probably greatly affected later fluid flow as well as the ultimate distribution of cements, dissolution, and bitumen in the central platform reservoir. The burial diagenetic overprint includes two major phases of reservoir modification: (1) a corrosion and cementation phase significantly enhanced existing matrix porosity in the interior central platform while reducing porosity in the exterior central and outer platform by pore-filling equant calcite cement, and (2) bitumen emplacement and associated corrosion.

Authors Collins, Kenter, Harris, Kuanyseva, Fischer, and Steffen examine the outer platform, rim and flank of the Tengiz field in “Facies and Reservoir Quality Variations in the Late Visean to Bashkirian Outer Platform, Rim, and Flank of the Tengiz Buildup, Precaspian Basin, Kazakhstan.” Platform backstepping from Tournaisian through late Visean resulted in approximately 800 m (2624 ft) of bathymetric relief. This topography was enveloped by as much as 2 km (1.2 mi) of Serpukhovian progradation, which formed a depositional wedge around the older platforms referred to as the Serpukhovian rim and flank. Lower-slope facies include mudstone, volcanic ash, and platform-derived skeletal packstone to grainstone interbedded with boundstone breccia; middle-slope
facies are poorly bedded to massive boundstone breccia with subtypes based on clast composition, size, and packing; and upper-slope facies consist of in-situ microbial boundstone. Facies of the outer platform are shallow-platform skeletal, coated-grain, and ooid packstone to grainstone. Periodic large-scale failure of the rim during both the Serpukhovian and Bashkirian resulted in a high degree of lateral facies discontinuity. Solution-enlarged fractures, large vugs, and lost circulation zones produced mainly during late diagenesis form a high-permeability, well-connected reservoir in the rim and flank.

**Middle East**

Lindsay, Cantrell, Hughes, Keith, Mueller, and Russell describe Ghawar field, which is the world’s largest and most prolific oil field, in “Ghawar Arab-D Reservoir: Widespread Porosity in Shoaling-upward Carbonate Cycles, Saudi Arabia.” Production occurs from the Jurassic Arab-D carbonates. The upper half of the reservoir is dominated by exceptionally high reservoir quality, and the lower half contains interbeds of less porosity. The reservoir is composed of two composite sequences. The upper composite sequence boundary is the top of Arab-D carbonate, which is locally characterized by collapse breccia. The lower composite sequence boundary between the Arab-D and the underlying Jubaila is marked by deeper water cycles occurring over grain-dominated cycles. Several high-frequency sequences are each composed of cycle sets that each contain approximately five individual carbonate cycles. These carbonates formed upon a broad, arid storm-dominated ramp with a variety of rock types deposited. Diagenesis that is common within the Arab-D reservoir includes several dissolution events, recrystallization, and physical compaction. The resultant limestone porosity is a mixture of interparticle (dominant), moldic (common), intraparticle (common), and microporosity (common) pore types. Less common dolostone porosity is a mixture of moldic (less common), intercrystalline (less common), and intracrystalline (least common) pore types. The vertical seal for the reservoir is the overlying Arab C-D anhydrite.

In “High-resolution Sequence Stratigraphy and Reservoir Characterization of Upper Thamama (Lower Cretaceous) Reservoirs of a Giant Abu Dhabi Oil Field, United Arab Emirates” authors Strohmenger, Weber, Ghani, Al-Mehsin, Al-Jeelani, Al-Mansoori, Al-Dayyani, Vaughan, Khan, and Mitchell describe the Lower Cretaceous Kharai (Barremian and early Aptian) and Shuaiba (Aptian) formations (upper Thamama Group) of Abu Dhabi in which important hydrocarbon accumulations occur in platform carbonates. The Kharaib and Lower Shuaiba formations contain three reservoir units separated by low-porosity and permeability dense zones. Core and well-log data from a giant oil field in Abu Dhabi and outcrop data from Wadi Rahabah in Ras Al-Khaimah were used to establish a sequence-stratigraphic framework and a lithofacies scheme. The Lower and Upper Kharai Reservoir Units, as well as the upper dense zone, are part of a late transgressive sequence set of a second-order supersequence, built by two third-order composite sequences. The overlying Lower Shuaiba Reservoir Unit belongs to the late transgressive sequence set and the early highstand sequence set of this second-order supersequence and comprises one third-order composite sequence. The three third-order composite sequences are composed of fourth-order parasequence sets that show predominantly aggradational and progradational stacking patterns, typical of greenhouse cycles. Reservoir lithofacies range from lower-ramp to shoal crest to near backshoal open-platform deposits, whereas nonreservoir (dense) lithofacies represent an inner-ramp, restricted shallow lagoonal setting. Integration of subsurface and outcrop data leads to more insightful and realistic geological models of the subsurface stratigraphy, and the geological model realizations based on core, outcrop, well-log, and seismic data constrain flow-simulation models.

