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ACCESS

Arctic Climate Change, Economy and Society

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Abstract

Aim of work package (WP) 4.2.2 within ACCESS is the assessment of existing subsea production systems and possible future developments including related onshore infrastructure as well as removal and disassembling of facilities after drilling and production, respectively. This assessment is based on future ice conditions and identification of requirements for adjustment to account for the special situation in the Arctic.

(Task leader: IMPaC (Hamburg)).

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1 INTRODUCTION

The Arctic is engaged in a deep climatic evolution. This evolution is quite predictable at short (year) and longer scales (several decades), but it is the decadal intermediate scale that is the most difficult to predict. This is because the natural variability of the system is large and dominant at this scale, and the system is highly non-linear due to positive and negative feedback between sea ice, the ocean and atmosphere.

Already today, due to the increase of the GHG concentration in the atmosphere and the amplification of global warming in the Arctic, the impacts of climate change in the region are apparent, e.g. in the reduction in sea ice, in changes in weather patterns and cyclones or in the melting of glaciers and permafrost. It is therefore not surprising that models clearly predict that Artic sea ice will disappear in summer within 20 or 30 years, yielding new opportunities and risks for human activities in the Arctic.

This climatic evolution is going to have strong impacts on both marine ecosystems and human activities in the Arctic. This in turn has large socio-economic implications for Europe. ACCESS will evaluate climatic impacts in the Arctic on marine transportation (including tourism), fisheries, marine mammals and the extraction of hydrocarbons for the next 20 years; with particular attention to environmental sensitivities and sustainability.

<u>Added in Revision B:</u>

This Report focuses on the use of subsea production facilities in the Arctic. Aim is to provide technical information about the main sub-systems and the applicability of subsea technology with regard to installation, operation, maintenance, and decommission of the facilities. Realized examples illustrate the complexity and costs and the required land based infrastructure. Implications on governance issues are based on current Rules and Regulations, which are partly still under development for the Arctic.

2 OBJECTIVE

The main objective of task 4.2 is to provide an assessment of technological issues related to the extraction of oil and gas in the Arctic.

Specific objectives of WP 4.2.x are according to the ACCESS project proposal:

> *Assessing existing technologies including fixed and floating structures (4.2.1) and subsea systems (4.2.2) suitable for safe extraction of energy resources under Arctic conditions with minimal impact on the Arctic environment. Including the identification of technological gaps that hinder Arctic development as well as providing pathways for future technological development including the removal and disassembling of offshore facilities and problems related to winterization (4.2.3).*

The following report focuses on subsea systems (according to 4.2.2) suitable to work in Arctic conditions. As these facilities heavily rely on safe and reliable installation methods as well as on maintenance and recovery activities which are mainly carried out by means of heavy duty vessels aided by remotely operated vehicles (ROV) and/or autonomous underwater vehicles (AUV), these parts of the supply chain have also been briefly assessed.

3 ABBREVIATIONS

AC	Alternate Current
ACCESS	Arctic Climate Change, Economy and Society
AMAP	Arctic Monitoring and Assessment Programme (refer [8])
AUV	Autonomous Underwater Vehicle
CCS	Carbon Capture and Storage (or Carbon Capture and Sequestration)
DC	Direct Current
EEZ	Economic Exclusive Zone
EPU	Electrical Power Unit
FPSO	Floating Production, Storage and Offloading (Unit)
FPU	Floating Production Unit
GHG	Greenhouse Gas
HPU	Hydraulic Power Unit
IMO	International Maritime Organization
ISO	International Standardization Organization
MEG	Mono-Ethylene Glycol
PLEM	Pipe Line End Manifold
PLET	Pipeline End Terminal
ROV	Remotely Operated Vehicle
SCSSV	Surface-Controlled Subsurface Safety Valve
SDA	Subsea Distribution Assembly
SIL	Safety Integrity Level
UNCLOS	United Nations Convention on the Law of the Sea
UPS	Uninterruptable Power Supply
UWPS	Underwater Production System
VSD	Variable Speed Drives
WDDM	West Delta Deep Marine
WP	Work Package
XTree	Christmas Tree

4 STANDARDS

The following standards have been applied for the assessment:

- ISO 13628-1 to 11: Standards for Subsea production Systems (refer Figure 11-21)
- NORSOK Standard U-001: Subsea production systems, Rev 3, October 2002
- GL (I-5-Section 3), Unbemannte Unterwasserfahrzeuge (ROV, AUV) und Unterwasser-Arbeitsgeräte, 2009
- IMCA, M series - Marine Division and DPVOA Series
- IMCA, R series - Remote Systems & ROV Division Series, Guidelines
- IMCA, S series - Offshore Survey Division Series, Guidelines

5 GENERAL REMARKS

The today available subsea production technology can be divided in two main groups of systems, the one used for satellite field developments without continuous connection to shore and the one with continuous connection to shore via pipeline and control umbilical.

The first group of subsea production facilities is fixed to the seafloor but continuously tied back to production, storage and offloading facilities (FPU or FPSO, see Figure 11-9). These floating production vessels receive the produced fluids and provide treatment and, partly, storage of the end products.

These systems are mainly used when one or more of the following factors are prominent:

- The reservoir holds only relatively marginal resources or the production profile requires relatively frequent change of location (e.g. re-location every 10-15 years)
- The step-out distance of the production location to shore exceeds abt. 150 km
- the subsea soil condition does not allow to safely lay pipelines and umbilicals (e.g. due to landslides, seismic activities, iceberg scouring, heavy currents, canyons)
- political, social or workforce constraints complicate the existence and operation of onshore receiving plants in the related region or state (e.g. terror attacks have to be expected, missing/insufficient infrastructure and logistic background, NIMBY (Not In My Backyard) or BANANA (Build Absolutely Nothing Anywhere Near Anything) local policy or attitude resulting in 'never ending' approval procedures)
- the environmental conditions at the sea surface allow for the permanent presence and operation of manned facilities

This group of facilities is covered by a dedicated assessment report within ACCESS (refer [1]) and shall not be further discussed in this report.

The second group of subsea production facilities is dedicated to locations not matching the above constraints or where the environmental conditions like strong winds and currents, high waves, and massive icebergs or closed ice do not allow working with permanently surface piercing structures.

Consequently, the following paragraphs describe the current state-of-the-art subsea production technology as well as the technology available most likely in the future to work in the Arctic with continuous connection to shore receiving plants, remotely controlled from land based control centres.

6 BASIC CHARACTERISTICS OF SUBSEA PRODUCTION TECHNOLOGY

6.1 INTRODUCTION

Production via subsea installations is the latest step technology has taken. This technology is characterized by 'intelligent' autonomous seabed facilities remotely operated from onshore receiving plants or worldwide operator headquarters. Ultra-long subsea tiebacks connect these installations by means of multipurpose umbilicals (for communication, power supply for electric driven motors and transmission of inhibitor fluids) and product export pipelines. Gathering of the infield wellstream is realized by smaller and flexible flowlines. As result subsea developments often cover large areas reaching several 10^{th} of sq. km.

The future will also see enhanced subsea (pre-) processing including separation of produced gas, water and sand from the wellstream, re-injection of the produced water into dedicated wells for pressure stabilization, subsea compression of gas and/or multiphase boosting of the fluids.

Main concern of production with large step-out distance (especially in the Arctic) is built-up of wax, hydrate or corrosion due to large temperature or pressure gradients in the long seafloor pipelines. These blockage phenomena reduce the transport capacity of the pipelines and are summarized under flow assurance problems, which are handled by injecting dedicated inhibitor fluids like e.g. methanol, MEG (monoethylene glycol) or by costly direct heating of segments of the pipelines. Also inhibitors are costly and thus are recovered and recirculated in onshore facilities if technically feasible and economically viable.

6.2 MAIN SUBSYSTEMS

The one solution for an underwater production system (UWPS) does not exist. This is mainly due to the fact that UWPS are like specialized and unique „underwater process plants“ for oil and gas, that means a highly complex facility composed of different, task dependent sub-systems and functions. Each UWPS is dedicated to its specific application, to the composition of the fluids in the reservoir, the production profile over time, the physical and chemical properties of the fluids and last but not least the environmental conditions and location of its installation. Each oil and gas company has its own strategy and philosophy to handle these questions in global and local view.

