Multilateral/ Extended Reach

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Our industry has overcome many difficulties during recent years. Successes have been achieved with drilling projects in sensitive environments, remote-access areas, and high-technological-demand projects. New technologies have been developed at a fast pace to fill the needs.

Technologies that achieve better recovery with a simultaneous reduction in capital expenditure are preferred. The use of extended-reach and multilateral wells aligned with good drilling performance will reduce capital expenditures. Although the profiles of those wells become more complex, with long horizontal sections or multiple legs, better performance is possible through deployment of an integrated project team that appropriately addresses the drilling and completion challenges during the planning phase. Subjects such as wellbore stability, well cleanliness, multilateral junctions, appropriate sand control, openhole completions, inflow-control completions, and inflow-performance relationship must be analyzed carefully during the well-design phase.

The project-team assessment during the execution phase must include the latest techniques in seismic interpretation, deployment of real-time logging tools to deal with reservoir heterogeneity, and real-time update of the Earth model. Real-time data are essential for management of equivalent circulating density because of the narrow margin between pore pressure and fracture gradient.

The well-planning process must be complemented by an improvement in operational performance. New approaches with good quality control must be implemented urgently to reduce the nonproductive time (NPT) while drilling wells. Our industry faces performance problems with wells reaching an NPT index of more than 40% in the Gulf of Mexico. The responsibility for such a high NPT index can be shared equally by drilling contractors, service companies, and operators. Today, NPT in offshore wells can reach an annual cost of approximately USD 70–90 million per rig, and this will be reduced only with improvement in maintenance, better engineering practice, and qualified personnel. Integrating the drilling engineers into the project team early, use of the latest technology, and focusing on operational excellence are essential for the industry success. **JPT**

Multilateral/Extended Reach additional reading available at the SPE eLibrary: www.spe.org

SPE 115099 *• "Technical, Economic, and Risk Analysis for a Multilateral Well" by D. Arcos, Texas A&M University, et al.*

SPE 119506 *• "How Continuous Improvement Led to the Longest Horizontal Well in the World" by Kumud Sonowal, Maersk Oil Qatar, et al.*

SPE 116138 *• "Multilaterals Drilling and Sustainable Openhole Production From Theory to Field Case Studies" by Son K. Hoang, University of Oklahoma, et al.*

SPE 115742 *• "Advanced Wells: How To Make a Choice Between Passive and Active Inflow-Control Completions" by V.M. Birchenko, Heriot Watt University, et al.*

Increasing Sakhalin Extended-Reach-Drilling and -Completion Capabilities

Extended-reach-drilling and completion capabilities at the Chayvo field, Sakhalin Island, Russia, have evolved in well-design and operational practices to increase well reach to more than 10.5 km. Disciplined redesign has been based on learnings acquired throughout the program. Learnings and design changes were applied to Well Z-12.

Introduction

The Chayvo field is on the northwest coast of Sakhalin Island, where operations must contend with harsh arctic winters and limited infrastructure. The field is a gas-filled anticline having an oil rim that is the current development-program target. The field is developed with horizontal completions from the Yastreb land location and from the Orlan offshore concrete-island drilling and production platform. Production from both wellsites is delivered to an onshore production facility, with oil subsequently delivered to tankers in protected waters off the Russian mainland. Most of the produced gas is reinjected to assist reservoir-pressure support, with lesser amounts consumed as fuel or sold.

During Chayvo development drilling, wells became increasingly complex. Longer throws have resulted in higher demands on rig equipment (especially the top drive and drillpipe) and have made successful placement of completion equipment more challenging. Twenty-one wells have been drilled and completed (17 oil producers, three gas-injection wells, and one cuttings-injection well).

This article, written by Senior Technology Editor Dennis Denney, contains highlights of paper SPE 119373, "Increasing Sakhalin Extended-Reach-Drilling and -Completion Capabilities," by ***Michael W. Walker,*** *SPE,* ***Andrew J. Veselka,*** *and* ***Shane A. Harris,*** *SPE, ExxonMobil, prepared for the 2009 SPE/IADC Drilling Conference and Exhibition, Amsterdam, 17–19 March. The paper has not been peer reviewed.*

Z-12 Case History

Well Z-12 has an ultimate total depth (TD) of 11 680 m measured depth (MD). Drilling operations on were completed in January 2008, and the well reached TD in 68 days. The well, on the north end of the Chayvo field, was designed to encounter potential productive sands on both the western and eastern flanks of the field. Previously drilled Well Z-11 had similar objectives but encountered significant difficulties with hole instability and placement of the production liner.

