Subsea Technology

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As oil prices approach half of their value of last year, when they hit all-time highs above USD 147/bbl, here I am again to address the *JPT* audience. Against all odds and in spite of the difficult economic times, the 2009 Offshore Technology Conference (OTC) had extraordinary attendance, proving the breath and strength of our industry. The fact is that we are accustomed to ups and downs and to riding out tough times with innovation and willingness to embrace new solutions. Actually, this is the time to hold and value a strong engineering team that is motivated to face challenges, come up with solutions, and deliver oil and gas on time and on budget.

Those who attended the presentations at OTC had the privilege to witness the industry's accomplishments and promises. Among them was what might be one of the greatest developments offshore in ultradeep water in Brazil: the presalt formations. Last year, Petrobras started a pilot production project that allows testing technologies for the full development of these giant fields.

The industry's accomplishments and promises are represented by the papers selected for highlighting and for additional reading in this issue. They illustrate developments in the Gulf of Mexico, the North Sea, and Africa. As you read them, you will have the opportunity to know more about the design/qualification of the Tahiti field in the Gulf of Mexico, Chevron's first high-pressure subsea development, and improvements in efficiency for subsea operations in deepwater Angola implemented by ExxonMobil. In addition, you will know how StatoilHydro proved subsea compression to be a cost-effective alternative to platform compression in the North Sea. Other highlights include multiphase boosting installed in the BP King field, the Moho Bilondo subsea-production system, and the Agbami field development and its subsea-equipment systems.

Therefore, I would like to invite you to read this selection of papers, a testimony of our flexibility and willpower to endure and create in tough times. Enjoy it! **JPT**

Subsea Technology additional reading available at OnePetro: www.onepetro.org

OTC 20146 *• "BP King—Deep Multiphase Boosting Made Possible" by B.E. Davis, BP America, et al.*

OTC 20280 *• "Moho Bilondo: Subsea-Production-System Experience" by D. Carré, Total, et al.*

OTC 19919 *• "Agbami Field Development—Subsea-Equipment Systems, Trees, Manifolds, and Controls" by Thomas P. Kelly, SPE, FMC Technologies, et al.*

OTC 20186 *• "Subsea Processing and Boosting—Building Blocks for Petrobras Scenarios" by M.L.L. Euphemio, Petrobras, et al.*

Tahiti-Project System Qualification

The design requirements of the Tahiti subsea facilities, while not dependent on the qualification of new or "enabling" technology, did depend on extending or "enhancing" the limits of existing technology. The full-length paper briefly describes some of the key design requirements, the approach to determine the then current level of equipment qualification relative to these design requirements, the qualification process, and the subsequent lessons learned.

Subsea Overview

The Tahiti project was the first high-pressure subsea development for Chevron. The Tahiti subsea facilities consist of an eight-well production drill center in the south and a six-well production drill center in the north of the field. There is a single-well, mid-flowline tie-in midway between the north drill center and the host facility. The drill centers are approximately 3 miles from the host facility, and each is served by a 2-×9-in.-nominal-outside-diameter (OD) production flowline and a 1-×6-in.-nominal-OD test flowline. Each drill center is served by two electrohydraulic steel-tube umbilicals.

Each manifold has 2-×9.625-in.-nominal-OD production headers and a 1-×6.625-in.-nominal-OD test header. All headers are rated to 12,900-psi operating pressure. Round-trip pigging of the production and test flowlines is achieved by means of removable pigging loops and a Y-spool. The Y-spool allows the smaller test pig to drop into the larger production header where it will be swept back to the host using a production-flowline pig. The manifold configuration enables production from any well to be directed into any header.

Each of the manifolds is supported by a single suction pile, 18 ft in diameter and 77 ft long. The wells are connected to the manifolds by means of rigid production-well jumpers that are as much as 120 ft long and 3.50 in. inside diameter.

Eight production trees were purchased, with the latter two of these configured for smart well completions. The trees are $5^{1}/_{8}\times2^{1}/_{16}$ in. and are rated to 15,000 psi and 0 to 250°F with HH-rated production trim and EE-rated annulus trim.

