Tight Reservoirs

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Attention to tight reservoirs has moved beyond the boundaries of North America as the importance of these hydrocarbon systems as global energy assets continues to grow. In addition to the complex geology, petrophysics, and reservoir heterogeneities dealt with in our industry today, tight reservoirs (<0.1-md permeability) provide unique challenges related to hydrocarbon storage and flow.

Over the coming years, drilling wells with an ever-reducing surface spacing will strain available resources. New technologies and processes (e.g., improvements to drilling and completion of horizontal wells) will be developed to increase reservoir contact and drainage, which in turn will improve operations efficiency, production, and recovery significantly. Effective exploitation of tight reservoirs will depend on new technologies and on improving the fundamental understanding of tight reservoirs over the life cycle of the field.

The evolution in fundamental understanding will rely on obtaining critical reservoir data including saturations, wettability, capillary pressure, structural features, deposition and diagenetic effects, volumes, mineralogy, lithology, in-situ stress effects, and rock strength. It will also rely on the ability to incorporate the structural, mechanical, and petrophysical properties of the reservoir into simulators so one may simulate and assess different reservoir-drainage strategies.

Achieving continuous subsurface monitoring and measurement during drilling, completion, stimulation, and production will be critical to evaluate the drainage behavior and to validate the optimization of the field-development strategy. In this way, we will not only lower capital expenditures, investment-recovery times, and operating costs but also ensure maximizing the recovery of the hydrocarbon from the reservoir over the life of the field.

Papers selected for this month's feature focus on the industry's progress in building the tight-reservoir knowledge base and how we are crafting methodologies to improve our decision making in reservoir development, characterization, and production. JPT

Tight Reservoirs additional reading available at the SPE eLibrary: www.spe.org

SPE 110050 • *"A Comparative Study of Capillary-Pressure-Based Empirical Models for Estimating Absolute Permeability in Tight Gas Sands" by J.T. Comisky, SPE, Apache Corporation, et al.*

IPTC 11545 • *"A Case Study: Using Wireline Pressure Measurements To Improve Reservoir Characterization in Tight Gas Formation—Wamsutter Field, Wyoming" by R.A. Schrooten, BP plc, et al.*

SPE 110809 • *"Barnett Shale Completions: A Method for Assessing New Completion Strategies" by R. Leonard, ProTechnics, et al.*

Rock Typing—Understanding Productivity in Tight Gas Sands

A workflow process is presented to describe and characterize tight gas sands. The ultimate objective is to provide a consistent methodology to integrate both large-scale geologic elements and small-scale rock petrology systematically with the rock physical properties for low-permeability sandstone reservoirs. To that end, the workflow integrates multiple data-evaluation techniques and multiple data scales by use of a core-based rock-typing approach designed to capture rock properties that are characteristic of tight gas sands.

Introduction

Unconventional natural-gas resources—tight gas sands, naturally fractured gas shales, and coalbed-methane reservoirs—comprise a significant percentage of the North American natural-gas resource base. Unlike conventional reservoirs, unconventional gas reservoirs typically exhibit gas-storage and -flow characteristics that are tied to geology (i.e., deposition and diagenetic processes). Effective resource exploitation requires a comprehensive reservoir-description and -characterization program to quantify gas in place and to identify the reservoir properties that control production. Although many unconventional natural-gas resources are characterized by low permeability, this paper addresses only low-permeability sandstone reservoirs (i.e., tight gas sands).

Understanding the pore structure and properties is critical in tight gas sands because diagenesis often modifies the original pore structure and reduces the average pore-throat diameter, typically causing an increase in both tortuosity and the number of isolated and/or disconnected pores. Some forms of diagenesis may increase porosity by creating secondary porosity, or microporosity. Regardless of the type of diagenesis, all tight gas sands retain some underlying traits of the depositional system, even though the original rock properties may have been altered (significantly). However, well productivity cannot be predicted accurately solely on the basis of the rock properties expected for those specific depositional environments and conditions. Therefore, a rock-typing workflow process was developed specifically for tight gas sands.

Many basin-centered gas-reservoir systems can be classified as tight gas sands. However, the characterization of basin-centered gas systems typically requires knowledge of the rock and multiphase-fluid properties and of the role of shale. Although basin-centered gas-reservoir systems are not specifically addressed in this paper, the proposed rock-typing approach is applicable to basin-centered gas systems.

Tables 1 and 2 of the full-length paper summarize rock-type definitions, data sources, and evaluation methodologies for selected reservoir-description and -characterization studies of sandstone and carbonate lithologies, respectively. Most of the technical literature addressing rock-typing studies includes some or most of the aspects suggested by Archie's definition. Although all rock-typing approaches evaluated from the petroleum literature use similar data sources and evaluation methodologies, none of these studies proposed a comprehensive methodology developed specifically to capture rock properties that are characteristic of tight gas sands. Therefore, the overall objective of this paper is to propose a workflow process that provides a systematic rock-typing process to integrate both large-scale geologic elements and small-scale rock petrology with the physical rock properties in low-permeability sandstone reservoirs. Essential components of the process model are identification, specification, and comparison of three rock types (depositional, petrographic, and hydraulic).

The full-length paper contains a detailed example of the workflow process for Bossier tight gas sand in the east Texas basin.

Rock Types for Tight Gas Sands

Although valid for most conventional oil and gas reservoirs, the rock-type definition given by Archie is too general for tight gas sands because the processes resulting in similar rock properties may not be unique, especially when the rocks have been subjected to significant diagenesis. Therefore, three rock types were integrated—depositional, petrographic, and hydraulic. Each rock type represents different physical and chemical processes affecting the rock properties during both depositional and paragenetic cycles.

