Advanced completion, or smart-well, technology is set to play a key role in the development and management of oil and gas fields. Today, the exploration and production industry faces oil-price fluctuations and increasingly hostile operating environments. Smart-well technology is helping operators in the Middle East and Asia to meet these challenges. In this article, Mustafa Sengul of Saudi Aramco, Burak Yeten of ChevronTexaco and Fikri Kuchuk of Schlumberger outline the value of multilateral techniques and examine how detailed modeling of possible multilateral strategies can help asset teams to optimize field development.
Advanced completion can be defined as using technologies that include monitoring and controlling well and reservoir performance without having to deploy a rig or mast to alter the physical configuration of the well. This capability, and the strategy of minimum intervention that it makes possible, can reduce the economic, health, safety, environment risks associated with hydrocarbon production.

When combined with multilateral wells, advanced completions allow the asset team to manage the reservoir more effectively and increase the production and recovery rates. The exploration and production industry has always understood how to optimize economic value through active management of the reservoir. But, until now, market conditions have never provided the impetus for implementation. Technology is a key element in the advanced completion story, but it is the need to overcome new economic challenges that has driven the industry toward the advanced completion concept.

In many parts of the world, easily recoverable reserves are becoming harder to find. For the operators who are aiming to replace their depleting assets and meet future demand, the challenge is to explore deeper reservoir formations, many of which are in deepwater plays or geographically remote locations, with relatively small hydrocarbon reservoirs (Figure 1.1). The whole process of asset management will have to change if these projects are to be economically viable.

Conventional completion techniques tend to result in delayed production and lower net present value (NPV). Oil and gas operators want to accelerate production and secure economic benefits as soon as possible (Figure 1.2). As a well’s life cycle progresses, numerous interventions for data collection, a key part of the reservoir characterization process, and subsequent closure or opening of new reservoir zones will be required. In some cases, these interventions can be the largest single cost in the life of a well. Well-intervention costs are significant in normal completions, but in new and remote subsea plays, intervention needs can be so demanding that the field becomes uneconomic.

These factors define the arena in which advanced completion must operate: they have to be able to accelerate production, reduce the need for well intervention, particularly downhole, and deal with the geological complexity and uncertainty of new or remote subsea fields. Advanced completions deliver flexibility in production management that allows operators to fine-tune productivity by penetrating more of the reservoir than a single-bore vertical or horizontal well (Figure 1.3). Multilateral wells allow higher flow rates at lower pressure drops. In certain situations, producing through shorter lateral branches may prove to be more cost-efficient than producing the same reservoir section through a single, longer horizontal borehole because spreading the production inflow across two or more laterals reduces the frictional pressure losses during production.

When a multilateral approach has been selected for reservoir development, the key challenges facing the asset team are placing the laterals accurately within the productive zones and controlling the flow of reservoir fluids to maximize production and recovery rates. Emerging advanced completion technologies allow asset managers to optimize reservoir performance in real time, and these powerful techniques look set to dominate the management of multilateral reservoirs for years to come. Advanced completions offer unrivalled flexibility and responsiveness, but, in this approach, operators must perform a cost-benefit analysis on a field-by-field basis.

Advanced completion technologies allow operators to reconfigure well architecture at will and to acquire real-time data without well intervention. However, there are additional benefits that can be gained from remote monitoring and control of a well. For example, operators can:

■ optimize reserves by choking zones with high gas/oil and water/oil ratios
■ eliminate intervention, which removes the risk of losing the well and reduces operating expenditure
■ minimize health, safety, and environment risks
■ acquire more accurate data that will facilitate informed decision making earlier in an asset’s life
■ optimize surface facilities and so reduce capital expenditure

The information gathered by smart wells provides a clearer image of the asset. When improved understanding is reached early in a reservoir’s life cycle, the operator will reap greater rewards from the application of that knowledge.
Marginal field exploitation

Advanced completion technology may also help operators to develop marginal fields. Minimal water production, coupled with the high oil-recovery rates that are possible with an advanced completion, makes the technology a natural choice for small or isolated oil accumulations (Figure 1.4). In the future, permanent reservoir monitoring will continue to expand its applications, and production control will become a standard part of completion. There will also be more integration between downhole technology and field management software. This means much greater field automation.

