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Offshore Processing Options for Oil Platforms

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Abstract

An examination of the various processing options that have been implemented on previous (and recent) offshore oil field developments indicates a very broad range of possibilities. The spectrum ranges from:

1. Minimal offshore processing with all produced fluids sent to an onshore terminal (or terminals) for final processing to meet saleable product specifications, to

2. Full processing offshore to make specification products on the offshore facility, with no further onshore processing required.

The decision as to where a given project ultimately ends up on this spectrum can have significant implications. For example:

- is the offshore platform small and simple or large and complex?
- is an onshore terminal (or terminals) required for final processing or not?
- does the gas export pipeline operate in multiphase, moderate pressure single-phase, or high pressure dense phase?
- what is the impact on project schedule and manning requirement? eg. offshore platform size and complexity, number of facilities – offshore only or both offshore and onshore?
- what is the impact on subsequent future projects?

There is little published information or guidelines as to how to make the onshore/offshore processing split decision. Often it is fairly obvious based on the proximity to existing infrastructure (developed areas). In other cases, eg. new offshore regions with minimal infrastructure, it is not. In this regard, the various major offshore producing areas around the world, eg. the Gulf of Mexico (GoM), North Sea, etc., have often taken different approaches. Even in these established regions, there are significant variations in processing scheme details, from facility to facility and between operating companies.

In order to begin to address the "optimum" offshore/onshore processing split issue, it is necessary to first gain an understanding of what the options actually are. The purpose of this paper is to review the main processing options available for an offshore oil production facility, including comparisons, major factors, pro's and con's, etc. This information can serve as a basis for evaluating processing alternatives for future projects.

The Gulf of Mexico and North Sea are large, well established offshore production arenas. They can be used to provide historical context and act as points of reference. The concepts discussed are applicable to all offshore production regions.

Introduction

In most of the developed offshore regions of the world, the decision with respect to the split between offshore and onshore processing will be relatively obvious and be driven by the type and proximity of existing infrastructure, eg. pipeline systems and onshore oil/gas reception and processing facilities. In newer/remote areas, where the designers effectively have a "clean sheet of paper" to deal with, the offshore/onshore split decision is much less clear.

The discussion below will cover various examples of processing solutions that have been implemented for oil projects in different parts of the world. There is a wide range of possibilities. Comparisons and recommendations will be made where appropriate.

Offshore Processing Options

Figure 1 summarizes the primary options available for offshore processing for a typical oil platform. These options are defined according to the degree of oil and associated gas processing that is performed offshore. As indicated, the majority of the offshore platforms fall into the following two categories:

1. Stabilized, spec crude/dehydrated gas produced offshore.
2. Unstabilized, wet crude/dehydrated gas produced offshore.

There are a relatively small number of oil platforms offshore that employ additional gas processing, eg. hydrocarbon dewpoint control/natural gas liquids (NGL) recovery, besides dehydration. It is relatively rare for an offshore oil platform to produce both specification oil *and* gas products. Besides the additional topsides complexity and cost, one of the main reasons for this is the difficulty associated with handling the intermediate components, i.e. C4 – C5, which tend to get "caught" between the crude product vapor pressure spec and a typical hydrocarbon dewpoint spec. These components can accumulate and recycle in the process until equilibrium is reached which will usually have a negative impact on the facility, in particular on the compression train. To alleviate this problem it may be necessary to utilize a more sophisticated separation scheme, eg. a fractionating column, to achieve finer control of the disposition of the C4 – C5 components, if it is necessary to simultaneously satisfy crude vapor pressure and hydrocarbon dewpoint specifications. In some cases it may be necessary to extract a stream rich in C4/C5 and use it for fuel, as an example.

Figure 2 provides a small sample of offshore platforms/regions and how they fit into the categories defined in **Figure 1**.

Gulf of Mexico

By far the most common strategy used for offshore oil platforms in the GoM is to make stabilized, spec crude offshore. The associated produced gas is typically only dehydrated with a triethylene glycol (TEG) unit prior to export.

The Gulf of Mexico has a well developed infrastructure of oil and gas pipeline transmission systems which criss-cross much of the region. Most of this infrastructure has been in place for a number of years and was installed to transport production from the numerous, relatively small platforms located on the Outer Continental Shelf (shelf) typically located in water depths of < 700 feet. The oil pipeline systems generally transport "spec" crude, i.e. Reid Vapor Pressure (RVP) < 11 psi, Basic Sediment & Water (BS&W) < 1% by volume, directly to refineries located mainly in the Texas and Louisiana gulf coast regions.

Figure 3 shows a map of the Gulf of Mexico region, indicating the shelf and deepwater areas, and major pipeline systems.

The offshore Gulf of Mexico can be divided into two main regions:

1. The shelf region:

- water depth < 700 feet
- approx. 4000 platforms
- generally < 10,000 BOPD/platform
- generally < 50 MMSCFD/platform
- total oil production – approx. 500 MBOPD
- total gas production – approx. 9 BSCFD

2. The deepwater region:

- water depth > 1000 feet
- approx. 40 platforms
- generally > 50,000 BOPD/platform
- generally > 100 MMSCFD/platform
- total oil production – approx. 1 MMBOPD
- total gas production – approx. 5 BSCFD

A fairly large proportion of the existing GoM pipeline infrastructure is relatively "full" or near capacity. As a result, the new deepwater developments are making it necessary to install new oil and gas pipeline systems to deliver their product to market, eg. Mardi Gras, Hoover Offshore Oil Pipeline System, etc.

In general, both regions have utilized the same processing approach, i.e. produce spec crude offshore and export dehydrated gas to shore for further processing and liquids recovery. As might be expected, the process flow diagrams for typical shelf and deepwater platforms are similar, though there are some differences that will be discussed.

Figure 4 shows a process flow diagram (PFD) for a typical GoM shelf oil platform. This PFD is representative of a large number of the existing shelf platforms.

Figure 5 shows a PFD for a typical GoM deepwater oil platform. This PFD is representative of the platforms currently being built.

A summary of the main features of GoM shelf and deepwater platforms is given in **Table 1**.

North Sea

Figure 6 shows a map of the North Sea, including major offshore producing areas, pipelines and onshore oil & gas terminals.

The North Sea can be subdivided into 3 main regions:

1. The Southern North Sea (SNS) – nearly all gas production.
2. The Central North Sea (CNS) – mostly oil production, but also several gas and gas condensate fields.
3. The Northern North Sea (NNS) – mostly oil production, but also several gas and gas condensate fields.

A fourth, smaller area is the West-of-Shetlands region which is primarily an oil region.

In general, North Sea oil platforms do not make stabilized, spec crude offshore. Typical offshore crude export specifications are a TVP of 150 psia and a water content of 2% by volume. This live, wet crude is transported by pipeline to an onshore terminal for the final processing required to make the necessary sales specifications. These same oil pipeline systems also transport significant volumes of condensate separated at the gas platforms in the Central and Northern North Sea regions.

Total offshore North Sea (UK sector) oil and gas production volumes are currently approximately 2 MMBOPD and 10 BSCFD, respectively.

There are a relatively few onshore oil terminals in the UK that receive and process the live, wet crude exported from the offshore oil platforms. The main ones include:

1. Sullom Voe in the Shetland Islands – production from the NNS.
2. Flotta in the Orkney Islands – production from the CNS.
3. Kinneil in Scotland – production from the CNS.
4. Teesside in England – production from the CNS.

Of these, Sullom Voe and Kinneil are processing 70 – 80% of the total UK sector crude production.

Similar to the Gulf of Mexico, processing of associated gas in the North Sea is usually limited to dehydration by triethylene glycol, though there are several facilities that perform hydrocarbon dewpointing/NGL recovery offshore as well.

Analogous to the relatively few onshore terminals for processing live wet crude, there are a limited number of onshore gas terminals in the UK that receive offshore gas and process it to the specifications for delivery into the UK gas grid. The major gas terminals on the east side of the UK include:

1. St. Fergus in Scotland – gas production from the CNS and NNS.
2. CATS (Central Area Transmission System) terminal at Teesside, England – gas production from the CNS.
3. Easington in England – gas production from the SNS.
4. Theddlethorpe in England – gas production from the SNS.
5. Bacton in England (several plants) – gas production from the SNS.

Of these, Bacton, CATS and St. Fergus handle the bulk of the gas delivered to the UK from North Sea platforms for additional processing.

As mentioned previously, the oil fields and facilities in the North Sea are mainly located in the CNS and NNS. Associated gas from these fields then is generally delivered to either the St. Fergus or CATS terminals. Gas is delivered to these terminals via a relatively limited number of large gas pipeline systems. The majority of these pipelines have been designed to operate at dense phase pressures, eg. 1600 – 2500 psig. Dense phase operation provides several benefits:

1. It is more efficient to transport gas at high pressures over long distances, especially when intermediate compressor booster stations are not generally feasible, eg. offshore.
2. Dense phase operation eliminates the problems associated with multiphase flow operation of long, large diameter pipelines.
3. Dense phase operation allows for reasonable flexibility with respect to gas composition, i.e. dehydration is normally all that is required, not hydrocarbon dewpointing/NGL recovery.

The drawbacks are thicker walled, more expensive pipelines, and additional compression offshore for the higher discharge pressures required.

Figure 7 shows a PFD for a typical CNS/NNS oil platform.

A summary of the main features of a North Sea oil platform is given in **Table 2**.

Stabilized, Spec Crude Offshore in the North Sea

The relatively few platforms in the North Sea that do make stabilized, spec crude offshore utilize offshore tanker loading to export crude directly to refineries. Most of these facilities are relatively new FPSO's, eg. BP's Schiehallion and Foinaven, Statoil's Norne, ChevronTexaco's Captain, Kerr McGee's Gryphon, etc. There are also a smaller number of fixed structure facilities that make spec crude and utilize offshore tanker loading including ChevronTexaco Alba, BP Harding, and ExxonMobil Beryl in the UK sector. In the Norwegian sector and the Norwegian Sea, the oil transportation and processing infrastructure (pipelines and onshore terminals) is more limited, and therefore a larger proportion of the offshore oil platforms utilize offshore tanker loading and thus must produce stabilized, spec crude, eg. Statfjord, Gulfaks, Draugen, Heidrun, Norne, etc.

