OVERVIEW

Offshore Completions

Last year, in this space, I commented on innovations being implemented on recent offshore completion projects and how offshore completion practices have undergone major changes. Our industry, regarding offshore developments, apparently has an unlimited ability to amaze the world with new advances. Projects that were considered not feasible 5 years ago now are being implemented. Driven by various reasons, including depletion of conventional reserves and increasing oil prices, oil and gas production in deep water became customary in many regions around the world, and it was not a surprise that, during the 2005 Offshore Technology Conference, oil companies started to reveal plans aiming at production of fields under 3000 m of water.

Use of intelligent-well completions is spreading globally, not only for large deepwater projects, but also for small offshore discoveries where its use in subsea satellite wells may bring profitability to an otherwise uneconomical project. Smart systems, with remotely operated valves, allow operators to control various producing zones, shutting down those not responding as expected without expensive well interventions. All of that can be achieved while data for each independent zone are simultaneously acquired and recorded.

Developing fields that present complex geology and deep reservoirs that have high pressures and temperatures still present challenges for the industry, mainly when unconventional-trajectory wells are used. Some of the issues being investigated involve completion of long horizontal sections in unconsolidated reservoirs; flow assurance, mainly for deepwater conditions; and subsea processing, including gas compression and gas/liquid and oil/water separation. Some of these challenges are addressed well in the papers featured in this issue. JPT

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Offshore Completions additional reading

Available from the SPE eLibrary: www.spe.org

- ***SPE 90552***
  "Gravel Packing Deepwater Long Horizontal Wells Under Low Fracture Gradient," by Chen, Zhongming, SPE, BJ Services, et al.

Available from the OTC Library: www.otcnet.org

- ***OTC 17399***
  "Subsea Gas Compression—Challenges and Solutions," by Fantoft, R., FMC Kongsberg Subsea A/S
- ***OTC 17397***
  "Hybrid Riser Towers From an Operator's Perspective," by Sworn, A., BP plc

Subsea Oil/Water Separation: Main Drives and Challenges

Petrobras is developing a subsea system for oil/water separation to minimize the effect that high water-production rates cause to the topside facilities when waterflooding an oil field. Most of the produced water can be separated at the seafloor and reinjected into the reservoir or into a water-bearing formation.

Introduction

During the exploitation-design phase of an oil field, activities focus on oil-production optimization. The oil-recovery mechanism is defined to maximize the recovery factor according to the reservoir and fluid characteristics. In most of the oil fields in Campos basin, waterflooding is used from the beginning of production. After water breakthrough occurs, the handling of produced water, which is a mixture of injected seawater and reservoir water, is of secondary importance during the design phase. Its priority increases only after water production increases. Conventionally, this water is separated from the oil and disposed of into the sea. This procedure takes place onboard the floating production units (FPUs) by use of very-large-volume vessels on a deck where space is critical, especially with the increasing plant capacity of recent units.

The use of a subsea system to separate most of the produced water at the seabed and send it somewhere other than the FPU plant is an attractive option. Such a system would allow the production plant to continue handling only a residual amount of water, eliminating new construction onboard to increase water-handling capacity. This system could enable adding extra oil-processing capability and, in many cases, increase oil production because of the lower wellhead backpressure that results from reduced water-lifting energy requirements.

Subsea separation presents challenging issues such as compactness and reliability. The full-length paper details this development, including the most promising scenario and the main benefits and challenges related to this scenario.

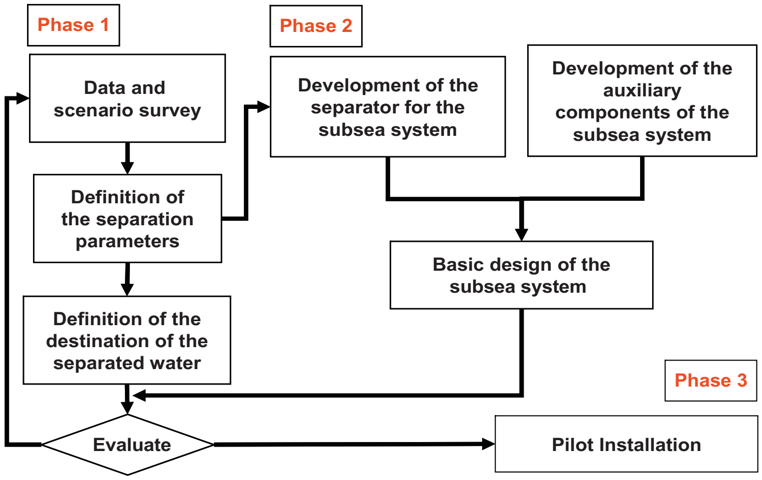

Fig. 1—Project structure.

