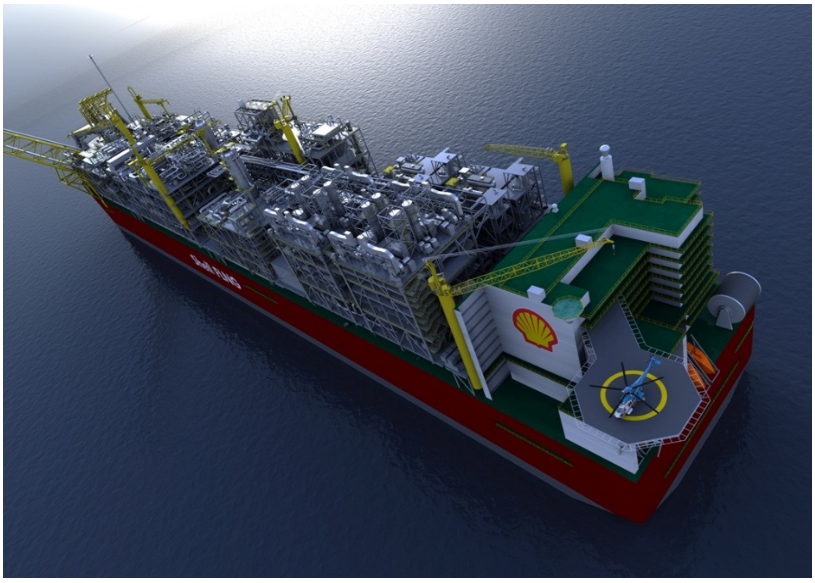

FLNG compared to LNG carriers

Requirements and recommendations for LNG production facilities and re-gas units

Master of Science Thesis

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Department of Shipping and Marine Technology
Division of Marine Design
CHALMERS UNIVERSITY OF TECHNOLOGY
Gothenburg, Sweden, 2012
Report No. X-12/279

A THESIS FOR THE DEGREE OF MASTER OF SCIENCE

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Abstract

An increasing price and demand for natural gas has made it possible to explore remote gas fields. Traditional offshore production platforms for natural gas have been exporting the partially processed natural gas to shore, where it is further processed to permit consumption by end-users. Such an approach is possible where the gas field is located within a reasonable distance from shore or from an existing gas pipeline network. However, much of the world's gas reserves are found in remote offshore fields where transport via a pipeline is not feasible or is uneconomic to install and therefore, to date, has not been possible to explore. The development of floating production platforms and, on the receiving end, regasification platforms, have increased the possibilities to explore these fields and transport the liquefied gas in a more efficient form, i.e. liquefied natural gas (LNG), to the end user who in turn can readily import the gas.

Floating production platforms and regasification platforms, collectively referred to as FLNG, imply a blend of technology from land-based LNG industry, offshore oil and gas industry and marine transport technology. Regulations and rules based on experience from these applications could become too conservative or not conservative enough when applied to a FLNG unit. Alignment with rules for conventional LNG carriers would be an advantage since this would increase the transparency and possibility for standardization in the building of floating LNG production vessels.

The objective of this study is to identify the risks relevant to FLNG. The risks are compared to conventional LNG carriers and whether or not regulatory alignment possibilities exist. To identify the risks, a risk analysis was performed based on the principles of formal safety assessment methodology. To propose regulatory alignment possibilities, the risks found were also evaluated against the existing rules and regulations of Det Norske Veritas.

The conclusion of the study is that the largest risk-contributing factor on an FLNG is the presence of processing, liquefaction or regasification equipment and for an LNG carrier it is collision, grounding and contact accidents. Experience from oil FPSOs could be used in the design of LNG FPSOs, and attention needs to be drawn to the additional requirements due to processing and storage of cryogenic liquid on board. FSRUs may follow either an approach for offshore rules or, if intended to follow a regular docking scheme, follow an approach for ship rules with additional issues addressed in classification notes.

Keywords: FLNG, FSA, FSRU, LNG, LNG carriers, LNG FPSO, risk assessment.

Preface

This thesis is a part of the requirements for the master's degree in Naval Architecture at Chalmers University of Technology, Gothenburg, and has been carried out at the Division of Marine Design, Department of Shipping and Marine Technology, Chalmers University of Technology.

I would like to acknowledge and thank my examiner and supervisor, Professor Jonas Ringsberg at the Department of Shipping and Marine Technology, for his help and guidance throughout this project.

I would also like to thank my co-supervisor, Conn Fagan, Vice President, Business Development, Floating Gas Projects at the head office of Det Norske Veritas in Høvik Oslo for sharing his knowledge and guidance during this project.

Further, I would like to thank Christian Hertzenberg, Head of Section at the department of Marine & Process Systems at the head office of Det Norske Veritas in Høvik Oslo for his help with practical and administrative issues during this project.

Finally, I would like to thank everyone at the head office of Det Norske Veritas who have helped out in different ways during this project.

Gothenburg, June, 2012
Erik Aronsson

Contents

List of abbreviations

AIS	Automatic identification system
ALARP	As low as reasonably practicable
DNV	Det Norske Veritas
ECDIS	Electronic chart display and information system
ESD	Emergency shutdown
FLNG	Floating liquefied natural gas unit
FMECA	Failure modes, effects and criticality analysis
FPSO	Floating production storage and offloading unit
FSA	Formal safety assessment
FSRU	Floating storage regasification unit
GCAF	Gross cost of averting a fatality
HAZID	Hazard identification study
HAZOP	Hazard and operational study
HVAC	Heating ventilation air-conditioning
IACS	International Association of Classification Societies
IGC	International code for the construction and equipment of ships carrying liquefied gases in Bulk
ILO	International Labour Organization
IMO	International Maritime Organization
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas
LRFD	Load and resistance factor design
MARPOL	International Convention for the Prevention of Pollution from Ships
MTPA	Million tons per annum
NCAF	Net cost of averting a fatality
PLL	Potential loss of lives
QRA	Quantitative risk analysis
RCM	Risk control measure
RCO	Risk control option
RPT	Rapid phase transition
SOLAS	International Convention for the Safety of Life at Sea
UNCLOS	United Nations Convention on Law of the Sea

1. Introduction

In the last decades, the international natural gas market has been growing at a very high rate and continues to increase [1][2]. Traditional offshore production platforms for natural gas have been exporting the partially processed natural gas to shore where it is further processed to permit consumption by end-users [3]. Such an approach is possible where the gas field is located within a reasonable distance from shore or from an existing gas pipeline network. However, much of the world's gas reserves are found in offshore fields [4] where transport via a pipeline is not feasible or is uneconomic to install and therefore, to date, it has not been possible to develop these fields [2][4].

During the past four decades studies have been carried out on offshore liquefied natural gas (LNG) production options [4]. This has resulted in a new kind of production facility called LNG floating production storage and offloading (FPSO). The benefits are a platform which does not need much external support and which allows for the transformation of gas into a readily transportable form, i.e. LNG. This also permits more flexibility in marketing the gas, since LNG shuttle tankers can be directed to where the market price is best [4]. When the gas field is depleted the production platform can be moved to a new gas field. To date, no LNG FPSO has been built. However, several concepts exist and have been planned to be built [5] [6].

A further development is the floating regasification units that transform the LNG back to natural gas at the market location. Such units are called floating storage and regasification units (FSRU). Many countries are today opting for the floating offshore option instead of onshore facilities [7]. According to Fagan et al. [3], an offshore unit usually means lower investment costs, quicker project realisation and avoidance of many permitting issues. A limited number of FSRUs have already been deployed, for example GOLAR LNG has today 5 FSRUs in operation. The fleet consists of converted LNG carriers [8]. Typically, LNG FPSOs and FSRUs are collectively known as floating LNG (FLNG) units. In this report, FLNG refers to both LNG FPSO and FSRU unless stated otherwise.

Concerns about global warming have been raised worldwide and governments are attempting to find strategies for decreasing emissions of greenhouse gases. When burned, natural gas emits lower quantities of greenhouse gases and criteria pollutants than other fuels and is therefore seen by many to have a key role in strategies for lowering carbon emissions [9]. FLNGs could contribute further with a reduced environmental footprint compared to an onshore LNG plant, with an associated offshore platform, that would require a significant land-take and possibly coastal dredging. In addition, FLNGs also have the possibility of being relocated to other locations.

1.1. Background

The FLNG concept is a mixture of technology from land-based LNG industry, offshore oil and gas industry and marine transport industry. Regulations and rules based on previous experience within respective field could become too conservative or not conservative enough when applied to a floating LNG offshore unit [3]. According to Det Norske Veritas (DNV) [2] an LNG FPSO could be considered as an offshore installation and would therefore follow offshore classification practice. An FSRU could follow classification according to offshore or ship classification practice depending on the mode of operation. Alignment with rules for conventional LNG carriers would be an advantage as this would increase the transparency and possibility for standardisation in the building of floating LNG production vessel. The inherent risk of gas treatment and its being stationary, either offshore or berthed close to shore, compared to the risk on board an LNG carrier may be significant.

1.2. Objective

The objective of this study is to identify the risks relevant to FLNGs, compare them to risks for conventional LNG carriers and propose regulatory alignment possibilities as input for future DNV rule development. To find the risks, the study was divided into four sub-targets:

- To study existing rules and regulations pertaining to LNG processes and storage.
- To perform a risk evaluation of key aspects of LNG production and re-gasification technology, both safety and regularity.
- To report and present the risks specifically related to FLNG concepts.
- To propose regulatory alignment possibilities.

1.3. Methodology and limitations

To achieve the objective and identify the risks relevant to FLNGs, comprehensive studies of the technology involved in both LNG FPSO and FSRU is necessary. In order to perform a risk evaluation of FLNGs, the formal safety assessment (FSA) method is used as a basis for the study. The method is chosen since it is used by the International Maritime Organization (IMO) in their rulemaking progress [10]. The FSA methodology consists of five steps; this study is limited to the first step, risk identification, due to limitations in knowledge and experience with the technology involved in FLNGs. As this step does not depend on the outcome of the other steps it can be performed independently. The IMO describes several techniques for hazard identification in the guidelines for FSA [10], and, according to Spouge [11], HAZID is the most appropriate for coverage of the wide range of possible hazardous events and is therefore chosen as the technique to be used. The risks found in the HAZID are then compared to the rules and regulations of Det Norske Veritas to investigate if any gaps exist. To compare the risk of FLNG to LNG carriers, external reports from the research project SAFEDOR [12] - [14] regarding the risk of LNG carriers was studied for comparison.

2. Rules and regulations

Each classification society has its own set of rules covering standard ship construction and supplements covering the specific application of different ship types and their equipment. The requirements are formed so that they implicitly describe the hazards. The rules are normally based on experience and operations within the shipping industry. The shipping industry traditionally had a prescriptive approach in implementation of new requirements and regulations. Gas carriers are today governed by essentially prescriptive regulation and class requirements, which is favourable for ship-owners and shipyards as it provides clarity for contracting vessels [3]. A tendency to move from the prescriptive regulations to goal-based regulations with an integration of risk analysis is seen today, and this will facilitate novel technology and novel ship design [15]. This section briefly describes how classification is obtained and which organizations that have an interest in the vessel.

2.1. Classification in general

To assure that a ship or offshore structure has an acceptable safety level it has to fulfil several standards. There are several different organizations that each have their own demands or regulations:

- ***Classification Societies*** issue classification certificates, which certify that safety and rule compliance is fulfilled. Their validity is five years given that annual and intermediate surveys are fulfilled successfully. Several parties have an interest in the safety and quality of a ship and the classification system serves as a verification system to ensure that the requirements of rules and other standards are fulfilled. Such parties could be, among others, insurance companies, ship owner, cargo owners and national authorities under whose flag the ship will sail [16].
- ***Coastal state*** is the state in which a foreign ship operates when entering a port or operating in the coastal areas of a country. According to the United Nations Convention on Law of the Sea (UNCLOS) [17], a coastal state has the right to enforce its own laws and regulations considering pollution on foreign ships entering their waters. A country could also act as a port state when a foreign ship enters a port or offshore terminal, and then the state has the right to detain a vessel and require repairs if the ship is not found to be seaworthy.
- ***Flag state*** is where a ship or offshore structure is registered in order to identify it for legal and commercial purposes. The object does not have to be registered in the same state as the company and it could be beneficial to register the ship in another flag state for tax reasons. The flag state is responsible for the ship and it complies with the law of the flag state. The most significant flag states have implemented the International Convention for the Safety of Life at Sea (SOLAS) and the International Convention for the Prevention of Pollution from ships (MARPOL) and other IMO conventions into their own laws. UNCLOS [17] states that the flag is responsible for the seaworthiness of a vessel flying its flag and that laws and regulations targeted at preventing and controlling pollution are followed.
- ***The United Nations*** set up the broad framework of the law of the sea, UNCLOS [17], and to date 162 states or entities have signed the convention. The IMO and the International Labour Organization (ILO) are the two agencies that they operate through.

