Subsea Development from Pore to Process

As oil companies step out into deeper waters, operators may discover that finding oil and gas is the easy part—the real challenge lies in moving produced fluids from the reservoir to the processing facility.

To replace reserves from their fields on the continental shelf, exploration and production companies around the world are turning to deepwater prospects. These prospects often require an operator to fabricate a floating processing facility and move it onto the concession before starting production. Some reservoirs, however, are simply not large enough to justify the expense of a dedicated processing facility. Rather than let such fields lie fallow, operators can take advantage of existing infrastructure by tying marginal-field production back to platforms that serve other fields. Operators whose fields have matured beyond peak production take a similar approach. With excess production capacity available at their platforms, these operators may seek to host production from other fields—even from other companies.

To reach a processing facility, production from remote reservoirs must flow throughjumpers, manifolds, flowlines and risers designed to withstand deep-ocean pressures, temperatures and currents (next page). However, extending tieback distances for several miles is not without problems. Hydrocarbons dominated by heavy fractions often have high viscosity; moving such fluids from deepwater reservoirs can be difficult. Any number of factors, acting singly or in concert, can lead to scale, hydrate, asphaltene or wax deposition in subsea flowlines. These deposits can be severe enough to impede flow to surface processing facilities.

The onset and magnitude of flow-assurance problems are largely influenced by the chemical compositions of produced fluids and by their temperatures and pressures as they travel from one end of a production system to the other. These problems can be mitigated. Through testing, design and monitoring, subsea production assurance experts are able to anticipate and manage conditions that affect hydraulic performance of production systems.

This article discusses production challenges faced by deepwater operators. It also describes new technologies and services developed to overcome obstacles to the flow of oil and gas from subsea wellhead to platform. A Gulf of Mexico scenario demonstrates how surveillance is closely linked to flow-boosting and flow-assurance functions in a subsea completion and flowline tieback.

Setting the Stage

Subsea production systems do not remain static over the course of their productive lives—reservoir pressure declines, fluid composition changes with depletion, water production increases, and corrosion takes its toll. From sandface to separator, operators must plan for change. Facility upgrades and modifications are generally more difficult and expensive in subsea fields; therefore, operators must anticipate as many of these changes as possible during the original facilities design, and then manage the rest.
Subsea layout. Generally, oil, gas and water flow from wellbore to subsea tree, thence to jumper, manifold and flowline, before finally reaching a riser that pipes it to surface for processing. Pressurized reservoir fluid samples collected in an openhole wellbore (upper left) will be analyzed at surface to characterize the physical properties of the fluids. An electrical submersible pump in a completed well (foreground, lower left) propels reservoir fluids thousands of feet up to the wellhead and beyond. Subsea trees positioned atop each completed well contain pressure control valves and chemical injection ports. A flowline jumper carries produced fluids from each subsea tree to the manifold, which commingles production from the wells before sending it through a flowline and up the riser to the platform’s production deck. Umbilical lines from the platform run back to a subsea umbilical termination assembly before branching off to each wellhead and then to the manifold. The umbilicals supply electric and hydraulic power for wellhead or manifold control functions, and chemicals to suppress the formation of scale and hydrates in the production stream. The umbilical lines also carry bidirectional communications and control instructions between the platform, wellhead and downhole devices. In this illustration, production from each well is allocated through a multiphase flowmeter mounted on the manifold.
Water depth represents the greatest challenge to subsea production. It dominates all process, design and economic considerations. To exploit deepwater and ultradeepwater reservoirs, operators must drill and complete wells in water depths of 1,000 to 10,000 ft [305 m to 3,048 m] or greater. Reservoirs that do not merit a dedicated platform often must be produced from as few as one to three wells. This number may also serve adequately in larger reservoirs—the challenge and expense of drilling in such deep waters will often dictate the minimum number of wells to be drilled in a reservoir. These water depths will also dictate that most wells be completed subsea, with wellheads and production-control equipment placed at the seafloor.

From deepwater and ultradeepwater subsea completions, produced fluids are sent to a production facility (above). In marginal fields, operators may seek a nearby facility with capacity to handle their production. In some cases, this facility may be miles away, in the shallower water depths—500 to 600 ft [152 to 183 m]—of the continental shelf.

Fluid produced from a deepwater reservoir experiences significant changes in pressure and temperature as it moves from pore space to production riser. Reservoir pressure drives fluids from formation pore spaces to the low-pressure sink of a wellbore. Inside the wellbore, some form of artificial lift may be required to produce the fluids to the subsea wellhead, or tree. In these cases, a gas lift system or electrical submersible pump (ESP) will be employed. While artificial lift adds energy to the well flow, it also imparts changes in heat, pressure or density to the produced fluids. For example, gas lift works by injecting natural gas into the production fluids. The injected gas reduces the fluid density, thus helping reservoir pressure lift the fluid to the tree. By contrast, impeller vanes inside an ESP subject fluids to centrifugal force and thereby compress the fluids. Furthermore, an ESP relies on reservoir fluids to cool its electric motor, thrust bearing and pump—the exact amount of heat exchanged depends on such variables as the composition of the fluid (especially the volume of gas contained within the fluid) and the efficiency of the mechanical system. As it discharges from the ESP, the fluid will carry this extra heat toward the subsea tree.