Project Structure

Conventional topside systems use gravity for separation, which requires large-volume vessels with enough retention time for the process. The subsea environment imposes limitations to the equipment, not allowing the same configuration as at topside. As shown in **Fig. 1,** the project was planned with three phases. The first phase collected data to support a pilot-system development. The second phase comprised separator development and the control- and monitoring-systems development to allow operation of the separator in the subsea environment. The third phase tests the subsea pilot.

Scenario Definition

The scenario survey determines the best potential locations. To understand the field production dynamics, interaction of the project group with the operation was fundamental. This kind of project is not typical of the daily activities of the operational group, which must be kept informed of the project targets and how to reach these targets.

Reservoir Characteristics. In Campos basin, many reservoirs have similar formation types and characteristics in terms of production mechanism, using waterfloods to maintain reservoir pressure and improve the oil sweep. The Marlim field was chosen. It has very thick (as thick as 60 m) and homogeneous productive sandstones, with high permeability (most greater than 1000 md). Seawater is used for injection with rigorous water-quality control, minimizing corrosion in the lines and strings and controlling parameters that could cause damage to the reservoir when the treated seawater mixes with reservoir water.

Location Characteristics. Marlim field produces to two different types of FPUs, semisubmersible and floating production, storage, and offloading (FPSO) vessels in water depths ranging from 600 to 1000 m. The production and injection wells are wet-tree satellite wells, connected to the FPU by flexible lines. Some wells produce to subsea manifolds, and the commingled production flows to the FPU through a larger-diameter flexible line.

There are different types of flowline connections to the trees and manifolds. Some are independent of the equipment, but in

*This article, written by Technology Editor Dennis Denney, contains highlights of paper SPE 97375, "Application of Subsea Oil/Water Separation: Main Drives and Challenges," by **M.W. de Figueiredo,** Petrobras, prepared for the 2005 SPE Latin American and Caribbean Petroleum Engineering Conference, Rio de Janeiro, 20–23 June.*

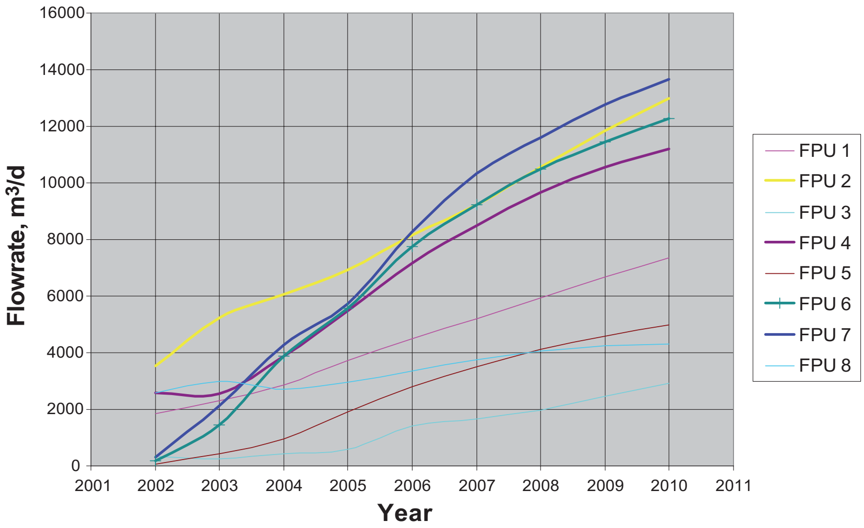

Fig. 2—Water production for Marlim FPUs.

some trees, the connection can be made and retrieved only with the tree pulled out, requiring the use of a drilling rig. The distance between production and injection wells was evaluated, as was the available location for the separation system, avoiding crossing lines for its installation.

Water Production. Marlim was defined as the most promising scenario for the subsea oil/water separation application because of its number of units producing at high water cut and wells with very high productivity. A detailed analysis, unit-by-unit and by individual wells, was performed. The first evaluation was of the basic sediment and water (BS&W) history for each unit. These data do not identify any unit with higher potential. Most of the units reach 50% BS&W at a similar time, not allowing identification of a candidate. The typical behavior indicated the high potential of applying this system to all of the units.

The next step was analysis of the produced-water volume of each FPU. Two groups were identified from **Fig. 2.** One group, FPUs 2, 4, 6, and 7, had a larger daily volume sooner than the second group, comprising FPUs 1, 3, 5, and 8. The analysis focused on the first group, in which application of the subsea system has a higher potential. In the first group, two FPUs are semisubmersibles and two are FPSOs with turret connections.

