

Treating and Releasing Produced Water at the Ultradeepwater Seabed

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Summary

Tomorrow's energy needs are driving the industry to pursue the concept of "no oil left behind." But this goal comes at a cost as the pressures in remote deepwater reservoir pockets are depleted and the water cuts increase. Existing technology is evolving to meet the challenges to automate water separation and purification in deepwater for environmentally safe discharge at the seabed.

To solve these problems, the objectives must be defined; the best available solutions must be selected, and the technology gaps must be identified and closed. Environmental protection is a priority, and the translation of the existing statutory regulations regarding discharged water quality is the starting point. Safety and reliability will follow along with the flexibility to tailor the system to match the reservoir's changing needs and to incorporate the best, newest, and fastest-developing technology. Equipment relocation may also prove commercially attractive.

Major challenges will include remote process train control and monitoring, and the ability to perform routine maintenance while the wells still flow. Some of this technology could have immediate benefits to surface processes that would in turn provide ideal proving grounds before the technology ventures into deepwater.

Introduction

This paper explains the challenges facing subsea processing technologies in handling and treating produced water at the seabed between 5,000 and 8,000 feet of water depth. It will discuss the regulatory standards used throughout the industry today to oversee produced water treatment (PWT). The paper will look at the marine life in this ultradeepwater (UDW) environment at the seabed conditions. It will also review the latest PWT technologies used throughout the topside offshore production industry. The paper will illustrate various concepts to perform subsea PWT and look at the many challenges and gaps to be addressed to make this technology viable and effective.

The paper will also identify the gaps and challenges to applying PWT and discharge at the seabed in UDW environments. Research and compiled information will be presented to support the concepts proposed to meet the challenges of PWT and discharge at the seabed in an UDW production system.

Technology Benefits

Seabed discharge of produced water and/or solids can provide many benefits, but this paper has been created with the focus on the three main benefits:

1. Elimination of the need to transport huge volumes of water from deepwater production sites to the tieback hosts, which may be many miles away, thereby significantly reducing the production-system costs.
2. Decreasing the hydrostatic pressure on the subsea production flow lines will help reduce the backpressure on the subsea wellhead and will ultimately allow for more subsea production from the reservoirs.
3. Installations of Subsea Produced-Water Handling systems will minimize the topside equipment footprint and will help protect the equipment from damaging tropical hurricanes and harsh weather systems.

Achieving these benefits establishes the need for operators to implement PWT at the seabed. The following details have been researched and identified to help promote the use of the technology.

Understanding the U.S. Regulatory Requirements for Discharge of Produced Water and/or Solids

Most countries and regions in the world regulate produced water and solids discharges offshore through three primary criteria: Oil and grease concentration, toxicity, and produced sands/solids. However, there are many differences in the details of the regulations across countries and regions of the world regarding produced water regulations. A detailed discussion of world regulations can be found in the OTC paper referenced as Daigle (2012). In the current paper, US regulations are taken as the basis for the conceptual designs. The concepts can be different for applications in other regions of the world.

For the US, the Clean Water Act of 2009 prohibits all discharges of pollutants unless they are authorized by National Pollutant Discharge Elimination System (NPDES) permits. The Act also requires that NPDES permits first-limit pollutants based on economically achievable treatment technologies and then includes additional limits as needed to protect water quality (EPA NPDES website 2011).

New-point sources and existing-point sources of pollutants have different NPDES regulations. New sources are subject to more-rigorous effluent limits than existing sources based on the idea that it is cheaper to minimize effluent pollutants if environmental controls are considered during plant design than if an existing facility is retrofitted. New-source discharges must comply with standards based on the performance of demonstrated technology with the greatest degree of effluent reduction. These new-source performance standards (NSPS) should represent the most-stringent numerical values attainable. NSPS are based upon the best available demonstrated control technology and are at least as stringent as best-available technology (EPA NPDES website 2011).

The US offshore regulations govern the quality of the produced water by the oil and grease concentration, toxicity limitation, and prohibition of offshore discharges of produced sands. Those produced-water discharges are limited to a monthly average of 29 mg/l and a daily maximum of 42 mg/l. The oil and grease limits

have been difficult to achieve in some cases where dissolved oil is present in the produced water. In many cases, operators have resolved that issue by adjusting the pH of produced water before treatment (EPA NPDES website 2011).

The US offshore regulation for oil in water analysis requires that US EPA Method 1664 is used. This is a direct measurement method in which “oil and grease” is defined as “a mixture of those components of produced water that are extractable in hexane at pH 2 or lower and remain after vaporization of the hexane” (Tyrre and Caudle 2007). That “oil” remaining from a 1-liter sample of produced water is weighed and the concentration of oil-in-water is directly reported in mg/l. This method is advantageous because it is straightforward and does not require a standard to compare with; however, it is limited by what components are actually extractable (EPA Method 1664). Any dispersed hydrocarbons that are not extracted are not legally considered oil by this method. Also, this procedure must be done in an accredited laboratory by trained technicians. Because this method cannot be used in the field, operators rely on indirect methods that use instruments that are calibrated with the oil produced by the facility. This gives a good estimate of what the 1664 method concentration will be so that discharges can be kept in compliance.

The approach to how toxicity is handled varies by region. For instance, the European approach is based on “single substance,” to control the use of chemicals because of their potential to be environmentally toxic. The US approach, however, is more concerned with controlling the final emissions (actual environmental toxicity of effluents). The regulations appear to undergo changes every 5 years. The latest regulations were adopted in the US EPA office on October 2007 and expired on 30 September 2012.

The EPA permit (EPA 2007) requires the following toxicity tests: “The permittee shall utilize the *Mysidopsis Bahia* (*Mysid* shrimp) chronic static renewal 7-day survival and growth test using Method 1007.0. A minimum of eight (8) replicates with five (5) organisms per replicate must be used in the control and in each effluent dilution of this test. The permittee shall utilize the *Menidia beryllina* (Inland Silverside minnow) chronic static renewal 7-day larval survival and growth test (Method 1006.0). A minimum of five (5) replicates with eight (8) organisms per replicate must be used in the control and in each effluent dilution of this test. For either of these tests, a NOEC (No Observed Effect Concentration) result must be obtained to have the samples pass the test. The NOEC is defined as the greatest effluent dilution which does not result in a lethal or sub-lethal effect that is statistically different from the control (0% effluent) at the 95% confidence level. In the case of a test that exhibits a non-monotonic concentration response, determination of the NOEC will rely on the procedures described in Method Guidance and Recommendations for Whole Effluent Toxicity (WET) Testing (40 CFR Part 136), July 2000, EPA 821-B-00-004.

If the effluent fails the survival endpoint (or the sub-lethal endpoint, after 2 years from the effective date of this permit) at the critical dilution, the permittee shall be considered in violation of this permit limit.”