Deep waters are cold; temperatures can drop to around 39°F [4°C] at the seafloor. These temperatures must be accommodated beyond the subsea tree, where fluids enter a flowline jumper that connects to a production manifold. The change in fluid temperature between the tree and the jumper will depend on the thermal management strategy of the operator. Some operators use electrically heated flowlines; some use foam-insulated pipe; some bury the flowline beneath the seafloor for insulation; others use no additional heat or insulation at all.

Before reaching the subsea manifold, the produced fluid may pass through a multiphase flowmeter, used to measure production from each well. The oil, water and gas phases of the reservoir fluid mix as they pass through the flowmeter’s venturi. Upon entering the manifold, the fluid is commingled with production from other wells before exiting the manifold to a flowline.

Flowlines tie fields back to a production facility—often a fixed production platform in shallower waters—but in some cases a tension

2. Drillers have long endeavored to reach the 10,000-ft mark. The record was finally broken in October 2003, when the Discoverer Deep Seas, owned by Transocean Inc., drilled an exploration well for ChevronTexaco on its Toledo prospect. This Gulf of Mexico well, located in Alaminos Canyon Block 951, was drilled in 10,011 feet [3,051 m] of water.

3. A prime example is the Canyon Express Project, developed to produce gas from three separate deepwater fields. Production from two wells in the Camden Hills field (developed by Marathon Oil Company), four wells in the Aconcagua field (developed by TotalFinaElf, now Total), and four wells in the King’s Peak field (discovered by Amoco, now BP) is tied back to a platform some 55 miles [89 km] north of Camden Hills. Over this distance, the flowline must climb from a water depth of 7,200 ft [2,195 m] at Camden Hills to reach the production platform in 299 ft [91 m] of water at Main Pass Block 261. For a review of Canyon Express operations: Carré G, Pradié E, Christie A, Delabroy L, Greeson B, Watson G, Dent D, Piedras J, Jenkins R, Schmidt D, Kolstad E, Stimmot G and Taylor G: “High Expectations for Deepwater Wells,” Oilfield Review 14, no. 4 (Winter 2004/2005): 52–63.


5. Multiphase flowmeters are not used to measure production in all subsea developments. Another way to determine production from each well is to allocate by difference. This technique requires the operator to shut in production from a well, then measure the decrease in production at the separator. By shutting in production separately from each well in the field, the operator can determine its contribution to total output. For more on multiphase flowmeters: Atkinson I, Theuveny B, Berard M, Conot G, Groves J, Lowe T, McDiarmed A, Meh dizadeh P, Perciot P, Pinglet B, Smith G and Williamson KJ: “A New Horizon in Multiphase Flow Measurement,” Oilfield Review 16, no. 4 (Winter 2004/2005): 52–63.

6. A hydrate is a crystalline solid consisting of water molecules in an ice-like cage structure. Water molecules form a lattice structure into which many types of gas molecules can fit. Under high pressure, gas hydrates can form in temperatures well above freezing. Gas hydrates are thermodynamically suppressed by adding antifreeze materials such as salts or glycols. Gas hydrates are found in nature, on the bottom of cold seas and in arctic permafrost regions. In such environments, hydrates affect both drilling and production operations. For more on hydrate control while drilling: Ebeltoft H, Yousif M and Soergaard E: “Hydrate Control During Deep-water Drilling: Overview and New Drilling Fluids Formulations,” paper SPE 38957, presented at the SPE Annual Technical Conference and Exhibition, San Antonio, Texas, USA, October 5–8, 1997.

7. The bubblepoint marks the pressure and temperature conditions under which the first bubble of gas breaks out of solution in an oil. Initially, petroleum reservoir oils contain some natural gas in solution. Often the oil is saturated with gas when discovered, meaning that the oil is holding all the gas that can at reservoir temperature and pressure, and that it is at its bubblepoint. Occasionally, the oil will be undersaturated. In this case, the pressure is lowered, the pressure at which the first gas begins to evolve from the oil is defined as the bubblepoint.


9. The Joule–Thompson effect produces a change in temperature as gas expands. It is often assumed that this change results in lower temperature. The change in temperature, however, depends on the inversion point of the gas. Each gas has its own inversion point, defined by temperature and pressure. Below the inversion point, the gas will cool, and above that point, it will heat up.
leg platform, floating production storage and offloading vessel (FPSO), spar, semisubmersible, caisson or even a shore-based processing facility could be used. When tieback distance and pressure drop preclude natural production flow, reservoir fluids must pass through a subsea booster pump before being sent through a flowline and up a production riser.

The flowline might not trace a constant azimuth from wellhead to platform, but may bend slightly to follow the course of a previously surveyed right-of-way. As it follows the undulating topography of the seafloor, the flowline climbs gradually from the colder, deeper reaches of the field up to relatively warmer, shallower waters of the continental shelf, where the host platform stands. If not managed properly, a scenario such as this can lead to trouble.

Temperature and Pressure Interactions
Changes in temperature and pressure along the length of the flowline promote asphaltene precipitation and wax deposition. Cold seafloor temperatures also promote formation of hydrates. Furthermore, as the oil crosses its bubblepoint pressure, light hydrocarbon fractions evolve as a gas phase. This, in turn, makes the oil more viscous, increasing backpressure on the system and changing flow patterns by increasing slippage, or differences in flow rates, between produced oil, gas and water phases.