Limitations. Typically, semisubmersibles have easy access to each well's production line but no space remaining on the deck for additional water-processing facilities. The opposite occurs with FPSOs, which have enough space on the deck, but access to a specific well is very difficult because the production is manifolded before reaching the turret swivel.

The next step was to verify the process capacity for each FPU of the first group to identify its sensitivity to the high water-flow rate. According to data available when the units were designed, the process plants were designed with water-processing capacity of 50% of the total liquid capacity. Upon reaching this capacity, new equipment would be installed, or wells with higher BS&W would be shut in.

After considering the production declines, limitations of the processing plants, and reservoir characteristics of each producing area, the conclusion was reached that the unit with higher potential for the pilot application was FPU 6, an FPSO vessel. This analysis indicated that the water-production curve will exceed the water-processing-plant capacity by 2007.

Another aspect that must be taken into account is the limit of allowable oil-in-water (OIW) content of the treated produced water to be disposed of into the sea, which is 20 ppm. When water quality is lower, the well and associated processing must be shut in to avoid water disposal above the admissible limits. The higher the water production, the more critical is the control.

Separated-Water Destination

Three separated-water disposal options at the seabed were considered. The first was reinjection into the reservoir for pressure maintenance, the second was injection into a disposal formation with capacity to receive water with a residual oil content, and the third was the construction of a gathering flowline to collect the separated water and send it to another unit with spare processing capacity. The first option was considered the most attractive with a lower investment level.

A feasible estimate for the OIW content was 100 ppm after all subsea processing, considered the limit for safe operations in the subsea environment. However, the treated seawater for injection has no oil. Studies showed that oil content in the injection water had little effect on the injection loss for reservoirs with the characteristics of the Marlim field. The effect varies with the size of the droplet and the total oil volume. Another aspect considered was the ability of droplets to carry produced solids, worsening the injection-loss process. Although the oil content does not normally represent a problem, it can be overcome with injection above the fracture pressure.

Reinjection into the formation was the most attractive option. It was decided to perform a field trial, reinjecting produced water with controlled OIW content, to a maximum of 200 ppm, and monitor the injection pressure to evaluate the reservoir behavior. First, a small-scale laboratory test was performed, circulating the produced water through a formation core sample and logging the circulation pressure. The field trial will be executed remotely, from the FPU in a satellite deviated well without gravel packing to minimize risk of damage to the well and reduce the number of parameters that influence the test results. The test duration will be 6 months, and it is planned to begin in August 2005.

Oil Characteristics

The oil is very viscous (395 cp at 25°C) and somewhat heavy (19°API), with a very strong tendency to form stable emulsions with water. The subsea system for water separation will operate in high hydrostatic pressure and low temperature. Because of the distance and amount of energy needed, heating was not a good option to control the process temperature. The fluid temperature at the wellhead is 55°C and, for the worst case, if the separator is installed far away from the wellhead, the estimated temperature is 45°C. The system is designed to separate water from oil while maintaining the pressure, allowing the oil and gas to flow naturally to the FPU.

Separator Influence on Production

Eliminating the large volume of water flow between the system and the FPU was evaluated. This influence appears in two main ways. Flow assurance improves because of a lower possibility of hydrate formation. Production increases because of reduced backpressure with lower hydrostatic fluid and better flow conditions.

Simulations performed with two wells showed gains in production with the insertion of the separation system. It should be noted that the results were obtained without optimization of the gas lift rate, which was kept constant and equal to that obtained at the last production test. The simulations used the production curves for each. One test showed additional oil production of 200 m^3/d with a 90% reduction of the total water produced to the FPU.

Separator Development

Cooperation agreements were signed with two companies, each developing a separate technology. Vetco applies gravitational separation with the use of electrocoalescence in its system. FMC-CDS applies cyclonic separation and inline electrocoalescence.

In parallel, Petrobras already was part of the CySep Joint Industry Project, coordinated by Aker Kvaerner, aiming to develop a separation system using hydrocyclones, mainly focused on topside applications for heavy oils but with high potential as a solution for subsea separation.

Conclusions

The subsea water-separation system is considered an attractive solution.

- It keeps the FPU production facilities dedicated to oil processing, operating within their design limitations.
- It allows tieback of new locations because of the additional processing capacity that results from reduced topside water treatment.
- There is a potential reduction of hydrate problems because there is only a residual fraction of water remaining in the flow stream.
- The environmental effects are minimal because most of the water is reinjected instead of disposed of into the sea.
- Oil production increases as a result of the better flow conditions after the separator.

Many issues are still under investigation.

- Scale-formation-risk assessment for the reinjection of separated water or separated water commingled with seawater.
- Compatibility of different types of reservoirs with the separated water, to allow reinjection. JPT

For a limited time, the full-length paper is available free to SPE members at www.spe.org/jpt. The paper has not been peer reviewed.