The EPA permit also provided tables of critical dilution concentrations which the NOEC must be equal to or greater than. The critical dilution is based on the highest monthly average discharge rate for the 3 months before the month in which the test sample is collected, the size of the pipe diameter discharging the effluent, and the water depth between the discharge pipe and the bottom of the seafloor. Operators must comply with this requirement within 2 years after the effective date of the permit. To meet the requirements, operators can increase mixing using a diffuser, add seawater, or install multiple discharge ports. Alternatively, operators wanting to reduce the critical dilution of the discharge may make operational changes that reduce the flow rate, such as shutting-in wells (EPA 2007).

All changes must be provided to the EPA with a description of the specific changes that were made and the resultant flow rates of

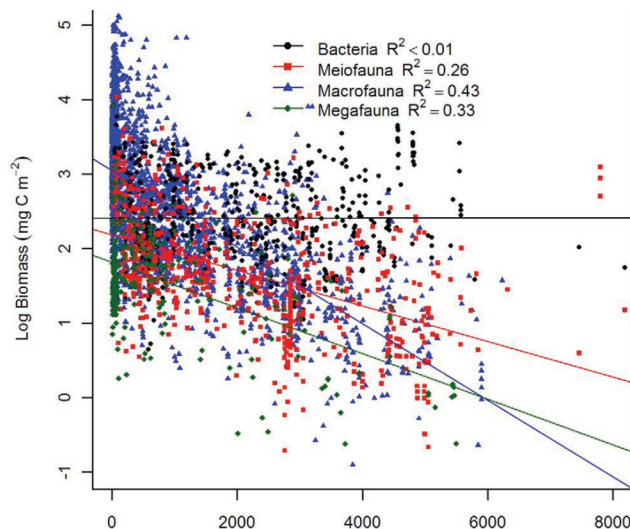


Fig. 1—Biomass is shown as a function of depth (in feet) for bacteria, meiofauna, macrofauna, and megafauna. Biomass was log10 transformed, and the effects of latitude and longitude were removed by partial regression (Rowe et al. 2008).

the discharge, along with a certification that the flow rate will not change, unless a new certification is made. Operators discharging produced water at a rate greater than 75,000 B/D shall determine the critical dilution using special EPA-approved software. When seawater is added to the treated produced water before discharge, the total produced water flow, including the added seawater, will be used in determining the critical dilution from specific dilution table (EPA 2007).

One obvious conclusion from this information is that operators with subsea interest wanting to perform PWT at the seabed will need to work closely with the regulators to develop new techniques to assure that the discharge is compliant with regulations and sufficient steps are being taken to manage the process properly without causing harm to the environment.

The Need for Understanding Potential Effects of Discharge on Marine Life

Successful discharge of produced water at the seabed must first receive regulatory approval. That approval is needed to primarily confirm that the discharge poses no harmful effects on the marine life in the environment. Because the industry has no standards for compliance of subsea discharge of produced water, understanding the potential effects of the discharge on marine life is important in establishing those regulatory standards.

For topsides, offshore discharge has low-molecular-weight hydrocarbons that volatilize into the air or are degraded by photolytic or biological processes. Also, the produced-water constituents are exposed to several chemical processes including precipitation, hydrolysis, oxidation, and complexation upon discharge. In the UDW environment, it is not understood what effect the low-molecular-weight hydrocarbons will have on the marine life. We still have the potential chemical reactions of hydrolysis, oxidation, and complexation, and the discharge will still undergo a biological process. A recent study done by Texas A&M University at Galveston determined that the quantity of bacteria is constant in all water depths throughout the world's oceans (Fig. 1) (Rowe et al. 2008).

Benthic invertebrates are found at water depths greater than 650 feet and are the most likely to be affected by subsea processing activities (Grieb et al. 2008). “Benthic invertebrates are organisms that live on the bottom of a water body (or in the sediment) and have no backbone. The size of benthic invertebrates spans 6-7 orders of magnitude (Heip 1995). They range from microscopic (e.g.,



Fig. 2—A small bush of tubeworms. When tubeworm bushes are young, only endemic species of animals can colonize them. The presence of the mussels (*Bathymodiolus childressi*) in the center of the bush means that methane is seeping just below. Image courtesy of Gulf of Mexico 2002, NOAA/OER.

micro invertebrates, <10 microns) to a few tens of centimeters or more in length (e.g., macroinvertebrates, >50 cm). Benthic invertebrates live either on the surface of bed forms (e.g., rock, coral or sediment–epibenthos) or within sedimentary deposits (infauna), and comprise several types of feeding groups (e.g., deposit-feeders, filter-feeders, grazers and predators). The abundance, diversity, biomass and species composition of benthic invertebrates can be used as indicators of changing environmental conditions” (Geoscience Australia 2012).

Another point to note here is that the UDWs of the Gulf of Mexico contain naturally occurring hydrocarbon seeps. These seeps are the most common place to find chemosynthetic communities in the Gulf of Mexico because these communities are able to use dissolved gasses as an energy source (Grieb et al. 2008). The presence of free-living or symbiotic sulfate-reducing bacteria creates the chemosynthesis. At least 60 of these communities have been located to date (Fig. 2). “These chemosynthetic communities are complex, with high abundances and organism densities (Paull 1984; Kennicutt 1985). They may be dominated by a single species or a combination of vestimentiferan tubeworms, seep (mytilid) mussels, large vesicomyid clams, small lucinid clams, and polychaete ice worms” (MacDonald, 2002)

The environmental and biological conditions of the deep Gulf of Mexico can be defined as having high pressures, low temperatures, and an absence of light, all which limit the types of organisms that can survive there. The deep Gulf also has low organic matter (or food) inputs, which affects “the overall abundance and biomass of the organisms that are present. However, unique communities (i.e., chemosynthetic organisms) are associated with the presence of conditions that provide nutrient subsidies such as methane hydrates or hydrocarbon seeps” (Grieb et al. 2008). Therefore, it is believed that UDW discharge will contribute more potential “food,” and discharge arrangements will need to consider bioaccumulations in the area of discharge to keep the mechanical system from being plugged or disrupted.

Lastly, in the early 1990s, a study was done in the Gulf of Mexico which compared the bioaccumulation of target chemicals in edible tissue of fish collected at Gulf platforms discharging >4,600 B/D to that of fish collected at platforms with no produced water discharges. It also evaluated the ecological and human health considerations of observed concentrations of target chemicals in edible tissues of fish collected near offshore platforms in the Gulf. None of the target chemicals were present in edible tissues

at concentrations that might be harmful to the fish or to human health. Also, there were no major differences in tissues collected from discharging sites as opposed to nondischarging sites. The few observed elevated concentrations were distributed equally between the discharging and nondischarging sites, suggesting that produced water discharge was not the source of the elevations (OGP 2005).

Having considered these findings, this early research can provide strong support in favor of further testing of discharge effects in the UDW environment, but it is clear that more research is needed.

Latest Equipment and Processes Used for PWT and Discharge Overboard

On a typical offshore facility, the produced water from the primary oil/water separation process has to be further treated before discharge. Separated water from all sources (HP/MP/LP separators, wash water from desalter/dehydrator, crude stabilizer overhead separator, condensate collection drum, condensate-stripper-overhead drum, and gas dehydration units) are collected and sent to a PWT package (PWTP) for recovery of oil and treatment of water. From the PWTP, the treated water is injected into subsea disposal wells or discharged to sea. The separating efficiency depends largely on the quality of the water being treated (i.e., on the concentration of oil and the average size of the oily particles). A typical host-facility process flow diagram for the PWTP is shown in Fig. 3.