In general the following main modules are part of an UWPS (Figure 6-1):

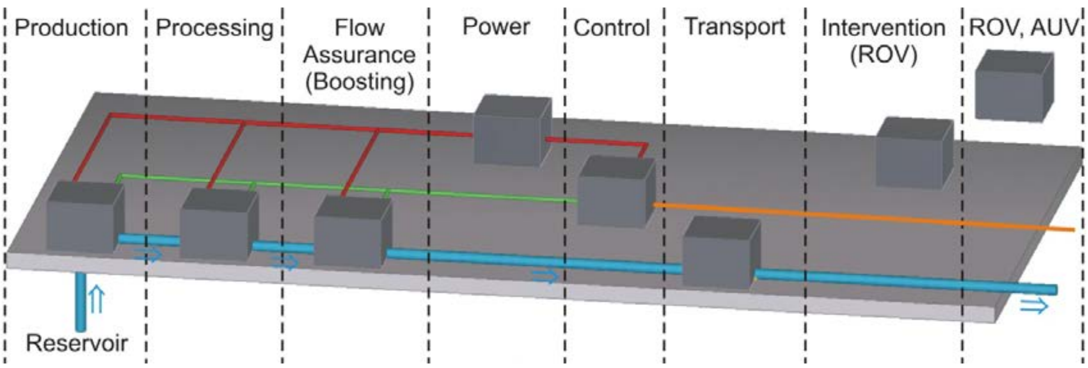

Figure 6-1: Main Modules of an Underwater Production System

- Reservoir: Borehole accessing the subsurface reservoir of oil and gas equipped with „down hole“ sensors and the SCSSV
- Production: Sealing the borehole at the seafloor to the environment by means of the underwater completion (wellhead with production tree or Xtree) equipped with safety valves, flow control valves and injection lines for flow assuring inhibitor fluids
- Processing: Process units for treatment of the fluid for easier send-out
- Flow Assurance: Systems for pressure increasing or temperature control assuring a reliable export of the fluid to the shore receiving plant
- Power: Energy supply of subsea facilities (e.g. pumps, actuators, compressors)
- Control: Technology for control of the UWPS and for reliable bi-directional data transfer with the shore control center
- Transport: Export system (flowline, pipeline, multipurpose umbilical). Often outlined as grid of lines for oil and gas export and for supply of flow inhibitors and hydraulics, for data transfer and power supply
- Maintenance / Repair: carried out by ROV, AUV and seafloor working tools (crawlers) operated from ships, barges or platforms
- Workover / Intervention: Carried out by instrumented (intelligent) pigs for flowlines and pipelines, and by drill strings and coiled tubing for boreholes

Most of these technology fields also exist in land based production scenarios (of course except AUV, ROV and ship involvements). Nevertheless, they are different in major details concerning e.g. accessibility, depth range (water depth plus drilling depth) and environmental loads (outer pressure might exceed the inner pressure of vessels). Important is to follow systematic approaches to every single production scenario.

More detailed information is given in paragraph 7.

6.3 BASIC PRINCIPLES

Some characteristics have proven to be advantageous for subsea production facilities. It should be checked if they can be met by Arctic subsea facilities if possible:

- A project-wide design basis should be developed and agreed on
- All developments and procedures should be as much as possible versatile, robust and simple
- The kernel components and especially the control system of the production facility should be dimensioned providing flexibility for future adaptations and extension of the facility. Subsystems like valves, transmitters, actuators have to be included in control loops resulting in a modular and expandable concepts for interfaces, the data management and the bandwidth of the communication network without the need for additional umbilical connections from shore to subsea
- The complete UWPS and especially its power supply system should be designed to cope with short-term load peaks and long-term load level changes in order to meet requirements of changing production profiles if possible
- It should be possible to install, test, maintain and survey main components of the UWPS with standard ROV and AUV in order to keep the costs reasonable. The interfaces and tools to be provided should be designed according to standards like ISO 13628-8

- A number of spare interfaces should be foreseen for connecting additional umbilicals, flowlines or pipelines if possible
- A trend can be identified that new subsea production plants will work in water depths up to 3000 m with step-out distances to shore up to 150 km or even more. This trend should be anticipated in the design of new components and concepts if feasible resulting in underwater replaceable modules with extended mean times between failure
- Modern UWPS should be connected to the (shore) control base by means of flexible and cost efficient bus communication systems. The control algorithms should be modular and upgradable via upload. The data transmission hardware will be most likely based on fibre optics for high bandwidth, low noise and against electric fields

6.4 INSTALLATION

Most installation locations require developing specific UWPS with suitable installation, operation and finally dismantling procedures.

Drilling of the wells in Arctic conditions takes place by means of special purpose, ice going drill ships (Figure 11-10). The following installation (and dismantling after end of the lifecycle) of the subsea facilities takes place by means of heavy load construction vessels, which are of shipshape or barge type or – for the very heavy loads – of semi-submersible type (Figure 11-11, Figure 11-12). The latter allows carrying loads up to 14,000 t at 31 m outreach by two cranes in tandem operation. Handling the loads is one important task, the other is to safely lower and land the heavy components and subsystems right at its final position at the prepared installation site without impacting the new or the already installed seafloor structures.

For compensating wave induced motions of the crane vessels heave compensation systems are available, either actively or passively acting at the load wires to reduce the vertical yo-yo effect of the load at the cable. In addition, a number of installation aids are available and proven, such as guide wires and guide posts allowing reaching exactly the mounting position of components at the seafloor facilities. Guide wires reach straight from the seafloor facilities landing position to the construction vessel (Figure 11-13). Components are fixed to the wires by means of funnels and then lowered to the facility. Often guide posts allow final orientation and alignment for precise landing (Figure 11-14, Figure 11-16).

Another installation method works without guiding structures but with thrusters or with aid of ROV which are also used to connect the multipurpose umbilicals to the new components (Figure 11-17).

Another complicate and time consuming task is the lay of the cables (umbilicals) and the pipelines connecting the subsea facilities with the shore based receiving plant and operating rooms. For this purpose dedicated lay vessel are in charge which have to work in moderate sea and ice free environment (Figure 11-19).

As conclusion it is important to note that subsea structures are often too heavy to lower them to the seafloor in one piece so that subsea assembly (and replacement or decommission if required) might be foreseen. Thus, wet mateable connectors and clamps which are actuated automatically or by ROV have to be considered.

The following phases during the lifecycle of production facilities have to be planned in detail:

<u>Phase 1:</u> Preparation of the System installation

<u>Phase 2:</u> Assembly / mounting

Phase 3:	Installation, test and commissioning of the UW-Modules, flowlines, cables and pipelines
Phase 4:	Operation of the UWPS
Phase 5:	Maintenance, repair and replacement of Modules; work over of wells
Phase 5a:	optional: comprehensive lifecycle extension measures
Phase 6:	Decommissioning and dismantling after end of lifecycle carrying out the procedures in Phase 1 to 3 in reverse order (refer paragraph 6.5)

6.5 DECOMMISSIONING, DISMANTLING

The finalization of the production has to be planned with every project prior to any installation of equipment. Bases are Rules and Regulations provided by UNCLOS (refer [13]) and IMO and the so called 1972 London Convention and follow ups (refer [14], [15], [16]).

As a general principle it can be stated: Abandoned or disused offshore installations are required to be removed, except where non-removal or partial removal is consistent with the applicable guidelines (related to each Country with related EEZ but to be agreed on for operations in the Arctic). The following has to be considered:

- All platforms installed at a water depth of less than 75 metres (100 metres if after 1st January 1998) and substructures weighing less than 4,000 tonnes in air must be entirely removed
- Installations installed at a water depth of more than 75 metres (100 metres if after 1st January 1998) may be partially removed subject to leaving a minimum clearance of 55 m
- After 1st of January 1998 no installation should be placed in the EEZ unless its design and construction is such that entire removal would be feasible

Thus, the obligation of removal is on the coastal State having jurisdiction over the installation. If it is decided to leave components on the seabed notification of non-removal or partial removal is to be forwarded to the IMO.

In this context it is important to note that placement of structures on the seabed for purposes other than disposal is considered NOT DUMPING (1972 London Convention).

The process of decommissioning includes the following steps:

- Complete shut-down, seal-off, disconnection, cutting, lifting
- Alternatively: Backfilling (e.g. pipelines, flowlines)
- Transport for cleaning, recycling, or wreckage
- Alternatively: Overhaul and re-commissioning -> increased viability of production even from marginal fields

These steps have to be considered and planned in detail in turn of a decommissioning and dismantling procedure of any subsea production facility – especially in the Arctic.

6.6 LONG STEP-OUT DISTANCES

It is most likely that subsea installations in the Arctic are used in very harsh environments with a high likeliness of occurring ice, icebergs or high waves with related icing, which otherwise would heavily influence any platform technology. Thus, it can be assumed that future step out distances will easily exceed 150 km with 1000 meters water depths or more.

These constraints influence the required technology needed to connect the submerged production sites with its onshore receiving plant and operator unit. The produced fluids are exported via pipelines after injection of flow assuring inhibitors or the pipelines are heated to guarantee satisfying flow, if required.

The following paragraphs deal with challenges with the supply of power, hydraulics and communication via long multipurpose subsea umbilicals (Figure 11-18).

6.6.1 Power Supply

An adequate power supply of the subsea production facilities is of great importance, especially when high water depths and long step out distances are considered.

Generally the following power sources are possible:

a) Electric energy is produced at onshore or offshore (topside) plants and send via multipurpose umbilical to the seafloor facilities (standard)

b) Hydraulic energy is produced at onshore or offshore (topside) plants and send via multipurpose umbilical to the seafloor facilities (standard)

c) Energy is subsea converted by means of turbo generators from high energetic produced fluids and distributed directly to consumers in the subsea production facility by means of infield cabling (not yet standard)

Nevertheless, the current dominating power supplies are typically AC with 400 Hz or 60 Hz at varying voltages up to 1000 VAC and more. It has to be considered that over long distances capacitance within the umbilical affect the power factor and can compromise the electrical power unit (EPU) design. In addition the impedance in AC circuits leads to increased dimensions of the cores resulting in increased weight and costs for the umbilicals. This phenomenon can be reduced by using DC power supplies which might reduce the costs for the umbilicals and the EPU design. On the other hand DC power has drawbacks including possibly reduced cable and connector ratings and the electronics required to perform the subsea regulation.

6.6.2 Hydraulic Supply

In a lot of today's standard supply configurations for control of subsea valves etc. hydraulic fluid is used. Unfortunately hydraulic fluid has major drawbacks so that modern concepts tend to work with electro-hydraulic systems where the local action is activated by electrical power driving low power pumps for charging accumulators. The most modern concepts do not include hydraulics at all (so called 'All Electric' systems, refer paragraph 9.1).

One problem is the standard design of open loops, where hydraulic fluid is vented to the environment after use. This pollution problem can be reduced by closed loop designs, which heavily rely on the availability of the components in the loop, which can only be guaranteed by a high level of redundancy, because subsea HPU have limited access for maintenance and repair.

