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Abstract

Gassco is the operator of two platforms with gas transport functions. These platforms are getting old and require large modifications to extend the lifetime and maintain their functions. Rapid development in subsea technology the recent years enables functions that earlier where performed by offshore platforms to be converted into subsea systems. Subsea developments offer the potential of reduced CAPEX, OPEX and risk reduction in terms of HSE. This makes subsea developments an attractive alternative to conventional topside developments. As a case study, this thesis evaluates the challenges and opportunities related to moving the functions of Heimdal Riser Platform into a subsea system. The requirements of a mid/downstream operator such as Gassco have not been widely evaluated by the subsea industry. A subsea gas transition hub is fundamentally different from other subsea developments due to the fact that there is no production involved. Subsea production systems have an increasing demand for power due to their complexity. A subsea gas transition hub is simpler and the power demand is low compared. With no nearby topside host facilities, there are challenges with respect to the subsea power supply and communication. Traditionally these requirements are provided by an umbilical which are tied-back to a host platform. Considering the low power demand and the long offsets to nearby host facilities, a long and costly umbilical may be hard to justify. Hence has the focus of this thesis been to eliminate the requirement of an umbilical. Many R&D projects, with the objective of reducing costs and risks related to umbilicals, have commenced the later years. Although many of the projects have been successful, the umbilical maintains as the only option to meet subsea production systems requirements. In this thesis, based on earlier studies, alternative solutions for power supply and communication have been evaluated. All the equipment that are required to maintain the gas transport functions will be incorporated within a 230 tons subsea manifold(excluding protection structure). This includes a remotely operated subsea flow control valve, a subsea High Integrity Pressure Protection System (HIPPS) and a subsea pig launcher guiding base. The structure also incorporate isolation valves which facilitate the opportunity to retrieve the HIPPS and flow control modules if maintenance is required. The subsea control system is based on the All-Electric technology which eliminates the requirement of hydraulics for valve actuation. The control system is powered by a rechargeable Lithium-Ion battery package which requires periodic recharging of energy from an intervention vessel. Communication between the subsea system and the master control station is provided by a connection to the integrated subsea fibre network in the North Sea. This subsea concept implements technologies that have not been widely used by the industry, hence a qualification program must be initiated before a fully functional subsea gas transition hub is ready for installation.

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Abbreviations

AE – All Electric Control system
ASC – Autonomous Subsea Control System
AUV – Autonomous Underwater Vehicle
CAPEX – Capital expenditure
CFD – Computing Fluid Dynamics
DRP - Draupner
EH – Electro Hydraulic
EM – Electromagnetic
EMI – Electromagnetic Interference
EPCDU – Electric Power And Communication Distribution Unit
EPU – Electric Power Unit
ESD – Emergency Shut Down
FEM – Finite Element Method
FFI – Forsvarets Forskningsinstitutt
FMECA – Failure Mode Effect Analysis
FPS – Floating Production System
FTA – Fault tree analysis
GoM – Gulf of Mexico
HAZID – Hazard Identification
HAZOP – Hazard and Operability Study
HIPPS – High Integrity Pressure Protection System
HMP – Heimdal Main Platform
HPU – Hydraulic Power Unit
HRP – Heimdal Riser Platform
HSE – Health, Safety and Environment
IMR – Inspection, Maintenance and Repair
MCP – Master Control Panel
MUX EH – Multiplexed Electro Hydraulic control system
NCS – Norwegian Continental Shelf
OGT – Oseberg Gas Transport
OPEX – Operational expenditure
PFD – Probability of Failure on Demand
PPS – Pressure Protection System
PSD – Process Shut Down System
PSV – Pressure Safety Valve
P&ID – Piping and Instrumentation Diagram
RAM – Reliability, Availability and Maintainability
ROV – Remote operated vehicle
RPM – Round Per Minute
SCADA – Supervisory Control and Data Acquisition
SCM – Subsea Control Module
SIL – Safety Integrity Level
SPCU – Subsea Power and Communication Unit
SSSV – Subsurface safety valve
SWB – Sea Water Battery
SWIFT – Structured What-If Technique
TLP – tension leg platform
TRL – Technology Readiness Level

ULF – Ultra Low Frequency
VLF – Very Low Frequency
XT – X-mas tree

1. Introduction

1.1 Background

Gassco was founded by the Ministry of Petroleum and Energy in 2001 to meet EU requirements to organisation and transportation of gas to the European market [1]. New regulations required an independent, neutral part to be the operator for the infrastructure that earlier were operated by several companies. Gassled, which is a joint venture stakeholder organisation, is the owner of the infrastructure. Gassco's responsibilities comprise the operation of pipelines and facilities, infrastructure development and to ensure that gas is transported to the market in correct volumes with right quality. The infrastructure includes 7975km pipelines, two processing plants (Kårstø and Kollsnes) and two riser platforms. In addition, gas receiving terminals located in Germany, Belgium, France and UK are parts of the network. See Figure 1 for an overview.

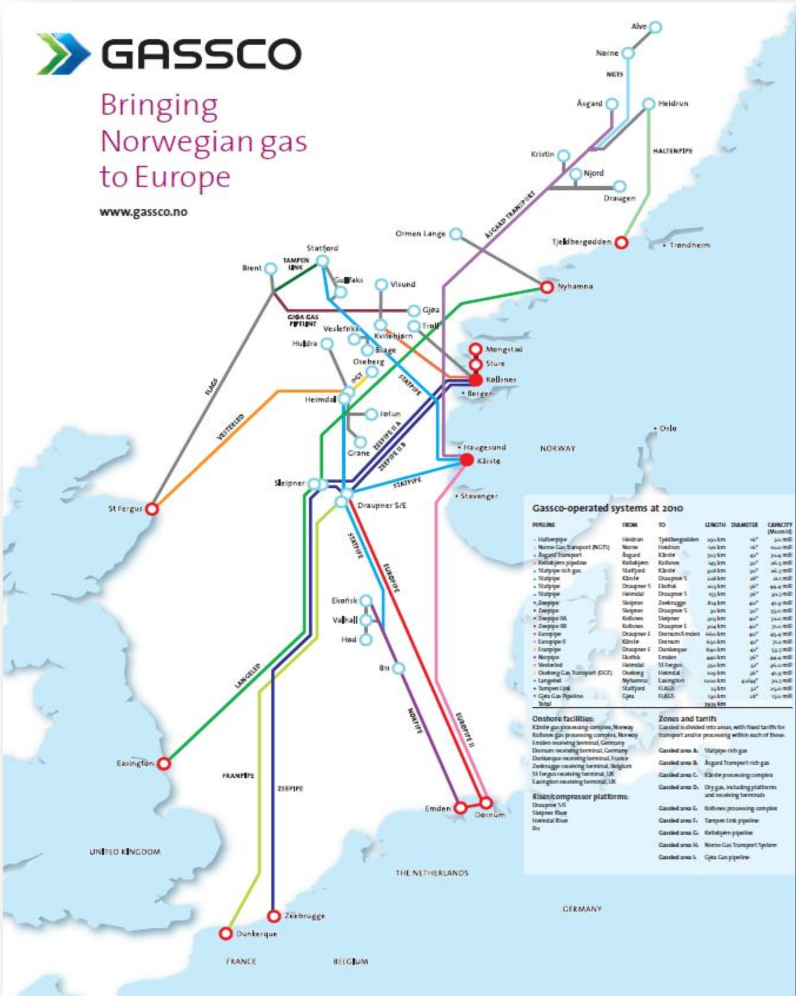

Figure 1: Gassco operated infrastructure (Gassco homepage, 2014)

The Heimdal Riser Platform (HRP), located in the North Sea is a gas transit hub (Jacket structure) for producing fields located in the region, see Figure 2. Gas from Oseberg, Huldra, Heimdal and Vale is allocated at HRP and distributed as specified to receiving terminals at the continent (through Statpipe) and St. Fergus in UK (through Vesterled). HRP is tied back to Heimdal Main Platform (HMP) which is operated by Statoil. Statoil also serves as technical service provider (TSP) of HRP on behalf of Gassco. HMP is a processing centre for fields located in the region. Its current status is that its licensees are searching for new resources in the region that can extend its lifetime [2]. HMP may however discontinue gas processing in near future which would affect the operation of HRP. Studies evaluating HRP's future as a gas transit hub need to be conducted.

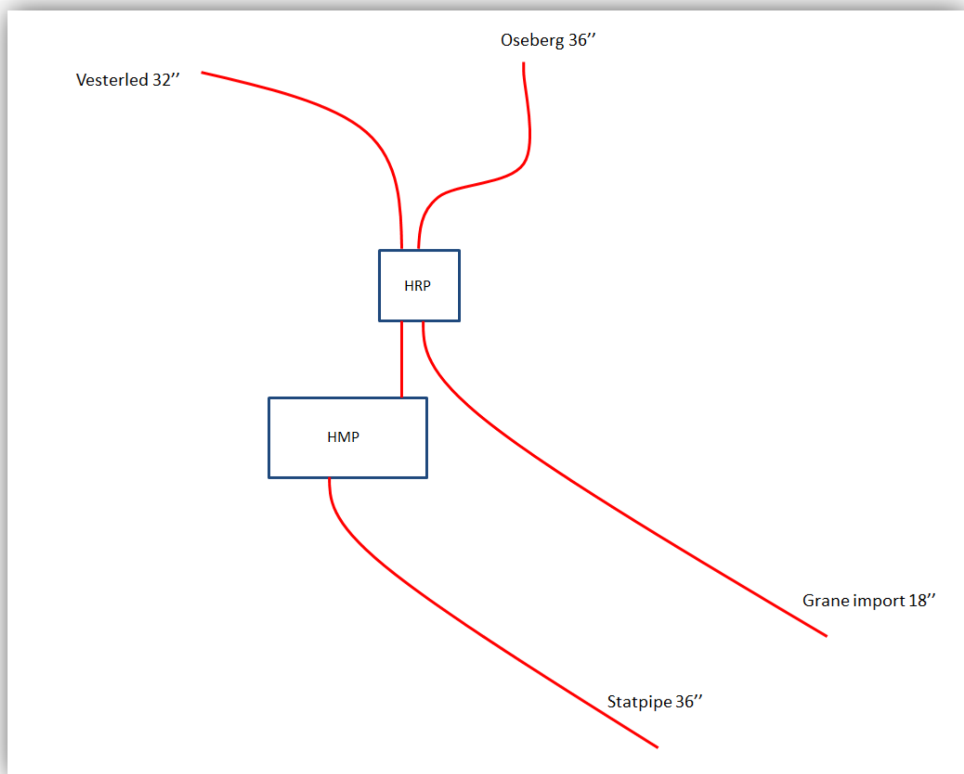

Figure 2: HRP and HMP with main pipelines [3] (in the event HMP processing is shut down)

1.2 Problem Description

Gassco is the operator of two platforms with gas transit hub functions (Heimdal Riser and Draupner). These platforms are getting old and require large modifications to extend the lifetime and maintain their functions. As a consequence, the operating costs will increase significantly and other alternatives to maintain the gas transport have to be evaluated. One alternative is to convert the gas transit hub functions performed by topside systems today into subsea systems.

Some platforms in the transport network, like the compressor platforms 2/4-S, MCP-01, H-7 and B-11 have over the last years been bypassed and are/will be removed. However, these platforms were replaced by simple bypass spools without valves and other functions to control the gas transport.

The function of a gas transition hub is to route and mix gas from different facilities. To control these functions, both on/off valves and choke/control valves are operated. Topside operation of such systems is today considered well known practice, but what about if they were located subsea?

Rapid development in subsea technology the recent years enables more and more complex functions to be performed at the sea bed. In this master thesis relevant subsea technology will be investigated and its application in a subsea gas transition hub system will be looked further into.

The Heimdal facilities and functions will be used as a base case. The case assumes that HMP processing is shut down, and that the gas transit hub functions performed by HRP today shall be converted into a subsea system.

Main challenges and areas of interest will be:

- Requirements of a subsea gas transit hub system
- Manifold Systems
- Subsea Control Systems
- Power and Communication
- Flow control systems
- High Integrity Pressure Protection System (HIPPS)
- System layout

The opportunities and challenges related to a subsea gas transition hub will be evaluated. As a product of this thesis, a recommendation for a subsea concept will be given.

1.3 Design Basis

In the event HMP processing is shut down, it is assumed that the fields Heimdal, Huldra and Vale will no longer transport gas through HRP. Grane is currently importing gas from Heimdal for injection and will in the future re-produce this gas. This gas will most likely be rich and require processing before entering the dry gas transportation system. As of today, the Grane facility does not have sufficient processing capacities and thereby has to find other transportation solutions than the Heimdal Subsea System. Hence, the system comprises pipelines connecting Oseberg Gas Transport (OGT), Vesterled, and Statpipe (Heimdal-Draupner) (Figure 3).The Statpipe pipeline is required to have bidirectional flow. The Vesterled pipeline has lower design pressure than Oseberg and thereby requires a pressure protection system in order to fully utilize the capacity of the system.

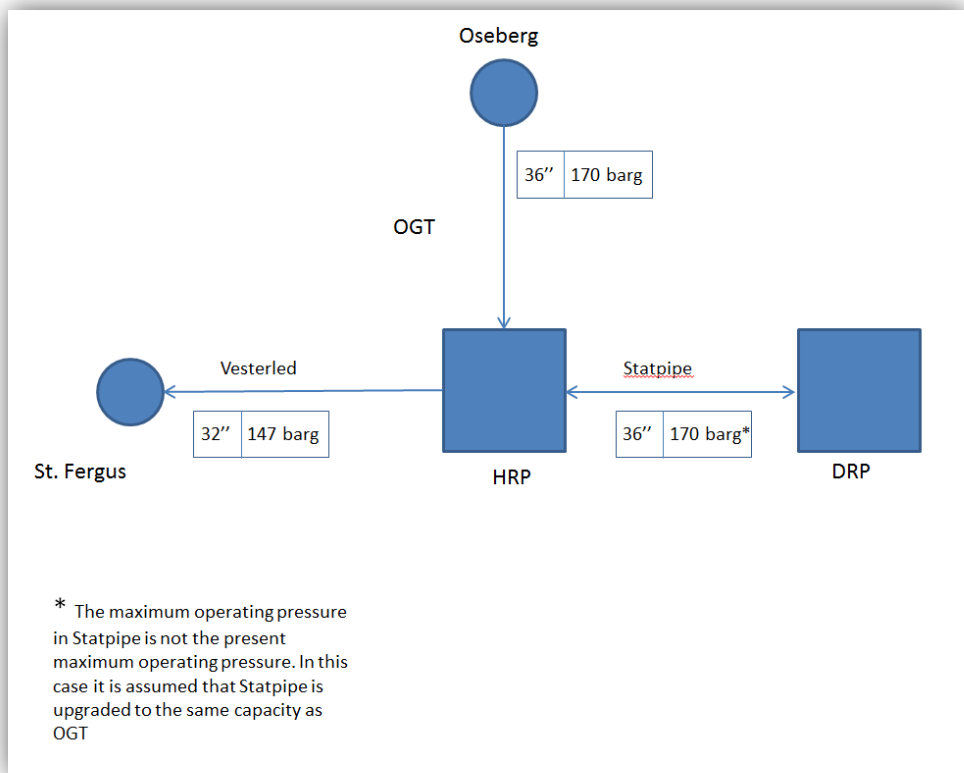

Figure 3: Battery limits

2. State of the art - Subsea Technology

Subsea technology in the oil and gas business is a large subject. Traditionally when talking about subsea systems one refers to subsea production systems. These systems comprise (to some degree) down-hole completions, X-mas trees (wet wells), control and power systems, manifolds, flow lines and risers. In this thesis the system under consideration is not a subsea production system but a subsea gas distribution system. The system is downstream of processing; hence there is no production or processing requirements. To fulfil the system's requirements, piping and valves must be arranged in a manifold. This manifold needs to be remotely operated and high availability of its functions is required.

The following sections will give a historical view of the development of subsea technology. Thereafter a state of the art introduction to subsea technology relevant for a subsea gas transit hub system will be given.

2.1 History

The first registered commercial activity on the sea bed was in ancient Greece where divers collected sponges, which at the time was discovered to be useful when taking a bath [4]. More advanced diving techniques were developed in the 17th century. Ballasted diving bells could be used for salvage work, e.g. of sunken ship wrecks. In 1658, as ordered by the king of Sweden, a successful subsea operation managed to retrieve most of the canons from the famous sunken Vasa ship using a diving bell [5]. Like many other technological advances, subsea technology evolved as a result of warfare. During World War I submarines were used in all navies for intelligence missions and to bring destruction to enemies. As the world's demand for energy increased after World War II, oil and gas exploration were moving offshore. In 1947 the first offshore wells were drilled in 100m water depth from a fixed Jacket structure in the Gulf of Mexico (GoM) [6]. After this, the offshore petroleum activity accelerated all over the world.

Hansen and Rickey [7] have given a good overview of the developments the following years. As the technology evolved and the search for energy continued, the petroleum activity moved into regions where conventional offshore platform concepts were limited by water depth. In 1961 the world's first subsea completion was installed in 16m water depth at the West Cameron field in GoM. This system was designed for remote installation and operation as an experiment for future deep water subsea developments. In the early 1960's the first full scale subsea developments were done. The Conception and Molino fields were both developed with subsea satellite wells tied back to a platform and to shore. Even though the Molino field was located in shallow water (so divers could access the system), a special robot was designed for remote intervention, indicating that operators were preparing for future deep water subsea developments. In the 1970's a pilot test programme was initiated in the GoM. A 3-well template was installed demonstrating technology required to install, operate and maintain a subsea production system throughout the field life. In 1971, Ekofisk, the first oil field to be developed on the Norwegian Continental Shelf (NCS) was allowed early production by installing four subsea satellite wells tied back to a jack-up platform. Some years later the Argyll field on UK sector was the first field in the world to be developed using a Floating Production System (FPS) with subsea wells.

At this time diver assisted installation and maintenance were well established practices. However, as discoveries were made in deeper waters, improving diver- less technology was required. In 1992 the Snorre field was developed as a subsea solution in 335m water depth. A 10-slot well template is tied back over 6km to a host Tension Leg Platform (TLP). Diver less technology developed from the pilot test programme in GoM was used for installation and maintenance of the subsea system. Robot systems to support installation and maintenance deployed from surface vessels evolved from fixed track systems to what today is known as the free flying Remote Operated Vehicle (ROV).

The advancements in subsea technology on the NCS have during the recent decade continued to break limits. Statoil's vision is to have a complete subsea factory within 2020 (Figure 4) [8], which means that processes that only have been feasible topside, can be moved to the sea bed. Such processes include: multiphase pumping, separation and compression. In addition challenges related to power support, instrumentation, logics of systems and so on must be dealt with. Multiphase pumping enabled the Lufeng field, located south-east of Hong-Kong, to be developed in 1997. Due to heavy crude oil and deep waters the field would not have been commercially possible to develop without this new technology [9]. The subsea separation milestone was reached in 1999 when the Troll pilot Separator Station was installed on the Troll field [9]. The concept included a separator and a produced water injection pump. By enabling subsea separation, the produced water could be extracted from the well-flow, de-bottlenecking the system, and thereby allowing higher hydrocarbon production. At the same time the separated produced water was re injected into the reservoir with a centrifugal pump to maintain reservoir pressure.

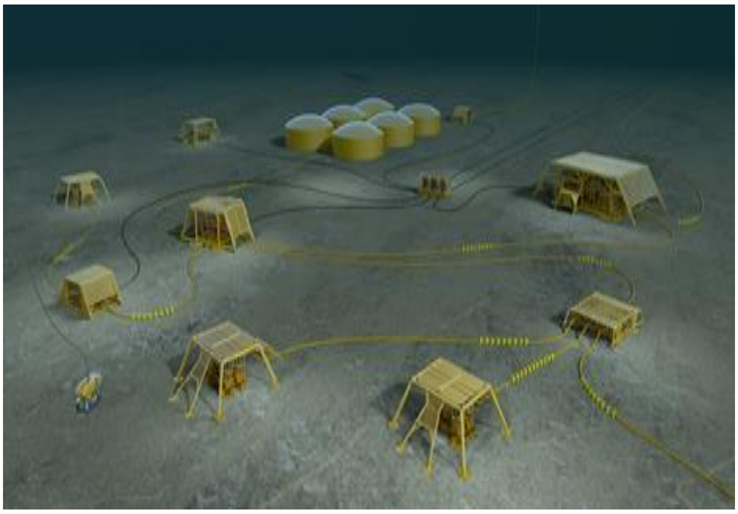

Figure 4: Statoil's subsea factory comprising wells, separators, oil storage, pumps, control systems and gas compression (Statoil homepage, 2014)

More recently, huge steps have been taken towards subsea gas compression. Gas reservoirs may be technical or economical unfeasible to develop due to long distances to host facilities and/or insufficient reservoir pressure. This has led to poor recovery rates and that smaller fields have not been developed. By installing a gas compressor on the seabed compared to topside, the suction pressure can be drawn further down allowing higher production rates and increased total production. The subsea solution also has advantages with respect to HSE, OPEX, energy efficiency and placement challenges (topside). In particular two projects need to be mentioned when talking about subsea gas compression: Ormen Lange Subsea Compression Pilot and Åsgard Subsea Compression [10].Ormen Lange is a gas field located 120km off the Norwegian Coast. It is developed as a subsea tieback to shore solution. Complex solutions and technologies have been utilized for this to be possible. In its later field life, subsea gas compression would be a solution to maintain optimal production rates for as long as possible. Ormen Lange Subsea Compression Pilot project was initiated by Norsk Hydro in 2006. In 2011 a 12.5 MW compressor and a 400kW liquid pump delivered by Aker Solutions were ready for installation in a test pit at Nyhamna. A final selection for compression concept has not yet been chosen. Meanwhile Statoil decided to go for a subsea compression solution on the Åsgard field. Due to pressure decrease in the Mikkel and Midgard fields which are tied back to Åsgard B, liquid accumulation will cause an unstable flow regime and slugs. Subsea compression is a solution for this problem and it will help to produce another 280 million barrels of oil equivalents. Studies and experience from the Ormen Lange pilot have made this possible and project start-up is scheduled for 2015.

2.2 Manifold

A manifold is a system of pipes and valves used to manage and distribute fluids. Subsea manifolds are traditionally used in subsea production systems, i.e. in connection with wells. There are mainly two solutions of manifold arrangements, the cluster and the multi-well template solution (Figure 5). Which of the solutions is chosen depends on reservoir conditions, drilling schedule, system complexity and so on. The focus will not lay on manifold concepts, but on their functions and requirements in a gas distribution system.

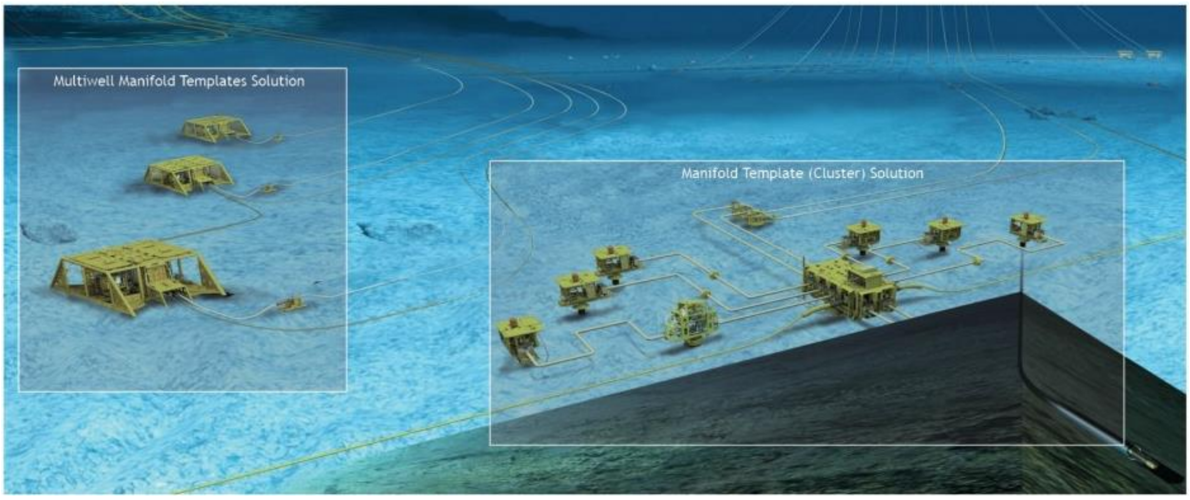

Figure 5: The cluster and multi-well manifold arrangement [11]

The manifold can be the host of many critical functions and equipment depending on its application in a system. A typical manifold arrangement will include pipe branching and isolation valves controlling flow directions. But it may also include other flow control devices such as choke/control valves, flow metering instrumentation and HIPPS. Also injection lines, subsea control module (SCM), control system functions and connection points for flow line tie-ins may be facilitated by the manifold. In other words, a manifold can be the structural foundation of all equipment required to perform all system functions.

The manifold may host complex equipment responsible for critical functions of a system. Downtime of its functions could lead to significant economic losses. Hence is high reliability required for a manifold to be economical feasible in a project. Paula et al. [12] identified the following critical components that affects the reliability of a subsea manifold:

- Subsea valves – Are used to direct and seal the flow and may be remotely operated or manually by divers or ROV's. The manifold functions are strongly dependent of the valves.
- Chokes – Valves used to control the flow. They are exposed to erosion and abrasion effects and unexpected maintenance may be required
- Control systems – the valves on the manifold are normally actuated by a control system (e.g. MUX E/H, direct hydraulic). Some failures that may occur are: Jumper and umbilical leakage, Surface power unit failure and failure of electronic components such as solenoid valves and Subsea Electronic Module (SEM) incorporated within the Subsea Control Module (SCM).

To obtain high reliability, these components must be designed with high quality and with respect to future intervention. Components with high failure probability rate should be modularized so that when components fail or require maintenance, they can be retrieved by intervention vessels. Such operations are expensive; the design should therefore be optimized with respect to IMR operation efficiency.

Most manifolds are constructed for subsea production systems, but there are examples where manifolds have been used to facilitate gas transit hub functions. In Trinidad and Tobago a 48 inch pipeline manifold was installed as a part of the BP Bombax Pipeline project [13]. To meet the increasing demand for natural gas, a 63km 48 inch pipeline was installed from the Cassia B platform to a LNG facility on the east coast of Trinidad. The 48 inch is connected to an existing 40 inch pipeline via a 20 inch jumper to increase the capacity of the system and provide flexibility. Also a new wellhead platform, Kapok, was installed with a 26 inch multiphase flow line connected to the Cassia B platform for processing. The Kapok platform was, due to the development scheme, ready for production before Cassia B processing was available. So to allow early production, the Kapok platform carried out separation with test separators and transported liquids through a 6inch to an existing 12inch liquid line. The separated gas was then transported through the 26inch pipe and connected to the 48inch pipe via an early jumper. See Figure 6 for an overview.

