PROJECT ATLANTIS: SUBSEA OIL AND GAS PRODUCTION CITIES

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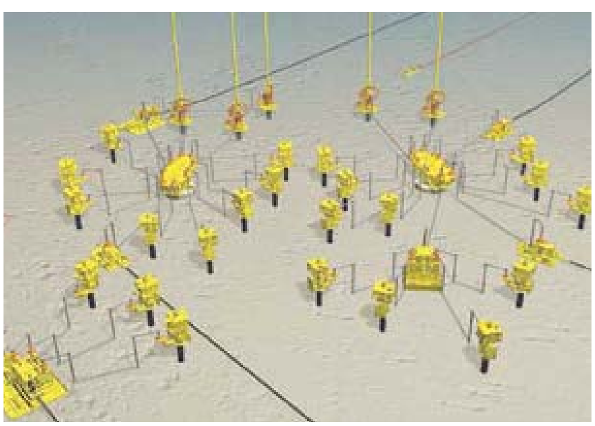

FIGURE 1 Subsea multi-well and multi-manifold oil and gas production system.
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Offshore oil and gas production has a history dating back to the late 1890s. The first offshore well was located 300 ft. from the California shoreline and connected to the coast by way of a pier [1]. The success and production performance of this first well produced a gush of additional offshore wells, each reaching further into the water. The next milestone in offshore oil and gas production was in 1947 when Kerr-McGee reached over 10 miles from the shoreline to produce hydrocarbons at a depth of about 20 feet [1-2]. The production facility was built on a "static-structure" that stood tall above the water line and its foundation was located on the mud-line (ocean-floor). What makes this offshore facility significant is that the shoreline was no longer visible from the production platform. By the mid-1970s, Shell Oil Company transformed offshore production through the marinisation of shallow water platform technologies to reach a reservoir in the Gulf of Mexico located 1,000 ft. deep, the Cognac. At the time, the Cognac production facility was the tallest structure in the world. A decade later, Shell continued to lead the quest for oil and gas production in deeper water with the world's first tension leg platform (TLP). The TLP is a floating structure with "sets-of-tentacles" located at each corner and fixed to the seabed. Controlling the tension in each tentacle enables dynamic control of the floating platform, namely isolation from wave motion. By the 1990's, the need for a production facility to hold onto the seabed and perhaps the desire to do so disappeared. The reason is to lower the capital expenditures (CAPEXs), thus improving the economic feasibility of producing deeper water reservoirs. Today's offshore oil and gas production facilities are located on the seabed. The only evidence of offshore energy production would possibly be a floating vessel, known as floating production and storage offloading (FPSO) vessel, used to transport the hydrocarbons to an onshore facility.

There are massive oil and gas reserves located in ultra-deepwater (depths greater than 10,000 ft.). Equally impressive to the billions of barrels of oil located in ultra-deepwater is that these reservoirs have shut-in pressures of 15,000 psi. The fundamental engineering challenges facing today's ultra-deepwater oil and gas production reside under a new engineering discipline, the subsea engineer. There is uniqueness to the harsh underwater location that manifests itself as a corrosive environment with external pressures of 5,000 psi and internal pressures reaching 15,000 psi. These underwater facilities (equipment) must have a useful service life of 30 years to be cost-effective despite being subject to huge producing well uncertainties (flow composition and pressures). Of even greater importance is that subsea production facilities must completely protect the environment.

