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A Report to

MMS

for

Enhanced Recovery Study

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1 Executive Summary

The Minerals Management Service (MMS) contracted Knowledge Reservoir LLC (Knowledge Reservoir) to perform a study on enhanced recovery in the U.S. Outer Continental Shelf (OCS). The objective of this study is to determine the benefits of subsea processing equipment and systems to improve hydrocarbon recovery in the OCS.

The subsea technologies documented in this report include:

- Seafloor pressure boosting
- Seafloor separation
- Seafloor compression
- Artificial lift in subsea wells

To date, gas compression equipment has not been installed on the seafloor, so discussions on this technology will be limited to ongoing testing by Statoil. The majority of the discussion is focused on subsea pumps, for which selection criteria is related to differential pressure and gas handling capabilities. Subsea separation is considered a supplemental process to remove water or gas from the flowstream as required, to meet pump criteria for efficient operation.

Many technical papers and industry publications were found on the subject of subsea processing, but the information presented in this report is largely based upon the “2010 Worldwide Survey of Subsea Processing” (2010 survey), prepared by representatives of INTECSEA, BHP Billiton, and Offshore Magazine, and supported by Aker Solutions, FMC Technologies, Baker-Hughes, Framo Engineering, Schlumberger, Cameron, and Technip. A copy of the 2010 survey is included in Appendix A.

The primary benefits of subsea processing are enhanced economics associated with increased oil and gas production (rates and ultimate recoveries) and cost reduction associated with reduced topside facilities.

The key element to increasing production rate and ultimate recovery is increasing pressure drawdown of the reservoir by reducing the back pressure imposed by the production system (wellbore, flowlines, manifolds, risers, etc). Reducing back pressure on the reservoir is accomplished through:

- Artificial lift in wells
- Pressure boosting using pumps (on seafloor and in wells)
- Pressure boosting using compressors
- Reducing hydrostatic pressures (in tubing and risers)
- Reducing frictional pressure losses in tubing, flowlines, risers
- Reducing surface operating pressures

Reducing back pressure becomes increasingly more challenging in deepwater developments, where hydrostatic pressures and frictional pressure losses are inherently greater. The entire production system (from reservoir to topside) should be analyzed using a fully integrated production modeling software to ensure that the most reliable and efficient subsea boosting technology is applied.

Subsea pump technology includes centrifugal, twin-screw, helico-axial, and electrical submersible pumps (ESP). Historical run times for these types of pumps are shown in Figure 1. Subsea runtimes are in excess of 2 years for all of these pumps, with the exception of twin-screw pumps which have had short run lives of approximately 1 year. The primary criteria for subsea pump selection are related to differential pressure and gas handling capabilities.

Helico-axial pumps have performed exceedingly well with run times of 2-10 years. ESP technology has advanced in recent years, with installations in subsea risers and in seafloor caisson separators, as well as in subsea wells. ESPs have demonstrated reliable performance in deeper waters (2-4 year run times). The centrifugal pump in the Lufeng field (South China Sea) has been running the longest, and its outstanding performance is due to the low gas volume fraction (GVF) of the Lufeng flowstream (2%) and a low differential pressure requirement (relatively shallow water depth and short tie-back distance). Centrifugal pumps have a low gas tolerance of less than 15%.

Figure 2 summarizes historical pump performance according to differential pressure and GVF capabilities, and indicates superior performance with ESPs at high differential pressures (~2000 psi) and GVFs up to 40%. Helico-axial pumps performed well at higher GVFs (75%), but at lower differential pressures (650 psi). As previously discussed, centrifugal pumps have low GVF tolerance, and twin-screw pumps have poor run-time performance.

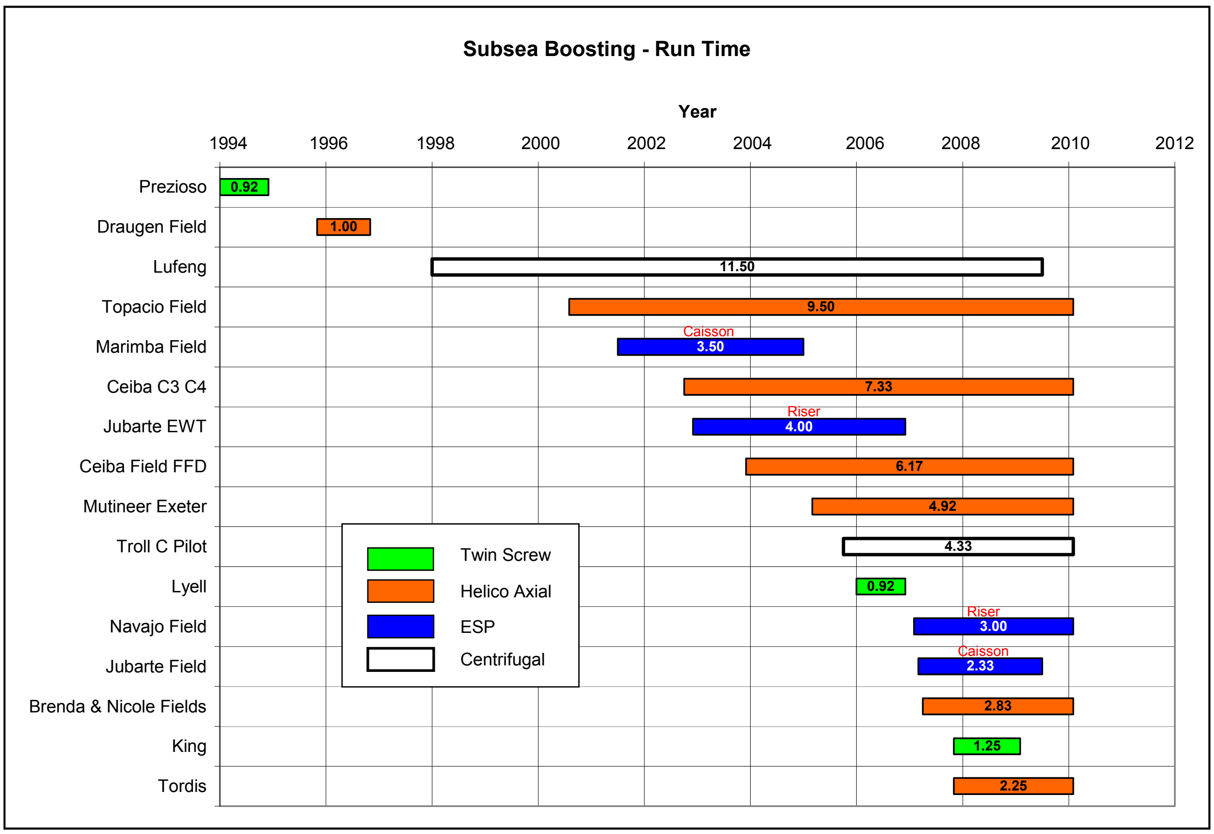


Figure 1: Subsea pumping project, runtimes

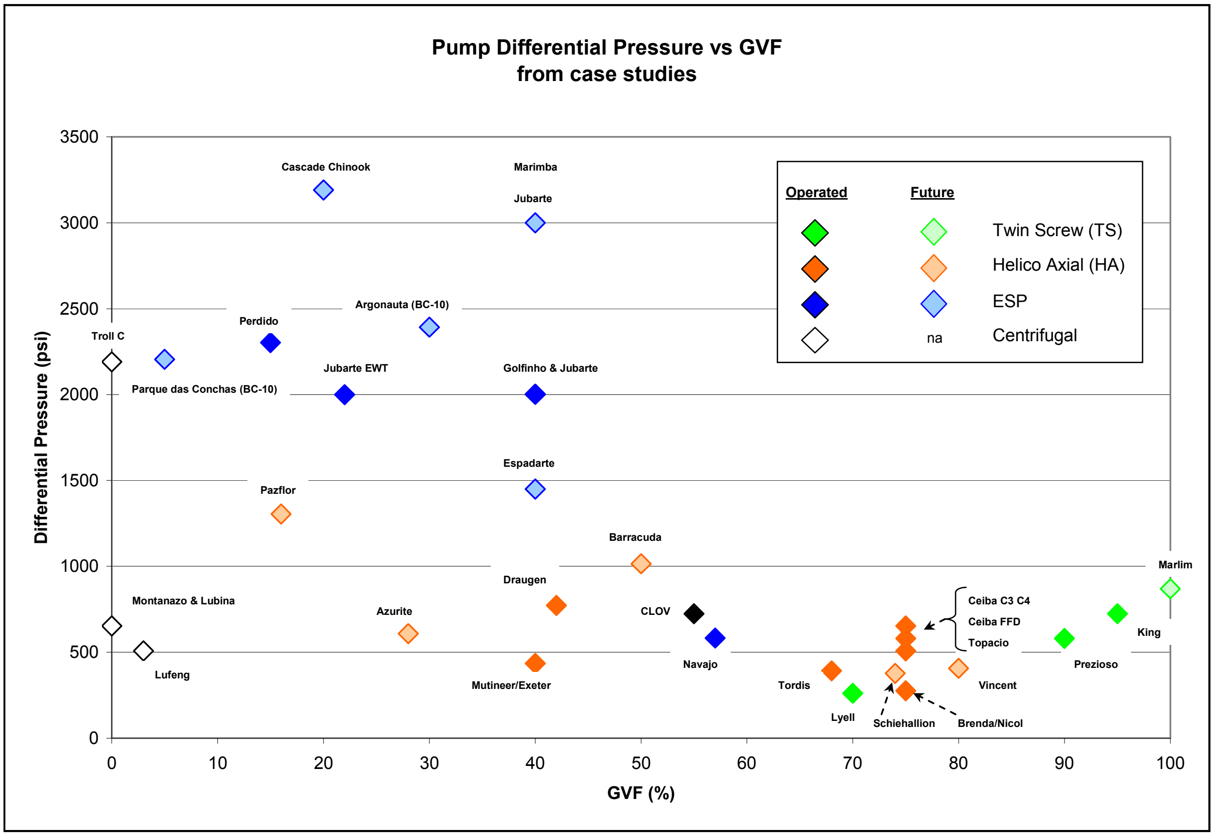


Figure 2: Subsea pumping projects, differential pressure and GVF capabilities

Seafloor separation technology has been installed in seven projects, of which two are still active (Troll-C and Perdido). The separation technology used includes seafloor horizontal oil-water separator (Troll-C and Tordis) and seafloor gas-liquid caisson separators (Marimba, Jubarte, Perdido). Good results have been achieved with seafloor caisson separators and seafloor horizontal separators (Troll-C and Tordis), and these technologies are suitable for Gulf of Mexico (GOM) applications.

Artificial lift in subsea wells has been implemented in shallow offshore waters where gas for gas-lift has been available, and in fewer cases, where power has been available for ESP installations. Gas lift is the predominant artificial lift method used in the offshore environment to date; however, as operators progressively move into deeper water, gas lift applications become more limited (operating pressures are higher) and ESPs become more suitable.

Data provided to Knowledge Reservoir by the MMS indicates that five wells have ESP installations in deep water (>1,000 ft). ESP run time data was not available for these wells, so a performance assessment could not be made; however, PIPESIM® models indicate more efficient lifting of fluids using ESPs in deepwater.

As previously mentioned, separation is a supplemental process to allow for efficient operation of pumps (and compressors). Subsea separators enable pumps to operate more efficiently by decreasing the differential pressure requirement (reducing hydrostatic head by removing more dense water) and lowering the GVF of the flowstream.

To date, five subsea separation projects have been implemented, and include two, three-phase horizontal separators and three gas-liquid seabed caisson separators, previously mentioned in the ESP boosting discussions of this report. Table 1 summarizes the five implemented projects.

Table 1: Subsea separation projects

Subsea Separation					
Field/Project	Location	Separation Method	Start Date	Runtime (months)	Current Status
Troll-C Pilot	Norway	3-Phase Horiz	Sep-99	124.8	Operational
Marimba	Brazil	Gas - Liquid Seabed Caisson	Jul-01	83.8	Non-Operational
Jubarte	Brazil	Gas - Liquid Seabed Caisson	Mar-07	27.5	Non-Operational
Tordis	Norway	3-Phase Horiz	Nov-07	1.0	Non-Operational*
Perdido	GOM	Gas - Liquid Seabed Caisson	Mar-10	1	Operational

* unable to inject water into reservoir, therefore separation not needed; currently operating as a boosting operation only.

While gas compression equipment has yet to be placed into subsea operation, extensive testing of compression equipment is ongoing in association with the Ormen Lange development (Norwegian North Sea). After the testing is complete, Statoil, the operator, will make the decision to install compression equipment on the seafloor or on a platform.

The economics required to justify the installation of subsea processing equipment are incremental economics, which capture the additional value above the value of a producing asset without subsea processing equipment. The major components of these incremental economics include incremental oil and gas volumes (rates and ultimate recoveries), and the additional cost to install and operate the processing equipment (CAPEX and OPEX).

While the objective of both Greenfield and Brownfield developments is to increase producing rates and ultimate recoveries, the economics of Greenfield developments may be more attractive with the initial placement of processing equipment on the seafloor, rather than on a surface platform. The installation of subsea processing equipment for Brownfield projects may be more costly and less economically attractive, as: 1) installation costs into an existing system may require significant modifications to accommodate the subsea processing equipment, and 2) incremental production is typically lower.

As with other oil and gas operations, the key elements of risk with subsea processing are associated with higher costs and less production than anticipated when developing the economics to justify a project. Oil and gas production deficiencies result in lower revenues, and when combined with excessive costs, result in poorer than expected economics.

In a post-project implementation study of twenty-five Gulf of Mexico fields, Knowledge Reservoir found that eighteen fields (72%) had less reserves and peak production rates than pre-development estimations. Excessive costs include both CAPEX and OPEX associated with the inherent unpredictability of the offshore environment, particularly in deep water (installation, operation, intervention, and environmental remediation costs).

The level of risk in subsea processing is a function of the proven reliability of a particular technology; i.e., how ready is the technology for use in a particular environment. Actual pump run times are an indication of technology readiness, and indicate that the following subsea pumps have the highest level of readiness:

- Centrifugal at Lufeng and Troll-C conditions (no gas production)
- Helico-axial at Topacio, Ceiba, Mutineer/Exeter, Brenda/Nicol conditions
- ESP in Riserat Jubarte and Navajo conditions
- ESP in Seafloor Caisson at Jubarte and Marimba conditions

Subsea horizontal oil-water SSBI (subsea separation, boosting and injection) system might also be ranked at a high level of readiness based on the performance of the separator at Troll-C; however, the failed water injection component of a similar system installed at Tordis should be evaluated to better understand the risk associated with this system.

Subsea vertical separators and compressors are ranked at lower levels because these technologies are currently in the testing stages, and have not been proved in actual commercial conditions.

Subsea boosting and separation projects are continuing at a fairly rapid rate, with seven projects recently installed (pending start-up) and seven projects in the manufacturing stage. These projects are as follows:

- Installed (pending start-up)
  - Vincent: Dual helico-axial pumps
  - Marlim: Twin-screw pump
  - Golfinho: Caissons with ESPs
  - Azurite: Dual helico-axial pumps
  - Parque das Conchas: Caissons with ESPs
  - Schiehallion: Dual helico-axial pumps
  - Marimba: Caisson with ESP
- Manufacturing stage
  - Espadarte: Horizontal ESPs on skid
  - Jubarte: Caissons with ESPs
  - Cascade/Chinook: Horizontal ESPs on skid
  - Barracuda: Helico-axial pump
  - Montanazo/Lubina: Centrifugal pump
  - Pazflor: Vertical separators + hybrid helico-axial pumps
  - Marlim: In-line separation

Future challenges in subsea processing technology are primarily associated with operating in deeper water and with longer tie-backs to host facilities, and involve hydrate management and power.

2 Introduction

Since 1994, there have been twenty-seven reported subsea processing installations (seafloor pressure boosting with and without separation), of which ten are currently active. Five of the twenty-seven installations include separation equipment. An additional eight subsea processing projects are currently in the manufacturing stage.

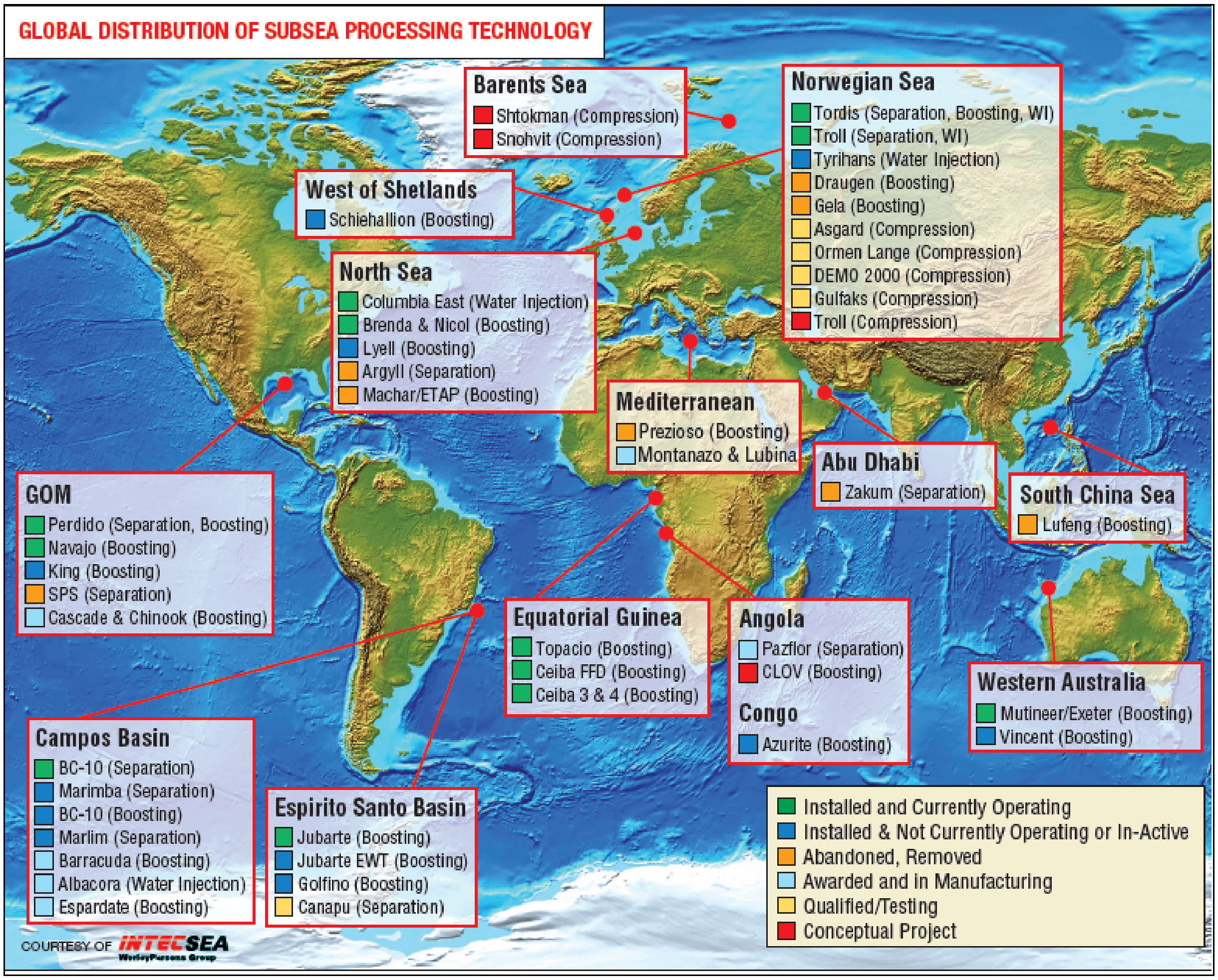


Figure 3: Global distribution of subsea processing technology

The testing of subsea processing equipment began in the 1960s and 1970s, leading to several commercial installations during the 1980s and 1990s. In the late 1990s and 2000s, as operators began exploring in deeper waters, subsea processing became more necessary for the development of these deepwater discoveries. Table 2 summarizes subsea processing “firsts”.

Table 2: Subsea processing "firsts"

Year	Operator	Water Depth (feet)	Comment
1968	Exxon	2001	1st subsea processing work; Submerged Production System (SPS) consisting of a manifold controlling 3-wells
1970	BP	72	1st subsea separation trial, Abu Dhabi, Zakum Field
1982	Exxon		1st commercial application of SPS in North Sea
1988	Texaco	550	1st subsea slug catcher, Highlander Field, North Sea
1992	Statoil & TOTAL		1st subsea helico-axial multiphase pump (MPP), Tunisia, Poseidon Project
1994	AGIP	164	1st subsea electrical twin-screw MPP in a live well, Italy, Prezioso Field
1998	Petrobras	3838	1st ESP in a subsea well, Brazil, Campos Basin, E. Albacora Field
2000	Petrobras	1296	1st ESP in a seafloor caisson separator, Brazil, Marimba Field
2001	Statoil	1116	1st pilot subsea separation/boosting/injection system (SSBI), Norwegian North Sea, Troll-C
2006	CNR	479	1st subsea twin-screw pump installed in North Sea, Lyell Field
2007	BP	5578	1st subsea MPP twin-screw pump installed in GOM, King Field
2007	CNR	476	1st subsea raw seawater injection, North Sea, Columba Field
2007	Statoil	656	1st commercial SSBI, Norwegian North Sea, Tordis
2007	Anadarko	3642	1st ESP in a GOM subsea riser, Navajo Field

In most cases, in the OCS, oil and gas processing (separation, pumping, and compression) has been performed using topside equipment. With the continuing exploration and discovery of oil and gas fields in deeper waters, operators and subsea equipment manufacturers are developing technologies to economically develop these resources. These technologies will not only enable the development of deep water discoveries, but will also increase hydrocarbon production rates and ultimate recoveries from existing Brownfield projects.

The ability to separate and transport produced fluids on the seafloor, via subsea pumps, compressors, and separate flowlines and risers, allows deep water fields to be developed economically. Seafloor processing enables subsea wells to be produced at higher rates and water cuts and to lower abandonment pressures, which results in greater ultimate recovery and the acceleration of reserves.

The placement of processing equipment on the seafloor reduces of the need for topside equipment and deck space, and protects processing equipment from hurricanes. The reduction of topside equipment significantly reduces the CAPEX required to develop deepwater discoveries, including satellite fields that would otherwise be uneconomic.

Deepwater and satellite fields inherently have a greater distance to move produced fluids to surface host facilities (onshore and offshore), and require longer tie-backs (flowlines, pipelines and risers). Greater frictional pressure losses and hydrostatic pressures cause higher back-pressure on subsea wells, limiting production rates and ultimate recoveries. In deep water, the hydrostatic pressure of the fluid column is often five to ten times greater than the friction loss in horizontal pipes (OTC - 20186).

3 Reservoir Engineering Considerations

While gas cap and over-pressured effects may contribute to recovery efficiencies in deep water Gulf of Mexico reservoirs, the largest contribution to recovery efficiency is from water drive and solution gas drive mechanisms, or a combination thereof. As such, these two drive mechanisms are the focus of the reservoir engineering discussions in this report. Figure 4 graphically presents production flowstream characteristics of solution gas drive and water drive reservoirs. Pump design should take into consideration changes in flowrate, pressure, water cut, and gas-oil ratio (GOR) as a reservoir is produced.

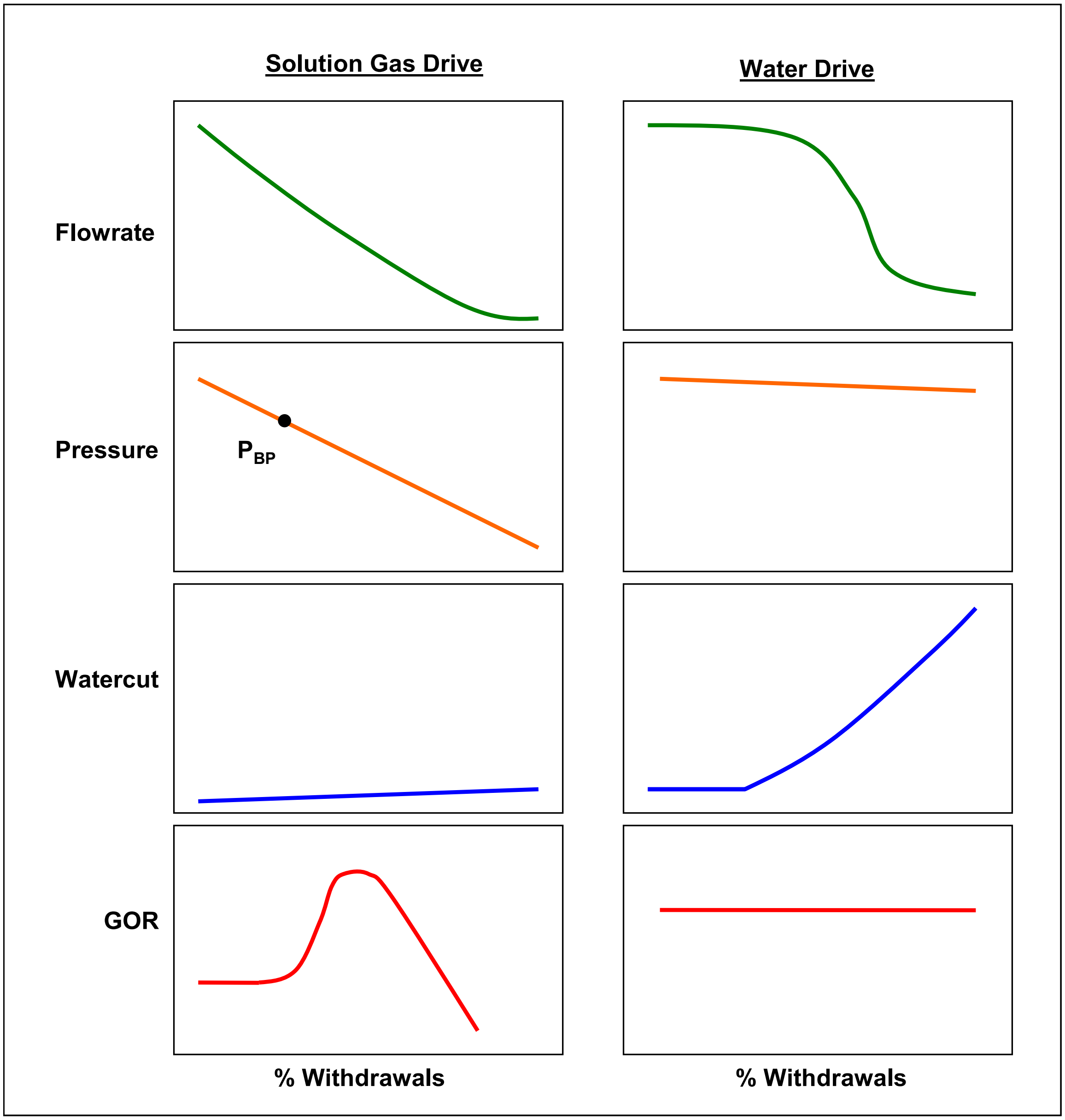


Figure 4: Flowstream characteristics by reservoir drive mechanism

3.1 *Solution Gas Drive*

Solution gas drive reservoirs are characterized by constant declines in reservoir pressure and producing rates, as fluids are withdrawn from the reservoir. As pressure decreases, the gas in solution expands, increasing the total volume of oil. This expansion is the driving force behind a solution gas drive reservoir; however, as pressure declines further to the bubble point pressure, gas is liberated (free gas forms) and the total oil volume begins to decrease. When the gas is fully liberated, the drive energy of the reservoir is significantly diminished. The amount of gas that is liberated as the pressure decreases is a function of the solution GOR.