Depositional. These rock types are derived from core-based descriptions of genetic units, which are defined as collections of rocks grouped according to similarities in composition, texture, sedimentary structure, and stratigraphic sequence as influenced by the depositional environment. These rock

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For a limited time, the full-length paper is available free to SPE members at www.spe.org/jpt.

types represent original large-scale rock properties present at deposition.

Petrographic. These rock types also are described within the context of the geological framework, but the rock-type criteria are based on pore-scale microscopic imaging of the current pore structure as well as the rock texture, composition, clay mineralogy, and diagenesis.

Hydraulic. These rock types also are defined at the pore scale, but hydraulic rock types quantify the physical flow and storage properties of the rock relative to the native fluid(s) (controlled by the dimensions, geometry, and distribution of the current pore and pore-throat structure). Each rock type represents different physical and chemical processes affecting rock properties during the depositional and paragenetic cycles. Because most tight gas sands have been subjected to post-depositional diagenesis, comparison of all three rock types enables assessment of the effects of diagenesis on rock properties. If diagenesis was minor, the depositional environment (and depositional rock types) and the expected rock properties derived from those depositional conditions will be good predictors of rock quality. However, if the reservoir rock was subjected to significant diagenesis, the original rock properties present at deposition will be quite different from current properties. More specifically, separate use of the depositional environment and the associated rock types to guide field-development activities may result in ineffective exploitation.

Note that all three rock types should be similar if the rocks were subjected to little or no diagenesis. For example, the permeability/porosity relationships for depositional rock types (derived from geologic models of the depositional environments and processes) should be applicable to petrographic and hydraulic rock types as well. However, as diagenetic effects increase in severity and occurrence, the original rock texture and composition, pore geometry, and rock physical properties will be modified. Under these conditions, there should be little or no correlation between permeability/porosity relationships derived for each of the different rock types. Ultimately, the permeability/porosity functions developed for the hydraulic rock types would be relied upon because they reflect the current rock properties.

Physical and Chemical Processes

Any description and characterization program is complicated because not all low-permeability sandstone reservoirs are alike. Therefore, each program should be designed to address a specific reservoir or field. However, there are common physical and chemical processes controlling tight-gas-sand properties, so identification of these processes can help develop common elements in a particular description and characterization program. Primary properties reflect the depositional environment—energy and sediment-flow regimes, including an evaluation of sediment composition and texture as well as sedimentary structure and reservoir morphology. Secondary properties represent diagenesis—defined as any post-depositional process (either physical or chemical) causing changes in initial rock properties. Note that diagenesis is very important because it is the principal cause of both low permeability and low porosity in tight gas sands.

Data Sources and Evaluation

Depositional Rock Types. The original rock properties vary depending on many factors, including the depositional environments, sediment source, and depositional regimes; sand-grain size and distribution; and type and volume of detrital clay and shale deposited. Therefore, the data-acquisition and -evaluation program is designed to qualify and quantify those factors. Depositional rock types are based principally on geologic interpretations and physical descriptions of whole core.

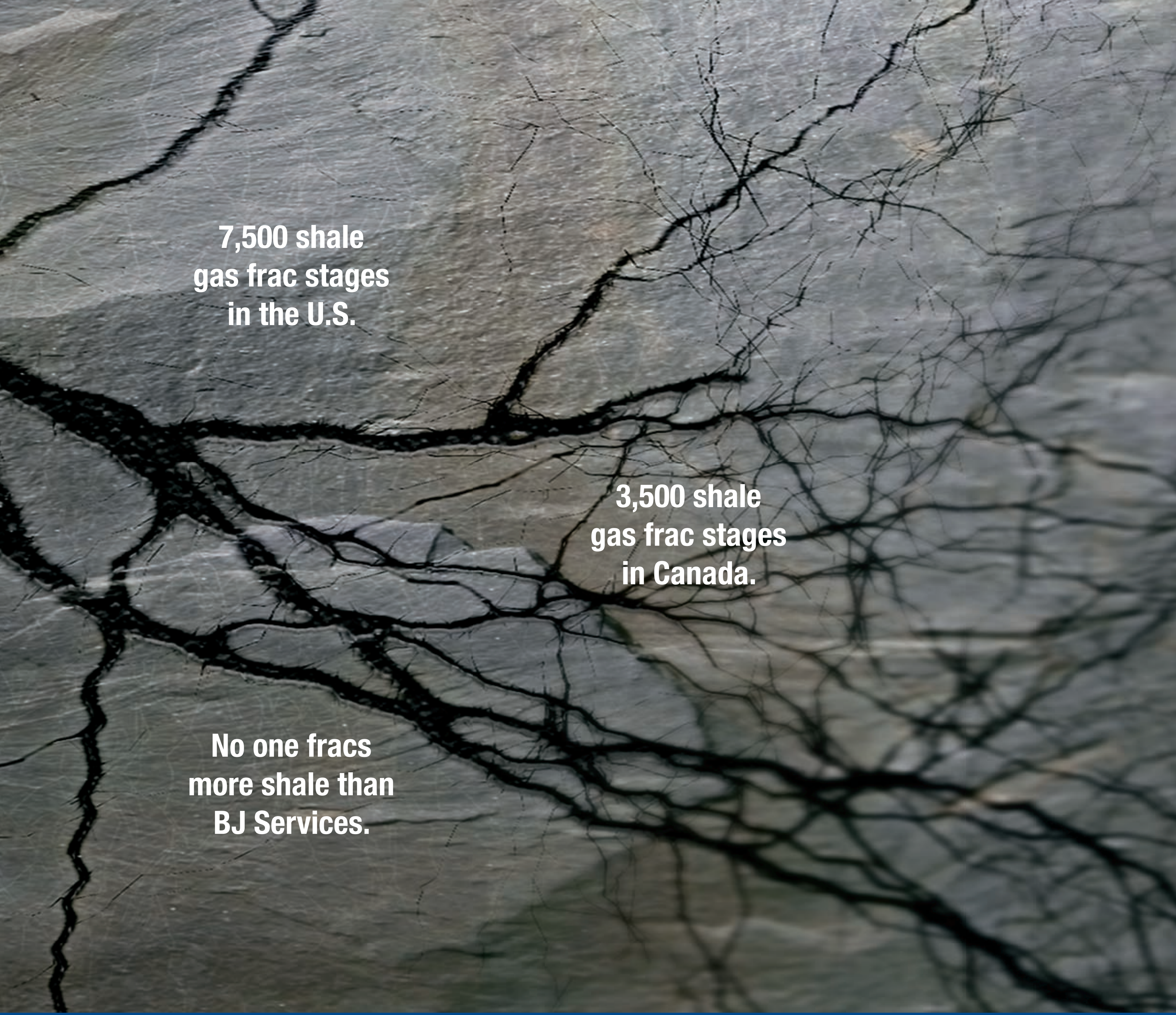
Identifying depositional rock types begins with a description of the small-scale geological reservoir architecture. These descriptions usually are derived from interpretations of the structural framework and stratigraphy. Within this framework, genetically related rock packages (both reservoir and nonreservoir rock) are identified and described.