2.2. Existing rules and regulations pertaining to LNG carriers

DNV rules for the classification of LNG carriers are found in Rules for Classification of Ships Pt.5 Ch.5. Liquefied Gas Carriers. In its most general form the Classification of ships is described in Pt.1Ch1.Sec.1 [16] as:

> ***B 100 General***
> ***101*** *The classification concept consists of the development and application of rules with regard to design, construction and survey of vessels. In general, the rules cover:*
> - *the structural strength (and where relevant the watertight integrity) and integrity of essential parts of the vessel's hull and its appendages, and*
> - *the safety and availability of the main functions in order to maintain essential services.*
>
> ***102*** *Class is assigned to a vessel on the basis of compliance with the rules. Class is maintained in the service period provided applicable rules are observed and surveys carried out.*

Ships carrying Liquefied Gases in Bulk have their own set of requirements in the International Code for the Construction and Equipment of Ships Carrying Liquefied Gases in Bulk (IGC) [18], which has been specified by the IMO in cooperation with the International Association of Classification Societies (IACS). The IGC addresses [18]:

- Flammability.
- Toxicity.
- Corrosivity.
- Reactivity.
- Collisions and strandings.
- Cryogenic release.

The IGC code is not mandatory, but most flag states require that the code is fulfilled if the ship is to sail under their flag. If an LNG carrier is classified according to DNV rules it is also fulfilling the IGC code:

> *Rules for Ships Pt.5 Ch.5 Sec.1* [16]
>
> ***A 100 Application***
>
> ***103*** *The requirements of this chapter are considered to meet the requirements of the International Code for the Construction and Equipment of Ships Carrying Liquefied Gases in Bulk, IGC Code, Res. MSC.5 (48). The following amendments to the IGC Code are included in this edition of the rules: Res. MSC.30(61) (1992 amendments), Res. MSC.32(63) (1994 amendments), Res. MSC.59(67) (1996 amendments) and Res. MSC.103(73) (2000 amendments).*

2.3. Existing rules and regulations considering FLNG

DNV have gathered their experience of classification rules for oil and gas carriers and Oil FPSOs into classification rules of Gas FPSOs. The result is DNV-OSS-103, *Rules for Classification of LNG/LPG Floating Production and Storage Units or Installations* [19]. In addition to the class rules, class notation PROD (LNG) will also supplement rules for the gas treatment and liquefaction plant. DNV-OSS-103 [19] contains references to the appropriate offshore standard applicable for the different areas of the unit, see Appendix A for details. Future rule development could benefit from alignment possibilities from the classification rules for LNG carriers. However, it is important that the rules allow novel technology so that future development of technology is not restricted for use due to regulations.

3. The working principle behind LNG FPSO

This section presents the technology of an LNG FPSO. LNG FPSOs are offshore floating production units that contain both gas processing and liquefaction equipment as well as storage for the produced LNG. The unit could have a fixed mooring or be equipped with a turret, external or internal, that will allow the unit to weathervane. On top of the main deck, a supporting structure, called the topside, is installed, which contains the gas processing and liquefaction equipment. The raw natural gas is transferred from the wells in risers and diverted to the topside through a turret, if equipped with a connection along the side of the hull. The produced LNG is then transferred from the topside to cargo tanks situated below deck. The stored LNG is frequently transferred to arriving LNG carriers via offloading equipment, which could be located amidships or in the aft of the unit. To provide the crew with living quarters, control room, etc., an accommodation block is needed, and this could be situated on the deck in front or aft of the topside. Fig. 1 shows a possible layout of an LNG FPSO and an artist's rendering can be seen in Fig. 2. The different building blocks and their difference compared to an LNG carrier are presented further according to the following list:

- Structure (Hull), see Section 3.1.
- Gas processing and LNG production (Topside, Flare), see Section 3.2.
- Cargo handling, see Section 3.3.
- Transfer systems (Risers, Turret, Offloading equipment), see Section 3.4.
- Additional systems (Accommodation), see Section 3.5.

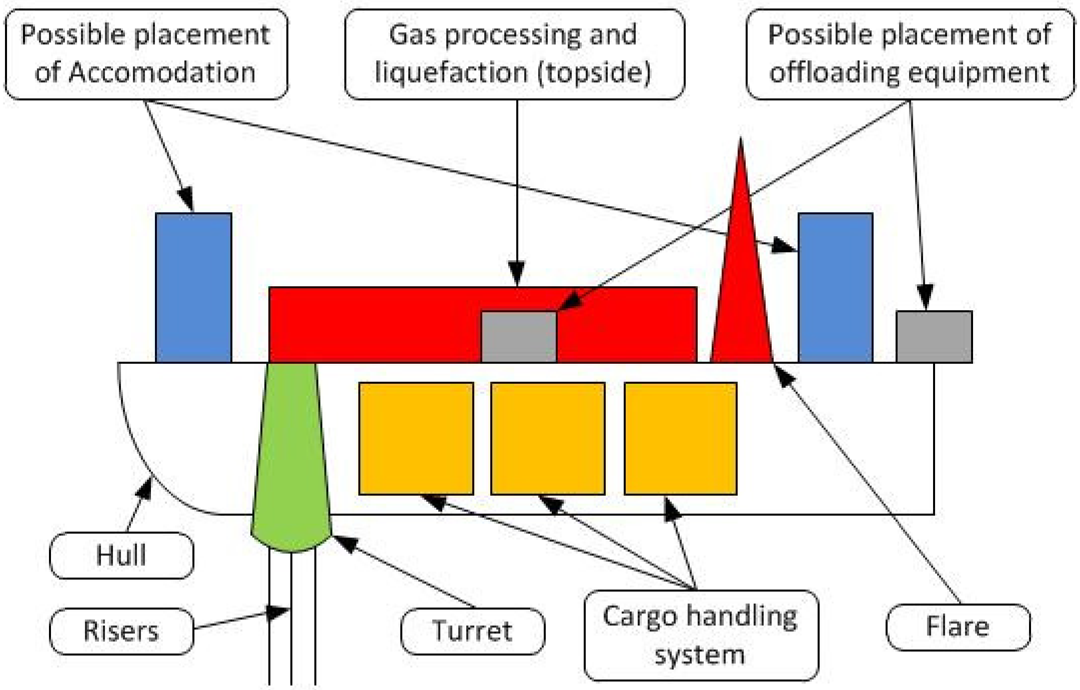

Fig. 1. Conceptual layout of LNG FPSO.

Fig. 2. Artist's rendering of an LNG FPSO; picture by courtesy of Technip.

3.1. Structure

The main structure of LNG FPSOs will be of similar design as oil FPSOs and oil tankers [2] and could generally follow the principles of the design of steel ships. Due to similarities to tankers with regard to structural arrangement, many reliability formulations developed for ships could be applied to LNG FPSOs [20]. The design of an offshore structure will, however, have additional requirements compared to a ship [2]. Due to continuous operation and the absence of regular docking, additional attention needs to be drawn to corrosion prevention. To ensure the structural integrity, corrosion-protective coating and cathodic protection could be used. For critical structural members, corrosion allowance should be used as a safety factor in design [2].

Additional loads on the hull structure from the topside and mooring equipment need to be accounted for in the design. Depending on the intended capacity of the LNG FPSO the weight of the topside could exceed 70 000 tonnes for a large production unit producing between 3-5 million tons per annum (MTPA) [2]. Today, there are two different mooring systems in use for permanently moored offshore structures, spread mooring and turret mooring [2]. The additional load will affect internal major load-carrying structural elements, such as longitudinal and transverse bulkheads, and, depending on the system used, the load will be taken up by different areas on the hull. Spread mooring constrains the vessel in one direction and is typically equipped with chain stoppers distributed along the main deck of the hull. A turret mooring system could be fitted externally or internally of the structure and will affect the structure in its vicinity [2].

3.2. Gas processing and LNG production

Raw natural gas can have a wide variety of compositions [21]. Natural gas is often found together with oil in the same reservoir. One of the first steps in the process is to examine which contaminates that are present in the entering gas stream. Therefore, an LNG process plant can differ between locations depending on the technique used to process the gas to reach a pure state [9]. A typical processing scheme of an LNG process plant is presented in DNV Offshore Technical Guidance OTG-02 [2] and can be viewed in Fig. 3. The sub-systems are presented in more detail below.

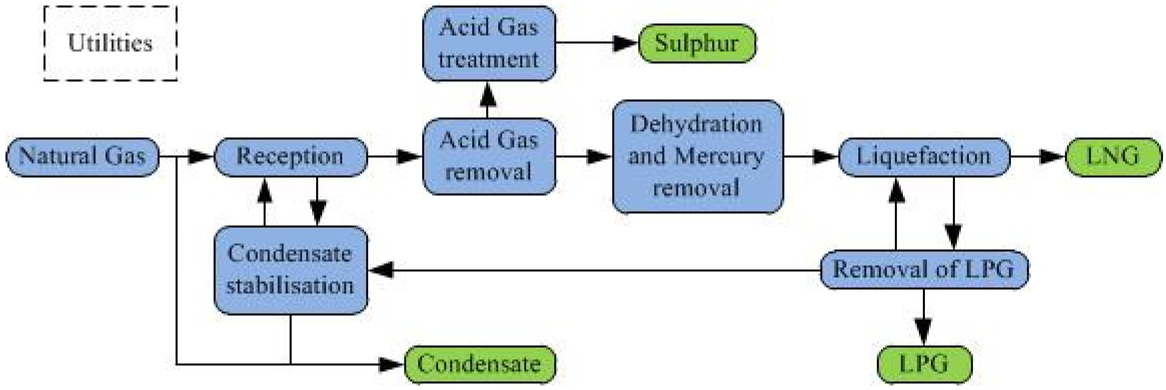

Fig. 3. Example of process layout for an LNG FPSO.

Reception
When the raw natural gas is brought up from the wells the first step is to separate erosive solids, water and condensate. Erosive solids, for example sand, could damage or tear piping and components. The separation could be achieved by three principles; momentum, gravity settling or coalescing. The technology used is dependent on the composition of the raw natural gas. Condensate is separated from the gas stream and routed to the condensate stabilizer [9].

Condensate stabilization
Composition of raw natural gas varies between different locations. Heavy hydrocarbon components are normally found to some extent in all gas reservoirs in its liquid state. In underground pressure they exist in a liquid state and will become gaseous at normal atmospheric pressure. In its liquid state these hydrocarbons are called hydrocarbon condensates which to a large percentage consist of lighter components. When brought up to atmospheric pressure these lighter components will flash off and therefore there is a need to stabilize the recovered hydrocarbon condensate to avoid flashing in storage tanks. Flashing occurs when a liquid immediately evaporates to vapour undergoing reduction in pressure. Stabilization could be achieved either through Flash vaporization of Fractionation [9][21].

- **Flash vaporization:** To allow flashing of lighter components, such as methane-ethane-propane, from the condensate, the pressure is lowered progressively through several stages. The flashing could be done in 2 to 4 stages. The vapour is injected back into the natural gas stream after recompression or could be used as fuel to on board power generation. The remaining heavy hydrocarbons are sent to a storage tank [21].

- **Stabilization by fractionation:** Fractionation removes and recovers the light components such as methane-ethane-propane and most of the butanes from the condensate. The liquid hydrocarbon from the inlet separation is either preheated or flashed down into a stabilizer feed drum and then further fed into the stabilization tower. The stabilization tower separates the lighter components, which are sent to a low-pressure fuel line. The technique allows the condensate liquid to keep a certain quality, which generates greater revenue since the condensate could be sold at a higher price [9].

According to Benoy and Kale [21], the Fractionation technique is the least space demanding of the two types and also requires less compressor power when compared to a three stage flashing plant.

Acid gas removal
To avoid damages on the equipment further down in the process, sour gases such as CO_2 and H_2S are removed from the flow. This could be done with various processes depending on concentrations of contaminants in the gas and the degree of removal desired, temperature, pressure, volume and composition of the gas, etc. Two general processes are used for removal; adsorption or absorption. Adsorption concentrates the impurities on the surface of an absorbing medium, usually granular carbon solid, while absorption relies on physical solubility of the impurities into an absorption medium [9]. The collected CO_2 could be released into the atmosphere, but this may not be desired due to environmental policies of the operator or not permitted by regulations of the site of operation. Re-injection to underground storage could be an option for the collected CO_2 [2].

Dehydration and mercury removal
To avoid freezing damages to pipes and equipment due to the formation of hydrates, water is eliminated from the flow [2]. The most common techniques to dehydrate gas is by injection of a solid or liquid desiccant or by refrigeration [9].The technique most preferable for offshore use is solid bed dehydration due to a relatively small footprint and being unaffected by vessel motions. If mercury is present in the gas flow it can cause corrosion of aluminium, therefore, it is also removed to avoid damages. The removal of mercury can be achieved by adsorption or by a bed filter [2][22].

Removal of liquefied petroleum gas (LPG)
LPG is a flammable mixture which consists of mostly propane and butane. For offshore use the preferred method for removal of LPG is fractionation. The amount of LPG presence in the gas flow will be an important factor. A large amount of LPG products can be produced for sale or used as fuel for power generation on board. A small amount of LPG in the raw gas is expensive to remove and could not fulfil the fuel consumption on board or is unprofitable to sell [2]. The fractionation train normally, depending on the composition of the raw natural gas, consists of three stages where the lighter product is boiled of in each stage [9].

- **Deethanizer:** In the first step ethane and propane is separated, the ethane goes overhead and propane and heavier components are extracted from the bottom and sent to the depropanizer.
- **Depropanizer:** In the second step the propane is separated, the propane now goes overhead and isobutene and heavier components are extracted from the bottom and sent further to the debutanizer.
- **Debutanizer:** In the last step butanes are separated from the flow leaving natural gasoline from the fractionation train.

Liquefaction
The liquefaction cools the clean feed gas in normally three steps down to its storage temperature of -160 to -163 °C [2][22]. When liquefied the natural gas is equivalent to 1/600 of its volume in a gaseous state. There are three main technologies, mixed refrigerant processes, cascade refrigerant processes and expander processes [2].