As seen in actual measurements of oil formation volume factor, Bo (relative volume of oil at reservoir conditions to that at 60° F, 14.7 psi), the crude oil depicted in Figure 5 expands as the pressure decreases, until it reaches the bubble point pressure, at which point the total volume begins to decrease.

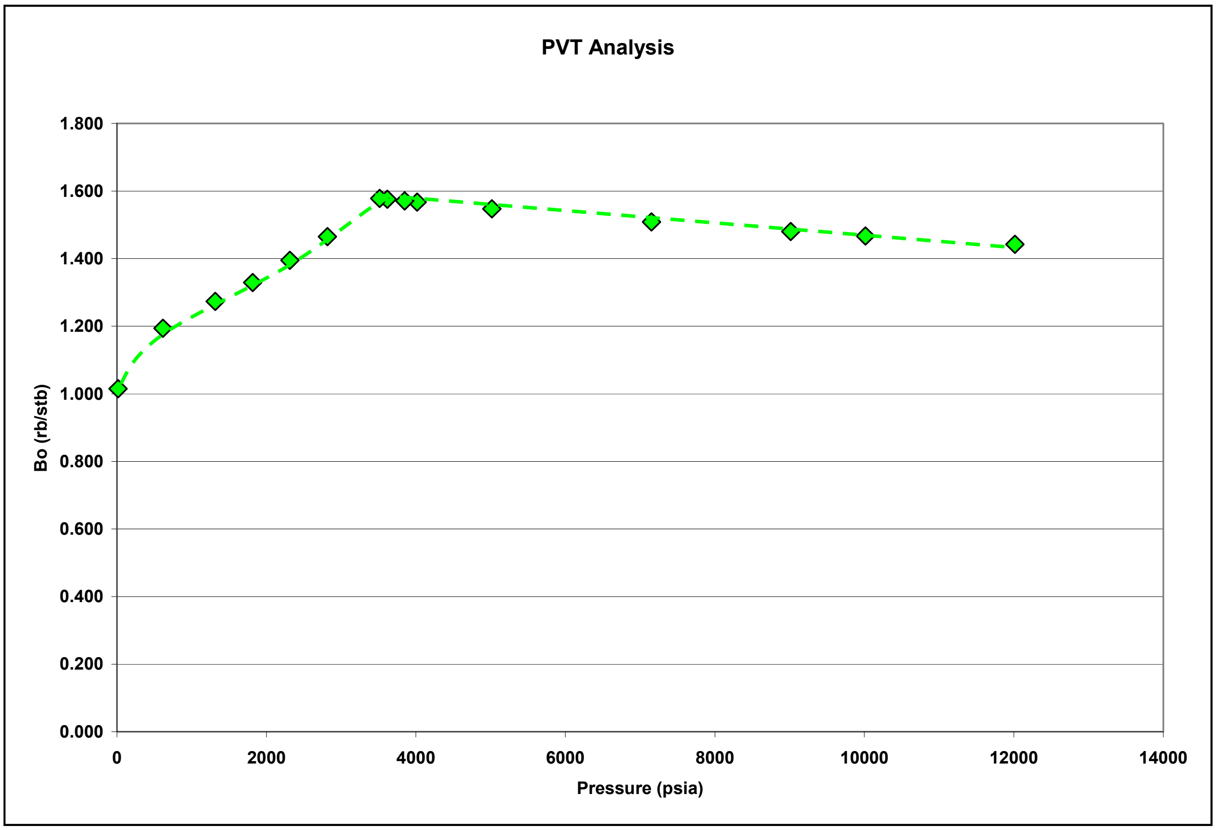


Figure 5: Oil formation volume factor as a function of pressure

Free gas in a production system causes slugging in wellbore tubulars, pipelines, and risers, and vapor locking of pumps that are unable to handle high GVF flowstreams. For this reason it is important to consider the PVT parameters of the oil (bubble point pressure, solution gas-oil ratio, and oil formation volume factor) and the anticipated pressures throughout a production system to understand where and when free gas may be present in the system so that the appropriate subsea technologies can be applied.

3.2 *Water Drive*

Water drive reservoirs are characterized by little or no change in reservoir pressure as fluids are withdrawn from the reservoir. This is due to the encroachment of an expanding aquifer. As the aquifer encroaches, the water cut of the produced flowstream increases.

While frictional pressure drop decreases in a higher water-cut flowstream, the hydrostatic pressure (in wellbore tubulars and subsea risers) increases significantly and should be anticipated in the design of subsea pumping systems.

Figure 6 is a plot of hydrostatic pressure vs. water cut, assuming 30° API oil and saltwater, at true vertical depth of 13,000 ft. The plot indicates an increase in hydrostatic pressure on the reservoir of almost 600 psi when the water cut increases from 0% to 70%.

A 600 psi increase in back pressure on a reservoir may seem insignificant; however, when considered in a deepwater environment where topside landing pressures are on the order of 200 psi, sufficient pressure may not be available to support production to the topside facilities at higher water cuts.

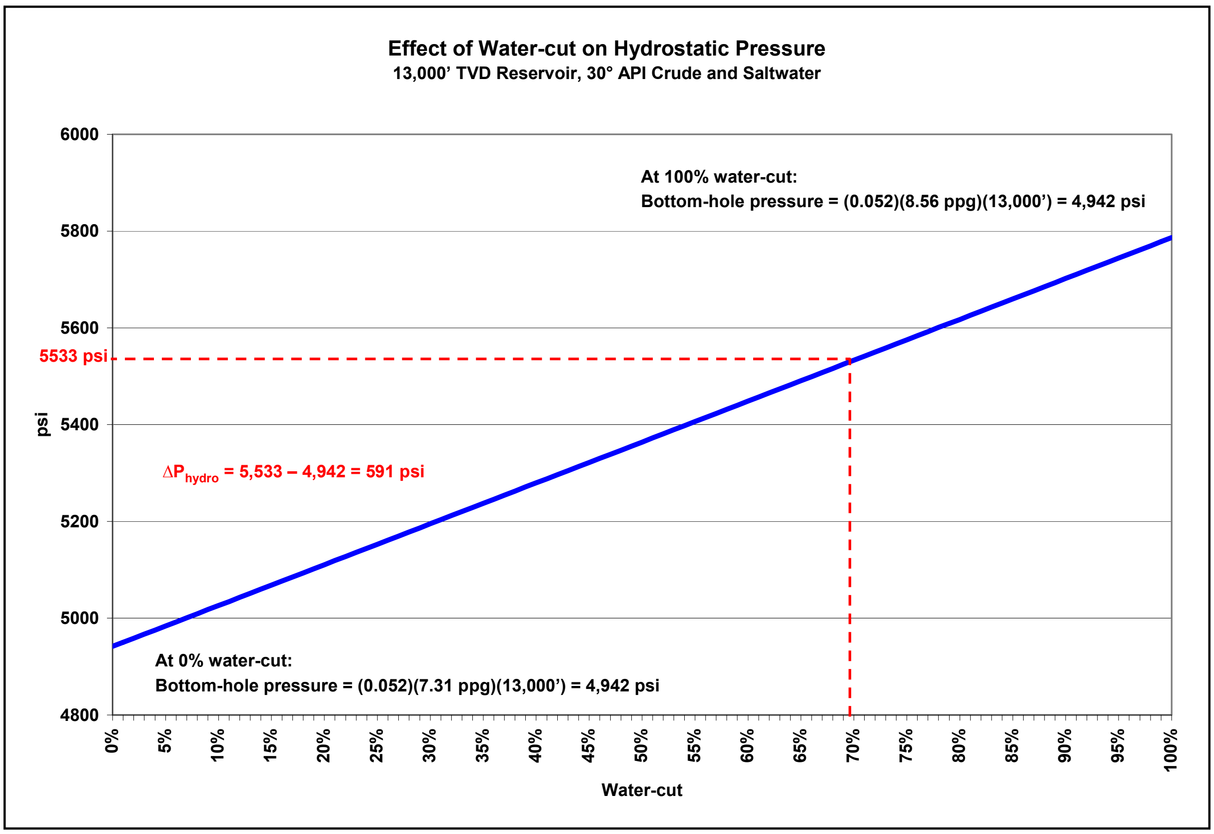


Figure 6: Effect of water cut on hydrostatic pressure

3.3 *Incremental Recovery*

Incremental oil recovery estimates for subsea processing are based upon a combination of increased production from increasing the drawdown of the reservoir (reducing back pressure), and minimum economic producing rates (economic limit).

Incremental recoveries should be estimated using a fully integrated production modeling software, which models rates and pressures throughout the production system from the reservoir to the sales point; however, rate and pressure extrapolations may also be used to complement the use of computer methods.

Petroleum Experts sells a suite of integrated production modeling (IPM) tools that can be used to estimate production rates and recovery, with and without artificial lift (i.e. gas lift, ESPs, etc). The most applicable programs for estimating incremental rate and recovery for artificial lift are the following:

- Prosper (nodal analysis package for modeling well performance: inflow and outflow)
- MBAL (material balance tool for modeling dynamic reservoir performance)
- GAP (multiphase oil and gas optimizer that models surface gathering networks, which can link MBAL models of individual reservoirs with Prosper models for well performance to achieve a fully integrated approach to system modeling)
- RESOLVE (allows integration of Prosper, GAP, and/or MBAL with commercial reservoir simulators to achieve the highest level of integrated system modeling)

At a minimum, Prosper can be used to predict the abandonment pressure of the reservoir, with and without artificial lift (subsea processing equipment and/or gas-lift). Then, either a material balance model (either MBAL or Excel based) or a correlation for recovery factor vs. abandonment pressure can be used to calculate recovery. Prosper will also calculate inflow/outflow curves for the well and tubing/flowline system to allow estimation of production rates (again with and without artificial lift). GAP is useful in combining MBAL and Prosper models to model a network of wells/flowlines (e.g. multiple well centers connect via a common flowline back to the host facility). Resolve is the most robust, and most expensive option but offers flexibility to integrate multiple simulation models into the well and flowline system.

Another approach to estimating production and recovery with and without subsea processing equipment (pumps and/or gas-lift) is to model the well performance in Prosper and export tubing tables that can be used within a reservoir simulator to generate flowstreams. The tubing tables relate flowing-bottom-hole pressure to separator inlet pressure for various flow rates, water cuts, GORs, amount of gas-lift-gas injected, etc.; of course, this method requires a simulation model of the reservoir being studied.

A Prosper model can be constructed using a limited amount of data that should be readily available for any field. Below is a brief overview of the data that is required to build a Prosper model:

- PVT data: Oil gravity, gas gravity, solution GOR, water salinity
- Wellbore trajectory (MD vs. TVD)
- Geothermal gradient (at a minimum: surface, mudline and reservoir temperatures)
- Well tubing/case information (tubing and casing size vs. MD, can include downhole flow restrictions)

- Flowline information, if modeling flowlines/risers (length vs. TVD, internal diameter, etc.)
- Reservoir pressure and separator inlet pressure
- Reservoir productivity index (PI=stb/psi/day) or enough reservoir parameters such that Prosper can calculate the inflow curve
  - Reservoir thickness, permeability, wellbore radius, drainage area, skin, etc.
- Gas-lift injection depth and gas-lift gas-injection rate (if modeling gas-lift)
- ESP (pump) location and expected flow rates for use with Prosper's ESP design module to help select an appropriate ESP (if modeling ESPs)

Once the basic Prosper model is constructed, one can quickly add an ESP or gas-lift and see the impact on production rates and abandonment pressure. Sensitivity analysis can also be performed to see the impact of GOR, water cut, reservoir pressure, separator inlet pressure, skin, etc. on production rates and abandonment pressure.

The extrapolation to an abandonment pressure, of flowing tubing pressure vs. cumulative oil production plot, is typically used to estimate incremental oil recoveries. Figure 7 is an example extrapolation, performed by Anadarko, for a well in their GOM Navajo field. The abandonment pressure is the pressure at which the well can longer produce to the production system, and is estimated using production modeling software.

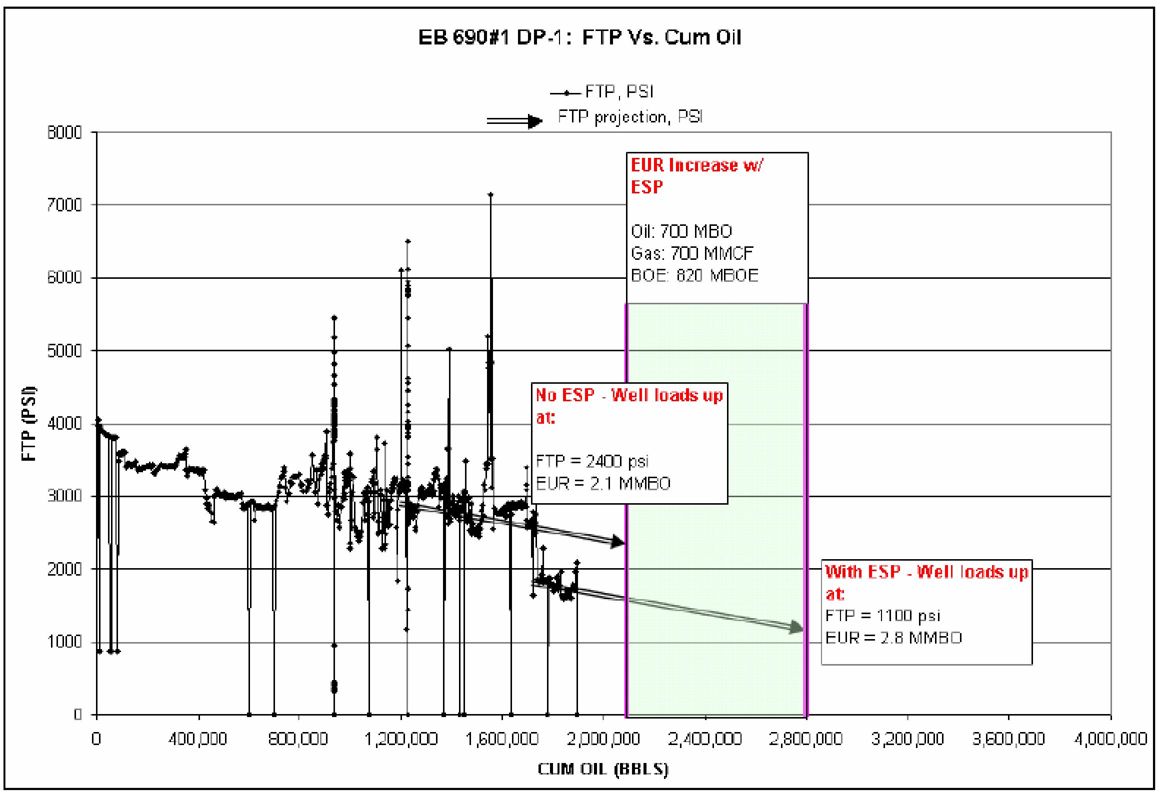


Figure 7: Example of estimating incremental oil recovery using FTP vs. cumulative oil production (Navajo field)

Incremental oil recovery may also be estimated using rate vs. time decline curve analysis, where a production rate curve is extrapolated in time to an economic limit (Figure 8). The economic limit is calculated based upon a breakeven point, where the operator's operating costs are equal to the net revenue.

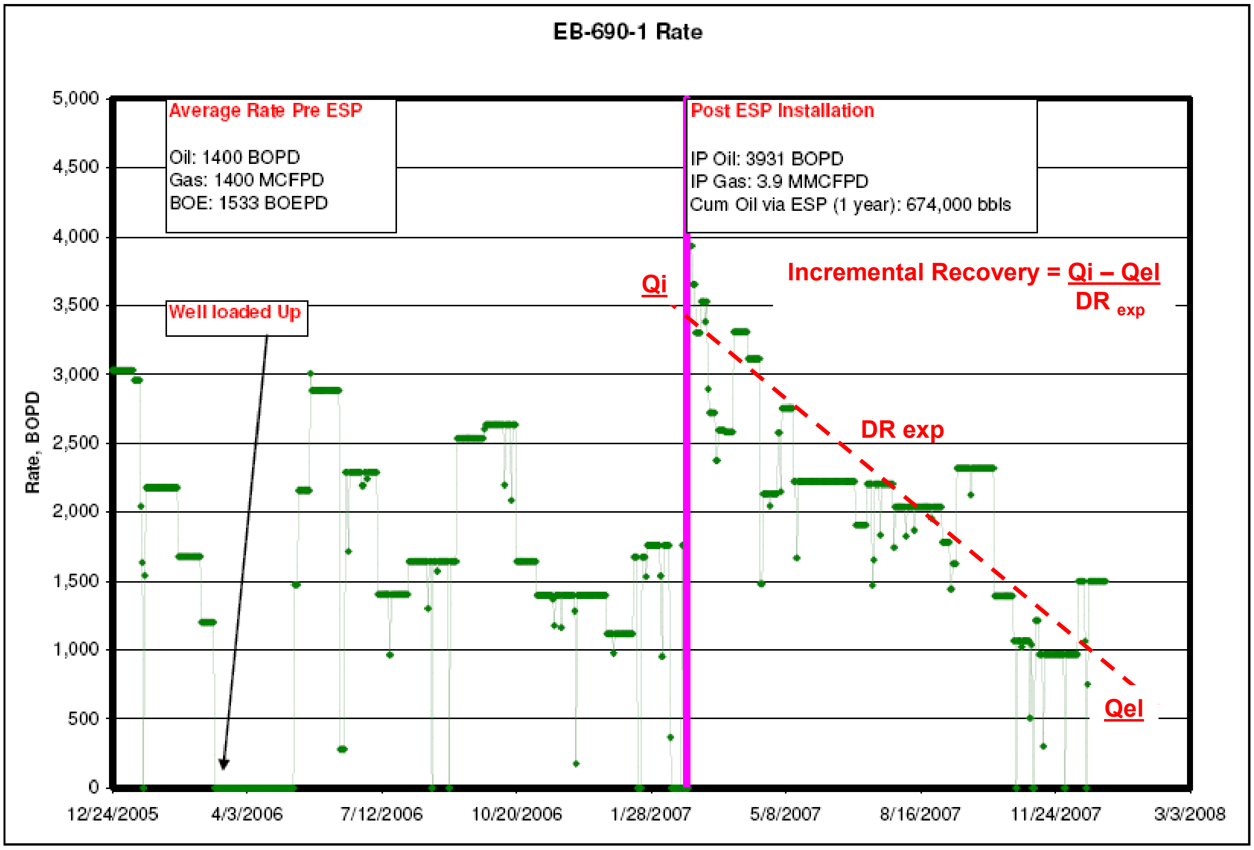


Figure 8: Estimating incremental oil production using oil rate vs. time decline curve analysis

In both of the aforementioned methods, the estimator should take care in estimating the slope of the extrapolated curve, as it may differ from the pre-installation slope due to more rapid drawdown of pressure and production rate decline resulting from the installation.

Still another method to estimate oil recovery is the extrapolation of a water cut vs. cumulative oil production plot, in which a water cut vs. cumulative oil production curve is extrapolated to a maximum economic water cut. This method is useful when water handling costs make up a significant portion of the total operating expense (Figure 9).

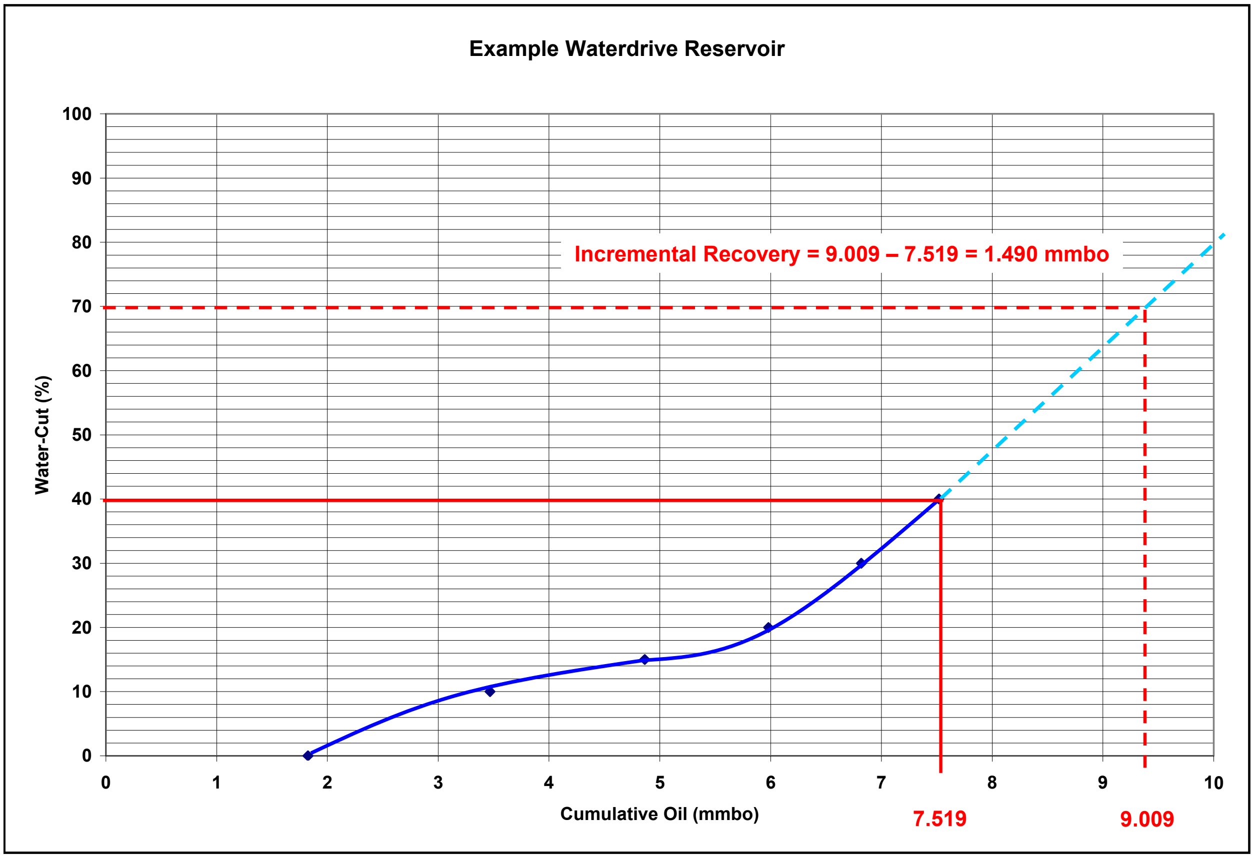


Figure 9: Estimating incremental oil production using water cut vs. cumulative oil production

4 Production Engineering Considerations

Inflow and outflow curves outline the basic components of the producing system (reservoir, wellbore, and surface flow-control equipment), and show the interrelated nature of these components from the perspective of the production engineer. The inflow and outflow curves capture conditions at a single point in time.

Figure 10 shows a generic reservoir inflow curve (orange), depicting bottom-hole pressure and rate from a shut-in condition at Point A to a theoretical maximum flow rate condition at Point B. This maximum flowrate is referred to as the absolute open flow potential (AOF, AOFP), and is the theoretical maximum flowrate, at the perforations, when the reservoir pressure is drawn down to zero.

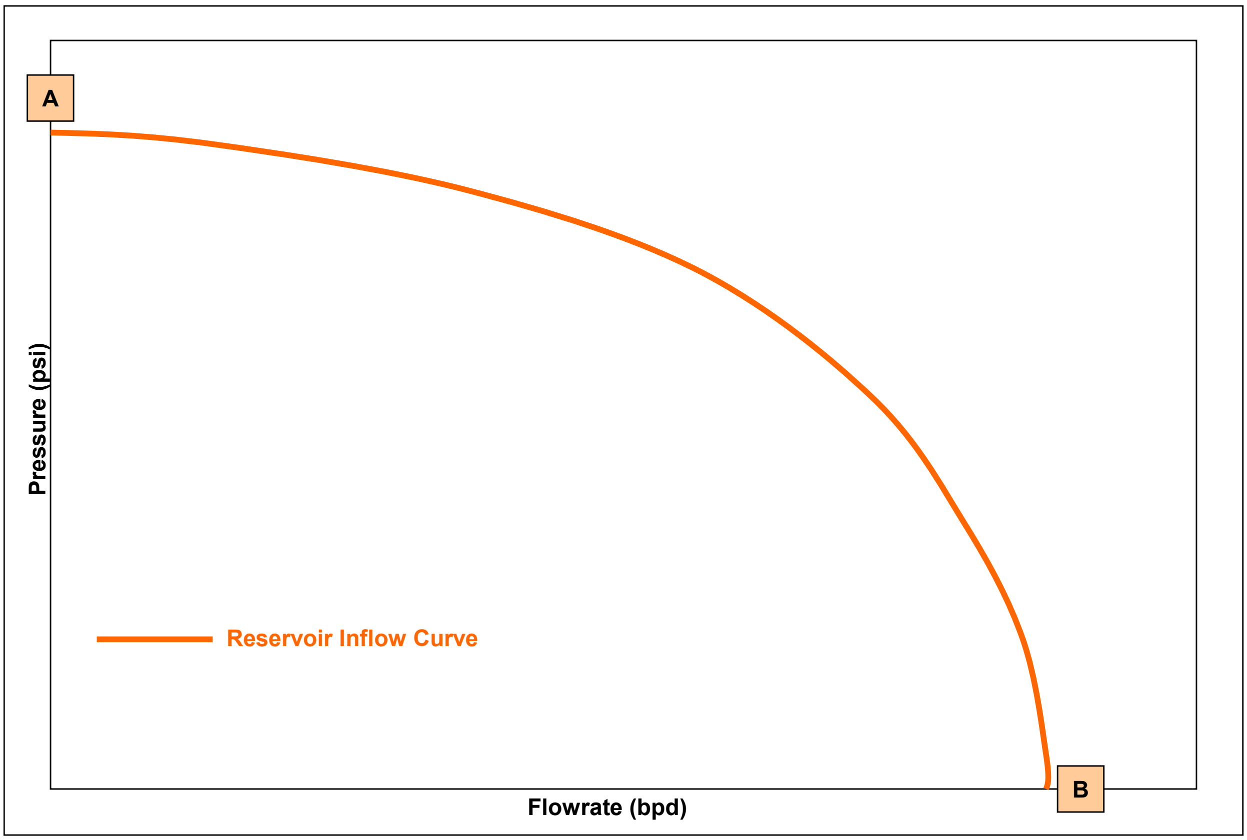


Figure 10: Reservoir inflow curve

Limiting this theoretical performance are components of back pressure on flow at the perforations due to hydrostatic pressures and frictional pressure losses in the production system (wellbore, flowlines, manifolds, risers, etc). These components are accounted for by superimposing a system outflow curve on the reservoir inflow curve, as shown in Figure 11. Point A’, on the system outflow curve represents a shut-in condition consisting of hydrostatic pressure and surface pressure (if any). Point B’ is the operating point, representing the maximum flowrate achievable in given production system. Note that the region to the left of the minimum pressure value on the system outflow curve is dominated by hydrostatic pressure resistance to flow, while the region to the right of minimum pressure value is characterized by friction pressure resistance.