Yose, Ruf, Strohmenger, Schuelke, Gombos, Al-Hosani, Al Masky, Bloch, Al-Mehairi, and Johnson integrate high-resolution three-dimensional (3-D) seismic with geologic and production data to describe the Lower Cretaceous (Aptian) reservoir in Abu Dhabi in “Volume-based Characterization of a Heterogeneous Carbonate Reservoir, Lower Cretaceous, Abu Dhabi (United Arab Emirates).” The reservoir is positioned over a platform-to-basin transition and records a diverse range of depositional facies and stratigraphic geometries. A second-order sequence set is divided into five depositional sequences. Sequences 1 and 2 are a transgressive phase showing the initial formation of buildup margins and dominated by algal-prone facies. The subsequent highstand phase of Sequence 3 is mainly aggradational and records the proliferation of rudists across the platform top. A late highstand phase of sequences 4 and 5 is progradational showing the progressive downstepping of the platform margin onto a low-angle slope. Three-dimensional seismic data in the southern field area show a complex mosaic of tidal channels, high-energy rudist shoals, and intershoal ponds. The geometry and reservoir-quality
variations of these geologic features have a strong impact on reservoir sweep and conformance in the platform interior. In the northern field area, seismic images of prograding slope cliniforms reveal systematic variations in architecture and reservoir quality that reflect multiple scales of stratigraphic cyclicity. A pattern gas flood has been implemented in the cliniforms to add pressure support and improve recovery. Business applications of the reservoir framework include (1) 3-D seismic visualization as a tool for optimizing well placement, identifying bypassed reservoirs and evaluating reservoir connectivity; (2) integration of quantitative, volume-based seismic information into reservoir models; (3) maximizing recovery through full integration of all subsurface data; and (4) enhanced communication among geoscientists and engineers, leading to improved reservoir management practices.

In “Sequence Stratigraphy and Reservoir Architecture of the Burgan and Maudud Formations (Lower Cretaceous), Kuwait,” authors Strohmenger, Patterson, Al-Sahlan, Mitchell, Feldman, Demko, Wellner, Lehmann, McCrimmon, Broomhall, and Al-Ajmi propose a new sequence-stratigraphic framework for the Burgan and Maudud formations (Albian) of Kuwait, which results in a predictable distribution of reservoir and seal facies. The Burgan and Maudud formations form two second-order composite sequences, the oldest of which constitutes the lowstand, transgressive, and highstand sequence sets of the Burgan Formation. This composite sequence is subdivided into high-frequency sequences that are characterized by tidal-influenced, marginal-marine deposits in northeast Kuwait grading into more fluvial-dominated, continental deposits to the southwest. The younger composite sequence consists of the lowstand sequence set of the uppermost Burgan Formation and the transgressive and highstand sequence sets of the overlying Maudud Formation. This composite sequence is subdivided into high-frequency sequences that are characterized by tidal-influenced, marginal-marine deposits in northeast Kuwait and is carbonate prone in southern and southwestern Kuwait and is carbonate prone in northern and northeastern Kuwait. The lowstand sequence set of the Burgan is subdivided into five high-frequency sequences, and the Maudud transgressive and highstand sequence sets are subdivided into eight high-frequency sequences. The traditional lithostratigraphic Burgan–Maudud contact is time transgressive. The upper Maudud highstand sequence set is carbonate prone and thins southward because of depositional thinning.

