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Subsea gas-liquid separation helps boost production rates

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Subsea gas-liquid separation combined with pressure boosting allows the development of fields that have insufficient tubinghead flowing pressure for attaining adequate production rates to the host facility.

The last few years have seen installation or planned installation of a variety of subsea processing schemes. The projects differ in scope but all aim to allow or improve oil recovery from subsea completed wells. The projects have included gravity-based separation as well as other separation techniques.

FMC Technologies Inc. has been involved in several subsea processing projects including Tordis in the North Sea, Cascade-Chinook and Perdido in the Gulf of Mexico, BC-10 off Brazil, and Pazflor off Angola.

Chris Shaw, manager of field development and technical sales, subsea systems for FMC provided some information on the design of these systems.

Subsea processing benefits

Some benefits of subsea processing listed by Shaw were:

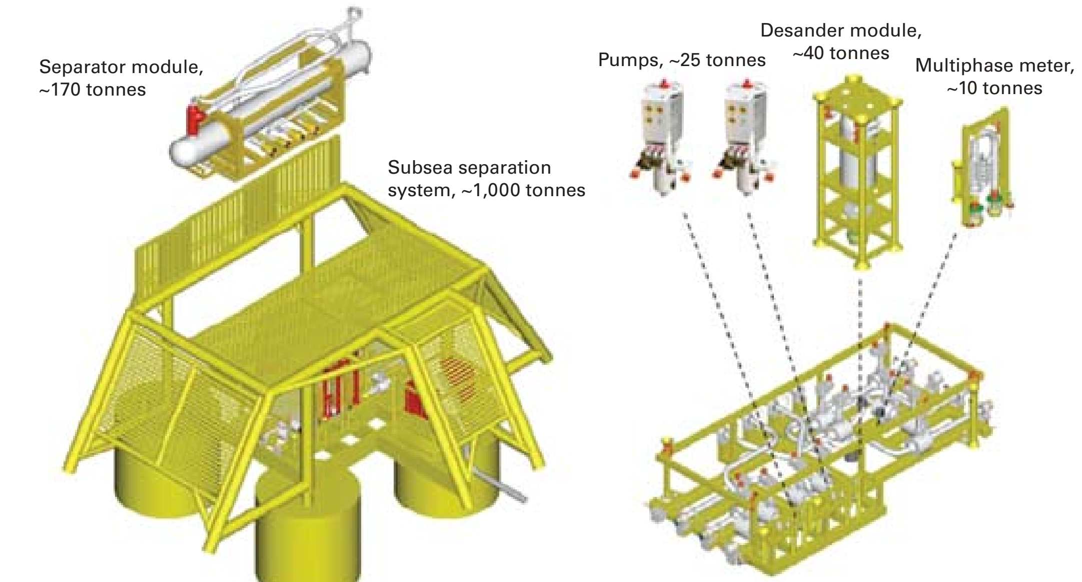
- Reducing back pressure on the reservoir, thereby increasing production rate, increasing time in production, and improving ultimate recovery.
- Extending plateau production.
- Enabling longer tiebacks for reservoirs with insufficient recoverable reserves to justify its own production platform.
- Improving recovery from deepwater reservoirs.
- Enabling exploitation of underpressured reservoirs and reservoirs with low permeability or poor fluid properties.
- Reducing capital expenditures, for instance subsea gas compression subsea costs less than building a structure in the case of the Ormen Lange development.
- Substituting processing for infill drilling because offshore drilling is expensive, risky, and requires the availability of a rig.

System design

Design of these systems requires extensive technology review and qualification per API RP 17N and must conform to API RP 17Q on system maintainability, Shaw said. The integrated components and subsystems also should have high system availability with component reliability capable of a minimum of 5-year mean-time between failure (MTBF) and with further development eventually a 7-year MTBF is hoped for, he added.