State of the Art of Ultradeepwater Production Technologies

The full-length paper summarizes some results of several recent joint industry projects (JIPs) on ultradeepwater field-development technologies. A review of emerging and existing technologies for deepwater development is presented, which would be of particular interest to technology-development personnel and asset-team personnel who are in the appraisal or concept-selection stages of a project.

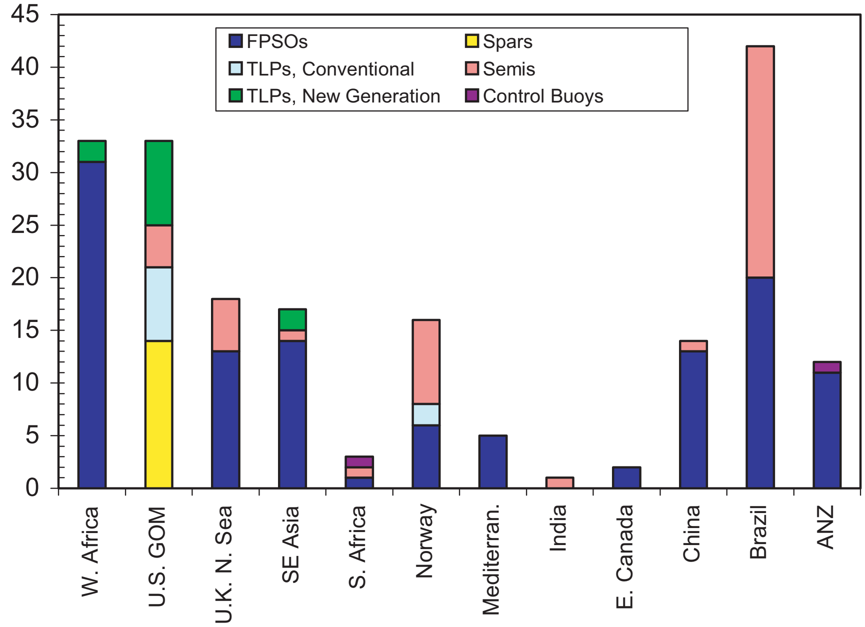

Fig. 1—Floating production systems installed worldwide by region; ANZ=Australia and New Zealand.

Introduction

As offshore production moves from deep water (3,000 to 6,000 ft) to ultradeep water (6,000 to 10,000 ft) and moves farther away from infrastructures, many existing technologies reach their limits or must be improved. Several successful JIPs have demonstrated that in the high-expense and -risk environment of ultradeep water, structured collaboration aligned with business drivers is a successful formula for delivering the technologies required to meet the ultradeepwater challenge. The demand for critical technology and engineering systems to enable production from ultradeep water has triggered breakthroughs in many conventional technologies. The full-length paper focuses on subsea, flow-assurance, floating-production-system, and riser technology.

Advanced Technologies

Subsea Processing (SSP). A generalized definition of SSP is any active treatment of the produced fluids at or below the seabed to improve the reservoir recovery factor. SSP typically is considered for systems with a tieback to a host structure and can influence all phases of project life. SSP can increase productivity by:

- Using single-phase or multiphase pumping systems to enhance the fluid driving energy (subsea boosting).
- Separating and disposing of the produced water subsea (two-phase separation).
- Separating the oil, gas, and water subsea (three-phase separation).

Subsea Separation. Subsea gas/liquid separation involves pumping the liquid phase through one line while the gas phase flows without pumping through a separate line. A Norwegian JIP has led the industry in initiating actual operations, while JIPs like DeepStar facilitated the much-needed exchanges between the supplier and user communities as well as instigated research and feasibility and conceptual studies.

Subsea water/hydrocarbon separation (bulk water removal) does not have a significant effect on the early production life when the water cut is less than 15% but becomes more significant as the water production increases. The gain in production is the result of the reduced liquid loading transported in the pipeline.

Two-phase separation can reduce time to first oil and reduce overall capital expenditures. Operational expenses also can be reduced because water separation increases oil production and minimizes the need for chemicals and remediation. Subsea separation allows improved production rates per well while reducing the number of wells required.