The most-effective technologies found in the industry today are more compact and have less moving parts. The desanders, hydrocyclones, compact flotation units (CFUs) and advanced filtration systems have become the preferred techniques for treating produced water today.

Many of the typical components of a PWTP have been tailored to fit into subsea systems to improve subsea processing. It is these types of projects that are making the prospect of PWT for subsea use a reality. **Table 1** lists some of the most significant subsea separation installations found throughout the world today, and **Figs. 4 through 17** are shown to help illustrate some of the more significant subsea processing installations deployed around the world. From a review of the state of the art technologies in topsides and subsea technologies relevant to seabed PWT and discharge, we have the following main findings (Vu et al. 2009):

- Available offshore water-treatment technologies are primarily used in topsides, which treat the produced water for discharge to sea. There is a very limited amount of subsea projects that separate oil and water. There is no subsea water treatment for discharge.
- Topsides water treatment generally requires a tertiary system involving a bulk separator, separator/hydrocyclones/skimmer, and induced gas flotation. Filtration is sometimes required after the tertiary systems as a polishing step to achieve low oil and grease concentrations. Membrane filtration is sometimes required to remove dissolved organics. A recent technology in filtration is to infuse hydrophobic polymer to filters to reduce the effluent oil and grease concentration.
- Subsea separation technologies have focused on two-phase gas/liquid separation. The installations with oil/water separation were intended for injecting water into wells, which allows a much higher oil-in-water content than discharge limitations. Suspended solids in the water are major challenges for injection.
- Compact subsea oil/water separators and desanders for deepwater have been developed and are to be installed in the near future. Multiple technologies in this area are under development.
- Currently, subsea oil/water separation systems do not meet discharge limitations on oil and grease concentrations. They can achieve oil-in-water concentrations of several hundred ppms, approximately 10 times the discharge limit.

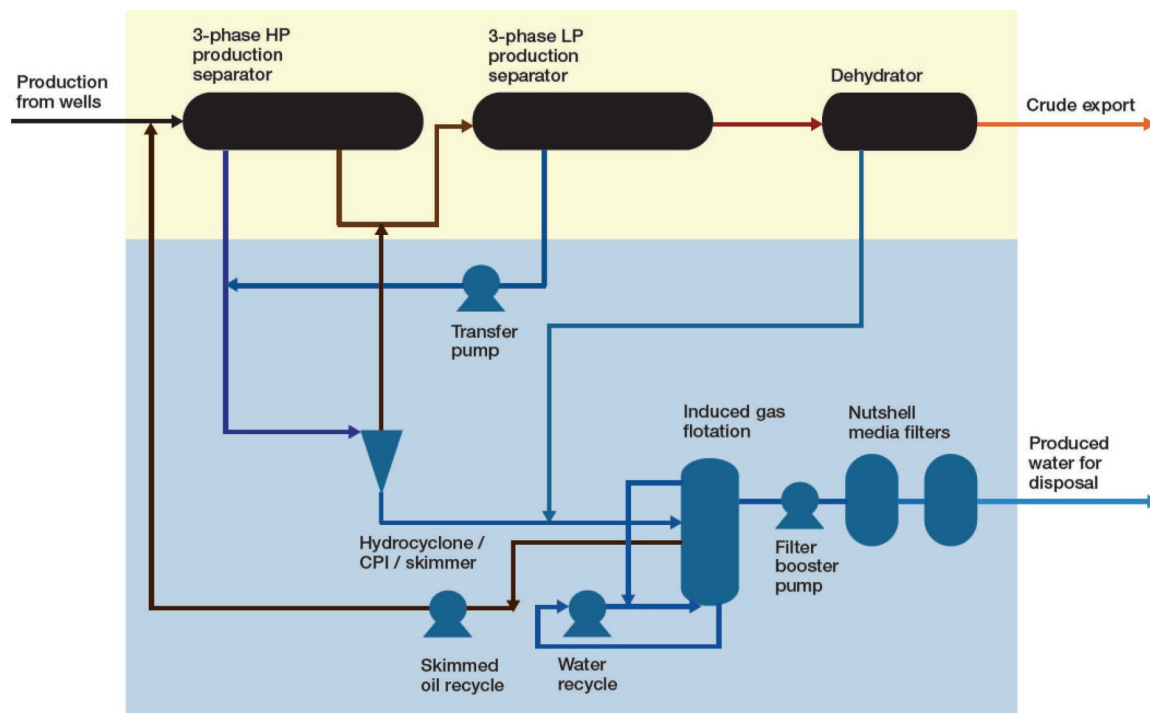


Fig. 3—Typical PWTP (courtesy of Prosep).

TABLE 1—LISTING OF SUBSEA SEPARATION INSTALLATIONS

Operator/Year	Field Name	Technology Used	Technology Type	Technology Supplier	Water Depth (ft)
Statoil 2001	Troll C	Horizontal SUBSIS	Separator	GE/Framo	1,116
Petrobras 2001	Marimbá	VASPS	Separator and electrical submersible pump (ESP)	Saipem	1,265
Statoil 2007	Tordis	Horizontal	Separator	FMC/CDS	689
Shell 2009	BC-10	Caisson	Separator and ESP	FMC/CDS	6,562
Shell 2010	Perdido	Caisson	Separator and ESP	FMC/CDS	9,600
Petrobras 2011	Marlim	Inline	Separator	FMC	2,881
Total 2011	Pazflor	Vertical separator	Separator	FMC/CDS	2,625
Petrobras 2012	Congro	VASPS	Separator and ESP	FMC	—
Petrobras 2012	Malhado	VASPS	Separator and ESP	FMC	—
Petrobras 2012	Corvina	VASPS	Separator and ESP	FMC	—
Petrobras TBA	Canapu	Inline supersonic	Separator	FMC Twister	5,579

- The control and monitoring of the process will be critical in providing confidence to the regulatory agencies that such processes are working and effective. Subsea sampling of separated water has been practiced.

It is also important to note that UDW seabed treatment and discharge of produced water and/or solids will likely require significant power for control and monitoring, and pumping the large volume of water to overcome the pressure difference between the seabed hydrostatic pressure and the treatment system pressure, which may be much lower. Current technology can provide the power required, because several deepwater projects already use significant power for seabed pumping.

The industry appears to have very capable vendors that supply these technologies and understand the challenges they face with delivering them to the seafloor. They well understand the requirements to provide reliable products to the subsea processing system, and most of these vendors have a research and development program that is being coordinated with various operators within the industry.



Fig. 4—BP Zakum (1969–1972).

