Technical University of Crete

Master Thesis

---

# LNG Transportation and Storage: Techniques and Standards

---

Author:

**Georgantas Kostas**

Supervisor:

**Dr. D. Marinakis**

A thesis submitted in fulfillment of the requirements for the degree of Master in Science in

**Petroleum Engineering**

**March 2020**

# Contents

# Acknowledgements

I would like to address my biggest and warmest appreciation to my **family**. Without their help and constant support I would not be able to move to Crete and study to become a Petroleum Engineer. All I have become is because of them.

To my supervising professor, **Dr. D. Marinakis**, I would like to express my gratitude for accepting to work with me. He was always there to answer my questions on academic matters, but most importantly, he helped me realize my worth and potential as a Chemical and Petroleum Engineer.

To my dear friend **Nikos Xynopoulos**, thank you so much for the assistance on both my thesis and my quest to find a job in what I love. But most of all, thank you for believing in me and boosting my confidence.

I also feel I should highlight the role of **Hellenic Petroleum** with respect to their contribution in this master, which made it possible for me and other students to stydy petroleum engineering. Their financial support to courses like this secures future engineers' quality and creates a pool of talent that has the potential to over-justify the company's investment. Moreover, my warmest thanks also go to Mr. **Konstantinos Roussis** from **Asprofos Engineering**, who provided me with his professional insight of the oil & gas industry.

Last but not least, I would like to thank **Dynamarine**, a Greek company specializing in STS operations. My deepest respect goes to **Mr. Alexandros Glykas**, CEO of Dynamarine and **George Papaioannou**, Project Manager, who gladly accepted to help me with my thesis and answer my questions about Ship to Ship operations. Dynamarine is an outstanding example of enterpreneurship and a firm confirmation of Greek tradition in the shipping/marine industry.

# Abstract

Liquefied Natural Gas, commonly known as LNG, is a practical way of transporting natural gas from stranded, offshore gas fields to gas distribution networks around the globe. Natural gas is liquefied at an ultra-low temperature (cryogenic liquid) of approximately -162$^{o}$C at a liquefaction plant. When liquefied, its volume decreases 600 times, which makes LNG a convenient and financially feasible technology of storing and transporting natural gas. Depending on its composition (predominantly methane), LNG has a density of around 450 kg/m$^3$ and its flammability limits are 5-15% volume in air. LNG's decreased volume compared to natural gas, its clean combustion and the ease of transportation, make LNG a valuable means of reducing environmental impact, monetizing stranded resources and establishing energy independence from pipeline gas.

The LNG market has witnessed remarkable expansion in the last decade, and according to industry majors and LNG experts, demand for LNG will continue to grow at a rate of about 3.5% per annum. This demand growth will mainly be driven by China's requirements for gas imports, Europe's declining gas production, as well as the fact that US producers will seek for overseas markets for their gas.

As far as its storage is concerned, LNG can be stored in a Floating Storage and Regasification Unit (FSRU), in a Floating LNG vessel (FLNG) or a regular LNG carrier ship. In onshore locations, LNG is stored in LNG terminals (regasification plants) where it is regasified and distributed to the local gas network. Given its cryogenic nature, LNG has to be stored in special tanks. Similar containment systems can be used for both onshore and offshore storage of the LNG cargo, utilizing the necessary materials and technology to withstand the low temperature and high vapor pressures of LNG.

The transfer of LNG is another important aspect of the LNG value chain, since its unique properties pose a threat in case of leakage. The technology of Ship to Shore LNG transfer has been well established in the industry, utilizing hard arms to transfer the cargo. On the other hand Ship To Ship transfer is a relatively new technology in the LNG industry, which offers a number of advantages over Ship to Shore transfer.

The LNG industry, just like any other, is looking for new ways to improve its efficiency and increase the profit margins for the parties involved. Pressurized LNG is a novel concept of storing and transporting LNG, while in-tank recondensing can reduce energy consumption in FSRU vessels.

# INTRODUCTION

## 1.1 What is LNG

Liquefied Natural Gas is natural gas in liquid state. In order to produce LNG, natural gas has to be purified and then cooled down to approximately -162$^0$C, which makes it a cryogenic liquid. Once liquefied, one volume of LNG equals approximately 600 volumes of natural gas at standard temperature (15$^o$C) and pressure (1bar), thus making it highly energy dense [1]. After the pretreatment and liquefaction processes, LNG is stored in cryogenic tanks and transported via ships to the LNG terminals. When it needs to be used, it is regasified at the regasification plant and introduced into the market through the gas pipeline infrastructure. The typical value chain of LNG is illustrated in Figure 1.


**Figure 1. LNG Value Chain**

Deriving from natural gas, LNG is a fossil fuel, meaning that it originates from organic matter accumulated and buried in appropriate depositional environments milions of years ago. Consequently, subjected to high temperatures and pressures over a long period of time, the organic material turned into what is known as 'hydrocarbons'. Natural gas, and thus LNG, comprises mostly of the light fractions of hydrocarbons, with one up to four carbon atoms.

## 1.2 LNG Properties

### 1.2.1 Chemical Composition

The chemical composition of natural gas varies, depending on the gas source and processing/fractionation history. It typically consists of methane ($CH_4$), ethane ($C_2H_6$), propane ($C_3H_8$), butane ($C_4H_{10}$) and small amounts of heavier components. Impurities are also included, namely nitrogen ($N_2$), mercury (Hg) , water vapors, carbon dioxide ($CO_2$) , hydrogen sulfide ($H_2S$) and other complex sulphur compounds, which have to be extracted prior to liquefaction. However, methane makes up for the majority of the natural gas composition, usually ranging between 85-97 mole% concentration, or even more. Table 1 illustrates typical LNG chemical composition ranges for various well known LNG terminals.

The composition of natural gas can potentially change in each step of processing and/or handling (mainly during transportation and storage). This alteration of the original composition, known as 'weathering', mainly affects the methane content, since it is the most volatile component of natural gas. Methane vaporization will lead to relative increase of the heavier hydrocarbons' concentration, namely ethane and propane, thus altering the products' properties. [2]

LNG is often wrongly confused with LPG or Liquid Petroleum Gas. While both originate from natural gas, LPG primarily consists of propane and butane and is stored in pressurized vessels. In turn, LPG falls into the NGL or Natural Gas Liquids category, which also involves methane, ethane and C5+ fractions.

### 1.2.2 Density

The density of methane vapour at ambient pressure and temperature is 0.671 $Kg/m^3$, while its specific gravity in the same conditions is about 0.45, which means that air is twice as heavy. The density of LNG (predominantly methane) is higher than that of air at temperatures below -107°C, which means that any LNG vapours dissipated below -107°C will be negatively buoyant and accumulate in low areas until it warms. Above -107 °C LNG vapours will disperse more easily.

LNG is a clear, colorless, odorless, non corrosive and non-toxic liquid. However, as is the case for any gaseous chemicals, boil-off gas from LNG can cause asphyxiation in conditions of no ventilation and lack of oxygen [3].

**Table 1. Chemical Composition of LNG for various LNG terminals**

| Component mole % | Das Island, Abu Dhabi | Whitnell Bay, Australia | Bintulu, Malaysia | Arun, Indonesia | Lumut, Brunei | Bontang, Indonesia | Ras Laffa, Qatar (Ras Gas) |
|---|---|---|---|---|---|---|---|
| Methane | 87.1 | 87.8 | 91.2 | 89.2 | 89.4 | 90.6 | 89.6 |
| Ethane | 11.4 | 8.3 | 4.28 | 8.58 | 6.3 | 6 | 6.25 |
| Propane | 1.27 | 2.98 | 2.87 | 1.67 | 2.8 | 2.48 | 2.19 |
| Butane | 0.141 | 0.875 | 1.36 | 0.511 | 1.3 | 0.82 | 1.07 |
| Pentane | 0.001 | - | 0.01 | 0.02 | - | 0.01 | 0.04 |

### 1.2.3 Flammability

As far as flammability is concerned, the lower and upper limits of methane are approximately 5 and 15% by volume respectively. When fuel concentration exceeds the upper limit, it cannot burn because too little oxygen is present. When fuel concentration is below the lower flammability limit, it cannot burn because too little methane is present [4]. However, these limits are affected by the presence of heavier fractions in the natural gas composition as they have lower flammability limits than methane, causing the lower flammability limit of LNG to decrease with increasing concentrations [2].

### 1.2.4 Auto Ignition Temperature and Gross Calorific Value

Auto ignition temperature is another physical property which, like flammability, plays a crucial role when it comes to safe operations and facilities design. Auto ignition temperature (AIT) is the lowest temperature at which a gas will ignite after an extended time of exposure. This temperature depends on factors such as air-fuel relative concentration, pressure and LNG composition. The richer the composition in heavy hydrocarbons, the lower the AIT, and thus easier for the fuel to ignite. For a mixture of 10% methane in air, the AIT is above 540$^{o}$C [2].

Since the primary use of natural gas is for fuel, it is normally sold and bought according to the heating or calorific value it produces when burned. This value is the amount of heat released during complete combustion under specific conditions of temperature and pressure. Discrimination must be made between Gross Calorific Value (GCV) and Net Calorific Value (NCV). When calculating the GCV, all water formed from the combustion is condensed into liquid state, while in NCV the water produced remains in vapor state. In this sense, as the additional energy for water vapor condensation is considered, the GCV is higher than NCV [5].

The GCV depends on the composition of the gas. For example pure methane gas has a GCV of 13284 Kcal/kg. The GCV for any mixture can be calculated if the calorific values and the mole % concentration of each component is known. For example a mixture of 98% methane and 2% ethane the GCV is calculated as follows:

$GCV_{methane} * C_{methane} + GCV_{ethane} * C_{ethane} = 0.98*13{,}284 + 0.02*12{,}400 = 13226$ Kcal/kg

### 1.2.5 Wobbe Index

The Wobbe Index (WI) is an indicator of the interchangeability of gaseous fuels and is frequently defined in the specifications of gas supply and transport utilities. It compares the energy output of different gases during combustion. It is calculated from the higher heating value (HHV) or gross heating value (GHV) divided by the square root of the specific gravity of the gas, as shown below. For the case of LNG, typical Wobbe Index ranges between 13.1 and 16.37 KWh/m$^3$ [6].

- $\mathrm{WI} = \frac{GHV}{\sqrt{SG}}$,

where GHV is the Gross Heating Value per volume and SG is the Specific Gravity.

It should be noted that the heating values used to calculate the Wobbe Index must refer to gas volume and not mass. In addition while the industrial practice is to express the GCV and WI in kWh/m$^3$ , it is more scientifically sound to express them in kJ/m$^3$ (or in Btu), since kWh is normally used as a unit for the energy content of work. Burning gas produces heat that is not entirely converted to work and thus, the use of thermal units is preferable. 1 kJ/m$^3$ is equals approximately 0.0002775 kWh/m$^3$ in standard temperature and pressure conditions [7]

The most commonly used physical properties and component concentration limits of LNG are summarized in Table 2.

**Table 2. LNG Quality Specifications [4]**

| LNG Quality Specifications | | |
|---|---|---|
| Boiling Point | $^{0}C$ | -161°C |
| Wobbe Index | $KWh/Nm^3$ | 13.10-16.37 |
| Gross Calorific Value | $KWh/Nm^3$ | 11.16-12.68 |
| Flash Point | $^{0}C$ | -188°C |
| Liquid Density | Kg/m3 | 430-478 |
| Molecular Weight | Kg/Kmol | 16.52-18.88 |
| Flammability in Air | % | 5 to 15 |
| Auto Ignition Temperature | $^{0}C$ | 540 |
| Storage Pressure | - | Atmospheric |
| Methane | % volume | 85-97 |
| i-butane & n-butane | % volume | 4 max |
| i-pentane & n-pentane | % volume | 2 max |
| Nitrogen | % volume | 1.24 max |
| Hydrogen Sulfide | $mg/Nm^3$ | 5 max |
| Total Sulphur | $mg/Nm^3$ | 30 max |

LNG chemical composition has a direct impact on its chemical and physical properties. Therefore, the Sales and Purchase Agreements (SPAs) between buyer and provider of LNG include gas quality specifications as well as the trade-off for delivering product which is off-specification (off-spec) [8].

Commonly, there are two LNG product specifications: one for the outlet of the LNG liquefaction plant and the other for the product at the customer port. The difference is due to the boil-off of the volatile components from heat leaks during storage, ship loading and unloading [3]. This phenomenon called weathering, will be described in more detail in Chapter 3.

LNG quantity is commercially measured in metric tons, while flowrates are usually expressed in thousand (Mile) MTPA or million (Mile Mile) metric ton per year (MMTPA). Sometimes, ton per year (tpy) or Mega-tons per annum (Mtpa) can be used.

## 1.3 LNG Production

The Natural Gas produced from oil or gas fields cannot be liquefied as it is, since it contains several contaminants that must be reduced to acceptable levels to ensure satisfactory liquefaction performance and/or be in compliance with the LNG SPAs. The contaminant concentration in the feed depends on the production field characteristics and the extent of gas treatment in the upstream production facilities [3].

In this sense, regardless of origin, the feed gas needs to be subjected to further treatment for the removal of heavier hydrocarbons, as well as non-hydrocarbon constituents before it can be sent to the liquefaction facilities. The pretreatment of natural gas includes the removal of condensates and acid gases ($CO_2$ and $H_2S$), dehydration and fractionation. After these processes, natural gas is ready to be cooled down to approximately -162$^{o}$C and be liquefied into LNG. A typical LNG production plant is illustrated in Figure 2.

The first step in gas processing is the separation of hydrocarbon condensates. These condensates can either be used as fuel for the processing plant or resold. Acid gas removal comes next, reducing the concentration of $CO_2$ down to approximately 50ppm. This way, freezing of $CO_2$ in the main cryogenic exchanger is avoided.

What is more, $H_2S$ concentration is also cut down to below 3ppm in order to comply with the typical gas specifications. In case the amount of $H_2S$ produced is significant, it may be necessary to convert it to sulfur by running the separated acid gas effluent stream through a sulfur recovery unit.

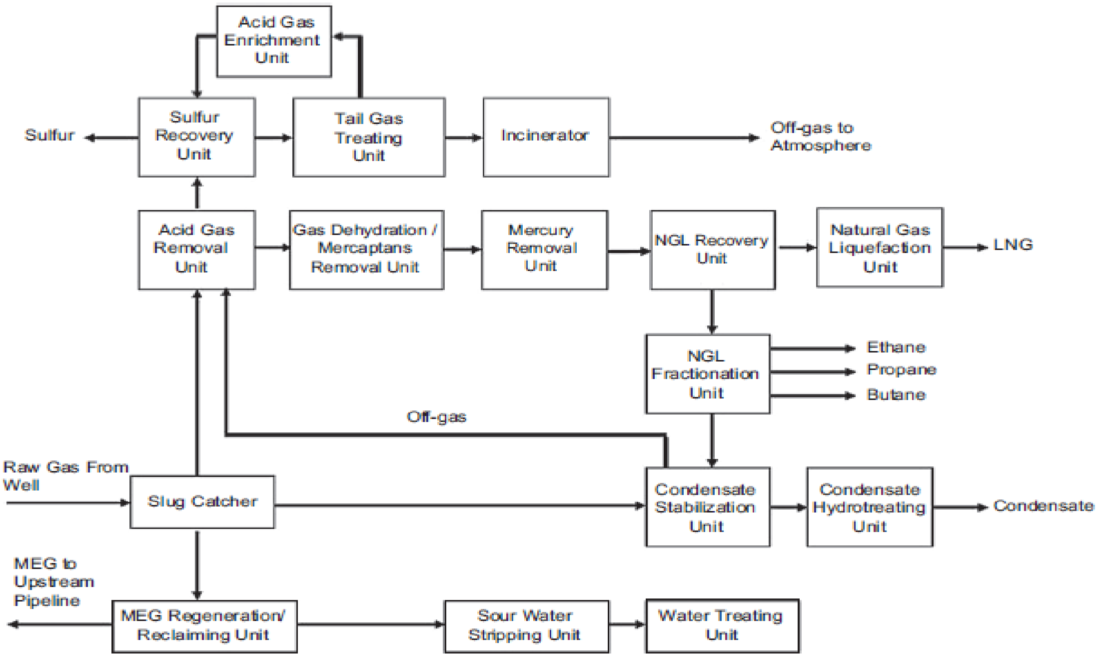



Figure 1. Typical LNG production plant [3].

The gas exiting the acid gas removal system is saturated with water vapor which needs to be removed to prevent freezing and hydrate formation in cryogenic conditions. The dehydration is achieved in a dual-step process during which the gas is first cooled using air or water and a precooling refrigerant to condense the majority of the water. Then, the gas is passed through a molecular sieve to reduce any remaining water vapor to trace levels (below 0.1ppm).

Mercury removal is also important. Given that mercury is highly corrosive and can damage the aluminum surfaces of the LNG plant equipment, its concentration has to be reduced below 0.1 $mg/Nm^3$ .The process of removing mercury typically utilizes a sulfur impregnated carbon bed, where mercury reacts with the sulfur to form mercury sulfide.

The final step before liquefaction, is to extract any remaining heavier hydrocarbon fractions which are heavier than methane, in order to prevent them from freezing at cryogenic temperatures. This is accomplished using a precooling refrigeration process with the formulated condensates routed to a subsequent series of distillation columns for the separation of the natural gas liquids from the rest of liquid mixture. The produced components, namely ethane, propane and butane can be sold separately as natural gas liquid (NGL) products, partially re-injected into the feed gas to meet specification limits or used as fuel for the plant itself [8].

The last stage of LNG production is the liquefaction process. Liquefaction technologies are based on refrigeration cycles, which take the pretreated feed gas and cool and condense it into LNG. The liquefaction process can be an open-cycle process, where the refrigerant is part of the natural gas feed, or a closed-cycle process in which the refrigerant is a fluid that is recirculated constantly through the liquefier or heat exchanger. In order for the natural gas to be liquefied, cryogenic temperatures need to be achieved, and to do so, work must be introduced into the refrigerant cycle through a refrigerant compressor. At the same time, heat must be rejected from the cycle through air or water coolers [3].

Based on this fundamental principle, several proprietary processes have been introduced to the LNG industry for natural gas liquefaction plants. These processes can be classified into the next broad categories [8]:

- Pure-refrigerant cascade process
- Propane-precooled mixed-refrigerant processes
- Propane-precooled mixed-refrigerant, with back-end nitrogen expander cycle
- Other mixed-refrigerant processes
- Nitrogen expander-based processes

A typical refrigeration cycle using a triple cascade process is illustrated in Figure 3. In this process more than one individual cycles are utilized with a common heat exchanger between cycles.

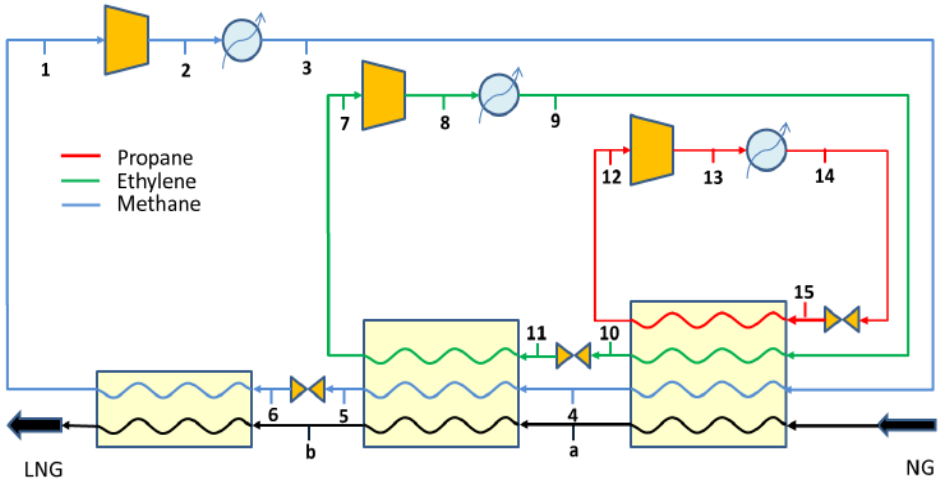



**Figure 3. Refrigeration cycle using a triple cascade**

After the liquefaction of the natural gas into LNG has been successfully performed, the product is usually loaded in the storage tanks of LNG carrier ships and transported to the LNG terminals. There, the LNG needs to be brought back to the gas phase in order to be distributed through the pipeline network to the end user. This process called 'regasification' is performed in the regasification plant.

As shown in Figure 4, the LNG is unloaded from the LNG carrier in the LNG storage tanks of the terminal. Utilizing pumps, the LNG is passed through vaporizers and is regasified. Before leaving the terminal, the regasified LNG passes through a pressure-regulating and metering station to measure the gas. The gas may be odorized (e.g., with mercaptan, a sulfur-based additive) to aid in the detection of any leaks in the gas transportation system or customer appliances [8].

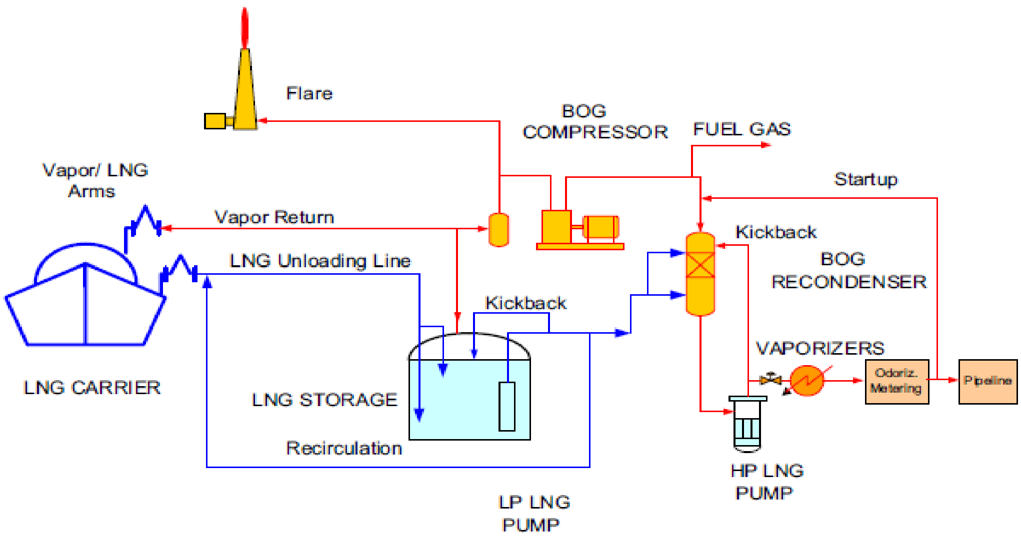



**Figure 4. Typical LNG receiving terminal flow chart [3]**

## 1.4 Why LNG

Growing global energy demand, diminishing oil resources, higher oil prices, the no-flaring regulations, and the benefits of lower greenhouse gas emissions from the burning of natural gas are leading to the increased popularity and growing demand for LNG.

LNG has some important environmental benefits. Clean combustion of LNG results in virtually no particulate matter (PM) due to the absence of nucleation particles. It also produces less gaseous emissions than other fossil fuels, such as nitrogen oxides ($NO_X$) and carbon dioxide ($CO_2$). In addition, regasified LNG produces minimal amounts of sulfur oxides ($SO_X$) thanks to the pretreatment process, which removes the majority of the sulfur content present in the natural gas [9].

LNG liquefaction technology produces liquid with roughly 600 times less volume than the volume occupied by the original natural gas. In this sense, natural gas becomes energy dense and easier to transport either using ships or trucks. This convenience in transportability can help tackle the problem of transporting stranded natural gas. Since many deposits are often in remote, offshore locations, long under-sea pipelines would have to be built in order to deliver natural gas to the point of consumption or storage.

As shown in Figure 2, LNG becomes economically attractive compared to pipeline gas when it comes to long distance transport. While gas pipelines are more economical for short distances, LNG becomes competitive for long distance routes, especially those crossing oceans or long stretches of water, since the cost of construction for subsea pipelines is prohibitive. For offshore stranded gas, LNG is cost effective when the offshore pipeline is less than 700 miles, while for onshore gas, the breakeven point is about 2,200 miles [10].

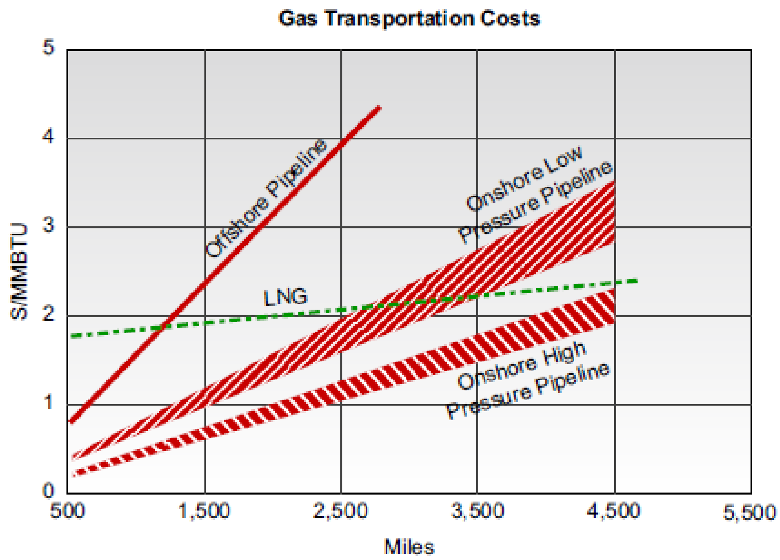



**Figure 5. Comparison of the cost of transporting gas via pipeline and LNG; for 1 tcf/yr and including regasification costs [10].**

Additionally, pipeline infrastructure is prone to geopolitical turmoil and discrepancies between nations. Since most of the pipeline networks cross national borders, they could be subject to political dispute, resulting in potential disruption in distribution from the discontented party. LNG, utilizing ship transportation, can provide a safe alternative and assist in the diversification of a nation's energy influx, thus making it less dependent on pipeline gas.

## 1.5 Scope and Significance of the Study

By thoroughly studying the bibliography and publications available, this document's goal is to highlight the industry's good practices and scientifically proven ways of safely storing and transferring LNG cargo across the world. Detailed description of both LNG cargo containment systems and transferring technologies is provided, aiming to their deeper understanding and therefore, better conception of the associated hazards and accident risks.

The main risk-bearing phenomenon concerning LNG storage tanks is the "rollover phenomenon", which occurs due to cargo weathering. This document describes the occurrence of this potential hazard and provides courses of action to prevent it. Moreover, since the risk of an LNG spill is higher during cargo transfer, this thesis highlights the outcome of a potential spill and the corresponding measures that need to be taken in order to avoid loss of life or equipment damage.

Finally, it is this paper's objective to showcase LNG as an environmentally friendly fuel, with considerably low emissions. LNG can constitute the bridge fuel towards an energy future of zero carbon footprint. However, for this to happen, the LNG industry has to stay competitive with respect to other challenging fuels like pipeline gas, and therefore research and technology development and improvement will be of outmost importance for the years to follow.

# CHAPTER 2

# DOMESTIC AND INTERNATIONAL LNG MARKET: FACTS AND FUTURE TRENDS

LNG has turned into the world's most rapidly growing gas transportation medium and is playing an ever-growing role in the global energy system [11]. As of 2018, global LNG imports reached 313.8 million tons, which accounts for a 8.3% increase compared to 2017. The largest share of LNG supply comes from the Pacific Basin, accounting for the 43.8%, followed by Middle East with 29.4% and the Atlantic Basin with 26.8%. At the same time, the global regasification capacity reached 868 MTPA while the liquefaction capacity was 406 MTPA. More details about the suppliers are presented in Table 3 [12].

**Table 3. Source of LNG imports in 2018**

| Country | $10^6$ $m^3$ liquid | $10^6$ T | Global Share (%) | Var. 2018/2017 (%) |
|---|---|---|---|---|
| **Australia** | 150,85 | 66,66 | 21,2 | 20 |
| **Brunei** | 13,99 | 6,37 | 2 | -7,5 |
| **Indonesia** | 41,21 | 18,21 | 5,8 | -2,7 |
| **Malaysia** | 54,35 | 24,66 | 7,9 | -8,2 |
| **Papua New Guinea** | 15,01 | 7,01 | 2,2 | -13,7 |
| **Peru** | 7,84 | 3,52 | 1,1 | -5,4 |
| **Russia** | 24,86 | 11,05 | 3,5 | -3,8 |
| **Pacific Basin** | 324,53 | 137,48 | 43,8 | 4,7 |
| **Oman** | 21,88 | 10,01 | 3,2 | 21,5 |
| **Qatar** | 171,81 | 76,79 | 24 | -0,9 |
| **UAE** | 11,96 | 5,54 | 1,8 | -0,9 |
| **Middle East** | 205,65 | 92,34 | 29,4 | 1,1 |
| **Algeria** | 22,46 | 10,1 | 3,2 | -18,1 |
| **Angola** | 8,99 | 3,98 | 1,3 | 12,9 |
| **Cameroon** | 1,35 | 0,61 | 0,2 | - |
| **Egypt** | 3,31 | 1,44 | 0,5 | 86 |
| **Equatorial Guinea** | 7,93 | 3,45 | 1,1 | -10,1 |
| **Nigeria** | 43,76 | 19,68 | 6,3 | -3,2 |
| **Norway** | 11,53 | 5,17 | 1,6 | 32,7 |
| **Russia** | 16,43 | 7,28 | 2,3 | - |
| **Trinidad and Tobago** | 27,19 | 11,63 | 3,7 | 14,2 |
| **USA** | 47,76 | 20,65 | 6,6 | 68,7 |
| **Atlantic Basin** | 174,27 | 83,99 | 26,8 | 25,1 |
| **Total** | 704,45 | 313,8 | 100 | 8,3 |

## 2.1 LNG cost for production, transfer, storage

Unlike crude oil market fixed prices, LNG does not feature a balanced global price. Instead of being priced relative to oil, its price is based on a variety of global reference prices. Referred to as ‘gas-to-gas’ pricing, this type of pricing is a measure of the relative supply and demand in natural gas markets, regardless of whether the oil market is in equilibrium or not. Specifically, the price of LNG is different depending on regional energy hubs, out of which the most significant are:

- The Asian market, including Japan, Korea and China, with the Japan Customs-cleared Crude price Index, referred to as Japanese Crude Cocktail (JCC)
- The North American market with the Henry Hub price Index
- The European market with the National Balancing Point price index

Pricing in Japan and the wider Asian market is based on a percentage of the price of JCC, which corresponds to the average price of custom-cleared crude oil imports into Japan, as reported in customs statistics. In North America, the major index is Henry hub, a distribution center in South Louisiana, pricing reference point for traded natural gas contracts. In Europe, a main index is the National Balancing Point (NBP), a virtual trading location for selling, buying and exchanging UK natural gas [13].