If flow velocity is not sufficient to keep the production stream thoroughly mixed along the entire length of flowline, then gravity segregation of oil, gas and water may take place. This condition allows lighter phases to flow along the high side of the flowline, with denser phases flowing along the bottom. Each phase flows at a different speed, depending on the inclination of the flowline.

Any vertical undulation in the flowline will allow one phase to slow with respect to the others; as the flowline climbs, the lighter gas phase can slip past the heavier liquid, while in downhill sections, the liquid can overtake the gas phase. The erratic production regime that results from such slippage between phases is known as slug flow. This terrain-induced slugging can adversely impact downstream processing facilities, and must be taken into consideration during the design phase of the project. A further consequence of gravity segregation is that liquids can accumulate in low-lying sections of the flowline and promote long-term corrosion.

Commingling different production streams from separate reservoir compartments can lead to incompatible fluid mixing and subsequent formation of organic or inorganic solids within the flowline. Pressure is released as fluids travel up the riser. As the gas phase of the fluid expands, Joule-Thompson cooling may lead to the formation of hydrates within the riser.

Asphaltene, wax and hydrate precipitation behaviors are determined in laboratories from samples collected downhole. The results indicate ranges of operation that require mitigation (above). A phase diagram is central to understanding the challenges faced by deepwater operators, who must pay special attention to components that fall out of reservoir fluids with changes in pressure and temperature. Particularly troublesome components include asphaltenes, waxes and hydrates.
Asphaltenes are complex molecules occurring in many hydrocarbons. These organic compounds become destabilized and precipitate as a result of shear in turbulent flow conditions; they can also precipitate with changes in pressure or temperature, or with changes in composition resulting from blending or commingling of incompatible fluids during production. Precipitated asphaltene particles can grow to create significant blockages in wellbore tubulars and flowlines.

Asphaltenes begin to precipitate in a pressure range between the reservoir pressure and the bubblepoint, known as the asphaltene precipitation envelope (APE). The APE is bounded on its upper edge by relatively high pressures at low temperatures and drops in pressure as temperature increases. At a given temperature within the APE, asphaltene precipitation typically increases as pressure decreases, reaching a maximum at the bubblepoint pressure, at which point precipitation decreases as pressure continues to decrease. The oil becomes denser below the bubblepoint pressure, as solution gas evolves from the oil, allowing previously precipitated asphaltenes to partially or completely resolubilize.

Paraffin or wax produced in crude oils can adversely affect production by precipitation and deposition within flowlines, causing blockages, or by increasing the fluid viscosity through gelling. Wax precipitates over a fairly wide range of pressures, but this phenomenon is temperature-dependent. On a phase diagram, this pressure range lies to the left of the wax appearance temperature (WAT) line. The WAT is temperature that is temperature at which a solid wax phase forms within a hydrocarbon fluid, at a given pressure. Below the wax appearance temperature, significant viscosity increase, deposition and gelling are possible. The WAT falls slowly with pressure until it reaches the bubblepoint of the oil. Below the bubblepoint pressure, the WAT increases with decreasing pressure.

Two other important parameters relate to wax in the production stream: pour point and gel strength. The pour point is the temperature, at a given pressure, at which the static fluid may form a gel. If a shutdown, blockage or flow interruption allows the fluid in the flowline to gel, it will not start to flow again until a certain minimum stress is applied. This yield stress is called the “gel strength.”

Hydrates are icy crystalline structures that contain gas molecules trapped in the spaces between hydrogen-bonded water molecules. Hydrates exist at higher temperatures than ice, and can coexist with water or ice depending on temperature and pressure conditions. Hydrates pose a plugging hazard to chokes, pipelines, separators, flowlines and valves. The hydrate-formation line maintains a relatively steady temperature across a wide range of pressures until it intersects the bubblepoint line, below which the hydrate-formation temperature decreases with decreasing pressure.

Stacking the Deck
Deep water to shallow, high pressure to low, cold temperature to warm—these are the changes to which oil, gas and water are subjected as they are produced to surface. Understanding the phase behaviors that accompany these changes and predicting their timing and magnitude are keys to developing successful design, operation and remediation strategies that maximize return on investment. This is the role of a subsea production assurance team.

The realm of the subsea production assurance team extends from reservoir to riser, helping offshore operators manage challenges to flow imposed by low temperatures, high pressures and extended tieback distances. Team members specialize in flow prediction and modeling, fluid analysis, artificial lift, multiphase boosting, metering and allocation, measurement, monitoring and control. These experts provide a fully integrated multidisciplinary approach to optimizing production from subsea fields.

Subsea production assurance can be divided into three interrelated functions: flow assurance, flow boosting and flow surveillance. Flow assurance involves analysis of reservoir fluid samples to characterize phase behaviors and anticipate associated flow problems so that production facilities can be designed and operated to prevent or manage these problems. Flow boosting involves the integrated design, placement and operation of artificial lift systems and subsea booster pumps, which are combined to overcome pressures between the reservoir and the surface production facility. Flow surveillance is used in a feedback loop to measure pressure, temperature, flow rates and a host of other variables that are instrumental in fine-tuning the operation of pumps, chemical injectors and other components to optimize performance of the production system.

