Many Middle East operators see multilateral drilling as a logical ‘next step’ from horizontal drilling, which has become commonplace in the Middle East. Multilaterals are particularly effective in complex carbonate reservoirs, but they have not been widely adopted as a result of general skepticism over risks, and more practical deterrents, such as the engineering of reliable, safe junctions in production strings.

All that is changing. One ingenious solution is a prefabricated, subsurface wellhead assembly that can be ‘unwrapped’ and installed downhole, splitting the main bore into two smaller, equal-sized, lateral bores and providing a high-pressure seal at the junction.

Asset teams are now turning their attention to the application of multilaterals in more hostile environments, where economic returns are greatest, and to the potential for ‘intelligent’ systems for remote monitoring and adjustment of reservoir conditions to achieve optimum completions.

In this article, Bernard Montaron, Tim O’Rourke, and John Algeroy introduce these rapidly advancing technologies.
For many years, field engineers and operating companies in the Middle East have battled with the challenges of obtaining maximum exploitation of reservoirs as safely and economically as possible. During the 1980s, improvements in horizontal technology were adopted quickly in the region to bring about significant improvements in productivity. The logical next step, keeping abreast of drilling technology, was to drill multilateral wells that allowed all the benefits of horizontal wells to be carried forward to multilayered or ‘stacked’ reservoirs as branches from a single main borehole.

Seen by some as risky and not sufficiently proven, multilateral drilling made its somewhat shaky debut in the Middle East in the mid-1990s. Much work has been done since, particularly to improve the construction and integrity of multilateral junctions, and today’s confidence is evidenced by the hundreds of multilateral wells now in existence.

No revolutions in Russia

Multilateral drilling has its origins in Russia during the 1940s. At that time oil was a strategic commodity in the Soviet Union and served as a ‘currency’ that could be exchanged for grain or other consumer goods. High quotas were imposed on drillers to bore as many holes as possible, in the belief that the more holes drilled, the greater the chance of tapping a reservoir and the greater the likelihood of an increase in production.

This supposition was contested by a Soviet innovator and inventor, turned drilling engineer, Alexander Mikhailovich Grigoryan, who believed that more oil could be produced by following a known oil sand rather than simply penetrating it with a number of boreholes. In 1941 Grigoryan drilled one of the world’s first directional wells – Baku 1385 – nearly 20 years earlier than anyone else. Without a whipstock or rotating drillstring, he used a downhole hydraulic motor to penetrate oil-bearing rock, significantly expanding reservoir exposure and production. This was the first time that a turbodrill had been used for both vertical and deviated sections of a borehole.

Grigoryan’s pioneering work led to scores of other successful horizontal wells across the USSR and he was promoted to department head at the All-Union Scientific Research Institute for drilling technology (VNIIBT). He went on to develop a new, borehole-sidetrack, kickoff technique, and a device for stabilizing and controlling curvature without deflectors.

However, his main contribution to drilling technology was still to come. This involved expanding on the theory, previously proposed by American scientist L. Yuren, that production could be improved by increasing the diameter of the borehole. He stated that branching the borehole in the productive zone “just as a tree’s roots extend its exposure to the soil” would increase production.

The theory was put to the test in the Bashkiria field complex (in what is today Bashkortostan, Russia) where Grigoryan drilled Well 66/45, the first multilateral well, using turbodrills without rotating drillstrings.

In the Bashkiria complex, late Carboniferous reefs had trapped vast oil reserves. However, most of the wells had been producing since before 1930 and were producing low volumes when Grigoryan drilled the first multilateral.

In 1953, Grigoryan selected Bashkiria’s Ishimbainefi field to drill Well 66/45 (Figure 3.1). This field contained an interval of Artinskian carbonate rocks with good reservoir properties over a wide area. The target was the Akavassy horizon, which was an interval with thicknesses varying from 10 to 60 m (33 to 197 ft). Nine branches were drilled from the borehole below 375 m (1230 ft). This was done without whipstocks or cement bridges, drilling by touch, with each branch extending from 80 to 300 m in different directions into the producing zone. The drill bit was allowed to follow the pay zone into the most productive areas and curved
automatically to follow the planned trajectory. Speed and penetration rate depended on the hardness of the rock and the power of the downhole motor. The nine producing laterals of Well 66/45 had a maximum horizontal reach of 136 m from the kickoff point and a total drainage of 322 m (1056 ft). It cost about 1.5 times as much to drill as the other wells in the field, but penetrated 5.5 times the pay thickness and, at 755 B/D, was 17 times more productive.

Over the following 27 years, a further 110 multilateral wells were drilled in Russia – 30 of them by Grigoryan himself. About 50 of these early multilaterals were exploratory and the remainder were for delineation of reefs and channel structures.

Many benefits

Until 1980, when ARCO drilled the K-142 dual-lateral well in New Mexico’s Empire field, there had been no attempts at multilateral drilling outside the USSR. This type of drilling was considered too risky and difficult as well as requiring substantial investment of time and money. For years, because there were few reliable examples of successful multilateral applications, operators lacked benchmarks for identifying suitable candidates for multilateral development. Higher initial costs, the risk of interference between laterals, crossflow, and difficulties with production allocations all hindered the introduction of multilateral technology. An increased sensitivity to and concern about reservoir heterogeneities such as vertical permeability also deterred multilateral development.

Complicated drilling, completion and production technologies, complex and expensive stimulation, slow and less-effective cleanup, and cumbersome wellbore management during production were all seen by operators as further obstacles.

Between 1980 and 1995, only 45 multilateral completions were reported, but since 1995 hundreds more multilateral wells have been completed and many more are planned, thanks to improved techniques and increased confidence.