After analyzing learnings from Well Z-11, several areas were determined as critical to the success of Well Z-12.

- Wellbore stability balanced against equivalent-circulating-density management in the 8-in. hole.
- Successful placement of the completion liner in the 8½-in. hole and the use of a designer running string.
- Torque management facilitated by a smooth wellbore trajectory and use of lubricants.
- Optimized rate of penetration (ROP) and improved bottomhole-assembly (BHA) life through application of the operator's drilling-performance-management system.

Drilling-Performance Management. Critical to the success of Well Z-12 was use of a drilling-performance-management process and integrated-hole-quality technology. The operator's drilling-performance-management process seeks to identify limiters to ROP performance and then strives to extend or eliminate them systematically from the drilling operations. Anything that limits ROP is evaluated, including drill-bit efficiency, bit whirl, vibration, stick/slip, BHA and/or measurement-while-drilling (MWD) failure, bit damage, available weight on bit, hole cleaning, torque, surface cuttings handling, controlled drilling for directional control, and other potential influences. One tool used to measure drilling performance was mechanical specific energy (MSE), which is a measure of how efficiently (or poorly) energy that is transferred into the drillstring is translated into actually drilling new hole, rather than being consumed by vibrations, whirl, bit balling, or other drilling inefficiencies. MSE monitoring on the rig floor provides real-time feedback to the driller, who can make operational changes as needed to maximize ROP and limit tool/bit damage. For limiters that cannot be resolved by real-time operational changes, engineering is involved to provide solutions.

Well Z-12 Planning. The operator used a structured well-planning process that detailed each step and outlined responsibilities of the various stakeholders, with the overall goal of achieving the well objectives at the lowest cost. This process provided the foundation for collaboration within a time frame that allowed cost-reduction opportunities to be considered and program tradeoffs to be evaluated fully for maximum asset value.

An integral part of this process involved input from technical experts and the transfer of applicable knowledge from the operator's worldwide experience base. In addition, input from the operations and engineering staff in Sakhalin was used fully to take advantage of their local experience and operational perspectives. This multifunctional planning effort leveraged best practices, technical experts, and

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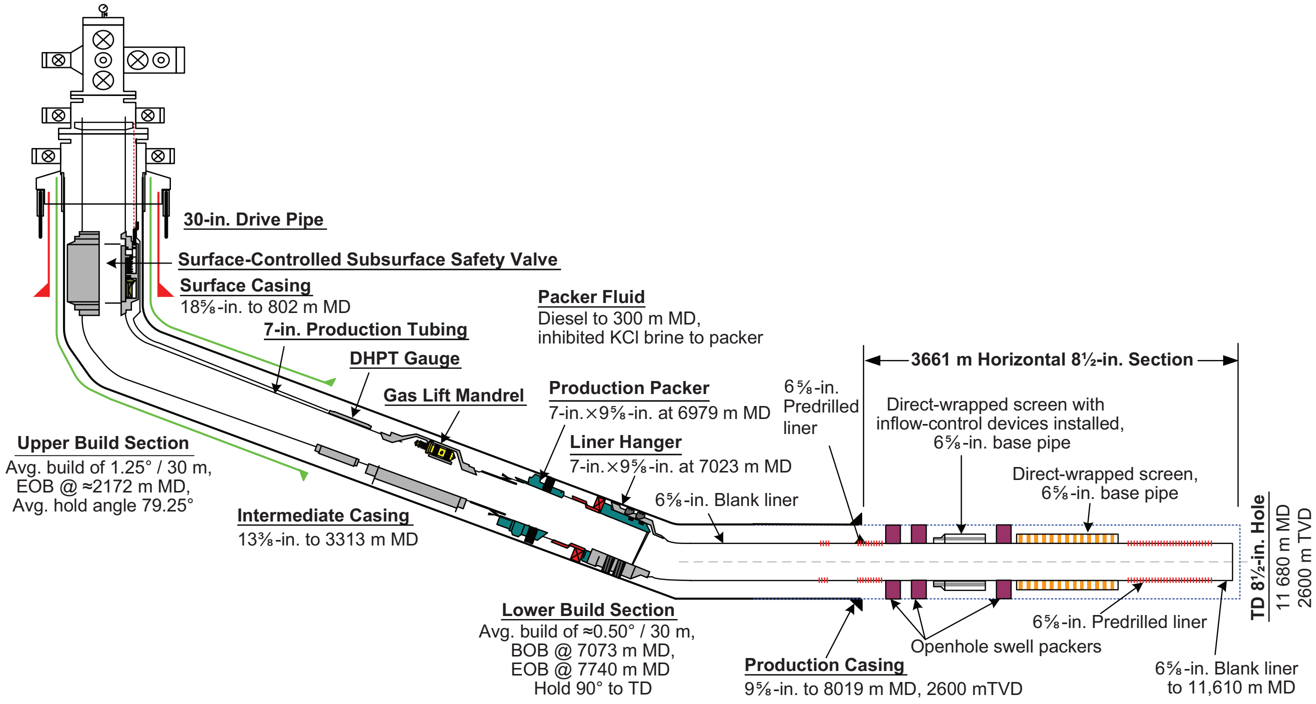