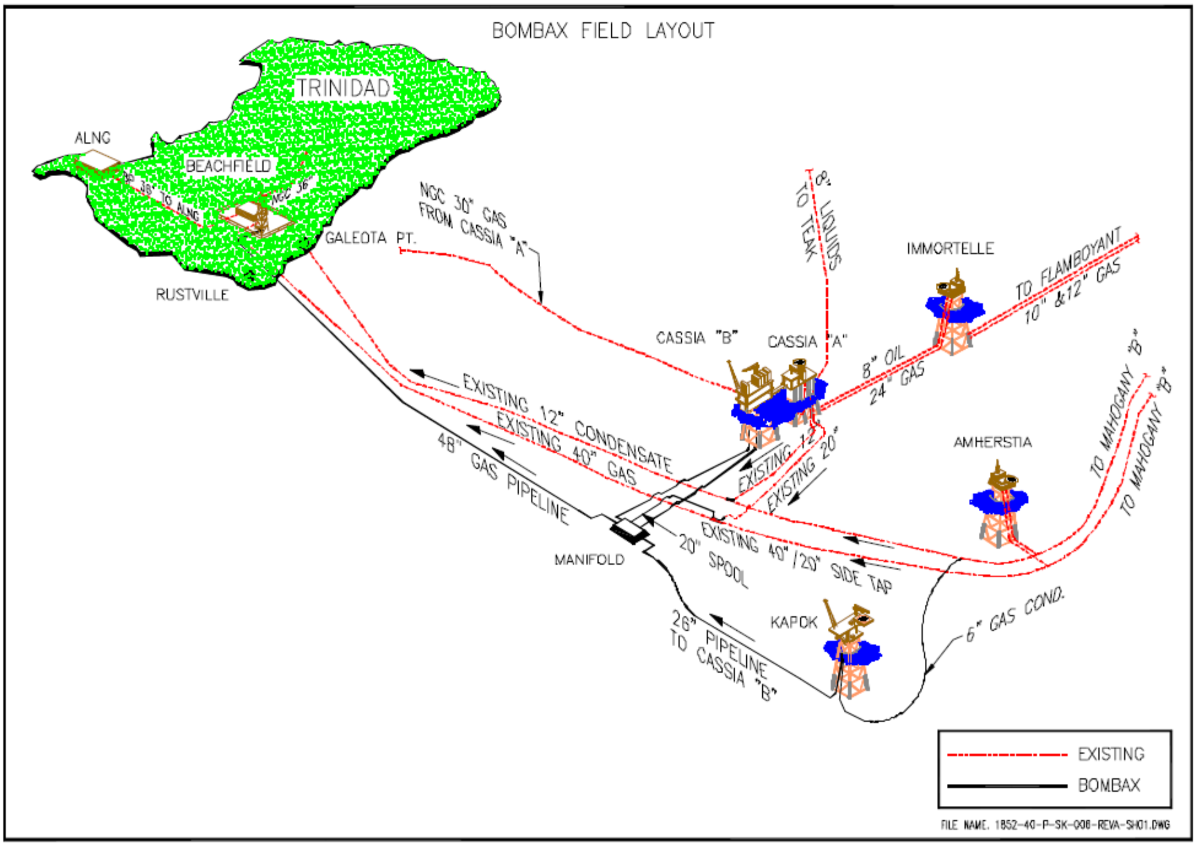

Figure 6: Bombax field Layout [13]

To facilitate looping of the 40 and 48inch pipelines with actuated valves, early production jumper, ESD valves, crossings of pipelines and providing connection point for future tie ins (with double block and bleed), a manifold was constructed and installed.

Summed up, manifolds facilitate many important functions when included in a system. Each of these functions are carried out by different equipment and arrangements. These sub functions and equipment are sometimes very complex and should be given closer attention. In the next sections the state of the art with respect to this equipment will be investigated.

2.3 Subsea Control Systems

The subsea control system might be the most critical part of the subsea system. Its function is to be the interface between the equipment installed on the sea bed and the topside host facility. This includes mainly equipment to monitor and operate the subsea system. Subsea control systems became a necessity when the development moved towards subsea production systems. The past decades the development of different control system concepts and types has been significant. The first types were of the direct hydraulic systems where valves were operated by a direct hydraulic connection to the host facility. The use of direct hydraulic systems was followed by the piloted and sequenced valve hydraulic systems. Drivers such as improved response time, accurate monitoring, reliability, harsher environments, costs and increasingly complex systems have later forced the development towards electro hydraulic systems and what today is the known as the multiplexed electro hydraulic system (MUX EH) [14]. The MUX EH system is today the most used control system for subsea developments; however the industry is always looking for better solutions. The following sections will evaluate the well-known MUX EH system, but also the unconventional All-Electric System and the Autonomous Control System will be given proper attention.

2.3.1 Multiplexed Electro Hydraulic Control System

The MUX EH control system is the preferred control system type for most subsea developments today. Compared to the earlier all-hydraulic based control systems, the MUX EH relies on optical or electrical transmissions of control signals which give this system excellent response time [15]. In general, the electro hydraulic control system consists mainly of three parts: Topside equipment, umbilical and subsea equipment, see Figure 7.

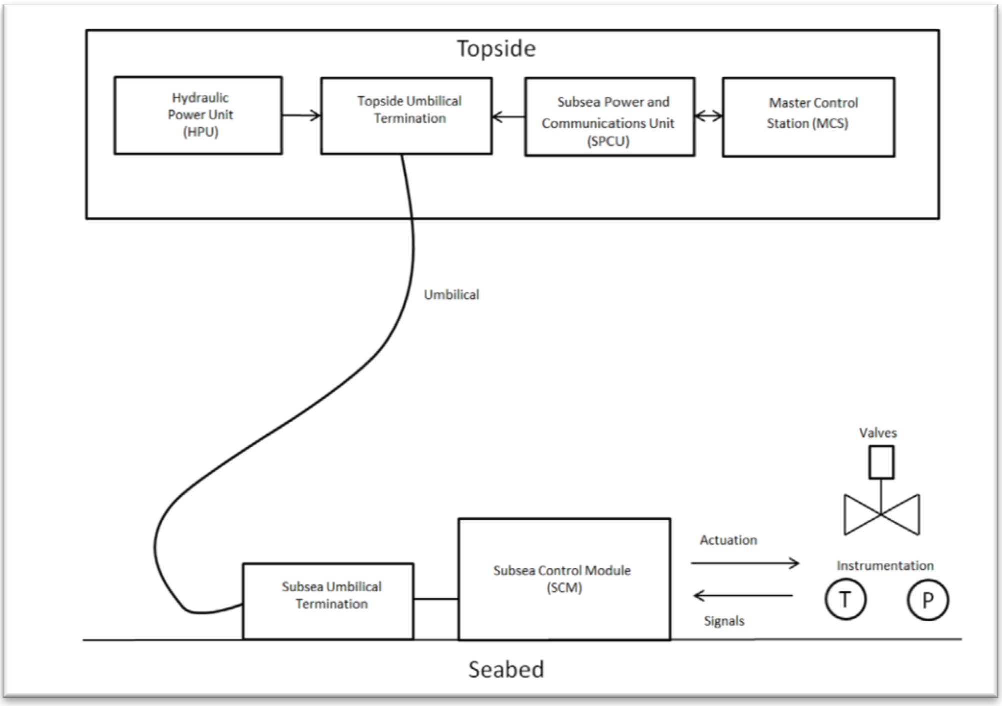

Figure 7: General overview of components in MUX E/H control system

The topside system comprises the Hydraulic Power Unit (HPU) which includes pumps, accumulators and storage of fluid to provide the necessary hydraulic power for the system, the Subsea Power and Communication Unit (SPCU) providing electrical power and distributing signals for communication, and the Master Control Station (MCS) for monitoring and operation of the subsea control system. The hydraulic circuit can be designed as an open or closed loop system. In open loop systems the hydraulic fluid is non-toxic; water based and is vented to the sea.

The umbilical connects the topside equipment to the subsea system. Electrical lines power the SCM and can be used for communication (normally only as back-up). The electrical lines are bundled together with hydraulic lines and fibre optics for communication (see more in section 2.5). In some applications, service lines like for e.g. chemical injection are included. Umbilicals (Figure 8) are often dynamic since they are subjected to currents, waves and vessel motions (depending on its application). To improve their dynamic behaviour buoyancy elements may be installed on the umbilical.

Figure 8: Umbilical cross section [11]

The subsea configurations and complexity varies from system to system, but the subsea control module (SCM) is always present. The SCM is the interface and communication unit between topside and subsea equipment. It distributes signals from subsea sensors and manages the hydraulic functions of the system. More attention will be given the SCM in section 2.3.4. The fast response of the system is achieved by the use of multiplexed electric signals that activates solenoid valves on hydraulic lines which in turn energizes actuators, see Figure 9. Inbuilt accumulators store energy when the demands are low and provides high pressure energy when required (e.g. when operating a valve) [16]. Energy stored at site will reduce the operating time. Also support equipment like flying leads, termination points, hydraulic couplers etc. are important parts of the system [17].

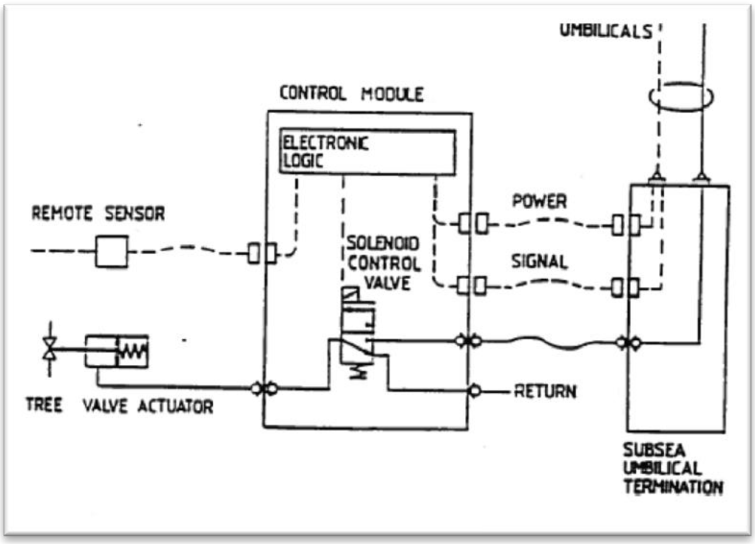

Figure 9: Simplified overview of the subsea functions in a MUX E/H control system (edited figure from [14])

2.3.2 All-Electric Control System

All conventional subsea control systems are until now based on hydraulic control technology. The MUX EH has proved to be fast responding and to provide good regularity for the systems. However, the system is not perfect and the industry is starting to recognize that as O&G activities move into deeper waters and more remote locations, the MUX EH control system will not be adequate [18]. Since the system is based on hydraulic energy, certain limitations due to the nature of hydraulic fluids and systems occur. In deep waters the hydrostatic pressure can be a major problem. Large volumes of accumulated energy may be required to operate valves and accumulators must be designed with large wall thicknesses to withstand the external forces. The results of this may be large accumulators which impose challenges with respect to installation and manufacturing . If the systems also are remotely located, the fluid volumes required to operate the system may be beyond what is possible for a topside facility to handle.

The MUX EH has successfully been applied in projects worldwide with excellent performance. However there are weaknesses that limit its application and economic feasibility. A hydraulic system consists of components such as pumps, valves, cylinders, hydraulic couplers and so on. These are all subjected to wear and tear. Studies have shown that a significant portion of reliability problems in production control systems are due to hydraulic components and activities such as installations and operation associated with these [18]. Also topside storage capacities introduce challenges, especially when the required fluid volumes are large. The driver is always to optimize system availability with cost efficient methods. New technology needs to be developed and existing systems need to be improved.

The weak link in today's conventional subsea control systems is the hydraulics and much effort has been given to improve reliability and costs. The recent years a new subsea control system concept has evolved significantly, namely the All-Electric control system (AE). This system relies on electric actuation of valves, thereby eliminating problems related to hydraulics. The industry's interest in all-electric systems is not new. Already in the early 1990's programs for developing electrical subsea actuators were initiated. However, the first all-electric production control system was delivered by Cameron in 2008 at the K5F field in the North Sea, Dutch sector. The tieback to the host platform is 9.6km in 37m water depth [19]. A Reliability, Availability and Maintainability (RAM) analysis conducted in advance of production initiation, calculated a 2% improvement of system availability compared to a MUX EH system. This corresponded to a total system availability of 95.5%. An examination of the performance of the system in July 2010, considering 16550 hours of operation, found that a total system availability of 99.98% had been achieved. The error leading to a 0.02% downtime was due to a topside network failure and was not subsea related [20]. The improved reliability of all-electric control systems had successfully been demonstrated.

Based on lessons learned from the pilot project, the work on developing the 2nd generation all-electric control was initiated [21]. Cameron together with operators, reviewed the pilot project and identified constraints for further application of the system. To reduce the costs and complexity a simplification of the subsea hardware was necessary. The amount of redundancy applied in the pilot system was in some areas considered superfluous. In addition, a state of the art communication technology was implemented into the system.

A simplified overview of the AE system is given in Figure 10 [22] [21].The topside of the AE consists of two electrical power units (EPU) which provides power and communication for the subsea system. These units are independent, hence power supply redundancy is provided. The MCS provides the human interface functions needed to monitor and operate the subsea system. The umbilical contains redundant optical fibre and power cables to establish reliable operation and communication with the subsea system. An umbilical termination assembly (not in shown in the figure) facilitates the tie- ins. Power and signals are transferred to the EPCDU where incoming fibre optic signals are converted into DSL signals which establishes further connection to the Electric Subsea Control Module (ESCM). The Power is regulated and distributed further to the ESCM. Each EPCDU is capable of controlling up to five ESCM's. The ESCM has the same functions as the traditional SCM (as for a MUX EH), but without the use of hydraulics. The ESCM can control up to 32 electrical actuators and redundancy is provided for power conversion and communications units. Without repeaters the step-out distance from host facility to EPCDU is 160km, and the maximum distance between EPCDU and ESCM can be 15km.

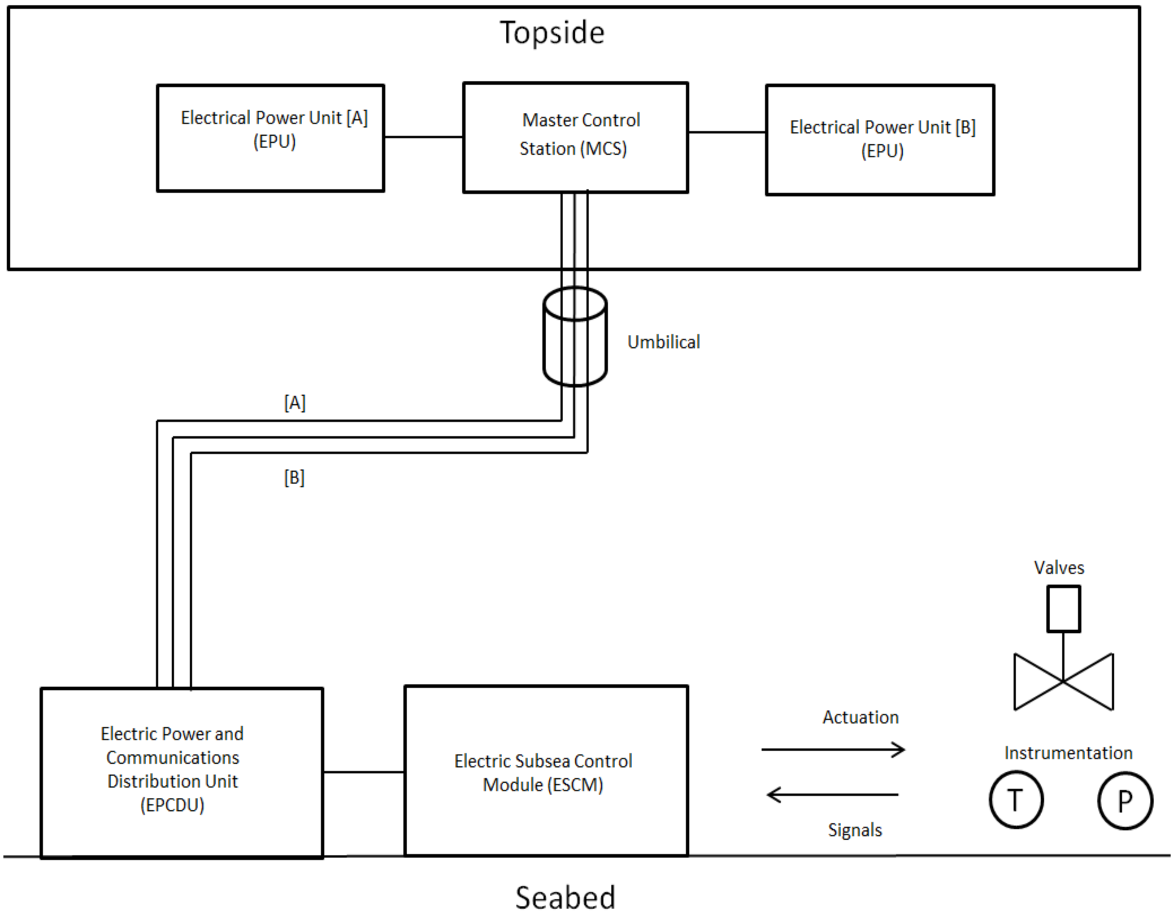

Figure 10: Simplified overview of the All-Electric control system

The 2nd generation AE is going through a comprehensive qualification process (2011) to verify its intended functionality in subsea systems [21]. The advantages of AE systems compared to hydraulic systems are evident and there is little reason to believe that the AE system will not be an important part in the future of subsea technology. Subsea technology is heading towards subsea processing which relies on smart, environmental friendly, fast responding and high accuracy control systems. The AE system is a step towards those requirements.

Summed up, the advantages of AE compared to traditional control systems are:

- Environmental friendly (risk of hydraulic fluid spill is eliminated)
- No hydraulic fluid
- Electrical engines give better operational control
- Real time feedback of operated equipment
- Reliability of electric components are better
- Enable efficient control of subsea systems in ultra-deep waters
- Enable efficient control of subsea systems for ultra-long offsets

2.3.3 Autonomous Control System

An autonomous subsea control system (ASC) serves the same functions as the MUX EH and AE systems, but it has one major disparity. The ASC has no hardware connection to the host facility, in other words, it is an umbilical-less control system. This eliminates the costs and risks associated with the umbilical. The main characteristics of the ASC are that it relies on a local power source and that it communicates with the host facility with wire-less technology. Since the 1980's several comprehensive R&D projects within the field of ASC have commenced. The ASC technology does not narrow down into one outstanding concept, rather several concepts have been introduced. This section will address what has been done within the field of Autonomous Subsea Control Systems the past decades.

In 1987 the world's first autonomous subsea production system was installed at the Luna 27 well development in the Ionian Sea [23]. The project named Subsea Wells Acoustic Control System (SWACS), was a joint venture project between Tecnomare, Kongseberg Vaapenfabrikk and Norsk Agip. The communication between subsea system and host facility was made by a hydro-acoustic link at a 3700m step-out. Further communication between the host and a main control station were established by a radio link, see Figure 11. High reliability of communication was achieved by using good transmission protocols and error detection algorithms.

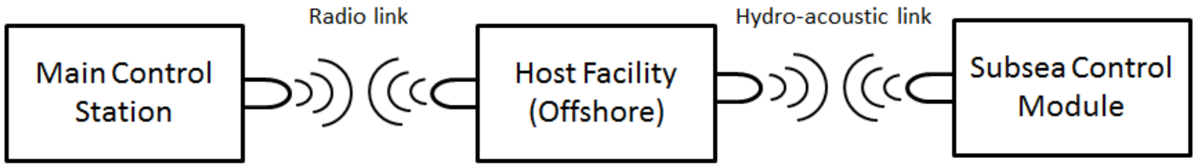

Figure 11: Communication concept in SWACS project

The SCM was designed to control eight valves, seven XT valves and the SSSV, in addition to monitoring five instruments (pressures, temperatures and valve positions). To minimize the power consumption, signals were sent to the host every half hour. In the period in-between signal transmissions, the SCM is capable of autonomously initiate safety procedures if necessary. Two closed-loop hydraulic circuits secure hydraulic pressure for the valve actuators, one for the SSSV and one for the XT valves. Power for the electromotor and hydraulic pump, instruments and signal transmission was initially provided by a Lithium battery package. The lithium battery package proved its feasibility. However, lithium batteries require regular substitution or recharging, which means additional costs of expensive intervention vessels. In 1996 a Sea Water Battery (SWB) was installed, replacing the lithium battery package [24]. These batteries generate power locally based on metal anodes which use sea water as an electrolyte with an inert cathode of titanium, see more in section 2.4. The performance of the SWB was as expected and concluded to be successful.

Other projects such as the Subsea Powered Autonomous Remote Control System (SPARCS) [25] and the Autonomous Power and Control System (APAC) [26] set focus on developing efficient local power supply. The SPARCS concept used turbine generators (if water injection well) or thermo electric generators (if production flow line) to generate power. The turbo electric generator is installed in the flow line and converts kinetic energy of injection water into electrical energy. A thermo electric generator uses the differential temperature between the production fluid and the surrounding water to generate electric power. See Figure 12 for concept overview.

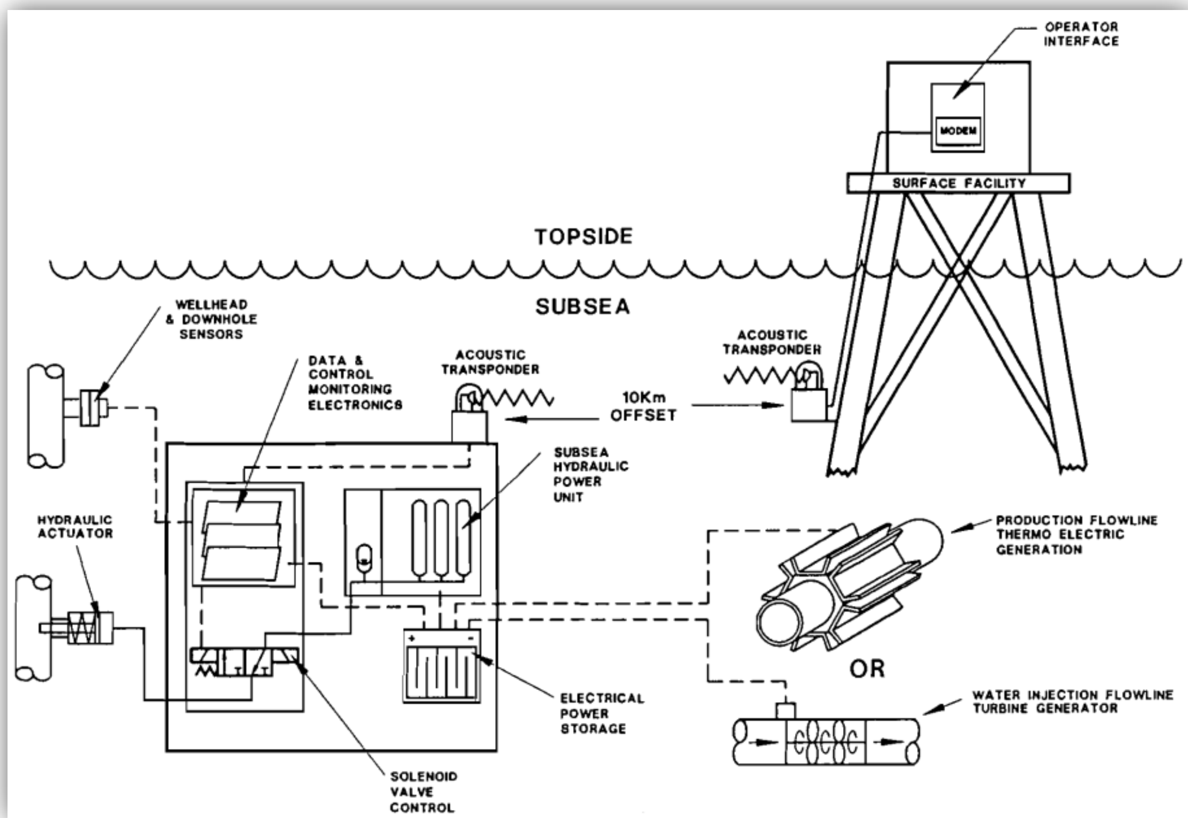

Figure 12: SPARCS concept [25]

For the APAC project, a thermo-electric power source was chosen. The requirements for the generator were to deliver 200W in 2000m water depth. A prototype testing proved that the thermo-electric technology was feasible as power source in an autonomous production system. The generators charge batteries when the power consumption is low, so sufficient power is available for peak demands.

All these concepts rely on hydro-acoustic communication with the host facility. I the North Sea a range of 10km in 100-150m water depths is considered to be practical [26]. So hydro-acoustic communication has limitations with respect to data capacity and step-out range (see more in section 2.5). These disadvantages are significant opposed to the other control systems discussed in the previous sections.

One concept dealing with the limitations of underwater wireless communication is the hybrid system [27]. The concept is characterized as a hybrid system since it has no umbilical connection to the host, but still has an umbilical connection to a surface moored control buoy. Different configurations of this concept can be implemented. The surface buoy may incorporate power supply, batteries, and hydraulic pumps which in other autonomous systems are placed on the seabed. But the main feature of this concept is the possibility for the subsea system to effectively communicate over long distances. Fibre optic communication lines incorporated in the umbilical can transfer high capacity data to the surface buoy, which further can communicate with the host by use of radio or satellite signal transmissions. See Figure 13 for system overview.

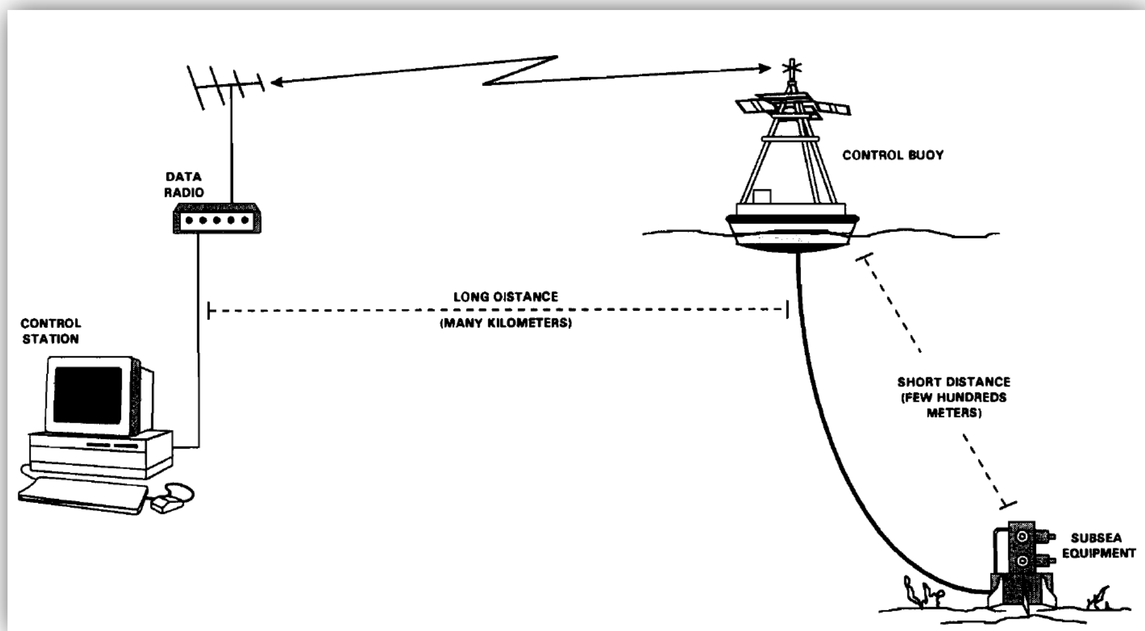

Figure 13: The surface moored autonomous buoy concept [28]

This concept was successfully installed offshore Brazil in 1996 [28]. Long distances to nearby platforms and coral reefs along the cost made it economically unfeasible to go for a long distance umbilical solution. In this case, solar panels and batteries, hydraulic accumulators, pumps and antennas for communication were installed on the buoy. A 500m umbilical providing communication, electric and hydraulic power provides energy for actuation of valves and communication with the subsea system. A surface moored buoy introduces challenges opposed to complete subsea solutions. Especially in regions with harsh weather conditions, the buoy will be subjected to dynamical forces which could compromise equipment installed on the buoy. Also the mooring introduce additional concerns. Opposed to the other concepts discussed above, critical hardware is easier to access and maintain. However, the more hardware is put on the buoy, the bigger and expensive it gets. Combinations of the buoy concept and those concepts earlier discussed might be beneficial.

Autonomous control systems introduce several advantages opposed to conventional control systems. The umbilical is one of the most expensive parts of a subsea system and marginal projects may be economical unfeasible due to expensive, long offsets. The fact is that the perfect subsea control system would not include an umbilical, but be fully autonomous. Autonomous control systems introduce several advantages. Not only is it umbilical-less, but it minimize topside control system features. It has been over 30 years since research and development of autonomous control systems became serious business; however, during the last decade they have not been widely used [18]. Limitations in communications are one of the main reasons. In addition it has been augmented that the additional required hardware limits the scope of reducing costs and introduces additional risks. On the other side, much have happened within communication technology and electrical systems the recent years, which are technologies that could be used in modern autonomous control systems. Combinations of electric and autonomous technology could prove to be a cost efficient alternative for some subsea projects.