Key PFD Issues

A discussion of the key aspects of a typical oil platform process flow diagram is presented below.

1. Number of Separation Trains

The major factors which would normally be expected to influence the selected number of separation trains for an offshore oil platform include:

- total flow rate and its effect on vessel sizes
- availability requirements – particularly the effect of sand, wax, asphaltenes, etc.
- layout/deck area utilization

Single train designs of up to 150 – 200 MBOPD are not uncommon. Typical maximum vessel diameters are in the 14 – 16 ft range, with maximum lengths of up to 80 feet. The largest vessels on the new deepwater GoM platforms are typically the electrostatic coalescers, often in the 12 – 14 ft diameter by 60 – 70 ft long range.

It is rare to see more than two parallel separation trains offshore, though a few examples exist. The Thistle platform in the North Sea, designed for a nominal 200 MBOPD has four oil separation trains, which is not common.

Figure 8 shows the number of separation trains vs. throughput for a selection of offshore oil facilities in different locations.

2. Number of Stages & Stage Operating Pressures

The number of stages of separation utilized on an oil platform, as well as the stage pressures, is a function of the following main parameters:

- flowing tubing pressure(s)
- relative amounts of oil vs. gas
- the required vapor pressure of the export crude product

Most GoM oil facilities utilize five stages of gas-oil separation, including the dry oil/surge tank, while a typical North Sea platform uses two or three.

Flowing tubing pressure

Flowing tubing pressure (FTP) is generally a function of the following main parameters:

- Reservoir pressure
- Well productivity, i.e. BPD/psi drawdown
- GOR
- Water cut

Fields that produce low API crude, eg. < 25 ^{o}API, often have low reservoir pressures, low GOR's and experience high water cuts later in field life. These factors favor low separation pressures and therefore fewer separation stages.

1'st stage operating pressures can be very high, up to 1500 – 1800 psig in the GoM. Often GOR's for some of the platform wells are > 2000+ SCF/STB, almost more like gas wells. These high GOR's in turn result in high flowing tubing pressures. Historically, relatively few of the GoM oil fields on the Gulf coast shelf used water injection for pressure maintenance, which contributes to the typically high producing GOR's. High GOR/FTP combined with relatively steep well inflow performance (IPR) curves as well as a need to choke wells to limit drawdown/sand production, favors a high first stage separator operating pressure, primarily as a means of minimizing platform gas recompression power. On shelf platforms where gas export pressures are generally low, eg. 1000 – 1200 psig, it is common for HP separator gas to flow straight to the glycol dehy then to sales, bypassing compression.

Several of the new deepwater oil platforms are now implementing process trains with fewer stages of separation and lower first stage separator pressures, primarily as a means to achieve higher flow rates from the typically much more prolific deepwater wells by reducing well FTP/separator back pressures. The higher production rates more than offset the extra compression costs, in most cases.

1'st stage separator pressures on North Sea platforms are usually < 750 psig, sometimes much lower. North Sea oil wells are also quite productive and sensitive to back pressure. GOR's are often lower, as most North Sea fields are utilizing water injection for pressure maintenance. Finally, because of the gas export system designs in the oil regions of the North Sea (CNS & NNS), i.e. high pressure/dense phase, the first stage pressure is "disconnected" from the gas export pressure and can be set more or less independently from the gas export pressure, i.e. gas export pressure is too high to allow the 1'st stage separator to "float" on the export line pressure in an attempt to minimize compression power/cost.

Relative amounts of gas and oil production

High volumes of gas production relative to oil, i.e. high producing GOR, will increase the size and cost of gas handling equipment on the platform, in particular compression. The goal will be to separate as much of the gas at as high a pressure as possible, balanced against well inflow performance and ultimate recovery. As discussed previously, high GOR production tends to allow for higher separator pressures due to the typically higher well FTP's.

Because well FTP's will change over time, normally decreasing, it is common practice to provide separate production manifolds for each separator to allow wells to be dropped down to lower pressure levels over time, maximizing production as their FTP's decline.

Vapor pressure of the exported crude product

This is where the primary impact of the stabilized crude vs. live crude export decision will be felt on the offshore platform.

The final gas-oil separation stage operating pressure, and temperature, dictates the vapor pressure of the export crude product. Generally a very low pressure, and quite high temperature are required to make a stable, i.e. 11# RVP crude product, typical for GoM oil platforms or any platform that needs to make a stable crude product for offshore loading. While there is a theoretical argument for using a stabilization column to replace simple flash separation stages, this has been done infrequently offshore.

It is not only the number of gas-oil separators that are impacted by the stabilized vs. live crude decision. Several other systems/pieces of equipment are involved. **Figure 9** illustrates the potentially large impact of the decision to make stabilized, spec crude offshore.

Figure 10 shows the number of separation stages vs. throughput for a selection of offshore oil facilities in different locations.

3. 2 or 3-Phase Separation for Higher Pressure Stages

In the GoM, it is nearly standard practice for the HP and IP separators, to be designed as 2-phase separators, with typical liquid residence times of 1 – 2 minutes. This sizing criterion is tight and provides limited capacity for handling unsteady flow and/or foam. Normally, the bulk of the produced water on a GoM platform is removed from the LP separator (3-phase) which typically operates at around 150 – 250 psig.

On a GoM platform, typical HP/1'st stage pressures are in the range of 1200 – 1600 psig while IP/2'nd stage separator pressures are normally in the range of 450 – 650 psig. A 2-phase HP separator makes sense under these conditions in that wells that are capable of flowing at tubing pressures this high generally aren't producing much water.

The norm in the North Sea is for all separation stages to be 3-phase. Typical sizing criteria is 3 – 5 minutes liquid residence time, which is normally sufficient for light crudes given the high temperatures that North Sea separation trains operate at, and the fact that the exported crude product typically allows a 2% v/v water content.

The decision to make the higher pressure separators 3-phase makes them bigger (increased residence time) and heavier (larger size and increased wall thickness). On the other hand, there are some advantages to making all separators 3-phase, including:

1) potential benefits for produced water treating → reduced shearing of oil-water mixture across level control valves. This topic is discussed in more detail later in this paper.
2) potentially easier emulsion resolution in subsequent stages → again, reduced shearing.
3) allows for easier implementation of sand jetting.
4) removal of water earlier in the process allows some reduction of downstream equipment sizes. In particular, if heating of the inlet wet crude is required for emulsion resolution/stabilization, it is often beneficial to remove as much free water as possible early in the process to reduce heating duty.

4. Process Heating

Normally only facilities making stabilized, spec crude require heating of the produced fluids. Exceptions include platforms that aren't making spec crude but are receiving relatively cool inlets from remote wellhead platforms or subsea wells and need heat input to facilitate separation. Heat is required to aid oil-water separation, mainly via crude viscosity reduction, and stabilization by driving off light ends. In addition to produced fluids heating, other major process heating loads include glycol regeneration and fuel gas superheating. Glycol regeneration typically requires the highest temperature level, i.e. 400+ F.

Nearly all GoM platforms require heat input to achieve the required crude export product vapor pressure and BS&W specifications. Typical temperature requirements are in the 140 – 160 F range.

As mentioned previously, North Sea wells tend to flow at much higher temperatures than GoM wells, due to their typically higher reservoir temperatures and flow rates. As most North Sea platforms do not export stabilized, spec crude, additional wellstream heat input is normally not required. For the relatively few North Sea facilities that do make spec crude for offshore tanker loading, wellstream heat input is typically required to achieve the vapor pressure and water content specifications.

In general, process heating in both the GoM and North Sea is achieved via waste heat recovery from power generation gas turbine exhaust utilizing hot oil as the heat medium fluid. As maximum process temperature requirements are typically around 400 F (TEG regeneration), the relatively inexpensive "mineral oil" based fluids are normally adequate for this service. In some cases, more "sophisticated" organic fluids are utilized. Other heat medium fluids that are used occasionally include hot water/steam, which can be operated under pressure at 400 F to satisfy glycol regeneration requirements, and glycol/water mixtures, usually < 300 F. On those platforms with relatively low process heating requirements, the heat medium system can be eliminated entirely and the relatively few and low duty heat loads can be supplied by electric resistance element heaters.

5. Heat Recovery via Back-exchange

Heat recovery via back-exchange is relatively common on offshore oil platforms, especially when a large amount of heat input is required, i.e. relatively low inlet temperatures, eg. reception of cool fluids from subsea wells/remote wellhead platforms combined with relatively high process temperatures required for crude dehydration/stabilization. A fair number of GoM platforms, shelf and deepwater, fall into this category, as do many other facilities around the world that make stabilized, spec crude offshore.

Heat recovery via back exchange is not particularly common on North Sea platforms, due to their typically high flowing wellhead temperatures and live, wet crude export. In fact, several North Sea platforms actually *cool* the oil after the first separation stage.

Back-exchange of hot crude product vs. inlet fluids is most common, though there are projects that also back-exchange separated hot produced water against the inlet fluids, though this is quite rare. Both shell and tube and gasketed plate-frame exchangers are used for this service. Experience with plate-frames has been mixed.

6. Process Cooling

The main choices are: air, direct seawater and indirect cooling medium (usually glycol/water). Historically, GoM platforms have been air-cooled while North Sea platforms have been cooled by direct seawater/indirect cooling medium. There are several reasons for this difference. North Sea platforms are generally much more crowded with little plot space available for air coolers. Also, most North Sea oil platforms utilize seawater injection for reservoir pressure maintenance. As large volumes of seawater must be lifted for injection, the incremental cost to utilize this water for process cooling purposes is considerably reduced. The heat exchangers used for water cooling tend to have a much smaller area footprint and are lighter than air coolers. The cold North Sea water temperatures also help reduce heat exchanger size and lower process temperatures are achievable which is generally beneficial.