Fig. 1—Chayvo Well Z-12 final completion schematic. BOB=beginning of build, EOB=end of build.

local experience to arrive at a technically achievable and low-cost well plan. A comprehensive "drill the well on paper" exercise was conducted with critical contractors, which provided additional fine tuning of the well plan.

Completion-Liner Running. A detailed analysis of the liner-running history at Sakhalin was performed, with the primary emphasis on understanding issues with stack out while running the liner in Well Z-11. Typically, friction factors of 0.15 to 0.20 in the cased hole and 0.10 to 0.50 in the open hole were used to model liner-running operations. However, a review of the liner runs indicated that openhole friction factors were not consistent across the entire openhole interval. Significant departures from the predicted slackoff hook loads suggested that much higher friction factors were likely in sections that typically corresponded with hole issues while drilling the 8½-in. production hole.

The two key issues addressed on the basis of Well Z-11 analysis were increased hole stability and improved liner-running capability. Hole stability was addressed by increasing mud weight while drilling the 8-in.-hole section. The primary design parameters for the string were its ability to deliver the required weight, to ensure ample slackoff capacity to reach TD, and sufficient stiffness to prevent buckling inside the 9⅝-in. casing. Multiple combinations of 5⅞-in. drillpipe, 5-in. heavyweight drillpipe (HWDP), and 5⅞-in. HWDP, along with 6⅝-in. liner or 7-in. production tubing incorporated into the running string, were evaluated.

The recommended running string used 7-in. production tubing to increase stiffness and mitigate buckling, and 5-in. HWDP to increase available slackoff weight. Adding these elements to the running string, along with the standard 5⅞-in. drillpipe and HWDP, the liner was run successfully to the planned depth of 11 610 m without the stack-out issues. The actual liner run tracked the 0.1- to 0.2-friction-factor prediction to TD of the well, including the entire openhole section. No anomalies or abrupt departures from the predicted slackoff hook loads were seen, indicating that the additional efforts to ensure hole stability in the drilling phase enhanced the running capability of the production liner. Use of the 7-in. production tubing as a running string also prevented buckling and allowed the liner to be run without the use of singles to break static friction when approaching TD.

Upper Operations. The upper portion of the completion, consisting of a seal assembly, production packer, gas lift mandrel, downhole pressure and temperature (DHPT) gauge, and subsurface safety valve were run on 7-in. production tubing. The seal assembly landed in the liner polished-bore receptacle on depth, and the tubing was spaced out and the tubing-hanger set and tested. A backpressure valve (BPV) was set, the surface-controlled subsurface safety valve was closed, the blowout preventers were nippled down, and the rig was skidded to the next slot.