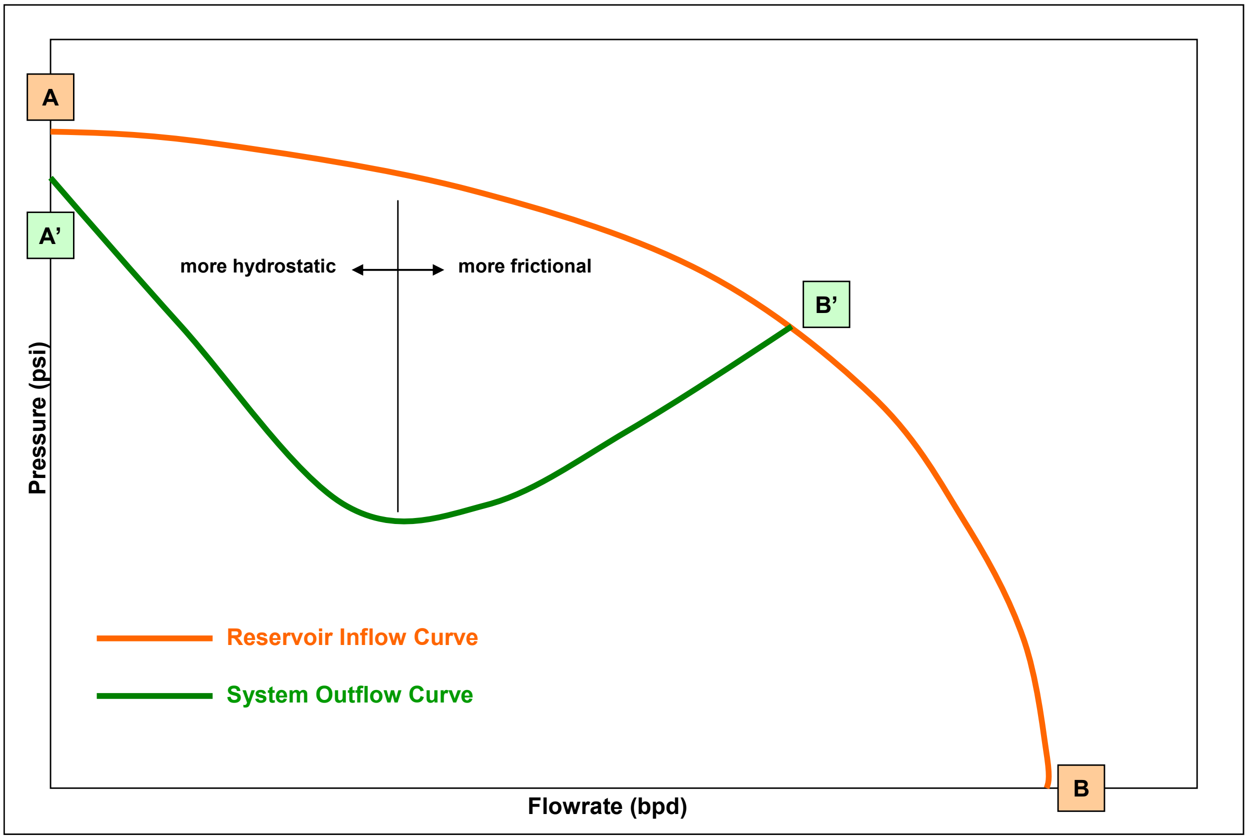


Figure 11: Reservoir inflow and system outflow curves

By adding artificial lift and/or pressure boosting to a subsea production system, back pressure is decreased (represented by a pressure decrease on the outflow curve), and flow rate is increased (Figure 12).

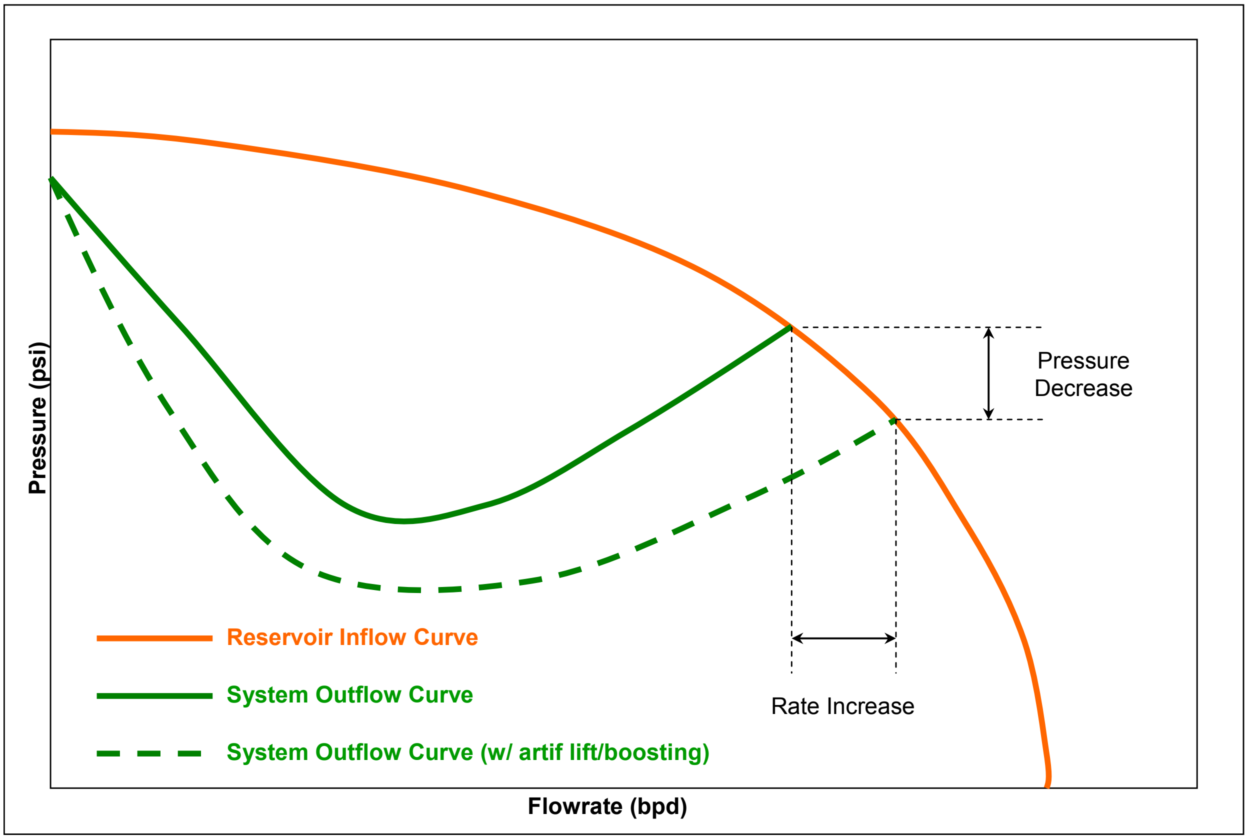


Figure 12: Reservoir inflow and system outflow curves with artificial lift and/or boosting

The above examples capture the reservoir at single point in time; however, the inflow and outflow curves change with time and this should be considered in the design of artificial lift/boosting installations. As shown in Figure 13, these curves will change as follows:

1. Reservoir pressure declines; inflow curve collapses inward
2. Water cut increases; outflow curve moves upward
3. Gas comes out of solution; outflow curve drops down
4. All gas liberated from solution; outflow curve moves upward

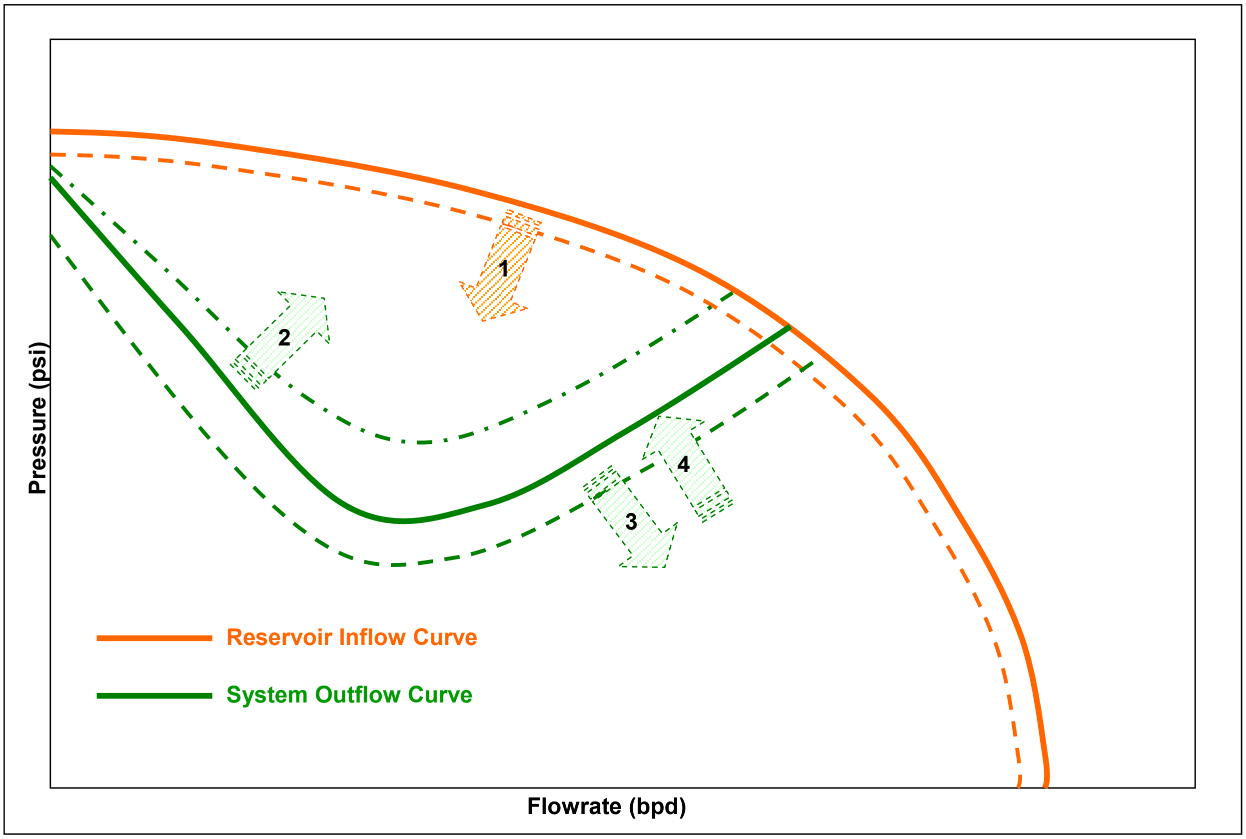


Figure 13: Reservoir inflow and system outflow curves with changes in reservoir parameters

With the exception of strong water-drive reservoirs, reservoir pressure will naturally decline, collapsing the inflow curve and reducing flowrate from the reservoir (see arrow 1).

In water-drive reservoirs, pressure decline has less of an influence because pressure is maintained by an expanding aquifer; however, increasing water cuts increase the hydrostatic component of back pressure on the reservoir (more so than the reduction in friction losses) and moves the outflow curve upward, reducing flowrate from the reservoir (see arrow 2).

As an example, consider a vertical well in 8,700 ft of water penetrating a reservoir with a total depth of 18,000 ft TVDss. Prosper was used to model the inflow/outflow performance of this well, using the fluid, well and reservoir parameters listed in Table 3. Inflow/outflow curves were generated for several different values of water cut (0%, 50% and 70%) and several reservoir pressures, as shown in Figure 14. Inflow curves are orange and outflow curves are green. The initial reservoir pressure is 8,370 and the lower reservoir pressure lines represent the outflow curve when the reservoir pressure is depleted to 7000, 6000, and 5000 psia.

At initial pressure with zero water cut, the well will flow at 8,300 stb/d with a flowing bottomhole pressure (FBHP) of 6,000 psia; when the reservoir pressure has declined to 7,000 psia, the well will produce at 5,000 stb/d with a FBHP of 5,600 psia. If the water cut remains at zero, the abandonment pressure is ~5,500 psia with a minimum rate of ~2,500 stb/d (the minimum value of the outflow curve is the point at which the well ceases to flow, which defines the abandonment pressure).

If the water cut increases to 50%, the outflow curve moves up and the abandonment pressure becomes ~6,700 psia. At 70% water cut the outflow moves up even further, and increases the abandonment pressure to ~7,200 psia.

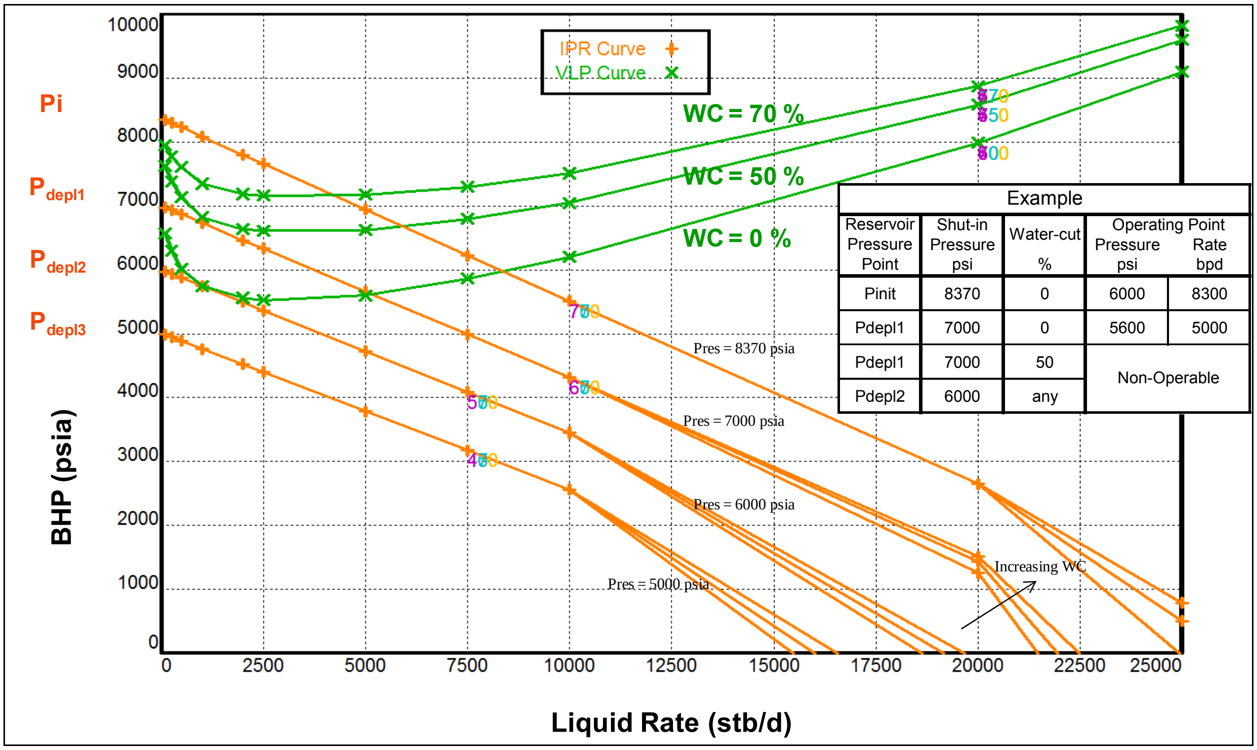
This example illustrates how Prosper can be used to model well performance and estimate initial rates and abandonment pressures. It is possible to add gas-lift or ESPs to the well and/or flowlines within the Prosper model to predict the impact on well performance.

Oil reservoirs with higher solution GORs may experience gas coming out of solution as pressure in the production system reaches the bubble point pressure. This effect assists in increasing the flowrate from the reservoir by reducing the hydrostatic and friction components of back pressure (see arrow 3); however, as production continues below the bubble point pressure, the gas in solution is depleted and the outflow curve will move upward to a more restrictive position.

Gas may come out of solution at different points in the production system, depending upon at what point in the system the bubble point pressure is reached. While some boosting pumps are capable of handling higher GVF percentages (and gas handling equipment can be installed), it is preferable to have as little gas as possible at the suction end of booster pumps. Accordingly, it is important to consider the bubble point pressure of the produced liquids, and anticipated pressures throughout the production system in the design of subsea processing facilities.

Table 3: Parameters for inflow/outflow calculation (Prosper example)

Parameter	Units	Value
PVT		
API	Degree	30
GOR	scf/stb	400
Gas Gravity	Air=1	0.65
Reservoir Properties		
Well PI	stb/psi/d	10
Resv Pressure	psia	8,370
Sub-sea Depth	ft, TVDss	18,000
Water Depth	ft	8,700
System Parameters		
Separator Inlet	psia	250
Tubing Size (ID)	inch	3.8
Temperature Profile		
Temp at surface	F	70
Temp at mudline	F	38
Temp at reservoir	F	220



Reservoir Pressure Point	Shut-in Pressure psi	Water-cut %	Operating Point Pressure psi	Operating Point Rate bpd
Pinit	8370	0	6000	8300
Pdepl1	7000	0	5600	5000
Pdepl1	7000	50	Non-Operable	
Pdepl2	6000	any		

Figure 14: Reservoir inflow/outflow curves (Prosper example)

5 Seafloor Pumping / Lifting

Subsea boosting has been an effective means of increasing production rates and recovery since the first installation of a twin-screw multiphase pump (MPP) by AGIP, at Prezioso in 1994. Since that time, there have been twenty-two reported subsea boosting installations around the world, and an additional five projects for which subsea boosting systems are currently being manufactured.

As previously discussed, deepwater discoveries and satellite fields require longer tie-backs (flowlines, pipelines and risers) to move the produced fluids to surface processing facilities and benefit greatly from subsea boosting to overcome the greater frictional pressure losses and hydrostatic pressure. Greater frictional pressure losses and hydrostatic pressure result in higher back-pressure on subsea wells, limiting production rates and ultimate recovery. In deep water, the hydrostatic pressure of the fluid column is often five to ten times greater than the friction loss inn horizontal pipes (OTC 20186).

Pumps used in subsea operations include both positive displacement and rotodynamic pumps (Figure 15), and consist of the following:

- Centrifugal
- Twin-screw
- Helico-axial
- Electrical submersible (ESP)

As reservoir pressure declines, the required differential pressure of the pump increases. The same is true as the water cut increases, as additional back pressure is exerted on seafloor equipment from an increased hydrostatic pressure in the riser.

In solution gas drive reservoirs, free gas becomes present in the flowstream as the pressure declines to the bubble point pressure. Free gas in a production system causes slugging in wellbore tubulars, pipelines, and risers, and vapor locking of pumps that are unable to handle high GVF flowstreams. For this reason, it is important to consider the oil PVT parameters (bubble point pressure, solution gas-oil ratio, and oil formation volume factor) and the anticipated pressures throughout a production system to understand where and when free gas will be present in the system, and to apply the appropriate technologies.

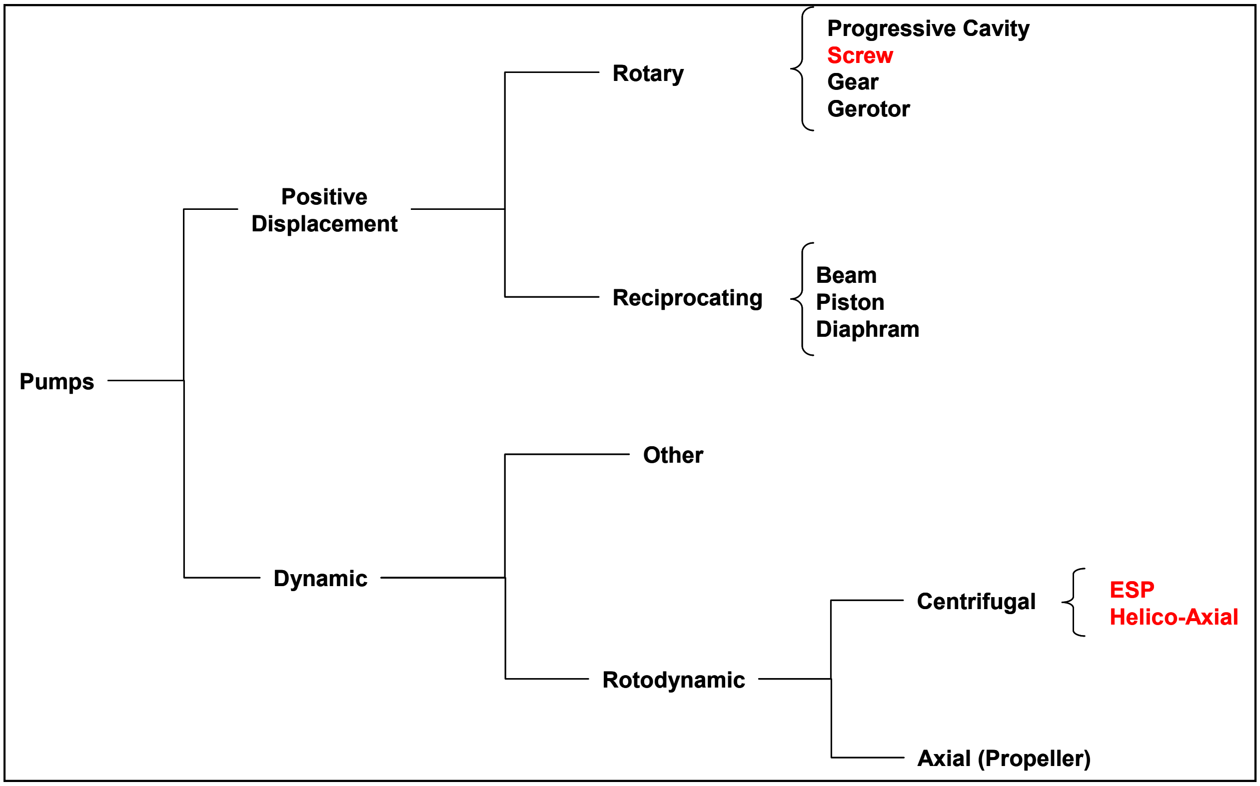


Figure 15: Pump families

Figure 2 (on page 3) summarizes historical operating differential and GVF capabilities of various subsea pumps, and Table 4 compares the historical values with manufacturer's published tested pump capabilities. With the exception of ESPs, the manufacturer-tested differential pressure is significantly higher than actual performance and is likely attributed to a low GVF flowstream during testing. The manufacturer-tested GVF values are more in line with actual historical performance, but still notably higher values for centrifugal and helico-axial pumps. Note that the individual pump manufacturer values of differential pressure and GVF are not achievable when considered together; i.e., a helico-axial pump cannot achieve a differential pressure value of 2,321 psi in a flowstream with a GVF of 95%.

Pump performance (and hence their selection criteria) is primarily a function of the required differential pressure and the GVF of the flowstream.

Table 4: Historical and test pump capabilities

Pump Type	ΔP		GVF	
	Historical	Manufacturer	Historical	Manufacturer
Centrifugal	2190 psi @ 0% GVF	5076 psi	3% @ 508 psi	15%
Twin Screw	725 psi @ 95% GVF	2176 psi	95% @ 725 psi	98%
Helico-Axial	773 psi @ 42% GVF	2321 psi	75% @ 276-653 psi	95%
ESP	2303 psi @ 15% GVF	2756 psi	57% @ 583 psi	50%

Manufacturer values are individual maximimum values, not achievable at combined values indicated

Historical performance charts depicted in Figure 1 (on page 2) and Figure 2 (on page 3) indicate the longest running subsea pump to be a simple centrifugal pump, installed in the Lufeng field (South China Sea). This excellent performance is attributed primarily to the low GVF of the Lufeng flowstream (2%), but the pump also benefited from a low differential pressure requirement (relatively shallow water depth and short tie-back distance). Centrifugal pumps have a low gas tolerance, GVF <15%.

The second longest running pumps are helico-axial pumps, and have operated successfully in environments with differential pressure requirements up to 653 psi and GVF as high as 75%.

ESPs, which have been employed in more recent applications, demonstrate run-times as high as 4 years in time-limited production tests. The superior pressure differential capabilities of the ESP (2,000 to 3,200 psi) with its ability to handle gas volumes up to 15% make it an excellent choice in ultra deepwater applications where hydrostatic pressures alone are on the order of 1,800 to 3,000 psi.

Centrifugal and helico-axial pumps operate efficiently in single phase, low viscosity flowstreams but become inefficient in high-viscosity, high-GVF flowstreams.

Literature on twin-screw pumps indicates a tolerance to sand production, a capability not noted in other pumps. Sand production problems are better addressed in the wellbore with sand control equipment.

5.1 *Centrifugal Pumps*

A centrifugal pump is a rotodynamic pump using a rotating impeller to move fluid inside a pipe. Liquid enters the pump suction at the center of the impeller, and is moved radially outward by centrifugal force, and through the piping system. As the liquid moves outward, away from the center of the impeller, a low pressure area is created at the center allowing more liquid to enter the pump inlet (Figure 16).