Another problem with hydraulic fluids is their stability over time, which becomes an issue especially with long step out distances where it is likely that fluid entering the umbilical will never be used during the whole lifetime of the plant (25 years or more; also depending on the step out distance and the number of consumers at the seafloor)!

6.6.3 Communication

It is essential to communicate with the UWPS for monitoring and control of the production process. Standard technology uses copper lines in the umbilical to communicate with 1200, 9600 or 19200 baud. The transfer distance for this technology is typically limited to a distance of approx. 100 km with repeater or amplifier modules. Compared to that communication over distances of 200 km and more with data rates up to Gigabit/s or more with high bandwidth can be achieved by using fibre optics. Thus, they are typically used between shore and the first subsea distribution assembly in the subsea field. As fibre optics is highly immune to most levels of electric noise it can be expected that they will be also used to interconnect the subsea components to the SDA in near future.

Problems with the use of fibre optics can be identified for wet mate connectors and the sensitive fibre handling on board the cable lay vessels and during lay-down to the seafloor.

6.7 OPENNESS AND MODULARITY

As several projects show open system architecture and modular design provide the best flexibility to cope with component upgrades or enhancements, e.g. change from copper to fibre optics, increase of the number of wells and manifolds. This openness and modularity has to comprise the software and hardware with its interfaces to the system as both have to be ready to be adapted, if necessary. Thus, it has to be guaranteed that interfaces are standard or made open to the market/to the client.

The advantageous can be summarized as follows:

- the modules can be independently developed and tested with modern ‚in the loop‘ strategies prior to tests after assembly
- it should be possible to combine modules or components case dependent or following a best of class strategy
- the UWPS would be open for future expansions, which might be delivered by alternative suppliers
- the modules and components can be better integrated in existing UWPS

7 MAIN COMPONENTS AND PROCEDURES

A main constraint and challenge of (deepwater) subsea facilities is that it must be possible to install, test, operate, maintain and dismantle them at the seafloor. Direct human intervention is not possible due to water depths reaching up to 1,500m in the Arctic. Thus, it must be possible to perform or assist these tasks by means of remotely operated vehicles (ROV) and / or autonomous underwater vehicles (AUV), see Figure 11-17.

In addition, very long lifecycles are often required as each of these operations is very expensive, mostly due to high day rates of the related installation vessels. Challenges like high inner and outer pressures, high inner and low outer temperatures, corrosion, fouling etc. have to be handled by each single component of a subsea facility.

These constraints influence several important design aspects e.g. choice of materials, modularity, autonomy, redundancy, and (remote) controllability.

The following kernel components are relevant for (subsea) production facilities:

7.1 DOWNHOLE INSTRUMENTATION

Already while drilling a measurement of density, pressure, temperature and particularly drilling parameters such as direction, rotational speed, vibration, etc. will be executed in the borehole (so called ‘Measurement While Drilling’).

Monitoring and maintenance of the planned production values is a main focus within operations. Aim is to early detect critical production parameters and /or bad influences on the production flow e.g. by the controlled gas injection within the gas lift procedure. A number of sensors and valves will be used in order to stop the inlet gas flow in an emergency (emergency shut-down, ESD).

7.2 WELLHEADS, XMAS TREES AND VALVES

In order to provide a safe shut down procedure, case specific and target-configured wellheads will be permanently installed within the well piping (Xmas trees, Xtree) and connected via the wellheads’ flanges. The wellheads are provided with remotely operated shut down valves, chokes, actuators, sensors and in most cases also armature for the injection of chemicals into the flow (anti-hydrant-inhibitors, anti-corrosion-inhibitors, anti-paraffin-inhibitors, etc.). These inhibitors are often configured for different working pressures – standard values are 35 MPa (5,000 psi), 70 MPa (10,000 psi) and 104 MPa (15,000 psi).

The configuration of the shut-down valves plays an important role in any HIPPS architecture (High-Integrity Pressure Protection System). There, valve barriers are provided within boreholes to secure the low pressure UWPS facility units e.g. against the high head pressure (shut-in tubing head pressure, SITHP). Thus, the implementation of the HIPPS is as a result of the actual risk assessment which is a core element for the classification of the UWPS according to the selected Safety Integrity Level (SIL).

Specialized remote-controlled valves must be operable from “outside” via ROV, which means they have to be operable without an electrical or a hydraulic actuation (override).

7.3 PROCESSING UNITS

The treatment facilities for the produced fluids should be ideally located close to the wellhead. Treatment comprises division of solids, fluid phase separation and possibly also dehydration. Also slug prevention and control systems belong to the processing issues. Slugs are defined in this context as big volumes of gathered liquids.

As a result of minor availability of UW-Systems these processing units are often designed to work on surface platforms. Nevertheless, a few modern systems can already be installed directly in the area of the UW-wellheads. An early treatment of the fluids significantly improves the transportability and reduces the wear-out within the transport chain as well.

Important processing units are as follows:

- Raw seawater injectors
- gas/liquid separators and liquid pumps
- two or three phase gravity separators

7.4 FLOW ASSURANCE ITEMS

To assure better flow characteristics of the extracted fluids either UW-Systems like separators and compressors or supplementary equipment like valves could be used. In the second case depending on the physical and chemical characteristics of the extracted fluids the chemicals such as glycol (MEG) will be injected through dedicated valves. Depending on the given conditions following results can be achieved within the pipeline by using inhibitors:

- prevention of the formation of hydrate (anti-hydrate-inhibitors)
- prevention of the paraffin precipitation (anti-paraffin-inhibitors)
- corrosion prevention (anti-corrosion-inhibitors).

Important flow assuring sub-systems are as follows:

- multiphase pumps
- gas/liquid separators and liquid pumps
- dry or wet gas compressors

7.5 MANIFOLDS AND TEMPLATES

The produced fluids as well as chemicals for injection are transported to the central collection- and distribution stations (manifolds) via so called infield pipelines (pipes of relatively small inner diameter). The consolidated production flows are further transported via large bore export pipelines while process fluids are distributed to the single wells.

Depending on the flow volume and type of the manifolds to be installed so called templates are used as landing base on the seabed. These templates are fixed to the bottom either via long piles or suction cans. The modular manifolds are installed on them (see Figure 11-14 and Figure 11-17).

The UW manifolds are equipped with remotely and/or ROV-operated shutdown and control valves. The remote control is executed via motor-driven actuators. The actual valve position is detected by location indicators; the signal is sent to the Control Room (CR) via transmitter.

To simplify the installation process and to provide modular replaceability of pipe segments, Pipeline End Terminals (PLET) are installed, which provide plug-in connectors for the pipelines and jumpers.

The valves installed on PLETs are normally not used during standard operation. Thus, they are mostly not remotely controllable from the CR but by means of ROV on demand.

7.6 MONITORING AND ASSET MANAGEMENT

All sensor data are tracked and stored in a database, managed via Control System and displayed for further analysis by the Operators via the SCADA environment. In order to reduce the amount of data and to facilitate the analysis of the data a pre-defined process image is automatically prepared out of the most relevant data by the Control System. Thus, the monitoring system is an integral part of the control system.

The monitoring comprises process parameters of the production (the fluid flow regime), the hardware and software ‘health’ condition as well as – in modern concepts – environmental data received from dedicated sensors in the neighborhood of the subsea facility, e.g. gas/oil in water sensors. In order to get the most out of the different sensors data cross correlation allows superposition of related data.

An automated data analysis scheme allows comparing with and adjustments to given or required conditions, such as different time frames and data volume. To achieve this goal the data are pre-processed in each local Subsea Control Module (SCM) and finally transferred to the overall Asset Management System. This Asset Management System might be located on the producing vessel or in an onshore facility. Network technology allows integrating specialists which might be located in a totally different place like e.g. the world engineering headquarter.

The following paragraphs describe different exemplary subsea developments made for remote subsea locations.

8 EXAMPLES

8.1 SNØHVIT

The Snøhvit development comprises three fields – Snøhvit, Albatross and Askeladd. These fields lie in the Barents Sea, about 143 km north-west of Hammerfest in northern Norway (Figure 11-2, Figure 11-3). The fields were discovered in 1984 in 250-345 m of water and extend across seven production licences. Due to the harsh environmental conditions in this area it was decided to develop these fields by means of subsea technology without surface piercing installations like fixed or floating platforms (Figure 11-7). The produced gas is transferred via 143 km long export pipelines to the onshore gas receiving and LNG plant at Melkøya Island near Hammerfest. Export of the processed and liquefied gas takes place via scheduled LNG carriers.

The production at Snøhvit is considered to be one of the most environmental friendliest as the produced CO_2 is pressed back to the reservoir in turn of a CCS process (refer [7] for details).