Subsea Flow Assurance
To optimize return on investment, operators must identify and manage any changes that might affect reservoir fluids as they move through the production system to the processing facility. Some of these changes are counterintuitive, and are recognized only through analysis of reservoir fluid samples and modeling of fluid behaviors between the reservoir and the processing facility. Flow-assurance specialists provide a multidisciplinary approach to fluid sampling, analysis and modeling. The information derived from analysis and modeling of fluid behavior serves as a basis for developing an overall production strategy.

Deposition of paraffin, hydrates, asphaltenes, scales, and other such flow-assurance issues must be addressed early in the design stage of production systems. In fact, the flow-assurance work process begins with formation fluid sampling during the drilling stage of the exploration and appraisal program (above). Analysis of reservoir fluid samples is instrumental in defining phase behaviors and physical properties of oil, gas and water produced in a reservoir. More importantly, it will identify and characterize the phase behavior of waxes, asphaltenes and hydrates that precipitate from the reservoir fluids with changes in temperature and pressure. Other important components of the production stream will be revealed through sample analysis. For example, some reservoir fluids contain trace amounts of corrosives, such as carbon dioxide, hydrogen sulfide or mercury; others may contain elements such as nickel or vanadium that inhibit downstream refining catalysts.

Properties of produced fluids impact the design of a production facility—its components, metallurgy, operational plans, contingency plans and remediation programs. However, data collected on poor-quality samples provide equally
poor results, leading to over- or underdesign of the production facility or mistaken assumptions about operating procedures.

Reservoir fluid properties are best determined with testing of representative samples. Samples can be taken using wireline-conveyed formation testers, such as the openhole MDT Modular Formation Dynamics Tester or the CHDT Cased Hole Dynamics Tester, during drillstem testing (DST) or from a surface separator. Samples taken using wireline formation testers, such as the openhole MDT formation testers, such as the openhole MDT or CHDT CHDT, during drillstem testing (DST) or from a surface separator. Samples taken using wireline formation testers represent a value from a point in the wellbore, while samples taken during a well test represent an average over a producing interval. Fluid properties, however, can vary across a field or across a reservoir.10

Whenever possible, samples from multiple depths or multiple wells should be considered to identify and quantify variations. Understanding the magnitude and nature of compositional variation is important for system design. These samples should be obtained early in the life of the field, during the drilling stage, before production depletes the reservoir below saturation pressure.

Flow-assurance models highlight the need for representative samples. Ideal fluid samples are obtained under reservoir conditions, above bubblepoint, with no asphaltene precipitation, and with little or no contamination. At the laboratory, such a sample would be virtually identical to the fluid in the reservoir. Unfortunately, some of the very same solids that come out of solution during production also come out of solution during the sampling process.12

As samples are brought to surface, changes in temperature and pressure may lead to phase changes that alter the fluid sample. Samples can also be altered by contamination, frequently caused by drilling fluid filtrate.

**Advances in Sampling and Analysis**

Fortunately, there are strategies for obtaining good samples that reduce the potential for contamination and phase changes. For example, the MDT tool can take downhole fluid samples at reservoir temperature and pressure. An OFA Optical Fluid Analyzer system within the MDT tool provides a qualitative measure of contamination by mud filtrate entering from the invaded zone of the formation surrounding a wellbore. For oil-base muds, sample contamination can be quantitatively monitored using the OCM Oil-Base Contamination Monitor.13 A methane detector in the LFA Live Fluid Analyzer module of the MDT tool provides a measure of gas content in the oil phase and allows calculation of the gas/oil ratio (GOR). This module can verify that the fluid pressure has not dropped below bubblepoint during sampling.13 Dropping below the bubblepoint would turn a single-phase fluid diphasic and render the sample unrepresentative.

In the past, downhole samples would invariably drop below bubblepoint as temperature and pressure decreased while the sample was brought to surface. Sample chambers carried by early downhole formation testers were designed to withstand pressures downhole, but were not designed to maintain such pressure on the fluid sample itself. Oilphase, acquired by Schlumberger in 1993, developed a single-phase multisample chamber to overcome this problem.

After the downhole MDT pumpout module fills a single-phase multisample chamber at reservoir pressure, a nitrogen charge provides overpressure to compensate for any temperature-induced pressure drop as the sample is retrieved to surface. This prevents flashing of the sample to keep the fluid in single phase (left).

In many cases, a single-phase multisample...
chamber will be run in conjunction with a multi-sample module to allow pressurized reservoir fluid samples to be transported offsite to a pressure-volume-temperature (PVT) fluid analysis laboratory.

These field-proven sampling systems are also used in cased-hole applications. The CHDT tool is fully combinable with MDT modules such as the pumpout module, multisample module and the OFA module. Other formation fluid samples may be obtained with a DST-conveyed sample carrier that complements existing wireline-conveyed samplers and surface sampling services. These carriers may be employed to collect samples in wells containing hydrogen sulfide and in high-temperature, high-pressure or heavy-oil wells.

At the surface, fluid samples can be obtained from a separator. In producing wells, recombinated fluid samples from a separator may be the only option available for determining reservoir phase behavior. Oilphase-DBR fluid sampling and analysis service provides single-phase sample bottles for transporting pressurized fluid samples and can also provide bottles for transporting pressurized gas samples.

Analysts take an incremental approach to sample testing, allowing initial results to dictate the course of subsequent tests. First, the composition and basic fluid properties of the sample are analyzed. Next, samples are subjected to wax, asphaltene and hydrate screening; samples that screen positive are subjected to further detailed analysis. Live fluid samples—those in which solution gas is preserved in oil samples, or in which heavy ends are maintained in the vapor phase of gas samples—are tested under special laboratory conditions. PVT tests, gas chromatography and mass spectrometry help to analyze phase behavior, fluid composition and flow properties.

The Oilphase-DBR service uses several special technologies to analyze reservoir fluids and quantify conditions that promote deposition of paraffins, hydrates and asphaltenes in the production system. Hydrate-formation conditions are measured in both the single-phase and two-phase regions, while precipitation boundaries, growth kinetics, morphology and solubility are characterized both visually and quantitatively.

A laser-based solids detection system evaluates changes in pressure, temperature or composition to define the point at which solids precipitate in a sample. The solids detection system projects near-infrared laser light through reservoir fluid in a special PVT cell. The intensity of transmitted laser light decreases at the onset of asphaltene precipitation. A high-pressure microscope allows analysts to directly observe the onset and growth of organic solid precipitates, at pressures to 20,000 psi [138 MPa] and at temperatures to 392°F [200°C]. This microscope can define the quantity and morphology of organic solids as they grow in order to evaluate and optimize the effectiveness of various chemicals for solids inhibition or remediation. A controlled-stress high-pressure rheometer operable to 6,000 psi [41.3 MPa] and 302°F [150°C] is used to define the rheology of waxy crudes.

To better understand how paraffin, scale and asphaltene are deposited, analysts use a rotating shear deposition cell to model turbulent flow and shear under pressure and temperature conditions found inside a flowline (right). Because surface irregularities such as rust, pitting or porosity influence deposition rates, special sleeves can be inserted in the cell to simulate the inner surface of the flowline. After running the shear deposition cell, analysts remove the sleeve inserts to measure the thickness and composition of the deposits.

These advanced technologies aid the production assurance specialists in defining behaviors of reservoir fluids to reduce uncertainty and potential overdesign of the production system.

Results from fluid sample tests are fed into modeling software to address flow-assurance challenges. PIPESIM production system analysis modeling can be employed to predict liquid holdup and pressure loss, along with simulating flow regimes and multiphase flow between wells, pipelines and process equipment. Using this modeling software, subsea production assurance specialists determine optimal pipeline and equipment size, carry out heat transfer calculations and generate flow models to predict conditions under which hydrates form. Just as important, it also models the effects of hydrate inhibitors or remediation systems. These models are integrated into the front-end engineering design process to develop optimal production systems and operability strategies that are neither over- nor underdesigned.

Flow-assurance management strategies, developed on the basis of fluid sample analysis, generally take the form of thermal management, pressure management, chemical treatments and mechanical remediation. 17 Thermal management typically consists of circulating hot fluids, electrical heating and flowline insulation. Pressure management can be carried out by downhole pumps and seabed booster pumps. Chemical treatments are injected into the production system to inhibit corrosion or deposition of wax, scale and hydrates. Mechanical remediation usually involves pigging of flowlines. 18

Managing Pressure through Flow Boosting

Beyond its critical role in controlling phase changes of reservoir fluids, pressure is the driving force that moves those fluids from pore spaces to processing facilities. To produce subsea wells, pressure from the reservoir must work against high static backpressures inherent in extended tiebacks and long risers. Backpressure comprises both frictional resistance to flow and pressure head caused by the elevation change between the subsea tree and the surface facility. Backpressure invariably wins out as reservoir pressure declines over time.

Conventional dry-tree wells are routinely drawn down to wellhead pressures of 100 to 200 psi [689 to 1,379 kPa] before being abandoned. 19 By contrast, subsea wells with long tiebacks may have to be abandoned much earlier and at higher pressures, sometimes as high as 2,000 psi [13.8 MPa] at the subsea, or wet, tree. 20 Such high abandonment pressures are dictated by backpressure at the wet tree, which increases in proportion to the length of flowline and riser, in addition to the number of constrictions caused by fittings or deposits within the production system.

Increased backpressure requires a higher bottomhole flowing pressure to maintain production. Typically, without some form of artificial lift, this increased backpressure results in a decline in reservoir production. Therefore, to continue producing reservoir fluids through the
Operators routinely use gas lift to maximize drawdown and increase total production of their offshore oil wells. A gas lift system draws high-pressure gas from a surface production facility and injects the gas into a well’s casing annulus. Gas is then injected into the tubing fluids through a gas lift valve housed in a side-pocket mandrel made up in the tubing string. The injected gas lowers the density of produced fluids in the production tubing and lifts the fluids to the wellhead. By lowering the weight of the hydrostatic column in the tubing, the gas decreases backpressure on the producing formation, allowing more flow from the reservoir into the well.

Total recovery will increase with the depth at which the gas is injected. This depth is limited by the operating pressure rating of standard gas lift valves. Surface compression is required to push the lift gas to deeper injection points, but this compression pressure must not exceed the maximum operating pressure rating of the gas lift valve. Standard gas lift valves are typically rated to inject gas at operating pressures of 2,500 psi [17.2 MPa] at valve depth. Beyond this pressure, the bellows within the valve gradually fatigue, eventually causing it to fail.

As operators venture into deeper waters, higher operating pressures and greater lift-valve depths are required to produce their subsea wells. These requirements are being addressed by new developments in gas lift technology. Using Schlumberger XLift high-pressure gas lift system technology, gas lift valves with bellows rated at 5,000 psi [34.5 MPa] can handle gas at greater compression pressures than those allowed by standard valves. This higher pressure rating enables the valves to be installed at deeper set-points, allowing increased drawdown, extended productive well life and added reserves.

Where heavy crudes, limited access to injection gas, high water cut or low bottomhole pressures preclude the gas lift option, an electrical submersible pump (ESP) can be used. ESPs generate centrifugal force to pressurize wellbore fluids and are capable of lifting fluids from depths of 20,000 ft [6,100 m] or more. With power ratings up to 1,500 hp [1,119 kW], they can move up to 100,000 B/D [15,890 m³/d] of fluids, depending on casing size and drawdown requirements.

On the seafloor, multiphase pumps provide further flow-boosting capabilities that help extend the life of a field. When backpressure from a long tieback and riser prevents a well from flowing naturally, a booster pump installed near the wellhead can help draw down wellhead pressure (left). The effect on the well is a reduction in backpressure, which allows increased flowline to the processing facility, this backpressure must be reduced.

Flow boosting helps manage pressures in the production system using two complementary approaches. First, downhole artificial lift is employed where needed, especially when low reservoir drive pressure cannot sustain acceptable production rates, or low gas/oil ratios (GOR) are combined with highly viscous oil. Second, seafloor booster pumps are used to propel produced fluids along the length of the flowline and up the production riser.

Artificial lift systems are installed to boost energy downhole or to decrease effective fluid density in a wellbore, thereby reducing hydrostatic load on the producing formation. Artificial lift improves recovery by lowering the bottomhole pressure at which a well must be abandoned. Gas lift and electrical submersible pumps account for the two most common forms of artificial lift in subsea wells.\(^\text{[17]}\)

---

18. Pigging allows operators to clean or inspect pipelines by pumping a spherical or cylindrical device, known as a pig, through the pipe. Fluid flowing through the pipe propels the pig along the length of the pipeline. Scraper pigs are fitted with cups, brushes, disks or blades to clean out rust, wax, scale or debris inside the pipe. Other pigs, often called smart pigs, can carry cameras, magnetic or ultrasonic sensors and telemetry devices to detect corrosion, cracks and gouges, or to measure temperature, pressure or wax deposition.
19. Offshore completions can be loosely classified as “dry-tree” or “wet-tree,” depending on where the wellhead, or “tree” is located. Generally, dry-tree completions are used in shallower waters, whereas a wellhead is placed on a platform, above sea level. In moderately deep waters, dry trees can be found on compliant towers, spars and tension leg platforms. Conversely, a wet tree is a subsea completion for deep and ultradepth water depths. The wellhead is situated on the seafloor, and production from the well is piped from the subsea tree to the platform.
flow from the well. Rather than abandon subsea wells at higher pressures, sometimes as high as 2,000 psi, operators can use booster pumps to extend production by reducing wellhead pressures, in some cases to as little as 50 psi [345 kPa].

By providing additional pressure for flow boosting, seafloor booster pumps also fill an important role in flow assurance. Without sufficient pressure in the flowline, a production stream will eventually separate into multiple phases. Gas will evolve out of solution, and gravity will stratify the fluids. Gas, flowing at the high side of the pipe, will overtake oil and water as they flow more slowly along the bottom. Ensuing transient flow conditions can cause process upsets in surface production equipment.

Multiphase booster pumps pressurize production streams, compressing the gas, and sometimes even driving it back into solution (below). A production stream is expelled from a multiphase booster pump as a homogeneous liquid, at elevated temperature and pressure and in a steady-state flow regime. As it exits the booster pump, the heat imparted by the pump is carried off by the production stream, thereby helping to reduce hydrate and wax formation problems. At the same time, the pressure increase helps boost flow velocities. The additional heat and pressure supplied by the pump can have a positive influence on flow assurance.

The multiphase booster pump plays a critical role in subsea production when used in conjunction with downhole gas lift. The behavior of injected gas in the production stream must be factored into the flowline operability plan when gas lift is used. Whether it is injected or liberated, gas will flow along the high side of a flowline, hampering movement of fluids through the flowline. However, subsea multiphase booster pumps are capable of handling a range of fluid phases from 100% water to 100% gas, and can manage transient flows generated in the flowline due to gas separation.

By compressing the gas back into solution, the ensuing reduction in gas volume allows more liquid to be carried within the same volume of pipe. Alternatively, the booster pump can be used to flow the same volume of fluid through a smaller diameter flowline. The subsequent increase in flow velocity helps reduce heat loss, thus lowering the risk of hydrate formation and wax buildup.

When used in conjunction with an ESP, seabed multiphase boosting takes up some of the burden carried by the downhole pump. In conventional dry-tree applications, an ESP must be powerful enough to lift fluids to the separator. In the case of ultradeep waters, however, the size of the ESP must be sufficient to pump fluids to the wet tree, through the tieback, and up the riser to the topside separator. With extended tiebacks in ultradeep waters, the capacity of the ESP and the number of pump stages must increase, sometimes doubling the power from that needed to pump fluid to surface. However, run life drops substantially as motor size increases.