An important aspect of this rock-typing step is developing an understanding of the vertical sequencing of the genetic units. Knowledge of the vertical distribution of depositional rock types helps define the depositional environment, which leads to a description of the reservoir geometry and flow properties. Interpretation of vertical or stratigraphic sequences also provides an understanding of the overall reservoir architecture that enables use of geological concepts and models to predict locations of the depositional rock types with the best production potential.

Key aspects of the sedimentary rock derived from core descriptions include lithology, texture, biogenic features, and identification of sand beds and sedimentary structure. Identification of biogenic features, including the type, ages, and mode of occurrence of trace fossils, provides clues on the depositional processes. A study of the sedimentary structure and beds will describe bed geometry, identify bedding planes and contacts between beds, and quantify bedding-plane orientation.

Because depositional rock types are based principally on core-derived descriptions of genetic units, comprehensive core-acquisition and -evaluation programs are critical for describing these rock types. It is worth noting that core data are necessary for identifying petrographic and hydraulic rock types. It is strongly recommended that large-diameter, conventional whole cores be obtained throughout the entire vertical section, including both reservoir and nonreservoir rock. Complete vertical sections are used for interpreting genetic units into a depositional sequence and predicting depositional environment and architecture. Core data will help develop an understanding of reservoir geometry and continuity and the distribution of rock types and properties. Although sidewall cores and cuttings can be used to evaluate some rock properties, their small scales make it very difficult to identify any large-scale geologic properties accurately. Consequently, sidewall cores should be used only to supplement a whole-core program, not as the primary source of rock material.

Petrographic Rock Types. Petrographic rock types are described on the pore scale, but within the context of the large-scale geologic framework identified from the depositional-rock-typing-evaluation step. The primary tools used for describing petrographic


7,500 shale
gas frac stages
in the U.S.
3,500 shale
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No one fracs
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rock types are microscopic-imaging techniques (i.e., thin-section descriptions, X-ray diffraction analysis, and scanning-electron-microscope imaging). Included in these evaluations are descriptions of sediment source, rock composition and texture, mineralogy, and clay types. An important component of the petrographic rock typing is an assessment of the types of diagenesis and the potential effect on rock flow and storage capacity. Supplementing the microscopic-image processes with pore geometry and other properties as identified from mercury-injection capillary pressure measurements is recommend.

Hydraulic Rock Types. Similar to the petrographic-rock-typing step, hydraulic rock types are quantified at the pore scale but represent the physical rock flow and storage properties as controlled by the pore structure. Hydraulic-rock-type classification provides a measure of the rock's flow and storage properties at current conditions (i.e., reflecting the current pore structure as modified by diagenesis). The primary tools for identifying hydraulic rock types are (1) routine core analysis, which includes measurements of total and effective porosity and absolute permeability, and (2) pore size and distribution from mercury-injection capillary pressure data.

Summary and Conclusions

A workflow process was developed that provides a consistent procedure to systematically integrate both large-scale geologic elements and small-scale rock petrology with the physical rock flow and storage properties in low-permeability sandstone reservoirs. This workflow process uses a core-based rock-typing approach to capture rock properties characteristic of tight gas sands. Fundamental to this process are identification and comparison of three different rock types—depositional, petrographic, and hydraulic.

Each rock type represents different physical and chemical processes affecting rock properties during the depositional and paragenetic cycles. Most tight gas sands were subjected to post-depositional diagenetic events, so a comparison of all three rock types will allow assessing the effect of diagenesis on the rock physical properties. If the effects of diagenesis are minor, the permeability/porosity relationships derived for depositional rock types (using expected rock properties derived from geologic models of the depositional environments and processes) would be expected to be applicable to both petrographic and hydraulic rock types.

However, as the effects of diagenesis increase in severity, magnitude, and occurrence, the original rock texture and composition, pore geometry, and physical properties will be modified. Under these conditions, one would expect little or no correlation of permeability/porosity relationships derived for each rock type. More importantly, use of the depositional environment and the associated (depositional) rock types to guide field-development activities would likely result in ineffective and inefficient exploitation. **JPT**

Integrated Development of the Changbei Tight-Gas Project

Changbei is an onshore tight gas field in north Shaanxi Province, China. The main reservoir is a thin and fairly complex braided-channel sandstone formation with a 5% average porosity and a 0.7-md permeability. For field development, a dual-lateral well with two 2000-m horizontal sections was selected. After a summary of the development-concept selection and the status of the project, the full-length paper details some of the development challenges.

