TECHNICAL REPORT

RISK COMPARISON SUBSEA VS. SURFACE PROCESSING

For

MINERALS MANAGEMENT SERVICE

DECEMBER 10, 2004

PROJECT NO. 70003245

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Client Company:	Minerals Management Service	*Project No:*	70003245, Rev. No. 02
Location:		*Total Pages:*	44
Client P.O. No:		*Date:*	December 10, 2004
Report Title:	Risk Comparison Subsea vs. Surface Processing		

Summary:

Det Norske Veritas (U.S.A.), Inc. (DNV) was contracted by the Minerals Management Service (MMS) to conduct a comparative risk assessment of subsea versus surface processing. The objective of this study is twofold:

- To provide a review of subsea processing equipment available in the industry and identify uncertainties and challenges related to these technologies.
- To perform a risk assessment and evaluate the additional implications and risks imposed by applying subsea processing equipment.

The MMS requires that new technology is proven to be as safe and reliable as existing technology with respect to personal and environmental risks. This study has therefore performed a thorough risk assessment of subsea processing technology with focus on the entire life of a field development, including issues related to commissioning, installation, repairs/maintenance and abandonment in addition to the in-service risk exposure. The focus of this risk assessment has been to identify, assess and compare the risk exposures related to subsea processing technologies to more conventional offshore field development concepts applied in the Gulf of Mexico today. For the quantitative risk comparison, a generic risk picture of a typical deepwater installation was used as a basis, while a typical subsea tieback was developed as the base case when assessing the environmental risks.

It was clear that the personnel/safety risk exposure would be reduced by using subsea processing equipment vs. surface processing equipment. When assessing the environmental risks, measured as release of hydrocarbons, the subsea processing resulted in a slightly higher frequency for small leaks compared to a conventional subsea tieback. However, the leak frequency assessment used very conservative assumptions, and the differences were minimal, $4.9\ 10^{-3}$ compared to $3.2\ 10^{-3}$. This risk comparison has demonstrated that there should be no “show-stoppers” from a safety or environmental point of view related to applying subsea processing technology. On the contrary, this assessment has demonstrated that there may be significant benefits by applying subsea processing technology.

Further, one of the key advantages of subsea processing is increased potential recovery from subsea wells, and improved exploitation of the resources. Subsea processing may allow for production from wells that are currently abandoned or not economic to develop..

Keywords			
Project Type:	Risk Assessment	*Prepared By:*	Håvard Brandt
Equipment:	Subsea Processing	*Verified By:*	Ernst Meyer
Material:		*Approved By:*	Stephen J. Shaw
Damage:			
Other:			

Miscellaneous:

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ISSUE LOG

Rev. No.	Issue Date	Prepared By	Reviewed By	Approved By	Comments
1	22 October 2004	H. Brandt	E. Meyer	S. Shaw	
2	10 December 2004	H. Brandt	E. Meyer	S. Shaw	

DISTRIBUTION LOG

Copy No.	Issued to
1	Minerals Management Service (electronic only)
2	Project File 70003245

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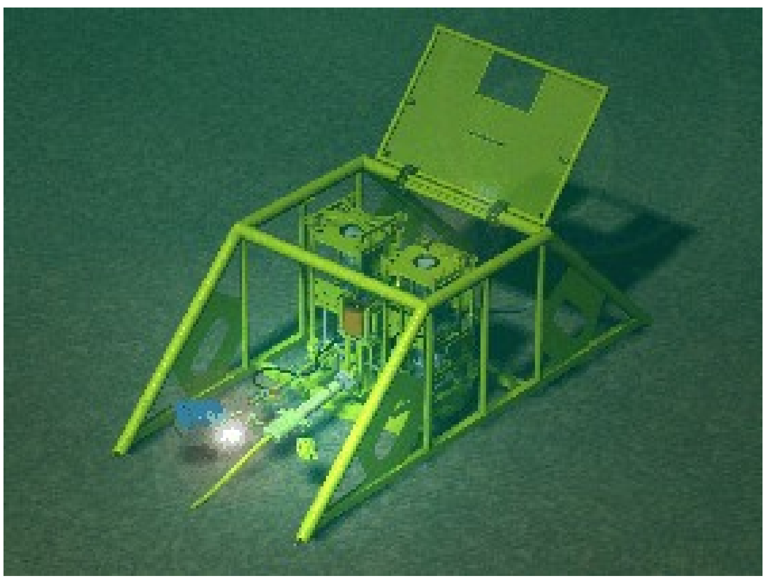
1. INTRODUCTION

1.1 Background

In deep water, transportation of produced fluids is often challenged by a number of factors that can make the exploitation economically marginal, particularly when relying on conventional technology solutions. The need to provide energy to the well stream to reach the treatment facilities is continuously increasing as exploitation moves into deeper waters and operators are evaluating longer tiebacks. Increased energy to the well fluids also has the potential to increase the ultimate recovery and accelerate production. These and other aspects motivate the interest in exploring the opportunities that novel technologies, like subsea multiphase booster pumping and gas compressors, offer.

The potential for slugging and challenges related to managing large amounts of produced water at the surface facility motivates the interest in subsea separation. Subsea separation can be based either on two or three phase separation, and pressure boosting to dispatch the liquid phase(s) to the receiving facilities. Two phase separation enables the reduction of the well back pressure by free flowing the gas phase and only boosting the liquid phase. Further, subsea separation could have a positive effect on flow assurance, including the risk related to hydrate formation and internal corrosion protection derived from the presence of the produced water in combination with gas.

Figure 1-1: The AkerKvaerner GasBooster™ Station



The opportunities and possible benefits related to subsea processing technologies are many; however, there are uncertainties related to the performance of these systems. Significant development and testing work has been undertaken in the effort of qualifying subsea processing technologies, and several systems have also been successfully deployed. While the technology itself is perceived as mature, limited operational experience is available. As a consequence, the anticipated reliability and risks related to applying these systems are subject to uncertainty.

Operators hesitate to be the first users of subsea processing technology before the benefits are fully understood, and currently there is no subsea processing equipment deployed in the Gulf of Mexico. One of the main concerns for the operators is the uncertainty related to the operating expenditures and intervention costs related to “unforeseen” events and equipment failures. Interventions and repair operations could potentially be very expensive; long waiting times for the required intervention vessels and resources and complicated intervention operations could be significant economical risk contributors.

Subsea processing equipment is characterized by use of novel technologies or extended application of existing technologies, increased reliance on remote operations and control systems and introduces additional complexity in a deepwater subsea production system. Further, when moving into deeper waters, the uncertainty related to whether “unforeseen” events will occur increases as the technology is introduced into an operating environment which is different compared to shallow water operations. These and other factors have motivated the interest in a risk assessment and risk comparison of subsea versus surface based processing.

1.2 Objective

The Minerals Management Service, MMS, requires that new technology is proven to be as safe and reliable as existing technology, with respect to personal and environmental risks. To provide a better understanding of subsea processing technologies and the associated risks and uncertainties, MMS has therefore initiated this comparative risk analysis.

The objective of this risk study is to perform a detailed risk assessment of subsea processing technology. The emphasis of the study is to assess technology solutions available for subsea processing, identify and evaluate the possible risks, and compare these risks to more conventional surface based alternatives which are applied today.

This study has focused on seabed processing, and different subsea processing technologies have been evaluated, including:

- ***Subsea Pressure Boosting***
  - Multi-phase Booster Pumping (twin screw pumps / helico-axial)
  - Gas compression (wet gas / dry gas)
- ***Subsea Separation***
  - Two Phase Separation (gas – liquid separation)
  - Three Phase Separation (oil – gas - water separation)

This risk assessment has addressed HSE risks, including environmental risks and safety risks introduced by these new subsea processing technologies.

1.3 Scope

The scope of this study has been to perform a comparative risk assessment of subsea processing technologies versus surface processing alternatives. A review of subsea processing equipment available in the industry has been performed, and uncertainties related to these technologies identified though input from operators and equipment manufactures. The focus of this assessment has been to evaluate the HSE risks related to subsea processing equipment and to evaluate how subsea processing risks compare to risks related to conventional surface based processing equipment which is typically applied for deepwater field developments today.

Figure 1-2: Overview of the Project Activities

SYSTEM REVIEW

- Technology assessment
- Maturity / Experience
- Benefits / Challenges

RISK ASSESSMENT

- Risk identification
- Assessing the risks
- Comparing the risks

1.3.1 System Review

The system review includes a detailed evaluation of available subsea processing technology solutions. The technologies are evaluated with respect to their maturity, considering existing applications, qualification programs and operator considerations for possible application of the specific technology. The system review also defines the basis for the more detailed risk assessment activities.

The objective with this initial phase of the project has been to review different subsea processing technologies available in the industry. DNV has actively worked with equipment manufacturers of subsea processing technologies to get a good understanding of the technical capabilities and major challenges related to subsea processing equipment. This initial review also provides a basic understanding of some of the important subsea technology enablers, their possible applications and key challenges.

Based on the initial technology review mainly with the equipment manufacturers, DNV conducted meetings and workshops with the operating companies. The objective has been to get an appreciation for the operator's considerations of the different subsea processing technologies and their possible application. This provides a basic understanding of which technologies are more likely to be considered within the near future for a Gulf of Mexico application, and provide valuable input on which equipment to focus on in the risk assessment.

1.3.2 Risk Assessment

This study has addressed risk exposure related to subsea processing equipment during the entire life of a field development, including issues related to commissioning, installation, repairs/maintenance and abandonment in addition to the in-service risk exposure. The risks evaluated in this assessment include HSE issues, with focus on environmental and personnel safety risks. The focus of this risk assessment has been to identify, assess and compare the risk exposure related to subsea processing technologies to more conventional surface based process systems applied in the Gulf of Mexico today.

Identifying the Risks

The first task of this risk assessment was to identify the relevant risks related to subsea processing technologies. A qualitative group session, HAZID, was used to brainstorm and evaluate major differences related to a field development, applying subsea processing equipment compared to more conventional deepwater field development. The HAZID review included a systematic evaluation of all the relevant risk elements for a quantitative offshore risk assessment.

Evaluating the Risks

The risks identified in the HAZID session have been reviewed and evaluated in a comparative risk assessment. One of the challenges related to this project has been to define the basis for this comparative risk evaluation of subsea versus topside processing. Subsea processing is an enabling technology, and a direct comparison with surface processing would probably not be realistic. The study has therefore adopted an approach to evaluate the additional implications and risks imposed by subsea processing equipment. Issues which have been evaluated include, but are not limited to:

- The impact on the surface facilities by introducing high voltage cables and connectors, additional power requirements, utility systems
- Possible risk related to leaks of hydrocarbons, reliability of seals and connectors
- Risks related to leaks of utility fluids, distribution systems, monitoring
- Risk issues related to additional offshore marine operations required to maintain subsea equipment

The risks related to conventional subsea systems and offshore topside process facilities have been used as a basis for the risk comparison. Subsea water separation has been compared to conventional technologies applied today for handling and treating produced water. Gas lifting and other means to maintain production pressure have been compared to subsea pressure boosting systems. The objective has been to provide a good appreciation of the risks related to subsea processing and an understanding of how these risks compare with today’s technologies.

2. SUBSEA PROCESSING TECHNOLOGY

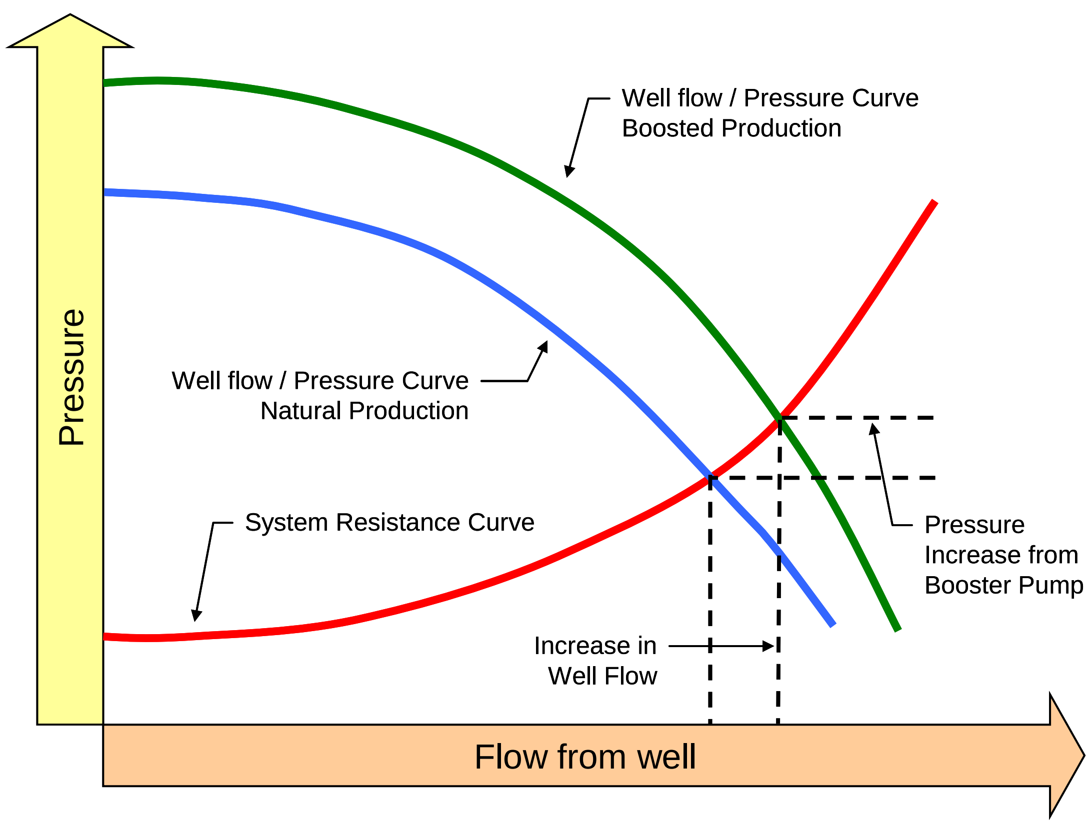
Subsea processing can be defined as any treatment of the produced fluids prior to reaching the offshore installation and the conventional surface process facility. In this risk assessment, seabed processing has been the focus, but subsea processing could also be considered to include downhole equipment, separators and pumps, as well as subsea metering systems.

The two main type of technologies evaluated in this risk assessment are pressure boosting and subsea separation.