Authors Dull, Garber, and Meddaugh describe the Maastrichtian (Upper Cretaceous) reservoir in the giant Wafra oil field in “The Sequence Stratigraphy of the Maastrichtian Reservoir at Wafra Field, Partitioned Neutral Zone, Saudi Arabia and Kuwait: Key to Reservoir Modeling and Assessment.” Oil production is largely from subtidal dolomite formed on a very gently dipping, shallow, arid, and restricted ramp setting that transitioned between normal-marine conditions to restricted lagoonal environments. The key to modeling the reservoir was the construction of an appropriately detailed sequence-stratigraphic framework for use in building the geostatistical reservoir model. Within the sequence-stratigraphic framework, 10 high-frequency sequences are correlated, albeit with some difficulty, across the entire field. Ultimately, diagenesis is a major factor in the distribution of porosity and permeability. Dolomitization is pervasive, but facies exerts some control on the distribution of porosity. Average porosity of the reservoir interval is 15%, with values as much as 45%, and permeability averages 30 md with core-plug measurements as much as 1200 md. The geostatistical model of the Maastrichtian reservoir demonstrates the layered and compartmentalized nature of the reservoir and clearly shows that the location of the reservoir facies is controlled by the original depositional fabric and subsequent dolomitization, both of which have been influenced by the paleotopography. This study was undertaken to determine reservoir volumetrics, understand the distribution of intervals likely to yield higher volumes of better quality oil, and provide a reservoir property model for use in fluid-flow simulation. Such an understanding is critical to efficiently develop the 1.5 billion bbl oil Maastrichtian resource at Wafra field.

West Africa

In “Stratigraphic Organization and Predictability of Mixed Coarse- and Fine-grained Lithofacies Successions in a Lower Miocene Deep-water Slope-channel System, Angola Block 15,” Porter, Sprague, Sullivan, Jennette, Beaubouef, Garfield, Rossen, Sickafoose, Jensen, Friedmann, and Mohrig describe the lower Miocene slope-channel systems from Angola Block 15, which regional seismic mapping, exploration drilling, and appraisal drilling have established as a world-class development opportunity. One of the major development targets in Block 15 is Burdigalian-aged slope-channel reservoirs, which are part of a system that traverses across the block in an east–west direction and can be continuously mapped on adjacent seismic datasets for more than 30–40 km (18–24 mi). The channel system was a sediment fairway for the delivery of coarse-grained turbidites and mixed muddy and sandy debrites into the Lower Congo basin.
Map patterns show distinctive changes in sinuosity, channel confinement, and degree of amalgamation broadly related to concurrent growth of salt-related structures. The episodic fill of the slope-channel system can be better understood by a hierarchical arrangement of unconformity-bounded stratal units. Nested channels form composite channel complexes that show distinctive trends in lithofacies type and vertical facies succession. Conventional cores calibrated to well logs and high-resolution seismic data show that the lower parts of the channel complexes are dominated by sandy-muddy debrites, slumps, and injected sandstones. These facies are typically overlain by coarse-grained, gravelly, and well-amalgamated sandy turbidites. The overlying facies succession is more variable, but commonly consists of interbedded sandy turbidites, injected sandstones, and a range of both muddy and sandy debrites.

North America

Dubois, Byrnes, Bohling, and Doveton document the reservoir characterization and modeling from pore to field scale of the giant Hugoton field in "Multiscale Geologic and Petrophysical Modeling of the Giant Hugoton Gas Field (Permian), Kansas and Oklahoma." Their work on this mature Permian gas system is aiding in defining original gas in place, the nature and distribution of gas saturation, and reservoir properties. The Kansas–Oklahoma part of the field has yielded 963 billion m³ (34 tcf) gas throughout a 70-year period from more than 12,000 wells. Most remaining gas is in lower permeability pay zones of the 170-m (557-ft)-thick, differentially depleted, layered reservoir system. The main pay zones have remarkable lateral continuity. They represent 13 shoaling-upward, fourth-order marine-continental cycles, comprising thin-bedded (2–10-m; 6.6–33-ft), marine carbonate mudstone to grainstone and siltstones to very fine sandstones. The pay zones are separated by low-reservoir-quality eolian and sabkha redseds. Petrophysical properties vary among major lithofacies classes. Neural network procedures, stochastic modeling, and automation facilitated building a detailed full-field 3-D cellular reservoir model using a four-step workflow: (1) define lithofacies in core and correlate to electric log curves (training set); (2) train a neural network and predict lithofacies at noncored wells; (3) populate a 3-D cellular model with lithofacies using stochastic methods; and (4) populate model with lithofacies-specific petrophysical properties and fluid saturations. Both the knowledge gained and the techniques and workflow employed have implications for understanding and modeling reservoir systems worldwide that have similar geologic age and reservoir architecture.