Introduction

A production-sharing contract (PSC) was signed between PetroChina and Shell in 1999 to develop the Changbei gas field, followed by a 2-year extensive evaluation and appraisal period to prepare a development plan. Appraisal activities performed included fracturing existing and newly drilled vertical wells and drilling/testing horizontal wells.

The Changbei tight-gas development is the largest onshore cooperative venture between an integrated oil company and one of the three Chinese oil majors in terms of investment and development scale. In addition to difficult reservoir conditions, challenges specific to the local environment had to be overcome [e.g., technology and equipment availability; local-contractor competence; community relations; and high health, safety, and environment (HSE) standards].

This article, written by Assistant Technology Editor Karen Bybee, contains highlights of paper IPTC 11408, "Integrated Development of Changbei Tight Gas Project," by ***Guilin Luan,*** *SPE,* ***Lin Li, Gary Nettleship,*** *SPE,* ***Luc Van Son,*** *and* ***Taco Hoekstra,*** *Shell China E&P;* ***Robert Deutman*** *and* ***Sieward Veeman,*** *Sarawak Shell Bhd.; and* ***Hua Wang,*** *PetroChina ChangQing Oilfield Co., originally prepared for the 2007 International Petroleum Technology Conference, Dubai, UAE, 4–6 December. The paper has not been peer reviewed.*

Field History

Exploration drilling in the Changbei Block began in 1991. The first small-scale gas production to supply the local community was recorded in 1995. Seismic was used to predict the lateral continuity of the reservoir-sand body and reservoir boundary, leading to an extensive exploration campaign during 1996–97, culminating in a successful well test. Two-hundred-fifty 2D-seismic lines with a 3800-km approximate length were acquired. Twenty exploration wells, nine development wells, and two appraisal wells were drilled before field-scale development planning and project execution. All wells were vertical except the two appraisal wells, where both vertical and horizontal sections were drilled. Basic well tests were conducted on most of the wells. Trial production on 16 wells began in November 1999, which provided valuable information on well/reservoir dynamic behavior and helped gain production experience with vertical and hydraulically fractured wells in the tight gas reservoir.

Reservoir

The three following reservoir characteristics need to be highlighted because of their effect on reservoir productivity and development-concept selection.

- The large and thin target QA reservoir is 5 to 40 m thick, averaging 15 m, with the sand distributed in an approximately 11 600-km^2 area in the PSC block.
- The trial production operations (TPOs) and exploration/appraisal wells are distributed unequally in the PSC area, with a well density of one well per 45 km^2 on average in the entire PSC block and one well per 7 km^2 in the core area.
- There is significant reservoir spatial variability and heterogeneity. Average thickness cannot be correlated and extrapolated toward the flanks from wells drilled in the axial trend of the incised valley.
- There is uncertainty in spatial variation of thickness and in sand-body geometry, internal reservoir architecture, and permeability distribution.

Well-test analysis for the TPO wells shows the existence of low-permeability barriers or "baffles," which are interpreted as the composite response of sedimentary features such as sand-body margins, channel-abandonment features, and bed-set boundaries. These baffles, or flow barriers, reduce transmissibility and lead to partial compartmentalization of the reservoir.

Development-Concept Selection

On the basis of Changbei-reservoir characteristics, the ideal well should pass through as many horizontal and vertical baffles as possible, intersect as many channels as possible, and intersect as much good-quality formation as possible. During well-concept selection, vertical wells with propped fractures, openhole horizontal wells slanting vertically across the reservoir, and dual-lateral horizontal wells slanting vertically across the reservoir were considered. The reservoir characteristics made the horizontal/dual-lateral well more favorable. With long horizontal wells, well productivity index is increased dramatically by increasing the production interval in the reservoir. Hence, well production rates are significantly higher for

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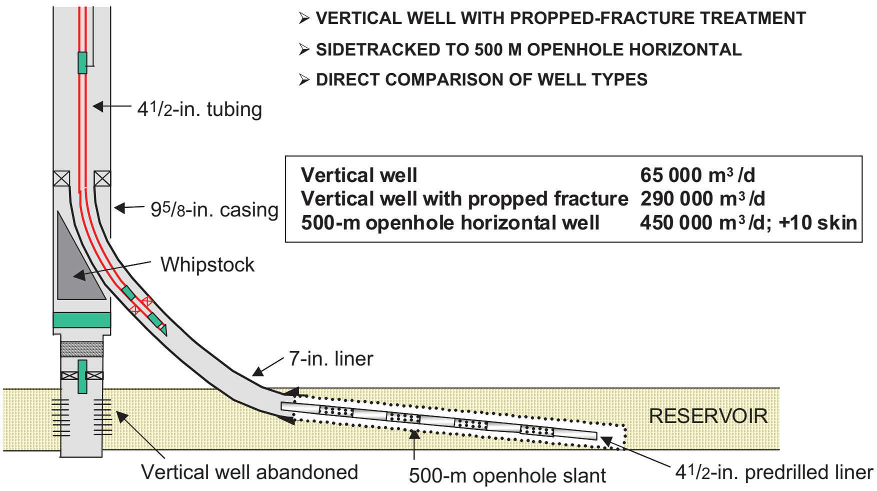


Fig. 1—Appraisal of development-well concept.

horizontal wells than for vertical wells. At the same time, use of a horizontal slant well mitigates flow restrictions caused by possible vertical baffles by providing completion intervals across the reservoir section. With a vertical well, only one block is produced directly, and the risk of bypassing gas and of rapid production decline is high. In addition, horizontal/dual-lateral wells, in combination with a well-cluster concept, can reduce the number of wells and surface facilities significantly.