2.1 Subsea Pressure Boosting

The impact on the production flow and pressure as a result of pressure boosting is illustrated in Figure 2-1. The red curve represents the system resistance, which is characterized by the specific system configuration and water depth. The blue curve represents the natural well flow, and is dependent on the specific reservoir conditions. By pressure boosting, the back pressure on the reservoir is reduced and the flow curve is shifted to the green curve. The intersection between the production curve and the resistance curve gives the flowing conditions. As indicated in the figure, both the production flow and pressure are increased as a result of the pressure boost, which is represented by the intersection between the red and the green curve.

Figure 2-1: Pressure Boosting of the Well Flow

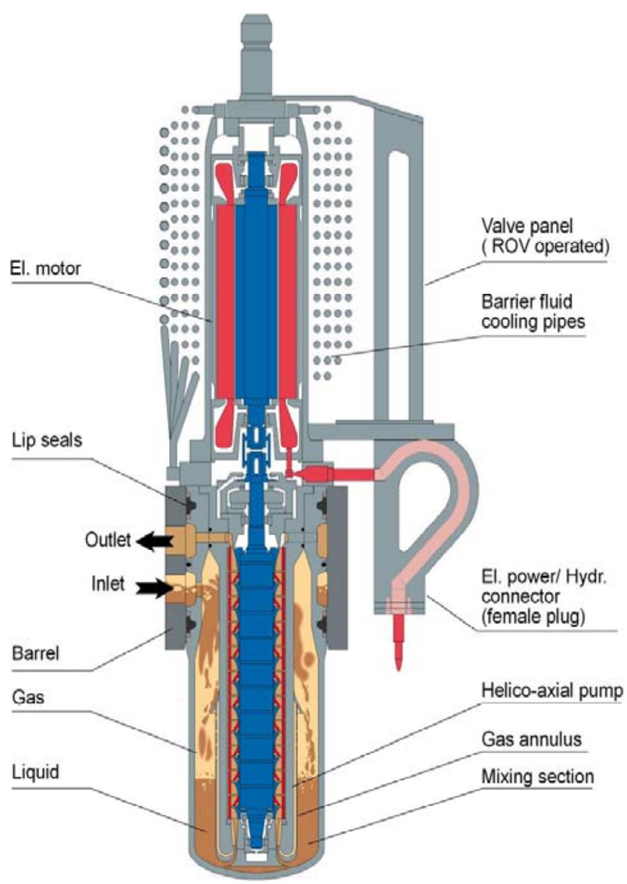


For a long tieback and in a deepwater operating environment the system resistance curve becomes steep, and the intersection with the production curve will be at a much lower flow rate. Similar, a low pressure reservoir results in a production curve which starts out with a lower shut-in pressure and decreases faster. The intersection with the resistance curve will again be at a lower production flow. These issues could potentially result in challenges meeting the desired flow rates and economic targets of a field development, and triggers the interest in a pressure boosting and subsea processing technologies.

2.1.1 Multiphase Booster Pumps

There are two main booster pump technologies available, the positive displacement pump and the centrifugal booster pump. Companies like Sonsub[1] and AkerKvaerner offer the conventional displacement technology with their subsea twin-screw booster pumps, while Sulzer and Framo represent the centrifugal booster pump technology with their subsea helico-axial pumps, an illustration of the Framo pump is given in Figure 2-2. The helico-axial technology was developed as part of the Poseidon research project, which was a joint venture between L'Institut Français du Pétrole, Total and Statoil.

Figure 2-2: The Framo Subsea Multiphase Booster Pump

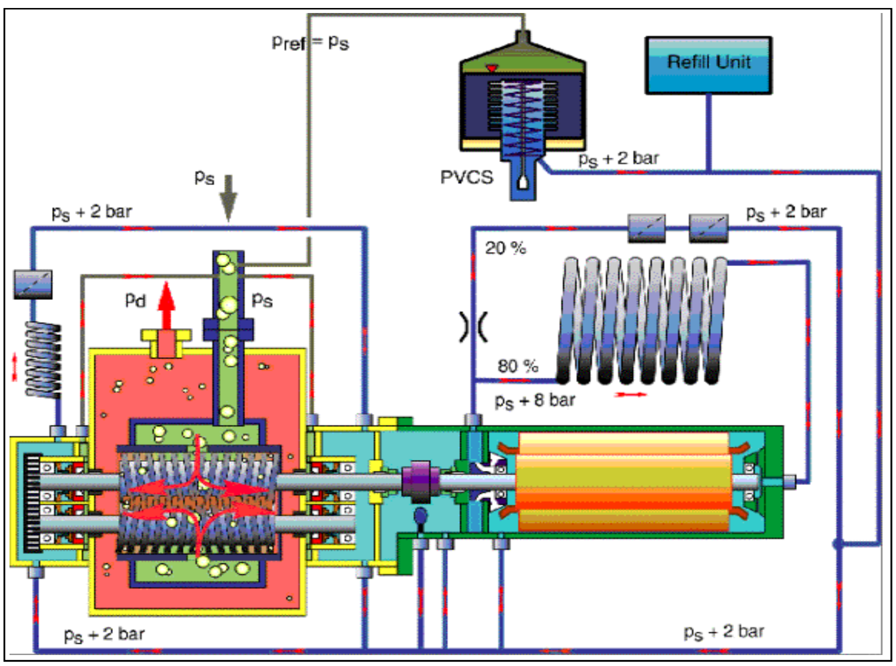


[1] The booster pump technology is developed by Nuovo Pignone, which now is a division of General Electric

The Framo pump design applies the Poseidon hydraulic technology and consists of a multistage pump design fitted to a rugged, stiff[1] diameter shaft assembly. From the upstream piping, the multiphase fluid enters the suction end of the pump through the integrated Framo flow mixer in which the fluid is mixed into a homogeneous mixture in the lower section of the unit. This feature provides stable operating conditions for the pump, independent of upstream flow conditions, such as transients and slug flow.

The shaft is supported by two radial bearings placed at the ends of the pump section. Internally pressurized mechanical seals are the primary seals for reasons of environmental control, possible erosion problems, and safety. A shaft extension hub at the drive end accommodates a flexible type shaft coupling between the motor and the pump. A barrier fluid system provides overpressure protection, lubrication and cooling of the pump critical parts, bearings and mechanical seals. The pump housing is designed to accommodate the rotating assembly and provide the required pressure integrity.

Figure 2-3: AkerKvaerner Subsea Multiphase Booster Pump



AkerKvaerner has developed a subsea multiphase twin-screw pump, as illustrated in Figure 2-3. The pump unit is supplied by Bornemann and is a positive displacement pump, which isolates a portion of the medium and moves it from the low pressure side to the high pressure side as a piston pump with an endless piston. The module consists of an electrical motor, the pump, cooling system, oil refilling and instrumentation. System design is based on proven equipment and components are selected based on high reliability and ability to sustain the load and wear imposed by all aspects of subsea installation and operation. The mechanical seals are designed to prevent scaling and sand flow, to restrict axial movements and to prevent damage to static sealing rings.

[1] The shaft is very resistant to bending forces

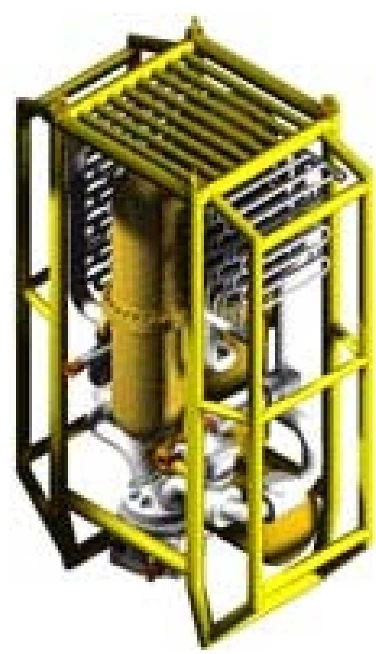
The motor is an oil-filled, wet winding, squirrel cage designed for variable speed drives, and low RPM (400–2200). The motor uses the same medium for cooling, bearing lubrication and seal fluid. The casing contains double seals in all connections (4 in total). No or little pressure differential over seals is achieved by equalizing pressurize with the cooling / lubrication fluid. The high voltage connector or penetration system consists of a copper core molded into a ceramic penetrator and features electromagnetic screening and pressure compensation towards the ambient sea. Loher supplies the motor.

The pressure and volume compensation system consists of a diaphragm located in a pressure vessel. One side of the pressure vessel interfaces towards the suction side of the pump and the other towards the motor. The diaphragm is loaded towards the motor with a spring to give a slight overpressure within the motor casing. This will give any internal casing leakage through the mechanical seals from the motor towards the pump. Pressure compensation of the motor towards the pump is done in order to reduce the shaft thrust on the bearings, pressure difference across the mechanical seals and to avoid particles, contamination and water within the motor casing.

2.1.2 Subsea Gas Compressors

For gas developments, subsea gas compressor concepts are being developed. Framo has developed a subsea wet gas compressor, which is quite similar to their helico-axial subsea multiphase booster pump. AkerKvaerner has, in cooperation with Nuovo Pignone, developed a subsea dry gas compressor, Figure 2-4. The benefit with the dry gas compressor is that it is more efficient; it will, however, typically require a subsea water separation stage prior to the compressor unit. Both of these concepts are, however, in the early concept phase, and although they are being qualified, it will probably be several years before there are any field applications.

Figure 2-4: The AkerKvaerner Subsea Gas Booster



2.2 Subsea Separation

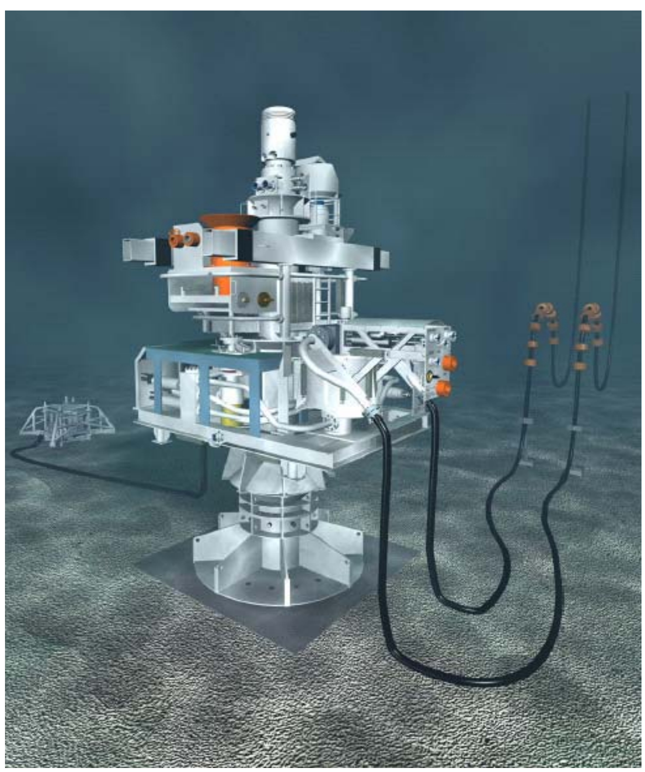
Subsea separation can be used in combination with subsea pressure boosting to enhance the production flow or with the purpose of removing excess production of associated well fluids later in field life. Water has higher density than oil; therefore, by removing the water from the production riser and flowline system, the back pressure on the well could be reduced, and the production flow be increased. This would, however, typically require a water injection well. Subsea gas separation in combination with pressure boosting is an alternative to enhance efficiency of a subsea boosting process.

2.2.1 Gas Separation

VASPS (Vertical Annular Separation and Pumping System) is an innovative concept for a two-phase subsea separation and pumping. The VASPS concept allows high-capacity integrated separation and pumping equipment to be installed within a 30" conductor in a dummy well. This compact configuration is obtained by the use of internals which, without moving parts, induce a helical flow path within the unit, thus generating centrifugal forces which enhance the gas-liquid separation. An Electrical Submerged Pump (ESP) is then used to boost the liquids back to the receiving host facility.

As a result of implementing the VASPS, the well could flow at a reduced pressure which allows a higher production rate, providing a positive impact on the operations. Essentially the system resistance curve, as explained in Figure 2-1, has been modified, resulting in higher production by implementing the VASPS.

Figure 2-5: The Vertical Annular Separation and Pumping System (VASPS)



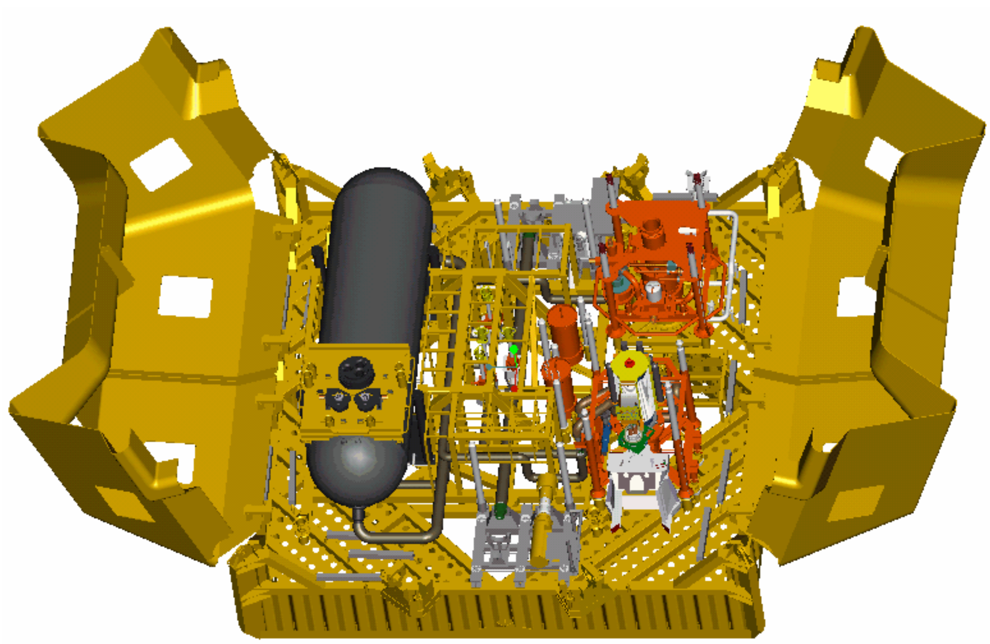
There are other concepts which have been developed for subsea gas separation, including the Shell Twister Supersonic Separator. The concept behind the Twister is to convert energy from an expansion process into high velocity. The result is lower temperature, which cools the gas and causes water and hydrocarbons to condensate from the gas. This allows the liquid to be separated from the gas. However, these technologies are in concept stage and have not been applied in a subsea field development.