2.3.4 Subsea Control Module

The subsea control module (SCM) controls the hydraulic functions of the subsea system and is the interface for signals and control between topside and subsea equipment. The SCM type depends on whether the control system is EH, direct hydraulic or all electric. The most common type today is EH, but also the all-electric (ESCM) system is advancing. Figure 14 show a typical EH SCM configuration.

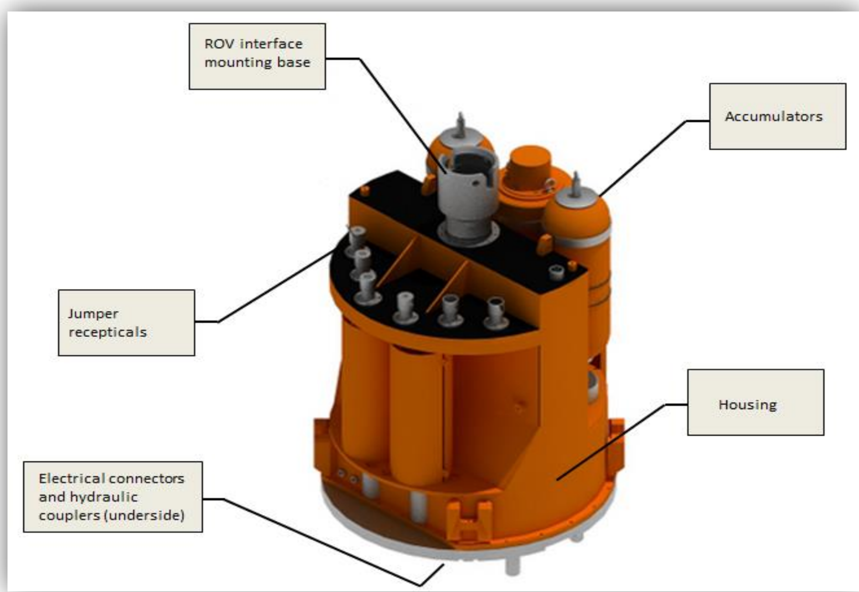

Figure 14: E/H control module configuration [11]

All hydraulic output functions are operated by electromechanically operated solenoid valves. When the solenoid (electromagnet) is energized or de-energized, it either opens or closes a valve orifice. Several types of solenoid valves and operation methods exist, but two general principles are: Direct acting and internally piloted. Direct acting opens or closes the valve by direct action of the core. This operational method has limitations in force and cannot manage high pressures. The internally piloted method uses line pressure to assist operations, thereby allowing a small solenoid valve to manage high pressures [29].

A good review of subsea control module functions was given by Bavidge [30]. The SCM receives both low pressure (LP) and high pressure (HP) hydraulics from the guide base through the hydraulic couplers mounted on the underside of the SCM. The LP circuit is used to provide pilot pressure for the operation of HP solenoid valves. When entering the SCM, both circuits pass a filter followed up by a solenoid operated selector valve, shear seal valve and a shuttle valve. LP and HP accumulators are mounted on the SCM and are connected to the hydraulic circuit downstream of the shuttle valves. From here, a variety of functional valves like chokes, seal valves, etc. may be operated by redundant solenoids. For improved reliability, two Subsea Electronics Modules (SEM) are installed inside one atmosphere vessels. The space surrounding the SEMs is filled with dielectric fluid which provides an additional barrier against seawater. If the SCM was the leader of the subsea system, the SEM would be the brain of the leader. It utilizes multiplexed electronic signals to communicate with the SPCU. Commands are given the SEM from the SPCU to perform hydraulic functions by energizing solenoid valves. The SEM also receives and distributes signals from monitors within the SCM and the subsea system. This information could be pressures, temperatures, valve positions, flow rates and so on.

With today's technology SCM's cannot be "designed out of maintenance". A review conducted by Chevron identified that there was close to a three-year mean time to failure (MTTF) of SCM's, and a 95,5 % probability of failure within 10 years [31]. Thus introduces the SCM one of the most considerable reliability challenges of a subsea system. Hence is the SCM normally designed to be retrievable by use of ROV assisted running tools.

2.4 Subsea Power

To operate and control subsea systems they need continuous supply of power. For conventional control systems (section 2.3.1) both hydraulic and electric power are required. The electric power is required for sensors and signal transmissions (and other electrical functions), and hydraulic power is required to actuate valves. In the All-Electric control system (section 2.3.2), only electric power is required. The power supply is traditionally generated at a host facility and transmitted through hydraulic lines and electrical conductors incorporated within an umbilical. A hot topic in the offshore oil and gas industry these days, is the electrical cable from shore concept. Projects such as the Martin Linge field development [32] and the electrification of the developments at Utsirahøyden [33] (among others) implements long distance power transmissions from shore. This eliminates the need for gas compressors offshore, hence reducing the environmental impact. When the industry move towards subsea processing and long tie-back scenarios (such arctic field developments), this concept may be the only feasible alternative. The concept has proved its feasibility and lots of literature papers focus on this concept. This section will not focus on long distance subsea power transmissions, but local power generation (autonomous technology, section 2.3.3) which eliminates the need for a power cable.

2.4.1 Thermo-Electric Generator

The Autonomous Power and Control System (APAC) project [26] employed a technology which utilizes the differential temperature between the well flow and surrounding water to generate electricity. The principle is based on the Seebeck Effect named after the German physicist Thomas. J. Seebeck, who discovered the phenomena in 1820 [34]. An electric circuit made of two dissimilar conductors is jointed at both ends. When there is a temperature difference in the junctions, an electrical current will flow in the circuit (Figure 15). The process is most efficient when the temperature difference is large. In the APAC project, the thermo electric generator is installed in a spool integrated in the flowline. The elements are configured in parallel and series to provide adequate power. Two production thermo-electrical generators were built and were capable of producing 100W, 70V for a temperature potential of 120 degrees Celsius in the production flow. The power is accumulated in a battery bank, so sufficient energy can be provided for peak demands.

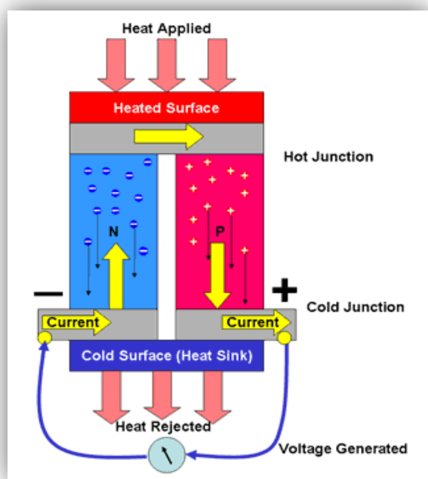

Figure 15: The Seebeck Effect [99]

According to the author's knowledge, no projects have applied the thermo-electric power generation technology for any commercial subsea projects. In a gas transportation system, where the temperature inside the pipelines is close to the ambient temperature, the potential of generating any electric energy is close to zero.

2.4.2 Sea-Water Battery

The first application of sea-water batteries in a subsea system was in the Subsea Well Autonomous Control System (SWACS) project [24] [35]. A prototype autonomous control system was installed on the Luna 27 gas well, offshore Crotone in the Mediterranean, in 1987. The well was controlled via a 3.5km acoustic link to the host facility. A local hydraulic circuit (no tie-back to host) supplied power for actuation of valves. An electric pump, initially supported by a lithium battery package, recharged the hydraulic accumulators when required. After 18 months, with an average power consumption of 15W, the battery package was exhausted. For long term applications, the SWACS would require periodic substitutions of power from an intervention vessel. This was not considered a cost efficient solution and the partners of the project commenced studies looking into other alternatives.

Among other technologies, sea-water batteries were considered the most suitable for this system. A sea-water battery package consists of cells based on metal anodes and inert cathodes. The surrounding sea water is used as electrolyte and oxygen dissolved in the water as oxidant. These cells requires continuous supplies of oxygen-rich sea water, hence the structures should be constructed to maximize the sea water velocity through the cells [35]. The chemical anode/cathode reaction will generate an electric current which in turn can provide the systems power requirements and/or charge an electric accumulator (a secondary battery package).

The sea water battery package installed on the Luna 27 well consisted of six cells, whereas the complete package dimensions were 5.2m×3.2m×4.2m (L×B×H). The package was fitted with six guide funnels for making it possible to replace the anodes by use of ROV's. A converter operating at an input voltage of 1.1-1.6V from the cells, delivers a voltage output of 27.6V to a lead-acid battery package. The buffer-battery supplies the electric pump with sufficient power to recharge the hydraulic accumulators when required. For a single satellite well, this solution was concluded to be successful. For systems with large power consumptions there are challenges in the capacity of such systems [24].

2.4.3 Turbo Generators

The Deep Water Autonomous Multi-Well Production Systems (DAMPS) research project was started in 1990 and completed in 1992 [36]. The project applied the local hydraulic circuit technology developed in the SWACS project, but focused on a turbo generator for local power supplies. The turbo generator architecture comprises a separator unit, turbo generator, AC/DC converter and control electronics, rechargeable lead acid battery package and lubrication accumulators. The power generator is installed in a by-pass parallel to the production line (Figure 16). Natural gas drives the turbine which in turn is connected to the generator by means of magnetic coupling.

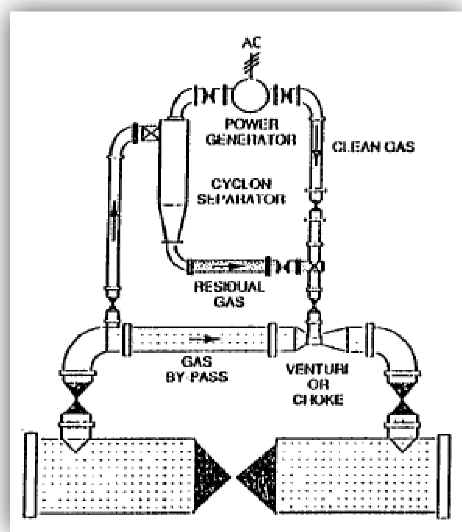

Figure 16: Turbo generator architecture [36].

As long as sufficient pressure is available in the flow, the capacity of the turbine can be regulated by choking the flow or by adding turbine steps. The Energy is stored in a battery package, so sufficient energy is available for peak demands (e.g actuation of valves). In the DAMPS project, the generator was given a requirement of 700W. This was considered sufficient for continuous operation of control functions and recharging of the battery package.

After a comprehensive testing scheme, the project concluded that the functionality of a low power gas driven turbine system for subsea application was feasible. However, for the concept to be qualified for commercial subsea projects, field trials are required. Although the concept seems to be promising, no subsea projects have applied this technology (according to the authors knowledge). Limiting factors may be the cleanness of the fluids and the required pressure differential over the expander (which requires a low pressure reservoir or a constant pressure loss in the main stream). Also erosional effects could compromise the reliability of the expander, so sufficient separation is required. Since 1992, huge steps have been taken towards subsea processing. Referring to the Åsgard Subsea Compression project, the compressor which is facing some of the same challenges as the turbo generator, has proved its feasibility. In a dry gas transportation system, where the cleanness of the fluid is high, erosional effects might not even impose a problem.

2.5 Communication

2.5.1 Conventional Cable Communication

Communication between subsea systems and topside host facilities has traditionally been established through copper wires. Copper has been the preferred medium for distribution of electrical signals and power due to its high conductivity. However, within the subsea industry, limitations in copper wire communication technology do not interact with the advances of subsea system complexity and requirements [37]. Advances in subsea processing and comprehensive field architectures require large amounts of data and signals to be transferred between topside and subsea equipment. The conventional copper wire's does not provide the required bandwidth for reliable operation of such systems.

The state of the art cable communication technology is currently optical fibre transmission, which introduces several advantages compared to copper transmission. Fibre optics are made of pure glass (or sometimes plastic) bundled together in a cable. Information is transmitted through the cable by use of light signals with little attenuation (Figure 17). This enables high bandwidth transmissions over long distances [38].

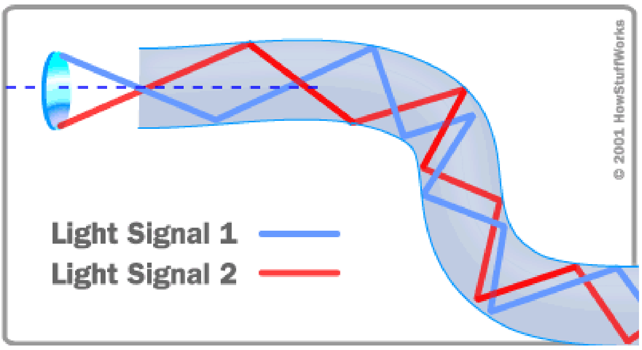

Figure 17: Light signals travelling through fibre optics [38]

The maximum data transfer of conventional electric (copper) cables is 20 kb/s (maximum 20km step-out), while fibre optic transmission of signals enables 10 GB/s data transfer in 140km step outs. Figure 18 shows the data transfer capacity and step out range for signal cable transmission methods.

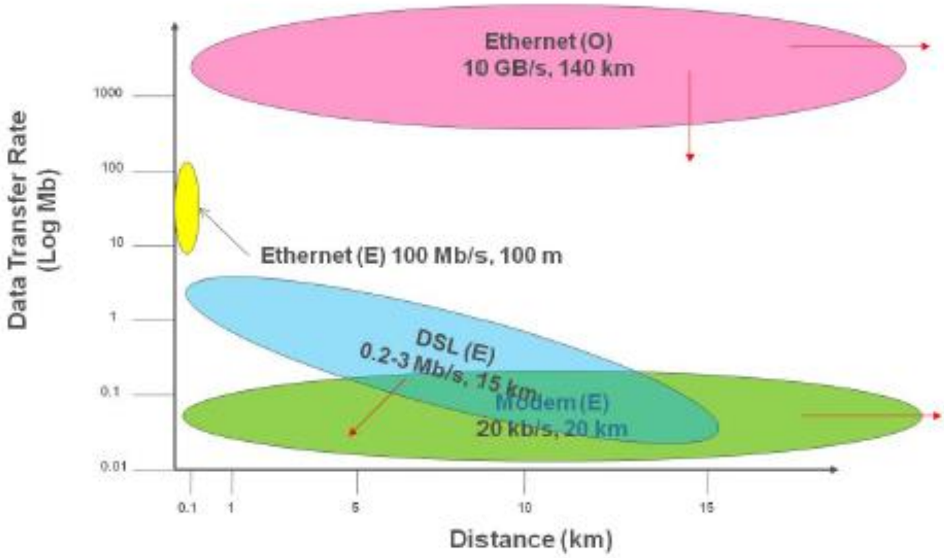

Figure 18: Data transfer rate and step out range of different data transfer methods [39]. (E) = electrical, (O) = optical

Another challenge which occurs due to increased subsea complexity is high levels of electromagnetic interference (EMI). High power equipment interfering with communication signals is a major problem for conventional conductors. However, fibre optic conductors are immune to EMI and thereby eliminate the issue. Fibre optic cables are also lighter than its counterpart, hence will the umbilical be lighter (and cheaper). But one should notice that fibre optic implementation comes with a higher cost due to comprehensive termination activities, and expensive connectors and system components [40].

2.5.2 Wireless Underwater Communication

The costs and risks associated with underwater cabling make wireless communication an attractive alternative. If a subsea system could establish efficient wireless communication with a remote located host facility, the benefits would be significant. Basically three methods for wireless underwater information transmissions exist today: acoustic, electromagnetic (EM) and use of optical waves. In this section their application and limitations in subsea systems will be addressed [41] .

2.5.2.1 Electromagnetic Waves (EM)

Radio waves are electromagnetic radiation travelling through air and vacuum of space by means of oscillating electromagnetic fields. Transmitters can transform information into radio waves and send them over large distances without significant attenuation. A receiver at the other end picks up the wave and transforms it back into its original form [42]. However, efficient underwater radio communication is a challenge. Due to the high attenuation in seawater, large distance radio wave communication is impractical. As the attenuation increases with conductivity and frequency, only low frequency signals are applicable for long distances. Low frequent waves carry little energy, not sufficient for communication purpose. Low frequent waves like ULF and VLF have their application in underwater communication (mainly military), but only with very limited data capacity and step-out range. Higher frequencies can be used for short range applications like for e.g. AUV's communicating with a subsea base.

2.5.2.2 Acoustic Waves

Acoustic transmission of information relies on propagating sound waves. Acoustic waves propagate at a much lower speed than EM and are dependent on factors such as water depth and temperature. On the other side, the attenuation in water is much lower than for EM waves. However, implications such as multiple paths and ambient noise reduces the reliability of the method. Multiple paths occur when the waves reflect on e.g. the sea bottom, and the sensor receives multiple arrivals of the same signal, which could introduce challenges in signal interpretation. Sources for ambient noise could be marine traffic, breaking waves, marine animals and so on. To avoid interference with signals, noise frequency needs to be considered. Even though acoustic wave attenuation is of less degree than EM it certainly has its limitations. Its attenuation is a function of absorption, scattering and geometric spreading. The absorption rate depends on the travelling medium and wave frequencies. Higher frequency means higher attenuation. As the distance from transponder to receiver increases, the energy flow will be smaller and the signal will eventually die. Scattering occur when particles in the water force the wave to deviate from its trajectory.

Far distance signals can only be sent with low frequencies; hence the bandwidth is very limited.

2.5.2.3 Optical Waves

Optical waves suffer from rapid absorption in water and scattering caused by particles and planktons. Thereby is communication by optical waves not considered feasible for long distances. High data rate transmissions can be achieved by sensors located close to each other.

2.5.3 Through Flow-line Communication

In the previous sections, wireless communication based on acoustic and electromagnetic wave technologies were discussed. These concepts are based on direct transmission of signals through open water which introduces several reliability challenges. Through flow-line communication is a concept utilizing the flow line itself as an acoustic communication link between the host and subsea system. Most subsea systems are in some way managing the operation of flow-lines, so they are always present and ready for use.

A research project named Deep Water Autonomous Multi-well Production System (DAMPS) were initiated in 1990 and completed in 1991 [43]. The communication between the host and subsea system was based on the "through flow-line" concept. The fluid contained inside the flow-lines was utilized to guide pressure signals made by a wave generator. The signals were received and decoded at the other end. The signals are protected against the external environment, so its limitations lie in the transmission medium. Different flow regimes and flow-line sizes will affect the signal attenuation. The project concluded that the transmission of sinusoidal pressure waves through two-phase fluids was possible, even at large step-outs. In a single-phase fluid the communication distance can easily exceed 10km, but the data capacity is very limited.

2.5.4 Communication summary

Table 1: Summary of different subsea communication methods for long step-out range

Method	Copper cable	Fiber optic cable	Radio waves	Acoustic waves
Data capacity	Low	Very high	Very low	Very low
Maximum transmission range*	20km	140km	100m	50km
Advantages	Proven technology, High speed, Cheap, Long step-out range, Easier terminations,	Proven Technology, Immune to EMI, Ultra- long step-out range, High speed,	Infield communication opportunities, no termination interface, no umbilical	Infield communication opportunities, no termination interface, no umbilical, lower attenuation of signal
Disadvantages	Vulnerable to EMI, High attenuation of signal, Heavier and more expensive umbilical,	Harder terminations, Complex connectors, Large costs	Very high attenuation of signal, Not applicable for long step-outs	susceptible to ambient noise, reflection of signals, poor reliability for long step-outs
* These values should not be emphasized since they vary in different sources. The reliability of the wire-less communication is also of great concern in long step-outs				

2.6 Subsea Adjustable Choke Valves

The control of flow is a requirement to obtain safe, flexible and reliable operations of subsea systems. This control is achieved by using choke valves, in some context referred to as control valves or flow control valves. Choke valves offer several advantages for subsea systems [44], [45]. In subsea production systems the use of choke valves allows high pressure wellhead flow to enter pressure restricted pipelines. In some cases the volume of the flow can be choked down to meet the separator capacity of the topside. In a gas transportation system it may be desired to regulate one main flow into several branching flows. This is all obtained operating a choke/control valve.

The basic principle of choke valves is that fluids are forced to flow through a reduced area which can be either fixed or adjustable. Different choke valve configurations exist, but the principle is always the same. When fluids are forced through a reduced area, the laws of fluids dynamics show that the velocity of the fluid will increase (see equations 1 and 2).

$$Q_1 = Q_2 \qquad (1)$$

$$A_1 * V_1 = A_2 * V_2 \qquad (2)$$

$$\frac{V^2}{2} + g*z + \frac{P^2}{\rho} = \text{Constant} \qquad (3)$$

Where:

Q = Volume flow [m^3]
A = Cross sectional area [m^2]
V = Velocity [m/s]
P = Pressure [Pa]
ρ = Density [kg/m^3]
g = Gravity constant [m/s^2]
z = Height [m]

The Bernoulli's principle (equation 3) shows that when the velocity increases, the pressure will fall. In a choke valve, when passing through the restricted area, the fluids will accelerate and the turbulence intensity will increase which results in a permanent pressure drop [46]. Most of the power will be dissipated as heat, but a significant amount is also produced as sound or pressure oscillations [47].

Choke valves are operated by actuators and can be either fixed or adjustable. Adjustable choke valves change their capacities by manoeuvring the valve stem. Since there are a variety of different trim designs, the flow characteristics of choke valves are not always linear (Figure 19).

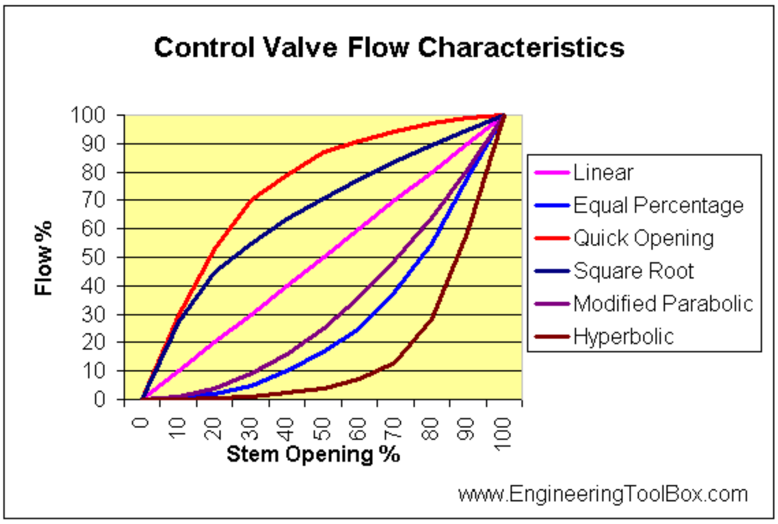

Figure 19: Choke valve flow characteristics [48]

The capacity of choke valves is often described by the flow coefficient C_v which is a measure that combines the flow rate and pressure drop across the valve (equation 4).

$$Cv = \mathrm{Q}\sqrt{\frac{\mathrm{SG}}{\Delta P}} \qquad (4)$$

Where:

Q = Volume flow
SG = Specific gravity
ΔP = Pressure drop across valve

Choke valves are characterised by manufacturers by an available C_v and a minimum C_v, hence the operational area must be within these values.

Choke valves can be installed on manifolds or X-mas trees permanently or as retrievable modules. These modules, often referred to as flow control modules may also incorporate flow meters, pressure transmitters and other instrumentations. From a reliability point of view, choke valves have been a major concern in subsea systems due to though working conditions. Erosion, abrasion and cavitation damage are critical issues which need to be considered in the choke design [45]. Large velocities in combination with changes from one phase to two phase fluid and impurities such as sand can damage the trim. Hence, the nature of the fluids needs to be considered in the design of the choke. The local pressure variations due to the turbulent flow, generate noise which propagate downstream of the choke as acoustical pressure waves [47]. If not dampened out, these pressure waves can cause vibrations which in combination with resonant effects of supporting structures can yield high cyclic stresses. Hence, dynamical analyses which consider all operational scenarios of the choke should be conducted. Another phenomenon which could in some choke applications cause problems, is the Joule-Thomson Effect. The Joule-Thomson Effect is the change in temperature of a fluid upon pressure decrease [49]. When the pressure decreases over the choke, depending on the extent of the pressure fall, the temperature will decrease. Normally the drawdown pressures of subsea chokes (well chokes) are not of such extent that this effect has any direct practical impact on the system [50]. However flow assurance problems (hydrates, wax) and icing of surrounding equipment may in some cases (if certain conditions are met) introduce challenges in choke valve applications.

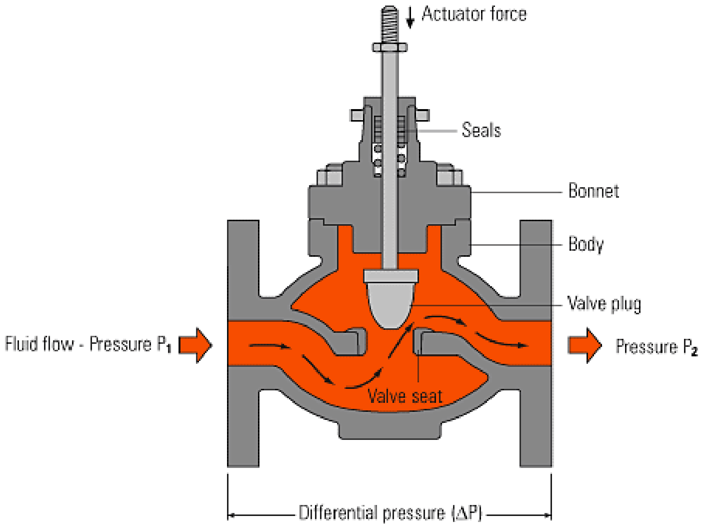

Figure 20: Flow Through a single seat, two-port globe valve [97]

2.7 Actuators

Subsea valves can be operated by ROV’s, divers or by means of remote actuation. Basically three remote valve actuation methods exist in the industry: Hydraulic, pneumatic and electric. Hydraulic actuators are considered the conventional method for subsea use. Hydraulic power is converted into mechanical work by means of a hydraulic cylinder or a hydraulic motor. This mechanical work is utilized to operate the valve positions. Since the liquids utilized in hydraulic circuits are nearly incompressible, hydraulic cylinders can provide precise displacements and thereby good valve control [51]. Pneumatic actuation suffers from the compressibility of gases and will not be given any further attention in this thesis. As discussed in section 2.3, the benefits of All-Electric control systems are many and electric valve actuation is a requirement for these systems. Hence will the focus lay on electric valve actuators.

Electric subsea actuators are field proven on the Norne and Statfjord fields in the North Sea [52]. Their functions are the same as for conventional actuators, but they introduce the benefits of no hydraulic components. FMC’s actuator concept comprises Electrical Subsea Control Modules (ESCM) and rechargeable Li-Ion batteries in addition to the actuator. The electric actuator consists basically of a communication unit, an Electric motor and a gear box incorporated within the actuator housing. It’s operation is controlled from the ESCM. The batteries accumulate sufficient power to drive the electromotor when valve operations are required. These are rechargeable, thus allowing a low power cable to charge the batteries in between operations.

State of the art electric actuators can provide the fail safe functions which may be required in a subsea production system [21]. These actuators consist of a drive motor and a clutch motor. The drive motor forces the valve to open against a spring. When the valve is in open position, the drive motor stops and the clutch motor ensures that the valve remains open. This clutch motor requires only small amounts of power to hold the position. If the power supply is interrupted, the clutch drive loses power and the valve will fail to its safe position.

Electric actuators are proven technology for subsea use. Their range of applicability covers all areas where its conventional hydraulic counterpart is applied. They have however, not been widely used.