Rigless Completion Operations

Following the rig skid, the tree was installed and the BPV was pulled. Once the tubing and liner lap were displaced to diesel, 25 bbl of diesel was pumped down the annulus for freeze protection. The annulus was shut in and pressure applied down the tubing to burst a rupture disk and set the production packer by use of wellbore hydrostatics. The DHPT gauge was monitored to ensure sufficient pressure was applied to set the production packer fully. The annulus pressure then was bled to zero, and the tubing pressure was monitored to ensure that the production packer was sealing. With the well ready to be brought on line, it was handed over to the production team for final hookup to flowline. The final completion schematic is shown in **Fig. 1.** **JPT**

Trials and Tribulations of a Long-Reach Well in Deepwater GOM

For deepwater offshore areas with irregular water-bottom topography, subsea infrastructure above the field often can be limited. Access to reservoir targets becomes constrained, particularly when drilling challenges exist above the reservoir, such as pressure ramps or layers with unstable lithologies. Long stepouts can be required. Strategies implemented to drill and access reservoirs successfully in a large faulted anticline in the deepwater Gulf of Mexico (GOM) are presented.

Introduction

Discovered in 1998, the subject field is in the Green Canyon protraction area of the GOM in a water depth of 6,800 ft. The main reservoir targets are stacked oil-bearing turbidite sands at a depth of approximately 9,800 ft below the mudline. As shown in **Fig. 1,** the field is a large faulted anticline 11 miles long by 4 miles wide. Development is complicated by shallow salt fingers that obscure seismic imaging of the north flank of the structure and create a complex water bottom across the middle of the field where water depth changes 2,200 ft across a 1-mile width. Because of this lack of clarity on the northern flank, the south flank of the field was developed first from a central drill center, designated as Drill Center One (DC1).

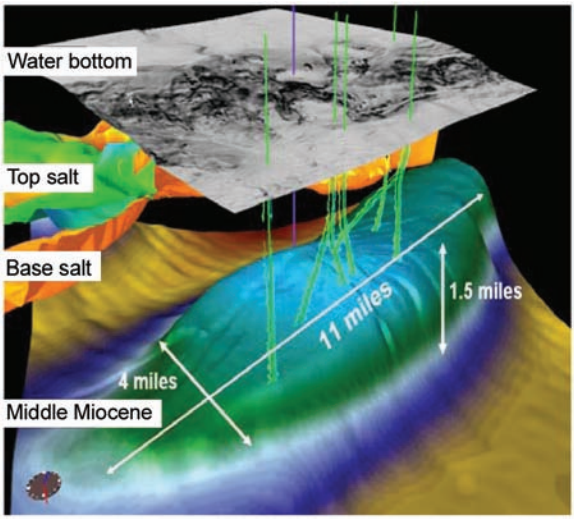

Fig. 1—Well U targeted Miocene reservoirs in a faulted anticline structure.

This article, written by Senior Technology Editor Dennis Denney, contains highlights of paper SPE 118705, "Trials and Tribulations of a Long-Reach Well in the Deepwater GOM," by ***Ron Day, Ramsey Fisher,*** *SPE, and* ***Louise Jacobsen Plutt,*** *SPE, BP plc, and* ***Nesny Pardo,*** *SPE,* ***Segun Jebutu,*** *SPE, and* ***Hans-Christian Freitag,*** *Baker Hughes, prepared for the 2009 SPE/IADC Drilling Conference and Exhibition, Amsterdam, 17–19 March. The paper has not been peer reviewed.*

Drilling Challenges

Well U was the sixteenth penetration in the field. Like all development wells drilled from DC1, Well U had three strings of casing (36-in. surface casing set approximately 200 ft below mudline; 26-in. conductor casing set at approximately 1,200 ft below mudline; and 20-in. casing set at approximately 2,300 ft below mudline) set during the 2004 batch-set operation. However, Well U, would need to mitigate three main drilling challenges in its remaining 17×20-in., $14^{3}/_{4}\times16^{1}/_{2}$-in., and $12^{1}/_{4}$-in. hole sections. First, Well U would need to navigate through a 1,000-ft-thick laminated and thin-bedded sand, which had caused severe lateral vibrations to the drilling assembly in previous wells, making directional control difficult and occasionally leading to downhole-assembly failures. As a result, vibration management became crucial in drilling the $14^{3}/_{4}\times16^{1}/_{2}$-in. section in one trip. An additional complication in the $14^{3}/_{4}\times16^{1}/_{2}$-in. section was that it would reach total depth in a pressure ramp, which could contribute to borehole instability.

The second main challenge was an 800- to 1,200-ft-thick mass-transport complex, or slump zone, made up of mechanically unstable fine-grained turbidite deposits, as shown in **Fig. 2.** Bedding in this interval can be highly contorted. Hole enlargement occurs in this slump zone, and hole quality can degrade quickly in the $12^{1}/_{4}$-in. section. Optimizing the well trajectory in this interval could minimize hole-instability problems, without increasing well tortuosity while stepping out to deeper reservoir targets.