Subsea High-Integrity Pressure Protection System (HIPPS). A HIPPS is an instrumented safety system that isolates downstream facilities from an overpressure. HIPPSs have been industry accepted for surface and onshore application for

*This article, written by Assistant Technology Editor Karen Bybee, contains highlights of paper OTC 17615, "State of the Art of Ultra Deepwater Production Technologies," by **J.M. Bell,** SPE, Chevron; **Y.D. Chin,** SPE, Aker Kværner; and **S. Hanrahan,** SPE, Chevron, prepared for the 2005 Offshore Technology Conference, Houston, 2–5 May.*

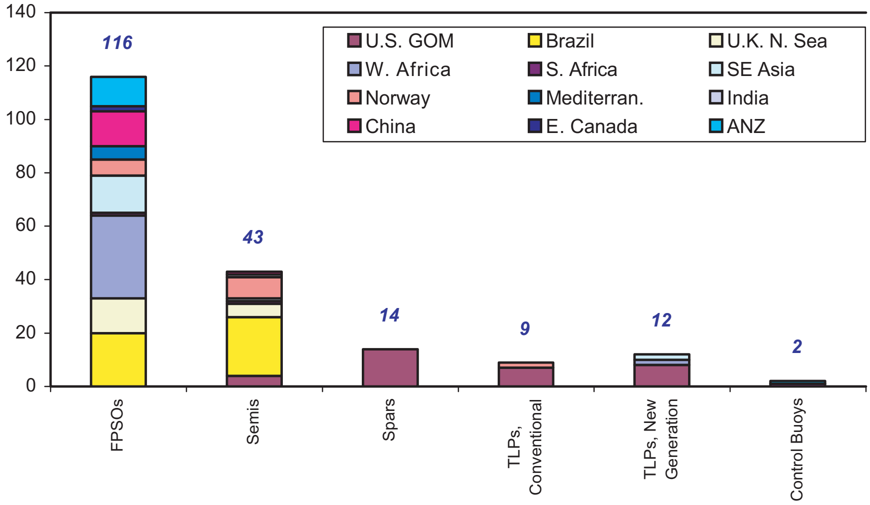

Fig. 2—Floating production systems installed worldwide by type.

many years. Applying HIPPSs subsea remains challenging. One of the benefits of using subsea HIPPSs is that they allow use of lower-pressure-rated flowlines downstream of the HIPPS. They also would allow tie in of high-pressure wells into existing low-pressure-rated subsea manifolds, sleds, and pipelines.

Flow Assurance. Flow assurance is recognized as one of the most critical issues to enable production in ultradeep water. The scientific breakthrough in hydrate kinetics of formation and dissociation and the development of hydrate-control products have transformed the industry from total hydrate prevention 10 years ago to hydrate management today and the possibility of cold-slurry flow in the future. These technologies will save substantial capital expenditures for dual lines, insulation, and active heating systems.

Floating-Production-System Technology. Various floating structures have been installed offshore worldwide **(Figs. 1 and 2).** One of the major challenges faced when deploying floating systems in ultradeep water is the response of the combined system of the vessel, risers, and moorings. In shallow water, risers and moorings have minimal effect on vessel motion. In ultradeep water, riser and mooring systems have significant effects on the global response of the system.

To ensure the integrity of the complete system including minimizing fatigue failure of the risers, an integrated design approach needs to be adopted that optimizes overall cost and technical assurance of the risers, hull, and moorings. Generally, vessel motion should be sufficiently limited so that economical and proven riser systems can be used. The knowledge and ability to model metocean conditions require improvement if the industry is to deploy optimized floating production systems.

Tension-Leg Platform (TLP). TLPs are a well-established dry-tree deepwater concept characterized by its vertical tendons that provide favorable heave motion. The deepest TLP installed today is in 4,700 ft of water. Application of TLPs in deep water is limited by their tendon weight to approximately 7,000 ft of water. The weight of tendons in waters deeper than 7,000 ft would restrict the hull size and make the hull uneconomical.

Semisubmersible. The concept of a semisubmersible with a wet tree has become technically mature during the past decade. Two record-depth fields under development with semisubmersibles are Atlantis in 7,000 ft of water and the Independence Hub in 8,000 ft of water, both in the Gulf of Mexico (GOM).

Spar Floaters. Spar floaters with dry-tree units have been popular for GOM deepwater fields. A total of 14 spars have been installed in the GOM in water depths as great as 5,700 ft. Spar technology has been evolving rapidly as the classic spar (Genesis and Hoover), truss spar (Horn Mountain, Boomvang, and others), and cell spar (Redhawk) have been installed. Spar technology has been used with both dry-tree and wet-tree field developments.

Floating Production, Storage, and Offloading (FPSO). FPSO systems have been used by the industry extensively as wet-tree gathering hubs, in conjunction with multiple fields, and with subsea tiebacks in water depths as great as 6,000 ft.