To appraise horizontal-well concepts for Changbei-field development, two appraisal wells were drilled. Each well first was drilled vertically through the reservoir, then extensively tested including a pressure-buildup test, followed by hydraulic fracturing, and testing once again. The vertical well was plugged back, sidetracked, and a horizontal well drilled **(Fig. 1).** The horizontal well then was tested. This gave a complete data set of vertical well, vertical well with propped fracture, and horizontal well production data. The outcome of the appraisal showed the advantages of the openhole horizontal-well concept.

Simulation models, which were matched with the production and pressure history of the TPO wells and tuned with the data gained from the two horizontal appraisal wells, were used for comparison of horizontal well vs. vertical well with propped fractures. In general, the ratio of initial rate for horizontal wells with a 2000-m length in the reservoir vs. vertical wells with propped fractures is approximately 3:1 to 4:1. The ratio of ultimate recovery is approximately 2:1 to 3:1. Costs for a horizontal well with a 2000-m reservoir length are on average less than two times the cost of a vertical well with propped fractures. These data confirmed the selection of the horizontal-well concept because the extra cost for the horizontal well is more than compensated for by the additional capacity and ultimate recovery.

The well number, well pattern, and cluster configuration were optimized by modeling both horizontal and dual-lateral wells in a hexagonal pattern and horizontal wells in an orthogonal pattern. To determine which well configuration was optimal, the three different well patterns were positioned in full-field models at locations with varying reservoir properties. The wells then were produced for 20 years. Dual-lateral wells produce significantly more than horizontal wells in either a hexagonal or an orthogonal cluster. However, considering the ratio of well costs to volume produced, dual laterals and horizontals in a hexagonal pattern are comparable. Horizontal wells in an orthogonal pattern were found to be significantly worse for all locations and were no longer considered for full-field development. Whether horizontal wells or dual laterals are most appropriate is determined by the available space and by reservoir thickness because dual laterals take up more space. Having more wellbores available as in the case of the dual lateral is insurance against leaving compartments undrained. The majority of the wells will be dual-lateral wells. For the entire development area, approximately 50 wells are to be drilled from 20 well-cluster locations to meet a target plateau gas production of 3×10^9 m^3/a.

Development Status

Project execution began in June 2005, with the surface engineering construction, drilling operations, and other project-related activities such as roads and supply-base construction. Three key engineering activities have been completed on schedule: (1) upgrading existing TPO facilities with the focus on automation and increasing capacity; (2) improving safety features; and (3) building the central processing facility (CPF) to process full-field development with peak production anticipated at approximately 3×10^9 m^3/a by 2008 to deliver gas to the Beijing Olympics.

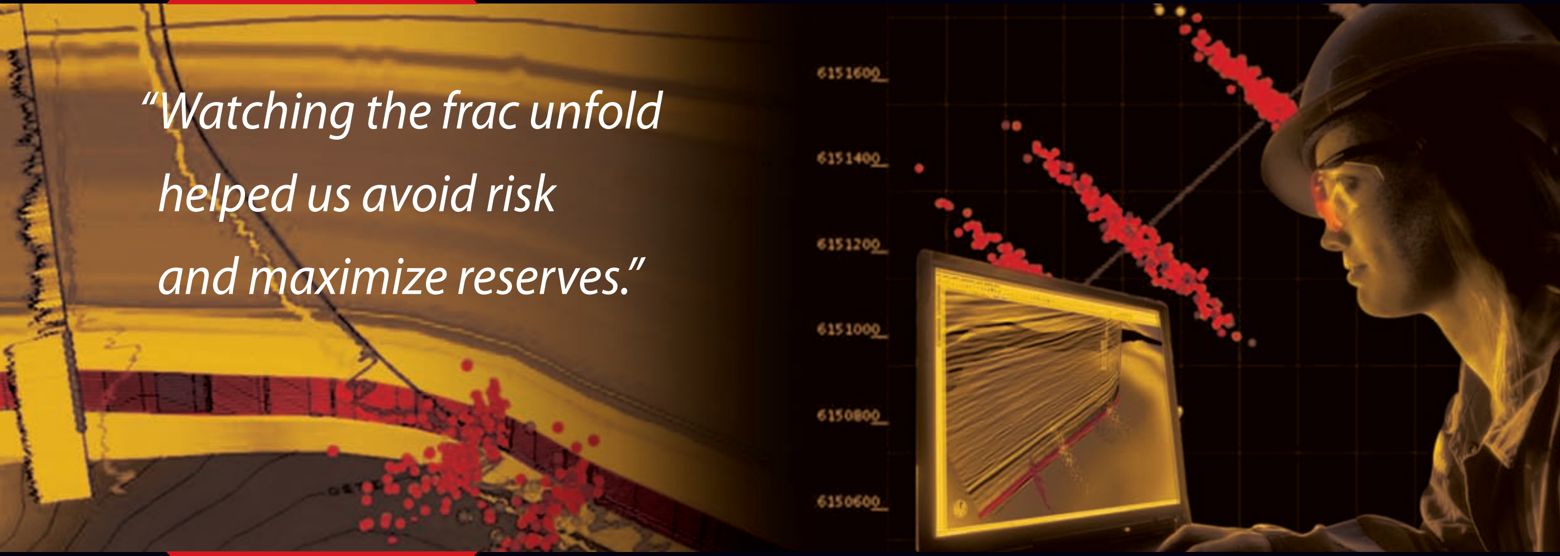
The first well was spudded on schedule in August 2005, and the project has since built to a three-rig operation. All three rigs are from two local vendors because of their competitive costs. However, this also brought challenges to the project from staff competencies, HSE mentality/culture, and equipment-availability/-quality aspects. By the end of June 2007, five wells had been completed and four had been connected and produced to the CPF.

Lessons Learned

During the past 2 years of the execution phase of the project, a number of lessons have been learned in both technical and organizational aspects.