While several of the GoM deepwater projects have used air cooling, the majority are using direct seawater or glycol/water cooling medium. These projects also have large seawater injection facilities for pressure maintenance, which as discussed above lends itself to water cooling. In fact, there are several projects – GoM, North Sea and other – that lift seawater for cooling purposes only, then discharge the water back overboard into the sea, i.e. no seawater injection facilities.

The decision as to whether to employ direct seawater vs. indirect cooling medium (usually a 30 wt % glycol/water mixture) comes up frequently. From an operations and maintenance point of view, the indirect system is normally favored due to reduced susceptibility to corrosion, scaling, fouling and hydrate problems typically associated with seawater. While there are several factors involved, the indirect system will normally have a somewhat lower CAPEX if there are a large number of cooling loads and total cooling duty is relatively high. In particular, the utilization of relatively clean and non-fouling cooling medium is much more compatible with the use of printed-circuit heat exchangers, which can offer significant space and weight savings compared to shell and tube exchangers, in the correct applications. For those platforms with relatively few cooling loads, that have chosen to use shell and tube exchangers, a direct seawater system is usually less expensive and simpler, though upgraded metallurgy is required.

7. Crude Dehydration Method/Equipment

In the GoM, the typical offshore spec is < 1% BS&W. In other parts of the world that make spec crude offshore, normally for offshore tanker loading, the specification is typically < 0.5% v/v water. In either case, the current practice is to use liquid filled electrostatic coalescers for crude dehydration. Vendor design flux rates for electrostatic coalescers have increased over the years, partly due to improved technology but probably also due to reduced conservatism in the design. Design fluxes of 200 bopd/ft^2 or even higher are now fairly typical for medium – light crude applications.

For light crudes, eg. > 35 ^{o}API, if flowing wellhead/separation train temperatures are high enough, a properly sized conventional 3-phase separator is usually adequate to achieve water contents of 2% v/v. For water content much below this level, and for heavier oils, an electrostatic coalescer will typically be required. Several North Sea facilities achieve < 0.5% water content (for offshore tanker loading) without electrostatic coalescers.

Desalting of produced crude is rarely performed offshore in the GoM or North Sea. In general, the refineries that process crude produced from these areas have adequate desalting capability. Other areas of the world *do* perform onshore and offshore “field” desalting, in particular the Middle East, offshore West Africa, and offshore China. Typical salt content limitations, where applied, are usually in the range of 10 – 20 pounds of salt (as NaCl) per thousand barrels of net oil (PTB). Depending on the salinity of the produced water, the salt spec can be achieved either by dehydration alone (low produced water salinity) or with dilution water in single or two-stage desalting arrangements.

Figure 11 shows the PFD for an offshore oil facility in West Africa that utilizes two-stage desalting.

8. Export Oil Cooling

In the GoM, export temperatures are usually limited to < 140 F. If the hot crude product is back-exchanged against inlet fluids a dedicated oil export cooler is not normally required. If the hot crude product is not back-exchanged, a dedicated oil export cooler is typically employed only if crude stabilization/dehydration temperatures above 140 F are required.

Although oil export temperatures are often higher in the North Sea, oil export coolers are quite common, due to the high flowing wellhead/separation train operating temperatures typical of this region. Often cooling of the export crude is required to limit expansion/stress on the oil export riser. The export crude cooler is often a direct seawater cooled plate-frame exchanger.

9. Produced Water Treating Systems

Equipment

Since the mid – 80’s most platforms around the world have been using hydrocyclones as their primary produced water cleanup equipment. Initially, a simple degassing vessel was typically installed downstream of the hydrocyclones. This is still the most common treating system in the North Sea. In other parts of the world, including the deepwater GoM, the simple degassing vessel has been replaced by an induced gas flotation (IGF) unit in recent years. This shift has been mainly due to the inability of the hydrocyclone/degasser combination to consistently achieve the required oil-in-water overboard discharge specifications, often in the 40 – 50 ppmw range (42 ppmw max/29 ppmw average, in the GoM). In the North Sea, the hydrocyclone/degasser combination can typically easily achieve the current 40 ppmw spec with many platforms achieving < 20 ppmw oil-in-water. Why the apparent difference in performance between the North Sea and other offshore regions?

There are several potential factors but perhaps the most important one is temperature. The separation trains and produced water treating systems on North Sea platforms typically operate at significantly higher temperatures than other parts of the world.

2-Phase vs. 3-Phase Separators

As mentioned under the "Oil Separation Trains" section, North Sea platforms typically use 3-phase separators for all stages while in the GoM only the "LP separator" and electrostatic coalescer/treater are typically 3-phase.

The 2-phase vs. 3-phase decision leads to a considerable difference in the complexity of the produced water treating systems (see **Figure 12**). Specifically, the North Sea 3-phase separator approach requires a dedicated hydrocyclone package for each separator while the typical GoM 2-phase approach requires only one hydrocyclone unit.

There is a potential argument that the 3-phase separation/dedicated hydrocyclone option for the higher pressure stages (typical North Sea) reduces oil-water shear and allows for better produced water treatment performance. Reduced shear of the oil-water mixture should have two major benefits with respect to produced water treating:

1) lower oil-in-water concentrations due to improved separation in the primary separators. Oil-in-water concentrations off the 3-phase separators in a North Sea separation train are typically < 1000 ppmw and often < 500 ppmw.
2) the oil droplets that remain in the produced water should generally be larger in size which makes them easier to remove with the water treatment equipment.

Produced water reinjection is also becoming an increasingly common option for disposal of produced water, though this practice is still not widely employed, with the primary issues being maintenance of acceptable injectivity into the subsurface formation, and compatibility with the seawater which is normally used for pressure maintenance.

10. Gas Handling

Compression

In general, centrifugal compressors are used offshore. They are smaller and lighter than reciprocating compressors, are available in higher capacities and power ratings and are more compatible with the most commonly used offshore drivers – gas turbines and electric motors. Maintenance costs are normally lower as well. Reciprocating compressors have been used extensively on GoM shelf platforms and in other locations where gas handling volumes are relatively low. For certain applications, eg. low pressure vapor recovery, rotary screw compressors are being used more frequently in place of reciprocating compressors.

Compressor driver selection varies. For the larger platforms utilizing high capacity/power centrifugal compressors, gas turbine drivers are probably most common. The use of electric motors for drivers combined with a central power generation facility is also an increasingly common arrangement that often has benefits with respect to availability, platform layout and environmental emissions, though this option is generally more suited to larger facilities. Gas engines have often been used to drive reciprocating compressors and pumps on smaller platforms.

Dehydration

Most oil platforms, regardless of location, limit gas processing to dehydration only, with the vast majority of these utilizing triethylene glycol units. Typical water content of the dried gas is in the range of 2.5 – 7 lbs of water/MMSCF, depending on pipeline/sales gas contract requirements, or hydrate avoidance requirements. High pressure gas export combined with low seafloor temperatures often dictate the dehydration requirements.

Most new platforms are using structured packing in the glycol contactors to reduce contactor diameter and weight due to the higher allowable velocities. Those installations that must achieve < 4 lb/MMSCF water content, normally need the equivalent of 3 – 4 theoretical trays in the contactor, in addition to an enhanced regeneration process to achieve 99+% lean glycol concentrations. Experience with the different enhanced regeneration methods, eg. DRIZO, Coldfinger, etc. has generally been mixed. While there has been a move away from the historical (and simple) stripping gas process over the years due to emissions concerns, routing the still overhead vapor to the suction of a low pressure vapor recovery unit (VRU), or to flare with the increasing implementation of flare gas recovery schemes, makes this method worthy of consideration.

In general, offshore glycol contactors are typically operated in the 1100 – 1200 psig range. In many offshore regions this pressure is equivalent to the gas export pressure. In areas where gas export pressures are > 2000 psig, there is usually a final stage of compression (export compressor), downstream of the glycol contactor. Platforms whose gas export pressures fall in the 1300 – 1900 psig range, typically have the glycol contactor operating at gas export pressure. Glycol contactors that operate at > 2000 psig do exist but are not common.

Several of the new deepwater GoM platforms have utilized 2 x 50% glycol contactors in parallel (common regeneration system), even for single train designs, though total gas flow rates are typically < 400 MMSCFD. The bigger North Sea gas platforms routinely process 500 MMSCFD through a single contactor. Another common difference between GoM and North Sea dehy unit designs is that the GoM units nearly always use a gas-glycol exchanger to achieve the normally recommended ΔT between the lean glycol and the contactor gas temperature, while a North Sea unit nearly always uses a water (seawater or cooling medium) cooler to cool the lean glycol.

Hydrocarbon dewpointing/NGL recovery

Hydrocarbon liquids recovery on offshore oil platforms is relatively rare. Having said this, oil platforms equipped with Joule-Thomson expansion, mechanical refrigeration and turbo-expanders for liquids recovery do exist, mainly in the North Sea. There are even a very few offshore facilities also equipped with NGL fractionating columns, eg. Nkossa (West Africa) and Ardjuna (Indonesia).

In the GoM, most of the offshore gas gathering/transmission infrastructure is designed to handle dehydrated but hydrocarbon wet gas. Liquids are typically handled in slug catching facilities located in shallow water or onshore. In addition, because of the low vapor pressure crude spec that generally applies to GoM platforms, only very small amounts of butane or lighter material can exist in the stabilized crude product.

While the higher vapor pressure crude spec normally applicable to offshore North Sea oil platforms allows more light ends to be exported with the crude, this does not normally warrant the additional complexity and cost associated with more sophisticated hydrocarbon liquids recovery schemes. The main exception would be a situation where the only reasonably nearby gas pipeline was transporting “sales gas spec” gas. In this case, the additional cost to make spec gas on the platform may be more than offset by savings related to the gas export system.

Processing of sour fluids

The number of offshore oil platforms currently processing sour fluids (specifically H_2S) is relatively small. Several of these platforms have chosen to sweeten the produced crude offshore. While H_2S-in-crude specifications vary, typical values are often < 10 ppmw. Using a conventional multistage separation process with heating to achieve vapor pressure and water content specifications, it is very difficult to achieve the 10 ppmw H_2S level in the final crude product unless the concentration of H_2S in the produced fluids is very low. Generally it will be necessary to utilize a trayed column with the sour crude fed in at the top of the column and sweet stripping gas introduced at the bottom. The sweet stripping gas would normally be obtained from a sweet fuel gas system, which usually requires an amine unit or equivalent for sweetening the sour associated gas separated from the crude.

