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Writer: Evgeny Pribytkov	………………………………………… (Writer's signature)
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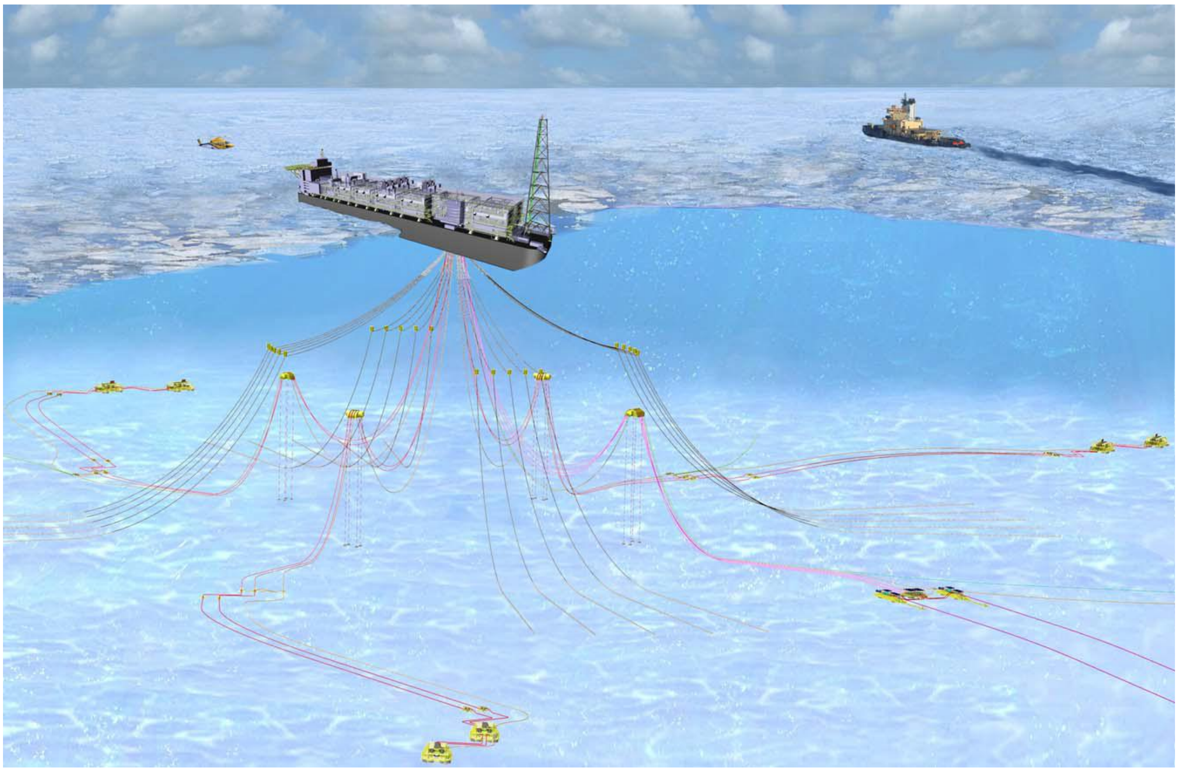


Selection of Integrated Template Structures for Shtokman Phase I Field Development

Master Thesis Spring 2013

Written by Evgeny Pribytkov

University of Stavanger

Gubkin Russian State University of Oil and Gas

Preface

During the spring semester of 2013 I have been writing my master thesis at the University of Stavanger. Writing this thesis was challenging for me because I had started my research work devoted to the Shtokman project in 2011.

This research topic is important since the Shtokman project is a part of the Russian government's strategy for the development of Russian Arctic. It is connected with the fact that the economically viable oil and gas fields deplete, therefore exploration and discovery head to other regions of the earth, such as the Arctic that hold valuable mineral deposits.

I would like to thank my supervisor Ove Tobias Gudmestad who has provided me with ideas and feedback during the writing of this thesis. I would also like to thank professors Anatoly Zolotukhin, Jonas Odland, Statoil ASA, Technip and Rambøll companies for the useful information, ideas and comments.

Selection of Integrated Template Structures for Shtokman Phase I Field Development

Evgeny Pribytkov, master student.

University of Stavanger

Abstract

In this thesis, an analysis of several functioning projects has been carried out, where their specifics were thoroughly studied and conclusions made. One of the important parts of the work was devoted to the requirements to integrated template structures conceived in relevant NORSOK, ISO and DNV standards.

The Main elements of Subsea Production Modules are considered in the work, their specific characteristics and components. Arctic metocean conditions that can affect selection, installation and the operational conditions of templates are analyzed.

Operations and installation of subsea modules at Shtokman location are considered in the Thesis. 4 scenarios with different numbers of integrated template structures (2, 3, 4 and 6) and different numbers of wellslots in each were suggested and analyzed. For each scenario an analysis of related marine operations for the subsea modules was carried out. A program for installation cost estimates was built that enabled us to find the optimal scenario for the integrated template structures design.

Various parameters affecting the cost of subsea infrastructure were analyzed and studied from different perspectives, e.g. geometrical well pattern system, the distance between drilling centers, drilling costs, etc.

Risk analysis regarding the threats and consequences is also performed; risk assessment matrices and mitigation actions are established.

As a result, a model for selecting an optimal Integrated Template Structure for the arctic/subarctic regions and Shtokman phase I field development was built.

Master thesis

Key words:

Integrated template structures, Subsea production systems, Arctic environment, offshore, marine operations, Shtokman, installation, cost benefit analysis.

Table of content

List of abbreviations

ALARP – As low as reasonably possible
BOP – Blow Out Preventer
BTA – Bow Tie Analysis
CAPEX – Capital Expenditures
CDU – Control Distribution Unit
CMD – Corrosion Monitoring Device
CNG – Compressed Natural Gas
DP – Dynamic Positioning
EIA – Environmental Impact Assessment
ESHIA – Environmental, Social, and Health Impact Assessment
FDE – Field Development Evaluation Program
FEED – Front End Engineering Design
FPSO – Floating Production Storage Offloading vessel
HAZID – Hazard Identification
HSE – Health, Safety and Environment
ID – Inner Diameter
IMO – International Maritime Organization
IMR – Installation, Maintenance and Repair work
ISO – International Standard Organization
ITS – Integrated Template Structure
JRA – Job Risk Assessment
LDS – Leak Detection System
LNG – Liquefied Natural Gas
NORSOK – Norwegian Standards for Norwegian Continental Shelf
NPV – Net Present Value
OD – Outer Diameter
OPEX – Operational Expenditures
PLEM – Pipeline and Manifold
QRA – Quantitative Risk Analysis
RA – Risk Analysis
RFO – Ready for Operation
ROV – Remotely Operated Vehicle
SPS – Subsea Production System
SSVC – Semi-Submersible Vessel Crane
SWL – Safe Working Load
WOW – Waiting on Weather
XMT – Xmas Tree

List of figures

List of tables

1. Introduction

In this thesis an analysis of the selection of integrated template structures for Shtokman phase I field development is presented. The thesis describes the selection of optimal number, layout and structure of the subsea production system for the Shtokman project.

- To be a good engineer we have to know about the past experience. Terra Nova and White Rose on the Grand Banks of Newfoundland in Eastern Canada to Snøhvit in Northern Norway have been developed and one is preparing for future projects such as Goliat, and Skrugard in Northern Norway. These projects can be considered as true stepping stones towards oil and gas development in the arctic region and will be discussed at the beginning of the thesis.

- According to accumulated experience we could make future projects real. So, in the second part of my thesis I'm analyzing the Shtokman project and local environment. After these, data about the integrated template structures and requirements for the Arctic are provided in this thesis. The possible operational vessels for the installation procedures have been discussed.

- Risk analysis is supposed to be carried out before any operations. A part regarding risk analysis is included before the calculations.

- The consistent selection of the installation vessel for the arctic region is very important.

- The next part presents the analysis of the integrated template structures selection for the Shtokman phase I field development. This part is divided into two: installation costs and total expenditures.

- After the evaluation of marine operations, risk assessment during the ITS installation in the Barents Sea is presented in part 7.

- There is a conclusion at the end which gives us the most important details during the thesis writing.

The thesis describes the selection of the optimal number, layout and structure of the integrated template structure for the Shtokman project according to the Barents Sea environmental challenges.

2. Theory

2.1 Past experience

Some companies have conducted several subsea harsh environment projects over the last fourteen years, from Terra Nova and White Rose on the Grand Banks of Newfoundland in Eastern Canada to Snøhvit in Northern Norway. This part, based on operational experience, will provide an overview of the challenges faced working in Eastern Canada, in the Jeanne D'Arc Basin, offshore Sakhalin Island and in Northern Norway, with specific reference to experience gained on the following projects: Terra Nova; White Rose; White Rose North Amethyst Extension; Sakhalin II, Snøhvit. The lessons learned from operations in these harsh environments in remote locations can be used to better prepare for any future operations in the Arctic [1].

The Terra Nova Project was the first subarctic subsea project and was implemented from 1997 to 2001. It was the first projects that used large scale open glory hole construction for the iceberg protection and it was the first project that deployed a disconnectable riser system in a harsh environment [1].

The White Rose project was built with strong reference to lessons learned from Terra Nova. Furthermore, Offshore Sakhalin construction operations were successfully conducted with significant sea ice coverage. The experience from these projects is supposed to represent a base, which Shtokman development may build on [1].

Construction work offshore Northern Norway brings its own challenges and give lessons learned. The combination of wave, current, wind, fog, ice, soils and short season makes this a very unique area of the world to undertake offshore operations. And this knowledge should be implemented during the Shtokman development. In addition to the environmental challenges, Northern Norway, Eastern Canada and Sakhalin offer excellent examples of working in remote areas with a lack of significant infrastructure and supply chain [1].

This part of the thesis provides a point of reference for both operators and contractors looking to understand challenges for producing oil and gas in the Arctic and Sub-Arctic regions including: logistics, equipment specifications, installation planning, wellhead protection and the construction challenges and operations management within an environmental sensitive area. We will look at a number of projects:

- Sakhalin Island, 12" Pipeline Repair, Offshore Russia
- Terra Nova Riser, Flowline and Umbilical System, Offshore Newfoundland
- Terra Nova Glory Hole Construction, Offshore Newfoundland
- White Rose Subsea Production System, Offshore Newfoundland
- White Rose North Amethyst Extension, Offshore Newfoundland
- Snohvit Development, Offshore Norway

Each of these projects are located in what can be considered to be sub-arctic conditions and each project has provided valuable knowledge that can be applied to the future development of Shtokman project or another projects in the arctic and subarctic region [1].

2.1.1 Project descriptions

Sakhalin II is located 13-16 kilometers offshore the northeastern coast of the Sakhalin Island, Russia [1]. Sakhalin II project and the oil export pipeline 12" from the Molikpaq platform to an offloading buoy in the sea of Okhotsk is shown on figure 1.

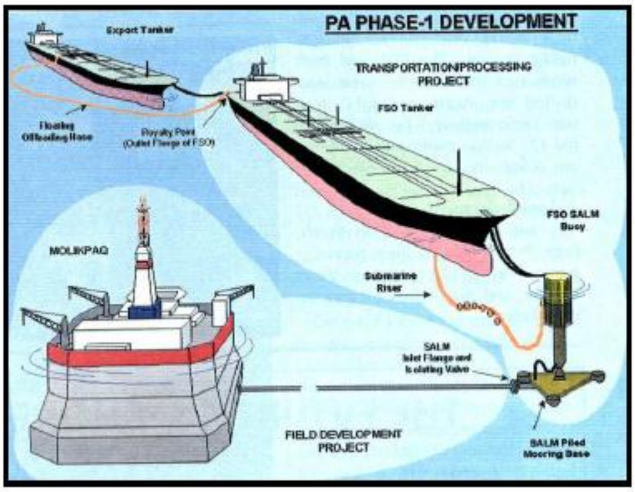


Figure 1 – Sakhalin II phase 1 development [1]

Terra Nova (Figure 2), located in the North Atlantic 350 km South East of St. John's, Newfoundland, was the first full field subsea development on the Grand Banks and the first FPSO to be deployed in North America. There are four subsea drill centers. Each drill center is linked by a flexible flowline / umbilical / riser system to the FPSO. Shtokman phase I has several similarities with this project scheme.

Figure 2 – Terra Nova field [1]

White Rose was the second FPSO development on the Grand Banks (figure 3). The White Rose development has benefited from many of the lessons learned from Terra Nova.

Figure 3 - White Rose field [1]

The lessons learned from both Terra Nova and White Rose were further utilized during the development of North Amethyst.

Some contractors and operators, such as Technip and Statoil, have experience working in the Barents Sea area through the Snøhvit project - the world's northern liquefied natural gas (LNG) project and the first major subsea development project north of the Arctic Circle.

Snøhvit is a gas field with a subsea tie-back to Melkoya which is the longest ever subsea tieback. It was completed in 2004 and 2005 in water depths from 18m to 440m, a key aspect was the work on the subsea tieback project to the LNG plant onshore (Figure 4) [2].

Figure 4 - Mobilization for the Snøhvit project [2]

There were many challenges to complete this project. These included:

- Remote location
- Lack of support infrastructure in the region
- Far North; Weather uncertainties and Polar Lows

- Complex logistics [1].

Indeed, Snøvit project was one of the most popular reference projects for engineers during the Shtokman front end engineering design (FEED) studies.

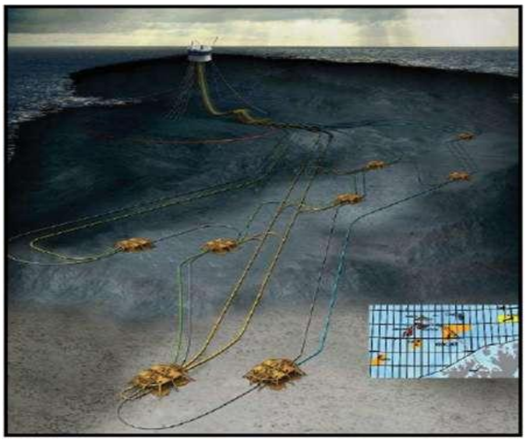


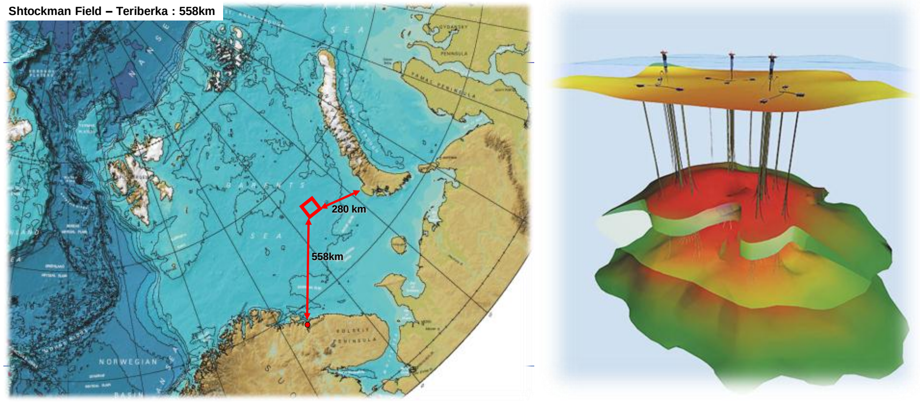
Figure 5 - The Goliat field lay out [2]

The experience gained during the Snøhvit project was used in ENI's Goliat project. The Goliat field (Figure 5) is located in the Barents Sea about 75 km North West of Hammerfest. Oil in the reservoir was found in year 2000. It is planned to start production in in 2013. The field will be developed with a FPSO and it will be the first platform in the area. The Snøhvit gas export pipeline passes by Goliat and is halfway between Snøhvit and the shore. The gas produced at Goliat will be re-injected into the Goliat reservoir; there are various alternatives for gas export, including Compressed Natural Gas (CNG) technology and export via a hot tap into the Snøhvit pipeline [2].

The Goliat project is located in an environmental sensitive area near the shore. It will be important to avoid any spillage to sea [2]. Again, this experience will be very important for the development in the Shtokman area, which is also significantly important for the petroleum industry.

2.2 Shtokman project

The Shtokman field (Figure 6) is one of the largest known offshore gas fields in the world and the challenges faced in bringing the field to production are significant. Discovered in 1988, the Shtokman gas condensate field lies in the central region of the Russian sector of the Barents Sea and approximately 558 km from the Kola Peninsula. The field lies in water depths up to 340 meters [3].



a **b**

Figure 6 – Shtokman project
a) The Shtokman field lay-out [3]; b) Dome-shaped anticline gas reservoir [4]

Originally it was planned to ship Shtokman's gas to the United States as liquefied natural gas. Later it was indicated by Gazprom that the majority of the produced natural gas would be sold to Europe via the Nord Stream pipeline. For this purpose, a pipeline from the Shtokman field to the Murmansk Oblast and further via Kola Peninsula to Volkhov in the Leningrad Oblast will have to be built. The LNG plant will be located near the village of Teriberka, about 100 kilometers north-east of Murmansk [3].

The field itself covers an area of 1,400 sq. km, and there are 4 reservoir layers with depths up to 2300m. Project life will be 50 years at the estimated production levels. Shtokman C1+C2 reserves, which are more than the world's annual total gas consumption, are estimated at 4 trillion cubic meters of gas and 37 million tons of gas condensate. The project will be developed in 3 phases. The LNG facilities were planned to provide a yield of 23.7 billion cubic meters of natural gas per annum [4].

The development cost for the first phase was estimated at $25bn and it was of course needed to get estimates for the economic assessment. But the total number of wells required to develop all 3 phases of Shtokman project will be 144, which breaks down to 134 production wells, three monitor wells and nine reserve wells [3].

2.3 Planned project infrastructure

The Shtokman gas reservoir is a big dome-shaped anticline spread over a very large area (48x35 km^2), about 2300 m below mud line. The main reservoir drive mechanism is pressure depletion; aquifer support is expected to be very limited. Three drill centers made up of 2 x 4-slot templates have been planned to be installed approximately 2km away from the FPSO. These 6 integrated template structures with 4 slots each would supply an overall gas production of about 71.2 MSm^3/d at wellhead (production for the Phase I). An equal production is targeted on a yearly basis with sixteen production wells (9 5/8" outer diameter - OD), plus four back-up wells (20 producing wells in the end). Two 16" outer diameter flowlines and two 14" inner diameter (ID) flexible risers provide the connection between each drill center and the FPSO.

From the FPSO, three multi-bore umbilicals supply the necessary chemical injection, electrical power, hydraulic control and fiber-optic communication to the subsea production system according to [12].

The disconnectable, ice-resistant Floating Platform Unit (FPU - ship shape) or FPSO is hosting gas processing, gas compression, living quarter, power generation and all other utilities required to operate. Gas transport from the process vessel to the LNG onshore plant and onshore pipelines will be ensured through two 558 km long 36″ trunklines (Figure 7).