Development Concept. Changbei is the first gas field in the Ordos basin to use horizontal/dual-lateral wells as the basic development concept. Although appraisal activities, including drilling two horizontal wells and extensive assessments and comparisons, were carried out during the concept-selection phase, well-capacity uncertainty was still high. On the other hand, fast production ramp up (2-year ramp up to 3×10^9 m^3) and gas delivery of 1.5×10^9 m^3 and 3×10^9 m^3 in the 2007 and 2008 contract years, respectively, are considered to be the most important success factors to fulfill the fast-growing gas demand in Beijing. Drilling and testing outcomes and production history for the new wells reduced this uncertainty significantly. Although the drilling performance is slower than originally planned, the capacities of the newly drilled wells are roughly 35% higher than anticipated. This extra capacity compensates for the effect on gas delivery of slower drilling.

Higher Well Capacity. Wells drilled so far achieved the objective of inter-


"Watching the frac unfold helped us avoid risk and maximize reserves."
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secting as much good-quality formation as possible. Interpretation of the pressure-buildup test in the first well gives a 1.5- to 3.2-md effective permeability with a base case of 2.5 md. This is much higher than the 0.7-md average effective permeability derived from pressure-buildup-test interpretation of 12 fractured vertical wells. Low formation damage through optimized drilling fluid and better well cleanup resulted in lower skin values than expected.

Drilling the Dual Lateral. Well capacity, production ramp up, and planned gas delivery are strongly dependent on achieving the 2000-m planned reservoir penetration. After startup problems, 2000 m proved to be an achievable and realistic target. The well profile for the build section was optimized. Initially a single-build well profile was selected. This was replaced by a build/tangent/build well profile because of difficulty in managing buckling in the $12^{1}/_{4}$-in. build section and $8^{1}/_{2}$-in. reservoir horizontal section. Currently, a pseudocatenary well profile is used because when designed properly, it can manage depth uncertainty and landing the $9^{5}/_{8}$-in. casing in the reservoir. Directional work is spread across a long distance, with the majority of the work being performed in rotary mode. Torque and drag are balanced to the capability of the rig equipment to complete each section. Buckling and its management were assessed extensively, and a $5^{1}/_{2}$-in. optimum drillstring size was selected.

Borehole Stability. Borehole stability was an important issue in the early drilling phase and remains challenging. The P1S2 reservoir is deposited in a braided river system with interbedded shales. The shale layers normally have less than 1 m thickness and are less than 100 m wide. In addition, coal-bearing intervals that usually are limited to 1-m-thick streaks exist in the Shanxi. Both shales and coals present potential borehole-stability risks during drilling. Studies performed during field-development planning found that a mud-weight window could be defined for drilling successfully through the various weak shales in vertical, slanted, and horizontal sections to reach the targets. Experience in the second horizontal appraisal well highlighted the potential instabilities in shale sections. These would be addressed by installation of predrilled liners if required. Presence of thin coal layers above the reservoir sandstone does not appear to prevent the use of horizontal wells if good drilling practices are followed. It was considered acceptable to have a $12^{1}/_{4}$-in. build section through the shales in the formations above the reservoir and for contingency predrilled liners to be prepared for shale instability in the $8^{1}/_{2}$-in. reservoir section. During drilling operations, issues were encountered related to borehole instability in the final $12^{1}/_{4}$-in. build section in the Shihezhi formation and while drilling the $8^{1}/_{2}$-in. reservoir horizontal section.

The intrareservoir claystones occur much more frequently than anticipated, and the instability of the claystones was worse than expected. The "pure" claystone was stable, as concluded from the earlier studies. The only issue related to the pure claystone was the reduced rate of penetration. However, the carbonaceous claystone was unstable and caused many problems, such as losses of bottomhole assemblies and other tools in the $12^{1}/_{4}$-in. build section and accidental sidetracks, hole packoffs, stalled drillstrings, and stuck pipe while drilling the reservoir section.

The problems encountered while drilling carbonaceous claystone resulted in forced sidetracks or even early total depth. It was realized that mitigations are required in both final buildup and reservoir sections for both drilling operation and later production. An expert group was formed to assess and recommend ways to mitigate borehole-stability issues. The assessment currently is ongoing and is expected to be complete in August 2007. Before obtaining the final recommendations from the expert group, the following mitigation options have been developed and are being implemented. For drilling the final build sections, two strategies were used: (1) set the planned $9^{5}/_{8}$-in. casing earlier, drill the remaining build section with an $8^{1}/_{2}$-in. bit into the reservoir, and set a 7-in. liner; and (2) alternatively, replace the $9^{5}/_{8}$ in. casing with $10^{3}/_{4}$-in. casing, setting it just above the troublesome zone, then drill out with an $11^{1}/_{4}$-in. bicenter bit and run $8^{5}/_{8}$-in. solid expandable tubulars. In this way, the reservoir section can be drilled at $8^{1}/_{2}$ in. as originally planned. **JPT**

Horizontal Wells in Tight Gas Sands: Risk Management To Maximize Success

Successful applications of horizontal wells have been limited to high-permeability reservoirs and unconventional formations such as coal, chalk, and shale. Horizontal wells are commonly two to four times more expensive to drill and complete than offset vertical wells, yet theoretically are capable of as much as three to five times the production. However, research shows that in practice, many of these wells produce only 10 to 30% more than offset vertical wells. The full-length paper presents a detailed methodology to identify, understand, and manage risk associated with horizontal wells drilled in tight gas sandstone reservoirs.

Introduction

Horizontal wells have had great success in high-permeability oil sands, unconventional gas shales, and carbonates. With advances in drilling and completion technologies, there has been a recent trend in North America to drill and complete horizontal wells in tight gas sandstones. In the full-length paper, tight rock is defined as sandstone with permeability less than 0.1 md. Whenever the gas price has been strong in North America, operators tend to attempt more-innovative and inherently riskier investments in natural-gas plays that include new-formation plays, varied drilling techniques, and experimental completion methods.