Downhole oil-water separation systems (Figure 1.5) enable engineers to separate produced fluids in the well. This separation results in an oil-rich stream being brought to surface, with the separated production water being reinjected. These systems will accelerate production, increase the recoverable reserves, and offer environmental advantages such as energy savings and smaller topside processing facilities.

Autonomous actuation of control devices in response to changes in water quality, injection pressure, or inflow water cut will improve the reliability of separation systems and enable operators to schedule maintenance by predicting the time to failure using output from the condition-monitoring sensors.

Reservoir management

Advanced completion technology has many potential applications. The most pressing need identified by the industry is minimizing the costs of the intrusive interventions that are required to prevent water breakthrough and sand inflow problems.

In the longer term, the ability to make real-time decisions for all surface and subsurface activities is the key to optimizing reservoir management, and advanced completions will play a central role.

Advanced completions will be particularly useful for water flow control in horizontal injectors, monitoring and control of electrical submersible pumps (ESP); intelligent gas lifting; multilaterals and the solution to crossflow, and intelligent data analysis and control.

Until recently, the main impediments to the adoption of advanced completion technology were concerns about the reliability of intelligent completions and their lack of track record. To overcome these obstacles, Schlumberger has worked to prove and improve the reliability of its systems at every stage in their development. The company has adopted “build on what you know” as its guiding design principle and has developed new systems from proven technologies.

At the strategic level, this has involved identifying and clarifying the risks, and undertaking experimentation, testing, and reliability monitoring and analysis, before carrying out integration testing and installation trials. This work has shown that there is no single solution for reliability testing. Engineers need to combine knowledge from field experiments, laboratory tests,失效设备postmortems, and mathematical analyses in their quest for improved reliability.

Making knowledge work

The range of sensors and measurement devices that can be fitted in wells is expanding rapidly. These systems provide data on reservoir pressure, temperature, flow rate, and even fluid composition. And, when the well features inflow control valves and chokes, data transmitted to surface can be translated into direct corrective action. This process-control loop allows engineers to optimize well performance and, by extension, the performance of entire fields. Data gathered can be used to continuously update field models so that asset teams can make informed decisions in every phase of field development.

Evaluating advanced well completions in Ghawar field

Saudi Aramco has conducted an evaluation study on the potential benefits of deploying and utilizing advanced completion technology within the Arab-D formation of the Ghawar reservoir (Figure 1.6). The study focused on the flanks of the reservoir where the remaining dry oil column is less than 40 ft thick. The aim was to explore the applicability and efficiency of advanced completion as a method for producing the remaining oil.

Well control optimization

A typical advanced completion well, with control and monitoring devices installed, divides the wellbore into several independent branches (Figure 1.7). The ultimate aim of this approach is to balance the inflow rates for each branch and, thus, maximize oil production. The main objectives of any well optimization study are to determine how many downhole flow control valves are required and where they should be placed, and then to develop the optimum scheduling for their use in fluid control operations.

The number and the location of the control devices are influenced by reservoir heterogeneity, particularly faults, fractures, and boundary conditions. Engineers can estimate the number and the location of the valves needed in the wellbore by using reservoir connectivity information, which can be derived from reservoir characterization. Reservoir sections with high flow rates—those dominated by strataform super-permeability (super-K) features or fractures—will lead to high inflow for a particular segment of the well.

Where the well intersects one or more super-K layers, engineers will...
Across section through the simulation model shows detailed permeability distributions and the thin layers that represent the stratiform super-K features (Figure 1.11). The WOC is set at 5560 ft and the structural high is seen at 5600 ft. The reservoir units dip gently to the east, with peripheral injection and a weak aquifer providing pressure support to the model from the east. Porosity and permeability values are represented as being homogeneous within each layer. The stratiform super-K layers are 2 ft thick. The average oil column is around 40 ft thick. The model included the Arab-D zones 1 and 2; generally, zone 2 has much better porosity and permeability than zone 1.

Well options

For the horizontal and multilateral options, the study also examined the potential benefits of using advanced completion technology. An ECLIPSE multisegment well model was used to evaluate the pressure drops within the horizontal well and in the laterals.

Vertical wells

The first option used three vertical wells. The performance of each well (Figure 1.12) is directly influenced by its proximity to the fractures within the reservoir (Figure 1.13). The wells were located 1600 ft apart. The lowest completions in the wells were situated immediately above the water/oil transition zone.