Summary

The discussion above covers the main issues associated with the different processing options available for an offshore oil facility. As stated previously, for most new facilities the highest level decisions as to the split between offshore and onshore processing and oil and gas product disposition, will usually be driven by the proximity and nature of existing infrastructure.

For true “clean sheet of paper” scenarios, the situation is much more complex. While the number of “frontier” offshore regions yet to be developed is decreasing with time, they still exist. Even in developed offshore areas with significant existing infrastructure, there will be occasions when this infrastructure is too far away to be accessed economically, or the infrastructure is “full”. Under these conditions, the designers have the opportunity to select the best facilities development option, from a wide range of possibilities. The processing options chosen, will impact the complexity, size and cost of the offshore platform, the cost of the oil and gas export systems, and the cost of the onshore oil and gas reception facilities, if required. There are a number of trade-offs involved, and the objective is to determine the optimum combination of these systems for a given development. These initial decisions are very important, as they will basically establish the infrastructure for the future developments in the area which are likely to follow.

Figure 13 indicates quite clearly, the potential impact of processing decisions on the complexity (and cost) of offshore oil facilities. While not the complete picture, the offshore facilities are often the major component of total project facilities costs, and to a large degree dictate the schedule to first oil production.

Conclusions

The intent of this paper is to provide an overview of the various options available for offshore oil processing. With a better appreciation of what options are available, and where/when they are most suitable, a wider range of possibilities can be considered in the concept selection stage for new developments. Depending on the offshore region and the background and experience of the personnel involved, the best answer might not be the traditional “GoM way” or the “North Sea way”, but a combination of the best aspects of all the available options.

Nomenclature

GoM = Gulf of Mexico
RoW = rest of world
BOPD = barrels of oil per day
BS&W = basic sediment & water
MBOPD = thousand barrels of oil per day
MMSCFD = million standard cubic feet per day
CNS = Central North Sea

NNS = Northern North Sea
SNS = Southern North Sea
LACT = lease automatic custody transfer
IGF = induced gas flotation
NGL = natural gas liquids
psi = pounds per square inch
ppmw = parts per million by weight
H_2S = hydrogen sulfide
% v/v = % by volume
FTP = flowing tubing pressure
GOR = gas-oil ratio
SCF/STB = standard cubic feet /stock tank barrel
RVP = Reid vapor pressure
TVP = true vapor pressure

Table 1. Typical Gulf of Mexico Oil Platform Characteristics

	GoM Shelf	GoM Deepwater
Oil rate, BOPD	< 20,000	50,000 – 250,000
Gas rate, MMSCFD	< 50	50 – 400
Individual well rate, BOPD	< 3,000	10,000 – 35,000
Flowing wellhead temp, F	90 – 110 F	110 – 200 F
# of separation trains	1	1 – 2
# of stages	4 – 5	3 – 5
Dehydration process	TEG	TEG, enhanced regeneration
Export gas water content, lb/MMSCF	7	2 – 4
Export gas pressure, psig	1,000 – 1,200	1,500 – 3,000
Export oil water content, % v/v	< 1	< 1
Export oil RVP, psi	< 11	< 11
Export oil pressure, psig	1,000 – 1,500	1,500 – 3,000
Process heating medium	Direct fired/hot oil	Hot oil
Process cooling medium	Air	Air/water
Compression equipment	Recip	Screw/centrifugal
Produced water treating equipment	Skim tank/IGF	Hydrocyclones/IGF
Water injection facilities	Occasionally	Common

Table 2. Typical North Sea Oil Platform Characteristics

	North Sea
Oil rate, BOPD	50,000 – 250,000
Gas rate, MMSCFD	50 – 300
Individual well rate, BOPD	10,000 – 25,000
Flowing wellhead temp, F	150 – 230 F
# of separation trains	1 – 2
# of stages	1 – 3
Dehydration process	TEG, enhanced regeneration
Export gas water content, lb/MMSCF	2 – 4
Export gas pressure, psig	2,000 – 2,700
Export oil water content, % v/v	< 2
Export oil TVP, psi	< 150
Export oil pressure, psig	1,500 – 2,800
Process heating medium	Hot oil
Process cooling medium	Seawater/(EG/water cooling medium)
Compression equipment	Centrifugal
Produced water treating equipment	Hydrocyclones/degasser
Water injection facilities	Common

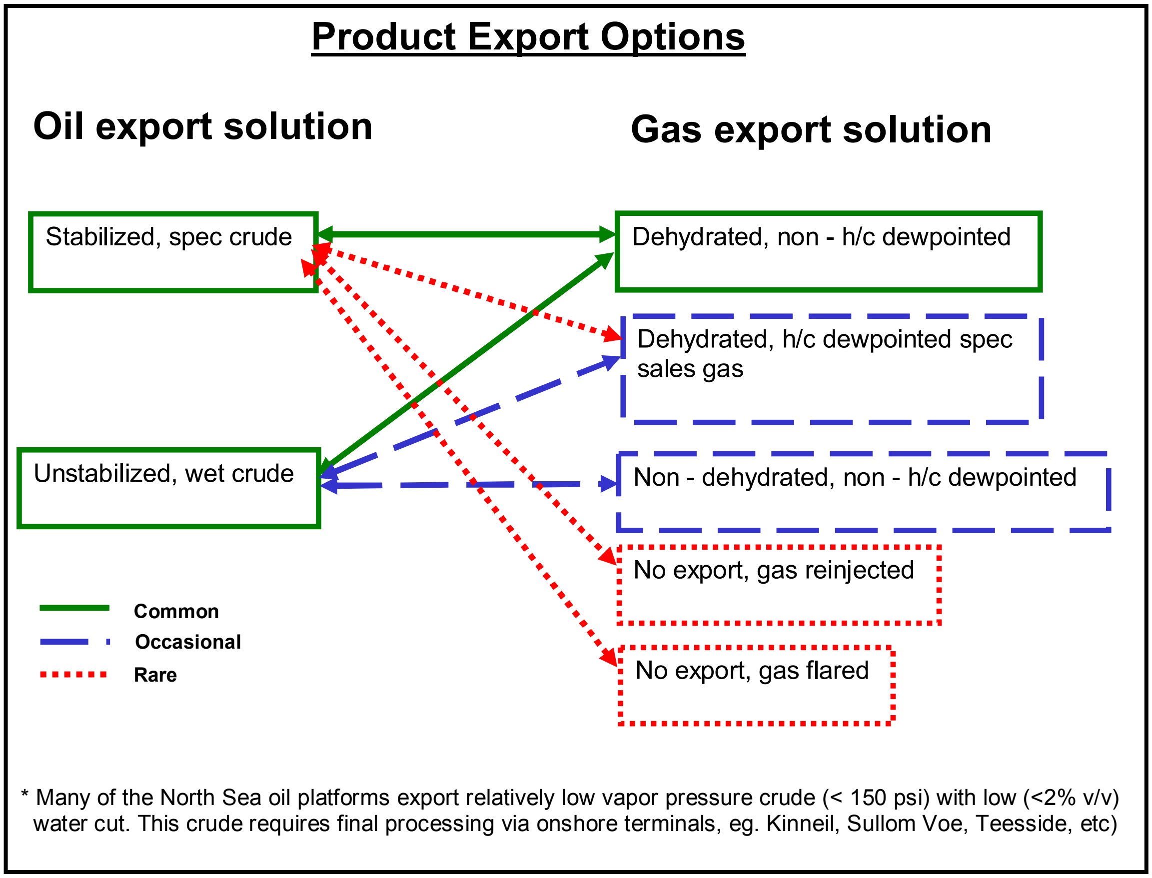


Figure 1.

Export Options for Various Offshore Regions

Oil export solution	GoM	North Sea	RoW
Stabilized, spec crude	Most of the GoM – shelf & deepwater	Relatively few - mainly platforms performing offshore tanker loading, eg. Schiehallion, Foinaven, Statfiord	Canada East Coast, West Africa, Indonesia
Unstabilized, wet crude	Few	Most of the North Sea oil platforms	Azerbaijan, Gulf of Suez (Egypt), Trinidad
Gas export solution			
Dehydrated, h/c dewpointed spec sales gas	Few	Relatively few	Indonesia
Dehydrated, non - h/c dewpointed	Most of the GoM – shelf & deepwater	Most of the North Sea	Most areas
Non - dehydrated, non - h/c dewpointed	Few	Few	Gulf of Suez, Trinidad
Gas reinjected	None - few	Few	West Africa, Canada East Coast
Gas flared	None - few	Few – mainly small, isolated fields, often with heavy oil & low GOR's	Several areas – mainly FPSO's/limited

Figure 2.