In “Key Role of Outcrops and Cores in Carbonate Reservoir Characterization and Modeling, Lower Permian Fullerton field, Permian Basin, United States” authors Ruppel and Jones discuss the rock-based model construction for Fullerton Clear Fork field, which is a shallow-water platform carbonate reservoir of middle Permian age in the Permian Basin of west Texas. Fundamental steps in their study included (1) creating and applying an analogous outcrop depositional model; (2) describing and interpreting subsurface core and log data in terms of this initial model; (3) defining the sequence-stratigraphic architecture of the reservoir section; (4) developing a cycle-based reservoir framework; and (5) defining controls, interrelationships, and distribution of porosity and permeability. Data used in this analysis included cores, thin sections, 3-D and two-dimensional (2-D) seismic data, borehole image logs, and outcrop models. Stratigraphic variations, differential dolomitization, karst fill, mineralogical variations, and rock-fabric distribution were incorporated into the model. These components were used to constrain interpretation and definition of flow units, permeability distribution, and saturation. The rock-based methods demonstrated in this study provide key insights with broader application into the formation, characterization, and interpretation of carbonate platform reservoirs.

Authors Weissenberger, Wierzbicki, and Harland describe the deep Panuke field in "Carbonate Sequence Stratigraphy and Petroleum Geology of the Jurassic Deep Panuke Field, Offshore Nova Scotia, Canada." Deep Panuke, which is located 250 km (155 mi) offshore of Halifax, Nova Scotia, Canada, contains gas-filled cavernous porosity in Jurassic carbonates of the Abenaki Formation. The Abenaki carbonates range from Bathonian to Neocomian in age and were deposited on broad carbonate platform attached to a siliciclastic hinterland. Seven third-order depositional sequences recognized in the Abenaki are correlated with geology and a 2-D seismic grid; 3-D seismic data are used for delineation drilling and reservoir characterization. Lithologies range from foreslope to reefal and shoal deposits near the platform margin. Open and restricted lagoon or tidal-flat deposits occur in the platform interior. Siliciclastics are concentrated near sequence boundaries or are distributed along strike, close to point sources such as rivers cutting through the platform. The reservoir occurs near the platform margin in coral and
stromatoporoid reef and associated skeletal-peloidal and occasionally oolitic shoal deposits. It comprises a range of porosity types, from vuggy limestone and dolomite to microporosity in limestone. Geochemical, isotope, and petrographic data suggest that the dolomitization and dissolution can be attributed to deep burial and hydrothermal fluids.

**South America**

In “Sedimentology, Sequence Stratigraphy, and Reservoir Architecture of the Eocene Mirador Formation, Cupiagua Field, Llanos Foothills, Colombia,” Ramon and Fajardo document the stratigraphic architecture and facies distribution in a high-resolution time-space framework to define the 3-D reservoir zonation of the Mirador Formation (Eocene) in the Cupiagua field. The Cupiagua structure is a large, east-verging, asymmetric anticlinal fold that trends north-northeast in the hanging wall of the frontal fault. The Mirador Formation accounts for approximately 55% of the recoverable oil in the field. Three scales of stratigraphic cycles are recognized based on stacking pattern and general trend of facies successions: short-term cycles or progradational and aggradational units stack systematically into intermediate-term cycles, which, in turn, are grouped into long-term cycles. The lower half of the Mirador consists of flood-plain facies with channel, crevasse splay, and swamp and flood-plain facies successions. Bay-head delta and bay-fill facies occur in the upper half of the Mirador Formation. The Lower Mirador consists of two intermediate-scale cycles showing a seaward-stepping stacking pattern overlain by a third cycle with a landward-stepping pattern, and the upper Mirador continues the landward-stepping pattern. This upper unit consists of three onlapping cycles composed of a succession of aggradational channel deposits, progradational bay-head delta and bay-fill deposits with a landward-stepping stacking pattern. The Mirador is capped by restricted marine shales of the Carbonera Formation.

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