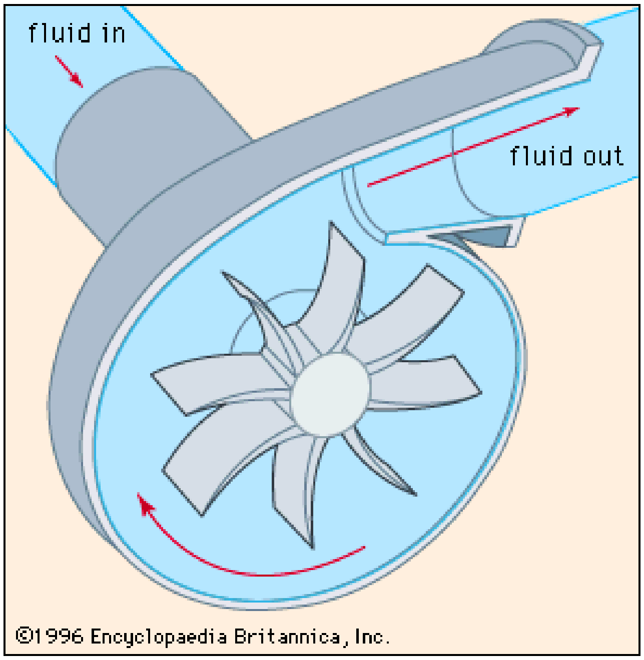


Figure 16: Centrifugal pump

Centrifugal pumps are proven deepwater pumps (~1,000 ft) in flowstreams with virtually no gas. Centrifugal pump systems at Lufeng and Troll-C operated for 11.5 and 4.3+ years, respectively (Troll-C is still in operation). See Table 5 for details of these installations.

Table 5: Historical operating parameters of subsea centrifugal pumps

Centrifugal Pumps											
Project Field	Project Type	Area	Operator	Start (year)	Water Depth (feet)	Tie-back Distance (miles)	Total Flowrate (bpd)	Flowrate per Pump (bpd)	Diff Press (psi)	GVF (%)	Current Status @ February, 2010
Lufeng 22-1	Well Boost	S, China Sea	Statoil	1998	1083	1	241,700	48,340	508	3	Non-Op after 138 months
Troll-C Pilot	Oil Boost off of Separator	Norwegian North Sea	Statoil	2005	1116	3	37,800	37,800	2190	0	Operating after 52 months

maximum values

5.1.1 Centrifugal Pumps at Lufeng

The Lufeng field (China Block 22/1) is located 250 km southeast of Hong Kong, and was Statoil's first overseas subsea project.

The Lufeng field came on production in December 1997, and was produced with no water or gas injection for pressure maintenance/secondary recovery. Initial production was approximately 60,000 bopd (31.1° API, paraffinic) from five horizontal wells, but dropped quickly with a corresponding increase in water cut.

A subsea centrifugal pump system was installed, and pumping operations began in 1998. The subsea pumping system was in operation until June 2009 and holds the record for the longest running subsea pump system at 11.5 years. The field was shut in, presumably due to poor economics.

The pumping system consisted of five centrifugal pumps (Framo) installed at the mudline, one pump for each well, boosting production to a topside FPSO. The excellent performance of this subsea pump system was due primarily to the low GVF of the Lufeng flowstream (0-3%), but also benefited from a low differential pressure requirement due to the relatively shallow water depth (1,083 ft) and short tie-back distance (0.6 miles). Each pump was rated at 400 kW (536 hp), 25,000 bpd, with a differential pressure of 508 psi.

During the first year of pump operation, a total of 23 days of production were lost:

- 9 days due to weather
- 3 days for pump repair
- 7 days for initial tuning of pump system
- 4 days for scheduled maintenance

During the first 2 years of operation, the pumps performed 92% of the time.

From 1998 through 2004, the system only experienced three pump failures (two electrical failures and one mechanical seal failure); however, an additional eight failures associated with the topside control air conditioning system were also experienced (OTC-20619).

The FPSO provided the power source and controlled the output of the subsea pumps.

Original estimates of recoverable reserves were 30 mmbo (25% OOIP recovery).

5.1.2 Centrifugal Pumps at Troll-C

NorskHydro (currently Statoil) installed two centrifugal pumps at their Troll-C pilot project for use in boosting oil production to a host facility, and injecting water into an injection well. The Troll-C pilot project is located in the Norwegian North Sea in 1,116 ft of water. This project was installed in 1999, but was not put into service until August 2001 when separation and injection operations began. Subsea boosting operations did not begin at Troll-C until late 2005, when a centrifugal booster pump was installed on the oil leg of the separator (no gas). Note that the well(s) ceased to produce on their own in 2003, prompting the subsequent booster pump installation.

The design parameters for the Troll-C project are as follows:

- Temperature: 140° F
- Design pressure: 2,600 psi
- Operating pressure: 510 – 1,520 psi
- Oil API gravity: 37°
- Total liquid rate: 63,000 bpd
- Oil rate: 25,000 bpd
- Gas rate: 28 mmcfpd
- Water injection: 38,000 bpd
- Design water in oil: <10% in oil outlet
- Design oil in water: < 1000 mg/l in water outlet

The booster and injection pumps are 1.6 MW (2,145 hp) units, capable of generating differential pressures of 2,190 psi.

5.2 *Twin-screw Pumps*

The twin-screw pump is a positive displacement pump constructed basically of two intermeshing screws. The fluidstream enters the pump, and is trapped between the screws of the pump. The rotation of the screws forces the flowstream into the downstream flowline.

The pump consists of two synchronized screws (one drive and one driven) with dual suctions and a single discharge. The screws provide mechanical separation between the suction and discharge, which minimizes slugging of liquids (in higher GOR flowstreams).

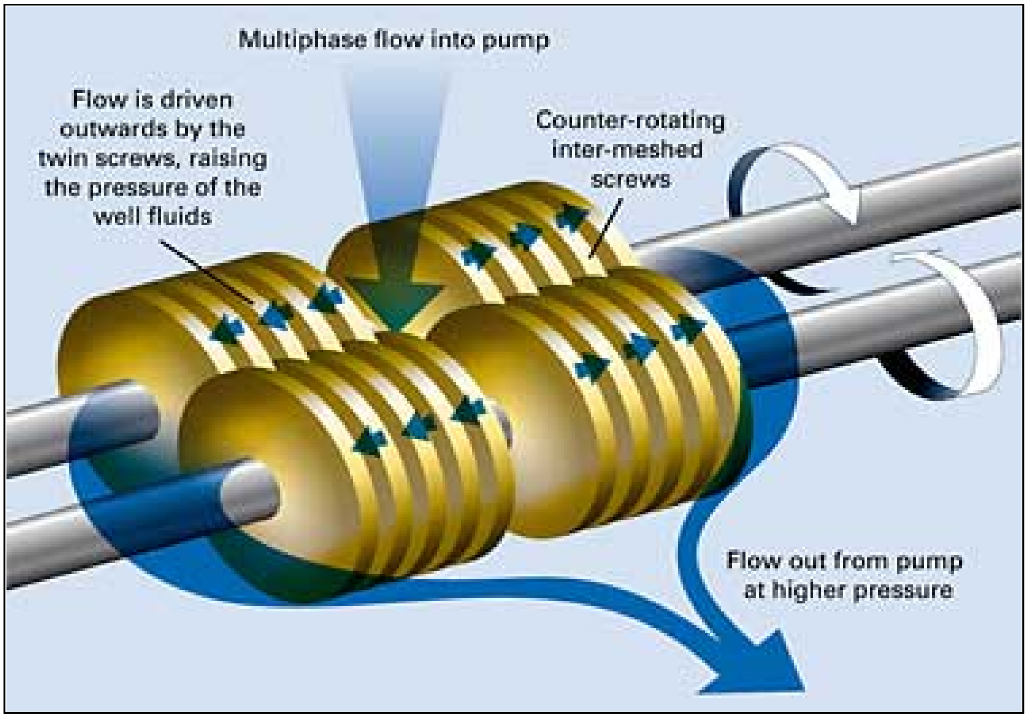


Figure 17: Twin-screw pump (http://www.bp.com)

Twin-screw pumps offer great flexibility with respect to their ability to handle a wide range of fluid properties, including multiphase flowstreams containing high viscosity crude and high GVF.

Reported advantages of twin-screw pumps include:

- Pumping efficiency is almost independent of gas (GVF=98%)
- Handles very viscous fluids (>1000cSt)
- Screws provide mechanical separation between suction and discharge => no slugging
- Slow speed=>Low sheer => Low emulsion
- Handles solids 0.3-10 mm
- Low pulsation => eliminates need for dampeners

Typical operating parameters for an Aker Kvaerner twin-screw MPP:

- Power: 2.3 MW
- Flowrate: 166,051 BPD (1100 m3/h)

- Differential pressure: 725 psi (50 bar)
- Viscosity: 1 – 1,000 cSt
- GVF: 0 – 98%
- RPM: 600 – 2,000
- Pressure rating: 5,000 psi
- Design depth: 9,840 ft (3000 m)

Camforce FlowBoost 2000 twin-screw system has a maximum flow rate of 181,847 bpd (1200 cubic m/hr), and a maximum differential pressure of 1,400 psi. This system is designed to work in 6,500 ft water depth and a maximum step-out distance of 25 miles (E&P Magazine, November 2009).

Three twin-screw pumps have been put into operation to date, and all have poor run lives of approximately 1 year (see historical operating parameters summarized in Table 6).

Problems associated with erosion or heat damage of the mechanical seals affect the operation of twin-screw pumps. Sand can also erode the screws and liners of the pumps.

Table 6: Historical operating parameters of subsea twin-screw pumps

Twin Screw Pumps											
Project Field	Project Type	Area	Operator	Start (year)	Water Depth (feet)	Tie-back Distance (miles)	Total Flowrate (bpd)	Flowrate per Pump (bpd)	Diff Press (psi)	GVF (%)	Current Status @ February, 2010
Prezioso	1-MPP @ base of platform	Italy	AGIP	1994	164	0	10,000	10,000	580	30 - 90	Abandoned after 11 months
Lyell	1-MPP Tie-back to Ninian South	UK North Sea	CNR	2006	479	9	166,200	166,200	261	40 - 70	Non-Op after 11 months
King	2-MPPs Tie-back to Marlin TLP	GOM	BP	2007	5578	18	75,000	37,500	725	0 - 95	Non-Op after 15 months

maximum values

Industry testing of twin-screw pumps indicates more favorable potential operating parameters than actual operating results. Testing by manufacturers indicates the following improved capabilities for the twin-screw pump:

- Flow rate: 182 mbpd (Camforce FlowBoost)
- Differential pressure: 2,175 psi (Flowserve's recent tests)
- Gas volume factor (GVF): 100 % (using liquid recirc system)

5.2.1 Twin-screw Pump at Prezioso

The first installation of a subsea twin-screw pump on an active well occurred in 1994, in the Prezioso field, located offshore Italy in 164 ft of water. The pump, located at the base of a platform, was tested successfully for total of 7,850 hours.

5.2.2 Twin-screw Pump at Lyell

The Lyell field is located 90 miles offshore the Shetland Islands in Block 3/2 of the UK North Sea, where the water depth is 469 ft. Production began in the Lyell field in 1993 and enhanced production by more than 3,000 bpd.

In January 2006, Canadian Natural Resources (CNR) installed a subsea twin-screw pump at Lyell, which was the first twin-screw pump to operate under true subsea conditions. While a WorldPumps.com article dated September 22, 2009 states that the Lyell twin-screw pump has been in operation since February 2006, the 2010 survey indicates that the pump only operated 11 months after its initial installation.

The Lyell twin-screw pump handled oil, water, and gas at 70-80% GVF. The pump operated at 800 – 2,000 RPM, and was rated at 750 psi differential pressure (suction pressure = 640 – 1,835 psi), and 1.0 MW (1340 hp).

5.2.3 Twin-screw Pumps at King

The King field is located in the Mississippi Canyon protraction area of the Gulf of Mexico, in 5,578 ft of water. The field first produced in 2001 from two wells (D5 and D6). Another well (D3) came on production in 2003. Production flowed naturally from the wells to the Marlin platform, 18 miles away.

Anticipating the need for future pressure boosting due to reservoir pressure depletion and increasing water cuts, the operator, British Petroleum (BP), installed two twin-screw multiphase pumps in 2007 (one pump for wells D5 and D3, and one pump for well D6). This installation set a record for water depth for an operational subsea pump. These pumps began operating in November 2007, and ceased operating in February 2009 due to “operational issues.” These operational issues might be associated with capacity constraints at the Marlin platform and the need to repair and upgrade one of the pumps.

The installed pumps are rated at 1.3 MW (1.43 hp) and designed to handle 75,000 bpd (total for two pumps) at a maximum differential pressure of 725 psi.

Twin-screw pumps can handle GVFs up to 95%.

The pump modules each weigh 88 tonnes (pump weighs 60 tonnes) and measure 30 ft by 11 ft.

An innovation applied during the installation of the subsea pumps at King was the use of a multiple application reinjection system (MARS), replacing the retrievable choke valve insert normally installed on a subsea tree. MARS enabled the installation of the subsea pumps without long periods of downtime associated with retrofitting the existing system to accommodate the pumps (Figure 18).

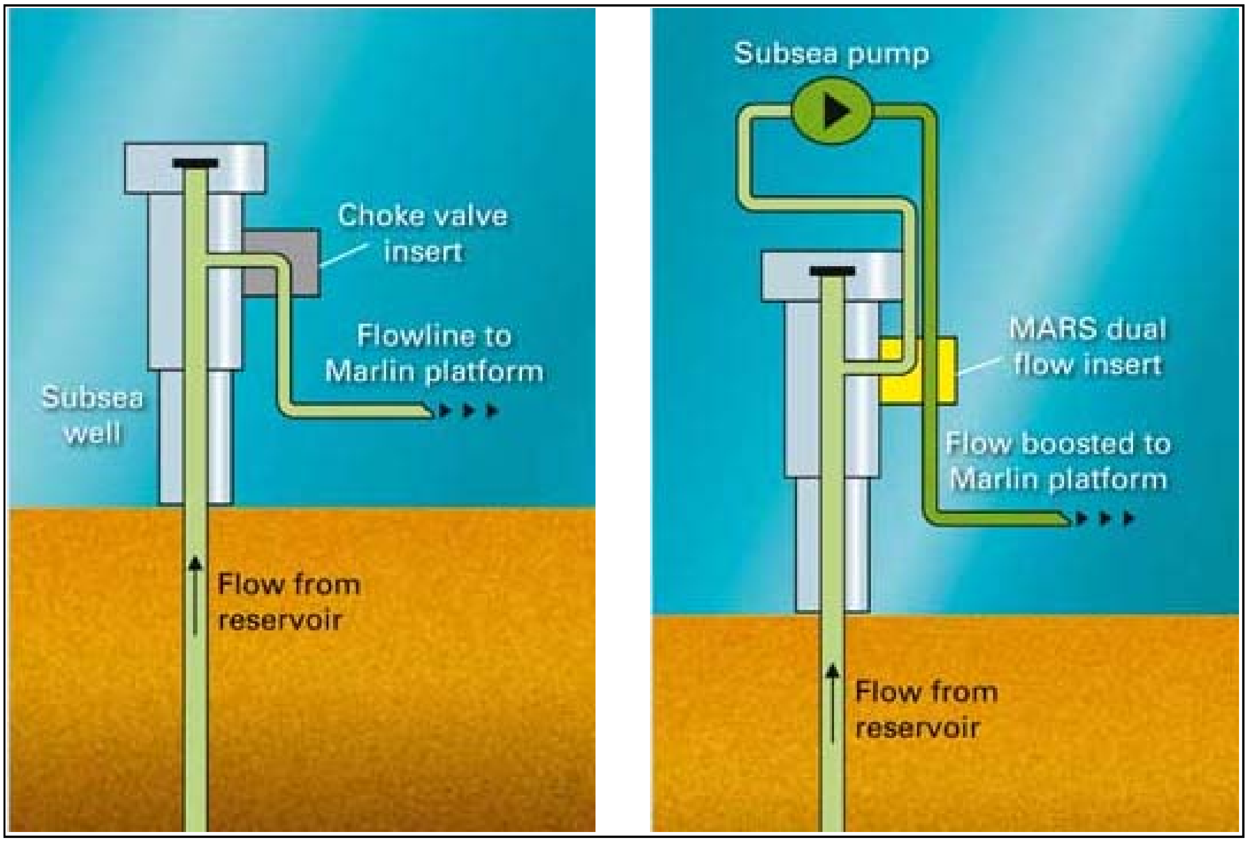


Figure 18: BP King use of the multiple application reinjection system (MARS)

5.3 *Helico-axial Pumps*

Helico-axial pumps are centrifugal pumps first developed in the late 1980s for Total's Tunisian Poseidon project. Helico-axial pumps are often referred to as Poseidon pumps.

The helico-axial pump is a cross between a centrifugal pump and an axial compressor, combining a screw drive (rotor or impeller) with turbine blades (stator or rectifier). The pump operates under a rotodynamic principle. Compression of the fluid is achieved through the transfer of kinetic energy from the rotating impeller blades through the fixed turbine blades. As fluid enters the pump, it is accelerated by the impeller blades into the fixed turbine blades, where kinetic energy is converted into pressure (Figure 19).

A pump consists of multiple stages of impellers (rotor) and turbine blades (stator). Larger differential pressure is achieved by increasing the number of stages, and flowrate is increased by increasing the diameter of the compression cell (OTC-7037, OTC-1992).

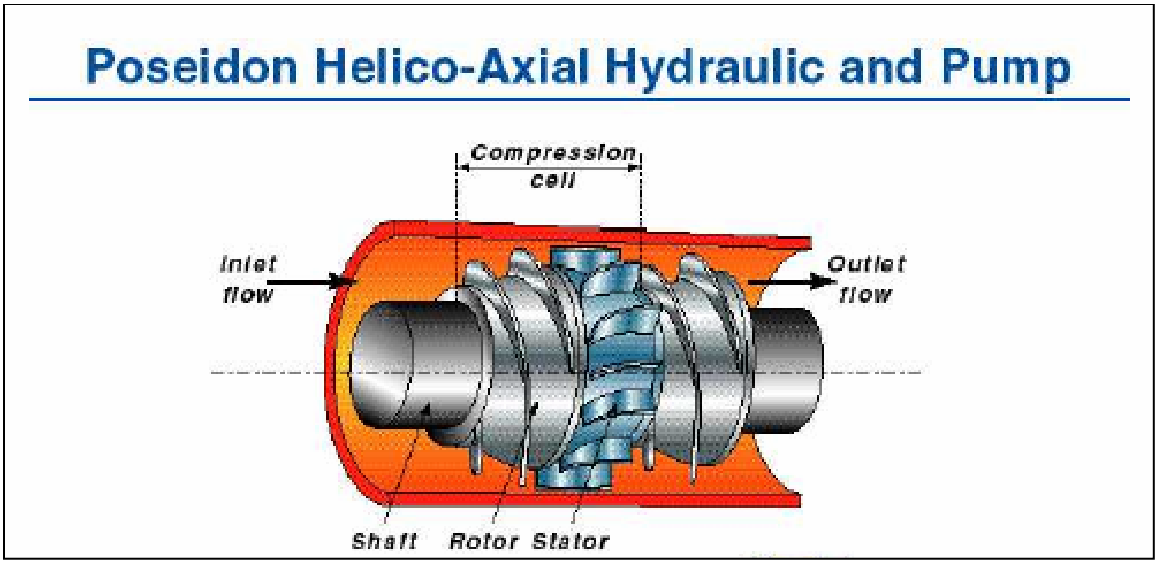


Figure 19: Helico-axial pump

As with twin-screw pumps, helico-axial pumps have problems associated with erosion or heat, which damage the mechanical seals. Excessive amounts of gas and long liquid slugs can affect the efficiency of helico-axial pumps.

Six helico-axial pumps have been put into operation to date. Their actual historical operating parameters are summarized in Table 7.

Table 7: Historical operating parameters of subsea helico-axial pumps

Helico Axial Pumps											
Project Field	Project Type	Area	Operator	Start (year)	Water Depth (feet)	Tie-back Distance (miles)	Total Flowrate (bpd)	Flowrate per Pump (bpd)	Diff Press (psi)	GVF (%)	Current Status @ February, 2010
Draugen Field	SMUBS, 1-MPP	Norway North Sea	Norske Shell	1995	886	4	29,200	29,200	773	42	Abandoned after 12 months
Topacio Field	2-MPPs	Equatorial Guinea	ExxonMobil	2000	1641	6	142,000	71,000	508	75	Operating after 114 months
Ceiba C3 C4	2-MPPs	Equatorial Guinea	Hess	2002	2461	5	90,600	45,300	653	75	Operating after 88 months
Ceiba Field FFD	5-MPPs	Equatorial Guinea	Hess	2003	2297	5	337,600	67,520	580	75	Operating after 74 months
Mutineer Exeter	2-MPPs	NWS Australia	Santos	2005	476	4	181,300	90,650	435	40	Operating after 59 months
Brenda & Nicole Fields	Multi Manif w/ 1-MPP	UK North Sea	OILEXCO N.S.	2007	476	5	120,800	120,800	276	75	Operating after 34 months

maximum values

The first subsea helico-axial pump installation was at the North Sea Draugen field by Norske Shell in 1994 (SPE-88643).

An ongoing test program for a high-boost helico-axial multiphase pump is being conducted by a joint industry project (JIP) with Shell, Total, BP, and Statoil. The pump development program began in 2007 and evolved into a full-scale prototype in 2008. The pump has been tested favorably at a differential pressure of 2,176 psi (150 bar) and a GVF of 50%, and at a differential pressure of 1,450 psi (100 bar) and a GFV of 80%. This pump can operate in water depths up to 9,842 ft (Offshore Magazine, Volume 70, Issue 2).

More than twenty helico-axial pumps are in operation worldwide, with more than 900,000 hours of run time (Offshore Magazine, February 2010).

For all applications the Framo helico-axial pumps are designed with retrievable insert cartridges (Figure 20). For subsea installations this enables installation and retrieval with light intervention vessels, a necessity for cost effective subsea developments.

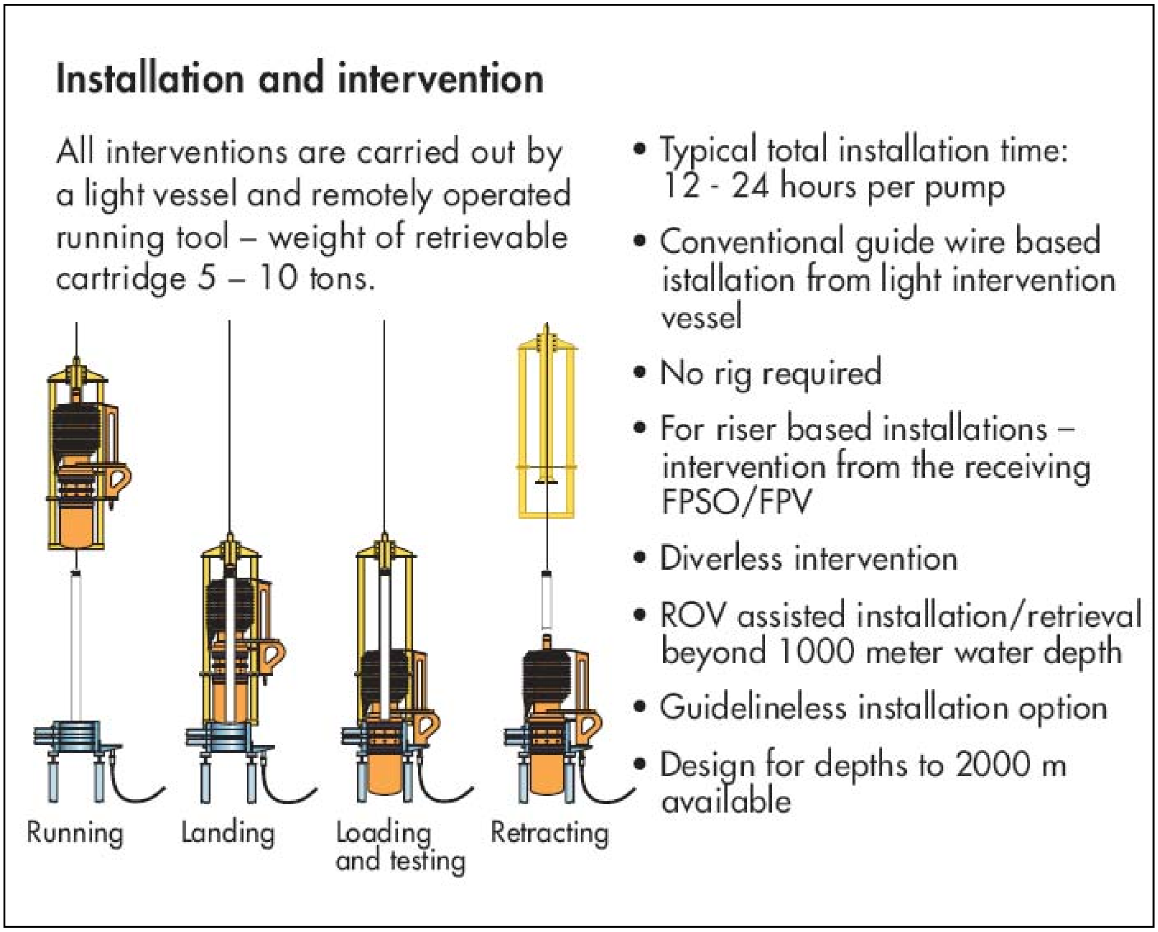


Figure 20: Installation and intervention procedure for subsea helico-axial pumps

(http://www.framoeng.no/Files/Bulletins/SubseaPumpsscreen.pdf)

5.3.1 Helico-axial Pumps at Topacio

The Topacio field is located offshore Equatorial Guinea in 1,641 ft of water. The field, operated by Exxon, is a satellite field to the Zafiro development project (5.6 mile tie-back). The Topacio field came on production in 1996, and a subsea multiphase pump system was installed during the summer of 1999, as a retrofit installation. The pump system is one of the longest running subsea pump systems at 9.5 years.

The pump system consists of two helico-axial multiphase pumps, each rated for 67,929 bpd, and 507 psi differential pressure (suction pressure = 218 psi), at a GVF of 75%. The pumps are designed to run at 5,060 RPM, and have a shaft horsepower rating of 840 kW. Each pump is 13.12 ft by 2.6 ft, and weighs 8 tons.

The initial expected increase in production was between 3,000 and 6,000 bopd.