With a multiphase seabed booster pump, the size of an ESP can be decreased, thus extending ESP run life and reducing the number of required interventions.

**Flow Surveillance**

To anticipate and manage conditions in subsea production systems, operators require the capability to monitor, measure and analyze key attributes, and they must have some means to control subsea processes. Production systems rely on instrumentation and control to predict and mitigate flow-assurance and flow-boosting problems. By taking measurements to characterize the system in real time, operators may be able to minimize chemical consumption or reduce energy input into the system by decreasing flowline heating requirements or pigging frequency.

Important downhole parameters, such as temperature, pressure, flow rate, fluid density and water holdup data, can be tracked on a real-time basis by the FloWatcher integrated permanent production monitor. Subsea flowmeters, such as PhaseWatcher fixed multiphase well production monitoring equipment, measure

---

*Helicoaxial booster pump. This Framo pump has four stages, with each stage comprising an impeller and a diffuser. The design combines the capabilities of a centrifugal impeller with an axial gas compressor, and can operate across a range of phases, from pure liquid to pure gas.*
multiphase flow rate and holdup, but require no phase separation and are insensitive to slugs, foam and emulsions. These systems can be combined with other sensors, such as sand detectors, pressure gauges and fiber-optic distributed temperature sensor (DTS) systems to provide a constant stream of data for diagnosis of wellbore and flowline performance. This information allows the operator to make proactive operational decisions—changing a valve setting, boosting pump output or starting chemical injection—based on factual analysis of validated data.

Data validation is an important aspect of subsea production assurance. Validated data are required to ensure that decisions are based on sound, proven information. Data can be validated by comparing measurements from one sensor to those from another corroborating sensor. For example, DTS data can be compared to tree temperature sensors located in close proximity to the DTS. In many cases, however, much of the validation information simply is not available because of low data transmission rates provided by production control systems.

Analysis generally requires comparison with older data and modeling against expected performance. A surveillance workflow collects and integrates data into a closed loop system to optimize production (above). One way around the bottleneck is to separate safety-critical control functions from subsea monitoring processes. Separation can be achieved through an industry-standard surveillance system with a high-bandwidth, networked communications link to the surface. This communications link can be implemented by installing a single low-cost fiber in the same umbilical used for tree control. A subsea monitoring and control (SMC) module has been developed as a central connectivity hub for downhole and subsea instrumentation that works in conjunction with traditional PCS wellhead safety-valve control systems. By taking this approach, the operator can employ a surveillance and monitoring system without interfering with the subsea safety functions of the PCS—in fact, its only impact is to reduce the burden of data transmission on the PCS. At the same time, the SMC permits data integration topside through standard links, thus providing the ability to utilize conventional data-handling and analysis systems similar to those used in processing facilities onshore.

The surveillance system utilizes data acquired by real-time sensors, along with fluid and pressure data obtained during the drilling phase, to monitor the state of the overall system. The same engineering models used to design the system can then be used to evaluate its performance.

Though wellbore and seabed monitoring and control systems are installed to improve productivity of subsea wells, the capability of these systems can be hampered by transmission bandwidth. Data transmission systems in the subsea realm have not always kept pace with sensor throughput. As subsea and downhole devices become more intelligent, providing more data and greater levels of diagnostics and control, communications may prove to be the weakest link in the system.

Great volumes of high-speed data must pass to the surface to provide an operator with real-time control of the production system. However, subsea control commands and production monitoring data are often bundled into a common transmission system. All data and commands pass through one of these systems, known as a production control system (PCS), designed largely for subsea valve control. Although most production facilities have topside systems to securely transmit large volumes of high-bandwidth data around the world, seafloor infrastructure can create information bottlenecks that delay timely analysis and action to optimize production.

Spring 2005
The subsea monitoring and control module allows subsea data acquisition and control devices to communicate directly between the subsea data hub and the topside data hub, using a high-speed data link to avoid passing through slower intermediary devices. The subsea data hub connects sensors to the surveillance system (above). The topside data hub is connected to data recording, analysis and alarm systems.

The SMC is capable of communicating over electrical or optical cable at rates up to 100 megabits/second—essentially creating a seabed local area network. The surveillance package mounts on a subsea tree or manifold, and can be expanded or upgraded without affecting production. Compliance with the industry's Intelligent Well Interface Standardisation (IWIS) procedure enables the open, plug-and-play SMC system to interact seamlessly at optimal transmission rates with any networked combination of acquisition sensors and control modules from Schlumberger or third parties.27

**Surveillance Scenario**

Subsea surveillance scenarios have been devised to test the capacity of the SMC to monitor and detect flow-boosting and flow-assurance issues. One laboratory simulation study, based on a deepwater field in the Gulf of Mexico, relied on input from several real and simulated instruments physically connected to an SMC. This input was provided by pressure and temperature gauges; a FloWatcher integrated production monitor for flow rate, fluid density and holdup measurements; a Sensa fiber-optic DTS monitoring system; a flow-control valve and simulated devices representing two ESPs, a subsea multiphase pump and a subsea multiphase flowmeter (next page, top). This example shows how one abnormal event can cascade into another, with potential for adverse impact on the production system.