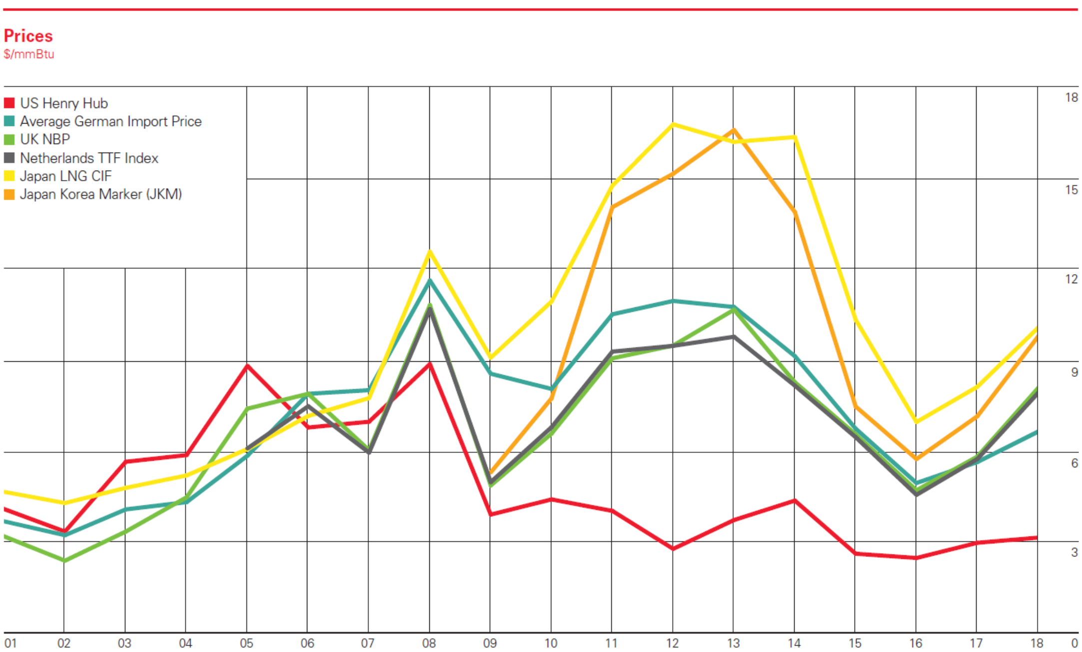



**Figure 6. Natural Gas and LNG Prices since 2001 [14]**

Liquefaction, regasification and transportation costs are barely published by operators and thus no rules of thumb currently exist to approximate how many $/MMBTU each process costs. However, it is easier to assess an average cost by separately considering different scenarios. For example, Michelle Michot Foss of the University of Texas suggests a 0.90-1.30$/MMBTU for the liquefaction, 0.50-1.80$/MMBtu for transportation via LNGCs and 0.40-0.60$/MMBTU for the storage and regasification of LNG (Figure 7). Taking into account the costs of exploration and production, the total amount for producing and delivering LNG to the United States rises to about 2.40-4.90$/MMBtu [15].


Figure 7. Typical LNG value chain Costs [15]

As another example, Professor Michael J. Economides of the University of Houston, considers a Qatari liquefaction plant of 4MMTPA. The operating costs for such a facility are assumed to be [16]:

- Liquefaction plant $1.0/MMBTU of gas processed
- Regasification $0.3/MMBTU
- Shipping costs $1.0/MMBTU

From the above, it can be argued that shipping costs constitute a major expense in the LNG value chain. As illustrated in Figure 8, for any given shipping route, shipping costs can be broken down to four main components: charter costs, fuels costs, canal costs and other costs. Depending on 2 main LNGC propulsion technologies, Steam turbine (ST) and Dual Fuel Diesel Electric (DFDE), the contribution of each cost can vary. For a DFDE carrier, the highest cost is attributed to charts costs while fuel costs are the second biggest expense. On the other hand, for an ST carrier, the opposite is true, with fuel costs accounting for the highest expense. However, in both cases the total cost for all shipping routes is approximately the same [17].

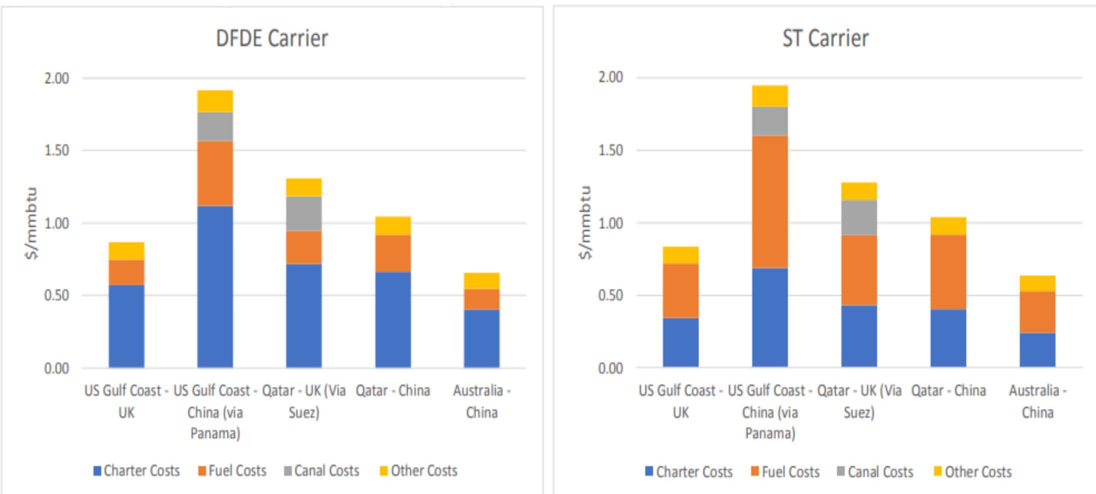



Figure 8. LNG Transport Costs by Propulsion Category, December 2017 [17]

Shipping costs constitute a significant component of the LNG purchasing costs, accounting for up to 10-35% of the final price paid for natural gas. LNG transport costs namely depend on the distance between the liquefaction and the regasification terminals. While using a larger amount of smaller LNGC's can provide more flexibility and reduced storage requirements, it results in increased unit shipping costs [18]. However, since the 1990s, new technologies of propulsion systems have replaced at a large extent the traditional steam turbine engines with smaller and more efficient units, resulting in reduced fuel consumption and higher storage capacities, thus cutting down the total shipping costs [15]. The average spot charter rate for a 160.000$m^3$ LNG carrier stood at 88,692$/day as of 2018 [12].

| Natural Gas (NG) and Liquefied Natural Gas (LNG) | | | | | | |
|---|---|---|---|---|---|---|
| **From** | **To** | | | | | |
| | billion cubic meters NG | billion cubic feet NG | million tonnes oil equivalent | Million tonnes LNG | trillion BTU | million barrels oil equivalent |
| | **Multiply by** | | | | | |
| **1 billion cubic meters** | 1,000 | 35,315 | 0,860 | 0,735 | 34,121 | 5,883 |
| **1 billion cubic feet NG** | 0,028 | 1,000 | 0,024 | 0,021 | 0,966 | 0,167 |
| **1 million tonnes oil equivalent** | 1,163 | 41,071 | 1,000 | 0,855 | 39,683 | 6,842 |
| **1 million tones LNG** | 1,360 | 48,028 | 1,169 | 1,000 | 46,405 | 8,001 |
| **1 trillion BTU** | 0,029 | 1,035 | 0,025 | 0,022 | 1,000 | 0,172 |
| **1 million barrels oil equivalent** | 0,170 | 6,003 | 0,146 | 0,125 | 5,800 | 1,000 |

Table 4. Natural Gas and Liquefied Natural Gas Units Conversion [14]

## 2.2 Main Suppliers, Storage and Transport Facilities

At a global scale, the leading current exporter of LNG as of 2018 was Qatar (global share of 24.9%) followed by Australia (global share of 21.7%) in the second place. Given the current LNG infrastructure being built and gas produced in Australia, Australian LNG exports are expected to surpass Qatari supplies by early 2020. Other major players in LNG exports include Malaysia with a global share of 7.7%, USA with 6.7% and Nigeria with 6.5% [12], [19].

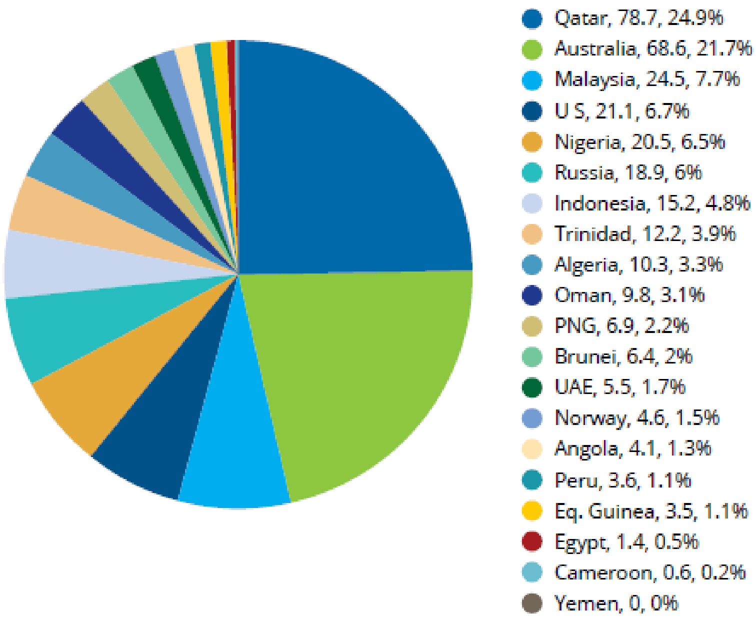



Figure 9. LNG Exports and Market Share (2018)

As far as European exports are concerned, Norway tops the list of LNG supply, with a global share of 1.6% or 11.53 million $m^3$ of LNG. With regards to imports, as shown in Table 5, there are currently 15 LNG importing countries in Europe. The biggest share of imports is held by Spain, accounting for 21.93% (24.17 million $m^3$) followed by Turkey and France [12]. The supply of those imports was largely dominated by Qatar and Algeria as shown in Figure 10.

Table 5 – European Imports, Global and European shares (2018) [12]

| Country | $10^6$ $m^3$ liquid | Global Share (%) | European Share (%) |
|---|---|---|---|
| **Spain** | 24,17 | 3,4 | 21,93 |
| **Turkey** | 18,59 | 2,6 | 16,87 |
| **France** | 17,82 | 2,5 | 16,17 |
| **Italy** | 13,76 | 1,9 | 12,48 |
| **UK** | 11,2 | 1,6 | 10,16 |
| **Portugal** | 6,35 | 0,9 | 5,76 |
| **Netherlands** | 4,56 | 0,6 | 4,14 |
| **Poland** | 4,44 | 0,6 | 4,03 |
| **Belgium** | 4,3 | 0,6 | 3,90 |
| **Greece** | 2,06 | 0,3 | 1,87 |
| **Lithuania** | 1,34 | 0,2 | 1,22 |
| **Malta** | 0,65 | 0,1 | 0,59 |
| **Sweden** | 0,55 | 0,1 | 0,50 |
| **Norway** | 0,26 | 0 | 0,24 |
| **Finland** | 0,17 | 0 | 0,15 |
| **Europe (15)** | 110,22 | 15,6 | 100,00 |

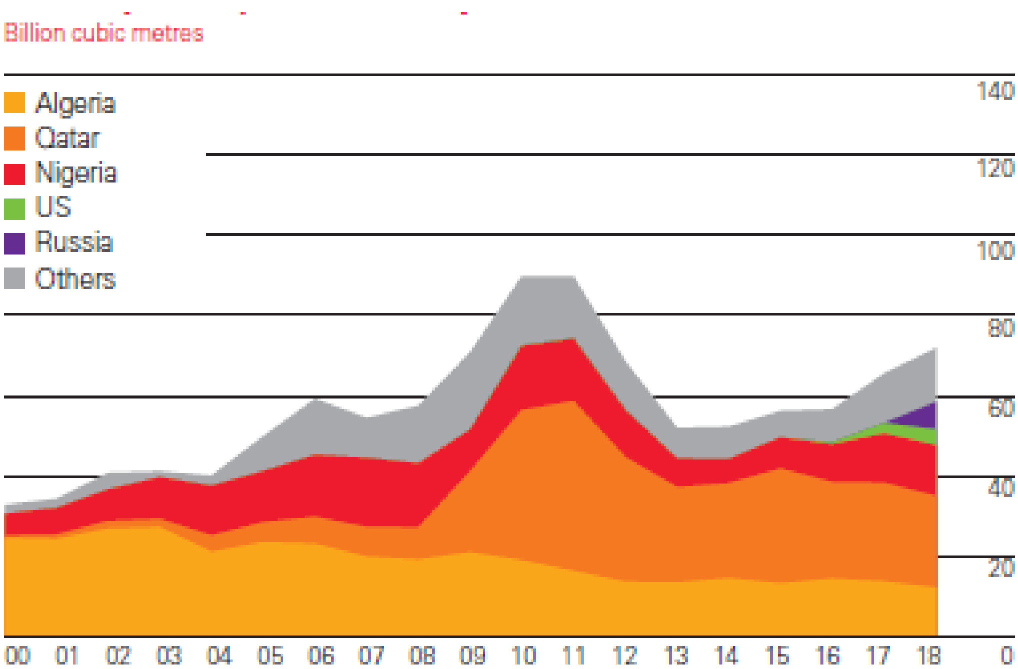



**Figure 10. European LNG imports by source [19]**

Greece held the 10th place in European LNG imports, with approximately 800.000 tonnes of LNG imported in 2018. Traditionally, the largest supplier of LNG in Greece has been the state-owned company DEPA, accounting for 92% of the Greek market share in 2018. However in 2019, for the first time after the liberalization of the gas market in Greece, private Greek industrial group MYTILINEOS displaced DEPA and climbed to the top of the list of LNG imports in Greece. Specifically, MYTILINEOS imported approximately 370.000 tonnes of LNG while DEPA supplied 273.000 tonnes. As indicated in Figure 11, other private importing companies include the Greek-Italian venture of ELPEDISON, Greek trader Motor Oil, Heron (ENGIE and Qatar Petroleum among its shareholders) and the Public Power Corporation (PPC). Their respective market shares for 2019 are illustrated in Figure 11 [20].

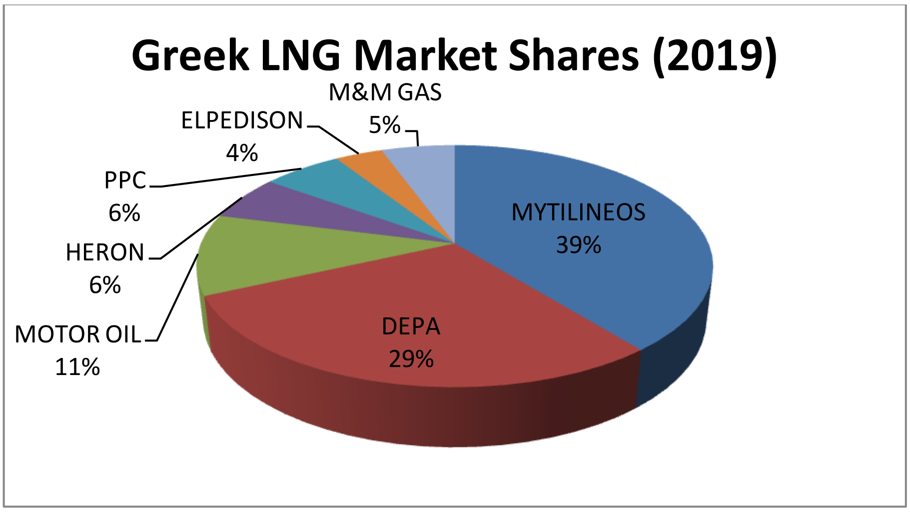



**Figure 11. Share of LNG imports in Greece for 2019**

The majority of the LNG imports in Greece in 2019 were from Nigeria (30%) and Algeria (20%), while considerable quantities were also imported from the USA, Norway, Russia, Qatar and Egypt. Figure 12 illustrates the evolution of the Greek LNG market shares over the last five years, as well as the sources of imported LNG during 2019.

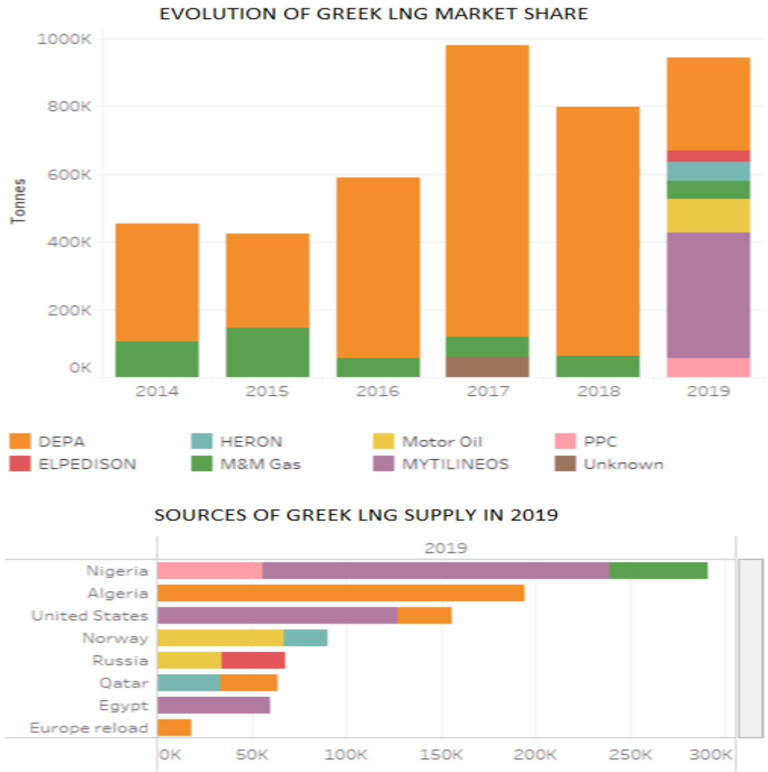



Figure 12. Evolution of the Greek LNG Market share and sources of supply for 2019

At a global scale, liquefaction capacity increased by 41 MTPA in 2018, to reach a total of 406 MPTA, mainly due to the Australian and US new projects that came on line. European contribution to the total liquefaction is minimal, as the current LNG liquefaction infrastructure is still undeveloped, mainly due the limited domestic gas production. The only country with a liquefaction plant is Norway, having a nominal liquefaction capacity of 4.2 MTPA (1% of the global liquefaction capacity) and storage capacity of 250.000m$^3$.

On the other hand, regasification facilities are more established across Europe. Table 6 shows the countries currently operating LNG regasification terminals and their respective storage and regasification capacity. In total, Europe's regasification capacity stands at approximately 20% of the global capacity of 868 MTPA. The global capacity is set to further increase as the total regasification capacity currently under construction reached 95 MTPA at the end of 2018 [12].

Table 6. European Regasification Plants and their respective Storage and Regasification Capacity [12]

| Country | Number of Plants | Total Storage Capacity (m3) | Regasification Capacity (MPTA) |
|---|---|---|---|
| Belgium | 1 | 386.000 | 6,6 |
| Finland | 2 | 78.500 | 0,5 |
| France | 4 | 1.370.000 | 25,3 |
| Greece | 1 | 225.000 | 5,1 |
| Italy | 3 | 487.000 | 10,9 |
| Lithuania | 1 | 170.000 | 2,9 |
| Malta | 1 | 125.000 | 0,5 |
| Netherlands | 1 | 540.000 | 8,8 |
| Norway | 2 | 12.400 | 0,1 |
| Poland | 1 | 320.000 | 3,7 |
| Portugal | 1 | 390.000 | 5,6 |
| Spain | 7 | 3.616.500 | 50,6 |
| Sweden | 2 | 50.000 | 0,6 |
| Turkey | 4 | 943.130 | 16,8 |
| UK | 4 | 2.095.000 | 35,3 |
| Total | 35 | 10.808.530 | 173,3 |

In Greece, the only LNG storage and regasification terminal is the Revithoussa Terminal in the gulf of Pahi at Megara, 45km west of Athens. Operated since the 2000s by the Hellenic Gas Transmission System Operator (DESFA), the Revithoussa LNG Terminal has a storage capacity of 225.000 $m^3$, with a peak send out rate of 1.650 $m^3$/h and maximum unloading rate of 7.250$m^3$/h [21].

The scarce Greek LNG infrastructure is set to be enhanced in the following years, with Greece aspiring to become a central energy hub in the Eastern Mediterranean [22]. The 'Poseidon Med II', a project co-funded by the European Union, is likely to put Greece at the forefront of LNG bunkering and distribution. This multi-million international project started in June 2015, is scheduled to finish in late 2020 and concerns three countries: Italy, Cyprus and Greece. The main goals of the project are [23].

- To facilitate the adoption of the regulatory framework for the LNG bunkering
- design the extension of Revithoussa LNG terminal (completed in 2018)
- design and construct an LNG fuelled specific feeder vessel
- implement technical designs and plan approvals for the retrofit/new building of LNG fuelled vessels and for additional ports' infrastructure for bunkering operations
- examine potential synergies with other uses of LNG
- develop a sustainable LNG trading and pricing pattern
- develop financial instruments to support the port and vessel installations

- develop synergies with other sectors (mainly Energy) that will create economies of scale in the use of LNG.

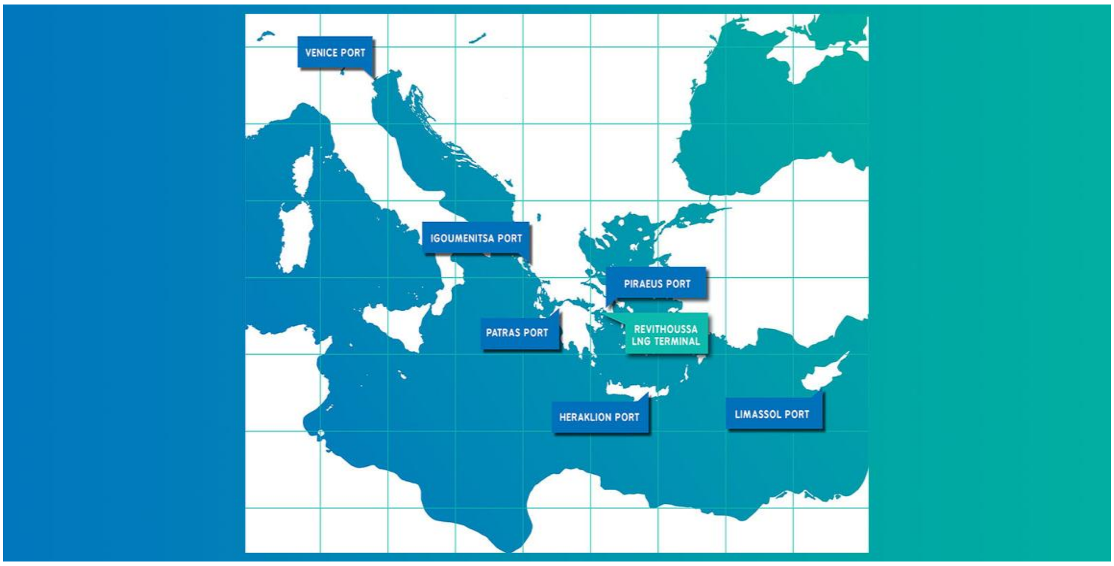



**Figure 13. Poseidon Med II Project Targeted Ports**

More specifically, the program includes installation of small-scale LNG infrastructures in six ports: Piraeus, Patra, Heraklion, Igoumenitsa, Limassol and Venice. In the framework of this project, critical role for the safe handling of LNG in Greece will play the recently issued Presidential Decree, which covers issues relative to LNG handling. These include safety zones, fire protection, communication protocols between the LNG operators, guidelines for personnel training etc. [24], [25]

Other potential/future LNG investments in Greece include the following:

- The design of an FSRU vessel in Alexandroupoli. The project is at a mature investment stage and its construction is expected to start soon, feeding the Greek, Bulgarian and Turkish gas market. The vessel will be located approximately 18km southwest of Alexandroupoli with a storage capacity of 150.000-170.000 $m^3$ [26].
- The Qatari company Powerglobe, is considering using an FSRU vessel in southeast Crete. The company is interested in building a new power generation plant to meet Crete's power shortage and plans to fuel it with gas from an FSRU vessel. On the other hand, DESFA has proposed to build an onshore regasification plant in Crete. However, such a project requires substantial capital investment and delivery time, which makes its implementation rather doubtful [27].
- Finally, another FSRU vessel is set to be built offshore Motor Oil's refinery at Ag. Theodoroi. The project has been approved from the Greek Regulatory Authority for Energy (RAE) and its construction period is 46 months. The vessel is expected to have a storage capacity of 135.000-170.000$m^3$, and it will include subsea and onshore pipelines to feed the country's downstream gas infrastructure [28].

The discovery of the giant gas field Glaucus-1 offshore Cyprus from the Exxon-Qatar Petroleum consortium further adds to the potential of Southeast Mediterranean being established as a dominant energy hub. According to Exxon Mobil, Glaucus-1 is the world's third largest natural gas discovery in the last two years, with estimated reserves of about 8Tcf [29]. As the East Mediterranean remains a frontier exploration area and huge amounts of natural gas are being discovered, new opportunities will arise and Greece can play a vital role in commercializing and trading natural gas in the form of LNG

With regards to transporting LNG, the LNG shipping sector has evolved over the past decade in conjunction with the substantial changes in the broader LNG market. In 2018, the global LNG tanker fleet consisted of 563 vessels, including 33 FSRUs. 53 vessels were added in 2018 accounting for a 11.5% increase of the tanker fleet compared to 2017 [19]. The LNG carrier orderbook consisted of 138 units expected to be delivered through 2022, out of which 46 are scheduled for delivery in 2019. This large number of newbuild orders was mainly driven by the increase in global liquefaction capacity.

Regarding the containment systems used by the LNG fleet, the majority utilized membrane tanks accounting for 69% of the LNG carriers, while the Moss design was implemented in 23% of the total vessels.

As far as the Greek LNG tanker fleet is concerned, at the end of 2018 it consisted of 105 vessels or, 18.6% of the global LNG fleet (Figure 14). The LNG evolution trend was followed closely by the Greek shipping industry which invested in the LNG supply chain, increasing its LNG vessels by 28% compared to 2017.

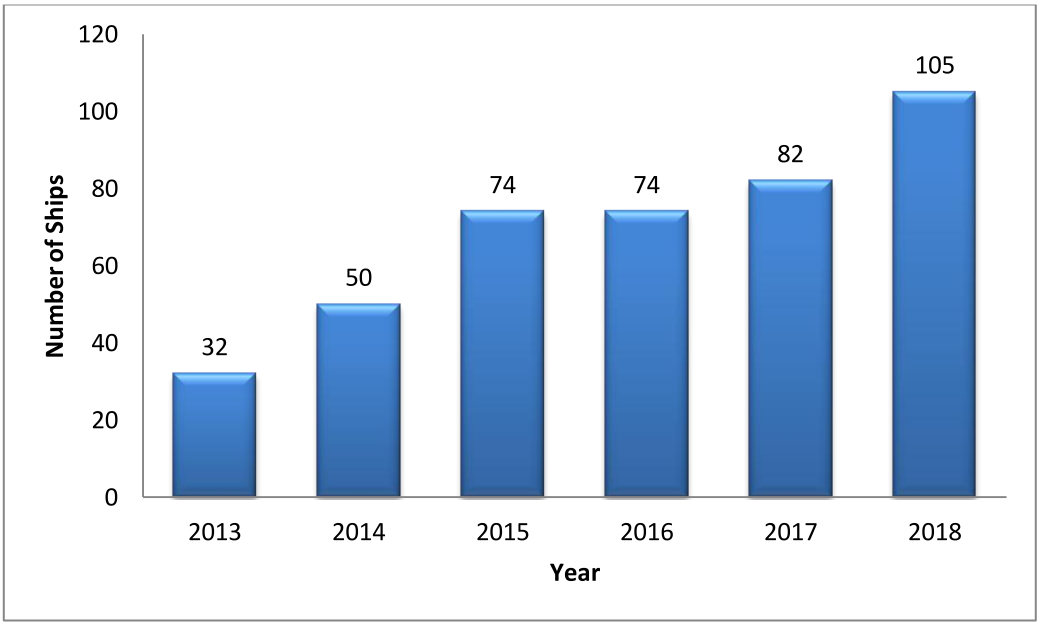



Figure 14 Greek LNG Fleet evolution

## 2.3 Expectations for production/demand growth and price

The growing recognition of climate change and the need to reduce carbon footprint will establish the use of LNG as a bridge fuel towards renewable energy sources. Also, the declining domestic gas production in Europe will result in increased demand for gas imports. LNG demand is predicted to grow by 3.6% per annum (compared to 8% in 2018) and the excess LNG capacity and planned capacity additions in the current market should be balanced by the mid-2020s. However, as Figure 15 illustrates, the existence of a potential gap between LNG supply and demand by 2035, highlights the necessity for investment to meet the growing demand for LNG. It is expected that in order to bridge this gap, 185 million tones of capacity growth will be needed, corresponding to more than $400 billion in investments. The majority of these costs will be for liquefaction facilities, accounting for up to $250 billion. The increasing imports arising from the growing demand will namely be absorbed by the Asian and European markets [30], [31].