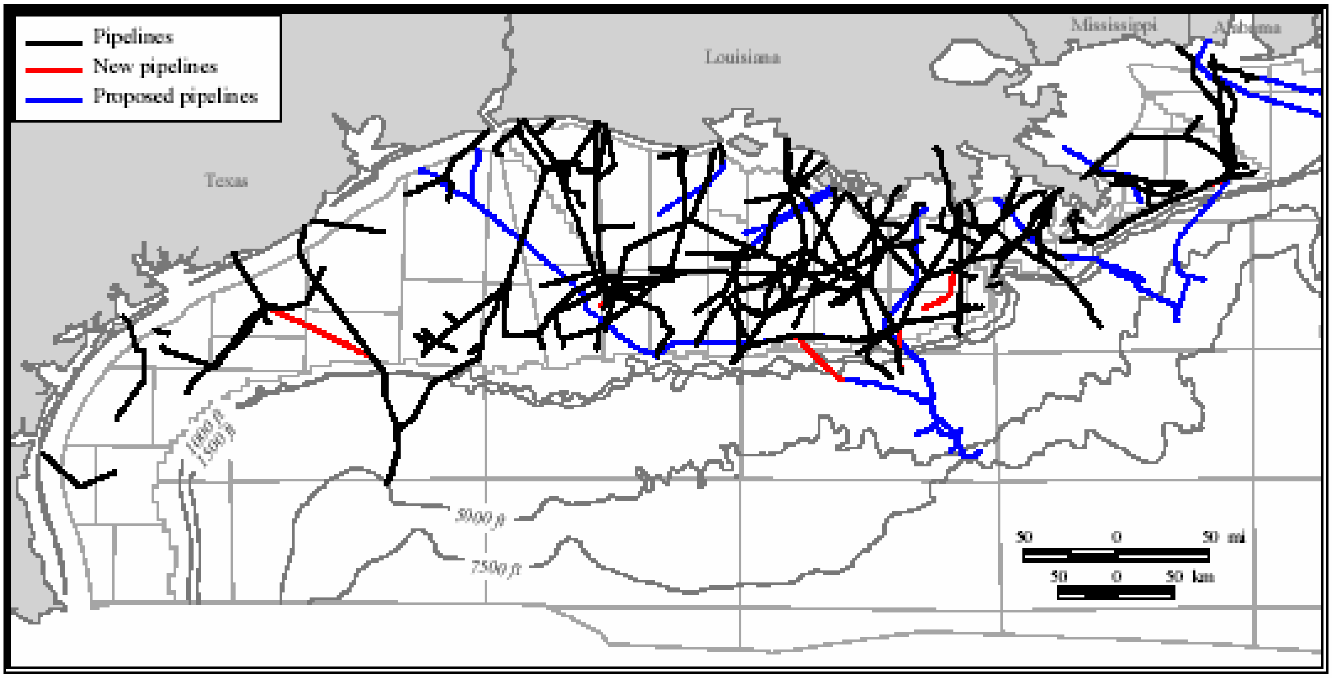


Figure 3. Gulf of Mexico Major Pipelines and Water Depths

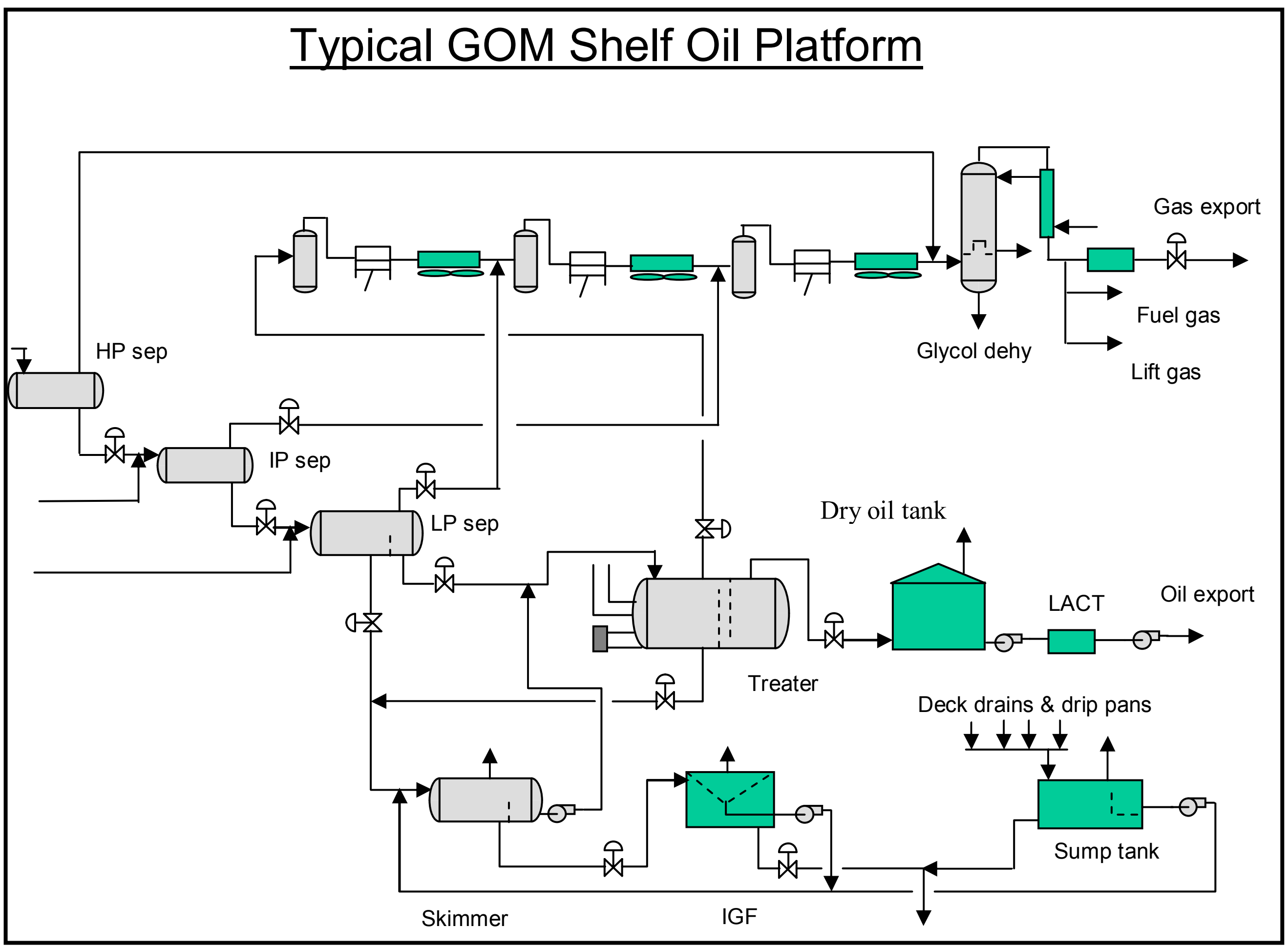


Figure 4.

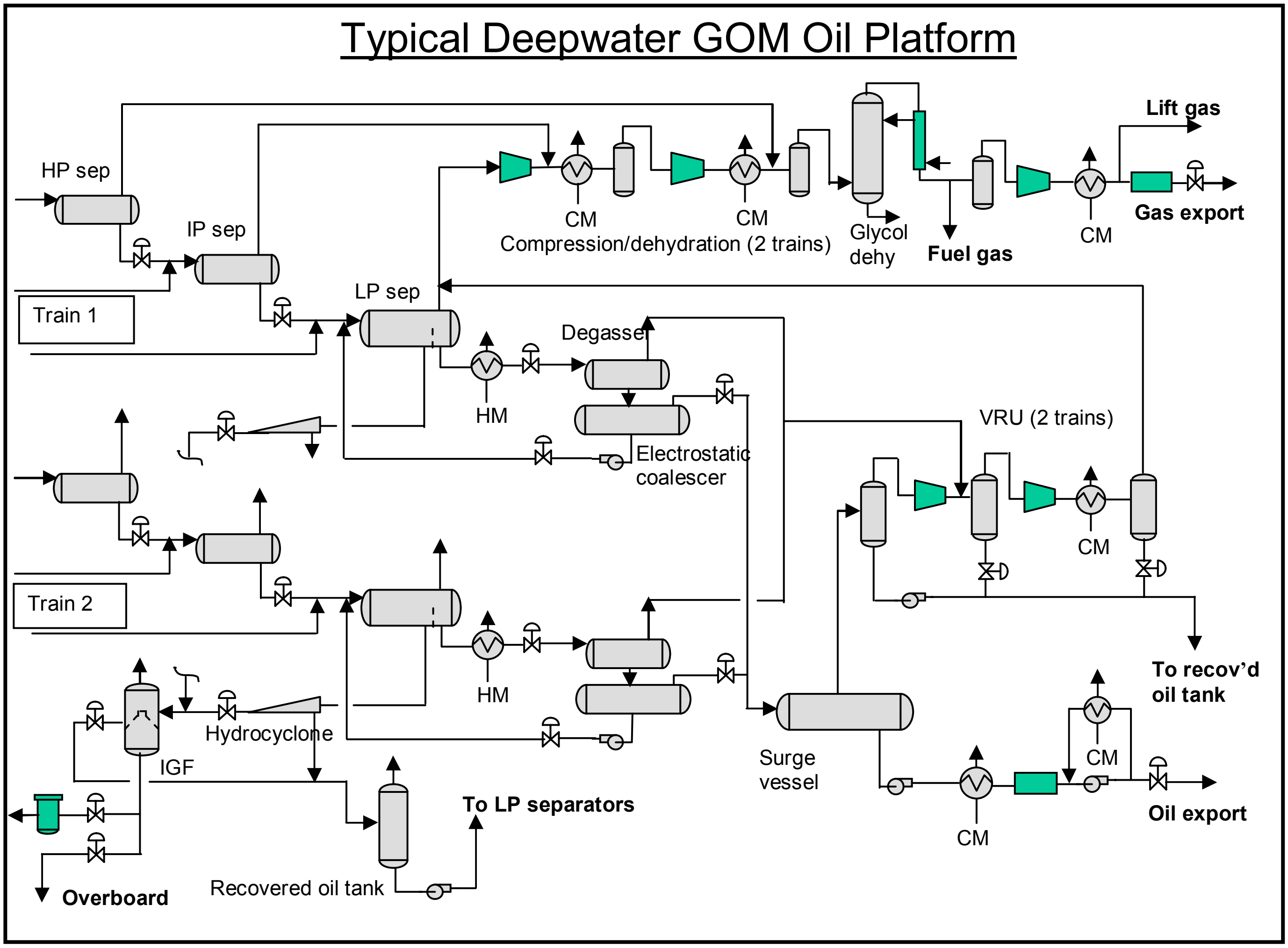
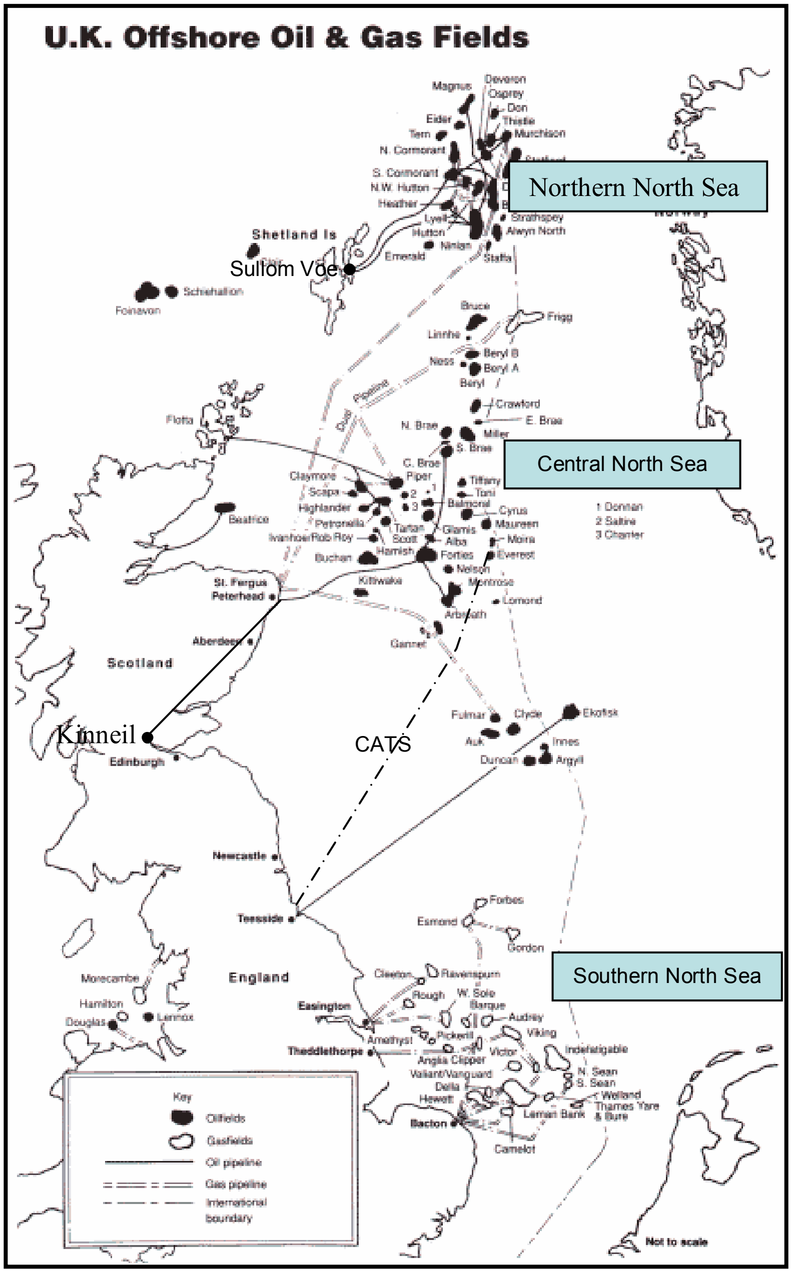