2.2.2 Water Separation

Troll Pilot, Figure 2-6, was the world's first subsea separation station of oil/water/gas when it was put into operation on the Troll field in August 2001. The separator tank is a cylindrical, horizontally placed, three-phase gravity based separator. The special cyclonic inlet device slows down the incoming flow without creating emulsion, while taking out the gas. Two weir plates for oil and gas overflow are located at the outlet end of the separator, downstream of the water outlet and level instruments. The bulk water is re-injected into a dedicated injection well, while the oil and gas is transported back to the host facility.

One of the motivations for implementing the Troll Pilot subsea separator was related to limited process capacity on the Troll host installation due to excessive amounts of produced water. As a consequence, oil production had to be cut back resulting in reduced income, and there were reduced possibilities to tie-in new wells and new fields in the area. The subsea separator provided an economical opportunity to de-bottleneck the surface process, without significant investments in the topside modifications. As a result of the installation, oil production increased with 15,000 BBLD.

Figure 2-6: The ABB Subsea Water Separator – Troll Pilot



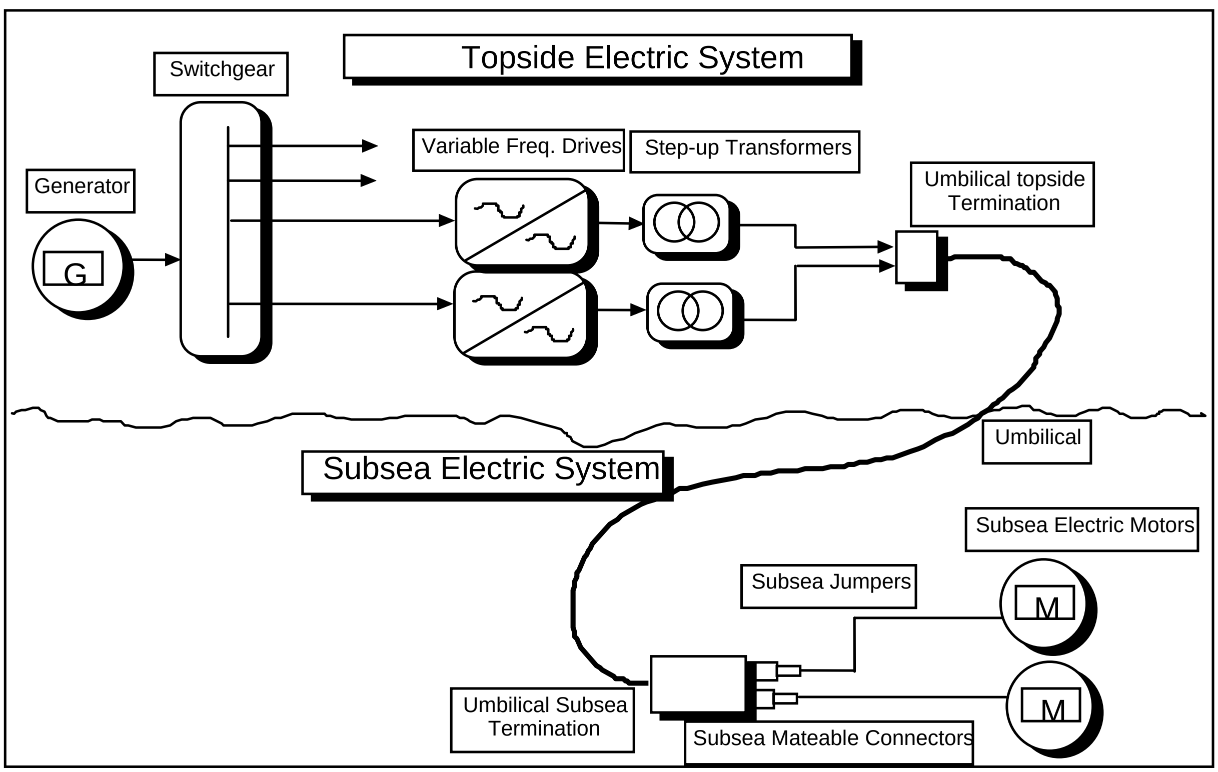
Other interesting subsea separation concepts are also being developed, including the Gas-Liquid Cylindrical Cyclone (GLCC), which has been developed as part of a joint industry initiative, known as the Tulsa University Separation Technology Project. This concept has been extended to include a three phase separation process, separating oil, water and gas. Water is separated from the oil by adding an additional Liquid-Liquid Cylindrical Cyclone (LLCC) downstream of the GLCC.

The GLCC concept receives the process fluid through a sloped tangential inlet nozzle, sized to deliver a preconditioned flow stream into the body of the separator. The momentum of the process fluid combined with the tangential inlet generates a liquid vortex with sufficient G-forces for bulk gas and liquid separation to rapidly occur. Finally, the gas exits through the top of the GLCC and the liquid exits though the bottom of the GLCC.

2.3 Subsea Power Systems

Most of the subsea processing systems will require a power supply arrangement to operate the equipment. There are two concepts available to provide the power to operate the subsea process equipment: electrical power supply or hydraulic driven concepts. Electrical systems have been installed in a number of applications and proven to be reliable. Hydraulic driven alternatives are still in a concept stage and would most likely not be applied in any field applications within the next couple of years.

Figure 2-7: Subsea Power Distribution System

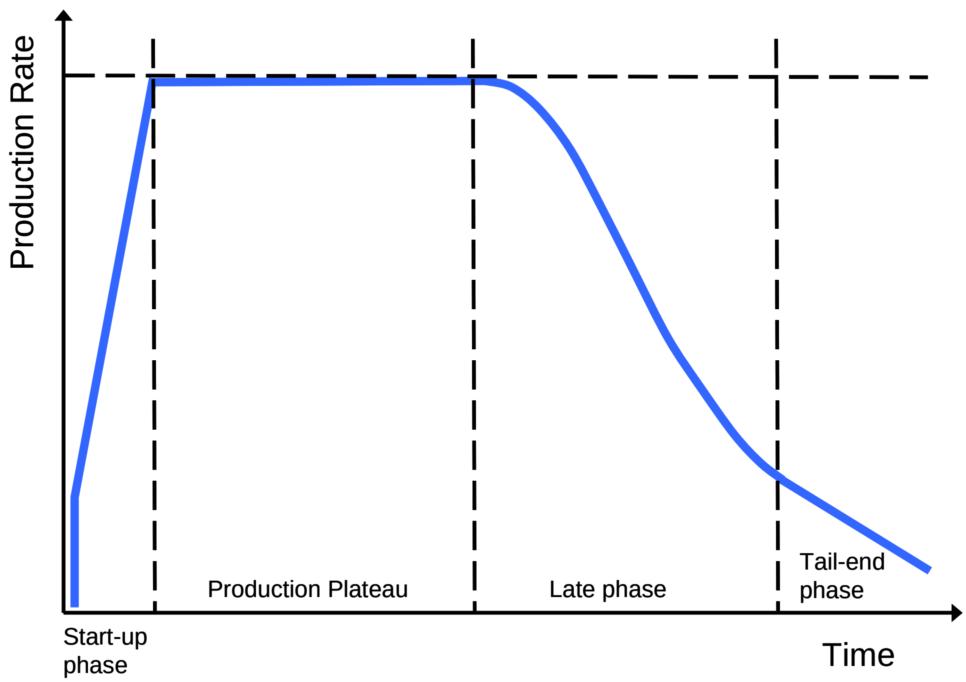


For a relatively short tie-back distance, a direct power distribution system similar to the one illustrated in Figure 2-7 would be a good alternative. In this system, the electrical motors are operated directly from the surface installation through the topside variable frequency drive. However, for a longer tieback distance, more than 5 miles, a subsea transformer will most likely have to be installed due to the power loss. With a subsea transformer, the tieback distance could be extended to approximately 50 miles, depending on the power requirements. For an even longer tieback distance, a subsea frequency converter would probably be required as the electrical supply would have to be DC and the electrical motor on the subsea booster pump is operating on AC. Currently, subsea transformers have been qualified and put in commercial application; however, a subsea frequency converter has not yet been qualified.

2.4 Benefits Related to Subsea Processing

When production from a new field development is planned, the process capacity at the installation must be balanced against the expected production rates from the reservoir and the overall field economics. An illustration of a typical production profile from a field development is given in Figure 2-8.

Figure 2-8: Typical Production Curve for a Field Development



As illustrated by the production curve in Figure 2-8, there will typically be spare capacity in the surface process equipment before and after plateau production. Subsea processing introduces an opportunity to enhance the economics of a field development by taking advantage of this lost potential. Possibly even more interesting is the fact that subsea processing potentially could challenge current field development planning, by enabling longer tiebacks in deeper water, which today would be considered marginal fields or not even considered economical to exploit.

2.4.1 Subsea Pressure Boosting

During the first initial years of production from a new development, the infrastructure utilization is typically constrained by the well production. The infrastructure would typically be dimensioned for nominal production from day one. Even with pre-drilled wells, it is difficult to achieve full processing capacity until additional wells are completed and put on stream and the total field is successfully ramped up to its capacity. Subsea processing may therefore offer an immediate opportunity to improve utilization of the surface processing capacity by providing a pressure boost of the production fluids in the initial start-up phase of a project.

Subsea processing reduces the wellhead flowing pressure by adding a pressure boost to the production flow. This could either be a subsea multiphase booster pump or subsea gas compressor, depending on the produced fluids in the particular reservoir. The installation of a subsea boosting system requires the investment in cabling and equipment for high voltage power supply, and it is therefore beneficial if this can be made and integrated during the initial phase of a project. The decision to pressure boost the production flow must also be balanced against potential unfavorable reservoir responses such as possible rate dependent water production and maximum sand free production rate.

Subsea boosting has significant potential later in the field life to maintain the flowing pressure and produce at the plateau production for a longer period of time. Subsea booster systems may replace the need for gas lifting and other means of artificial lifting later in field life when the wells start to deplete.

2.4.2 Subsea Separation

Later in the field life, the infrastructure is typically constrained by excess production of associated well fluids. This means that the full production rate cannot be maintained, and that valuable processing and transport capacities are not utilized for hydrocarbons. For an oil field development, this is represented by water cut and gas breakthrough in the reservoir. Due to limited capacity in flowlines, risers, and the topside processing facilities, production may have to be choked back from the production wells, resulting in reduced oil production. The excess of produced water will also have a negative effect on the well flow as it will increase the wellhead back pressure, and potentially reduce the flow rate significantly. During this phase of the project, there is a potential to increase the surface infrastructure utilization by introducing subsea separation and equipment to handle the associated well fluids.

If water-cut is the challenge, a subsea water separation unit may be the solution. Water has higher density than oil; therefore, by removing the water from the production riser and flowline system, the back pressure on the well could be reduced and the production flow be increased. Further, by separating out the water, process constrains in the surface processing facility or flowline system may be overcome, increasing the recovery of hydrocarbons. Current subsea separating technology will, however, require a water injection well to dispose the water; the potential benefits would need to be evaluated against the potential cost of drilling a water injection well; and there may also be reservoir restrictions related to injecting the water back into the reservoir.

If gas breakthrough is the problem, subsea gas separation combined with re-injection or possibly re-routing may be a solution. Re-injecting the gas would, however, require the application of large subsea (wet) gas compressors, which could be a restriction both in terms of cost and available technology. The other alternative solution is to route the separated gas to another topside facility. This is obviously dependent on having an available installation with spare gas handling capacity in the area. Subsea gas separation can also be used to enhance the efficiency of a subsea booster system, similar to the VASPS.

In the final phase of the field life, the infrastructure utilization is typically limited by decreasing production due to depleted reservoirs, often in combination with large amounts of produced water. This can be countered by drilling more wells and bringing on stream additional satellite subsea tiebacks; however, these drilling operations can be very expensive and often difficult to justify based on economic considerations. Further, the challenges related to multiphase flow and flow assurance are often a limiting factor ,making tail end production uneconomical and resulting in significant amounts of hydrocarbons never being recovered from the subsea well. Subsea processing may offer interesting opportunities for tail end production, through increased recovery and enabling new resources from an extended reach area.

Topside modification often required to accommodate additional subsea tiebacks could often be difficult due to space and weight limitations. Subsea processing could be a flexible and economic way to de-bottleneck a surface process facility and overcome some of the typical challenges and restrictions, which will allow additional wells to be tied back to the installation.

2.4.3 Enabling Marginal Fields

While field applications of subsea processing technology typically would be considered and evaluated based on the technology's ability to enhance the Net Present Value, NPV, in field developments (which are currently being developed based on conventional solutions), this technology could potentially provide complete new field development opportunities.

Subsea pressure boosting will enable longer subsea tiebacks, which potentially could enable the economics of exploiting small, remote, marginal fields. Subsea separation could provide an economic alternative for de-bottlenecking existing surface process facilities, allowing better utilization of these installations by adding new subsea tiebacks which currently would not be economic to develop. Subsea gas separation may allow oil and gas to be separated at the seabed and be transported to different production facilities. This may be another opportunity to better utilize existing infrastructure.

Subsea water separation could potentially reduce the flowline insulation requirements as there will be no risk for hydrates if the water could be removed completely[1] from the production flow. This may also reduce the flowline sizes required, and potentially the need for dual flowlines, as hydrate remediation like depressurization or dead-oil displacement is no longer required.

These considerations will, however, require a shift in the way operators are evaluating subsea processing technology, and would also require a strong confidence in the technology's ability to operate reliably over a significant period if time.

2.5 Applications of Subsea Processing

Of the technologies evaluated in this study, subsea booster pumping is the most mature of the subsea processing technologies. Both single phase and multiphase subsea booster pumps have been deployed, and several oil companies have stated that they regard this technology as mature, based on this experience. All the subsea booster pumps applied in field application, at the time this report is being prepared, are based on the Framo helico-axial technology. Several other subsea booster pumps have been tested in subsea applications, however, and there are indications that a twin-screw pump will be deployed in a field application in the near future. Some of the current field applications of subsea booster pumps include:

- Draugen, North Sea
- Lufeng, South China Sea
- Topacio, West Africa
- Zafiro, West Africa
- Ceiba, West Africa

The Troll Pilot water separation and injection station, operated by Hydro, was deployed in June 2000 as a pilot project. After some initial problems with high voltage and hybrid (optical / Hydraulic) connectors, the system has demonstrated excellent availability. The water separation efficiency experienced has been somewhat lower than anticipated, but the system has demonstrated its value and capabilities. Statoil is currently evaluating an even larger subsea water separation and re-injection system for their Tordis field, a subsea tieback to the Gullfax C installation in the North Sea.