8.1.1 Main Characteristics

These are the key data of the Snøhvit development (refer [3], [4]):

• Ownership	Snøhvit is jointly owned by	
	operator Statoil AS	(36.79% stake), as well as
	Petoro AS	(30% stake),
	Total E&P Norge AS	(18.4% stake),
	GDF SUEZ E&P Norge AS	(12% stake),
	RWE Dea Norge AS	(2.81% stake)
• Location	Barents Sea, 143 km north-west of Hammerfest	
• Discovery	1984	
• Water depth	250-345 m	
• Fields	3: Snøhvit, Albatross and Askeladd	
• Wells	20 (in total for all three fields)	
• Production	Subsea	
• Production started	2007	
• Liquefaction plant	Barge (integrated in Melkøya onshore facility) (dimensions: 9 m high, 154 m long, 54 m wide)	
• Process equipment	24,000t	
• Speciality	reduced emissions due to Carbon Capture (at onshore facility) and Storage (CCS) in a 2,600 m-deep sandstone formation at Snøhvit	
• Pipeline	143 km gas line, 68 cm ID (29-inch) 2 chemical lines (5-inch) umbilical 153 km CO_2 disposal pipeline (9-inch, for CCS)	

•	Reserves	193 billion cubic meters of natural gas 17.9 million cubic meters of condensate 5.1 million tonnes of natural gas liquids (NGL)
•	Annual exports	5.75 billion cubic meters of LNG 747,000 tonnes of condensate 247,000 tonnes of liquefied petroleum gases (LPG)
•	Estimated investment	Nkr 53.1 bn (abt. 6.67 bn EUR) summing up from: Nkr 34.2 bn (abt. 4.29 bn EUR) (field development, pipeline, onshore plant) Nkr 18.9 bn (abt. 2.37 bn EUR) (ships: LNG carrier, tugs etc.)

Further information can be derived e.g. from [5] for online general information about Norwegian Oil and Gas recovery activities.

8.1.2 Product Receiving Plant

The product receiving and treatment plant for the Snøhvit subsea field is located at the island of Melkøya, north Norway close to Hammerfest (Figure 11-4, Figure 11-7). Parts of the rocky island have been artificially modified in order to provide the flat spaces for constructing the gas treatment facilities. The whole island of Melkøya has been occupied for the plant with an area of abt. 0.7 km².

The LNG process technology (the so called Coldbox technology designed and delivered by the German company Linde) has been built in various vendors places around Europe. These have been transported to the assembly site at a yard in Spain. Here a self-floating barge was fully equipped and commissioned with the cooling facility. The barge was then delivered by a heavy load vessel in an approx. 5000 km voyage to the operating site at Melkøya (Figure 11-6). Here an artificial harbour like site was prepared where the barge was floated in and landed for final settling. After landing the 'harbour' was closed again to provide protection against the seawater. Thus, the assembly site and the final operation site were different resulting in significant cost savings compared to an assembly scenario with Arctic constraints (Figure 11-5).

The produced fluids are added at the wellheads by antifreeze inhibitors to prevent the flow from ice plugging due to high pressures and low temperatures in the wellstream. If required pipeline heating can be additionally used. Nevertheless, the production at Snøhvit is considered to be very environmentally friendly as the produced CO_2 is captured at the receiving plant and send back for storage to the formation, which is called CCS.

8.1.2.1 Operation Support Centre

The operation of the Snøhvit gas receiving and LNG cooling plant is realised with a permanent crew of abt. 200 persons. The highly expert crew must be regularly exchanged and reliably provided with daily consumables. Also the process plant must be occasionally provided with spare parts and continuously with consumables for production purposes like flow assuring fluids.

8.2 THE WDDM CONCESSION

The multi-phase deepwater gas fields development in the West Delta Deep Marine (WDDM) concession off Alexandria (Egypt) was the first such project offshore Egypt, an area with no experience in deepwater developments and with little associated infrastructure (). The development was pioneering as it was one of the longest tie-backs to shore at this time (90 km), initially from the Scarab /Saffron fields.

Since the first development phase the work alongside Burullus Gas was continued reaching a tie-back distance from shore of 124 km (!) and a maximum water depth of 1024 m.

The gas fields have been developed in several Phases (with tasks within phases):

- Phase 1: Fields Scarab / Saffron
    - subsea trees down to 610 m — 8
    - manifolds in 415 m — 2
    - PLEM for expansion
    - SDA — 1
    - 1 hydraulic and 1 electrical umbilical — each 83 km
    - infield umbilicals — 42 km
    - Pipeline (shore to PLEM) — 65 km 36"
    - Pipeline (shore to PLEM) — 65 km 24"
    - Pipeline (PLEM to field) — 38 km 20"
    - infield pipeline — 42 km 10"
    - MEG pipeline — 83 km 4"
- Phase 2+3: Fields Simian / Sienna and Sapphire
    - subsea trees down to 1024 m — 16
    - manifolds, 1 at 120 m & 1 at 925 m & 2 at 310 m — 4
    - Tie-in manifolds to PLEM — 2
    - SDA — 2
    - control platform — 1
    - main umbilical from control platform — 77 km
    - infield umbilical — 87 km
    - pipeline (field centres to PLEM) — 57 km 26"
    - pipeline manifold to manifold (Phase II) — 7 km 20"
    - infield pipeline — 75 km 10"
    - MEG pipeline (field centres to shore) — 196 km 4"
    - vent pipeline (field centres to PLEM) — 62 km 4"
- Phase 5: Fields Scarab / Saffron expansion
    - subsea trees down to 770 m — 7
    - manifolds at 415 m — 2
    - Tie in Spool Bases — 3
    - SDA — 1
    - Infield umbilical — 66 km

- Infield Pipeline 66 km 10"

- Phase 6: Field Sequoia joint development
  - subsea trees down to 500 m (3 on WDDM) 6
  - manifolds (1 on WDDM) 2
  - SDAs (1 on WDDM) 2
  - Export pipeline / main umbilical (all on Rosetta) 24 km x 22"
  - Infield flowlines (11 km on WDDM) 30 km x 10"
- Summary: Current status
  - Xmas trees 34
  - Manifolds 9
  - Subsea distribution Assemblies 4
  - Umbilicals 396 km
  - Pipeline (36") 65 km
  - Pipeline (26") 57 km
  - Pipeline (24") 65 km
  - Pipeline (20") 45 km
  - Pipeline (10") 194 km
  - Pipeline Vent (4") 62 km
  - Pipeline MEG (4") 279 km
  - different subsea control systems 2
  - different umbilical manufacturers 3
  - different installation contractors 3

8.2.1 Main Characteristics

These are the key data of the developments for the WDDM concession (refer [6]):

• Ownership	the WDDM concession is operated by Burullus Gas Co., which is a joint venture of Egyptian Gen. Petrol. Co (50% stake), BG-Egypt SA (25% stake), Petronas Carigali (25% stake)
• Location	Mediterranean Sea, abt. 65 km north-east of Alexandria
• Discovery	before 1999
• Water depth	300-1024 m
• Fields	8: Scarab, Saffron, Simian, Sienna, Sapphire, Serpent, Sequoia, Saurus
• Wells	34 (in total)
• Production	Subsea
• Production started in six phases	2003 (Scarab / Saffron) 2005 (Simian / Sienna)

	2005 (Sapphire) ? Sequoia
• Liquefaction plant	located at Idku, near Alexandria
• Speciality	each development phase was accompanied by another or a changing control system supplier (Aker Solutions, Vetco Gray, Cameron)
• Reserves	NN
• Annual exports	Scarab / Saffron: 700 MMSCFD Simian / Sienna: 150 MMSCFD Sapphire: 1.400 MMSCFD Sequoia: NN
• Estimated investment	NN

8.2.2 Future developments

In the future significant further extensions are planned leading to the following total of (refer [6]):

o Xmas trees (wells)	64
o Manifolds	15
o Subsea distribution Assemblies	9
o Umbilicals	616 km
o Pipeline (36”)	65 km
o Pipeline (26”)	57 km
o Pipeline (24”)	65 km
o Pipeline (20”)	45 km
o Pipeline (10”)	413 km
o Pipeline Vent (4”)	65 km
o Pipeline MEG (4”)	288 km

8.2.3 Product Receiving Plant

The produced fluids are exported and treated at an onshore receiving plant where the treated gas is cooled down to minus 162°C. The resulting LNG is stored in cryogenic tanks.

8.2.3.1 Operation Support Center

No further information available.

9 LEADING EDGE TECHNOLOGY

The following specific fields of technology are currently under development and will definitely be used in the near future. They offer advantages in terms of monitoring issues, control issues and, utmost important, environmental friendliness. By using these technologies it becomes possible to move production into ever deeper waters and towards ever larger step-out distances to shore while maintaining full control over each relevant function and production parameter in 'real time'.

The overall goal is to enable the 'subsea factory' where major (if not all) relevant process modules are relocated from platforms to seabed. Key technological issues are briefly described in the following paragraphs (for basic introduction please refer paragraph 7).

9.1 ALL-ELECTRIC SYSTEMS

The so called all-electric (subsea) systems are characterized by the general absence of hydraulic control fluids, which are today almost always used to operate e.g. actuators and valves. Thus, all-electric subsea developments are classified as environmentally sound because no hydraulic fluid will be released to the environment, neither in turn of standard venting procedures nor in turn of accidental leakages.

All-electric technology is well suited for a large number of subsea applications:

- Long distance tiebacks
- Water injection wells
- Chokes
- Manifold valves
- Valve actuator retrofits
- Process control valves for subsea separation
- Anti-surge valves for subsea gas compression

The most important advantages of all-electric systems are:

- They can be used with high voltage DC allowing to reach the mentioned long step-out distance (≥200km); when used with AC step-out distances ≤200km can be reached
- DC power results in a reduced cable diameter (single phase compared to three phase required for AC), which in turn results in a reduced dimension and weight of the umbilical
- DC power provides an efficiency of 80-90% compared to AC power with less than 20% efficiency
- the use of electric energy instead of hydraulic allows removing the hydraulic hoses from the umbilical, resulting in reduced cable storage and lay capacity of the installation vessel and thus smaller (less expensive) lay-vessels
- all-electric umbilical are significantly cheaper in CAPEX and OPEX as there is no need for hydraulic control fluid and high pressure units (HPU) to feed in

9.2 SUBSEA PROCESSING

The term 'subsea processing' will at least comprise subsea phase separation, subsea pumping and boosting, and subsea gas compression.