Each well was allocated to produce 2000 STB of liquid and was set a constraint of 250 psi of tubinghead pressure. During the simulations, any completion where water cut exceeded 60% was automatically worked over and its production shut off by the simulator. Vertical wells 1 and 2 required several workover operations. Well 2 was watered out before the end of the simulation period because it was very close to a fracture, whereas well 3, which required no workovers and produced steadily, was located far away from the fractures. For the vertical wells, the cumulative oil production after 1800 days of simulation was 4.37 MMSTB—a recovery of 24%.
Horizontal well
The next option was a single horizontal well about 1-km long and intersecting both fractures (Figure 1.14). In the simulation, the well was not completed at the fracture, thus followed current field practice. Selective perforation was applied whenever possible, especially in thin oil zones. Selective perforation requires a liner, as do advanced completions. However, by not completing the horizontal well at or around the fractures, the detrimental effects of fractures (such as accelerated water breakthrough) are greatly reduced.

As it had been decided not to complete within the fractures, there was almost no potential application for an advanced completion in the horizontal well. There was no preferential coming tendency, nor an obvious path for water breakthrough. However, to test the technology, a single flow control device was installed at the heel of the well and a packer placed close to the midpoint (Figure 1.15). The left branch of the packer had a liner completion, while the right branch had a tubing completion that was required for the flow control device. The well was then ready for cycling, which simply involved opening and closing the valve for set time periods so that production alternated between the heel and the toe of the well. This was done to test whether water moving through the matrix might recede from the areas around the choked branch. It was hoped that this approach would help to reduce water cut and so increase recovery. However, high matrix permeability in zone 2A prevented this technique from working efficiently. When a side was choked, the water did not recede, but moved quickly to the open branch through the highly permeable matrix. Cycling was more effective, but the incremental recovery obtained was little more than 1%.

The standard horizontal well, which was not completed at and around the fractures, produced 5.74 MMSTB of oil—a recovery of 32%.

Multilateral well
The third option considered in the study was a trilateral well with the laterals positioned so as to be consistent with previous well configurations. All three laterals and the main trunk were horizontal (Figure 1.16).

The first simulation for this configuration was performed without advanced completion technology. Figure 1.17 shows the oil production profiles for individual branches. The 6-MMSTB production target was distributed unequally among them and resulted in imbalanced production. Branch A, which was closer to the heel of the well, tended to pull more than the other branches because of pressure losses along the main trunk. Branch B produced significantly more than branch C, especially during the early stages before water broke through. The greater length of branch C, which it was believed might boost oil rates, had little effect on production.

Plots of water cut for each branch (Figure 1.18) indicated that the water content in branch C barely reached 10%, while the other branches watered out early. Water built up quickly in them and reduced the overall oil production.

Production from the trilateral well, without smart control, amounted to 6.16 MMSTB of oil—a recovery of 34%.

Trilateral well with advanced completion
The next step was to transform the well into an advanced completion unit by deploying control devices. Three valves were installed, one for each lateral, on the tubing within the main trunk to act as gates to the main trunk. Altering the closure of each gate controlled the flow. Each lateral was an openhole completion and had its own branch within the main trunk as a result of separation provided by the packers.

An algorithm was developed to determine the optimum closure of the valves at various time steps, thereby maximizing the cumulative oil production.

With optimized valve settings, the oil-production profiles showed that more production was allocated to branch C than to the other branches (Figure 1.19). The production allocation was reset at 720 days to favor branch C, while production from branch A was in rapid decline. Branch B, with its direct connection to the fracture, was given the smallest production allocation.

The smart trilateral well produced 7.14 MMSTB of oil, which corresponded to a recovery of 40%. A comparison of oil production from the original trilateral well with that of the smart trilateral well indicated an incremental recovery of about 1 MMSTB (Figure 1.20). Applying smart-well technology accelerated production and reduced water cut by almost 5% after five years.

The horizontal well had an incremental recovery 31% higher than the three vertical wells, and the
trilateral well with smart control had an incremental recovery 16% above that of its conventional counterpart. All the alternatives with laterals had substantially higher incremental recoveries than the three vertical wells. The additional production obtained from the smart trilateral well was around 3 Mbbl. Recovery from the trilateral well was not substantially better than that from the horizontal well because branches A and B were the main producing laterals on the trilateral well and their combined lengths almost matched the length of the horizontal well. There was, therefore, little difference between the two wells, except that the trilateral well had wider areal exposure to the reservoir. Thus and the additional lateral (branch C) added 427,000 bbl to production. Field economics would have to be used to help the asset team to select the best development option.