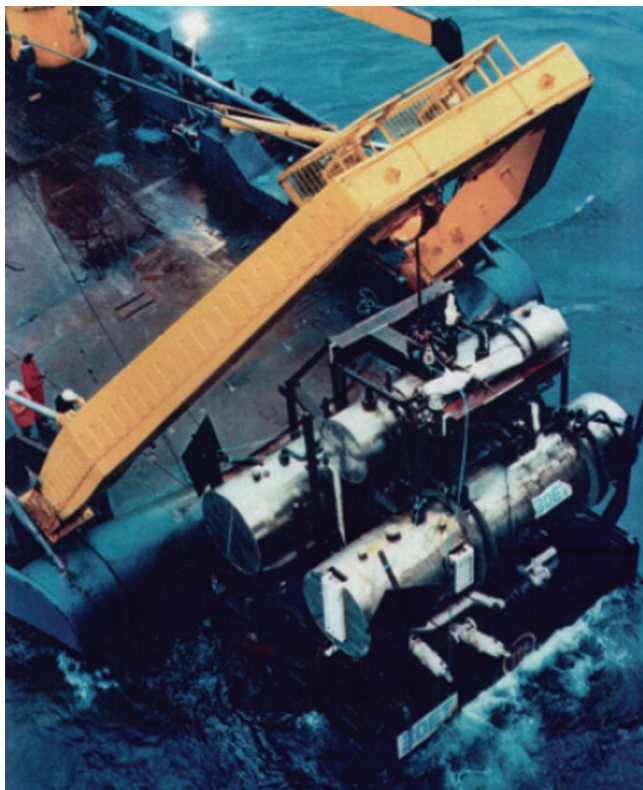


Fig. 5—Kvaerner booster station (mid-80s).

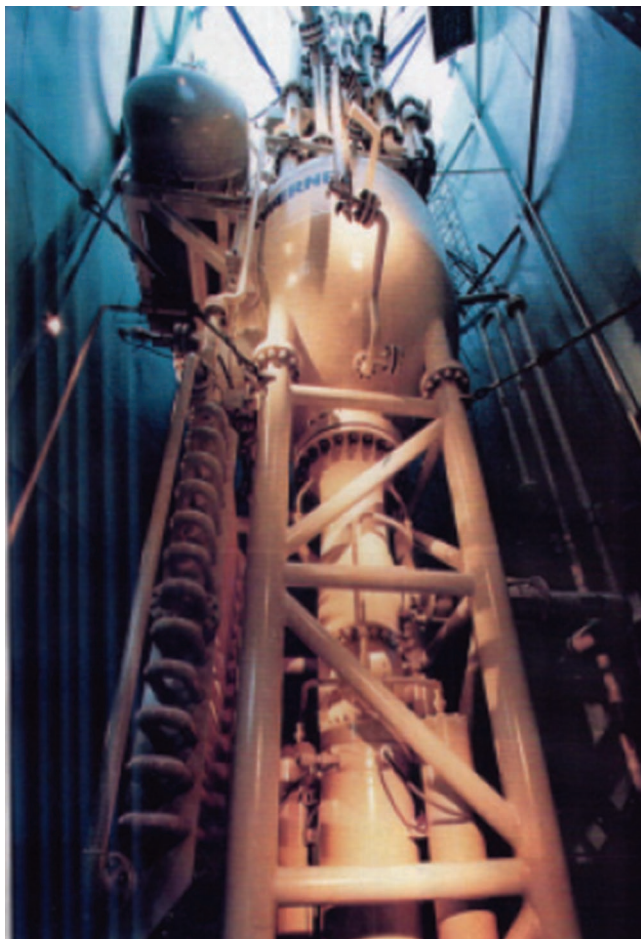


Fig. 6—Argyll, British Offshore Engineering Technology (1986–1989).



Fig. 7—Petrobras VASPS technology (2000–ongoing).

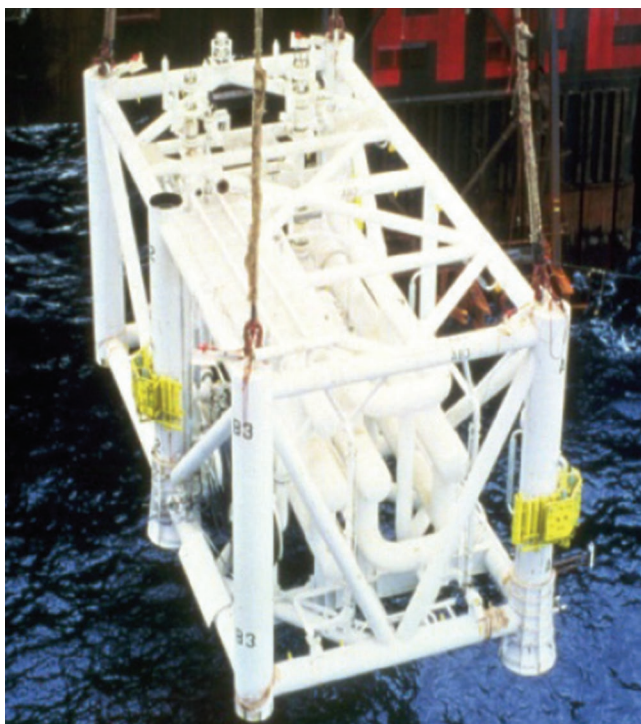


Fig. 8—Texaco Highlander subsea slug catcher and vertical separator (1985).



Fig. 9—Alpha Thames AESOP (1999–2000 successfully tested).

Review of the Initial Conceptual Designs for Seabed Discharge of Produced Water

Establishing a strong basis of design (BOD) is critical to the selection of the key components required within a subsea PWT system. Many different configurations can be designed and deployed, but it is important for the industry to achieve some standardization in what works best subsea and what does not. Many vendors can be used for these techniques, and it is critical to include their experience and opinion where appropriate.

For some of the basic concepts that can be standardized, the industry would want to make certain that sands and solids handling be addressed at the front end of the process train to avoid plugging the system components. In addition, some components work better at low-pressure conditions, and others require higher pressure to enable coalescence and separation where needed. All the systems will be subjected to external pressure from the hydrostatic head from approximately 2,500 to 4,000 psi in water depths of 5,000 to 8,000 ft of water. At these depths, the ambient temperature may be only 38°F, and many of the processes benefit from being as warm as possible. This would suggest that a compact thermally insulated system would work better. Issues of component size and weight must also be considered. Large, thick-walled pressure vessels may have to be installed individually without guidelines. Compact seabed template solutions will increase the potential hazards of dropped objects. Safety zones around the process train can be staged. With associated pumps, switch gears, transformers, chemicals, and controls equipment used throughout the system, this will make for a large installation area on the seabed. The design scenario will be a remote installation for which the reliance on intervention and maintenance must be kept to a minimum for both safety and cost reasons.

Fewer stages in the train simplify the installation and controls. No moving parts and the use of corrosion-resistant materials will minimize maintenance. External pumps and manifolds could be modularized for recovery to the surface to receive repair or maintenance.



Fig. 10—Goodfellow Associates subsea production project (1986–1990 successfully tested).