9.2.1 Subsea Separation

Most important separation technology includes:

- Gas-liquid separation
- Oil-water separation
- Three phase separation (oil, gas, water)
- Primary separation
- Secondary separation
- Treatment of the produced water
- Greenfield (new designed facilities) and brownfield (existing facilities) application

Major advantages of subsea separation technology are (Ref. [9]):

- Enables viability of challenging reservoirs
- Accelerates and increases production and recovery
- Prolongs the economic life of a field
- Handles water and sand at the seabed, therefore, reduces the potential costs associated with a topside facility
- Provides a flexible solution with a broad operating envelope for a wide range of gas-liquid fraction operating conditions
- Typically safer and demonstrates less environmental impact, compared to a topside installation
- Debottlenecks flowlines, risers and topsides
- Effective solution for flow assurance challenges
- Demobilization of topsides facilities that may have limited remaining life (thereby avoiding potential integrity and operating cost challenges) and transport of fluids to other hosts with longer remaining life

9.2.2 Subsea Pumping and Boosting

The use of subsea boosting technology enables, on one hand, to accelerate the reach of a certain production plateau and, on the other hand, the prolongation of production on a certain plateau, especially for economically marginal subsea fields. The technology allows to tieback remote fields to existing production facilities, either subsea export pipelines or platforms.

Today are three multiphase pump technologies available, for seabed application prevailing is the helicoaxial technology, followed by the twin-screw technology with fewer applications and finally the ESP (Electric Submersible Pump). ESP are installed directly in the well and operated as stand-alone application or in combination with seabed booster pumps (dual-boost concept).

Subsea multiphase pumps provide enhanced hydrocarbon recovery in various applications (Ref. [11]):

- Improve production profiles and maximize production plateau
- Increase the reach of satellite fields (increase efficiency of existing infrastructure)
- Increase the production rate or even the recoverable reserves
- Maintain production rates at increased water cuts
- Balance wellhead performance from comingled multi-well or multi-template field designs
- Inject raw seawater at reservoir pressure
- Inject produced water, reducing load on topside water handling equipment (advantageous for floating production platforms like e.g. FLNG, FPSO)

9.2.3 Subsea Gas Compression

Gas compression is widely used in onshore applications when the well stream has been phase separated in oil, gas, water and solids and the different phases can be boosted with the specific most efficient technology. Nevertheless, when it comes to subsea application gas compression is not yet often used. This is caused by the significant higher complexity of the subsea gas compression facilities when designed to provide drastically increased maintenance intervals. Another reason is that gas compression requires pre-processing of the well stream by a separation unit, which also was not available in the last years. This will change in the near future resulting in an increased use of this type boosting technology.

9.3 SUBSEA POWER TRANSMISSION AND DISTRIBUTION

The need to get more power to more consumers at wide distributed locations at the seabed poses a major challenge to technology suppliers. The cost-efficiency and reliability of each solution heavily influences the acceptance of electrically driven systems.

Latest electric subsea developments utilize existing low to medium (AC) voltage umbilical and connector technology providing a safer operating environment and prevent corrosion from stray high-voltage currents (Ref. [9]). This technology reduces costs for topside power generation, transformer equipment and umbilical, and components are adaptable to upgrade existing systems. The technology uses standard subsea cables and connectors along with rechargeable subsea batteries to power valve and actuator operations, so no high-power/ high-voltage cables from the surface might be needed.

A suitable (subsea) power system comprises transformers, switchgears, variable speed drives (VSD) and a power control and communication system, which all have to be qualified to work up to 30 years in up to 3000 m water depth (Ref. [10]). Today's concepts consider step-out distances up to 200 km to be reached by AC power transmission – for longer step-out distances DC power would be used providing better efficiency (80-90%) compared to AC (less than 20% with).

To allow the subsea modules to work in these depths they will be oil filled and thus pressure balanced. In addition the windings will be separated and insulated; the surrounding sea water allows for natural cooling.

10 CONCLUSION

Exploration and production of hydrocarbons (and other resources) from subsea reservoirs is a major field of development since several years. Aim is to get access to resources located in areas with harsh environments characterized by heavy storms, ice and drifting icebergs but also in deepwater (>500 m water depth) or even in ultra-deepwater (>1500 m water depth) with step-out distances up to 200 km and more. It must be expected that this tendency holds on in order to conquer also the Arctic when suitable technology becomes available.

To achieve this, an increasing number of sophisticated technologies are under development, allowing planning the 'subsea factory' (Figure 11-20). This factory comprises all modules required to operate and support subsea production like energy supply, processing, treatment, storage, flow assurance, export etc. directly at the seafloor. The development and qualification of the required technologies are goals of a small number of globally acting high-tech companies with capacity to develop, test and maintain these expensive modules (hardware and software) with appropriate level of risk mitigation, which is especially required in the sensitive Arctic region.

The Report summarizes the main modules needed to build the 'subsea factory' and gives examples for today's most advanced comparable realizations with step-out distances of up to 145 km. Upcoming leading edge technologies are briefly outlined in order to sketch near future developments.

<u>Added in Revision B:</u>

- The shipping part of decommissioning and dismantling of offshore and subsea facilities follows Rules given by the IMO organization: The 'Polar Code', which is under preparation by IMO, covers the full range of design, construction, equipment, operational, training, search and rescue and environmental protection matters relevant to ships operating in the inhospitable waters surrounding the two poles (refer [12]). This also includes vessels and platforms used to install, maintain and dismantle subsea production facilities. The current draft Polar Code includes mandatory measures covering safety part (part I-A) and pollution prevention (part II-A) and recommendatory provisions for both (parts I-B and II-B).
- Refer Paragraph 6.5 for details of Rules and Regulations relevant for the justification of decommissioning and dismantling of offshore and subsea facilities.
- Recommendations for governance issues should focus on the above mentioned Rules and Regulations for shipping, decommissioning and dismantling operations in Arctic waters. Special emphasis should be laid on the clarification of EEZ matters and the applicability of the Rules in offshore areas (UNCLOS) and disputed areas.
- Concerning technical items (and many other related disciplines) it must be clear that any extension of offshore resource extraction activities in the Arctic will be closely accompanied by further development of land based supporting infrastructure and human activities. Or with other words, no offshore – and even no subsea - facility without appropriate onshore backbone, resulting in the need for an adequate coverage of related governing issues.

11 REFERENCES

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[15] 1996 Protocol, Amendment to the 1972 London Convention

[16] 2000 London Convention: *Guidelines for the Assessment of Wastes and other Matter that May be Considered for Dumping*, London, 2000

ANNEX

Annex A Images

Annex A Images

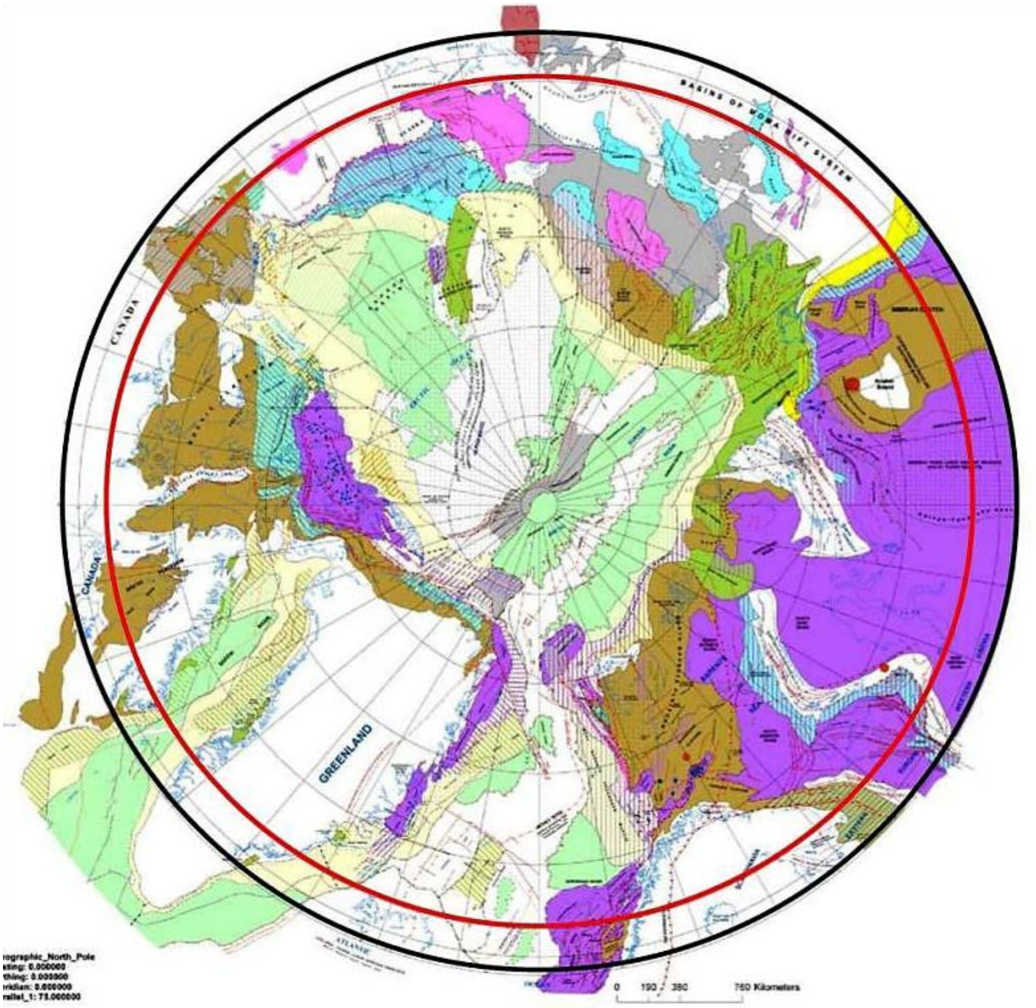

Figure 11-1: The Arctic circle (red) circumferences the geologic area of interest for ACCESS