Each tree has its own subsea control module (SCM) that also controls the manifold branch-isolation valves. The control system is fully redundant, from the master control station to the SCM hydraulic control valves. Each manifold has its own SCM that controls the pigging-loop isolation valves and the methanol-injection isolation valves and monitors the pressure, temperature, and corrosion sensors. The corrosion sensors are located on each of the flowline jumpers connected to the manifold headers.

The development requires equipment to be rated for 5,000-ft water depth, 15,000 psi, and 0 to 250°F, with high-pressure/high-temperature flowlines and steel catenary risers.

Six production wells were completed during the first phase of the Tahiti development. The second phase of the Tahiti development will provide additional production and water-injection wells, including a water-injection pipeline-end manifold, water-injection flexible flowline, and controls umbilical.

Equipment Qualification

The subsea equipment, although considered to be existing "off-the-shelf technology," required a substantial amount of qualification testing to meet the Tahiti-project requirements. During front-end engineering (FEED), the project team identified a list of more than 140 critical subsea components. These components included gate valves, mechanical connectors, seals, electrical and hydraulic connectors, and solenoid valves. The team then set the minimum qualification and acceptance requirements.

A survey was undertaken in which a detailed questionnaire was requested to be completed by each of the four preferred equipment vendors. This was complemented by follow-up clarification meetings between the representatives of the vendors and the project team. The results of this exercise revealed that none of the vendors fully met the Tahiti qualification requirements and that no vendor was considered to be significantly ahead of or behind the other vendors.

The qualification status of the selected vendor for the supply of the subsea equipment was the basis for the 36 qualification tests that were identified to be completed during contract execution and that were therefore included in the contract "scope of work" and scheduled to be completed in parallel with detailed design, soon after contract award. The qualification testing to be completed included combined pressure/temperature cycling, hyperbaric testing, cycle testing, make/break testing, and combined pressure/load testing.

This article, written by Assistant Technology Editor Karen Bybee, contains highlights of paper OTC 19859, "Tahiti-Project Subsea System Design/Qualification," by ***Chris Hey,*** *SPE, and* ***James Rasmussen,*** *Chevron, and* ***Steve Tattersall,*** *SPE, Cameron, originally prepared for the 2009 Offshore Technology Conference, Houston, 4–7 May. The paper has not been peer reviewed.*

The full-length paper is available for purchase at OnePetro: www.onepetro.org.

Once the subsea-project team had mobilized onto the premises of the vendor, a thorough review was conducted in which all of the qualification records for the critical components were examined to verify the earlier survey results. This extensive review lasted several months and required additional project resources. The result of this work revealed that an additional 40 qualification tests would have to be performed and that this posed a significant risk to what was already a very aggressive delivery schedule.

The reason for this increase in qualification testing was a combination of incomplete documentary evidence of qualification results, lack of clarity of test procedures used, and failure to meet the extended Tahiti test requirements. Also, it was apparent that although some components were claimed to be “field proven” and had been in use for a number of years, in some instances there was no traceability of qualification testing. To mitigate the effect of this increase in scope, additional resources were added and the qualification-testing activities were shared between the eight worksites worldwide of the vendor and its Houston-based research and development (R&D) facility.

As a result of the additional qualification scope, qualification testing had to be performed in parallel with manufacturing, meaning that equipment that not yet had met the Tahiti qualification requirements was already being used in assembly of the equipment. Clearly, in this situation it is very important that confidence of success be high, but that the risk of failure be understood and that a mitigation plan be put in place in the event of a test failure.

Lessons Learned

The period from the start of the subsea FEED to the subsea-equipment contract award was only 8 months. Evaluating the qualification status of the subsea vendors in addition to normal FEED activities during this short time was very challenging. For the more technically challenged projects, evaluating the status of the technology of the vendor should begin as early as possible during FEED and even during concept selection.