- **Mixed refrigerant process:** A single mixture of nitrogen and hydrocarbons is used as refrigerant to cool the natural gas. The mixture is composed to match the cooling curve of the natural gas.

- **Cascade refrigerant process:** The natural gas is cooled in three steps using different refrigerants for each step. Propane is used in the first step to pre-cool the gas, secondly ethylene or ethane is used to bring the gas down to its liquefaction temperature. In the final sub-cooling step methane is used to cool the gas.
- **Expander processes:** The natural gas is cooled in a heat exchanger process with either methane or nitrogen as refrigerant gas. The refrigerant gas is cooled in a compression-expansion cycle.

For offshore application, an expander process utilizing Nitrogen as cooling medium would be preferable due to its small form factor and to its being less sensitive to motion than the other techniques. Other advantages of the technology are higher safety and that it is easier to operate compared to the others. Generally, the expander process has a higher power consumption and poorer economy compared to cascade and mixed refrigerant processes [23] [4].

Power generation
The power demand of an LNG FPSO is large mainly due to the large amount of compressors involved in the process. Proposed LNG FPSOs have a power demand between 100 to 250 MW [2][22]. Directly driven equipment would reduce the complexity but add even more layout challenges to the platform. Electrical motors would most likely be the choice for powering the compressors and pumps, which offers more flexibility in the power supply. Several solutions for power supply have been proposed. Due to its small form factor and high power output, gas turbines would be a good choice for powering electrical generators. The gas turbine could be equipped with a waste heat recovery system utilizing the exhaust heat from the gas turbines. The recovered waste heat could also be used to generate steam used for powering equipment and/or used in the pre-heat process. Pure steam driven systems have also been considered [2].

Cooling water
The different processes on board require a large amount of cooling. Sea water would likely be used for cooling the medium of a closed loop cooling system. To prevent marine growth and corrosion, substances such as biocides need to be added to the water. To prevent pollution of the marine environment around the FLNG the residual of these substances have to be held at a low level. The amount of cooling water needed for the FLNG could reach levels of 50,000 m^3 per hour [24].

3.3. Cargo handling

In marine transportation of LNG the IGC code [18] designates a number of tank types. These can be divided into two main types, membrane tanks and independent tanks.

Membrane tanks: The membrane tanks are non-self-supported and rely on the double hull surrounding the tank for structural strength. The tank consists of a cryogenic liner composed of primary and secondary membrane separated by insulation, which is designed to compensate for thermal and other expansion. The benefits of the tank system are the high utilization of space available and the disadvantages are large impact loads due to sloshing when partially filled. Fig. 4 shows the inside of a typical membrane tank; note the absence of internal structure which could reduce motions of the liquid. To reduce the influence of sloshing, large tanks can be replaced by smaller tanks arranged in parallel rows [2][18].

Fig. 4. NO96 Membrane tank system; picture by courtesy of GTT.

Independent tanks: Independent tanks are divided into three types:

- Type A – Full secondary barrier.
- Type B – Reduced secondary barrier.
- Type C – No secondary barrier.

Type B tanks are common on existing LNG carriers and often proposed for use on FLNG, therefore type A and type C will not be described further [2][4]. Type B can be divided into Prismatic and Spherical types.

Prismatic type: the tanks, shown in Fig. 5, are built up of a single primary barrier and have an internal structure with typical ship hull structural elements in a plate –stiffener - girder system. The tank system has a partial secondary barrier in the form of an insulation system surrounding the tank, and drop trays covering the bottom and side of the tank. The internal structure will reduce liquid motions and consequently the effects of sloshing, and this, however, could be significant if not designed properly [2][4].

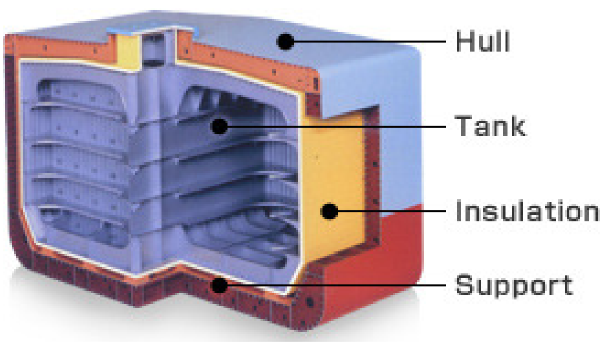

Fig. 5. IHI-SPB tank system; picture by courtesy of IHI Marine United Inc.

Spherical tank: the spherical tank system, shown in Fig. 6, consists of a primary barrier of aluminium and a partial secondary barrier made from insulation surrounding the entire sphere and drip trays beneath. A cargo pump tower is installed reaching from the bottom to the top of the sphere. Sloshing can be significant but the impact pressure is insignificant due to the spherical design of the tank [2]. Low utilization of hull space and the absence of deck space for process equipment makes this tank solution unlikely for use on an LNG FPSO [4].

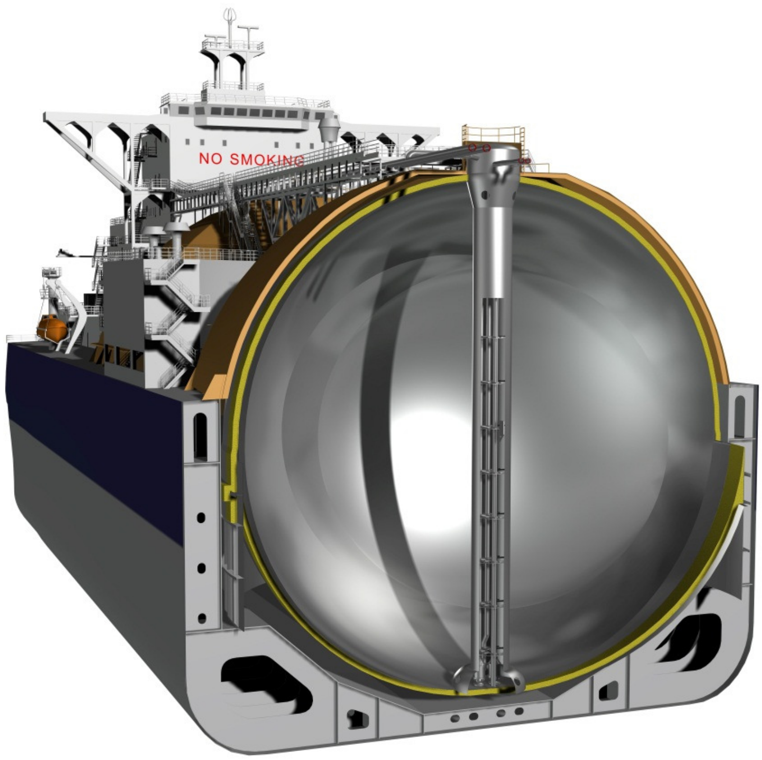

Fig. 6. Moss spherical tank system; picture by courtesy of Moss Maritime AS.

3.4. Transfer systems

The wellheads are either placed sub-sea directly on the well or on the LNG FPSO. If placed sub-sea, a flow line transports the raw gas from the wellhead to the LNG FPSO via risers. The FPSO is usually tied to multiple sub-sea wells. Depending on the harshness of environment of the intended location and the need to disconnect from the risers, the LNG FPSO could be equipped with a turret which the risers are connected to. The offloading is an important part of the LNG FPSO. The produced LNG must be offloaded onto an LNG carrier arriving periodically. The design of an offloading system can be divided into two main categories, side by side and tandem.

Side-by-side transfer

Side-by-side transfer, shown in Fig. 7, is carried out by a shuttle tanker temporarily moored alongside the FLNG. The transfer of the LNG is performed via rigid connection arms located on the side of the FLNG. The operation is normally supported by tugboats [2]. Up to four tugboats could be required to get the carrier alongside the FLNG [1]. Calm weather is required for this offloading system since the loading arms do not allow for a wide range of relative motion, and this limits the window of offloading for many locations [25]. The advantage of this solution is that conventional LNG carriers could use their standard amidships manifold without modification, which minimizes the cost [1].

A novel technology, HiLoad DP [26], originally developed by Remora, utilizes a self-propelled unit that attaches itself to the carrier. The unit is always connected to an FLNG or pipeline. Since the unit manoeuvres itself alongside the LNG carrier and attaches itself using suction, the relative motion between carrier and platform is absent. The possibility of multiple units increases the offloading capacity and the redundancy of the production unit [26].

Fig. 7. Side-by-side transfer; picture by courtesy of Höegh LNG.

Tandem transfer

Tandem transfer, shown in Fig. 8, is performed from the stern of the FLNG to the bow of the shuttle tanker. There are several different technologies available. The benefits of tandem transfer are less influence from relative motion between the FLNG and the shuttle tanker [2]. The tandem transfer technique allows for a more severe sea state than side-by-side transfer, which makes it preferable if the location of the FLNG is under the influence of harsh weather [25].

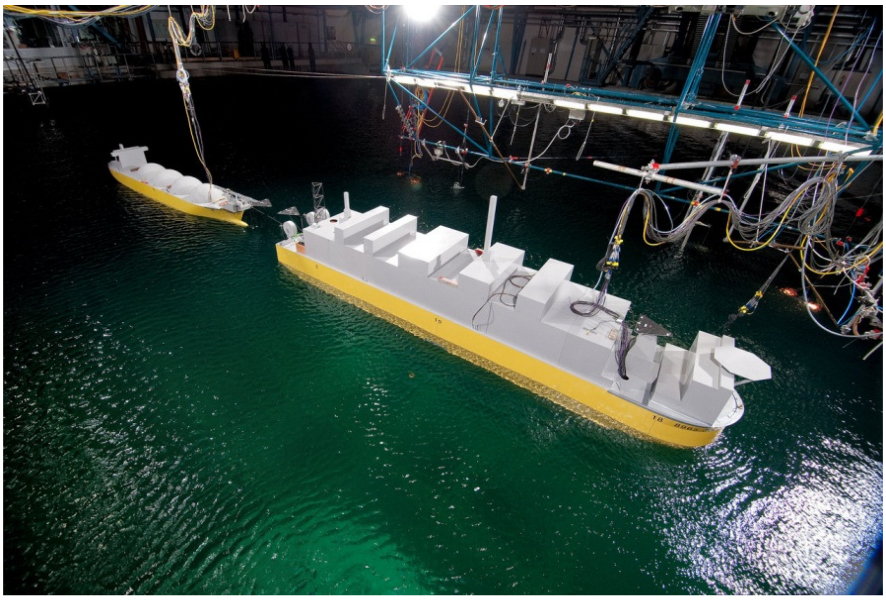

Fig. 8. Tandem transfer; picture by courtesy of SBM Offshore.

3.5. Additional systems

There is a need for several different utility systems on board. Some different utility systems are briefly described below.

Accommodation

Accommodation is needed to provide the personnel on board with living quarters, a control room, and medical facilities, etc. The location of the accommodation needs to be as far away as possible from the most hazardous process plant areas as well as the flare [4][24].

Fire fighting system

The required amount of water spray capacity would be larger than for an LNG carrier since the gas treatment and processing plant need to be covered as well. If the FLNG store condensates and in addition to LNG, there is a need for different measures for fighting potential fires. The redundancy of the system must be kept high [2].

Flare and venting systems

During operation, the need for the disposal of gas arises several times. This could be done by release of the gas directly into the atmosphere, called venting, or burned in a controlled manner, called flaring. Flaring requires a flaring tower on board the platform. Both options have advantages and disadvantages and studies need to be carried out for each case [2]. The location of the flare will have to take the placement of living quarters and process plant into account [27].

Control and safety systems

To further increase safety on board the vessel, several control systems would need to be implemented aboard. The complex environment of an FLNG with processing and simultaneous transfer to shuttle tankers makes an integrated control system necessary. Normally, the control and safety systems consist of systems controlling the following: normal process control, interlock and shutdown, fire and gas detection, heating-ventilation-air-conditioning (HVAC) and emergency shutdown (ESD) [28]. It is crucial that the software is designed and meets the requirements of safety, functionality, and reliability [2].

4. The working principle behind FSRU

The main difference between an LNG carrier and an FSRU is the presence of a re-gasification plant. The FSRU could either be purpose-built or a rebuild of a conventional LNG carrier, which is fitted with a re-gasification plant. The FSRU receives LNG from arriving shuttle tankers via loading equipment fitted amidships or in the aft part of the unit. The transferred LNG is diverted to the storage tanks situated below main deck. The re-gasification plant receives LNG from the storage tanks and the vaporised natural gas is fed into a pipeline. The pipeline could be connected in the turret if the FSRU is equipped with one of these or with loading arms if the FSRU is moored to a jetty. Fig. 9 shows a possible layout of an FSRU and an artist's rendering can be seen in Fig. 10. The different building blocks and their difference compared to an LNG carrier and/or an LNG FPSO are presented further according to the following list:

- Structure (Hull), see Section 4.1.
- Gas processing (Re-gasification plant), see Section 4.2.
- Cargo handling, see Section 4.3.
- Transfer systems (Risers, Turret, Offloading equipment), see Section 4.4.
- Additional systems (Accommodation), see Section 4.5.