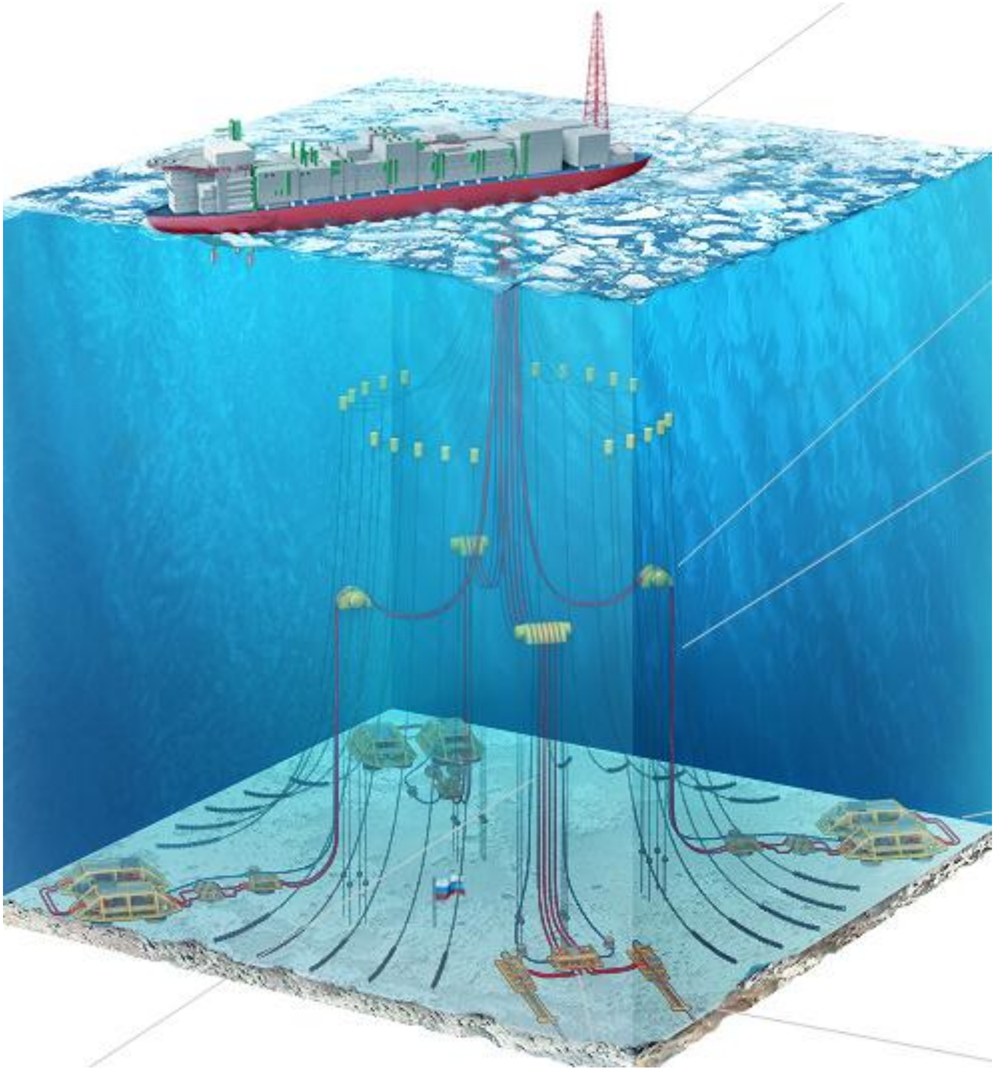


Figure 7 – Shtokman offshore and subsea facilities [11]

The Integrated Template Structures (ITS) will consist of Xmas trees (XMT), each linked via a well jumper to a template gathering the gas produced from 4 wells and a manifold with several hubs (Figure 8). There will be up to 30 subsea connections [11]. The suggested Shtokman Subsea Architecture – Schematic is presented in APPENDIX C.1.

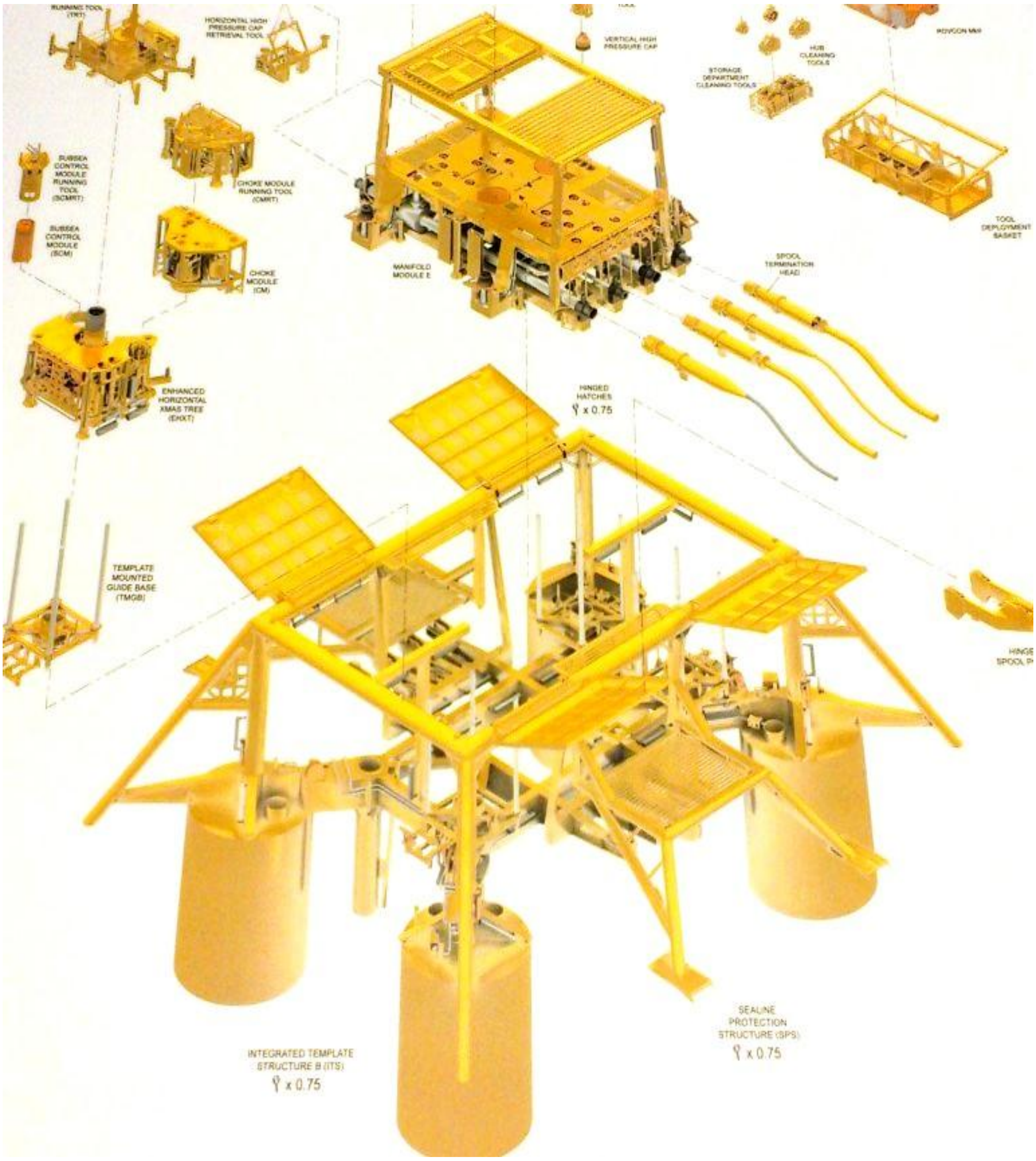


Figure 8 – 4–Slot integrated template structure [31]

2.4 Physical environment

The harsh conditions due to the Arctic environment (low temperatures, icing, snow, fog, polar night) for development and operation refer to weather season limitations, required «winterization», complex logistics and difficult Emergency Evacuation and Rescue organization [8].

The geographical position of the Shtokman field and the severe climatic conditions make the development of this field and execution of offshore and subsea marine operations extremely challenging [10]. Features affecting on safe offshore operations, subsea construction work and field development are:

- Remote location: coastal infrastructure and complex logistics
- Needs of an uninterrupted supply of materials
- Transfer of personnel, evacuation of personal
- Harsh arctic conditions: weather season limitations/seasonal installation;
- Open sea - risk of severe weather conditions.
- High cost
- Long distance export gas and condensate – additional heavy cost
- Lack of technology, competence and experience in offshore field development
- Emergency response time
- Severe climate conditions
- Presence of ice
- Environmental risks
- Very short time operating window [7].

Environmental loads are loads imposed directly or indirectly by the physical environment. The principal environmental parameters are waves, sea spray, current, ice/atmospheric ice and wind/wind-chill [6].

Some specific enviromental conditions:

1. Winds.

The most winds are from the north/south/west. There are less winds from East where land (mountains) protects. You can also get the information about the winds from the weather maps but sometimes low-pressures are almost invisible between the measurement grids. Such low pressures (in particular Polar low pressures) are extremely dangerous for the all marine operations [8].

2. Waves.

Most storms in the Barents Sea are characterized by south-westerly weather, and this sector has the longest wave generating ranges. Further south the energy levels associated with swell are higher. The Hs/Tp scatter table indicates the presence of low frequency energy that may significantly impact floating structures (Figure 9) [8].

The variation in the mean significant wave height in the western Barents Sea is not big, however the wave height decreases eastward. The ice edge also has an important influence on the wave climate in the northern and eastern areas. The wave heights will be greater in summer than winter.

Occurrence	Peak Period (s)								
Significant Wave Height (m)	0 - 2.9	3 - 5.9	6 - 8.9	9 - 11.9	12 - 14.9	15 - 17.9	18 - 20.9	21 - 23.9	TOTAL
0.0 - 2.9				0.01	0.05				0.06
3.0 - 5.9			0.02	0.97	0.45	0.03			1.5
6.0 - 8.9		<0.01	8.0	6.8	1.9	0.08	<0.01		16.7
9.0 - 11.9		15.2	48.5	13.5	8.4	0.94	0.12	0.09	81.7
TOTAL	0.0	15.3	51.5	21.3	10.7	1.1	0.13	0.09	100.0

Figure 9 – Typical Hs/Ts scatter table for Eastern Barents Sea (Based on World waves data) [8].

3. Currents.

The Norwegian Coastal Current follows the coastline of Norway into the Barents Sea. The highest velocities exist along the slope. At the banks, the velocities are reduced by bottom friction [6].

Further east, the current is divided into several branches, but an essential part of the current follows the Russian Coast and turns north-west along the western coast of Novaya Zemlja.

4. Polar Lows.

A polar low is a low pressure phenomenon which appears when there are changes of cold arctic air over the sea. Heat and humidity transferred from the sea and energy transformations within the atmosphere drive the system [9].

In polar low the wind speed usually increases to storm force very fast (1/2 - 2 hours) and wind direction changes. Heavy snowfall begins, and the visibility is poor.

Polar Lows are often unexpected as they are difficult to forecast. They last on average only one or two days and they can lead to harsh weather condition with strong winds, cold rains and occasionally heavy snow and relatively high waves [9]. The wave height would be quite limited due to a limited fetch length and also a quite short duration of the low if a polar low would be stationary. Due to the fact that they do moves, also big waves can develop rapidly. These develop on that site of the low where the wind speed has the same direction as the direction of the low itself. A group velocity of waves equal to the velocity of the polar low can stay in the low for quite some time and can thus develop into larger waves (Figure 10) [9].

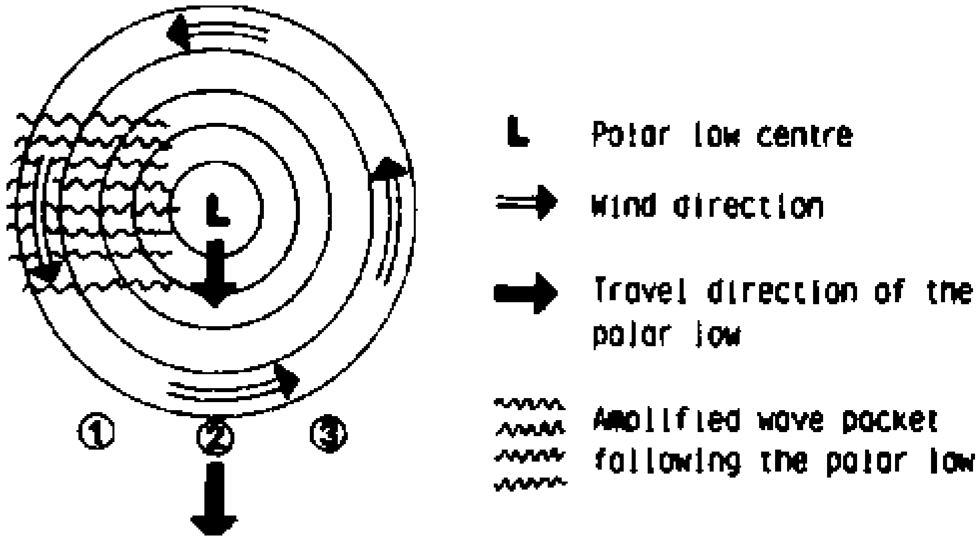


Figure 10 – Simplified model of wave generation under a polar low [9]

In the past many people, especially, fishermen lost their lives due to the strong winds and big waves that can develop so quickly and unexpectedly in the northern part of Norway and Russia [9].

Polar lows can still have severe consequences for the marine operations due to the sudden increase in wind speed and wave height. For example a wind speed of 35m/s leads to a significant wave height of 5.5 m over a fetch length of 100km. Depending on the operation a typical limit for carrying out a marine operation could be 3m maximum wave height. Furthermore also the wind speed 29 can be critical for the marine operations. High wind speeds can be very dangerous during the lifting operations [9].

Figure 11 shows all polar lows that were registered by the Norwegian Meteorological Institute from 1999 to 2010. The triangles mark the points where the polar lows were discovered.

It should be noted, however, that polar lows are infrequent in the summer months (to September).

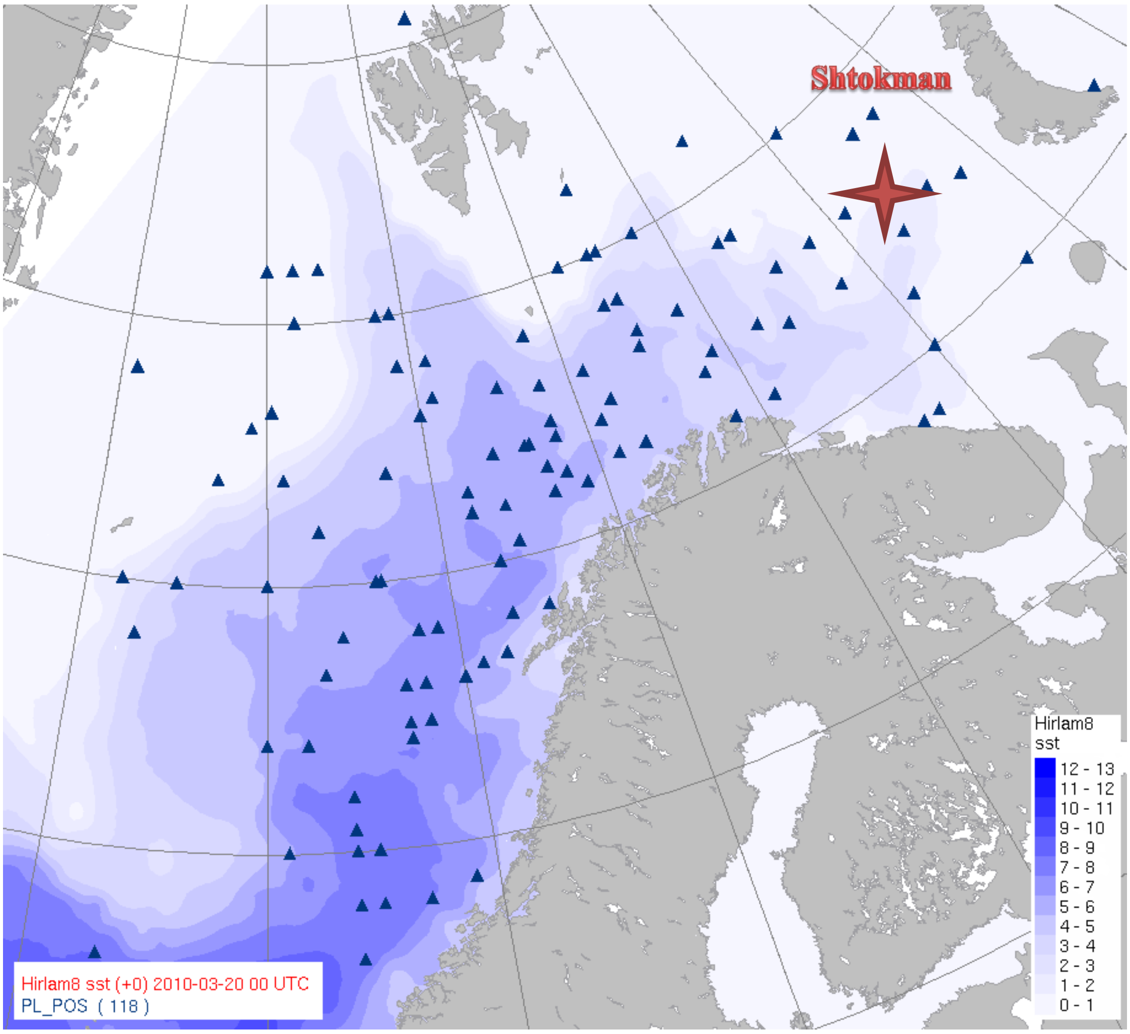


Figure 11 – Polar lows registered from the Norwegian Meteorological Institute in Tromsø from 1999 to 2010 [9]

5. Operation criteria.

Operation criteria are based on several weather parameters. A wave height and the period are important for heave motions of a semi-submersible rig. Long periodic swells can be worse for many vessels than a higher wave height but shorter period. So, we can say that the operation should be aborted in the case of significant wave height and the wave spectra top period. We should calculate critical vessel parameters for different combinations of significant wave height and the spectra top period according to [7].

Scenarios of the climate variations, supposed by foreign experts should be taken into account, according to which remained will be a tendency to warming in the Barents Sea [10].

The Shtokman is fully committed to preserving the regional and Barents Sea environment. The project shall be built with the proven and environmentally sound technology. Shtokman's ambitious safety concept will set new standards for the project safety:

- Based on a thorough dialog with the authorities and public in the region, the operating company is completing a comprehensive Environmental Impact Assessment (EIA) and

Environmental, Social, and Health Impact Assessment (ESHIA), in accordance with international and national regulations.

- The key to project safety is the implementation of high technical safety standards [10].

A huge risk assessment program and risk evaluation documents have to be written before a project will pass the execution decision gate.

2.5 Integrated template structures

2.5.1 Basics

Historically, subsea wells have had a good track record. This part presents an assessment of the integrated template structures (ITS) for the arctic regions, considering the technical, functional and design considerations [17]. The ITS will consist of Xmas trees (XMT), each linked via a well jumper to a template gathering the oil or gas produced from wells.

