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Deep sea power energizes Total

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Subsea automation and control systems have been around for a long time. The traditional driver for development of this equipment has been safety. With a subsea safety valve in place, even a major catastrophe on the surface facility will not cause loss of well control. As the use of floating production systems evolved, the need for highly reliable subsea valves became obvious, and in fact has been mandated by the regulatory authorities in most countries with offshore production. Over the years, a variety of valves, controls and sub-assemblies have been qualified for subsea use, each with the goal of facilitating remote control and operation from the surface.

With increasing water depth, purely mechanical systems quickly became impractical, and the industry turned to hydraulic or electrohydraulic systems to operate subsea equipment. But there were problems. The inherent drawbacks of hydraulic systems experienced exponential growth with increasing water depth, step-out distance and seawater temperature. System reliability, actuation response time, hydrostatic effects and the risk of environmental incidents should the hydraulic fluid leak or spill into the sea were factors that drove the search for a new solution.

Safety not at issue

Interestingly, the principle driver for development of a new subsea production control system was not safety — at least not directly. Operational reliability, command sensitivity and actuation response time were the critical factors that required improvement, and a good business case could be made on these merits alone.

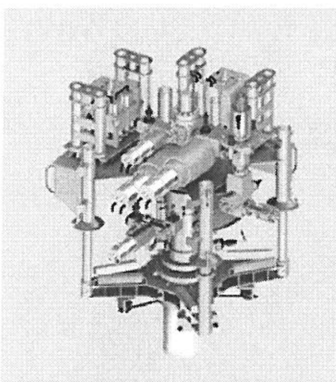

Figure 1. CameronDC all-electric subsea production system for K5F field development. (Images courtesy of Cameron)

At the same time, the industry had reached an economic frontier of sorts. Deep and ultradeepwater developments required huge elephantine fields to make a feasible economic case, and there simply were not enough of these to keep up with demand. First in the North Sea and later in the Gulf of Mexico, Brazil, West Africa and offshore Canada, the idea to link several smaller satellite fields to a central production facility gained popularity. In the Gulf of Mexico, Kerr-McGee exploited its "Hub-and-spoke" development strategy in which the production facility, spar or semisubmersible, was centrally located. Linked to satellite fields with subsea gathering lines, and production manifolds and flowlines, the hubs were frequently not situated directly over any of the fields served.

Enter the DC Tree

As early as 1999, Cameron recognized the need for a better subsea production control system, and started work on what was to become its all-electric subsea completion system, commonly called the DC Tree (Figure 1). The name is an understatement. Far more than a simple Christmas tree, the system can be designed to address almost any production control requirement by adding customizable configurable modules. In addition, the all-electric feature eliminated what was perceived as a major environmental risk — potential spillage of hydraulic fluid into the sea. As an example, recent studies made in conjunction with planning Russia's huge **Shtokman** field development make the point. A single 1/2-in. diameter control line from the field to the control facility contains 1.2 million liters of hydraulic oil. Risking such a spill in sensitive Arctic environments was unthinkable.

Building on an early design, the Mark 1 electric gate valve actuator, the company started to realize the advantages of low-power direct current motors to perform work remotely, at great depths and distances. DC is simple. It does not suffer the degradation of AC over long distances, and it is fairly straightforward to quickly raise the voltage to perform a task, then scale it back to maintain system status. In other words, power consumption is kept to a minimum.

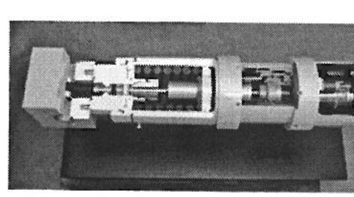

Figure 2. Subsea gate valve with electric actuator and failsafe spring.

A comparison of response-time contrasts the DC system to its hydraulic counterpart. Not only is response smoother and faster, but the operator gets real/time feedback regarding system performance and instantaneous valve status.

A look at the bottom line

Economics always play a role when new systems are introduced. The DC Tree was deliberately made compatible with the company's popular Spool Tree design so it could be used both on new installations and for upgrades or retrofits to existing subsea production systems.

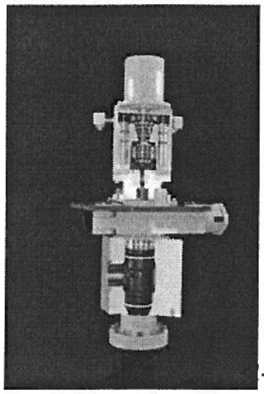

Figure 3. Subsea choke module with electric actuator.

And the all-electrical design supports and provides telemetry for large number of intelligent well system and production optimization designs including permanent gauge monitors, flowmeters, booster pumps and downhole well control systems. With an eye to the future, designers have made the new system compatible with planned subsea processing equipment such as subsea separators, booster pumps, and all -electric production manifolds. Standard tooling is needed to install and commission the new system.

A study performed jointly by BP, Cameron and Cranfield University in the United Kingdom, did some life-of-the-field modeling to estimate the economic impact of the DC production system. Using a base-case consisting of a four-well field in 5,000 ft (1,524 m) of water, 12.5 miles (20 km) from the production facility and flowing 100,000 b/d of oil, the study calculated the number of necessary intervention days using the DC system vs. an hydraulic system over a 12-year field life. Results were impressive.