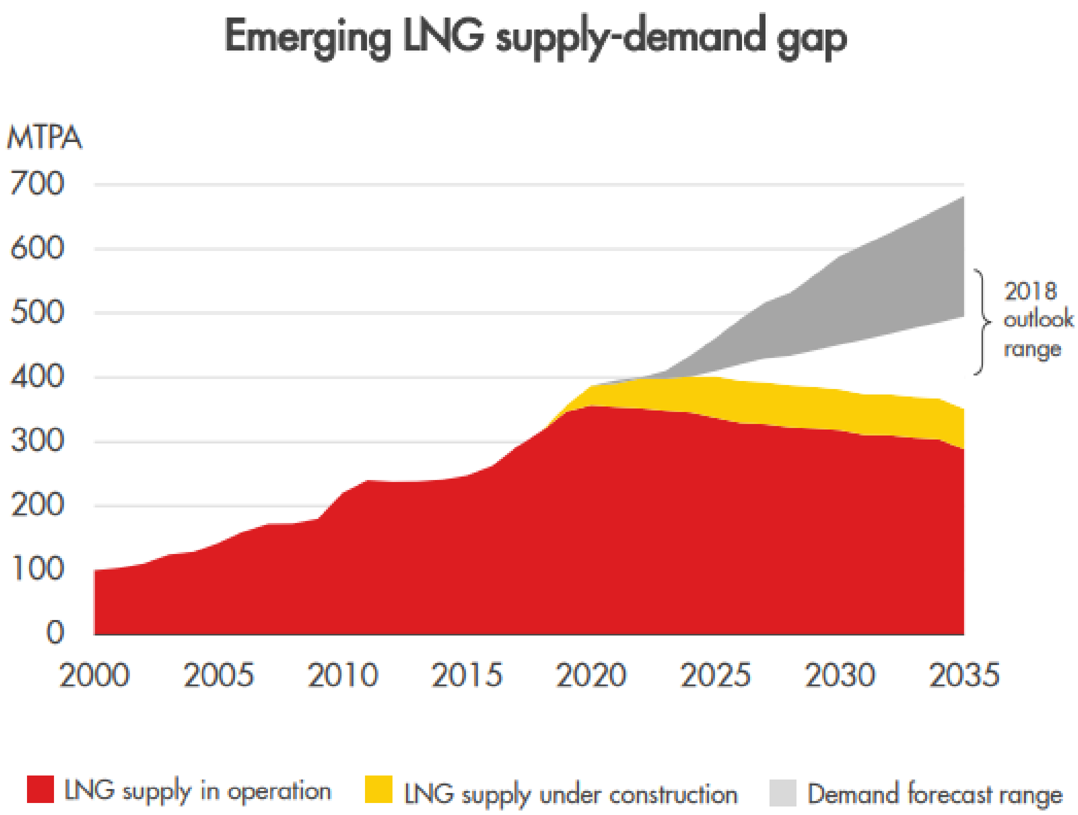



Figure 15. Emerging LNG Supply-Demand gap [31]

As gas markets further develop in Asia, trading hubs can develop where gas will be traded and priced on its own, rather than having to be benchmarked against other fuels or indexes. While oil indexation will continue to play a role in all supplies into Asia, there will be more and more contracts set up with the Henry Hub as a benchmark. There are also efforts in Europe to establish a widely accepted pricing pattern, and projects such as the Poseidon Med II work towards this goal. Finally, increasingly more spot sales instead of long term contracts will result in narrowing the price gap between regions [32].

In its global LNG outlook by 2040, Nexant suggests a Henry Hub price of \$4/MMBtu, NBP at \$11/MMBtu and average LNG price in Japanese at \$12/MMBtu. Figure 16 illustrates the price predictions until 2040.

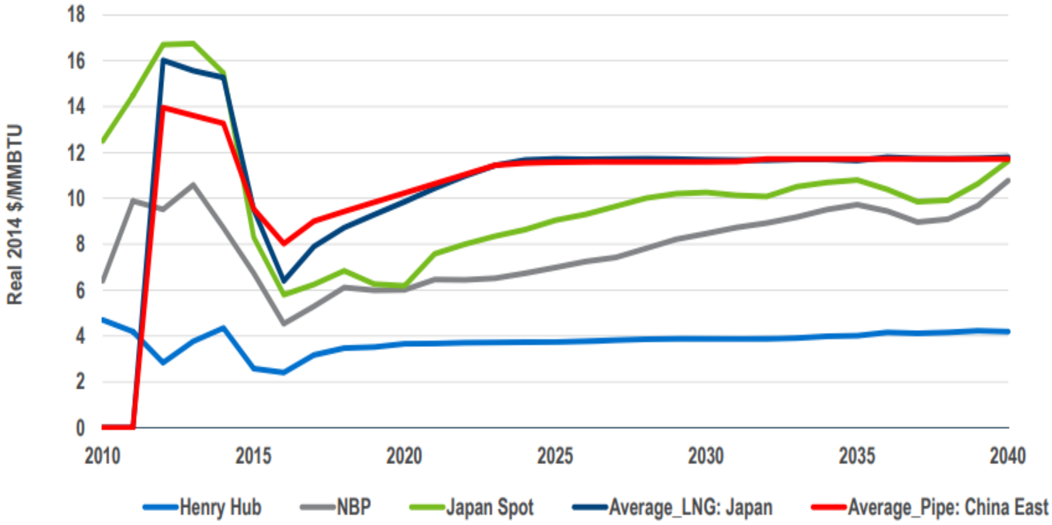



**Figure 16. Natural Gas Price Prediction [33]**

# CHAPTER 3

# LNG STORAGE

After liquefaction, LNG needs to be stored in order to be transported to LNG terminals, where it is regasified and subsequently enters the pipeline infrastructure towards end users. LNG can be stored in these specially designed tanks at the following locations:

- At the liquefaction plant,
- At the regasification plant,
- At the LNG tankers

Given the cryogenic temperature (-162$^0$C) of LNG, special insulated ship tanks are used for its storage, which can also withstand the sloshing due to ship motion [34].

**Figure 17. LNG Storage Tanks in Revithousa, Greece [21]**

In the framework of this dissertation all available storage types for LNG will be studied. The related regulatory requirements and constraints together with the analysis of the operational and safety issues will also be considered.

## 3.1 LNGC's Storage Technologies

FLNG, FSRU and regular LNG carriers are exposed to a wide range of sea conditions and are required to handle all possible cargo tank fill levels in the course of normal operations. What is more, such vessels are required to remain on station providing uninterrupted service, often times for the whole course of a twenty year project or more, without drydocking [34].

The term "Storage Tanks" refer to the total arrangement for containing LNG cargo. It includes a primary barrier (the cargo tank), a secondary barrier, thermal insulation and an adjacent structure for supporting the aforementioned components [35].

There are four LNG containing systems: two freestanding or independent tanks and two membrane or nonfreestanding tanks.

### 3.1.1 Freestanding Tanks

The freestanding or independent tanks are entirely self-supporting and do not constitute part of the ship's hull structure, neither do they contribute to the hull's strength. As defined by the International Code for the Construction and Equipment of Ships Carrying Liquefied Natural Gas in Bulk (IGC), there are Type A, Type B and Type C tanks [3], [35]. Out of these types, only Type B tanks are used for LNG storage.

The most common arrangement of Type B tank is the **spherical tank of the Moss design**, developed by Moss Maritime of Norway. The tank consists of either an aluminum alloy or 9% nickel steel sphere welded to a vertical cylindrical skirt of the same material, which is the only connection to the hull. The sphere can expand and contract freely, since all movements are compensated for in the top half of the skirt [36].

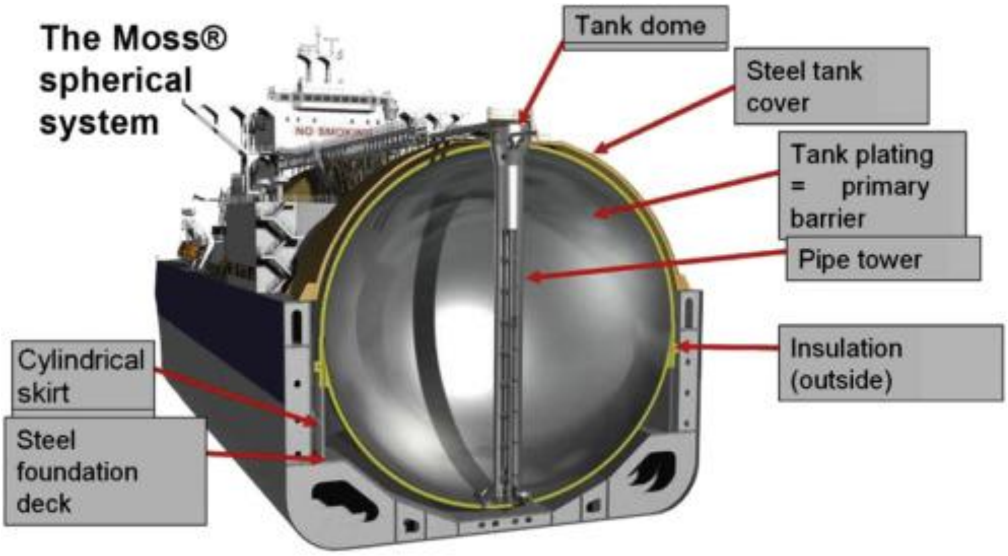



Figure 18. Spherical tank of the Moss design

In this design, only a partial secondary barrier in the form of a drip tray is used. The space between the two barriers (hold space) is filled with dry inert gas or, in today's practice, with dry air. The latter is applied on condition that inerting of the hold space can be achieved in case cargo leakage is detected. What is more, a protective steal dome covers the primary barrier above the ship's deck level and polyurethane foam insulation is applied on the outside of the tank [35].

Spherical tanks are characterized by poor utilization of the cargo space, thus requiring a substantial hull to house, for example, five large spheres of 25.000 $m^3$ capacity each, providing a total cargo capacity of 125.000 $m^3$ .

Another Type B tank, is the self-supporting, **prismatic Type B (SPB) tank** (Figure 19). This design has the advantage of maximizing the utilization of the ship's hull space, making it possible to be placed entirely under the ship's deck [35]. However, these types of tanks have a significant contribution to weight and cost since they include heavy plates and a considerable amount of bracing in order to prevent the plates from distorting under the hydrostatic load [3].

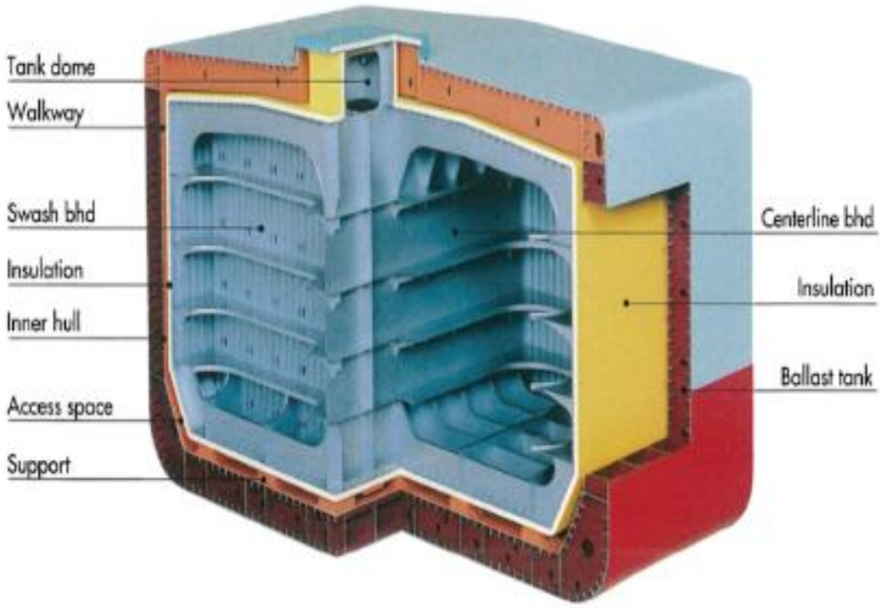



Figure 19. Prismatic Type B tank (SPB).

### 3.1.2 Membrane Tanks

The membrane containment system utilizes a very thin primary barrier (membrane) with thickness between 0.7 to 1.5 mm. The membrane's design allows for thermal contraction or expansion, without over-stress.

The membrane tanks are not self-supported and are surrounded by a double hull ship structure, the inner part of which plays the role of the load bearer [35]. There are two main types of membrane containment systems used in LNG ships, the Gaz Transport and the Techknigaz system.

The Gaz Transport membrane containment system (GT No96) utilizes an Invar primary barrier, which is attached to perlite-filled plywood boxes of 200-300mm thickness that act as the primary insulation. This thickness is adjustable in order to comply with any Boil Off Gas (BOG) requirements. The boxes standard size is 1m x 1.2m [34]. In turn, the structure rests upon another identical Invar secondary barrier. Finally, one more set of plywood boxes is used for further insulation. The membranes are made out of Invar due to its very low thermal expansion coefficient, which makes the use of expansion joints unnecessary. Invar is a nickel-iron alloy with 36% nickel.

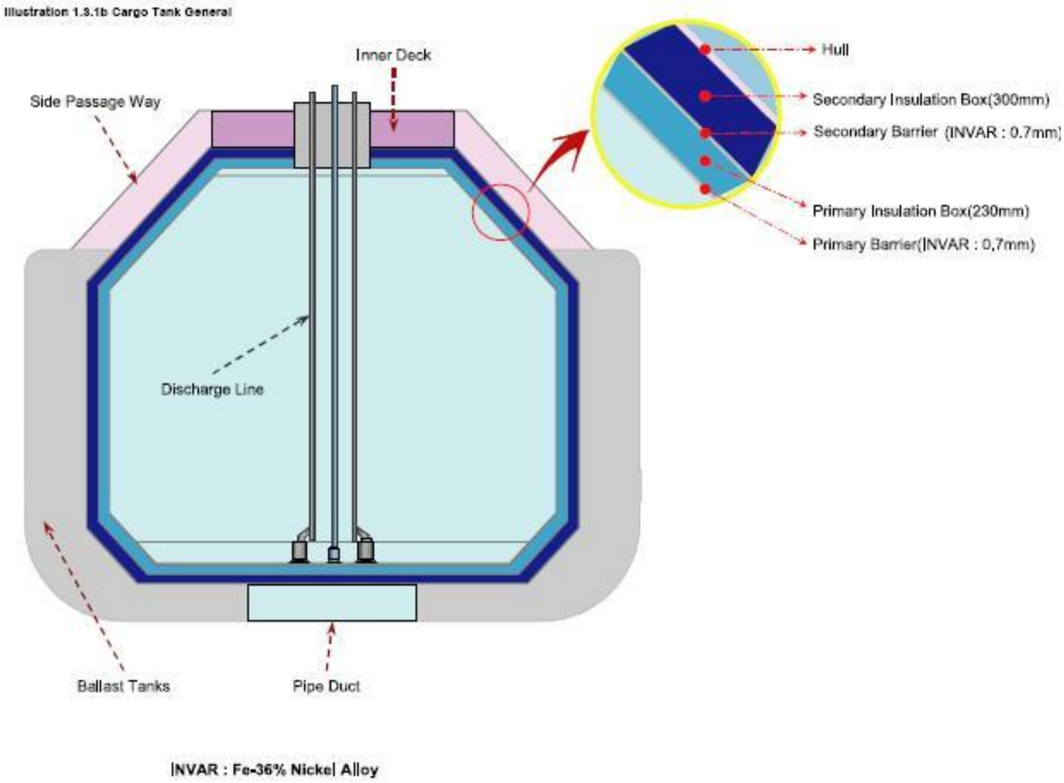



**Figure 20. The GT No96 containment system design [37]**

The Technigaz membrane system is comprised of a stainless steel primary barrier 1.2 mm thick, having raised corrugations to allow for expansion or contraction. In the early model Mark I, the insulation supporting the primary membrane was made of laminated balsa wood held between two plywood layers. The outer layer of plywood acted as the secondary barrier. The latest Mark III design utilizes reinforced polyurethane foam (RPUF) instead of balsa wood as insulation. Within the foam there is fiberglass cloth/aluminum laminate acting as a secondary barrier, called Triplex [35].

The two companies responsible for these designs, Gaz Transport and Techigas are now merged (GTT) and they have released a 'hybrid' containment system incorporating characteristics from both designs. This new design called Combined System One (CS1) uses reinforced polyurethane foam insulation and two membranes: the primary one which has a thickness of 0.7mm and is made of Invar, and the secondary barrier made of a composite aluminum-glass fiber, called triplex. While this containment system is designed to make assembly easier and prefabricated thus reducing the assembly time, some vessels have encountered leakage problems from the secondary membrane [3].

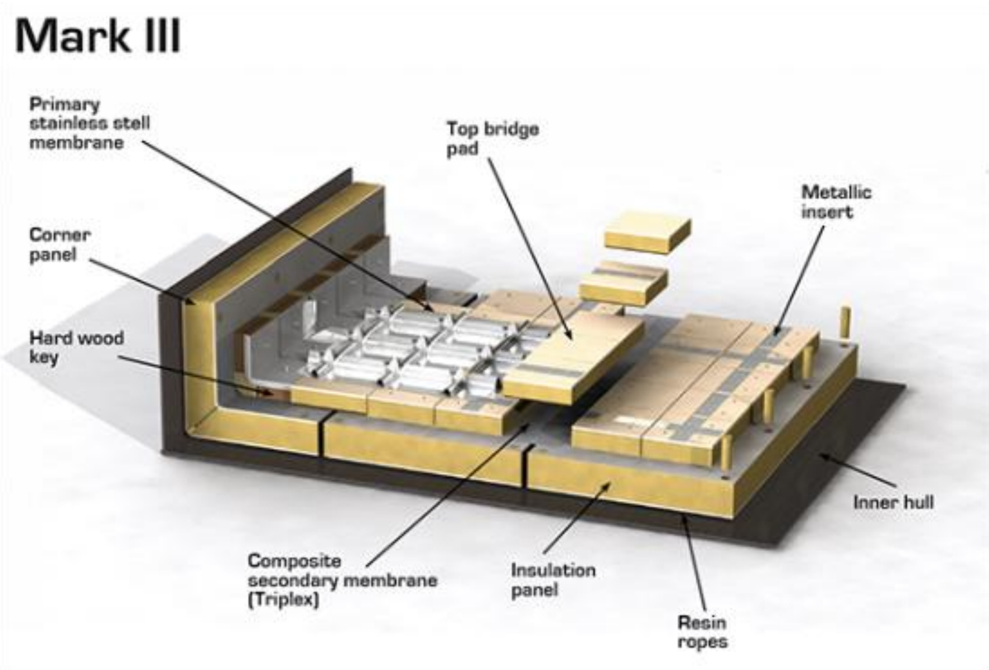



Figure 21. The Mark III containment system design.

### 3.1.3 Membrane Tanks Design Evolution

Recently, there have been some modifications in both GT No96 and Mark III technologies aiming to improve thermal insulation and reduce BOG rate. The basic No96 system has been augmented by the ones of No96 GW, the No96 LO3 and LO3+. With the GW design, the insulation material of the boxes backing the system's two metallic barriers is glass wool (GW). For the LO3 and LO3+ designs, while the primary insulation still consists of GW, the secondary insulation is split into two different layers. For LO3, there is a box insulated with GW attached to a panel assembled from plywood and reinforced polyurethane foam; for L03+, both secondary layers are made up of plywood and polyurethane foam. Table 7 shows the differences in thermal performance between the No96 types. It is obvious that the LO3+ design provides the highest performance among the four alternatives. It guarantees daily Boil Off Rate (BOR) of 0.1% of the tank volume per day. It is worth mentioning that the typical BOR of the No96 design for 175.000m$^3$ LNG carrier is about 0.15% of cargo volume per day.

Mark III Flex and Mark III Flex+ have been introduced as improvements of the Mark III design. These containment systems utilize thicker insulation layers, thus decreasing the BOR. In particular, The Flex design uses 400mm insulation thickness while the Flex+ uses 480mm, providing a BOR of approximately 0.07% of the tank volume per day. A significant improvement compared to the typical 0.135% BOR of the original Mark III. The differences between the above mentioned designs are illustrated in Table 8.

Table 7. Evolution of the GTT No96 membrane containment system

| | NO96 | NO96 GW | NO96 LO3 | NO96 LO3+ |
|---|---|---|---|---|
| **BOR** | 0,15% | 0,13% | 0,11% | 0,10% |
| **Main insulating material** | Perlite | Glass wool | - | Glass wool and polyurethane foam 130kg/m3 |
| **Primary Membrane** | Invar 0,7 mm | | | |
| **Secondary Membrane** | Invar 0,7 mm | | | |
| **Thickness** | primary box 230mm + secondary box 300mm | | | |

Out of the approximately 500 LNG carriers and FSRU's currently in service, 75% are equipped with GTT's membrane containment systems. This percentage is evenly distributed between the Mark III and the GT N096 technologies [38].

Table 8. Evolution of the GTT Mark III membrane containment system.

| | MARK III | MARK III FLEX | MARK III FLEX + |
|---|---|---|---|
| **BOR** | 0,14% | 0,085% | 0,07% |
| **Main insulating material** | Reinforced Polyurethane Foam | | |
| **Primary Membrane** | Stainless Steel corrugated Membrane | | |
| **Secondary Membrane** | Single Triplex | | Strengthened by double Triplex |
| **Thickness** | 270 mm | 400 mm | 480 mm |

## 3.2 Onshore Storage Technologies

LNG is stored onshore in liquefaction plants or regasification terminals. As in offshore LNG storage tanks, onshore tanks have more than one means of containment. The primary barrier is provided by the tank in which the LNG cargo in contained. Thermal insulation is used to prevent heat ingress, reduce BOR and protect the structure's material from the cryogenic temperatures at which LNG must be stored. Secondary containment is provided either by means of a secondary tank around the primary one, or by using dikes or impoundment dams. These act as protective measures in the unlikely event of spill from the primary containment barrier [39].

The tank capacity required, namely depends on the planned LNG tanker size. In addition, provisions must be made concerning tank capacity, so as to provide flexibility in the tanker's schedule and cope with potential planned or unplanned supply outages. Consequently, tanks are typically designed to allow for twice the capacity of the largest LNG tanker planned to operate at the plant facilities [8]. Additionally, given that there are various storage tank designs, the choice of the correct one is determined by safety and operational considerations regarding plant location, layout limitations, codes and engineering standards. Types of onshore LNG containment systems include the following [39]:

- Single containments tanks,
- Double containment tanks
- Full containment tanks,
- Membrane tanks, and
- In-ground tanks.

### 3.2.1 Single Containment Tanks

A single containment tank is made of a freestanding, self-supported inner cylindrical container composed of 9% nickel steel which has an open top. The inner tank is surrounded by a secondary, carbon steel outer tank that holds perlite insulation in the annular space [40]. The outer tank cannot hold the cryogenic LNG cargo since it does not meet the ductility requirements for cryogenic liquids storage, and is only designed to constrain the vapor pressure in case of boil-off leakage from the primary barrier. However, a dyke is usually build external to the tank in order to provide full secondary containment in the event of total failure of the inner tank. These tanks also have a steel roof designed to contain gas vapor and support a suspended ceiling that insulates the top surface of the inner tank. The whole structure rests upon rigid foam blocks for insulation, then on the foundation, which is chosen according to the soil conditions of plant the location. Moreover, the tank base normally utilizes a heater system to prevent temperature fluctuations [8].

These type of tanks are the most cost effective and have been in operation across the globe for more than 30 years with an excellent safety record. However, due to the external dykes needed, these tanks require substantial plot area [8]. A typical single containment tank design is illustrated in Figure 22.

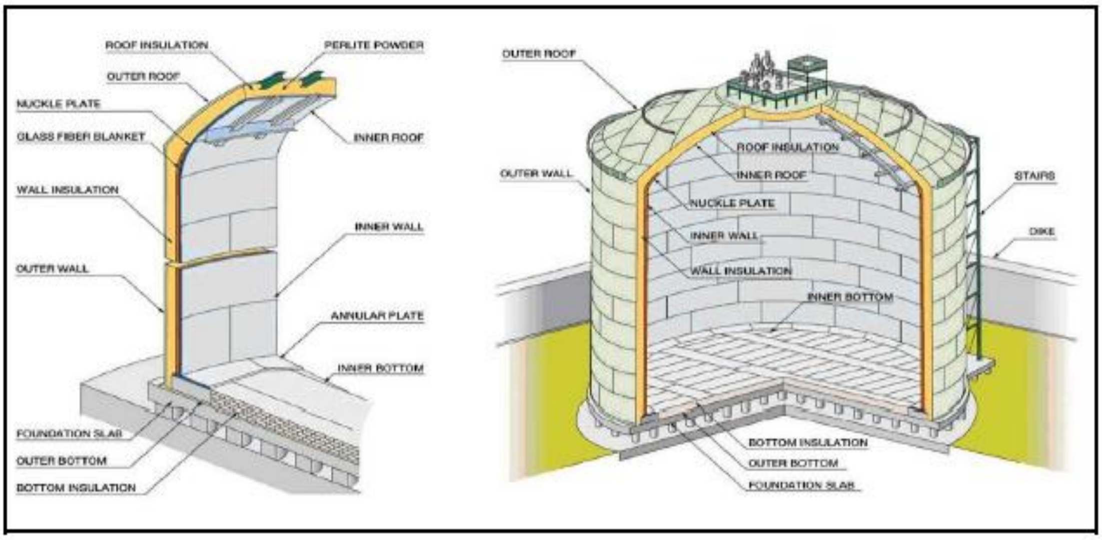



Figure 22. Single Containment tank design [39]

### 3.2.2 Double Containment Tanks

The double containment tanks are similar to the single containment ones, with the difference being that instead of an external dyke, an outer wall of pre-stressed reinforced concrete is used. Therefore, in this design, the tank arrangement is capable of containing all the cryogenic liquid in case of a spill from the inner tank. On the other hand, if a spill does occur, the double containment tank cannot constrain LNG vapors, resulting into gas escaping from the annular space – the space between the tank and the concrete wall [39].

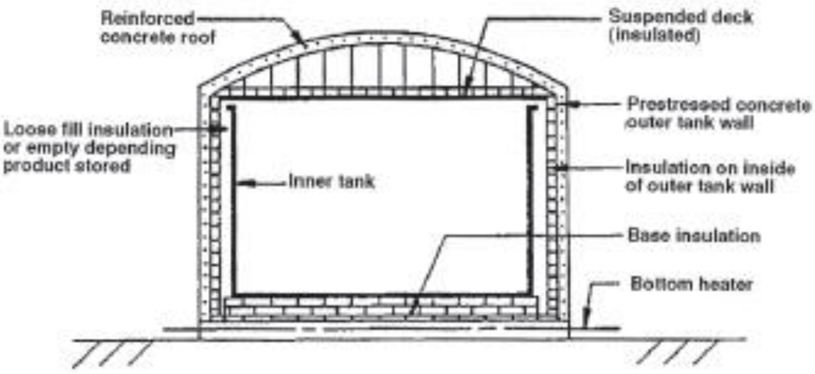



Figure 23. Double Containment tank design

The cost of these tanks is about 40% higher compared to the single containment tanks, but they require significantly less plot area [8].

### 3.2.3 Full Containment Tanks.

The full containment tank is constructed so as to be capable of containing both vapor and cryogenic liquid in case of a primary container breach. For this to be achieved, the annular gap between the inner and outer tank is sealed, using a concrete roof. A metallic roof can also be employed [39]. Nevertheless, the concrete roof allows for a higher design pressure (290mbrag) than the metallic one (170mbarg) [40]. In respect with all the other design features, these tanks are similar to the double containment tanks.

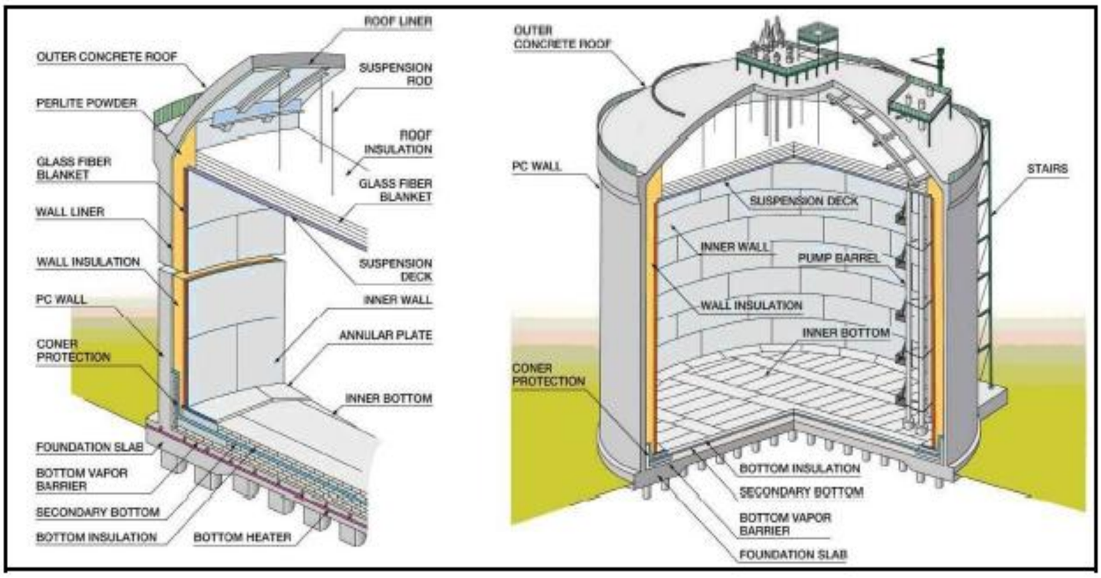



Figure 24. Full Containment Tank design [39]

The majority of the LNG tanks built during the last decade are full containment tanks since they provide the highest design integrity. Moreover, little spacing is required between adjacent tanks resulting in lower land footprint. However, these tanks are the most expensive, usually costing up to 50% more compared to single containment tanks [8].