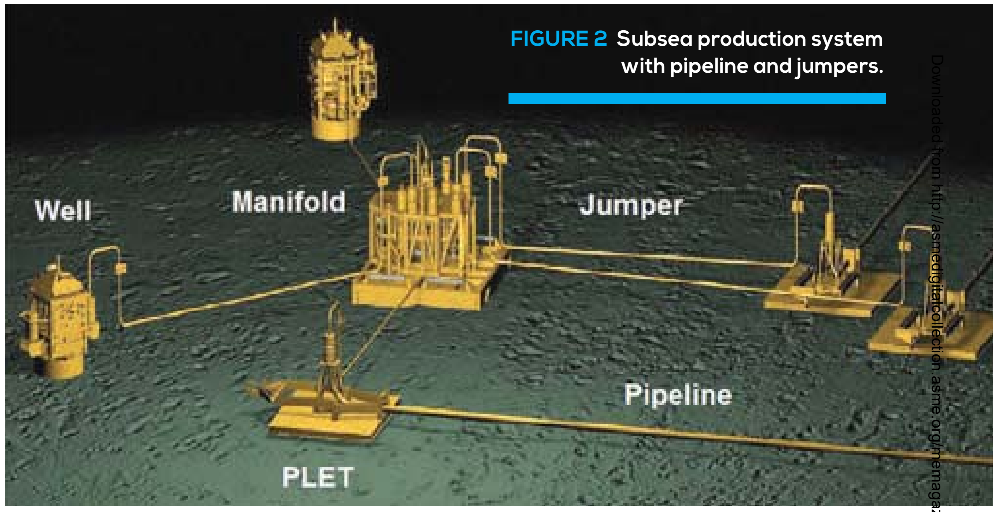

FIGURE 2 Subsea production system with pipeline and jumpers.

SUBSEA OIL AND GAS PRODUCTION EQUIPMENT

The major cost for producing an ultra-deepwater reservoir is the drilling operation. At this stage it is important to note that oil and gas reservoirs are not subsurface cavities filled with crude oil. Instead a reservoir is a subsurface formation of permeable rock containing hydrocarbons. Ultra-deepwater drilling is accomplished using dynamically positioned (DP) drill ships enabled through global positioning systems (GPS). The drilling operation is known as upstream oil and gas engineering. Offshore drilling operations are occurring everyday where the drill string (thick walled piping with a bit attached at the end) travels 2 miles to reach the mud line and then another 3 miles to the reservoir. Roughly speaking, this is equivalent to stretching a guitar string the length of a football field and twisting one end to perform drilling. Once the well is established, the engineering operations necessary to produce oil and gas are known as downstream engineering. This phase of subsea oil and gas production focuses on the design and installation of the subsea production system (Figure 1). The primary issues facing downstream engineers include equipment reliability, connectors (connections between subsystems) and multiphase flow (flow comprising oil, gas, water and sand).

Subsea hydrocarbon production facilities are separated into two primary categories, subsea (Figure 1) and topside (above the water). To describe an underwater production facility, we will begin at the wellhead. The wellhead is a pipe with a flange put in place by upstream operations. This pipe (well casing) travel into the earth's crust to penetrate the reservoir. The well casing within the reservoir is perforated to allow flow from the high-pressure reservoir. Bolted to the well casing flange is the so-called Christmas Tree (XTree) (Figure 2, see the engineered system below the word "Well").

XTrees can be either horizontal or vertical and allow both access and control of the reservoir. These two functions are needed to guarantee production flow (flow assurance) over the life of the well while producing the reservoir in a manner that does not collapse its porous rock composition.

The product flows from the XTree to a subsea manifold via a jumper (Figure 2). The jumper is a pipe designed to withstand sand erosion and product corrosion. All jumpers have U-like shapes enabling stiffness/flexibility and function [3].

Owing to the capital expenditures associated with ultra-deepwater systems, it is mandatory for each subsea production site to have multiple wells (Figure 2). Each well has its dedicated XTree and jumper, and is producing hydrocarbons. A subsea manifold gathers these individual productions into a central place. Subsea manifolds are not small. In fact, subsea manifolds can reach dimensions of up to 75ft. x 40ft. x 20ft., having huge weights that match their dimensions. A subsea manifold serves many functions. For example, the manifold allows access to the flow hydrocarbons to inject chemicals for flow assurance issues. Manifolds provide the primary location for pipeline cleaning using pipeline inspection gauges (PIGs). However, the primary function of the subsea manifold is to combine flow hydrocarbons from multiple wells and send the resulting aggregate through a single pipeline to the so-called tieback. The manifold is connected to the pipeline

FIGURE 3 Subsea tieback with slug flow.

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via the pipeline end termination (PLET) assembly.

