Na Kika Intelligent Wells—Design and Construction

Reservoir uncertainties in Shell/BP's ultradeepwater Na Kika development (such as compartmentalization, proximity and connectivity between gas- and oil-bearing reservoirs, and aquifer size) made it necessary to design a development plan for maximum flexibility. Intelligent-well technology was used to mitigate these uncertainties in two of the five Na Kika fields. The final development plan featured four intelligent wells to develop reserves from 11 discrete reservoirs.

This article, written by Technology Editor Dennis Denney, contains highlights of paper SPE 90215, "Na Kika Intelligent Wells—Design and Construction," by ***C.D. Stair,*** *SPE, Shell Intl. E&P Inc.;* ***M.E.P. Dawson,*** *SPE, Halliburton Energy Services Inc.;* ***S. Jacob,*** *SPE, Well-Dynamics Inc.; and* ***D.B. Hebert,*** *SPE, Shell Intl. E&P Inc., prepared for the 2004 SPE Annual Technical Conference and Exhibition, Houston, 26–29 September.*

Introduction

The Na Kika development is 144 miles southeast of New Orleans, in water depths ranging from 5,800 to 7,000 ft in the U.S. Gulf of Mexico. **Fig. 1** shows the subsea development that comprises five moderately sized (20 to 100 million bbl oil equivalent) fields, containing both oil and gas reservoirs, tied back to a permanently moored central floating development and production host facility in 6,340 ft of water. This dispersed subsea development does not depend on a single large accumulation of oil and gas. Individual reservoirs in each of the fields contain recoverable reserves as small as 10% of the field totals. **Figs. 2 and 3** show, respectively, the Ariel and Fourier fields that are characterized by multiple stacked discontinuous reservoirs.

Stacking multiple completions in a single wellbore carries risks such as differential depletion and crossflow or early water breakthrough, which require costly well interventions. Intelligent-well technology was used in four of the 10 Na Kika wells to manage the production uncertainties associated with commingling and to avoid well intervention. In the extreme water depths, drilling and completion costs on the order of U.S. $50 million/well for a single-zone completion compelled optimization by combining multiple completions into a single wellbore.

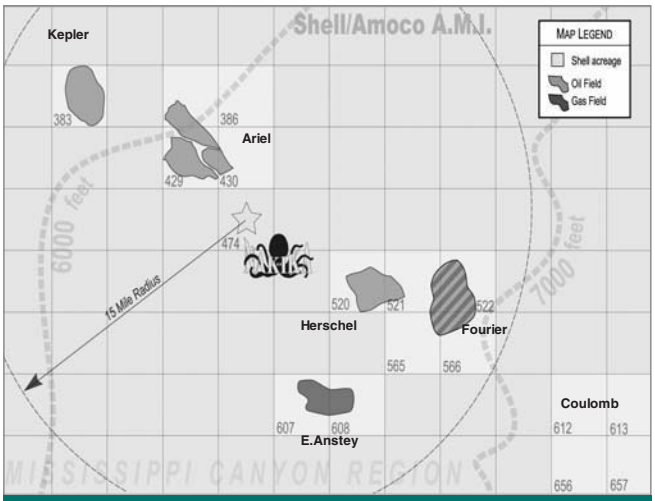

Fig. 1—Na Kika field area.

Intelligent-Well Design

A governing design principle for the relatively shallow, unconsolidated-sandstone formations was that all zones would require competent sand control. To maximize productivity and reliability, cased-hole frac-pack completions were used wherever possible. Because the geometry of frac-pack completions eliminated the capability of placing interval-control valves (ICVs) between zones, the ICVs were run as part of the upper completion. This design allows fluid from the lower zone(s) to be produced up the inner tubular flow path to the lower ICV, which was run inside a shroud to isolate flow between the two ICVs. Production from the upper zone(s) follows an annular flow path around the shrouded lower ICV and into the upper ICV, where production from both intervals is commingled.

The requirement for shrouded-ICV systems in the upper completion limits the number of zones that can be controlled effectively to two per well. In a triple-zone completion, either the upper two zones or the lower two zones must be commingled in an uncontrolled manner, but they can remain isolated from the third zone.

Completion designs for the 10 Na Kika wells were standardized, where appropriate, to simplify logistics and design issues and to enable efficient equipment usage. As part of this effort, the deepest zones in the intelligent wells used the same tubing-pressure-activated fluid-loss scheme used in most of the single-zone wells at Na Kika. In the upper zones of the intelligent-well completions, fluid-loss control was incorporated into the isolation string that separated the upper and lower zones.