Shaw listed several benefits of gas-liquid separation and boosting compared with boosting only designs. One

TORDIS MODULAR SYSTEM Fig. 1



Source: FMC Technologies

PAZFLOR

Water depth: 2,700 ft

Step-out: 2.5 miles

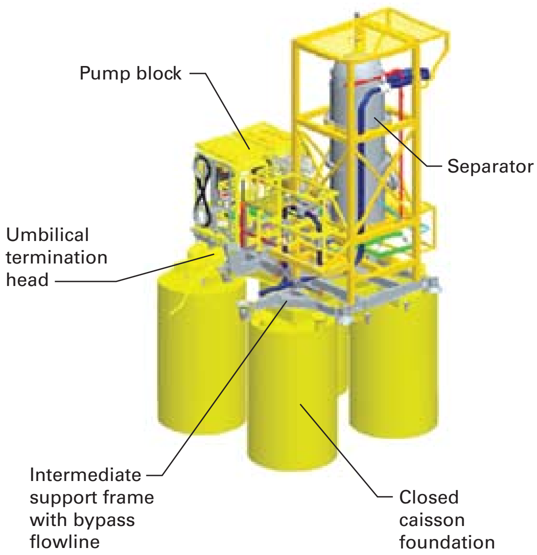
Design pressure: 5,000 psi

Process capacity: 110,000 bo/d and 35 MMscfd

Gas tolerant pumps: Hybrid to 18% GVF

Gas: Free flows through two 6-in. flowlines

Fig. 2



Source: FMC Technologies

PUMP CAPABILITIES

Type	Maturity	Maximum inlet GVF,* %	Efficiency, %	Available shaft power, MW	Maximum pressure bar (psi)	Sand tolerance
Single phase centrifugal	Field proven Qualified	~10 ~10	65-75 65-75	2.6 2.5	190 (2,700) 250 (3,500)	Sand tested
Helico-axial	Field proven	~70	30-60	2.6	55 (600)	Sand tested
Hybrid (gas tolerant liquid pump)	Qualified	~40	50-70	2.6	120 (2,200)	Sand tested
Centrifugal split vane hybrid (ESP)	Field proven	~30	50-65	1.2	290 (4,000)	Sand tested
Twin-screw (positive displacement)	Installed and proven	~92	60-80	1.3	50 (600)	Critical for sizes about 300 µm

*GVF = gas volume fraction.
Source: FMC Technologies

of the main ones is that single-phase and hybrid pumps can operate with higher pressure rise than multiphase helico-axial and twin-screw pumps that have about a 600-psi differential pressure limit (table).

Other benefits Shaw said were:

• Single-phase and hybrid pumps have higher hydraulic efficiency than helico-axial pumps, with less power generation required for given hydraulic duty.

• Venting below the hydrate-formation pressure provides a means for managing hydrate formation in flowline jumpers and the liquid pipeline.

• Separation eliminates slugs or liquid surges, thereby decreasing the size of the needed separator on the host platform.

• Common concerns about subsea separation are that there is increased technical risk associated with the separator and there is an extra pipeline. Shaw countered these assertions by saying that separation is already part of a multiphase boosting-only solution as liquid is required to be separated for recycling.

• The gas line remains available for roundtrip pigging provided the manifold is properly designed to manage the gas to liquid transition. The gas line does not have to be insulated and operates under continuous hydrate inhibitor injection at low rates.

• Conditions at the production manifold where gas bubbles are large, temperatures are still hot and gas-liquid density differences are large greatly facilitate gas-liquid separation. Coupled to the lax gas and liquid outlet stream quality requirements makes separation readily achievable.

• Densitometers can control the pump speed thereby avoiding the need for distinct gas-liquid interface.

• Long skinny caissons can separate the gas and liquid, making the process suitable for deep water and high pressure.