While the Troll Pilot is a three-phase separator, the Vertical Annular Separation and Pumping System, VASPS, is essentially the only subsea separator applied to separate liquid and gas. The VASPS was installed on the Marimba in Brazil in 2001. There have been some reliability issues, but the system has now generated significant operational time and provided valuable knowledge and feedback to the operator, Petrobras.

[1] Hydrate will not be an issue if the water content is less than 2%

2.6 Challenges Related to Subsea Processing

The benefits of subsea processing are evident, and operators seek to take advantage of some of the additional capabilities these systems provide. However, there are many challenges and uncertainties related to the application of this technology, and operators are hesitating to be the first users of new technology before all these risks and uncertainties are fully understood.

While some of the technology is perceived as mature, limited operational experience in subsea applications is available. As a consequence, the anticipated equipment performance and the associated operating costs are subject to uncertainty. In addition, moving into deeper water, subsea system interventions become more expensive and are associated with longer waiting times for the required intervention vessels. The risk related to system reliability is therefore significant.

2.6.1 Subsea Booster Pump Challenges

Subsea booster pumping, both single phase and multiphase, is the most mature subsea processing technology available. These systems have been deployed in several areas of the world, including the North Sea, West Africa and the South China Sea. The current systems are limited, however, with respect to water depth and pressure boosting capabilities. For a deepwater Gulf of Mexico application, there could potentially be additional qualification requirements to meet the specific operating challenges. Sand production could also be an additional issue. While the current subsea booster pump technology supposedly is designed to handle significant amounts of sand production, this has not been an issue in the current field applications.

At the time this report is being prepared, all the subsea booster pumps applied in field application have been based on the helico-axial technology. There are, however, obvious applications were a positive displacement pump would have a larger operating envelope and be the preferred pumping alternative. It is therefore also important that this technology becomes field proven and becomes an available tool for future field developments.

Currently, there are no subsea compressor systems available for field application. Several concepts are being developed, but there are significant challenges particularly related to the high power requirements on these systems. The development work of these subsea compressor systems is continued through joint industry initiatives like the Norwegian government founded DEMO2000.

Regarding the power supply, one of the limitations has been related to the electrical penetrators and high voltage wet-mateable connectors. However, significant improvements and qualification work have been undertaken in this area over the last couple of years. Another challenge has been that there are currently no high voltage wet-mateable connectors available; a subsea transformer will, therefore, have to be attached to the power umbilical with a permanent dry connection. Tronic is currently in the process of qualifying a 36 kV wet-mateable connector.

2.6.2 Subsea Separation Challenges

A deepwater separation will require a different system from the traditional gravity vessel which has been applied in topside applications and installed subsea on the Troll field, the Troll Pilot. To meet the hydrostatic pressure requirements, the wall thickness would make the gravity separator impractical for a deepwater application; hence, the technology needs to be further developed or alternative technologies like cyclone or centrifugal separators need to be considered.

Another challenge with the current subsea separator is that the quality of the produced water cannot be measured online. On the Troll Pilot, this is done by an intervention; an ROV is sent to the station and samples are collected from a sampling point. The problem with this is that the water quality between the sample times is not known. A better system would be an online monitor; however, the nature of this type of monitoring is complicated. The remaining hydrocarbons can both be in droplet form, and dissolved in the water, calling for different monitoring principles. The normal topside approach where manual samples are taken and analyzed cannot be adapted or marinized.

Other challenges related to subsea separation include:

- Improved solutions for sand management to avoid build-up of sand in the tank and protect reservoir from clogging.
- Improved water separation efficiency. For hydrate prevention, the water content in the oil needs to be reduced to in the range of 1-2%.

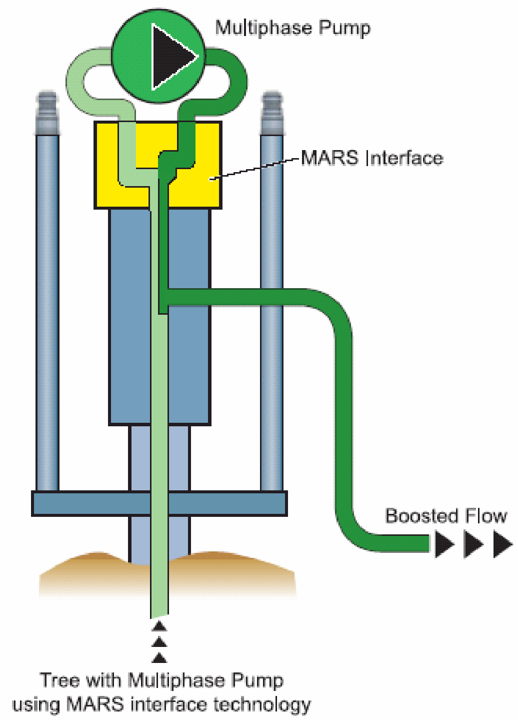
There are different initiatives being developed to find solutions to these issues. An important step for successful development of technology is through combined efforts between operators and manufacturers.

2.7 Other Subsea Processing Concepts

There are a number of other companies which have capabilities in the area of subsea processing which have not been mentioned specifically in this technical report. Two interesting companies which should be mentioned include Alpha Thames and DES Operations.

These two companies provide an integrated solution for subsea processing, but essentially apply the same technologies for the subsea process equipment as described earlier in this report. Alpha Thames provides a modularized based system, which can integrate solutions from different equipment manufacturers. DES Operations has a concept named Multi Application Re-injection System (MARS), Figure 2-9, which is an integrated solution of subsea processing solutions at the subsea X-mas tree. Both these companies offer flexibility. A common difficulty for project teams is to convince asset managers to spend more capital than is required on a development in order to build in capacity for the future; this is exactly what the Alpha Thames' or DES' concepts provide. These systems create the framework on which a variety of configurations can be achieved, but with minimal upfront cost.

Figure 2-9: The MARS Concept from DES Operations



3. RISK IDENTIFICATION

The initial part of a risk assessment was a detailed hazard identification (HAZID) review. A thorough hazard identification process is the most important step in the risk assessment, as it provides the basis for the assessment by identifying all the potential issues which needs to be evaluated. The HAZID further enables the development of plans to avoid (or prevent, control, mitigate) the hazards.

A HAZID is a multidisciplinary team exercise. In this assessment, the HAZID has been developed based on a number of meetings with different operating companies and equipment manufacturers, as well as active involvement of DNV resources with expertise in different relevant disciplines and areas. The HAZID method is designed to provide a thorough means of identifying potential hazards and concerns associated with a system. It is a structured exercise driven by the use of thought provoking "what if" questions to stimulate the team discussion. During the HAZID review, information is recorded systematically in a dedicated HAZID worksheet. The completed worksheet which was used for this assessment is included in Appendix I of this report. The following section includes a more thorough discussion on some of the issues which were discussed during the HAZID session and the meetings with the industry.

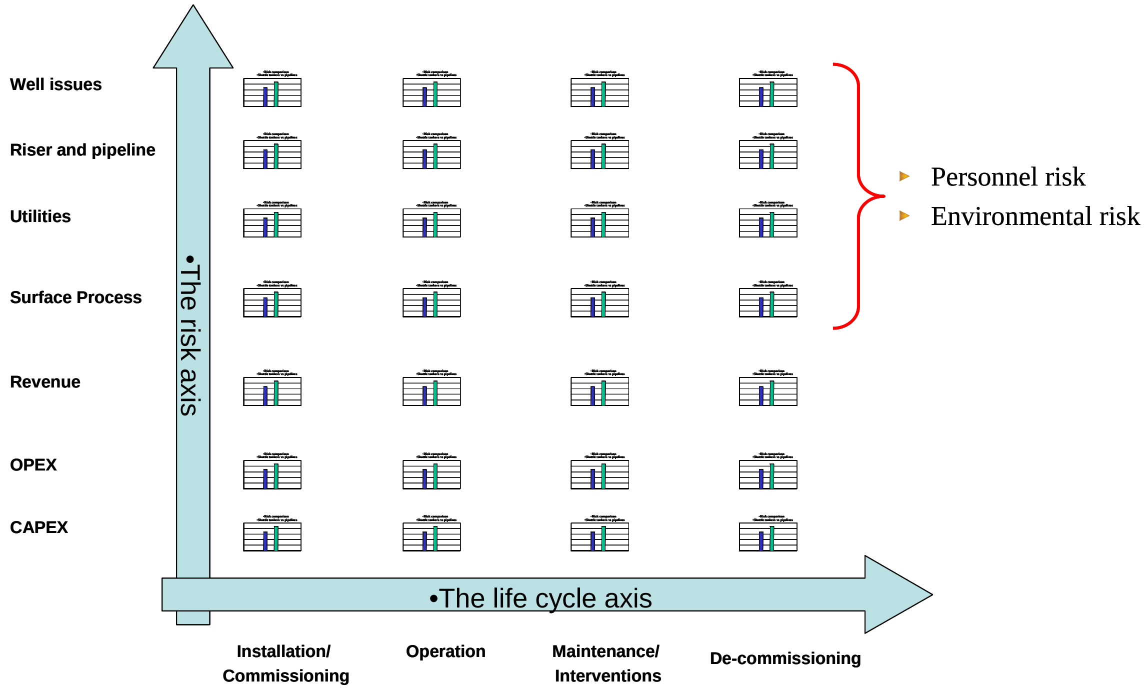
3.1 The Hazard Identification Process

To assure a thorough identification of all the potential risks related to the application of subsea processing equipment, a set of nodes were defined. The objective was to assure that all relevant elements of an offshore field development were reviewed in detail with respect to the implication of applying subsea processing technology. The following nodes were defined and reviewed as part of the HAZID process:

- Well and Reservoir Issues
- Riser and Pipeline Issues
- Umbilical and Utility Issues
- Surface Process Issues
- Other Issues

In addition to the physical boundaries defined by the nodes listed above, each of the operational stages of an offshore field development project were reviewed during the HAZID session, including installation/commissioning, production operation, maintenance/intervention operations and decommissioning. Figure 3-1 provides an illustration of the HAZID matrix approach adopted for this project. As focus of this assessment has been to evaluate the environmental and personnel risks, the economical issues have not been addressed specifically as part of this review.

Figure 3-1: Hazard Identification Matrix Review Approach



The focus of the risk identification process has been to evaluate the *additional* implications and risks imposed by applying subsea processing equipment. Risks related to conventional subsea systems and offshore topside process facilities have been used as a basis during the risk identification. Key internal resources with detailed knowledge of safety and environmental risk assessments, as well as technical knowledge of the relevant process equipment reviewed, have been utilized and complemented by meetings with operators and equipment manufacturers.

3.2 Risks Identified

Some of the key issues identified during the HAZID session, were that subsea processing introduces a potential increased risk related to the required marine operations and complexity of the subsea systems. The subsea process equipment needs to be installed and retrieved with the use of dedicated vessels, typically equipped with heavy lift capabilities. Some of the potential risks which should be considered include:

- The increased requirement for marine operations, which could pose an increased risk for collisions with the offshore installations.
- The handling and lifting of the subsea process equipment during installation and retrieval, which represent a potential risk for dropped objects.
- The increased complexity represented by the subsea processing equipment, which introduces a potential increased risk for subsea leaks.

The HAZID review of subsea processing systems also revealed a number of issues which will have a positive effect on risks related a field development. One of the key advantages with subsea processing, which is not directly HSE related, is the potential for increased recovery from the subsea wells. Subsea processing will extend the production from the well by providing pressure boosting or removing excess fluids. This will extend the production and result in increased recovery from the well in the tail-end production when the well is depleting. Current subsea wells will have to be shut-in and abandoned when the production flow makes these wells un-economical to produce or the pressure depletes resulting in flow assurance challenges and slugging.

Subsea processing will have a positive effect on flow assurance. In deepwater applications, the hydrostatic head represents a potential challenge which could create hydrostatic instability at turndown flow conditions. With subsea processing, slugging issues can be reduced, the hydrostatic pressure can be compensated and the hydrate risks may be reduced. This could have a very positive effect, resulting in reduced need for chemical injection and slug catchers. The flow assurance issues are discussed in more detail in the sub-section covering the riser and pipeline issues.

The key benefit related to subsea processing from an HSE risk point of view, is however the potential reduction in topside processing requirements. Some of the main risk reduction potentials discussed during the HAZID session, which also are covered in more detail in the sub-section covering surface process issues, include:

- Possibly no gas lifting requirements, due to the pressure boost provided by the subsea processing system[1]
- Potentially a significant reduction in the surface water treatment requirements if subsea water separation is applied
- Potentially reduced topside separation requirements and surface gas treatment requirements if subsea separation technology is applied

The next sub-sections describe some of the key issues which were identified and reviewed in more detail as a result of the HAZID process.

3.2.1 Well and Reservoir Issues

In a field development which applies subsea processing technology, all the wells will be subsea completions. This implies that a dedicated drilling vessel, drillship or semi-submersible, will perform the drilling, workover and well operations. In general, it can be concluded that the risk exposure related to a subsea completion is smaller compared to a dry tree completion. Typically, there will be more people on a production installation. There could also be issues related to simultaneous operations in order to maintain production during the well intervention, and in general there will be fewer well operations.

[1] Either through subsea booster pumps or subsea water separation, which will reduce the hydrostatic pressure

The risk related to drilling and well operations is a significant contributor to the overall risk exposure in an offshore development. This is illustrated with the picture of an uncontrolled blowout in Figure 3-2. To assure all these risks were fully understood for a field development which applies subsea processing, special guidewords and critical questions were used to trigger this discussion during the HAZID session.