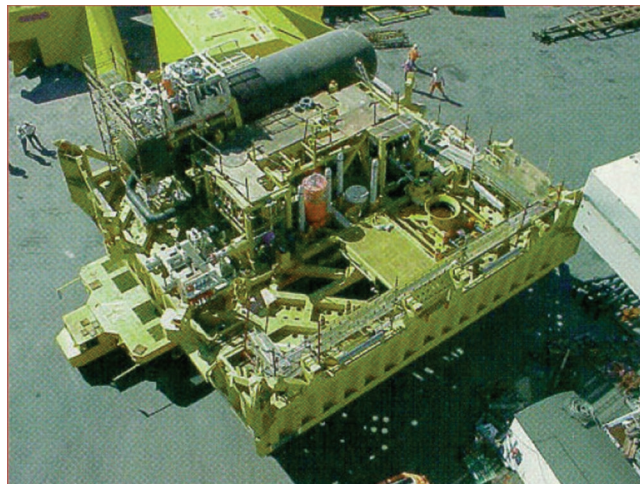


Fig. 11—Statoil Troll C SUBSIS (2000–ongoing pilot).

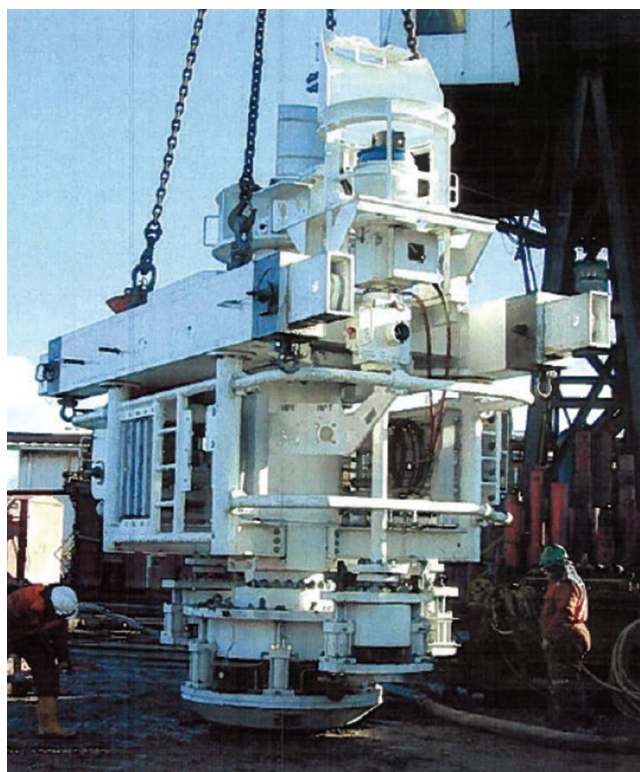


Fig. 12—Marimba VASPS (2001).

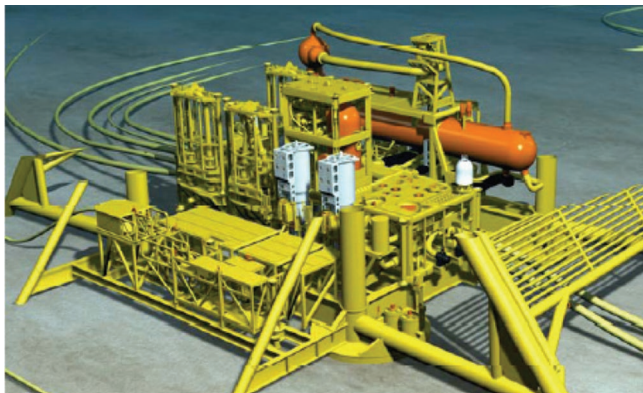


Fig. 13—Statoil Tordis SSBI (2007).

Fig. 18 shows one basic layout of the process configuration. It is used here to help provide a common challenge to the physical installation that any subsea processing system must consider.

Forward planning at the installation design stage can allow the introduction of modules tailored to the needs of the production fluid. Valves indicate how the flow can be shunted through the separator module and back to the flowline. The same could happen with the pump and compressor module, or the flow could be routed from the separator through the water-treatment train and straight into the pump module.

Some additional assumptions can be made when developing the BOD:



Fig. 15—Shell Perdido separation caisson and boosting (2010).



Fig. 16—Petrobras Marlim inline separator (2011).

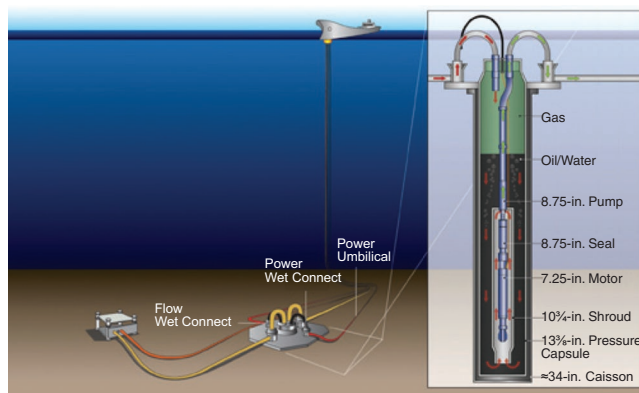


Fig. 14—Shell BC-10 separation caisson and boosting (2009).

1. The system may be included as part of the installation during the initial field development
2. The system design life and major intervention should be considered
3. How many flowlines are needed
4. Whether the flowline needs to be piggable from the drill center to the facility
5. The train should be designed to contain the wellhead shut-in pressure
6. Booster pumping, desanding, and gas/liquid separation may be installed before water processing is required
7. Gas and filtered water may be used to lift and drive the produced fluid within the train
8. Nitrogen may be required if natural gas will cause hydrates
9. For reservoir flow-continuity considerations, a 100% redundancy in the process train should be required. A sparing philosophy should be considered as well
10. Planned testing, maintenance, and sampling will not interrupt flow
11. Planned or emergency shutdown stages may extend to and include backflushing the system with seawater into the wellbore to avoid environmental contamination.

For a retrofit application, the following considerations also need to be included when developing the BOD:

1. The system may be installed in stages as the existing field depletes
2. If only a single flowline is available, it should be sized for initial field-flow rates
3. Whether the flowline is piggable from the drill center to the facility
4. Wellhead pressures may have decreased as the water cut has increased



Fig. 17—Total Pazflor vertical subsea separator (2011).