5.3.2 Helico-axial Pumps at Ceiba

The Ceiba field (operated by Hess) is located 22 miles offshore in Block-G of the Rio Muni basin, in 2,297 ft of water. Production began in November 2000 from four early production wells. In October 2002, Hess installed two helico-axial multiphase pumps on two of the early production wells to maintain/increase oil production in an increasing water-cut flowstream, thereby increasing oil recovery. These pumps continue to operate after 7 ⅓ years.

The pumps used for the C3 and C4 wells were rated at 38,000 bpd, and a 660 psi differential pressure. GVF was advertised by Framo to be between 50 and 90%; however, based on other sources, the high side is likely to be 75%. Each pump is 13 ft by 2.5 ft, and weighs 8 metric tonnes.

In 2003, based on the success of the subsea booster pumps on wells C3 and C4, Hess installed an additional three helico-axial multiphase pump systems at Ceiba as part of their full field development (FFD) of the Ceiba field. Each system provides pressure boosting for two production wells. These pumps are rated at 37,739 bpd and 580 psi differential pressure with a GVF of 75%. The pumps were designed to run at 3,500 RPM and have a shaft horsepower rating of 1,500 kW.

The five subsea pumps boost production approximately 5 miles to an FPSO. The Ceiba crude is 30° API.

5.3.3 Helico-axial Pumps at Mutineer / Exeter

The Mutineer and Exeter fields are located 94 miles offshore on the Northwest Shelf of Australia in 492 ft of water. The fields were discovered in 1997 and 2002, respectively. Production commenced in March 2005 from four horizontal wells.

A seafloor pump system was installed at the beginning of the project, and consists of two helico-axial multiphase pumps fed by dual ESPs in the four horizontal wells. These pumps are still in operation after 5 years.

The pump system consists of two helico-axial multiphase pumps, each rated for 45,286 bpd, and 435 psi differential pressure (suction pressure = 87 psi), with a GVF range from 0 – 40%. The pumps are designed to run at 3,600 RPM, and have a shaft horsepower rating of 1,100 kW.

The fields currently produce 50,000 bopd.

5.3.4 Helico-axial Pumps at Brenda / Nicol

The Brenda and Nicol fields are located 138 miles northeast of Aberdeen, Scotland, in 476 ft of water. The development of these fields began in 2006, and included the drilling and completion of four horizontal wells at Brenda and a single well at Nicol. The Brenda and Nicol fields are tied-back to the Balmoral floating production vessel 5.9 and 6.2 miles away, respectively.

Operator, OILEXCO included artificial lift to assist with kicking-off production and to maintain production rates at high water cuts.

OILEXCO evaluated the use of ESPs in wells, gas lift in wells, and/or seafloor multiphase pumps. They opted for a combination of gas lift in wells and seafloor multiphase pumps at Brenda/Nicol. This combination allows the fields to be produced at high flow rates and water cuts using a minimum amount of gas-lift gas.

Framo supplied a modular manifold unit consisting of a helico-axial pump and multiphase flow meter plumbed into a production manifold, allowing for the testing of individual wells, as well as the transport of the combined flowstreams to the Balmoral facility. The pump began operating in April 2007 and is still in operation after more than 3 years.

The helico-axial pump is rated at 1.1 MW (1,475 hp) and operates at 121 bpd, 276 psi differential pressure in a flowstream with a 75% GVF.

5.4 *Electrical Submersible Pumps (ESP)*

An ESP is a multi-stage pump consisting of driven impellers and a diffuser which directs flow to the next stage of the pump (Figure 21). Generally ESPs are intolerant of high gas volumes, effectively operable in flowstreams where GVF is less than 20% (E&P Magazine, August 2009). ESP manufacturer, REDA states a GVF tolerance of 10-25%; however, ESPs have reportedly run for extended periods pumping fluids with GVFs as high as 57%. Due to their operation at high rpms (4,000 rpm) and tight design clearances, ESPs are not tolerant to sand production.

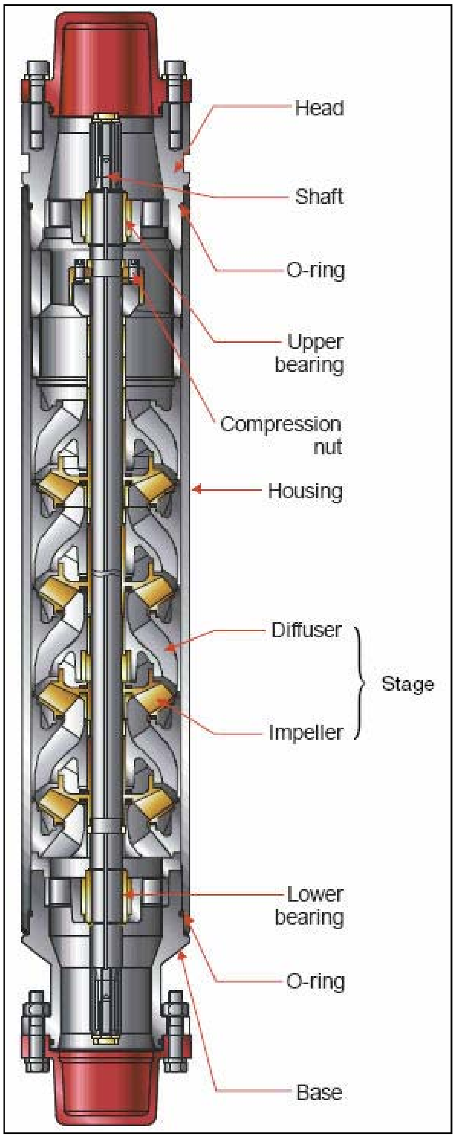


Figure 21: ESP

ESPs traditionally have been used as an artificial lift method in oil wells, but recently have been used to boost production on the seafloor from multiple wells/fields to surface host facilities. This seafloor boosting is accomplished by installing ESPs in either subsea rises or seafloor caisson gas-liquid separators.

Prior to 2002, subsea pumping requirements were limited to differential pump pressures of less than 700 psi (see Figure 26); however, as operators ventured further into deeper waters, greater differential pressures were needed to overcome the larger hydrostatic pressures and frictional losses associated with longer risers and subsea tie-backs.

At this time, the only pumps proven to have a differential pressure capability of 2,000 psi are centrifugal pumps and ESPs. Centrifugal Pumps have operated with flowstreams having GVFs up to 3%, while ESPs have operated with flowstreams having GVFs up to 57% (but optimum up to 25%). With subsea separation, both pumps could be used; however, the GVF is likely to increase above 3% if the reservoir pressure, or pressure in the flowline before the pump, drops below the bubble point pressure in reservoirs with low natural drive energy, which is typical in the deepwater Gulf of Mexico. Therefore, the ESP is the pump of choice for deepwater Gulf of Mexico reservoirs.

The following example indicates the differential pressure requirement of a seafloor pump in water depths of 1,000 ft and 5,000 ft, and demonstrates the need for greater pump differential pressure capabilities in deep water:

- Given:
  - Water depth = 1,000 ft or 5,000 ft
  - Multiphase gradient = 0.30 psi/foot
  - Tie-back length = 5 miles
  - Multiphase pipe friction loss = 50 psi/mile
  - Surface boarding pressure = 250 psi
- Required:
  - Pump duty
- Solution:
  - $\Delta P = 250 + (1{,}000 \times 0.30) + (5 \times 50) = 600$ psi
  - $\Delta P = 250 + (5{,}000 \times 0.30) + (5 \times 50) = 2{,}000$ psi

To date, four ESP pumps have been put into operation for use in seafloor boosting (two in a riser and two in a caisson separator). The actual historical operating parameters are summarized in Table 8.

Table 8: Historical operating parameters of subsea ESPs

Electric Submersible Pumps (ESPs)											
Project Field	Project Type	Area	Operator	Start (year)	Water Depth (feet)	Tie-back Distance (miles)	Total Flowrate (bpd)	Flowrate per Pump (bpd)	Diff Press (psi)	GVF (%)	Current Status @ February, 2010
Marimba Field	Caisson 1-ESP	Brazil	Petrobras	2001	1296	1	9,100	9,100	754	na	Non-Op after 42 months
Jubarte EWT	Riser Lift 1-ESP	Brazil	Petrobras	2002	4593	1	21,900	21,900	2000	22	Non-Op after 48 months
Navajo Field	Riser Lift 1-ESP	GOM	Anadarko	2007	3642	5	3,600	3,600	583	57	Operating after 36 months
Jubarte Field	Caisson 1-ESP	Brazil	Petrobras	2007	4429	3	18,100	18,100	2002	10 - 40	Non-Op after 28 months

maximum values

5.4.1 ESP in Caisson Separator at Marimba

The first installation of an ESP in a seafloor caisson occurred in the Marimba field, located in 1,296 ft of water, offshore Brazil. This installation was in conjunction with a joint industry project (JIP) with Petrobras, ENI-Agip, and ExxonMobil. Referred to as a vertical annular separation and pumping system (VASPS), this ESP installation occurred in the year 2000 and began operating in July 2001, but experienced a failure less than 6 months later. The pump was replaced in 2004, resumed operations in 2005, and ran continuously for 3.5 years until “well failure” in July 2008.

The next reported installation of an ESP in a seafloor caisson was in the Jubarte field, located in 4,429 ft of water, offshore Brazil. This system was called a seabed ESP-MOBO (modulo de bombas or production module). The pump began operating in March 2007, and operated for 28 months before experiencing operational problems.

5.4.2 ESP in a Subsea Riser at Jubarte Extended Well Test (EWT)

The Jubarte field is located 48 miles off the Brazilian coast in the northern Campos basin, in 4,593 ft of water. The field was discovered by Petrobras in 2001, and came on production in 2002. The producing reservoir has good rock characteristics (23% porosity, 1200 md permeability), but the oil is a heavier 14 cp viscosity crude (17° API).

As part of a technical and economic analysis of artificial lift methods for the heavier Jubarte crude, Petrobras initiated a series of phased tests of ESP applications to determine the reliability of ESPs (run life) in a deepwater environment. The testing of ESPs began with an extended well test (EWT) of well 1-ESS-110 utilizing an ESP in the drill pipe riser, above the wet tree. The ESP was located in a 9 ⅝ in. capsule at the bottom of the riser.

The EWT began in October 2002 and officially ended in January 2006 (38 months); however, the well continued to produce with the ESP in the riser for another 10 months under the Phase-1 testing of ESPs, for a total time-limited run life of 4 years. Production rates of 22,000 bpd were achieved.

The ESP was rated at 900 HP (700 kW), 25,000 bpd ESP. During the EWT, the ESP operated with a differential pressure of 2,000 psi, handling a water and 17° API oil flowstream with a 22% GVF.

5.4.3 ESP in a Subsea Riser at Navajo

The Navajo field is located in the east banks protraction area of the Gulf of Mexico in water depths ranging from 3,600 to 4,200 ft. Production from well EB-690 No. 1 began in December 2005 and flowed naturally through January 2007, when Anadarko installed an ESP in a production riser to enhance production from well EB 690 #1 back to the Nansen Spar facility. Prior to the installation, the well produced erratically with gas slugging and liquid loading of the riser. The ESP is still in operation after more than 3 years.

The ESP at Navajo is a 4 in. OD unit rated at 3,600 bpd and 0.75 MW (1,005 hp) and handles a 57% GVF flowstream.

5.4.4 ESP in Caisson Separator at Jubarte Phase-1

Subsequent to the Jubarte EWT (discussed previously), Petrobras continued with their phased testing of ESP applications with the placement of an ESP in a seabed caisson, referred to as a MOBO (modulo de bombas or production module), and a VASPS (vertical annular separation and pumping system).

The Jubarte field is located 48 miles off the Brazilian coast in the northern Campos basin, in 4,339 ft of water. The field produces a 14 cp viscosity crude (17° API), with water and gas.

The Phase-1 development of the Jubarte field included producing a well (7-JUB-02) to a MOBO, and boosting a separated oil and water flowstream to the topside FPSO (Phase-1 also included producing two wells using gas lift inside a well, and one well using and ESP inside the well). The MOBO installation started in March 2007, and continued until July 2009 (2 ⅓ years).

The MOBO consists of a 30 in., 130 ft deep caisson, located 650 ft from the well. The ESP is a 1,200 hp (0.9 MW) pump having an expected run life of 4-6 years. High-resistant shims are used to impede abrasion from sand production.

Based upon the results of the EWT and Phase-1 testing of artificial lift methods, Petrobras is proceeding with Phase-2 development of Jubarte (The Definitive Jubarte Production System), in which they will produce fifteen horizontal wells using MOBOs equipped with 1,500 hp ESPs. Gas lift valves will be installed in the wells as back-up to the ESPs.

Rigs are used to pull ESPs, so intervention costs can be high; however, work is being done to facilitate ESP change-out with a special boat using cables.

During testing, scale formed on the ESP impellers, so continuous injection of scale inhibitor was implemented. Water in oil emulsion was also an issue, so continuous injection of de-emulsifier was also implemented.

The MOBOs can be bypassed to allow pigging of the flowlines.

5.4.5 **ESP in Caisson Separator at Parque das Conchas Project (BC-10)**

The Parque das Conchas project is located in Block BC-10 offshore Brazil in 7,054 ft of water. Phase-1 of the project includes the development of the Ostra, Albalone, and Argonauta-BW fields, which were recently put on production. Under Phase-2 of the project, the Argonauta-ON will be developed.

During Phase-1 of the project, Shell installed six subsea boosting systems consisting of boosting modules installed in the seabed. These modules are referred to as MOBOs (modulo de bombas or production module). Each MOBO consists of the following:

- 48 in. conductor pipe (driven into the seafloor)
- 42 in. conductor pipe (drilled and installed inside 48 in. conductor pipe)
- 3280 ft - 32 in. caisson pipe (drilled and installed inside 42 in. conductor pipe)
- 7 in. helical inlet for gas-liquid pre-separation
- 5 in. gas outlet
- 5 in. oil/water outlet
- 1,500 hp ESP
- Junk basket
- ESP monitoring system
- Pressure gauges for fluid level control

5.4.6 ESP in Caisson Separator at Perdido

Perdido is located 200 miles off the Texas Gulf Coast in 8,000 ft of water, and is the first producing development from the Lower Tertiary in the Gulf of Mexico.

Five vertical annular separation and producing systems (VASPS) were recently installed in the Perdido deepwater development, with first production achieved in the first quarter of 2010.

The five VASPS will handle an expected peak production in excess of 100,000 bopd and 2 mmcfpd. According to Chevron, the VASPS at Perdido reduce back pressure on the production wells by 2,000 psi, and that without the VASPS Perdido would only produce for 18 months.

Each of the VASPS at Perdido consists of the following components:

- 48 in. conductor pipe (jetted into seabed)
- 42 in. surface casing (cemented inside conductor)
- 345 ft x 35 in. OD casing
- MW (1340 hp) ESP
- ESP wellhead

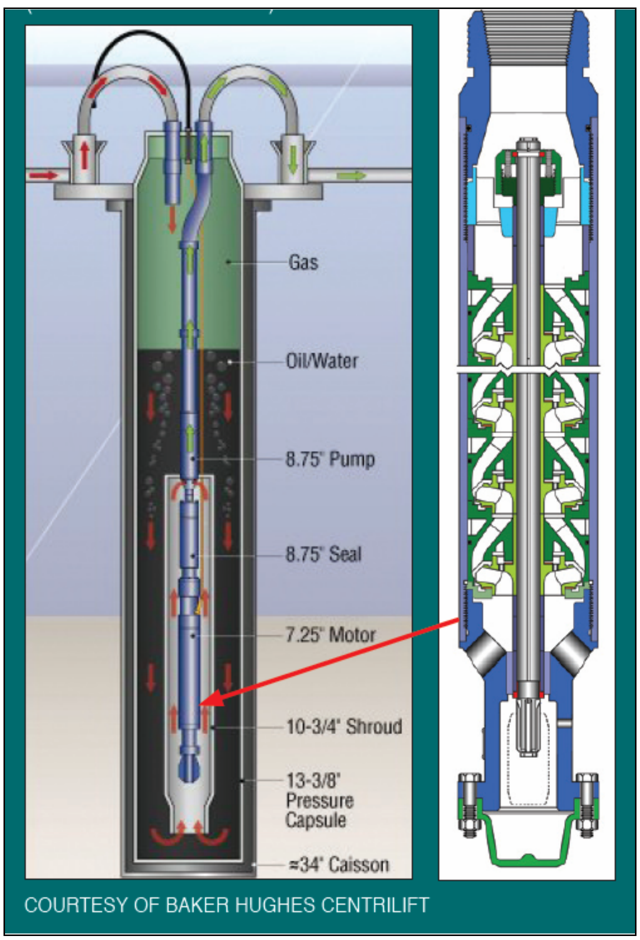


Figure 22: Vertical annular separation and pumping system (VASPS)

5.5 *Pump Performance*

This section of the report summarizes and discusses actual historical and future predicted subsea pump performance. Actual pump performance is the basis for establishing pump selection criteria as well as assessing risk associated with future installations.

Historical runtime data from the 2010 survey indicates good historical subsea runtimes in excess of 2 years for helico-axial, ESP, and simple centrifugal pumps, with a simple centrifugal pump having the longest runtime of 11.5 years (see Figure 23). This pump was installed in the Lufeng field in 1998, and had a flowstream GVF of only 3%, which likely accounts for the long runtime.

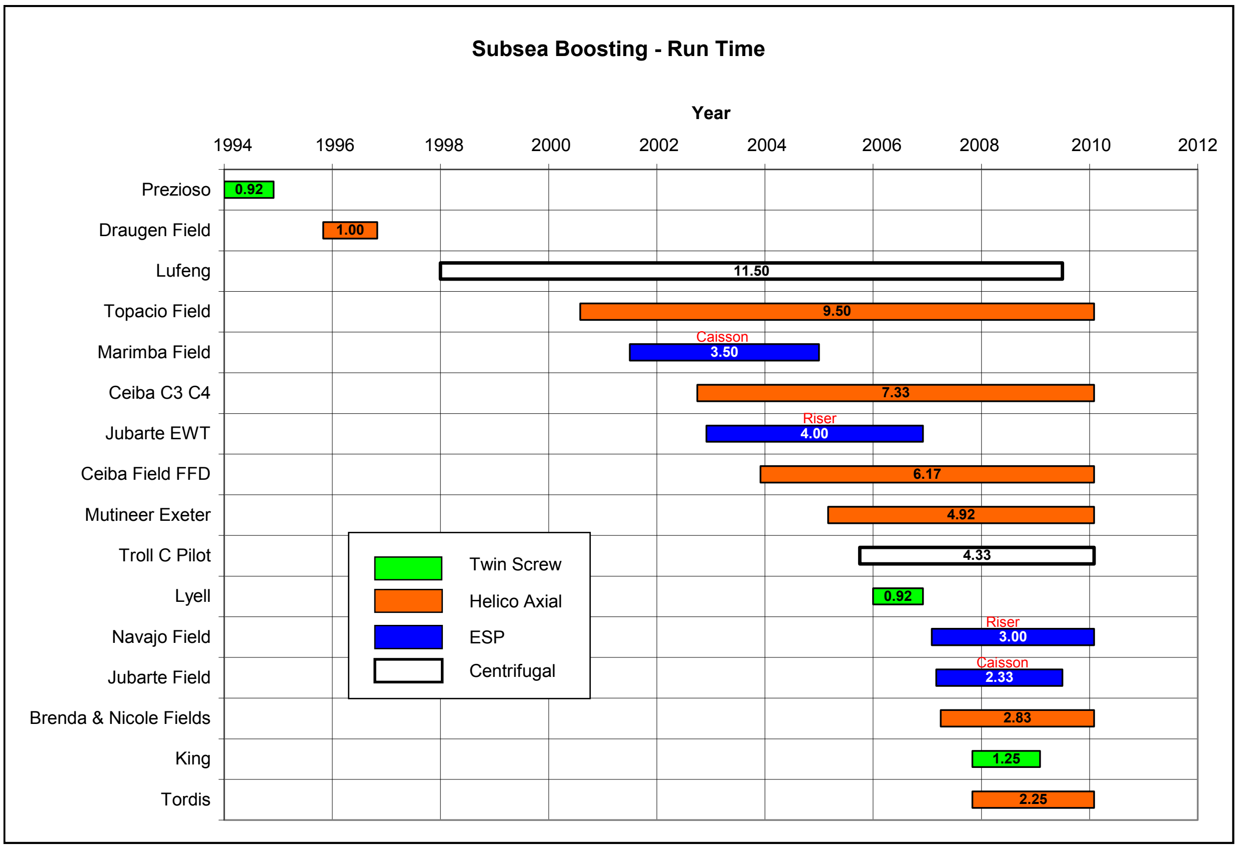


Figure 23: Subsea pumping projects, runtimes

Very good runtimes (2-10 years) were also achieved with helico-axial pumps, with flowstreams having GVFs as high as 60-75%. All of the helico-axial pumps in the database are still in operation with the exception of one pump installed in the Draugen field in 1995, which only operated for 1 year.

The Topacio field, located in Equatorial Guinea, operates with two helico-axial pumps that are still in operation after 9.5 years. These pumps demonstrate the superior handling of higher flowstream GVF over that of the simple centrifugal pump at Lufeng (75% vs. 3% GVF). Similar high GVF flowstreams have also been pumped using helico-axial pumps in the Ceiba field, also in Equatorial Guinea.

More helico-axial pumps have been used in subsea operations than twin-screw pumps, and the run-lives of helico-axial pumps far exceed those of twin-screw pumps (114 vs. 15 months). Currently, there are no reported subsea twin-screw pumps in operation.

ESPs have been run through a number of field tests, including installations in the Marimba and Jubarte fields, both located in Brazil. These tests have been performed in both riser and seafloor caisson applications, and have experienced significant runtimes of 2-4 years. The seafloor caisson application involves subsea gas-liquid separation prior to boosting, and is discussed further in the Subsea Separation section of this report.

Figure 24 shows a distinct progression of subsea booster pump installations into deeper waters through time. Early installations included twin-screw and helico-axial pumps installed in shallow waters, followed by helico-axial pumps installed in deep water.

A further progression into deep and ultra deep waters is also noted, with dominance in the use of ESPs where larger differential pressures are required to overcome greater hydrostatic heads in risers and friction losses in longer tie-backs (Figure 24, Figure 25, Figure 26).

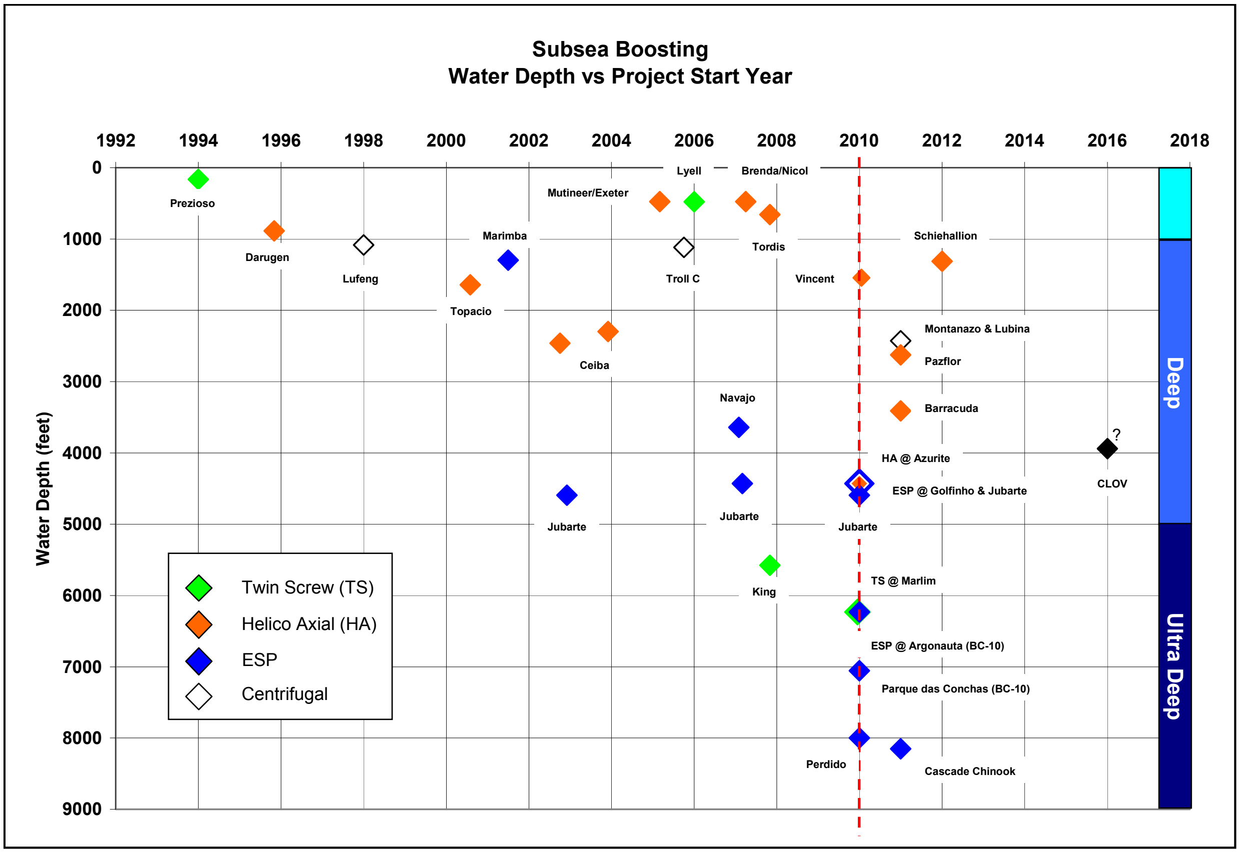


Figure 24: Subsea pumping projects, water depth vs. start date

Most of the ESP installations are in conjunction with the use of seabed caisson separators, which remove gas from the flowstream prior to boosting. Significant subsea caisson ESP boosting projects have recently been installed at Parque das Conchas (Brazil) and at Perdido (GOM) in ultra deep water depths from 6,200 to 8,000 ft.

Horizontal skid-mounted ESPs are currently being manufactured for the Cascade and Chinook fields in the GOM, and in the Espardate field in Brazil. The Cascade-Chinook installation will be in the deepest water depth to date (8,150 ft). Horizontal skid-mounted ESPs are suitable for low GVF flowstreams requiring high differential pressures.

The only twin-screw application in deep/ultra deep water was installed in the King field in the GOM, but ceased operation after 15 months due to operational and capacity issues at the Marlin TLP facility. An ultra deepwater, a twin-screw field test is planned for the Marlim field (Brazil) in 2010.