With the current active climate and favorable gas price, increasing emphasis is being placed by exploration-and-production companies on getting as much gas out of the reservoir as quickly as possible, while minimizing cost. Horizontal wells allow operators to increase gas production of a well by exposing more of the reservoir to fracture stimulation. This increases the likelihood that a horizontal well can produce more than its offset vertical counterparts. The key is that the production increase must more than make up for the cost increase associated with the horizontal well. The challenge is identifying and mitigating risks in tight gas sandstone horizontal wells.

This article, written by Assistant Technology Editor Karen Bybee, contains highlights of paper SPE 110067, "Horizontal Wells in Tight Gas Sands—A Methodology For Risk Management To Maximize Success," by ***Jason Baihly,*** *SPE,* ***Dee Grant,*** *SPE,* ***Li Fan,*** *SPE, and* ***Suhas Bodwadkar,*** *SPE, Schlumberger, originally prepared for the 2007 SPE Annual Technical Conference and Exhibition, Anaheim, California, 11–14 October. The paper has not been peer reviewed.*

Methodology

The full-length paper discusses each phase of the methodology that can be used to minimize the risk and maximize the success of horizontal completions in tight gas sandstones. The sections include the reservoir model, planning, drilling, completion, and production. In the full-length paper, throughout the various phases there are some discussions about how one or more aspects of a certain phase will affect the design and success of the overall horizontal well or affect other phase aspects that occur subsequently. This methodology is by no means a linear progression; it is circular, so that all aspects of each phase have the greatest amount of input to design and risk mitigation of horizontal completions in tight gas sandstones.

Reservoir Model

A fieldwide reservoir model can help identify where potential horizontal-well locations should exist in mature tight gas sandstone reservoirs. It also can help identify and quantify risks. A reservoir model may not be developed fully for every field because data may be insufficient to qualify each candidate. However, when a reservoir model is available, it aids in both horizontal- and vertical-well placement.

There are many challenges for drilling successful horizontal wells in tight gas formations. Tight gas sands typically are thin and laminated, with very low vertical permeability, so a lateral by itself cannot make an economic well. Multiple transverse hydraulic fractures are needed to produce the horizontal well at economic rates. Unlike blanket sands in high-permeability environments, tight gas sands appear and disappear within a short distance both in vertical and lateral directions. After many wells have been drilled and produced in a tight gas field, uneven pressure distribution usually is created in the reservoir. Some new wells, which immediately offset the older wells, may encounter virgin reservoir pressure, while other new wells may experience pressure depletion even if they are far away from existing wells.

To identify horizontal-well locations in tight gas sands accurately, the first step is to define the trend or distribution of the sand in each reservoir. The second step is to estimate and calibrate the current pressure distribution within the sand with measured-pressure-data points. The last step is to evaluate the economics for drilling the horizontal well in predetermined locations from the two preceding steps. To complete all of the steps successfully, a detailed, integrated reservoir model needs to be built.

The best horizontal locations for field development can be identified by locating the reservoir zones and aerial extents that have both high sand content and fairly virgin reservoir pressure. Once these locations have been determined, a simulation model can be run to determine how much gas has been produced and how much producible gas still exists in the reservoir after the given time period. The simulation thus can pre-

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dict how much gas can be recovered from each possible horizontal-well location. Upon completion of the production and reserves simulation, economic and risk analysis can be performed on each location to rank and finalize optimized horizontal-well locations.

Planning Challenges

The planning phase encompasses many steps and covers a large quantity of upfront information. It includes horizontal-well economics, geologic considerations, lateral azimuth, well placement, production performance, hydraulic-fracture behavior, forecasting, and initial design. Valuable information can be gained from offset wells in the planning phase. By gathering data in offset wells, crucial information can be obtained with significantly less economic risk than drilling a horizontal well with minimal pay identification and fracture-growth-behavior information. It is important to note that not every tight-sandstone zone is a candidate for a horizontal completion and that this phase of the process is used to determine if a candidate meets the economic goals of the operator.

The first step in the planning phase is to determine the current drilling and completion costs of offset vertical wells and to estimate the added costs associated with various horizontal alternatives, including running the economics of various drill bits, motors, and penetration rates vs. total time. From a fracturing standpoint, fluids, proppants, staging, and hydraulic-horsepower costs are analyzed. Both drilling and completion tools and processes are analyzed from an economic and feasibility perspective to narrow the alternatives used, and not to choose the finalized equipment/design.

Forecast Matrix. Calibrating the permeability within the reservoir of interest for horizontal-well placement is another important factor to mitigate risk and maximize success. These data can come from core analysis, production modeling, log-derived permeability model, pressure-buildup test, or any combination of these techniques. Once permeability is calibrated and the net-pay properties are determined, an accurate forecast matrix can be performed.

The forecast matrix looks at the various drilling and completion scenarios for the horizontal well, and it can vary certain completion parameters to determine the optimum hydraulically-fractured-well design. The matrix can alter the lateral length and number of fractures along the horizontal wellbore. It can take into account various fracture half-lengths and height-coverage scenarios. Another variable that can be altered in the forecast matrix is the fracture conductivity. These values can be determined on the basis of fluid types and proppants used in the hydraulic-fracture treatment. More parameters can be adjusted, depending on the inputs of the software forecasting tool. The gas price also can be fixed at specified values or adjusted over time. The forecast is not fixed and can be performed over various time periods. By running the various scenarios over time, the operator can obtain a first look at whether or not a fractured horizontal completion will be viable in the targeted zone(s) of the sandstone reservoir.