Coordinating an extensive qualification-testing program across multiple sites worldwide, particularly when the testing is performed in parallel with manufacturing, requires good interface management. Pressure- and temperature-cycle testing of components in laboratory conditions using test fixtures requires that attention be given to ensuring that the test fixtures and components are identical in size and surface finish to the actual production pieces. In one instance, it was noticed that the test fixture for a metal seal that was intended to replicate a critical seal bore of the subsea tree had a higher surface finish than was called for on the machining drawing of the tree bore. Although a higher surface finish was achieved, it was still within drawing tolerances, but this was deemed unrepresentative for test purposes. This error was discovered after the extensive pressure- and temperature-cycle qualification testing had been completed. Because of time constraints in the R&D facility, the decision was made to modify the tree bores to the higher surface finish of the test fixture, thereby mitigating schedule impact.

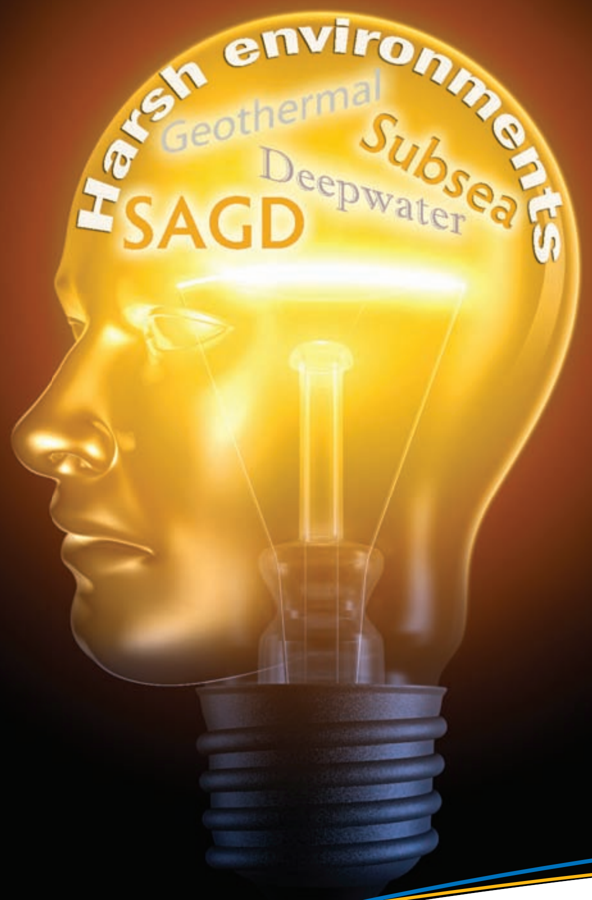
While it is important to set qualification-testing acceptance criteria that will provide confidence that the equipment is fit for purpose, it is important not to be too conservative because this may have a significant effect on project schedule and cost for no significant benefit. For example, the Tahiti-tree temperature rating was set at 0 to 250°F, with the installation tooling governed by the same temperature range. After unsuccessful attempts to complete pressure- and temperature-cycle testing on some elastomeric seals fitted to this tooling (in this instance, a tubing-hanger running tool), the temperature requirements were re-evaluated and found to be too conservative. This enabled the temperature range to be relaxed to 0 to 180°F. The testing was completed successfully, with minimal effect on schedule, and the equipment remained fit for purpose.

“Field proven” does not mean necessarily that the product or components in question have been qualified. Some products may have been in use, and may have performed successfully, in the field for many years without failure. However, obtaining in-service data, particularly failure data, can be difficult because operators typically do not report failure data to the vendors.

Before contract award, much work was conducted on material selection and compatibility.This work was critical in establishing the specific requirements of the project. The materials selection was consistent with benchmarked competitors and industry practice, and the requirements were established and communicated to the subsea-equipment vendors through comprehensive specifications. Despite having this work completed early and made available to the vendors during the bid phase of the project, it is very difficult to specify the material for every component used in very complex and varied subsea equipment.