Typical Deepwater GOM Oil Platform
HP sep
IP sep
LP sep
Train 1
Train 2
CM
Compression/dehydration (2 trains)
Glycol
dehy
Fuel gas
Lift gas
Gas export
Degasser
HM
Electrostatic
coalescer
VRU (2 trains)
To recov'd
oil tank
Hydrocyclone
IGF
Overboard
Recovered oil tank
To LP separators
Surge
vessel
Oil export

Figure 5.


U.K. Offshore Oil & Gas Fields
Northern North Sea
Central North Sea
Southern North Sea
Magnus
Deveron
Osprey
Don
Thistle
Murchison
Eider
Tern
N. Cormorant
S. Cormorant
N.W. Hutton
Heather
Lyell
Hutton
Ninian
Strathspey
Alwyn North
Emerald
Staffa
Shetland Is
Sullom Voe
Schiehallion
Foinavon
Bruce
Frigg
Linnhe
Beryl B
Ness
Beryl A
Beryl
Crawford
E. Brae
N. Brae
Miller
S. Brae
Flotta
C. Brae
Piper
Claymore
Scapa
Highlander
Petronella
Ivanhoe/Rob Roy
Tiffany
Toni
Balmoral
Cyrus
Maureen
Glamis
Alba
Moira
Everest
Tartan
Scott
Hamish
Forties
Nelson
Montrose
Lomond
Arbroath
Buchan
Beatrice
Kittiwake
Gannet
1 Donnan
2 Saltire
3 Chanter
St. Fergus
Peterhead
Aberdeen
Scotland
Kinneil
Edinburgh
CATS
Fulmar
Clyde
Ekofisk
Auk
Innes
Duncan
Argyll
Newcastle
Teesside
Forbes
Esmond
Gordon
England
Morecambe
Hamilton
Douglas
Lennox
Easington
Cleeton
Ravenspurn
Rough
W. Sole
Barque
Audrey
Amethyst
Pickerill
Viking
Theddlethorpe
Victor
Indefatigable
Anglia
Clipper
Valiant/Vanguard
Della
Hewett
N. Sean
S. Sean
Welland
Thames Yare & Bure
Leman Bank
Bacton
Camelot
Key
Oilfields
Gasfields
Oil pipeline
Gas pipeline
International boundary
Not to scale
Figure 6.

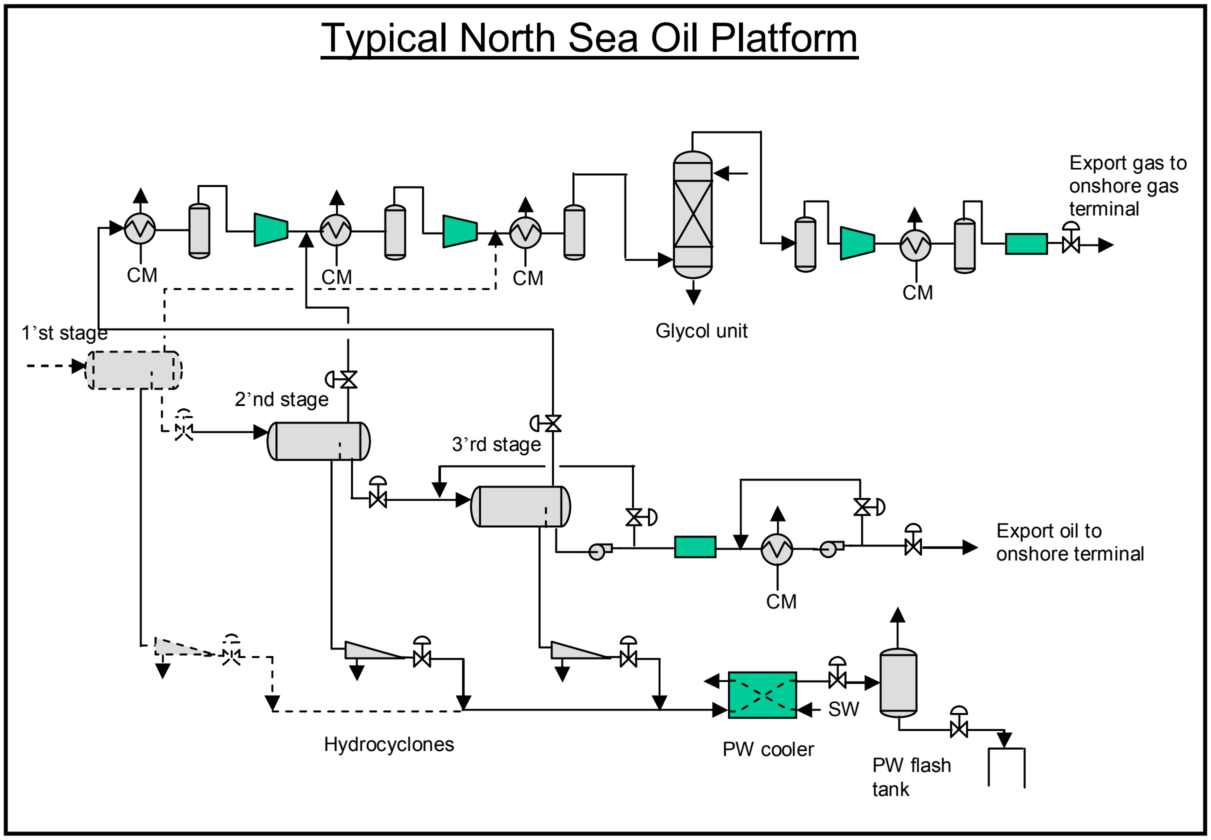
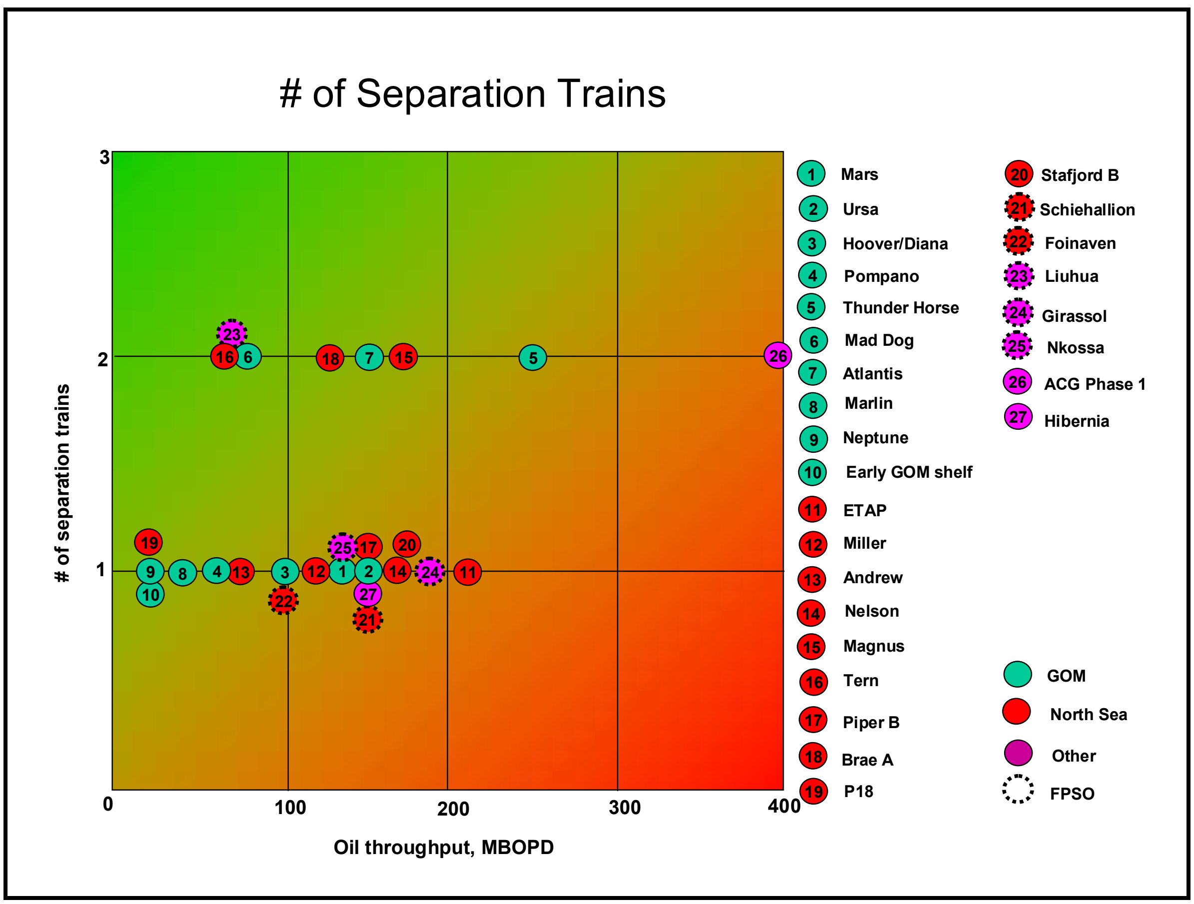