Other Considerations. Other concerns and/or unknowns within a field may exist that need to be addressed from offset-well/field data before a competent horizontal-well design can be performed. These may include reservoir-pressure determination, natural-fracture identification, geopressured-reservoir issues, and depletion-area determination.

After all relevant data have been collected, a finalized design can be performed and the resultant production can be forecast. These results then can determine if the well will be economically superior to offset vertical wells in the field, or if it will be viable in an area that has no wells. If the horizontal-well design does not lower the cost per hydrocarbon unit recovered compared to vertical wells, then it makes no economic sense to drill a lateral.

Drilling Challenges

The drilling phase of the methodology focuses on all aspects of drilling the horizontal well, through logging the final open hole. In horizontal completions, it is important to drill the well as quickly as possible to minimize daily rig costs. In expediting drilling, it is important not to sacrifice hole quality. The hole should be round and smooth with a continuous diameter, stable, free of debris, and maintained in the target zone with minimum undulation. These factors all have an effect on the initiation ease, isolation, and overall success of hydraulic-fracture treatments along the wellbore. Stress and image logs can be run in the borehole to aid in fracture staging by looking for potential high-stress intervals or geologic anomalies.

Completion Challenges

The completion phase encompasses every aspect of the fracture execution and crosses over to data collection to help improve the fracture design and staging. The topics discussed in this phase include isolation method, fracture staging, fracture design, and fracturing-fluid and -proppant selection.

Hydraulic-Fracture Microseismic Monitoring. Regardless of the isolation method used, it is important to perform real-time microseismic hydraulic-fracture monitoring if suitable offset wells or surface locations exist. Microseismic hydraulic-fracture monitoring in real time can identify unwanted fracture-growth behavior, allowing the user to change the design on the fly. Real-time monitoring can show how the alteration affected the overall treatment and, ultimately, if it was a success. If the treatment change was ineffective, then another fracture-treatment alteration can be attempted and the results can be viewed in real time to determine if that was successful.

Microseismic hydraulic-fracture monitoring can aid in determining if the fracture is getting out of zone or if length extension still is occurring. It also can determine the effectiveness of the isolation method used. If fracture stages are overlapping, a stage can be terminated early and the subsequent fracture stage can begin or a diversion technique can be used in an attempt to propagate the fracture in its designed fairway. When multiple fractures occur, the stage can be pumped longer than designed if excess fluid and proppant volumes exist or diversion can be attempted to continue growth in a single hydraulic fracture. If microseismic results show that a fracture is following a fault into an unproductive or wet zone, the stage can be terminated early or an attempt to divert can be made. **Fig. 1** shows an example of a horizontal well with hydraulic fractures to highlight the importance of real-time microseismic hydraulic-fracture monitoring. This figure shows a 3D view of a seven-fracture-stage horizontal well. The microseismic events are colored by stage.

Production

Determining success of the execution generally is measured in actual pro-

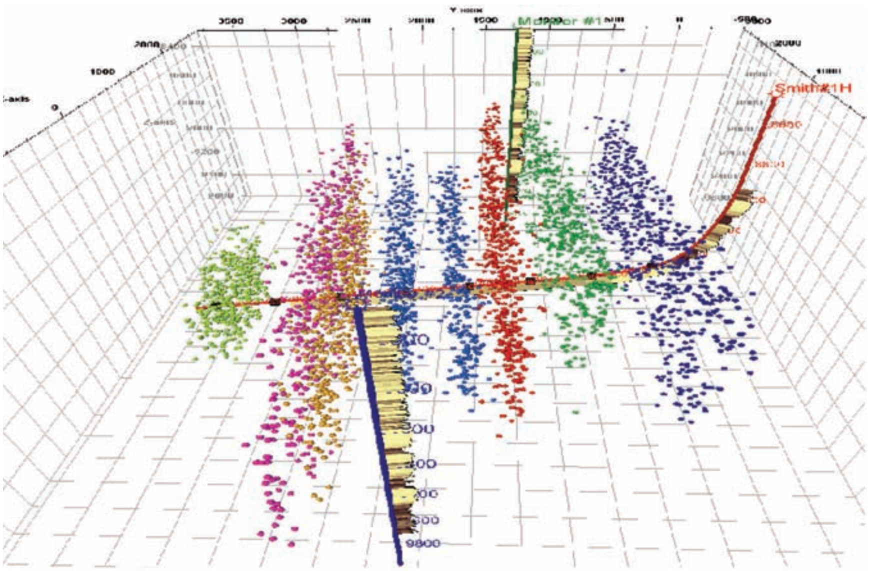

Fig. 1—3D view of microseismic results for a horizontal well.

duction and its resultant economics. Wells should be flowed back as soon as possible after the fracture treatment to minimize fracture-fluid damage and maximize proppant-pack conductivity. It is unknown if stages flow back commingled or if the stages toward the heel flow back first and then successive stages toward the toe are added later. Either way, getting the fracturing fluid out of the formation as soon as possible is essential. A small suite of fit-for-purpose production-logging tools exists that can be run in horizontals to determine how flowback and production are behaving in the lateral. Knowing which stages are contributing to production can make it easier to understand how successful each stimulation stage was. Production modeling can aid in determining the productive dimensions and the number of fractures successfully pumped by altering the number of stages, height of the fracture, and length of the fracture to obtain a match. Microseismic hydraulic-fracture monitoring can give the operator an idea of which stages were fractured and isolated successfully and can identify areas that are unstimulated and may need to be exploited by other infill wells.

The knowledge gained from analyzing a horizontal well completed in a given field can aid in the risk identification, risk mitigation, and overall design of future horizontal completions in that field. Understanding the resultant production from each stage and the commingled system can aid greatly in the step changes that need to be made in the next lateral completion in the field. **JPT**