2.5.2 Technical requirements for the arctic/subarctic region

2.5.2.1 General

Arctic completions are basically driven by economics. Arctic wells are expensive to drill and complete. This feature results in completions incorporating remotely actuated downhole flow control equipment, multiple chemical injection lines and downhole gauges. This clearly increases complexity and reduces reliability [17].

Industry and regulators are increasingly becoming aware that long, multiphase flowlines reduce backpressure, flow rates and recoveries. This part presents technical and operational requirements for subsea facilities in the arctic/subarctic regions [17].

2.5.2.2 Arctic design

Arctic Subsea production has a number of technical issues. To make a good design the ITS design criteria have to be listed. Some of them are already known (input) but other ones have to be determined as output data [15] and [16].

Table 1 – Arctic ITS design criteria (prepared by the author)

INPUT	OUTPUT
Bottom Conditions - Soil shear strength is the ability of the seabed to support the load of a template or a manifold and how a template could be buried [16].	ITS sizing, number of templates, jumpers, connectors.
Geohazard Analyses	ITS arrangement selection
Seismic wave propagation analysis	Selection of the Leak Detection System (LDS) and applications
Planned product properties and content	Stability analysis and determination type of foundations and/or trenching/buried requirements
Production volumes	Cost Estimates
Water depth	Determine the most cost effective method to install ITS in this very dynamic region and provide necessary protection
Number of Wells - The number of wells served by a template will determine its size.	ITS installation studies to verify multiple installation options, which can be maintained for cost and contractor competitiveness (templates are commonly installed by a drilling rig as the first step prior to drilling)
Bottom hole zone locations	Risk analysis due to external influences, and definition of risk reduction measures
Interferences due to another pipelines (not so relevant)	Material Specifications

There are several aspects of ITS design in the arctic regions or the arctic environments, which offer additional challenges to the designer. Due to a very harsh environment and presence of ice it is objective to determine a template type [17]. Special requirements and design details have been presented in APPENDICES A and B. The 8–Slot ITS is represented in Figure 12.

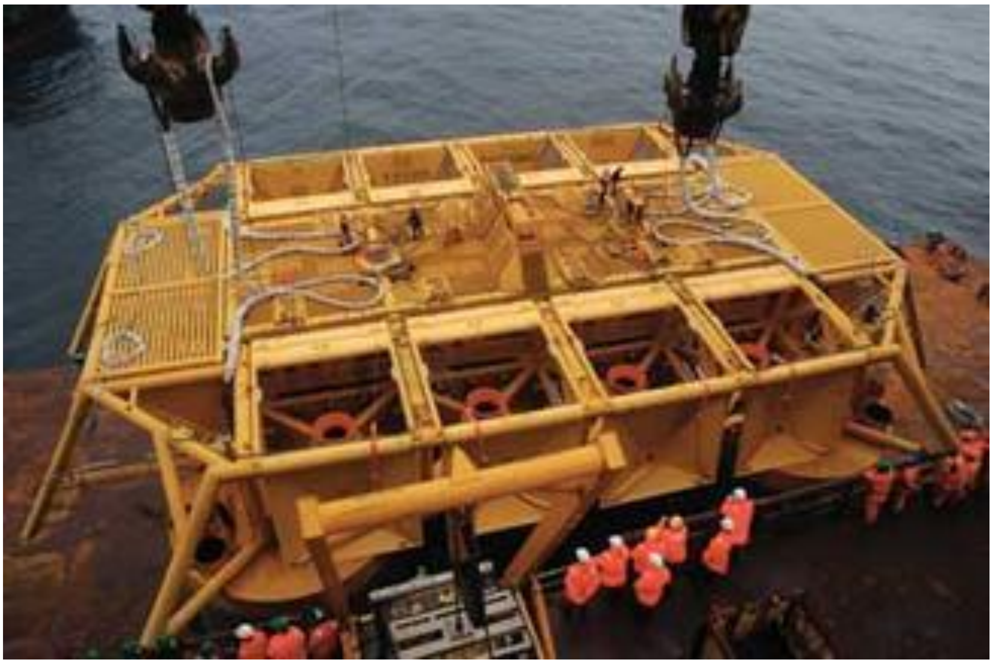


Figure 12 – 8–Slot ITS [20]

2.6 Analysis of possible vessels for the template installation for the Shtokman project

Another challenging problem for the Shtokman ITS is the installation process. What kind of vessels is required for the Shtokman area environment? Four types of vessels have been reviewed when trying to answer this question (monohull, semi-submersible crane, barge crane and wet tow vessels).

2.6.1 Monohull vessel

Vessels for offshore construction work can be defined in two ways. The monohull vessels is typically up to 170m long and can perform installation work up to 400 tons, which is quite relevant for the 4 slots ITS installation operations. They have high transit speeds up to 18 knots and are designed for harsh weather conditions. Typical types of work are:

- Smaller installation work
- IMR work (Installation, Maintenance and Repair work)
- Reeling and flexible pipe lay
- Umbilical installation

Figure 13 – Nordic monohull vessel [23]

Due to the flexible design and high transit speed, the vessels can work in remote areas [7].

Monohull vessels can also be flat bottomed vessels equipped with dynamic positioning (DP) systems usually operate in calm environments. Typical areas for the use of these vessels are: West Africa, Asian waters and the Gulf of Mexico. Because of the size and the shape of the hull a vessel like Nordic (Figure 13) will perform badly in harsh environments. The advantages of vessels are high crane capacity, large deck space and pipe lay possibilities. The size of the vessel and the transit speed are also important when evaluating different vessels and making the cost decisions [23].

2.6.2 Semi-submersible crane vessels

One of the most important issues in offshore field development is the need for cost reduction. Semi-submersible crane vessels (SSCV) have DP with heavy lift cranes that can perform lifts up to 14200 tons. They can operate all over the world and perform both topside and subsea lifts. in the last few years they have also been involved in decommission work. . The large displacement is also an advantage during operations in deep waters with large top tension requirements. SSCV's like a Hermod (Figure 14) has been originally designed for lift of modules like jackets and topsides. However, these vessels also perform installation of large subsea modules [22]. But the SSCVs usually do not have possibilities for heave compensation.

Figure 14 – Hermod crane vessel [22]

2.6.3 Barges

Barges offer a cheap way for transportation of offshore structures, and have been used since the early years of the industry. They are cheap to build, and have a small amount of equipment and are cheap to hire. Barges are designed in many ways but the common characteristics is the flat bottomed hull, as a box, where the hull is divided into compartments for both structural and ballasting purposes (Figure 15).

As a cargo mover the barge represents large load capabilities to a low cost, but the limitations are high. Some barges are designed to lift large loads. Barges perform badly in wave condition that is based on simple calculations of the heave period. Barges consist of small mass, and the water plane area is very large, which gives a low heave period.

Figure 15 – Barge crane [22]

2.6.4 Wet tow vessel

To increase the operational window and reduce high costs, new concepts have been developed. Subsea 7 company has patented a method for wet tow of heavy templates. The templates will be transported on a barge, deployed in calm environments, and wet stored for later pickup by a construction vessel.

By use of relatively small monohull vessels the ITS can be wet towed to its location, avoiding offshore lifts. Instead of an offshore crane there is used a standard offshore winch for the lift. A lift wire is routed through the moonpool and is used for pickup of the template. Located on site the winch takes over the lift again, now mounted with an in-line passive heave compensator, and the template is submerged to the seabed. The system was first used the summer of 2007 on Tyrihans field in northern North Sea, during installation of 4 x 260 tons templates [21].

3 Risk analysis

3.1 General

There are several trends in offshore development projects: offshore operations are becoming more and more complex and there exists an increased focus on more cost-effective (quicker and cheaper) field developments. That leads to more complex marine operations in the "winter season" (September/October to April for the operations in Arctic) [8]. When carrying out complex operations during this part of the year, a high quality weather forecast is needed. Not only are the average wave heights and wind speeds more severe, but the weather windows are generally short and changes in the weather conditions are very frequent and quicker than in the summer season [8].

Risk analysis has become a powerful tool for identifying technical solutions and operations with high risk especially for the Arctic regions Risk analysis is also used to identify, assess and compare risk-reducing measures [7]. Risk assessment provides a structured basis for offshore operators to identify hazards (this procedure is called HAZID and to be explained further) and to ensure that risks are reduced to appropriate levels in a cost-effective manner. There exist special regulations applying to offshore operations. They require operators to perform risk assessment in order to identify appropriate measures to protect people against accidents, so far as is reasonably practicable [20]. The safety of offshore and subsea installations against marine hazards has traditionally relied on International Maritime Organization (IMO) legislation and classification society rules. Moreover, the Petroleum Safety Agency's regulations and requirements for risk reduction show us the need for risk analysis [20].

The project aims to design and carry out installation, modification in an efficient and safe way. The term "efficient" relates not only to a budget, but also the arctic operational window which is extremely short [19].

There are three main steps to analyze the risk acceptance [19]:

1. Hazard Identification – is done through HAZID with the use of Bow Tie (Barrier) Analysis (BTA) to identify threats that can lead to realization of hazards and available barriers. That can prevent hazard realization and further escalation, protect personnel and the assets, and mitigate the consequences. This step is followed by

2. Qualitative Risk Analysis (RA) – to understand risk results presented in the form of a risk matrix, and a sufficient number of barriers. The process is then extended to cover:

3. Quantitative Risk Analysis (QRA) – to facilitate decision making about operations, state of the vessel and to compare different options regarding the interaction between operations and activities on a vessel [19].

There is another algorithm that analyses risks from another perspective. Steps in Risk Analysis are [7]:

0. Acceptance criteria set
1. Identify causes and consequences (HAZID)
2. Probability
3. Consequence grading (Risk Matrix)
4. Estimate risk
5. Compare to acceptance criteria
6. Introducing risk reducing measures
7. Use quantitative measure to evaluate cost-benefit
8. Carry out the operation.

3.2 HAZID basics

The main purpose for performing the HAZID study is to identify the hazards at an early stage. It might provide input to the project design. The use of the HAZID may lead to a safer and more cost-effective design [27]. Moreover, the HAZID shall ensure that the identified hazards have been properly considered. The HAZID provides recommendations to the design activities and establishes requirements for design checks or additional studies. The main objectives of the HAZID are:

- To identify any hazards which may cause a risk to persons, environment, installations or equipment;
- To check if the design is sufficient to prevent the hazards or reduce the related consequences to an acceptable level [27];
- To recommend the actions and promote the design verifications that is necessary to improve the overall safety level of the project. The HAZID study will generally include follow-up activities to ensure that health, safety and environment (HSE) goals are achieved.

There are several ways to do this: use a checklist, critically rehearse the activities and tasks on the site, and do the brainstorming with the personnel to encourage participation and understanding [19].

3.2.1 Input for HAZID

The HAZID shall be based on the following four types of input [24]:

- Description of the system (schematics, etc.)
- Description of the installation of the ITS
- Ready For Operation (RFO)
- Description of operational procedures. This covers primarily future vessel operations and requirements for operation of the subsea systems.

A schematic of subsea production system is provided in APPENDIX C.1.

3.2.2 HAZID methodology

The HAZID is the starting point for the risk assessment activities. The overall methodology for the risk assessment is shown on Figure 16.

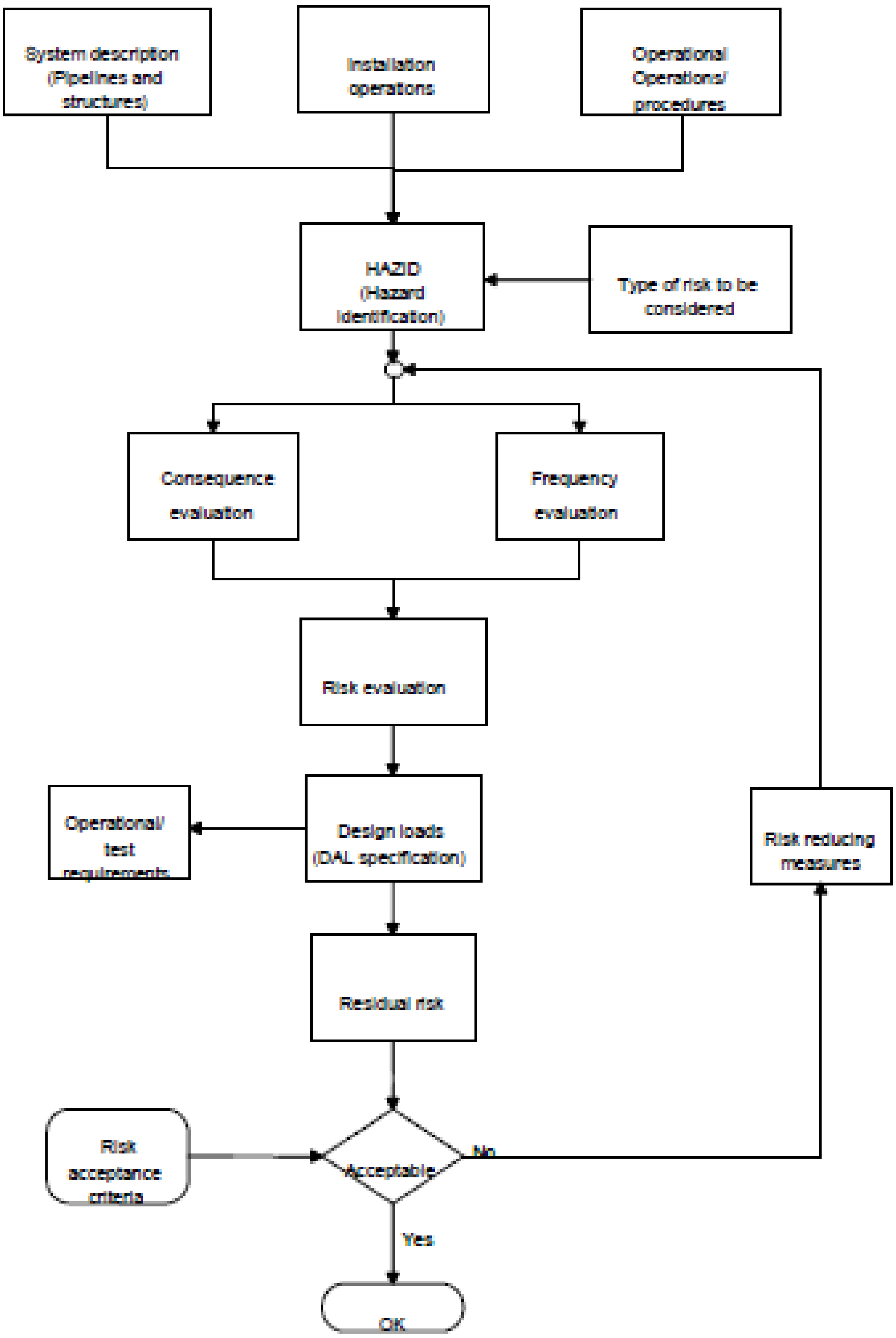


Figure 16 – The overall methodology for the risk assessment [24]

As shown in Figure 16, the HAZID is a very central part of the risk assessment. The HAZID is focusing on risks related to humans, environment, project delay and economical loss [27].

Basically, the HAZID is focusing on the following project phases:

• Design phase
• Installation phase
• Commissioning phase (Ready for operation)
• Operation phase

The commissioning phase is an integrated part of the installation phase [24].

There is no design responsibility for the riser and subsea templates as they are from a hazard identification point of view considered as interfacing items in terms of compatibility [27].

The identified hazards applicable for the Shtokman ITS will be ranked to identify major hazards. These will be analyzed further and addressed during the detailed design. The ranking will be made according to the matrix in APPENDIX C2.

Risk-reducing measures should be evaluated with accordance to HAZID. The best way to do it, is to put the barriers to control the threats. So, the barriers (risk controls) are the main handles for controlling the threats. In addition, knowledge of major hazards, facility operations and maintenance represent efficient barriers [19].

Most of the work is at the stage of hazard identification and collection of information. Bow tie models have, in general, a large number of "barriers" and may give a false impression that the safety level is high. Often most of the barriers are not effective. When the threat takes place there is normally just the existing safety practice in terms of procedures, notices, etc. [19].

A bow tie model for the sequence from threats to consequences is shown in Figure 17.

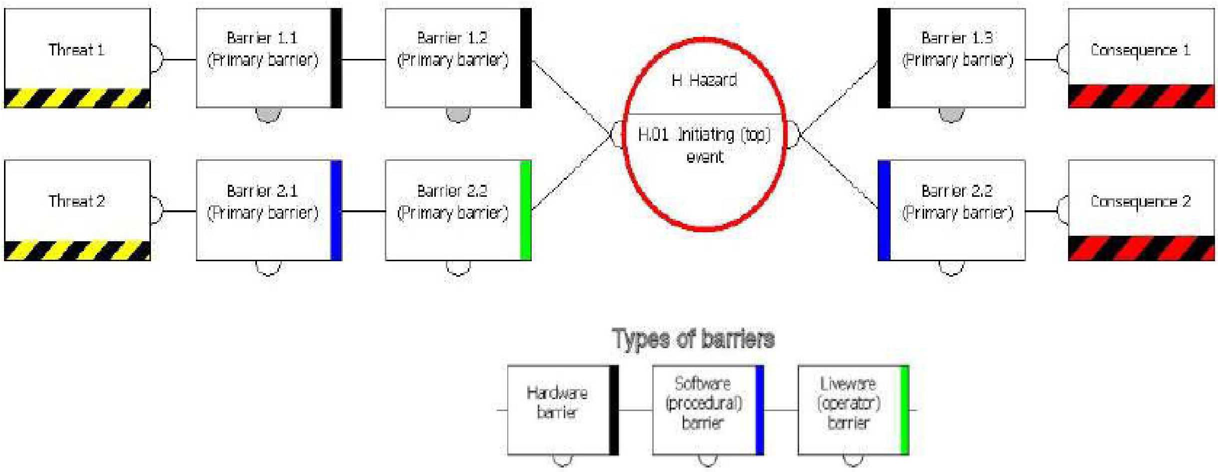


Figure 17 – Bow tie model [19]

The initiating event is denoted by a red circle in the middle of the bow tie. Boxes with black/yellow stripes at the bottom are threats, boxes with black/red stripes are consequences, and the boxes with the vertical thick bars are barriers. A technical barrier like a crane wire can fail if it is not checked and changed when it is required by the maintenance plan. An operator (barrier) can also fail if the operator leaves his post, falls asleep, makes a mistake etc. A procedural barrier such as permit to work system can fail if there is too much paper work, or if there is a lack of safety culture [19]. It can also happen if carrying out tasks and procedures are not monitored. This is shown in Figure 18. The boxes with the red horizontal bar represent barrier failure modes. The boxes next to failure modes are secondary barriers (with vertical thick bars).