Even today there are still acknowledged risks in multilateral wells such as borehole instability, stuck pipe, cementing and branching; but in the 1990s, as more multilaterals were drilled successfully, even the simplest wells confirmed the potential of this emerging technology. The main benefits of these successful wells were increased production, increased reserves, and overall reductions in reservoir development costs.

Traditionally, increasing the productivity of known reserves has been achieved by drilling additional wells to increase drainage and sweep efficiency. Multilateral technology provides the required increased contact between the borehole and the reservoir without drilling additional wells. By drilling the main trunk and overburden to the reservoir only once, surface can continue to be a single installation with obvious cost savings over the multiwell situation. Similar benefits can be seen in offshore and subsea scenarios where a limited number of slots are available, and in onshore locations where surface installations are particularly expensive.

Multilateral penetrations are commonly used to increase the effective drainage and depletion of a reservoir, particularly where low permeability restricts hydrocarbon mobility or low porosity limits production flow. When independent reservoirs are targeted, production can either be commingled into a single production tubing string or produced separately in multiple strings (Figure 3.2). Multilateral wells are also economic for rapidly depleting a reservoir; effectively accelerating production, shortening the field life cycle, and reducing operating costs.

Multilateral wells are more efficient than conventional or horizontal wells in thinly layered formations or significantly fractured systems, or for specific enhanced oil-recovery situations such as steam-assisted gravity drainage. The application of multilateral technology can also reduce water and gas coning.

Improving the vertical and horizontal drainage of reservoirs increases recoverable reserves significantly, while both capital and operating costs per well and per field are minimized. In fact, the cost of achieving the same degree of

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Figure 3.2: In shallow or depleted reservoirs, branched horizontal wellbores are often most efficient, whereas in layered reservoirs, vertically stacked drainholes are usually best. In fractured reservoirs, dual-opposing laterals may provide maximum reservoir exposure, particularly when fracture orientation is known.
drainage with conventional wells would be prohibitive in most cases, especially in situations such as deepwater, subsea developments. The costs of multilateral wells can be recovered over several reservoir penetrations and, in some cases, the need for infill drilling has been eliminated completely.

Multibranched wells can tell operators a great deal about their reservoirs. This is particularly advantageous in anisotropic formations, where the directions of preferred permeability are unknown. In these cases, lateral branches can help compensate for nonuniform productivity, with corresponding economic benefits and enhance formation evaluation.

**Classification on the level**

In 1987 in Aberdeen, Technology Advancement-Multilaterals (TAML) – a forum of experts in multilateral technology from leading oil companies – set out to define a system of classifying multilateral wells in terms of complexity and functionality, which would also relate to difficulty and risk. The complexity of multilateral wells is now described on a scale from Level 1 (the simplest) through 6S (the most complex) (Figure 3.3), with an additional code representing type and functionality.

The most difficult part of drilling a multilateral well is producing a stable junction between the main trunk and the wellbore branches. For this reason about 95% of the world’s multilateral wells have been at level 1 or 2. But in 1998, about 50% of the multilateral wells drilled were level 3 or 4. Rapid advances in multilateral connectivity, accessibility and isolation capabilities, together with new junction systems, are allowing operators to select more-complex solutions.

**Level 1:** Openhole sidetracking technique. The trunk and laterals are all drilled in openhole, usually in hard rock with unsupported junctions. Lateral access and production control is limited. This is similar to the pioneering multilaterals that were drilled in Russia.

**Level 1:** The main bore is cased and cemented but laterals are in openhole, although sometimes they have a ‘drop-off’ liner that is not cemented or mechanically connected to the main casing. RapidAccess® multilateral completion systems that provide selective

**Figure 3.3: Multilateral configurations and classification by level**
drainhole access addressed some of the shortcomings associated with current multilateral practices, such as:

- uncertain accessibility to the laterals for workover
- casing obstruction and/or reduction of effective inside diameter
- reduced casing stress, running casing and placement of the window
- inflexible drilling sequence.

RapidAccess is designed to be installed for either immediate use or for future use in reentry operations. Sidetracks can be performed and then the whipstock can be retrieved leaving unobstructed, fullbore casing. This allows operators to readily access the sidetracked wellbores remaining. Multiple RapidAccess couplings can be installed in casing strings to allow many reservoir penetrations for optimum field development. In these cases, depth and orientation can be determined by a monitoring-while-drilling survey after cementing, or by coiled-tubing or wireline conveyed USI UltraSonic Imager surveys (Figure 3.4).

The complete system

The complete RapidAccess System has several main components:

- The indexed casing coupling (ICC), a casing nipple with selective key profiles to accommodate sidetracking and completion tools. It uses a muleshoe orienting profile to receive a key that rotates the whipstock or reentry deflection tool (RDT) assembly to the desired orientation relative to the muleshoe’s orienting keyway.
- The selective landing tool (SLT) is a locating and anchoring device. It has selective keys that allow it to be positioned in the profile of the desired ICC along with its attached tool such as a whipstock, RDT and orientation confirmation assemblies.
- The RDT assembly is recoverable by overshot. It resembles a small whipstock and acts as a guide for rotary drilling, running liner, completion equipment running and workover operations.

Drillers can also carry out window milling in existing wells using conventional retrievable whipstock or cement plug techniques. Premilled casing subs are sometimes employed to avoid the increased risk of milling in situ. The Level 2 RapidAccess process is shown in Figure 3.5.

**Level 3:** Both connectivity and access are present in Level 3 multilaterals. The main trunk and laterals are cased, although only the main bore is cemented. There is no hydraulic integrity or pressure seal at the lateral-liner-to-main-casing junction but there is main bore and lateral reentry access. The Level 3 RapidConnect* multilateral completion system (selective drainhole access and connectivity) provides high-strength junctions – where lateral liners are anchored to the main bore by liner hangers or other latching systems – and is important in wells where sand or shale may affect well stability.