Semisubmersibles and spar systems currently are feasible alternatives in the ultradeepwater environment. TLPs will require adoption of new technology for their tendon systems for ultradeepwater applications. FPSO systems for ultradeep water will require advancements in riser systems because of the large motion of the FPSOs, especially in the GOM. An unmanned buoy that supports partial or full subsea production may provide another feasible alternative in the future. Compact and lightweight surface-processing equipment combined with riser systems that provide significantly reduced hang-off weight compared to steel catenary risers (SCRs) has the potential to alter the landscape of options available.

Riser Technology. *SCR.* The SCR is a single pipe with or without insulation and casing, suspended from surface facilities in a catenary contour. SCRs are connected to the floating facility with a hang-off component or a flexible joint to absorb the dynamic moment generated by the floater. The dynamic motion of the floater affects the fatigue performance of risers. Heave-suppressing floater concepts like spars and TLPs have more-SCR-friendly motions than a semisubmersible or an FPSO. The spar, TLP, and semisubmersible have proved to work well with SCRs in deep water, and the spar and semisubmersible with SCRs have qualified for ultradeep water through the recent DeepStar project. The long-term performance of connection methods such as flexible joints, titanium stress joints, and direct hang-off methods needs to be improved.

The insulation requirements of the SCR make the effective hydrodynamic diameter larger. This typically increases riser dynamics. The pipe-in-pipe SCR designs make the risers heavier, but the dynamic motions are usually significantly smaller than for an externally insulated riser. Heavy risers impose large loads on the hull, but the riser loads acting at a submerged location affect floater sizing much less than equivalent topside loads.

Top-Tensioned Riser (TTR). Riser-weight management is the biggest challenge for TTRs. Riser-weight reduction is desired to reduce the effect of risers on hull design as well as riser-tensioner design. Riser configuration has a big effect on riser weight. The dual-casing configuration is the most common type because it offers greater flexibility in riser workover and completion operations. Riser-casing weight can be reduced by use of alternative riser materials such as composites, titanium, and aluminum.

Hybrid Risers. Hybrid risers are developed in various configurations and by several companies. Their application has been pioneered by the Grand Banks 388 installation in the GOM and the Girasol installation in the west of Africa. A hybrid riser consists of a foundation and a tower section consisting of one or more risers, normally with a lightweight conduit pipe. A buoyancy tank is located below the main wave zone at the upper end of the tower section. Jumpers connect the top of the tower or buoyancy tank to the floater.

Hybrid risers are self-supporting and independent of the floater, eliminating large horizontal motions and vertical loading. The main benefit is to reduce the dynamic motions over a large part of the riser. Most of the motion occurs in the jumpers. Until now, jumpers have been made of a flexible pipe.

Compliant Vertical Access Riser (CVAR). The original CVAR concept was proposed in a patent application more than 20 years ago and has been the subject of several JIPs. CVAR studies range from FPSOs in Brazil and Indonesia, to spars, and recently, semisubmersibles in the GOM.

This concept has no tensioner system because the riser shape absorbs the relative motion between the floater and the seabed. The risers land vertically on top of the wellhead or production tree, making direct access to the wellbore possible. In the dry-tree version, the trees will be on deck and risers could be designed as tubing risers. The dry-tree concept may have a workover rig on the deck, making it possible to perform a wide range of completion, production, workover, logging, and other well interventions from the surface. A CVAR can be used on a semisubmersible to provide dry-tree functionality.

The biggest benefit of the CVAR is the ability to perform workover operations from the production floater without having to mobilize a mobile offshore drilling unit. Operations could be performed through the CVAR, making separate drilling- or workover-riser installations unnecessary. The CVAR allows multiple subsea tiebacks, accommodates irregular positioning of subsea wells, and functions for single- or dual-casing risers. JPT

The full-length paper is available for purchase at the OTC Library: www.otcnet.org. The paper has not been peer reviewed.

Benefits of All-Electric Subsea Production-Control Systems

The oil and gas industry currently is using electrohydraulic subsea control systems as the standard to manage hydrocarbon production from subsea oil and gas fields. While these electrohydraulic controls will continue as the system of choice for the next 5 years, a desire to improve reliability and operational routines will increase the opportunity to use all-electric subsea production-control systems. The first offshore trial of an all-electric subsea production-control system and wellhead tree system was completed recently at the BP Magnus platform in the North Sea.

Introduction

To produce from greater water depths and harsher metocean conditions, the offshore industry has become technologically sophisticated. This applies both to the floating structures that support topside facilities in water depths greater than 200 m and the tieback technology to produce from long-distance remote step-out wells many tens of kilometers from the host facility.