### 3.2.4 Membrane Tanks

The membrane tanks used in onshore terminals are similar to those used in LNGC's described in Chapter 3.1.2. Since membrane tanks are not self-supported, they rest upon an outer concrete tank, which supports the hydrostatic load.

### 3.2.5 In-ground Tanks

In-ground tanks are less visible in their surroundings and they are usually preferred for aesthetic reasons and in densely populated areas, since they do not require dykes and thus can be build in close to each other [8]. Their use is limited across Europe and they can mostly be found in Japan and some other Asian countries. A typical tank of this type is illustrated in the Figure below [39].

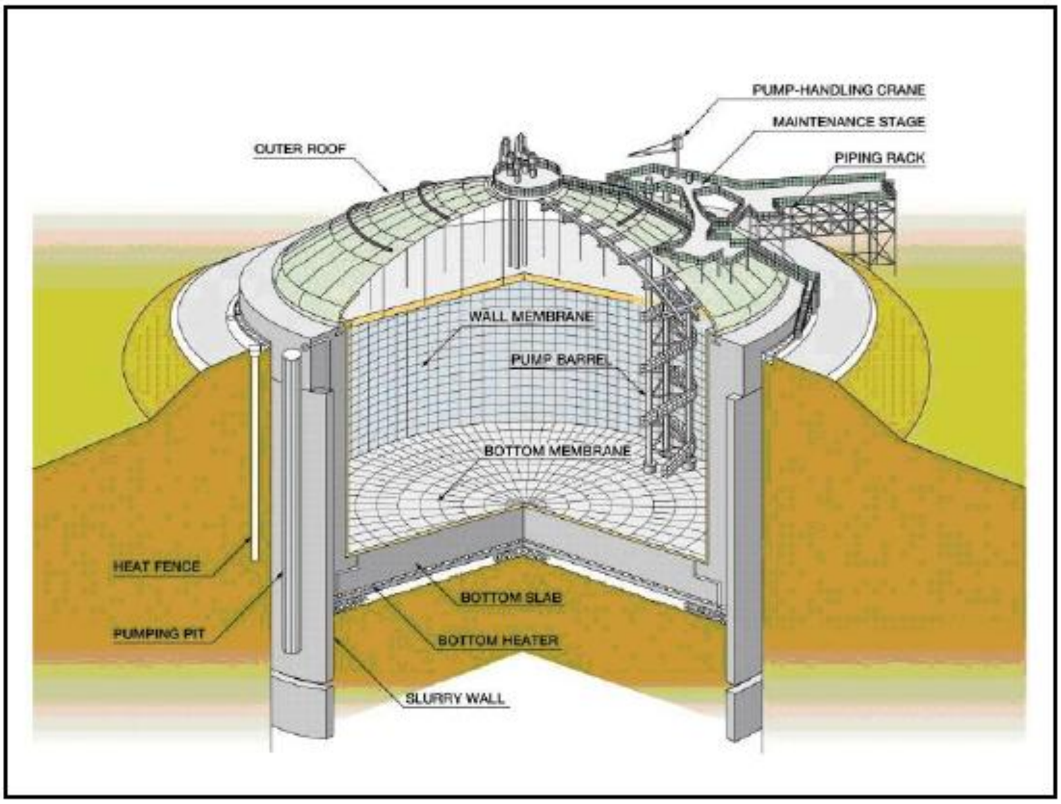



**Figure 25. In-ground Tank design [39]**

## 3.3 Liquefaction Facilities at Storage Sites.

Liquefaction facilities can be found in two sites: onshore liquefaction plants and offshore LNG vessels, known as Floating Liquefied Natural Gas vessels (FLNG). The typical arrangement and common facilities an onshore liquefaction plant is equipped with were described in Chapter one. In this chapter the technology used in FLNG's will be briefly analyzed.

FLNG vessels are specially designed ships or modified LNGC's which can accommodate the production and storage of LNG. They fall into two categories in terms of deployment mode: the inshore/nearshore and offshore/ open ocean. Inshore or nearshore FLNG's are located in relatively calm water conditions with the protection of a harbour or breakwater.. Offshore FLNG's on the other hand, are located in open seas and exposed to the prevailing weather conditions, in which case the vessel has to be designed to withstand the worst potential sea state conditions.

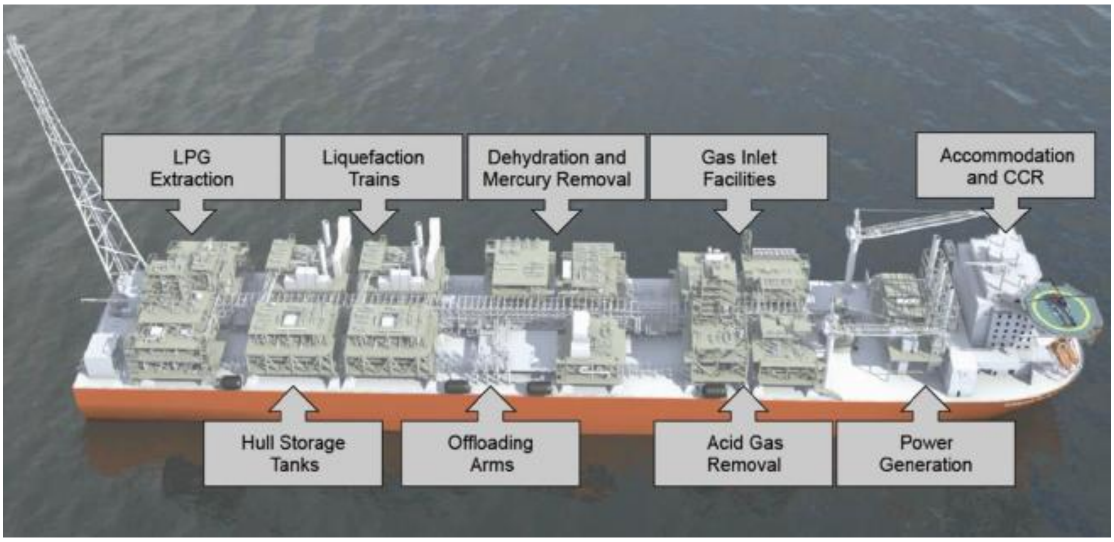



Figure 29. Typical FLNG vessel arrangement.

In terms of gas processing and liquefaction facilities, FLNG's use the same technology as onshore plants: condensate removal, acid gas treatment ($CO_2$ and $H_2S$), dehydration, mercury removal, LPG extraction and finally gas liquefaction to produce LNG. The utilization of similar liquefaction processes is mainly practiced in order to minimize the technical risk. Due to space and marine limitations the most widely used processes are the mixed refrigerant (MR) and nitrogen cycle ($N_2$) [41].

The storage type used in FLNG's can either be a membrane containments system or an independent Type B tank (Moss design or PSB).

The major differences between an FLNG and an onshore plant include the following:

- Much smaller plot space is used – typically about 60% of an onshore plant.
- Maneuvering of two moving vessels alongside each other for LNG unloading.
- Modular FLNG design (although modularized onshore plants are lately being built in areas where construction labour is scarce or expensive).
- Higher OPEX due to offshore logistics
- FLNG's non-stop offshore operation with no dry-docking requires higher design margins and top quality equipment.

Some of the advantages and drawbacks that FLNG's provide are shown in Table 9 [42].

Table 9. Advantages and Disadvantages of FLNG's

| Advantages | Disadvantages |
|---|---|
| Wide range of production (0.5 to 6.0 MTPA) | Time restriction of berthing and transfer due to sea state |
| Lower CAPEX for high-cost areas | High OPEX |
| Shorter delivery time | Congested layout |
| No jetty or breakwater required | Safety design and risk analysis not mature |
| Option to lease | Marine classification process not mature |

| | |
|---|---|
| Avoidance of costly gas pipeline from field to shore | Tanker conversions have limited design life |

The largest FLNG vessel currently operating is Shell's Prelude FLNG. The vessel operates in the Prelude Gas Field , 475 km off the coast of Western Australia and has a capacity 3.6 mtpa of LNG [43].

**Figure 26. Prelude FLNG while unloading to a Moss Type LNGC.**

## 3.4 Regasification Facilities at Storage Sites.

Depending on the facility set-up, LNG regasification terminals can be classified in the following categories [44]:

- Onshore Terminals
- Offshore Gravity Based Structures (GBS)
- Floating Storage and Regasification Units (FSRU)

The most commonly used technology is the onshore regasification terminal. This plant is normally located by the sea, nearby a seaport area. Basic components include a docking area with loading/unloading arms, LNG storage tanks and vaporizers for the regasification of LNG. A typical flow diagram of an onshore regasification facility is illustrated in Figure 27. Since the equipment for all three regasification sites mentioned above are approximately the same, Figure 31 presents the layout of a regasification plant and its key components, either it is an onshore plant, a GBS or an FSRU. The vapour return line usage will be described in Chapter 4 along with the LNG transfer safety issues [44].

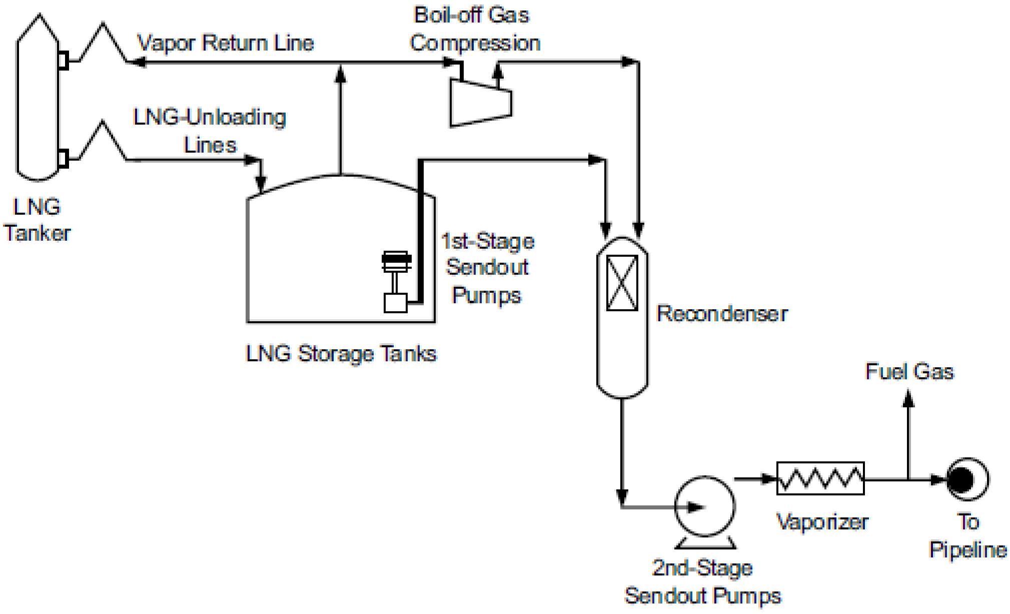



**Figure 27. Typical Regasification Plant Layout**

**The GBS facility** is a relatively innovative technology concerning LNG storage and is intended for shallow waters, providing artificial offshore land. Specifically, massive concrete structures are prefabricated onshore and then floated into place at the installation location. There, they are flooded and sunk to rest on the seabed. The type of containment systems used, can be either of the self-supporting SPB type or of the membrane type [46].

**FSRU vessels** provide another alternative to the above technologies. Such vessels can either be custom built or a converted LNGC permanently moored at the desired site. Converted LNGCs use their cargo tanks for storage and are fitted with onboard regasification equipment. FSRUs require a minimum water depth of approximately 45 meters for economic mooring and a turret system to allow the vessel to rotate around a fixed point, according to the wind and sea state conditions. A typical operation includes side-by-side or end-to-end unloading from an LNGC, storage of the feed LNG in the FSRU’s tanks, onboard vaporization and gas send-out via subsea pipelines [47].


**Figure 28. FSRU vessel with Membrane Tanks and its Regasification Facilities on the Deck.**

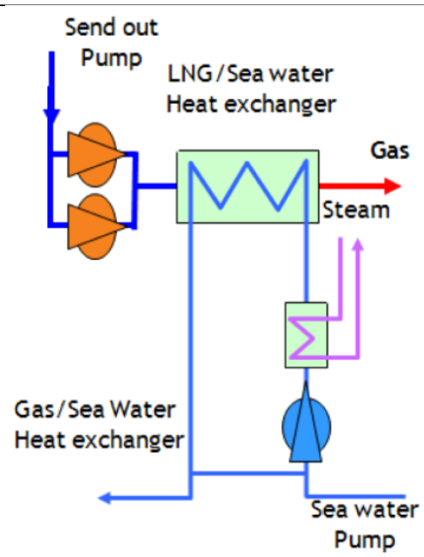
The hull and storage of an FSRU are identical to that of a normal LNGC, typically of the Moss design or membrane type. Lately, membrane tanks are being increasingly used in new-built FSRUs, since their geometry allows for greater storage capacity and no gaps between the tanks. Also, the flat deck provides easier installation of the regasification equipment. On the other hand, when spherical tanks are used, the regasification equipment is either placed between the tanks or on the bow of the vessel. Regasification capacities range from 1.7-3.4 MTPA for early-built FSRUs to 5-6 MTPA for more contemporary vessels.

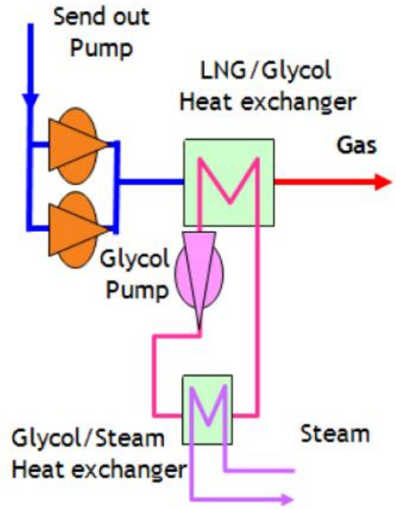
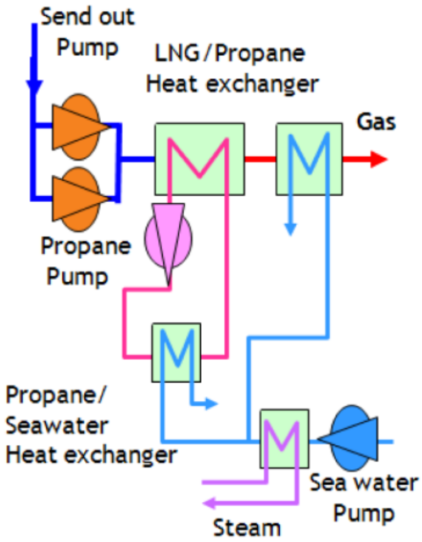

**Figure 29. FRSU with Moss Type Tanks and its Regasification Facilities on the Bow of the vessel.**

The regasification onboard an FSRU vessel, is achieved by using heat exchangers that warm up the cryogenic liquid and convert it to its gaseous state. There are three ways to achieve regasification [48]:

1. **Open loop system**. Sea water is pumped directly from the sea and driven through a shell and tube heat exchanger, therefore vaporizing the LNG and exiting 10$^{o}$C colder straight back into the sea. This process is favored in climates with warm seawater in order to mitigate the risk of freezing the seawater. The fact that the warm outlet water is sent directly back into the sea ('open loop') can cause permitting issues. The energy consumption of the pumps during the process accounts for approximately 1.5% of the send-out gas.
2. **Closed loop system**. Utilizing a compact heat exchanger, this system circulates a mixture of fresh water/glycol, which is preheated by steam produced from the ships' boilers. This process consumes an additional 1% of the send-out gas for the heating of the circulating medium, reaching a total 2.5% consumption.
3. **Intermediate Fluid Vaporization system (IFV)**. This system can either be in closed loop or open loop, but utilizes a two-step vaporization: the first stage uses propane vapour for condensation and the second warm seawater or a heating medium. This system reduces the risk of freezing by not contacting the LNG with sea water while at the same time compact heat exchangers can be used, thus reducing weight and size. However, the introduction of propane vapour onboard the FSRU constitutes a safety issue since it is highly flammable.

Table 10. Regasification Technologies

| | |
|---|---|
| **Open loop system** |  |

| | |
|---|---|
| **Closed loop system** |   |
| **Intermediate Fluid Vaporization system (IFV).** |   |

Often times, FSRU vessels implement both closed and open loop systems in order to cope with the varying needs of different locations. This way, if cold seawater discharge is allowed by the local authorities its use is preferred, since the fuel consumption is less and therefore operating costs and $CO_2$ emissions are cut down [47].

A summary of the strengths, weaknesses, opportunities and threats (SWOT), as suggested by B. Songhurst of the Oxford University, is shown in Table 11 below.

Table 11 SWOT analysis for an FSRU vessel.

| Strengths | Weaknesses |
|---|---|
| Lower (capital) cost and less capital outlay – better cash flow and return on Investment. Ideal for smaller independent energy companies where raising capital may be difficult | Storage and regas capacity limited to maximum ship size – nominally 173,000 m3 and 6 MTPA albeit larger vessels have been constructed but on a project dedicated basis |
| Shorter schedule - earlier gas to market | Expansion is more difficult than onshore |

| | |
|---|---|
| improving competitiveness and securing the supply contract | requiring a larger replacement unit or adding another FSRU |
| Option to lease (most are) improving cash flow and return on investment – not sunk cost as onshore but increased OPEX | Typically less buffer storage – most land terminals have 2 x 160,00 cm tanks |
| Can be relocated to meet seasonable gas demands | Offshore located FSRUs sensitive to weather windows – not an issue with inshore |
| Easier permitting process, minimizes the 'not in my back yard' issues frequently associated with onshore | Limited local content during construction – onshore terminals are major civil engineering projects |
| Shipyard construction results in very high confidence on delivery cost and completion date | No room on FSRU for nitrogen balancing to adjust heating value – could be onshore |
| Shipyard construction minimises local disruption compared with onshore which are major civil engineering projects | - |
| FSRU can be reassigned to LNG tanker use thus minimizing utilisation risk if gas demand falls | - |
| **Opportunities** | **Threats** |
| To purchase outright if long term market is identified | FSRU owner goes into liquidation – covered by contract |
| Deliver early gas whilst establishing long term market need | Not approved due to low local content |
| Ideal component for providing early gas for a power project – or even as a complete floating power barge | Not approved as not regarded as a permanent facility and major infrastructure as is onshore |
| For new smaller gas markets including gas to power projects | Major port development costs make the project uneconomic e.g. breakwater- could apply to onshore too. |

## 3.5 Handling and Safety Issues During LNG Storage

### 3.5.1 Occurrence of the 'Rollover' phenomenon.

LNG 'rollover' refers to the rapid release of LNG vapours from a storage tank due to stratification. Although the fluid dynamics of this mixing phenomenon are incorrectly described by the word rollover, this name has been well established among the industry members, in the sense that the different LNG layers roll over or reverse.

Layer stratification can occur when different LNG qualities exist in the same tank, that is, cargos with different compositions and therefore different densities. Given the rapid growth of LNG trade and its global reach, it is likely that different qualities can be unloaded at the same terminal or LNG carrier with high variations in the component spectrum. If the two liquids are not properly mixed, then the formation of two independent layers is possible. This type of stratification is called **fill-induced stratification**. Fill induced stratification occurs if the unloaded LNG during a bottom fill procedure is denser than the heel or lighter than the heel in case the tank is filled from the top [49].

Under these circumstances, liquid from the top layer gets warmer due to the heat ingress from the tank's surroundings and rises up to the surface where it eventually evaporates. Since the lighter components (namely $CH_4$) evaporate easier, the top layer gets richer in $C_2$+ and thus heavier and denser. This phenomenon is called **weathering**. Accordingly, the bottom layer, which also warms up due to heat leakage into the tank, starts moving by free convection towards the interface of the two layers. In this case however, little mass or heat transfer takes place towards the upper layer and thus the bottom layer is getting warmer and less dense. At this point, boil-off rate is reduced, which is a direct indication of stratification occurrence. Therefore, the densities of the two layers gradually approach equilibrium and when they reach a critical difference they rapidly mix. As they mix, the superheated bottom layer releases the entrained heat resulting in the emission of huge amounts of LNG vapours, at a rate considerably greater (5-50 times higher) than the normal evaporation rate of 0.05-2.0 % of the tank volume per day [50]. Studies have shown that a density difference of about 1kg/m3 can lead in stratification if the unloaded LNG is not mixed properly with the heel or is filled at a fast rate into the tank.

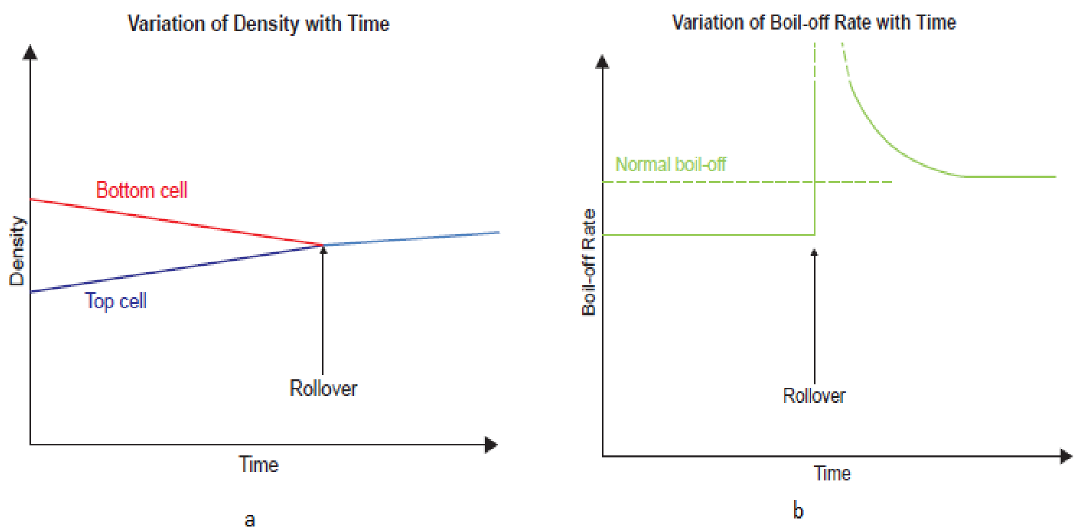



Figure 30. (a) variation of layer density with time, (b) variation of BOR with time

For LNG, the level of heat flux through the insulation is approximately about 15 W/m2, which is way too small compared to the minimum required to initiate nucleate boiling. In the total absence of boiling, all heat entering the liquid is absorbed by primary natural convection currents which carry the heated liquid to the surface, in an open loop circulation: a boundary-layer flow develops at the tank walls, moving heated liquid towards the surface. Once it reaches the surface, this liquid flow turns through $90^0$ and starts moving horizontally and radially inwards just below the surface, as shown in Figure 31. During this inward radial flow the normal boil-off is taking place in an LNG tank and the heat is released through latent heat of evaporation [51].

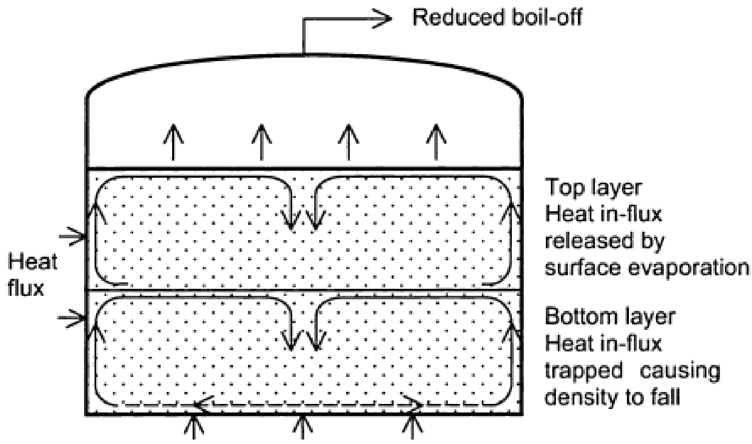



**Figure 31. Boundary layer flow within two stratified cells**

However, in case there is stratification established and two different density layers exist, the boundary layer flow in the bottom layer will similarly turn over through $90^0$ at the liquid-liquid interface. Thus, heat in-flow in the bottom layer cannot be released through surface evaporation and remains trapped as thermal overfill. Consequently, a mechanism is developed whereby heat entering the lower layer cannot be released but is instead circulated within the bulk of the liquid resulting in mean temperature increase and density decrease. At the same time since in the top layer surface evaporation takes place normally, methane is preferentially removed as boil-off gas, thus making the layer denser. This way, the conditions for a rollover are established. [52].

Besides the rollover caused by fill-induced stratification, rollover incidents can potentially occur due to stratification from nitrogen effects, in which case it's called auto-stratification or nitrogen-induced stratification. Since $N_2$ is heavier than $CH_4$ (28 versus 16g/mol respectively), the preferential vaporization of $N_2$ (boiling point at -196$^oC$) tends to make the LNG lighter and therefore less dense. Consequently, in a liquid with sufficient nitrogen content, its evaporation will cause the remaining liquid to be less dense and gradually accumulate near the surface. At some point, this accumulation will result in a layer of light liquid with such height that the kinetic energy of the boundary flow cannot overcome the potential energy due to the density difference. Therefore, flashing can no longer take place and heat is trapped below this newly formed, light layer [49].

Chatterjee and Geist came up with an equation to calculate the height of the flashed liquid required for the establishment of stratification:

$$\mathbf{h} = \frac{u^2}{2g} \times \frac{\rho 1}{(\rho 1 - \rho 2)}$$

where h is the layer height, u the average flow velocity of the liquid, ρ1 the density of the unflashed LNG, ρ2 the density of the flashed LNG and g the gravity acceleration.

After the layer has been established, the rollover takes place in the same way described for fill-induced stratification.

The authors suggest that for a nitrogen content above 4% in volume, auto-stratification is an established cause of rollover, while for 1-3% content, the rollover incident is not certain and has mild effects [53].

However, most LNG plants produce LNG with a nitrogen content significantly lower than 1%. The production of LNG with a high nitrogen content would cause reduction in plant efficiency and a subsequent inccrease in operating costs [50].

Layer stratification in LNG storage tanks can occur as a consequence of mixing either fresh 'light' LNG with a denser heel or by unloading LNG of different qualities into a storage tank. Heel LNG is a small quantity of LNG remaining inside a storage tank after discharge of regular cargo. This ensures that the storage tank is in a cold and ready to load condition for the next operation [54].

The main safety hazard that can possibly occur in case of a rollover accident is the over-pressurization of the storage tank. Under these conditions it is also likely that the pressure relief system of the tank may not be capable of handling the high boil-off rates, which can lead to tank failure and the subsequent release of large amounts of LNG to the atmosphere. LNG Rollover phenomena received the required attention after a major incident occurred in La Spezia, Italy (1971), resulting in the venting of approximately 185 tons of LNG into the atmosphere. This incident, which led to no ignition or injuries, acted as the stepping stone for the subsequent changes in storage tank design, instrumentation and operations within the LNG industry [49].

### 3.5.2 Methods for the Detection of Stratification

In case stratification has been established in an LNG storage tank, the BOR decreases due to the formation of a stabilized interface which entrains the overheated vapours of the bottom layer. This constitutes a good indication of an imminent rollover. In this sense, measuring the temperature profile along the height of the tank can help identify such a potential. The accuracy of temperature measuring instruments needs to be highly precise, in the order of 0.1 $^{0}$C. For this purpose, a standard setup has been developed for all LNG storage tanks which normally consists of two level gauges with associated temperature arrays for average LNG temperature, a high level gauge, a level density temperature (LTD) gauge and an arrangement for measuring the skin temperature of the tank for cool-down monitoring purposes.

**The LTD travelling gauge** is designed to measure the temperature and density over the entire depth of a storage tank. This is done by traversing a single, multifunctional probe across the height of the liquid and recording the temperature and density. This procedure, depending on the LNG cargo height, can take up to an hour to complete and the operation can be repeated as many times as required. Normally, the LTD gauge is run when the conditions in the storage tank are significantly altered e.g. after an unloading operation [50].

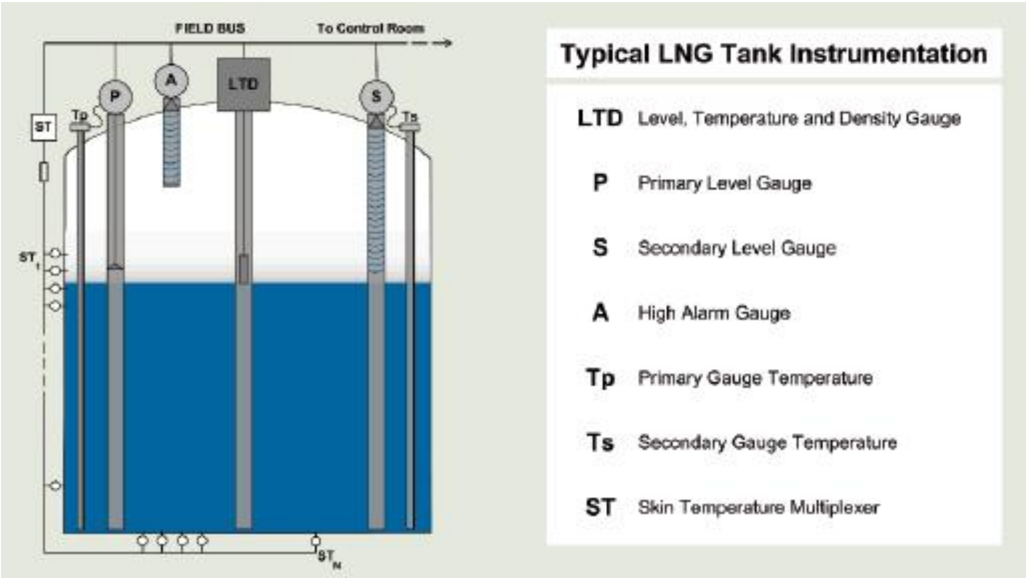



Figure 32. Typical LNG onshore tank Instrumentation

The LTD gauge can be coupled with rollover prediction software to provide an integrated operators an integrated solution in predicting potential rollover incidents in real time, this optimizing LNG storage management. The more sophisticated of these softwares also utilize tank construction data (aspect ratio, insulation efficiency, volume etc) and measure BOR, send-out rate and initial LNG composition in order to more accurately predict the 'time to rollover' as well as the impact of a potential rollover (maximum tank pressure, volume of gas flashed etc).