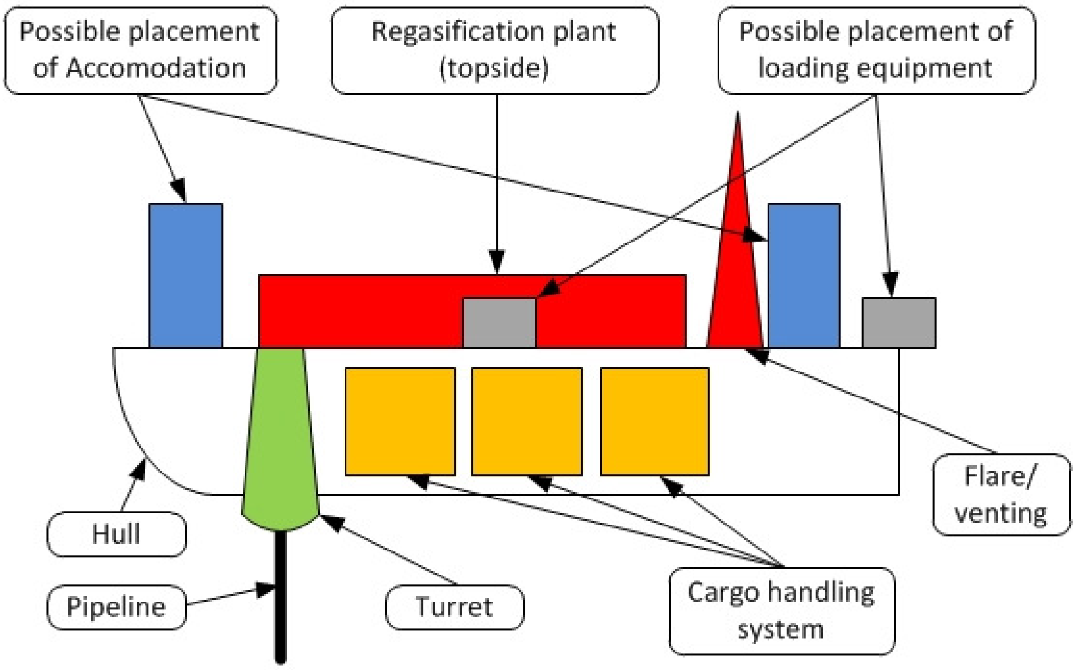

Fig. 9. Conceptual layout of an FSRU.

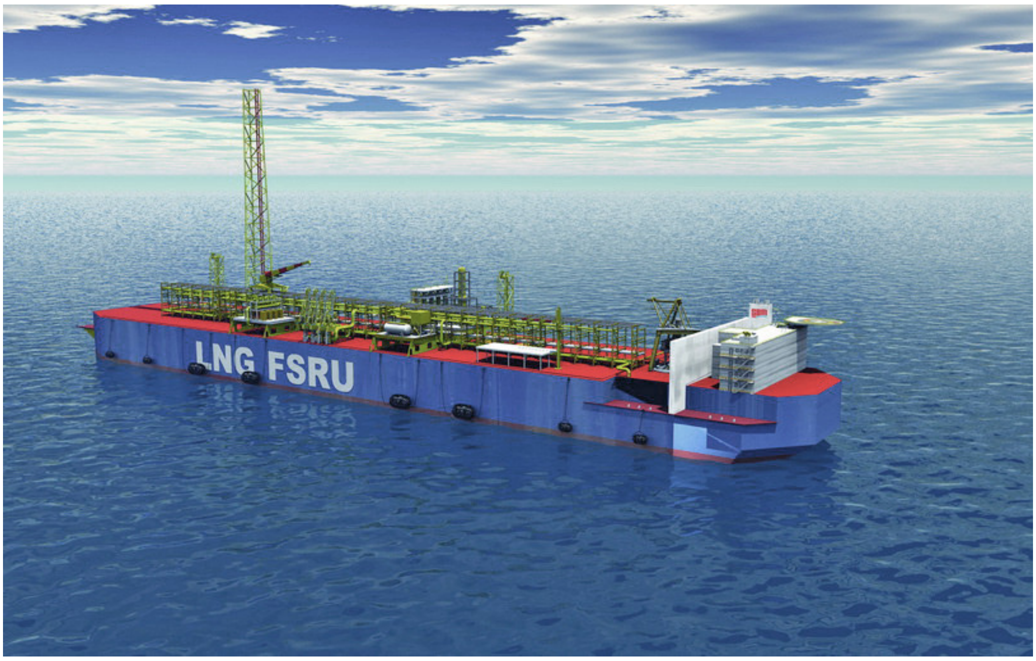

Fig. 10. Artist's rendering of an FSRU; picture by courtesy of SBM Offshore.

4.1. Structure

The structure of an FSRU will be similar to an LNG FPSO, which is described in Section 3.1. With conversions of existing LNG tankers to FSRUs, attention needs to be on additional loads from the topside and the mooring system if the FSRU is equipped with a turret mooring system [2].

4.2. Gas processing

Different techniques are available for vaporisation of LNG. Land based regasification plants normally use water heating: Open Rack Vaporization, or fuel-fired heating: Submerged Combustion Vaporization [2].

Open rack vaporization

An open-loop water system uses sea water to heat the LNG and therefore it requires all-the-year-round warm water to operate and may not be suitable for the intended site of operation, for example in Arctic conditions where no warm water is available. Since the system releases water of a lower temperature back into the local environment, and considering the use of biocides, it has a potential to impact on marine life. A permit from the authorities is therefore normally needed [2].

Submerged combustion vaporization

Direct fired heaters could be used where warm sea water is unavailable or a cold water release is not permitted. Natural gas is typically used as fuel to heat the LNG. The burning of fuel leads to air pollution and production of CO_2 and has therefore been questioned for offshore use [2].

Remote heated vaporizers

An alternative to the two techniques above is the open loop system with an intermediate fluid to heat the LNG. The intermediate fluid could be glycol, propane or a proprietary fluid. Air-based systems have also been developed [2].

4.3. Cargo handling

The cargo containment systems described in Section 3.3 will also be applicable to an FSRU. The storage capacity of an FSRU will depend on the designed gas emission rate, which, in turn, is decided by the market needs and the economic considerations of the project. The possible calling frequency and capacity of arriving LNG carriers will also affect the storage capacity needed [4].

4.4. Transfer system

Transfer of LNG from arriving LNG carriers can be performed in the same way as for LNG FPSOs described in Section 3.4. Offshore moored FSRUs will export the evaporated gas in flowlines connected to onshore pipeline. FSRUs located near the shore could be connected to a jetty and use loading arms to export the gas [2].

4.5. Additional systems

Will be the same as described for an LNG FPSO in Section 3.5.

5. Risks for an LNG carrier during operation

This section presents data and conclusions of a Formal Safety Assessment (FSA) study of LNG carriers from the research project SAFEDOR [12] - [14]. This can be seen as an example of how an FSA is carried out, and some of the results are discussed in Section 7.5. The principles of risk-based design and the FSA methodology can be found in Appendix B.

According to IMO [12], major concerns regarding the safety of LNG shipping have resulted in the fact that the general reputation of LNG carriers is that they are well designed, constructed, maintained, manned and operated, with a high focus on safety in every aspect. LNG carriers are considered to be among the safest vessels in the merchant fleet of today, but a single catastrophic event could damage the whole LNG shipping industry.

5.1. Historical LNG accidents and hazard identification

According to Vanem et al. [13], the history of LNG trade spans over 40 years and contains 182 events. Of these events, 158 have occurred during regular service. Table 1 shows the distribution of these events together with the estimated frequency of the event.

Table 1. Distribution of historic LNG accidents on categories [13].

Accident category	Accidents (#)	Frequency (per ship year)
Collision	19	$6.7x10^{-3}$
Grounding	8	$2.8\ x10^{-3}$
Contact	8	$2.8\ x10^{-3}$
Fire and explosion	10	$3.5\ x10^{-3}$
Equipment and machinery failure	55	$1.9\ x10^{-2}$
Heavy weather	9	$3.2\ x10^{-3}$
Events while loading/unloading cargo	22	$7.8\ x10^{-3}$
Failure of cargo containment system	27	$9.5\ x10^{-3}$
TOTAL	**158**	$\mathbf{5.6\ x10^{-3}}$

The first step of an FSA is to identify the hazards and to evaluate them against each other in which case a risk index could be used. The IMO guideline [10] gives an example of several available techniques for finding hazards and how the ranking could be achieved. This is further described in Appendix B.2. The first step of the ranking process is to establish the probability and consequence of each hazard. In order to facilitate the ranking, the indices of consequence and frequency are defined on a logaritmic scale and the “risk index” is obtained by adding the frequency and consequence indices according to:

$$\text{Risk} = \text{Probability} \times \text{Consequence} \tag{1}$$

$$\text{Log(Risk)} = \log(\text{Probability}) + \log(\text{Consequence}) \tag{2}$$

According to Østvik [14], HAZID was chosen as the technique in the study and was performed in a workshop event with participants from various sectors within the LNG industry. The result was a list of 120 hazards within 17 different operational categories. The probability index and consequence index used in the project is shown in Table 2 and

Table 3, and the risk matrix in Table 4. The risk index for each hazard was assigned by the assessment of the participants in the HAZID regarding probability and consequence.

Table 2. Definition of probability index [14].

PI	Probability	Definition	P(per ship year)
8	Very frequent	Likely to happen once or twice a week on one ship	100
7	Frequent	Likely to occur once per month on one ship	10
6	Probable	Likely to occur once per year on one ship	1
5	Reasonably probable	Likely to occur once per year in a fleet of 10 ships, i.e. likely to occur a few times during a ship's life	0,1
4	Little probability	Likely to occur once per year in a fleet of 100 ships, i.e. likely to occur in the total life of a ship's life	0,01
3	Remote	Likely to occur once per year in a fleet of 1000 ships, i.e. likely to occur in the total life of several similar ships	0,001
2	Very remote	Likely to occur once per year in a fleet of 10,000 ships	0,0001
1	Extremely remote	Likely to occur once in the lifetime (20 years) of a world fleet of 5,000 ships	0,00001

Table 3. Definition of consequence index [14].

CI	Consequence	Human safety	Environment related	Cargo / Monetary losses	Effect on ship	3rd party assets	Equivalent fatalities
1	Minor	Single or minor injuries	Negligible release - negligible pollution - no acute environmental or public health impact	30.000 US$	Local equipment damage (repair on board possible, downtime negligible)	Minor damage	0,01
2	Significant	Multiple or severe injuries	Minor release - minimal acute environmental or public health impact - small, but detectable environmental consequences	300.000 US$	Non-severe ship damage - (port stay required, downtime 1 day)	Significant damage	0,1
3	Severe	Single fatality or multiple severe injuries	Major release - effects on recipients – short-term disruption of the ecosystem	3 mill. US$	Severe damage - (yard repair required, downtime < 1 week)	Severe damage in vicinity of ship	1
4	Catastrophic	Multiple fatalities	Severe pollution - medium-term effect on recipients - medium-term disruption of the ecosystem	30 mill. US$	Total loss (of, e.g. a medium-size merchant ship)	Extensive damage	10
5	Disastrous	Large number of fatalities	Uncontrolled pollution - long-term effect on recipients - long-term disruption of the ecosystem	300 mill. US$	Total loss (of, e.g. a large merchant ship)	Major public interest	100

Table 4. Risk matrix [14].

PI	Probability	Consequence/Severity				
		1	**2**	**3**	**4**	**5**
		Minor	**Significant**	**Severe**	**Catastrophic**	**Disastrous**
8	Very frequent	9	10	11	12	13
7	Frequent	8	9	10	11	12
6	Probable	7	8	9	10	11
5	Reasonably probable	6	7	8	9	10
4	Little probability	5	6	7	8	9
3	Remote	4	5	6	7	8
2	Very remote	3	4	5	6	7
1	Extremely remote	2	3	4	5	6

The hazards with the highest risk found by Østvik [14] are shown in tableTable 5. The values were obtained as a mean value of the independent score from the participants in the HAZID.

Table 5. Top ranked results from hazard identification [14].

Hazard	Risk Index
Faults in navigation equipment (in coastal waters)	7.0
Crew falls or slips on board	7.0
Shortage of crew when LNG trade is increasing	6.8
Rudder failure (in coastal waters)	6.8
Rudder failure (in manoeuvring)	6.8
Severe weather causing vessel to ground/collide (in transit)	6.6
Steering and propulsion failure (in manoeuvring)	6.6
Severe weather causing vessel to ground/collide (in manoeuvring)	6.6
Faults in navigation equipment (in manoeuvring)	6.6
Steering and propulsion failure (in coastal waters)	6.6
Collision with other ships or facilities (in port)	6.6
Terrorist attacks/intentional accidents	6.5

According to Vanem et al. [13], the following accident scenarios were chosen for further study:

- Collision.
- Grounding.
- Contact.
- Fire or Explosion.
- Incidents while loading/unloading cargo.

The choice was based on the historical accidents of LNG carriers, presented in Table 1, and the top-ranked hazards found in the HAZID, presented in Table 5. Vanem et al. [13] regarded these 5 accident scenarios are associated with severe consequences in terms of fatalities and the risk from other scenarios was assumed as being negligible in comparison.