A critical deliverable in any major subsea project is a comprehensive material-compatibility report. However, because of the accelerated schedule, this review had to be conducted in conjunction with raw-material procurement and equipment manufacturing. This was similar to the qualification review and testing and added risk to the project. Any missed components or errors were potential risks to the schedule. Any material changes caused by qualification issues could compound the risk. The amount of time required to confirm the compatibility of the numerous different components necessitates that this work be performed as early as possible to resolve any issues with minimal effects to the schedule.

The Tahiti review was completed quickly and efficiently. Although no major areas of concern were found, material substitutions and compatibility testing were required to ensure a sound system. What was not fully appreciated early on was the risk to certain assemblies during the extended wet-storage period. The risk of pitting/crevice corrosion and microbiologically influenced corrosion to the manifolds and jumpers was not realized until just before load out and installation. Material changes or additional equipment requirements at this point could have had a significant effect on the schedule. Fortunately, all parties involved came together quickly for a solution. The subsea-equipment vendor expedited design, procurement, and manufacture of the plugs needed to seal the debris caps, and the preservation-fluid supplier expedited mixing and bacterial testing. The lesson in this case is that a thorough understanding of all the operating conditions needs to be considered at the beginning of the project. Reviews also need to be performed once the equipment designs are complete, to validate the original work. **JPT**


Harsh environments
Geothermal
Subsea
Deepwater
SAGD

Efficiency Improvements for Subsea Operations in Deepwater Angola

Esso Exploration Angola Limited (EEAL) has realized substantial improvements in the efficiency of subsea operations in the deepwater environment of Angola Block 15 (AB15). EEAL has increased its efforts to improve efficiencies for subsea operations, specifically during simultaneous operations. Improvements in efficiency and schedule certainty were realized as a result of dedicating a work vessel primarily to subsea operations. The full-length paper presents case histories of various operations and discusses the effect on efficiency of a dedicated work vessel.

Fig. 1—Dedicated A-frame vessel.

Introduction

EEAL along with coventurers is developing several fields in AB15, 145 km west of Soyo, Angola, and approximately 386 km northwest of Luanda. Water depths range from 700 to 1435 m. Exploration rights were awarded in 1994, and drilling began shortly thereafter. AB15 currently is producing from five floating production, storage, and offloading (FPSO) facilities. The Kizomba C development project, which supplies FPSOs Mondo and Saxi-Batuque, is under way, and a Kizomba Satellites development project is in the planning stages.

To bring these developments on line in the timeliest manner possible, as many as six rigs have operated simultaneously on the different fields within AB15. Two of these rigs are tension-leg platforms, and the remaining rigs were mobile offshore drilling units (MODUs) working on a drilling schedule of more than 100 subsea wells distributed amid 18 subsea drill centers. This high amount of activity within the block created the potential for large schedule conflicts as a result of installation-vessel and MODU simultaneous operations.

In response to these potential conflicts, EEAL evaluated operations to identify which nondrilling tasks could be separated from critical-path MODU operations. Removing these tasks from the MODU schedule increased schedule flexibility and decreased cost.

This article, written by Assistant Technology Editor Karen Bybee, contains highlights of paper SPE 119651, "Improvements in Efficiency for Subsea Operations in Deepwater Angola," by ***Jason Zook,*** *SPE, ExxonMobil Development Company, and* ***Arran Keith,*** *Swift Technical Group, originally prepared for the 2009 SPE/IADC Drilling Conference and Exhibition, Amsterdam, 17–19 March. The paper has not been peer reviewed.*

Suction-Embedded-Plate-Anchor (SEPA) Installation

Early in the project planning for the AB15 development, drill centers were planned in close proximity to one another to enable the most cost-effective subsea architecture. The decision was made that AB15 would use one or possibly more conventionally moored MODUs for its subsea development wells. To achieve such a subsea layout and its related cost savings, the anchor pattern of a conventionally moored MODU must become more compact. This more-compact anchor pattern required the use of taut-leg-mooring (TLM) systems to allow a MODU to moor safely over drill centers set relatively close to each other.