In the early days of subsea tiebacks, each of the hydraulic valves needed to control the flow of hydrocarbons from the wellhead systems was controlled individually by a direct hydraulic connection back to the host facility and a topside control panel. The panel consisted of hydraulic pumps, motors, valves, and accumulators. This was a very successful and reliable concept because of its simplicity and relatively low cost. However, the limitation of direct hydraulics resulted in slow subsea-to-host actuator response times, and this limited tieback distance to approximately 15 km. In addition, the size and weight of the connecting umbilical hoses in all but the simplest of systems resulted in difficulties with transportation and installation. These limitations, together with the increasing requirements to collect reservoir-pressure and -temperature data, prompted the industry to develop more-sophisticated technology, including subsea control systems.

Subsea Production-Control System

As subsea technology advanced, piloted and sequenced valve hydraulic systems were used. These offered improved hydraulic response times but still were not able to provide the level of monitoring capability the industry required. This ultimately drove the industry to develop a subsea production-control system with the ability to provide safe and reliable control of wellhead and downhole isolation valves and provide accurate and reliable monitoring of downhole, wellhead, and flowline instrumentation.

These systems were not widely used because of the communication limitations of underwater accoustics in terms of distance (10 to 15 km) and data-transfer rates (approximately 100 baud). Also, the added complexity of additional hardware resulted in only limited scope to reduce costs and improve reliability relative to that of the umbilical system.

Multiplexed Electrohydraulic Subsea Control Systems

Most subsea developments use a multiplexed electrohydraulic subsea production-control system. This is essentially a subsea computer, communications system, and series of hydraulic directional control valves. These valves allow stored pressure within subsea accumulators to be routed to individual hydraulic lines and onward to actuators and valves on the Christmas trees. The computer, or subsea electronics module, interfaces to a range of sensors collecting data used for efficient and safe hydrocarbon production.

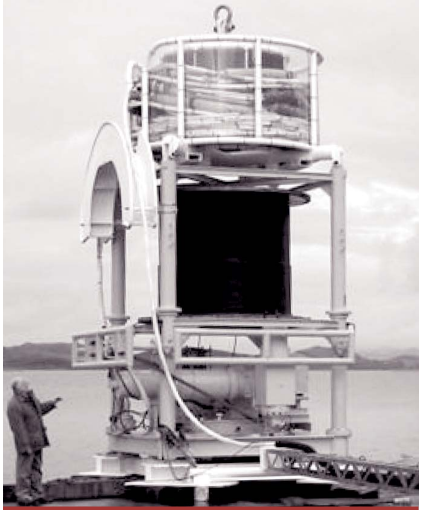

Fig. 1—Prototype all-electric subsea production-control system.

The multiplexed electrohydraulic system obtains its hydraulic and electrical power from shared lines within the umbilical. This allows many Christmas tree subsea control modules to be connected in parallel. Redundancy easily can be provided for increased availability in the event of an individual line becoming faulty. Complex systems often are subdivided to provide some production, even if part of the system is unavailable.

Typically, subsea communication speeds are low to medium (1,200 to 9,600 baud) because of the relatively small amount of data required. Increasingly, fiber optics is being used in umbilical systems, replacing traditional copper modem systems for direct connection to advanced types of downhole sensors. These sensors typically use Bragg gratings to derive more-accurate and -reliable pressure, temperature, and flow-rate data.

Despite the many advantages of the multiplexed electrohydraulic control system, there are weaknesses in the system relating to susceptibility to hydraulic-fluid cleanliness, materials compatibility, hydrostatic effects in deeper waters, and limitations over long-distance tiebacks. As the oil and gas industry has discovered reserves in deeper and more-remote locations, there has been a focus on improving the economics of subsea projects both through reduced capital expenditure (capex) and greater availability

*This article, written by Assistant Technology Editor Karen Bybee, contains highlights of paper OTC 17106, "Benefits of All-Electric Subsea Production-Control Systems," by **M. Theobald** and **C. Lindsey-Curran,** BP plc, prepared for the 2005 Offshore Technology Conference, Houston, 2–5 May.*

and reliability of production-control systems. Long-distance multiplexed electrohydraulic umbilicals can be very expensive.

All-Electric Subsea Systems

Several recent subsea reliability initiatives, in association with specialist academic and reliability consultants, have identified a significant proportion of reliability problems attributed to hydraulic components and the operational and installation methods associated with high-pressure/high-fluid-volume hydraulic systems. For deepwater and long stepout, umbilical-fill and recovery times for the necessary volumes of accumulated hydraulic energy become impractical for valve actuations. Exploitation of higher-pressure offshore reserves also is approaching the practical limits of multiplexed electrohydraulic systems.

The development of electrical valve actuation has been the subject of several research programs. However, these have tended to be standalone-type research projects. To successfully commercialize these systems, it is necessary to consider the tree actuator assembly as part of an integrated subsea production-control system.