5.2. Risk summation

To determine whether a risk is acceptable, criteria need to be established. According to Skjong et al. [29], a criterion widely used is the As Low As Reasonably Practicable (ALARP) principle in combination with the Net Cost of Averting a Fatality (NCAF) and Gross Cost of Averting a Fatality (GCAF). These are further described in Appendix B.7. ALARP refers to a level of risk that is neither negligibly low nor intolerably high. Vanem et al. [13] concluded that the total potential loss of lives (PLL) per ship year with a contribution of the various accidental scenarios was within the ALARP area, see Table 6. The individual risk was from ship accidents and contributions from occupational accidents were not included. Even when the occupational fatality risk, estimated by Hansen et al. according to Vanem et al. [13], was added to the individual risk it was still in the ALARP area. The risk for crew members is dominated by the occupational fatalities with a ratio of 3 to every fatality due to ship accidents.

Table 6. Potential loss of lives from LNG carrier operations per ship year [13].

Accident category	PLL (crew)	PLL (passengers of other ships)
Collision	$4.42\ x10^{-3}$	$1.59\ x10^{-3}$
Grounding	$2.93\ x10^{-3}$	0
Contact	$1.46\ x10^{-3}$	0
Fire and explosion	$6.72\ x10^{-4}$	0
Loading/unloading events	$2.64\ x10^{-4}$	0
TOTAL	$\mathbf{9.74\ x10^{-3}}$	$\mathbf{1.59\ x10^{-3}}$

Vanem et al. [13] also find that the societal risk is within the ALARP area, as well as collision, contact and grounding, are the largest contributing factors to the overall risk. Fire and collision were found to dominate the low-consequence risk contribution in the order of one fatality.

5.3. Risk control options and cost benefit

According to IMO [10], accidents with an unacceptable risk level, i.e. above the ALARP limit, need risk control measures (RCM). RCMs should, in general, reduce the frequency of failure or the severity of an accident. Risk Control Options (RCO) are composed of a limited number of RCMs and their cost-effectiveness in relation to the benefit of the implementation is determined. According to IMO [12], as a basis for recommendations an RCO was considered to be cost-effective if the NCAF and GCAF was less than $3 million each. Through a brainstorming event, a total of 33 alternative RCOs were produced. To verify the RCOs, a second workshop was held that reduced the number to nine for further assessment. Out of these nine, five were considered to considerably reduce the risk in a cost-effective manner:

- Risk-based maintenance of navigational systems.
- Electronic Chart Display and Information System (ECDIS).
- Automatic Identification System (AIS) integrated with radar.
- Track control system.
- Improved bridge design.

According to IMO [12] two additional RCOs were found to be cost-effective but with limited risk reduction effects:

- Risk-based maintenance of propulsion system.
- Risk-based maintenance of steering systems.

5.4. Recommendations

The recommendation from IMO [12] was that additional navigational equipment should be made mandatory in the IMO requirements for LNG carriers. Although some RCOs were rejected, the IMO [12] states that the rejected RCOs could be cost-effective for particular ships or particular trades. It is always important that the RCOs are suitable for the intended site of use or transfer route of a vessel. The three RCOs that were recommended were the following:

- Electronic Chart Display and Information System (ECDIS).
- Automatic Identification system (AIS) integrated with radar.
- Track control system.

To further increase the safety on board LNG carriers, the IMO [12] also proposed the requirement of a risk-based maintenance plan for critical navigational equipment. The final proposal was that the bridge design should be beyond the standard/minimum SOLAS bridge design.

6. Risk evaluation of FLNG during operation

The first step of the FSA methodology is to perform a risk assessment. This section presents some of the hazards due to the physical properties of LNG and LNG vapour. The risk analysis is mainly focused on the LNG FPSO due to its larger complexity compared to an LNG carrier or an FSRU.

6.1. Hazards due to the physical properties of LNG and LNG vapour

According to the IMO [12], LNG is a colourless, odourless, non-corrosive, non-toxic and cryogenic liquid, but when vaporized it forms a visible cloud that can become flammable if the gas-to-air mixture is between 5 – 15 %. LNG will behave differently if spilled over water compared to land. When spilled over land, the vaporization will be rapid but decreases as the ground underneath is cooled down, and therefore the evaporation of the created LNG pool can proceed during a long period of time. If spilled over water, LNG will float on the surface due to lower density. In contrast to when spilled on ground, heat will be transmitted through the water causing the LNG pool to boil and rapidly vaporize. A gas-to-air mixture of 10 % LNG vapour has an auto-ignition temperature of 540 °C [12], and therefore the vapour cloud is highly unlikely to self-ignite and will dissipate into the atmosphere unless it encounters any source of ignition.

According to the IMO [12], the main hazards of LNG in liquid or vapour form are:

- **Pool fires:** If the spilled LNG is ignited the mixture of evaporated gas and air will burn above the LNG pool. The fire cannot be easily extinguished. The heat from the fire may injure people or property at a significant distance from the fire.
- **Vapour clouds:** The vapour cloud can travel some distance from the spill site before encountering any source of ignition - the vapour cloud is normally expected to burn back to its source of spill and continue to burn as a pool fire.
- **Cryogenic temperature:** LNG is held at a temperature of -160°C, if human skin is exposed to this temperature the damage effect will be similar to a thermal burn. If structural elements and equipment are exposed to LNG and have not been designed to withstand the low temperature they will most likely become brittle and failure will occur.
- **Asphyxiation:** LNG is non-toxic but can cause death by replacing breathable air if spilled and could be of significant risk in enclosed or confined spaces.
- **Rollover:** When loading LNG with different compositions, these might not mix at once but form layers with different density within the tank. After a period of time the LNG may rollover to stabilize the liquid in the tank. The rollover causes the liquid to give off a large amount of vapour, which creates an overpressure in the tank.
- **Rapid phase transition (RPT):** When large enough quantities are rapidly spilled over water the LNG could change phase at such a fast rate that a cold explosion occurs. No combustion occurs but a large amount of energy is transferred in the form of heat from the water to the LNG.
- **Explosion:** LNG is not explosive in a liquid state and the vapour is only flammable at gas-to-air mixture of 5-15%. The only way for LNG to cause an explosion is if being ignited in an enclosed or semi-enclosed space and at the same time being in the flammable region.

6.2. Identification of hazards

The identification of hazards was established by a brainstorming event and followed the guidelines of IMO for FSA [10]. The study was limited to the first step of the FSA, risk identification. A schematic model of the process of an LNG FPSO can be seen in Fig. 11 and a schematic model of the process in a FSRU can be seen in Fig. 12. The consequence of a hazard is normally calculated on computational models of the actual problem. IMOs severity index, see appendix B.2, was used to give a rough estimate of the consequence of a hazard. The frequency of an event can be predicted from similar onshore plants or historical data, in this study the frequency index proposed by IMO, see appendix B.2, have been used to estimate a rough value.

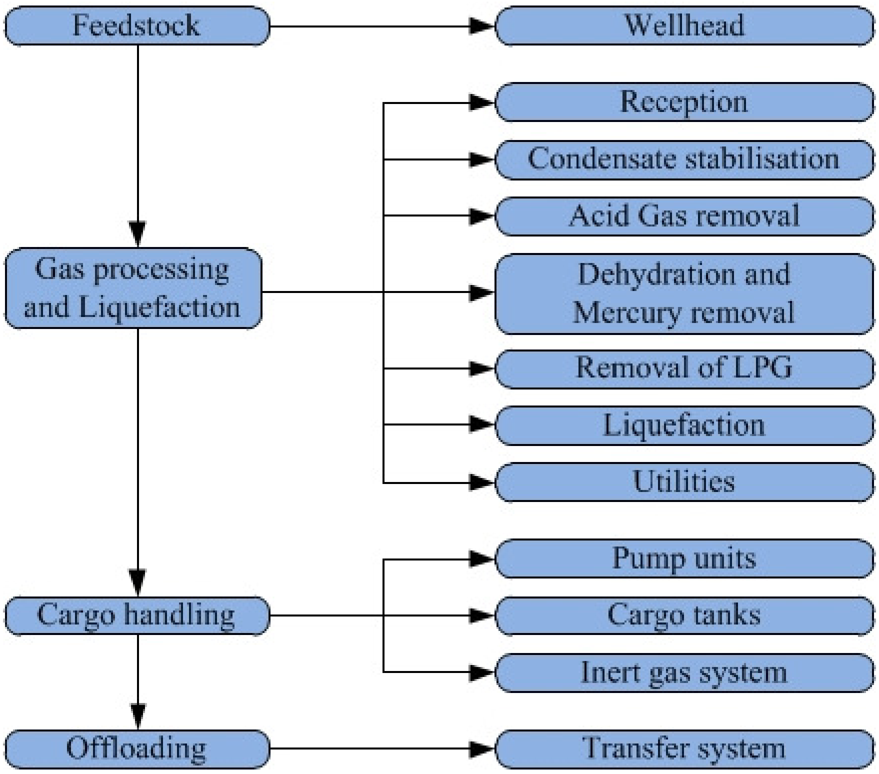

Fig. 11. Schematic overview of an LNG FPSO.

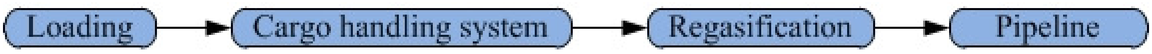

Fig. 12. Schematic overview of an FSRU.

Table 7 lists the different hazards which were found in the brainstorming event. The hazards are described in more detail in Appendix B. All hazards listed in Table 7 will affect an LNG FPSO. An FSRU will be not be influenced by hazards 1 and 2.

Table 7. List of hazards to LNG FPSO.

Area	Hazard no	Hazard	Frequency	Consequence	Risk level
Feedstock	Hazard 1	Blowout	3	1	4
	Hazard 2	Hydrocarbon release from the turret	2	3	5
Gas processing and Liquefaction /Regasification	Hazard 3	Hydrocarbon release in process area	2	3	5
	Hazard 4	Cryogenic spill in liquefaction area (regasification plant in case of FSRU)	1	3	4
	Hazard 5	Spill of hazardous substance	2	1	3
	Hazard 6	Fire/explosion in process area	2	3	5
Cargo handling	Hazard 7	Fire/explosion in containment area	2	4	6
	Hazard 8	Inert gas release in containment area	2	1	3
	Hazard 9	Sloshing in cargo tanks	4	1	5
Offloading And vessel overall	Hazard 10	Ship collision	1	2	3
	Hazard 11	Cryogenic leak during offloading (loading in case of FSRU)	1	3	4

6.3. Check of hazards against existing rules

To investigate if the current rules cover the hazards found in the risk identification, each hazard from Table 7 was checked against the rules, and if found to be covered no further action was made. A summary of the rules that were found applicable to the respective hazard are found in Table 8. A more thorough description of each rule and the applicable section is given in Appendix D.

Table 8. Summary of comparison of hazards against rules.

No	Hazard	Rule	Comment
1	Blowout	DNV-OS-E201 [30]	
2	Hydrocarbon release from the turret	DNV-OS-E201 [30] DNV-OS-C102 [31] CN 61.3 [32]	*Classification note 61.3* only applicable for FSRU following ship classification practice
3	Hydrocarbon release in process area	DNV-OS-E201 [30]	
4	Cryogenic spill in liquefaction area (regasification plant in case of FSRU)	DNV-OS-E201 [30]	
5	Spill of hazardous substance	DNV-OS-E201 [30]	
6	Fire/explosion in process area	DNV-OS-D301 [33] CN 61.3 [32]	*Classification note 61.3* only applicable for FSRU following ship classification practice
7	Fire/explosion in containment area	DNV-OS-D301 [33] CN 61.3 [32]	*Classification note 61.3* only applicable for FSRU following ship classification practice
8	Inert gas release in containment area	DNV-OS-E201 [30]	
9	Sloshing in cargo tanks	Rules of Ships, Pt.5, Ch.5 [16]	Offshore rules refer to Ship rules regarding cargo containment system
10	Ship collision		IGC code states the requirements on hull strength in case of collision
11	Cryogenic leak during offloading (loading in case of FSRU)	DNV-OS-E201 [30] Rules for ships, Pt.5 Ch.5 Sec.6 [16]	*Rules for Ships* only applicable for FSRU following ship classification practice

7. Discussion

One of the most distinct differences between an LNG carrier and an FLNG is the ability to transport LNG between different locations. While the FLNG could be moored on location for several years at a time, the LNG carrier is always in transit. This changes the requirements on service and surveys. An FSRU could have the option to follow a regular service and survey plan giving it the possibility to follow classification according to ship rules with the supplement of Classification Note 61.3 - Regasification vessels [32].

7.1. Structure design

On an LNG FPSO, the large topside, which contains the production unit of the vessel, will have a large influence on the hull structure of the vessel. The additional weight needs to be considered during construction of the vessel to ensure that no buckling occurs on the hull structure. The topside support structure will principally be the same as for oil FPSOs with the exception of deformations of the containment system during loading and offloading in an LNG FPSO.

According to Fagan et al. [3], the fatigue strength of the hull differs between an FLNG and an LNG Carrier. LNG carriers are normally designed with a fatigue life of 20 years in North Sea conditions. If an FLNG follows offshore class, it will be designed to meet site specific conditions. Some of the proposed locations for operation have a significant wave height of 8-9 metres, which is less than North Atlantic conditions, but, on the other hand, some locations proposed have a harsher environment. The offshore standard DNV-OS-C102 [31] could give the vessel class notation FMS, which is based on a design fatigue life of a minimum of 20 years. The data for transit and intended site of use is included in the fatigue life. Ship rules give a design condition for a fatigue life of a minimum of 20 years in North Atlantic conditions if the vessel is intended to operate in all seas and follow a regular docking scheme. It also gives the option to a vessel being moored in one location to be designed for a 100-year return period at the specific site.