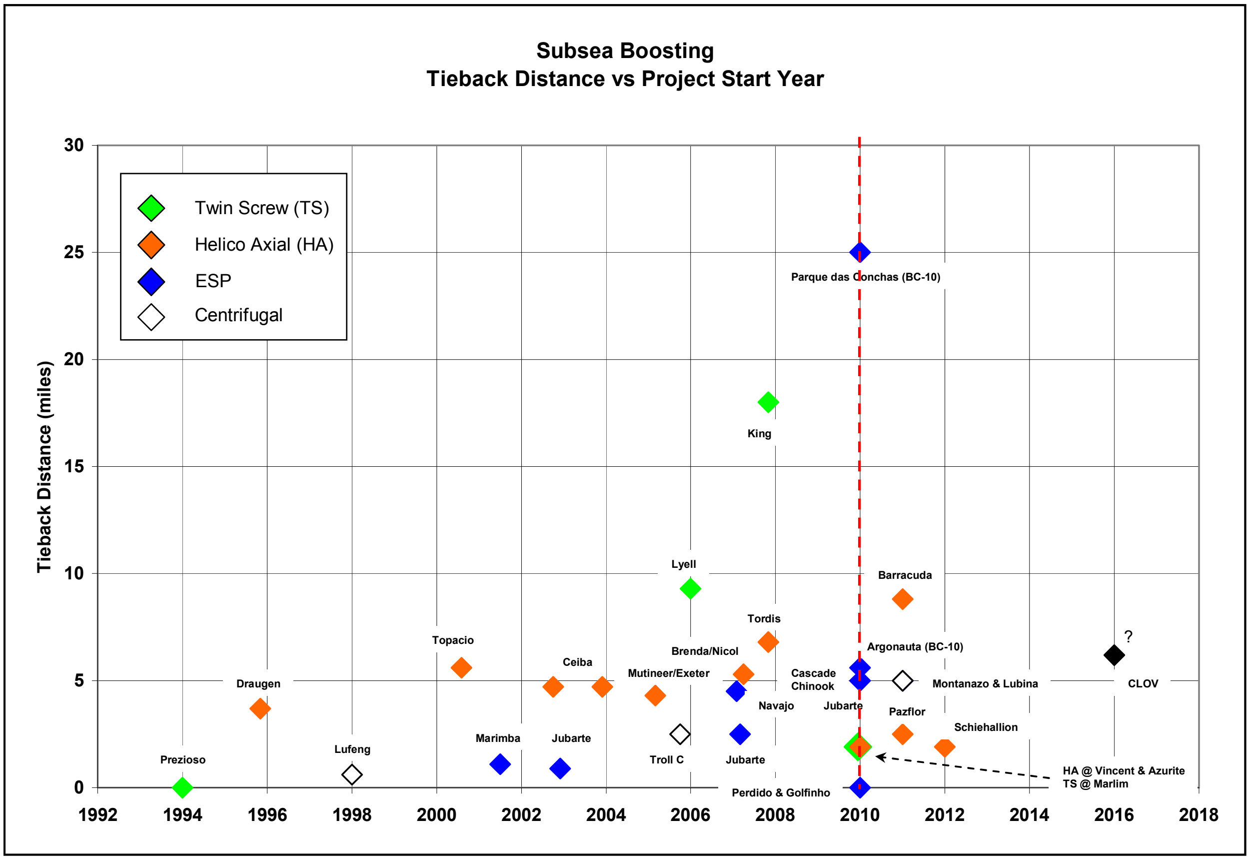


Figure 25: Subsea pumping projects, tie-back distance vs. start date

Historically, subsea boosting has been limited to fields with relatively short tie-back distances of less than 7 miles. Most pumps used have been helico-axial pumps with tie-backs of 4-5 miles.

A twin-screw pump was employed in the Lyell field (UK North Sea), with a 9 mile tie-back; however, for unknown reasons, this pump was only in operation for less than 1 year.

The twin-screw booster pumps, recently installed in the King field (GOM), are currently idle after operating for 15 months due to operational and capacity issues at the Marlin TLP facility.

A significant step-change in subsea boosting will take place in the Parque das Conchas project in Brazil, where production from several fields will be boosted 25 miles through a tie-back to the surface host facility.

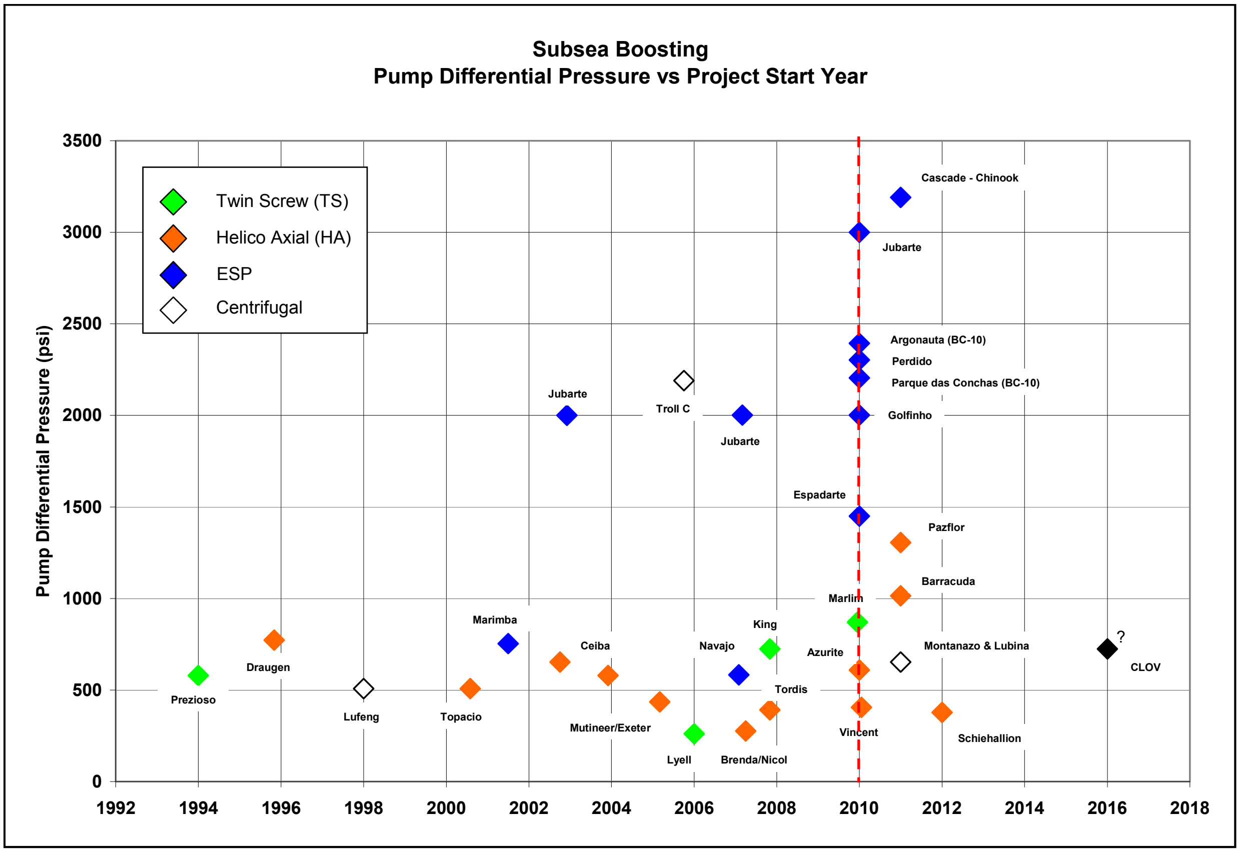


Figure 26: Subsea pumping projects, differential pressure vs. start date

The centrifugal pump installation for Troll-C Pilot in Norway has the highest operating differential pressure (2,190 psi) of all past subsea pump installations. This subsea boosting installation operated for 54 months, pumping a gas-free flowstream downstream of a subsea horizontal separator.

Seabed riser and caisson ESP installations in the Jubarte field (Brazil) achieved 2,000 psi differential pressure in pumping flowstreams with GVFs of 22% and 40%, respectively.

While the 25 mile subsea tie-back at Parque das Conchas dictates a larger differential pump pressure to overcome frictional pipe losses, most future cases involve relatively short subsea tie-backs but lengthy riser heights associated with deep and ultra deep water depths (as great as 8,200 ft). These great depths create large hydrostatic pressures, which are often 5 to 10 times greater than the friction loss in horizontal pipes (M.L.L. Euphemio et al of Petrobras, OTC-20186).

While historical performance proves the successful application of subsea boosting of 20-40% GVF flowstreams to 2,000 psi differential pressure using ESPs (Figure 2, on page 3), recent manufacturer tests indicate the ability to achieve slightly higher differential pressures depending upon GVF percentage (Table 4, on page 6). The selection and design of subsea pump systems need to take into consideration the full range of pressure and GVF over the life of a project.

Actual performance data indicate similar pressure differentials for twin-screw and helico-axial pumps (725 vs. 773 psi). Recent results from Flowserve's subsea pumping system testing also indicates similar pressure differentials for the twin-screw and helico-axial pumps, but at much higher values than observed in actual installations (2,174 vs. 2,320 psi).

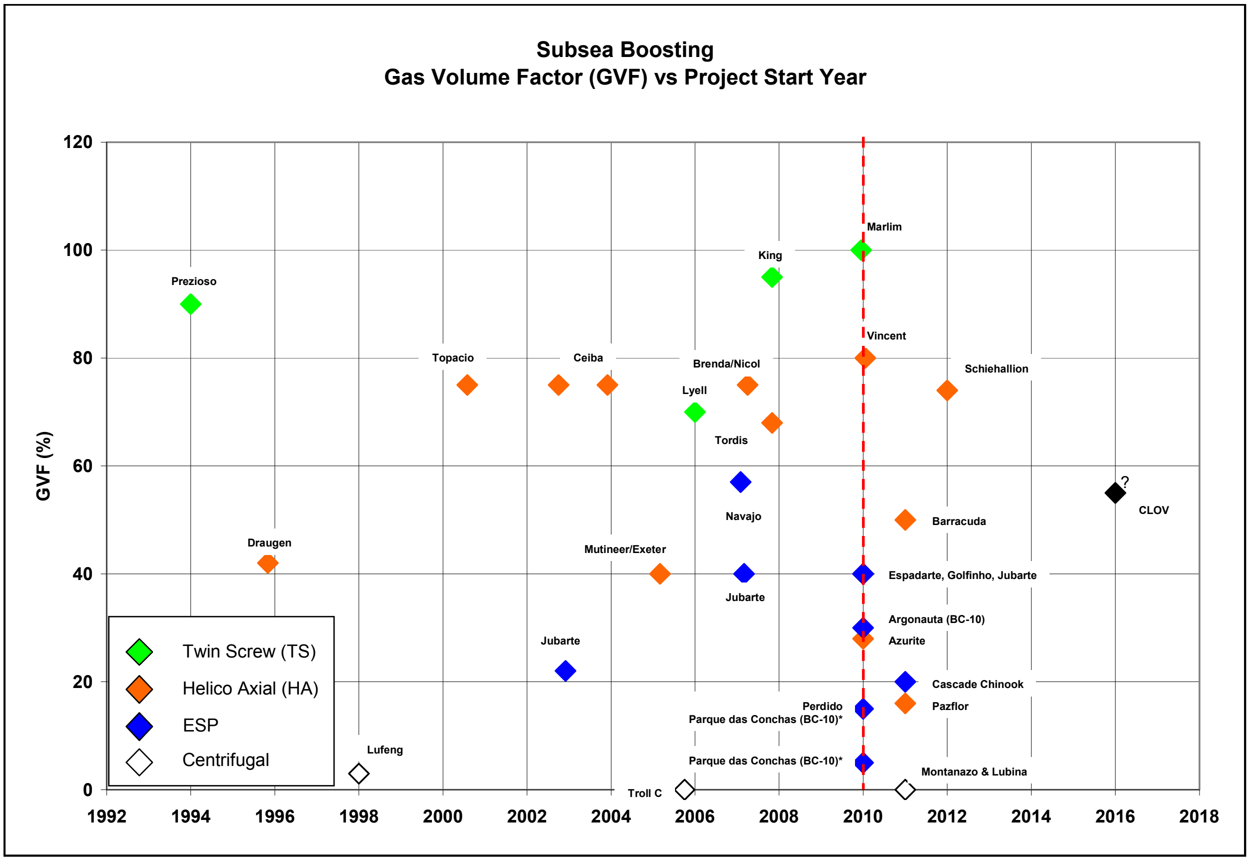


Figure 27: Subsea pumping projects, GVF vs. start date

Figure 27 summarizes flowstream GVFs of past and future pump installations. Actual performance data indicate twin-screw pumps operating with flowstreams having GVFs of 90-95% for periods of less than 1 year. The recent short runtimes in the King field are attributed to operational and capacity issues, and are inconclusive at this time.

The use of helico-axial pumps at relatively high GVFs flowstreams, however, are conclusive and indicate the ability to pump 75% GVF flowstreams for periods of 9.5 years and greater.

Performance data from actual installations indicate that twin-screw pumps are capable of handling flowstreams with higher GVF (95%); however, helico-axial pumps have been tested at similar GVF values of 95%.

General trends show the boosting capabilities of helico-axial and twin-screw pumps at fairly constant values of differential pressure until GVFs approach 70% and 85%, respectively, at which point their boosting capabilities decline. The boosting capability of the centrifugal pump also declines with increasing GVF, but completely loses its boosting capability at a GVF of 20%.

While ESPs and centrifugal pumps have performed well at higher differential pressures (2,000 psi), only ESPs have pressure boosting capability in flowstreams having GVFs of greater than 20%.

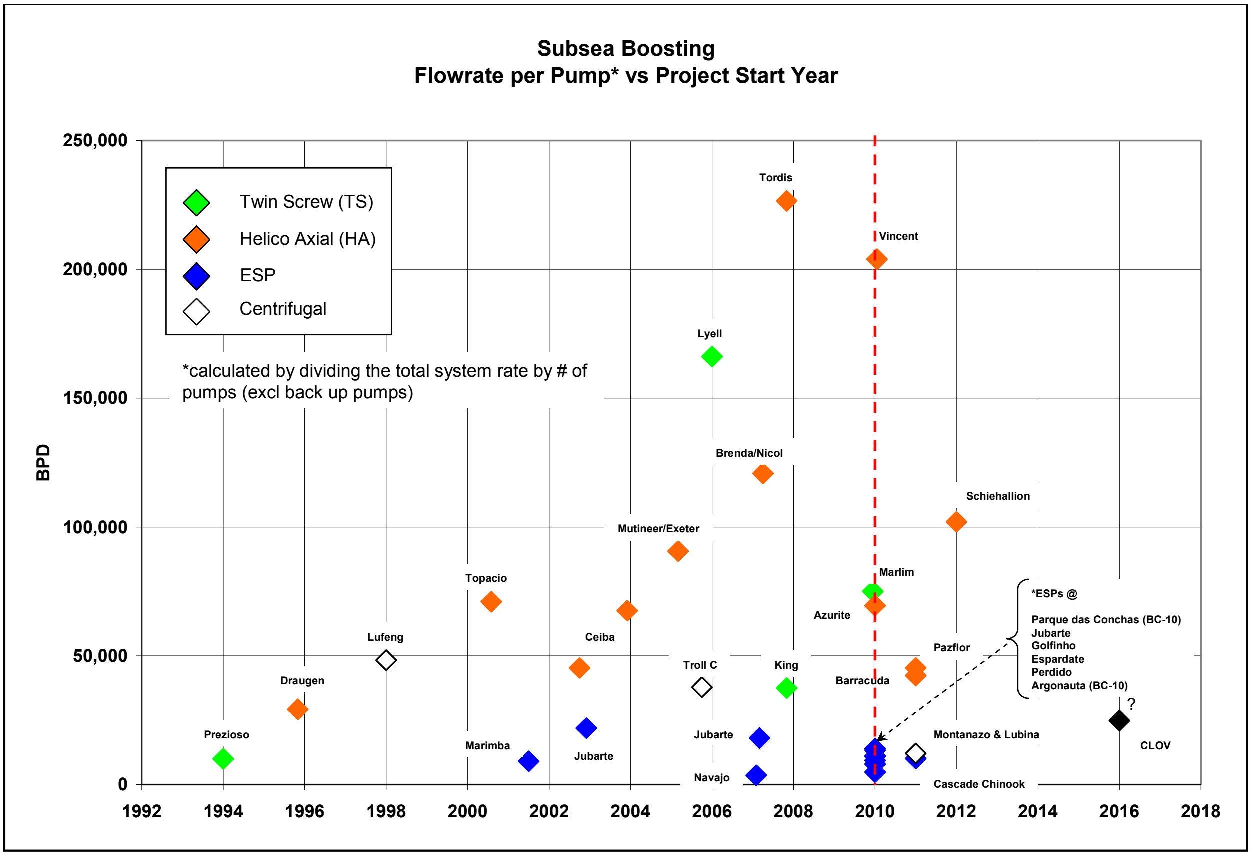


Figure 28: Subsea pumping projects, individual pump rates vs. start date

Historical data indicates higher individual pump rates can be achieved using helico-axial and twin-screw pumps (Figure 28). While individual ESPs provide less pump rates, multiple pumps operated in parallel can be used to achieve higher total project rates. This is particularly applicable in cases where higher pump differential pressures are required to move produced fluids to host facilities.

Manufacturer information indicates individual pump rate capabilities in excess of the values shown in Figure 28 (see Table 9). These results are likely at very low GVFs.

Table 9: Manufacturer tested pump rates

Pump Type	Manufacturer	Individual Pump Rate (bpd)
ESP	REDA	100,000
Helico-Axial	Sultzer	600,000
Twin-Screw	Leistritz	604,000

6 Riser Gas Lift

The use of gas-lift inside of a production riser has been employed in multiple subsea operations, and is a proven method to increase and stabilize production rates. The injection of gas into the flowstream, at the base of the riser, lightens the fluid column, thereby reducing the hydrostatic pressure in the riser. Additionally, gas-lifting a production riser has proven useful for hydrate remediation by depressurizing flowlines below hydrate dissociation pressures, and in kicking-off production after shut-in periods (OTC-18820).

Gas-lifting a production riser is often the boosting method of choice simply because of the lack of moving parts in the subsea realm; it provides a reliable means of boosting/artificial lift, with little downtime, and relatively inexpensive topside repairs (if needed).

Gas-lifting a production riser is typically used in marginal and late-life fields where flowstreams are characterized by:

- Lower production rates (from reservoir pressure decline)
- Higher water cuts (higher hydrostatic back pressures in riser)
- Low gas-oil ratios (no gas to lighten-up the hydrostatic pressure in riser)

In cases where production rates are higher, the injection of gas-lift gas in the riser flowstream may actually increase back pressure on the wells, impeding production. Therefore, the entire production system (from reservoir to topside) should be analyzed using a fully integrated production modeling software to ensure that the most reliable and most efficient boosting technology is selected.

Obviously, a source of gas and gas compression is required to utilize a gas-lift. In the case of depressurizing a riser for hydrate remediation, another source of gas (gas from a gas sales line) may be required if the hydrate remediation calls for a full-field shut in of gas production. Riser gas-lift has been installed in the following locations:

- Placid/Enserch – GOM, Green Canyon Development, 469 ft water depth
- Total – Angola, Girassol field, 4,428 ft water depth
- Exxon – Angola, Kizomba A and B, 3,936 ft water depth
- Total – Angola, Rosa, 4,400 ft+/- water depth
- BP – Block 18
- Petrobras – Brazil, Campos basin, Roncondor field, 5,900 ft water depth

7 Seafloor Separation

To date, five subsea separation projects have been implemented, and include two three-phase horizontal separators and three gas-liquid seabed caisson separators (previously mentioned in the ESP boosting discussion of this report). Table 10 summarizes the five implemented projects.

Table 10: Subsea separation projects

Subsea Separation					
Field/Project	Location	Separation Method	Start Date	Runtime (months)	Current Status
Troll-C Pilot	Norway	3-Phase Horiz	Sep-99	124.8	Operational
Marimba	Brazil	Gas - Liquid Seabed Caisson	Jul-01	83.8	Non-Operational
Jubarte	Brazil	Gas - Liquid Seabed Caisson	Mar-07	27.5	Non-Operational
Tordis	Norway	3-Phase Horiz	Nov-07	1.0	Non-Operational*
Perdido	GOM	Gas - Liquid Seabed Caisson	Mar-10	1	Operational

* unable to inject water into reservoir, therefore separation not needed; currently operating as a boosting operation only.

7.1 *Horizontal Separator*

Figure 29 shows how reservoir fluids (oil, water, and gas) are produced from the reservoir into a sea floor gravity based horizontal separator, where water is removed from the bottom of the vessel and pumped back into a reservoir, and oil and gas are flowed or pumped to a surface facility via a flowline riser. By removing the water from the flowstream, the hydrostatic back pressure in the riser is reduced.

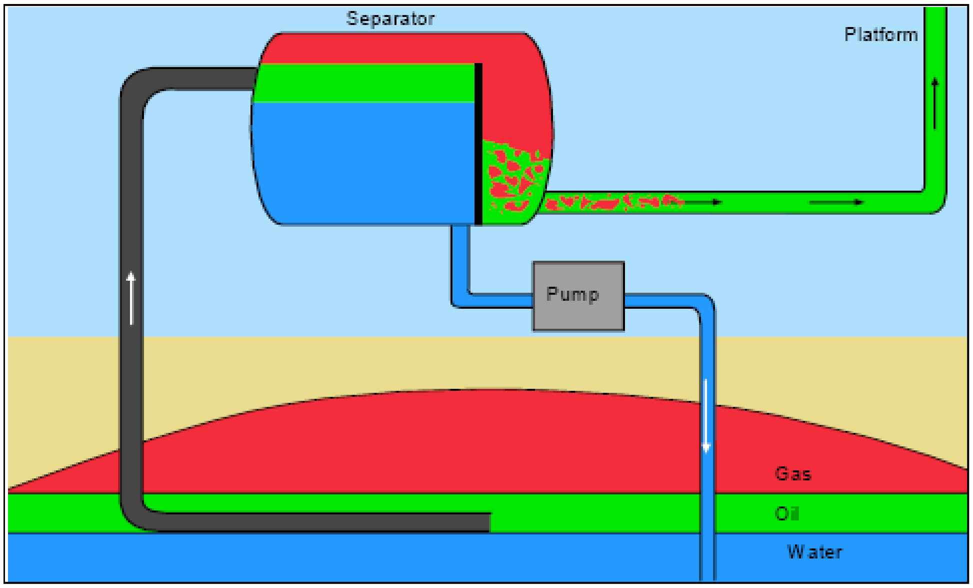


Figure 29: From Hydro Oil and Energy Presentation, Appex London 2005, E&P Hotspots II: Deepwater and Frontiers, Olav Nipen

7.1.1 Horizontal Separator at Troll-C Pilot

The first application of this subsea technology was by NorskHydro in the Troll-C pilot project, located in the Norwegian North Sea in 1,116 ft of water. This project was installed in 1999, but was not put into service until August 2001, when separation and injection operations began. Subsea boosting operations did not begin at Troll-C until late 2005, when a centrifugal booster pump was installed on the oil leg of the separator (no gas). Note that the well(s) ceased to produce on their own in 2003, prompting the subsequent booster pump installation.

The Troll-C separator vessel is 39 ft long with a diameter of 9 ft, and has the following design/operating parameters:

- Temperature: 140° F
- Design pressure: 2,600 psi
- Operating pressure: 510 – 1,520 psi
- Oil API gravity: 37°
- Total liquid rate: 63,000 bpd
- Oil rate: 25,000 bpd
- Gas rate: 28 mmcfpd
- Water injection: 38,000 bpd
- Design water in oil: <10% in oil outlet
- Design oil in water: <1,000 mg/l in water outlet

The Troll-C separator includes a cyclonic inlet to provide pre-separation of gas and liquids, as well as a sand removal system (although no sand has been produced at Troll-C).

While water sometimes flows naturally into the injection well at Troll-C, it is usually boosted via a 2-MW (2,700 hp) centrifugal pump capable of generating a differential pressure of 2,175 psi.

After a wet mate electrical failure during the initial start-up in 2000, the separator station was put into operation in August 2001. The station operated "with high regularity and availability" during the first 3 years of operation, requiring minimum interventions for pump and level control repairs. From 2005 to 2006 instrumentation problems occurred, but did not result in system downtime. The separator station has operated at nearly 100% availability since 2008.

7.1.2 Horizontal Separator at Tordis

Building on the success of the Troll-C pilot project, Statoil (formerly Hydro) installed a similar subsea separation, boosting, and injection (SSBI) station in the Tordis field. The Tordis field is located in the Norwegian North Sea in 690 ft of water. This project was installed in 2007, when separation and injection operations began.

The Tordis SSBI is significantly larger than its Troll-C predecessor, with overall unit dimensions of 62 ft high, 131 ft long, 82 ft wide, and a weight of 1,250 tons. The Tordis separator vessel is 56 ft long with a diameter of 7 ft, and has the following design/operating parameters:

- Temperature: 167° F
- Design pressure: 2,600 psi
- Operating pressure: 360 - 580 psi
- Oil API gravity: 37°
- GOR: 110 - 138
- Total liquid rate: 189,000 bpd
- Oil rate: 57,000 bpd
- Gas rate: 35 mmcfpd
- Water injection: 150,000 bpd
- Design water in oil: <57,000 bpd
- Design oil in water: < 1000 mg/l in water outlet
- Sand handling: 110 – 1,100 lbs per day
- MPP: 2.3 MW (3,085 hp)
- SPP: 2.3 MW (3,085 hp)

Both multiphase and water injection pumps are standard Framo helico-axial pumps, driven by electric motors powered by electrical cables from the Gulfaks-C platform. Both pumps can be retrieved and replaced using a pump running tool.