This initiative to reduce the anchor-pattern footprint on drill centers led EEAL to search for a TLM system suited for the soft-clay seafloor of AB15. After consideration of all available systems, SEPAs were selected and qualified on the basis of their high holding capacity and ability to be positioned precisely on the seafloor. SEPAs consist of a plate anchor that is embedded in the seafloor by use of a suction follower installed with the assistance of a remotely operated vehicle (ROV). Once the plate anchor is installed subsea, and the suction follower is removed, the only equipment remaining above the mudline is the mud mat resting on the seafloor with the mooring connector accessible by ROV. The decision was made to award a turnkey contract to an experienced contractor for installation of these initial SEPAs.

Later in AB15 development, during the planning of the Kizomba C phase,

For a limited time, the full-length paper is available free to SPE members at www.spe.org/jpt.

market rates were at an elevated level and vessel availability was at a premium. This caused EEAL to explore other alternatives to the turnkey installation contract for its SEPAs. The minimum installation-vessel equipment required to perform this operation consists of an A-frame system, a suitably rated winch wire, and an ROV. These requirements all were readily available on the dedicated support vessel already at work in AB15 shown in **Fig. 1.** With a suitable vessel at hand in a tight market and the experience gained during the initial SEPA installations, the decision was made to install SEPAs for Kizomba C with the dedicated A-frame vessel instead of awarding another turnkey installation contract. The SEPA installations were planned in phases, around current well work and other AB15-development activities. In the past, these third-party-controlled schedules often caused simultaneous operations conflicts that were difficult to manage and affected MODU operations, causing critical-path delays. With EEAL controlling its own dedicated work vessel, it had the schedule flexibility to avoid these simultaneous-operation conflicts. The schedule flexibility of the dedicated vessel allowed the installation of all Kizomba C SEPAs to be completed without any notable delays to its other required duties or to any MODU critical-path activities. This resulted in substantial cost savings with one less vessel operating in the block and additional cost avoidance in the form of greatly enhanced MODU schedule certainty.

Horizontal-Christmas-Tree (HCT) Installation

The largest driver of the cost and schedule benefits and justification for the dedicated vessel in AB15 is the installation of HCTs on subsea wellheads. This is the most vital function of the vessel from the standpoint of saving critical-path rig time. A dedicated vessel has the potential to save days on every well while minimizing risk to subsea infrastructure. Use of the vessel also improves schedule certainty and flexibility by providing the capability to install HCTs off of the critical path in the event of simultaneous-operation conflicts with higher-cost subsea-infrastructure-installation vessels, or other MODUs operating in the block.

To run HCTs from a MODU, the blowout-preventer (BOP) stack and marine riser must first be recovered to surface. This is a time-intensive task in shallower-water environments, and even more so in deeper-water environments such as AB15 where the riser length can account for as much as half the measured depth of the well. After the riser is recovered, the HCT then is run on drillpipe to just above the wellhead and landed using the heave-compensation system of the MODU. After the HCT is landed on the wellhead, the installation tools and drillstring are recovered to surface. Then, the BOP stack and riser are rerun so well work can continue until the well is completed.

The EEAL team identified two inefficiencies within this process that were considered unacceptable for such a large subsea project. These were the time required to run the HCT from the MODU on drillpipe and the time for riser-retrieval and -running operations. The time required to run the HCT on drillpipe could be eliminated by the use of a properly rated subsea work wire on the MODU, but riser retrieval still may be required. To maximize savings and risk avoidance, another means of deploying HCTs was needed. By using a vessel, all BOP and riser handling is eliminated along with the time spent making drillpipe connections. The only MODU operation required is to unlatch from the subsea wellhead and lift the BOPs sufficiently high to clear the subsea infrastructure. This provides an egress from the wellsite and allows the rig to skid away in a short period of time.

In the earlier phases of the Kizomba development, there were occasions when only one MODU was operating in the block. Because of this, an A-frame vessel was chosen for its overall utility. Its strengths as a multipurpose vessel were an asset to the block during anchor handling, ROV operations, and later SEPA installation.