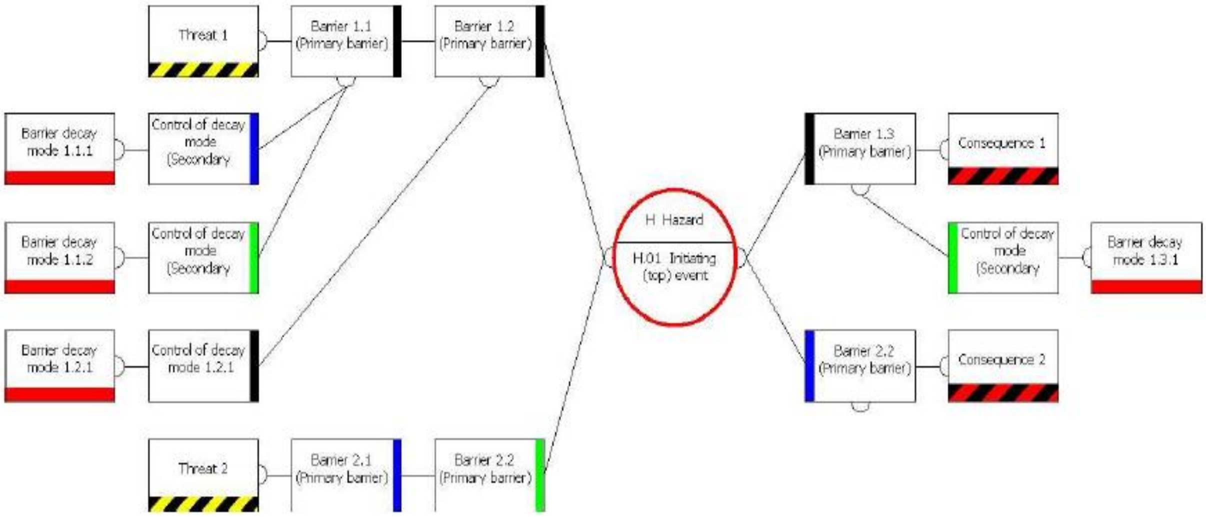


Figure 18 - Expanded bow tie model [19]

3.3 Qualitative risk analysis

For each scenario we have to carry out a job risk assessment. A competent risk assessment person, together with the project team, should carry out a site specific JRA before the work begins. This is normally carried out using a job risk assessment form. The competent person should ensure that appropriate controls have been fulfilled for those hazards that are identified in the written risk assessment. The risks are managed as an integral part of the installation plan [7]. The risk assessments for the Shtokman project are presented in part 7.

3.4 Quantitative risk analysis

Quantitative risk analysis (QRA) is usually carried out by quantification and summing up the information from the fault/event trees that are represent initiating events. QRA offers opportunities for decision making and a good choice of risk reducing measures. QRA is normally used to help with reducing risks, help to perform an option selection by means of ranking options in terms of risk. QRA is also used to assist in the cost-effectiveness of risk-reducing measures, assist in the demonstration and achievement of ALARP to indicate if risks are tolerable or not [19].

An example of the risk assessment matrix is presented in Table 2.

Table 2 – An example of the risk assessment matrix

Hazard severity category	Descriptive words	Probability rating				
		A	B	C	D	E
		Very likely	Likely	Possible	Unlikely	Very unlikely
1	Very high	1A	1B	1C	1D	1E
2	High	2A	2B	2C	2D	2E
3	Moderate	3A	3B	3C	3D	3E
4	Slight	4A	4B	4C	4D	4E
5	Negligible	5A	5B	5C	5D	5E

There are three zones/levels in table 2:

1) Green – Acceptable zone
2) Yellow – ALARP zone
3) Red – Not acceptable zone

4 Selection of the installation vessel

4.1 Heave period calculation

The heave period is found by analyzing the simple mass/water plane ratio. The lower this period becomes, the worse the vessel will perform in waves [7].

For the Barents Sea metocean conditions it will be more suitable to take into consideration SSC and Monohull vessels even we will operate during the summer season (May – August/September).

Semi-submersible Crane Vessel: Hermod [22] with the capacity: 1st crane – 4500 t, 2d crane – 3600 t. Total mass: $m_v = 58300$ t.

Dimensions:

- length ≈154 m;
- Width ≈86 m;
- Max draft ≈28 m;
- Dimensions of each 6 columns (rough estimation): $a \times b$ = 15×15 m^2

Monohull vessel: Nordic with the capacity of 5000 tons [23].

Dimensions:

- Length (at waterline) ≈150 m;
- Width (at waterline) ≈32 m;
- Max draft ≈11 m.

Let's find the natural period of the heave for them.

The equation for the heave motion:

$$m\ddot{z} + c\dot{z} + kz = Q(t) \quad (1)$$

The solution:

$$z = z_n + z_p \quad (2)$$

Assume no damping in the system, and initial conditions ($z(t{=}0){=}0$ and $\dot{z}(t{=}0){=}z_0\omega_0$)

$$z_n = \frac{H}{2} sin\omega_0 t \quad (3)$$

Where $\frac{H}{2}$ – amplitude – very important in lifting operations, effects of loading/unloading;

ω_0 - eigen frequency – very important (we need to know whether we are in resonance with waves in the heave):

$$\omega_0 = \sqrt{\frac{k}{m}} \quad (4)$$

Also the velocity (in terms of speed of lifting operations) and the acceleration (vertical forces/fastening the cargo) of the heave motion are of big importance.

Hence, in order to find the natural period of the heave we need to know the stiffness *k* and the mass *m*.

To find the true mass we have to take into account the effect of the added mass in front of the motion [7]:

$$m = m_v + m_a \quad (5)$$

Where m_v- vessel mass, kg;

m_a- added mass, kg.

The stiffness is determined as the resistance against the vertical motion [7]:

$$k = A_w \cdot \rho \cdot g \quad (6)$$

Where A_w – area at waterline;

ρ - water density (1025 kg/m^3).

Let’s calculate the added mass for the chosen vessels.

We can assume that the monohull is a rectangular body shape vessel; SSCV columns and pontoons are the square prisms.

Then, the added mass for the rectangular plate is [28] and [29]:

$$m_a^{mh} = \rho \cdot C''_A \cdot \frac{\pi}{4} \cdot a^2 \cdot b \quad (7)$$

Where C''_A – added mass coefficient for the Nordic vessel, $C''_A = 0.76$ [29],

$\frac{\pi}{4} \cdot a^2 \cdot b -$ reference volume of the monohull vessel, m^3.

Added mass for the prism is [29]:

$$m_a^{ss} = \rho \cdot C'_A \cdot a^2 \cdot b \quad (8)$$

Where C'_A – added mass coefficient for the Hermod vessel, $C'_A = 0.36$ and 0.68 [29], $a^2 \cdot b$ – reference volume of the columns and pontoons, m^3.

Therefore, the natural period of the heave is [7] and [29]:

$$T_{heave} = 2\pi\sqrt{\frac{m}{k}} = 2\pi\sqrt{\frac{m_v+m_a}{A_w \rho g}} = 2\pi\sqrt{\frac{\rho \cdot A_w \cdot d + m_a}{A_w \cdot \rho \cdot g}} \quad (9)$$

For the chosen monohull crane vessel:

$$T_{mh} = 2\pi\sqrt{\frac{\rho \cdot A_w \cdot d + \rho \cdot C''_A \cdot \frac{\pi}{4} \cdot a^2 \cdot b}{A_w \rho g}} =$$
$$= 2\pi\sqrt{\frac{(1025 \cdot 150 \cdot 32 \cdot 11) + (1025 \cdot 0.987 \cdot 0.785 \cdot 150 \cdot 32 \cdot 32)}{150 \cdot 32 \cdot 1025 \cdot 9.81}} \approx 11.6\ s$$

For the chosen semi-submersible crane vessel:

$$T_{ss} = 2\pi\sqrt{\frac{m_v + \rho \cdot C'_A \cdot a^2 \cdot b}{A_w \rho g}} =$$
$$= 2\pi\sqrt{\frac{58300000 + (1025 \cdot 0.36 \cdot 15 \cdot 15 \cdot 6 \cdot (28-20)) + (1025 \cdot 0.68 \cdot 152 \cdot 22 \cdot 20 \cdot 2)}{(6 \cdot 15 \cdot 15 + 152 \cdot 22 \cdot 2) \cdot 1025 \cdot 9.81}} \approx 21.3\ s$$

Mass of the monohull crane vessel with a 4-slot ITS on board:

$$m'_v = m_v + m' \quad (10)$$

Where m' – the ITS mass.

Masses of the different types of ITS (APPENDIX E) are presented in table 3.

Table 3 – Masses of the different types of ITS

ITS	m', t
4-slot	500
6-slot	800
8-slot	1400
12-slot	2200

The heave period of the installation vessel with the ITS on board is:

$$T_{mh} = 2\pi\sqrt{\frac{m'_v + m_a}{A_w \rho g}} \tag{11}$$

4.2 Selection of vessel

The monohull crane vessel could get in resonance with waves according to the Barents Sea environmental conditions (according to the scatter diagram [8], mainly T_s = 3 - 13 sec) It's more convenient to shift the natural period of the vessel to the greater value where the energy of resonance is small – increase the deadweight, or choose another crane. The use of the crane barge shall be neglected due to low natural period. The results are presented in table 4.

Table 4 – The heave period of the installation vessels

Vessels	Heave period, s	Comments
Monohull	11.6	Can get in resonance with waves. Need to shift the natural period to the greater value where the energy of resonance is small – increase the deadweight [7].
Semi-submersible	21.3	Applicable for Barents Sea.
Barge	5 - 7	Unsuitable

The heave period doesn't change so much when the installation vessel get the ITS on board.

5 ITS installation analysis for the Shtokman project

During the Shtokman FEED studies carried out by Gazprom, Total and Statoil in 2012, gas was planned produced by using 3 twin four-slot ITS, APPENDIX C1. During the Phase I of the field development the plan was to drill 20 wells [5].

We have analyzed this recommendation and have chosen to consider four different scenarios of Subsea Production Systems with 2, 3, 4 or 6 integrated template structures for the field development:

1) Base case / A4 - 6 ITS with 4 well slots (proposed by the operator).
2) A6 - 4 ITS with 6 well slots
3) A8 - 3 ITS with 8 well slots
4) A12 - 2 ITS with 12 well slots

Due to the hostile physical environments in the Barents Sea, we will have operational limitations in many aspects [7]:

- Long transit time
- The cold
- Freezing sea spray, icing
- Iceberg or ice
- Darkness
- Polar Low
- Weather forecast is unpredictable
- Short seasonal weather window

According to the weather and seasonal limitations installations shall therefore be carried out during the summer time (May to August/September).

5.1 Installation procedures

Module installations offshore are challenging operations both when the modules are in the air and in the splash zone. Often the module faces the largest forces in its lifetime during installation.

Work on the installation can be divided into two main types: surveys and installation of structures [15]. Installation of the ITS on the Shtokman field will be carried out in two stages: 1) foundation, drilling frame, protective structure and then 2) the module manifold. Let's consider that manifold will be preinstalled. Seasonal weather window should be considered from May to August - September only.

During the development of the schedule the installation included the following conditions:

- to maximize the preliminary work on equipment installation to produce first gas in prescribed period,
- to provide flexibility time schedule
- to minimize the amount of mobilization and demobilization of vessels, in order to reduce the costs [15].

Each ITS will be (prepared by the author according to [7] and [12]):

1) transported to the site on a barge or a SSVC,
2) lifted by the vessel crane equipment,
3) lifted quickly through the wave zone. This operation will be carried out to ensure an acceptable distribution of snap loads,
4) oriented at a specific position (installation point),
5) established at location. Need to define the following parameters: maximum speed of hook and heave,
6) moored/lowered. To exclude the possibility of the resonance.

Main installation vessel will be supported by a number of additional vessels such as cargo barge and service vessels. Vessels have to be ready to stop work if waves are getting larger or ”ride off” a storm. Every hour weather forecast is needed due to uncertain weather predictions – polar low [7].

The installation operation requirements according to ISO and NORSOK standards see in APPENDIX A, B.

5.2 ITS installation time schedule

Total time of the installation operations (prepared by the author):

$$T_{total} = \sum T_i \tag{11}$$

Where T_i:

$\mathrm{T_{trans}}$ - transportation time, h.,
$\mathrm{T_{fast}}$- time for sea fastening, h.,
$\mathrm{T_{lift}}$ - lifting time, h.,
$\mathrm{T_{orient}}$ - time for orientation, h.,
$\mathrm{T_{estab}}$ - time for establishing frame on location, h.,
$\mathrm{T_{fix}}$ - time for fixing to bottom, h.,
$\mathrm{T_{cp}}$- change location time, h.,
$\mathrm{T_{back}}$- move back time, h.

$$\mathrm{T_{trans}} = \mathrm{T_{trans1}} + \mathrm{T_{wait}} \tag{12}$$

Where T_{trans1}- transportation time of one template, h.,
T_{wait} - waiting time, h.

$$T_{wait} = T_{trans1} + T_{back} - (T_{fast} + T_{load-out} + T_{lift} + T_{orient} + T_{estab} + T_{fix} + T_{cp}) \quad (13)$$

Assuming equations (12) and (13) we can get:

$$T_{trans} = N_{trip} \times (2 \times T_{trans1} + T_{back} - (T_{fast} + T_{loads1\,e} + T_{orient} + T_{estab} + \\ + T_{fix} + T_{cp}))$$

Where N_{trip}– a number of barge's trips, $N_{trip} = 1$.

Scenario A12: 2 ITS with 12 wellslots.

Equipment: 2 Service vessels, 1 SSCV for example Hermod (can transport a template), 1 Cargo Barge (for the second ITS transportation).

Weight of the ITS is 2200 tones (APPENDIX E). Installation operations for the scenario A12 (prepared by the author) [7] and [14], [15] are presented in table 5.

Table 5 – Installation operations for scenario A12, excluding vessel mobilization and transfer to Murmansk and vessel demobilization.

Operations	Time, h
Transportation from Murmansk harbor to the Shtokman field (distance - 558 km),	48
Cut sea fastening and prepare for lift	6
Lift off	12 (depth - 350 m)
Oriented	1
Established on location	2
Fixed with piles	12
Change location	12
the 2^{nd} template was transported during previous operations	
Cut sea fastening	4
Load out	2
Lift off	12 (depth - 350 m)
Oriented	1
Established on a location	2
Fixed with piles	12
Move back to the harbor	40
- Check the weather every hour. - 4 hours of extra time should be included due to heavy lift operations.	
Total time, T_{total}, hours	168 (7 days)

Another relevant time calculations are presented in table 6.

Table 6 – Operation time

Scenario	Template	Transport	Cut sea fastening	Lift off	Oriented	Establish	Mooring	Change location	Wait time	Move back	**Total, h**	**Total, days**
A12	2	48	12	24	2	2	24	12	0	40	168	**7**
A8	3	48	12	30	3	3	24	20	44	40	224	**10**
A6	4	40	12	32	4	4	24	32	0	32	180	**7**
A4	6	40	18	36	6	6	36	42	44	32	260	**11**

Several types of vessels which could be applicable for this kind of installation operations are recognized. Due to heavy cargo transportation and heavy lift operations we have to be sure about the vessel's stability and response functions in waves [7].

We can transport only one template by the crane vessel or the barge for scenarios A12 and A8. However, we can transport two templates simultaneously for scenarios A6 and A4. The crane vessel shall transport one or two templates to the location, and then the cargo barge will transport it from Murmansk harbor to the place. According to scenarios A8 and A4 the cargo barge has to move back to the harbor for the additional template transport.

5.3 Installation cost benefit analysis

An increasing challenge at the Shtokman field is to design, construct, and install offshore installations that give an acceptable return of the investments. However, the considerations and the cost reduction elements are valid for offshore field developments in general. The main cost reductions are obtained by:

- Maximum use of industry capability
- Application of new organization principles
- Focus on functional requirements
- Shortened project execution time [7].

Cost benefit analysis of installation operations depends on quantitative analysis of full information related to these procedures.

For each installation operation we need at least one Supply and one ROV vessels. For the template transportation the cargo barge is needed. Several types of the crane vessels can contribute for the lifting operations: monohull, semi-submersible crane vessel, crane barge or wet tow. The daily rent varies. Assumptions are presented in table 7.

Table 7 – Assumption of the daily rent of the equipment

.

Scenarios	A4 (<500 t)	A6 or A8 (1000 t)	A12 (2200 t)
Supply vessel, $/day	15000	15000	15000
ROV vessel, $/day	70000	70000	70000
Cargo barge, $/day	30000	50000	100000
Monohull vessel, $/day	200000	250000	-
SSVC, $/day	-	500000	700000
Wet tow, $/day	400000	-	-

We have to include the transfer costs as well. Transfer costs are the cost for mobilization to site and demobilization of all vessels. We assumed that the vessels were transported from the port of Stavanger to the Murmansk harbor. Obviously, during the logistic studies we have to examine the demand of the vessel market and order the vessels in advance. Transfer time is presented in table 8.

Table 8 – Transfer period from Stavanger to Murmansk harbor and back [30].

Vessels	Vessel speed, knots	One way transfer, days	Total, days
Supply vessel	14	4	8
ROV vessel	14	4	8
Cargo barge	9	6	12
Monohull vessel	9	6	12
SSVC	6	8	16
Wet tow	10	5	10

As far as the crane vessel has the longest transfer time, we take into consideration 16 days as a transfer time for scenarios A12 and A8. In reality we have to make the logistic studies to order the vessels at the right time. We can order the service vessels 5 days after the crane vessel has been ordered. With regards to that our calculation has been made. Total time for the installation is presented in table 9.

Table 9 – Total time

Scenario	Transfer time, days				Operation time, days	Total, days
	Service vessels	Cargo barge	Monohull	SSVC		
A12	8	12	-	16	7	23
A8	8	12	-	16	10	26
A6	8	12	12	-	7	19
A4	8	12	12	-	11	23

As we can see from table 9, the transfer period for the vessels is not the same. For scenarios A8 and A12 it will be longer due to very low transit speed of SSCV. The time estimation should be very confident. During the calculations the waiting period for the crane vessels have been added into account to ensure that the rest of the operational fleet arrives in Murmansk at the same time as the SSCV.

Overall costs of the rental equipment for each scenario are presented in table 10 and Figure 19.

Table 10 – The cost of the rented equipment

Costs, $	Service vessels	Cargo barge	Crane vessel	Total costs, $M
Scenario A12	1275000	1800000	16100000	19.175
Scenario A8	1530000	1050000	13000000	15.58
Scenario A6	1275000	900000	4750000	6.925
Scenario A4	1615000	660000	4600000	6.875

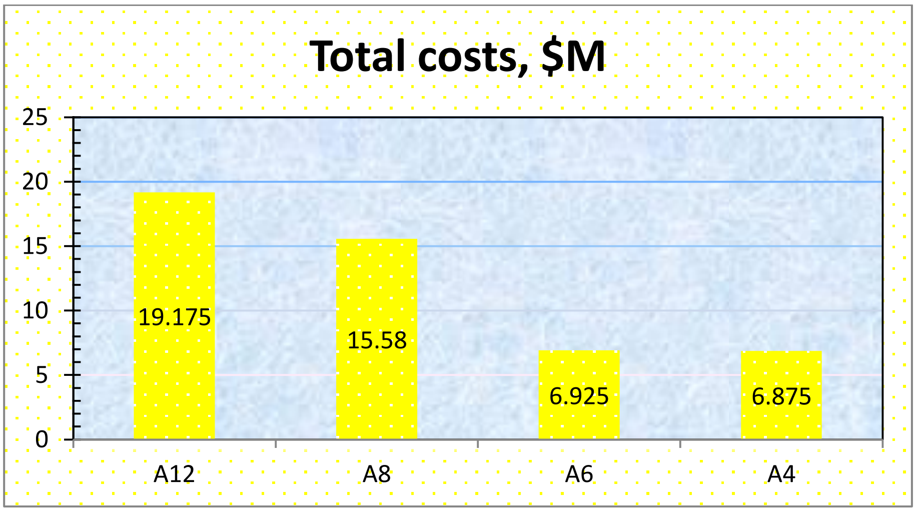


Figure 19 – Total costs on the installation operations of the ITS.