Density profiling is also of high importance when it comes to detecting stratification and preventing rollover. LTD devices provide a thorough density profile along the height of the liquid, with typical accuracy of 0.5 $kg/m^3$ . However, resolution and repeatability of the measurements are considered more important than accuracy, since it is vital that the device detects even slight changes in the density of potential layer within the storage tank. Figure 4 illustrates a typical LTD gauge profile measurement [50].

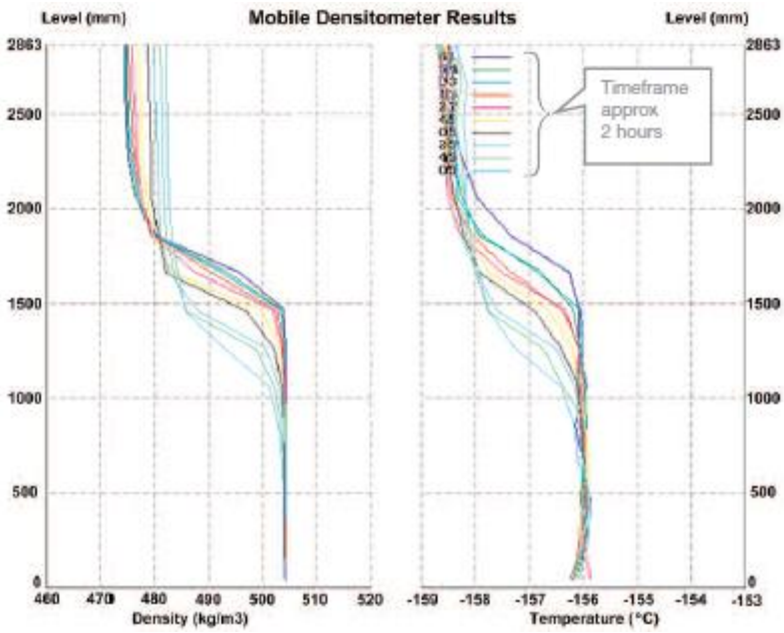



Figure 33. Density and Temperature profiling along the the depth of an onshore LNG storage tank

### 3.5.3 Prevention Methods

**Bottom Filling.** If the incoming LNG is lighter than the heel in the tank, a bottom filling operation is suggested since it will generally ensure complete mixing of the two LNG grades and therefore prevent stratification. This operation also aids the reduction of boil-off gas during the transfer of LNG from an LNGC to a shore tank due to the hydrostatic load exerted by the heel LNG [50].

The bottom filling device consists of a vertical tube going from the top of the tank all the way to the bottom and is installed near the wall of the tank. The bottom side of the tube is equipped with slots that direct the incoming LNG in different directions in order to promote mixing.

**Top Filling.** Accordingly, if the incoming LNG is heavier than the heel, a top filling operation is preferred to effectively mix the different LNG qualities, avoid stratification and therefore rollover. However this procedure usually results in increased BOR and pressure in the tank due to the flashing of the injected LNG. This side effect can be mitigated by decreasing the unloading rate, which, however, is not always commercially feasible due to e.g. maximum staying time of the LNGC at berth [50], [55].

An alternative way of minimizing the aforementioned problem consists of a 3-step procedure:

1. Lowering the tank's operating pressure in order to pre-cool the heel. Decreasing the pressure will result in increased BOG generated and thus the heel will eject heat in the form of latent heat of vaporization, and thus cool down.

2. Prior to unloading increase the tank's operating pressure above nominal so as to limit the amount of flashing of the LNG to be injected. The increased pressure in maintained throughout unloading.
3. Progressive lowering of the pressure to the initial nominal value after unloading is complete.

This procedure has been proved to reduce the BOR by about 50% as shown in the figure below [53].

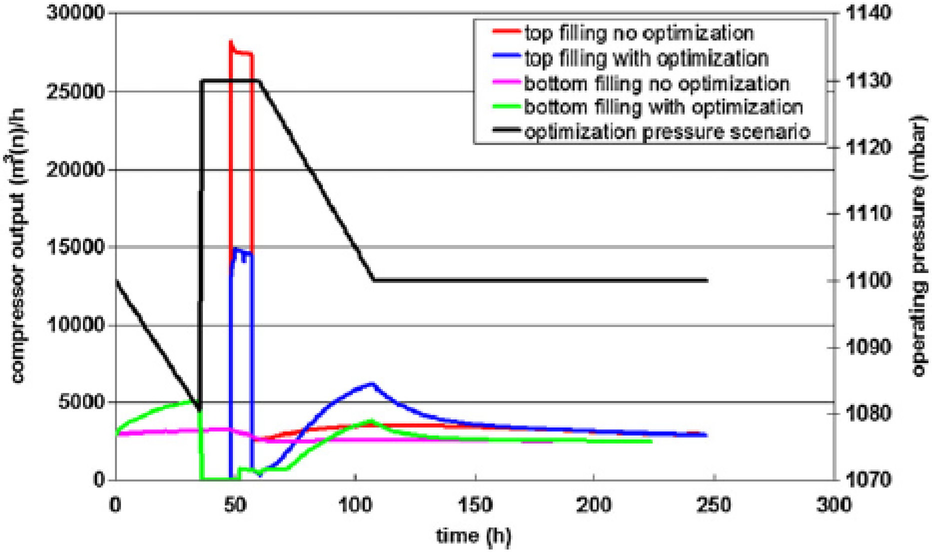



**Figure 34. Pressure optimization of BOR during a top/bot filling of heavy LNG with a light heel LNG at a filling rate of 10.000 $m^3/h$**

**Jet Nozzles and Other Mixing Devices.** A jet nozzle fitted to a fill line located at the bottom of the tank can be very effective in preventing stratification, but there must be sufficient head in the filling line to ensure the jet can reach the surface of the liquid and sufficient time must be allowed to ensure the mixing process takes place in all of the tank contents. Diffusers at the bottom of the fill line can also aid mixing.

If, for any reason, stratification is eventually established, the following processes can be utilized to break up the stratified layers:

- Transfer of the liquid from the tank either by exporting or transferring to another tank
- Circulation of tank contents through jet nozzles or other mixing devices
- Recirculation of the liquid through a top fill line. The efficiency of this depends on the flow rate and it can result in high boil-off losses.

### 3.5.4 Stratification and Rollover Prevention in LNG ships.

FSRU vessels are usually equipped with the aforementioned instrumentation and can effectively mitigate stratification and prevent rollovers. However, is case such instrumentation is not installed and the risk of stratification is identified prior to unloading, then the cargo is simply not acceptable.

On the other hand, conventional LNG carriers do not utilize such equipment. Their storage tanks are not equipped with neither LTD devices nor top filling arrangements and mixing devices. Therefore the best way to prevent a rollover incident is to avoid creating the circumstances of its occurrence in the first place.

However, the risk of rollover in LNG ships has always been considered low, mainly due to the establishment of dedicated trading routes, with vessels trading from a single loading port. Under these trading conditions, stratification, and thus rollover, cannot exist unless there has been a sudden significant increase in the density of the export LNG. LNGC's typically practice bottom filling operations whereby the weathered heel is denser than the incoming LNG. Therefore, since the heel quantity is normally very low and the light LNG is unloaded under the heel, mixing is promoted and stratification is unlikely.

Steps such as keeping LNGC's in dedicated trading routes, reducing the heel for ships arriving at load ports and FSRU's being replenished from the same source can help avoid the risk of stratification. Nevertheless, in case the conditions for stratification arise, the Society of International Gas Tanker and Terminal Operators (SIGTTO) suggest the following practices [50]:

1. Consolidate the heel into one tank.
2. Partially load a second tank to a level such that there is room to transfer into the tank the entire heel.
3. Close the manifold liquid valves - leaving the vapour manifold open.
4. Transfer the heel into the partially filled tank. This should be done using the ship's cargo pumps as fast as safely possible, prudence and vapour generation permitting. The reason for speed is to promote as much turbulence as possible in the bottom of the receiving tank to aid mixing.
5. Do not load any further LNG into the tank containing the mixture.
6. Complete loading the other tanks as per normal procedures.

It should be noted that this procedure is likely to generate large amounts of boil-off.

## 3.6 European Regulations and Standards for Onshore Storage Facilities

**European Committee for Standardization**. CEN is a private non-profit organisation whose mission is to "contribute to the objectives of the European Union and European Economic Area with voluntary technical standards which promote free trade, the safety of workers and consumers, interoperability of networks, environmental protection, exploitation of research and development programmes and public procurement." [57].

In Europe, the codes and regulations specific to LNG import facilities include, but are not limited to, the following:

- **European Union Seveso-III Council Directive 2012/18/** EU of 4 July 2012 - Control of Major-Accident Hazards involving Dangerous Substances. For the European Union all operation and maintenance activities are under the control of a Safety Management System required by Directive Seveso-III 2012/18/EU, which includes requirements relating to safety management systems, emergency planning and land-use planning and provisions on inspections to be carried out by Member States. Seveso III lays down rules for the prevention of major accidents which might result from certain industrial activities and the limitation of their consequences for human health and the environment [57].
- **EN 13645:** "Design of onshore installations with a storage capacity between 5 tonnes and 200 tonnes".
- **EN 1473**: "Installation and equipment for LNG – Design of onshore installations" for storage capacities over 200 tones. The European code EN 1473 is based on a risk assessment approach [58]
- **EN 14620**: "Design and manufacture of site built, vertical, cylindrical, flat-bottomed steel tanks for the storage of refrigerated, liquefied gases with operating temperatures between 0°C and -165°C".
- **EN 1160:** "Installations and equipment for liquefied natural gas — General characteristics of liquefied natural gas". This standard contains guidance on properties of materials that may come in contact with LNG in the facility [59].

Standards/Guidelines are also provided with the intention to act as a reference document for the implementation of regulations and correct practices in the LNG field. Some standards/guidelines that may be applied in Europe are:

- **NFPA 59A:** Standard for the Production, Storage, and Handling of Liquefied Natural Gas ( LNG ). NFPA is an international non-profit organization which specializes in fire prevention and serves as an authority on public safety practices. The NFPA 59A requirements are, for the most part, prescriptive as to the siting and design of an LNG facility [60].
- **33 CFR Part 127** - Waterfront Facilities Handling Liquefied Natural Gas and Liquefied Hazardous Gas [61]
- **ISO 16903:2015** "Petroleum and natural gas industries - Characteristics of LNG, influencing the design, and material selection gives guidance on the characteristics of liquefied natural gas (LNG) and the cryogenic materials used in the LNG industry." It also gives guidance on health and safety matters. It is intended to act as a reference document for the implementation of other standards in the liquefied natural gas field [62]
- **SO/TS 16901:2015**: "Guidance on performing risk assessment in the design of onshore LNG installations including the ship/shore interface." provides a common

approach and guidance to those undertaking assessment of the major safety hazards as part of the planning, design, and operation of LNG facilities onshore and at shoreline using risk-based methods and standards, to enable a safe design and operation of LNG facilities [63]

- **JGA-107-RPIS** – Recommended Practice for LNG in-ground Storage. JGA is the Japan Gas Association.
- **JGA-108-109** – Recommended Practice for LNG Aboveground Storage.

Some industry organizations also aid in the dissemination of correct practices and acquired knowledge regarding LNG operations and handling. The International Group of Liquefied Natural Gas Importers (GIIGNL) is a non-profit organization composed of more than 80 member companies and is involved in the importation of LNG, with its operational focus being on import terminals. It provides its members with overviews on the economic condition of the industry as well as the state of the art LNG technology. Activities of shared interest to GIIGNL members include the handling, importing, processing, purchasing, regasification, and transportation of LNG around the world.

Another non-profit organization, the International Gas Union (IGU), aims to advocate gas as an integral part of a sustainable global energy system, and to promote the political, technical and economic progress of the gas industry. Having more than 150 members representing approximately 97% of the gas market, it covers the whole value chain of natural gas from exploration and production, to transportation through pipelines and LNG.

International codes and regulations addressing aspects of LNG ships include, but are not limited to the following [57]:

- **MARPOL Annex VI**, first adopted in 1997, limits the main air pollutants contained in ships exhaust gas, including sulphur oxides (SOx) and nitrous oxides (NOx), and prohibits deliberate emissions of ozone depleting substances (ODS). MARPOL Annex VI also regulates shipboard incineration, and the emissions of volatile organic compounds (VOC) from tankers [64].
- **International Convention for the Safety of Life at Sea (SOLAS)** is an international maritime treaty detailing general safety obligations of merchant ships.
- **International Ship and Port Facility Security (ISPS)** Codes detailed security measures applicable to ships and port facilities.
- **International Code for the Construction and Equipment of Ships Carrying Liquefied Gases in Bulk** commonly referred to as the **IGC** code provides an international standard for the safe carriage of LNG (and other fuels) in bulk.

# CHAPTER 4

# LNG TRASNFER

# 4. LNG TRANSFER

The ease in transportation of LNG has been key in its establishment as a major player in the contemporary energy scene. However in order for the LNG cargo to be transported, it first needs to be loaded/unloaded either from Ship to Ship (STS) or from shore to ship (and vice versa). These operations require a great deal of attention, since any mistake during handling or equipment malfunction/failure can have dangerous consequences for both the personnel involved and the environment. In the following pages, STS and Ship to Shore transfer operations will be described along with their associated hazards in the event of a spill. Moreover, the current regulations and standards applied during these operations will be considered.

## 4.1 STS LNG Transfer

Although STS transfer is relatively new in the LNG industry, following the initial commercial operation of LNG STS transfer in February 2007, it has quickly managed to become commonplace. STS transfer provides flexibility against port restrictions, addresses the lack of compatibility between ships and terminals, while at the same time it allows for cargo redirection while at sea. Furthermore, the increasing development of floating facilities to monetize stranded gas resources and safety concerns to the community near LNG processing facilities, enhance the usage of STS LNG transfer and impose the implementation of proper and safe technologies. Despite the good safety record of such operations, they are still regarded as high risk procedures, namely due to the unique properties of LNG, such as its cryogenic temperature, flammability etc. The operational challenges of berthing and unberthing between ships, also adds to the risk of STS operations [65], [66].

The equipment used for STS operations is described below.

### 4.1.1 Fendering Equipment

Fenders are used to assist the berthing and mooring of a ship to another ship, preventing collision between the two vessels during STS operations. They aim to provide adequate energy absorption in order to avoid hull plate damage to either vessel.

Fenders used in STS operations fall into two main categories [67]:

- Primary fenders, which are positioned along the parallel body of the ship to afford the maximum protection while alongside. They are also designed to absorb energy as the vessels berth alongside.

- Secondary fenders, which are used to protect the bow and stern plating from inadvertent contact if the ships get out of alignment during mooring or unmooring.

In any case, fenders used in LNG STS operations should preferably be pneumatic rubber fenders and must be certified according to the ISO 17357 standard and the PIANC:2002 guideline. The latest ISO 17357:2014 specifies the material, performance, and dimensions of floating pneumatic rubber fenders, which are intended to be used for the berthing, and mooring of a ship to another ship or berthing structure. It also specifies the minimum test and inspection procedures for floating pneumatic rubber fenders. Other industry guidelines for the provision of STS fendering equipment are provided by the 'Ship To Ship Transfer Guide (Liquefied Gases) 2nd Edition' and the OCIMF/ICS 'Ship To Ship Transfer Guide (Petroleum) 4th Edition' [68].

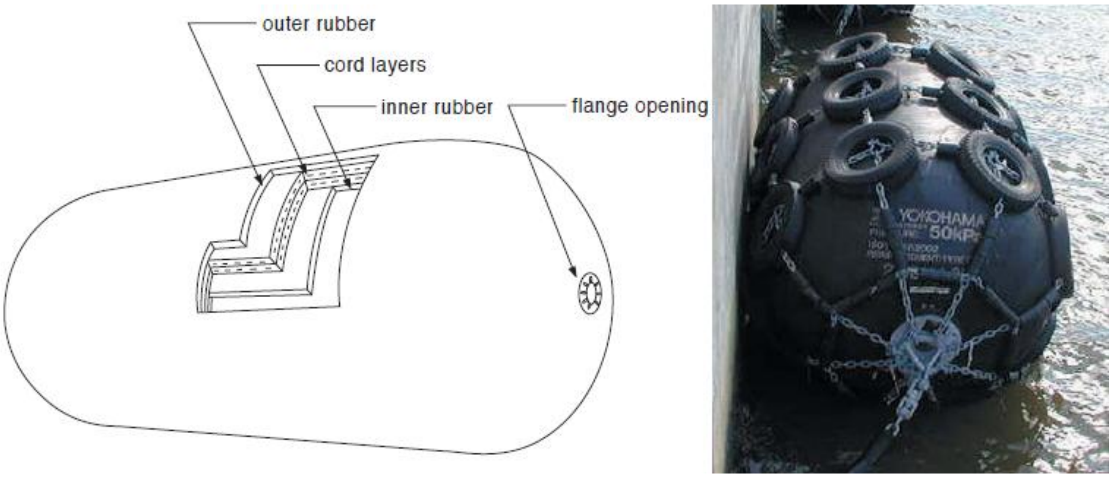



**Figure 35. Basic Construction of Floating Pneumatic Rubber Fenders (source: Yokohama rubber CO.,LTD)**

The selection of fenders number, size and arrangement should be selected based on the particular STS operation, taking into account ship types and sizes, as well as prevailing weather conditions [68]. After these variables have been established, calculation of the Approach Velocity, Equivalent Displacement Coefficient and Berthing Energy (Figure 36) can be performed and fender characteristics can be derived from Table 12 [69].

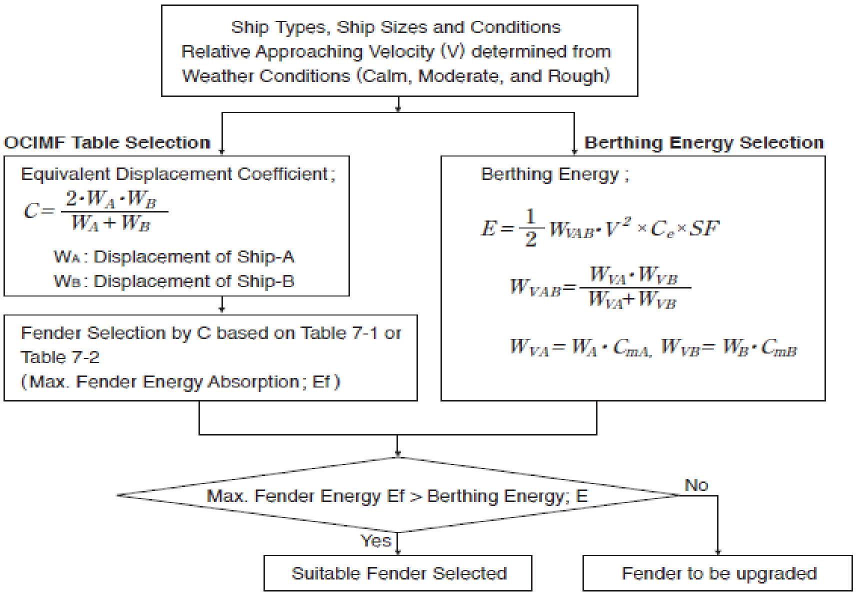



Figure 36. Fender selection for STS usage

Table 12. Reference Guide to Fender selection for STS Operations

| PETROLEUM, CHEMICALS and LIQUEFIED GASSES | | | | |
|---|---|---|---|---|
| Equivalent Displacement Coefficient (C) | Relative Velocity | Berthing Energy | Suggested Fenders | |
| Tonnes | m / s | Tonnes.m | Diameter × Length (m) | Quanitity |
| 1,000 | 0.30 | 2.4 | 1.0 × 2.0 | 3 or more |
| 3,000 | 0.30 | 7.0 | 1.5 × 3.0 | 〃 |
| 6,000 | 0.30 | 14.0 | 2.5 × 5.5 | 〃 |
| 10,000 | 0.25 | 17.0 | 2.5 × 5.5 | 〃 |
| 30,000 | 0.25 | 40.0 | 3.3 × 6.5 | 4 or more |
| 50,000 | 0.20 | 48.0 | 3.3 × 6.5 | 〃 |
| 100,000 | 0.15 | 54.0 | 3.3 × 6.5 | 〃 |
| 150,000 | 0.15 | 71.0 | 3.3 × 6.5 | 5 or more |
| 200,000 | 0.15 | 93.0 | 3.3 × 6.5 | 〃 |
| 330,000 | 0.15 | 155.0 | 4.5 × 9.0 | 4 or more |
| 500,000 | 0.15 | 231.0 | 4.5 × 9.0 | 〃 |

Attention should be paid to the appropriate storage, inspection and maintenance of the fenders. Manufacturers and licensed distributors must provide guidelines for these purposes, while their inspection must be performed by authorized professionals and properly calibrated equipment at given time intervals [66].

### 4.1.2 Cargo Transfer System

**Hoses.** STS hoses consist the means by which the LNG cargo is transferred from one ship to another. At present, LNG transfer hoses are categorized in two types based on their method of construction:

1. Corrugated metal hoses, based on a reinforced corrugated metal hose construction,
2. Composite hoses, based on a construction in which polymeric films and fabrics are entrapped between a pair of close wound helical wires.

Figure 37. Composite STS Hoses (source: KLAW LNG)

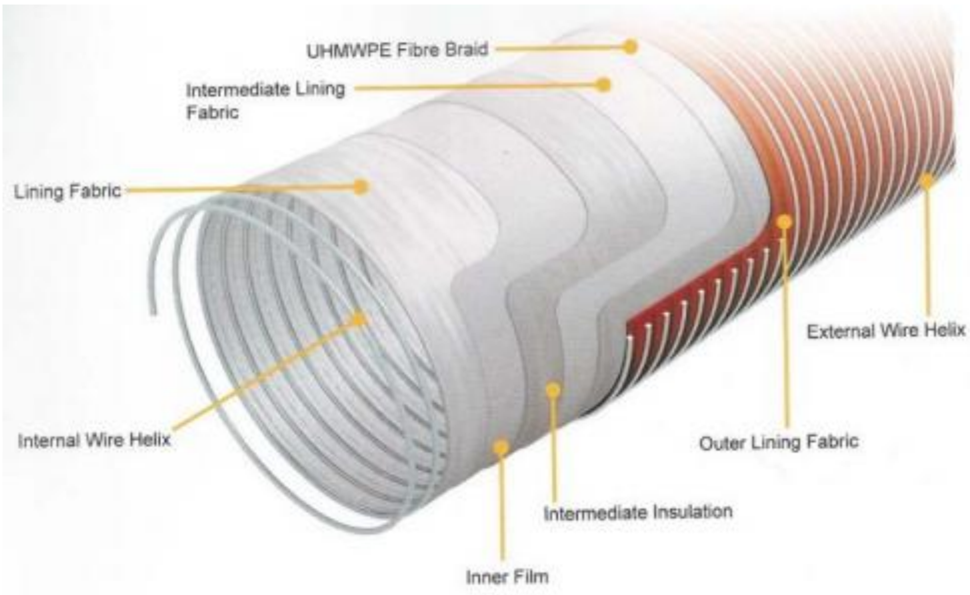



Figure 38. Lightweight, Flexible Composite Cryogenic Hose.

The use of composite hoses is more widespread in STS operations (Figure 37). They typically consist of multiple, unbonded, polymeric films and woven fabric layers encapsulated between two stainless steel wire helices, one internal and one external. Essentially, the film layers provide a fluid-tight barrier to the conveyed product, with the mechanical strength of the hose coming from woven fabric layers. The number and arrangement of multiple polymeric film and woven fabric layers is specific to the hose size and application. The polymeric film and fabric materials are selected to be compatible with the conveyed product and the operating temperatures likely to be encountered [70].

The diameter of the hose is governed by the required LNG transfer rate and vapour return transfer rate. The maximum hose size is usually dictated by the on-board lifting equipment and manifold construction limitations [68]. The hose size and length are also subject to the following criteria:

- Minimum allowable bend radius of the hose,
- horizontal distance between the vessels
- manifold offset
- vertical and horizontal vessels movement
- flange connections minimized and accessible
- allowable flow velocity
- allowable pressure drop
- hose handling requirements and limitations of the ship's equipment

An example of the manufacturer's specifications given for their LNG STS hose is given in Table 13 [71].

**Table 13. Technical Design Data for Continental's LNG STS hoses (source: Continental)**

| Hose application | LNG & LNG vapour marine transfer |
|---|---|
| Hose nominal size | 16 inch |
| Hose internal diameter | 400mm |
| Single hose length | 40m |
| Hose outer diameter | 455mm |
| Maximum working pressure (MWP) | 20 bar |
| Qualification pressure (5xMWP) | 100bar |
| Dynamic minimum bend radius (MBR) | 1,5m |
| Maximum working tension (MWT) | 30 tonnes |
| Minimum breaking tension (5xMWT) | 150 tonnes |
| Working temperature | -196 °C to 40°C |
| Maximum LNG transfer rate | 5000 m3/h |

The integrity of the hoses should be checked prior to LNG transfer operations, tests should be performed at intervals not exceeding 12 months in line with the manufacturer's guidelines and the results shall be recorded and stored. What is more, provisions should be made for their maintenance and proper storage utilized in order to prevent their deterioration from humidity, temperature and physical damage [72].

As far as the certification of the STS hoses is concerned, they should at least be compliant with the EN1474 regulation: ‘Installation and equipment for liquefied natural gas – Design and testing of marine transfer systems’. Another regulation is the EN 12434 (Cryogenic vessels – Cryogenic flexible hoses), while industry good practices are provided by the IMO’s International Gas Code (IGC).

**Quick Connect/Disconnect Couplings (QC/DC).** QC/DC’s are used to aid the faster connection and disconnection of hoses to the ship’s manifolds, as an alternative to bolted flanges. QC/DC’s can be either manually or powered activated.

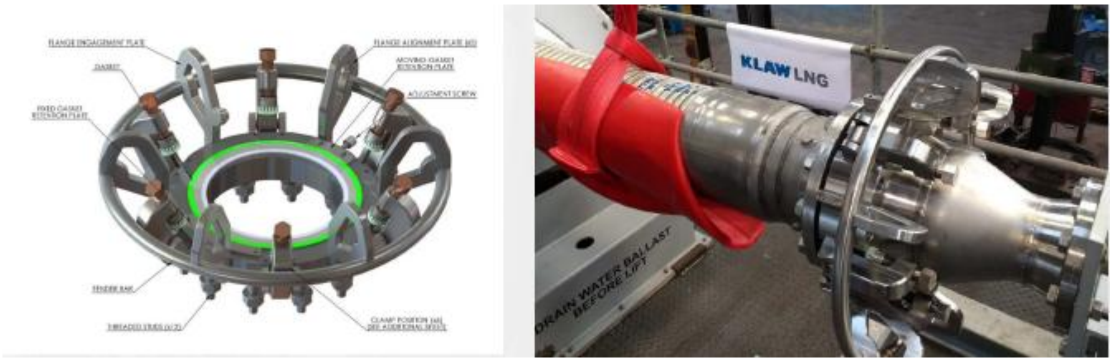



Figure 39. QC/DC connected to the cryogenic hose (source KLAW LNG)

**Emergency Shut Down Systems (ESDS).** The ESDS is a requirement of the IGC Code and its purpose is to protect the vessels. Specifically, the system will stop the flow of LNG liquid and vapor by shutting down the pumps and gas compressors in the event of a fire or cargo leakage [73].

**Emergency Release System (ERS).** Due to wave motion and wind conditions, ships during STS operations can move away from each other beyond permitted limits and therefore, load exceeding the permissible value can be applied on the transfer hoses. To avoid this occurrence, the ERS allows for automatic, emergency release of the transfer hoses in the event of separation of the two ships, fire or other disaster. The ERS consists of several components including the Emergency Release Coupling (ERC) which is integrated within the transfer line, providing a safety link between the on-ship transfer system and the transfer hose [73].

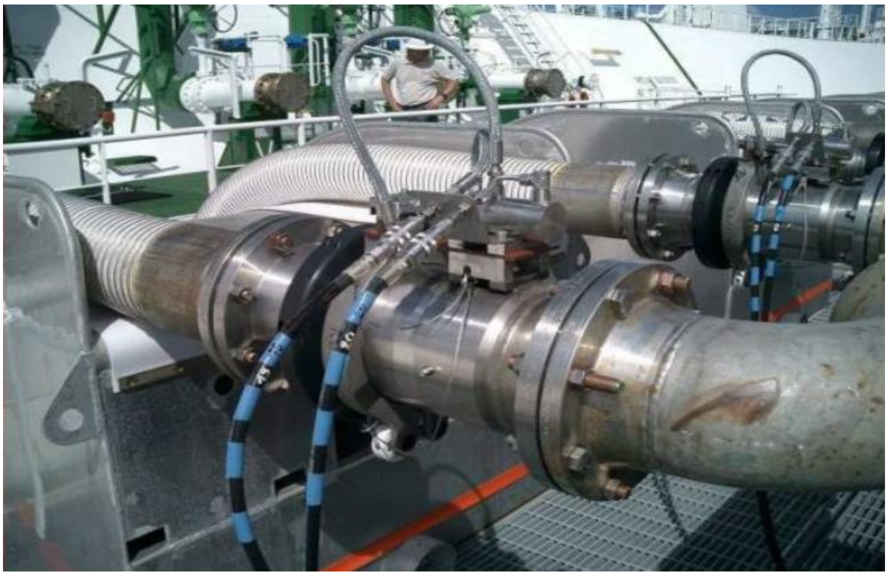


Figure 40. Emergency Release Coupling (source Excelerate Energy)

The ERS is also applied in the vapor return line and manual activation is also possible, in case power to the ERS is disrupted for any reason.