The third main challenge was to avoid drilling faults within the target horizon because of the effect on reservoir thickness and resulting production. These faults often are not seen

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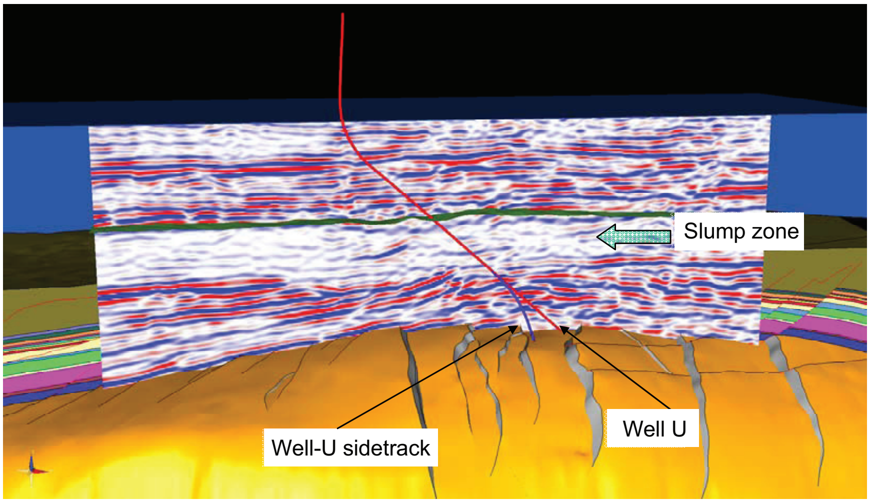

Fig. 2—View of the slump zone above the targeted reservoirs in a north-northwest direction. The mapped horizon is the top of the A sand, and map interpretation is the post-Well-U and Well-U-ST1 drilling interpretation.

on seismic and, in previous wells, have resulted in either sidetracks or in changes to the completion plan.

Hole cleaning in previous DC1 development wells was a challenge with the high drilling rates (greater than 100 ft/hr). With the Well-U trajectory, hole cleaning would become even more complicated in a 48°-angle hole with a long stepout. A constant-rheology synthetic-based-mud system was used. This mud system was similar to conventional synthetic-based mud, but used a different viscosifier package. The mud system provided sufficient hole cleaning and reduced surge and circulating pressures while drilling.

A rotary-steerable system was used for drilling to maintain a low dog-leg severity of 2.5°/100 ft. Drilling parameters were optimized by use of the vibration-management tool, and backreaming was kept to a minimum. Additional challenges in the extended-reach scenario involved the ability to trip the bottomhole assemblies (BHAs) to depth and set casing strings successfully. While tripping out, tight spots were experienced but were worked through successfully. Casing operations were uneventful as a result of hole-cleaning efficiency.

Collaboration in Real Time While Drilling

The well trajectory was planned as a build/hold and build/drop trajectory. Vibration-mitigation-management strategies were used for the $14^3/4 \times 16^1/2$ in. hole section through the laminated-sand interval. While drilling the section, the advanced vibration system detected two major whirl events. Drilling parameters were adjusted immediately, and the section was drilled to total depth in a single run without rotary- or reamer-system failures.

Formation-Evaluation Program

The evaluation program for Well U included only logging-while-drilling (LWD) tools, given the hole angle, long stepout, and challenges of wireline logging in previous development wells with inclinations greater than 40°. The formation-evaluation program for the $14^3/4 \times 16^1/2$-in. hole section included structural dip and azimuth by use of a dual-gamma-imaging tool, along with gamma ray, resistivity, and pressure-while-drilling tools.

Formation evaluation for the $12^1/4$-in. hole included structural dip and azimuth by use of density and dual-gamma-imaging tools, an LWD formation-tester tool, an LWD pressure tool, and gamma ray, resistivity, density, and neutron tools. The drilling rate of penetration (ROP) was maintained below approximately 180 ft/hr in the $12^1/4$-in.-hole section to provide high-quality images for good-quality dip and azimuth data. Real-time formation-pressure data and rush processing of the azimuthal-density image confirmed that the well had crossed an unexpected fault zone, which resulted in the absence of one of the targeted reservoir sections. Structural data derived from the density-image log and projected fluid contacts based on LWD formation-pressure tests were integrated into the existing field model rapidly, and a recently acquired seismic volume was examined. This process allowed the team to update the field's structural model quickly, define the fault-block size, and then plan and deliver a sidetrack well.