The WOW factor has to be included for the operations in Barents Sea.

$$T_{wtotal} = T_{total} \times WOW \qquad (14)$$

Where WOW – waiting on weather factor, we assume WOW=1.5 (50%).

Total costs on the installation operations with WOW factor are presented in table 11 and Figure 20.

Table 11 – Total costs with WOW

Scenario	Total days with WOW	Total Costs with WOW, $M
A12	35	29.795
A8	39	23.835
A6	29	10.775
A4	35	10.655

Due to the big rent of the crane vessel, scenario A12 is the most expensive in this case and scenario A4 and A6 are the cheapest.

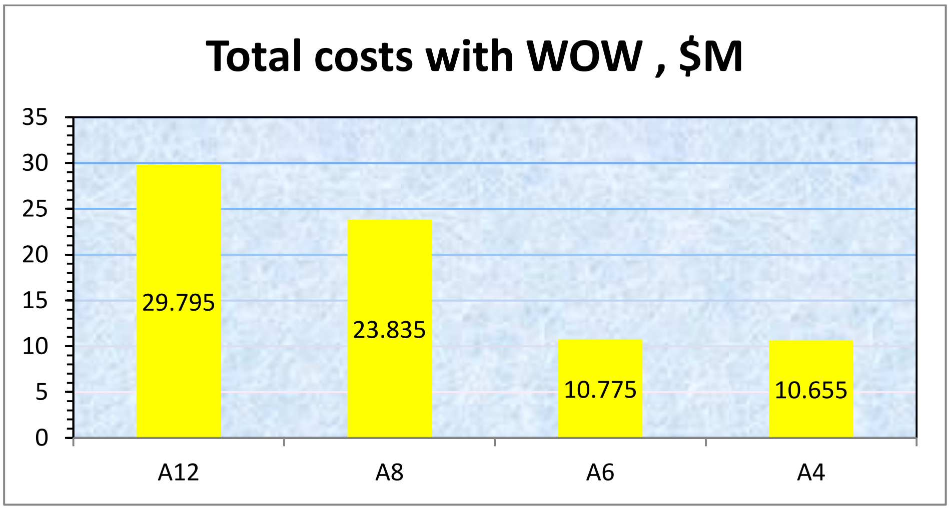


Figure 20 – Total costs on the installation operations of ITS with WOW.

Total costs for each scenario are presented in table 12.

Table 12 – Total costs on the installation operations

Scenario	Number of wellslots	Number of ITS	Installation period, days	Cost on installation, $M	Costs with the WOW factor, $M
A12	12	2	35	19.175	29.795
A8	8	3	39	15.58	23.835
A6	6	4	29	6.925	10.775
A4	4	6	35	6.875	10.655

One of the most important factors in cost estimations for the installation procedures is the rental cost of the equipment. Expenditures are the highest for the crane vessel (APPENDICES E1, E2, E3). As we can see from Figure 20, the most economically effective scenario is A4: 8 production templates with 4 wellslots, while scenario A6 has the same costs for the installation.

Also we have to admit that the transfer costs are very high. The logistic plan has to be very consistent and thought through. It is also necessary to reduce the waiting time due to waiting of the cargo vessel bringing templates for scenarios A8 and A4 to the offshore location. Scenarios A12 and A8 are very expensive due to extremely high daily rent for SSCV. Scenarios A12 and A8 have a greater number of wellslots and a smaller number of ITS, but this fact is not relevant since operational time is almost the same as for scenarios A6 and A4.

6 Models for the total cost of subsea production system

6.1 Cost benefits analysis for the ITS construction

Excluding drilling cost we can evaluate the capital expenditures of the ITS using a plot, which is presented in Figure 21 [25].

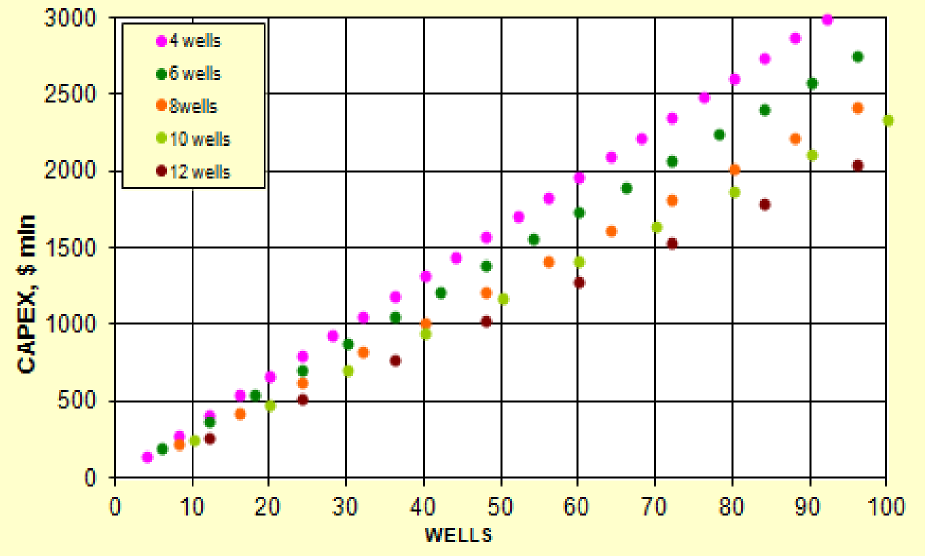


Figure 21 – ITS costs [25] (mln = Million, wells=wellslots)

From Figure 21 we can find the dependence of the template costs from the slope angles. So, we can easily get the cost for the predefined template's number.

We can consider that each line has the structural equation according to the plots [25] and [26]:

$$CI = a \cdot N \tag{15}$$

Where CI – capital expenditures,

N - number of wellslots,

a - Slope angle.

From Figure 21, we will get the slope angle equation for the known number of ITS,

$$a = (c \cdot ITS + d) \tag{16}$$

Where c,d – plot parameters.

Let's put equation (16) to equation (15), then

$$CI = (c \cdot ITS + d) \cdot N \tag{17}$$

Let’s take 80 wellslots as a starting point from Figure 21 to evaluate the capital expenditures and then the slope angle.

According to equation (15) we can compose table 13 with CAPEX and slope angles.

Table 13 – CAPEX number versus slope angle

Number of slots of each template	N, number of wellslots	CI, \$M	Slope angle ($a = \frac{CI}{N}$)
4	80	2600	32.5
6	80	2330	29.1
8	80	2000	25
10	80	1840	23
12	80	1730	21.6

According to Figure 21, the solutions which have a bigger number of wellslots inside the ITS have lower capital expenditures. But we have to be more certain. Let’s find the *CI* number for the Shtokman project phase I field development.

These results, as found from table 13, give us the possibility to calculate the costs of ITS using the simple dependency from Figure 21. We can then say how much the Shtokman project will cost, having the final number of wells and with suggested number of ITS. The difference between the capital expenditure is rising with the higher number of wells on a field. This is important to understand and keep in mind for the first and the next phases of the project.

The capital expenditures of the integrated template structures for the Shtokman phase I field development are presented in table 14 and Figure 22.

Table 14 – Capital expenditures of the integrated template structures for the Shtokman phase I field development

Scenario	ITS’s slot number	Total number of wellslots, N	Number of ITS, *ITS*	CI, \$M
A12	12	24	2	518.4
A8	8	24	3	600
A6	6	24	4	698.4
A4	4	24	6	780

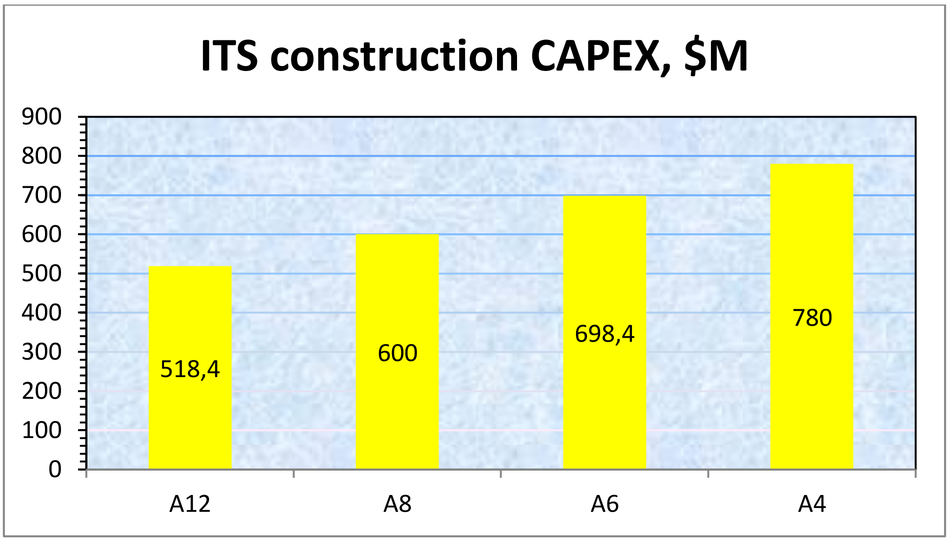


Figure 22 - Capital expenditures of the integrated template structures for the Shtokman phase I field development

According to table 14, we must say that the structures with 12 wellslots will be much cheaper to construct. But we have to admit that the drilling costs should be much higher since the horizontal parts of the wells will be longer. And it is very important to take into consideration the drilling cost in our model.

6.2 Field Development Evaluation (FDE) Program and algorithm results. Drilling included

Since the drilling cost is one of the important factor for the development, another cost model taking into account all cost items, are considered in this paragraph.

A Field Development Cost Evaluation Program was used during writing of the thesis (APPENDIX D). The Field Development Evaluation Program (FDE) was developed by prof. Jonas Odland and changed for the Shtokman requirements by the thesis's author.

According to the Shtokman project input data [3], [11] and [12], which have been put in the FDE program, we got the following output results. These results are presented in table 15.

Table 15 – FDE program output data

Scenario	Number of templates	Template costs, $M	Drilling costs, $M	Infield Pipeline costs, $M
A12	2	480	1330	294
A8	3	585	1106	299
A6	4	680	974	303
A4	6	720	820	310

The template costs are quite similar to the result which has been evaluated from the previous analysis but the drilling costs are the most significant factor here. Table 16 and Figure 23 with the total costs for each scenario are presented below.

Table 16 – Total costs

Scenario	Number of templates	Total costs, $M
A12	2	2104
A8	3	1990
A6	4	1957
A4	6	1850

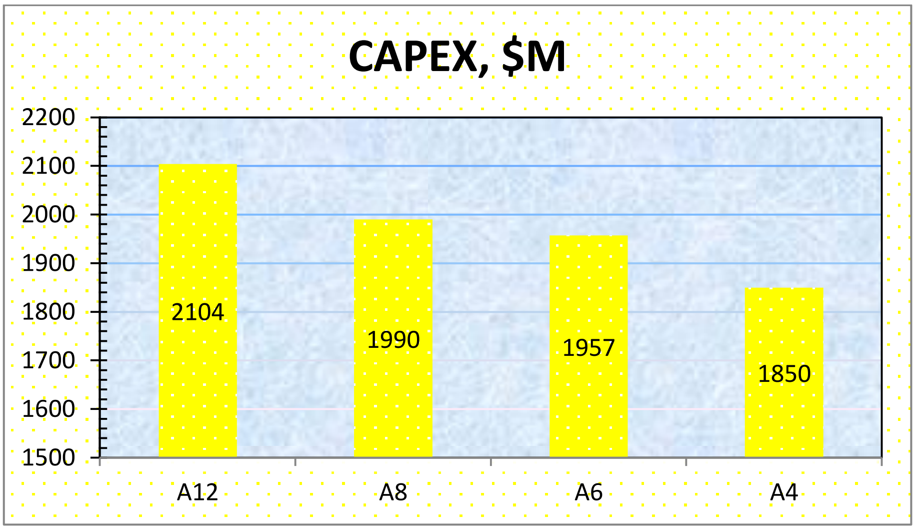


Figure 23 – Total costs for the Shtokman phase 1 subsea development, drilling included

Scenario A4 is the economically most attractive for the Shtokman project according to the FDE program output data and according to this model. Drilling costs have to be evaluated with more certainty. Scenario A6 is also economically attractive and could be applied during the Shtokman project phases 1, 2 and 3.

6.3 Discussion

Now we would like to make notes and discuss scenarios all together. This will give us a clear picture of what we are doing.

We have evaluated the cost benefit analysis for the installation operations. The installation cost calculations are approximate and can vary due to market demand, price uncertainty and time.

As we can see from table 9, the transfer periods for the vessels are not the same. For scenarios A8 and A12 it will be longer due to very low transit speed of a SSCV. The time estimation should be very confident and persistent. During the calculations the waiting periods for the crane vessels have been included in the transfer costs of the rest of the operational fleet.

Let’s have a look at Figure 20; the most economically effective scenario is A4: 8 production templates with 4 wellslots and scenario A6 which have the same costs for the installation. Also, we have to admit the transfer costs are very high. The logistic plan has to be very consistent and thought through. It is also necessary to reduce the waiting time due to the waiting for the cargo vessel with templates for scenarios A8 and A4.

Scenarios A12 and A8 show that installation costs are very expensive due to extremely high daily rent for the SSCV. Scenarios A12 and A8 have a greater number of wellslots and a lower number of ITS but this fact is not relevant, since operational time is almost the same as for scenarios A6 and A4.

Another issue could be the possible underestimation of the construction cost. Due to the big amount of production wells, which are supposed to be needed to develop the Shtokman phases I, II and III, costs for ITS construction could be much higher with scenario A4. A model for the ITS construction cost benefit analysis has been suggested. We can calculate the costs of ITS using the simple dependency from Figure 21. We can also say how much the Shtokman project will cost, having the final number of wells and suggested number of ITS. The difference between the capital expenditures is rising with the greater number of wells in a field.

According to table 14, we must say that the structures with 12 wellslots will be much cheaper to construct. But we have to admit that the drilling costs would be much higher since the horizontal parts of the wells will be longer. Therefore, it is very important to take into consideration also the drilling cost in our model.

During the FDE program calculations, all relevant Shtokman project input data have been implemented. The FDE program has provided us with good output results which gave us an understanding of the total field development cost. According to the suggested model for the construction cost estimation and the FDE program, we have got almost the same results for the ITS construction. The FDE program, furthermore, gives us an approximate estimation of the drilling costs which is a very important factor, especially in the Arctic. The drilling costs should be estimated with in more details during the FEED studies. It is therefore important to be in contact with a drilling department during the subsea development concept studies.

Scenario A8 could also be a good design for the subsea infrastructure. There are some past examples when the A8 scenario has been used as a main subsea field development design. But we have to be aware of the high potential risk during the installation operations. Moreover, it is necessary to estimate the drilling cost due to the long horizontal part of the wells.

Scenario A12 could be neglected due to high risks, big distances between wellheads and bottom holes, high drilling costs and poor drilling flexibility. It is also the most expensive installation scenario for the Shtokman project. Besides, the arctic region is not the place to deploy risk and uncertainty.

It is very interesting and inspiring that the installation costs of A4 and A6 scenarios are not so different, although scenario A6 is slightly cheaper to construct and faster to install. We recommend scenarios A4 and A6 as possible scenarios for the Shtokman phase I field development and scenario A8 as a possible one for the future phases of the Shtokman project. Even so, scenario A4 with 6 ITS and 4 wellslots in each is the most attractive scenario when we include drilling expenses and operational aspects. A4 is based on proven technology, it is easy and cheap to install. It also gives us drilling flexibility and excludes the short well path deviation from the bottom hole, which, obviously, decreases the drilling costs.

We have here discussed the CAPEX, the capital cost expenditures. The operational costs (OPEX) have not been discussed here. It could be realized that ITS with few wellslots could provide less problems for the total production, should it be necessary to close down all wells in one ITS for maintenance in the arctic/subarctic regions.

Furthermore, we have not discussed the net present value (NPV) of the investments and operational costs. It is, however, a fact that small ITS with fewer wells can be installed as the field development progresses thus avoiding early capital expenditures.

7 Risk analysis for the Shtokman ITS installation

7.1 HAZID

As was mentioned, the installation process is a very challengeable task in Arctic. The identified hazards applicable for the Shtokman ITS will be ranked to identify major hazards. These will be analyzed further and addressed during the detailed design. The ranking will be made according to the matrix in APPENDIX C2.

We consider that it is important to enumerate the issues that could influence installation operations. Here is the list:

1. Weather conditions (unpredictable weather)
2. Engine break down
3. Poor sea fastening
4. Personal accidents
5. Loss of structural integrity (e.g. hull, ballast, support structure failure)
6. Loss of stability (e.g. ballast failure, cargo loads)
7. Loss of marine/utility systems (e.g. propulsion, power generation, hydraulics, failure of navigation system)
8. Loss of stability during lift operations
9. Vessel delay (due to big transfer distance)
10. Wire damage (due to big snap load in wire) [7]
11. Lack of fuel (due to long installation operation)
12. Collision/impact (e.g. support vessel, passing vessel, stand-by vessel, aircraft crash on barge, including military, fishing vessels, naval vessels, including submarines, flotel), capsizing (due to heavy lift operations).

We could exclude several causes due to summer time installation (e.g. icing, big waves, equipment freezing, etc.). Main consequences are delaying, capsizing, loss of cargo (e.g. ITS).

Due to the complexity of working offshore with subsea facilities, it is difficult to foresee all possible interactions if something go wrong. An offshore installation or vessel has personnel onboard; however, the risk analysis of the installation operations mainly considers its technical aspects [19].

7.2 Qualitative risk analysis

For each scenario we have to carry out a risk assessment. Basically, a competent risk assessment person, together with the project team, should carry out a site specific JRA (job risk assessment before the work begins. This is normally carried out using a job risk assessment form. The competent person should ensure that appropriate controls have been fulfilled for those hazards that are identified in the written risk assessment. The risks are managed as an integral part of the installation plan [7].

A risk assessment matrix will be used with the job risk assessment (Table 17 – Job Risk Assessment for the scenario A4). This permits us to quantify the probability and severity of the hazards for a particular activity. The product of both indicates the level of risk. A typical risk assessment matrix is shown in APPENDIX C2 [21].

Risk assessment approaches are increasingly used for the assessment of major hazards and the demonstration that risks have been reduced to an ALARP level (2^{nd} zone, yellow-marked in the risk assessment matrix) [7].