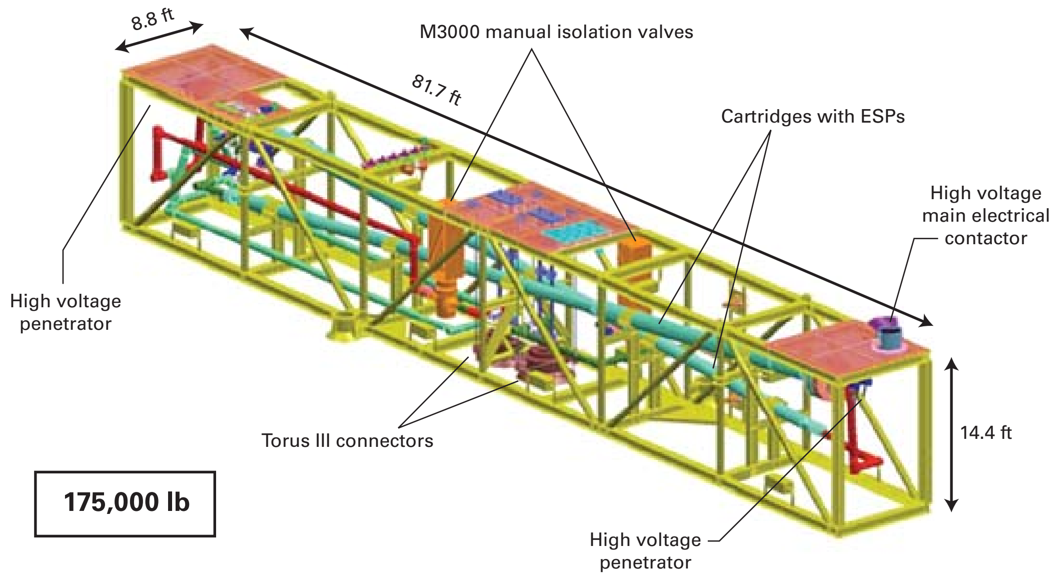
• Gas-liquid separation lowers the back pressure on the wells to a greater degree than all other processing concepts.

• Gas-liquid separation allows gas-lift in the well because the flowing tubinghead pressure can be below the bubblepoint. Gas-lift is not recommended with helico-axial pumps because the gas-volume fraction at inlet will exceed the 65% v/v, which is the pump's maximum operating design limit.

• A separator upstream of a pump will improve reliability especially when combined with a fast reacting control valve currently under qualification. This is due to the separator dampening the dynamic nature of typical multiphase flow.

CASCADE-CHINOOK PUMP CARTRIDGE

Fig. 3



Source: FMC Technologies

Tordis

One of the first subsea processing systems installed was the oil-water separation and reinjection system on StatoilHydro-operated Tordis field off Norway. The system with a 150,000-b/d liquid capacity was installed in 2007 in 650 ft of water.

Separating the water and reinjecting it reduced the need to increase water handling on the host facility as well as reduced the back pressure on the subsea completed wells. The system also separates and reinjects the produced sand with the water.

Shaw noted that Tordis was able to lower the back pressure on the production wells in this case by employing multiphase pumps in addition to removing the produced water.

The installed multiphase pumps have a 450-psi differential pressure rating (Fig. 1) while the injection pumps were capable of 1,450-psi differential.

Pazflor

The Total SA-operated Pazflor development in Block 17 off Angola will have three subsea vertical separators to separate gas from the liquids. The separators will be in 2,700-ft water depths (Fig. 2). Hybrid pumps will pump the liquids to an FPSO.

These will be the first gas-liquid gravity separation vessels installed subsea and the first hybrid-pump system with subsea barrier fluid control, according to FMC.

Each separator has a 3.5-m OD and 9.0 m height. Total expects production from the field to start in 2011.

Pazflor field will produce two different oils, Miocene and Oligocene. The Miocene reservoirs contain heavy 17-22° gravity, highly viscous oil and will have 18 producers and 17 water injectors.

The subsea separators are for the Miocene oil. The separation unit includes two hybrid liquid-boosting pumps on each of the three subsea production lines from the Miocene fields. Three flexible risers carry the liquids to a floating production, storage, and offloading (FPSO) vessel and six similar risers carry the gas to the FPSO.

The Oligocene reservoirs contain a light 35-38° oil that will be produced through a conventional loop linked to three manifolds and seven producing wells. The Oligocene reservoirs will also have five water injection and two gas injection wells.

Cascade-Chinook

First phase of the Petrobras Americas Inc.-operated Cascade-Chinook development will have horizontal electric submersible pumps (ESPs) to move liquids to the host FPSO, the first in the US portion of the Gulf of Mexico (Fig. 3).