In Level 3 systems, upper laterals can be isolated at the junction to allow production from lower laterals. Selective access to laterals is achieved by the oriented diverter positioning.

A complete Level 3 RapidConnect system has several main components (see Figure 3.6):

- selective landing sub (SLS)
- template
- connector.

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*Note: Figures 3.4, 3.5, and 3.6 show diagrams and images related to the RapidAccess and RapidConnect systems, illustrating the components and their configurations.*
The most common completion performed in Level 2 and 3 wells is uncemented, predrilled or slotted liners and prepacked (but not gravel-packed) screens. Anadrill uses a drop-off liner completion design in which the top of the liner in the lateral is immediately released outside the casing exit through a hydraulic sub. External casing packers are often used in the drop-off liner completion assembly to isolate zones, anchor the liner top and facilitate reentry access to the liner.

Another mid-tier approach to multilateral completion offers only individual hydraulic isolation of a lateral. In this case, laterals are drilled using whipstock sidetracking procedures, and any completion performed in the lateral uses a drop-off liner. Conventional casing packers in the main casing with tubing between them – straddle packers – are used to isolate each of the laterals hydraulically. Production from the laterals is controlled with sliding sleeves and other flow-control devices. This is an inexpensive and relatively straightforward multilateral completion method that was proven in the North Sea and is now being adapted for deepwater, subsea wells.

The critical technology in these completions is operation of flow-control

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**Figure 3.5: Level 2 RapidAccess**

1. The main wellbore casing is run with indexed casing couplings (ICC) as integral components. 2. The main wellbore casing is cemented. 3. The lower branch is drilled, completed and isolated with a retrievable bridge plug. 4. The coupling orientation is determined from a USI log or by running a selective landing tool (SLT) with Slim 1* slim and retrievable MWD system in the universal bottomhole orienter (UBHO). The coupling can be cleaned during this trip and a gel pill may be spotted in the kickoff section to suspend debris. 5. The whipstock is aligned with the SLT key and run into the well. The assembly automatically aligns and latches and the milling tool is released from the whipstock. 6. A casing window and short section of pilot hole are cut with the special milling assembly powered by a downhole motor. 7. After a lateral is drilled to depth, the well may be left openhole or as a simple cemented or drop-off liner run. The SLT is released and the entire assembly is retrieved. The hole is cleaned out and the bridge plug removed.

8. The process is changed for a cemented liner by replacing the full-size whipstock with a smaller diameter reentry deflection tool (RDT) that is run and latched into an ICC. 9. The bottomhole assembly (BHA) is run and a lateral branch is drilled. 10. A liner is run into the lateral and may be cemented back into the main casing. 11. The liner running tool is released, the hole cleaned up by reverse circulating and the liner running tool is pulled out of the hole. 12. After the lateral is completed the RDT is retrieved by releasing the SLT. RDT and SLT are pulled from the well. 13. The lower wellbore section is cleaned out, the isolating bridge plug retrieved and the main bore is ready for completion.
devices downhole. Schlumberger Camco intelligent well technology is now capable of activating and controlling these flow control devices remotely.

**Level 4:** In Level 4 wells, both main bore and laterals are cemented at the junction. This provides a mechanically supported junction with the lateral cemented to the main casing, but no hydraulic integrity. The sidetrack is usually achieved by whipstock-aided milling of the casing windows, although premilled windows may be used in some cases. There is no pressure seal at the junction, but main bore and laterals have fullbore access. Level 4 technology is complex, high-risk and still under development, but it has been successful in multilateral wells worldwide.

**Level 5:** The techniques used in levels 3 and 4 for lateral connections are also used in Level 5, but additional completion equipment is employed to create a pressure seal across the junction of the lateral and the main casing. Cement is not acceptable for hydraulic isolation of the junction. Isolation is achieved using auxiliary packers, sleeves and other completion equipment in the main casing bore to straddle the lateral junction with production tubing. This arrangement provides reentry to both the main bore and the laterals.

**Level 6:** Level 6 multilateral techniques were first evaluated by Schlumberger in 1995 with a system developed by Anadrill, Camco and Integrated Drilling Systems. There has recently been much research and development effort concentrated on sealing for hydraulic isolation and pressure integrity for Level 6 junctions. (See separate panel, overleaf.)

**Level 6S:** This is a subset of Level 6 that uses a downhole splitter, or subsurface wellhead assembly to divide the main bore into two smaller, equal-sized, lateral bores.

Multilateral technology is now focused on new Level 6 designs. A major part of this development centers on the most difficult aspects of multilateral technology, hydraulic isolation and integrity at high pressure.

**Starting at the bottom**

When planning a multilateral well, the first step is to establish the desired position of each lateral in its producing formation. The design is then worked back until the trajectories of all the laterals, the main bore up to the wellhead, have been determined. This process must consider reservoir properties such as the rock-stress regime and the geometries of the productive reservoir zones. Information from various sources, including 3D surface and borehole seismic data, well logs and core analyses, formation and well testing, fluid properties and production histories, must also be examined.

Permeability differences and stress anisotropy are important factors in deciding whether laterals should be vertical, horizontal or slanted. For example, slanted and horizontal laterals are most productive when oriented perpendicular to natural fractures, and slanted laterals are best when vertical permeability is much less than horizontal permeability.

Geological and petrophysical modeling tools like INFORM® Integrated Forward Modeling help to identify risks along proposed trajectories by providing initial petrophysical descriptions. These forward models are completed using synthetic log data sets generated by 2D and 3D LWD measurements.
An exciting new development for Level 6 junction integrity that comes from countless staff hours of research and analysis is the RapidSeal™ multilateral completion system providing selective drainhole access and connectivity with pressure-sealed connection. This junction is made at surface, deformed to fit inside 13 3/8-in. casing, then reformed when it reaches its position in the well.

The RapidSeal junction is run as 9 5/8-in. casing and is formed by integrating two sections of 7-in. casing below the 9 5/8-in. casing. This design features strong but highly ductile components. If the outlet sections were installed side-by-side, the diameter of the whole assembly would be too large for the 13 3/8-in. casing. In the RapidSeal design, the two outlet sections are plastically deformed so that the effective diameter is just 12-in. and runs easily in 13 3/8-in. casing.

When the junction is in place in the wellbore, the RapidSeal outlets are slowly and uniformly reformed using wireline tools with surface control and monitoring that allow minimization of stresses.
The best drilling and completion strategy is to construct laterals from the deepest branch up. In this way, the wellbore above the branch point remains trouble-free whatever happens below.

**Drilling multilaterals**

The earliest multilateral wells, like those drilled by Grigoryan in 1953, were, in terms of the present-day classification, levels 1 and 2 – openhole completions in hard rock. Since then, directional drilling technology has become more complex. This reflects the demands for higher levels of multilaterals as asset managers gain more comprehensive and sophisticated information about reservoir properties and geological conditions.

The tendency is for small-diameter boreholes to be drilled to reduce cost, and multiple, slimhole horizontal reentries to be drilled from small-diameter wells to further increase reservoir exposure. Coiled tubing is also employed to drill multiple radials from the main bore. Coiled tubing drilling is frequently used to remove near-wellbore formation damage in order to increase reservoir flow potential or for drilling drainholes to replace perforations.

Further cost savings are achieved by drilling short-radius wells with build angles up to 1.8°/ft, a method that can change a well’s orientation from vertical to horizontal in just 50 ft. There is less formation damage in these wells, and they are faster and therefore more economical to drill for many reasons, including smaller drilling fluid volumes and reduced rig time.

Among the most challenging aspects of multilateral drilling today, is the development of suitable reentry techniques. These must go far beyond traditional sidetracking methods in order to keep pace with advances in operations such as stimulation, acidizing and perforating. The increasing complexity of multilateral configurations mean that reentry to a single branch or reentry to one of several branches at a common level presents one of the greatest difficulties. Further factors to consider when selecting a reentry technique include the type of completion (whether openhole or cased), hole size, vertical-to-lateral build rate and the need to hydraulically isolate the lateral.

The first step in a reentry operation is to recognize the reentry point. The next step is to enter the lateral. This can be achieved by running a tool on coiled tubing that rotates to reentry depth. The tool is designed with a bend on the end that registers a weight change when it enters a lateral window. The VIPER* slimhole CTD MWD and motor system employs a bottom orientation sub that locates and accesses laterals. Another method is to run a whipstock diverter, that orients in a predefined tubing or casing profile nipple to accurately locate the diverter at the lateral opening. This technique is used where completion equipment is specifically designed for through-tubing reentry into laterals.

**Wellbore management**

In production engineering and the operation of multilateral wells, the key considerations are whether a well needs artificial lift, and the degree to which imposed formation pressure drawdown is affected by frictional pressure drop inside the well. For example, short,
opposed laterals are preferable to a long, single horizontal well in one direction if drawdown is about the same as pressure drop in the wellbore. Conversely, if drawdown is several hundred pounds per square inch, or more, a single horizontal leg may be adequate.

Selective wellbore control is provided by three basic completion configurations:

• individual production tubing strings tied back to surface
• commingled production
• commingled production from individual branches that can be reentered or shut off by mechanical sliding sleeves or plugs.

As more parts of a reservoir are exposed to wellbores, careful reservoir management becomes paramount. For example, laterals that drain multiple layers or different formations will require selective management if pore pressures and fluid properties differ widely between zones. The degree of communication between the drainage areas of individual laterals may be the most important reservoir engineering issue in multilateral applications.

Reservoir exploitation strategies often define the best configuration for the completion. In selecting the degree of connectivity, isolation and access, three of the most commonly used configurations are:

• drain several stacked layers that may not be in communication
• drain a single layer in which areal permeability anisotropy is critical
• drain geologic compartments that may not be in communication.

A vertical main bore is the most suitable for draining stacked layers. The commingled production from stacked laterals can be compared with commingled production from two or more layers in a vertical well, except that each lateral has higher productivity than a vertical completion through the same layer. In addition, control of vertical inflow, or conformance, is easier because the productivity of each lateral is roughly proportional to its length. Vertical flow conformance avoids differential depletion under primary production, and uneven water or gas breakthrough under secondary production.

Future multilateral technology

There are still different opinions within the industry on the best approach to improving and optimizing multilateral connectivity, as well as on new completion strategies to connect more lateral wellbores with the productive reservoir intervals.

Firstly, the casing windows need to be improved for ease of drilling and reentering multiple lateral drainholes. Many believe that a technique must be developed to seal casing window connections, providing pressure integrity at the junction. To achieve this, a great deal of work is being done to perfect a reliable mechanical seal or new chemical sealants for Level 6 wells.

Other experts, however, maintain that the vast majority of multilaterals exit the main bore into the same reservoir, where the pressure differential at the junction is negligible. In that case, priority should be given to developing fit-for-purpose junction integrity to increase production and the ability to manage laterals over the life of a well.

Downhole construction of lateral junctions has associated problems such as generating debris and lack of cementing options. Surface construction, as in Level 6S wells, is debris-free but can only be done for new, shallow wells.

Opinion is also divided on the subject of casing windows. Downhole construction favors milling standard casing by referencing inexpensive casing profile nipples or packers. Multiple nipples can be designed into casing strings, permitting operators to choose sidetrack locations when they are ready and providing a reentry sleeve reference as well. However, operators can also run a composite casing section (Figure 3.7) with a profile nipple below it from which the drilling whipstock and lateral entry system sleeve can be spaced. Although there is no milling, casing strength is compromised.

Premilled windows or casing stock that has removable sleeves or is encased in drillable material are promoted by many to provide tensile strength without having to mill downhole. As with composites, the whipstock and lateral

![Figure 3.7: Composite casing window](image-url)
entry system sleeve are deployed through casing nipples. Generally, lateral casing is allowed to protrude into the main casing, where it is cemented in place and then milled or washed over to restore full main-bore diameter. Both mechanical and pressure-tight tie-backs are being developed.

Other technical issues need to be resolved, including the management and monitoring of production. A new generation of intelligent downhole technologies has long been heralded as the future of the upstream petroleum industry.

Schlumberger is involved in the development of several new, intelligent completions-related products that were developed in cooperation with operators. A systems-integration-type approach was taken, which focused on working with operators to develop customized solutions for problems specific to a given reservoir. For this purpose, in October 1999 Schlumberger opened its Rosharon Center to accommodate its Advanced Completions Group. Intelligent completions may ultimately yield remotely operated subterranean and subsea factories with oil and gas as the finished products.

**Multilaterals in the Middle East**

Multilateral drilling began in the Middle East during the mid-1990s, and more than 200 horizontal wells have been drilled in the region. In the United Arab Emirates, Zakum Field Development Co. (ZADCO) and its operating company Abu Dhabi Marine Operating Co. (ADMA-OPCO) are developing Zakum field, one of the largest in the region. ZADCO’s experience and expertise in multilateral technology are vital to this development program.

Zakum field, discovered in 1963, is situated offshore in the Arabian Gulf about 80 km (50 miles) northwest of Abu Dhabi. The producing formation is a large Cretaceous limestone with various layers in three main stacked reservoirs (Figure 3.8). Development began in 1977 with conventional drilling. Horizontal drilling was introduced in 1989, and extensive multilateral drilling commenced in 1994 as a result of improvements in horizontal technology. The first multilateral well was completed in March 1995. Encouraged by a significant production increase, ZADCO decided to develop the stacked reservoirs using a combination of horizontal and multilateral drilling. To date, 39 dual-lateral and 45 multilateral wells have been drilled and completed, and more are planned.

Initially, the complex of reservoirs was penetrated by a deviated wellbore and then by a single horizontal drainhole through most of the layers. These two techniques increased borehole exposure to the reservoir and allowed the operators to produce oil from the highest permeability layers. However, oil in less permeable layers was left behind with subsequent substantial loss of reserves. Drilling separate drainholes for subzones provided a better opportunity for stimulation and enhanced production because each horizontal hole was connected directly to the main wellbore.

**Drilling multilaterals**

Level 2 multilateral wells at Zakum field (Figure 3.9) begin with a deviated section, having a maximum inclination of 55° for ease of wireline operations. Surface and intermediate casing are cemented, and wells are deepened to 95/8-in. production casing or 7-in. liner depth just above lower reservoir. Using a retrievable whipstock, a casing window is milled near the top reservoir and the upper drainhole is drilled using intermediate- and short-radius techniques. The whipstock is removed and the next horizontal hole is kicked off below the production casing string. Wellbore inclination is increased to...
horizontal, and a lateral is drilled into the reservoir. The deviated wellbore is continued from the last kickoff point, and another lateral is drilled using the same procedures. Specialized or custom profiles, like a stepped pattern that maximizes footage in certain intervals, can also be used (Figure 3.10).

Curvature ranges from $6^\circ/100$ ft to $10^\circ/100$ ft, depending on reservoir requirements and whether medium- or short-radius techniques are being used. Horizontal sections are typically 750 to 3000 ft, with hole size normally 6 in. Planned trajectories in thin oil layers are followed using MWD and LWD.

Several factors contribute to a successful multilateral well:

- **Zonal isolation** – The pressure difference between the two reservoirs means that it is extremely important to isolate zones between upper laterals and lower drainholes. Cement additives and operations are optimized to improve primary cement bond and sometimes external casing packers are used on the production casing.

- **Window milling** – Accurate and efficient positioning, setting and removal of whipstocks are key to successful multilateral drilling. More than 50 horizontal wells have been sidetracked using retrievable whipstocks. Until very recently, a minimum of three trips was necessary to install a retrievable whipstock, so new single-trip whipstocks are a welcome step forward (Figure 3.11).

- **Drilling dense barriers** – Drilling techniques are selected to minimize drilling in the dense, low-permeability rock that separates the porous layers of Zakum field and to maximize the horizontal footage within the reservoir zones for optimum oil recovery. Each technique presents its own challenges. Stepped drilling through various reservoir layers is operationally difficult because of the low angles of incidence when trying to cross barriers. Another technique, drilling separate drainholes for each reservoir zone, can present postdrilling problems associated with production monitoring and stimulation of individual drainholes.

- **Early water breakthrough** – Multilateral wells are drilled to avoid or delay water breakthrough by selecting the horizontal section position and length within desired layers based on specific reservoir requirements.

- **Low-departure targets** – Another challenge was drilling multilateral wells with targets less than 1000 ft (305 m) from the platform wellheads. Various options were considered for drilling the deviated sections of these low-departure multilateral wells, but a hook-shaped profile was found to be the best. This well profile can be designed to have sufficient inclination to use previously successful, medium-radius drilling. Several hook-shaped multilateral wells with four drainholes from the main bore were successfully drilled and completed.

- **Low-permeability zones** – Multilateral wells are particularly effective for exploiting thin reservoirs. One of the field’s reservoirs that held substantial oil in place was an 8-ft (2.5 m) thick zone with 6-md permeability. Two branches were drilled in different directions to increase the drainage area and improve production. The number and geometry of the branches were dictated by reservoir characteristics.

- **Staying within targets** – Another challenge for drilling multilateral wells is to correctly position and maintain horizontal sections within existing sweep patterns. Since branches drilled in opposing directions were found to be optimum, severe left- and right-turning trajectories were drilled at Zakum field to achieve the required reservoir exposure. A significant increase in production rates was observed in wells drilled in this manner.

- **Multiple holes from a single casing window** – Several drainholes were successfully drilled from the same main borehole after exiting casing in reentry and new wells. This procedure can avoid the time and expense of multiple casing exits, but does limit the ability to monitor and stimulate laterals.

- **Stimulation of multilateral openholes** – Production from reservoirs I and II at Zakum field is kept separate using dual-tubing completion. Current through-tubing stimulation systems access each drainhole selectively, so common practice is to pump stimulation treatments down the
production tubing from surface. Wherever possible, coiled tubing was run through the production tubing to selectively treat individual openhole laterals in the main reservoirs. Permeability varies in each productive layer, so acid must be diverted across all intervals where coiled tubing is unable to reach total depth. The diversion techniques in use do not always stimulate the desired number of laterals, and production logs are being used to further evaluate stimulation effectiveness as well as design and procedural modifications.

**Future multilaterals**

Multilateral drilling in Zakum field provided an opportunity to improve recovery and manage field production more efficiently. More than 80 new and reentry Level 1 and Level 2 multilateral wells (from single and dual laterals up to seven laterals) have been successfully completed. These have boosted production from the field's thin, low-permeability reservoirs, where development by deviated or vertical wells had not been effective. The best results were achieved from horizontal wells with branches in opposing directions. One of the remaining challenges is to perform independent operations in each lateral to overcome zonal isolation difficulties.

Cost analysis has shown that short-radius drilling is more expensive, but the rapid growth in short-radius drilling technology has reduced the cost per foot of horizontal drilling by 30% after drilling 27 horizontal sections in 10 wells. Generally, the higher costs are justified by improved productivity. Lower costs, resulting from steerable drilling technology, have encouraged ZADCO to continue drilling multilateral horizontal wells.

**Remote-control reservoirs**

Today, 3D seismic and horizontal drilling are practically routine operations for wells drilled in the Middle East. Multilateral drilling, although still being technologically refined, is also becoming more commonplace. Meanwhile, asset teams are turning their attention to the application of multilaterals in more hostile (e.g., deep-sea) environments, where economic returns over individual wells are greatest, and to the potential for ‘intelligent’ systems that monitor and adjust to reservoir conditions to achieve optimum completions.

The focus at the Rosharon Advanced Completions Center in Texas is on reservoir-driven and custom solutions that require a lot of early cooperation with the operator. One of the main aims in modern completions is to be able to manipulate production and to perform well intervention downhole. Putting sensors downhole means that real-time or near real-time measurements can be collected and input to computer programs that help to analyze the reservoir and production operations. Monitoring in this way enables engineers to control, for example, water movements and to ensure maximum sweep efficiency.

**Considerations for competent completions**

Many of the factors that had to be considered in ‘standard’ completion technology have led to the development of new equipment and advanced techniques over recent decades. A number of operations must be carried out effectively for successful production. These include cementing, casing, installing production tubing, packers and other production equipment, and also perforating zones of interest. Of course, the completion design must address reservoir type, drive mechanism, fluid properties, well configuration and any other complications that might exist, such as the production of sand or paraffin deposition.

As well designs become more complex, well intervention is increasingly risky and it is necessary to find better ways to optimize production in the new operating environments. Surface intervention is difficult, and deepwater or subsea intervention even more so. Completion technology that relies on surface flow-control valves alone imposes significant limitations, since it is impossible to be selective between production from multiple-flow units in a single wellbore or one lateral of a multilateral well. Neither can production from commingled flow units be controlled in the absence of downhole flow technology.
In standard completions, the absence of downhole monitoring limits the available reservoir data. Measurements such as total flow rate, wellhead pressure and fluid composition can be taken at surface, but the conditions at a producing zone and the contributions from individual zones can only be precisely determined by ‘smart’ measuring devices installed downhole. Well tests and production logging provide data from discrete points, rather than a continuous history, and well tests mean costly interruption of production.

Clearly, the ability to adjust downhole equipment in response to real-time data minimizes the possibility of production surprises that can happen despite the best completion technology practices.

**Ingredients of intelligent completions**

An intelligent completion is defined as one that allows operators to both monitor and control at least one zone of a reservoir. Monitoring is achieved by downhole gauges that continuously record data for downhole pressure, temperature and flow rate. Control is by valves operated remotely from the surface (Figure 3.12). The main aim of intelligent completion devices is to use them to safely, and reliably integrate zonal isolation, flow control, artificial lift, permanent monitoring and sand control. The result will be the ability to address a situation before it becomes a problem.

The successful downhole use of surface-operated, flow-control equipment depends upon reservoir data that facilitate decisions about the efficient production of reserves. In an ordinary completion, well tests, production logs and seismic surveys provide only static snapshots of the reservoir. These might not always represent the reservoir’s normal behavior or capture events that require corrective action. In complex well configurations, such as multilateral wells, production logging is difficult. Simply getting to the reservoir to acquire data can be risky, time-consuming and expensive. Workover operations, such as plugging and abandoning a zone, can be challenging and costly because a workover rig must be brought to the wellhead and remediation equipment placed in the wellbore.

**Figure 3.12: The elements of an intelligent completion**

**Figure 3.13: Hydraulic wireline-retrievable flow control valve**
Reservoir engineers first developed the idea of monitoring downhole conditions in onshore wells in the 1960s. The downhole gauges they used were actually modified wireline equipment. Significant developments in permanent monitoring technology have since resulted in permanent downhole gauges that are incorporated in today’s intelligent completions to allow continuous data acquisition. Permanent gauges have established an impressive worldwide track record for reliably monitoring downhole pressure, temperature and flow rate. Real-time or near real-time pressure, temperature and flow-rate data show the continuous variations in reservoir performance.

While second-by-second data collection might seem excessive during routine production operations, the abundance of data ensures that high-quality analysis can be performed when needed. Once reservoir behavior has been carefully evaluated, the reservoir team can decide if or when adjustments to the completion might be appropriate, using actual data rather than assumed input values in reservoir simulations. Operations can continue while downhole conditions are adjusted using remotely controlled valves operated from surface.

Field-proven flow-control valves are hydraulically actuated, variable-window valves that can be incrementally adjusted to control the flow area more accurately. In contrast, their less reliable predecessors could only operate in the fully closed or fully open state.

The flow-control valve is mounted in a side-pocket mandrel, or a cylindrical section offset from the tubing, so that the valve can be retrieved by wireline or slickline if necessary (Figure 3.13). By applying hydraulic pressure, a variable window valve can assume one of six sequential positions to set the rate at which fluids are produced from the formation into the tubing, or injected from the tubing into the formation. Check valves prevent crossflow between the reservoirs.

An electrically controlled valve that goes a step further and allows infinitely variable adjustment between the opened and closed positions is currently under development (Figure 3.14).

Electrically and hydraulically operated, tubing-retrievable flow controllers also have no practical depth limitations and can include instruments to measure formation temperature, pressure and flow.

The reliability of flow-control devices is a critical concern because, like permanent gauges, they are meant to last for the life of the well and, with the exception of wireline-retrievable devices, are not usually recovered for repair, maintenance or post-mortem failure analysis. These demands make long-life field trials impractical and the identification of risks through other techniques essential. Simple, robust and field-proven equipment is fundamental to the designs. Therefore flow-control valves incorporate proven technology,
such as hydraulic motors from subsurface safety valves. Newly developed components have passed rigorous qualification tests.

Initially, it might be difficult to choose from the dozens of options for completing a wellbore in a new reservoir. Until the reservoir has been characterized to the satisfaction of the operations team, completion specialists recommend ensuring flexibility; continuously acquiring data and then using reservoir-modeling tools to compare predictions with actual results.

**First fields with flow control show the benefits**

At present there are no examples of advanced completion technology being applied in the Middle East. Indeed, fewer than 20 advanced completions have been deployed around the world, but where they have been installed, these systems are increasing recovery and proving their economic and operational value.

In major fields, reserves that might have been left in the ground are being recovered through the use of flow-control devices. For example, a thin oil zone under a large gas cap in the massive Troll field, offshore Norway, is being drained by extended-reach or horizontal wells that contact a greater area of the reservoir than vertical wells and reduce the drawdown per unit area to avoid premature gas coning. At the same time, downhole, gas-lift technology significantly reduces the costs associated with injection from the surface.

In another example of intelligent completions, an innovative extended-reach, multilateral well in the Wytch Farm field in Dorset, UK (Figure 3.15) uses flow control to produce from two different sections of an oil reservoir where water is expected from one of the zones.

This installation was prompted by problems that had been encountered in the original well. The solution was a flow-control device developed by Camco that had been successfully installed in the Troll field. The operators now anticipate that an additional 1MM bbl of oil will be recovered that might otherwise have been left in the ground.

Currently, advanced completions are used in areas where interventions are most costly – deep-sea, arctic and environmentally sensitive locations – which also tend to have more complicated wells. To date, five valves have been installed in the Troll field and three valves in the Wytch Farm completion, all of which are currently in operation.

Other applications of flow-control valves and permanent gauges include:
- Downhole gas production and autoinjection, which may eliminate the need for gas-production and gas-injection wells (Figure 3.16). In addition to economic benefits, this practice also reduces the environmental impact.
- Commingling production in stacked reservoirs with potential for crossflow, or in areas where government regulations require separate accounting for production from separate hydrocarbon zones. In fields undergoing secondary recovery such as waterfloods, flow-control devices and permanent gauges can be used to maintain critical injection rates. This will help to avoid premature breakthrough caused by injecting fluid too rapidly and to prevent the inefficient displacement of reservoir fluids caused by an injection rate that is too low.

Clearly, remote monitoring and flow control can address complications presented by multiple reservoirs, multiple fluid phases, formations that are sensitive to drawdown pressures and complex well configurations.

*Figure 3.15: Wytch Farm field. Significant oil reserves lie beneath the bay and are drained by extended-reach wells*
Figure 3.16: Producing gas-free oil. The left wellbore produces gas. The middle wellbore is a gas-injection well. Downhole gas production and autoinjection using flow-control technology, shown right, can replace costly surface facilities and gas-injection wells.
**Planning the plumbing**

Monitoring and controlling flow from the surface are the first stages in optimizing reservoir plumbing. Ideally, future reservoir management projects will routinely involve observation and data gathering, interpretation and intervention (Figure 3.17).

Dynamic updating of the reservoir model, using feedback from real-time monitoring, maximizes the value of the data, and allows operators to determine optimum flow, and to make informed adjustments to downhole valves that control flow from the reservoir.

The Reservoir Dynamics and Control group at Schlumberger-Doll Research, Ridgefield, USA designed a laboratory experiment to assess the impact of real-time data collection and flow control on recovery. The experimental apparatus simulates a deviated well in an oil reservoir near an oil–water contact (Figure 3.18).

The Berea sandstone reservoir in the experiment was saturated with fresh water to represent oil in an actual reservoir. The ‘oil’ was displaced by salt water representing connate water in an actual reservoir.

The ‘well’ has three flow-control valves. When the valves were opened fully, ‘oil’ production was followed by early ‘water’ breakthrough at the deepest completion in the wellbore because this part of the well is closest to the ‘oil–water’ contact and is the path of least resistance. Consequently, the reservoir was poorly swept.

An optimal production strategy was then designed using the model that had been prepared for the laboratory reservoir. A simulation, performed with ECLIPSE® reservoir...
simulation software, was linked to an optimization algorithm that combined the objective of maximum recovery with practical constraints, such as the reservoir pressure at each part of the wellbore, a fixed total production rate and maximum water cut. The simulation showed that more oil could be recovered by varying offtake in different segments of the well. By adjusting the valves in the next phase of the experiment, more ‘oil’ was indeed recovered because the ‘water’ front approached the wellbore evenly rather than breaking through one zone of the completion prematurely.

In the experiment, adjustment of the flow into each of the valves was made on the basis of observations of the front movement, using computer-assisted tomographic scans (Figure 3.19). In subsurface reservoirs it will also be necessary to image the front movement in order to devise a control strategy. Research is underway to develop reliable sensors for this purpose.

The experiment demonstrated that producing each zone at its optimal rate improves the overall hydrocarbon recovery from the well. When all three valves in the wellbore were fully opened, only 75% of the ‘oil’ was displaced. By judiciously adjusting the three valves in the experimental apparatus, sweep efficiency increased to 92%.

State-of-the-art monitoring and flow-control technology minimize the need for well interventions and make those interventions that are necessary more cost-effective by simplifying them or timing them optimally. As demonstrated in the Wytch Farm and Troll field examples, additional incremental reserve recovery is more likely when the individual zones or wellbores can be operated independently, produced at precise rates to avoid water or gas coning or excessive drawdown, and assisted by artificial lift systems.

Intelligent completions also affect the way people work. Designing these systems involves closer interactions on a technical basis between operators, and service and equipment providers to ensure safer and more effective completions. A remotely operated, intelligent completion may reduce the number of people needed at the wellsite, so field operations become less expensive and more people can remain in their offices.

Advanced completion technology is still in its infancy and is currently most useful in high-cost areas, but ultimately will enter other cost markets as the technology is simplified and proven in other theaters of operation. A future challenge will be to build intelligent completions equipment for casing of less than 7-in. in diameter. The combination of expertise in flow-control valves and downhole electronics is crucial, and will determine the future development of monitoring and flow control systems. The joint efforts of reservoir specialists and completion experts will put downhole process control on the road to ubiquity.

![Figure 3.19: The optimization strategy experiment demonstrated that producing each zone at its optimal rate improves the overall hydrocarbon recovery from the well](Image)

<table>
<thead>
<tr>
<th>Flow rate, cm³/hr</th>
<th>No control</th>
<th>Control</th>
</tr>
</thead>
<tbody>
<tr>
<td>180</td>
<td>75%</td>
<td>92%</td>
</tr>
<tr>
<td>Injection, cm³/hr</td>
<td>180</td>
<td>180</td>
</tr>
</tbody>
</table>

| 27               | 49.5       | 103.5   |
| 180              |            |         |
RapidTieBack

The Schlumberger RapidTieback® nonmilling multilateral drilling and completion system can be used at a Level 3 multilateral junction or upgraded to Level 4 and 5. The 95/8-in. Level 4 system is designed to provide drilling and drift workover access for 7 in. through the upper lateral, while maintaining normal drift through the mother casing to the lower lateral. The upper lateral is mechanically connected and cemented to the mother casing, and the junction provides a debris barrier, but is not intended to act as a hydraulic seal, due to the permeability of the cement.

The system incorporates a patented premilled window system that eliminates the need to mill casing material to exit the upper lateral. This removes the inherent risks with milling, and reduces the time required to exit the casing. The exiting system utilizes Schlumberger’s unique whipstock, and running/setting equipment, which are designed for ease of installation and removal.

1. Drill to total depth (TD), run the appropriate logging package, attach window section to casing, and locate the appropriate depth
2. Orient the casing window section using gyro/MWD. Cement casing using standard techniques and a dual-tubing plug
3. Drill out the urethane-filled inner sleeve from the window section. The lower drain can be drilled, completed and isolated with a retrievable bridge plug (RBP)
4. Run the whipstock and mono-positioning tool assembly. Set it in lower internal orient (IO) profile below premilled window. Retrieve running tool
5. Drill the lateral to TD (no milling is necessary). Retrieve drilling assembly
6. Retrieve whipstock and mono-positioning tool to allow clean-up run
7. Run cement deflector and deflect into lateral, continue in hole to bottom
8. Liner tie-back set by snapping into premilled window, locking casing in place. Liner can now be cemented if needed
9. Release running tool from liner and lift inner string to bushing-in liner. Pump cement through inner string into the liner
10. Retrieve cementing string and liner-setting assembly

11. Wash down with wash-over shoe and latch cement deflector. Retrieve cement deflector and mono-positioning tool from wellbore

12. Cemented junction complete as Level 4 with no restrictions in main bore