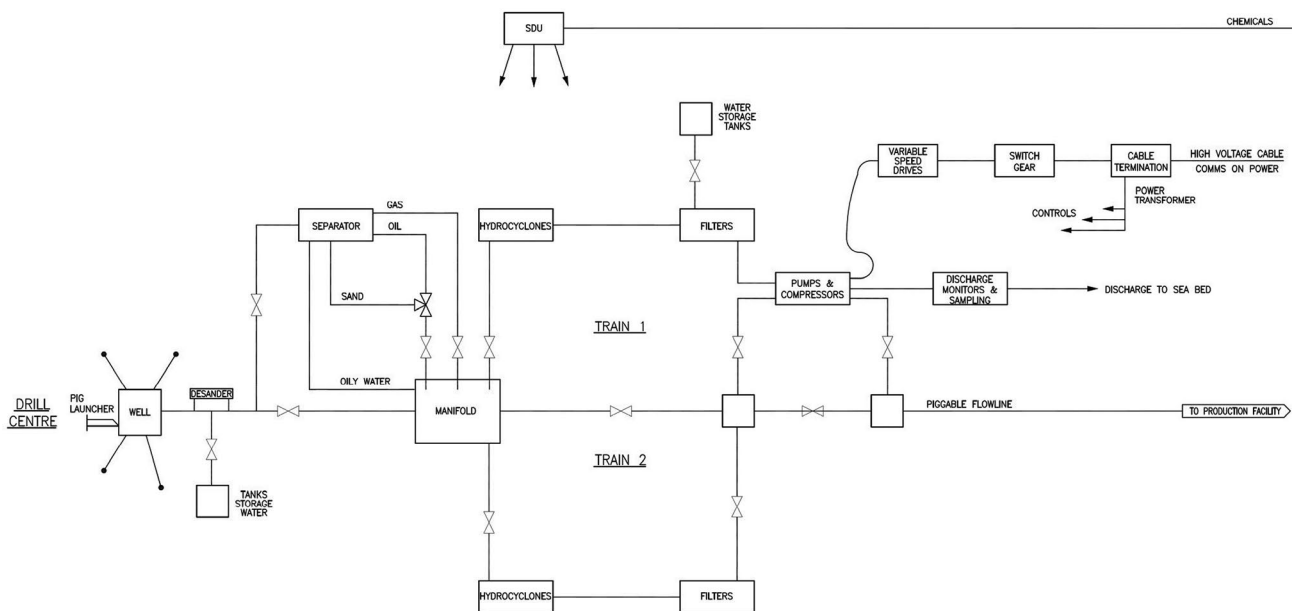


Fig. 18—How an installation can use a plug-and-play methodology.

5. The shut-in pressure used as the system design pressure is the current value and not the higher pressure that may have existed earlier in the field's life

In a typical surface treatment system, produced water exits the bulk separators (i.e., free water knockout) with 1,000–2,000 ppm oil-in-water content. The water will be near wellhead temperature and from ambient to near-wellhead pressure. For offshore installations, the primary treatment step is a deoiler hydrocyclone, which reduces the oil in water (OIW) to the range of 29–100 ppm followed by a secondary treatment stage using a hydraulic flotation cell to meet overboard discharge requirements of <29 ppm OIW.

One significant finding is the usefulness of the next generation of compact flotation technology (CFT). It is relatively new to the North American region but has been well proven, with more than 50 installations worldwide on offshore platforms. The Cameron TST TM CFU is the next-generation CFU that uses gas flotation and additional centrifugal forces to separate and remove hydrocarbons as liquid and gas, aromatic compounds, hydrophobic substances, and small solid particles from produced water. The technology uses special internals for mixing of gas and oil through several stages within one vessel. These internals are designed to achieve effective separation of this gas and oil from the water. The TST TM CFU performed well under high OIW concentrations and small oil-droplet-size distributions. This CFU is capable of handling higher inlet oil concentrations, over 1,000 ppm, and providing lower outlet OIW concentrations of less than 10 ppm. The TST TM CFU system requires less equipment, has a lower weight and a smaller footprint, and is less-dependent on chemicals and can potentially replace multiple PWT stages.

Fig. 19 shows a flow diagram of a single train for a surface PWT system based on Cameron's CFU. Fig. 20 shows a cross-section of the CFU.

The technology is based on both induced and dissolved gas flotation. External gas injection and special internals for mixing of gas and oil have been developed to achieve easy separation of this mixture from the water. The water can be treated through several stages, and up to four stages can be housed in one vessel. The numbers of stages needed depends on the application. Multiple stages within one vessel bring lower fabrication costs and require less space. Each stage has multiple input pipes that create better internal mixing and contact between the gas bubbles and oil droplets without any moving parts. The design is claimed to have higher

performance than existing CFUs with less equipment, lower weight and to be less dependent on chemicals than the first generation of CFUs. This system can be used with a gravity separator, hydrocyclones staged to help handle slugs and upsets, and final polishing filters to assure regulators that discharge water will meet the required standards criteria.

Currently, CFU applications have been on topsides and onshore, typically with vessels of 3 ft or larger in diameter. For deepwater subsea applications, minimizing the vessel size is a key consideration because of the high hydrostatic pressure. Research shows that using vessels with a diameter no more than 3 ft for collapse resistance is reasonable to achieve and would be more cost-effective and easier to manufacture. Therefore, multiple parallel CFU units may be necessary to handle the total water flowrate.

Many new subsea processing designs are being identified and tested every day, some with patent-pending designs that are being built and tested onshore to prove their effectiveness before being developed for subsea use. One such technology is the Unocell design from Fluor (Fig. 21), which chemically treats an underflow from a primary water knockout drum, where it enters the Unocell vessel tangentially into the center column. Then, the mass flow spins and rises at a controlled optimum velocity through the center column, enhancing the coalescence of oil particles. The flow exits upward into the established pool of oil and water and is forced to turn uniformly downward in the opposite direction to the center column.

The downward flow velocity is considerably lower than the rising velocity in the center column, and the free oil in the incoming water is trapped in the oil pool at the oil/water interface level. Large oil droplets and the difference between the oil and water's specific gravity helps to float away any entrapped oil in the downward traveling water before it exits the Unocell. Recovered oil accumulates at the top of the vessel, and its level begins to rise. At the predetermined set point, the effluent valve starts to slowly close.

The water level in the Unocell starts to rise, and it pushes the accumulated oil through the v-notch weir into the effluent launder and out through the exit line. At a predetermined level, as the recovered oil is being removed, the effluent valve starts to open and lower the water level to the normal operating level, and this operating scenario repeats itself continuously.

Any settleable suspended solids will accumulate at the bottom of the Unocell and will be flushed out through the valve at the bottom