Pumps are required despite the very high shut-in pressures because the reservoir has poor permeability and some decline in reservoir pressure is expected. In this case the pumps are required to ensure that the wells can achieve an economic rate and can extend plateau production.

Shaw noted that the wells have a high 12,000 psi shut-in pressure and ESPs are the only pumps available for that pressure. Another requirement not available from other pump systems is the pressure rise, rated at 3,200 psi with 15% gas.

The pumps will be in 8,800 ft of water with production start-up planned for 2010.

Cascade-Chinook project will produce from deep discoveries in the Lower Tertiary trend of the Walker Ridge and Keathley Canyon areas of the gulf.

Perdido

Because of the water depth of 8,200 ft and its low pressure-low temperatures, the Perdido development in the Alaminos Canyon of the Gulf of Mexico requires pressure-boosting liquids at

PERDIDO

Fig. 4

Water depth: 8,200 ft

Step-out: 0 miles

Design pressure: 4,500 psi

Process capacity: Five gas-liquid separator direct vertical access caissons, 25,000 bo/d and 55 MMscfd

Gas tolerant pumps: ESP to 15% GVF, 25,000 bo/d pump systems, 1.2 Mw 2,200 psi differential

Gas: Free flows up top-tensioned riser annulus

Source: FMC Technologies

BC-10

Fig. 5

Water depth: 5,900 ft

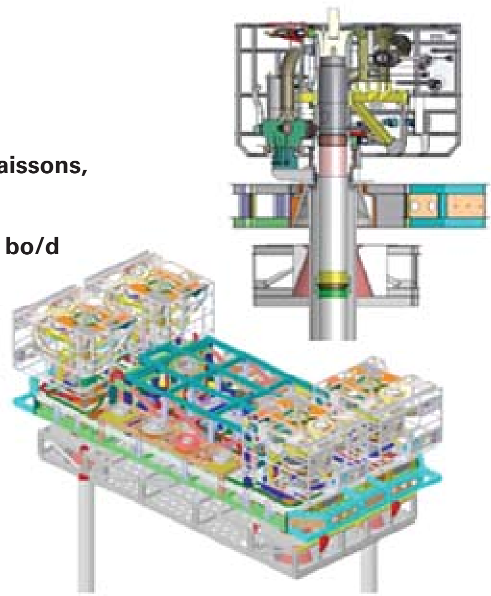
Step-out: 5 miles

Design pressure: 5,000 psi

Process capacity: Four gas-liquid separator caissons, 30,000 bo/d heavy oil and 3.5 MMscfd

Gas tolerant pumps: ESP to 15% GVF, 30,000 bo/d pump systems, 1.2 Mw 1,800 psi differential

Gas: Free flows through 6-in. flowlines



Source: FMC Technologies

the seabed. Shell Exploration & Production Co. operates Perdido.

The boosting technology involves a 330 ft, 35-in. diameter caisson in the seabed that contains an 8-10 in., 1,500-hp ESP (Fig. 4).

The multiphase produced fluid flows into the caisson's inlet block, located just above the mud line, where the associated gas separates out and flows up the riser, while the liquid flows down and receives pressure boosting from the ESP.

Risers allow direct vertical access of the caissons from the Perdido regional host spar. Perdido will have five caissons for producing the three fields: Great White, Tobago, and Silvertip.

Production is expected to start in early 2010.

BC-10

Shell's Parques das Conchas project in BC10 of the Campos basin will have six (plus one spare) caissons for boosting production from the initial three fields: Abalone, Argonauta, and Ostra. Expected production through each ESP is 25,000-30,000 b/d.

The fields lie in 5,900 ft of water and are connected to a floating production and offloading (FPSO) vessel with flowlines and risers.

All four fields are low pressure and require boosting. Abalone and Ostra contain gas and require subsea separation. Argonauta has less gas and no need for caisson separation.

The Abalone appraisal well produced a 42° API light oil compared with the 16-24° oil from the other fields.

As with the Perdido, the project involves separating gas and liquids in 35-in. OD by 350-ft caissons with an ESP for pumping the liquid to the FPSO.

Production started in July 2009. ✦