Another opportunity for improvement was identified as the volume of work on the dedicated vessel changed because of the progression of the project and the addition of two more MODU rig lines in the block for the Kizomba C program. With the rig count in AB15 rising, the potential for schedule conflicts and time lost waiting on the critical path among the MODUs increased significantly. Once all SEPA-installation operations were complete, the A-frame vessel was no longer necessary and a boat with an active-heave-compensated (AHC) -crane system could improve HCT installation efficiency further and the overall flexibility of the operation.

As SEPA installations came to an end, EEAL sourced an AHC-crane vessel. The 45-m cargo-deck length and 200-ton (twin fall) AHC crane make it ideal for staging as many as three HCTs onboard and deploying them as needed without returning to shore. The AHC crane also decreased the actual time spent lowering the HCT by approximately 10 hours vs. the heave-compensated landing system.

Synergistic Benefits

Other opportunities for efficiency improvements and enhanced schedule certainty exist if appropriate windows in the vessel schedule are present. One of the biggest opportunities comes from the availability of an extra ROV in the field. This ROV has been used to assist a MODU's ROV in latching a BOP stack in high currents, to troubleshoot mooring-equipment problems outside the reach of the MODU's ROV, and to provide redundancy to rig ROVs in the event of critical-path downtime. These ROV-support operations reduce critical-path downtime, and as a result, MODU schedules continue as planned. Because the vessel was typically working non-critical-path activities, its schedule was sufficiently flexible to accommodate urgent requests within the field.

While ROV work and minor logistics support could be carried out from either of the two dedicated vessels, other opportunities depended on which vessel was present at the time. For instance, early in the development, the A-frame vessel was scheduled to provide anchor-handling support on a regular basis because of its capabilities. This freed a boat to maintain logistics support for the remaining rigs in the field instead of being occupied with rig moves.

Results

The operator determined that the HCT-installation portion of this project could justify the cost of sourcing a dedicated subsea-operations vessel. As the dedicated subsea vessel became an integral part of field operations, additional benefits were realized and the operator saw the justification for using the vessel become even more compelling. The use of a dedicated subsea work vessel resulted in a combined overall time savings of 5 to 7 days per well. **JPT**

Ormen Lange Subsea-Compression-System Pilot

Ormen Lange is a long-tieback gas field with gas-processing facilities onshore 120 km from the production wells. The development strategy is pressure depletion. To maintain the production plateau for as long as possible and recover the anticipated gas and condensate resources, offshore compression is required to maintain production. The full-length paper describes subsea compression as a cost-effective alternative to the platform-compression solution and the strategy for qualifying the subsea-compression system before offshore-compression concept selection.

Introduction

Ormen Lange is a gas field 120 km off the northwest coast of Norway on the Norwegian continental shelf, in water depths varying between 850 and 1100 m. The reservoir covers an area 40 km long, 8 to 10 km wide, and 3000 m below the surface. Recoverable reserves are estimated at approximately 397 billion std m^3 of dry gas and 28.5 million m^3 of condensate. Ormen Lange has been in production since October 2007.

This article, written by Assistant Technology Editor Karen Bybee, contains highlights of paper OTC 20028, "Ormen Lange Subsea-Compression Pilot System," by ***Bernt Bjerkreim, Snorre Frydelund, John Arild Lie, Knut Ola Staver,*** *and* ***Karl Olav Haram,*** *StatoilHydro;* ***Bjørn Nystad,*** *Shell;* ***Håkon Skofteland,*** *AkerSolutions;* ***Hans Gedde,*** *VetcoGray;* ***Alberto Tesei,*** *GE Oil and Gas; and* ***Michel Postic,*** *ConverTeam., originally prepared for the 2009 Offshore Technology Conference, Houston, 4–7 May. The paper has not been peer reviewed.*

The main drive mechanism for the Ormen Lange reservoir is pressure depletion. The estimated recoverable reserves are based on the use of offshore compression facilities for pressure boosting upstream from the onshore plant as the reservoir pressure declines. The Ormen Lange subsea-production system is designed to accommodate the flexibility to decide the type of offshore-compression concept at a later stage. The options considered were subsea compression **(Fig. 1)** or platform compression.