2.8 Subsea Pigging

Subsea pipelines require periodic inspection and internal maintenance to verify the integrity of the transportation system. This is most efficiently achieved by employing a pig (a scraping tool). Different pigs are employed for different purposes. Maintenance pigs are used to remove wax or scale formations which may cause flow assurance problems. Inspection pigs, also referred to as intelligent pigs, are used to detect deviations in the pipeline design as a result from e.g. corrosion. The maintenance pig is normally run prior to the inspection pig to remove debris and to verify the "pigability" of the pipeline. Traditionally the Magnetic Flux Leakage Technology has been used for inline inspection of gas pipelines [53], but a new method using acoustic technology is currently being developed [54]. In pipelines where high accuracy of measurements is required, an ultra-sonic pig is run in a liquid batch isolated by two isolation pigs in both ends. The liquid batch is required as a medium for this method to be feasible.

A pipeline pigging operation is conducted by inserting the pig in a pig launcher at one end of the pipeline and is retrieved in a pig receiver at the other end. Traditionally, the pig launcher and receiver is installed on topside facilities (platform or onshore). The pig can be launched and received at the same facility (round-trip pigging), or launched at one facility and received at another (see Figure 21).

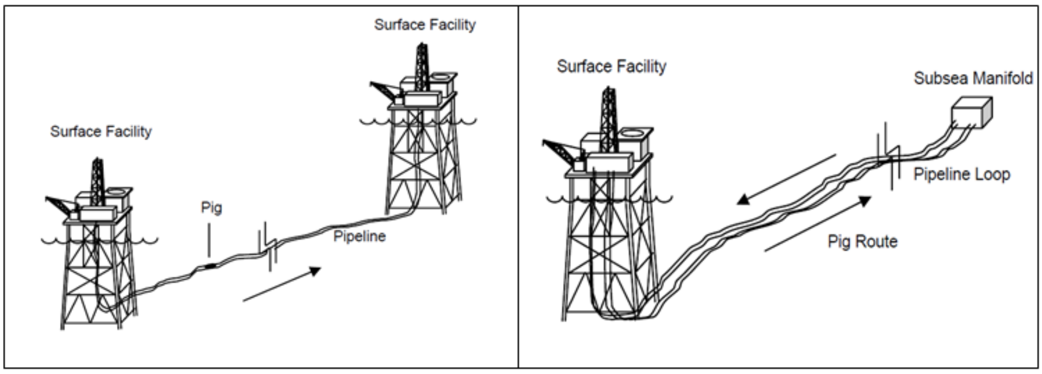

Figure 21: Conventional surface pig launching and receiving concepts [55]

The surface to surface configurations is not always technical feasible in a project, particularly in subsea developments. Single flow line subsea developments may require the pig to be either launched or received subsea (or both launched and received in rare cases), since a round-trip configuration cannot be economically justified [56]. The subsea pig launcher concept comprises a fixed arrangement on a template or integrated in a manifold which the temporary pig launcher can be mated with. When a pig operation campaign is conducted, an intervention vessel will use a guiding system, assisted by ROV's to install the launcher (Figure 22) [55]. The mating of the launcher and the subsea arrangement can be

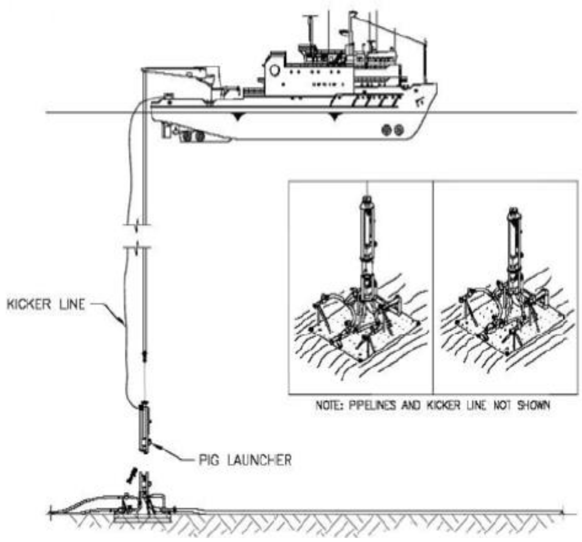

Figure 22: Intervention vessel deploying pig launcher [59]

either vertically oriented (Figure 23) or horizontally oriented. Vertically oriented systems are easier to deploy and represents a more compact structure, but horizontal systems allows the deployment of a larger launchers. One of the world's largest subsea pig launch operations was conducted at the Åsgard field in 2004 [57]. A multi-diameter(28/42 inch) pig (horizontally oriented) was launched successfully in 300m water depth and was traveling 684km from the Åsgard export riser base to the Kårstø processing facility. An example of a subsea pig launch procedure is given below [58].

The pig is installed within the pig launcher in advance of deployment. Before the launcher is deployed, a leak test of the isolation valve is conducted and the pressure cap is removed (see Figure 24). When the integrity of the seal is verified, the launcher is lowered to the guide base by a crane and guiding wires. When fitted at the guiding base, the wires are disconnected and the launcher is stroked into the hub with a torque tool. The connection is leak tested by injecting MEG through a hose deployed from the vessel. When integrity once again is verified, the isolation valve is opened by means of ROV actuation. A second hose is deployed from the vessel and connected to the pig launcher. This hose contains fluid (e.g. MEG or Naphtha) which is pumped into the launcher to force the pig into the pipeline. From this point, the pig follows the gas flow and is retrieved at the pig receiver facility. Note that this is an example of a subsea pig launcher procedure, other procedures probably exists for other configurations.

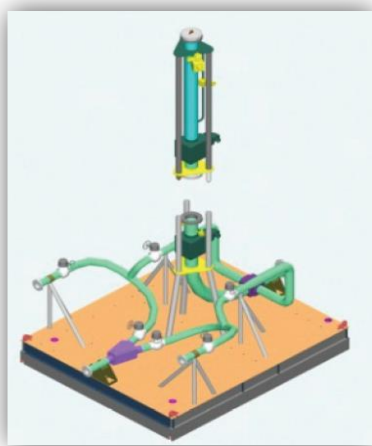

Figure 23: Vertically oriented subsea pig launcher concept by Chevron. The pig launcher is vertically mated with the subsea structure [59].

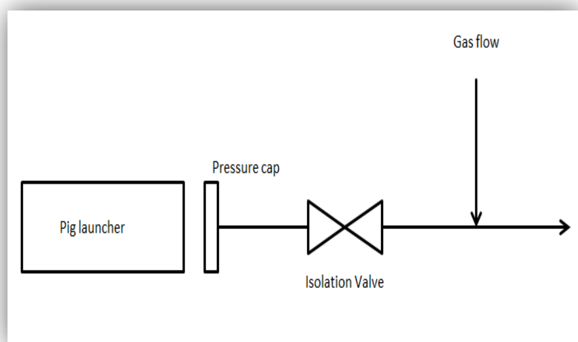

Figure 24: Simplified subsea pig launcher configuration (horizontally oriented)

2.9 Pressure Protection

Subsea pipelines have traditionally been designed to the meet the maximum pressure of a system to assure safe transportation of hydrocarbons. This restriction has made high pressure/ high temperature reservoirs economical marginal to develop due to the need for high specification pipelines [60]. In the 1990's effort was put into developing a system which safely allows a high pressure flow to enter a pressure restricted pipeline (or equipment). This system is today known as the subsea High Integrity Pressure Protection System (HIPPS). By continuously monitoring the pipeline pressure, an automatic sequence will close two isolation valves if the pressure rises above what is allowed in the pressure restricted pipeline. Figure 25 gives a basic overview of the HIPPS arrangement.

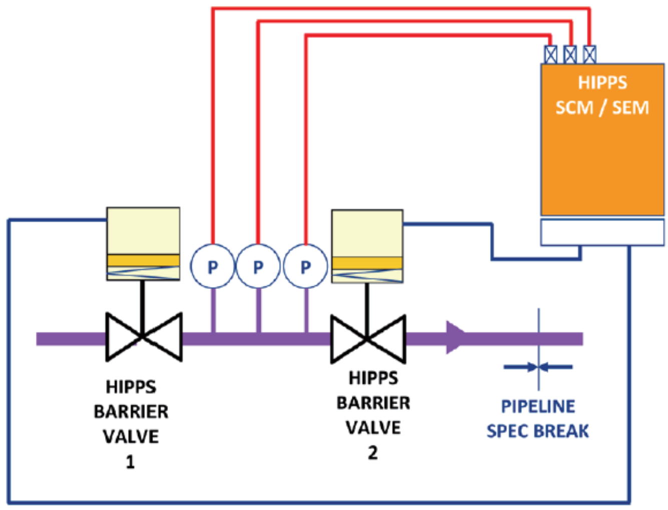

Figure 25: HIPPS arrangement comprising two barrier valves (isolation valves), three pressure transmitters and a HIPPS Subsea Control Module controlling its functions [61].

Three pressure transmitters are continuously communicating with the Subsea Electronic Module (SEM) incorporated within the SCM housing. The SEM is the decision maker which compares the signals from the transmitters with the operational threshold. If two out of three transmitters exceed the threshold, the SEM automatically initiates a shutdown sequence, which closes the barrier valves and isolates the downstream pipeline [61]. Under normal operational conditions the flow is controlled by a choke (see section 2.6) which regulates the flow based on pressure measurements.

To justify the implementation of a HIPPS opposed to a conventional design, the reliability of the system is crucial. The HIPPS control system is to a large degree independent of the subsea control system controlling the other subsea system functions [60]. Only the umbilical and umbilical termination and distribution unit are shared with the subsea control system. In addition, redundancy is provided for all components such as pressure transmitters, SEM and valves.

The design of a HIPPS system should comply with the international standards IEC 61508 and IEC 61511. These standards give requirements for specifications, design, installation, operation and maintenance of safety instrumented systems, “so that it can be confidently entrusted to place and/or maintain the process in a safe state” [61]. IEC 61508 gives a risk based approach for deciding the Safety Integrity Level (SIL) required for Safety Instrumented Systems [62].

Table 2: Safety Integrity Levels for safety functions operating on demand or in a continuous demand mode [62]

Safety Integrity Level	Demand Mode of Operation (average probability of failure to perform its design function on demand - PFD)	Continuous / High Demand Mode of Operation (probability of a dangerous failure per hour)
4	$\geq 10^{-5}$ to $< 10^{-4}$	$\geq 10^{-9}$ to $< 10^{-8}$
3	$\geq 10^{-4}$ to $< 10^{-3}$	$\geq 10^{-8}$ to $< 10^{-7}$
2	$\geq 10^{-3}$ to $< 10^{-2}$	$\geq 10^{-7}$ to $< 10^{-6}$
1	$\geq 10^{-2}$ to $< 10^{-1}$	$\geq 10^{-6}$ to $< 10^{-5}$

A specific approach for deciding the SIL rate of a HIPPS is not given. But projects such as the Kristin Field development on the NCS have used the IEC 61508 standard and decided that SIL 3 rate is required for a HIPPS [63]. A SIL 3 rate sets strict requirements to reliability, redundancy and fail-safe functions of all components. In addition, a comprehensive operational testing scheme is required on a continuous basis to document the probability of failure on demand (see Table 2). Once every year, a full functional test of the HIPPS system is required. At the Kristin project, the functionality of the system is verified by isolating two of the pressure transmitters from the control room, while two other transmitters verifies that the valves have closed. The second step is to re-open the isolation valves, relieve the up-stream pressure in the manifold and re-pressurize above the threshold pressure by injecting MEG. The signals from all pressure sensors should then initiate the shutdown sequence. In addition, a leak test is conducted. Also, every second month the operators of Kristin conducts a test where the isolation valves are closed 20%, to verify their functionality. This test is conducted during operation and has no significant impact on production. This data is used to continuously calculating the reliability of the system.

HIPPS systems have not been widely used in subsea systems since it first was implemented on Shells Kingfisher project in 1997. In 2010, 11 subsea HIPPS had been installed [61]. Mainly three reasons are believed to be the reason why operators do not implement this solution in their projects [64].

- The possibility to bleed down the upstream pressure is limited subsea. This could lead to the formation of hydrate plugs if the valves are closed over an extended period. When the HIPPS valves are re-opened, they do so with a full differential pressure which could lead to erosional wear inside the isolation valve. This problem could be solved by adding a relief line or a bypass relief choke, but such additional features make the system even more complex.
- IMR tasks associated with the HIPPS are difficult and expensive
- To keep the reliability confidence high, regular testing of the system is required. The full functional test (discussed above) which is required to conduct once a year, means a full shut-down of the system. The pressure test involving MEG injection introduces another complication which must be dealt with.

HIPPS systems are not considered conventional technology, although their applications in subsea systems are proven with successful implementation in several projects. This technology enables high pressure reservoirs to be developed without the additional costs of thick walled flowlines and riser to safely meet the high pressures. It also enables existing low(er) pressure rated pipelines to meet high pressure systems.

3. Heimdal Subsea System

In chapter 2 relevant subsea technologies are identified and discussed. The further work focus on the application of these technologies in a subsea gas transition hub.

3.1 Functional Requirements

The case assumes that Heimdal processing is shut down and that the topside facilities at Heimdal will be by-passed as illustrated in Figure 26. A 36’’ bi-directional pipeline will be installed connecting Oseberg to Draupner. A branching spool will connect the Oseberg-Daupner (OGT-DRP) system together with Vesterled in a subsea manifold. The Vesterled pipeline will be connected directly to the manifold. This lay-out will allow the OGT-DRP pipeline to by-pass the subsea manifold in the pre-installation phase or in events (such as maintenance campaigns) where the subsea system is out of operation.

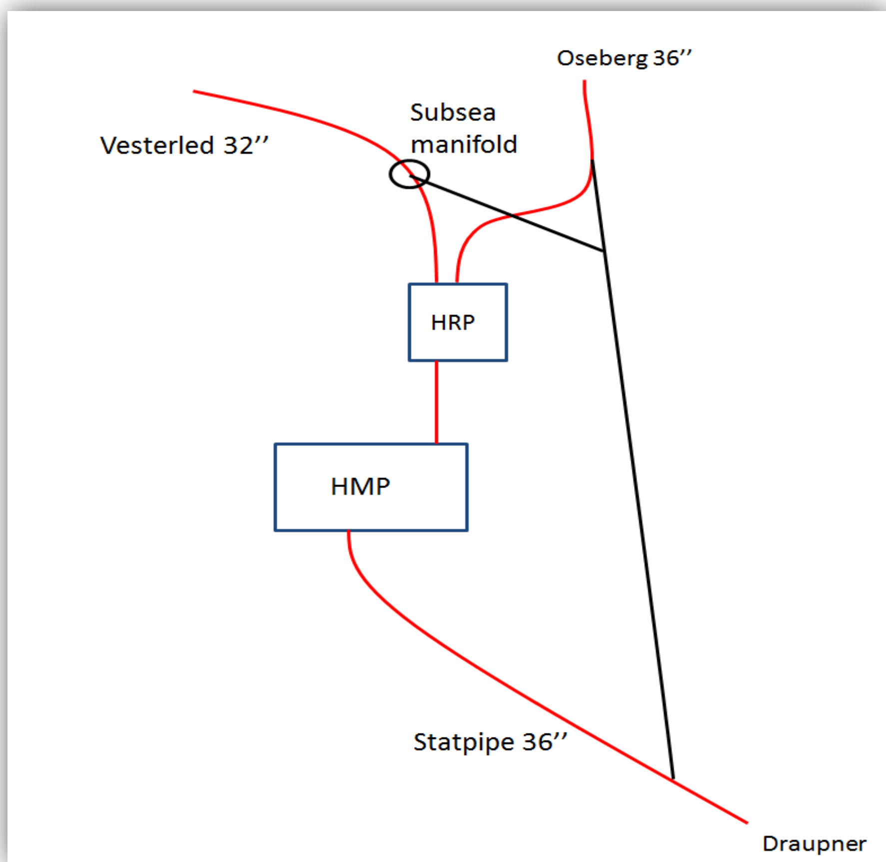

Figure 26: Heimdal area overview. The red lines indicates the current arrangement of pipelines, while the black lines are the future arrangement when Heimdal is by-passed.

An overview of the pipelines specifications is given in Table 3. Note that assumptions have been made. The risks of over pressuring the Vesterled pipeline from the Oseberg and Draupner facilities sets requirements to a pressure protection system. If the pressure in OGT-DRP exceeds the Vesterled design pressure, a choke/control valve will choke the flow to meet the requirements. In normal operations, the pressure in OGT-DRP is not expected to exceed the Vesterled design pressure. A pressure protection system is however required to give a satisfying safety level.

Table 3: Overview of the pipelines capacities, design pressures and outer diameters. * It is assumed that pipeline which today connects Heimdal to DRP can be upgraded to the same level as OGT. The capacity of 35 MSm^3/day at OGT-DRP may possibly be upgraded if a new design study is initiated.

Pipeline	Hydraulic capacity [MSm^3/day]	Design Pressure [barg]	Diameter [inches]
Oseberg-Draupner*	35	190	36
Vesterled	39.9	148.9	32

To maintain the flexibility in gas transportation the topside facility has today, a manifold comprising control functions and safety systems will be installed on the seabed. In chapter two, applicable technologies are discussed and in the next sections, a subsea gas transition hub concept will be presented.

3.2 Subsea concept

Going subsea introduces several challenges compared to conventional topside solutions. The harsh environment and remote location requires high reliability of components for the concept to be justified. This section will evaluate the applications of technologies discussed in section 2 and in the end, give a recommendation for a subsea concept.

3.3 Manifold

The manifold is the structural foundation for pipelines, control equipment and safety systems which are required to operate the system with high integrity. It is desirable to minimize the weight and the size of the manifold since the costs of manufacturing and installation are very dependent of these factors. The installation costs represents a significant amount of the overall costs of a subsea manifold, the installation should therefore be continuously evaluated in the design process. This should include identification of installation vessels with adequate crane capacities, planning of marine operations and identification of risks associated with the installation. The manifold will host equipment which needs periodic maintenance; hence should these components be modularized so that they can be separately retrieved. Easy access for ROV's will make interventions more efficient and thereby save operational costs. The manifold will be installed on a subsea template (with protection structure) which provides the foundation on the seabed in addition to protection against impact loads such as from fish trawlers or dropped objects. If feasible, the structure comprising template, manifold arrangement and equipment modules should be installed in one lift.

A Piping and Instrumentation diagram (P&ID) of the manifold and its interfaces are presented in Figure 27.

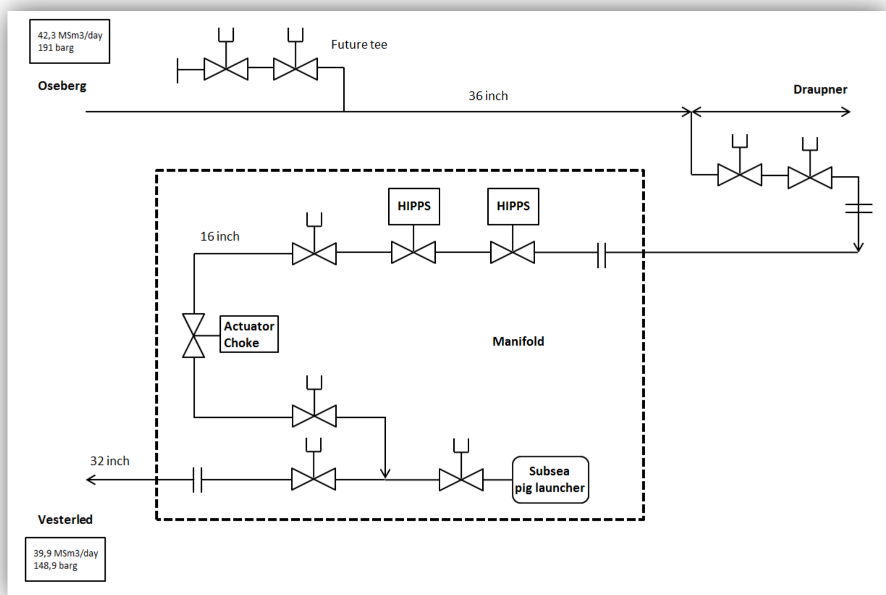

Figure 27: P&ID of the subsea manifold

The OGT-DRP by-pass is supposed to be installed with two tees. One tee for possible future tie-ins and one for the tie-in to the subsea manifold. The manifold arrangement includes seven valves: two HIPPS valves, four isolation valves and one choke/control valve. The Choke valve controls the flow by means of remote actuation. This allows the gas flow in OGT-DRP to be branched into two separate directions (to Draupner and Vesterled). Two isolation valves are required in case of maintenance or to retrieve the flow control (choke) module. To satisfy the pigging requirements, a subsea pig-launcher arrangement will be incorporated within the manifold. This system is based on diver-less deployment of the pig-launcher, hence only one isolation valve in front of the launcher is required. However, two isolation valves will be implemented for increased reliability of the seal (see more in section 3.8). A HIPPS comprising two isolation/barrier valves and separate control system is installed to protect the Vesterled pipeline from being over-pressured by the Oseberg and Draupner facilities. The manifold will also support the control systems equipment and additional instrumentation.

To reduce the weight of the manifold, it is beneficial to reduce the diameter of the piping. This is also beneficial with respect to valve sizing, since large pipelines introduce the requirements of large valves and actuators.

When sizing gas pipelines, NORSOK P-001 states that the sizing criteria will be a compromise between maximum allowable velocity and allowable pressure drop [65]. Where the pressure drop is not critical, the gas velocity should not exceed limits which may create noise or vibrations problems. The velocity should be kept below:

$$V = 175 \times \left(\frac{1}{\rho}\right)^{0.43} \qquad (5)$$

Where:
V – Velocity [m/s]
ρ – Density of gas [kg/m^3]

Data retrieved from SCADA (Appendix A) shows that the maximum density of the gas is approximately 170 kg/m^3. Substituting the density into (5) gives:

$$V = 175 \times \left(\frac{1}{170}\right)^{0.43} = 19.23 \text{ m/s}$$

which is the maximum allowable velocity of the gas.

By assuming that the gas volume flow is constant, the gas velocity in a reduced pipeline can be calculated:

$$Q1 = Q2 \qquad (6)$$

$$A1 \times V1 = A2 \times V2$$

$$V2 = \frac{A1 \times V1}{A2} \qquad (6b)$$

Where:
Q – Volume flow [m^3/s]

V1 – Inlet velocity [m/s]
V2 – Velocity in reduced diameter pipeline [m/s]
A1 = Cross sectional area of pipeline [m^2]
A2 = Cross sectional area of reduced diameter pipeline [m^2]

The maximum velocity measured at Heimdal reporting point (from Oseberg) (Figure A 2) is: V1 = 3.56 m/s with a cross sectional area of 0,65m^2 (36 inch pipeline). The Velocity in the reduced area is calculated with different pipeline diameters, see Table 4.

Table 4: Velocity in reduced area pipeline as a function of pipeline diameters

Pipeline diameter [inches]	Velocity, V2 [m/s]
8	73,9
10	47,3
12	32,9
14	24,1
16	18,5
18	14,6
20	11,8
22	9,8
24	8,2
26	7,0
28	6,0
30	5,3

The 16 inch pipeline is thus the lowest allowable pipeline diameter when comparing with the NORSOK gas velocity criteria.

3.4 Control system

The subsea control systems function is to control and operate the subsea system with high reliability and integrity. Conventional subsea systems are based on hydraulic actuation of valves. The state of the art within hydraulic subsea control systems is the MUX EH (section 2.3.1). This systems has proved to be reliable and fast responding in numerous subsea projects the last years. However, it has its limitations with respect to long offsets, deep waters, fluid storage capacity and reliability of hydraulic components. The recent years, the development of All-Electric control systems has advanced (section 2.3.2). This control systems relies on electric actuators (section 2.7) to operate valves, thus eliminates the challenges related to hydraulic systems. The control system establishes contact between the host facility and the subsea system. This connection is normally established through an umbilical which incorporates hydraulic lines (if hydraulic control system), fibre optics for communication and electric conductors which energizes the electrical components of the system. The umbilical is one of the largest expenses in subsea developments. In the North Sea, trawling activity sets requirements for the umbilical to be trenched, which is very costly. It will however always be a risk for umbilical rupture which would put the subsea system out of operation. Hence, have much effort been put into developing umbilical-less control systems, or in this case referred to as Autonomous Control systems (section 2.3.3). Although several projects have concluded fully autonomous control systems to be feasible alternatives to conventional control systems, they have their limitations with respect to reliable communication.

The advantages of All-Electric control systems are evident opposed to the conventional hydraulic systems. A hydraulic control system would set requirements to a hydraulic fluid storage unit and pumps at a nearby host facility. This will probably be very challenging due to the already limited storage capacity at offshore platforms. All-Electric control system eliminates the requirements of hydraulics, but still requires solutions for communication and electric energy. The conventional concept for communication and energy supply would be an umbilical which incorporates fibre optics and electric cables. This will again create a dependency of third party offshore platforms and the risk and costs associated with the umbilicals are still present (although at a somewhat lower cost).

For the case of the Heimdal subsea system, it must be appreciated that the power demands are low compared to large subsea production systems. This system requires energy for actuation of the choke valve and instruments, opposed to several Xmas-trees and manifolds in subsea production systems. It may be hard to justify the risks and costs associated with a long step-out umbilical for the Heimdal subsea system.

A combination of autonomous energy supply and the All-Electric control system is considered a more commercially realistic and cost efficient alternative. The control system will be powered by a rechargeable lithium Ion battery package (discussed further in section 3.5), thus eliminating the need for a power cable. Once every two years, an intervention vessel will recharge the battery package as a part of the maintenance strategy for the system. The All-Electric control system comprises an Electric Power and Communication Distribution Unit (EPCDU) and an Electric Subsea Control module (SCM). The EPCDU regulates and distributes the energy from the battery package further to the SCM. The SCM is the interface for signal transmissions and controls of the electric actuator between the subsea system and the master control station. Communication between the subsea system and the control centre is established through the integrated fibre optic cable network in the North Sea (section 3.6). An overview of the recommended subsea control concept is presented in Figure 28.

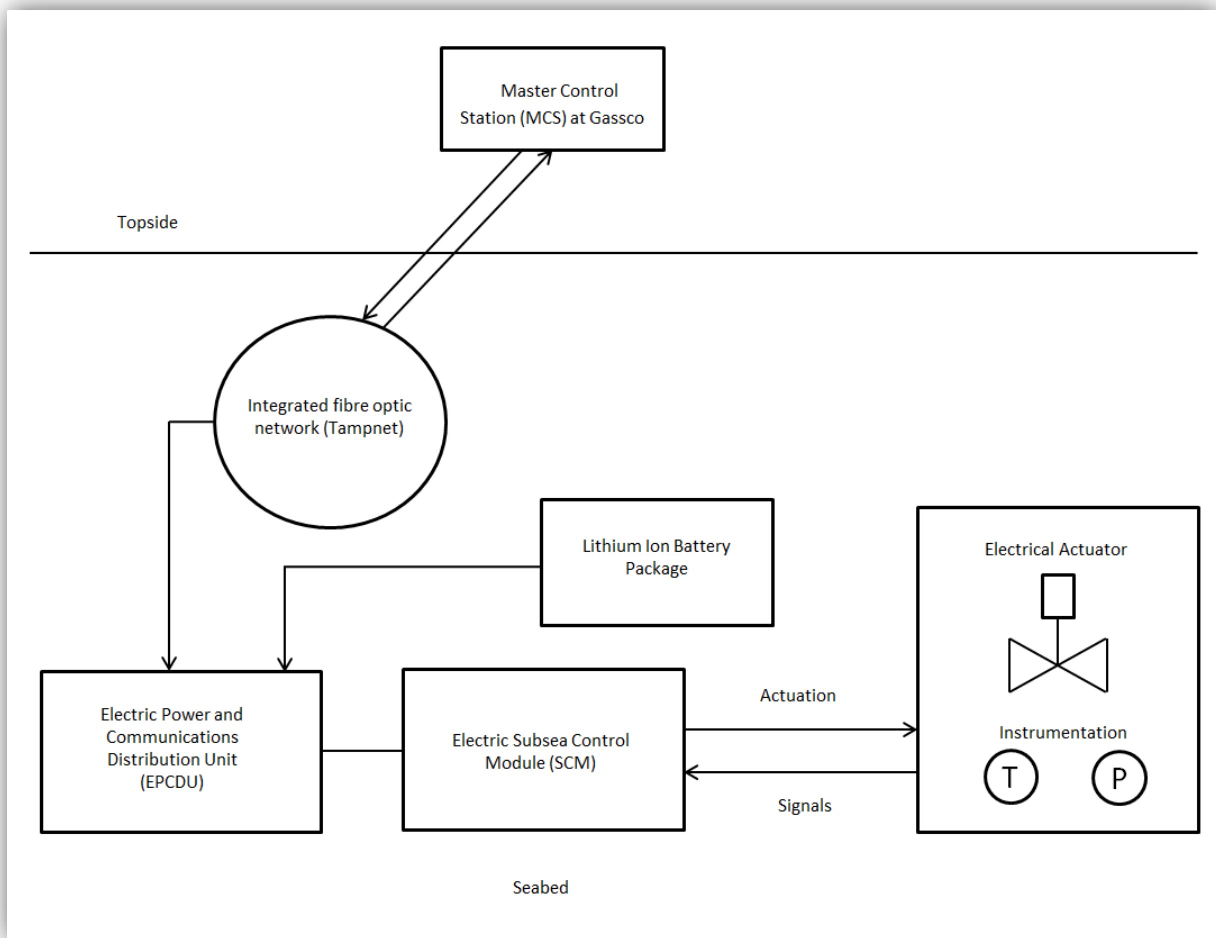

Figure 28: Recommended subsea control system concept overview

3.5 Power

3.5.1 Subsea power concept selection

The All-Electric control system eliminates the need for hydraulic energy to actuate valves. Power for actuation of the choke valve, in addition to the functions of the subsea control module is provided by an electric power source. In section 2.4, different local power generation methods were discussed.