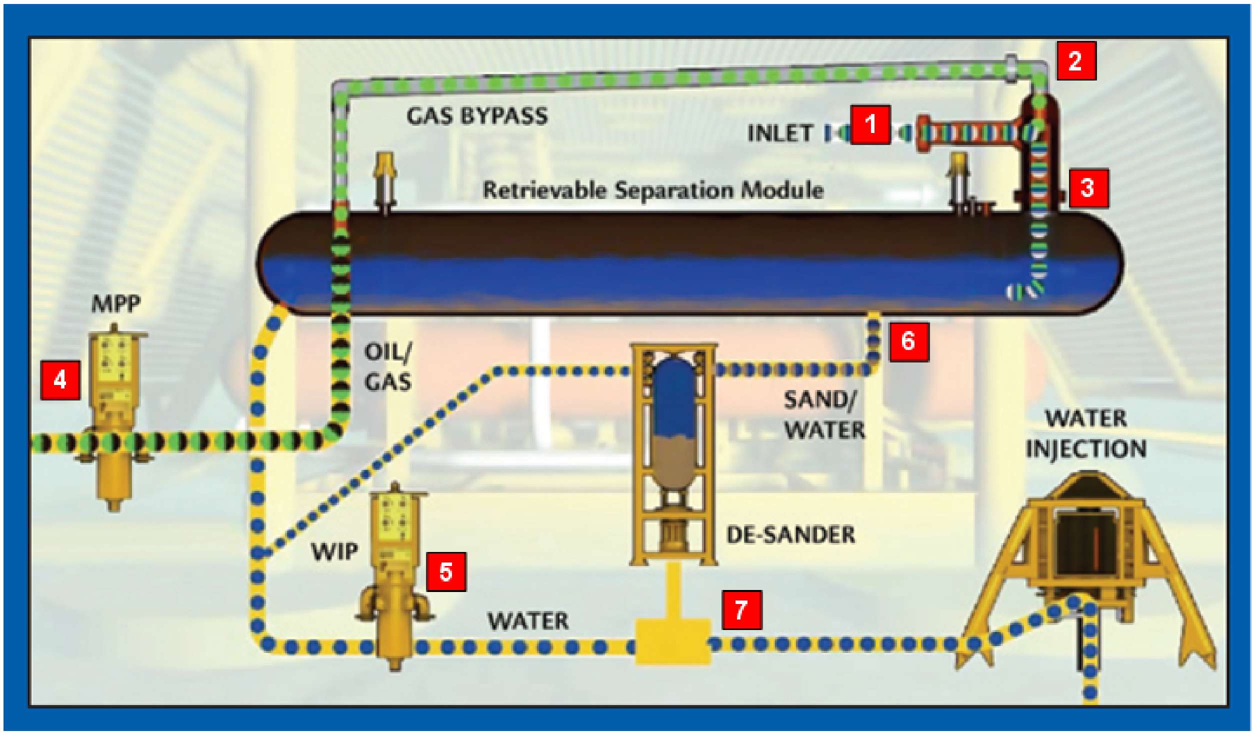


Figure 30: Tordis SSBI

Figure 30 is a schematic of the Tordis SSBI station. The key points of operations are as follows:

1. Well fluids enter the inlet cyclone
2. Gas is routed through the gas by-pass to top of separator vessel
3. Oil, water, and sand enter the separator vessel
4. Multiphase pump pumps oil, gas, and some water 11 km to Gulfaks C platform
5. Water is pumped via a water injection pump to disposal well
6. Sand is removed from the separator vessel 1-2 times per week
7. Sand is inserted into water stream for disposal into injection well
   a. Downstream of pump
   b. 110 – 1,100 pounds per day

Unfortunately, reinjection of produced water (and sand) in the Tordis project ceased after only one month, when the injection zone no longer “took” water. According to Statoil’s chief researcher of upstream process and flow assurance (E&P Magazine, March 2010), “the aquifer was not suited for reinjection of produced water, but we proved the technology worked”. The station is currently in operation, but only as a booster station pumping oil and water back to the Gulfaks C platform. Statoil is currently evaluating options to either add a new injection well or increase the water handling capacity of the Gulfaks platform.

7.2 *Gas-Liquid Seafloor Caisson*

The gas-liquid caisson separator is a component of the vertical annular separation and pumping system (VASPS), first developed by Petrobras in Brazil. This system has also been referred to as MOBO (modulo de bombas or pumping module).

The VASPS separator is basically a "dummy" well, drilled in the seafloor (~300 ft deep), cased with large diameter pipe (30 in. – 34 in. OD), and sealed-off with a subsea wellhead. Produced fluids from producing wells flow into the separator, where gravity separation of water, oil, and gas takes place. An ESP is installed in the "dummy" well at a depth such that oil and some water enters the pump, and is transported to a surface host facility via a separate oil/water production riser. Gas is vented out the top of the well, and is transported via a separate riser (see Figure 22 on page 37).

The VASPS allows for the transport and ultimate sale of oil and gas by removing gas from the flowstream at the seafloor. Removing gas from the flowstream at the seafloor enables the use of high-powered, high ΔP pumps required to overcome high back pressure on wells associated with large hydrostatic pressure from deepwater and ultra deepwater risers, and frictional pressure drop from long tie-backs.

The first installation of an ESP in a seafloor caisson occurred in the Marimba field, offshore Brail in 1,296 ft of water. This installation was in conjunction with a joint industry project (JIP) with Petrobras, ENI-Agip, and ExxonMobil. Referred to as a vertical annular separation and pumping system (VASPS), this ESP installation occurred in the year 2000 and began operating in July 2001, but experienced a failure less than 6 months later. The pump was replaced in 2004, resumed operations in 2005, and ran continuously for 3.5 years until a "well failure" in July 2008.

The next reported installation of an ESP in a seafloor caisson was in the Jubarte field, located in 4,429 ft of water, offshore Brazil. This system was called a Seabed ESP-MOBU (modulo de bombas/pumping module) (modulo de bombas/pumping module). The pump began operating in March 2007, and operated for 28 months before experiencing operational problems.

Five VASPS were recently installed in the Perdido deepwater development, with first production achieved in the first quarter of 2010. Perdido is located 200 miles off the Texas Gulf Coast, in 8000 ft of water, and is the first producing development from the Lower Tertiary in the Gulf of Mexico.

7.3 *Vertical Separator*

A seabed vertical separator has not been utilized to date. This technology is scheduled to be installed in the Pazflor development, located 93 miles offshore Angola in 2,000 to 4,000 ft of water. The Pazflor project is scheduled to start-up in 2011.

Lighter Oligocene crude (35° API) will be boosted from the seabed using riser gas-lift, while heavier Miocene crude (17° API) will be separated from gas in a vertical separator and boosted to the surface utilizing a helico-axial/centrifugal hybrid pump. The separated gas will flow to the surface in its own riser.

The Pazflor project will utilize three vertical gas-liquid separation systems and six hybrid booster pumps (two pumps per separation unit) to process the viscous Miocene crude (3-10 cp at reservoir conditions). Miocene crude, which makes up two-thirds (2/3) of the total crude to be produced at Pazflor, requires separation specifications capable of handling 110,000 blpd and 35 mmcfpd.

Each of the hybrid pumps are 2.3 MW units, and are capability of pumping 70,000 blpd at differential pump pressures from 1,160 to 1,450 psi (SPE-123787). These pumps are a variation of a helico-axial pump, and have multiple rotors in series, followed by multiple diffusers in series (Chris Shaw, FMC Technologies).

The separator vessels at Pazflor will have dimensions of 30 ft length and 12 ft in diameter.

Figure 31: Pazflor vertical separation system

8 Seafloor Compression

Historical pressure boosting operations have been in the realm of wet gas compression with GVFs greater than 80%. Pressure boosting operations in the Prezioso and King fields operated with GVFs greater than 80% using twin-screw multiphase pumps (MPPs). Unfortunately, both pumps had short run times of 0.92 years and 1.25 years, respectively. The Lyell field had a twin-screw pump with a high GVF of 70%, and had a short runtime of 0.92 years.

While true gas compression equipment has yet to be placed into subsea operation, extensive testing of compression equipment is ongoing in association with the Ormen Lange development (Norwegian North Sea), after which operator, Statoil, will make the decision to install compression equipment on the seafloor or on a platform.

Discovered in 1997, Ormen Lange is the third largest gas field in Europe, with estimated reserves of 10 Tcf of natural gas. This volume was recently reduced from 14 Tcf, after delineation drilling failed to prove-up the previous higher estimate. Ormen Lange is located 75 miles offshore Norway, in the Norwegian Sea, in water depths of 2,625 to 3,609 ft. The productive reservoir lies 9,843 ft below the surface.

Extreme temperatures and strong currents make field development difficult, with low water temperatures causing hydrate formation in seafloor production equipment (potential plugging) and strong currents threatening subsea facilities. Mountainous sea floor topography in the area also creates unique challenges for subsea development.

In spite of these challenges, Phase-1 of the development was completed and production commenced in 2007. Ormen Lange currently produces to an onshore processing plant via two 75 mile, 30 in. diameter multiphase flowlines. The processed gas is transported through the Langeled pipeline, 746 miles to Easingtown in the UK.

As pressure (and production) decreases at Ormen Lange, compression will be required to sustain production through the long pipeline to the onshore processing plant. While a floating deepwater platform was considered for compression facilities, a subsea compressor facility was chosen as a more cost efficient option. At a cost of about US $ 401 million, the subsea option is about half the cost of the offshore platform option.

Reportedly, two subsea compression pilot programs are being designed for use in the field. One of the pilots is being run by Aker Solutions, which recently opened a new subsea test/construction hall at its yard in Egersund, Western Norway. The 20,451-sq ft, 85-ft high site will be occupied by Aker's 115 ft x 21 ft x 42 ft pilot subsea compression station, which weighs 1,212 tons. Following assembly and testing in Egersund, the pilot will be transferred to the gas-reception terminal at Nyhamna for endurance testing in a purpose-built test pit.

Statoil plans to use four trains identical to the equipment used in Aker's pilot in its actual subsea installation (Offshore Magazine, January 2010), but if the compressor does not perform well during testing a compression platform can still be built.

The compression unit being tested was built by Siemens, and has the motor, shaft and compressor housed in a single container with rotating seals isolated from gas pressure differentials

The normal maintenance interval for a subsea compression system is anticipated to be 4-5 years, compared to 1 year for a topside facility. The subsea compressor can be pulled as a single unit.

9 Artificial Lift in Subsea Wells

Due to the higher rate requirements from offshore wells (>2,000 bpd per well), the discussion on artificial lift in subsea wells is limited to electrical submersible pumps (ESP) and gas lift (GL).

Artificial lift is widely used in the shallow waters of the Gulf of Mexico, but its use in deepwater (>1,000 ft) is limited at this time. It is certain that most deepwater oil fields will ultimately require artificial lift to maintain production and achieve economic objectives. Planning for artificial lift in deepwater is critical, as the environment is operationally more difficult and economically more challenging.

As is the case in most offshore environments, most wells are drilled as deviated wells from a central location and are tied-back via flowlines to a central gathering facility. Deviated wells present wellbore clearance issues for both ESPs and GL, but both can be utilized if designed properly. In most deviated hole cases, GL is preferred over ESP, as less equipment is put at risk (in the case of equipment getting stuck in the hole). Load-bearing deck space requirements for generators (ESP) and compressors (GL) must be considered in developing the economic justification for artificial lift. Additional equipment and deck space may also be required to handle larger volumes of produced water resulting from artificial lift.

Gas lift is the predominant artificial lift method used in the offshore environment to date; however, as operators progressively move into deepwater, GL applications become more limited (due to higher operating pressures) and ESPs applications become more suitable.

A case comparison was performed by R. Shepler et al of Schlumberger, in which the software, PIPESIM® was used to compare two separate artificial lift installations (GL and ESP) in identical deepwater production systems, as well as combinations of artificial lift in subsea wells and seafloor boosting using a helico-axial multiphase pump (Figure 32).

The system consisted of four wells producing through a subsea manifold and an 8 mile tie-back to a host facility, located in 7,000 ft of water. The reservoir and wellbore characteristics are the same for both cases.

In the ESP case, a REDA JN21000 ESP was selected based on its design rate of 15,000 bpd. The pump was set at 13,500 ft md. In the GL case, the lowest GL injection point was limited to 11,500 ft tvd by GL valve injection pressure. GL injection volumes were 6 mmcfpd.

PIPESIM® results for GL and ESP in the wells (with no seafloor boosting) indicate an 81% higher rate using ESPs over GL (62,500 vs. 34,500 bpd). When used in combination with the seafloor booster, ESPs produced at 51% higher rates over GL (72,000 bpd vs. 47,650 bpd). See Figure 32 for PIPESIM® results.

As previously discussed, the results of Petrobras' testing of artificial lift methods in the Jubarte field (included ESPs in risers, ESPs in wells and ESPs in seafloor caissons), led them to their definitive development plan in which production will be boosted to surface facilities via ESPs in seafloor caissons.

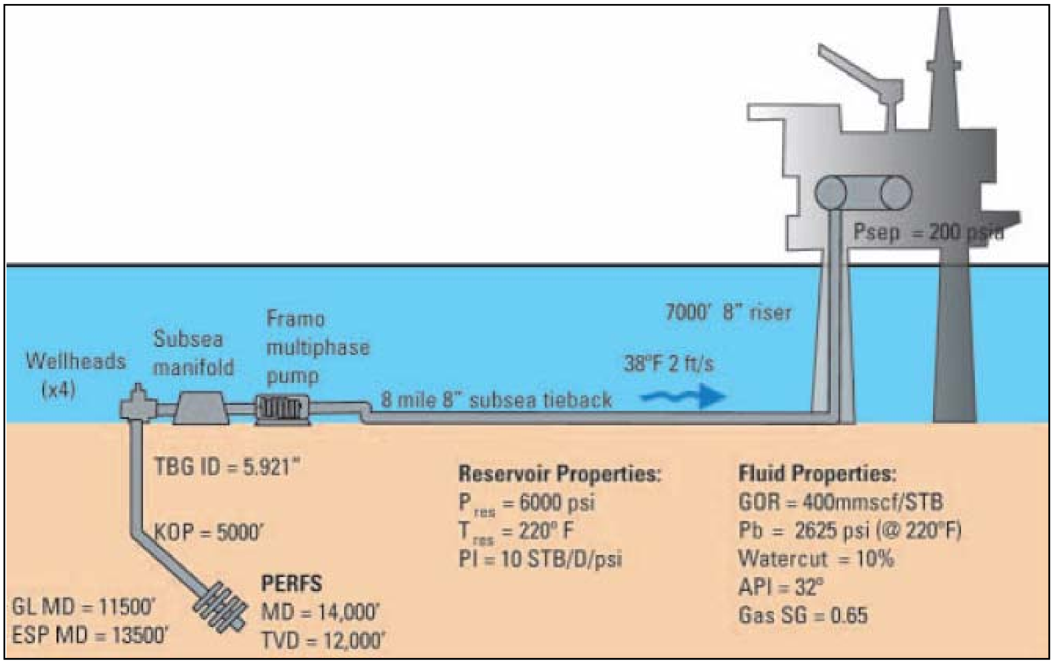


Figure 32: Production system PIPESIM® comparison

(http://www.slb.com/~/media/Files/subsea/industry_articles/200504_ep_lifting_seabed_boosting_payoff.ashx)

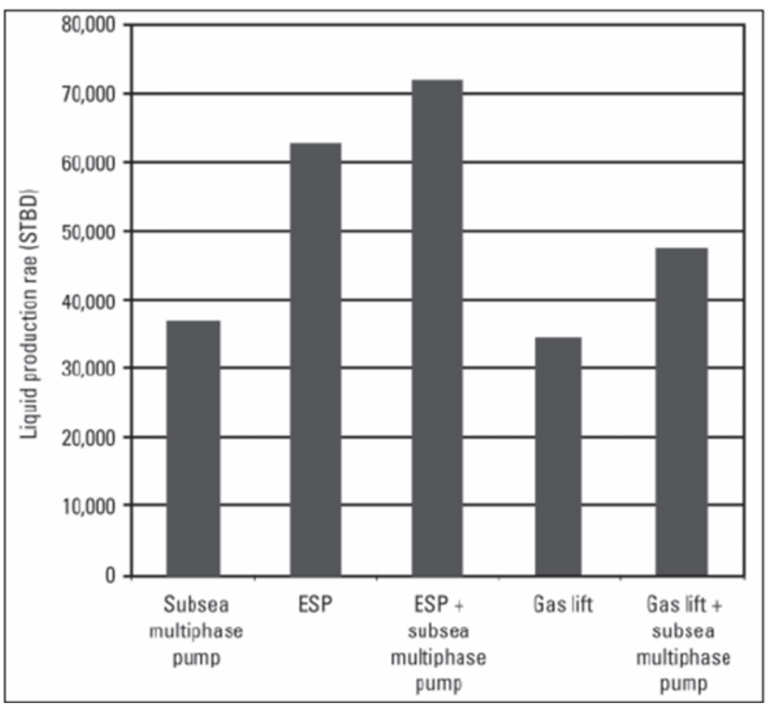


Figure 33: Comparison of production systems using PIPESIM®

(http://www.slb.com/~/media/Files/subsea/industry_articles/200504_ep_lifting_seabed_boosting_payoff.ashx)

10 Flow Assurance

Flow assurance is critical to deepwater oil and gas projects, where blockages either reduce or shut-off oil and gas production altogether and remediation costs can be high. The major areas of concern with flow assurance are wax, asphaltenes, and hydrates.

Figure 34 is an oil phase diagram from a deepwater Gulf of Mexico field, depicting crude oil phase changes as pressure and temperature are decreased in a production system. The diagram shows how asphaltenes, wax, and hydrates form as the crude flows from the reservoir into a flowline (line A – D). Gas also comes out of solution if the pressure in the system drops below the bubble point pressure.

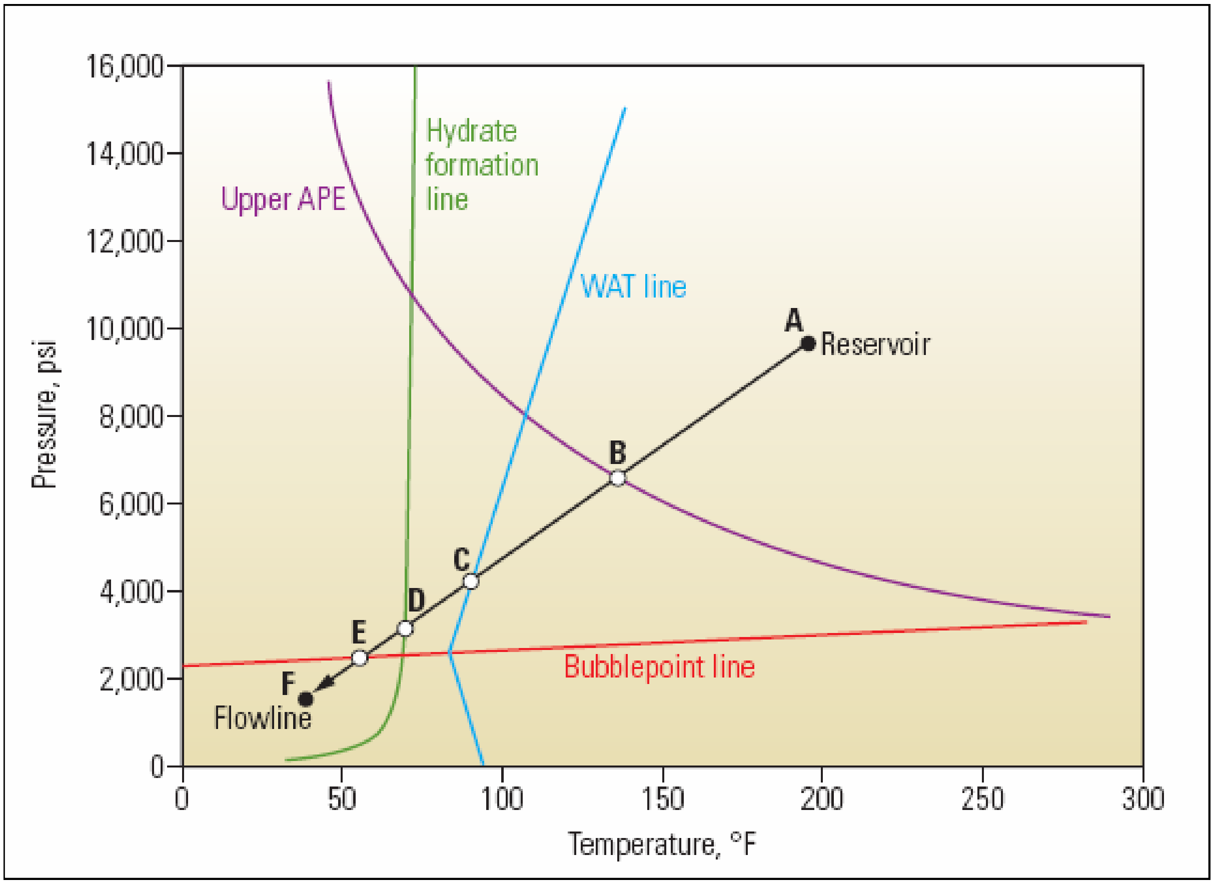


Figure 34: Deepwater GOM oil phase diagram (APE=asphaltene precipitation envelope, WAT = wax appearance temperature)

(http://www.slb.com/~/media/Files/resources/oilfield_review/ors05/spr05/01_subsea_development.ashx)

Samples of reservoir fluids should be tested for potential formation of asphaltenes, wax, and hydrates, and appropriate facility design and/or treatment programs should be considered during project planning.

Proper fluid characterization is important in understanding the conditions under which these flow restrictors form. Knowing the pour point of a hydrocarbon fluid (temperature at which it ceases to flow) is important in the design of production systems. While high pour point crudes are common to API gravity crudes, high pour points can also occur in lighter oils.

10.1 *Wax and Asphaltenes*

Wax and asphaltene formation in pipelines and risers is a significant flow assurance problem, particularly offshore where remediation costs are significantly higher than onshore. While asphaltene formation restricts flow in production systems, it does not usually stop flow completely, as does wax.

Figure 35: Wax removal during offshore pigging operations

(http://www.hydrafact.com/Wax_and_Asphaltenes.html)

The wax appearance temperature (cloud point temperature) and asphaltene flocculation points (precipitation point) can be measured in the laboratory, and should be considered when designing production systems.

Formation prevention techniques include pipeline heating and insulation, and chemical and hot oil treatments. Remedial techniques include chemical and hot oil treatments, and pipeline pigging.

10.2 *Hydrates*

Hydrate formation in deepwater is more likely to occur due to low ambient water temperature at high pressure (resulting from greater subsea depths), during both shut-in periods and during normal operations. Figure 36 is a hydrate stability curve for a typical Gulf of Mexico gas condensate showing how at lower temperatures small changes in pressures, corresponding to shut-in vs. producing conditions, hydrate formation can occur. The shut-in condition aggravates the situation when the warmer reservoir fluids are cooled by the surrounding subsea water, which is typically ~40° F.

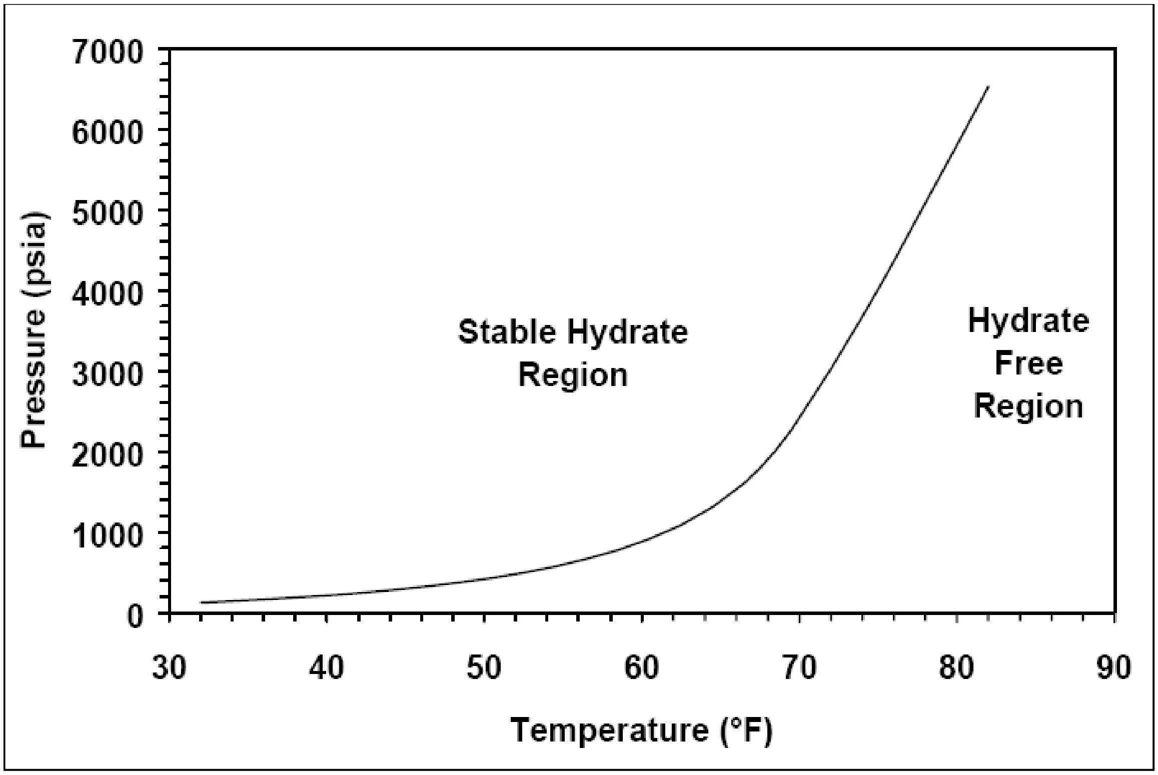


Figure 36: Hydrate stability curve for a typical GOM gas condensate (Int J of Oil, Gas and Coal Technology, Volume 2, No. 2, November 2, 2009)

While the majority of hydrate plugging problems have occurred in gas and gas-condensate systems, hydrate plugging can occur in black oil systems, particularly as water cut increases. In most deepwater Gulf of Mexico oil developments, high water cuts have not been achieved; however, with the application of subsea separation and boosting technologies, fields will be produced to higher water cuts. As such, the design of subsea processing systems for oil fields should consider hydrate formation (Int J of Oil, Gas and Coal Technology, Volume 2, No. 2, November 2, 2009).