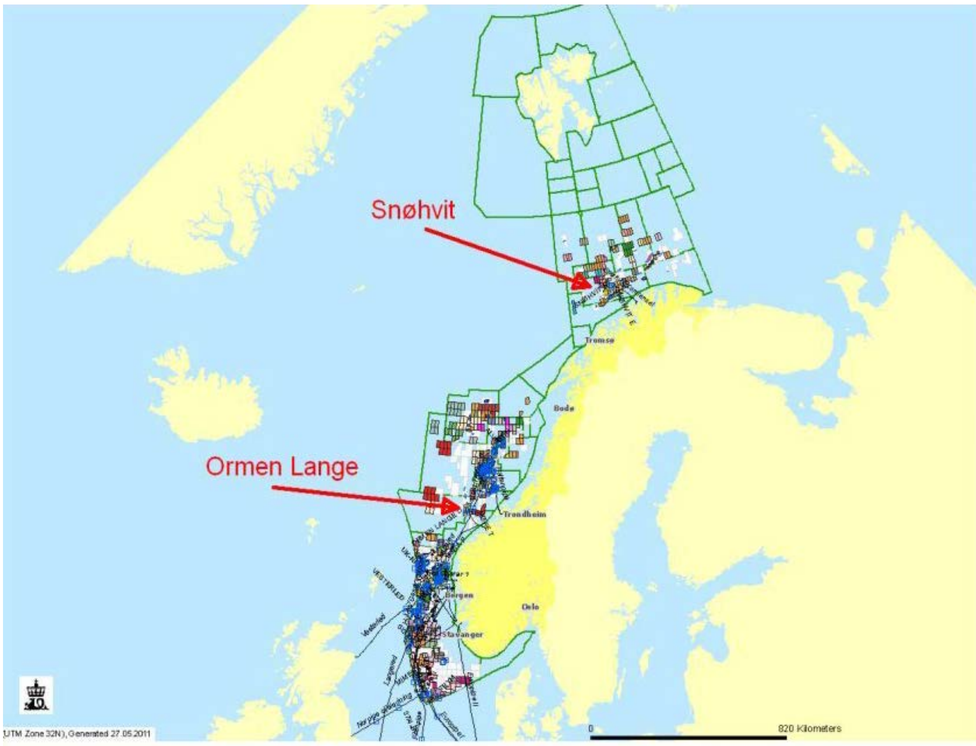

Figure 11-2: Location of the subsea developments *Ormen Lange* and *Snøhvit* offshore Norway and boundaries of current Norwegian offshore prospects (refer [5])

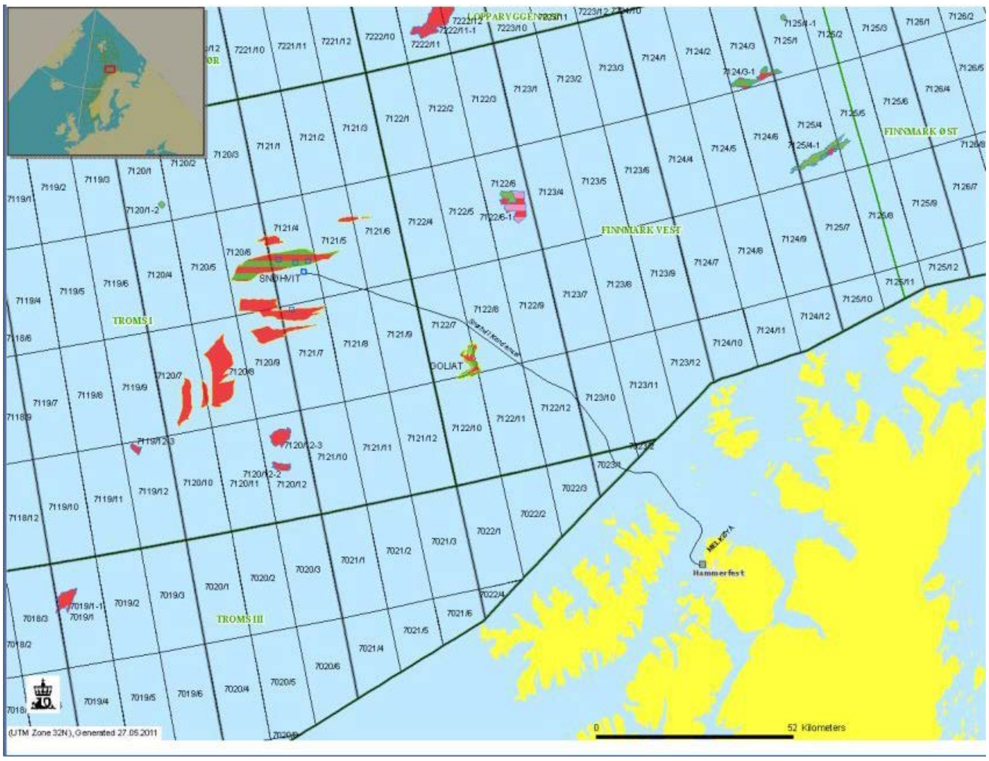

Figure 11-3: Location of the *Snøhvit* subsea reservoir offshore Hammerfest, Norway (refer [5][3])

Figure 11-4: Melkøya Island near Hammerfest, Norway, prior to construction of the *Snøhvit* plant (Statoil)

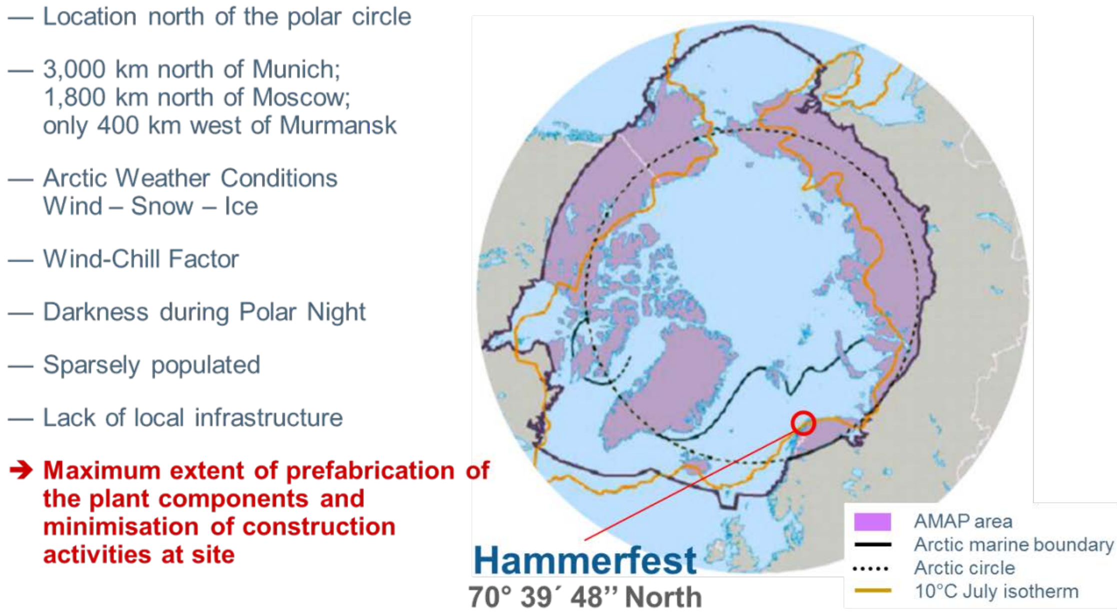

Figure 11-5: Arctic constraints significantly dominated the *Snøhvit* project development plan (refer [8])

Figure 11-6: Travel of the barge with the Coldbox LNG plant technology on top of a heavy load carrier vessel to Melkøya Island (Linde, Germany)