The Thermo-Electric Generator (section 2.4.1) which utilizes temperature differences in the gas to generate electricity is not considered feasible for this system. The temperature in the gas will probably be close to the ambient seawater temperature, and small potential for electric power generation is available.

The turbo generator (section 2.4.3) is a promising concept for local power generation. Why not utilize the available high pressure gas in the pipeline to generate electricity? The turbo generator could be installed in a by-pass on the manifold. Small volumes of gas could be routed through the by-pass line into an expander which in turn is connected to a generator. There are several challenges however, to overcome before this concept can be implemented into the Heimdal Subsea System. A low pressure reservoir downstream of the expander would be required, or alternatively, a constant pressure loss in the main stream (from e.g. a venturi or a choke valve) to ensure a differential pressure over the expander. And also, there are challenges with respect to the regularity of such systems, it needs to be functional for different pressures and flow rates. The DAMPS project [36] concluded that this concept was technical feasible for a subsea system. However, the concept has not been commercially qualified. It is recommended that Gassco look further into this concepts technology and its limitations. The concept would require comprehensive testing and qualification work to obtain acceptable functionality and reliability, and it will not (at least for now) be recommended as a local power generation source.

In section 2.4.2 the sea-water battery was discussed. This local power generation concept relies on a chemical anode/cathode reaction to generate electricity. The technology of sea-water batteries has successfully been applied in a subsea satellite gas-well development in the Ionian Sea and in 3 seismic stations offshore Japan. The Norwegian Defence Research Establishment (FFI) did in 2005 a study on behalf of Norsk Hydro, where the feasibility of subsea energy supply was investigated [66]. Among other technologies, the sea-water battery was considered the most reliable and cost efficient alternative. Each cell consists of a magnesium anode surrounded by carbon fibre cathodes. The capacity of each cell is to a large degree dependent of the sea current. A load of 2 W per meter cell (W/m) was concluded to be the ideal load on each cell. The lifetime of each 2 W/m cell is 2-3 years. The sea-water battery recommended by FFI consists of 100 cells with the dimensions 6m height and 800mm diameter. Each cell is equipped with a DC to DC converter and a buffer accumulator (e.g. Lithium Ion battery), which in turn is connected to a common 24V hub. Each DC to DC converter is capable of providing 15W resulting in a total battery capacity of 1500W. A battery package could consist of four modules, each supporting 25 cell modules. The distance between each cell module should be 1m, hence will one (of four) battery modules be 10 × 10 × 7-8m (Width × Length × height). The total weight of each module would be somewhere around 35 tons, so each module can be installed and retrieved as one unit. The dimensions of the battery package may introduce challenges with respect to the requirements of protection structures due to trawling activity in the area. Also installation and maintenance activities could be challenging (and costly). Sea-water batteries with lower capacities and somewhat proportional lower dimensions could be designed for the Heimdal Subsea System. The technology is tried and ready for implementation (some qualification work is probably required), and it is considered the best alternative for local subsea power generation.

Out of the three local electric power generation methods the sea-water battery is the most promising. It is however not considered conventional technology. Large structural dimensions and uncertainties in performance of such systems are risk factors that must be avoided.

If the local subsea power generation concepts are excluded, there are two options left: Electric cable from an offshore topside host facility (or from shore), or a secondary (rechargeable) battery which can provide the required energy for a specified period. A combination of these could also be an alternative. A low energy power cable (which is cheaper than a high power cable) could charge a battery when the systems energy demands are low. When the energy demands peak, the battery can provide the required capacity.

A subsea rechargeable lithium ion battery will be the recommended concept for the subsea power supply. The electric cable concept would be the safe and conventional choice for the power supply. However, due to the relatively low power consumption of the Heimdal Subsea System, a battery package (with no connection to a host facility) is a cost efficient alternative. Every two years, an invention vessel will recharge the battery package with a cable deployed from the vessel. The following section demonstrates the dimensioning of the battery.

3.5.2 Rechargeable Lithium Ion Battery

In order to estimate the required battery capacity, the systems power consumption must be decided. This cannot accurately be calculated at this stage of the study, however, simplified estimates will be given. The battery shall provide the control system with adequate power to fulfil its functional requirements. This comprises continuous transmissions of command and control signals, in addition to actuation of the choke valve. The electric actuator consists basically of an electric motor and a gearing system. The electric motor generates a rotating movement (a torque) which needs to be converted into linear motion. This conversion is achieved by using lead screws such as the acme screw, a ball screw or the roller screw [67]. Roller screws have better efficiency than acme screws and can carry larger loads than the ball screws. For the further calculations, an electric actuator arrangement comprising an electric motor and a roller screw will be used. Note that the calculations are simplified.

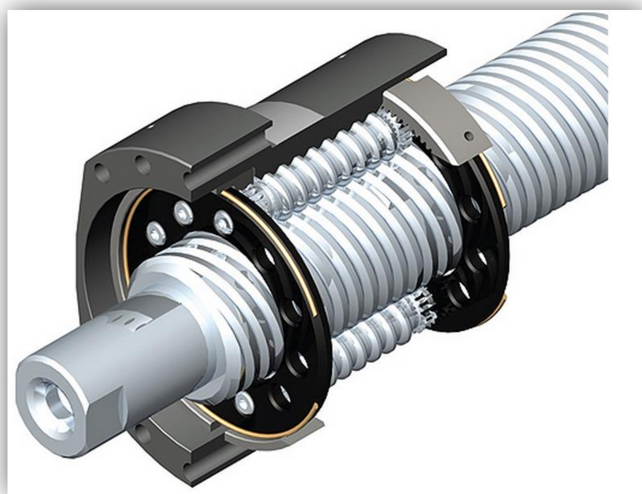

Figure 29: Roller Screw arrangement [68]

The electric motor generates a torque which is converted into a linear force by the roller screw. This linear force is utilized to manoeuvre the valve position. How much force is required to change the valve position depends mainly of the bore size and the pressure within the valve. Figure 30 shows the forces the actuator must overcome.

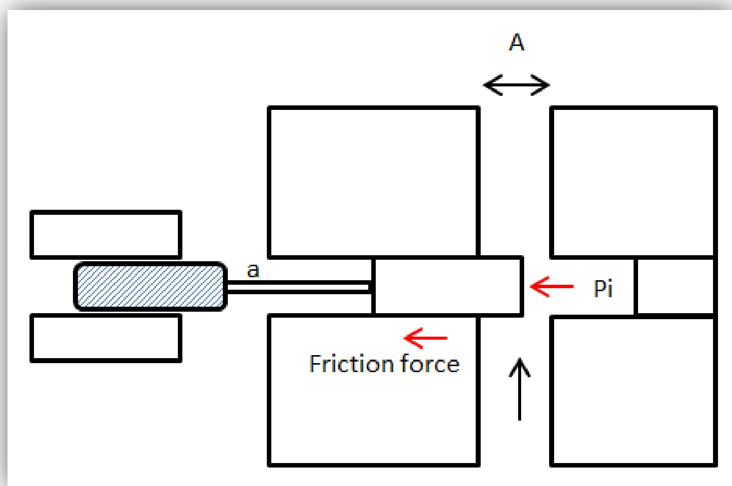

Figure 30: A valve/actuator arrangement showing the frictional and pressure forces caused by the inner pressure Pi.

An equation for calculating the force required to change the valve position is shown below (1). This equation is simplified and does not consider the gearing arrangement and the systems friction. See Appendix B for assumptions (Table B 1) and calculations.

$$F = Pi \times a + \mu \times Ff \text{ [N]} \qquad (1)$$

Where:

Pi – Internal Pressure [Pa]
a – Stem cross sectional area [m^2]
Ff – Vertical force on the valve block [N]
μ – Friction Coefficient

The pressure inside the valve will create a vertical force on the valve block which in turn creates a horizontal frictional force. The vertical force is found by equation (2).

$$Ff = \Delta P \times A \text{ [N]} \qquad (2)$$

Where :

ΔP – is the differential pressure over the valve [Pa]
A – Valves cross sectional area [m^2]

From (2) it is observed that a large ΔP results in large frictional forces.

The required torque applied on the roller screw to overcome the load F is given by the relation [69]:

$$T = \frac{S \times F}{2 \times \pi \times \eta} \; [Nm] \qquad (3)$$

Where:

S – Screw lead [m]
η – Motor efficiency

Further, the required power from the electric motor can be calculated by the relation (4):

$$P = T \times \omega \; [W] \qquad (4)$$

Where the angular velocity ω is given by (5).

$$\omega = \frac{2\pi \times n}{60} \quad [\frac{rad}{s}] \qquad (5)$$

And n is the speed, rounds per minute (rpm).

The actuators power consumption is to a large degree dependent of the pressure differential across the valve. This can be observed from Figure 31 .

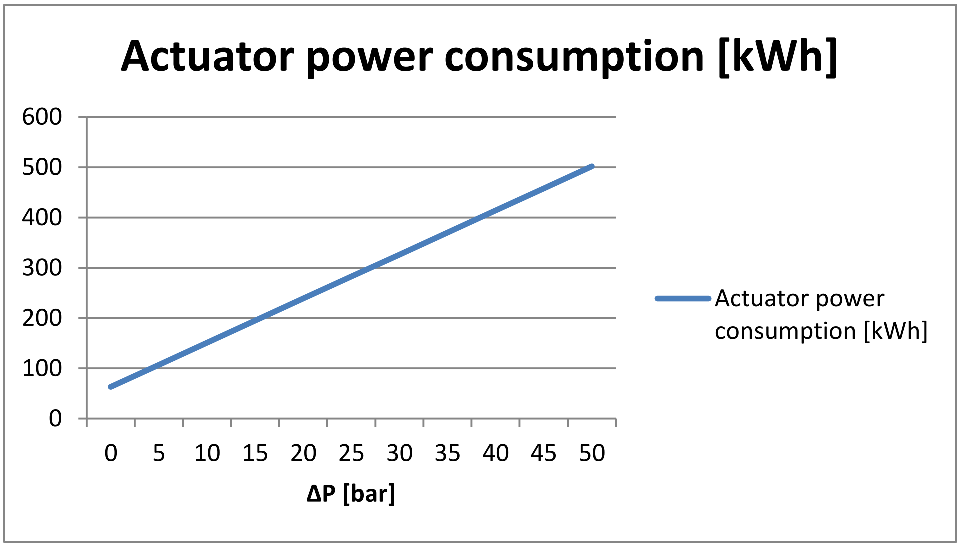

Figure 31: The actuators total power consumption as a function of the differential pressure across the valve over two years. See appendix B, Table B 2 – B4 and Table B 7 for calculations. The assumptions are given in Table B 1.

The pressure differential is not expected to reach large values, even when the valve is to be actuated from fully closed position. For the further calculations, a ΔP = 10 bar is assumed (which may be conservative). A pressure differential of 10 bar and an inner pressure Pi of 150 bar, requires a 10kW electric motor to change the valve position.

Calculations show that the largest power consumer of this system is not the electric actuator, but the continuous power supply required by sensors and signals transmissions etc. The SWACS project [24] used a continuous power consumption of 20 W for the calculations. From Figure 32 it can be observed that the required battery capacity (and mass) increases rapidly when the continuous power supply increases.

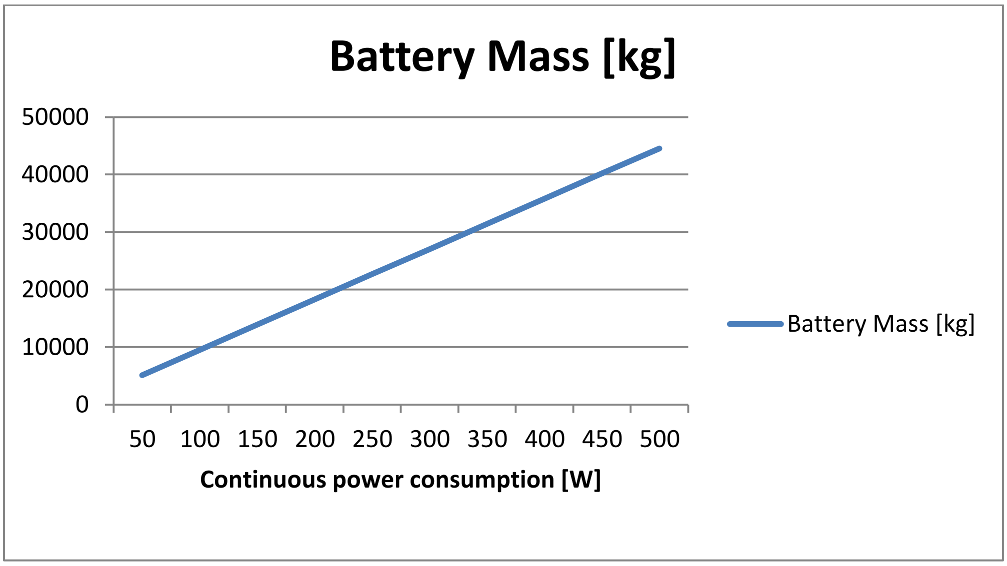

Figure 32: The required battery capacity/mass as a function of the continuous power consumption. See Table B 9 in Appendix B for calculations.

Comparing with the SWACS project, a continuous power consumption of 100 W is assumed for the further calculations. This may be conservative, but should provide safety in calculations and balance uncertainties.

With an average $\Delta P = 10$ bar, a continuous power consumptions of 100W and the assumptions given in Table B 1, the required battery capacity is 1903 kWh over two years. However, the self-discharging rechargeable batteries experience must be considered. Lithium Ion batteries has a low self-discharge rate compared to other rechargeable batteries (about 1.5% per month [70]). A self-discharge rate of 3 % is assumed for this case.

Table B 8 shows that to account for the batteries self-discharging, a factor of 1.4 can be multiplied with the required capacity. This results in a total required battery capacity of 2664 kWh.

Lithium ion batteries contains from 80 to 220 Wh/kg [71] [72]. Hence, the mass of the battery package (excluding protection structures and the battery container) will be in the region from 13.3 tons to 33.3 tons. A 20 tons lithium Ion rechargeable battery package should have the capacity to provide the Heimdal subsea system with sufficient power for a period of two years. Also the battery containers, protection structures and modularization of the battery should be given closer attention. These are however not considered in this report.

3.6 Signals and Communications

Several subsea communication concepts were discussed in section 2.5. The wireless communication concepts introduce, in combination with local electric energy supply and the All-Electric control system, a fully autonomous subsea system. However, limitations in data capacity and unreliable signal transmissions restrict the application of subsea wireless communication technology for the Heimdal Subsea System.

Fibre optic communication technology is considered the best alternative. Tampnet operates the largest offshore high capacity communication network in the world and more than 100 platforms, FPSO's and exploration rigs utilize the integrated fiber network in the North Sea [73]. Tampnets integrated fiber optic network provides all the communication requirements for the Heimdal Subsea System.

Figure 33: Integrated fibre optic network in the North Sea operated by Tampnet [73]

3.7 HIPPS

The Vesterled pipeline system is a 32'', 360km pipeline starting at Heimdal and ending at St. Fergus. It consists of two parts, where the first part has a design pressure of 164 barg and the second 148.9 barg. Both the Oseberg and Draupner facilities can export gas with pressures beyond the design conditions of the Vesterled pipeline. Hence, the risks of over pressuring the Vesterled pipeline must be considered. A study carried out by Statoil on behalf of Gassco concluded that the Vesterled pipeline shall be protected by means of two independent safety systems [74]. These systems can be either of conventional type (PSD and PSV), or unconventional (HIPPS) systems. The report evaluated the system as it is today and did not evaluate subsea solutions.

The Vesterled pipeline needs to be protected by two independent safety systems. When the Heimdal facilities are removed, these systems can be located topside at the Oseberg and Draupner facilities, and/or at the Heimdal subsea manifold. It is further assumed that the Oseberg and Draupner facilities have conventional safety systems installed. These systems include Process shut down systems (PSD) and Pressure Safety Valves (PSV). The secondary safety system will be the instrumented (unconventional) Pressure Protection System (PPS), or High Integrity Pressure Protection System (HIPPS) which is discussed in section 2.9.

The HIPPS system can be located at Oseberg and Draupner, or at the Heimdal subsea manifold. Subsea HIPPS introduces several additional challenges compared to topside solutions. However, a HIPPS system located at the subsea manifold, would only set requirements to one HIPPS compared to two for the topside alternative (at both Oseberg and Draupner). A subsea HIPPS is also beneficial with respect to future high pressure tie-ins to the system that could set requirements to an additional, third HIPPS to be installed.

Safety instrumented secondary pressure protection systems, such as the HIPPS, shall be designed in accordance with IEC 61508 and IEC 61511 and OLF document GL 070 can be used as guidance for application of the standards [65]. IEC 61508 gives a risk based approach for deciding the Safety Integrity Level (SIL) required for Safety Instrumented Systems. Other projects, such as the Kristin field development [63] determined that a SIL 3 level was required for their HIPPS. It is further assumed that a SIL 3 rate is a reasonable requirement also for the Heimdal Subsea HIPPS.

The function of the HIPPS is to safely isolate the downstream pipeline if the pressure exceeds the maximum allowable pressure. Initiators detect high pressures and closes one or two barrier valves (depending on the required safety level). Basically there are two types of HIPPS [75]: The integral mechanical and the full electronic. The electronic version uses three pressure transmitters as initiators. The signals from the transmitters are interpreted by a logic solver, and initiate the shutdown sequence by de-energizing the solenoids if 2 out of 3 pressure transmitters exceeds the threshold pressure. The final element actuators will then be de-pressurized and the spring will close the barrier valve. See Figure 34 for overview. The final element actuator could also be electric.

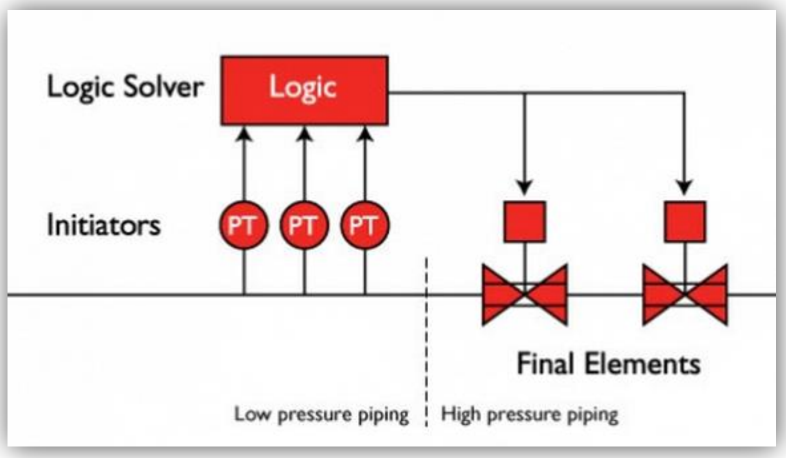

Figure 34: Typical HIPPS safety loop (electrical initiators) [75]

The HIPPS system with Integral mechanical initiators (Figure 35) relies on pressure control valves to initiate the shutdown sequence if the threshold pressure is met. No electronics are used. According to the author's knowledge, no subsea projects have implemented this HIPPS technology, but for topside systems its functionality has been proven. For remote areas, a full stand-alone alternative is available. This system requires no external energy, but relies on pneumatic or hydraulic actuation utilizing the energy in the pipeline [76]. The redundant HIPPS system in Figure 35 obtains a SIL 4 rate.

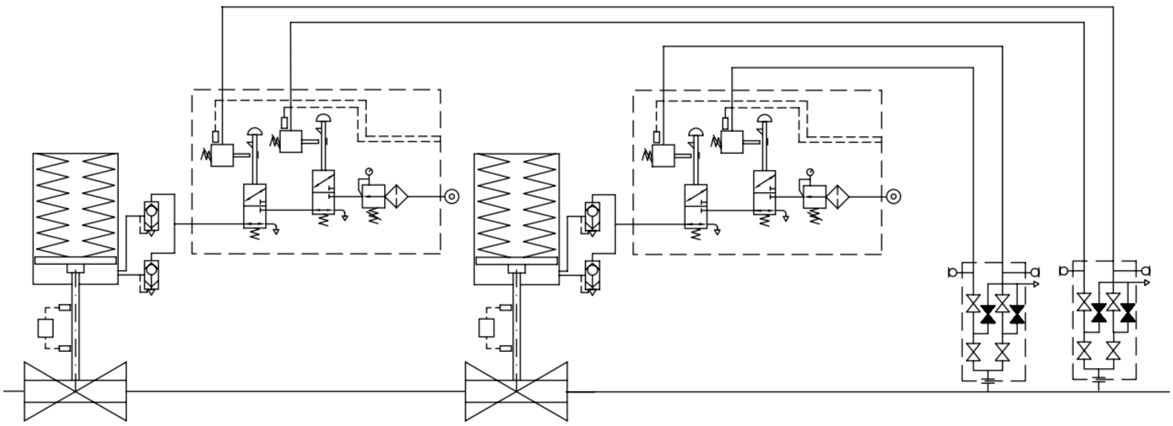

Figure 35: HIPPS system with integral mechanical initiators [75]

To meet the requirements of the determined SIL rate, the HIPPS system requires periodic testing (proof testing) to verify the reliability of the system [77]. The testing frequency is related to the Probability of Failure on Demand (PFD). See Table 2 in section 2.9 for the required PFD's in relation to the SIL rates. Once a year (SIL 3) a full functional test is required. In addition comes valve leakage tests, sensor testing and response time testing. The required frequency of these tests must be specified for each project.

The HIPPS system with electronic initiators is the only available on the subsea market as of today. Thus it will be the recommended concept for the Heimdal subsea system. However, Mokveld is currently in the patenting process of a new subsea HIPPS concept. They could not at the moment provide any information about the system due to the confidentiality involved in such processes.

3.8 Subsea pig launcher

The Vesterled pipeline system must be designed suitable to pass pigs. Pigging operations are required for the pre-commissioning, commissioning and de-commissioning, in addition to periodic inspection and maintenance pigging operations. The Oseberg – Draupner pigging operations are conducted by launching the pig topside at the Oseberg facility and by retrieving it at the Draupner facility. Topside to topside pigging operations are not feasible for the Vesterled pipeline due to the decrease in diameter, bends and other obstructions in the manifold. Hence, a subsea pig launcher is required (See more in section 2.8).

To meet the pigging requirements of the Vesterled pipeline, the manifold shall be designed with a guiding base arrangement into which a temporary pig launcher can mate. Opposed to the manifold piping, which minimum allowable diameter is 16’’, the tie-in to the Vesterled pipeline must be 32’’ to ensure its “pigability”.

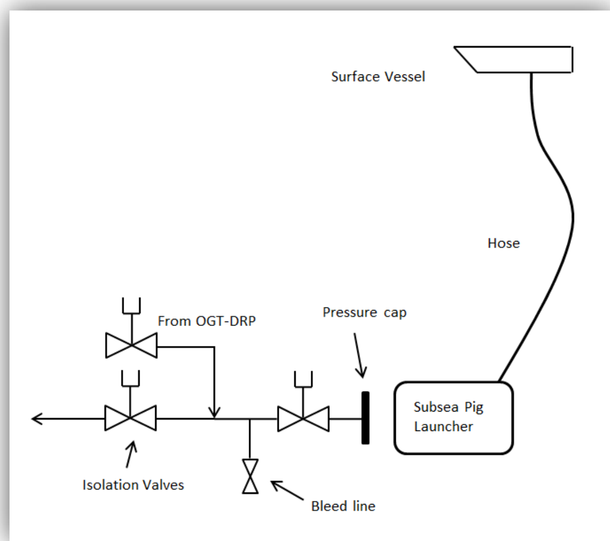

Figure 36: Subsea pig launcher arrangement

The mating of the subsea launcher and subsea arrangement is based on a horizontally oriented system (Figure 36). When a pigging operation campaign is to be conducted, an intervention vessel will use its guiding system to install the launcher on the subsea guiding base. The pig is pre-installed in the launcher. The main stream needs to be isolated prior to mating of the launcher and the pipeline. This is achieved by implementing a double block and bleed system which consists of two isolation valves in series, or a single integral double sealed valve with a bleed point in between [78]. The integrity of the seal is verified by monitoring the pressure at the bleed connection in between the two seals. For this case, a system comprising two isolation valves in series and a bleed point in between is considered the best isolation concept. A single integral double block and bleed system is beneficial with respect to the manifolds weight. However, the increased reliability of two valves in series compared to one is emphasized. In situations where there are problems with the integrity of one seal, two seals provides redundancy. This can potentially save large costs when expensive intervention vessels are on the clock.

A leak test is conducted at the bleed point by measuring the pressure. After the integrity of the seal is verified, the pressure cap is removed by opening the clamp with a ROV torque tool. The pig launcher is deployed with the vessel crane and lowered onto the guide base. It is further stroked into the hub and connected by closing the clamp with the ROV torque tool. The integrity of the connection is verified by injecting MEG from a hose deployed from the vessel. The isolation valves are opened by ROV actuation and the pig is pushed out of the launcher and into the flow line. This is achieved by pumping fluids (e.g. methanol or naphtha) into the launcher from a vessel deployed hose. The pig follows the gas flow and is retrieved at the St. Fergus gas terminal.

3.9 Flow control module

The flow control module incorporates an electric actuated choke/control valve in addition to instrumentation such as pressure and temperature transmitters. The module is constructed retrievable, meaning that it can be retrieved separately from the manifold if maintenance is required.

Various control valve designs exists on the market, but the use of high capacity subsea control valves is limited. The subsea axial control valve [79] delivered by Mokveld is considered a good alternative.

Figure 37: Mokvelds Subsea Axial Control Valve [79]

Mokveld has delivered a 8'' electric actuated anti-surge control valve to the subsea compressors on the Åsgard Subsea Compression Project. The manufacturer sees no limitations in implementing a 16'' control valve into the Heimdal Subsea System [80].

The subsea axial control valve has linear characteristics, fast and accurate control, high capacity and are designed for automatic operation with hydraulic or electric actuation.

As 16'' valves has not been requested by any operators before, the 16'' subsea axial control valve must go through a qualification program before it can be implemented into the Heimdal Subsea System.

3.10 Subsea Concept Summarized

This section summarizes the Heimdal Subsea manifold concept and its equipment. A 3D illustration (Figure 38) has been prepared in Autodesk Inventor. The model is for illustration purposes only.