Alignment possibilities with regard to the fatigue life are hard to find for offshore moored FLNGs. If the site of intended operation has a less severe sea state than the North Atlantic, the ship rules could be too conservative in some aspects. When following offshore class the fatigue life would be specific to the intended site of operation for the vessel. For an FSRU it could be beneficial to follow ship rules if the intended site of operation is near shore or moored to a jetty and a regular docking scheme is to be followed.

7.2. Gas processing and LNG production

The regulations for the process plant are covered in DNV-OS-E201 [30]. Regulations and standards are often well established for onshore use of the different technologies involved in the processing and liquefaction of natural gas, but hazards that occur when placed in an offshore environment need to be addressed.

The process plant, and, especially, the liquefaction stage are large power consumers. Power generation on board would most likely be solved by gas turbine driven generators. Today's rule requirements for gas carriers are restrictive and do not allow the placement of machinery spaces in front of cargo holds. Attention needs to be drawn to the placement of ventilation to machinery space considering hazardous vapours. According to Fagan [34], this has been solved by risk assessment on oil FPSOs and the same approach could be used for LNG

FPSOs. The relative safety of the different liquefaction processes differs. The Mixed Refrigerant and Cascade process, see Section 3.2, involves large quantities of flammable refrigerant which circulates through the process lines with extensive overpressure potential in the event of a leakage and explosion. Facilities for obtaining and storing the refrigerant are also needed. The Expander process uses nitrogen as refrigerant and is safer due to the inert properties of nitrogen. Besides the higher safety, the expander process is beneficial due to a smaller footprint and its being unaffected by motions due to the refrigerant that always operates in a gas phase [1][35]. However, the lower efficiency compared to other systems argues against its selection.

LNG carriers are designed with requirements for minimizing potential leakage sources and with the provision of safety measures in form of protective water spray. For FLNG applications the potential leak sources will increase. This needs to be addressed and additional installations of water spray and drip shields for protecting critical structural members should be implemented in design. With regard to such leakage, experience from oil FPSOs cannot be used as they do not involve cryogenic leakage, and neither are onshore- based process plants affected to the same degree as a floating steel structure in case of leakage. A process plant on land uses typically a “safety by separation” philosophy. Due to the limitations of space on a floating unit, more attention needs to be paid to layout and arrangement and to avoid the congestion and confinement of gas in case of leakage, which could increase the effects of any fire and explosion.

7.3. Cargo handling

On an LNG tanker, the inspection of tanks could occur during dry-docking since the cargo system will be fully shut down and the tanks empty. On an FLNG, the shutdown of the complete cargo system would be too costly and impracticable since it would demand a shutdown of the process plant at the same time. Therefore, the tank system needs to be designed to allow a survey of the tanks individually with the remaining tanks fully operational. This requires modifications to the standard gas ship piping design in order to permit safe isolation of individual tanks. Attention also needs to be drawn to the offloading pump system of an FSRU as it involves high pressure cryogenic liquid on the inlet side and exits the vaporizer as high pressure gas. FSRUs will also involve more pump units than an LNG carrier or LNG FPSO [28].

Due to the large topside process plant the membrane tank, or the equivalent, would be favourable compared to spherical tanks due to the availability of a flat deck, which permits installation on the topside. These tanks are, however, sensitive to additional loads due to sloshing. During operation of an FLNG, the tanks will be partially filled during the whole operational time. Classification Note 30.9 [36] should be used to show that the design accounts for the additional loads due to sloshing.

Offshore rules have generally the same requirements as the ship rules regarding cargo containment. Partially filled tanks deviate from the normal mode of operation, which demands a risk assessment to be made in order to investigate the risk. This may result in the strengthening of standard membrane designs or operational measures to minimize sloshing loads. The ability to inspect in situ and possible repair procedures need to be considered when not following a regular docking scheme. Future rules regarding the cargo system could use the IGC code [18] as a basis and deviations could be verified by risk assessment.

7.4. Transfer systems

The side-by-side transfers offer a great advantage due to the possibility of using conventional LNG carriers with amidships manifolds without modification. Experience of loading arms is wide since they are used on onshore terminals and since marine versions are available [1]. Depending on the intended site of operation the side-by-side may not be feasible due to a limitation of operation at a significant wave height of between 2.5- 3 m [37][38]. Tandem transfer systems could be possible up to a significant wave height of 5.5 m and would therefore not restrict the operation as much as a side-by-side would [38]. A side-by-side would also require the arriving LNG carriers to operate close to the FLNG during a critical operation [4]. Mooring loads and hydrodynamic interactions between the LNG carrier and FLNG during the transfer of LNG also needs to be evaluated when a side-by-side transfer is used to determine the safe operating environmental limits [39].

7.5. Additional

The research from the SAFEDOR project described in Section 5 concluded that 90 % of the accidents of an LNG carrier occurred during collision, grounding and contact accidents and their RCOs regarded implementation of several navigational systems to lower the risk of these hazards. The risk to a moored unit should be investigated by risk analysis with traffic information for the intended site as a base. The frequent arrival of shuttle carriers also increases the risk of collision or contact.

The continuous operation involving both the processing of natural gas and the simultaneous offloading sets high demands on control and safety systems. Fire and gas detection systems should be based on risk assessment so that even the smallest amount of gas is detected and proper actions for the prevention of an accident are launched. Due to the complexity of an FLNG, the regulations regarding the safety systems in today's regulation may not be sufficient to cover all areas and hazards. Future rules could implement risk assessment to determine the necessary level of safety systems in order to ensure safety on board.

With regard to the LNG FPSO application, the raw natural gas will (depending on the well) to some extent contain CO_2, which needs to be reduced to a certain level before the liquefaction process. To reduce the CO_2 emissions to air, it needs to be collected and disposed in some manner and there are several techniques available. One possibility is to inject the recovered CO_2 back into the well. This could also be beneficial as it could improve oil and gas recovery for an LNG FPSO. The environmental impact of an FSRU could be lowered by not using a direct fired heater for vaporization.

8. Conclusions

The risk analysis performed on the FLNG showed a large risk contribution from the topside process equipment and of fire or explosion in this area or within the cargo hold. The external FSA on LNG carriers studied showed that the largest risk contributing factors were collisions, grounding and contact accidents. Although an FLNG will be permanently moored it will still need monitoring of its perimeters and a high rate of arriving shuttle tankers will increase the risk of contacts or collisions.

An FSRU may follow ship rule practice or it may follow offshore rule practice. Generally, if the FSRU intends to follow a regular dry dock scheme similar to a gas carrier, it may follow a ship class approach. If it intends to remain permanently on location without dry docking it may follow the offshore approach. Whichever approach is selected needs to be accepted by the relevant Flag State and the requirements applied should address the additional safety concerns relevant for operation as an FSRU compared to operation as a conventional LNG carrier. An LNG FPSO will generally not follow a regular docking scheme and therefore needs to follow an offshore class approach. Below are listed the differences between an LNG carrier and an FSRU/LNG FPSO that have been discussed in this report and for which special attention needs to be drawn:

FSRU

- Additional load from topside and mooring equipment.
- Fatigue design life.
- Sloshing in cargo tanks.
- Venting of cargo tanks.
- Access for inspection and repair during operation.
- Additional fire and explosion loads.
- Additional LNG leakage sites.
- Presence of high pressure LNG and high pressure gas.
- Proximity of arriving shuttle tanker.
- Complex integrated Control System.
- Design of loading system.

The list should not be seen as comprehensive. It is important that while Rules for Gas Carriers [16] may form the basis of an FSRU design, these additional issues, addressed in Classification Note 61.3 [32], are also addressed. Determining concrete requirements risk studies will need to be carried out.

LNG FPSO

- Additional load from topside and mooring equipment.
- Fatigue design life.
- Gas processing and LNG production.
- Sloshing in cargo tanks.
- Venting of cargo tanks.
- Access for inspection and repair during operation.
- Additional fire and explosion loads.
- Additional LNG leakage sites.
- Proximity of arriving shuttle tanker.
- Complex integrated control system.
- Design of offloading system.

Experience from oil FPSOs could be used with additional requirements to address the safety concerns regarding processing and handling of cryogenic liquid. Experience from the cargo containment system of LNG carriers, and thereby the IGC code [18], could form a basis for the regulations of cargo systems for both LNG FPSOs and FSRUs. However, deviations from the IGC code exist and could be assessed by risk assessment.

9. Future work

To fully analyse the risk of an FLNG, a full FSA needs to be performed. Suggestions for the different steps involved are presented below.

Risk analysis

To be able to perform a real risk analysis of the hazard due to fire and explosion, a detailed analysis has to be performed. Drawings of the equipment and location in the process plant must be known or estimated. The risk assessment referenced in this work [13] and performed on an LNG carrier showed that the greatest risk contributors are collisions, groundings and contact accidents. To investigate the risk contribution from collisions and contact accidents to an FLNG, information regarding traffic in the intended area and the frequency of shuttle tankers arriving also needs to be implemented in such an analysis. The risk analysis could implement a numerical simulation of gas leakage. In order to analyse the risk in case of a release event during offloading, a comparison between the different offloading methods described in Section 3.4 could be made.

Risk control options and cost benefits

The risk found in the risk analysis could be further investigated. For example, for hazard 11, drip trays could be installed below critical points in the offloading station. Water curtains could also be installed to decrease the risk of an explosion in case of an LNG leakage. The different RCOs and their effectiveness should be compared to each other.

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Appendix A. Applicable rules for an FLNG

If an FSRU unit would be classed as an offshore unit, the rules listed in Table A.1 could be applicable to the respective area of the unit. For an LNG FPSO the Offshore Standard, which could be applicable to the respective area, is listed in **Table A.2**.

Table A.1. DNV Rules applicable to Offshore FSRU.

Area	Offshore Rule
Safety and Arrangements	DNV-OS-A101 [40]
Materials	DNV-OS-B101 [41]
Hull structure	DNV-OS-C101 [42] DNV-OS-C102 [31]
Stability	DNV-OS-C301 [43]
Fabrication	DNV-OS-C401 [44]
Marine Systems	DNV-OS-D101 [45]
Electrical	DNV-OS-D201 [46]
Instr. and Automation	DNV-OS-D202 [47]
Power Generation	DNV-OS-D201 [46] DNV-OS-E201 [30]
Fire	DNV-OS-D301 [33]
LNG Transfer	DNV-OS-E201 [30]
Position Mooring	DNV-OS-E301 [48]
Anchors	DNV-RP-E301 [49] DNV-RP-E302 [50] DNV-RP-E303 [51]
Helideck	DNV-OS-E401 [52]
Risers	DNV-OS-F201 [53] DNV-RP-F201 [54] DNV-RP-F202 [55]
LNG Containment System	Classification of ships Pt.5 Ch.5 [16]
Regasification	CN-61.3 [32]

Table A.2. DNV Rules applicable to an LNG FPSO.

Area	Offshore Rule
Safety and Arrangements	DNV-OS-A101 [40]
Materials	DNV-OS-B101 [41]
Hull structure	DNV-OS-C101 [42] DNV-OS-C102 [31]
Stability	DNV-OS-C301 [43]
Fabrication	DNV-OS-C401 [44]
Marine Systems	DNV-OS-D101 [45]
Electrical	DNV-OS-D201 [46]
Instr. and Automation	DNV-OS-D202 [47]
Power Generation	DNV-OS-D201 [46] DNV-OS-E201 [30]
Fire	DNV-OS-D301 [33]
Process, Pre-treatment and Liquefaction	DNV-OS-E201 [30]
LNG Transfer	DNV-OS-E201 [30]
Position Mooring	DNV-OS-E301 [48]
Anchors	DNV-RP-E301 [49] DNV-RP-E302 [50] DNV-RP-E303 [51]
Helideck	DNV-OS-E401 [52]
Risers	DNV-OS-F201 [53] DNV-RP-F201 [54] DNV-RP-F202 [55]
LNG Containment System	Classification of ships Pt.5 Ch.5 [16]

Appendix B. Risk Assessment

Today's ship safety is well regulated and a tendency to move from prescriptive to goal-based regulations is seen. Novel technology and on-going research for new ship design requires risk assessments to be performed in the design process. A risk assessment is used to measure and quantify the risks that could endanger safety on-board. In prescriptive rule-based design there is no amount of novel technology; everything is proven and the issues are well understood. By introducing novel technology the uncertainties occur and the prescriptive rules do not cover all aspects of the ship. Risk analysis is now needed for evaluating the novel technology and introducing new regulations to ensure the safety on board [15]. One of the methods for performing a risk assessment is the FSA methodology. The IMO have developed guidelines for the usage of FSA [10] in the IMO rulemaking process, the guidelines and the methodology is described briefly in Sections B.1 - B.7 and if no other reference is given these sections refer to the IMO guidelines [10].

B.1. The Formal Safety Assessment method

The Formal Safety Assessment (FSA) is a methodology for assessing risks relating to maritime safety including life, health, marine environment and property. The method uses risk analysis and cost benefit assessment as a basis for a decision-making process. This makes it very well suited as a tool in the evaluation of new regulations or in making a comparison between existing and improved regulations. The five steps of the method can be seen in Fig. B.1 and are described in Sections B.2 - B.7.

The process begins by defining the problem. The depth of the investigation is defined and a coarse analysis is suggested at an early stage in order to include all aspects of the problem. The human element should be incorporated in the risk analysis since it is one of the most contributory aspects to accidents, both as the cause of and the avoidance of accidents. Prior to the risk analysis, the risk acceptance criteria need to be established, and this is described in Section B.7.