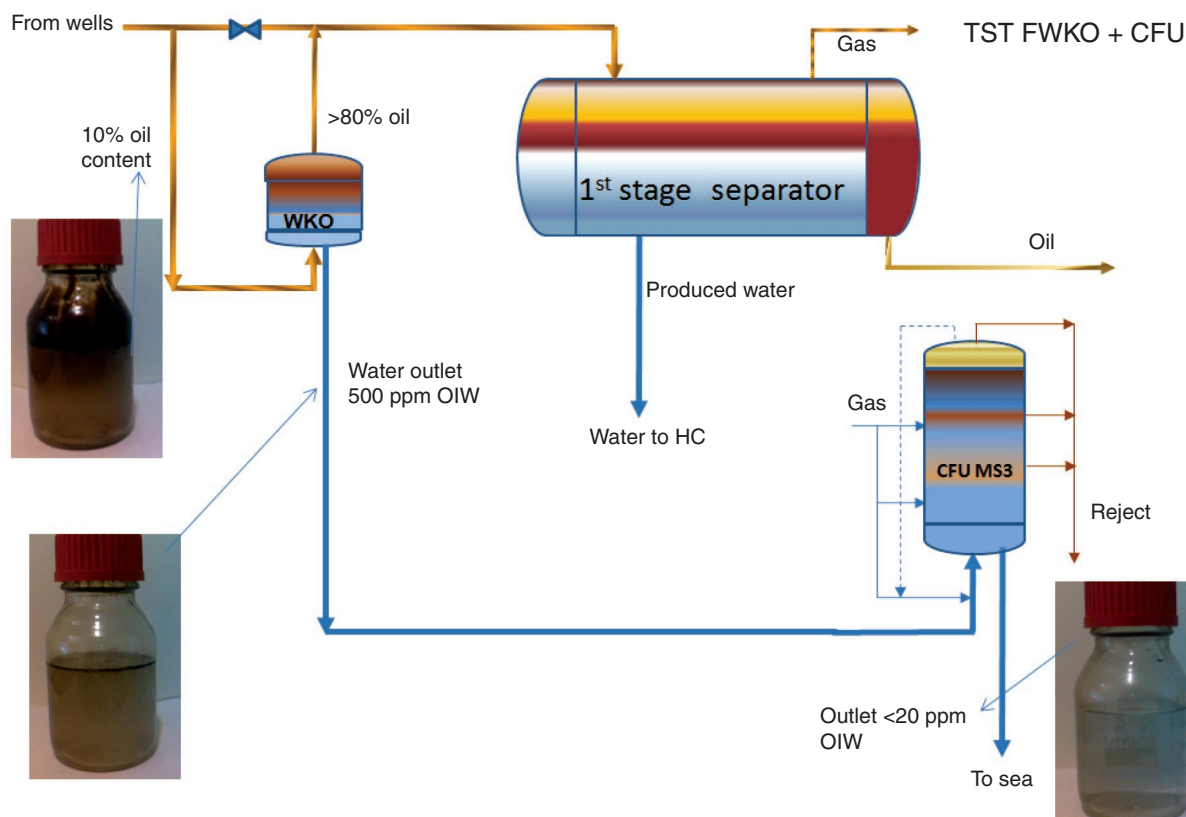


Fig. 19—Cameron CFU: water purities.

of the vessel into a solids accumulator for disposal. The recirculation pump outside the vessel ensures the optimum chemical process by constantly introducing treated water with the incoming untreated produced water. This maintains a constant flow rate through the center column for consistent higher oil-removal operations.

Units like these can then be applied to a flow in parallel to take on as much volume and redundancy as needed. The industry can expect to see more designs like this and further advances in subsea processing technologies that will increase production and provide greater reliability to protect the environment.

Gap Identification and Conclusions

The following 10 potential gaps have been identified. Some have been created because the technology has not been developed or adapted to this application. An example would be comprehensive, on-site fluid monitoring. Other gaps show that the technology to solve them does not currently exist. Theoretical solutions will have to be subjected to the careful R&D process and field trials before they can reliably fill some of these gaps.

Sand and Solids Removal. In the earlier life of a well, the sand it produces is controlled by controlling the fluid drawdown rate from the well and gravel packs with sand screens, but as the water content in the flow through a sandstone reservoir increases, the structure breaks down and sand flows with the fluid. Hundreds of pounds of sand a day would plug the screens, so it has to be allowed to travel to the top of the wellbore for extraction and to allow the well to flow.

Sand will cause erosion and blockages. Trees and their valves can be designed for sand service, but experience from the Gulf of Mexico is that the sand and oil cling together into a mass that quickly solidifies if not kept moving. Sand and the other solids need ideally to be removed from the flow through the process train and as close to the wellhead as possible to limit damage and take advantage of the higher pressure that makes the desanding cyclones more efficient.

It is not environmentally safe to discharge formation sand to the sea in its oily condition, and onsite chemical treatment is impractical. The sand has to be transported to the surface or, if permitted, has to be pumped deep into an otherwise disused well. Sand educators could mix the oily sand and solids into slurry with the rejected oily water and be pumped either downhole or back along a separate flowline to the surface facility.

If the field only has one flowline, then as it declines in oil production and the water is removed, the flow rate will drop. This would mean that if the sand was reintroduced to the flowline after the water separation, it may not be able to entrain the sand all the way back to the surface facility. Regular pigging could be required; however, if other, more productive wells could be introduced or if the field had been set up with two flowlines for round-trip pigging and only one was used for the “new” flow, then the flow rate might carry the sand.

A VASPS installation that would take 6 months to produce 700 lbs/day of sand has chosen to drop the sand into the caisson sump below the pump and recover it when servicing the pump. Vessels at or below the seabed could be used to store the rejected sand and solids for periodic recovery to the surface for treatment and safe disposal.

Filter Design. A filter is any substance, such as wire mesh, paper, porous porcelain, or a layer of charcoal or sand, through which liquid or gas is passed to remove suspended impurities or to recover solids. The filters will either trap or redirect the impurities to clean the water. The trapping can be temporary or permanent in that the impurities can be stopped and flushed back upstream to be dealt with elsewhere or can be trapped and held to be removed with the filter when it becomes clogged with impurities. Alternatively, small oil particles can be held by the filter fabric and caused to combine or coalesce together until buoyancy overcomes adhesion and the droplet floats to the top for extraction.

Many filter methods can achieve the required water purity in surface installations. The difficulty is transferring that technology

to the remote seabed, where thousands of pounds of pressure will crush large vessels and the flow cannot be interrupted. The performance of a filter in terms of surface area to volume flowing and how compactly that surface can be enclosed in a collapse-resistant pressure vessel is a major selection criteria. High-frequency maintenance must be kept to a minimum. All filters need backwashing to extend their service life; flow has to be diverted to other filters while this is carried out. Selecting which filters to flush and when and how to control flow without restriction is a complex systems issue.

The backwash has to go somewhere. Recycling this backwash fluid through the system will not remove it, and reinjecting it down-hole will probably plug the rock pores. A separate flowline to the surface mixed as slurry with the sand may be the only route out for backwash. Filters that permanently trap the impurities would be recovered to the surface in batches of canisters to be swapped out for their replacements. They would probably be purged of liquid by the gas line from the surface and then be disconnected by a remotely operated vehicle for a cable lift to the surface. Again, selection of which filters to recover and flow control will be complex.

In the future, filters may perform better, be smaller and more compact, and last longer and cost less to replace, but the solids will still be the same. They are the issue, and without a definitive solution this is a technology gap.

Control System. Subsea high-integrity pressure protection systems, or HIPPS, has not yet gained acceptance in the Gulf of Mexico. The technology is in service elsewhere, for example in the shallower Norwegian waters. The relevance here is the control requirements for autonomous, remote, paired functions subsea. For HIPPS, this is two fast-closing large-bore gate valves with flow monitored by pressure sensing and the valve action triggered by a logic voting-control system. The system is tested frequently to prove that it is still operational. Some regulations only require partial closing while others require a full closure. With the HIPPS located in a straight flowline where pressure fluctuations are kept to a minimum, the valves are prone to be triggered by false alarms, and even with the fast-closing valves, the pulse from the pressure surge can be a mile down the flowline before the valve shuts.