Figure 7.



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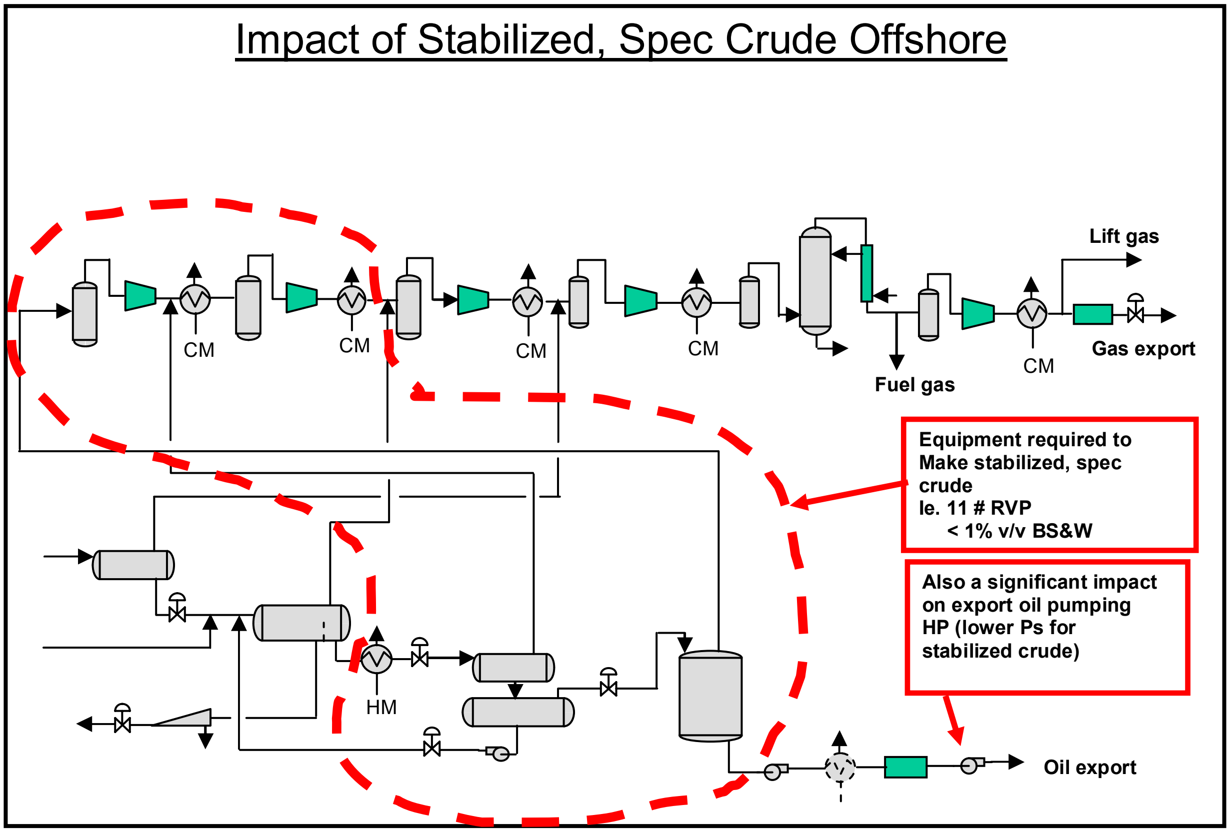

Figure 9.

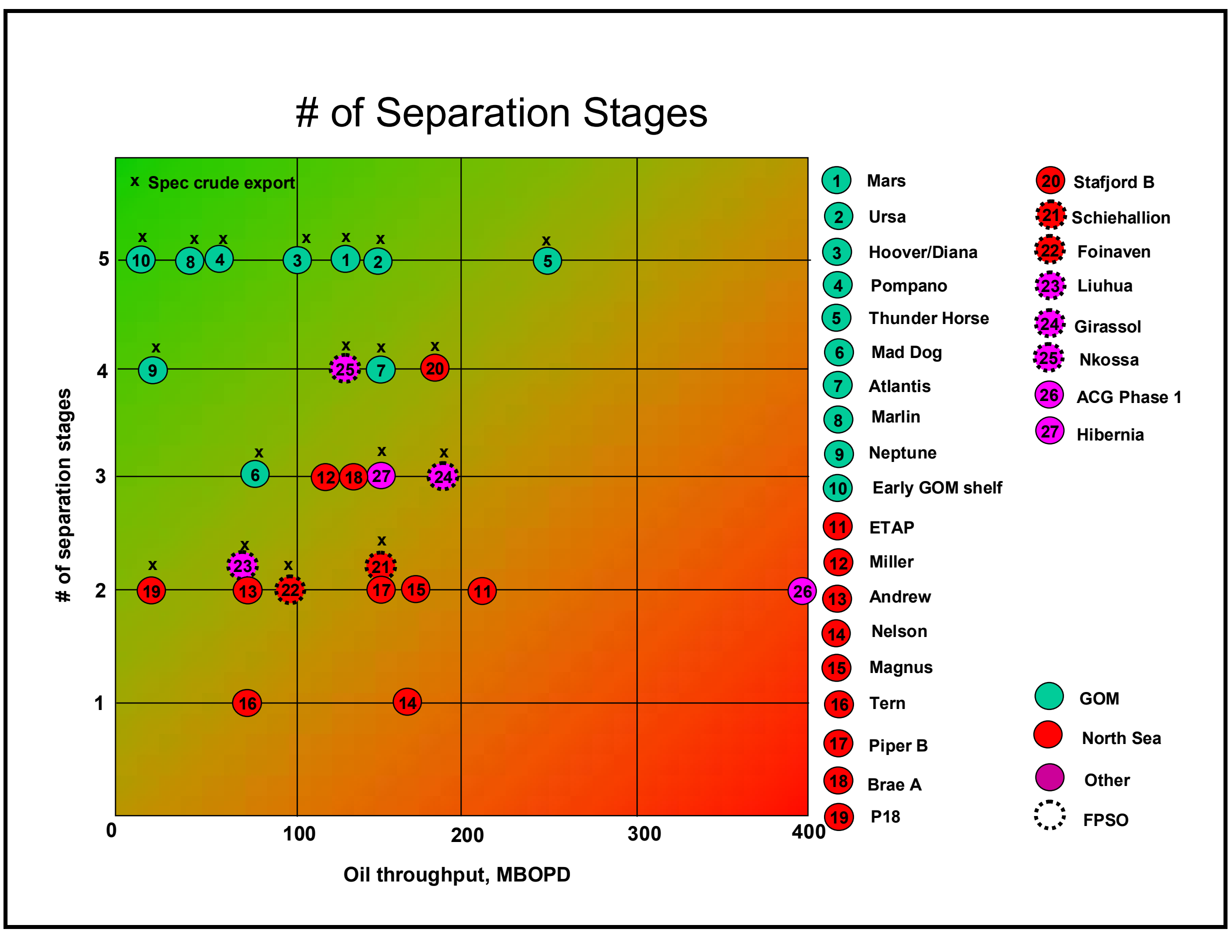

Figure 10.