In this simulation, electrical windings in one of the ESP motors began to overheat, setting off an alarm at the controller workstation when pump temperature exceeded its specified set point.28 ESP performance curves indicated that the pump was operating outside of specifications, so test personnel took corrective action to return the pump to original operating conditions before damage occurred (next page, bottom).

27. The Intelligent Well Interface Standardisation (IWIS) Panel formed in 1995 as a joint industry project between oil and gas operators and downhole equipment manufacturers and service companies. Their stated intent is “To assist the integration of downhole power & communication architectures, subsea control systems and topsides by providing recommended specifications (and standards where appropriate) for the interfaces between them, and other associated hardware requirements.” For more on the IWIS joint industry project: http://www.iwis-panel.com/index.asp (accessed February 4, 2005).

Seabed installation with multiphase pump, manifold, subsea trees and flowline leading to a distant FPSO. This typical installation served as a model for a laboratory scenario in which increased water production from one well was detected at a downhole pump and flowline.

ESP performance display. Pump intake pressure, temperature sensors and water cut indicate that pump performance is outside of normal operating parameters (red boxes).
Meanwhile, other sensors incorporated in the system, particularly a FloWatcher production monitor and a simulated seabed multiphase flowmeter, relayed readings consistent with increased water cut. An advisory system that simultaneously analyzed sensor readings from the wellbore and seabed suggested adjusting the pump's variable speed drive to reduce the ESP motor speed, and choking back the downhole control valve to decrease water production in the well.

In this instance, the rise in pump temperature was attributed to increased water production, which subsequently raised the fluid density and caused the pump to work harder to lift heavier fluids. By choking back water production at the downhole control valve, oil cut increased, thus lowering fluid density and easing the load on the pump. These actions led to cancellation of the alarm and returned pump operations to a safe performance level.

Beyond its adverse effect on flow boosting, the increased water cut also raised concerns from a flow-assurance standpoint. The Sensa fiber-optic monitoring system acquired DTS temperature traces along the flowline. These traces were transmitted by the SMC system. \(^{29}\) Alarms were generated as temperatures fell along a length of flowline near the riser (above). The system event analyzer indicated that the flowline temperature-pressure profile had crossed the hydrate-formation curve (next page). This unexpected decrease in DTS temperature readings corresponded to an increase in water cut and a decrease in pipeline boarding pressure at the production facility.

Increased water cut would eventually encourage the formation of hydrates in the presence of any gas in the line. Based on analysis of SMC output, test personnel took remedial action, simulating an increase in methanol injection into the pipeline while production was choked back. This remediation caused temperatures to move outside the hydrate envelope, forcing disassociation of any hydrates that may have formed in the system. The well in the simulator was then brought back on production, and methanol injection was adjusted to avoid further problems.

This simulation showed how the SMC surveillance system, wellbore and subsea sensors, real-time data, static data and predictive models can be integrated to monitor and interpret system performance. Abnormal events were recognized, diagnosed and resolved before they became unmanageable. This response optimized both the flow-assurance operating strategy and the efficiency and reliability of the flow-boosting systems.

One Step Forward, One Step Back

Innovative offshore well-completion technology will drive advances in subsea production assurance. New power-delivery systems, separators, dehydrators, compressors, single- and multiphase pumps and flowmeters are being developed for seafloor applications. These technologies are paving the way for processing produced fluids at the seafloor. Not all subsea processing systems will have the same capabilities, but the ability to separate water from a production stream results in lower lifting costs and improves flow assurance by reducing hydrate and scale formation.

\(^{29}\) Amin et al, reference 26.
As subsea completion technology matures, developments such as coiled tubing have spurred offshore operators and service companies to apply their deepwater experience to marginal fields in shallower waters on the continental shelf. Continuous lengths of coiled tubing can be manufactured to withstand pressures required of subsea production lines, and require fewer welds per mile than traditional pipelines.

Some single-well reservoirs on the US Continental Shelf have been tied back to existing platforms, often using coiled tubing for flowlines and umbilicals. For example, an 18-mile [30-km] coiled tubing tieback in the Gulf of Mexico was commissioned from 1,250-ft [381-m] waters of Garden Banks Block 208 to an existing platform at Vermillion Block 398 in 450 ft [137 m] of water. At Garden Banks Block 73, 2.7 miles [4.3 km] of coiled tubing were used to tie a single subsea well to a platform in water depths ranging from 500 to 700 ft [152 to 213 m]. A well in 375 ft [114 m] of water at West Cameron Block 638 was tied by coiled tubing to another operator’s platform in 394 ft [120 m] of water at West Cameron 648.

However, flowline systems in shallow waters are not completely free of subsea production assurance problems. In some cases, the problems can be addressed by injecting methanol, corrosion inhibitors and paraffin suppressants at the subsea tree. In any event, the reservoir must be sampled, the samples must be analyzed, and the analysis must be incorporated into the design plan to anticipate and prevent production assurance problems.

In deep and shallow waters, reservoir fluid analysis and front-end engineering design, coupled with advances in artificial lift, flow boosting and fast-acting subsea monitoring systems are turning small, sometimes isolated, reservoirs into economically viable assets. — MV

---

Event analyzer output. DTS, wellbore pressure and flowline pressure trends are integrated and displayed by the subsea monitoring and control connectivity platform. Taken together, these trends indicate that the fluid system had dropped into the hydrate formation zone.