The process train will have the equivalent control points between stages giving feedback on flow rates, fluid impurities, temperature, and pressure. The response could be a shutdown, but should more likely be flow modulation by valves and pumps at many points along the train. Well startup water and methanol may go straight into the flowline. Then, the process train will start up, probably circulating seawater in a closed loop before introducing well fluid. Working slowly at first, it will extract the oil and cycle the water until monitoring indicates it is ready for discharge. The system will run at steady state, adjusting for transients and upsets. Periodic flow redirection and backwashing must occur. Then, a controlled shut-down will need to occur as flow is transferred to the other train, and the initial train self-flushes to prepare for maintenance.

Like the HIPPS systems, the logic can be put together and a process simulator can be developed to perfect the control operations. Critical to this system will be the development of remote fluid-monitoring systems. Creating a process simulator and effective monitoring systems will be vital in the development of a process-control system. Even if the hardware to construct this control system is available, it needs to be assembled and rigorously tested. Many surface installations could benefit from this as-yet-unavailable system to reduce or de-man offshore topside process trains. A long and favorable track record on the surface is required before this technology can be transferred subsea. Until then, this is a technology gap.

Power Supply. UDW electrical power booster pump technology development is well underway in the Gulf. The need for local variable-speed drives (VSD) may not have reached the seabed yet. If the process train needs several electrical motors working independently, then power distribution to each motor's VSD and appro-

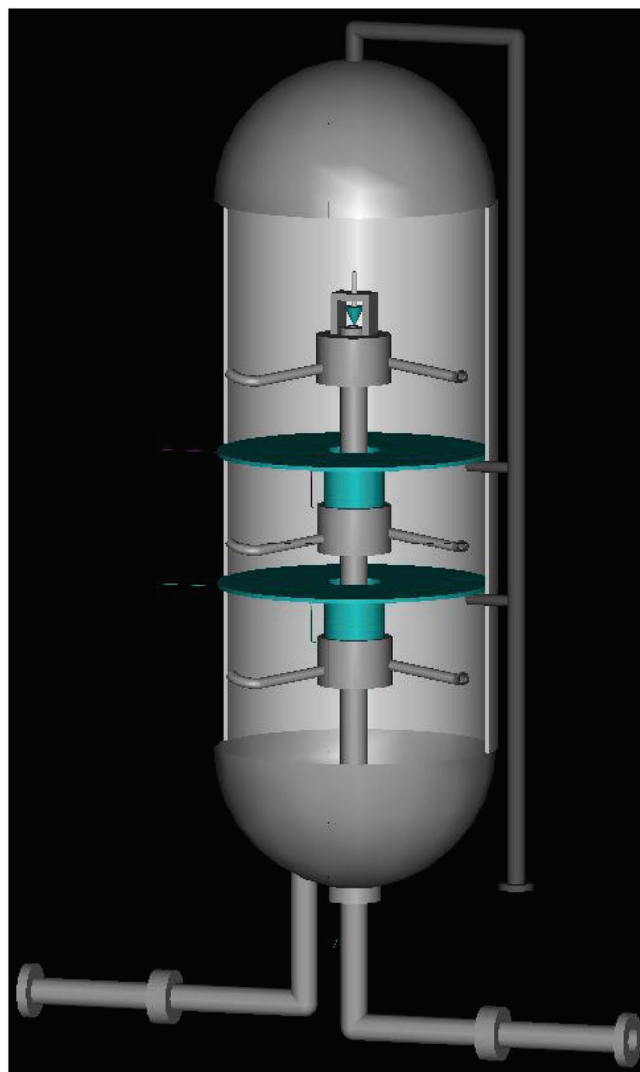


Fig 20—Cameron CFU MS3 (three-stage vessel).

prate controls is required. With the work and experience already available, the hardware necessary for the system process train is not a technology gap.

Valves. Flow from the drill center will probably be through a single line. This flow through the process modules will probably require flowlines that have gate valves that will have to respond quickly to commands to stop flow in one direction and open alternative flow paths through another. Fast opening is not a common specification or dual-acting, but the technology exists. Large volumes of high-pressure control fluid will be stored in accumulators, probably charged with the help of local booster pumps. Alternative electrically powered actuators could be considered. Flow-modulating valves of a significant size to adjust the flow rates through the train are more of a challenge. Choke technology may help, but the mechanical mixing would cause potential emulsion problems. This technology needs further investigation.

Data Transfer. The process train or trains will have significant amounts of monitoring, generating large volumes of data to transmit back to the facility. Fiber optics can provide the necessary band width.

Marinization and Pressure Vessels. Given the approximate ambient pressure conditions at the seabed, a simple analysis of the



collapse load on a cylindrical vessel shows that a 3-ft diameter vessel would need a 1½- to 2-in. wall thickness. This represents a compromise between diameter and weight for manufacture and handling. Note, however, that boilermakers have been making vessels in much larger diameters and wall thickness for many years. The same boilermakers are able to pierce the vessel walls and pull out necks for side or end outlets. The issue would be the cost not the availability of the technology. Pressure vessels can be made stronger by internal and external bracing, but direct attachment of the bracing can cause issues when the vessel expands or contracts. It must also be possible to access the vessel to install and maintain the process equipment. A mid-length full-body flange is a solution. A multibore connector may then be bolted into the access port and allow the vessel assembly to be plugged into its manifold. As a preference, these vessels would be installed vertically, because it is easier to handle and connect subsea.

Operations and Maintenance. UDW separation technology will be developed in subassemblies that will be brought together in stages and be put into service on the surface for study, working experience, and further development. Troubleshooting operational and maintenance protocols will evolve and be tried and tested. Operators will develop hands-on experience with the system in preparation for when it is remotely installed on the seabed. This training and experience will fill the technology gaps.

essary to combine their abilities to gain the required information. Different information is needed at different stages along the process train. It will be important to know what sand and solid concentrations are at specific points in the system and, because discharge of sand will likely be prohibited, having the ability to handle the sand will be critical.

When the techniques have been integrated, they will then have to be marinized, not only to be waterproof but to be installed in such a way that they can be retrieved for maintenance, repair, and upgrade. The seabed-data collection can use existing flying lead and subsea control-module technology, including fiber optics. This is a significant technology gap that is currently pending study within various research organizations such as DeepStar and the Research Partnership to Secure Energy for America (RPSEA).

Seabed Discharge Legislation. Protection of the environment is the priority. Discharge of processed water at the seabed is new territory for operators and regulators. To fill the technology gap, an attempt has to be made to piece together existing surface and subsea performance regulations for the quality of the water discharged. These potential statutory requirements must be reviewed and approved by the regulators to ensure that there are no gaps or shortfalls and that they meet environmental protection standards. This will then provide tangible objectives against which operators and manufacturers can commit resources to increase oil recovery from UDW fields.

Having reviewed the challenges for the use of this technology, it should be suggested that its implementation appears to be possible and would eliminate the need to transport huge volumes of water from deepwater production sites to the tieback hosts. This would significantly reduce the production-system costs; decrease the hydrostatic pressure on the subsea production flow lines, helping to reduce the backpressure on the subsea wellhead; and ultimately allow for more subsea production from the reservoirs. Installations of subsea produced-water handling systems will minimize the topside equipment footprint and help to protect the equipment from damaging tropical hurricanes and harsh weather systems.

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