The importance of heterogeneity

All of the simulations and optimizations were repeated for various types and combinations of heterogeneity, such as fractures and high-permeability layers, to assess the cumulative production in each case (Figure 1.21). Where there was no special heterogeneity, the three vertical wells performed adequately, but not as well as the unconventional alternatives, which produced about 20% more oil than the vertical wells.

Neither the horizontal nor the vertical wells performed well when exposed to stratum super-K features, since these layers are continuous and bring water quickly from the aquifer to the wells. The trilateral wells were least affected by the presence of stratum super-K features. Their wider areal coverage meant that drawdown was distributed in a plane. As a result, the super-K layers could not influence the well from a single point (as in the vertical well) or from a line of points (as in the horizontal well). The incremental production obtained by applying each well type was crucial in establishing the economic viability of any planned development and would allow the asset team to base its technical planning on sound economic data (Figure 1.22).

Lessons from Ghawar field

The comparison of completion types in Ghawar field indicated that unconventional wells outperformed vertical wells in terms of accelerated production. Multilateral wells offered major benefits, especially when dealing with heterogeneous features of the type that are commonly encountered in Ghawar. Drilling multilateral wells would also allow the asset team to improve efficiency and boost field performance by allocating the appropriate production to each lateral. It may be difficult to determine the optimum production to be allocated for each lateral if there is no history-matched model of the area. In this case, it might be appropriate to test the laterals using the permanent gauges.

The sensitivity studies also indicated that unconventional wells reduced the level of uncertainty concerning oil recovery. Multilateral wells, in particular, have the potential to buffer reservoir performance against the unexpected effects of heterogeneity. Converting these high-performance wells into smart wells would allow the asset team to improve efficiency and boost field performance by allocating the appropriate production to each lateral.

Evaluation and Imaging While Drilling

The RapidConnect system, which provides selective drainable access and connectivity, with expandable sand screens was recently deployed in a multilateral well in the Java Sea, offshore Indonesia (Figure 1.23). The operator’s principal aim was to boost well productivity in an established field. Careful planning and detailed modeling of the asset played a crucial role in the success of this project. Two service companies collaborated on the project, with Schlumberger acting as the main service provider during the planning, drilling, and completion phases. After completing a detailed study of reservoir data, the team optimized well placement using the Brion multipurpose service vessel to drill two sacrificial vertical wells. This careful refinement of the target location helped the team to exploit a net oil pay zone that was much thicker than expected.

The casing window was milled, and the drill-in fluid was circulated to expose new formation, and a directional pilot well was drilled through the reservoir and into the lower water-contact zone. The project completion, may have contributed to a reduction in the skin effect and the much improved productivity index. Since production startup, the multilateral well has surpassed all previous field productivity levels and achieved a stabilized rate of 566 B/D of oil and 4.5 MMcf/D of gas. These rates are three to four times the net oil-production rate for any other well in the field. From spudding to ESP startup, the job was completed in 36 days—2 days ahead of schedule.

Reassessing mature reservoirs

Weizhou field in Bohai Bay, China, (Figure 1.24) is a mature field where pressure has slowly fallen and producing wells have been converted to use ESPs. Oil production from the field has declined, but the continued use of ESPs has raised the drawdown pressure and increased the volume of water produced from the reservoir. Faced with high water cuts in some wells, the operators selected several new wells for temporary abandonment.

In 1999, the operating company decided to use multilateral wells as a cost-effective alternative to drilling new wells. In June 2000, a candidate well was selected and approved. The first step was to isolate the lower unproductive zones. A casing exit window was milled to expose new formation, and a directional pilot well was drilled through the reservoir and into the lower water-contact zone. The project
Managing data throughout the life of a field

In the future, there will be much greater volumes and a wider range of well data, these data will be gathered continuously throughout the life of a field. At present, data are usually restricted to point values of temperature and pressure within the wellbore and to some flow profiling. However, there is considerable uncertainty and ambiguity in this approach.