Table 17 – Job risk assessment for A4 (prepared by the author according to [7])

Initial Assessment						Final mitigated assessment	
Item no	Specific activity	Hazards identified	Severity	Proba-bility	Initial risk*	Risk-reducing measures	Final risk
1	Transportation Installation	Bad weather conditions. Polar low.	2	B	2B	Weather forecast (every hour) [7]. Polar low probability forecasts [9].	2C
2	Transportation Installation	Engine break down	3	E	3E	Maintenance Availability of lugs	4E
3	Transportation Installation	Poor sea fastening	2	E	2E	Double check work	4E
4	Transportation Installation	Personal accident	3	E	3E	Physical inspection Doctor presence	5E
5	Transportation	Loss of structural integrity (e.g. hull, ballast, support structure failure)	1	E	1E	Safety navigation Double hull	2E
6	Transportation	Loss of stability (e.g. ballast failure, cargo loads)	1	E	1E	Correct double calculation	1E
7	Transportation	Loss of marine/utility systems (e.g. propulsion, power generation, failure of navigation system)	1	E	1E	Maintenance Double check work High quality personal	2E
8	Installation	Wire damage (due to big snap load in wire)	1	E	1E	Accurate lowing Correct double calculation	2E
9	Installation	Loss of stability	1	D	1D	Double check vessel stability and response function in waves.	1D
10	Transfer	Vessel delay	4	C	4C	Confident plan. Logistic studies.	4C
11	Installation	Lack of fuel	4	C	4C	Get more fuel onboard, possibility to refuel	4C
12	Installation	Vessels collision, capsizing	1	E	1E	Safety navigation, check the calculations	1E

*Risk = Severity × Probability

Probability rating:

A Very likely - almost inevitable that an incident would result.
B Likely - Not certain to happen, but an additional factor may result in an incident.
C Possible - Could happen when additional factors are present but otherwise unlikely to occur.
D Unlikely - A rare combination of factors would be required for an incident to result.
E Very unlikely - A freak combination of factors would be required for an incident to result.

Risk priority code:

1 Very High - Must not proceed – change task or further control measures required to reduce risk.
2 High
3 Moderate - Can only proceed with senior management authorization.
4 Slight
5 Negligible - Permissible by those trained and authorized to do so, but a review should be carried out to see if risk can be reduced further [21].

A risk priority code of less than 3 is not acceptable for hazards that target personnel. Potential costs of loss shown could vary dependent on company and operations [21].

We still have four scenarios to go. All the scenarios are presented in table 18.

Table 18 – Suggested scenarios for the Shtokman phase I field development

Scenarios	Type of ITS	Number of ITS	Weight, t	Installation period, days
A4	4 wellslots structure	6	400	35
A6	6 wellslots structure	4	800	29
A8	8 wellslots structure	3	1200	39
A12	12 wellslots structure	2	2200	35

There are different installation procedures and different risks between these four scenarios. The risk rating will shift to higher values due to more complex and heavy lift installation operations of bigger templates. We have to consider all processes and all items during the installation operations to establish the risk assessment matrix for each scenario.

According to the list of hazards and table 17, the risk assessment matrices have been established. The risk assessment matrix for the scenario A4 is presented in Figure 24.

Hazard severity category	Descriptive words	Probability rating				
		A	B	C	D	E
		Very likely	Likely	Possible	Unlikely	Very unlikely
1	Very high				9	6,12
2	High			1		5,7,8
3	Moderate					
4	Slight			10,11		2,3
5	Negligible					4

Figure 24 – Risk assessment matrix for the scenario A4, after risk mitigation

In accordance with Figure 24, we assume that after the risk-reducing measures all 12 hazards will be located in acceptable/negligible zones. The installation of 4 slots structures is common, well-known, very confident and conservative.

The risk assessment matrix for the scenario A6 is presented in Figure 25.

Hazard severity category	Descriptive words	Probability rating				
		A	B	C	D	E
		Very likely	Likely	Possible	Unlikely	Very unlikely
1	Very high				9	6,12
2	High			1		5,7,8
3	Moderate					
4	Slight			10,11		2,3
5	Negligible					4

Figure 25 – Risk assessment matrix for the scenario A6, after risk mitigation

The 6 wellslots structures also have a very good and high rating of successful operations, similar to scenario A4.

A job risk assessment is presented in table 19, similar to table 17.

The risk assessment matrix for the scenario A8 is presented in Figure 26.

Table 19 – Job risk assessment for the scenario A8

Initial Assessment						Final mitigated assessment	
Item no	Specific activity	Hazards identified	Severity	Proba-bility	Initial risk*	Risk-reducing measures	Final risk
1	Transportation Installation	Bad weather conditions. Polar low.	2	B	2B	Weather forecast (every hour) [7]. Polar low probability forecasts [9].	2C
2	Transportation Installation	Engine break down	3	E	3E	Maintenance Availability of lugs	4E
3	Transportation Installation	Poor sea fastening	2	C	2C	Double check work	3D
4	Transportation Installation	Personal accident	3	E	3E	Physical inspection Doctor presence	5E
5	Transportation	Loss of structural integrity (e.g. hull, ballast, support structure failure)	2	C	2C	Safety navigation Double hull	2D
6	Transportation	Loss of stability (e.g. ballast failure, cargo loads)	1	C	1C	Correct double calculation	1D
7	Transportation	Loss of marine/utility systems (e.g. propulsion, power generation, failure of navigation system)	1	E	1E	Maintenance Double check work High quality personal	2E
8	Installation	Wire damage (due to big snap load in wire)	1	C	1C	Accurate lowing Correct double calculation	1D
9	Installation	Loss of stability	1	D	1D	Double check vessel stability and response function in waves.	1D
10	Transfer	Vessel delay	3	B	3B	Confident plan. Logistic studies.	3C
11	Installation	Lack of fuel	3	B	3B	Get more fuel onboard, possibility to refuel	3C
12	Installation	Vessels collision, capsizing	1	E	1E	Safety navigation, check the calculations	1E

*Risk = Severity × Probability

Hazard severity category	Descriptive words	Probability rating				
		A	B	C	D	E
		Very likely	Likely	Possible	Unlikely	Very unlikely
1	Very high				6,8,9	12
2	High			1	5	7
3	Moderate			10,11	3	
4	Slight					2
5	Negligible					4

Figure 26 – Risk assessment matrix for the scenario A8, after risk mitigation

Because of the fact that complex operation risks are moving to an ALARP level, the loss of stability during the transportation and installation operations and wire damage due to big loads are the most dangerous hazards for scenario A8.

The risk assessment matrix for the scenario A12 is presented in Figure 27. A job risk assessment is presented in table 20, similar to table 17.

Table 20 – Job risk assessment for the scenario A12

Initial Assessment						Final mitigated assessment	
Item no	Specific activity	Hazards identified	Severity	Proba-bility	Initial risk*	Risk-reducing measures	Final risk
1	Transportation Installation	Bad weather conditions. Polar low.	2	B	2B	Weather forecast (every hour) [7]. Polar low probability forecasts [9].	2C
2	Transportation Installation	Engine break down	3	E	3E	Maintenance Availability of lugs	4E
3	Transportation Installation	Poor sea fastening	2	B	2B	Double check work	3C
4	Transportation Installation	Personal accident	3	E	3E	Physical inspection Doctor presence	5E
5	Transportation	Loss of structural integrity (e.g. hull, ballast, support structure failure)	2	B	2B	Safety navigation Double hull	2C
6	Transportation	Loss of stability (e.g. ballast failure, cargo loads)	1	B	1B	Correct double calculation	1C
7	Transportation	Loss of marine/utility systems (e.g. propulsion, power generation, failure of navigation system)	1	E	1E	Maintenance Double check work High quality personal	2E
8	Installation	Wire damage (due to big snap load in wire)	1	B	1B	Accurate lowing Correct double calculation	1C
9	Installation	Loss of stability	1	C	1C	Double check vessel stability and response function in waves.	1D
10	Transfer	Vessel delay	3	B	3B	Confident plan. Logistic studies.	3C
11	Installation	Lack of fuel	3	B	3B	Get more fuel onboard, possibility to refuel	3C
12	Installation	Vessels collision, capsizing	1	E	1E	Safety navigation, check the calculations	1E

*Risk = Severity × Probability

Hazard severity category	Descriptive words	Probability rating				
		A	B	C	D	E
		Very likely	Likely	Possible	Unlikely	Very unlikely
1	Very high			6,8	9	12
2	High			1,5		7
3	Moderate			3,10,11		
4	Slight					2
5	Negligible					4

Figure 27 – Risk assessment matrix for the scenario A12, after risk mitigation

The most dangerous scenario is A12. The 12 wellslots structure weights more than 2200 tones and that installation would be the most difficult issue to solve in the Arctic. There is a need of risk-reducing measures for heavy lift operations. The loss of stability and wire damage due to extremely heavy structure are located in the red zone, which is not acceptable for installation operations.

And we can see from these matrices that the risk rating values are shifting from the green acceptable zone to an ALARP and not acceptable zones, meaning that the installation operations with a bigger template have a higher risk due to complexity of heavy structure transportation and heavy lift operations. Moreover, as we can see from part 5, installation costs for scenario A8 and A12 are much higher than for scenarios A4 and A6. That could lead to higher economic risks and losses. The most safe scenarios for the ITS installation in the Arctic region and for the Shtokman project are A4 and A6.

8 Conclusion

The following conclusions can be drawn from our observations and the calculated results.

This research topic is important since the Shtokman project is a part of the Russian government's strategy for the development of the Russian Arctic. It is connected with the fact that the economically viable oil and gas fields deplete, therefore exploration and discovery head to other regions of the earth, such as the Arctic that hold valuable mineral deposits.

In this thesis an analysis of the selection of integrated template structures for Shtokman phase I field development is presented. The thesis describes the selection of optimal number, layout and structure for the subsea production system for the Shtokman project.

First of all, one shall analyze past projects and accumulated experience. Past projects shall be considered as true stepping stones towards oil and gas development in the arctic region. They have been discussed at the beginning of the thesis in part 2.

The Shtokman field is one of the largest known offshore gas fields in the world and the challenges faced in bringing the field to production are significant. The main data and planned infrastructure of the Shtokman project have been presented in the thesis.

The geographical position of the Shtokman field and the severe climatic conditions make the development of this field and execution of offshore and subsea marine operations extremely challenging [10]. Features, factors and specific environmental conditions affecting safe offshore operations, subsea construction work and the field development have been listed and described.

All together this gives us some special requirements which have to be implemented during the arctic subsea field development. There are several aspects of ITS design in the arctic regions or the arctic environments which offer additional challenges to the designer. Due to a very harsh environment and presence of ice it is objective to determine a template type [17]. Special requirements and design details have been presented in APPENDIX A and B [14], [15], [16].

Another challenging problem for the Shtokman ITS is the installation process. What kind of vessels is required for the Shtokman area environment? Four types of vessels have been reviewed when trying to answer this question (monohull, semi-submersible crane, barge crane and wet tow vessels).

Several subjects are to be considered when planning the offshore operations. Part 4 looks at the vessel stability and the vessel response function in waves [7]. Stability checks are used to calculate if a vessel is capable of performing the planned operations. The main considerations are buoyancy and keeping stable equilibrium during all phases of operation.

For the Barents Sea metocean conditions it has been considered to involve SSCV and monohull vessels even if we operate during the summer season (May – August/September). Due to heavy cargo transportation and heavy lift operations we have to be sure about the vessel's stability and response functions in waves. The period of heave, added mass and other characteristics have been considered during the selection of the installation vessel in the Shtokman area.

The monohull crane vessel could easily get in resonance with waves according to the Barents Sea conditions (according to the scatter diagram [8], mainly the T_s = 3 – 13 sec). It's more convenient to shift the natural period of the selected vessel to a greater value where the energy of the -resonance is smaller; this means to increase the deadweight or choose another vessel. The crane barge shall be neglected due low natural period (5 – 7 sec).

Then, we have analyzed and chosen for consideration four different scenarios for Subsea Production Systems with 2, 3, 4 or 6 integrated template structures (ITS) for the field development:

1) Base case / A4 - 6 ITS with 4 well slots (proposed by the operator).
2) A6 - 4 ITS with 6 well slots
3) A8 - 3 ITS with 8 well slots
4) A12 - 2 ITS with 12 well slots

For each scenario an analysis of the related marine operations for the subsea modules was carried out. This part was divided into two: installation costs and total expenditures. ITS installation time schedule has been presented. Table 6 with the operation time for each scenario has been prepared.

An increasing challenge at the Shtokman field is to design, construct, and install offshore installations that give an acceptable payback of the investments. However, the considerations for cost reduction are important for offshore field developments in general. The main cost reductions are obtained by:

- Maximum use of industry capability
- Application of proper organization principles
- Focus on functional requirements
- Shortened project execution time [7].

Cost benefit analysis of the installation operations depends on a quantitative analysis of the full information related to these procedures.

We have included the transfer costs as well. We assumed that the vessels were transported from the port of Stavanger to the Murmansk harbor. Obviously, during the logistic studies we have to examine the demand of the vessel market and order the vessels in advance.

As we can see from table 9, the transfer period for the vessels is not the same. For scenarios A8 and A12 it will be longer due to a very low transit speed of SSCV. The time estimation should be very confident. During the calculations the waiting period for the crane vessels have been added to the transfer costs of the rest of the operational fleet. Due to the high rent of the crane vessel, scenario A12 is the most expensive in this case and scenarios A4 and A6 are the cheapest.

One of the most important factors in cost estimations for the installation procedures is the rental cost of the equipment. Expenditures are the highest for the crane vessel (APPENDICES E1, E2, E3). As we can see from Figure 20, the most economically effective scenario is A4: 8 production templates with 4 wellslots while scenario A6 has the same costs for the installation. Also we have to admit the transfer costs are very high. The logistic plan has to be very consistent and thought through. It is also necessary to reduce the waiting time due to waiting of the cargo vessel bringing templates for scenarios A8 and A4 to the offshore location. Scenarios A12 and A8 are very expensive due to extremely high daily rent for the SSCV. Scenarios A12 and A8 have a greater number of wellslots and a smaller number of ITS, but this fact is not relevant since operational time is almost the same as for scenarios A6 and A4.

During the selection of ITS for the Shtokman field development it is important to keep in mind the ITS construction cost. It depends on the number of wellslots in the module. It is much cheaper to construct 2 templates with 12 wellslots in each than to construct 6 templates with 4 wellslots. According to this, we have decided to deploy a cost benefit analysis for the ITS construction. We calculate the costs of ITS using the simple dependency from Figure 21. We can then say how much the Shtokman project will cost, having the final number of wells and with the suggested number of ITS. The difference between the capital expenditure is rising with the higher number of wells in a field. This is important to understand and keep in mind for the first and the next phases of the project.

According to the results, we must say that the structures with 12 wellslots will be much cheaper to construct. But we have to admit that the drilling costs should be much higher since the horizontal parts of the wells will be longer. And it is very important to take into consideration the drilling cost in our model. That’s why it has been decided to work with a Field development cost evaluation program. The construction cost results from the FDE program were quite similar to the result which has been evaluated from the previous analysis. Scenario A4 economically is the most attractive one for the Shtokman project according to the FDE program output data and according to this model. Drilling costs have to be evaluated with more certainty. Scenario A6 is also economically attractive and could be applied during the Shtokman project phases 1, 2 and 3.

We recommend scenarios A4 and A6 as possible scenarios for the Shtokman phase I field development and scenario A8 as a possible one for the future phases of the Shtokman project. Even so, scenario A4 with 6 ITS and 4 wellslots in each is the most attractive scenario for operations. A4 involves proven technology, it is easy and cheap to install, and also it gives us drilling flexibility and excludes a big well path deviation from the bottom hole, which, obviously, decreases the drilling costs.

During the work I have faced a lot of challenges, which were very interesting to solve. The Arctic region is quite a new area for oil and gas industry. We have to understand that this region can give us a lot of uncertainty and unpredictability. In this case we say that the role of risk assessment and analysis can’t be underestimated. Risk analysis is supposed to be carried out before any operations. Moreover, the number of accidents should be decreased towards zero. It is vitally important to deploy and take into account any possible unwanted scenarios in the Arctic. That's why risk analysis is also the important part of the thesis.

A chapter regarding risk assessment is included after the presentation of the cost benefit model and discussion of all the scenarios. A HAZID and a qualitative risk analysis have been made according to the risk management papers [19], [27]. The main purpose for performing the HAZID study is to identify the hazards at an early stage. It might provide input to the project design. The use of the HAZID may lead to a safer and more cost-effective design [27]. We have established job risk assessment for all the scenarios. Furthermore, we have evaluated the risk assessment matrices for each scenario.

And we can see from these matrices that the risk rating values are shifting from the green acceptable zone to an ALARP and not acceptable zones, meaning that the installation operations with a bigger template have a higher risk due to complexity of heavy structure transportation and heavy lift operations. Moreover, as we can see from part 5, installation costs for scenario A8 and A12 are much higher than for scenarios A4 and A6. That could lead to higher economic risks and losses. The most safe scenarios for the ITS installation in the Arctic region and for the Shtokman project are A4 and A6. This confirms the conclusions of the economic evaluations.

It should also be noted that OPEX and NPV considerations would support the decision, see discussion, page 51.

Nevertheless, a huge risk assessment program and risk evaluations documents have to be prepared before project will succeed to pass the execution decision gate [9].

The final selection of ITS for the Shtokman phase I field development is a very long and sophisticated process which will be carried out by several specialists from different company departments. The analysis carried out in the thesis has been a rather big ambition to take on.

"Arctic must be conquered and it is especially important for direct industrial development of mankind, at least the same as the triumph of knowledge. The victory may be deemed complete, however, only if a vessel outfit in Europe goes fast and directly to the Bering Strait. Russia is to crave for true victory over Arctic Ocean even more than any other country, for none else owns greater length of shore line in the Arctic Ocean".

From: "The Arctic Ocean Investigation" by Dmitry Mendeleyev, 1901

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APPENDIX A

In APPENDIX A we provide the general ISO requirements and overall recommendations for the development of complete subsea production templates.

1.1 Template and manifold systems

The template is the framework that supports other equipment such as manifolds, risers, drilling and completion equipment, pipeline pull-in and connection equipment and protective framing (template and protective framing is often built as one integrated structure, however if early drilling is required then a predrilling template is usually installed to permit drilling activities to commence, followed by subsequent installation of a protective structure with integrated manifold onto the pre-drilling template) [15]. The template should have a foundation that will transfer the design loads into the seabed [15].

1.2 Drilling and completion interface

The integrated template or pre-drilling template should provide a guide for drilling, landing and latching of the conductor and conductor housing, and provide sufficient space for running and landing of the blowout preventer (BOP) stack [15]. The template slots are normally capable of supporting the weight of the conductor and conductor housing until cementing operations are complete [15].

1.3 Alignment

The template should provide alignment capability for proper physical interfaces among subsystems, such as wellhead/tree, tree/manifold and manifold/flowlines [15].

1.4 Guidance

The template should provide for a guidance system to support operations through the life of the installation [15]. If guidelines are used, the template should provide proper spacing and installation/maintenance capability for the guide posts. If guidelineless methods are used, the template should provide sufficient space and passive guidance capability to successfully install key equipment items [15].