### 4.1.3 Ship To Ship LNG Transfer Procedure

Before commencing the STS transfer between the two vessels, there are various conditions and requirements that must be met in order for the safety of the operation to be established. Namely, ship compatibility should be checked, authority approvals should be granted, the transfer area should be considered and weather conditions should be taken into account.

Figure 42. Connecting the STS hoses

Prior to initiating the STS operation, a full compatibility assessment should be undertaken. This assessment must confirm the full suitability of the two vessels for the STS operation and identify any aspects that may call for special attention and management. Amongst others, it should include the vessel characteristics, manifold arrangements, cargo handling equipment, mooring arrangements, emergency procedures etc.

A comprehensive mooring plan should be carried out in order to establish the safety of both vessels while coming alongside. A Mooring System Management Plan (MSMP) is part of the requirements of OCIMF to ensure risks are managed through the safe design and operation of mooring systems. Part of a MSMP is illustrated in Figure 46 [74].

Furthermore, local and national regulations should be considered in order to determine the level of approval needed for the LNG STS operation at a given area. Once these have been established and approval has been granted, authorities and government agencies should be made aware of the imminent operation [68].

Weather conditions play a vital role in an STS LNG transfer operation, as wind and wave motion can pose restrictions during mooring and equipment handling. In this sense, if the weather forecast suggests that visibility, wind direction and velocity and wave height are forbidding, the LNG STS transfer should be suspended [67].

**Figure 41. Two membrane type LNCs performing STS LNG transfer in the Arctic circl**

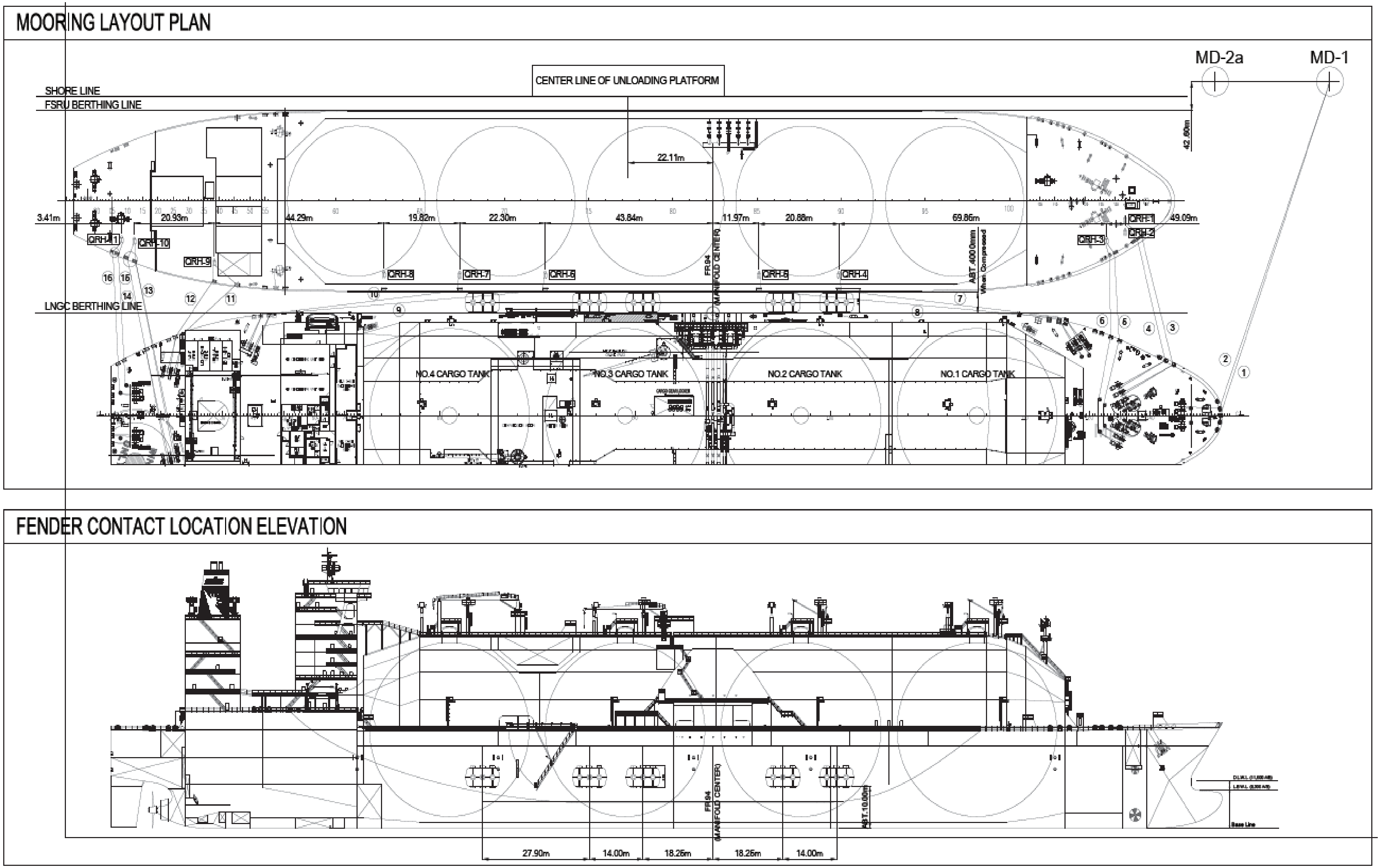



**Figure 42. Part of a Mooring Plan**

After the aforementioned prerequisites are established, the transfer hoses are connected to the respective ship manifolds and **purged with nitrogen**. Specifically, the manifolds are pressurized to 4-5 Bars for 5 minutes in order to make sure the system is leak-proof. Subsequently, nitrogen purging is initiated until the oxygen meters read $O_2$ concentration less than 5% to prevent the formation of an explosive atmosphere. Provisions should be made for the proper calibration of all meters prior to STS operations. Both ships should measure the $O_2$ concentration and cross check their measurements to verify the accuracy of their instruments.

Next, the **transfer lines need to be cooled down**. To accomplish this, one or more cargo spray pumps are utilized, re-circulating LNG vapor back to their respective tanks. The process is completed when the liquid lines, manifold and transfer lines on both vessels reach an agreed temperature, normally around 157 $^{o}$C. During this operation special attention should be paid at the cool down rate while at the same time checking for leaks around the flange connections and transfer hoses is important [73].

The LNG cargo transfer can now commence safely at the agreed transfer rate. During operation, the maximum transfer rate of LNG must be consistent with the receiving vessel's reliquefaction capacity so as no excess LNG vapors exists. In case the receiving ship is not equipped with reliquefaction facilities, a vapor return hose connection must be fitted to the discharging vessel [75].

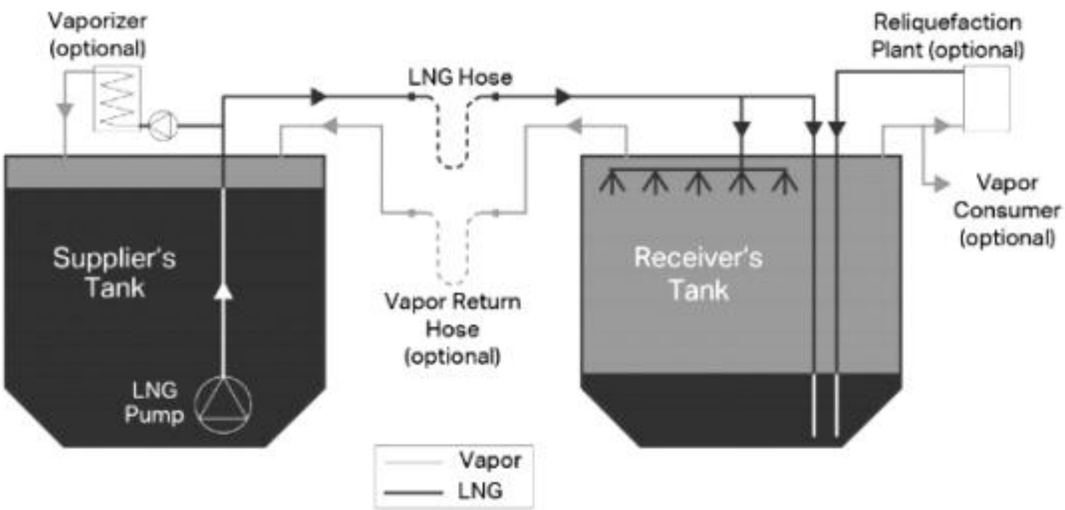



Figure 43. Typical arrangement of LNG vapor management during STS transfer.

Throughout the loading operation the filling of the cargo tanks is alternated in order to allow time difference between each of the tanks finishing, procedure known as 'topping off'. During topping off, the transfer rate is reduced according to the agreed transfer plan. The tank filling limits stipulated by the IGC code is 98% by volume. [73].

Upon transfer completion, all cargo lines should be drained and consequently purged with nitrogen until the reading at the disconnection points is below 2% methane by volume. The cargo transfer equipment is then ready to be disconnected and blanked [68].

## 4.2 Ship to Shore Transfer

LNG cargo transfer from ship to shore or vise versa is the most common type of LNG transfer operations. This can be conducted either between a liquefaction plant and an LNGC or a regasification plant and an LNGC. The transfer is conducted in benign waters while the ship is berthed at the terminal's jetty. The jetty is equipped with fenders to provide for the safe berthing of the LNGC's and loading arms, which consist the LNG transfer system. The Revithoussa LNG Terminal jetty is illustrated In Figure 44 below, where one can observe the five fenders and four loading arms of the facility.

**Figure 44. The Jetty in Revithoussa LNG Terminal (source: DESFA)**

### 4.2.1 Transfer System

The means of transferring LNG cargo during a ship to shore operation are hard arms (loading arms), which are fitted in the terminal's jetty. Loading arms are typically fall into two categories: Rotary and Double Counterweight Arms (Figures 45, 46).

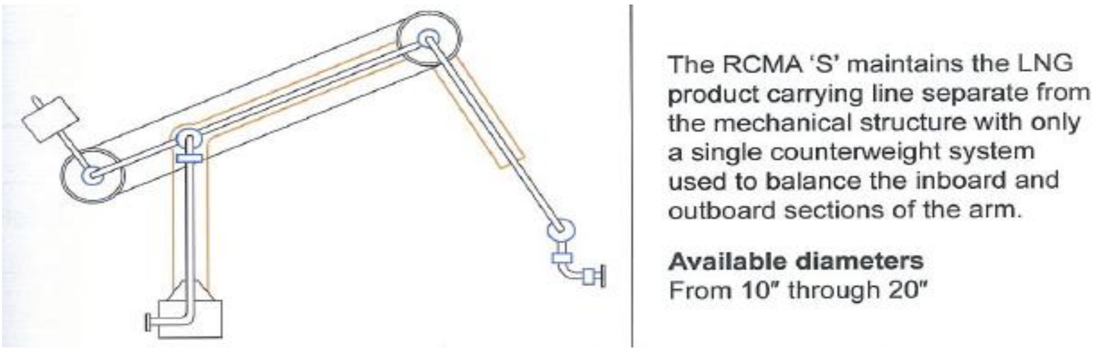



**Figure 45. Rotary Counterweight Marine Arms 'S' (RCMA-S) [73]**

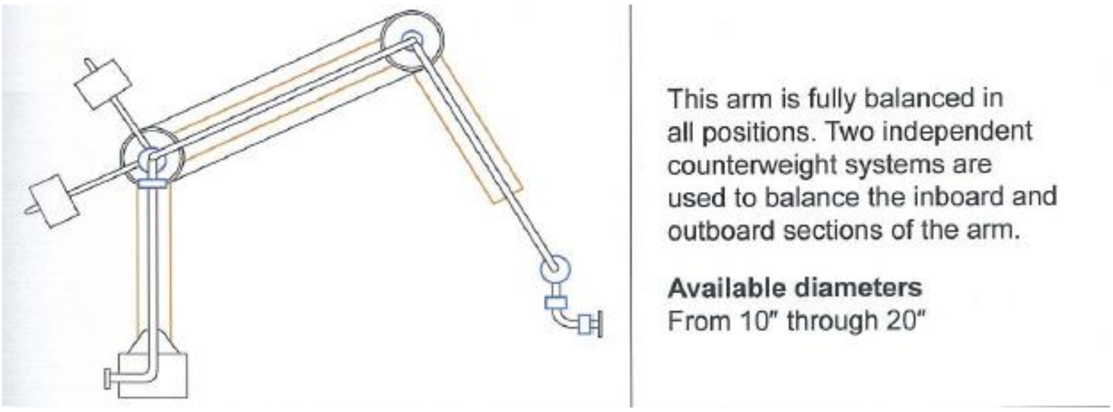



**Figure 46. Double Counterweight Marine Arms 'S' (DCMA-S) [73]**

Both arrangements have swivel joints so as to provide the necessary movement allowance between the ship and shore connections. They are also fitted with a counter- balance weight to reduce the arm's deadweight on the ship's manifold connection and reduce the power needed to maneuver the arms into position [35].

The operation of the loading arms has a certain range, which is stipulated by the operating envelope. The operating envelope's limitations are in turn mandated by the tidal variation and changes of the ship's freeboard during loading/unloading. Moreover, allowance is provided due to the ship's movement fore and aft along the jetty or drift away from berth [35]. As shown in Figure 48, when the arms reach any point of the emergency shut-down zone the ESD system will be activated and the transfer of LNG will stop. If the arms reach further into the emergency disconnection zone then the ERS will be activated and the Emergency Release Coupling will free the arm from the manifold.

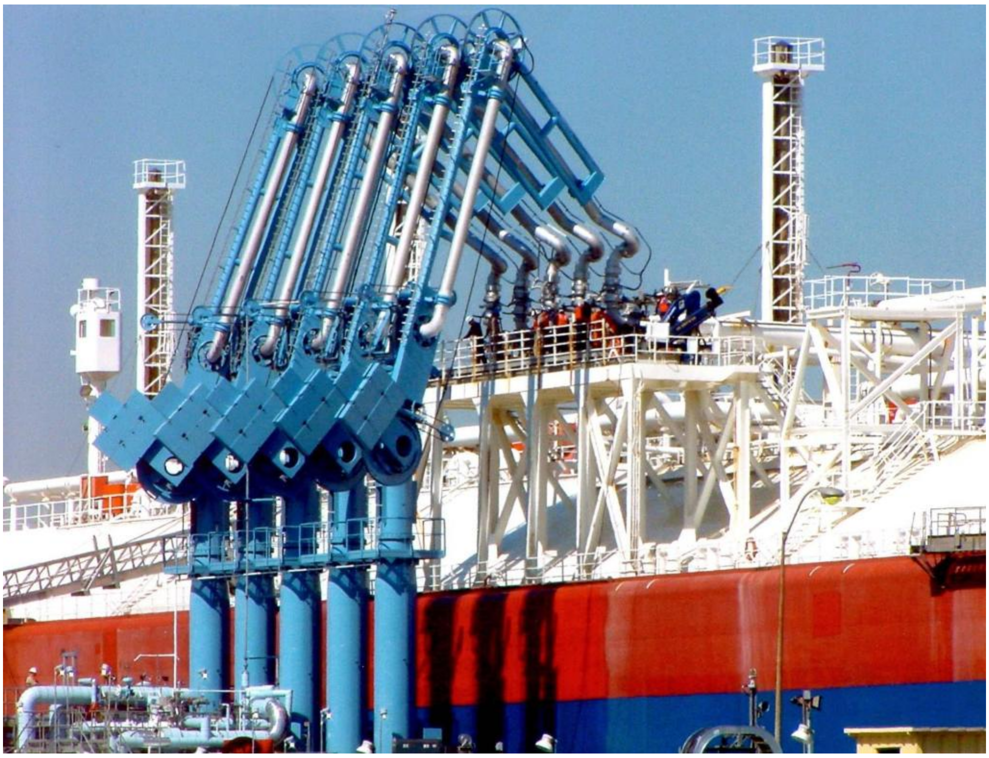


Figure 47. LNG loading arms (source HASMAK)

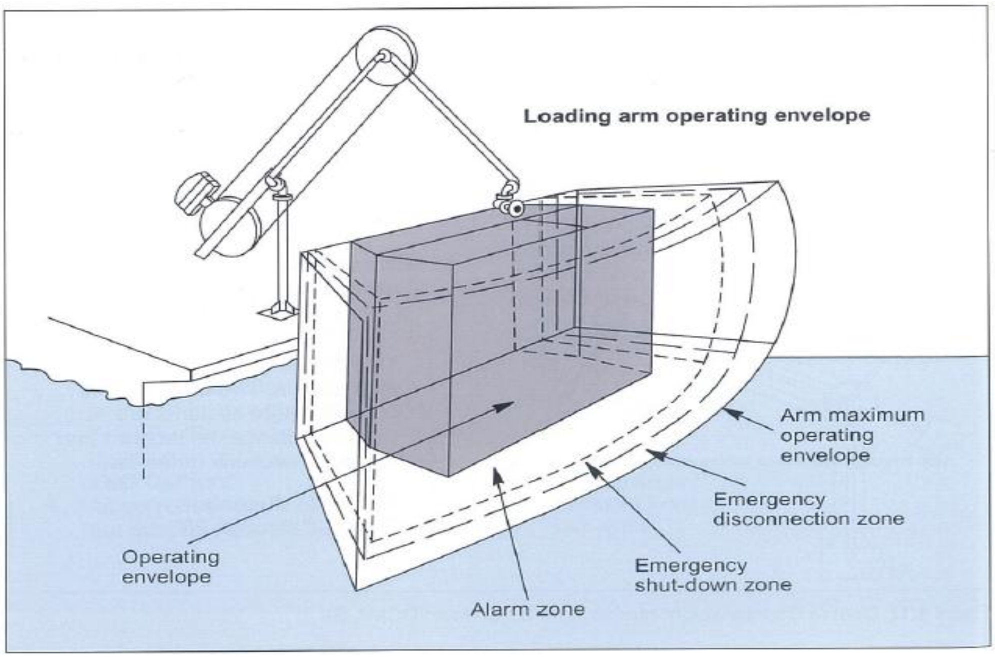



Figure 48. Loading Arms Operating Envelope

The connection between the hard arms and the ship can be done either by bolted flanges or by QC/DCs. Using QC/DCs can reduce the time required to make the connection and disconnection during operations and is considered safer for the personnel involved. As in the case of STS LNG transfer, Ship To Shore operations also utilize Emergency Shut Down and Emergency Release Systems for the same purpose.

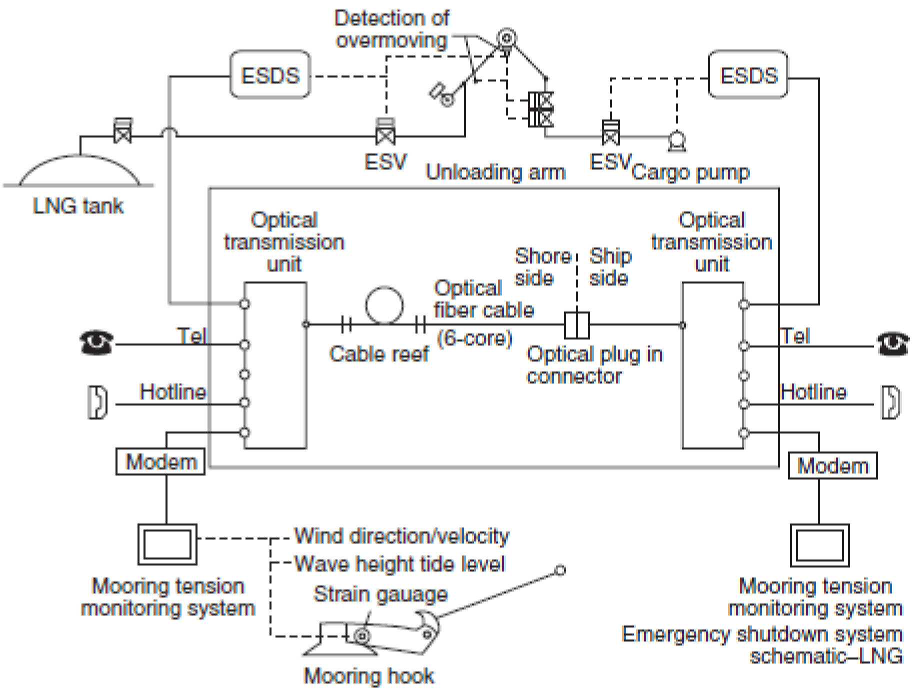



**Figure 49. Typical emergency shutdown systems associated with Ship to Shore LNG unloading**

### 4.2.2 Ship To Shore Transfer Procedure

Similarly to the STS pre-transfer requirements, before any Ship To Shore operation commences, a full compatibility study needs to be carried out in order to establish total compatibility between ship and shore. New LNG carriers normally operate in designated ports and therefore the compatibility assessment with the respective terminals they are expected to visit is already produced [73].

Purging of the manifolds with $N_2$ is then carried out until the meters read $O_2$ concentrations below 1%. Ship and shore should have their respective measurements crosschecked and verified. The loading arms are then connected, pressurized and purged with $N_2$ while at the same time checks are made to ensure they are leak-proof. Subsequently, the loading arms are gradually depressurized while making sure that $O_2$ concentration in the vented gas is below 1%.

Next, the Vapor Return Line (VRL) must be connected and opened. Vapour is generated during transfer operations mainly due to heat ingress into the tanks and pipelines from the surroundings. In case the LNGC is discharging LNG cargo, the vapours generated are returned to the ship's tanks in order to avoid overpressurization of the receiving terminal's tanks and the creation of backpressure (Figure 50). The opposite is practiced in case the terminal is discharging to maintain a positive pressure (Figure 51) [40].

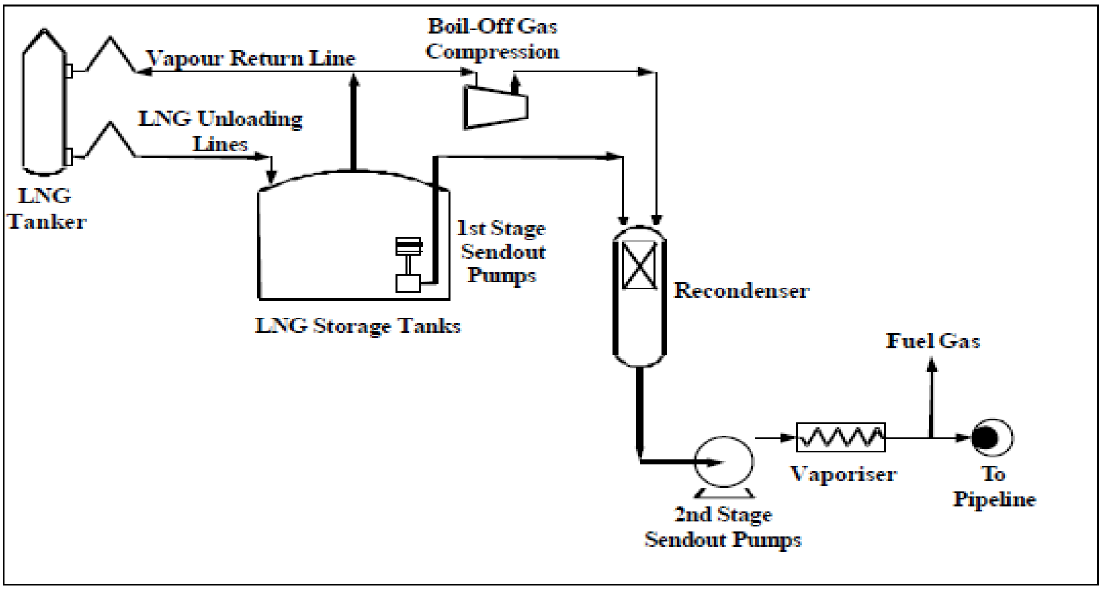



Figure 50. Schematic of an LNGC discharging cargo to a regasification terminal .

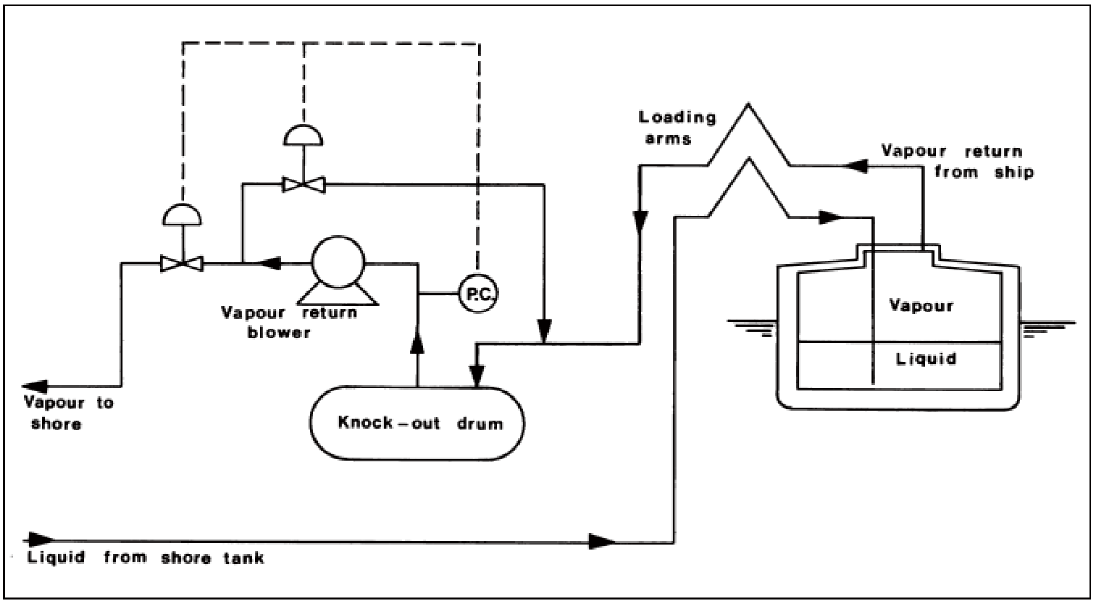



Figure 51. Schematic of an LNG Terminal discharging cargo to an LNGC.

The terminal will now commence the cool down of the transfer lines in the jetty and the loading arms and then the same process is followed by the ship. The cool-down procedure concludes when the desired temperature is chieved in all the transfer lines, normally about -157$^{o}$C. The transfer of LNG can now safely commence at the agreed rate, usually 10.000-12.000 m$^3$ /h. For such an unloading rate, a 135.000m$^3$ ship would need about 12-14 hours to unload. For example, the Revithoussa terminal in Greece has an unloading rate capacity of 7.250 m$^3$/h which means it would take a 135.000m$^3$ LNG about 18-20 hours to unload [35].

Upon completion of the transfer operation, loading arms must be drained by pressurizing lines with $N_2$ from the shore. This procedure is terminated only when the hydrocarbon concentration measured is less than 1%. The loading arms can then be disconnected and the ship prepare for sea.

## 4.2 LNG Safety and Handling Issues

The main safety issues concerning LNG during transfer operations derive from a potential spill which can result in fire, since natural gas is flammable under certain conditions. The following Table summarizes the occurrence of potential hazards during an LNG spill. Depending on the type of LNG release, ignition, level of confinement and operating pressure, there can be various consequences from the resulting fire.

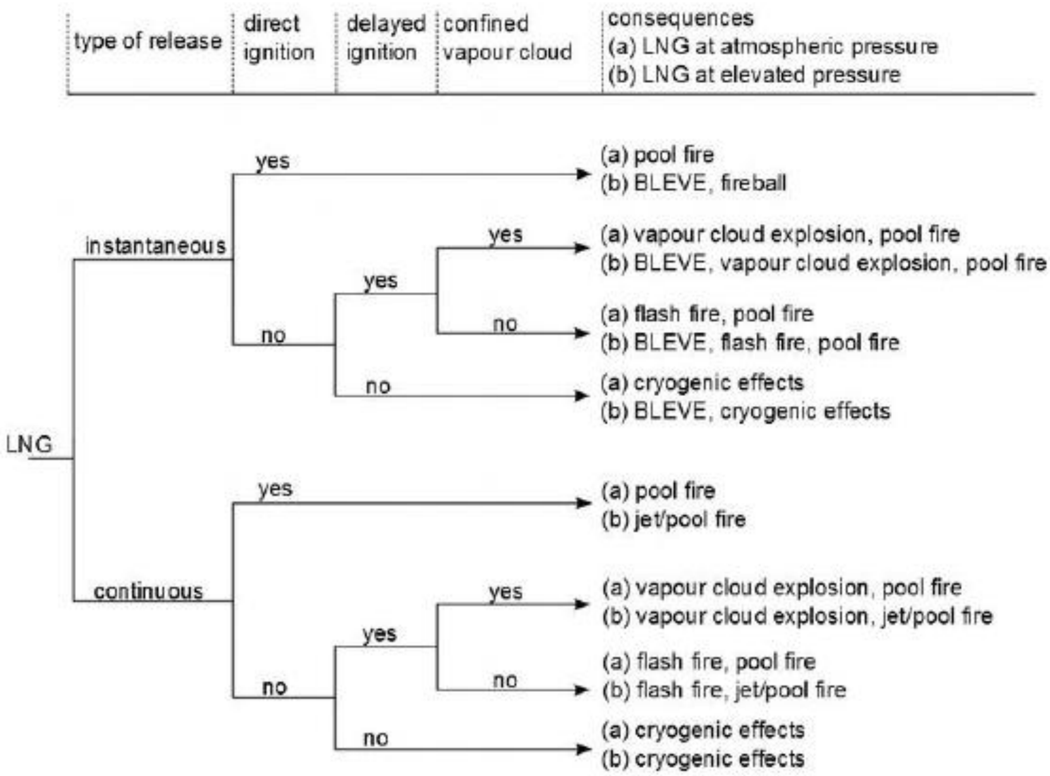



**Figure 52. LNG Hazards (source EMSA)**

### 4.2.1 Pool Fire

When there is a large LNG spill, air cannot transfer enough heat to vaporize all the quantity of LNG and therefore part of it accumulates and liquid pool is formed, which spreads and evaporates at the same time. The rate of the pool spread is described by the following, generally accepted equation:

$$\frac{dR}{dt} = 1.64 \frac{1}{R} \sqrt{\frac{Mg(\rho_w - \rho)}{\pi \rho \rho_w}}$$

where R is the pool radius, ρ is the LNG density, M is the mass of the liquid in the pool and subscript w refers to water. Depending on wind conditions, wave motion and currents (in case of spill over water) the shape and size of the pool varies.