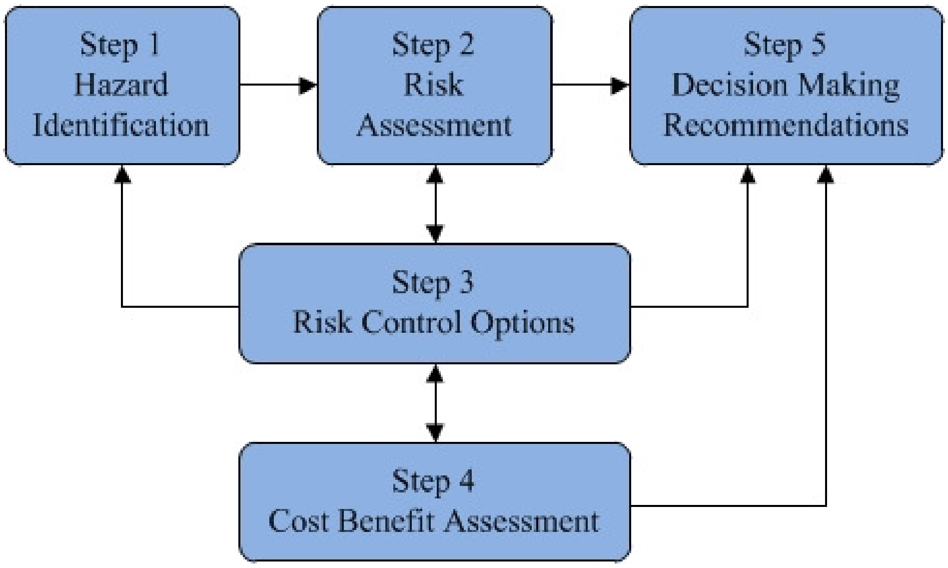

Fig. B.1. Working principle of FSA.

B.2. Identification of hazards

The first step is to identify a list of hazards and associated scenarios. The identification generally comprises a combination of both creative and analytical techniques. A coarse analysis of possible causes and outcomes of each hazard should be performed in this step. The analysis should be performed by a group consisting of experts and specialist from appropriate aspects of the subject being analysed. To help identify the hazards there are several techniques available:

- Hazard review.
- Hazard checklist.
- Hazard and operational study (HAZOP).
- Procedural HAZOP.
- What-If Analysis.
- Hazard Identification (HAZID).
- Failure modes, effects and criticality analysis (FMECA).
- Emergency Systems Survivability Analysis.
- Safety inspections and audits.

In the offshore industry, the HAZOP and hazard checklists are the ones most widely used. In the early stages of design a HAZID is normally used, which is a high level version of HAZOP. According to Spouge [11], the strengths of HAZID are:

- It is flexible, and applicable to any type of installation, operation or process.
- It uses the experience of operating personnel as part of the team.
- It is quick, because it avoids repetitive consideration of deviations.
  It is able to cover low-frequency events, and hence relates better to Quantitative Risk Analysis (QRA) than most hazard assessment techniques.

The weaknesses are:

- Guide words require development for each installation, and may omit some hazards.
- Its benefits depend on the experience of the leader and the knowledge of the team.

The different hazards are then ranked to prioritize them against each other using available data and judgement. The IMO guidelines [10] give an example of how to rank the different scenarios. To facilitate the ranking and validation of ranking the indices of consequence and frequency are defined on a logarithmic scale. The "risk index" is obtained by adding the frequency and consequence indices:

$$\text{Risk} = \text{Probability} x \text{Consequence} \tag{3}$$

$$\text{Log(Risk)} = \log(\text{Probability}) + \log(\text{Consequence}) \tag{4}$$

Table B.1 shows an example of the Severity Index, an example of the Frequency Index is shown in Table B.2

Table B.1. Severity Index [10].

Severity Index				
SI	SEVERITY	EFFECTS ON HUMAN SAFETY	EFFECTS ON SHIP	S (Equivalent fatalities)
1	Minor	Single or minor injuries	Local equipment damage	0.01
2	Significant	Multiple or severe injuries	Non-severe ship damage	0.1
3	Severe	Single fatality or multiple severe injuries	Severe damage	1
4	Catastrophic	Multiple fatalities	Total loss	10

Table B.2. Frequency Index [10].

Frequency Index			
FI	FREQUENCY	DEFINITION	F (per ship year)
7	Frequent	Likely to occur once per month on one ship	10
5	Reasonably probable	Likely to occur once per year in a fleet of 10 ships, i.e. likely to occur a few times during the ship's life	0.1
3	Remote	Likely to occur once per year in a fleet of 1,000 ships, i.e. likely to occur in the total life of several similar ships	10^{-3}
1	Extremely remote	Likely to occur once in the lifetime (20 years) of a world fleet of 5,000 ships	10^{-5}

The combination of Table B.1 and Table B.2 give the risk matrix shown in Table B.3.

Table B.3. Risk matrix for Risk Index [10].

Risk Index (RI)					
		SEVERITY (SI)			
		1	2	3	4
FI	FREQUENCY	Minor	Significant	Severe	Catastrophic
7	Frequent	8	9	10	11
6		7	8	9	10
5	Reasonably probable	6	7	8	9
4		5	6	7	8
3	Remote	4	5	6	7
2		3	4	5	6
1	Extremely remote	2	3	4	5

The output from step 1 is a list of hazards and a description of causes and effects, all ranked by risk level. According to Spouge [11], the first step is often referred to as the most important step since it identifies all hazards. If a hazard is missed it will not occur later in the process and hence will not be evaluated.

B.3. Risk analysis

In step 2 a more detailed investigation of the causes and consequences is performed on the more important scenarios identified in step 1. By using suitable techniques for modelling the risk, attention would be focused on high risk areas. A risk tree model could be built using a fault tree or event tree, which is standard risk assessment procedure. Data from previous accidents and failures could be used as information when modelling the risk, otherwise simulations, calculations and/or expert assessment may be used to provide the data.

B.4. Risk control options (RCO)

In step 3 a proposal for effective and practical RCOs is performed. It comprises 4 main steps:

(1) Focusing on risk areas needing control.
(2) Identifying potential risk control measures (RCMs).
(3) Evaluating the effectiveness of the RCMs in reducing risk by re-evaluating step 2.
(4) Grouping RCMs into practical regulatory options, RCOs.

By analysing the different risks considering their frequency and severity of outcome, the risks with an unacceptable risk level will become the primary focus. Measures that reduce these risks have to be identified. Probability of the risks should be reviewed irrespective of the severity. The aim of the produced RCMs is to reduce the frequencies and mitigate the effect of failures and accidents. Potential RCMs are compiled into groups of RCOs that can focus on controlling the initiation or escalation of accidents.

B.5. Cost-benefit assessment

The costs and benefits for the implementation of different RCOs, identified in step 3, are evaluated in step 4. Benefits could include reduction in fatalities, injuries, casualties, environmental damage, etc. The cost of the implementation of the RCO should be expressed in terms of life cycle costs and could be expressed in relation to safety of life or property.

B.6. Recommendations for decision making

The final step compares and ranks the different RCOs and their associated costs and benefits. The final report should be presented in an auditable and traceable manner so it could be understood by all parties irrespective of their experience in the techniques involved in the FSA methodology. A method to visually show and compare different societal risk against each other is the FN diagram, see Section B.7.

B.7. Risk acceptance criteria

There are several different standards for establishing risk criteria. Most of the criteria normally place the risk in one of the three categories; unacceptable, tolerable and broadly acceptable. For offshore applications the ALARP, short for ‘as low as reasonably possible’, is often used and refers to the cost-effectiveness and benefits of the solution. The term is derived from the UK Health and Safety at Work Act 1974 [56]. The risks of the intolerable and tolerable should be ALARP and have proved to be so. In the risk assessment the individual, societal and the environmental risks should all be taken into account.

For risks in the ALARP area a criterion is needed to determine when a risk is reasonably practicable. According to Skjong [29], this is often given in terms of the cost of averting a fatality normally referred to as Net Cost of Averting a Fatality (NCAF) or Gross Cost of

Averting a Fatality (GCAF). Quantitative values must be set for the optimum/maximum of the cost of averting a fatality, and the definitions of NCAF and GCAF are:

$$GCAF = \Delta Cost/\Delta PLL \quad (5)$$
$$NCAF = (\Delta Cost - \Delta Economic\_Benefits)/ \Delta PLL \quad (6)$$

With the parameters:

ΔCost = Marginal cost of the Risk Control Option, see Section B.4
ΔPLL = the reduced number of fatalities
ΔEconomic Benefits = the economic benefits of implementing the RCO

According to Skjong [29], the IMO proposed values for the individual risk to be used as risk acceptance criteria. For a large project exposing a large number of people to risks, the societal risk criteria is preferable. This criteria is expressed in frequency versus number of fatalities, but the risks are not as straightforward to develop as the individual risk criteria. In some cases both societal and individual risk criteria must be complied with. For example, with a passenger ferry that carries a large number of passengers the risk should be expressed in societal risk. However, the crew is exposed to additional hazards related to their work and this should be expressed as individual risk. A technique for presenting risk is FN curves, see Fig. B.2.

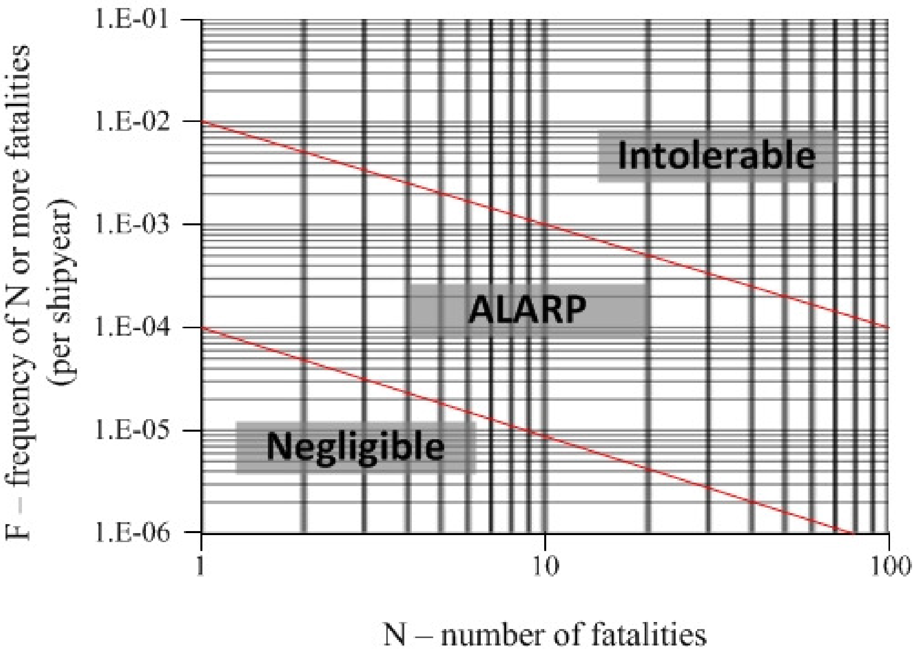

Fig. B.2. FN-curve.

Different models exist on the inclination angle of the boundary between the ALARP region and the intolerable. The FN diagram shows the relationship between the frequency F and accidents with N or more fatalities. The FN curve gives a good overview over accidents which span from a single to multiple fatalities.

Appendix C. Hazard register

Appendix C contains the hazard register for all hazards identified in the HAZID.