BP has tested an all-electric platform tree on the U.K. continental shelf Andrew platform. This system was designed specifically for surface applications and would have required substantial development for use in a subsea environment. To evaluate the possible benefits of such a system for subsea use, BP commissioned a cost/benefit concept study. The results of the study justified further evaluation of the all-electric subsea controls concept.

Operator Benefits

Operational Expense. The most valuable operator benefit identified in the evaluation study was a significant increase in system availability through improved system reliability. This would result in less downtime and associated production losses, together with less costs associated with subsea intervention and repair.

In addition to lower costs associated with fewer breakdowns, the all-electric system offers the possibility of fast-actuation choke systems. The all-electric system has the ability to drive the choke directly to any desired position, with a much reduced duration and significant operational savings. The design concept of the all-electric choke and control system would allow the operator to return to any desired choke position in less than 1 minute.

Capex. The main components of a subsea production system generally consist of topside hardware and a service umbilical system and subsea hardware mounted on the Christmas tree. When comparing the all-electric system to a conventional electrohydraulic system, the main topside hydraulic power unit (HPU) is eliminated. This not only saves equipment hardware costs, but also the weight (as much as 10 tonnes) and deck space normally needed. The HPU can be a significant piece of hardware to maintain and service. It contains high-pressure hydraulic accumulators and piping systems, requiring specialist maintenance personnel.The amount of fluid consumed by a conventional system can vary depending on whether the system is designed as an open-loop or closed-loop system. The closed-loop system usually is more expensive to install, but cheaper to run. The open-loop system uses a fluid that is acceptable to vent to sea as part of the normal valve-actuation cycle, but increasingly stringent environmental regulations may result in this system being more difficult to install in the future.

Costs associated with both the initial fill and replacement fluid can be significant, with this providing a substantial cost savings when the all-electric system is considered. Specialist engineering teams for land-based integration testing and offshore commissioning also can be reduced.

It is estimated that the capex savings of the overall all-electric subsea production system could be approximately 5 to 10% over the cost of a complete subsea production-control system.

Reliability

A joint study involving BP, Cooper Cameron, and the reliability engineering group at Cranfield U. was performed in May 2004 to establish a detailed comparison between Cooper Cameron's all-electric and electrohydraulic subsea production-control systems.

The system modeled was a four-well cluster. The analysis was concerned solely with a comparison of the production loss during operations for the two systems and its effect on the production availability of the field. The software used encouraged the use of a modular approach to the breakdown of complex system-reliability block diagrams. This was done by permitting a hierarchical structure of diagrams and subdiagrams to be constructed in which one block at a higher level is represented by a lower-level structure of several or many blocks. In the present study, this approach could be exploited fully in the case of the electrohydraulic system. This was possible to a lesser extent for the all-electric system because of the dual-redundancy running all the way from the topside systems down to the actuators. It was necessary to retain most of this detail in the highest-level diagram to avoid misrepresenting the failure logic of the system. The data show that the all-electric system gives improvements across the whole range of production scenarios, reducing single-well failures by approximately 20%.

Offshore Field Trial

BP's E&P technology group in conjunction with Cooper Cameron Corp. and the BP-operated Magnus North Sea Asset recently has deployed the first all-electric subsea control system as part of a qualification offshore field trial. Magnus is approximately 560 km northeast of Aberdeen and is in 185 m of water. Magnus was chosen instead of a floating structure to test the prototype equipment over a 6-month period.

The hardware deployed on the seabed was close to the platform, but linked to the topside control cabin by a 10-km power/communications cable wound around a drum deployed with the Christmas tree. The electric tree system contained a representative range of valves and actuators, including a fast-acting all-electric choke. In addition, the Christmas tree was internally pressurized, from the surface, to represent realistic operating conditions on the electric valves and actuators. At the conclusion of the field trial, the system was recovered and returned to the supplier for strip-down and evaluation of any wear characteristics. The results of this evaluation are currently being prepared, but the initial outcome has not shown any adverse conditions.

To minimize disruptions to the normal platform production operations, the all-electric prototype equipment was mounted on a dummy tree base and did not control the flow of any actual hydrocarbons. In addition, the valve actuations were automatically preprogrammed on a daily cycle, with the condition monitoring recorded for later analysis.

As part of the offshore trial precommissioning testing, a dock trial at Stavanger was completed successfully in November 2003. This deployment was in 30 m of water and was designed to test the deployment and cable-reeling operations. **Fig. 1** shows the trial equipment comprising the prototype all-electric subsea tree together with the underwater-deployed power/communications cable and basket-mounted pull-in section. JPT

The full-length paper is available for purchase at the OTC Library: www.otcnet.org. The paper has not been peer reviewed.