Figure 3-2: Drilling Rig Blowout

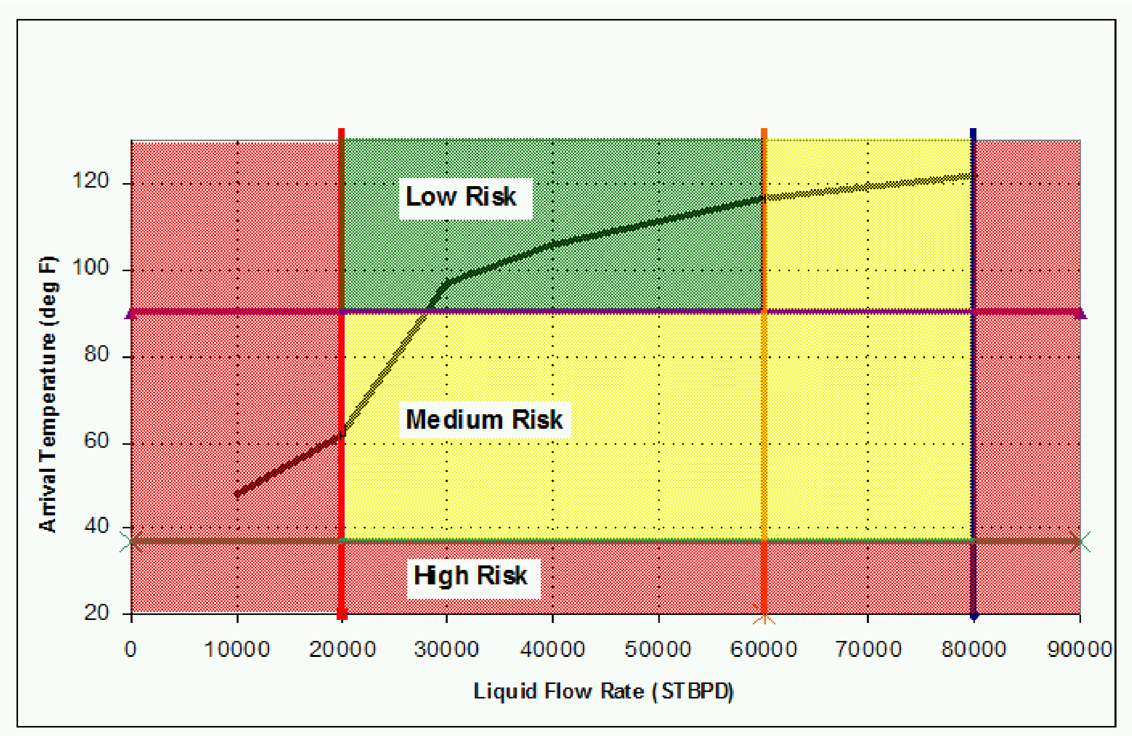
The main conclusion from the HAZID session is that the production wells in a field development which is applying subsea processing technology will be identical to conventional subsea production wells. Seabed processing equipment should not have an impact on the production wells or the drilling program. Some potential risks were identified related to operation of the subsea booster pumps, including the possibility for drawdown on the wells as a result of rapid pressure boosting. This could potentially have an impact on the reliability of the sand control system, triggering additional workover operations; with appropriate operating procedures this should not be an issue.

Subsea processing would more likely have a positive effect on the reservoir/well risks. Potentially, pressure boosting could reduce the number of wells required for the field development. Further, pressure boosting could result in extended production resulting in less need for workover operations. Typically, the reservoir pressure in a field development which applies subsea processing technology will be less than for a conventional subsea development. As a consequence, the risks related to the drilling and completion operations would probably be less than for a conventional subsea field development.

3.2.2 Riser and Pipeline Issues

Flow assurance was one of the key topics discussed when addressing the pipeline and riser system. There are two main issues related to flow assurance: thermal risks and hydraulic risks. Hydrate formation and wax deposition are the two main concerns related to thermal risks while slugging and erosion are the key concerns related to hydraulic risks. An illustration of the most important flow assurance risks for a typical deepwater development is given in Figure 3-3. The vertical lines represent the critical production flow related to the hydraulic risks; erosion becomes an issue when production exceeds 60,000 BBLD and will be a concern if approaching 80,000 BBLD. On the other hand, slugging will become a concern if the flowrate is reduced to 20,000 BBLD. The horizontal lines represent the thermal risks; with the wax deposition temperature being about 90^{o} F, and the hydrate formation temperature being close to 40^{o} F.

Figure 3-3: Flow Assurance Risks for a Typical Deepwater Development



The challenges related to flow assurance escalate significantly as tieback distance increases and production moves into deeper water. In deepwater, the significant hydrostatic head could represent a major challenge when bringing hydrocarbons on stream, and the cold seabed conditions and long tieback distances also represent a potential challenge with respect to cooldown of the production fluids. In a field development which applies subsea processing technology, the flow assurance risks will be reduced during normal operation. Pressure boosting will have a positive effect on the production flow, which reduces the cooldown of the production fluid and minimizes the risks related to slugging. Subsea separation may also have a positive effect on the hydraulic stability.

Although most of the experts agree that subsea processing has a positive effect on flow assurance, there are some uncertainties. Current subsea water separation technology is not capable of completely removing the water from the production fluids, and a water content of more than 2% could still be a concern with respect to the potential risk of forming hydrates. It should also be pointed out that by removing the water from the production flow, the thermal mass is reduced, which will result in more rapid cooldown. It is therefore a challenge to improve subsea water separation efficiency to possibly eliminate some of these flow assurance issues.

There is also uncertainty related to transient operations, process shutdowns and start-ups. It is likely that a field development which applies subsea processing equipment will have a shorter cooldown time than a typical subsea field development. Further, failure of the subsea processing equipment may impact the number of shutdowns. On the other hand, the reduced pressure in the flowlines may have a positive effect on the risk of forming hydrates. The subsea processing equipment is also likely to have a positive effect during system start-up. With subsea water separation, the chemical injection requirements, methanol or glycol, may be significantly reduced. Subsea processing will also assist in increasing the temperature of the produced fluids during a start-up.

The overall conclusion is that subsea processing equipment will have a positive effect on flow assurance. Flow assurance will continue to be a concern, however, for deepwater and long subsea tieback developments. Existing prevention strategies, including chemical injection and proper insulation of flowlines and subsea equipment, will still need to be considered for field developments which intend to apply subsea process equipment. The subsea process equipment itself will also require local chemical injection to protect it against hydrates during process shutdowns; there should, however, not be any major differences compared to current practices for chemical injection at the wellheads, manifolds or other subsea equipment.

Figure 3-4: Hydrates Being Scraped Out of A Pipeline

Subsea processing equipment introduces additional complexity and additional connection points in the subsea production system, which potentially could increase the risk of a hydrocarbon releases. It will be important to understand the possible leak paths which are introduced by the subsea processing equipment, and build confidence in the reliability of new connection points and possible leak paths. Pressure protection could be an issue which needs to be addressed when introducing subsea booster pumps. While the helico-axial pump has a technical limitation with respect to building up pressure, the positive displacement pump may require a pressure protection system. Other issues which should be addressed include:

- A thorough evaluation of the structural integrity of the subsea processing equipment, this equipment could be relatively large and its susceptibility to currents and other environmental factors should be evaluated.
- The modularization of the subsea processing equipment. A possible risk was identified during the HAZID session related to the isolation of the system during retrieval of the equipment for maintenance and replacement.
- The possibility for a small release of hydrocarbons from the subsea process equipment during retrieval. The need for flushing or proper isolation should be considered.

Subsea processing technology may allow for a smaller riser / pipeline compared to a conventional subsea tieback, which possibly could reduce the consequences related to a rupture or a leak due to reduced volumes contained. On the other hand, the hydrocarbon inventory in the flowlines for a field development that applies subsea processing equipment could potentially be larger due to longer tiebacks. One of the advantages with subsea processing is that it enables larger tiebacks. It is therefore difficult to conclude that the consequences related to a hydrocarbon release would be any different for a development applying subsea processing equipment compared to a conventional development using surface processing equipment.

Subsea processing equipment introduces additional leak paths, which need be evaluated appropriately. However, a number of issues were also identified during the HAZID session, which indicate that subsea process equipment may have a positive effect on the integrity of the pipeline and risers. Subsea water separation reduces the water content, which could reduce corrosion mechanisms, and possibly the probability of a leak. Water separation and pressure boosting improve the hydraulic stability of the flow, which will reduce slugging and possibly reduce the stresses in the riser and improve its fatigue life. Subsea process equipment would probably also collect much of the sand produced from the wells, which would result in less erosion in the pipelines, and possible reduced probability of a leak. However the subsea process equipment will have to be designed to handle sand production[1].

[1] As discussed earlier, the increased drawdown and other reservoir may result in increased sand production from the wells. Sand production has not been a major issue in the field developments which currently have installed subsea process equipment.

3.2.3 Surface Process Issues

The most significant potential related to subsea processing from an HSE point of view is related to the possible reduction in the topside process requirements. As more of the processing can be done on the seabed by applying subsea processing, the topside process requirements can be significantly reduced, which may reduce the weight and complexity on the surface facilities. This may provide the industry new opportunities to further develop and apply minimum facilities concepts, characterized by fast-track, low-fabrication cost solutions. An illustration of the Atlantia Mini-TLP concept is given in Figure 3-5. Less topside process equipment may reduce the risk exposure for operators and personnel on the installations. Further, subsea processing may reduce the number of operators and personnel required to maintain the offshore installations, due to less complex systems and reduced number of surface process equipment.

Figure 3-5: The Atlantia Mini-TLP

Subsea processing offers an alternative to gas lifting and other artificial lift solutions. Subsea pressure boosting or water separation can potentially eliminate the need for gas lifting, reducing the requirements on the surface process facility. Further, application of subsea gas separation may potentially significantly reduce the surface gas processing requirements, by redirecting gas to another dedicated gas processing platform or re-injecting the gas. These potential reductions in the surface process facility will, however, have to be considered against the additional power generation requirements and power demands which will be required to operate the subsea process equipment.

Subsea water separation and re-injection could reduce, or possibly eliminate, the need for surface water treatment facilities. This could significantly reduce the environmental issues related to dumping produced water with oil content and chemicals over board. On the other hand, without subsea water separation, subsea processing will probably increase the need for surface water treatment facilities, as the productive life of the field is extended, and tail end production typically will include significant amounts of produced water.

If surface process equipment is eliminated by introducing subsea process equipment, there will be reduced maintenance requirements on the surface installation. As a result, the risks related to personnel safety during repair and maintenance operations can be reduced. Repairs of surface process equipment require specialized personnel, and the offshore operating environment could be a significant risk contributor with respect to personnel safety. Maintenance personnel could be exposed to difficult operations, possibly in close proximity to other producing process equipment. Subsea process equipment, on the other hand, will be changed out from a support vessel and all repairs and maintenance work will be done onshore in dedicated facilities.

As discussed in the previous section, subsea processing will have a positive effect on flow assurance. Some of the potential benefits include:

- Improved hydraulic stability, less slugging
- Reduced need for chemical injection, glycol or methanol

Reduced slugging in the gathering network and production risers could eliminate the need for topside slug catchers, or significantly reduce the risks related to operating topside slug catchers. There have been severe personnel injuries related to operating slug catchers. By boosting the production flow, the temperature and flow rate increase, which may reduce the need for methanol, glycol and other flow assurance inhibitors. As a consequence, there could be a reduced need for methanol recovery or glycol units on the installation, reduced surface processing risks and reduced environmental effects related to chemicals in the production flow.

The reduction in chemical injection could be significant related to a cold start-up. The subsea processing equipment would accelerate a start-up process by providing energy to the production flow, and subsea water separation could have a significant impact on the amount of chemicals required during a cold start-up[1].

The general conclusion from the HAZID review of the surface process risks is that subsea processing potentially provides an opportunity to reduce the surface process requirements. As more of the processing can be done on the seabed, the topside process requirements can be reduced, which may reduce the complexity of the facilities and, as a consequence, the risks related to personnel safety.

[1] The chemical inhibitor dosage could be between 0.7 – 1.0 bbl per bbl of produced water

3.3 Risk Summary

Some of the key issues identified during the HAZID session of subsea processing were that these systems introduce a potential increased risk related to the required marine operations and complexity introduced in the subsea production system. The HAZID review did also reveal, however, a number of issues which will have a positive effect on the risks related a field development. Subsea processing will extend the production from the wells by providing pressure boosting, which results in increased recovery. Further, subsea processing will have a positive effect on flow assurance. The most significant potential related to subsea processing from an HSE point of view, however, is the possible reduction in the topside process requirements and manning. A summary of the key issues identified during the HAZID review and discussed in this section of the report is given in Table 3-1.

Table 3-1 Summary of HAZID Review of Subsea Processing

Increased Risk	**Reduced Risk**
Increased number of marine operations resulting in:	Increased recovery, fewer well operations
Dropped objects	Improved flow assurance
Collision with the installation	Less chemical injection
Increased risk of a subsea release due to:	Less water / slugging
Additional complexity	Less erosion
Pressure build-up	Reduced topside requirements
Structural damage to subsea equipment	No gas lift requirements
Isolation and shut-down	Reduced water treatment requirements[1]
	Reduced gas processing requirements

[1] Will require a subsea water separation unit, subsea processing will in general extend the productive life of the well, which will result in more produced water on the surface installation

4. RISK COMPARISON

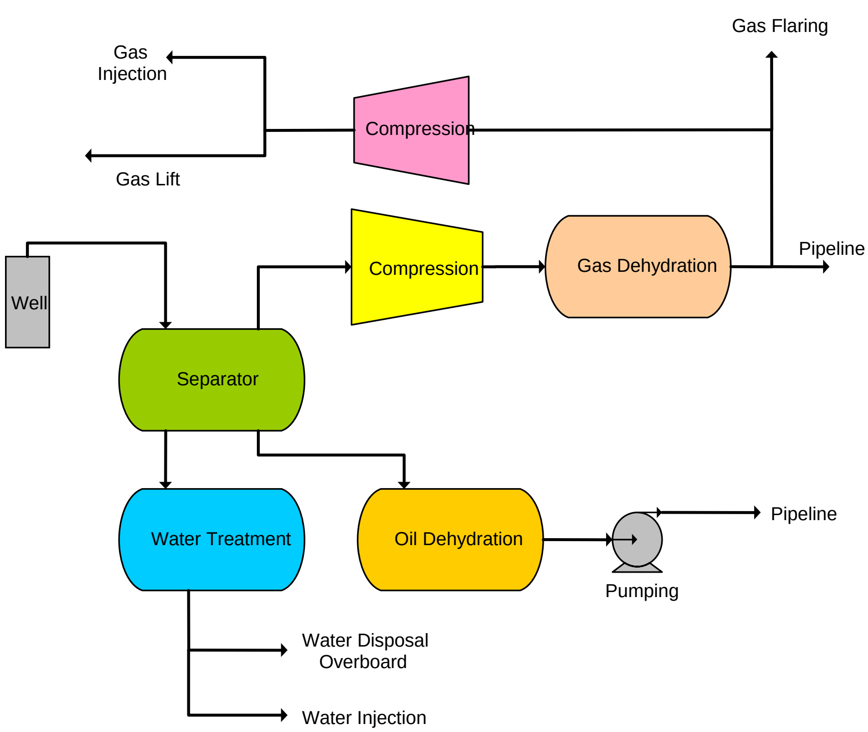
The HAZID process is a systematic and thorough exercise to assure all potential risks are identified and evaluated from a qualitative point of view. Some of the key issues revealed during the HAZID sessions are listed in Table 3-1, and were discussed in detail in the previous section. To better understand the implication of the risks identified, a Quantitative Risk Assessment (QRA) was undertaken. This section presents the result from this QRA comparison of a conventional offshore field development to a field development applying subsea processing technology.