1.5 Abandonment provisions

If the template is to be recovered at the end of the project, its design should include provisions for this requirement [15].

1.6 Structures

All subsea structures shall be designed according to internationally recognized standards such as ISO 19900 [16]. The following apply:

- “the structure should ensure sufficient alignment capability for physical interfaces between subsystems such as wellhead/production guidebase, subsea tree/manifold and piping system, manifold/flowline termination and installation aids, protective structure (if relevant) and other relevant interfaces;
- the subsea structures may be either fixed/locked to the wellhead system or separate with no direct fixed connection to the wellhead” [16].

Another operation which is supposed to be quite important and challengeable in the Arctic regions is intervention.

In order to facilitate efficient intervention, the subsea template, structure and its equipment should be designed as follows [16]:

- “all retrievable modules and structures should, if not otherwise secured, be properly locked down by means of a locking mechanism operated according to the selected intervention strategy;
- hinged protective structures should be designed for replacement;
- the landing area and surrounding areas should be designed to withstand loads imposed by the respective intervention system during landing and operation. For wire-deployed running tools, a maximum landing speed of the unit equal to 1,6 m/s should apply. For drillpipe-deployed running tools, the maximum landing speed should be 0,8 m/s;
- suitable viewing positions should be provided for observation during running, connection and operation of tools, modules and equipment;
- suitable landing area and/or attachment points should be provided where manipulative tasks are required to be carried out;
- sensitive components/items on the subsea structure which can be damaged by the intervention system should be protected;
- bucket(s) designed for easy replacement of acoustic transponder(s) may be provided. Acoustic shielding and potential snagging should be avoided;
- all locking mechanisms on protection hatches and lifting frames should be easily operated in accordance with the defined intervention strategy;
- replaceable guideposts should utilize locking mechanisms operated by the selected intervention system;
- all permanently installed guideposts which require guidewire attachment should be designed such that a new guidewire can be re-established upon broken wire or anchor overpull;
- equipment installed on the subsea structure which requires torque or stroking to be applied during operation can require a dedicated tool and interface;
- the design should be such that location of anodes and other construction details do not represent any obstruction or snagging point for the selected intervention system;
- landing velocity and the need for soft landing systems should be evaluated;
- operational requirements for running intervention systems from vessels, necessitating offset angles on the guidelines, should not restrict ROT access, reduce running clearances or otherwise be detrimental to operational safety and reliability;
- marking shall be provided to permit easy identification of equipment by divers and/remotely operated vehicle (ROV);
- tools, BOP, modules and all retrievable equipment should have an adequate running clearance to any part of the structure, adjacent module or equipment, etc. to avoid any unintended impacts or clashes during installation and retrieval. There should be no

physical contact between modules being run and the surrounding structure, even at worst-tolerance stack-up;

- for guidelineless operations, physical restrictions, such as guide funnels or bumper beams, should be provided to avoid impact between adjacent equipment [16].

1.7 Bottom Frame/Main Frame and Protection Structure

Structures the following functional requirements apply [15]:

a) The well supporting structure/production guide base design shall allow for individual thermal expansion of the conductor/wellhead housings. The thermal expansion data are to be included in the basis for interface tolerance design of template mounted objects. A system for monitoring well expansion may be provided

b) A drill cuttings disposal system should be included. Alternatively accumulation of cuttings shall be considered.

c) Snagging on the structure during pull-in and pull-out of sealines shall be avoided.

d) All retrievable modules and structures shall if not otherwise secured, be properly locked to the bottom frame structure by means of a locking mechanism operated according to the selected intervention strategy [15].

1.8 Foundation and leveling

Generally, subsea systems require the template to be reasonably level in its final position for proper interface and mating of the various components and subsystems. Typical leveling methods include one- and two-way slips between piles and pile guides, jacking systems at the template corners and the active suction method. A means for level indication should also be included. Piled template systems shall be provided with a means to mechanically fix the template to the piles (i.e. grouting or swaging) [15].

1.9 Template installation requirements

When installing the template, all installation requirements should be fulfilled. There can be used different types of installation vessel, such as drilling rigs or crane barges. The requirements may include several or all of the items below:

- load-out;
- transportation to site;
- launch capability;
- crane capacity;
- buoyancy capability;
- ballast/flooding system;
- system for lowering to seabed;
- positioning capability;
- leveling system;
- foundation interface [15].

During the installation procedures, the subsea production system components should follow to the following requirements [15]:

- not rely on hydraulic pressure to retain the necessary locking force in (module-to module) connectors;
- allow cessation of operations without compromising safety;
- allow testing/verification of interface connections subsequent to connection;
- allow for quick, easy and reliable make-up of modules;
- have facilities for testing prior to deployment by the use of test skids, if applicable;
- minimize entry of water or contamination into hydraulic circuits during connections (which can jeopardize system functionality);
- facilitate orientation and guidance during installation;
- provide means (temporary or otherwise) of gauge-pigging of flowlines;
- be tolerant of small amounts of seabed debris between the interface connections or allow flushing prior to the make-up action;
- be tolerant to wave-induced loads;
- avoid loss of harmful fluids during installation and operation;
- minimize impact of equipment malfunction leading to discharge of hydrocarbons;
- facilitate periodic testing to verify that the system is fully functional [15].

APPENDIX B

In APPENDIX B we provide the general NORSOK requirements and overall recommendations for the ITS installation operations.

1.1 Template structure design

This is a summary of the template structural design requirements. This is based on several standards such as NORSOK U-001, N-001, N-003, N-004 [13] and [14].

The layout of the well slots within one template shall be such that the rig, if anchored, shall not have to move anchors while drilling and completing the wells [14].

All templates shall be prepared for the maximum number of wells available on the templates, including complete set of guide posts and electrical cabling. Any cables routed on template structure shall be directed through dedicated cable trays protecting cables from damage during installation, operation and intervention. Any sharp edges shall be avoided. It should be possible to install new cables in dedicated cable trays.

The templates shall be equipped with dedicated parking places for hydraulic, electrical & optical connectors as dictated by the control system. This applies for both permanent and dummy connectors on same panel. Connector parking position shall be selected to minimize risk of jumper and connector damage [14].

Structural support at template structure lifting padeye areas shall include cradles for temporary support of ROV shackles during installation, retrieval and re-installation of lifting equipment subsea.

Particular attention shall be paid on loads and load effects related to wet towing; hereunder: seastate, duration, towing speed, current; all related to selected wet tow concept and with special focus on fatigue issues. Lifting areas (lugs, trunnions) shall be documented to have high fatigue resistance.

The template structure shall be furnished with suitable tugger wire attachments for clump weight, minimum in each corner of the structure above mudline. Minimum capacity: 25 ton. Low positioned tugger points on skirt anchors should be evaluated based on installation vessel handling/installation method. In addition template structures shall be delivered with a safe working load (SWL) 20 ton hook-up interface dimensioned to suit a 20 ton ROV operated hook in the pipeline and umbilical pull-in/connection area [14].

During installation, retrieval and re-installation of lifting equipment structural support at template structure lifting padeye areas shall include cradles for temporary support of ROV shackles [14].

1.2 Protective structure design requirements

The height of the protection structure shall be minimized in order to reduce the installation height. In order to ensure a safe installation and pulling of the BOP, the maximum lifting height from the wellhead (connected) and to the BOP is clear of the top of the protection structure frame shall be 7 meters. This to allow the rig to lift the BOP off of the wellhead and move sideways to get the BOP out of the critical area without having to disconnect any joints at deck level. There should be no critical equipment underneath the BOP on the outside of the template structure top members during this horizontal movement. Critical equipment is considered as equipment that requires extensive remedial actions or that represents hazards in case of BOP drop/uncontrolled movements. Typically this means flowlines and associated equipment and/or other sealines. BOP lifting across a roof hatch is not considered as critical in this respect [14].

The following main design principles shall be used for the protection structure design [14]:

- The Protection structure size shall take into account all fabrication, installation and operational tolerances (e.g. well expansion) of the protection structure and production equipment.
- The protection roof shall not have physical contact with the production equipment (i.e. XMT, manifold) caused by deformation after a dropped object impact.
- Any instrumentation shall be located at a low level (but sufficiently above seafloor to avoid poor ROV visibility) and have easy and safe access for connecting cables offshore and be protected against potentially moving wires.
- Water filling of tubular volumes prior to installation offshore should be avoided if practical, however, if required it shall be possible to be effectively and safely carried out from deck level by using a quick connector and fixed pipes routed to the actual volumes.
- Observation-ROV shall have access for inspection and manipulative tasks without the need for opening the hatches/covers.
- The template/manifold/protective structure design shall allow for manifold valve operation by using a WROV without need for operation of primary protective hatches.
- Roof panels shall be arranged to allow for simultaneous operations; e.g. during intervention on one wellslot the neighboring wellslot shall be protected.
- Preferably hinged panels should be hinged towards the sealine hub area. This is in order to allow BOP lifting across the two hub-free sides of the structure. For satellite structures there are normally allowances for more sideway lifting directions of the BOP.
- Hinged roof panels shall be able to opened 180 degrees from the initial horizontal position unless the roof design allows sufficient lifting height for the BOP (7m) at other angles.
- The arrangement of the roof panels shall not prevent W-ROV access to manifold, to other areas identified for intervention tasks, or to adjacent Xmas trees (XMT) while performing rig operations (drilling and completion) on a wellslot.
- Roof panels (hatches) shall be made separately retrievable/installable, and incorporate a self-guiding design that ensures safe and efficient landing of the panel into its hinge/interface. The hinge/interface on the subsea structure shall be designed to maintain its functionality upon panel damage and allow for retrieval and re-installation of a roof panel.
- The protective structure should allow for being suitable for tie-in of any applicable sealine connection system (sealine tie-in, spools as well as flexible tails).
- The hatches shall be possible to operate both by direct and indirect pull. Indirect pull by use of wires with anchors, both for closing and opening. Indirect pull closing principle is shown on the sketch below. Indirect pull can be avoided if a properly documented weak link concept is used.
- Any use of transportation/safety slings for sea fastening etc. on the hatches shall be sufficiently designed to take all loads and be easily removable by ROV [14].

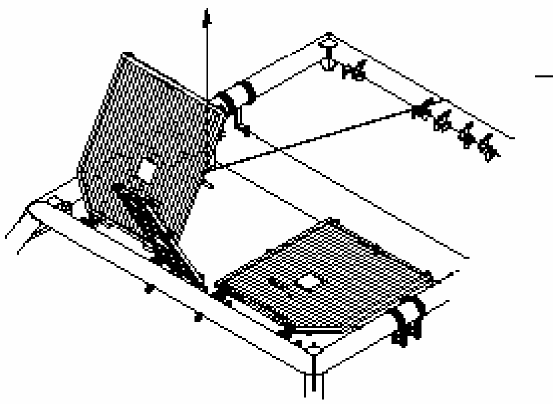


Figure B. 1 - Principle of hatch indirect pull. Closing sequence of hinged roof hatch

Special attention shall be paid on the design of the wire guides on protective covers. It shall be possible to easily thread and unthread the wire by ROV when the cover is either fully open or fully closed. Check for potential jamming or locking of the wire at any end position.

The design shall allow for minimum 30 degrees out-of-verticality of the lifting wire in any direction and at any cover position without allowing the wire to slip out of the wire guide system. The sketch below shows a wire guide principle that should be considered to achieve this [14].

1.3 Installation requirements

There are some special requirements for the template installation procedures which have been listed in NORSOK [14].

The requirements listed below apply both to structures and manifolds.

Template structures and manifold systems shall be designed for installation by appropriate installation vessels. All structures and lifting interface/rigging shall be designed for offshore lifting of flooded and completely assembled structures [14].

The structure shall be designed in such a way that it could be installed together with the manifold system and as a separate template installation, unless other method is stated in the project.

Structures shall be designed for installation and lifting according to NORSOK J-003 and DNV Rules for planning and execution of marine operations [14].

The structures and modules shall be designed for a standard offshore installation without the need for special installation. The design shall focus on simple, reliable and efficient offshore operations, especially in Arctic. Restrictions concerning sequence of marine installations and drilling rig activities shall be minimized.

The Subsea Structures shall include sufficient openings in mudmats and protection covers or roof hatches to avoid uplift during lifting through the splash zone and lowering through water [14].

The lifting arrangement shall ensure that the structure is horizontal within 0.2 degrees relative to the true horizontal for submerged lift. If it is necessary, ballasting weights on the structure shall be installed.

All retrievable components shall be properly designed in order to allow depressurization and zero harmful discharge to sea. In order to document structural deflections and module retrievability/reinstalability in the various stages from fabrication through transportation, site testing, lifting, installation, commissioning and production, a tolerance budget and tolerance verification system shall be provided [14].

Wet tow shall be allowed for integrated structures and separate protection structures considering the special limits. A project may require that the manifold should be wet towed together with the structure. Separate wet towing of the manifold is not possible. The structures, assembled in one unit or separated, shall be towed submerged from shore to site at a towing speed up to 4 knots. It is important to perform model tests to check this [14].

In case of abandoned installation or towing, the structures need a special design for making possible further wet storing (emergency parking on seabed) as this is not a general design requirement.

In order to limit installation height there should be considered lifting points located at the bottom frame of larger structures and modules. Total lifting height for template structure should as a guide not exceed 30 meters in total including the lifting arrangement up to the crane master link hook.

Design, fabrication, testing and documentation of lifting gears and corresponding padeyes on the structures, modules and components shall be according to NORSOK R-CR-002 and DNV Rules for Certification of Lifting Appliances [14].

All subsea equipment and lifting equipment shall be designed for safe subsea retrieval and subsea re-installation. The use of lifting frames should be avoided in case of large lifting height or reducing safety. Simple spreader bars can be used.

HSE shall be an especially important item in design of template structure. In order to achieve this it is important to implement permanent attachment points for safety harness on the structures. The advantage of this is that it should be easy to attach and remove the fences and rope and this can be used at all stages of fabrication, testing and installation. Safe personnel access to lifting points etc. on the structures shall be ensured by using safety harness attachment points, ladders, grating etc. for the fabrication period [14].

Points or areas for sea fastening of the modules and structures shall be identified and designed for the special loads. Requirements for installation tolerances are listed in table B.1 [14].

Table B. 1 - Requirements for subsea structures installation tolerances

Description	Requirement	
	Templates w/wells	Other structures
Installation tolerance	+/- 5 meters from predefined origo	+/- 5 meters from predefined origo
Orientation	+/- 3 degrees from predefined coordinate system	+/- 3 degrees from predefined coordinate system
Seabed inclination	Up to 3 degrees	Up to 3 degrees
Structure inclination after leveling	Max 0.3 degrees from horizontal plane	Max 1.0 degree from horizontal plane

Specific conditions of the Shtokman project may imply more strict requirements.

There shall be developed a proposal for type and placement of instrumentation necessary in order to control the installation of the structure within defined criteria based on the structural analysis and design [14].

Facilities for monitoring inclination and offsets on the structure shall be provided on the structure or the ROV panel and there should be used sufficient resolution/accuracy to comply with installation tolerances. In order to achieve the above mentioned installation criteria, alternative primary and secondary (back up) instrumentation and methods shall be considered, designed and planned for based on structural deflection measurements and installation water depth.

For all the structures the following shall be used as basis for installation:

- Identification of minimum 4 physical points/ brackets on the template structure. These points/brackets shall be marked with unique identification tags; the marking and the points shall be accessible by ROV during installation and throughout the life time.
- Critical horizontal planes shall be identified for each structure.
- Each critical plane shall be defined by three of above points [14].

Fixed high precision water pressure gauges or inclinometers shall be the primary tool for determining structure inclination. Method and instrumentation shall be based on structural deflection analysis, structural base lengths and installation water depth.

For water pressure gauges: the structures shall be equipped with brackets or other suitable means for supporting such gauges. There shall be made necessary interface arrangements for central monitoring (e.g. ROV panel) of installed or planned instrumentation [14].

APPENDIX C

Figure C. 1 – Suggested Shtokman subsea architecture – schematic [12]

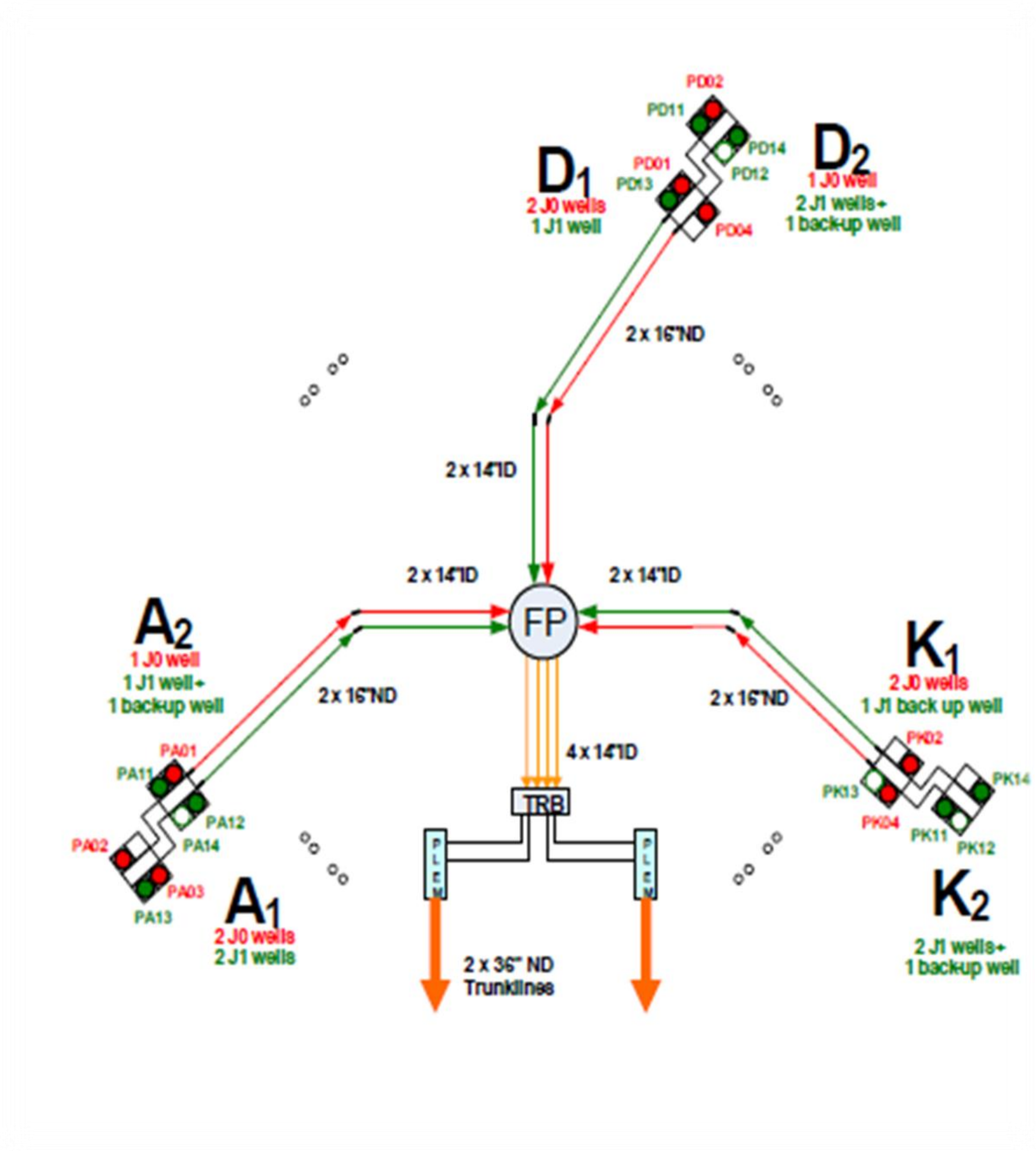


Figure C. 2 - Risk assessment matrix

Hazard severity category	Descriptive words	Actual/potential consequences: Personal illness/injury	Environmental *(any incident that ...)*	Cost of loss	Probability rating A very likely	B likely	C possible	D unlikely	E very unlikely
1	Very high	Fatality(s), terminal lung disease or permanent debility	potentially harms or adversely affects the general public and has the potential for widespread concern regarding the company's operations. Can have a serious economic liability on the business	>$1m	1	1	1	2	3
2	High	Serious injury, poisoning, sensitisation or dangerous infection	potentially harms or adversely affects employees and the environment at the worksite. Requires specialist expertise or resources for correction	>$250,000	1	1	2	2	3
3	Moderate	Injury leading to a lost time accident or persistent dermatitis or acne	potentially harms or adversely affects employees and the environment at the worksite. Requires general expertise or resources for correction	>$50,000	1	2	2	3	3
4	Slight	Minor injury requiring first aid treatment or headache, nausea, dizziness, mild rashes	presents limited harm to the environment and requires general expertise or resources for correction	>$10,000	2	2	3	3	3
5	Negligible	Negligible injury or health implications, no absence from work	presents limited harm to the environment and requires minor corrective action	>$10,000	2	3	3	3	3

Probability rating

A Very likely - Almost inevitable that an incident would result.