During drilling of the $12^1/4$-in. hole, the equivalent circulating density averaged 12.03 lbm/gal and the acoustic caliper on the azimuthal-density tool showed that 99.8% of the borehole was within $^1/4$ in. of the bit size, or in gauge. This condition was typical of previous DC1 development wells that showed the borehole to be in gauge while drilling, but in which hole conditions would degrade and enlarge with time. The azimuthal formation-bulk-density measurements indicated that the borehole was enlarging and becoming unstable as tripping out of the hole operations progressed while collecting LWD formation pressures and backreaming tight spots. In the subsequent sidetrack well, the same section was drilled with an 11.8-lbm/gal mud without incident.

Summary

Long-reach-well trajectories are viable for economic development of deepwater fields. Incorporating lessons learned and the real-time collaboration of the rig, drilling-engineering, and subsurface staffs allowed Well U and the Well-U sidetrack to be drilled successfully.

Major achievements included the following.

- No health or safety incidents occurred during drilling of Well U.
- Minimal hole problems were encountered on the field's longest stepout well.
- Some 96 successful LWD formation-pressure tests were performed in one well.

Given the drilling and subsurface challenges faced in Well U, it still achieved a drilling rate of 26.5 days/10,000 ft. Future extended-reach developments, including future DC1 development wells, will benefit from lessons learned from this well. **JPT**

New Technology Applications for Improved Attic-Oil Recovery: Slim Smart Completions

Smart completions, passive inflow-control devices (ICDs), and maximum-reservoir-contact (MRC) wells are some recent technologies used to enhance recovery and extend the life of mature oil fields. In a Saudi Aramco field, one challenge was to maximize production from the inadequately swept attic-oil zone. Since 1995, new technology has improved oil recovery from this thin attic-oil zone. Technology deployments included recompletion with short-radius-horizontal (SRH) sidetracks, single-lateral re-entry sidetracks equipped with passive ICDs, and multilateral MRC wells equipped with intelligent completions. A slim smart completion (SSC) was run in a multilateral sidetrack enabling production optimization and control of individual laterals.

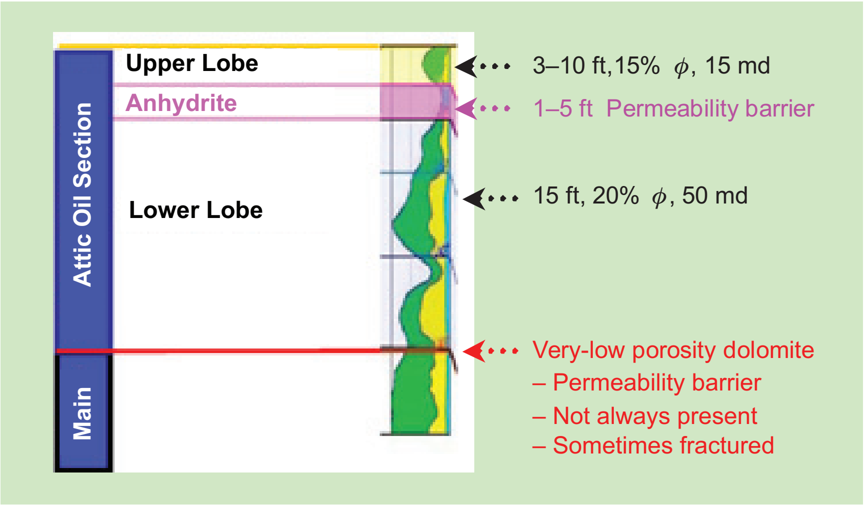

Fig. 1—Attic-oil layering schematic. ϕ=porosity.

Introduction

This field in Saudi Arabia was discovered in the early 1940s. A pressure-support program was started after 8 years of primary depletion. During a 24-year period, the produced solution gas was reinjected as part of the reservoir-pressure-support program. Gas injection was into the primary reservoir at the crest of a high-relief dome feature. A flank water-injection program was started in the mid-1950s, and it became the main field pressure-support mechanism.