The focus of the QRA has been to assess the HSE risks related to subsea processing equipment, and evaluate how the risks related to subsea processing compare to the risks on a conventional offshore facility currently being applied for deepwater field developments in the Gulf of Mexico. The objective is to demonstrate, through a quantitative risk comparison, that the risks related to subsea processing are acceptable when compared to the existing risk exposure on an offshore installation.

4.1 Base Case Development

In order to quantify the impact of subsea processing, a base case was developed. No specific installation was used as the basis for this risk assessment; a generic production facility with conventional surface process equipment was used as the basis for the risk comparison. An illustration of the base case facility is given in Figure 4-1.

Figure 4-1: Typical Surface Process Facility



As illustrated in Figure 4-1, the base case for this comparative risk assessment is a surface production facility that includes oil and gas treatment in addition to a water separation and treatment facility. Both the oil and gas are transported through export pipelines from the installation. It has also been assumed that the base case installation will use gas lifting to boost the production flow. The base case has been selected to be a good representative for a typical Gulf of Mexico field development.

It should be noted that the risk picture of a specific installation will be very dependent on the installation's size, production capacity, layout, manning, and equipment as well as many other factors and variables that impact the overall risk exposure for an offshore installation.

4.2 Personnel Risk

Individual risk per annum (IRPA) was used as the risk measure for personnel risk exposure on the installation. The IRPA represents the risk that one individual would be susceptible to on the installation during one year. As no specific installation information has been defined, the representative risk picture for the base case was defined by representing the different risk categories as a percentage of the total IRPA of the installation. By using the percentage values, the base case can remain generic yet still provide a sound breakdown of the different risk elements which impact the risk exposure on the installation.

DNV performs a number of quantitative risk assessment (QRA) studies for offshore installations and field development projects around the world. An extensive list of QRA projects was reviewed in detail and applied to develop a representative risk picture for the defined base case. The usual risk contributors, risk categories, on an offshore facility were evaluated and given a percentage contribution to the overall risk exposure. The following categories of hazardous events were considered:

Process Accidents:	Hydrocarbon releases downstream of well chokes and topside of riser shutdown valve and occurring in the main production flow
Blowout:	An uncontrolled release of fluid (hydrocarbon, water, drilling fluid) from a well.
Riser / Pipeline Accidents:	Releases from export / import pipelines on the seabed and from risers from the seabed to the topside shutdown valve.
Non-Hydrocarbon Fire:	Any fire not modeled as a hydrocarbon event, including electrical fires, accommodation fires, methanol fires, helifuel fires, generator / turbine fires, and many others.

Dropped Object: A load or object either falling, swinging, tilting, or sliding, and causing material or human damages.

Collision with Installation: Collision between the installation and another vessel, which can include fishing vessels, passing merchant vessels, visiting / support vessels, offshore tankers, etc.

Helicopter Accidents: Accidents involving transport of the crew via helicopter to and from the installation.

Workplace Accidents: Accidents with no potential to cause fatalities out of the immediate area of the incident and no more than 5 fatalities (the majority cause only a single fatality). They include a variety of events such as falls, falling overboard, and burns.

Other: Including structural failures and environmental loads such as extreme weather, earthquakes, marine corrosion, fatigue, foundation failure, and construction / design failures.

The review of previous QRA studies of offshore installations generated a wide range of possible values for the different risk categories. The high and low values are presented in Table 4-1, which are the extreme values from the QRA studies evaluated when trying to define the base case. The proposed base case breakdown of risk contributors was developed partly by considering the average of the historical values in the QRAs and partly based on the specific system configuration and process facilities defined for the base case. DNV's extensive experience with offshore QRA studies was used to assure a representative risk picture was developed for the base case.

Table 4-1 Risk Values for the Base Case

Risk Category	High	Low	Base Case
Process Accident	71 %	21 %	42 %
Blowouts	12 %	0 %	5 %*
Riser / Pipelines	38 %	1 %	10 %
Non-HC Fire	6 %	0 %	3 %
Dropped Objects	2 %	0 %	3 %
Collision with Installation	29 %	0 %	9 %
Helicopter Accidents	30 %	0 %	11 %
Workplace Accidents	33 %	8 %	13 %
Other	13 %	7 %	4 %

* If all the wells are subsea completions, the blowout risk on the installation is probably negligible

In order to do a proper comparison of the risks, the process accidents were evaluated in more detail. As indicated in Table 4-1, the process risks contribute to 42% of the overall risk exposure on the offshore installation. By evaluating QRA studies of representative offshore processing facilities, the gas process was estimated to contribute to 40% of the process risk exposure. With the basis from similar surface processing facilities, a breakdown of the gas related process risks was also developed and is presented in Table 4-2. The "Other Equipment" category includes items such as high pressure (HP) and low pressure (LP) separators and other gas handling equipment that do not fall within the gas injection / lift or compression categories.

Table 4-2 Breakdown of Gas Related Process Risks

Contributing Gas System	% Contribution
Gas Injection / Lift	20 %
Gas Compression	25 %
Other Equipment	55 %

Each of the risks identified during the HAZID session have been evaluated and quantified with respect to their relative effect on the specific risk categories by modifying the numbers defined for the base case. This provides a systematic approach to compare the risk exposure related to applying subsea processing compared to the risks related to a more conventional field development.

4.2.1 Assessing the Subsea Processing Risks

Subsea Pressure Boosting:

Subsea pressure boosting will provide sufficient energy to the production flow to most likely remove the need for gas lifting. Since 20% of the gas related process risks are due to gas lift / injection and gas related risks contribute to 40% of the process risks, 8% of the total process risk exposure could be eliminated.

Subsea Gas Separation:

Subsea gas separation and re-injection, or possibly re-direction to another host facility, could reduce or potentially eliminate the need for a surface gas compression and process facility. The gas compression trains account for approximately 25% of the gas related process risks. Thus up to 10% of the process risk could be eliminated.

Reduction in the gas handling equipment would also remove potential ignition sources. To account for the removal of a compressor, the ignition probability would decrease by 0.3%. The reduction in ignition would probably impact the process risk directly; therefore, the total process risk would be reduced by 0.3%.

Subsea Water Separation:

Subsea water separation and re-injection would eliminate or reduce the amount of topside water handling equipment. Based on the elimination of 10 topside pumps, the ignition probability would decrease by 0.1%. Although accounted for, the effect is negligible on the total process risk. The benefit related to eliminating the topside water handling equipment is mainly related to the environmental impact of not dumping produced water, which will always contain small amounts of associated oil.

Other benefits related to subsea water separation include the potentially reduced need for topside chemicals. Subsea water separation would reduce the requirements for hydrate preventative chemical injection such as methanol or glycol. Reduced chemical storage and handling would, however, have a negligible impact on the individual risk on the installation. There are environmental benefits related to reducing the chemical usage, however.

General Risk Impact:

Subsea processing equipment will be installed with the support of special intervention vessels, which will also be required during any maintenance or repair operations. As identified during the HAZID session, this increase in the number of marine operations could potentially increase the risk of a collision with the topside installation. Depending on the location of the subsea process equipment and the installation, the risk of collision as a result of the additional vessel's activity could be very different; a conservative estimate was proposed to increase the collision risk by 5%.

The installation and maintenance of the subsea process equipment will require complicated heavy lift operations. Dropped object was identified as a potential risk during the HAZID session. Dropping the subsea process equipment during handling could pose a risk of damaging the subsea wellheads, trees and flowlines. The subsea process equipment will also represent a potential target for dropped objects. Based on an evaluation of the additional lifting operations required, and the additional subsea equipment which could be hit by dropped objects, the dropped object risk was increased by 5%.

Subsea processing was also identified to affect the pipeline / riser integrity. There would be less sand in the system and thus less effect from sand erosion. Reduced amounts of water and chemicals would further reduce corrosion of the pipelines and risers. Also the reduced need for slugging would decrease the amount of strain placed on the system. All of the benefits, though significant, are difficult to quantify in terms of risk. It was conservatively estimated that these benefits would reduce the riser / pipeline risks by 5%.

Subsea process equipment will require a significant increase in the power demand on the topside installation. An additional generator or turbine would probably be required to supply the additional power demand. Adding a generator or turbine to the topside would potentially increase the ignition probability and thus the process risk by 4%.

Reduced equipment topside may reduce the amount of maintenance and hot work required on the facility. Reducing the hot work would have a negligible impact on the ignition probability. Reducing the amount of people on board the facility would have a great impact on the total risk of the installation. This study is based on IRPA values, which account for only the risk exposed to one individual. Reducing or increasing the amount of people on the facility would not change the risk of each person. However, other measures of risk would be impacted by any change in the number of persons on board.

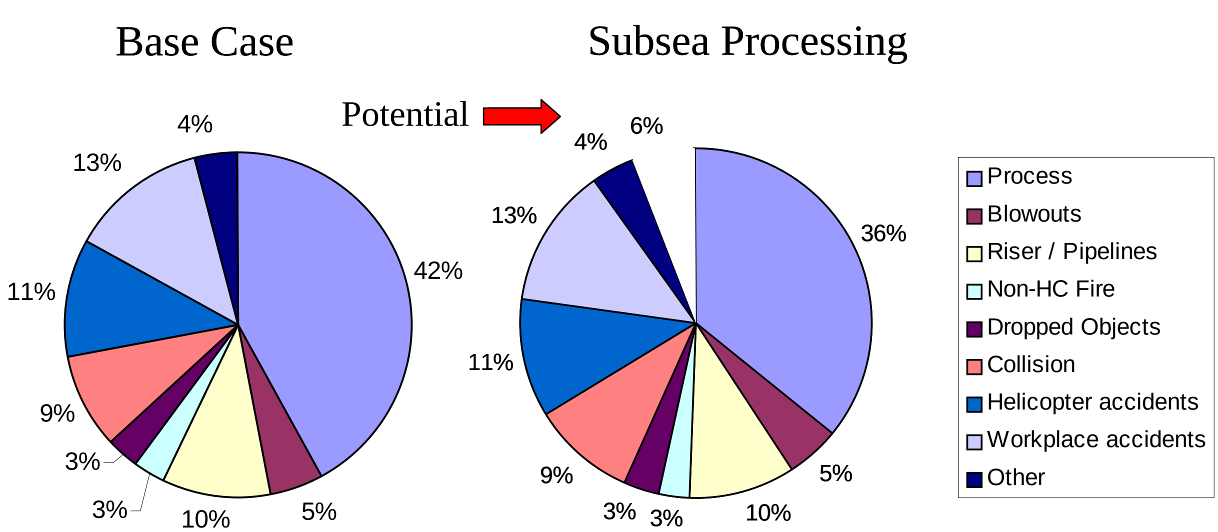
A summary of the risks evaluated for subsea processing, which formed the basis for the comparison, is provided in Table 4-3.

Table 4-3 Summary of The Subsea Processing Risks

Risk Factors	Impact on the Risk Assessment
Eliminate gas lift	Decrease process IRPA by 8%
Reduce or eliminate gas compression equipment	Decrease process IRPA by 10% Decrease ignition prob. by 0.3% or more
Reduce water handling equipment	Negligible impact on ignition prob. (0.1%) Greater environmental benefit
Reduce chemical requirements	Negligible impact on process IRPA Significant environmental benefit
Increase collision risk with the facility	Increase collision risk by 5%
Reduce riser / pipeline erosion, corrosion, and slugging	Decrease riser / pipeline risk by 5%
Increase number of generators	Increase ignition prob. by 4%
Increase number of heavy lifts	Increase dropped loads IRPA by 10%
Reduced hot work	Negligible impact on ignition probability No impact on IRPA, but potentially significant impact on the risk exposure is other risk measures are used

By quantifying the impact of all the risks identified related to subsea processing, an evaluation of how these risks compare to a more conventional field development could be performed. Figure 4-2 compares the personnel risks for the base case defined with the risk impact represented by introducing subsea processing. As indicated, subsea processing is expected to have a positive effect on the personnel risk exposure; in the case example developed, the personnel risk has been reduced by approximately 6%.

Figure 4-2: Comparison of the Personnel Risk Base Case and Subsea Processing



It should be noted that the base case developed presents a very generic risk picture of an installation during normal operations. The subsea case reflects any increase or decrease to the base case IRPA, based on the estimated benefits or disadvantages to the system from implementing subsea processing equipment. It is important to realize that each installation will have a unique risk profile based on its design, function and operation. The values presented in the analysis only represent a case to demonstrate the possible areas of benefit and/or concern related to applying subsea processing equipment. Each facility will be impacted differently based on the type of subsea technology implemented and the topside facility characteristics.

The conclusion from this risk comparison is that subsea processing is expected to have a positive effect on the overall personnel risk exposure on an offshore facility. By moving more of the process facilities to the seabed, the personnel risk on the installation will be reduced.

4.3 Environmental Risks

A similar approach as applied when evaluating the personnel risks was adopted to assess the environmental risks related to subsea processing. Results from environmental impact studies of a number of different offshore developments were used to establish a representative study base case. The frequencies of different size hydrocarbon releases were used when evaluating and comparing the environmental risks for a conventional field development to a development applying subsea processing technology. Three different leak categories were defined:

Small: < 10,000 BBL

Medium: 10,000 – 100,000 BBL

Large: > 100,000 BBL

To assure a realistic comparison, a conventional subsea tieback to a host facility was assumed when defining the base case. The host facility has been assumed to be similar to the process facility which was outlined in Figure 4-1. The leak frequencies, and associated consequences or volumes released, will vary depending on the number of wells, tieback distance and production rates; however, the numbers presented in Table 4-4 are representative for a typical subsea tieback.