The additional data gathered from future wells will fall into two categories: well data and between-well data. Within this decade, oil and service companies will definitely enhance the quality of well data, and gather more detailed and accurate pressure, temperature, water-cut, viscosity, and compositional profiles. These will provide substantially more information about the day-to-day performance of both reservoir and well. However, acquiring between-well data is a major challenge. If an asset team could image the structures and fluid flow between wells, it would represent a dramatic step toward managing reservoirs as process-production systems. These developments will help to move reservoir management away from imprecise visualization of what appears to be happening toward more precise mapping of fluid fronts and reservoir properties throughout the reservoir.

More data, more detail

The volume of well data gathered will increase dramatically, and this will influence how the asset team handles and uses data. Traditionally, wellbore data have been low volume and relatively simple. In the future, reservoir management will rely on two-way communication between surface and downhole, with a high-volume data stream from the bottom of the well to the surface. This will provide detailed information on pressure, temperature, and fluids. Surface-data-handling systems and associated network links to the reservoir database are well-developed areas of technology. Transmission speeds and bandwidth will undoubtedly improve and will allow the teams to share information more effectively.

As teams change the way they control assets and move from a simple, extractive model to managed process control, a key consideration will be the design of the reservoir database system. This must store data continually collected from many fields and wells, and provide ease of access to numerous technical specialists.

Software enhancement

The first challenge facing the software developers is how to improve data visualization and interpretation. Interpretation of reservoir behavior requires analysts to examine data at many different scales. For example, a geoscientist examining a 3D image of a reservoir unit may want to examine the pressure history of a particular well that penetrates the unit and then switch to examining a specific build-up from that well. The complex interaction of datasets at varying scales presents a significant challenge to the industry (Figure 1.25).

An improved understanding of reservoir structure and behavior must then be applied to the practical issue of enhancing the field’s economic value by accelerating production, increasing recoverable reserves, or both.

In some oil provinces, engineers are installing downhole systems that allow them to control reservoirs in the same way as process plants. This requires a very detailed understanding of reservoir structure and facies variations (Figure 1.26). In their simplest form, reservoir partition systems divide the reservoir into management intervals. A typical interval would comprise a group of sands or limestones, which are expected to behave as a single flow unit, usually with impermeable layers, such as shales, above and below (Figure 1.27). The ability to differentiate clean sands from shaly sands or shales gives a clearer indication of pay thickness, which can be difficult to establish in thin-bedded reservoirs, and allows the asset team to calculate the sand/shale ratio and define flow units between major shale boundaries. In the wellbore, zone isolation packers separate the production liner into these managed intervals, which are typically between 10- and 30-m thick. Between the packers, variable chokes regulate the movement of fluids in or out of the reservoir management interval. The key components of this system are power supply, surface facilities, control devices, instrumentation, and communications.

The emergence of multilateral wells has greatly improved reservoir management. Increased reservoir coverage allows greater control and, potentially, access to more oil. By adopting a multilateral technique, reservoir engineers can use the primary well to:

- produce oil from low-permeability areas in heterogeneous reservoirs
- access a large number of high-productivity fractures
- reach several reservoirs

manage water and gas injection more effectively.

Controlling the flow from multiple laterals is critical to their success. Basic flow modeling indicates that the highest-pressure lateral will dominate the system and restrict flow from the laterals where pressures are lower.

Downhole choking devices can help engineers to maximize production by choking back flow from high-pressure laterals. Supplying power to the laterals is still a major challenge. Future field developments will deliver improved understanding of the reservoir that should help to increase recoverable reserves beyond the 20% typical in existing fields and to enhance the value of each new field. At the same time, the reduced need for well interventions, for either data acquisition or changing well configurations, should cut operating costs.

Going underground

In the future, advanced completions may also offer processing options such as dehydration, separation and even chemical or energy conversion. Moving surface processes downhole presents a range of technical challenges. However, the potential benefits are minimal surface facilities and wells that deliver only the desired production fluids.

The technology associated with advanced completions is moving rapidly. Those who adopt this approach to well control and field management are helping to define how the industry will develop over the coming decades.

Figure 1.25: The complex interaction of datasets from various sources and at varying scales presents a significant challenge to the industry. Seismic, well, and production data all influence the reservoir model and simulations based on it.

Figure 1.26: Reservoir facies derived from image heterogeneities and openness log is a lower Cretaceous limestone sequence. The degree of detail is essential in reservoir development and helps reservoir engineers to plan multilateral wells.

Figure 1.27: The high-resolution conductivity measurements recorded by the FMI* UltraFast Formation Microimager help geologists to calculate sand/shale ratios and identify the sedimentary features that influence reservoir performance.