In case of direct ignition of LNG a pool fire will occur. For pool fires on water, both the flame height and burning rate are higher compared to land pool fires, due to the increased heat flow from the water [76].

**Figure 53. LNG Pool Fire**

As far as flame height and burn rate are concerned, LNG pool fires exhibit different behavior than most hydrocarbon pool fires of similar scale. Since LNG is a cryogenic liquid it has at least ten times higher burn rate than other higher molecular hydrocarbons. The volatilization rate or burn rate, affects thermal hazard distances by altering the size of an unconstrained pool: higher burn rates lead to smaller pools while lower burn rates lead to larger pools. In turn, the burn rate affects the flame height, with increasing burn rate resulting in higher flame heights. Given that increased flame height results in higher heat influx to an object, this would result in increasing the thermal hazard distances. However, while an increase in burn rate would reduce the thermal hazards distances by decreasing the pool diameter, the associated increase in flame height would in turn tend to increase hazards distances [77].

Wind also affects the hazard distances, by affecting both the flame height and burn rate. The flame height can be reduced from 10 to 40% depending on wind speed, although this effect is not certain in case of large pool fires. The burn rate will be increased with increasing wind speed [77].

A LNG pool fire generates significant amounts of thermal radiation with the surface emissive power beyond 200kW/$m^2$. For comparison purposes, a person wearing protective clothing can withstand around 12kW/$m^2$ [79].

### 4.2.2 Flash Fire

In case there is no direct ignition, the LNG leakage will form a vapor cloud, which grows with the pool vaporization. If the leakage occurs in unconfined water, the LNG evaporates at a high rate due to the heat influx from water. In contrast, a LNG spill on land has a high evaporation rate in the beginning which falls off with time. If the concentrations in the vapor cloud reach values between the lower and upper flammability limits of methane, 5 and 15% by volume respectively, then in case of ignition a flash fire can occur with a combustion wave moving through the cloud. Below 5% methane the mixture is to lean to ignite, while above 15% too saturated to ignite [76]. While the duration of the flash fire is relatively sort, the fire can propagate back to the source and cause a late pool fire.

a b c d

Figure 54. Evolution of a Flash Fire as it propagates back to the spill source

The major hazard a flash fire can impose, is to people in the flame envelope or people located above it in elevated areas. Combustion temperatures can reach up to 1200°C and lead to fatalities, but given the sort duration of a flash fire (a few seconds), it is unlikely to cause serious damage to structures or facilities equipement [79].

### 4.2.3 Vapour Cloud Explosion (VCE)

A vapour cloud explosion can occur when a large flammable mass of LNG vapour is ignited within a confined space. The amount of explosive overpressure is determined by the flame speed of the explosion. In turn, flame speed is a function of the turbulence created within the LNG vapour cloud released and the level of fuel mixture within the combustible limits (5-15% volume). Maximum flame velocities occur for methane concentrations just above 5%. Turbulence is created due to the confinement and congestion in spill area [80].

Once the explosion occurs, it generates a blast wave with an abrupt pressure rise at the wave front. The impact of the blast on the surrounding structures is known as the blast loading. Blast loading largely depends on the flame velocity, where speeds up to 100m/s are not likely to cause damage. In experiments conducted by the Christian Michelsen Institute in Norway, it was found that for damaging velocities to occur the vapour cloud's diameter has to be at least 5.5 meters [80].

### 4.2.4 Rapid Phase Transition (RPT)

The Rapid Phase Transition phenomenon occurs when there is a LNG spill over water, whereby the LNG vaporizes violently due to heat ingress from the water, causing what is known as cold blast or physical explosion. These types of explosion do not involve combustion or chemical reactions to generate mechanical explosion energy. The required energy rather comes from the rapid expansion of a high pressure, thermodynamically unstable (meta-stable) fluid to ambient pressure [81].

A fluid can become meta-stable by rapidly changing its temperature and pressure so that it can no longer exist under those conditions in its initial liquid state, and eventually has to change phase. The pressure and temperature limits at which this phase change occurs are called thermodynamic stability limits or superheat limits [81].

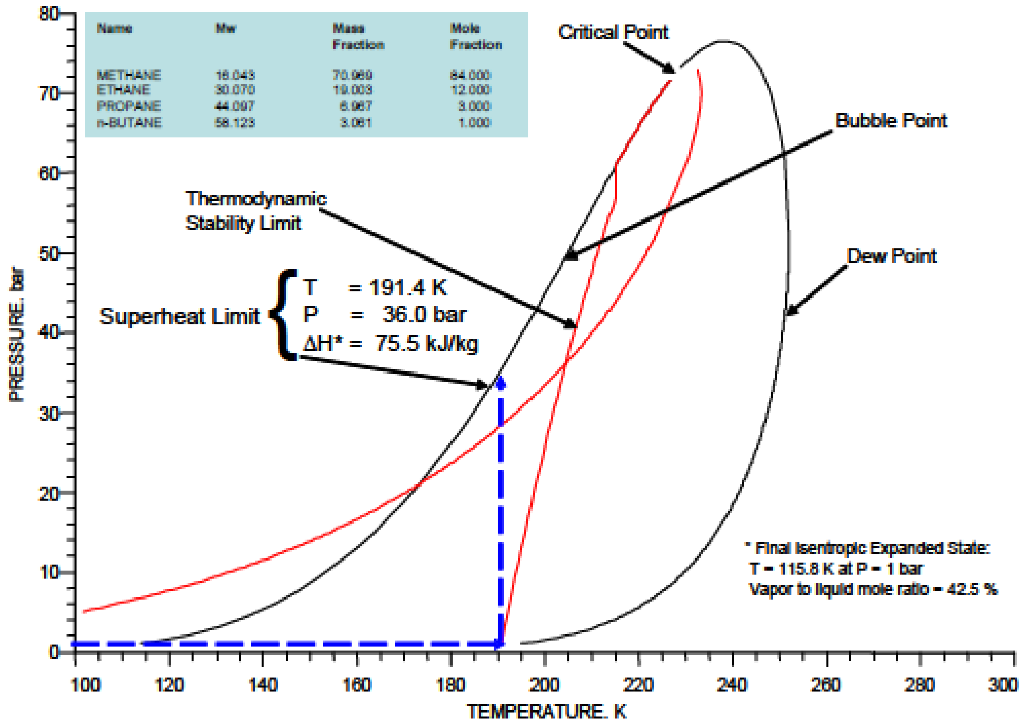



**Figure 55. The Superheat Limit for an LNG Mixture (Source: SuperChems Expert v5.7, ioMosaic Corp.)**

The phase envelope of an LNG mixture is illustrated in Figure 55. The dashed blue lines represent the rapid heating of this mixture at ambient pressure, causing the LNG to reach the thermodynamic stability limit at 191.4K or -102$^{o}$C. At this temperature the LNG becomes a superheated liquid, that is, a saturated liquid with a bubble point pressure of 36 bars. Being at a superheated state, the LNG mixture has to expel its superheat by expanding since ambient pressure is at 1 bar. Therefore, the maximum rapid phase pressure that the mixture can reach is 36 bars, exerting mechanical explosion energy of approximately 37.75 kJ/Kg. That is almost 1.5 times less han the overpressure energy per unit mass generated during the combustion process of the same natural gas mixture [81]. The energy of explosion produced by the work of expansion of vapors during an RPT is given by the following equation:

$$W = \int P dv = \frac{(P_1 v_1 - P_2 v_2)}{(k-1)} \models \frac{nRT_2}{\left(1 + \frac{nR}{C_v}\right)}$$

Where subscript 1 refers to the initial conditions, 2 to the final conditions, P2 is atmospheric pressure, v is the specific volume (m3/kg), k is the index of expansion, R is the gas constant and n is the number of moles of expanding gas [79].

When LNG is spilled over water, the difference in temperature is initially very high, causing the LNG to start boiling. However, due to the vast temperature difference between the LNG and the water surface, a vapour film is formed at the point of contact between the water and LNG (leidenfrost effect). This vapour film will persist until the surface cools enough and will greatly reduce the heat transfer between water and LNG, acting as insulation. When the temperature difference is low enough, the vapour film is consequently destroyed and the heat transfer rapidly grows by orders of magnitude. This in turn leads to the LNG almost instantaneously being superheated and an RPT occurs [82].

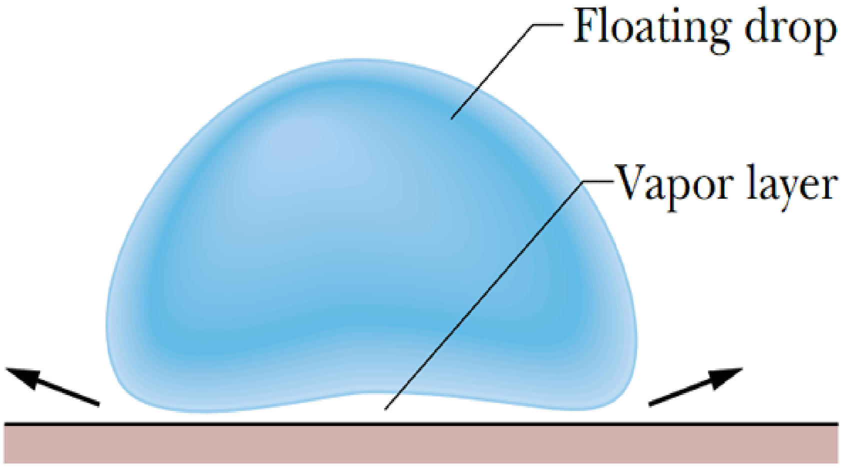



Figure 56. A Leidenfrost drop in cross section

As concluded by G. A. Melhem et. al. in their work, RPTs are largely depend on the LNG composition and are more likely to occur for heavier LNGs (rich in ethane and propane). Moreover, spill rate and spill duration also affect the likelihood of an RPT, with higher LNG spill rates and duration increasing the chances of producing an RPT.

In case the LNG vapour cloud is released in a confined space and sufficient mixing with air is achieved, RPT can result in an explosion [76]. However an explosion caused by RPT is not likely to cause damage to elements on a LNGC or jetty. Also no rapid phase changes have resulted in any known major incidents involving LNG [78].

### 4.2.5 Boiling Liquid Expanding Vapor Explosions (BLEVE)

BLEVE, also known as fire balls, are very rapid combustion processes that involve pressurized liquids. In this sense, when pressurized liquid LNG is released quickly, LNG vapours will flash creating extreme speeds and turbulence. Subsequently, and in case of ignition, the flame front will travel rapidly across the whole flammable envelope. Since these types of release do not entrain large quantities of air, the fireball will burn across the entire external envelope and cause the flammable mass to rise and radiate large amounts of heat in a time frame of 20 to 40 seconds.

Figure 57. Evolution through time of the fireball after the explosion

## 4.3 LNG Spill and Fire Control Measures

An accidental release of flammable gas at an LNG carrier or LNG terminal can result in any of the previously mentioned fire types, and therefore it must be detected as quickly as possible in order to prevent these occurrences. Especially in land facilities, where personnel is kept to a minimum and human overseeing is often limited, it is crucial that detection systems are well established. If an LNG leakage occurs and is not detected on time, then spill and fire control plans need to be followed in order to avoid physical and structural damage.

### 4.3.1 Vapor and Fire Detection

For the detection of LNG vapours in LNG carriers, the IGC code requires that a fixed gas detection system with both audible and visual alarms is fitted onboard. In particular, detector heads must be installed in the following areas of the ship [73]:

- Cargo compressor room
- Electric motor room
- Cargo control room (unless classified as gas-safe)
- Enclosed spaces such as hold spaces and interbarrier spaces (excepting hold spaces containing Type ‘C’ cargo tanks)
- Airlocks
- Burner platform vent hoods and engine room gas supply pipelines

With regards to the detection systems used, there are two main types: infrared gas analyzers and the catalytic combustion method. In both cases, depending on the density of the LNG vapors, careful consideration should be given as to the installation height of the detection heads in order to achieve the earliest possible detection. In this sense, for heavier than air vapor the detector heads should be sited at a low level while for lighter than air vapors they should be fitted at a high level. The IGC Code stipulates sampling intervals not exceeding 30 minutes, while alarms should be activated in case vapor concentration detected reaches 30% of the LFL [35]. Gas detection systems are utilized in onshore LNG terminals.

In case the gas detection systems fail to alert the personnel about the leakage, a fire can occur if the vapors encounter an ignition source. In this case, fire detection systems are responsible for the timely detection of either smoke, heat or flame detection. Smoke detectors can be of various types, with the main ones being :

- Ionization smoke detectors
- Optical smoke detector
- Beam detectors
- Incipient smoke detector

Detection of heat utilizes detectors that respond to an increase in temperature associated with developing fires. On the other hand, flame detectors convert electromagnetic radiation emitted from flames into an electrical signal, which in turn activates an alarm. Such detectors should be installed in areas where fire occurrence is regarded high in order to effectively operate [2]. For the correct design of detection systems both offshore and onshore, there is a number of standards that should be followed. The most significant one is the family of standards EN-54: fire detection and alarm systems. Also, the British Standard BS8539 'Part 1: Code of Practice for the Design, Installation and Maintenance of Automatic Fire Detection systems' should be referred to.

### 4.3.2 LNG Fire-Fighting

**Water.** As discussed earlier, upon contact with water, LNG vaporization rate increases rapidly and therefore water should at no case be used for direct application to an LNG fire. However, water is essential for a terminal's or LNGC's fire-fighting system since it is an excellent cooling medium. It can be used to protect exposed facility surfaces from fire or heat radiation in the form of jets, sprays, fixed deluge systems or water curtains [35]. Water curtains can limit LNG vapor dispersion and act as a radiation protective shield if properly designed.

Figure 58. Water curtain utilized during LNG STS transfer to protect the ship's hull from a potential leak and subsequent embrittlement of its structure

**Foam.** Foam application aims to reduce the vaporization rate of an LNG spill. High expansion foams, with expansion ratios of 500:1, will efficiently reduce LNG vaporization rate, and therefore the fire's intensity, when used in large quantities against a pool fire. For unignited LNG pools, foam application can restrict the horizontal traveling of vapor clouds by introducing heat and increasing their buoyancy, thus reducing the hazardous vapor dispersion zone. While at the initial stages of its application foam can increase the vaporization rate, when it becomes stable it can freeze at the interface and ultimately decrease vapor realease [35].

The amount of foam used should be enough to maintain a foam depth of one to two meters. In its 'Process Safety Series: LNG Fire Protection and Emergency Response', BP recommends that high expansion foam systems are used for LNG pool fires at a rate of 10 litres/min/$m^2$ and a minimum foam depth of 1.2m. Such a practice can reduce the radiated heat by 90% within a time frame of one minute. BP also suggests that high expansion foam systems be fitted in [2]:

- LNG storage tank dikes/bunded areas
- Sumps
- Transfer lines
- Pump areas
- Jetties
- Liquefaction and vaporizer heat exchanger facilities

- LNG truck loading/unloading areas

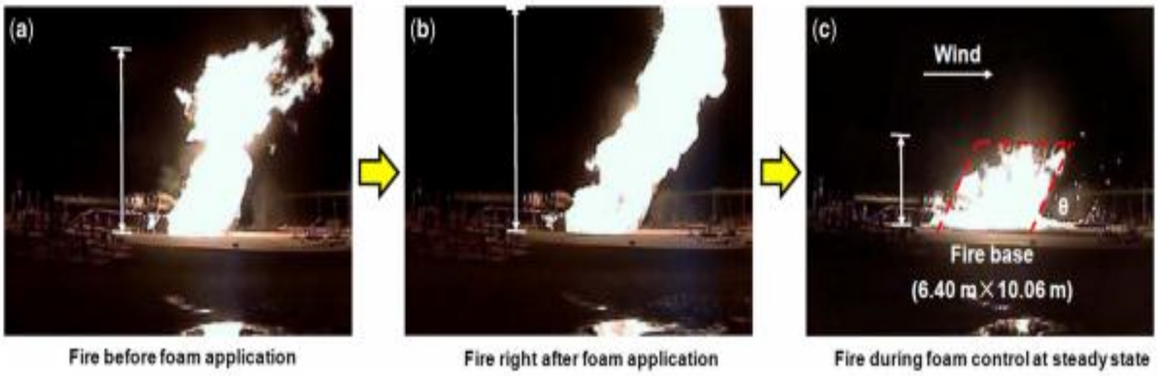



Figure 59. Expansion Foam application on LNF pool fire suppression (source Yun 2011)

**Dry Chemical Powders.** Dry chemical powders such as sodium biocarbonate, potassium bicarbonate or urea potassium bicarbonate are effective against small LNG fires. They deal with the flames by absorbing free radicals in the combustion process. The time needed for chemical powders to extinguish a fire largely depends on the burning rate and the powder's application rate. Dry chemical powders can be applied from fixed, mobile, or portable systems.

Despite the fact that dry chemical powders are effective in putting out LNG fires, remaining LNG vapors can accumulated into and vapor cloud after the fire has been extinguished. It is therefore important that attention is paid, since post extinguishment vapor formation and movement may pose an even greater hazard than the fire itself [2].

Figure 60. Application of chemical powder in an LNG pool fire

## 4.4 LNG Transfer Regulations and Standards

International standards have huge contribution towards building a safety and confidence framework for LNG operations and the industry in general. Composed by international standardization bodies (ISO, CEN, IEC), these standards have helped establish the great safety history of LNG trading around the globe and keep working in the same direction to further improve all aspects involving LNG operations.

The following Table summarizes the European Standards developed to regulate the LNG transfer interface, safety and protection measures that need to be taken. It also gives a brief description of their respective contents.

**Table 14. European Standards issued by the international standardization bodies**

| Title | Responsible | Type | Scope |
|---|---|---|---|
| **EN 1474-1** - Design and testing of marine transfer systems. Design and testing of transfer arms | CEN | European Norm | (replaced by EN ISO 16904) |
| **EN 1474-2** - Design and testing of marine transfer systems. Design and testing of transfer hoses | CEN | European Norm | Installation and equipment for liquefied natural gas. Design and testing of marine transfer systems.<br>Design, minimum safety requirements and inspection and testing procedures. |
| **EN 1474-3** - Design and testing of marine transfer systems. Offshore transfer systems | | European Norm | Loading and unloading devices, Liquefied natural gas, Natural gas, Petroleum products, Loading (materials handling), Tankers, Ships, Design, Safety measures, Risk assessment, Equipment safety, Safety devices, Alarm systems, Control systems, Inspection, Performance testing |
| **EN 12065** - Testing of foam concentrates of extinguishing powders used on LNG fires | CEN | European Norm | Installations and equipment for liquefied natural gas. Testing of foam concentrates designed for generation of medium and high expansion foam and of extinguishing powders used on liquefied natural gas fires. Flame retardants, Foams, Particulate materials, Concentrates, Fire retardants, Test equipment, Expansion (deformation), Testing conditions, Efficiency, Reports, Fire tests, Compatibility, Performance testing, Fire extinguishers |
| **EN13463-1** - Non electric equipment for use in potentially explosive atmospheres | CEN | European Norm | Standard with requirements for non-electrical equipment for use or located in potentially explosive atmospheres. |
| **EN 13766:2010** – Thermoplastic multi-layer (non-vulcanized) hoses and hose assemblies for the transfer of liquid petroleum gas and liquefied natural gas – Specification | CEN | European Norm | Requirements for two types of thermoplastic multi-layer (non-vulcanized) transfer hoses and hose assemblies for carrying liquefied petroleum gas and liquefied natural gas. |
| **ISO/DTS 16901 -** Guidance on performing risk assessment in the design of onshore LNG installations | ISO | ISO Technical Specification | Risk assessment for LNG facilities onshore and at shoreline (export & import terminals) |

| | | | |
|---|---|---|---|
| including the Ship/Shore interface | | | |
| **EN ISO 16904** - Design and testing of LNG marine transfer arms for conventional onshore terminals | ISO | International Standard | Specifies the design, minimum safety requirements and inspection and testing procedures for liquefied natural gas (LNG) marine transfer arms intended for use on conventional onshore LNG terminals, handling LNG carriers engaged in international trade. It can provide guidance for offshore and coastal operations. It also covers the minimum requirements for safe LNG transfer between ship and shore.<br>Although the requirements for power/control systems are covered, this International Standard does not include all the details for the design and fabrication of standard parts and fittings associated with transfer arms.<br>ISO 16904:2016 is supplementary to local or national standards and regulations and is additional to the requirements of ISO 28460 |
| **ISO/TS 18683** - Guidelines for systems and installations for supply of LNG as fuel to ships | ISO | ISO Technical Specification | ISO/TS 18683:2015 gives guidance on the minimum requirements for the design and operation of the LNG bunkering facility, including the interface between the LNG supply facilities and receiving ship as shown in Figure 1.<br>ISO/TS 18683:2015 provides requirements and recommendations for operator and crew competency training, for the roles and responsibilities of the ship crew and bunkering personnel during LNG bunkering operations, and the functional requirements for equipment necessary to ensure safe LNG bunkering operations of LNG fuelled ships.<br>It covers LNG bunkering from shore or ship LNG supply facilities, as shown in Figure 1 and described in Clause 4, and addresses all operations required such as inerting, gassing up, cooling down, and loading. |
| **EN ISO 20519** - Specification for bunkering of liquefied natural gas fuelled vessels | ISO | International Standard | Requirements for LNG bunkering transfer systems and equipment used to bunker LNG fuelled vessels, including equipment, operational procedures, training and qualifications of personnel involved.<br>ISO 20519:2017 sets requirements for LNG bunkering transfer systems and equipment used to bunker LNG fuelled vessels, which are not covered by the IGC Code. This document includes the following five elements:<br>a) hardware: liquid and vapour transfer systems;<br>b) operational procedures;<br>c) requirement for the LNG provider to provide an LNG bunker delivery note;<br>d) training and qualifications of personnel involved;<br>e) requirements for LNG facilities to meet applicable ISO standards and local codes. |
| **ISO 28460** – Standard for installation and equipment for LNG – Ship to shore interface and port operations | ISO | International Standard | Onshore LNG terminals and LNG carriers.<br>ISO 28460:2010 specifies the requirements for ship, terminal and port service providers to ensure the safe transit of an LNG carrier through the port area and the safe and efficient transfer of its cargo |
| **IEC 60079-10-1:2015** | IEC | International | Standard concerned with the classification of |

| | | | |
|---|---|---|---|
| - Explosive atmospheres - Part 10-1: Classification of areas - Explosive gas atmospheres | | Standard | areas where flammable gas or vapour hazards may arise and may then be used as a basis to support the proper selection and installation of equipment for use in hazardous areas. It is intended to be applied where there may be an ignition hazard due to the presence of flammable gas or vapour, mixed with air |

In addition to the standards issued by standardization bodies, industry best practices and guidelines are published by some LNG industry organizations, such as SIGTOO, GIIGNL and others. Their scope is to provide practical and technical information on various LNG chain processes, including LNG transfer operations. The following table mentions the most important guidelines and recommendations currently available in the industry.

Table 15. Guidelines/Recommendations provided by industry organizations

| Title | Responsible | Type | Scope |
|---|---|---|---|
| **Manifold recommendations for Liquefied Gas Carriers** | SIGTTO | Industry Guidance | Developed by SIGTTO and OCIMF, these recommendations summarise the manifold arrangements and strainer guidelines for LPG and LNG carriers. The document's aim is to promote improved safety and efficiency in operations and to assist in planning the position of loading and discharging facilities in new jetties. |
| **Liquefied Gas Fire Hazard Management** | SIGTTO | Industry Guidance | The Fire Hazard Management guidelines covers many aspects of the liquefied gas industry, including large refrigerated and smaller pressurised storage terminals, ships, cylinder filling plant and road and rail tanker loading racks. The development of these guidelines focuses on operational staff, such as plant supervisors and ships' officers, who are involved in the handling of flammable liquefied gases. It will also be beneficial to fire officers and emergency planners who have liquefied gas instillations within their jurisdiction, or experience regular road or rail car traffic involving these products in their area. This publication has been compiled to provide readers with an insight into the design and operation of liquefied gas installations and the equipment essential to the safe and efficient functioning of such installations. |
| **ESD Arrangements and linked ship to shore systems for Liquefied Gas Carriers** | SIGTTO | Technical Note | A note produced (2009) solely due to clarify the functional requirements for ESD systems, primarily differences between the needs of the LNG industry and those of the LPG industry.<br>Proposals are presented for a standardised links to connect ship and terminal emergency shutdown (ESD) systems that are designed to communicate and initiate ESD of cargo transfer as safely and as quickly as possible. |
| **LNG Transfer Arms and Manifold Draining, Purging and Disconnection Procedures** | SIGTTO | Industry Guidance (also adopted as Policy Letter USCG) | Due to confusion and misunderstanding among some ship and jetty operators regarding safe conduct of this operations these guidelines have been prepared. This advice specifically pertains to terminals employing rigid transfer arms. (The basic |

| | | | |
|---|---|---|---|
| | | | principles are applicable for hose systems that may be used for LNG ship to ship transfer, but there will be differences in the detail.) |
| **The safe transfer of Liquefied Gas in an offshore environment** | OCIMF | Best practice document/ Guidance | This publication primarily addresses the inter-relation between a Floating-Production-Storage-Offloading (FPSO) unit and conventional gas tankers operating in a side by side mooring configuration. It includes recommendations for mooring equipment, considers mooring loads and operations, motions of the FPSO and gas tanker, station keeping, cargo transfer equipment and cargo transfer operations.<br>The Guidelines are primarily intended to familiarise Masters, ship operators, FPSO operators and project development teams with the general principles and equipment involved in LPG offloading activities between FPSOs and gas tankers. |
| **Mooring Equipment Guidelines** | OCIMF | Guidelines | First published in 1992 and now on a third edition reflecting on changes in ship and terminal design as the shipping industry has always been concerned with safe mooring practices. A fundamental aspect of this concern entails the development of mooring systems which are adequate for the intended service, with maximum integration of standards across the range of ship types and sizes.<br>Although numerous standards, guidelines and recommendations concerning mooring practices, mooring fittings and mooring equipment exist they are often incomplete. These guidelines are intended to provide an extensive overview of the requirements for safe mooring from both a ship and terminal perspective embrace the full spectrum of issues from the calculation of a ship's restraint requirements, the selection of rope and fitting types to the retirement criteria for mooring lines. |
| **Accident prevention – The use of hoses and hard-arms at marine terminals handling Liquefied Gas (2nd edition)** | SIGTTO | Industry Guidance | This paper covers accidents relating to hoses, hard-arms and pipeline incidents close to ship or shore manifolds. The report only covers the liquefied gas industry. Where possible, and resulting from incidents, the design and operation of various equipment types is discussed |
| **SIGTTO - LNG ship to ship transfer guideline** | SIGTTO | Industry Guidance | The LNG Ship to Ship Transfer Guidelines, published in 2001, covers the transfer of LNG from LNG carriers at anchor, alongside a shore jetty or while underway. They are also useful for reference when establishing rules and procedures for transfer operations between seagoing ships and LNG regasification vessels (LNGRV) or LNG floating storage and offloading vessels (FSOs) in inshore waters. |
| **SIGTTO – Ship/shore interface – Safe working practice for LPG & Liquefied Chemical Gas Cargoes** | SIGTTO | Industry Standard | The main objective of this document is to improve safety at the ship/shore interface. The document considers cargo transfer operations and the processes involved within the ship/shore interface to ensure cargo transfer of LPG and liquefied chemical gases is carried out safely and reliable. |

| | | | |
|---|---|---|---|
| **GMPHOM 2009 - Guide to Manufacturing and Purchasing Hoses for Offshore** Moorings | OCIMF | Industry Guidance | This guide provides technical recommendations and guidance to ensure the satisfactory performance of hoses commonly used at offshore moorings. |

# CHAPTER 5

# STATE OF THE ART TECHNOLOGY AND FUTURE TRENDS

As the planet's population increases and rapidly growing economies like India or China emerge, the need for more energy becomes the driving force for innovation towards improving current technologies, as well as coming up with new, more efficient ones. The same principle applies for the LNG industry, which has seen remarkable growth the last decades and is expected to keep evolving at a great pace the following years. In the context of this evolution, experts are constantly trying to combine the existing 50 years of experience in the industry with contemporary, new ideas to cut down on the costs of the LNG value chain, and make it even more attractive for all parties involved.

## 5.1 Pressurized Liquefied Natural Gas (PLNG)

As the name suggests, PLNG is a novel way of transporting LNG, whereby the LNG cargo is produced and stored under moderate pressure in special containment systems. This idea is not new to the LNG industry, but has yet to be implemented in a large scale.

The potential benefits of PLNG are based on the associated reduction in facilities needed for the production of the final product. For a given facilities output, only about half of the regular LNG facilities are required for PLNG, resulting in decreased capital cost and reduced facilities weight and footprint. In this sense, PLNG technology could be utilized in cases where infrastructure for gas production and import limit economic feasibility, such as densely populated areas. Moreover, the increased operating pressure results in higher processing temperature, which in turn results in less energy consumption. In addition, PLNG could allow the development of smaller gas fields in a cost-effective way. Since the facilities costs are a smaller fraction of the overall project costs, PLNG is therefore less dependent on high capacities and large resources required for conventional LNG to achieve economies of scale.