In oil systems with <50% water cut, hydrates form as follows (JPT December 2009: Hydrates: State of the Art Inside and Outside Flowlines):

- Water is entrained as droplets in an oil-continuous-phase emulsion
- As the flowline enters the hydrate-formation region (low temp-high press), hydrates grow rapidly (hydrate shell around droplet)
- Hydrate shell grows inward
- Hydrate droplets agglomerate, forming large masses, which can plug the pipeline

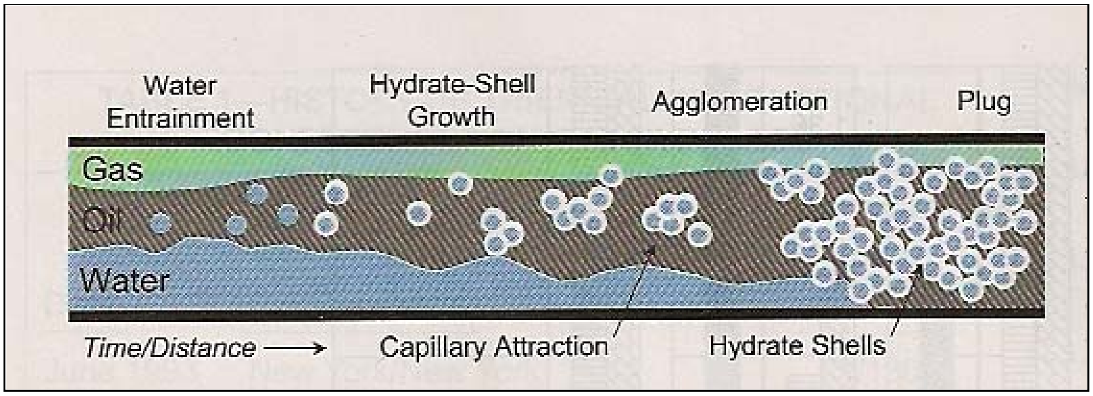


Figure 37: Hydrate formation in an oil dominant system (JPT December 2009: Hydrates: State of the Art Inside and Outside Flowlines)

Removal of hydrate plugs in production systems is difficult and slow, and requires a large amount of energy. Additionally, one cubic foot of hydrate can contain as much as 182 scf of gas, so the process of depressurizing a hydrate plug can result in a rapid release of gas, creating safety concerns.

A better approach to managing hydrates in a production system is by prevention rather than removal. Prevention is achieved through pressure and temperature control, and through chemistry.

Temperature in production systems is managed through tubing and pipeline heating and insulation, while the addition of a desiccant such as Monoethylene Glycol (MEG) to the flowstream creates larger hydrate free regions (Figure 38). Pressure in production systems is controlled through isolating and bleeding-off pressure in pipelines.

At Pazflor in Angola, TOTAL will operate using two anti-hydrate strategies:

- In the Pazflor Miocene production system, operating pressures downstream of the subsea separators will be maintained outside the hydrate forming envelope. In case of an extended shut-in of production, the system upstream of the separators will be depressurized.
- In the Pazflor Oligocene production system, hydrate formation will be prevented with the installation of an insulated pipe-in-pipe production loop. In normal operating conditions, the loop ensures that the produced oil is delivered to the FPSO at a temperature of at least 104°F (wellhead temperature: 230 °F). In case of an extended shut-in of production, inert oil is circulated to maintain temperature (from Total's website).

A new patented process currently being studied is Cold Flow in which hydrate particles are allowed to form, but their agglomeration is prevented through emulsification. This process keeps the hydrate particles entrained in the oil phase, allowing the hydrate particles to flow.

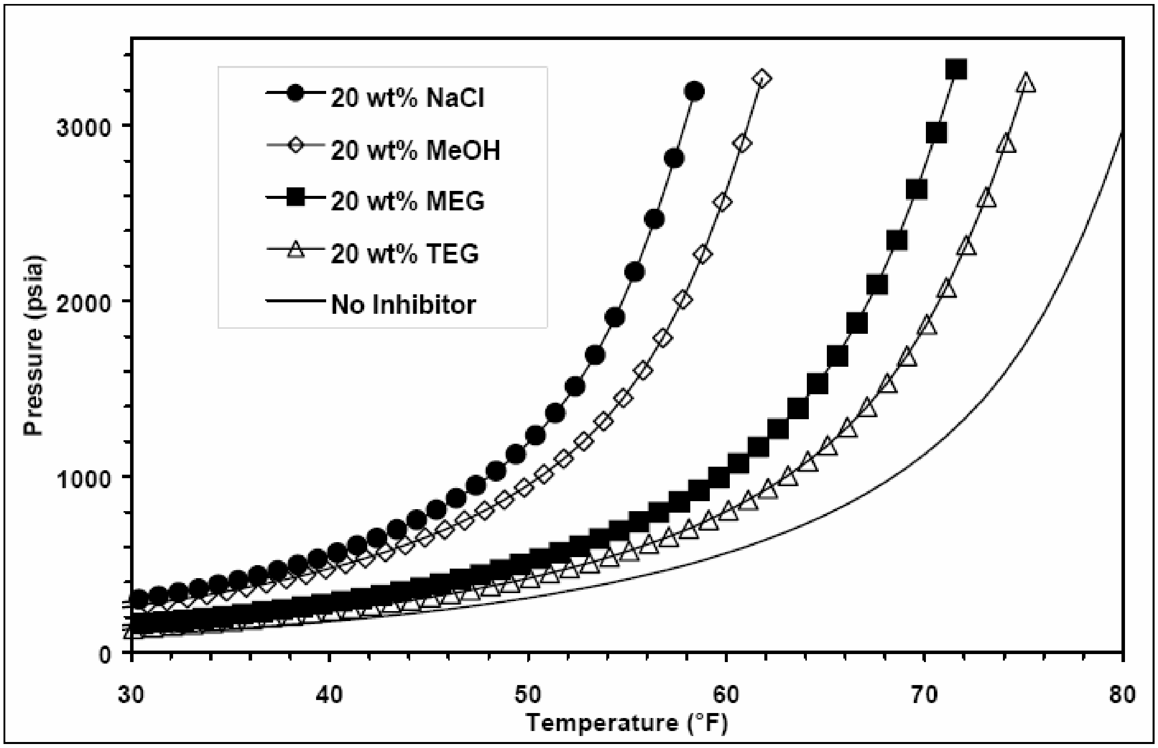


Figure 38: Effect of inhibitors on hydrate stability (Int J of Oil, Gas and Coal technology, Volume 2, No. 2, November 2, 2009)

11 Economics and Risk Assessment

11.1 *Economics*

The economics required to justify the installation of subsea processing equipment are incremental economics, which capture the additional value above the value of a producing asset without the subsea processing equipment. The major components of these incremental economics include incremental oil and gas volumes (rates and ultimate recoveries), and the additional cost to install and operate the processing equipment (CAPEX and OPEX).

While the objective of both Greenfield and Brownfield developments is to increase production rates and ultimate recovery, a significant consideration in the economics of Greenfield developments is the initial placement of processing equipment on the seafloor (rather than on a surface platform), thereby eliminating the need for platform space for processing equipment and reducing platform CAPEX costs.

Typical, oil and gas economics involve the estimation of future cash flows generated by revenue from oil and gas production and costs required to drill wells, install production equipment, and operate the asset. Annual cash flows are then discounted, based upon the owner's cost of capital, and totaled over the life of the asset to arrive at a net present value (NPV). Rates of return on investments are also calculated from the cash flows generated from an asset. Rates of return on projects must meet the operating company's hurdle rate.

Incremental oil and gas volumes resulting from installations of subsea processing equipment result can be realized by both producing at increased rates and producing for a longer period of time. As previously discussed, increased produced volumes are realized when the system outflow curve (back pressure curve) moves down with respect to the reservoir inflow curve; this is accomplished by reducing the back pressure on the reservoir, primarily through artificial lift and boosting in the production system.

While incremental costs associated with subsea installations were not disclosed in the numerous technical papers and industry magazines reviewed, a common opinion is that CAPEX will be reduced because of the reduced topside facility requirements. While OPEX costs were also opined to be lower using subsea processing (due to shorter production lives), intervention costs to replace/repair subsea equipment, and additional remediation costs associated with flow assurance (wax, asphaltene, and hydrate formation due to the lower system pressures and/or cold seafloor temperatures) may actually increase OPEX.

11.2 *Risk*

As with other oil and gas operations, the key elements of risk with subsea processing are associated with excessive costs and less production than anticipated. Oil and gas production deficiencies result in lower revenues, and when combined with excessive costs, result in poorer than expected economics.

In a post-project implementation study of twenty-five Gulf of Mexico fields, Knowledge Reservoir found that eighteen fields (72%) had less reserves and lower peak production rates than pre-development estimations (see Figure 39 and Figure 40).

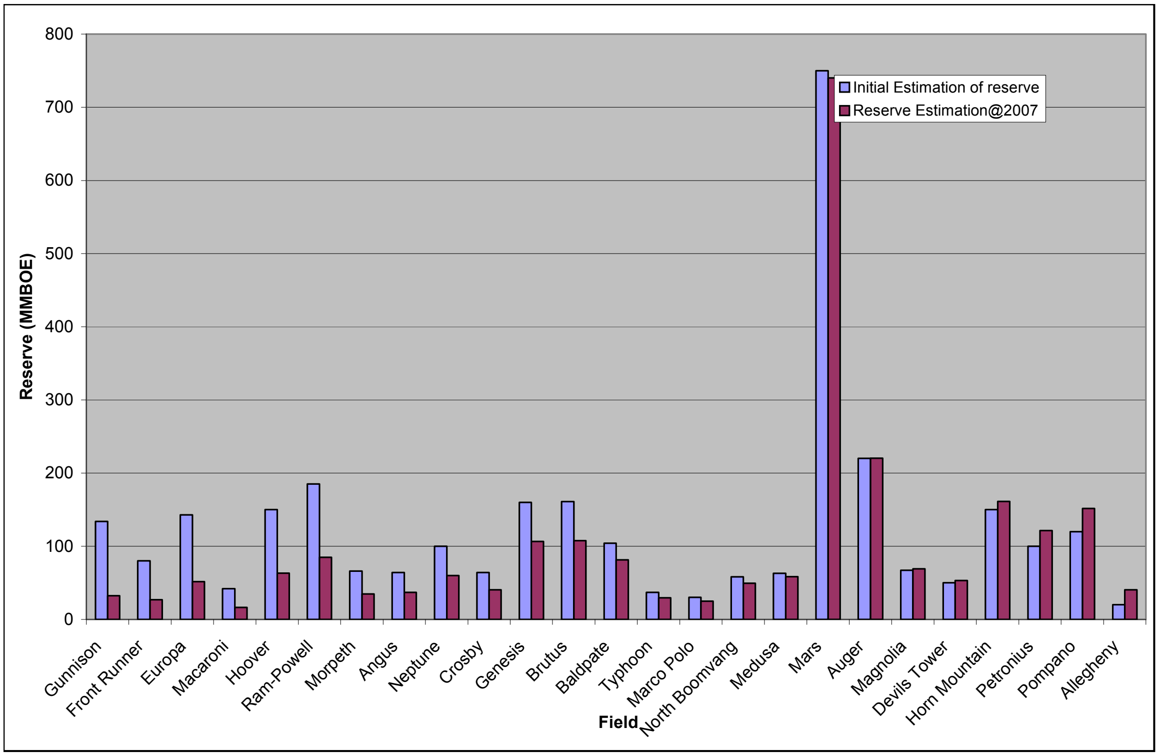


Figure 39: GOM project reserve estimates, pre and post implementation

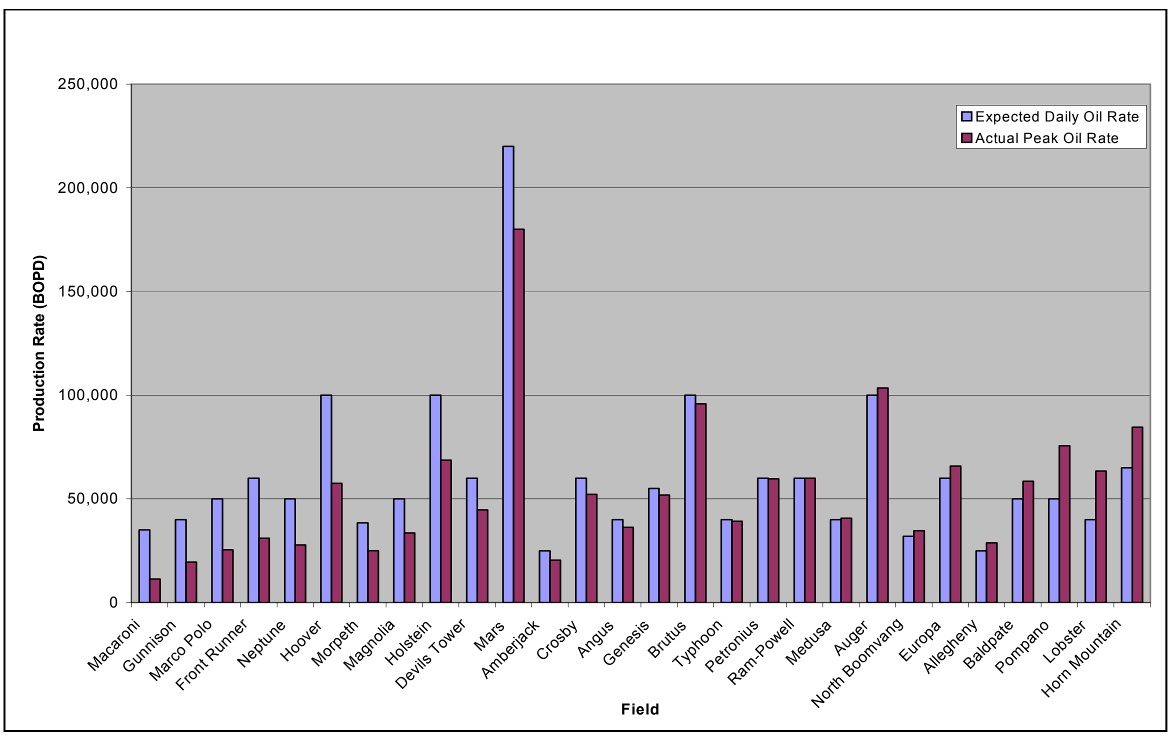


Figure 40: GOM project peak producing rate estimates, pre and post implementation

Excessive costs include both CAPEX and OPEX and associated with the inherent unpredictability of the offshore environment, particularly in deep water (installation, operation, intervention, and environmental remediation costs).

The level of risk in subsea processing is a function of the proven reliability of a particular technology; i.e., how ready is the technology for use in a particular environment. Technology readiness can be measured by actual runtimes, as depicted in Figure 1 (on page 2) for subsea pump systems.

Table 11 summarizes a technology readiness level (TRL) system, adopted by DeepStar, in which the readiness of a particular technology is ranked from TRL 0 to TRL 7, with level 7 being the most ready for application. Additional details can be found on the DeepStar website, www.deepstar.org.

Based on the operating performance summarized in Figure 1 (on page 2) and Figure 2 (on page 3) and Figure 21 (on page 33) through Figure 25 (on page 40), the following pumps may be ranked as TRL 7 and present less risk to install:

- Centrifugal at Lufeng and Troll-C conditions (no gas production)
- Helico-Axial at Topacio, Ceiba, Mutineer/Exeter, Brenda/Nicol conditions
- ESP in Riser at Jubarte and Navajo conditions
- ESP in Seafloor Caisson at Jubarte and Marimba conditions

Subsea horizontal oil-water SSBI system might also be ranked at Level TRL 7, based on the performance of the separator at Troll-C; however, the failed water injection component of the similar system installed at Tordis should be evaluated to better understand the risks associated with this system.

Twin-screw pumps might be rated at TRL 6, as these pumps have been installed at Lyell and King (479 ft and 5,578 ft water depth, respectively) but have operated for short periods of time.

ESPs in caissons, as installed at Perdido (GoM) and BC-10 (Brazil), might be rated at TRL 6, as these subsea systems have been tested onshore in a test pit, but they have only been operating subsea for a short period of time (several months).

Subsea vertical separators and compressors might be ranked at Level 4 or 5, based on the current technology testing for Pazflor and Ormen Lange, respectively.

While risk associated with subsea processing is consistent with other offshore operations, consideration should be given to an actual reduction in risk associated with the placement of processing equipment on the seafloor rather than on a topside platform where the equipment is exposed to weather and waves. Environmental considerations should be paramount in assessing risk.

Table 11: Technology readiness level (Deepstar, DNV, API)

LEVEL		NAME	DEFINITION
Conception	TRL 0	Unproven Idea (paper concept, no analysis or testing)	At TRL 0, a technical need has been identified and a concept has been conceived. The description of the technical need is general in nature without specific performance or functional requirements. The concept has been refined to the point that the physical principles have been documented and simple sketches, if applicable, have been produced. No analysis or testing has been performed.
Proof-of-Concept	TRL 1	Proven Concept (functionality demonstrated by analysis or testing)	At TRL 1, the concept has been refined to the point where the basic physical properties (dimensions, material types, rates, etc.) have been developed and documented and preliminary drawings, if applicable, have been produced. The primary technical requirements are documented. Analysis and/or testing have been performed demonstrating that the concept functions as conceived. The testing may be conducted on individual subcomponents and subsystems without integration into a broader system. The concept may not meet all of the technical requirements at this level, but demonstrates the basic functionality with promise to meet all of the requirements with additional development.
	TRL 2	Breadboard Demonstration (breadboard tested in "realistic" environment)	At TRL 2, the concept is developed into an ad-hoc system of discrete components (breadboard) to establish that the components work together. The system validates that it can function in a "realistic" environment, with the key environmental parameters simulated. Reliability testing is performed on key subcomponents or subsystems.
Prototype	TRL 3	Prototype Tested (prototype developed and tested in non-field realistic environment)	At TRL 3, the technical specifications are developed further and a prototype has been developed. The technical specifications include details of the performance, functional, environmental, and interface requirements. The prototype is tested in a limited range of operating conditions to demonstrate its functionality. The test environment may not be field realistic. This is an isolated test of this technology, without integration into a broader system.
	TRL 4	Environment Tested (prototype tested in field realistic environment)	At TRL 4, the technology meets all of the requirements of TRL 3 and below, except that the testing is conducted in a relevant environment (simulated or actual) over its full operating range. If economically feasible, reliability testing is performed on the prototype system in a realistic environment.
	TRL 5	System Tested (prototype integrated with intended system and functionally tested)	At TRL 5, the technology meets all of the requirements of TRL 4 and below and is integrated into its intended operating system and tested. The testing includes full interface and functional testing. The test environment may not be field realistic. (This TRL may not be applicable for all technology.)
Field Qualified	TRL 6	Technology Deployed (prototype deployed in field test or actual operation)	At TRL 6, the technology has been developed into a field-ready prototype or production unit and has been integrated into its intended operating system and installed in the field. The technology has successfully operated for <10% of its expected life.
	TRL 7	Proven Technology (production unit successfully operational for >10% of expected life)	At TRL 7, the technology is now in production and has been fully integrated into its intended operating system and installed in the field. The technology has successfully operated with acceptable reliability for >10% of its specified life.

12 Future Outlook

Subsea boosting and separation projects are continuing at a fairly rapid rate, with seven projects recently installed (pending start-up), and an additional seven projects in the manufacturing stage. These projects are as follows:

- Installed (pending start-up):
  - Vincent: Dual helico-axial pumps
  - Marlim: Twin-screw pump
  - Golfinho: Caissons with ESPs
  - Azurite: Dual helico-axial pumps
  - Parque das Conchas: Caissons with ESPs
  - Schiehallion: Dual helico-axial pumps
  - Marimba: Caissons with ESP
- Manufacturing stage:
  - Espadarte: Horizontal ESPs on skid
  - Jubarte: Caissons with ESPs
  - Cascade/Chinook: Horizontal ESPs on skid
  - Barracuda: Helico-axial pump
  - Montanazo/Lubina: Centrifugal pump
  - Pazflor: Vertical separators + hybrid helico-axial pumps
  - Marlim: In-line separation

A horizontal ESP boost system will be included in the subsea development of the Cascade and Chinook fields, located in the Walker Ridge area of the Gulf of Mexico, in an average water depth of 8,500 ft. The system, consisting of two horizontal skid mounted electric submersible pumps in a riser, is the first seabed horizontal ESP booster system planned in the Gulf of Mexico. First production is expected by summer, 2010. Baker Hughes Centrilift has been awarded the contract for six seabed electrical submersible pumping (ESP) systems and the associated topsides ESP Management System.

The horizontal ESP booster station design places the ESP system on a permanent base on the seafloor, providing ease of system change out. This design allows an operator to configure systems for redundancy and increase overall availability.

Subsea pressure boosting using horizontal seafloor ESPs will also be installed in Petrobras' Espadarte field, located offshore in the Campos basin in 4,600 ft of water.

Subsea gas compression technology is advancing at a good pace; two subsea compression pilot programs are being tested for use in Statoil's Ormen Lange field. One of the pilots is being run by Aker Solutions, which recently opened a new subsea test/construction hall at its yard in Egersund, Western Norway. Following assembly and testing in Egersund, the pilot will be transferred to the gas-reception terminal at Nyhamna for endurance testing in a purpose-built test pit. Statoil plans to use four trains identical to the equipment used in Aker's pilot in its actual subsea installation (Offshore Magazine, January 2010). If the compressor performs well during testing, the best system reportedly will be chosen by 2011 and installed in 2015; otherwise a compression platform may be built.

Statoil also has plans to install subsea compression in Asgard B field in 2012/2013.

Future challenges in subsea processing technology are primarily associated with operating in deeper water and with longer tie-backs to host facilities.

Deeper water environments are conducive to hydrate formation (lower temperatures and higher pressures), and present significant challenges to flow assurance. Removing hydrate blockages through depressurizing the system can be time consuming, resulting in increased costs and deferred production. The use of hydrate inhibiting chemicals (alcohols) is currently used to prevent hydrate formation, but a new technology called Cold Flow is being tested for oil-water-gas flowstreams. In Cold Flow, hydrate particles are allowed to form but their agglomeration is prevented through emulsification. This process keeps the hydrate particles entrained in the oil phase, allowing the hydrate particles to flow.

Subsea power for long tie-backs may be the biggest challenge of the future. Currently, subsea pumps are operated using AC power provided by a topside generator. Subsea transformers are currently used to make up for resistivity line losses, and operated satisfactorily for up to 50 mile tie-backs. For longer distances, subsea frequency converters are required to convert DC power to AC to operate subsea pumps (DC power losses are not as great as AC in long lines).

13 Summary and Conclusions

The main conclusions from this study are summarized below:

- Subsea processing is centered on pressure boosting, with subsea separation as a supplemental process to modify the flowstream to meet the capabilities of the pump (or compressor).
- The primary benefit of subsea processing is enhanced project economics associated with increased oil and gas production (rates and ultimate recoveries), and cost reductions primarily associated with the elimination of surface facilities.
- Other benefits include:
  - Faster start-up of low energy wells (unloading of wells)
  - Hydrate prevention through depressurization of lines
  - Prevention of slugging in flowlines and risers
  - Allows for development of smaller satellite fields via longer tie-backs.
- The key to increasing oil and gas production is by reducing back pressure on the reservoir, imposed by the production system.
- Reducing back pressure on the reservoir is accomplished through:
  - Artificial lift in wells
  - Pressure boosting using pumps and compressors
  - Reducing hydrostatic pressures in tubing and risers
  - Reducing frictional pressure losses in tubing, flowlines, and risers
  - Reducing surface operating pressures.
- In solution gas drive reservoirs, oil PVT parameters and anticipated pressures should be considered to understand when and where in the production system free gas will exist.
- In water drive reservoirs, increasing water cut should be anticipated to account for an increase in hydrostatic back pressure.
- Brownfield subsea processing projects may not be as economically attractive as Greenfield projects due to higher installations costs to retrofit an existing system, and lower incremental production in already produced fields.
- Subsea centrifugal pumps have historical run lives of 4.3 and 11.5 years, and have proven operations in flowstreams with no gas, and differential pressures up to 2,190 psi. This pump is suitable for GOM applications with no gas in the flowstream.
- Subsea helico-axial pumps have historical run lives up to 9.5 years (six of seven pump systems are still in operation) and have proven operations in flowstreams with GVFs up to 75% at differential pressures of 580 to 750 psi, This pump is suitable for GOM applications.
- Subsea electrical submersible pumps (ESP) have historical run lives up to 3.5 years and have proved operations in flowstreams with:
  - 57% GVF at a differential pressure of 583 psi
  - 15 – 40% GVF at differential pressures of 2,000 to 2,300 psi
  - This pump is suitable for GOM applications.
- Subsea twin-screw pumps have historical run lives less than 1.25 years and have operated in flowstreams with 95% GVF at 725 psi differential pressure.

- The deepest subsea pump installations are ESPs installed at the Perdido project, in 8,000 ft of water.
- The deepest future subsea pump installation is a horizontal, skid-mounted ESP installed at the Cascade/Chinook project, in 8,150 ft of water.
- The longest tie-back associated with a subsea pump system is 18 miles, at the King field.
- The longest future tie-back associated with a subsea pump system is 25 miles, at the Parque da Conchas project.
- Higher rates are achieved with helico-axial pumps (226 mbpd at Tordis).
- Higher differential pressures are achieved with ESPs (2,300 psi at Perdido).
- Higher GVFs are achieved with helico-axial pumps (75% at Ceiba).
  - Twin-screw pumps can pump up to 95% GVF, but have poor run lives, so excluded from this metric.
- Riser gas-lift is a proven subsea technology and is suitable for GOM applications.
- Seafloor caisson separators and subsea horizontal separators are proven subsea technologies, and are suitable for GOM applications.
- Subsea compression is not a proven subsea processing technology.
- Artificial lift in subsea wells includes gas lift and ESPs
  - Gas lift limited to shallower water depths
  - ESPs used in deeper water depths (primarily in seafloor caissons and risers).
- Flow assurance concerns associated with subsea processing include:
  - Hydrate formation in deeper waters where temperatures are less
  - Hydrate formation as wells are produced to higher water cuts
  - Wax and asphaltene formation as production system pressures are decreased.
- Actual incremental CAPEX and OPEX numbers are not available for economic analysis (subsea systems are custom built and costs should be calculated for each individual application).
- Risk associated with subsea processing is based upon proven reliability of a technology, and is primarily a function of the actual operating life of a particular technology.
- The subsea processing technologies with the least amount of risk include:
  - Centrifugal pumps at Lufeng, Troll-C conditions (no gas production)
  - Helico-axial pumps at Topacio, Ceiba, Mutineer/Exeter, Brenda/Nicol conditions
  - ESPs in riser at Jubarte and Navajo conditions
  - ESPs in seafloor caisson at Jubarte and Marimba conditions
  - Subsea horizontal oil-water SSBI system at Troll-C conditions.
- The immediate future outlook for subsea processing includes:
  - ESPs at greater water depths
    - Horizontal ESPs on skids
    - ESPs in seafloor caissons
  - Helico-axial pumps at shallower water depths

- Immature subsea technologies include:
  - Compression
  - In-line separation (Deliquidiser, Twister, etc)
  - Electrical frequency converters
- Technical challenges in subsea processing:
  - Sand handling capabilities
  - Gas handling capabilities
  - Power
  - Intervention simplification.

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Appendix A: Subsea Processing Poster