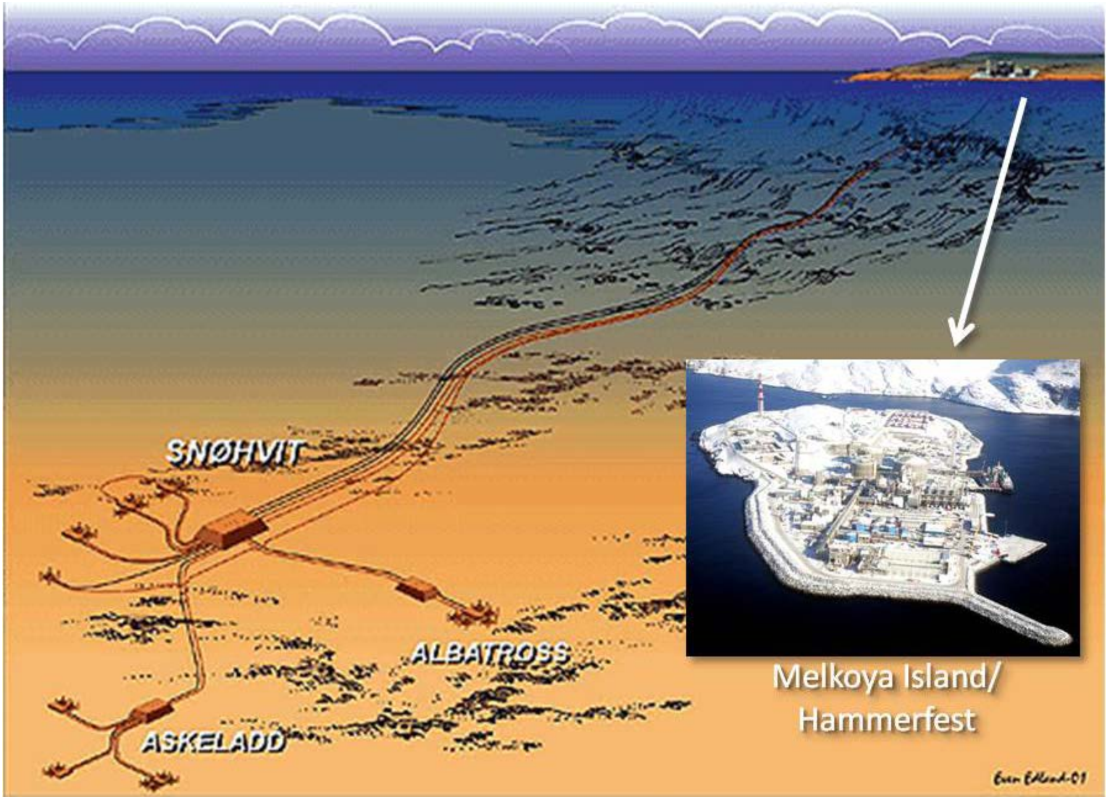

Figure 11-7: Artist impression of the *Snøhvit* subsea development with related onshore gas receiving and LNG plant at Melkøya Island, Norway (Statoil)

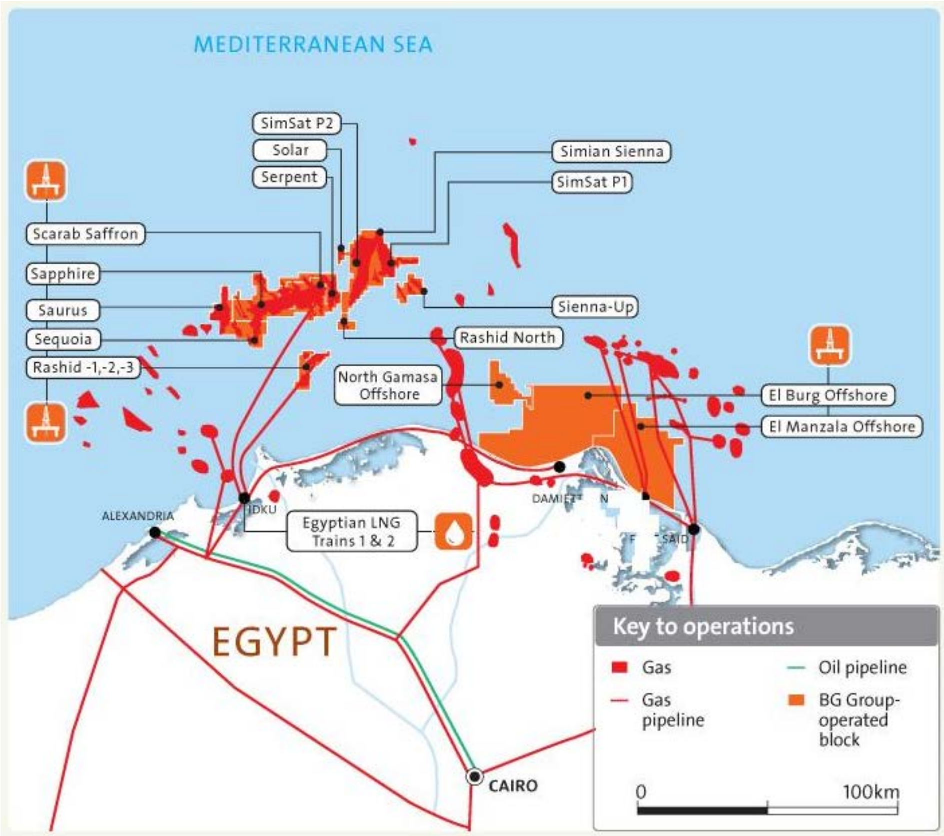

Figure 11-8: The multi-phased WDDM development offshore Egypt, (BG Group)

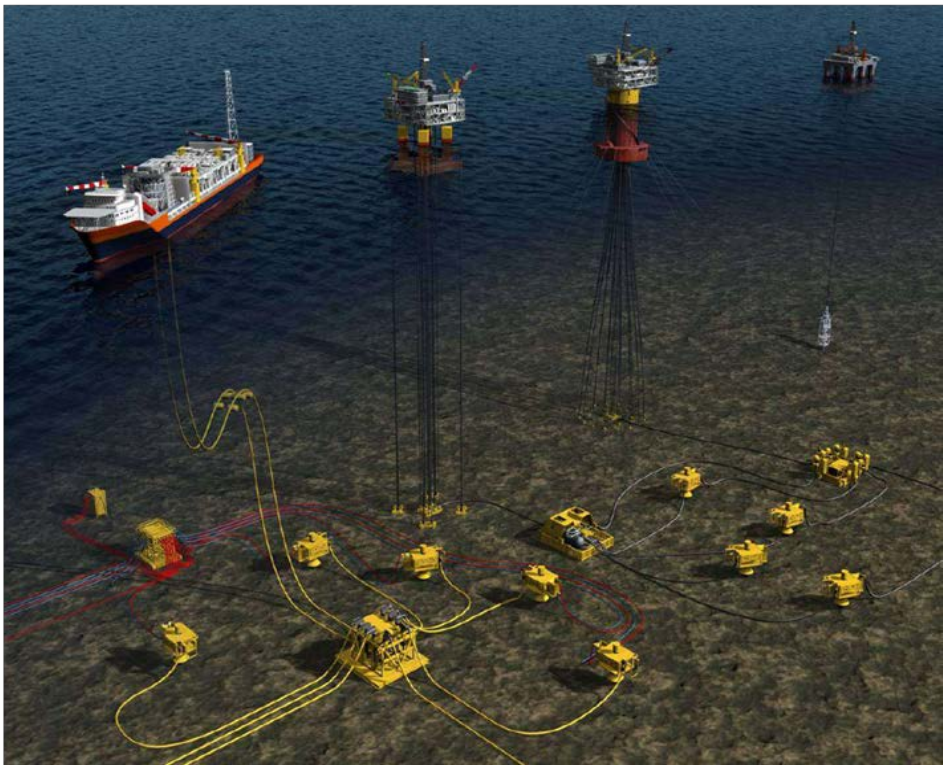

Figure 11-9: Subsea installations with relevant floating production units: (top, from left to right: FPSO, Tension Leg Platform, SPAR buoy, Semi-Submersible).

Figure 11-10: Drillship suitable for Arctic conditions 'Stena Drillmax' (www.aerialphotographer.com.sg)

Figure 11-11: Multipurpose construction vessel with crane load capacity up to 300 t

Figure 11-12: Super heavy-load construction vessel (semi-submersible ‘Thialf’) with crane capacity up to 14.000 t (2x 7.000 t, Heerema)