The date for the final decision on the offshore-compression concept is planned to be 2012, 4 years after subsea-production startup **(Fig. 2).** An evaluation of the technical maturity and cost for the two offshore alternatives will be the basis for concept selection. The current plan is to start offshore compression in 2016. Onshore precompression may be used and may delay the investment in offshore compression by some 2 years.

Business Case

Subsea compression represents a number of significant advantages compared to a platform solution. The solution is capital-expenditure cost efficient. This can be illustrated easily by the weight difference. With the Ormen Lange core functionality, the subsea-compression station has a weight of 6500 tonnes, while a platform will have a total weight of 25 000 tonnes. Further, operating expenditure cost also will represent a significant advantage for the subsea-compression alternative. No additional operational manning will be required to operate the field from the onshore terminal, including reduced logistics and reduced offshore operations. Using subsea compression compared to platform compression also will contribute to increased safety by reducing helicopter flights that would be required for the platform alternative. Additionally, locating compression closer to the reservoir will enhance the ultimate recovery, and subsea compression can be optimized easily for tail-end production.

Subsea Compression

To ensure fully qualified subsea-compression equipment and increase confidence in the equipment, 2 years of subsea-compression pilot testing has been allowed for.

The subsea-compression system will be designed to

- Deliver approximately 58 MW of electrical power and signals from shore to the subsea-compression station placed at Ormen Lange, with a 125-km-long power umbilical.
- Transform the power from the transmission voltage of 120 kV down to a distribution voltage level of 22 kV.
- Distribute the electrical power to all consumers and individually regulate the torque and speed of all electrical motors according to process requirements.
- Control and regulate the subsea-compression station with an all-electric control system, including an uninterruptible-power-supply system for critical loads.
- Receive wellstream from each of the two already-installed Templates A and B, and eventually receive wellstream from the two future Templates C and D.
- Separate the wellstream phases, compress the gas, boost the liquid, and recommingle the phases.
- Distribute the compressed wellstream to both of the two 30-in. pipelines.

Subsea-Compression Station

The configuration of the subsea-compression station is based on four identi-

The full-length paper is available for purchase at OnePetro: www.onepetro.org.

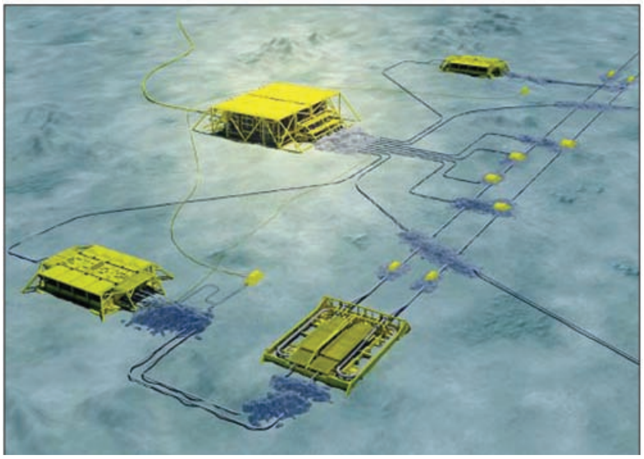


Fig. 1—Ormen Lange development with subsea compression.