Table 4-4 Base Case[1)] – Annual Frequency of Hydrocarbon Release

Risk Category	Small	Medium	Large
Process – leaks	0	0	0
Blowouts	1.2E-04	1.6E-04	3.7E-04
Riser / Pipelines	1.6E-03	1.0E-06	0
Dropped Objects	3.8E-05	7.5E-05	0
Collision with installation	1.1E-03	2.2E-05	0
Other	4.0E-04	0	0
Total	**3.2E-03**	**2.6E-04**	**3.7E-05**

1) Base case is a six well subsea tieback, 8 miles, with peak production rates approximately 80,000 BBLD

As seen from Table 4-4, leaks from the process facility are assumed negligible due to the drain system. The contributors to hydrocarbon leaks are:

- Blowouts
- Riser / Pipelines
- Dropped Objects
- Collision with installation

Blowout was the only risk category identified, which potentially could result in a large, >100,000 bbl, release of hydrocarbons. The frequency of a blowout was based on the SINTEF Offshore Blowout Database /4/, and an evaluation of the typical duration of an offshore blowout. The large hydrocarbon release relates to an uncontrolled blowout which exceeds five days.

Once a blowout has occurred, the operator will try to regain control of the well. The speed with which this is achieved, however, can have a significant influence on the amount of hydrocarbon spilled. The circumstances surrounding each blowout are different and so the methods used to regain control will also differ. In some circumstances, it may be possible to kill and secure off the well, while in other cases, i.e. a riser disconnect, all control of the well may be lost.

Oil blowouts, particularly those with low gas content, tend to reduce naturally as the reservoir pressure drops. Bridging or natural exhaustion may occur before other methods of control are successful. However, bridging is very unpredictable and is not considered a valid contingency plan for regaining control of the well. Drilling a relief well, which could require mobilizing a new drilling rig, may be required as a final solution to regain control of a blowout. The time needed to acquire and mobilize a rig, drill a relief well and perform a kill operation can vary from at least several weeks to potentially several months. In deepwater, the seawater column may provide sufficient back-pressure to prevent bridging. The risk of having to drill a relief well in order to control a blowout might therefore increase as more wells will not bridge-over.

For all the other risk categories, a leak will be contained by closing valves and isolating the leak point. There will typically be a number of isolation valves in the subsea system, including the valves on the X-mas trees and manifolds; there is also the downhole safety valve to isolate the production flow from the well. As a consequence, the maximum possible hydrocarbon release will be defined by the inventory in the flowlines and riser system.

4.3.1 Assessing the Subsea Processing Risks

A conventional subsea tieback has many similarities to a field development which applies subsea processing technology. All wells will be subsea completions and there will be flowlines tying the production back to the host facility. However, there will be some differences and these are discussed and evaluated in the following section.

As identified in the HAZID session, the subsea process equipment will possibly introduce some additional complexity in the subsea system, which could increase the risk of a leak. To compensate for this additional complexity, a conservative approach was adopted by assuming that the subsea process equipment introduces new leak points similar to the entire flowline and riser system in a conventional subsea tieback development. This is a very conservative assumption; the subsea process equipment will typically be integrated as a relatively simple bypass arrangement to the existing flowline system or integrated with a conventional manifold. Further, the connection points to the subsea process equipment will essentially be the same as the connection points currently applied on subsea wellheads or pipeline flanges and other connections.

The main conclusion from the HAZID session is that the production wells in a field development which is applying subsea processing technology will be identical to conventional subsea development. However, subsea processing could potentially have some positive effects on the reservoir risks: reduced number of wells required for the field development due to pressure boosting, less workover operations as a result of the extended production from the wells and possibly reduced risk of blowout because of the lower reservoir pressure in a typical well where subsea processing technology is applied. As a consequence, the risks related to the drilling and completion operations would probably be less than for a conventional subsea field development, and the blowout frequency was decreased by 10% compared to the base case.

One of the key issues identified during the HAZID session was that a number of additional marine operations will be required to install and retrieve the subsea processing equipment. This could potentially increase risk of collision with the installation, and this risk category was increased by 5% for the subsea processing case. Another major risk identified in the HAZID session was the potential risk related to dropped objects. An assessment of the increased dropped object risk was performed by evaluating the increased number of lifting operations required when applying subsea processing equipment[1]. This assessment evaluated the additional number of heavy lift operations required to repair and maintain the subsea processing equipment, and compared these operations to the typical lifting operations required for a conventional subsea field development.

Subsea processing technology may allow for a smaller riser / pipeline compared to a conventional subsea tieback, which possibly could reduced the consequence related to a rupture or a leak due to reduced volumes contained. However, the tieback could be significantly longer and the flow could be more concentrated hydrocarbons for a development applying subsea processing equipment. It is therefore difficult to conclude that the consequence would be any different. A conservative assumption was made to increase the riser risk by 5% due to the possible larger oil inventory in the system.

A summary of the modified annual frequencies for a hydrocarbon release in the subsea processing case is given in Table 4-5.

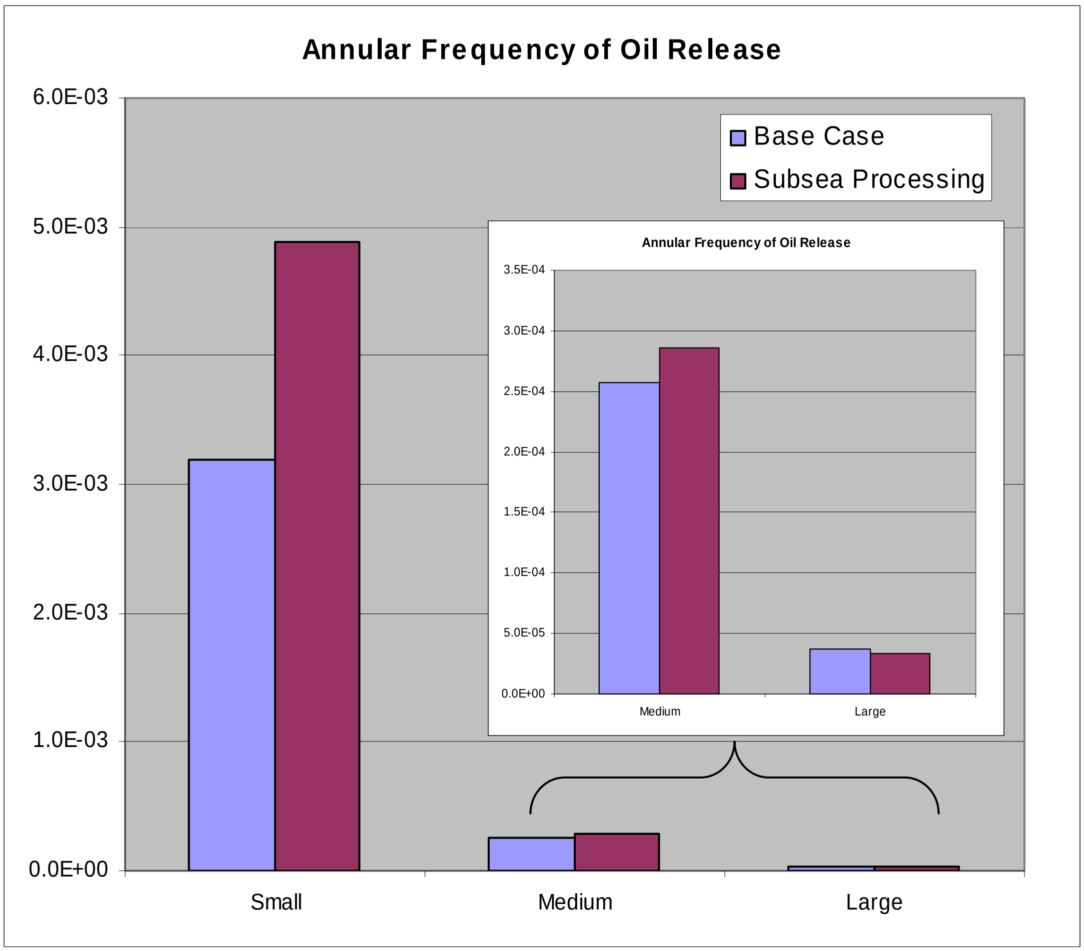
[1]Two subsea processing units was assumed when defining the lifting requirements, and comparing with the other lifting requirements in a typical six well subsea development

Table 4-5 Subsea Processing – Annual Frequency of Hydrocarbon Release

Risk Category	Small	Medium	Large
Process – leaks	0	0	0
Blowouts	1.1E-04	1.4E-04	3.3E-04
Riser / Pipelines	1.6E-03	1.1E-06	0
Dropped Objects	4.2E-05	1.2E-05	0
Collision with installation	1.1E-03	2.3E-05	0
Subsea Equipment	1.6E-03	1.0E-06	0
Other	4.0E-04	0	0
Total	**4.9E-03**	**2.9E-04**	**3.3E-05**

A comparison of the hydrocarbon release frequencies estimated for the base case and the subsea processing scenario is given in Figure 4-3. As seen from the results, the leak frequency is increased for small leaks, mainly driven by the additional leak points accounted for in the above assumptions. The frequency of a large leak is reduced, however, due to the reduced risk of a blowout.

Figure 4-3: Comparison of Subsea Processing vs. Conventional Subsea Tieback



The conclusion from this comparison of the environmental risks is that subsea processing may increase the frequency related to small leaks. However, the difference is nominal. Further, no major risks which would significantly increase the risk of a hydrocarbon release compared to a conventional deepwater subsea field development have been identified.

4.3.2 Other Environmental Issues

The quantitative comparison has assessed and evaluated the risks related to a hydrocarbon release. It should be noted that there were a number of other issues discussed related to environmental risks during the HAZID session, the two key issues being the use of chemicals and produced water.

The most common method of hydrate prevention in deepwater developments is injection of thermodynamic inhibitors, which typically includes methanol or glycol. These chemicals inhibit hydrate formation by reducing the temperature at which hydrates form. While being effective inhibitors, there are environmental issues related to the use of these chemicals, particularly methanol. In many areas, there are restrictions related to discharge of these chemicals, and even with regeneration equipment installed on the installation, the recovery of methanol would normally not exceed 80%. As discussed in the risk assessment, subsea processing will reduce the amount of chemicals required, particularly with subsea water separations. Thus, subsea processing would most likely have a positive effect on this specific environmental risk.

Produced water contains hydrocarbons (dispersed and soluble), natural soluble organic components and traces of heavy metals. High concentrations of hydrocarbons in the produced water may form oil droplets, thin oil layer or blue shine if discharged, with a potential for impacting marine life. Further, soluble hydrocarbons (e.g. alkylated phenols) and fractions with low bio-degradability (like PAHs and heavy metals) are toxic to marine organisms even at low concentrations. The latest research indicates a possibility for developing genetic effects with, for example, reduced fish reproduction as a consequence. As subsea processing will extend the productive life of a field, it would typically result in increased water production and could represent a concern. Requirements for treating or re-injecting the produced water should be considered. An estimate of how much the Troll Pilot subsea water separator and re-injection system has saved the sea environment has been performed. Existing requirements in the North Sea are 40ppm oil content in produced water dumped overboard. In four months in 2001, Troll Pilot injected 1.5MM bbl water, saving 50 bbl of oil from being dumped into the environment.

4.4 Relevant Design Codes

While the overall conclusion from the risk comparison is that the risk exposure related to subsea processing is comparable to conventional offshore developments, it is important that appropriate design practices are followed when considering application of these systems. Detailed failure mode and effects analysis should be performed to highlight failure mechanisms and consequences in a specific field application.

There are a number of applicable design codes and recommended practices which may be applicable when evaluating subsea processing for a field development. Some possible relevant standards and recommended practices include:

- ***API RP 14H* –** Recommended Practice for Installation, Maintenance, and Repair of Surface Safety Valves and Underwater Safety Valves Offshore
- ***API 14 C* –** Recommended Practice for Analysis, Design, Installation and testing of Basic Surface Safety Systems for Offshore Production Platforms
- ***API Spec 14D* –** Specification for Wellhead Surface Safety Valves and Underwater Safety Valves for Offshore Service
- ***API RP 17A* –** Recommended Practice for Design and Operation of Subsea Production Systems
- ***DNV RP 401* –** Safety and Reliability of Subsea Systems
- ***DNV RP 203* –** Qualification of Technology
- ***DNV – OS – F101* –** Submarine Pipeline System

These documents provide valuable input and assure important issues are considered for a specific field development. They provide support to ensure that adequate access for ROV or other special tools has been considered to allow safe operation, maintenance, inspection and testing. Further, they ensure materials and corrosion protection are appropriately addressed and ensure physical protection of the subsea installation (which may be beneficial for protection from dropped objects) is considered. Any environmental factors and load that may impact the operation and reliability of the system have been evaluated, including: waves, currents, geological, and geotechnical conditions, temperature, biological activities and water chemical composition. Issues related to the geology, topography, soil exploration and geotechnical properties at the location of the subsea process equipment.

5. CONCLUSIONS AND RECOMENDATIONS

The overall conclusion from the risk comparison is that the HSE risk exposure using subsea processing is not significantly different compared to a conventional deepwater field development. In the quantitative risk comparison, a very generic risk picture of a typical deepwater installation was used as a basis, while a typical subsea tieback was developed as the base case when assessing the environmental risks. It was evident that the personnel risk exposure will be reduced by introducing subsea processing equipment. The risk reduction will be very dependent on the specific installation and actual subsea processing technology applied, but in general, the personnel risk is reduced by moving more of the process equipment to the seabed, allowing smaller installation and less offshore operators. When assessing the environmental risks, measured as release of hydrocarbons, the subsea processing resulted in a slightly higher frequency for small leaks compared to a conventional subsea tieback. However, the leak frequency assessment used very conservative assumptions, and the differences were minimal, 4.9×10^{-3} compared to 3.2×10^{-3}.