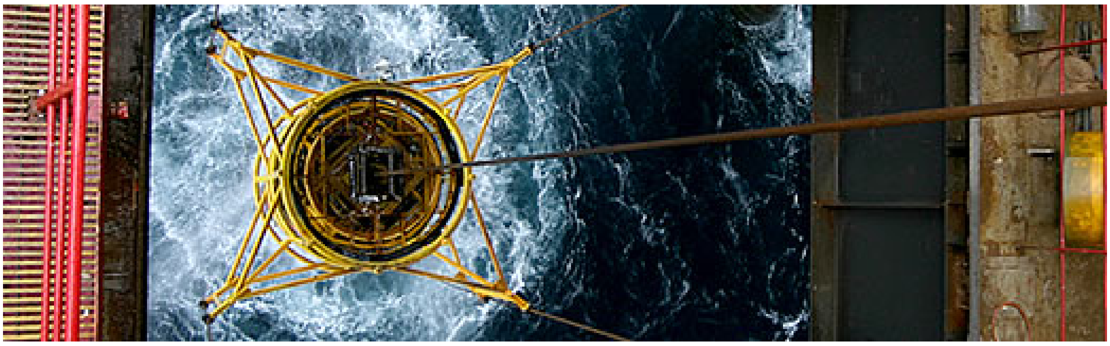

Figure 11-13: Subsea component lowered to the seafloor aided by guide wires

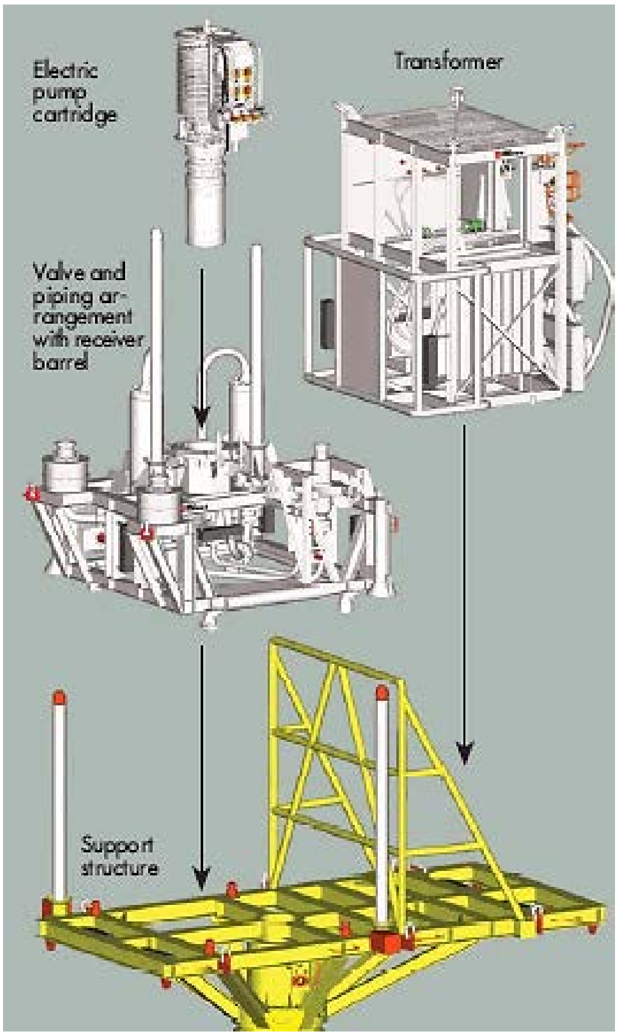

Figure 11-14: Subsea production component vertical assembly aided by guide posts

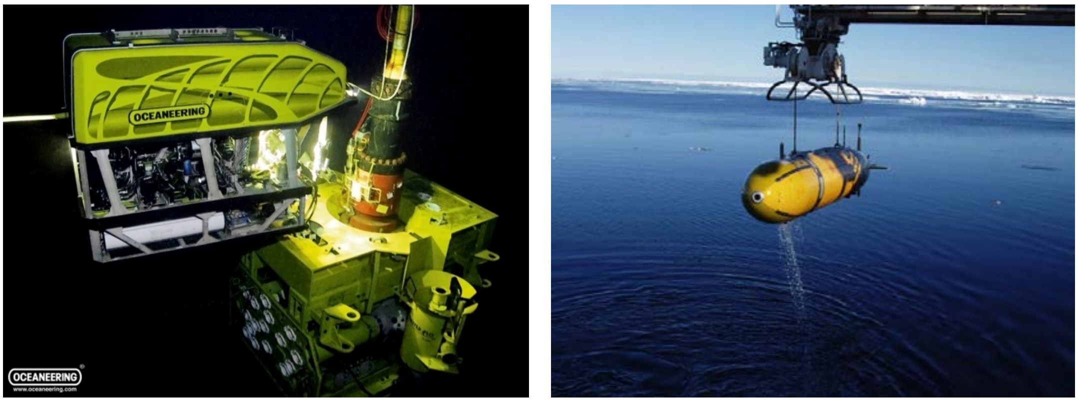

Figure 11-15: ROV at an XTree (left, Oceaneering) and AUV during launch for under ice survey (Autosub)

Figure 11-16: Two types of subsea completion (XTree, General Electrics)

Figure 11-17: Vertical installation of subsea spool pieces (artist impression, Aker Solutions)

Figure 11-18: Multipurpose subsea umbilical allowing transferring power, data and fluids over long distances

Figure 11-19: Cable lay vessel with dynamic positioning (DP)

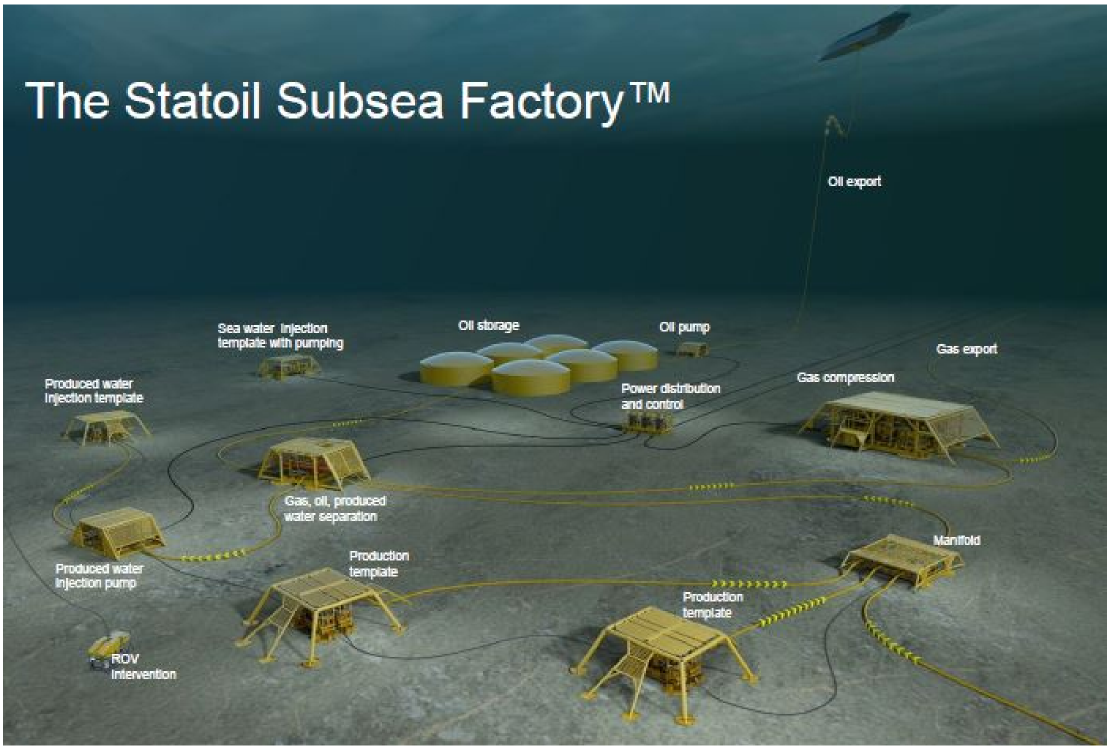

Figure 11-20: Vision of the Subsea Factory (Statoil)

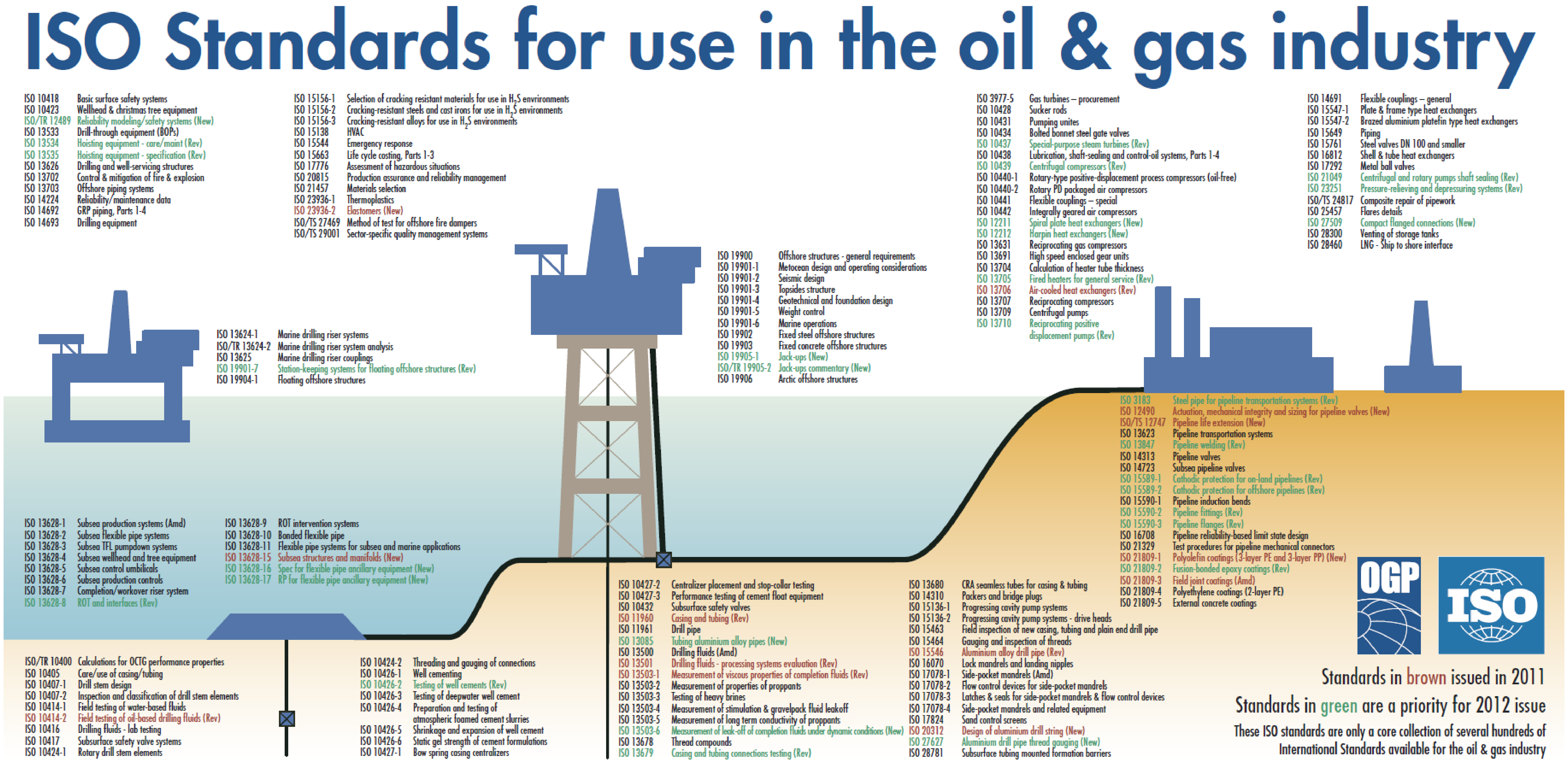

Figure 11-21: ISO Standards for use in the oil and gas industry