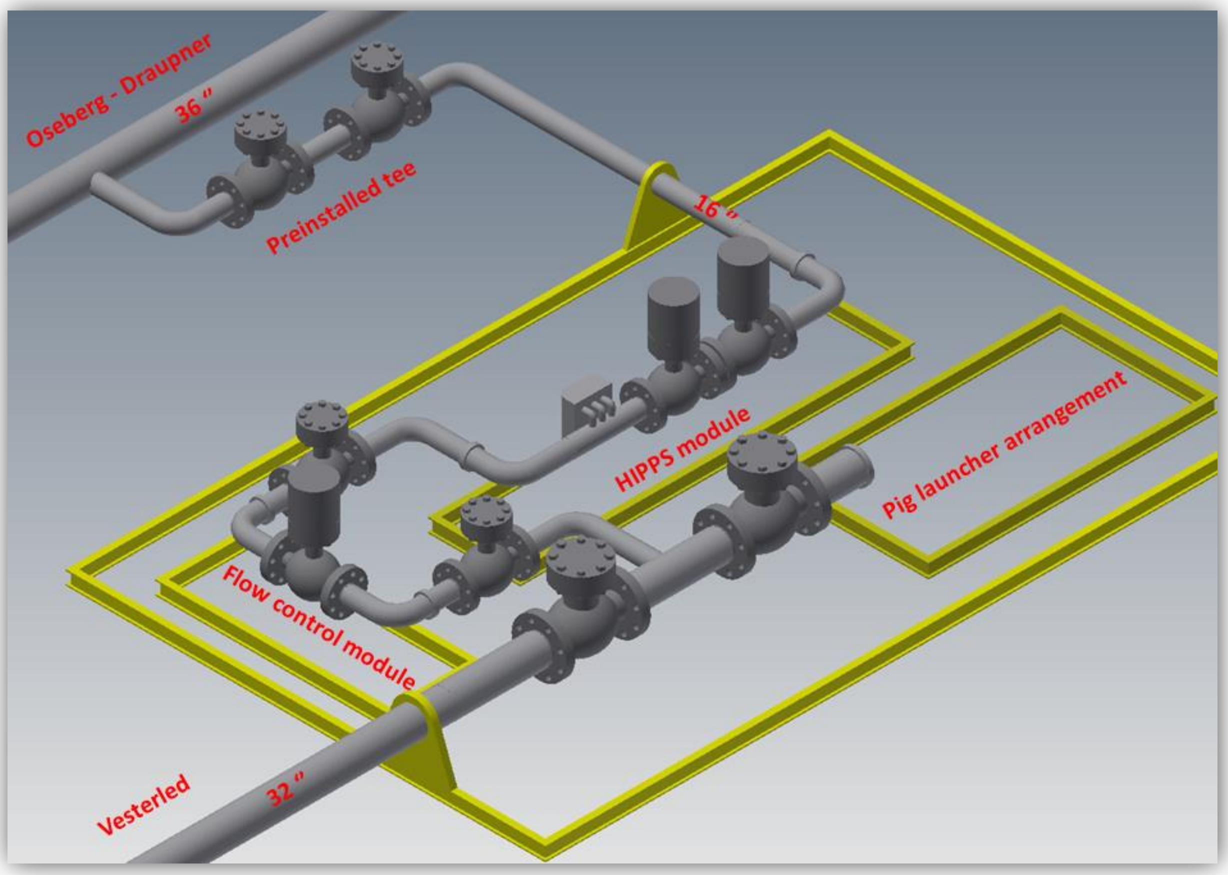

Figure 38: 3D model of the Heimdal Subsea manifold

A spool connects the OGT-DRP by-pass to the manifold. The spool is connected to the preinstalled tee connection on the by-pass at one end, and to the manifold on the other. The manifold components comprise a HIPPS module, flow control module, four isolation valves and a pig-launcher guiding base. In addition it facilitates the tie-ins to the OGT-DRP pipeline and the Vesterled pipeline. The HIPPS and flow control modules can be retrieved separately if maintenance is required. The isolation valves provide the seals that are required for such operations. Two isolation valves are installed on the 32'' piping to facilitate pigging operations. The Subsea Control Module (SCM) and Electric Power and Communication Distribution Unit (EPCDU) are not illustrated in the model, but will be installed as retrievable modules.

The manifold structure will be protected from third party impact loads (such as dropped objects and trawling) by means of a protection structure. The protection structure has not been considered in this report.

The battery package will be installed on a separate template close to the manifold template.

3.11 Weight Estimation

It is desirable to minimize the weight and size of the manifold since the costs of manufacturing and installation are very dependent of these factors. The installation costs represent a significant amount of the overall costs of a subsea manifold. The installation should therefore be continuously evaluated in the design process. This should include identification of installation vessels with adequate crane capacities, planning of marine operations and identification of risks associated with the installation.

At this stage of the study it is difficult to accurately calculate the weight and dimensions of the manifold. A coarse estimate of the total weight and dimensions are however provided. The calculations and assumptions are given in Appendix F. The manifold dimensions are shown in Figure F 1 and the total manifold weight is given in Table 5.

Table 5: Weight estimates of manifold components (ref Appendix F)

Component	**Weight [tons]**
Structures	138
Flow control module	30
HIPPS module	30
32'' ball valve ×2	16
16'' ball valve ×2	9
Piping	7
Total weight	**230**
Protection Structure	**40**
Battery package (excluding structures and additional components)	**20**

Further studies needs to be initiated in cooperation with engineering companies and technology suppliers to achieve accurate values. These values will be the basis for the planning of marine operations and cost estimates.

4. Risk Assessment

For the subsea concept discussed in this thesis to be justified, there are strong requirements to high availability of its functions and safe operations. To ensure these requirements, all risks associated with the design, installation and operation of the system must be identified. At this stage of the study, a review of the risks associated with the design and operation of the system will be performed.

A risk assessment includes risk identification, risk analysis and risk evaluation. The NORSOK standard Z-103 sets the following requirements for a risk assessment process [81]:

a) Identify hazardous situations and potential accidental events
b) Identify initiating events and describe their potential causes
c) Analyze accidental sequences and their possible consequences
d) Identify and assess risk reducing measures
e) Provide a nuanced and overall picture of risk, presented in a way suitable for the various target groups/users and their specific needs and use

The first step of the risk analysis process is to identify all relevant hazards. To carry out such identification processes several structured techniques such as FMECA, HAZOP/HAZID and SWIFT are used by the industry. These techniques have in common that they are based on brainstorming sessions. At this stage of the study it is important to establish the overall risk picture. This can be done by conducting a Simplified Risk Analysis [82]. This technique identifies the most important risk contributors which can be further investigated by using more detailed analyses. In early studies it may be misguiding to use quantitative measures for risk description. Thus will a qualitative approach be given in this report.

The risk analysis is conducted by dividing the subsea manifold into sub elements. These sub elements are: HIPPS, isolation valves, choke valve, subsea pig-launcher, tie-in points and manifold structure. Each sub element is evaluated by using a check list where undesirable events related to the sub element are identified. Further will the causes leading to the undesirable events be identified together with the consequence of the events. Since the Heimdal subsea manifold implements several unconventional technologies, it is challenging to assign probabilities. So to identify which risk contributors that are important to look further into, the risk picture will be presented in a qualitative risk matrix. See Table D 1 (Appendix D) for consequence categories. The uncertainties regarding the occurrence of the undesirable events are considered by the categories in Table D 2.

To identify relevant risks, a brainstorming session was arranged. The participants represented experience within subsea systems, marine operations, platforms and pipelines. The further risk analyses should also include representatives from the technology suppliers. To set focus on the most important risk contributors, the top 11 risks associated with the subsea system were identified. The check list that was used during the session is presented in Table D 3. The risks (or undesirable events) were evaluated in terms of causes, consequences and the probability/uncertainty of occurrence. The evaluation of the risks are presented in the risk matrix (Table 6).

Table 6: The top 11 identified risks presented in a risk matrix (see Table D 3 for references)

	Probability			
Consequence	Minor	Unlikely	Likely	Frequent
Extensive				
Severe	Dropped objects (10) HIPPS fails to isolate (1) Hydrate formation due to cool-down effects (5)	Damage of subsea structures due to third party marine activity(11)		
Moderate	Hydrate formation due to HIPPS functional tests(2) Gas leakage in tie-in points(9)	Isolation valves fails to open/close(3) Pig-launcher mating problems(7) Integrity of seals are not verified(8)	Inaccurate choke regulation(4) Problems with module retrievals (6)	
Minor				

The red region in the risk matrix is categorized as unacceptable risks. If the risks are in the red region after mitigating measures have been taken, the project cannot continue. The risks in the yellow region are acceptable after cost efficient measures have been implemented and the project finds the risks to be satisfactory. The risks in the green region are considered acceptable risks. They should however be subject to the" As Low As Reasonable Practicable" (ALARP) principle.

Seen from the risk matrix, no risks are categorized as unacceptable. But the yellow region high lights risks that require risk reducing measures and/or further analyses before they can be deemed satisfactory. In Table 7 are recommended risk reducing measures presented.

Table 7: Risk reducing measures to reduce the risks to acceptable levels

Risks	Risk reducing measures
Dropped objects (10)	-Protection structures -Mechanical analyses
HIPPS fails to isolate (1)	-Further analyses in cooperation with technology suppliers. -The Safety Integrity Level (SIL) gives the requirements for the reliability of such systems -Quantitative analyses must be conducted
Hydrate formation due to cool-down effects (5)	-This risk must be further analyzed (see section 4.1)
Damage of subsea structures due to third party marine activity (11)	-Protections structures -Statistical analyses of marine activity -Mechanical analyses of impact scenarios -Trenching
Inaccurate choke regulation (4)	-Further analyses in cooperation with technology suppliers -Analyses of interface with control system -RAM analyses
Problems with module retrievals (6)	-Further analyses with technology suppliers and IMR contractors

This simplified (or coarse) risk assessment identified several risks that need further analyses before they can be deemed satisfactory. They should be given close attention in the further development of the Heimdal Subsea System. In the next section, the risk of hydrate formation due to cool-down effects is further analyzed.

4.1 Hydrates

One substantial consideration for gas transportation networks is the risk of hydrate formations in the pipelines. Hydrates have the potential to reduce the capacity of the pipeline and in the worst case to plug it. With the presence of liquid water in the gas flow, hydrates are formed under low temperature and high pressure conditions. (see Figure 39).

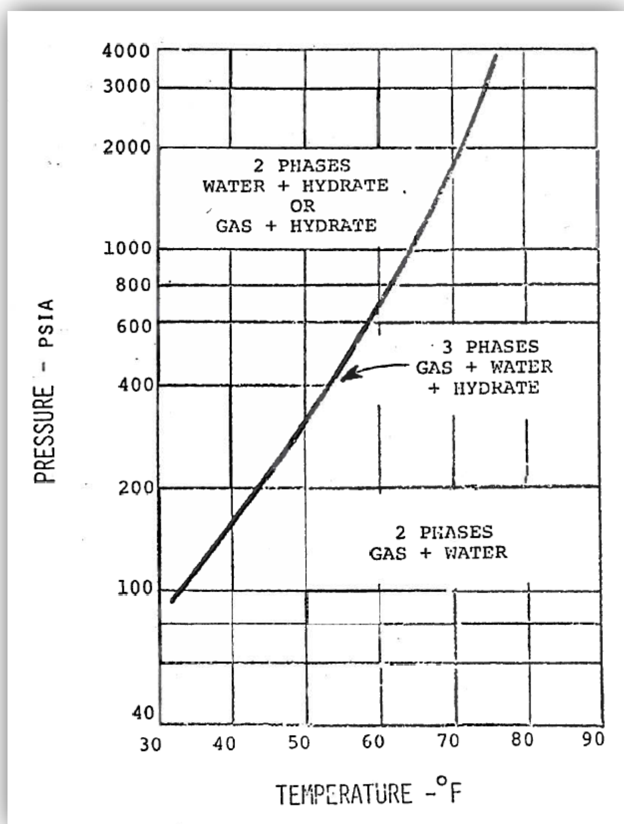

Figure 39: Hydrates forming conditions for 0.7 gravity natural gas [83]

Natural gas often contains solved water vapour which has the potential to dissolve and accumulate as liquids in the pipeline. To avoid the risk of hydrate formations, the gas requires sufficient dehydration before entering the transportation network.

The Heimdal subsea manifold could be vulnerable to hydrate formations due to significant choking of the gas flow across the choke valve (which in some operational scenarios could be required). See more about choke valves in section 2.6. The pressure loss will be followed by a decrease in temperature (the Joule-Thomson effect), and the conditions for hydrate formations could be present. Also the yearly functional test of the HIPPS barrier valves could introduce problems with hydrate formations. When the valves are closed, depending on the time before they are re-opened, the gas will cool down to ambient sea water temperature. However, the Heimdal subsea manifold is located so far away from the Oseberg and Draupner facilities that the gas flow temperature will be equal to ambient temperature anyways. Hence, functional testing of the HIPPS valves shouldn't introduce any additional challenges with respect to hydrate formations. Significant choking scenarios should however be investigated.

The export gas compressors at the Oseberg facility have the capacity to deliver gas at 170 bar with typical 50° Celsius. At the Heimdal subsea manifold (which is located approximately 110 km away from the Oseberg facility), the temperature will be close to the ambient seawater temperature which ranges from 4-10° Celsius. There will not be a significant frictional pressure loss over this distance. See Appendix C Figure C 2 for temperature and pressure profiles. To calculate the expected temperature loss across the choke valve, an extreme case will be evaluated. The design pressure in OGT-DRP is 40 bar larger than Vesterled, which in few cases could be the required differential pressure across the choke valve. This will be the base case for the calculations.

The relationship between pressure loss and decrease in temperatures is given by the Joule-Thomson coefficient [83]:

$$\mu = (\frac{1}{CP}) \times (\frac{RTm^2}{Pm})(\frac{\partial Z}{\partial T}) \approx \frac{\Delta T}{\Delta P}$$

Where:

CP = Specific heat capacity of gas [J/kgK]
R = Gas constant [J/kgK]
Tm = Average temperature [K]
Pm = Average pressure [Pa]
Z = Compressibility factor
T = Temperature [K]
P = Pressure [Pa]

See Appendix C for calculations.

The calculations shows that the differential temperature across the choke valve is 7-8 °C under the given conditions. This results in a temperature T2 = -4 °C downstream the valve (when the ambient seawater temperature is 4° C). Due to inaccuracies in calculations and the fact that the calculations are based on a theoretical model, the uncertainties in calculations should be considered. Typical cool down values for Joule-Thomson expansion is 0.25-0.4 °C/bar [84] , which in this case is between 10 and 16°C. Comparing to the theoretical model, the inaccuracies range from 20 to 50%. For safety reasons, the 16° C differential temperature is considered for the further evaluations. This results in a temperature T2 of -14° C when the ambient seawater temperature is 4° C.

A Pressure, Volume and Temperature (PVT) simulation was conducted to evaluate the risk of deposition of liquid water in the gas flow due to a temperature decrease across the choke valve. The Gas Chromatograph (GC) at the Oseberg facility shows typical water containment in the range 1-5ppm. For safety reasons, a simulation of the hydrocarbon (yellow) and water (blue) phase envelopes with a 20ppm water containment was conducted (Figure 40).

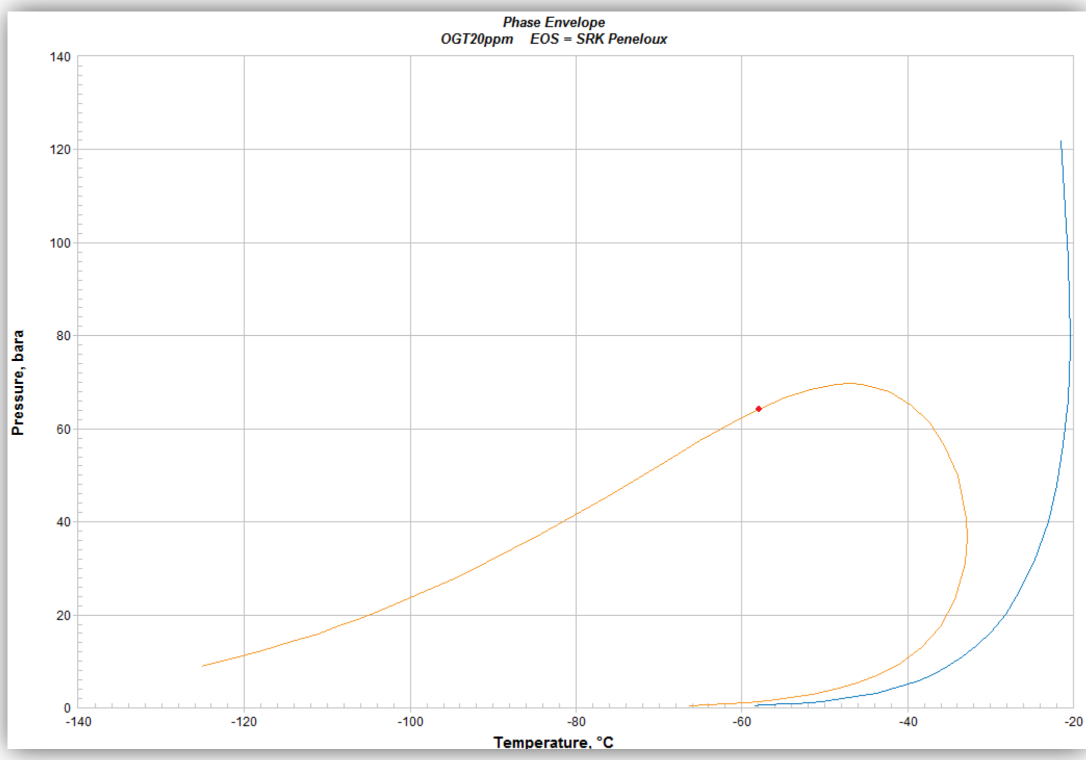

Figure 40: Phase envelopes of the Oseberg gas with 20ppm water containment. The blue curve indicates the phase of water and the yellow curve, the phase of hydrocarbons. In the regions to the left of the curves there will be liquid deposition.

It is observed from Figure 40 that there will be no depositions of liquid water under the given conditions.

A second analysis was conducted to investigate the critical water containment which could result in liquid water deposition (Figure 41). The results show that with a water containment of 35ppm and -14°C, there is a risk of liquid deposition in the manifold which could result in hydrate formation.

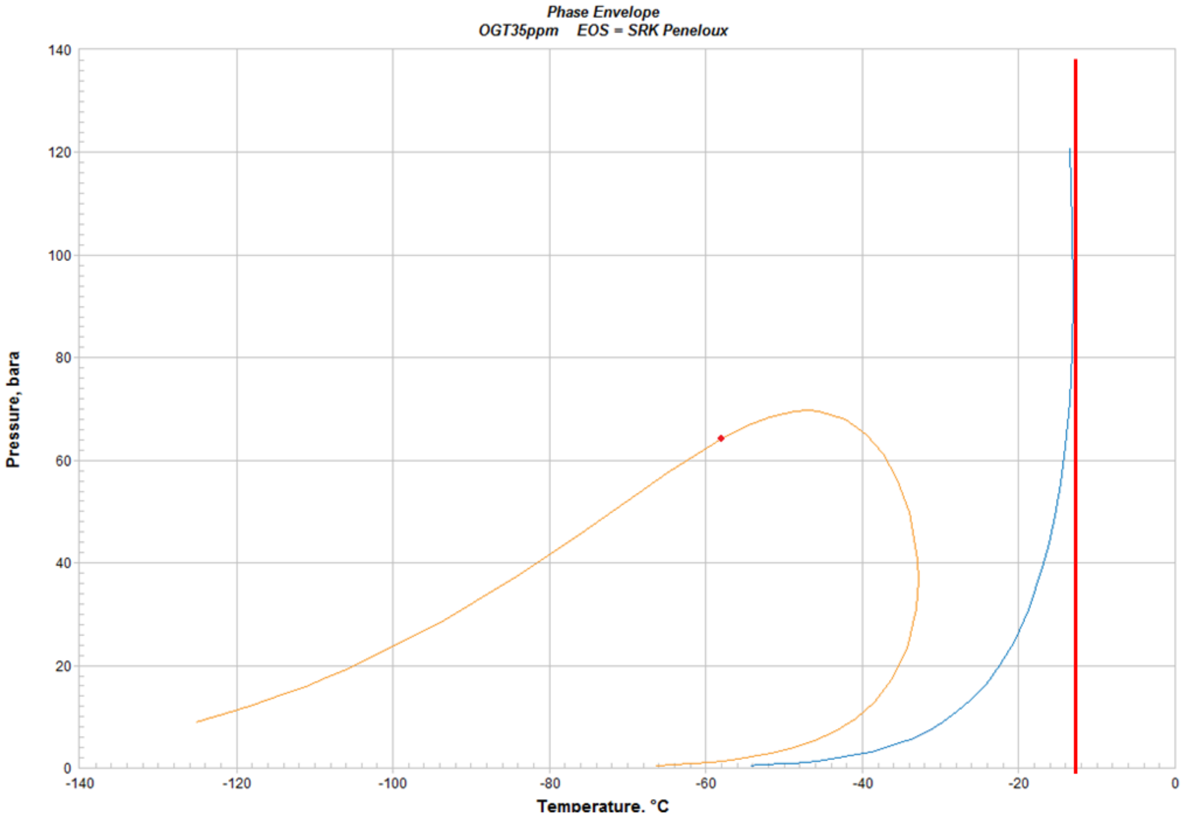

Figure 41: Phase envelopes with 35ppm water containment. With a temperature of -14°C and 35ppm water containment, there is a risk of liquid water deposition.

The analyses shows that with a ΔP = 40bar over the choke valve and a water containment of 35ppm, there could be depositions of liquid water which could result in hydrate formation in the manifold.

A water containment of 35ppm is not considered realistic since this is a deviation of the terms and conditions for entering the Gassco operated gas transportation system [85]. In addition, is a ΔP = 40bar across the choke valve normally not required. Hence is the risk of hydrate formation in the Heimdal subsea manifold minimal. It is however recommended that different operational scenarios are investigated and that the risk of off-spec gas entering the system is evaluated.

5. Alternative Concepts

The advances of subsea technology the past decades have been significant and the future offshore O&G production facilities are moving from the topside to the seabed. When O&G developments move towards increasingly harsher environments and deeper waters, subsea developments may be the only feasible alternative. However, it is important to evaluate other concepts as well.

5.1 Conventional Topside Alternative

When Heimdal processing is shut down, the decommissioning process of Heimdal Main Platform (HMP) initiates. Today, all utility systems that are required to operate the Heimdal Riser Platform (HRP) are provided by HMP. Hence, the functions performed by HMP must be replaced. A study carried out by Gassco evaluated different concepts to maintain the functions of HRP [86]. A new living quarter/utility jacket with associated safety systems in addition to a flare jacket platform was the recommended solution (Figure 42). Modifications on HRP will also be required.

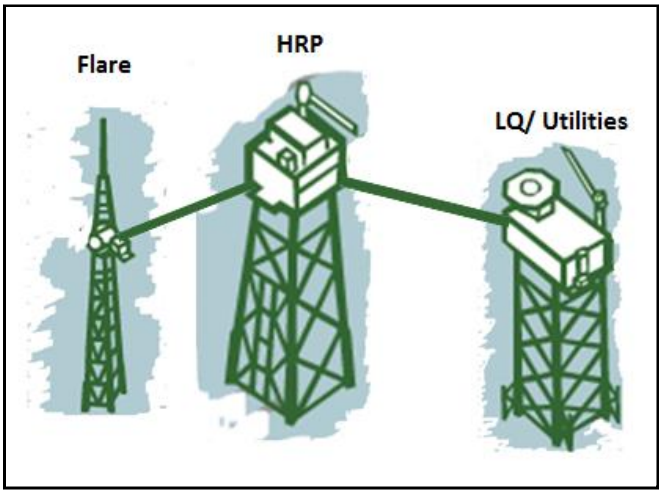

Figure 42: New topside concept to maintain the functions of Heimdal Riser Platform

The new platform concept is considered technical feasible. However, significant investments are required. The total CAPEX is estimated to 5000-6000 MNOK. Also considering the OPEX of a standalone gas transition hub with utilities and personnel, the costs could be difficult to justify.

In the next section an alternative topside concept will be briefly evaluated.

5.2 Unmanned Platforms

Operators are constantly focusing on optimization and cost reduction to maximize the profits of their offshore projects. As an alternative to subsea developments, Statoil recently announced that they were studying a concept which is a competing alternative to subsea developments: “Subsea on slim legs” [87]. “Subsea on slim legs” represents a relatively small and unmanned platform without helideck and living quarters (Figure 43). This concept could be a cost effective alternative to subsea satellite well developments in shallow waters.

Figure 43: «Subsea on slim legs» concept [87]

Unmanned platforms are not a new concept. Unmanned satellite platforms were first introduced in 1979 and have been used in many developments the later years. In the South China Sea, unmanned satellite platforms were successfully implemented in the 1980’s [88]. These platforms were installed on four legged jacket structures with two modules(utility and well module), helideck and a crane. Regular maintenance was required (up to five times a week), thereby challenging the claim that the facilities were unmanned. In 1990 the first Slim Tripod Adapted to Rig (STAR) satellite platform was installed in the Danish sector of the North Sea [89]. The STAR platform concept was developed to meet the requirements of a small and simple platform type for shallow waters (Figure 44).

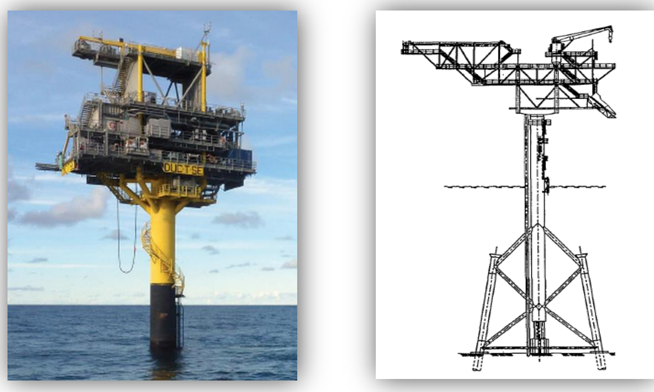

Figure 44: Tyra Southeast extension in the North Sea (Danish sector) [90] and STAR platform Concept (type B topside) [89]

The topsides installations can be put to a minimum (type A) or with extended installations (type B). The difference between type A and B is that type B also have a helideck installation, a 20 tons crane, a test separator and emergency accommodation for 9 men. All access to the type A platform is facilitated by vessels.

The unmanned satellite platforms were developed to reduce the costs of developing marginal fields as an alternative to subsea satellite wells. The costs are saved by a combination of smart design and minimal staffing. This concept, whether it is a STAR or a conventional jacket design, should also be feasible to maintain the functions of the Heimdal gas transition hub.

When Heimdal Processing is shut down, the decommissioning process of HMP initiates. The topside structure on HRP could be removed, leaving the jacket structure as the fundament for the unmanned platform topsides. The unmanned topside installation could comprise a utility module, the manifold, safety systems and control systems. The power supply could be provided by a diesel generator or an electric cable from shore.

For this concept to be feasible, a maintenance strategy which minimizes the required presence of personnel at the facility is required. This is probably one of the main challenges with this concept. Without a helideck, the maintenance personnel would be required to access the platform by a vessel. This could be challenging due to the vessels motions. Hence, are the weather conditions a factor. The fact that the vessel is very close to the platform when the crew is boarding, would probably set strict operational criteria. The risks of vessel-platform impact and personnel injuries would be a major concern. Maintenance is often an all-year requirement, also at winter time when the weather windows for such marine operations may be small and few. The risk of “waiting on weather” could prove to be an expensive truth. Without living quarters, a vessel would be required to be present at all times during the maintenance campaigns. With limited operational window and high vessel day rates, the costs of such operations could be significant. Choosing an efficient maintenance strategy and at the same time maintain high integrity of the platform could prove to be very challenging.