HAZARD REGISTER	
Hazard no	1
Hazard	Blowout
Area	Feedstock
Description	Uncontrolled flow of well fluid
Cause	Pressure failure
Effect	Potential economic losses due to downtime of process plant
Frequency	3
Severity	1
Risk level	4

HAZARD REGISTER	
Hazard no	2
Hazard	Hydrocarbon release from the turret
Area	Feedstock
Description	Uncontrolled release of well fluid in the turret
Cause	Could be caused by mechanical failure due to fatigue and/or design fault in the turret
Effect	If leakage is ignited it could cause injury or death to personnel in the area. Severe damage to ship could occur
Frequency	2
Severity	3
Risk level	5

HAZARD REGISTER	
Hazard no	3
Hazard	Hydrocarbon release in Gas process area
Area	Gas Process area
Description	Uncontrolled release of hydrocarbon in the process area
Cause	Could be caused by mechanical failure or equipment failure. Human error could also be the cause
Effect	If ignited it could cause injury or death to personnel in the area. Severe damage to ship could occur. Fire and explosion will give different degree of severity. Fire is assumed in this investigation
Frequency	2
Severity	3
Risk level	5

HAZARD REGISTER	
Hazard no	4
Hazard	Cryogenic spill in liquefaction area (regasification plant in case of FSRU)
Area	Gas Process area
Description	Spill of cryogenic liquid (LNG)
Cause	Damage to or fatigue of piping and/or equipment, corrosion, thermal effects
Effect	Multiple injuries and/or fatalities among crew, damage to ship could be severe. Vaporized LNG could cause asphyxiation to crew over the entire ship.
Frequency	1
Severity	3
Risk level	4

HAZARD REGISTER	
Hazard no	5
Hazard	Spill of hazardous substance
Area	Gas Process area
Description	Spill of hazardous substance used in process
Cause	Failure of equipment, human error, dropped objects
Effect	Single or minor injuries, only small damage to ship, could be potentially hazardous to the environment
Frequency	2
Severity	1
Risk level	3

HAZARD REGISTER	
Hazard no	6
Hazard	Fire/explosion in the process area
Area	Gas Process area
Description	Fire and/or explosion in the process area
Cause	Ignition of released LNG vapour or hydrocarbon
Effect	Depending on the size of the release the damage to crew and ship could be minor to catastrophic. Severe effect on crew and ship is assumed
Frequency	2
Severity	3
Risk level	5

HAZARD REGISTER	
Hazard no	7
Hazard	Fire/explosion in cargo containment area
Area	Cargohandling system
Description	Fire and/ or explosion in containment area due to spillage of LNG
Cause	Failure of cargo tank system, collision, process error
Effect	The effects would probably be catastrophic due to the contained space surrounding the cargo tanks
Frequency	2
Severity	4
Risk level	6

HAZARD REGISTER	
Hazard no	8
Hazard	Inert gas release in containment area
Area	Cargohandling system
Description	Release of inert gas in the containment area
Cause	Failure of equipment, mechanical failure, mechanical failure due to fatigue
Effect	Cold burns could occur if human skin comes into contact with the inert gas
Frequency	2
Severity	1
Risk level	3

HAZARD REGISTER	
Hazard no	9
Hazard	Sloshing in cargo tanks
Area	Cargo handling system
Description	Sloshing could occur in cargo tanks when partially filled
Cause	Partially filled cargo tanks could cause sloshing when the FLNG is under influence of bad weather
Effect	The effects of sloshing could involve damage to cargo tanks and cause instability to the FLNG causing production shutdown
Frequency	4
Severity	1
Risk level	5

HAZARD REGISTER	
Hazard no	10
Hazard	Ship collision
Area	Total ship
Description	Collision with LNG carrier or other ship
Cause	LNG carrier drift into the FLNG
Effect	During docking the LNG carrier would most likely have a low speed and the effects would be held at a significant level. Due to the assistance of tugboats the frequency is assumed low
Frequency	1
Severity	2
Risk level	3

HAZARD REGISTER	
Hazard no	11
Hazard	Cryogenic leak during offloading (loading in case of FSRU)
Area	Deck of FLNG
Description	Rapture of loading arm or other mechanical failure of offloading system
Cause	Mechanical failure of offloading system
Effect	Severe fatalities and severe damage to hull
Frequency	1
Severity	3
Risk level	4

Appendix D. Hazards compared to rules

Since most hazards in Table 7 concern the process plant and its equipment DNV-OS-E201 - *OIL AND GAS PROCESSING SYSTEMS* [30] will be applicable. The objectives and scope can be seen below:

DNV-OS-E201 Ch.1 Sec.1

A 100 Introduction

101 *This offshore standard contains criteria, technical requirements and guidance on design, construction and commissioning of offshore hydrocarbon production plants and associated equipment. The standard also covers liquefaction of natural gas and regasification of liquefied natural gas and also associated gas processing.*

102 *The standard is applicable to plants located on floating offshore units and on fixed offshore structures of various types. Offshore installations include fixed and floating terminals for export or import of LNG.*

103 *The requirements of Ch.2 relate primarily to oil and gas production activities. Ch.2 Sec.11 provides additional requirements to LNG terminals and should be read as a supplement to the other sections in Ch.2.*

104 *The standard has been written for general worldwide application. Governmental regulations may include requirements in excess of the provisions of this*

A 200 Objectives

201 *The objectives of this standard are to:*

- *provide an internationally acceptable standard of safety for hydrocarbon production plants and LNG processing plant by defining minimum requirements for the design, materials, construction and commissioning of such plant*
- *serve as contractual a reference document between suppliers and purchasers*
- *serve as a guideline for designers, suppliers, purchasers and contractors*
- *specify procedures and requirements for hydrocarbon production plants and LNG processing plant subject to DNV certification and classification.*

A 400 Scope and application

401 *The standard covers the following systems and arrangements, including relevant equipment and structures:*

- *production and export riser systems*
- *well control system*
- *riser compensating and tensioning system*
- *hydrocarbon processing system*
- *relief and flare system*
- *production plant safety systems*
- *production plant utility systems*
- *water injection system*
- *gas injection system*
- *storage system*
- *crude offloading system*
- *LNG Liquefaction system*
- *LNG regasification system*
- *LNG transfer system.*

Ch.2 Sec.1 states:

A 100 Overall safety principles

101 *Hydrocarbon production systems shall be designed to minimize the risk of hazards to personnel and property by establishing the following barriers:*
- *preventing an abnormal condition from causing an undesirable event*
- *preventing an undesirable event from causing a release of hydrocarbons*
- *safely dispersing or disposing of hydrocarbon gases and vapors released*
- *safely collecting and containing hydrocarbon liquids released*
- *preventing formation of explosive mixtures*
- *preventing ignition of flammable liquids or gases and vapors released*
- *limiting exposure of personnel to fire hazards*

Deviations from DNV-OS-E201 [30] or hazards which are not covered are shown below:

- **Hazard 1 - Blowout**

Following rule is applicable [30]:

DNV-OS-E201, Ch.2, Sec.1
A 100 Overall safety principles
A 400 Scope and application

- **Hazard 2 - Hydrocarbon release from the turret**

In addition to E201 the structural design load is also considered in DNV-OS-C102 [31]:

DNV-OS-C102 Sec. 12

C 100 Mooring loads

101 *A unit may be kept on location by various methods. These methods may include several different types of station-keeping systems such as internal and submerged turret systems, external turret, buoy, fixed spread mooring and dynamic positioning. Each mooring system configuration will impose loads on the hull structure. These loads shall be considered in the structural design of the unit, and combined with other relevant load components.*

To ensure the fatigue life the following rule is applicable [31]:

DNV-OS-C102 Sec. 12:

G 400 Areas to be checked
401 *Fatigue sensitive details in the hull and topside supporting structure shall be documented to have sufficient fatigue strength. Particular attention should be given to the following details as described in Table G3, but not limited to:*

Table G3 Areas to be checked	
Hull	*—main deck, including deck penetrations, bottom structure and side shell* *— longitudinal stiffener end connections to transverse webframe and bulkhead* *— shell plate connection to longitudinal stiffener and transverse frames with special consideration in the splash zone.* *— hopper knuckles and other relevant discontinuities* *— openings and penetrations in longitudinal members*

	— toe and heel of horizontal stringer in way of transverse bulkhead *— bilge keels.*
Hull-topside interface structure	*— attachments, foundations, supports, etc. to main deck and hull* *— topside stools and supporting structures* *— caissons* *— turret and supporting structures* *— riser interfaces* *— crane pedestal foundation and supporting structures* *— flare tower foundation and supporting structures.*

Classification note 61.3 for the Regasification Vessels [30]:

9. Arrangement for submerged turret offloading

The design of submerged turret offloading system is to be in compliance with DNV's Rules for Classification of Ships Pt.5 Ch.3 Sec.14. In addition, the following apply for Submerged Turret Loading system (STL) intended for export of high pressure natural gas:

- *Explosion design loads due to explosion overpressure to be quantified and specifically designed for with respect to STL trunk and explosion relief arrangement.*
- *The STL room to be fitted with two independent means of escape.*
- *It must be ensured that positive isolation of regasification from STL can be provided, as well as positive isolation of regasification from the pump in the cargo tank. The isolation valves to STL to be remotely operable and fitted with position monitoring, which interfaces with STL depressurization and purging cycle monitoring.*
- *It must be ensured that PSD is immediately activated if green line signal in STL is lost.*
- *In case of differential pressure between sub-sea pipeline and regasification export pipe, it should be ensured that pipeline and buoy valves cannot be opened until the pressure difference is equalized.*
- *It must be ensured that the pipeline and regasification system will shut down upon positive confirmation of gas detected in the turret compartment.*
- *Prior to disconnecting the STL piping must be depressurized and purged. Depressurization and purge cycle to be completed and confirmed, as part of the STL logic before next step can be initiated.*
- *Buoy and sub-sea valves should be fitted with proximity switches or similar for positive confirmation of connection/disconnection.*

To ensure the fatigue life the following rule is applicable:

CN 61.3, Ch.8

8.1 Environmental conditions

A vessel intended to operate in all sea areas should be designed, with regard to structural strength, for the environmental loading in the North Atlantic conditions with a return period of 20 years.

For vessels located continuously at one location design should consider environmental conditions for a 100 years' return period at the specific site.

For fatigue the basic requirement is 20 years' design life based on a scatter diagram for worldwide operation or at designated operation site as applicable.

- **Hazard 3 - Hydrocarbon release in process area**
- **Hazard 4 - Cryogenic spills in liquefaction area**
- **Hazard 5 - Spill of hazardous substance**

All above applicable by [30]:

DNV-OS-E201, Ch.2, Sec.1
A 100 Overall safety principles
A 400 Scope and application

- **Hazard 6 - Fire/explosion in process area**
- **Hazard 7 - Fire/explosion in containment area**

For offshore hazards related to Fire the following rule is applicable [33]:

DNV-OS-D301 Sec. 9:

A 100 Introduction

101 *This section gives fire technical requirements applicable to oil production and storage units. The requirements are to be applied supplementary to the requirements given by Sec.1 to Sec.5.*
102 *For specific requirements for ESD and fire and gas detection systems, see DNV-OS-A101 and DNV-OS-D202.*

For an FSRU unit classed according to Ship and Classification Note 61.3 [30], fire is regulated through a risk assessment which has to be performed in order to establish the risk:

CN 61.3 Sec.5:

5.1 Risk assessment

A risk assessment should be conducted, preferably in the early phase of the project, and should include at least assessment of the following:

-*Collision*
-*fire- and explosion*
-*dropped object*
-*cryogenic leakage.*

The findings from the risk assessments carried out are to be considered in the design phase and addressed in the documentation submitted to class. The risk assessment should comply with the principles outlined in DNV-OS-A101 App. C. Design loads and recommendations from the risk assessment are to be addressed in the final design.

- **Hazard 8 - Inert gas releases in containment area**

The following rule could be applicable [30]:

DNV-OS-E201, Ch.2, Sec.1
A 100 Overall safety principles
A 400 Scope and application

- **Hazard 9 - Sloshing in cargo tanks**

Offshore rules [19] refer to Ship rules [16] regarding cargo containment systems:

DNV-OSS-103, Ch.2 Sec.4
C 200 Supplementary technical requirements

202 *Containment systems may in general be designed using the methodology described in DNV Rules for Classification of Ships Pt.5 Ch.5 Gas Carriers, provided the loading conditions and operational modes for an offshore application are taken into account.*

Guidance note:
Aspects such as the actual site-specific environmental conditions, partial filling modes, project-specific accidental loads, provision for in-situ inspection for units not intending to dry-dock will need to be specially assessed.

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In Ship rules sloshing is considered in [16]:

Rules of Ships, Pt.5, Ch.5,
Sec. 5 Scantlings and Testing of Cargo Tanks

A 800 Sloshing loads

801 *When partial tank filling is contemplated, the risk of significant loads due to sloshing induced by any of the ship motions mentioned in 703, shall be considered.*

802 *When risk of significant sloshing induced loads is found to be present, special tests and or calculations will be required.*

Guidance note:
For membrane cargo tanks reference is made to Classification Note 30.9; Sloshing analysis of LNG membrane tanks.

---e-n-d---of---G-u-i-d-a-n-c-e---n-o-t-e---

Classification Note 30.9 [36] supplements the rules as to how the additional loads due to sloshing should be accounted for.

- **Hazard 10 - Ship collision**

The IGC code [18] states the following:

Preamble

3 Severe collisions or strandings could lead to cargo tank damage and result in uncontrolled release of the product. Such release could result in evaporation and dispersion of the product and, in some cases, could cause brittle fracture of the ship's hull. The requirements in the Code are intended to minimize this risk as far as is practicable, based upon present knowledge and technology.

Chapter 2 Ship survival capability* and location of cargo tanks

2.1.1 Ships subject to the Code should survive the normal effects of flooding following assumed hull damage caused by some external force. In addition, to safeguard the ship and the environment, the cargo tanks should be protected from penetration in the case of minor damage to the ship resulting, for example, from contact with a jetty or tug, and given a measure of protection from damage in the case of collision or stranding, by locating them at specified minimum distances inboard from the ship's shell plating. Both the damage to be assumed and the proximity of the tanks to the ship's shell should be dependent upon the degree of hazard presented by the product to be carried.

2.1.2 Ships subject to the Code should be designed to one of the following standards:
.1 ' A type 1G ship' is a gas carrier intended to transport products indicated in chapter 19 which require maximum preventive measures to preclude the escape of such cargo.
.2 ' A type 2G ship' is a gas carrier intended to transport products indicated in chapter 19 which require significant preventive measures to preclude the escape of such cargo.

2.2.2 The stability of the ship in all seagoing conditions and during loading and unloading cargo should be to a standard which is acceptable to the Administration.

- **Hazard 11 - Cryogenic leaks during offloading**

For offshore use regarding the transfer of LNG the following rule could be applicable [30]:

DNV-OS-E201, Ch.2 Sec.11
C 500 LNG transfer

For the transfer of LNG the following rule in Ship rules could be applicable [16]:

Rules for ships, Pt.5 Ch.5 Sec.6
C. Cargo Piping Systems

If the transfer system is intended to be placed in the bow or stern [16]:

Rules for ships Pt.5 Ch.5 Sec.6
E. Bow or Stern Loading and Unloading Arrangements