PLNG can be shipped in varying pressures but for typical applications the pressure is 1.7 MPa, corresponding to a temperature of -115$^0$C. At this temperature, the horsepower required to liquefy the natural gas in approximately 50% less than the energy needed for conventional LNG liquefaction (at -162$^o$C). In turn, the lower energy needed results in reductions in the most expensive components of the LNG chain, the refrigerant compressors, the associated gas turbine drivers and the liquefaction heat exchangers.

In addition, the increased pressure and temperature of PLNG result in increased $CO_2$ solubility, with PLNG able to retain up to 2% $CO_2$ in solution without solids formation at -115°C. Therefore, the need for amine treatment during acid removal can be eliminated. Similarly, the solubility of paraffins and aromatics is increased. In a typical LNG facility, in order to separate these components a scrub tower would be used. Depending on the feed gas composition the scrub tower can also be eliminated.

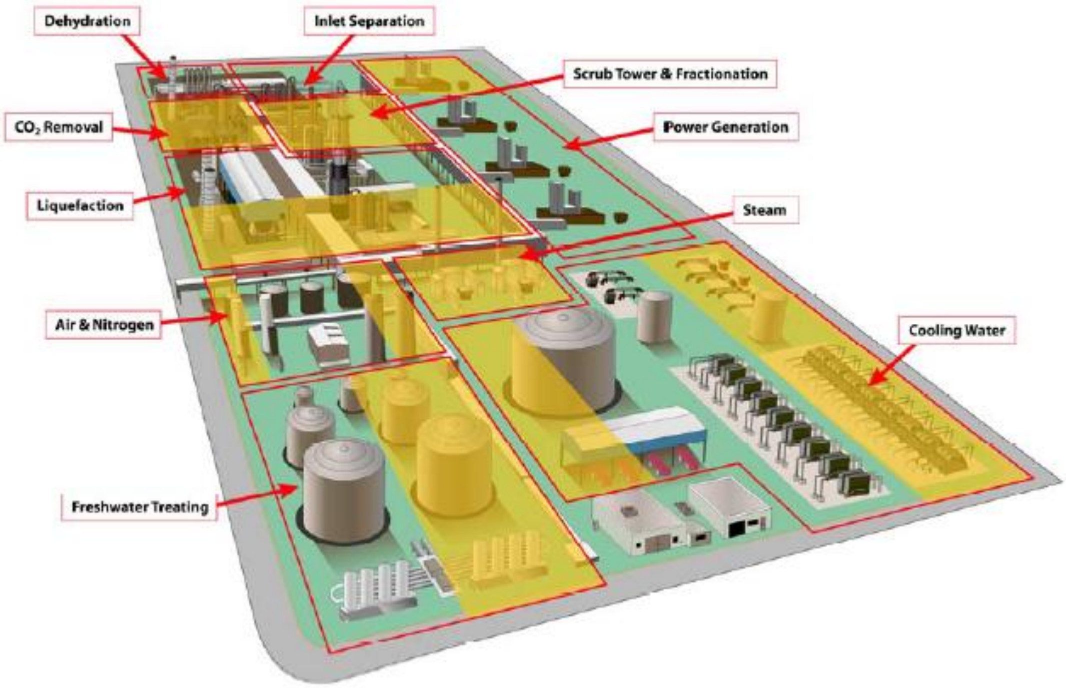



**Figure 61. Reduction of facilities and footprint of an LNG facility compared to a PLNG facility**

However, the containment system used for PLNG storage needs to be able to withstand the higher associated pressure. This means that if conventional steel is used for the fabrication of the tanks, their cost would be really high and their weight would also increase due to more material usage, resulting in increased shipping costs.

Exxon Mobil came up with a solution to the PLNG containment, with its high strength, low temperature (HSLT) steel. The HSLT pressure vessel design reduces the amount of steel needed for the structure, thereby cutting down the cost of the PLNG ship. These pressure vessels are 46 meters high and have 10 meter diameter. They are all fitted inside a single, N2 purged coldbox aboard the PLNG ship as illustrated in Figure 2 [83].

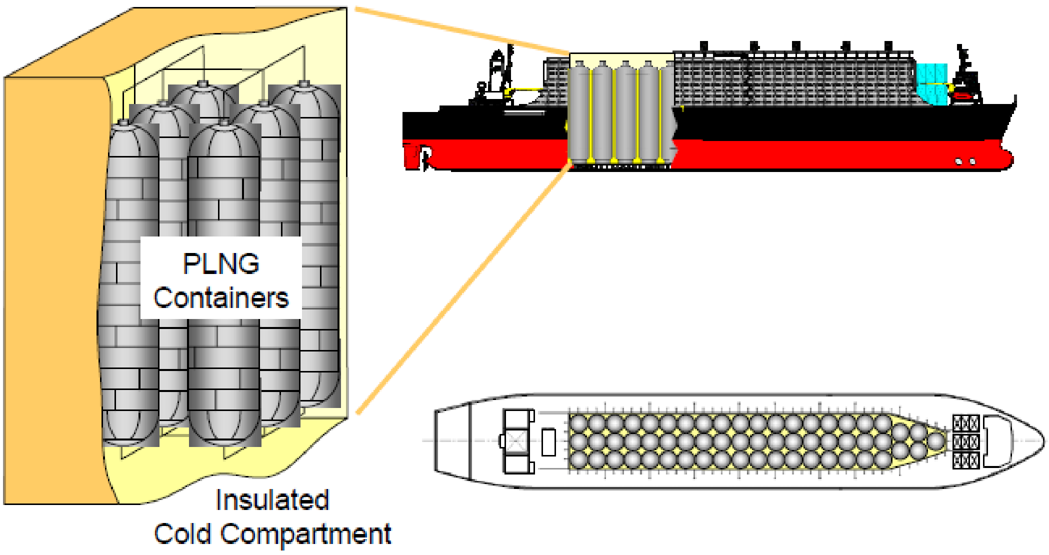



**Figure 62. Schematic of a PLNG ship and containment system using the Exxon Mobile concept design**

Another study on PLNG technology performed by Sanghyuk Lee et.al. in 2016, used a novel concept for a prismatic pressure vessel for the pressure cargo tanks. In their economic evaluation of the supply chain of PLNG, they found that the critical cost component was the pressure containment system. They conclude that under optimum conditions, the cost for transporting PLNG was reduced by 6% compared to that of transporting regular LNG [84].

## 5.2 In-Tank Recondensing

Taking into account the liquid column height and the corresponding hydrostatic pressure head of the overlying LNG mass within an LNG storage tank, the LNG pressure grows as its depth below the LNG surface increases. Therefore, its boiling point at the bottom of the tank is at a different temperature –slightly warmer- than the LNG at the surface. In this sense, the temperature profile of the LNG cargo is expected to be warmer at the bottom of the tank, gradually getting colder towards the surface of the liquid column.

In practice, the temperature difference between the top and bottom of the liquid, measured by temperature sensors, is not more than 0.1$^{o}$C, suggesting that the saturated vapor pressure (SVP) is the same throughout the tank's vertical height. Therefore, the LNG is saturated (i.e., at its boiling point) only close to the free liquid surface. The remaining liquid below the surface is sub-cooled due to the pressure exerted by the overlying liquid column, and becomes progressively more sub-cooled towards the bottom of the tank. For instance, in a typical FSRU tank of 26 meters height, the hydrostatic pressure of the liquid column at the bottom is around 100-120mbar, suggesting the need to heat by an additional 1-1.2 $^{o}$C to reach the saturation point.

The concept of in-tank recondensing exploits this sub-cooled state of the LNG at the bottom of a tank. Specifically, it involves transporting LNG vapor from the top of the tank and injecting it into the mass of the sub-cooled LNG near the bottom, where it recondenses. In the process of vapor condensing, the sub-cooled LNG near the tank bottom accumulates the latent heat of vapor condensation. Consequently, this portion of LNG warms up and the condensed BOG adds mass to the liquid. Figure 3 below shows a phase diagram for in-tank recondensing versus recondensing in a conventional FSRU recondenser.

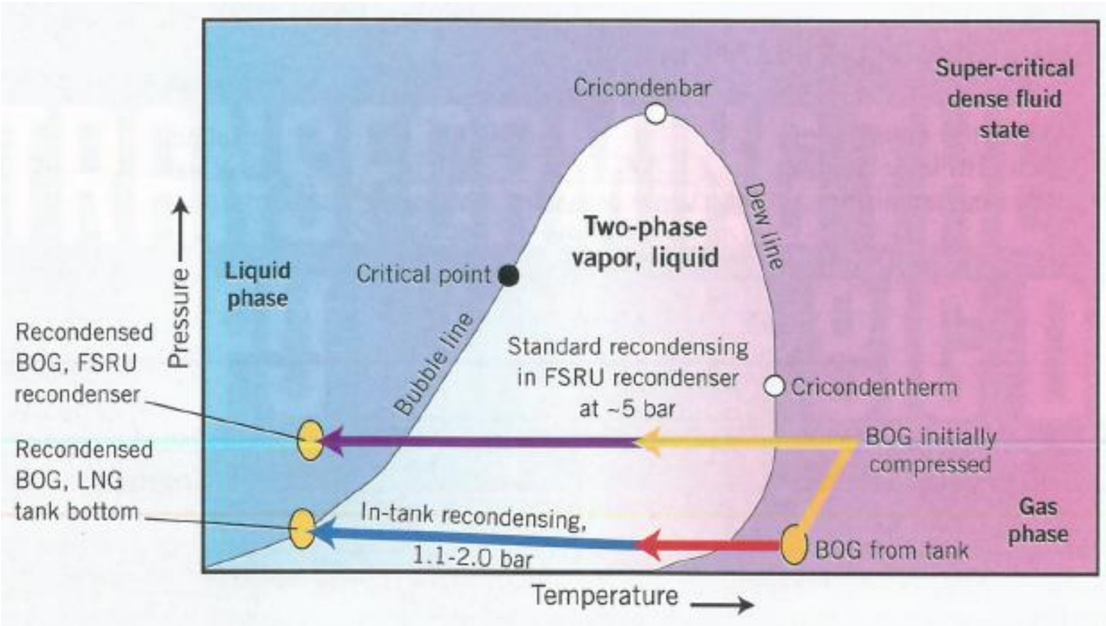



Figure 63. Phase Diagram, In-Tank Recondensing compared to conventional recondensing

This concept can be used during STS transfers, where the need for handling BOG and the subsequent rise in the cargo tank is high. Condensing tank vapor via this in-tank circulation method theoretically stops when local tank-bottom LNG warms to its SVP and is no longer sub-cooled. However, during an STS transfer this is unlikely to occur, since there is continuous introduction of fresh , cold LNG supply which also increases the mass of the liquid column. Therefore, the process can run safely until the tank pressure slowly approaches its upper operating pressure.

As the tank is progressively filled during an STS LNG transfer, the recondensing of BOG becomes increasingly more effective, with all recirculated BOG likely to be condensed by the latter stages of the operation. Figure 4 illustrates typical expected tank pressure and temperature trends during STS transfer, with and without applying the in-tank recondensing concept.

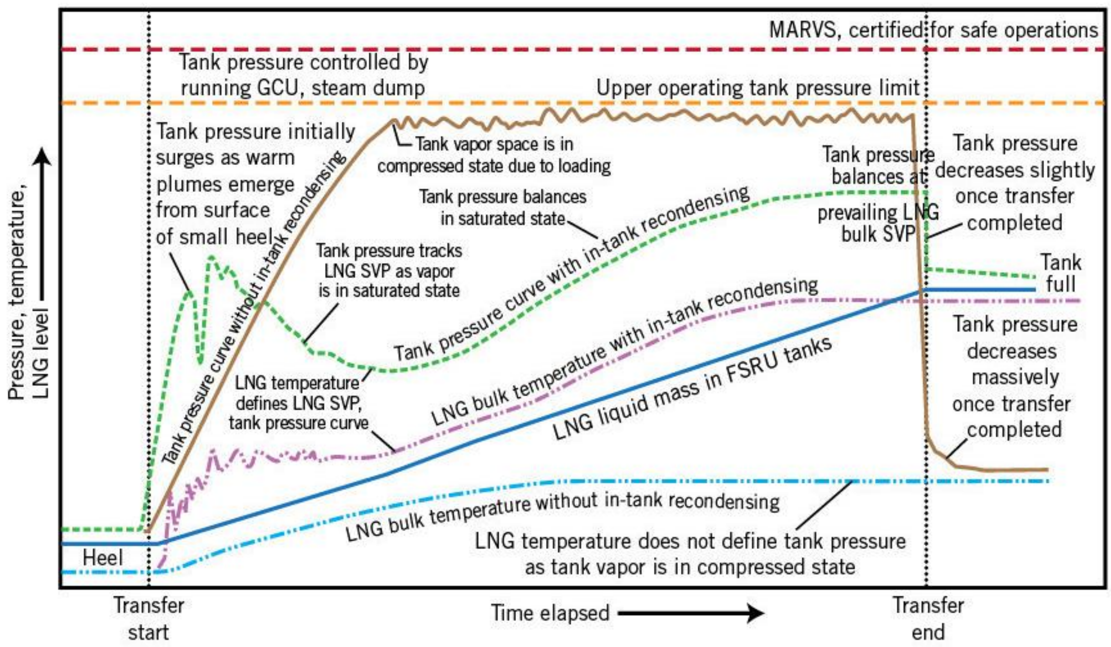



Figure 64. Pressure and Temperature trends with and without in-tank recondensing during STS transfer

When in-tank recondensing is applied during STS transfer, the sub-cooled bottom LNG layers become hotter by accumulating the latent heat of condensation, subsequently travelling upwards with convective currents and warming the LNG bulk. However, since BOG is removed from the tank vapor space, the tank pressure decreases. On the other hand, if the concept is not applied, the LNG in the tank remains colder but the tank pressure rises significantly faster, resulting in the need to control it by utilizing the gas combustion unit or steam dump.

In order for the in-tank recondensing concept to be commercially viable though, it needs to be less energy demanding, and therefore more financially efficient than its alternatives. This is achieved by taking advantage of the Venturi Effect.

When LNG passes through an in-tank vertical pipe it accelerates due to gravity. This liquid velocity increase and mass continuity creates a Venturi effect like that exploited by jet pumps that use pressurized fluid to entrain, mix and pump other fluids by creating a vacuum or pressure reduction. In this sense, the LNG loading pipe can be designed to take advantage of the Venturi effect, entraining BOG from the tank’s vapor space and delivering it to the tank bottom. The velocity of the LNG traveling inside the vertical pipe can be increased by narrowing the aperature of the pipe, thus increasing the amount of BOG entrained.

This in-tank BOG transport-delivery concept consumes no additional energy since it requires no additional pumps, compressors etc. Instead, using the Venturi effect caused by falling LNG liquid, vapor is entrained through special nozzles in a specifically modified or designed loading pipe section (Figure 5).

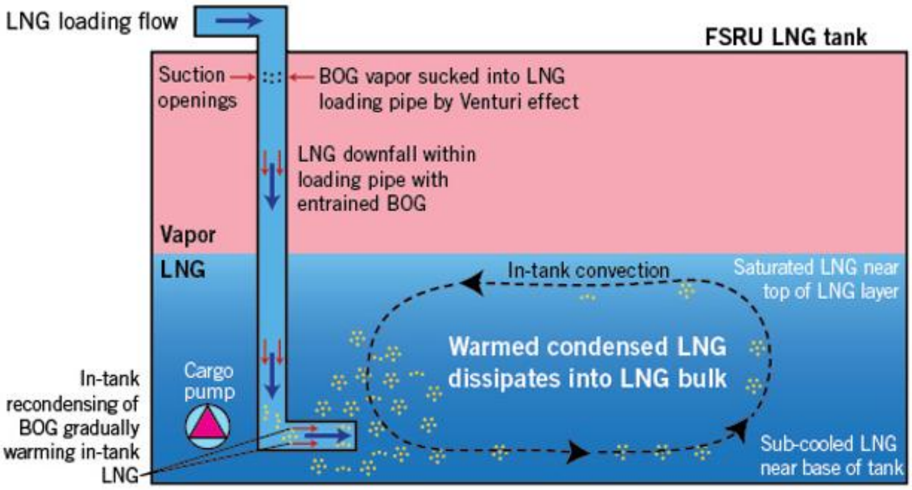



**Figure 65. In-tank Recondensation, BOG to Tank Bottom.**

A minimum LNG flow rate through the loading pipe is required for enough suction pressure to be created. Flow rates during STS transfers are high enough for the concept to be feasible. Moreover, STS loading typically increase tank pressure, calling for enhanced BOG handling capacity. The concept of recirculating BOG to the tank bottom provides a self-regulated solution: its condensing capacity increases as tank filling progresses, while at the same time the tank's vapor pressure increases (due to increasingly limited tank vapor space), increasing LNG sub-cooling, which in turn leads to higher BOG suction into the loading pipe [85].

# CONCLUSIONS

With the current global energy scheme still revolving around fossil fuels, the demand for LNG is expected to keep growing at a steady rate in the next decades. The fact that LNG is environmentally friendly with low $CO_2$ and virtually no $So_x$ and PM emissions, the rise of shale gas, as well as the ease of transportation of LNG are some of the reasons driving the LNG market evolution. Also, large evolving Asian economies and declining gas production in Europe are set to further enhance LNG imports. However, there seems to be an excess supply compared to demand, which is projected to even out around the mid 2020's.

The LNG market exists for around 50 years, thus the technologies involved are mature and have a proven history of safe operations. Onshore storage of the cryogenic fuel takes place in special tanks either at liquefaction or regasification plants. However, seaborne storage and transportation of LNG in LNG carrier ships is what has brought this industry to its current prominent position in the global energy mix. Specially designed ships utilizing either Type B tanks (spherical or prismatic) or, in most cases, membrane containment systems are used to temporarily store and transport LNG to its intended destination. Also, floating storage and/or regasification units (FSUs/FSRUs), as well as floating production units (FLNG) offer additional tools in the quest to make offshore gas production viable.

Despite the long safety record of the industry, LNG transfer operations, if not conducted with caution, can result into material damage or even life threatening accidents. RPT's and pool fires are examples of what can happen during a transfer operation if LNG is spilled over water or land respectively. While the conventional way of transferring LNG is from ship to shore (or vice versa), in 2007 the first LNG STS transfer was conducted. STS operations offer a number of advantages such as no port fees or ship size restrictions, but at the same time they are considered to be of higher risk since they are subject to prevailing sea conditions.

Both the design and operation of those means of LNG storage and transport are regulated by international bodies, such as IMO or IGC. Also, bodies created by industry players and field experts willing to contribute to the LNG market's safety and prosperity, like GIIGNL or SIGTTO, regularly come up with operational guidelines, good practices and safety procedures.

Finally, as technology evolves and expertise in the LNG field is enhanced, new ways of making LNG more attractive may arise. The industry's attention seems to be in boil-off gas management on board LNGCs and ways to make LNG storage even more energy efficient.

**BIBLIOGRAPHY**

[1] A. Arteconi, F. Polonara, "LNG as vehicle fuel and the problem of supply: The Italian study, Energy Policy, Elsevier, 2013

[2] The Institution of Chemical Engineers, "BP Process Safety Series: LNG Fire Protection and Emergency Response", 2007

[3] S. Mokhatab, J. Y. Mak, J. V. Valappil, D. A. Wood, "Handbook of Liquefied Natural Gas", Elsevier, 2014

[4] https://pnglng.com/media/PNG-LNG-Media/Files/Environment/EIS/eis_attachment01.pdf (accessed 15/010/2019)

[5] A. Pustisek, M. Karasz, "Natural Gas: A commercial Perspective", Springer, 2017

[6] S. Mokhatab, W. A. Poe, J. Y. Mak, "Handbook of Natural Gas Transmission and Processing Principles and Practices", Third Edition, Elsevier, 2015

[7] Offshore LNG Toscana S.p.A, "LNG and Gas Quality Measurement Manual for LNG Carriers Calling at Terminal", 2017

[8] M. Tusiani, G. Shearer, "LNG a Nontechnical Guide", PennWell, 2007

[9] Jiří Pospíšil, Pavel Charvát, Olga Arsenyeva, Lubomír Klimeš, Michal Špiláček, Jiří Jaromír Klemeš, "Energy demand of liquefaction and regasification of natural gas and the potential of LNG for operative thermal energy storage", Elsevier, 2019

[10] S. Mokhatab, W. A. Poe, J. G. Speight, "Handbook of Natural Gas Transmission and Processing", Elsevier, 2006

[11] Journal of Petroleum Technology, "LNG at crossroads", Vol 71, June 2019 https://pubs.spe.org/en/jpt/jpt-article-detail/?art=5598&utm_source=linkedin-spe&utm_medium=social-content&utm_campaign=jpt&utm_content=LNG%2520at%2520a%2520Crossroads (accessed 13/10/2019)

[12] GIIGNL - International Group of Liquefied Natural Gas Importers, Annual report 2019

[13] United States Department of Energy, "Understanding Natural Gas and LNG Options", 2017

[14] Bp Statistical Review of World energy, 68th Edition, 2019

[15] M. M. Foss, "Introduction to LNG", Center for Energy Economics, 2012

[16] M. J. Economides, "The Economics of Gas to Liquids Compared to Liquefied Natural Gas", World Energy Magazine, Vol. 8, No. 1, 2005

[17] The Oxford Institute for Energy Studies, University of Oxford, “The LNG Shipping Forecast: costs rebounding, outlook uncertain”, 2018

[18] S. Cornot-Gandolphe, “LNG Cost Reductions and Flexibility in the LNG Trade Add to Security of Gas Supply”, International Energy Agency, 2005

[19] International Gas Union, World LNG Report 2019

[20]https://www.icis.com/explore/resources/news/2019/08/06/10401426/interactive-greece-s-mytilineos-leapfrogs-incumbent-depa-as-top-lng-buyer (accessed 09/10/2019)

[21] https://www.desfa.gr/en/national-natural-gas-system/lng-facility

[22] http://www.ekathimerini.com/229505/article/ekathimerini/business/greece-aims-to-be-marine-lng-hub-within-years

[23] https://www.poseidonmedii.eu/category/THE_PROJECT/About.html

[24] https://www.naftemporiki.gr/finance/story/1410570/poseidon-med-ii-sxediazontas-mia-olokliromeni-kai-biosimi-efodiastiki-alusida-gia-ton-anefodiasmo-ploion-me-ygropoiimeno-fusiko-aerio-lng

[25] Greek Presidential Decree for Safe LNG Bunkering, 2019

[26] https://energypress.gr/news/entos-ton-ergon-pci-i-ypogeia-apothiki-n-kavalas-kai-fsru-alexandroypolis-stis-4-oktovrioy

[27] https://energypress.gr/news/ektasi-stin-kriti-agorase-i-katariani-powerglobe-gia-na-egkatastisei-ilektriki-monada-120-mw

[28] https://energypress.gr/news/prasino-fos-apo-ti-rae-gia-ploto-termatiko-lng-tis-motor-oil-stin-korintho

[29] Journal of Petroleum Technology, “ExxonMobil Makes Huge Gas Discovery Offshore Cyprus”, Vol 71, February 2019

[30] https://www.mckinsey.com/industries/oil-and-gas/our-insights/global-gas-and-lng-outlook-to-2035

[31] Shell LNG Outlook 2019

[32] H. Sherer, “Feasibility Study for Setting up SAARC Regional/Sub-regional LNG Terminals”, SAARC Energy Center, 2016

[33] https://eneken.ieej.or.jp/data/7283.pdf

[34] Royal Belgian Institute of of Marine Engineers, “Reinforcing the LNG membranes”, 2014

[35] McGuire and White, "Liquefied Gas Handling Principles On Ships and in Terminals", 3rd Edition, SIGTTO, 2000

[36] D.J. Eyres, G.J. Bruce, "Ship Construction", 7th Edition, 2012

[37] http://www.liquefiedgascarrier.com/LNG-vessel-construction.html

[38] www.lngworldshipping.com

[39] GIIGNL - International Group of Liquefied Natural Gas Importers, LNG Information Paper No. 5: Managing LNG Risks – Containment

[40] J. Tarlowski, C. Durr, D. Coyle, "LNG Import Terminals – Recent Developments", 2004

[41] B. Songhurst, "Floating Liquefaction (FLNG): Potential for Wider Deployment", The Oxford Institute for Energy Studies, 2016

[42] B. Songhurst, "FLNG has come of age", Oxford energy Forum, 2016

[43] https://www.shell.com/about-us/major-projects/prelude-flng.html

[44] A. Tugnoli, N. Paltrimeri, G. Landucci, V. Cozzani, "LNG Reagsification Terminals: comparing the inherent safety performance of innovative technologies"

[45] https://excelerateenergy.com/fleet/

[46] American Bureau of Shipping, "Guide for Building and Classing Offshore LNG Terminals", 2004

[47] B. Songhurst, "The Outlook for Floating Storage and Regasification Units (FSRUs)", Oxford Institute for Energy Studies, 2017

[48] S. Egashira, "LNG Vaporizer for LNG Re-gasification Terminal ", Kobelco Technology Review No. 32, 2013

[49] GIIGNL - International Group of Liquefied Natural Gas Importers, "Rollover in LNG Storage Tanks", 2nd Edition: 2012-2015

[50] SIGTTO - The Society of International Gas Tanker and Terminal Operators, "Guidance for the Prevention of Rollover in LNG Ships", 1st Edition, 2012

[51] Nakano, R. Sugawara, Y. et al. An experimental study on the mixing of stratified layers using liquefied Freon. 9th International LNG / LPG Conference (Gastech 82), Paris, October 1982

[52] R. G. Scurlock, "Stratification Rollover and Handling of LNG, LPG and Other Cryogenic Liquid Mixtures", Springer, 2016

[53] Chatterjee, N. Geist, J.M., “Spontaneous stratification in LNG tanks containing nitrogen”, ASME paper 76-WA/PID-6, American Society of Mechanical Engineers, New York, 1976

[54] (http://www.liquefiedgascarrier.com/LNG-discharging.html)

[55] Y. Zellouf, B. Portannier, “First Step in Optimizing LNG Storages for Offshore Terminals”, Elsevier, 2011

[56] Uznanski, Dominik, Versluijs, Pieter, “Advanced LNG storage tank management”, AIChE Spring Meeting, 3rd Natural Gas Utilization Topical Conference, Session LNG VI Storage & Facilities, New Orleans, Louisiana, March 30 April 2003

[57] GIIGNL - International Group of Liquefied Natural Gas Importers, “Retail LNG & The Role of LNG Import Terminals”, 1st Edition , 2015

[58] BS EN 1473:2007: Installation and equipement for liquefied natural gas – Design of onshore installations

[59] BS EN 1160:1997: Installations and equipment for liquefied natural gas – General characteristics of liquefied natural gas

[60] https://www.nfpa.org/codes-and-standards/all-codes-and-standards/list-of-codes-and-standards?mode=code&code=52

[61] https://www.ecfr.gov/cgi-bin/text-idx?SID=aae3e02039eeab8e756322f8230cdd4b&mc=true&node=pt33.2.127&rgn=div5#se33.2.127_1101

[62] https://www.iso.org/standard/57891.html

[63] https://www.iso.org/standard/57889.html

[64]http://www.imo.org/en/OurWork/Environment/PollutionPrevention/AirPollution/Pages/Air-Pollution.aspx

[65] Keppel Offshore & Marine Technology Center, Technology Review 2012

[66] Ship Safe Marine Equipement Ltd, “Safety Measures & Guidelines in the Selection & Usage of STS Fenders & Hoses”, June 2019

[67] Port of Gothenburg, Ship to Ship Transfers, December 2011.

[68] SIGTTO - The Society of International Gas Tanker and Terminal Operators, “LNG Ship to Ship Transfer Guidelines”, 1st Edition, 2011.

[69] https://www.y-yokohama.com/global/product/mb/pneumatic/

[70] Lagarrigue, V., & Hermary, J. “Re-Shaping LNG Transfer”, Offshore Technology Conference, April 30 2018

[71] https://www.contitech-oil-gas.com/pages/lng-hoses/lng-hose-design/lng-hose-design_en.html

[72] http://www.mlit.go.jp/common/001173458.pdf

[73] SIGTTO - The Society of International Gas Tanker and Terminal Operators, “LNG Shipping Knowledge”, 2$^{nd}$ Edition, 2011

[74] https://www.dynamarine.com/index.php

[75] http://www.liquefiedgascarrier.com/cargo-transfer-between-vessels.html

[76] M. Ramos, E. L. Droguett, M. Martins, H. Souza, “Comparison of Possible consequences of LNG Leakages in Offshore and Onshore Terminals: the Case of the Port of Suape”, November 2014

[77] A. Luketa, “Recommendations on the Prediction of Thermal Hazard Distances from Large Liquefied Natural Gas Pool Fire on Water for Solid Flame Models”, Sandia National Laboratories, 2011

[78] European Maritime Safety Agency, “Guidance on LNG Bunkering to Port Authorities and Administrations”, 31-01-2018

[79] J. L. Woodward, R. M. Pitblado, “LNG Risk Based Safety: Modeling and Consequence Analysis”, Wiley, 2010

[80] A. Luketa, M. M. Hightower, S. Attaway, “Breach and Safety Analysis of spills Over Water From Large Liquefied Natural Gas Carriers”, Sandia National Laboratories, May 2008

[81] G. A. Melhem, S. Saraf, H. Ozog, “LNG Properties and Hazards: Understand LNG Rapid Phase Transitions (RPT)”, ioMosaic Corporation, July 2006

[82] J.Walker, “Boiling and the Leidenfrost Effect”, Cleveland State University, January 1994

[83] R. R. Bowen, M. C. Gentry, E. D. Nelson, S.D. Papka, A. T. Leger, “Pressurized Liquefied Natural Gas (PLNG): A New Gas Transportation Technology”, GasTech 2005, Bilbao, Spain, March 2005

[84] S. Lee, Y. Seo, J. Lee, D. Chang, “Economic Evaluation of Pressurized LNG Supply Chain”, Elsevier, July 2016

[85] M. Kulitsa, D. A. Wood, “In- Tank Recondensing Improves FSRU Transfer Efficiency”, Oil & Gas Journal, June 2018