--[if !supportLists]-->•□□□□□□<!--[endif]-->40% reduced intervention time the first year, followed by 20% reduction in subsequent years;

<!--[if !supportLists]-->•□□□□□□<!--[endif]-->20% reduction in single-well failures over the life of the field; and

<!--[if !supportLists]-->•□□□□□□<!--[endif]-->15% reduction in system downtime over the life of the field.

Using very conservative US $25/bbl of oil and $3.50/MMcf of gas commodity prices and a 10% discount rate, the model calculated a $129 million improvement in net present value over the life of the field.

Testing the concept

In assessing the viability of the DC production control system, Total engineers did a rigorous analysis of all data acquired over several years of component testing, as well as two significant system tests. Field trials were conducted with the cooperation of BP on its **Magnus** field in the UK North Sea. (Prior to that, a 22-day "shakedown" test was conducted in the fjord near Stavanger, Norway).

The test system consisted of a representative number of valves and chokes, all equipped with DC electric actuators:

<!--[if !supportLists]-->•□□□□□□<!--[endif]-->5 1/8-in. 5,000 psi FLS gate valve;

<!--[if !supportLists]-->•□□□□□□<!--[endif]-->2 1/16-in. 5,000 psi FLS gate valve;

<!--[if !supportLists]-->•□□□□□□<!--[endif]-->5 1/8-in. 5,000 psi insert choke;

<!--[if !supportLists]-->•□□□□□□<!--[endif]-->3/4-in. 5,000 psi chemical injection valve;

<!--[if !supportLists]-->•□□□□□□<!--[endif]-->Pressure transmitters on supply and return lines; and

<!--[if !supportLists]-->•□□□□□□<!--[endif]-->Hydraulic accumulator to provide bore test pressure and flow.

In addition, a 6.25 mile (10 km) power and control cable bundle was spooled on top of the test tree to simulate step-out distance and quantify its effect on power and data transmissibility.

The Magnus test spanned 6-months, during which time the system was subjected to 20-years worth of actuation. With 5,000 psi in the well bore and 5,000 psi differential pressure across the valve gates, each valve on the test tree was operated 240 times.

The choke with electric actuator was subjected to the equivalent of 1 million steps on a hydraulic stepping choke.

Contributing to the success of the field testing was the fact that the all-electric system has much fewer moving parts and seals than its hydraulic counterpart. The average electro-hydraulic control module alone has more than 500 moving parts and seals, whereas the all-electric version has none. And hydraulic systems require full power at all times to maintain status. Electrical systems maintain status at low power (the equivalent of a standard light bulb) and only consume high power (equivalent to a standard household appliance) during actuation.

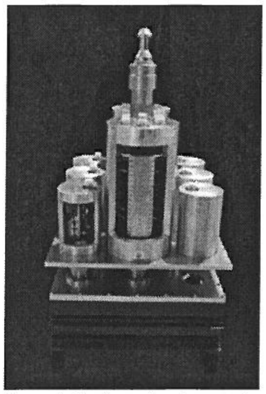

Figure 4. A subsea electric control module.

A unique design

Each module is based on field-proven, reliable valve designs, in fact the electrical actuator conforms exactly to the interface previously used for the Cameron hydraulic actuator. A mechanical failsafe spring will close the valve in the event of an emergency. Three basic actuator sizes will cover the complete range of subsea gate valves from ¾ in., 15,000 psi through 6 3/8-in., 15,000 psi. All valves are designed for low power actuation and a reduced power requirement to maintain the valve's status once actuated (Figure 2).

Subsea choke actuators followed a similar design philosophy, except there was no requirement for a failsafe mechanism. Chokes were designed to be infinitely variable with fast response and low power consumption. Reliability was assured by equipping the chokes with redundant motors and position sensors. Like the valves, the choke interfaces are interchangeable with previous hydraulic versions to enable upgrading of existing trees (Figure 3).

An advantage of an all-electric system is that each actuator is equipped with highly accurate position sensors so the operator can monitor exactly the position of the valve or choke. The actuator motors provide digital feedback that not only relays signals from the position sensors but send a stream of diagnostic information on the motors, valves and chokes that can be used over time to assess performance and efficiency including that of pressure closing parts and seals.

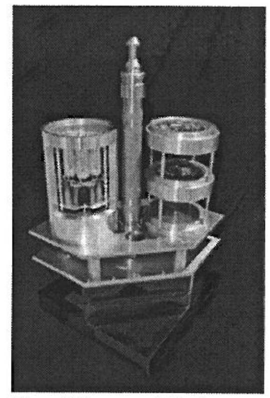

Figure 5. Power regulation/ communications module.

The "brains" of the system is the electrical control system which consists of a surface module and two subsea modules: the power regulator and communications module and the subsea control module (Figures 4 and 5). A key feature of the subsea modules is the wet-mateable pressure-balanced power connector. With an eye to the future, the connector was designed to accommodate a fiber-optic communication system. This will provide the bandwidth needed for sophisticated data communications from all sorts of wellhead and downhole production monitors and gauges.

A world's first

When they are installed in 2007, the first two all-electric subsea systems will enable production control from Total's K5F gas field located about 68 miles (110 km) northwest of Den Helder, and will tie-in to a new 6.2 mile (10 km) pipeline to the existing K-6 satellite platform and treatment facility. Production is expected to reach 99 MMcfg/d (2.5 MMcm/d). The option exists to add two additional DC production control systems in the field at a later date. The company anticipates 99% or better uptime availability with the all-electric systems.