Subsea tiebacks involve the transportation of flowing hydrocarbons collected at the manifold to an offloading location through a subsea pipeline (Figure 3). The FPSO previously cited is one example of an offloading facility. Other tieback locations include existing static structures of older offshore production facilities and back to shore. Tieback distances of over 50 miles are not uncommon with ultra-long tiebacks approaching 200 miles on the immediate horizon. Subsea pipelines are critical to the success of a subsea tieback. Subsea pipeline design is a multi-domain design problem concerned with multiphase flow, heat transfer, material erosion and corrosion, and many a misplaced ship's anchor. Pipeline designs are further complicated by irregular terrain of the ocean floor traveling over hills and valleys, and external vortex-induced vibrations (fatigue). The design, installation and maintenance of subsea pipelines are paramount for subsea production profitability and environmental protection.

The growing ultra-deepwater depths have begun to experience new challenges, viscous flow losses and hydrostatic head. Despite the high pressures of the reservoir, the pressure losses along the pipeline and hydrostatic head of reaching the surface have made artificial lift a necessity in many subsea applications. There are two basic artificial lift methods, gas injection and compression systems. Gas injection is the most common form of artificial lift. The injected gas is used to reduce the hydrostatic head in the riser to allow the reservoir to produce. Compression systems are multistage compressors driven by electrical motors. It is not uncommon for the electrical motors to be rated to 8 megawatts and stand about 20 feet tall. The multistage compressor comes in two varieties, single-phase and multiphase compression systems. Single-phase compressors have a subsea separator upstream which segregates the gas, oil, water and sand using gravity and baffles. Multiphase compressors do not require the upstream separator, directly boosting the pressure of the multiphase flow as it leaves the compressor. There are unfinished engineering challenges with both compression-based systems. The subsea separator has a foaming problem that occurs during the separation process. The multiphase compression system faces the stall phenomena similar to gas turbine engines. Both solutions face blade wear (due to sand) and corrosion.

If the tieback terminates to an existing platform or an FPSO, the pipeline must interface with a riser, a vertical pipe reaching the water's surface. Risers are subject to dynamic loading conditions caused by the water currents [4]. Risers are vulnerable to undesirable weather conditions such as hurricanes. Essentially, risers accumulate metal fatigue and present a

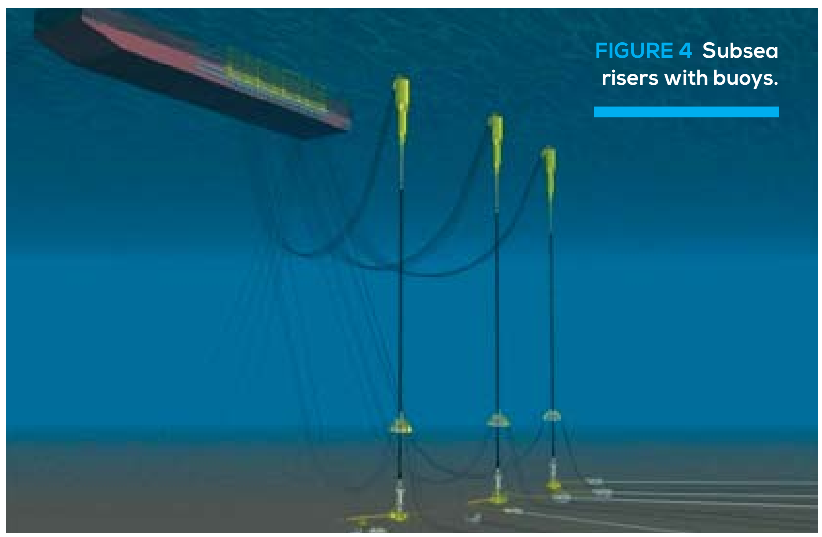

FIGURE 4 Subsea risers with buoys.

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completely different multiphase flow challenge than do pipelines (horizontal flow). Newly-designed risers are now terminating 300 ft. below the water's surface, thereby isolating them from storms. These risers have redundant buoys (the size of school buses) and cabling systems that provide riser support, stability and buoy separations.