After more than 60 years of production, approximately 57% of the oil initially in place in the primary reservoir has been produced. Still, the field water cut has remained less than 35%. The absence of vertical barriers, relatively long distance from injector to first-row producers, and managed production offtake have allowed gravity to play the primary role in the recovery process.

The main-reservoir permeability distribution (higher permeability toward the top, excluding the top 25 ft) allowed oil production from the top section while gravity drainage occurred in the lower, poorer reservoir section. As a result, water production has been very limited. The normal production practice during the first 34 years was to shut in any producing well with crude samples containing salt.

This article, written by Senior Technology Editor Dennis Denney, contains highlights of paper IPTC 12365, "New Technology Applications for Improved Attic-Oil Recovery: The World's First Slim Smart Completions," by ***Stig Lyngra,*** *SPE,* ***Abdulkareem M. Al-Sofi,*** *SPE, Uthman* ***F. Al-Otaibi,*** *SPE,* ***Mohammed J. Alshakhs,*** *SPE, and* ***Ahmad A. Al-Alawi,*** *SPE, Saudi Aramco, prepared for the 2008 International Petroleum Technology Conference, Kuala Lumpur, 3–5 December. The paper has not been peer reviewed.*

Attic-Oil Target Zone

The attic-oil section is approximately 25 ft thick. Saturation logs run in 2007 in wells very close to flank injectors indicated that this interval is at original oil saturations. **Fig. 1** is a schematic showing the main layering of the attic-oil interval.

Early Attic-Oil Development

Attic-oil development started in the early 1990s with recompletions by setting through-tubing bridge plugs in vertical wells. These wells penetrated the entire reservoir section, but only the attic-oil interval was left open after plugback. The early development phase consisted of the following well types.

- Pre–1995: vertical wells
- 1995–2003: SRH wells
- 2003–07: long-radius-multilateral sidetracks

The vertical wells yielded very little production. Significant production started in the mid-1990s with the first single-lateral SRH well.

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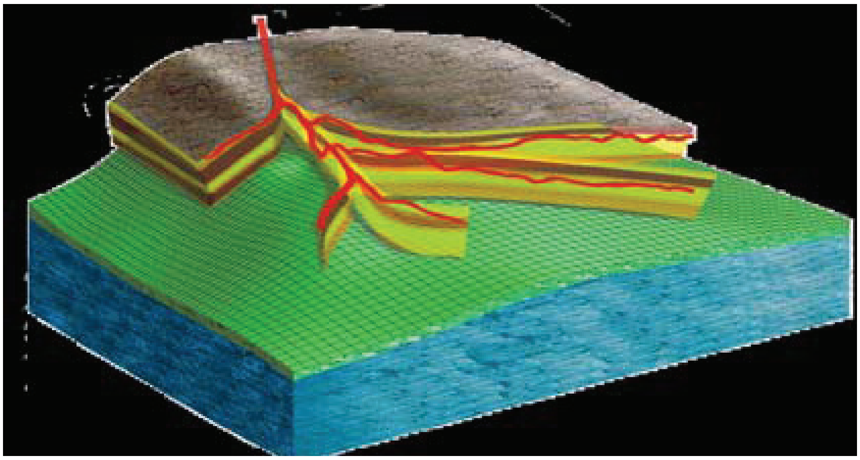

Fig. 2—Quadrilateral design of the first MRC producer.

MRC Multilateral Producer

The long-radius re-entry sidetrack was an improvement over the SRH well. The SRH sidetracks had a high failure rate. Wells would not flow or came in at high water cut after sidetracking. As a result, the MRC well became the preferred well type for this development. The first attic-oil MRC well was completed in June 2003.

The well was drilled as an $8\frac{1}{2}$-in. motherbore cased with a 7-in. liner. A $6\frac{1}{8}$-in. motherbore extension was drilled, followed by two openhole sidetracks from the motherbore extension. Two additional laterals were opened from the 7-in. liner. The quadrilateral design is shown in **Fig. 2.** The total openhole reservoir contact for this first MRC well was approximately 7 km. The restricted oil-production rate throughout the life of the well has been approximately 6,000 STB/D. The water cut has increased gradually to approximately 40%.