It is important to realize that each installation will have a unique risk profile based on its design, function and operation. The values presented in the analysis represent a typical case in order to demonstrate the possible areas of benefit and/or concern related to applying subsea processing equipment. Each facility will be impacted differently based on the type of subsea technology implemented and the topside facility characteristics. This general risk comparison has demonstrated, however, that there should be no “show-stoppers” from an HSE point of view related to applying subsea processing technology. On the contrary, this assessment demonstrates that there may be significant benefits to applying subsea processing technology. This may become even more evident if considering issues like commissioning and manufacturing of conventional deepwater offshore installations or addressing the potential for less manning and reduced transportation (supply vessels and helicopters) required to operate the field in more detail.

The technical review of the subsea processing technologies demonstrates some of the potential benefits and possibilities related to application of these systems. For example, subsea processing could enable longer subsea tiebacks and utilization of existing infrastructure, allowing exploitation of fields which currently would be considered uneconomical or marginal to develop. Subsea processing may also enable ultra-deepwater developments, where the hydrostatic head currently is a significant challenge. Finally, improved subsea water separation processes may eliminate the risks related to hydrate formation, which could have a significant positive economic impact on deepwater field developments.

While many of the potential benefits are clear, limited operational experience is available. Therefore, the anticipated reliability and risks related to applying these systems are not known, thus operators are hesitant to start applying the technology before all the risks and benefits are fully understood. Further, current decision processes typically do not consider lifecycle costs, which often makes it difficult to justify any additional initial investments for later benefits and improved recovery or tail-end production.

To reduce this reluctance, significant work needs to be undertaken to demonstrate benefits and build confidence in the reliability of subsea processing equipment, and the potential economical benefits related to applying this technology. An important step in successfully achieving this industry acceptance is through combined efforts between operators and manufacturers. Technical studies to assess the life cycle economics of applying subsea processing technology, which also incorporate realistic models for the economic risks related to equipment failures, are critical to improving industry perception related to subsea processing.

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APPENDIX I
HAZID WORKSHEETS

Subsea Processing (Subsea Pressure Boosting and Subsea Separation)

Well/reservoir Issues	*For a subsea processing field development, there will essentially be no differences in the wells and completions compared to a conventional subsea field development.*		
	Installation / Commission	**Operations**	**Maintenance / Interventions**
+	**Subsea Completions**	**Increased Recovery**	**Reduced Well Pressure**
	Reduce Number of Wells		
-	**Dropped Loads**	**Drawdown**	**Dropped Loads**
		Reservoir Souring	

Dropped Loads	With subsea processing equipment, there is an increased risk of dropped objects onto the subsea wellheads and trees when lifting and installing the subsea process equipment. The dropped objects could result in damage to the subsea wellhead equipment and possibly result in a release of hydrocarbons. (The risk will depend on the proximity to the wells) There is also a possible concern related to drilling operations and the risk of dropped objects onto the subsea equipment from the drilling rig during the drilling and completion operations
Subsea Completion	In a development considering subsea process equipment, all wells will be subsea completions. This means less workover operations and a dedicated drilling rig for the drilling and completion operations. The risk related to blowouts would be reduced compared to a dry tree completion, which would have more frequent workovers as well as a higher risk exposure related to drilling and completion operations as these would be performed from the production installation.
Increased Recovery	The subsea processing equipment increases the recovery from the wells, and may reduce the number of subsea completions that may be required. The increased recovery will result in less remaining oil in the reservoir when the well is abandoned.
Reduce Number of Wells	Possibly reduce number of wells required due to the pressure boost and the increased recovery rate from the wells
Reduced Well Pressure	A field development with subsea processing equipment will most likely have reduced well pressure compared to a typical subsea well. This would result in less risks related to drilling and completion operations, as there would typically be a sufficient riser margin to maintain well control even in the event of a riser or BOP failure.
Drawdown	Pressure boosting system may affect drawdown of the well. The increased push and pull on the wells, may result in failure of sand controls, damage to wells and cause additional workover of the wells. Increased sand production could also be an issue
Reservoir Souring	With subsea water separation, there would be dedicated water injection well. The water injection well may pose a risk to the reservoir, further there could be a potential risk of souring reservoir (H_2S formation) if the produced water is mixed with seawater in the water injection well. Possible oil content in the injected water.

Riser & Pipeline	*The riser and pipeline network in a subsea processing field development would face the same general risks as risers and pipelines in a conventional subsea tieback development. The main difference is the integration of the subsea process equipment into the pipeline structure.*		
	Installation / Commission	**Operations**	**Maintenance / Interventions**
+		**Improved Flow Assurance**	**Less corrosion and erosion mechanisms**
		Gas Lift Eliminated	
-	**Dropped Loads**	**Hydrocarbon Releases**	**Dropped Loads**
		Over-Pressure risks	**Flow Assurance Requirements**
			Subsea Equipment Isolation

Dropped Loads

Concern related to dropped objects and impacts on riser / pipeline, when handling the subsea process equipment or during drilling and completion operations.
(Probably not a major concern to the risers due to the distance to the installation)
Dropped loads are a relevant concern during both installation and maintenance/intervention

Flow Assurance

Subsea process equipment would enhance the flow assurance of the system, reduced water production and increased pressure of the production flow would all have a positive impact on flow assurance.
May result in reduced methanol, chemical/glycol injection requirements, the need for chemical injection at the subsea process equipment should however be considered.
Reduced chance of slugging and hydrate formation during normal operation. However, during shutdowns there are potentially serious issues related to flow assurance (reduced cooldown time, water cut issues etc. which needs to be considered).

Hydrocarbon Release

Additional leak points will be introduced by the subsea process equipment in addition to the required piping and integration of this equipment. Possible increased risk of a hydrocarbon releases from the subsea processing equipment.

Isolation Issues

Possible concerns related to isolation and barriers preventing a leak when retrieving the subsea equipment for maintenance and replacement.

Flushing Equipment

Flushing and isolation of subsea process equipment prior to maintenance and retrievals, possible release of small amounts of hydrocarbons from the equipment

Corrosion Mech.

Reduction of water in process, in case of subsea water separation, could reduce corrosion mechanisms, and possibly reduce the probability of a leak

Less Erosion

Subsea process equipment and separators would possibly collect much of the sand produced in the subsea separator, which would result in less erosion in pipelines (sand build-up is issue), and possible reduced probability of a leak. How the equipment will handle sand should however be carefully addressed and evaluated, increased drawdown and other reservoir issues may result in increased sand production from the wells

Reduced Slugging

Reduced slugging in the risers could reduce the stresses on the riser and improve its fatigue life.

Consequence of hydrocarbon release

Subsea technology may allow for smaller riser / pipeline compared to a conventional subsea tieback, which possibly could reduced the consequence related to a rupture or leak due to reduced volumes contained. However the tieback could be significantly longer, and the flow could be more concentrated hydrocarbons for a development applying subsea processing equipment
Possibly longer tiebacks, which would also increase the consequence related to a leak due to larger inventory
The difference between a release in a subsea development with subsea process equipment would probably not be much compared to a conventional subsea tieback (not a significant issue)

Gas Lift Eliminated

Subsea processing, boosting or water separation, could eliminate the need for gas lifting the production risers. The gas inventory required in the riser for gas lifting could be eliminated and the HSE risks related to the risers leaks reduced.

Over-Pressuring Line	If line becomes blocked, the subsea process equipment may increase the pressure in the pipeline, possibly resulting in a rupture. Pressure ratings of risers / pipelines could be exceeded. (- Pressure relief systems or pressure protection systems, leak detection needs to be addressed for the relevant subsea processing technologies)
Reduced Pressure	Production flow / reservoir pressure in a field development considering subsea processing would normally be reduced compared to a conventional subsea production system. Pressure boosting would bring the pressure to normal production pressures and thus the additional boost would not be very different to the production pressure from conventional wells. High Integrity Pressure Protection Systems (HIPPS) would typically not be required for a typical subsea process development as the anticipated pressures would be much lower than the capacity of the equipment (Blocks and pressure protection on the equipment should however be addressed)

Utilities / Umbilical	*Subsea processing equipment requires additional utilities to be provided, auxiliary fluids, dedicated power and possibly subsea transformers. Control systems would be very similar to conventional subsea production systems*		
	Installation / Commission	**Operations**	**Maintenance / Interventions**
+			
-	**Dropped Loads**	**Auxiliary Fluid Leaks**	**Dropped Loads**
		Loss of Auxiliary Supply	**Repair of electrical cable**

Dropped Loads	Installation of the umbilicals, including electrical cables and auxiliary supply system should be conventional, with no specific issues compared to a typical subsea field development. There could potentially be some risks related to defects or kinking of the auxiliary lines which should be considered In some cases there may be a need for a subsea transformers and frequency converter, this will depend on the distance to the subsea equipment. Dropped object risk related to dropping the subsea transformers and other utility equipment during installation, may be a possible risk for these developments
Repairs of auxiliary lines	Repair of high voltage cables could be a possible risk, there have been some repair operations of electrical cables done from DP based vessels
Auxiliary Fluid Leaks	Possible concern or risk related to a leak or release of auxiliary fluids. The specific fluids required to support the subsea process equipment should be considered and evaluated
Auxiliary Supply	The effect of a possible interruption in the supply of critical auxiliary fluids to the subsea process equipment during operation should be considered. Dropped objects may result in kinking or damage to the supply lines, which may affect the cooling or other critical elements of the subsea equipment.

Surface Process Equipment	*Subsea processing equipment will require additional power generation on the installation. Due to improved flow assurance with subsea processing equipment the requirements for methanol and other chemicals may be reduced. Also surface water treatment can be reduced with subsea separation.*		
	Installation / Commission	**Operations**	**Maintenance / Interventions**
+	**Reduced Surface Processing Requirements**	**Reduced Gas Processing Requirements**	**Reduced Surface Maintenance**
	Reduced Methanol/Glycol Requirements	**Gas Lift Eliminated**	
	Smaller Footprint	**Reduced Flow Assurance Issues (slugging, chemicals)**	
		Reduced number of Operators	
		Reduced Produced Water (with subsea water separation)	
-	**Additional Power Requirements**	**Additional Surface Controls**	**Flow Assurance Strategy for Shutdowns**
	Auxiliary System Requirements		

Reduced Processing Requirements	Subsea process equipment could reduce the surface process requirements; may result in reduce weight and complexity on the surface processing facility Subsea water separation could reduce/eliminate need for surface water separation equipment and produced water treatment facilities, this could significantly reduce the environmental issues related to dumping produced water with oil content over board Subsea process equipment may reduce the risk exposure for surface operators and personnel (less topside equipment)
Flow Assurance	Subsea process equipment will require a flow assurance strategy to manage the flow assurance risks related to shutdowns. Issues regarding the need for dry oil storage on the instillation and pressure blowdown capabilities to prevent hydrates should be considered. In addition to the needs for methanol / glycol injection during shutdowns and start-up should be considered for a field development with subsea process equipment
Reduced Slugging	Reduced slugging in the system, could eliminate the need for topside slug catchers, or significantly reduce the risks related to topside slug catchers. There could be a significant personnel risk related to operating slug catchers
Reduced Chemicals	Subsea processing equipment may reduce the need for methanol, glycol and other flow assurance inhibitors. This will reduce the need for methanol recovery and glycol units' and reduce the surface process risks and also have a positive environmental effect as here will be less chemicals in the production flow. The specific need fro chemicals in the subsea process equipment should be considered
Additional Power	Additional power generation requirements on the host installation to feed the subsea equipment may be required. These gas turbines and generators may introduce an additional ignition source and pose an addition risk to the installation. The power demands may need high voltage cables and connectors, which could increase the topside risks - cables, sparks, additional ignition sources
Reduced Maintenance	Subsea processing equipment will potentially reduce the risks related to personal safety during repair and maintenance operations. If process equipment is eliminated by introducing subsea process equipment, there will be reduced maintenance requirements on the surface installation. Repairs of surface process equipment require offshore personnel and the operating environment could be a significant risk contributor. Maintenance personnel could be exposed to difficult operations which may be in close proximity to other producing production equipment. Subsea process equipment will be changed out from a support vessel, and all repairs and maintenance work will be done in a dedicated onshore facility. The reliability of subsea process equipment will also be greatly improved to justify the expensive intervention operations.
Produced Water	If subsea separation is applied there could be environmental advantages related to re-injection water versus dumping produced water from the installation. Subsea processing will however extend the productive life of the field and could result in increased water production, due to tail end production. A development with subsea boosting and no subsea water separation and injection, could therefore result in increased water production and water treatment requirements on the surface installation
Reduced Gas Processing	Subsea processing, pressure boosting and water separation, could eliminate the need for gas lifting. By eliminating the surface gas processing required to support gas lifting, the HSE risks could be significantly reduced. Subsea gas separation also has the potential to significantly reduce the surface gas processing requirements. By redirecting gas to another dedicated gas processing platform or re-injecting the gas, the surface gas processing requirements and associated risks can be significantly reduced.
Reduced Personnel	Possible reduced requirements on the number of operators/personnel required on the surface process plant (reduced surface process requirements and reduced complexity)
Auxiliary System	Control station for subsea monitors and controls needs to be installed on the surface installation, there will also be a requirement for operators of this control station. Subsea auxiliary systems need support equipment on surface facility.
Smaller Footprint	Subsea process equipment has a much smaller foot print than a comparative topside process installation. Subsea processing may enable smaller installations

Other Issues	*Subsea process equipment may be more vulnerable to met-ocean issues and environmental loads, additional marine operations may pose am increased threat for collision with the installation. These issues should be discussed when addressing the reliability of the equipment and the risk for a leak/release.*		
	Installation / Commission	**Operations**	**Maintenance / Interventions**
+		**Transport Accidents**	
-	**Weather Restrictions**	**Met-ocean**	**Weather Restrictions**
	Collisions with installation	**Noise Pollution**	**Collisions with installation**

Weather Restrictions Extreme weather may complicate installation, maintenance of the subsea equipment; could also affect dropped load risk

Met-ocean Loads and stress due to vibrations, loop currents etc. should be considered

Noise Pollution Noise pollution could be generated by subsea equipment, and possibly have an effect on marine life

Marine Life Marine growth could reduce/inhibit the cooling capacity of subsea equipment

Collisions Subsea process equipment will require support vessels to install and retrieve the subsea process equipment. This will result in additional marine operations and potentially increase the risks of a collision between the support vessels and the installation

Transport Accidents Subsea process equipment may result in less surface process equipment required, and therefore reduced manning requirements. This could have a positive effect on the risks related to helicopters and transportation risks

Equipment damage / leaks Earthquakes could affect the subsea equipment
Challenges to seabed conditions (mud, stable soil, etc.)