The topside of subsea production is where the subsea production system is managed and the power necessary to run the subsea facility is supplied. Subsea production facilities are powered by two basic power forms, electrical power and fluid power. The electrical power supports sensors, subsea control modules (SCMs), and communication (including acoustic communication). The fluid power is the muscle controlling subsea production. The subsea gate valves (high pressure isolation) and subsea chokes (flow control) are actuated using hydraulics. Both forms of power have redundant sources for emergency shutdowns. Electrical power and hydraulic power are also stored subsea to reduce the source-to-consumption path. Also located on the topside are well intervention chemicals such as methanol, the master control system and emergency shutdown (ESD) system.

The topside and subsea production systems are connected to each other through an umbilical. The umbilical is a watertight conduit carrying electrical power, hydraulic power, chemical inhibitors, as well as other electrical conductors and optical fibers for sensor interfacing, communications and condition monitoring. The umbilical leaves the topside from the topside umbilical termination assembly (TUTA) and plugs into the subsea distribution unit (SDU). The SDU distributes electrical and hydraulic power, and receives sensor and other communications all through flying leads (cables and flow lines connecting one subsea subsystem to another).

ENGINEERING CHALLENGES FACE SUBSEA SYSTEM DESIGN

Designing subsea systems for 30 year long controllability, safety, maintenance, and real-time optimization are critical issues and present an open-ended problem. Below is a summary of the two primary challenges associated with the design of the subsea architecture. Topics not reviewed include condition and performance monitoring, materials and corrosion, and installation.

Safety is absolutely a primary focus on any subsea production system design. There must be multiple independent safety paths in place to isolate a producing well. The most common subsea safety system is located within the well. It is called the surface control subsurface safety valve and requires hydraulic pressure to keep the reservoir flowing. When hydraulic power is lost, the valve closes thus isolating the well. The subsea XTree can also be used to isolate the well by closing the choke. Downstream of the manifold is a high integrity pressure protection system (HIPPS). This system automatically closes a gate valve when the pressure in the pipeline is too high.

The presence of multiphase flow in a subsea production system complicates system design and operation. There are multiple flow regimes that can exist for multiphase flow in horizontal pipelines [5]. Pioneering work performed at the University of Houston provided mathematical relationships to predict the flow regime given gas and liquid velocities, including dispersed bubble flow, elongated bubble flow, slug flow and stratified flow to name a few. Vertical multiphase flow has completely separate flow regime prediction equations. However all of the cited multiphase flow studies are applicable to steady-state flowing conditions. The development of reduced-order mathematical models

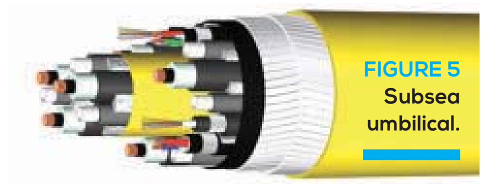

FIGURE 5 Subsea umbilical.

predicting multiphase flow under transient conditions is completely missing in the open literature. There is an unexplored coupling between the transient multiphase flow and the heat transfer (heat flow from the product through the pipeline and into the ocean environment). The field of modeling multiphase transient transport is important to the subsea architecture design and real-time optimization of subsea production.

SUMMARY

Subsea engineering presents many new challenges and opportunities for engineers from any discipline. An excellent tutorial reference source is [3]. Success in subsea engineering directly addresses energy security while protecting the environment and marine life. ■

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ABOUT THE AUTHOR

Dr. Matthew Franchek is the founding director of the University of Houston Subsea Engineering Program. He received his Ph. D. in mechanical engineering from Texas A&M University in 1991 and started his career at Purdue University as an assistant professor in mechanical engineering. He was promoted to full professor in 2001. While at Purdue, he initiated and led two industry supported interdisciplinary research programs: in automotive research and electro-hydraulic research. From 2002 to 2009 he served as chair of mechanical engineering at UH while simultaneously initiating the UH biomedical engineering undergraduate program. After his term as Department Chair, Dr. Franchek worked with Houston area companies to create the nation's first subsea engineering program. His expertise is in model-based methods for diagnostics and control of aerospace, automotive, biomedical and energy systems. His current research program focuses on multiphase pipeline flow, artificial lift, blowout preventers and electrical power distribution. He has authored over seventy archival publications, and over 100 conference publications.