Development Status and Current Development-Well Types

The attic-oil-zone development program was executed during 2006–07. This zone has 98 km of active-well reservoir contact. All new wells drilled since 2004 have been MRC multilateral producers with smart completions. Because early water breakthrough was a problem in the first MRC well, individual lateral control was needed to control water production for prolonged well life and improved recovery—hence, the smart completion.

Two types of re-entry sidetracks are used, single-lateral sidetracks with slim-hole passive ICD completions and re-entry sidetracks with openhole SSCs. In the dome region, multilaterals are impractical because of the steeply dipping structure. The fracture density in this region has resulted in rapid water breakthrough from below, resulting in short well lives. The first slimhole passive-ICD completion was deployed in May 2006 into a single-lateral sidetrack. This type of completion has been used in nine re-entry attic-oil single-lateral sidetracks. These sidetracks were drilled along strike on the flank of the dome. Multiarm-caliper and image logs are run before running the completion. If any major fracture zones were observed, blank pipe and packers were used to isolate the fracture zones from the productive-well intervals to prevent water production and prolong well life. The slim-ICD-completion sidetracks are producing 3,000 to 5,000 STB/D at low water cut.

First SSC Deployment

In the planning process for the re-entry operation, it was evident that the standard technology used for a sidetrack out of a 7-in. liner would prohibit installation of a production SSC system because the openhole size was $3\frac{7}{8}$ or $4\frac{1}{8}$ in. The possible remedial options are severely limited in these hole sizes. A larger hole was needed to install an SSC. This need was met with expandable liner and the slimhole smart-completion system. A $5\frac{1}{2}$-in. expandable liner was used as an intermediate-liner string set at the top of the reservoir. This liner is required to isolate a permeable section just above the primary reservoir. An SSC was developed to pass through the post-expanded 5.5-in. inner-diameter (ID) liner.

The first workover operation was to mill a window in the existing 7-in. liner approximately 800 ft true vertical depth above the top of the reservoir, and drill a $6\frac{1}{8}$-in. hole to the top of the reservoir. The hole was underreamed to $7\frac{1}{8}$ in., and an expandable liner was deployed. After the liner was in position, cement was pumped before an expansion tool was used to expand the liner to an ID of 5.57 in. Subsequently, the reservoir section was drilled as a trilateral $5\frac{1}{2}$-in. open hole with 13,300 ft of total reservoir contact. Advanced density-image logging-while-drilling geosteering tools were used for all laterals to keep the well within the thin target zone. The petrophysical evaluation indicated an 18% average porosity with no indication of moveable water.

Thereafter, the completion equipment was run into the openhole section of the trilateral attic-oil sidetrack. Before running the completion, the motherbore was reamed, followed by running a four-arm caliper log with a directional tool. This log confirmed that the wellbore was suitable for running the completion. Use of the directional survey proved that the correct lateral (the motherbore) was reentered. The last step before running the completion was to perform a dummy completion run to verify suitable condition of the hole down to 100 ft below the setting depth of the lowermost packer.

The SSC system consists of three major components:

- Downhole hydraulic flow-control valves—Three downhole valves were run to provide the necessary controls to choke or shut in laterals.
- Downhole-pressure and -temperature gauges—Permanent gauges provide real-time data to optimize well production. After production startup, individual lateral production tests are performed to determine the productivity index and reservoir pressure for each lateral. This information is used with flow-modeling software to determine the optimum flow-control-valve setting for each valve to achieve the desired rate from each lateral.
- Openhole packers—These packers hydraulically isolate and compartmentalize the three laterals. The packer is a hydraulic-set openhole packer with a high-expansion solid rubber element capable of setting and sealing in washouts up to 2.5 in. larger than the run-in outer diameter of the completion string. The packers were set in anhydrite sections to ensure complete isolation from the other laterals. Proposed packer depths were confirmed suitable by the four-arm caliper log as gauge-hole intervals.

After running the completion, a full function test of the completion was performed to ensure valve functionality before setting the packers. The packer seal was tested by applying annulus pressure and monitoring returns. Valve and gauge functionality were tested while flowing back each lateral for cleanup.

The first SSC well was put on production in October 2007 at a restricted oil-production rate of 5,200 STB/D with no water production. A test conducted in August 2008 indicated approximately 10% water cut. Individual lateral testing is performed to identify which lateral is producing water, and then lateral-valve optimization is performed. **JPT**