These isolation schemes allowed a clear separation between the lower (sandface) and upper (production string) completions in each well, avoiding the need to run an isolation string across the gravel packs at the bottom of the upper completions. Instead, the upper and lower completions were mated at the top of the uppermost sandface completion with a production-seal and latch assembly that completed and isolated the tubing- and annular-flow paths to the lower and upper ICVs, respectively.

Lower-Completion Design

Lower-Zone(s) Mechanical Fluid-Loss Control. In all the intelligent-well completions, the deepest zone used a ball-and-seat arrangement, integral to the gravel-pack assembly (GPA), for mechanical fluid-loss control following placement of the gravel pack. The fluid-loss ball was held on its seat by gravity and positive differential pressure from above. If positive differential pressure develops from below the ball, it would lift off its seat and allow the well to flow. Ultimately, the fluid-loss ball

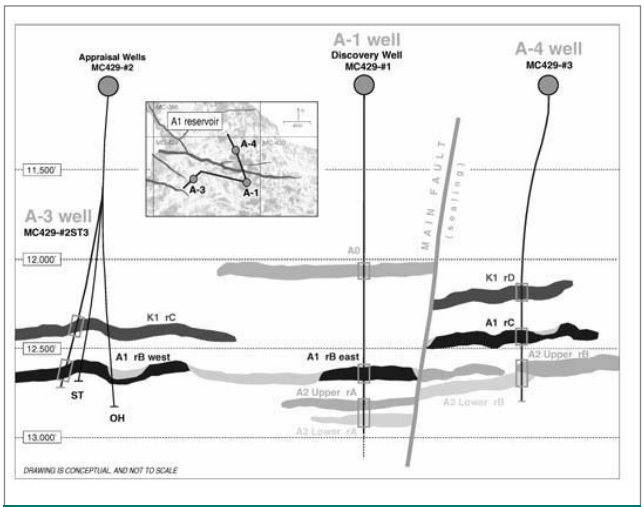

Fig. 2—Ariel field layout.

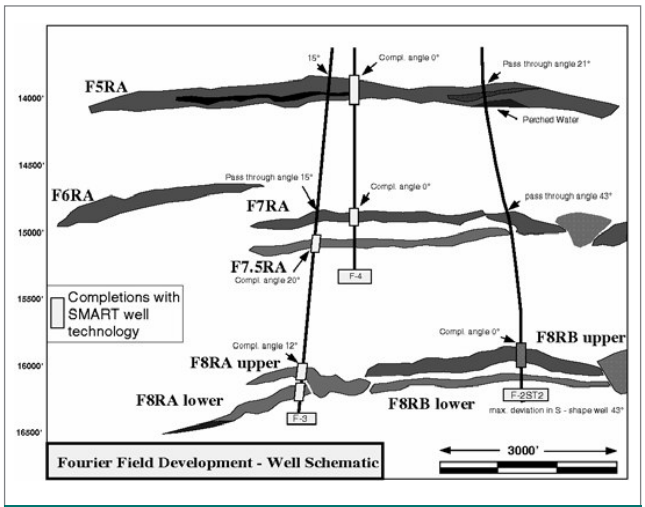

Fig. 3—Fourier field layout.

expends when sufficient tubing pressure is imposed from above to shear the collet into a recess, allowing the ball to fall into the sump. If a second zone were opened above a zone isolated with the ball-and-seat-type mechanical fluid-loss device (MFLD), the pressure gradients in the two zones must be close enough to keep the ball on its seat without allowing it to expend. The zones also must be in close enough proximity that no significant "dead spaces" are created above the ball and below the upper zone to avoid the exchange of completion brine for hydrocarbons in the dead space.

Isolation Assemblies. Certain wells had considerable separation between the lower zone(s) and the uppermost interval. In these cases, a separate isolation assembly was run between the zones. The isolation assemblies were built to expend the lower-zone fluid-loss balls hydraulically when landed. The full-bore isolation valve in the isolation assembly provided a bidirectional barrier that hydraulically isolated the upper interval from the lower interval(s), eliminating fluid loss to the lower interval(s) during subsequent operations.

Upper-Zone(s) Mechanical Fluid-Loss Control. The upper zone of each intelligent completion required the use of a novel fluid-loss device that was run with the GPA. An isolation tube was set across the upper-zone screens to provide a flow path for the lower-zone fluids, while the upper-zone fluids flow up the outside of the isolation tube to the upper ICV. The upper-zone MFLD sealed off the top of the annulus between the isolation tube and the upper-zone screens.

Upper-Completion Design

The production string in the intelligent-well completions consisted of equipment run in the well above the upper GPA. The equipment, from top to bottom, was as follows.