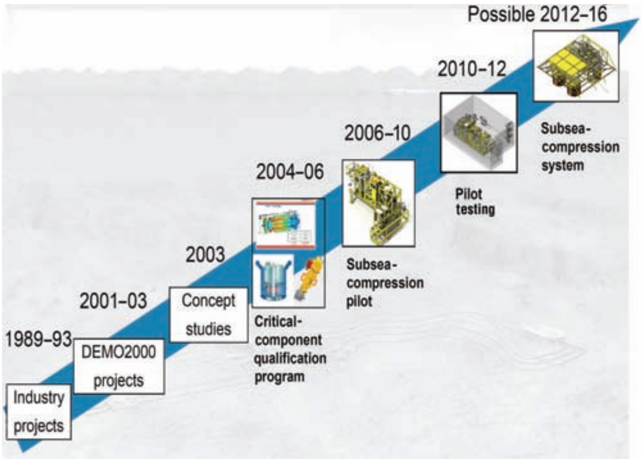


Fig. 2—Ormen Lange subsea-compression road map.

cal and segregated compressor trains. The main benefits with this configuration are as follows:

- It allows shutdown and maintenance of one train without affecting the production through the other trains.
- Each compression train can be tested individually and installed sequentially if required.
- The complexity is greatly reduced by not providing any cross connection of process lines or electrical jumpers between the trains. Simplicity and robustness are seen as key design objectives, given the novelty of this type of equipment.
- The process and power modules are identical and interchangeable. Common spare modules can be used.

The current plan is to have all four compressor trains installed from commencement of subsea compression. The reservoir pressure and the compression-station inlet pressure will fall gradually over time, and only three trains will be in operation during the initial years of operation. This gives an overcapacity and increased availability, and the compression system can produce up to the maximum capacity of the onshore plant.

All four trains (4×25%) are required for the design production case with an inlet pressure of 80 bar and a discharge pressure of 140 bar.

The flowline tie-ins and the process modules are located on one side of the subsea-compression station, and the power umbilical termination and the power modules are on the other side.

The inlet wellstream from the production templates to the subsea-compression station is distributed equally to each compressor train because of symmetrical piping in the tie-in and inlet manifolds. The wellstream is separated in the separator where the hydrocarbon liquid, water, and solids are routed to the subsea pump module. The gas is routed to the subsea compressor, and the separator is designed to provide a clean gas with a limited amount of liquid and solids. The pressurized liquid and gas are mixed at the discharge and routed to the export pipelines for transport to the onshore facility.

Subsea-Compression-Station Pilot

A pilot test facility at Nyhamna onshore terminal will be built. The test facility will host and supply the equipment required for testing at the onshore test pit at the Nyhamna facilities. The process facilities will represent the well flow to the subsea-compression station. The subsea-compression pilot system will be installed submerged in a water basin 28 m wide, 42 m long, and 14 m deep, filled with seawater.

The design of the test setup shall, as far as possible, enable control and operating conditions similar to those expected for the permanent subsea installation. The test facilities will be able to conduct representative wet-gas testing representing Ormen Lange wellstream conditions. In addition, the test facilities will be constructed so that the subsea-compression system pilot can be used as an additional first-stage gas-export compressor.

The subsea-compression-station pilot comprises one compression train equal to, and with the same capacity and duty as, one of the four compression trains for the future Ormen Lange subsea compression station. The pilot station will be installed and tested in a test pit at Nyhamna, the Ormen Lange onshore facilities. A cooling-water system provides continuous flow of seawater into and out of the test pit for cooling of the equipment during operation. The pilot will be operated with the real wellstream composition received from the Ormen Lange onshore facilities, and the test facilities are equipped to emulate slug production, sand production, and other operating conditions for the future Ormen Lange subsea-compression station.

The electrical power from the test facilities is provided in a power umbilical to the pilot main-transformer unit located in the test pit. The main transformer is connected to the 22-kV circuit-breaker module, which includes circuit breakers for the compressor and pump variable-speed drives.

The pilot arrangement comprises the following main components.

- Compression train with process and electrical-power modules.
- Circuit-breaker module.
- Control system including subsea control modules.
- Main inlet transformer—part of the long-stepout power-supply system.

The pilot is arranged in the test pit at Nyhamna with interfaces for process-fluid inlet/discharge, electrical-power supply, and communication. The process- and power-module arrangements are identical to the future Ormen Lange subsea-compression station, to ensure that all aspects of the process equipment, electrical-power equipment, and overall system operation are qualified. **JPT**