Challenges related to regularity and potential unplanned shutdowns of unmanned platforms are major concerns for riser platforms where high availability is required.

6. Qualification of new technology

The functional requirements of the Heimdal Subsea System are fundamentally different from other subsea developments due to the fact that no O&G production is involved. The technologies that have been assessed in this report have evolved from R&D projects with the objectives of improving subsea production systems. The application of these technologies have however, been very limited. The reason for this could be the increasing complexity of such systems. The subsea concept presented in this report is much “simpler” than subsea production systems. And this may be the reason why technologies that earlier have been screened by operators, in this system can find their application. Some of the technologies that have been assessed in this report are considered unconventional technologies. They are not new technologies, but they lack the field experience of their conventional alternatives. Implementation of such technologies introduces uncertainties that imply risks for the operator. And before this technology can be applied, a comprehensive qualification program is required. DNV’s recommended practices gives a systematic approach on how to manage the risks associated with the implementation of new (and unconventional) technology [91]. The qualification program (Figure 45) shall be an iterative process with a strategy that shows how the technology shall be taken from its existing stage of development to its goal.

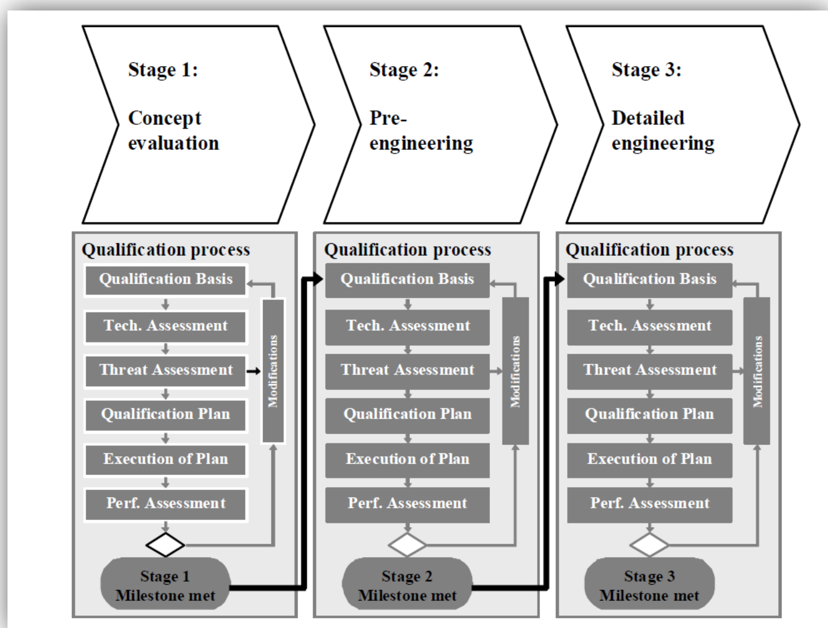

Figure 45: The technology qualification program iterating through three stages [91]

The qualification program consists of three stages: the concept evaluation, pre-engineering and detailed engineering stages. At each stage, milestones should be established to guide the program. Before entering a new stage, decision gates should be linked to the verification of these milestones. To meet the requirements and milestones of the qualification program, a systematic approach is given by the Qualification Process (Figure 46).

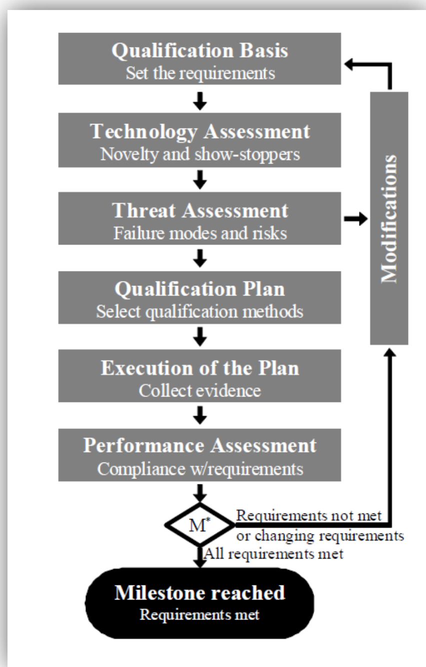

Figure 46: The qualification process. M* = milestone [91]

If there are, through the process discovered changes in boundary conditions, reliability, safety, etc. that requires modifications, this will trigger full or partial iterations of the process for the basis to be satisfied. The steps of the qualification process are given below:

- The technology basis shall specify the technology and answer questions such as; how the technology will be used, what is the environment, what are its required functions, how shall it perform and what is the acceptance criteria. It shall also specify the milestones it needs to meet in order to be qualified.
- The technology assessment determines which elements that introduce new technology and what their challenges and uncertainties are. For complex systems it is recommended that the main challenges and uncertainties are identified by conducting a HAZID (Hazard Identification).
- The threat assessment shall identify all failure modes and the risks associated with these. To guide the process, methods such as FMECA, FTA and HAZOP may be used. In the early technology development, qualitative methods can be used, but as the program develops quantitative measures should be given. The identified failure modes and risks should be categorized in a risk matrix so that the risks can be prioritized in the qualification plan.
- When the basis is set and the uncertainties and challenges are identified, a qualification plan must be set in order to determine the activities and methods that are required to provide the evidence which shall comply with the requirements of the technology basis. Such activities comprises engineering analyses, numerical analyses such as e.g. CFD and FEM, experimenting, investigating earlier studies, looking into standards and so on.
- Further comes the execution of the qualification plan. This step includes carrying out all the planned qualification activities, collecting and documenting data and determining the

performance margin of each failure mode. The product of this step is well documented evidence that complies with the qualification basis.

- The performance assessment reviews the evidence acquired from the qualification activities against the technology qualification basis. This includes confirmation that all the requirements are met and the risk and uncertainty are reduced to an acceptable level. The performance assessment is concluded by decision makers whether or not a specific qualification stage in the program has been reached. If the evidence doesn't comply with the design basis, modifications are required (See Figure 46) or the technology is screened.

The iterative process in the qualification program gives a well-defined; risk based and well documented approach on how to qualify technology.

The industry uses a Technology Readiness Level (TRL) as a measure of a technology's development state. This scale varies from unproven ideas (TRL 0) to proven technology (TRL 7). Various scales are in use by the industry today. A technology readiness ranking from the API standard [92] is given in Figure 47. TRL 7 is considered proven technology and TRL 0-6 shall be qualified according to a qualification program (E.g. as given by DNV-RP-A203).

Criteria describing the technical readiness level

Technology readiness level		Criteria describing the technical readiness level
7	*Proven technology*	*Production unit integrated into intended operating system. The technology has successfully operated with acceptable performance and reliability >10% of its specified life*
6	*System installed*	*Full scale prototype (or production unit) built and integrated into intended operating system with full interface and functionality test program in intended environment. The technology has successfully operated <10% of its expected life.*
5	*System integration tested*	*Full scale prototype (or production unit) built and integrated into intended operating system with full interface and functionality tests.*
4	*Environment tested*	*Full scale prototype (or production unit) built and put through a product qualification test program in (simulated or actual) intended environment.*
3	*Prototype tested*	*Full scale prototype built and put through a product qualification test program. The prototype is tested in a robust designed test program over a limited range of operation conditions to demonstrate its functionality.*
2	*Physically proven concept*	*Concept design or novel features of design validated by model or small scale testing in laboratory environment. The system validates that it can function in a "realistic" environment with the key environmental parameters simulated.*
1	*Analytically proven concept*	*Functionality proven by analysis. Reference to common features of existing technology or testing on individual subcomponents/subsystems. The concept may not meet all of the technical requirements at this level but demonstrates the basis functionality with promise to meet all the requirements with additional testing.*
0	*Unproven idea*	*Paper concept. No analysis or testing has been conducted.*

Figure 47: Technology readiness ranking [92]

Since acceptance criteria are ambiguous and vary in the industry it is difficult to determine when a TRL has been reached. To guide this process, acceptance criteria should be assigned to each TRL. These acceptance criteria shall be verified by evidence which is acquired through the qualification process. The TRL ranking in Figure 47 is given in API 17N, Recommended Practice for Subsea Production System Reliability and Technical Risk Management. This ranking system will be used to assess the readiness of some of the technologies discussed in this report. First a coarse assessment of each technology component in the subsea manifold is given. This is done to focus the work on the technologies that requires the most comprehensive qualification programme. The assessment is subjective and is based on knowledge achieved by the author through the work of this thesis.

Subsea manifold

Subsea production manifolds have been widely used in the O&G industry the last decades. A gas transition hub manifold presents a simpler concept than production manifolds and there is no reason to believe that there are any limitations in the design of such systems. The BP Bombax gas pipeline project (section 2.2) is the best reference to similar projects.

All-Electric control system

The All-Electric control system is an advancing technology. The system has not been widely used subsea, but several R&D projects within this field have commenced the later years. This technology is critical for the concept discussed in this report to be feasible, since the alternative would introduce the implementation of hydraulic control systems. Further studies, in cooperation with manufacturers, have to be initiated for this technology to be qualified for the Heimdal Subsea System.

Lithium-Ion battery package (remote energy supply)

The concept proved its feasibility in the SWACS project in 1987 (ref section 2.3.3), but the project replaced the system with a sea-water battery due to its dependence of periodical recharging by interventions vessels. Since 1987 much work has been done within lithium-Ion technology and it is reasonable to believe that the maturity and feasibility of such systems are much greater today. This is also a key technology in the development of autonomous vehicles such as the AUV's. This technology may not be feasible for subsea productions systems due to the high power demands. Until now, manufacturers may have lacked the drivers to develop high capacity rechargeable subsea lithium-ion batteries. In combination with the All-Electric control system, this is a key technology that requires comprehensive studies before its functionality can be verified.

Subsea isolation valves

Without further references, it is concluded that subsea isolation valves are well qualified technology in the industry.

Subsea Control/choke valves

Subsea control/choke valves have been widely used by the industry. The use of high capacity subsea control valves have, however, been limited. Their compatibility with electric actuators does require further studies.

HIPPS

A subsea HIPPS system is considered an unconventional pressure protection technology, although it has been applied by several subsea projects. Its compatibility with the All-Electric control system will require qualification. The HIPPS system that relies on mechanical initiators would however, eliminate the dependence of a control system. This system do not currently exists for subsea systems and studies should be initiated to investigate its feasibility.

Subsea Pig-launching

Subsea pig-launching is considered a proven technology

Installation and Tie-ins

Without further reference, installation of the by-pass, manifold and the tie-in operations are considered well known operations.

Summary

The course assessment high lightens the Lithium-Ion rechargeable battery, All-Electric control system and HIPPS system as immature technologies. In Appendix E an evaluation of these technologies are given. In Table 8 are the assigned TRL's given. Note that these are based on a subjective evaluation by the author and that further studies are required to verify these levels.

Table 8: Technology Readiness Level of immature technologies according to API 17N

Technology	Technology Readiness Level (TRL)
All-Electric Control System	TRL 4
Rechargeable Lithium-Ion Battery Package	TRL 3
Subsea HIPPS	TRL 4

To reach higher levels of technology readiness, a comprehensive qualification process is required (Figure 46). Such processes require a consistent basis which defines the required functions and the activities that can provide the evidence for decision makers to conclude that the milestones have been reached. A simplified strategy for reaching a higher technology readiness level is given in Table 9.

Table 9: Qualification strategy

Technology	Functions	Performance	Qualification Activities	Milestones
All-Electric Control System	-The interface between subsea system and master controls station - Electric actuators for operation of choke/control valve -Signal transmissions	Continuous operation. Availability ≈ 100 %	-Carry out risk analyses such as FMECA, HAZID/HAZOP and FTA to identify failure modes and risks -Verify compatibility between the electric actuator and the 16'' choke valve -Contact relevant manufactures - Investigate the power consumption	-Electric actuator is compatible with the choke valve -The Lithium Ion Battery package can provide the required energy for the control system - Fiber network can provide the required data capacity - The identified risks must be managed
Lithium-Ion Battery	-Provides electric energy for operation of the control system	Continuous operation. Availability ≈ 100 %	-Carry out risk analyses such as FMECA, HAZID/HAZOP and FTA to identify failure modes and risks -Verify the compatibility between the control system and battery - Do analyses of the required battery capacity -investigate requirements for power substitution - Investigate requirements for intervention vessels and marine operations	-The Battery is compatible with electric control system -A strategy for energy substitution by intervention vessel - The battery can provide the required energy in its operation interval - The identified risks must be managed

HIPPS	Isolates the lower pressure rated pipeline if maximum allowed pressure is exceeded	Continuous operation. Availability ≈ 100 %	-Carry out risk analyses such as FMECA, HAZID/HAZOP and FTA to identify failure modes and risks -Verify the compatibility between electric actuators and barrier valves - Investigate the possibilities to implement mechanical initiators -Investigate requirements to functional testing	-The barrier valves are compatible with electric actuators - A testing strategy to achieve the required SIL rate - The identified risks must be managed

In this section a simplified method on how to approach a qualification processes is given. Qualification of new technology is a time consuming process which requires a significant proportion of resources. The process should involve representatives from the technology suppliers and the operator of the system. All functions must be well-defined and unambiguous. To guide the process, milestones must be established to ensure that all participants work towards the same goal. The most time consuming part of the process is the activities that are required to provide the evidence which verifies if the milestones are met. If the evidence comply with the milestones and the risks associated with the technology are reduced to a satisfying level, a new level of qualification is reached. This will be the process from the concept evaluation phase, through the pre-engineering phase and at last the detailed engineering phase.

7. Conclusion

Recent advances in subsea technology enables functions that earlier were performed by platforms to be converted into subsea systems. Subsea developments permits offshore production in areas where conventional platform designs are economical or technical unfeasible. They also offer reduced CAPEX and OPEX in addition to risk reduction in terms of HSE. This makes subsea developments attractive alternatives to conventional topside developments.

Traditionally in the O&G industry, subsea developments have involved production and processing. Until now, the requirements of a mid/down-stream operator such as Gassco have not been widely evaluated. Operators are continuously focusing on optimizing functions to reduce the costs and risks associated with their subsea projects. As a result of this, many R&D projects within subsea technology have commenced the later years. The applications (and further development) of some of these technologies have been limited. However, the requirements of a subsea gas transition hub enables technologies that earlier have been screened out by operators to be applied in the Heimdal Subsea System.

The functions that are required to obtain high system availability and regularity in addition to safe operations, are incorporated within a 230 tons subsea manifold (excluding protection structure). The manifold components comprises a HIPPS module, flow control module, 4 isolation valves and a pig launcher guiding base (Figure 48). A lithium-ion battery package will be installed on a separate template close to the manifold template for the power supply. The battery will be recharged periodically by an intervention vessel.

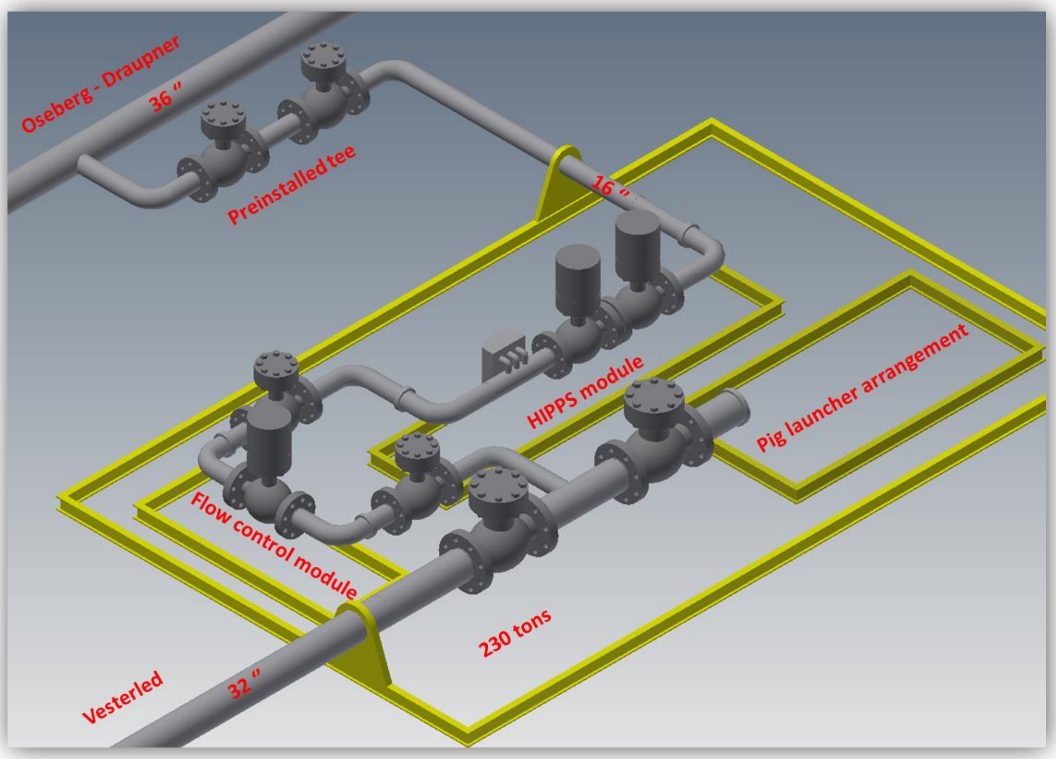

Figure 48: Heimdal Subsea System

A 16’’ spool connected to a pre-installed tee on the 36’’ bypass spool ties the manifold to the OGT-DRP system. The tie-in to the Vesterled pipeline must be 32’’ to ensure its “pigability” with a subsea pig launcher.

The All-Electric control system will be implemented for control and operation of the system functions. Compared to conventional control systems, the All-Electric technology eliminates problems and challenges related to hydraulics. In combination with a rechargeable Lithium-Ion battery package, this concept eliminates the requirement of a long and costly umbilical. Reliable and high capacity communication is established through the Tampnet operated subsea fibre network.

The requirements of this system is fundamentally different from other subsea developments due to the fact that no production is involved. This thesis evaluates the opportunities and challenges related to subsea technology relevant for a subsea gas transition hub. Several of these technologies are considered unconventional and a technology qualification program is required before they can be implemented into the Heimdal Subsea System. This does not mean that the concept is unfeasible, but a combination of technology uncertainties and a conservative industry may have limited the applications of such systems.

8. Recommendations for Further Work

This report have assessed opportunities and challenges related to a subsea gas transition hub. The focus has been on unconventional technologies that have not been widely used by the industry. If the concept shall reach satisfying levels of qualification, further studies have to be initiated. This section gives recommendations for studies and assessments that should be given proper attention in the process towards a full functional subsea gas transition hub. See section 6 for more details.

Marine Operations

The installation costs represents a significant amount of the overall costs of a subsea manifold, the installation should therefore be continuously evaluated in the design process.

IMR

A subsea system requires periodic inspection and maintenance. An Inspection, Maintenance and Repair (IMR) strategy should be developed.

The strategy for the recharging of the battery package must be developed.

All-Electric Control System

The All-Electric control system is critical for the feasibility of the concept presented in this report. All-Electric subsea control systems have not been widely used by the industry and further studies in cooperation with technology suppliers should be initiated.

Lithium-Ion subsea battery

The high capacity subsea Lithium-Ion battery is a new concept that requires qualification work before it can be implemented into the Heimdal Subsea System. Section 3.5.2 presents calculations for the capacity requirements of the battery. These calculations are however simplified and should be given further attention.

Alternative energy sources

The conventional electric cable concept for the power supply was early screened out by the author of this report. This was due to the costs and risks that were assumed to be of such magnitude that it could not be justified. This is however an alternative that should be further investigated as it eliminates the risks that are accompanied with the implementation of new technology (Subsea high capacity batteries).

The local energy sources discussed in section 2.4 and 3.5 should also be further investigated.

Weight estimates

Section 3.11 give a simplified weight estimate. As the weight of the manifold is critical with respect to costs, more accurate estimates should be provided.

HIPPS technology

The compatibility between the subsea HIPPS and the All-Electric control system must be verified. Also the feasibility of subsea HIPPS based on mechanical initiators should be investigated.

Cost estimates

The potential of reducing costs compared to alternative solutions must be proven. This will include cost estimation in terms of both CAPEX and OPEX.

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Appendix A

Density, velocity, pressure, temperature and flow rate data retrieved from SCADA.

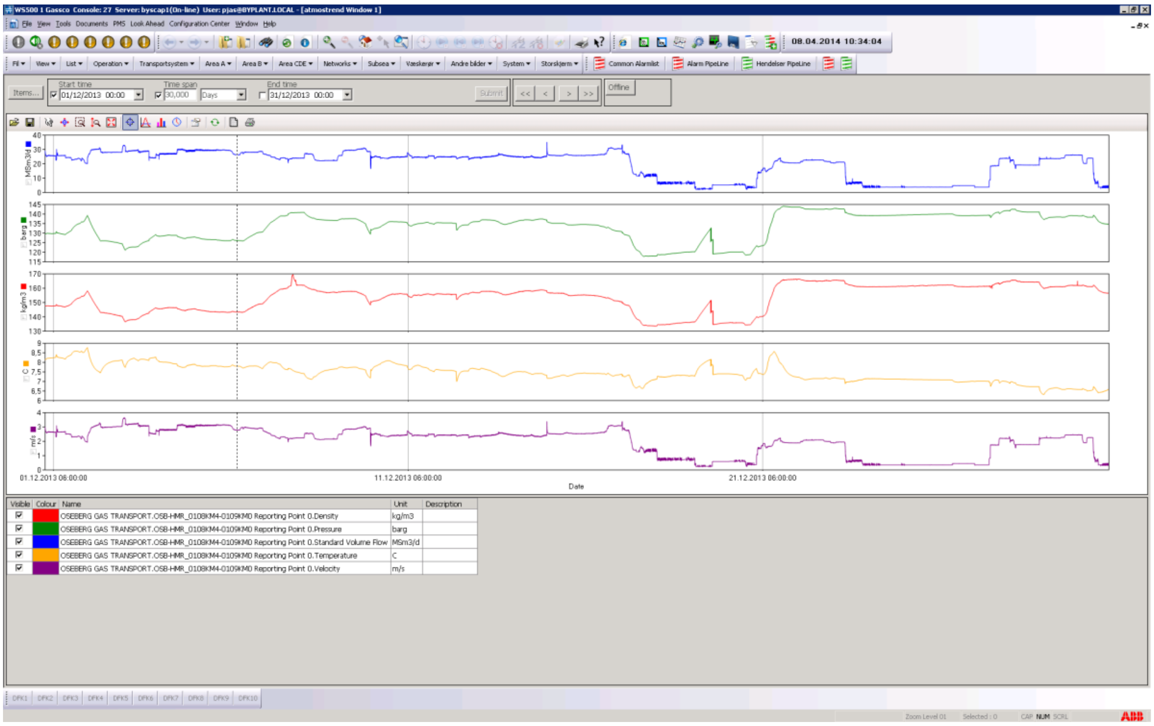


Figure A 1: SCADA measurements at Heimdal reporting point (Oseberg-Heimdal Riser), december 2013.

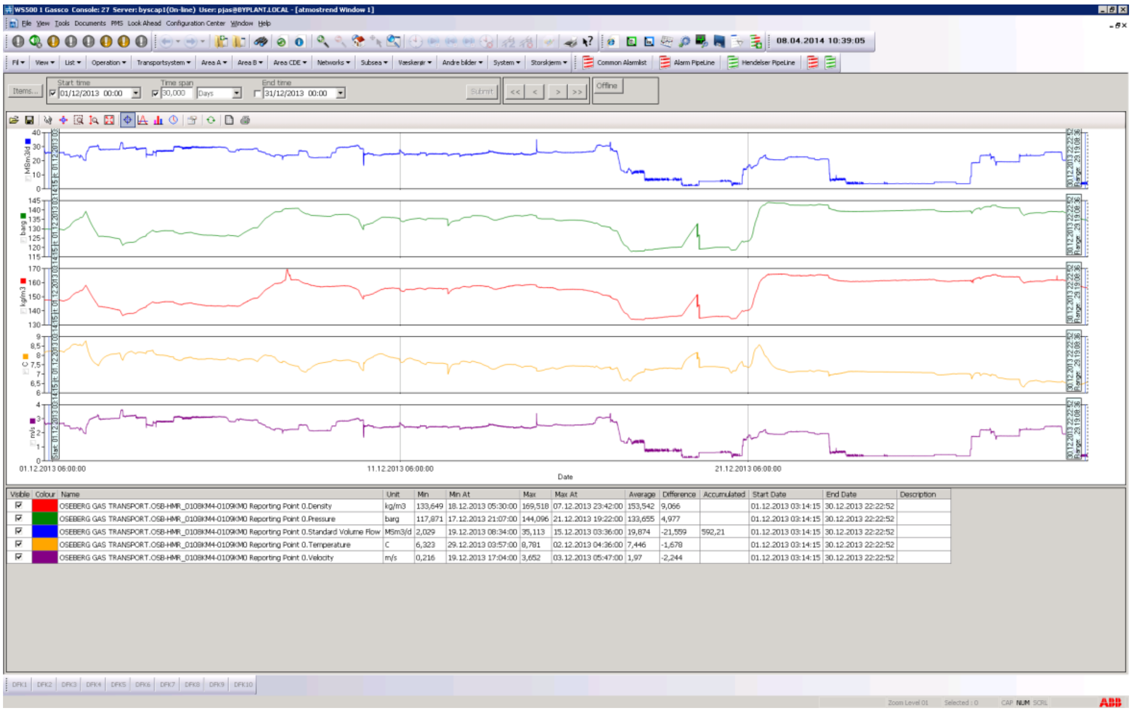


Figure A 2: SCADA measurements at Heimdal reporting point (Oseberg-Heimdal Riser), december 2013. Average, minimum and maximum values.

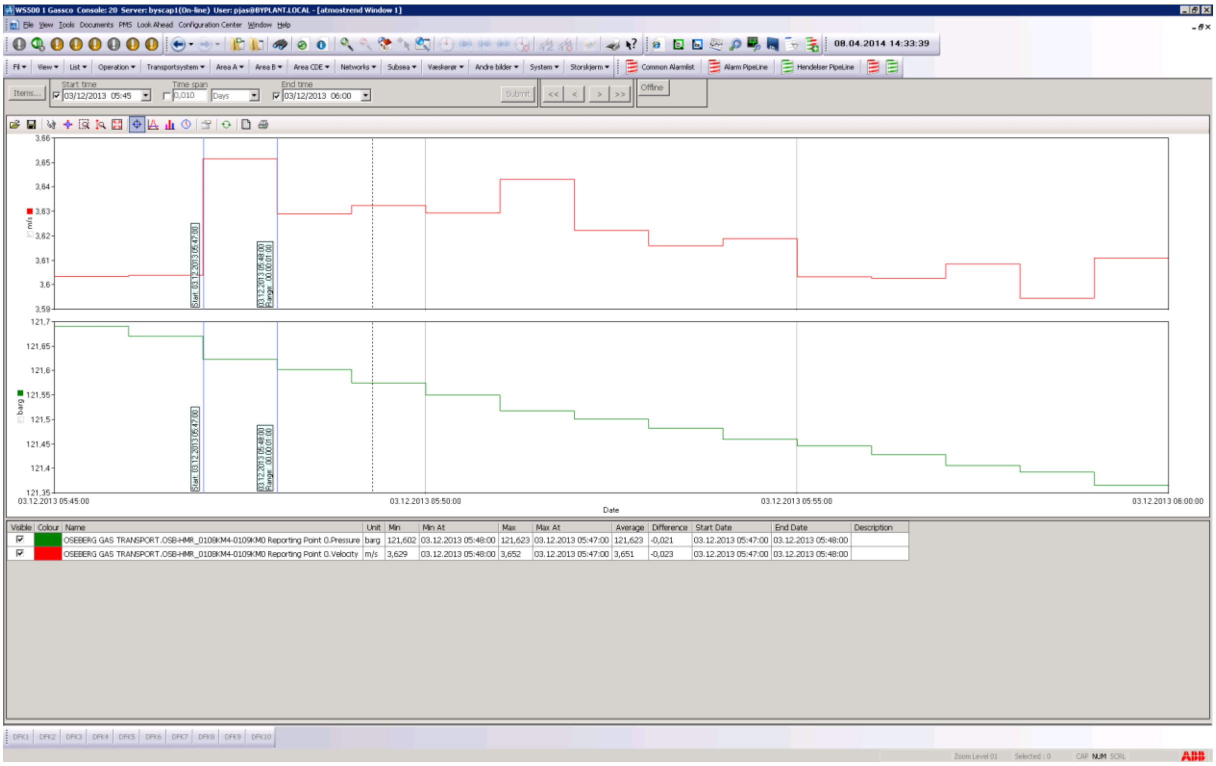


Figure A 3: SCADA measurements at Heimdal reporting point (Oseberg-Heimdal Riser). Measured pressure when the velocity peak (V=3.625 m/s)

Appendix B

Calculations of the required battery capacity.