- Tubing hanger.
- Two flat packs for intelligent-well and surface-controlled subsurface-safety-valve (SCSSSV) control and one encapsulated line for chemical injection.
- Vacuum-insulated tubing.
- The SCSSSV.
- Chemical-injection assembly.
- Intelligent-well completion assembly.
- Sealing polished-bore receptacle with telescoping joint.
- Production-seal and latch assembly.

Intelligent-Well Completion Assembly. This assembly was 63 ft long and consisted of the following (from top to bottom).

- Splice subassembly.
- Retrievable, hydraulically set production packer with control line and tubing-encapsulated-conductor pass-through ports.
- Landing profile for setting a slickline plug (contingency for setting packer).
- Mandrel housing the three pressure/temperature sensors.
- ICV for the upper interval(s) (annular flow path).
- Shrouded ICV for the lower interval(s) (tubular flow path).
- Slickline-retrievable plug to divert flow from the bottom end of the tubing to the lower (shrouded) ICV.

ICVs. Each ICV uses a tungsten carbide choke with a metal-to-metal sealing surface rated to 7,500-psi differential pressure in either direction. Each ICV contains a locking mechanism to lock the choke in the closed position and prevent inadvertent functioning from downhole conditions. In case of damage to the hydraulic control lines, the ICVs are "fail as is." As a backup to the hydraulic operating system, the ICV has a built-in shifting profile to allow the ICV to be shifted by use of coiled tubing or slickline. The tool also has polished surface areas on either side of the ICV to allow the placement of an isolation tube across a leaking ICV.

Downhole Pressure/Temperature Gauges. The mandrel that houses the three pressure/temperature sensors is directly below the production packer and a landing profile. The sensors in the mandrel detect pressure in three locations in the intelligent-well completion assembly. One sensor detects the pressure inside the tubing at the mandrel (the combined flow-stream pressure from both zones). A second sensor detects the pressure outside the tubing in the annulus at the mandrel (pressure of the upper-completion interval). The third sensor monitors pressure in the lower-completion interval and is accessed through a 1/4-in. sensing tube run from the mandrel to the shroud. The second and third sensors monitor pressure upstream of their respective ICVs, enabling pressure-buildup tests on the individual zones when the respective ICVs are closed.

Results

Installation of the intelligent-well completion assembly and the rest of the production string went exceptionally well on all four intelligent-well completions. Deviations from the planned operations occurred primarily as a result of problems with the equipment below the production string,

specifically the MFLDs and isolation valves between certain zones. In several cases, an MFLD or isolation valve could not be cycled open initially because of sand and/or debris on top of the valve. In each case, the intelligent-well completion assembly was subjected to many additional ICV shifting operations, high pressure differentials, and retrieving of the slickline plug at the bottom of the intelligent-well completion assembly to remove debris from the lower completion.

ICV in Well-Suspension-Barrier Application

The Na Kika project was designed so that a separate installation vessel could be used to install the vertical guidelineless subsea trees after each completion was finished. To use a separate vessel for tree installation, the wells required a remotely operated downhole-suspension-barrier system that would adequately contain well pressure so that the blowout-preventer stack could be disconnected after the completion was landed and tested.

An important function of the downhole-barrier system was the capability of opening remotely to avoid the conventional practice of removing barriers by use of slickline through a completion riser after setting the tree. Additional testing was required to demonstrate that the ICVs would hold, leak-free, with differential pressures up to 7,500 psi. This testing was performed to the satisfaction of the U.S. Minerals Management Service, which allowed the use of the ICVs as downhole barriers.

Production Operations

After well-completion operations in February 2003, the wells were suspended with the downhole valves closed. The production systems were commissioned in November 2003, and the wells were unloaded to the host platform and brought on production between December 2003 and April 2004 by opening the downhole valves remotely from the Na Kika floating platform.

Because of well conditions and production requirements, some wells produce from individual zones, while other wells have commingled zones. The permanent downhole gauges provide real-time data on well and reservoir conditions, and the generated data are used on an ongoing basis for production and reservoir-management decisions.

The intelligent completions at Na Kika provide the operator with a high level of flexibility in producing the wells. For example, zones may be individually produced until reservoir pressures enable commingling without crossflow. Zones with high water or gas content may be shut in and other, more-suitable zones opened to compensate. Intelligent-well configurations also enable the operator to respond quickly to reservoir uncertainties by reconfiguring flow into the tubing. Individual zones can be shut in for buildup tests while continuing to produce the remaining zones. Sequential buildup tests avoid wells being shut in and the associated cost of deferred production. JPT

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