B Likely - Not certain to happen, but an additional factor may result in an incident.

C Possible - Could happen when additional factors are present but otherwise unlikely to occur.

D Unlikely - A rare combination of factors would be required for an incident to result.

E Very unlikely - A freak combination of factors would be required for an incident to result.

Risk priority code

1 High risk - Must not proceed – change task or further control measures required to reduce risk.

2 Medium risk - Can only proceed with senior management authorization.

3 Low risk - Permissible by those trained and authorized to do so, but a review should be carried out to see if risk can be reduced further.

Note: Risk priority code of less than 3 is not acceptable for hazards that target personnel.

Potential costs of loss shown could vary dependent on company and operations [21].

APPENDIX D

Figure D. 1 - Excel sheet of the field development evaluation program. Input data is according to [3], [11] and [12].

PROSP for PETRAD COURSES

Field Development Evaluation Program

Developed by Jonas Odland

FOR PETRAD COURSE ONLY!		
CASE:		11-дек-11

PROSP CALCULATION DATE:	11-дек-11

INPUT DATA - (ALL INPUT ON YELLOW FIELDS)		
0	Input	Info
Options choose 6!	6	
Water depth	350	metres
Design life for installations (years) (999=default)	999	333
Type of reservoir: Option 1-4 (See Table B below)	3	Gas Cond
Recoverable volume of oil and/or condensate	40,0	mill Sm3
Recoverable volume of gas	3900,0	GSm3
Reservoir area [km2] (999 - default)	999	748
Reservoir depth (from MSL)	2000	metres
Reservoir quality: Option 1-5 (See Table C below)	2	Good
Complexity of drilling - relative	1,0	(0,5-2,0)
Frequency of well interventions - relative	1,0	(0,5-2,0)

TARIFFS		
Oil Transport	37,74	NOK/Sm3
Gas Transport	0,00	NOK/Sm3
Oil Processing	0,00	NOK/Sm3
Gas Processing	0,00	NOK/Sm3
PRICES		
Oil price	642	NOK/Sm3
Gas price	0,71	NOK/Sm3

OTHER CALCULATION PREMISES		
Currency - use 2 for USD	2	
Rate of interest (discount rate)	8	Percent
Number of stream days per year, 999=default	999	338
Production start (years from project sanction) 999=defau	999,0	5,8
Plateau start (years from project sanction) 999=default	999,0	7,2

TECHNICAL INPUT SPECIFICATIONS		
TOPSIDES (see also below)	70718	
No. of beds (999=default)	999	156
Oil throughput capacity [Sm3/day]	20000	16244
Gas throughput capacity [mill Sm3/day]	70,000	1950,000
Water injection capacity [m3/day]	0	0
Produced water treatment capacity [m3/day]	15000	15000
PLATFORM WELLS & DRILLING	0	0
No. of production wells	0	353
No. of water injection wells	0	0
No. of gas injection wells	0	0
X-mas trees: Dry trees=1, Wet trees=2	0	(1 or 2)
Drilling concept factor (see Table D below)	0,00	(0,0-1,0)
SATELLITE PRODUCTION SYSTEM	98121	20
No. of production wells	20	353
No. of water injection wells	0	0
No. of gas injection wells	0	0
No. of Subsea Templates	6	6
No. of WHD Platforms	0	25
Type of wellhead platform (see Table E below)	2	(1, 2, 3, 11, 22, 33)
Flowline material (1, 2 or 3 - See Table F below)	1	Carbon
Direct tie-back = 1, Tie-back via trunk line = 2	1	(1 or 2)
Average distance from field center (km)	2,00	13,67
EXPORT/IMPORT SYSTEM		
Oil storage volume (FSU)	0	120000
Loading buoy type (STL=1,0)	0	(0,0-1,0)
Length of Oil pipeline	0	km
Length of Gas pipeline	550	km
SUBSTRUCTURE and RISERS		10,0
Concept: Options 0-12 (See Table G below)	9	FPSO
Integrated Oil storage volume	150000	120000
Riser system (1 or 2 - See Table H below)	1	Individual
ADDITIONAL FUNCTIONAL SPECIFICATIONS		
Test separator	1	0=no 1=yes
Wellstream export (pipeline)	0	0=no 1=yes
Dehydrated wellstream export (pipeline)	0	0=no 1=yes
Unstable oil export (pipeline)	0	0=no 1=yes
Stabilized oil export (tanker or pipeline)	1	0=no 1=yes
Gas reinjection	0	0=no 1=yes
Rich gas export (pipeline)	0	0=no 1=yes
Sales gas export (pipeline)	1	0=no 1=yes
Desalting of crude oil	0	0=no 1=yes
Desulphatation of injection water	0	0=no 1=yes
CO2 removal - (indication only)	0	0=no 1=yes
Artificial lift	1	0=no 1=yes
Fiscal meetering of oil	0	0=no 1=yes
Fiscal meetering of gas	1	0=no 1=yes
Electric power generation	1	0=no 1=yes
Inlet separator pressure, [bar] (999 - default)	999	100
Gas export pressure - [bar] (999 for default)	999	160
End plateau - [percent] (999 for default)	999	71

FACILITIES COSTS		mill.USD	P/L 1/0
TOPSIDES			
		146	1
		371	1
		0	1
		83	1
		731	1
		855	1
		117	1
Sub-total Topsides		2303	
SUBSTRUCTURE	FPSO		
		102	1
		113	1
		44	1
		16	1
		9	1
Sub-total Substructure		284	
PLATFORM WELL/RISER SYSTEM			
		92	
		0	
Sub-total Platform well system	N.A.	92	
SUBSEA PRODUCTION SYSTEM (sps)			
		287	
		88	
		102	
		41	
Sub-total Subsea Production System (SPS)	26	517	
EXPORT/IMPORT SYSTEM			
Offloading/Storage Unit (m3)	0	0	1
Oil Pipeline (km)	0	0	
Gas Pipeline (km)	550	3669	
	0	0	
Sub-total Export/Import system		3669	
Project team and insurance		382	
TOTAL PROJECT COSTS		7247	

DRILLING	No.of	mill.USD
Platform Wells	0	0
Satellite Wells / Predrilled Wells	20	718
TOTAL DRILLING COSTS	20	718

ANNUAL OPERATING COSTS		mill.USD
Offshore Personnel and Catering		20
Production and Maintenance Materials		52
Well Maintenance - Platform wells		0
Well Maintenance - Subsea wells & pipelines		9
Logistics (helicopters, boats, bases)		5
Onshore Organization and Overhead		12
CO2 Tax and Area fee		0
Insurance		26
Leased Equipment		0
Total annual operating costs ex. tariffs	2620	124

OFFSHORE MANNING	
Manning (ex. drilling)	78

TARIFFS FOR OIL AND GAS		Costs
Tariff (per Oil Equivalent)		0
Tariff per year at plateaux	35	2

COST PHASING (Capex ex Drilling)	11-дек-11
Cost reference year :	0
Investment period, years	6
Year 1	0
Year 2	0
Year 3	0
Year 4	0
Year 5	0
Total Capex ex Drilling	0

	18237	17,00
	0	0,00
	-435	-0,41
	-781	-0,73
	-10	-0,01
	17012	15,86
	-12780	-11,91
	4231	3,94

	1,14

Figure D. 2 – Definition of input parameters according to the field development evaluation program

Definition of input parameters

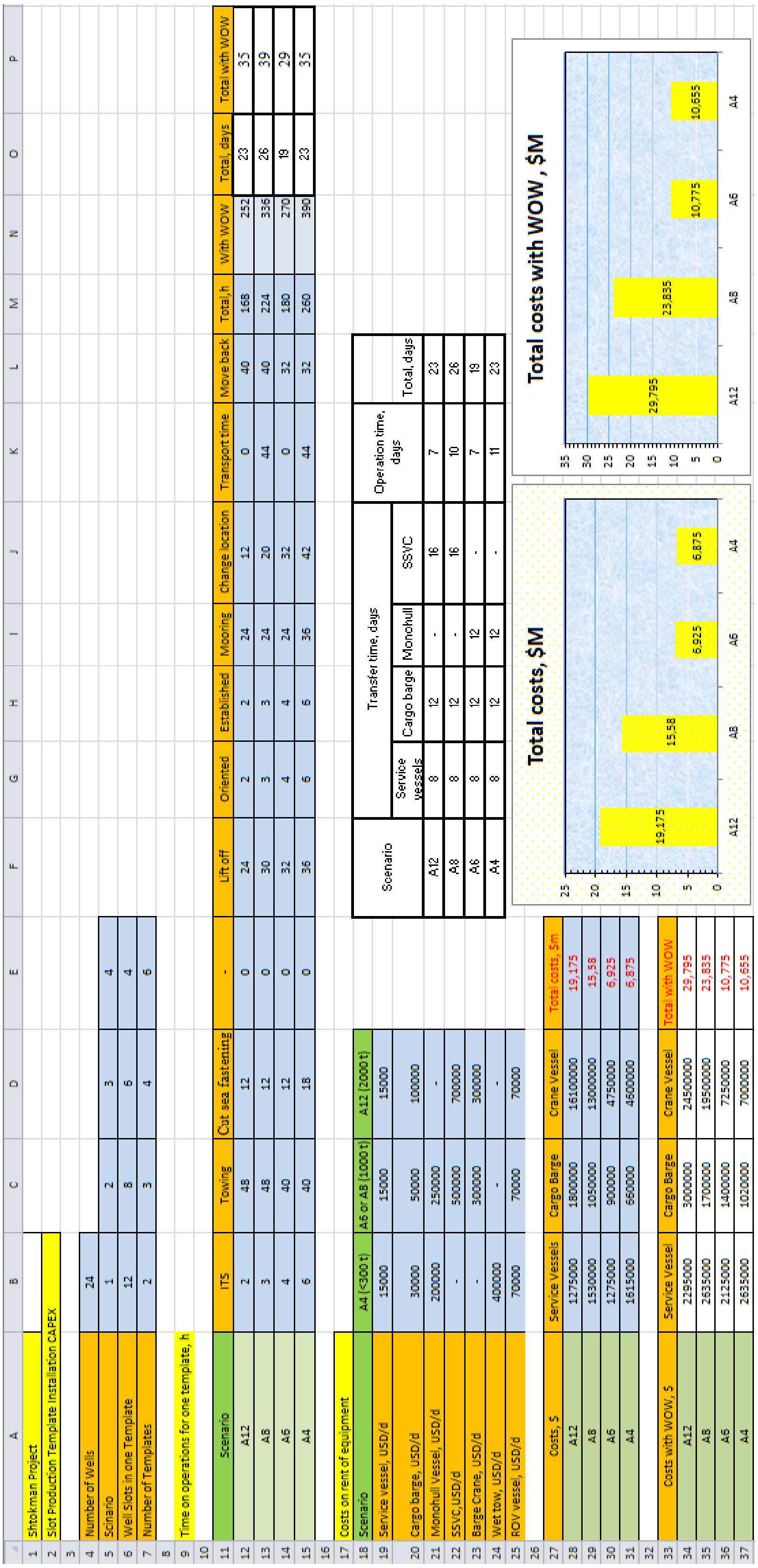
Water depth	Water depth on location in [metres]
Design life of facilities	Given in years or as 999 for default
Type of reservoir	See Table B below
Recoverable volume of oil and/or condensate	Given in mill. Sm3
Recoverable volume of gas	Given in GSm3 (mrd.Sm3)
Reservoir area	Given in [km2] or as 999 for default
Reservoir depth	Depth measured from mean sea level (MSL) to top of reservoir given in [metres]
Reservoir quality	Permeability, porosity etc (qualitative), see Table C below
Complexity of drilling	Assessment of well/drilling complexity in relative terms (low=0,5 medium=1,0 high=2,0)
Well maintenance frequency	Assessment of well maintenance needs in relative terms (low=0,5 medium=1,0 high=2,0)
TARIFFS	
Oil Transport	Given in [NOK/Sm3 oil]
Gas Transport	Given in [NOK/Sm3 gas]
Oil Processing	Given in [NOK/Sm3 oil]
Gas Processing	Given in [NOK/Sm3 gas]
PRICES	
Oil price	Given in [NOK/Sm3 oil]
Gas price	Given in [NOK/Sm3 gas]
OTHER CALCULATION PREMISES	
Currency	If currency = 1: NOK and if currency = 2: USD
Rate of interest	Given in percent (for Present Value calculation)
Number of stream days per year	Availability = Number of stream days/365
Production start	No of years after project start/sanction
Plateau Production start	No of years after project start/sanction
TECHNICAL INPUT SPECIFICATIONS	
TOPSIDES (see also below)	
No. of beds	Number of beds in living quarters or 999 for default
Oil throughput capacity	Given in [Sm3 oil per stream day]
Gas throughput capacity	Given in [mill. Sm3 gas per stream day]
Water injection capacity	Given in [m3 water per stream day]
Produced water treatment capacity	Given in [m3 water per stream day]
PLATFORM WELLS & RISERS	
No. of production wells	Underneath and accessible from platform
No. of water injection wells	Underneath and accessible from platform
No. of gas injection wells	Underneath and accessible from platform
Tree type: Dry trees=1, Wet trees=2	Dry tree=Deck completed well, Wet tree=Subsea completed well
Drilling concept factor	Definition of drilling package according to Table D below
SATELITE PRODUCTION SYSTEM	
No. of production wells	Remotely located wells (on templates or unmanned wellhead platforms)
No. of water injection wells	Remotely located wells (on templates or unmanned wellhead platforms)
No. of gas injection wells	Remotely located wells (on templates or unmanned wellhead platforms)
No. of Subsea Templates	(equal to no. of wells in case of single satellites)
No. of Unmanned Wellhead Platforms	
Type of wellhead platform	See Table
Flowline material	1=Carbon, 2=Cr13%, 3=Duplex
Flowline concept	1=direct tie-back, 2=tie-back via trunkline and manifold
Average distance from field center to templates or wellhead platforms measured in [km]	
EXPORT/IMPORT SYSTEM	
Oil storage volume in FSU	Measured in [Sm3] (length of connecting oil pipeline to be specified below)
Loading buoy type	No. loading buoy=0, Submerged Turret Loading (STL) system=1
Length of Oil pipeline	Measured in [km] (Use 3 km in case of Storage Tanker or STL system)
Length of Gas pipeline	Measured in [km]
SUBSTRUCTURE	
Platform/Ship type - Options 0-12:	Selection of substructure according to Table E below
Integrated Oil storage volume	(only relevant for GBS, DCF, SPAR, BUOYFORM, BARGE, FPSO, TANKER)
Riser system for satellite wells	1=individual risers, 2=riser tower

APPENDIX E

Table E. 1 – ITS data (source Hydro, 2007)

Criteria	Wellslots				
	4	6	8	10	12
Weight, t	400 - 600	700 - 1000	1300 - 1600	1800 - 2000	2000 - 2500
Cost, $M	110-130	160-175	185-200	210-230	235-255
Rent of ship, $M/d.	0.6 – 0.8	0.6 – 0.8	0.8	0.8	0.8

Figure E. 2 – Excel sheet – ITS installation cost benefit analysis



Shtokman Project	
Slot Production Template Installation CAPEX	

	B	C	D	E
Number of Wells	24			
Scinario	1	2	3	4
Well Slots in one Template	12	8	6	4
Number of Templates	2	3	4	6

Time on operations for one template, h

Scenario	ITS	Towing	Cut sea fastening	-	Lift off	Oriented	Established	Mooring	Change location	Transport time	Move back	Total,h	With WOW	Total, days	Total with WOW
A12	2	48	12	0	24	2	2	24	12	0	40	168	252	23	35
A8	3	48	12	0	30	3	3	24	20	44	40	224	336	26	39
A6	4	40	12	0	32	4	4	24	32	0	32	180	270	19	29
A4	6	40	18	0	36	6	6	36	42	44	32	260	390	23	35

Costs on rent of equipment

Scenario	A4 (<300 t)	A6 or A8 (1000 t)	A12 (2000 t)
Service vessel, USD/d	15000	15000	15000
Cargo barge, USD/d	30000	50000	100000
Monohull Vessel, USD/d	200000	250000	-
SSVC,USD/d	-	500000	700000
Barge Crane, USD/d	-	300000	300000
Wet tow, USD/d	400000	-	-
ROV vessel, USD/d	70000	70000	70000

Scenario	Transfer time, days				Operation time, days	Total, days
	Service vessels	Cargo barge	Monohull	SSVC		
A12	8	12	-	16	7	23
A8	8	12	-	16	10	26
A6	8	12	12	-	7	19
A4	8	12	12	-	11	23

Costs, $	Service Vessels	Cargo Barge	Crane Vessel	Total costs, $m
A12	1275000	1800000	16100000	19,175
A8	1530000	1050000	13000000	15,58
A6	1275000	900000	4750000	6,925
A4	1615000	660000	4600000	6,875

Costs with WOW, $	Service Vessel	Cargo Barge	Crane Vessel	Total with WOW
A12	2295000	3000000	24500000	29,795
A8	2635000	1700000	19500000	23,835
A6	2125000	1400000	7250000	10,775
A4	2635000	1020000	7000000	10,655

Figure E. 3 – Cost relations according to the cost benefit analysis