Assumptions:

Table B 1: Battery capacity sizing assumptions

1	Typical roll screw diameters ranges from about 0.14 to 5.91 inches. It is assumed that the diameter of the stem is close to the diameter of the screw. For these calculations, the diameter of the stem is set to d = 1,57'' (40mm) [69]
2	The materials are not specified. The friction factor μ is assumed to be 0,20. Steel vs Steel friction factor with lubricated surfaces is 0,16. [93]
3	Frictional losses in the gears, screws and other mechanical losses is not considered in detail. They are however considered by implementing an uncertainty factor which is set to 1.2.
4	The motor speed is assumed to be 500 rpm
5	The time it takes to manoeuvre the valve position is 15s.
6	The valve will be actuated 5 times a day (average)
7	The Motor efficiency is 0,9
8	An inner pressure of Pi = 150 bar is used in the calculations. The design pressure of Vesterled is 149 bar.
9	The period in-between service/recharging of the battery package is two years (730 days)
10	The energy density in lithium-ion batteries is 200 Wh/kg [71]
11	Self-Discharge rate of lithium-ion batteries is 3 % per month (1.5 % is given in [70]). This is considered a conservative assumption, so safety is included.

The following calculations consider a 10 bar pressure differential across the valve. Other pressure differentials are presented in the tables below. Note that the calculations of the required force to operate the valve is simplified, and that an uncertainty factor of 1.2 is included.

Table B 2: Calculations of the force which is required to manoeuvre the valve position. An uncertainty factor of 1.2 is included to account for simplifications and assumptions.

Calculation of forces the roller screw must overcome to manouvre the valve position

Input					
Pi	150	bar			
ΔP	10	bar			
μ	0,2	-	(assumed)		
Di	16	Inch			
d	1,57	inch	(assumed)		
A	0,130	m^2			
a	0,001	m^2	(assumed)		
Pressure Force	18735	N	1910	kg	$Pi \times a$
Friction Force	25943	N	2645	kg	$\mu \times Ff$
Total Force F	44678	N	4554	Kg	$F = Pi \times a + \mu \times Ff\ [N]$
Uncertainty factor	1,2				
F	53613,8	N	5465,2	kg	

Table B 3: Calculations of the required motor torque

Torque calculation

F	53613,8	N		
S	20	mm	(assumed)	$T = \dfrac{S \times F}{2 \times \pi \times \eta}\ [Nm]$
η	0,9	-	(assumed)	
T	190	Nm		

Table B 4: The actuator power consumption over two years (given the assumptions of actuation frequencies and manoeuvring time).

Total Actuator Power Consumption			
Speed, n	500	rpm	$\omega = \frac{2\pi \times n}{60}$ [rev/s]
manouvering time	15	s	
Actuation frequency	5	times/day	
Days	730		$P = T \times \omega$ [W]
Actuator power requirement	10	kW	
Manouvering time in hours	0,00417	h	
Energy per actuation	0,041	kWh	
	41	Wh	
Total actuator power consumption	151	kWh	
	150996	Wh	

Table B 5: The continuous power consumed by signal transmissions, sensors, etc. (over two years)

Continueous consumption	0,1	kW
	100	W
Total time (2 years)	63072000	s
	17520	h
Continueous power consumption (sensors, signals transmissions etc.)	1752	kWh
	1752000	Wh
Actuator + Continueous power consumption	1902996	Wh

Total power consumption and the corresponding required battery mass:

Table B 6: The mass of a lithium-ion battery which can provide the required energy throughout two years (assuming 200 Wh/kg)

Actuator + Continueous power consumption	1902996	Wh
Mass battery	9515	kg

Table B 7: The table shows the relation between the differential pressure across the valve and the required battery mass. (a continuous consumption of 100W is assumed)

ΔP [bar]	F [N]	Torque	Actuator power consumption [kWh]	Continueous power consumption [kWh]	Total Power Consumption [kWh]	Battery mass [kg]
0	22482	80	63	1752	1815	9077
5	38048	135	107	1752	1859	9296
10	53614	190	151	1752	1903	9515
15	69180	245	195	1752	1947	9734
20	84746	300	239	1752	1991	9953
25	100312	355	283	1752	2035	10173
30	115878	410	326	1752	2078	10392
35	131444	465	370	1752	2122	10611
40	147010	520	414	1752	2166	10830
45	162576	575	458	1752	2210	11049
50	178142	630	502	1752	2254	11269

The self-discharge rate of 3% per month must be considered. In Table B 8 is the power consumption of the subsea system compared to the required battery capacity due to self-discharge presented:

Table B 8: Considering the self-discharging secondary batteries experience, the table shows that the battery must be designed with larger capacity due to this phenomena.

Month	Remaining energy in battery [kWh]	Required energy [kWh]
1	1903	2700
2	1767	2540
3	1634	2384
4	1506	2233
5	1382	2087
6	1261	1945
7	1144	1808
8	1030	1674
9	920	1545
10	813	1419
11	709	1297
12	609	1179
13	511	1064
14	417	953
15	325	845
16	236	740
17	149	639
18	66	540
19	-16	445
20	-94	352
21	-171	262
22	-245	175
23	-317	91
24	-387	9

A factor of 2700/1900 = 1,42 ≈ 1,4 must be multiplied with the required power consumption to account for the battery self-discharge rate of 3% per month.

Table B 9 demonstrates the dependencies between continuous power consumption and the required battery mass. A pressure differential across the valve of 10 bar is assumed for these calculations. The numbers shows that the continuous consumption is the most critical factor with respect to the required battery capacity.

Table B 9: These number demonstrates the dependencies between the continuous power consumption and the corresponding required battery mass. It can be observed that the continuous power consumption is critical with respect to the required battery capacity.

Actuator Consumption ΔP = 10 bar [kWh]	Continueous consumption [W]	Cont. Tot Consumption [kWh]	Total Consumption [kWh]	Battery Mass [kg]
151	50	876	1027	5135
151	100	1752	1903	9515
151	150	2628	2779	13895
151	200	3504	3655	18275
151	250	4380	4531	22655
151	300	5256	5407	27035
151	350	6132	6283	31415
151	400	7008	7159	35795
151	450	7884	8035	40175
151	500	8760	8911	44555

Appendix C

Joule – Thomson Effect

Expanding gases will experience a decrease in temperature. The relation between pressure loss and decrease in temperature is given by the Joule – Thomson Coefficient [reference]:

$$\mu = (\frac{1}{CP}) \times (\frac{RTm^2}{Pm})(\frac{\partial Z}{\partial T})$$

Where:

CP = Specific heat capacity of gas [J/KgK]
R = Gas constant [J/kgK]
Tm = Average temperature [K]
Pm = Average pressure [Pa]
Z = Compressibility
T = Temperature [K]

The Gas composition and properties is given in Table C 1.

Table C 1: Gas composition and calculations of properties

Component	yi	M	Mm [kg/kmol gas]	Tcr [K]	yi × Tcr [K]	Pcr [Mpa]	yi × Pcr [Mpa]
C1	0,87557	16,04	14,044	196,700	172,225	4,641	4,064
C2	0,07514	30,07	2,259	305,400	22,948	4,883	0,367
C3	0,02077	44,09	0,916	370,000	7,685	4,257	0,088
i-C4	0,0013	58,12	0,076	408,200	0,531	3,648	0,005
n-C4	0,00168	58,12	0,098	525,200	0,882	3,797	0,006
i-C5	0,00013	72,5	0,009	461,000	0,060	3,330	0,000
n-C5	0,0001	72,5	0,007	469,800	0,047	3,375	0,000
C6	0,00001	84	0,001	503,000	0,005	2,976	0,000
C7	0,00175	96	0,168	542,100	0,949	3,014	0,005
N2	0,00832	28,02	0,233	126,000	1,048	3,392	0,028
CO2	0,01542	44,01	0,679	304,300	4,692	7,398	0,114
H2S	0,01	34,08	0,341	1210,300	12,103	9,005	0,090
SUM	1,00		**18,83**		**223,17**		**4,77**

Case Data:

- Valve inlet pressure P1: 190 bar (design pressure OGT-DRP)
- Valve outlet pressure P2: 150 bar (≈ Vesterled design pressure)
- Inlet temperature T1: 10°Celcius = 283K
- CP = 3250 J/kgK (assumed value)
- ΔP = 40 bar

- Pm (mean value) = 170 bar
- ΔT = 16K (assuming decrease in temperature 1°C per 2.5bar pressure loss)
- Tm = 275 K

<u>Pseudo reduced temperature Tr: Temperature* / T'cr</u>

- Temperature = Tm ± 10 K (assuming that the temperature will vary with 10K around mean temperature)
- T'cr = 223.17
- Tr = 1.28 and 1.19

<u>Pseudo reduced pressure Pr: Pm / P'Cr</u>

- P'cr = 47.7 bar
- Pr = 3,57

From Figure C 1: <u>Z = 0,62 and 0,57</u>

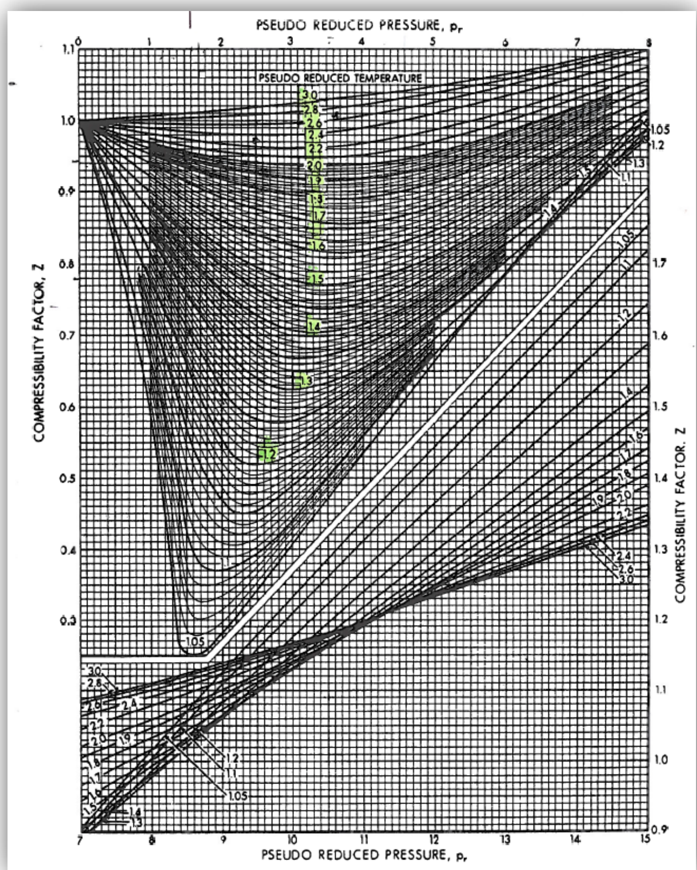


Figure C 1: Compressibility factor for real gases [83]

From Table C 1:

- Mm = 18.83 kg/kmol
- Relative molecular weight G = 18.83/29 = 0.65
- R = 8.314 / 18.83 = 441.5 J/KgK

- The weight G is relative to the weight of air: Mair= 29 kg/kmol

- 8.314 is the universal gas constant

The Joule Thomson Constant μ:

$$\mu = (\frac{1}{3250}) \times (\frac{441.5 \times 275^2}{170 \times 10^5})(\frac{0.62 - 0.56}{20})$$

μ = 0.000307 × 1.964 × 0.003 = 1.8074×10^-6

$$\mu \approx \frac{\Delta T}{\Delta P}$$

ΔT = 1.506 × 10^-6 × 40 = 7.2°C
T2 = 2.8°C

In Table C 2 the differential pressure across the valve is calculated as a function of valve inlet temperature

Table C 2: Differential temperature across the choke valve as functions of inlet temperature T1

T1	Z		ΔT	T2
10	Z1	0.62		2.8
	Z2	0.56	7.2	
9	Z1	0.61	7.2	1.8
	Z2	0.55		
8	Z1	0.61	7.2	0.8
	Z2	0.55		
7	Z1	0.62		-0.7
	Z2	0.555	7.7	
6	Z1	0.62		-1.6
	Z2	0.555	7.6	
5	Z1	0.61		-2.6
	Z2	0.545	7.6	
4	Z1	0.61		-4.1
	Z2	0.545	8.1	

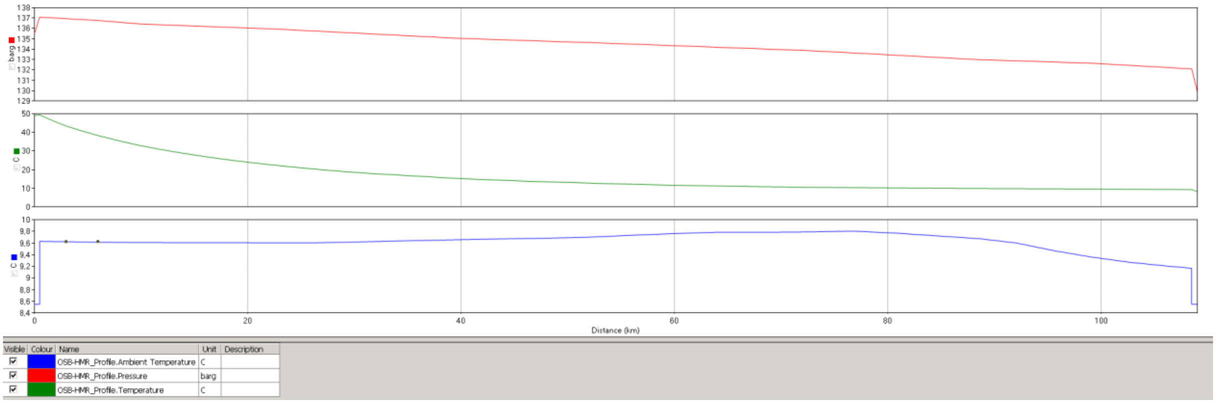


Figure C 2: Typical temperature and pressure profile at the Oseberg-Heimdal pipeline. Data collected from SCADA 1.12.2013.

PVT.SIM – Phase envelopes

PVT SIM is a PVT (Pressure Volume Temperature) simulation program developed for reservoir engineers, flow assurance specialists, PVT lab engineers and process engineers. The programme combines fluid characteristics with complex algorithms to simulate fluids behaviour. In this case, a simulation of a typical Oseberg gas composition (Table C 1) is conducted.

Appendix D

Table D 1: Consequence categories [94]

Consequence				
Category	**Personnel**	**Environment**	**Assets**	**Reputation**
Extensive	Fatalities	Global or national effect	Project costs > USD 10 mill	International impact/neg. Exposure
Severe	Major injury	Restoration time > 1 yr. Restoration cost > USD 1 mill.	Project costs > USD 1 mill	Extensive national impact
Moderate	Minor injury	Restoration time > 1 md. Restoration cost > USD 1 K.	Project costs > USD 100 k	Limited National impact
Minor	Illness or slight injury	Restoration time < 1md. Resoration cost < USD 1K	Project costs < USD 1 K	Local impact

Table D 2: Probability categories [94]

Probability			
Minor	**Unlikely**	**Likely**	**Frequent**
Has occured - not likely	Could occur	Easy to postulate	Occur regularly

Table D 3: Risks identified in brainstorming session

Sub-element	Undesirable event	Causes	Consequence	Uncertainty/probability	Consequence Category	Comments
HIPPS module	HIPPS fails to isolate Vesterled pipeline (1)	Failure of: actuator, logics, pressure sensors, valve components	Over-pressurization of Vesterled, shutdown	Minor	Severe	Ref: Section 3.7
	Hydrate formation due to cool-down effects during HIPPS functional tests (2)	Off-spec water containment in gas	Reduced capacity in pipeline, plugged pipeline	Minor	Moderate	Ref: Section 4.1
Isolation valves	Fails to isolate/open (3)	Defect ROV tool interface, corrosion, valve block defects	IMR activities are delayed	Unlikely	Moderate	
Choke valve module	Inaccurate regulation (4)	Failure of: control system components, Actuator, Signal transmissions, Defect valve.	Loss of system regularity	likely	Moderate	Likely during life
	Hydrate formation due to cool-down effects (5)	Off-spec water containment in gas flow, large differential pressure across valve.	Reduced capacity in pipeline, plugged pipeline	Minor	Severe	Ref: Section 4.1

	Problems with retrieval of module (IMR) (6)	ROV interfaces, Isolation valves (see Isolation valves)	IMR activities are delayed	Likely	Moderate
Subsea pig-launcher	Mating problems (7)	ROV interfaces, vessel support	Pig operation is delayed	Unlikely	Moderate
	Integrity of seal is not verified (8)	Isolation valves, ROV seal integrity tools,	Pig operation is delayed	Unlikely	Moderate
Tie-in points	Gas leakage (9)	Integrity of Seal not provided	Gas leakage	Minor	Moderate
Manifold Structure	Dropped objects from support vessels (10)	During installation, during IMR activities	Damage of equipment and structures, loss of integrity, shut-down, Gas release	Remote	Severe
	Damage due to third party marine activity (11)	Trawling activity, Anchor hooking, dropped objects	Damage of equipment and structures, loss of integrity, shut-downs, Gas release	Unlikely	Severe

Appendix E

All-Electric Control System

Table E 1: Technology Readiness Level for the All-Electric Control System. See Figure 47 for description of TRL's.

TRL	API 17N	
0	**Unproven Concept** Basic R&D, paper concept	OK
1	**Proven Concept** Proof of concept as a paper study or R&D experiments	OK
2	**Validated Concept** Experimental proof of concept by using physical model test	OK
3	**Prototype Tested** System function, performance and reliability tested	OK
4	**Environment Tested** Pre-production system environment tested	OK
5	**System Tested** Production Interface tested	
6	**System Installed** Production System Installed and tested	
7	**Field Proven** Production system field proven	

- The reader is referred to section 2.3.2 for references.

An All-Electric control system was installed on K5F field in the North Sea in 2008. An examination of the system performance found that a total availability of 99.98% was achieved. The 2nd generation All-Electric control system is today going through a comprehensive qualification process.

The All-Electric subsea control system was tested for a subsea well. No known projects have applied this technology for actuation of a 16'' control valve with a Lithium-Ion battery power supply.

The All-Electric control system satisfy the criteria (Figure 47): Full scale prototype built and put through a product qualification test program in (simulated or actual) intended environment. This qualifies to TRL 4.

To reach TRL 5, a full scale prototype must be built and integrated into intended operating system with full interface and functionality tests. The compliance between 16'' control valve, signal transmissions and energy supply through a Lithium Ion battery must be verified before TRL 5 can be reached.

Lithium-Ion Rechargeable battery package

- The reader is referred to section 2.3.3 and 3.5 for references

Table E 2: Technology Readiness Level for the Lithium-Ion battery package. See figure 47 for description of TRL's.

TRL	API 17N	
0	**Unproven Concept** Basic R&D, paper concept	OK
1	**Proven Concept** Proof of concept as a paper study or R&D experiments	OK
2	**Validated Concept** Experimental proof of concept by using physical model test	OK
3	**Prototype Tested** System function, performance and reliability tested	OK
4	**Environment Tested** Pre-production system environment tested	
5	**System Tested** Production Interface tested	
6	**System Installed** Production System Installed and tested	
7	**Field Proven** Production system field proven	

In 1987 the world's first autonomous subsea production system was installed at the Luna 27 well in the Ionian Sea. Electric energy for the electric motor was initially provided by a Lithium battery package. The later years, according to the authors knowledge, no subsea projects have applied battery packages of comparable sizes (capacities). However, Lithium Ion battery technology have advanced rapidly the later years. And it is reasonable to believe that the feasibility of a high capacity subsea battery package has increased since 1987.

The Lithium-Ion battery package satisfy the criteria: Full scale prototype built and put through a product qualification test program. The prototype is tested in a robust designed test program over a limited range of operation conditions to demonstrate its functionality. This qualifies to TRL 3.

To reach TRL 4, further studies have to be initiated to identify the capacity requirements (a coarse analyse was conducted in section 3.5.2). The compatibility between the All-Electric control system and intervention vessels (for recharging) must be verified.

Subsea High Integrity Pressure Protection System (HIPPS)

- The reader is referred to section 2.9 for references

Table E 3: Technology Readiness Level for Subsea HIPPS. See figure 47 for description of TRL's.

TRL	API 17N	
0	**Unproven Concept** Basic R&D, paper concept	
1	**Proven Concept** Proof of concept as a paper study or R&D experiments	
2	**Validated Concept** Experimental proof of concept by using physical model test	
3	**Prototype Tested** System function, performance and reliability tested	
4	**Environment Tested** Pre-production system environment tested	
5	**System Tested** Production Interface tested	
6	**System Installed** Production System Installed and tested	
7	**Field Proven** Production system field proven	

Subsea HIPPS is not considered conventional technology by the industry. It was first implemented in Shells kingfisher project in 1997 and in 2011, 11 subsea HIPPS had been installed worldwide. Normally are HIPPS valves actuated by hydraulics, which in the case of Heimdal Subsea System is not possible. The actuation has to rely on electric actuators. The alternative is to use mechanical initiators, which according to the authors knowledge, has never been done. Either way, this introduces the requirements of comprehensive qualification processes. So to assign a TRL for a HIPPS in this case, is very complicated.

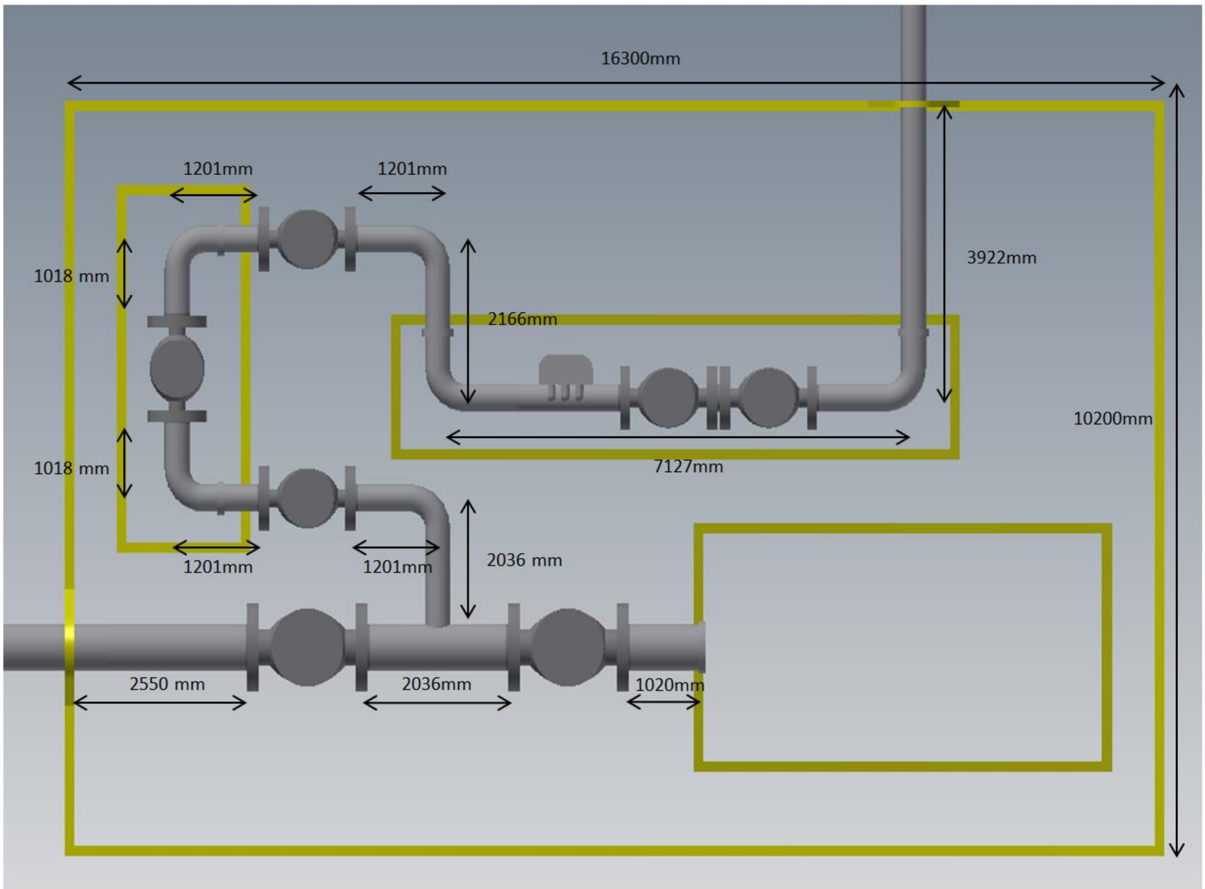
Subsea HIPPS have proved their functionality, but not with the interfaces the Heimdal Subsea System introduces (electric controls). Considering the HIPPS that have been installed, the technology satisfy the requirement: A full scale prototype has been built and put through a qualification test program in the intended environment. This qualifies to TRL 4.

To reach TRL 5, a full scale prototype must be built and integrated into intended operating system with full interface and functionality tests. The compatibility between the barrier valves and electric actuators and/or mechanical initiator must be verified.

Appendix F

Figure F 1 has been modelled in Autodesk inventor. The measures in the model are not correct according to the real measures of the module. The measures have been scaled to its real values based on the 16'' isolation valves which the lengths are 1500mm.

Figure F 1: Scaled measures of manifold with the basis of 1500mm 16'' ball valves.



Weight estimation calculations:

These calculations are based on measures received from a valve manufacturer [95] and a report delivered by the engineering company Reinertsen [96]. Note that these are rough estimates.

Isolation valves

Ball valve size	Weight [kg]	Length (end to end)[mm]	Number of valves
16''	4080	1500	2
32''	8000	Irrelevant for calculations	2

Flow control module

The flow control module comprises a choke valve and control systems (actuator and instruments).

Comparing to similar modules the module weight is assumed to be 30 tonnes.

HIPPS module

The HIPPS module comprises two barrier valves, actuators and instrumentation.

Comparing to similar modules the module weight is assumed to be 30 tonnes.

Subsea control system components

The subsea control system comprises the SCM and EPCDU. The weight of these components is incorporated in the Weight/areal factor W (see structures), and in the HIPPS and flow control module.

Structures

To estimate the weight of the structures (and additional components), the areal of the manifold is multiplied with a Weight/areal factor "W". This factor has been calculated based on similar subsea structures [96].

$W = 830\ kg/m^2$

With reference to Figure F 1:

Length of manifold = 16300mm

Width of manifold = 10200mm

Weight of structures = $830 \times 16.3 \times 10.2 \approx$ 138 tonnes

Piping

With reference to Figure F 1:

	Length[m]
16''	22.1
32''	5.6

Assuming:

- steel density $\delta_{steel} = 7840\ kg/m^3$
- Wall thickness t = 18mm

Weight pipe 16''	
Di [mm]	406.4
t [mm]	18
Density [kg/m^3]	7850
Weight [kg/m]	188.3941

Weight pipe 32''	
Di [mm]	812.8
t [mm]	18
Density [kg/m3]	7850
Weight [kg/m]	368.79797

	Length[m]	Weight
16''	22.1	4163
32''	5.6	2067
Sum		6229 kg

Protection Structure

Based on similar subsea structures, the weight of the protection structure is assumed to be 40 tonnes.