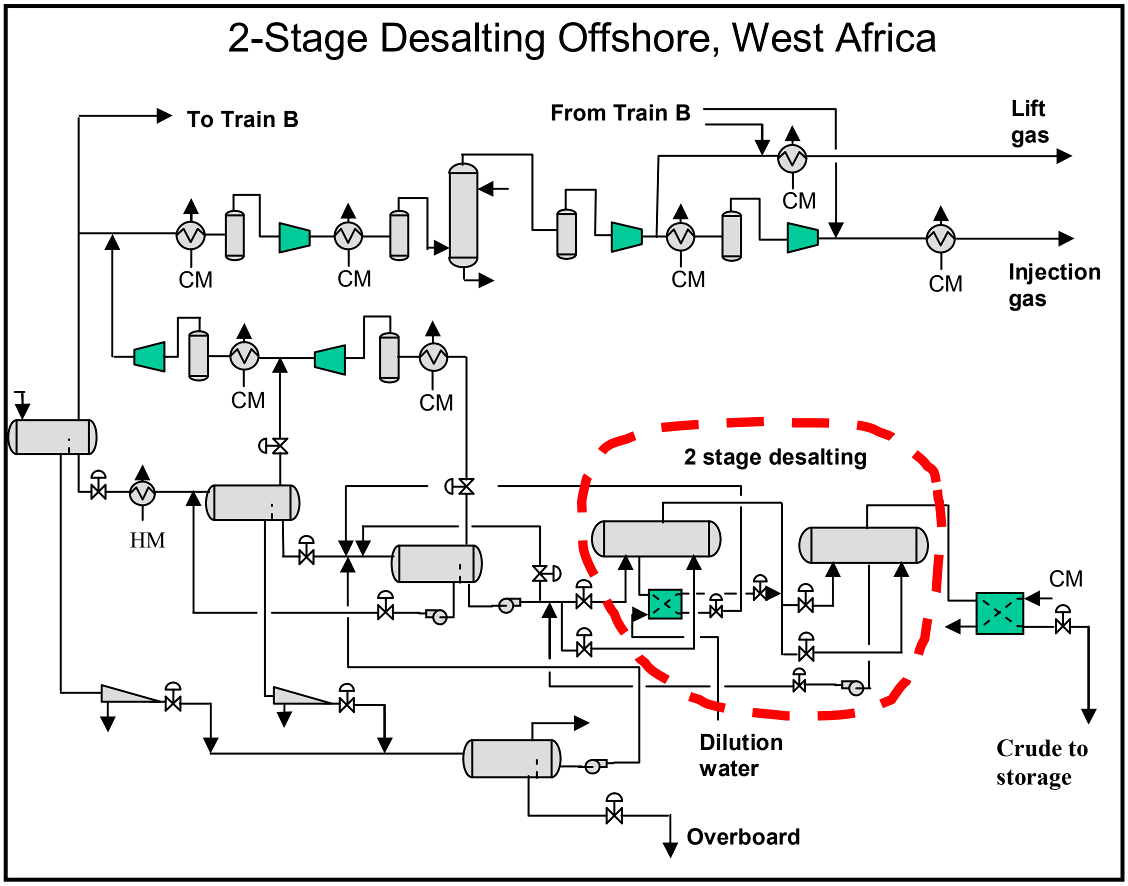

Figure 11.

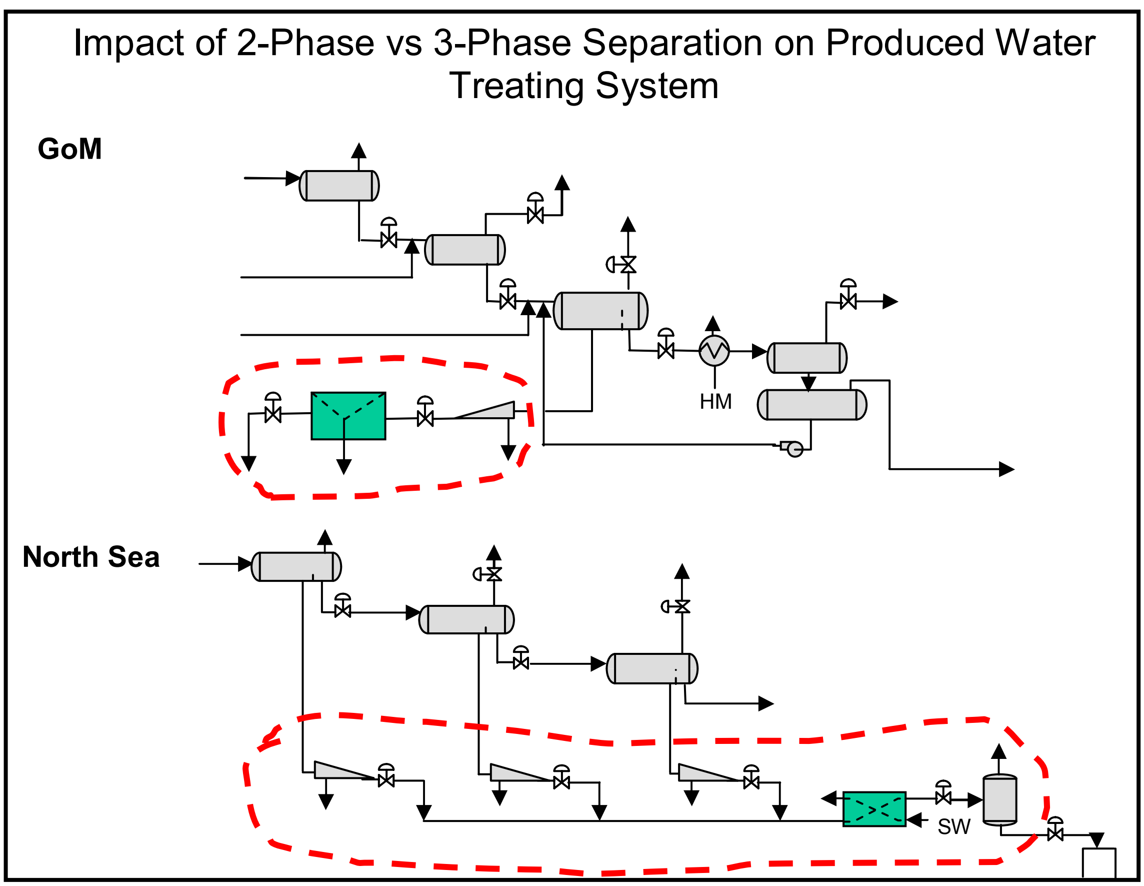

Figure 12.

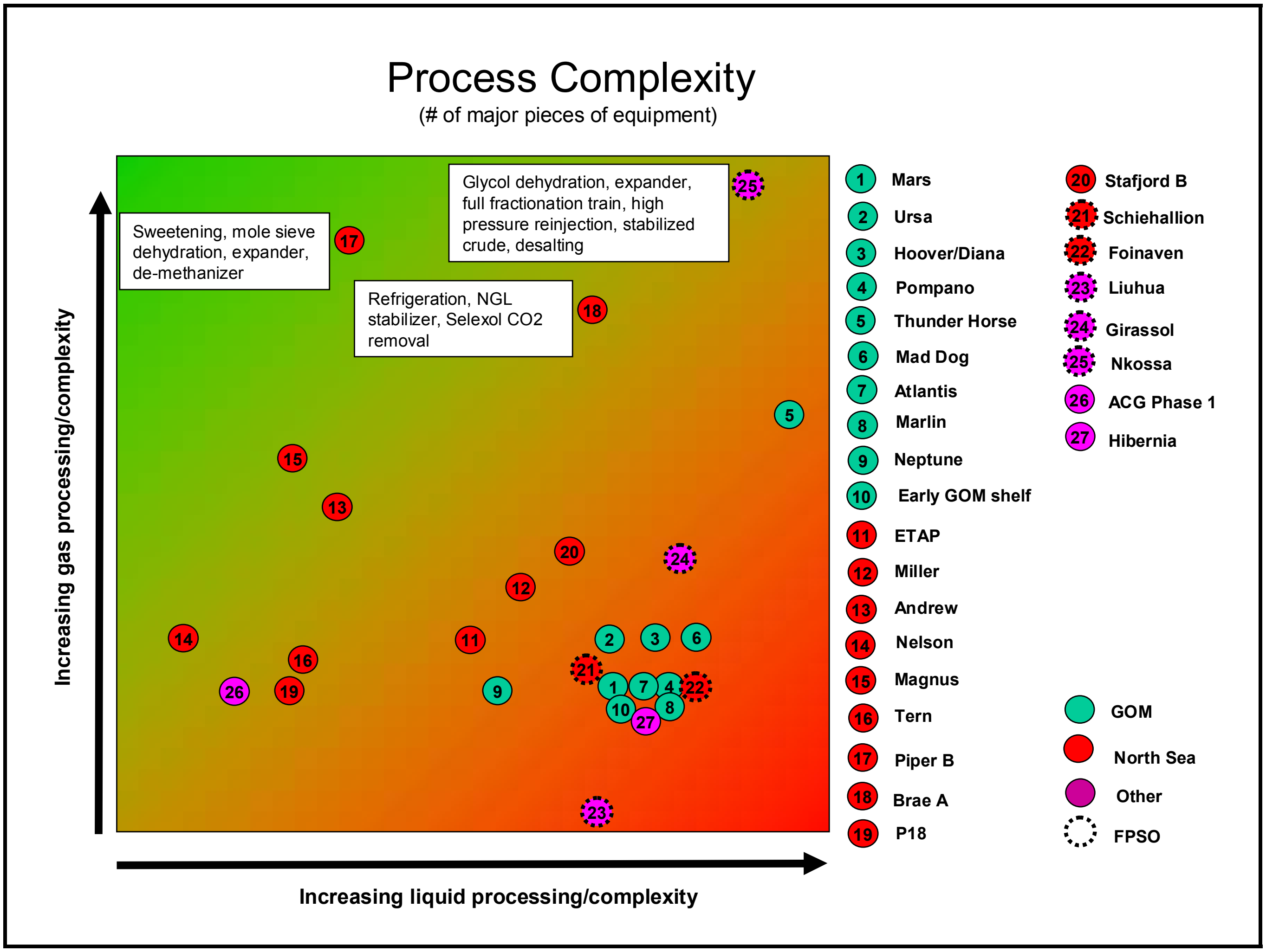
Process Complexity
(# of major pieces of equipment)
Sweetening, mole sieve dehydration, expander, de-methanizer
Glycol dehydration, expander, full fractionation train, high pressure reinjection, stabilized crude, desalting
Refrigeration, NGL stabilizer, Selexol CO2 removal
Increasing gas processing/complexity
Increasing liquid processing/complexity
1 Mars
2 Ursa
3 Hoover/Diana
4 Pompano
5 Thunder Horse
6 Mad Dog
7 Atlantis
8 Marlin
9 Neptune
10 Early GOM shelf
11 ETAP
12 Miller
13 Andrew
14 Nelson
15 Magnus
16 Tern
17 Piper B
18 Brae A
19 P18
20 Stafjord B
21 Schiehallion
22 Foinaven
23 Liuhua
24 Girassol
25 Nkossa
26 ACG Phase 1
27 Hibernia
GOM
North Sea
Other
FPSO

Figure 13.

NOTES: