National Technical University of Athens
School of Naval Architecture and Marine Engineering

# Feasibility Study for the Deployment of Floating Storage Regasification Unit

DIPLOMA THESIS

OF

**TRAKADAS DIMITRIS**

**Supervisor:** Dimitrios V. Lyridis
Assoc. Professor N.T.U.A.

Athens, March 2018

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Approved by the three-member select committee on 7th March 2018.

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| ................................... | ................................... | ................................... |
| Dimitrios V. Lyridis | Nikolaos P. Ventikos, Dr. | Athanasios Tolis |
| Assoc. Professor N.T.U.A | Assistant Professor N.T.U.A | Assistant Professor N.T.U.A |

Athens, March 2018

(Signature)
...................................
Trakadas Dimitris
Undergraduate Naval Engineer & Marine Engineer N.T.U.A.

# Περίληψη

Ο σκοπός της παρούσας διπλωματικής είναι η μελέτη του φυσικού αερίου και της πλωτής μονάδας αποθήκευσης και επαναεριοποίησης φυσικού αερίου (FSRU). Αρχικά, παραδίδονται τεχνικές πληροφορίες σχετικά με το φυσικό αέριο, καθώς και τα πλεονεκτήματά του έναντι άλλων καυσίμων και οι τρόποι με τους οποίους η Ευρωπαϊκή Ένωση ευνοεί την χρήση του. Εν συνεχεία, καλύπτεται το θέμα της εφοδιαστικής αλυσίδας του φυσικού αερίου από τα φυσικά υπόγεια αποθέματα του μέχρι της κατοικίες και επιχειρήσεις. Ιδιαίτερη ανάλυση γίνεται σε κάθε στάδιο αυτής δίδοντας ποικίλους τρόπους επίτευξης των σταδίων αυτών. Έπειτα, παρουσιάζονται γενικές πληροφορίες και τεχνικά χαρακτηριστικά για το FSRU.

Τελευταία, διεξάγεται η μελέτη σκοπιμότητας, ακολουθώντας κάποια οικονομικά κριτήρια που παρατίθενται στην εργασία. Το σχέδιο της μελέτης αφορά σε μια εταιρία ιδιοκτήτη και διαχειριστή του FSRU στην οποία συμμετέχουν μια ναυτιλιακή και η δημόσια εταιρία φυσικού αερίου (ΔΕΣΦΑ) και χειρίζονται ένα FSRU έξω από την Αλεξανδρούπολη. Στην παρούσα μελέτη γίνεται εξέταση του σχεδίου από δύο οπτικές. Η πρώτη αφορά στην εξερεύνηση της περίπτωσης της παραπάνω εταιρίας σύμπραξης ως μονάδα. Από την άλλη μεριά, η δεύτερη αφορά στην εξέταση του σχεδίου από δυο διαφορετικές σκοπιές, αυτήν της ναυτιλιακής εταιρίας που είναι ιδιοκτήτρια και διοικεί το FSRU και εκείνη της εταιρίας Φ.Α. που ναυλώνει το FSRU από την ναυτιλιακή και χρεώνει την χρήση του ως σημείο εισόδου Φ.Α. στην Ελλάδα. Στο τέλος κάθε σεναρίου γίνεται σχολιασμός των αποτελεσμάτων.

Αξίζει να σημειωθεί ότι η έρευνα χρησιμοποιεί πραγματικά δεδομένα που εισήχθηκαν από έγκυρες πηγές, οι οποίες φανερώνονται στην βιβλιογραφία, οι υπολογισμοί τελέστηκαν με την βοήθεια του προγράμματος Microsoft Excel® και τα αποτελέσματα καθώς και η μεθοδολογία της έρευνας εμφανίζονται στο $6^{ο}$ κεφάλαιο της εργασίας.

# 1 Abstract

The aim of this diploma thesis is the study of natural gas and Floating Storage and Regasification Unit (FSRU). Firstly, technical information is displayed about natural gas as well as its advantages over other fuels and ways European Union favors it over them. In addition, the supply chain of natural gas from its natural underground reservoirs to people's residences and companies is covered, analyzing each and every different stage of it numbering various ways of fulfilling them. After that, general information and technical characteristics about the FSRU are presented.

Lastly, the feasibility study is conducted following some economical criterions, which are also displayed in this thesis. The study's project is about a joint company consisting of a shipping company and a natural gas public company operating an FSRU outside of Alexandroupolis. Two different scenarios are assumed on this study. The first explores the option of the joint company as a unit. The second one examines the project from two independent scopes, the one of the shipping company as owner and manager of the FSRU and that of the NG company chartering the FSRU from the shipping company and charging its use as a point of entry of NG. In the end of each scenario there is commentary of the results.

It should be mentioned that the study uses real data taken from valid sources and all calculations are done via Microsoft Excel® and the results and methodology of them are appeared on the 6th chapter.

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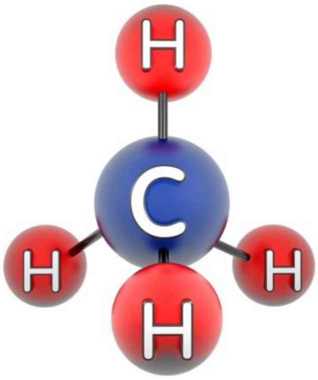
# 2 Introduction to LNG and the LNG market

## 2.1 Technical description and uses of LNG

Natural gas is a gaseous hydrocarbon mix consisting principally of methane ($CH_4$) usually over 80% volume per volume and in lower quantities of ethane ($C_2H_6$), propane ($C_3H_8$), butane ($C_4H_{10}$) and pentane ($C_5H_{12}$). It also contains carbon dioxide ($CO_2$), hydrogen sulfide ($H_2S$) and nitrogen ($N_2$) in low contents. (Gastrade, 2013)




**Picture 2-1 Methane molecule (Gastrade, 2013)**

Methane is a light, colorless, odorless and non-toxic gas which is artificially odored after its production in order to be detectable in case of leakage. As it is lighter than air, in the case of leakage, it moves upwards in the air where it is diluted and becomes harmless.

Natural gas is produced, under conditions of high pressure and temperature in considerable depth underground, from the thermal dissolution of the initial high-molecular weight organic matter which originates from organic sediments (terrestrial or marine). The methane produced under such conditions is trapped into impervious geological formations creating gas deposits on the bottom of which it is very common to also find trapped oil.

Natural gas produced from different reservoirs may differ in composition, since the composition of the gas is related to its origin and the species of the organic matter from which it has been formed. (Gastrade, 2013)

Liquefied Natural Gas (LNG) is a clear, colorless and non-toxic liquid which forms when natural gas is cooled to -162°C (-260 °F). The cooling process shrinks the volume of the gas 600 times, making it easier and safer to store and ship. In its liquid state, LNG will not ignite. Natural gas liquefaction is achieved at special plants (LNG liquefaction terminals) usually at a relatively small distance from the production fields. When LNG reaches its destination, it is turned back into a gas at regasification plants. It is then piped, usually, to homes, businesses and industries where it is burnt for heat or to generate electricity. (“Liquefied natural gas (LNG),” 2016)

**Picture 2-2 LNG carrier ship ("Marubeni joins Peru LNG project | Global Trade Review (GTR)," 2007)**

Although most natural gas is used to heat buildings and to generate electricity, some consuming sectors have other uses for natural gas. The **electric power sector** uses natural gas to generate electricity. In 2016, natural gas was the source of about 27% of U.S. electric power sector energy consumption. (Other consuming sectors also use natural gas to generate electricity.) The **industrial sector** uses natural gas as a fuel for process heating and for combined heat and power systems and as a raw material (feedstock) to produce chemicals, fertilizer, and hydrogen. In 2016, natural gas was the source of about 31% of U.S. industrial sector energy consumption. The **residential sector** uses natural gas to heat buildings and water, to cook, and to dry clothes. About half of the homes in the United States use natural gas for these purposes. In 2016, natural gas was the source of about 22% of U.S. residential sector energy consumption. The **commercial sector** uses natural gas to heat buildings and water, to operate refrigeration and cooling equipment, to cook, to dry clothes, and to provide outdoor lighting. Some consumers in the commercial sector also use natural gas as a fuel in combined heat and power systems. In 2016, natural gas was the source of about 18% of U.S. commercial sector energy consumption. The **transportation sector** uses natural gas as a fuel to operate compressors that move natural gas through pipelines. A relatively small amount of natural gas is used as vehicle fuel in the form of compressed natural gas and liquefied natural gas. Nearly all vehicles that use natural gas as a fuel are in government and private vehicle fleets. In 2016, natural gas was the source of about 3% of U.S. transportation sector energy consumption, of which 97% was for natural gas pipeline and distribution operations. (figure 2-1) ("Use of Natural Gas - Energy Explained, Your Guide To Understanding Energy - Energy Information Administration," 2017)

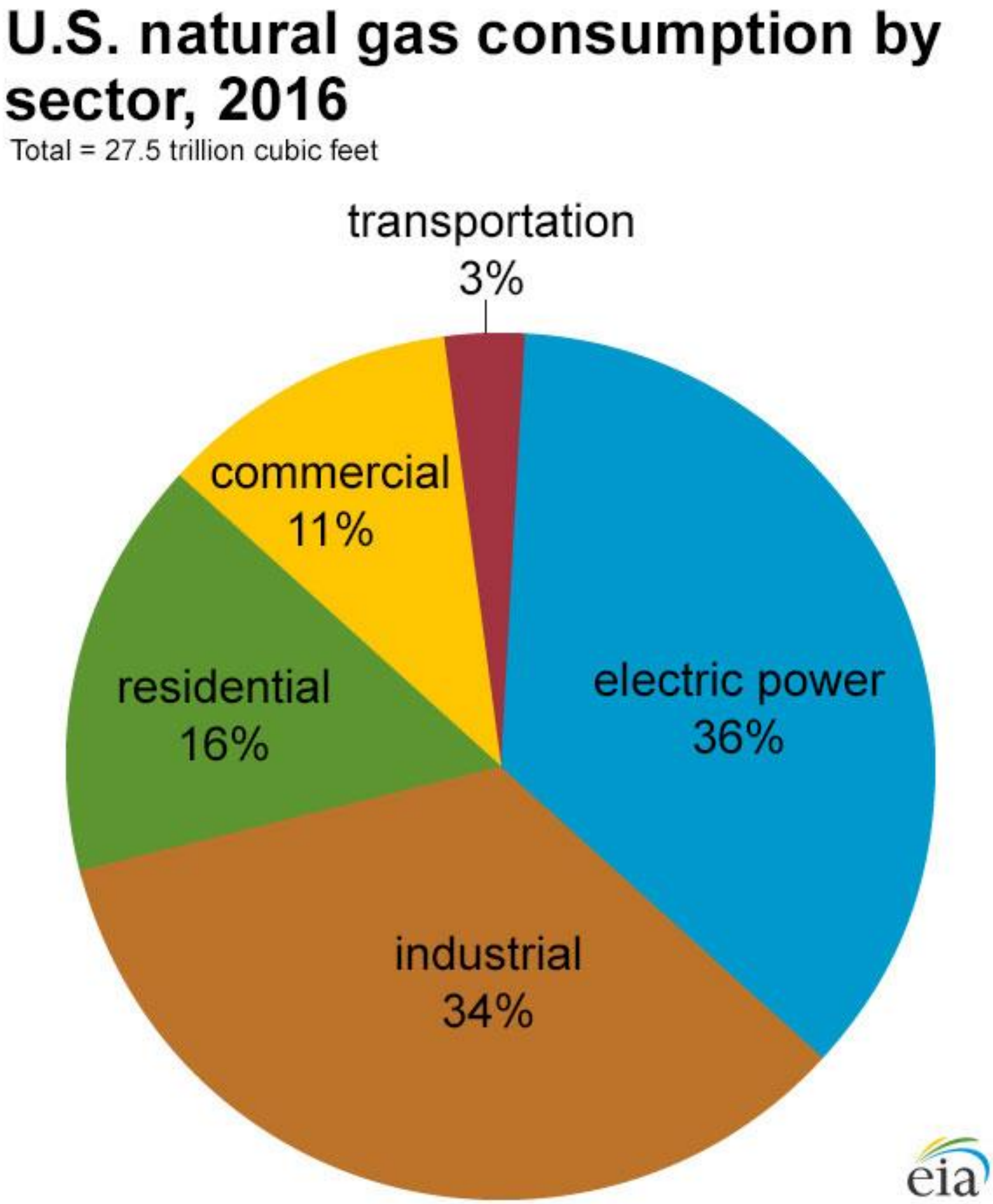



**Figure 2-1 U.S. NATURAL GAS CONSUMPTION BY SECTOR, 2015 (U.S. ENERGY INFORMATION ADMINISTRATION (EIA), 2017)**

## 2.2 Natural Gas – Part of the Global Energy Demand

Energy demand continues and will continue to grow over the years. This is mainly due to the rise of activity and life standards in the modern world. Moreover, population and income are two key drivers behind growing demand for energy. The world's population is projected to increase by around 1.5 billion people to reach nearly 8.8 billion people by 2035 (figure 2-2). Over the same period, GDP is expected to more than double (figure 2-3); around one-fifth of that increase comes from population growth and four-fifths from improvements in productivity (i.e. GDP per person) (figure 2-4). China and India together account for almost half of the increase in global GDP, with OECD (*Organization for Economic Cooperation and Development*) economies accounting for around a quarter.  Africa accounts for almost half of the increase in the world's population, such that by 2035 it is projected to have 30% more people than China and 20% more than India. Yet Africa accounts for less than 10% of the expected increase in both global GDP and energy consumption. (BP p.l.c., 2016)

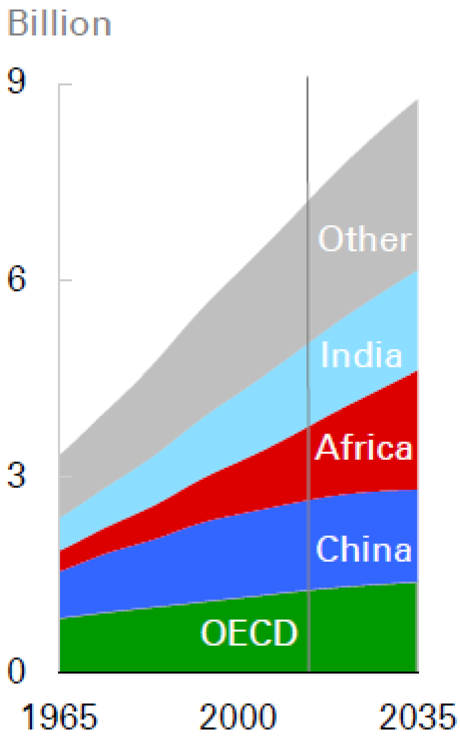



**Figure 2-2 Population expected 2014-2035 (BP p.l.c., 2016)**

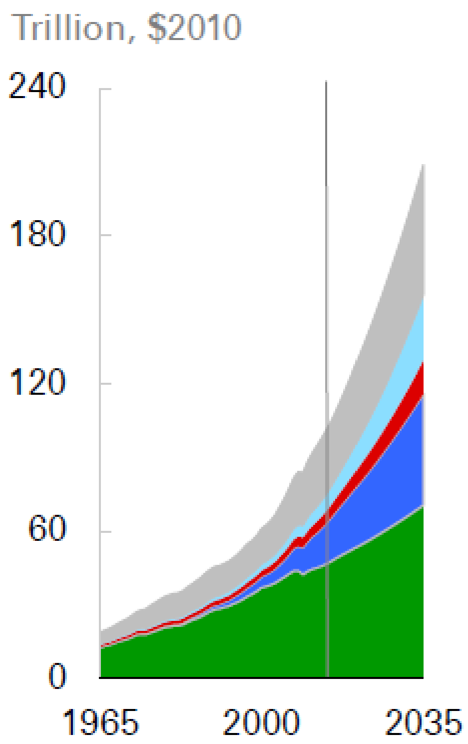



**Figure 2-3 GDP expected 2014-2035 (BP p.l.c., 2016)**

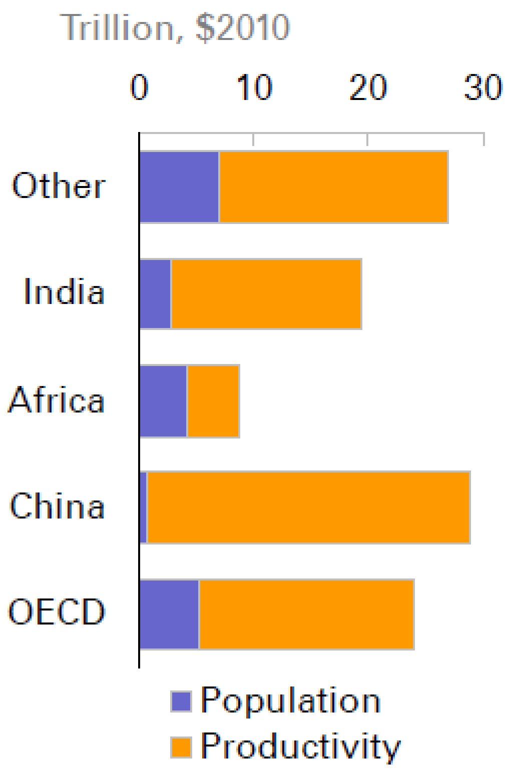



**Figure 2-4 CONTRIBUTION TO GDP GROWTH EXPECTED 2014-2035 (BP P.L.C., 2016)**

The growth in the world economy means more energy is required and consequently energy consumption is expected to increase by 34% between 2014 and 2035 (figure 2-5). Virtually all of the additional energy is consumed in fast-growing emerging economies; energy demand within the OECD barely grows. The growth of energy is slower than in the recent past – 1.4% per annum (p.a.) versus 2.3% p.a. in 2000-14 – reflecting significantly faster falls in energy intensity (energy used per unit of GDP) (figure 2-6). China's energy demand growth slows as its economy rebalances, towards a more sustainable rate. By the final decade of this period, China contributes less than 30% of global energy growth, compared with nearly 60% over the past decade. The sharp slowing in China's energy demand growth is partially offset by a pickup in other developing countries. India accounts for more than a quarter of the growth in global energy demand in the final decade of the time period, double its contribution over the past decade. (BP p.l.c., 2016)

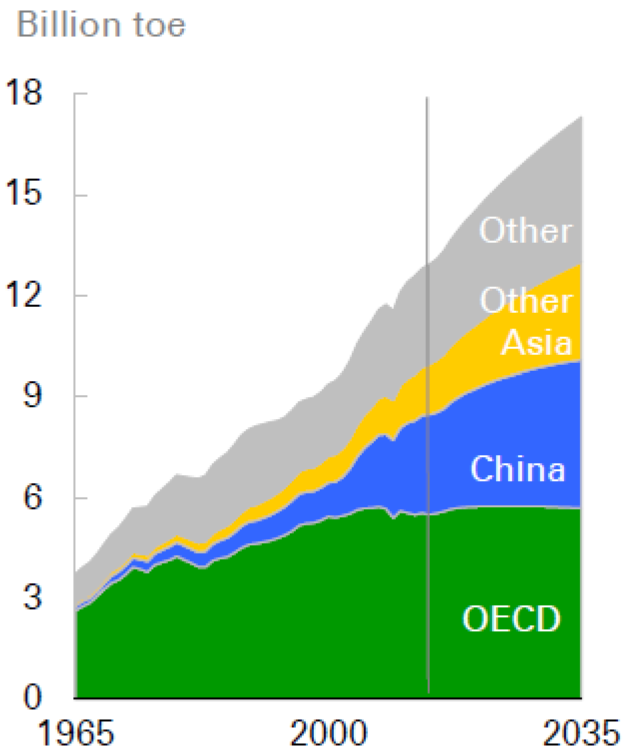



**Figure 2-5 Energy consumption by region expected 2014-2035 (BP p.l.c., 2016)**

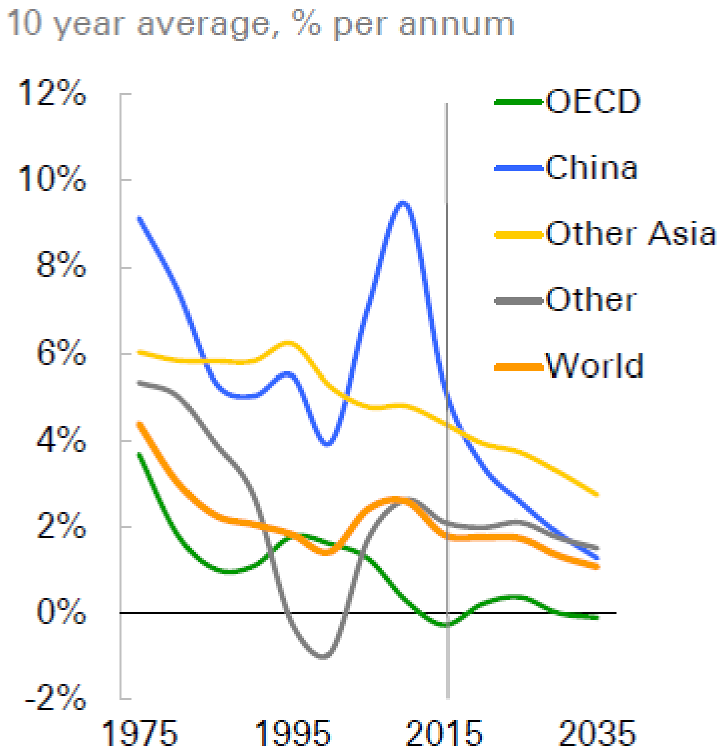



**Figure 2-6 Energy Consumption Growth by region expected 2014-2035 (BP p.l.c., 2016)**

Second, the fuel mix continues to shift. Fossil fuels remain the dominant source of energy powering the world economy, supplying 60% of the energy increase out to 2035. Within that, gas looks set to become the fastest growing fossil fuel, spurred on by ample supplies and supportive environmental policies. In contrast, the growth of global coal consumption is likely to slow sharply as the Chinese economy rebalances. Renewables are set to grow rapidly, as their costs continue to fall and the pledges made in Paris support their widespread adoption. (BP p.l.c., 2016)

This can be observed in figure 2-7. Natural Gas is rapidly growing in comparison to other sources of energy, whereas the traditional energy sources (I.e. oil and coal) are losing their place in market's demand as the Earth's natural oil and coal reserves are diminishing.

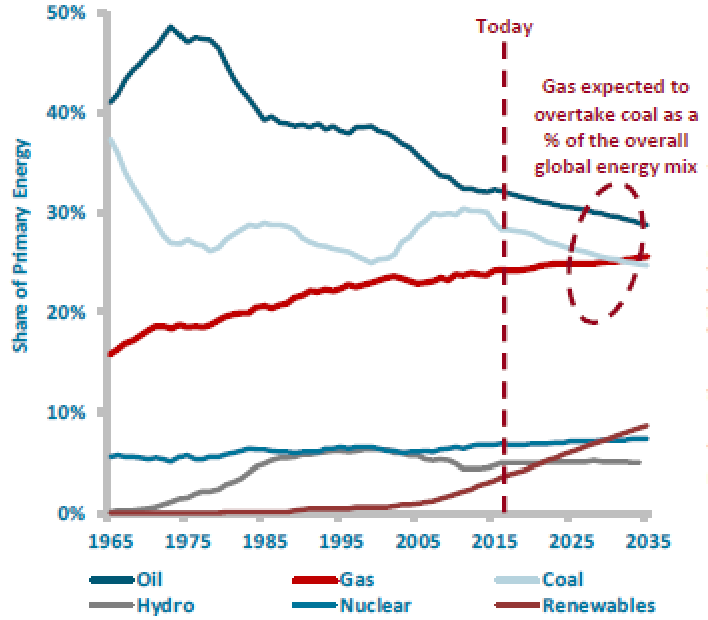



**Figure 2-7 Natural Gas Market Share of Primary Energy Consumption (GASLOG LTD., 2017a)**

Third, the outlook for carbon emissions is changing significantly. In particular, the rate of growth of carbon emissions is projected to more than halve over the upcoming decades relative to the past twenty years. That reflects both faster gains in energy efficiency and the shift towards lower-carbon fuels. Despite this, carbon emissions are likely to continue to increase, indicating the need for further policy action. (BP p.l.c., 2016)

Natural gas is now also emerging as a cost-competitive and cleaner fuel , because gas plants are cheaper to build and operate in comparison to using other types of fuel (figure 2-8) and its emission of pollutants is far lower than coal emissions (figure 2-9) causing better local air quality. Moreover, natural gas is emitting less $CO_2$ (figure 2-10) thus contributing far less to climate change than coal.

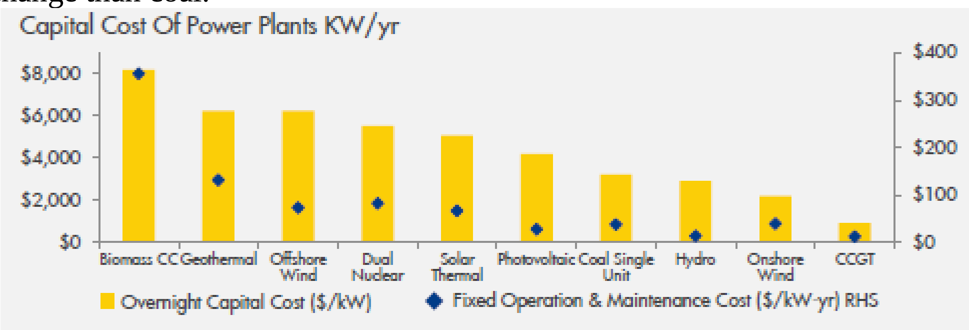



**Figure 2-8 Capital costs of power plants per year (Royal Dutch Shell plc, 2017)**

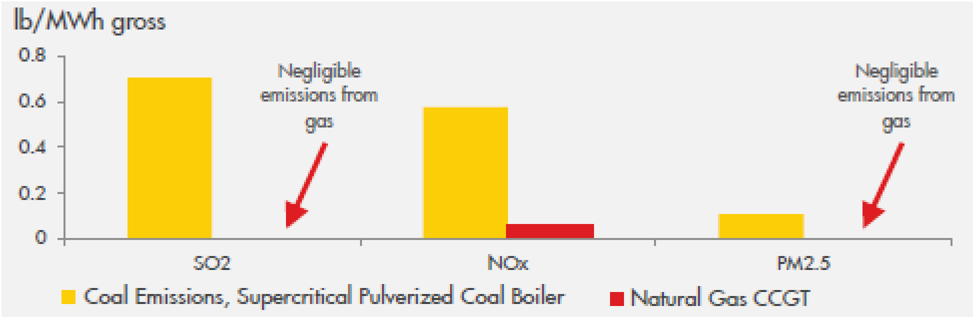



**Figure 2-9 Pollutant emission (Royal Dutch Shell plc, 2017)**

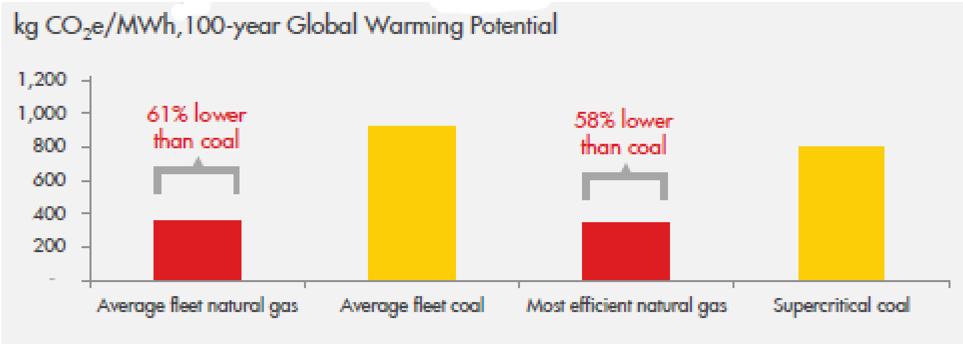



**Figure 2-10 $CO_2$Emissions (Royal Dutch Shell plc, 2017)**

As demand continues to grow and the value of natural gas remains high, the impetus to monetize non-traditional gas resources also grows. However, a considerable portion of the world's natural gas falls into the category termed "Stranded" where conventional means of transportation (e.g. via pipeline) are not economically feasible. (Edwin and Sunday, 2013)

In addition the location mismatch of gas reserves versus energy demand (e.g. USA and Japan) leads to the increase of LNG usage in International trade and in a couple of decades it is expected for LNG to overtake pipeline gas as a percentage of the overall global energy mix (figure 2-11).

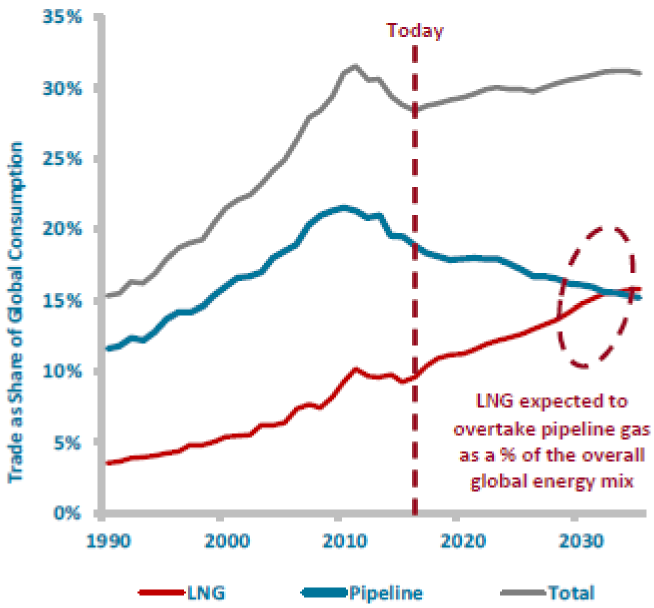



**Figure 2-11 International Trade as A Percent of Global Consumption (GASLOG LTD., 2017a)**

## 2.3 The LNG market

The LNG market is developing according to the EIA (Energy Information Administration) and IEA (International Energy Agency) respectively for USA and European gas demand and production in the past couple of years (table 2-1). In summary, 2016 did see the beginning of the much-anticipated LNG supply surge, but the supply increase was consumed by Asian and Middle Eastern markets before it reached Europe.

| | 2014 | 2015 | 2016 |
|---|---|---|---|
| **Global LNG Supply** | **329** | **331** | **350** |
| Asian Demand | 245 | 236 | 253 |
| South America Demand | 17 | 17 | 12 |
| Middle East Demand | 5 | 14 | 24 |
| Other Demand | 13 | 13 | 12 |
| | | | |
| **LNG Available for Europe** | **49** | **51** | **50** |
| | | | |
| **Europe Gas Demand** | **476** | **496** | **517** |
| Production | 255 | 248 | 246 |
| Storage Inventory Change | - 7 | 6 | 1 |
| **Russian Pipeline Imports** | **148** | **160** | **172** |
| Other Pipeline Imports | 32 | 30 | 49 |
| **LNG Required** | **49** | **51** | **50** |

**Table 2-1 Global LNG and European Balance 2014 – 2016 (bcm) (Howard Rogers, 2017)**

In consumption, LNG global demand is on the rise now, and this rise is explained in more detail on figure 2-12.

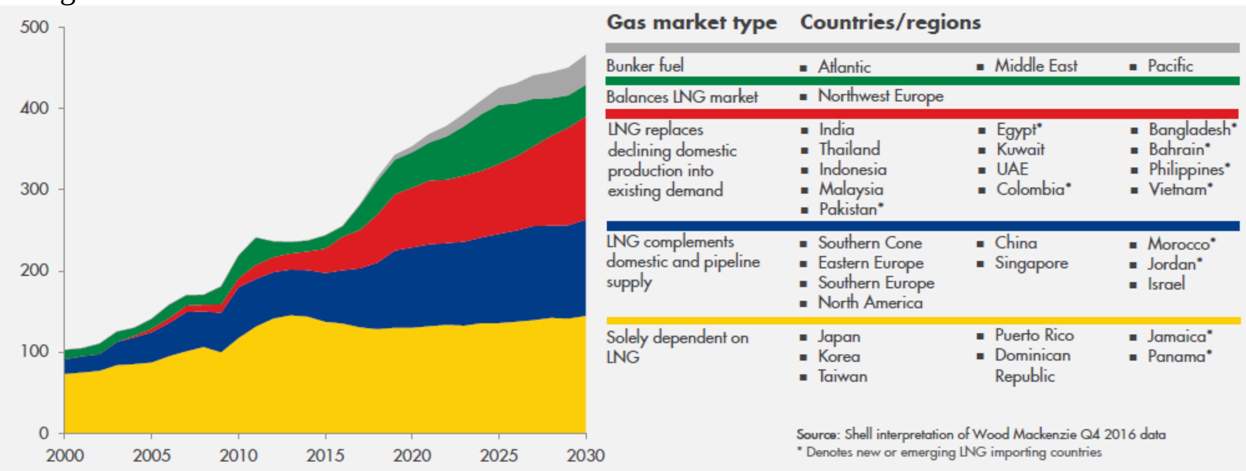



**Figure 2-12 LNG imports by role in domestic market (MTPA) (Royal Dutch Shell plc, 2017)**

Europe's supply of natural gas comes from different sources such as Russian pipelines, Norwegian pipelines and other pipelines or indigenous production. However, LNG plays a significant role there, and it is expected as seen above that Europe's supply of natural gas in form of LNG to increase (figure 2-13).

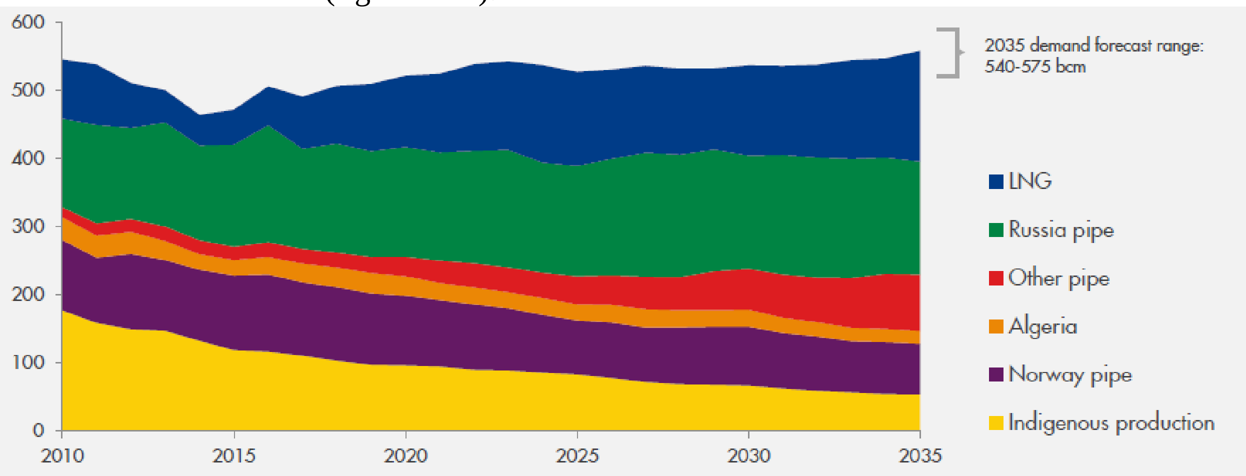



**Figure 2-13 European gas supply (bcm) (Royal Dutch Shell plc, 2017)**

Moreover, there are regulations and policies aiding to the rise of the Natural Gas as main fuel. These are written from international associations and organizations like G20 or the IMO (International Marine Organization).

To begin with, $SO_x$ and particulate matter emission controls apply to all fuel oil, as defined in regulation 2.9 of IMO (International Marine Organization), combustion equipment and devices onboard and therefore include both main and all auxiliary engines together with items such boilers and inert gas generators. These controls divide between those applicable inside Emission Control Areas (ECA) established to limit the emission of $SO_x$ and particulate matter and those applicable outside such areas and are primarily achieved by limiting the maximum sulphur content of the fuel oils as loaded, bunkered, and subsequently used onboard. These fuel oil sulphur limits (expressed in terms of % m/m – that is by mass) are subject to a series of step changes over the years, regulations 14.1 and 14.4 of IMO (table 2-2) (International Maritime Organization, 2017)

| Outside an ECA established to limit SOx and particulate matter emissions | Inside an ECA established to limit SOx and particulate matter emissions |
|---|---|
| 4.50% m/m prior to 1 January 2012 | 1.50% m/m prior to 1 July 2010 |
| 3.50% m/m on and after 1 January 2012 | 1.00% m/m on and after 1 July 2010 |
| 0.50% m/m on and after 1 January 2020 | 0.10% m/m on and after 1 January 2015 |

**Table 2-2 Changes to fuel oil sulphur limits over the years (International Maritime Organization, 2017)**

As shown above, LNG is a low sulphur emission fuel and by obeying the sulphur emission regulation 14 issued by IMO it's gaining a higher place in marine fuel market.
Secondly, the International Gas Union (IGU) and the National Energy Administration of China (NEA) co-hosted the G20 Natural Gas Day in Beijing, China, on 29 June. In this event, the main goal was to emphasize the role of natural gas as en economic, secure and clean source of energy, and the role it can and should play as the main energy fuel. Eventually, via debates, the delegates were convinced and determined to support the natural gas industry by enacting the appropriate policy. (IGU, 2016)

Moreover, it has been observed that between 2000 and 2014, China's total annual natural gas consumption increased from 25.3 to 185.5 bcm (BP (2015)). The International Energy Agency (IEA) (2014) projected that China's gas demand in 2019 will reach 315 bcm. Based on this projection, IEA believes that the golden age of natural gas will extend to China over the next five years. China's policy makers are also very positive about gas demand growth: they first projected 230 Bcm demand by 2015 in the Twelfth-Five Year Natural Gas Development Plan (NDRC, 2012), and then projected a 360 Bcm demand by 2020 in the Thirteenth-Five Year Natural Gas Development Plan (NDRC, 2016), which would result in gas representing 7.5 % and 10% of the total energy demand, respectively. To achieve a demand target of over 300 bcm by 2020, China needs to increase its gas consumption by at least 20 bcm each year on average between 2015 and 2020. (Li and Oxford Institute for Energy Studies, 2015)

Also, India is instituting a number of policy initiatives like the Hydrocarbon Exploration and Licensing Policy (HELP) and major infrastructure investments such as expanding domestic gas pipelines and LNG import terminals. This is due to the fact that as India's economy continues to grow, its energy needs, including the need for natural gas, will likely grow as well. India's economy is expected to grow fivefold by 2040, according to its Prime Minister Narendra Modi. Its population is expected to surpass China's as the world's largest by 2022, reaching approximately 1.4 billion people, creating greater demand for energy. Natural gas makes up 7% of India's total energy consumption, well behind coal and oil. Similarly, natural gas accounts for 6% of China's energy mix, though China uses almost four times as much natural gas as India. If global natural gas prices continue to be relatively low, natural gas consumption in India will likely grow in the coming decade. According to the International Energy Agency (IEA), India's natural gas demand is forecasted to grow at about 6% annually over the next five years, due to increases in domestic production and falling LNG import prices. Last but not least, apart from the fact that India is continuing to build its energy infrastructure for natural gas to reverse the recent declines in natural gas consumption, the infrastructures which had been almost exclusively configured for coal and oil are being used less and less in favor of increasing the ones configured for natural gas. (Michael Ratner, 2017)

## 2.4 The Strategy of European Union on LNG

In addition, there is a strategy by the European Union (EU) that aims to exploit the potential of LNG and gas storage to make the EU gas system more diverse and flexible, thus contributing to the key Energy Union objective of a secure, resilient and competitive gas supply. This will be accomplished by doing three things:

- Firstly, it needs to ensure that the necessary infrastructure is in place to complete the internal market and allow all Member States to benefit from access to international LNG markets, either directly or via other Member States. This is particularly urgent for Member States that are overly dependent on a single supplier.
- Secondly, the EU needs to complete the internal gas market so that it sends the right price signals – both to attract LNG to where it is needed and to allow the necessary investments in infrastructure to take place.
- Thirdly, the EU steps up its efforts to cooperate closely with international partners to promote free, liquid and transparent global LNG markets. This means intensifying dialogues with current and future suppliers and other major LNG consumers to remove obstacles to the trading of LNG on global markets. (EUROPEAN COMMISSION, 2016)

Lastly, the 2016 United Nations Climate Change Conference was conducted and held in Marrakech, Morocco from November 7 to 18. This is an international meeting of political leaders and activists to discuss environmental issues. The conference incorporated the twenty-second Conference of the Parties (COP22), the twelfth meeting of the parties for the Kyoto Protocol (CMP12), and the first meeting of the parties for the Paris Agreement (CMA1). The purpose of the conference was to discuss and implement plans about combatting climate change as well as the ways in which the Paris Agreement will be applied. Australia agreed to the long term Paris Agreement objectives meaning it needs to move on from its excessive focus on 2030 targets to longer term modernization and decarbonization planning. Also, more countries did just that and release or announce decarbonization plans by 2050 such as Canada, US, Mexico, Sweden and Germany and plans or objectives to guide investment and boost competitiveness in a world moving to clean energy. That plan leads to the energy transition beyond fossil fuel and into renewable energy sources, nuclear energy and Natural Gas. (John Connor, 2016)

# 3 The Supply chain of LNG

The process of extracting natural gas from the ground up to its consumption from residences and industrial businesses as an energy source, is a complicated one. This chapter provides an overview of the LNG supply chain and its different parts and stakeholders. For each dinstict part of this chain the specific operations are described (Figure 3-1).

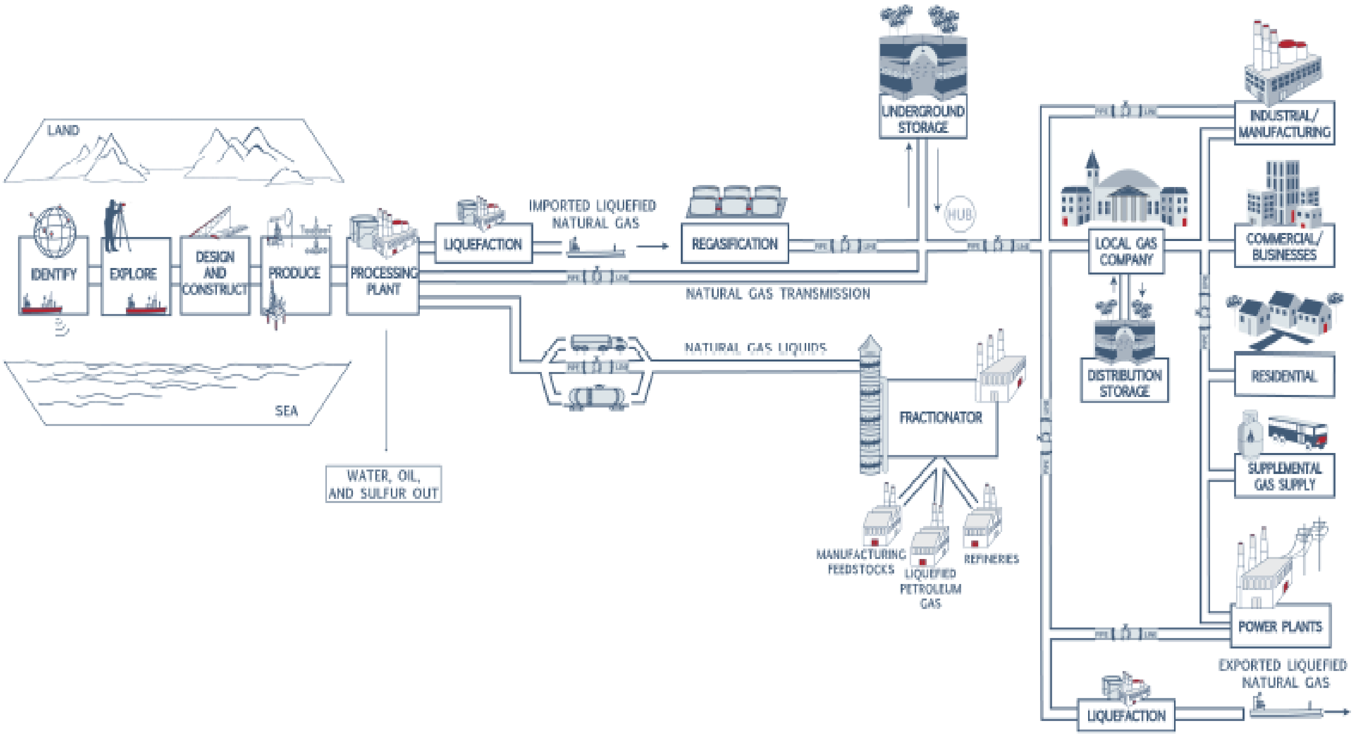



**Figure 3-1 The Natural Gas supply chain (Energy API, 2017)**

## 3.1 Exploration

A critical part of the supply chain is its upstream part, during which companies identify and explore regions onshore and offshore for reserves and specific deposits of natural gas that can be commercially exploited. Depending on the identified and proven reserves of natural gas, companies take multi-million, even billion worth investments decisions that develop the midstream and downstream segments of the chain.

The procedures of exploration for natural gas have been transformed dramatically in the last 20 years with the invention and application of extremely advanced technology. Until the mid-1900s, the only way of locating underground gas deposits was to search for surface evidence of these underground formations such as seepages of gas emitted from underground. However, this was a rather inefficient and difficult exploration process, because a low proportion of natural gas actually seeps to the surface. As the demand for fossil fuel energy has increased dramatically over the past years, so has the necessity for more accurate methods of locating these deposits. (“Natural Gas Exploration,” 2013)

The biggest breakthrough in natural gas exploration came through the use of basic seismology. In 1855, L. Palmiere developed the first "seismograph". Seismology refers to the study of how energy, in the form of seismic waves, moves through the Earth's crust and interacts differently with various types of underground formations. Its concept is that as the Earth's crust is composed of different layers, each with its own properties, energy (in the form of seismic waves) traveling underground interacts differently with each of these layers. These seismic waves, emitted from a source, will travel through the earth, but also be reflected back toward the source by the different underground layers. Through seismology, geophysicists are able to artificially create vibrations on the surface and record how these vibrations are reflected back to the surface, revealing the properties of the geology beneath. Seismology is divided into two categories depending on the area, in which the exploration takes place: ("Natural Gas Exploration," 2013)

### 3.1.1 Onshore exploration

➢ Onshore seismology, which is used for exploring onshore areas. In this procedure, seismic waves are created artificially and the reflection of them is received via sensitive pieces of equipment called "geophones", which are embedded in the ground. There is a seismic recording truck nearby, where data received by the geophones is transmitted to (figure 3-2). The seismic wave is created by a mobile drilling rig (picture 3-1).

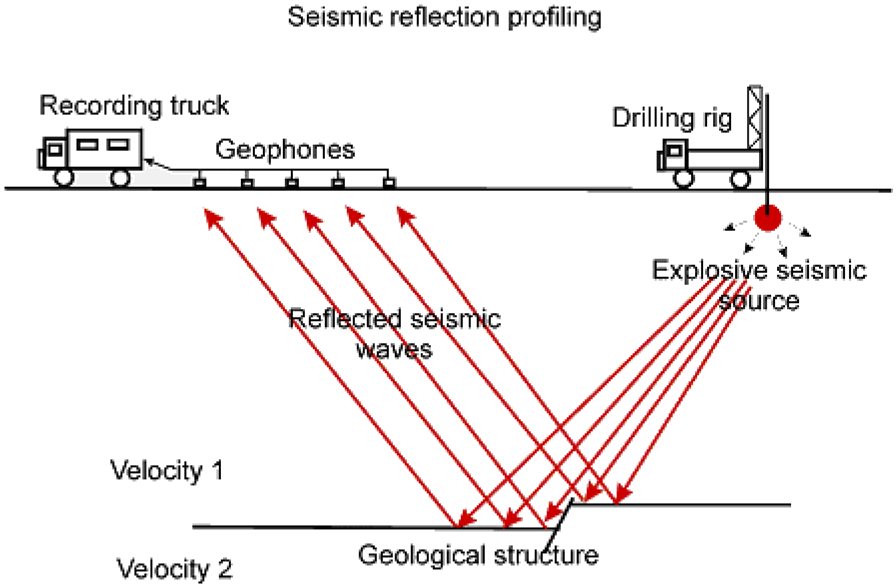
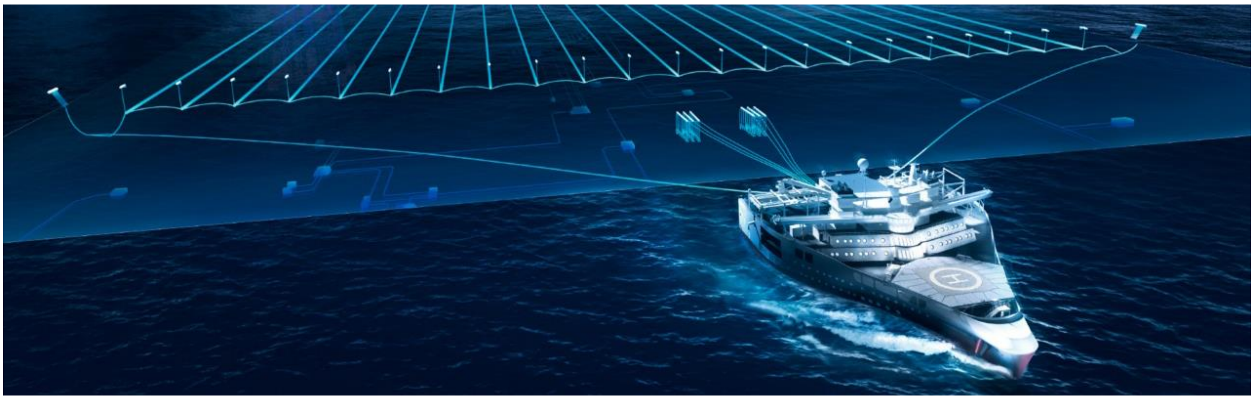



**Figure 3-2 Onshore seismic profiling technique ("Deep seismic profiling of the earth's crust in Australia: startup, 1950s and 1960s - Historical Data - IGCP Project 599, Crustal Architecture and Images," 2016)**


**Picture 3-1 ANSIR vibrator seismic energy source "Brolga", 60,000 pounds pressure (“Deep seismic profiling of the earth’s crust in Australia: startup, 1950s and 1960s - Historical Data - IGCP Project 599, Crustal Architecture and Images,” 2016)**

### 3.1.2 Offshore exploration

➢ Offshore seismology, which is the same as the onshore procedure, but is performed by specialized offshore vessels (picture 3-2). More specifically, instead of geophones the ship acquires seismic data with the use of hydrophones that are used to pick up seismic waves underwater. The hydrophones are linear-arranged in a 4000 m long streamer which is hauled behind the ship in about 8 m depth. (figure 3-3). (“BGR - Registration - Marine seismic data registration,” 2016)



**Picture 3-2 Offshore seismic exploration (“Liquidators Recover Seismic Data Surveys Money,” 2014)**

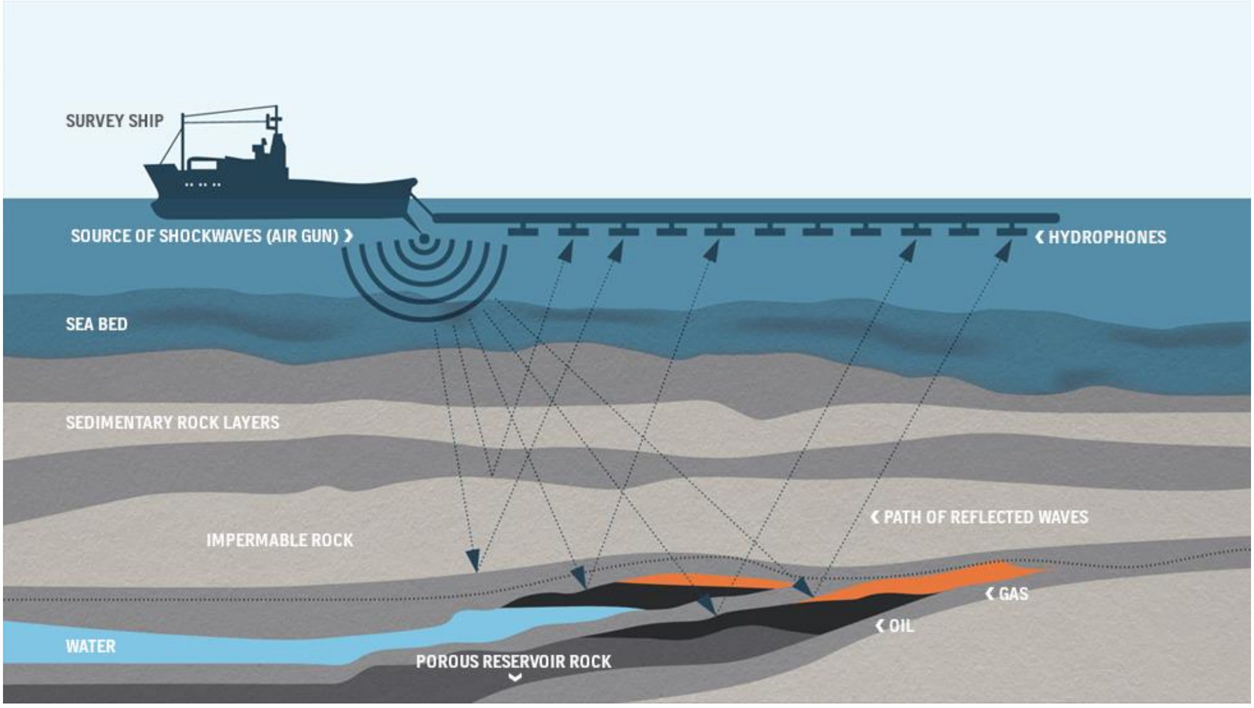



**Figure 3-3 Offshore seismology ("The Basics of Natural Gas Exploration and Production - Zoombd24," 2015)**

Last but not least, after these procedures take place, exploratory wells are drilled in order to validate the reserves identified with the aforementioned methods. This is extremely important as it the only way to certify the existence of natural gas reserves.

State-run companies or state authorities/directorates specialized in the hydrocarbon industry conduct such surveys in order to:

- Provide the produced data to the state run company to start production.
- Market the produced data to private companies that are interested in investing in the sector.

Additionally, private companies that are contracted by state authorities to exploit specific regions, separated in blocks, can make their own seismic surveys in order to have more accurate data to plan the exploratory drilling.

If the exploitation of the reserves proves to be commercially feasible, the company selected as an operator proceeds to the investment decision for the whole project.

## 3.2 Extraction

The first stage of the project is the extraction of the natural gas. This is a procedure of drilling by a team of experts using special drilling equipment where the natural gas is located by a team of exploration geologists and geophysicists. The extraction can be done either onshore or offshore depending on where natural gas resources have been located.

For the extraction to begin a number of requirements have to be met such as the economic potential of the natural gas reservoir to be high enough. That is a significant economic risk factor because of the serious cost for searching and drilling for natural gas, when there is a chance that no natural gas will be found. Also, the exact point of drilling has to be specified, which depends on many factors, such as the sub-surface's geology and the depth and size of the target deposit. In addition, the drillings operations need to comply with the relative

legislation. If the procedure is successful and the drilling leads to natural gas resources, then the well will be termed a “development” or “productive” well, whereas, if it’s not successful it will be termed a “dry well”. (“Natural Gas Extraction,” 2013)
As previously mentioned, there are two main types of extraction:

### 3.2.1 Onshore extraction

➢ Onshore drilling, namely drilling that takes place on land. In modern industry, there are two main types of onshore drilling: Percussion, or ‘cable tool’ drilling, which consists of raising and dropping a heavy metal bit into the ground, effectively punching a hole down through the earth (picture 3-3). Cable tool drilling is usually used for shallow, low pressure formations. The second drilling method is known as rotary drilling, and consists of a sharp, rotating metal bit used to drill through the Earth’s crust (picture 3-4). This type of drilling is used primarily for deeper wells, which may be under high pressure. (“Onshore Drilling NaturalGas.org,” 2013)

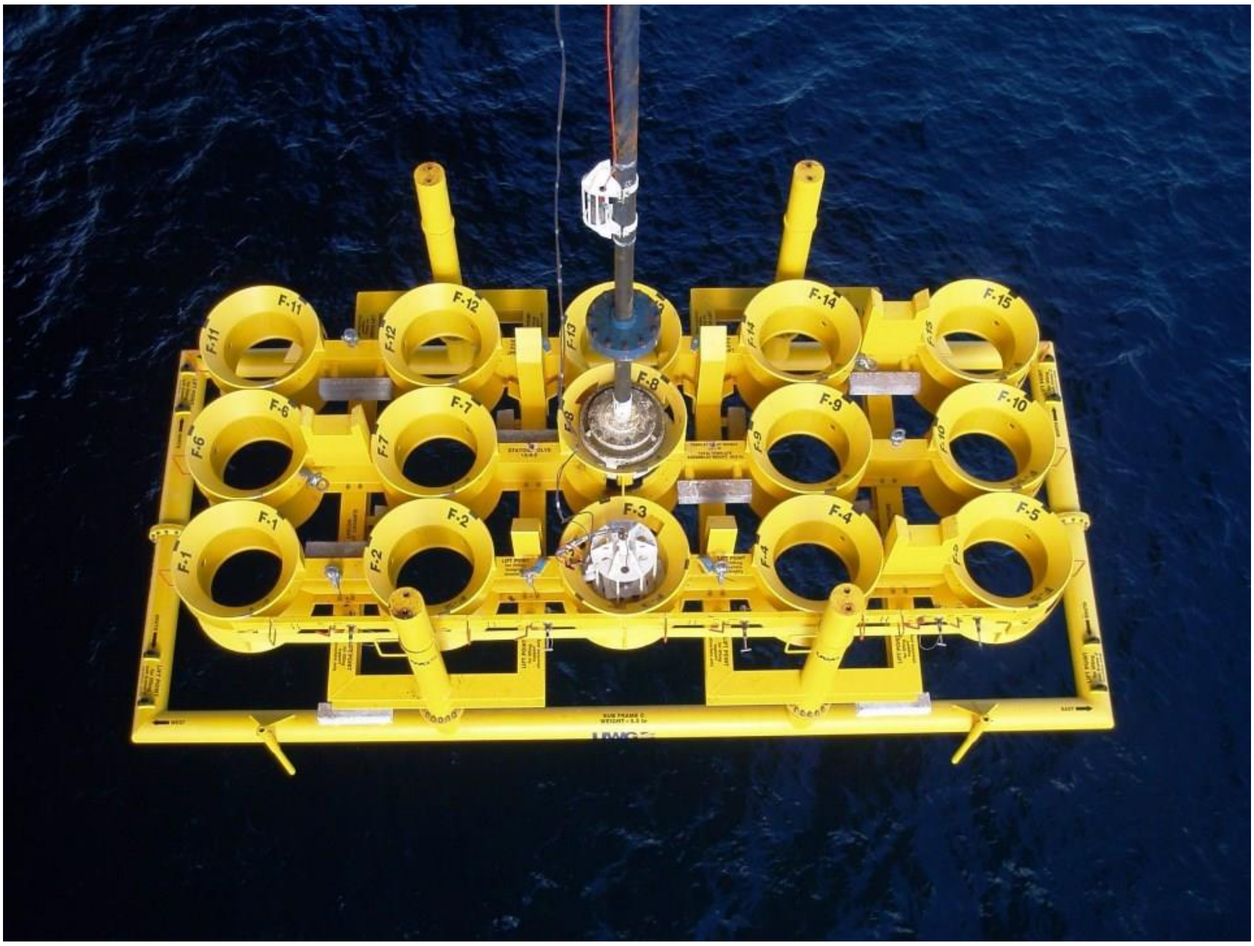
Picture 3-3 A Modern, Mobile Cable Tool Drilling Rig ("What is percussion well drilling method - Massenza Drilling Rigs," 2017)

**Picture 3-4 Rotary Drilling Rig ("SWDM22B," 2017)**

### 3.2.2 Offshore extraction

- Offshore drilling refers to drilling of wells on the seabed. It is a procedure with a number of different challenges compared to drilling onshore. While, the drilling mechanism both offshore and onshore may be similar, the drilling at sea is performed by drillings rigs in the sea water, which is not as stable as the solid ground onshore.

A complex marine structure has to be created in order to conduct the offshore drilling. This structure can take many forms, depending on the water depth, the marine environment, and the characteristics of the well to be drilled. Also, the drilling template should be mentioned, which is one of the most important pieces of equipment for offshore drilling. Essentially, this piece of equipment connects the underwater well site to the drilling platform on the surface of the water. It consists of an open steel box with multiple holes in it, dependent on the number of wells to be drilled (picture 3-5). This drilling template is placed over the well site cemented into place. The drilling template, secured to the sea floor and attached to the drilling platform above with cables, allows for accurate drilling to take place, but allows for the movement of the platform, which will inevitably be affected by shifting wind and water currents. From the template anything from 4 to 64 vertical top holes can be drilled through each slot. Lastly, there are two basic types of offshore drilling rigs: floatable and bottom founded (figure 3-4). ("Offshore Drilling NaturalGas.org," 2013)



**Picture 3-5 15-slot Claxton subsea drilling template for Statoil's Volve project ("15-slot-Claxton-subsea-drilling-template-for-Statoils-Volve-project.jpg (960×720)," 2017)**

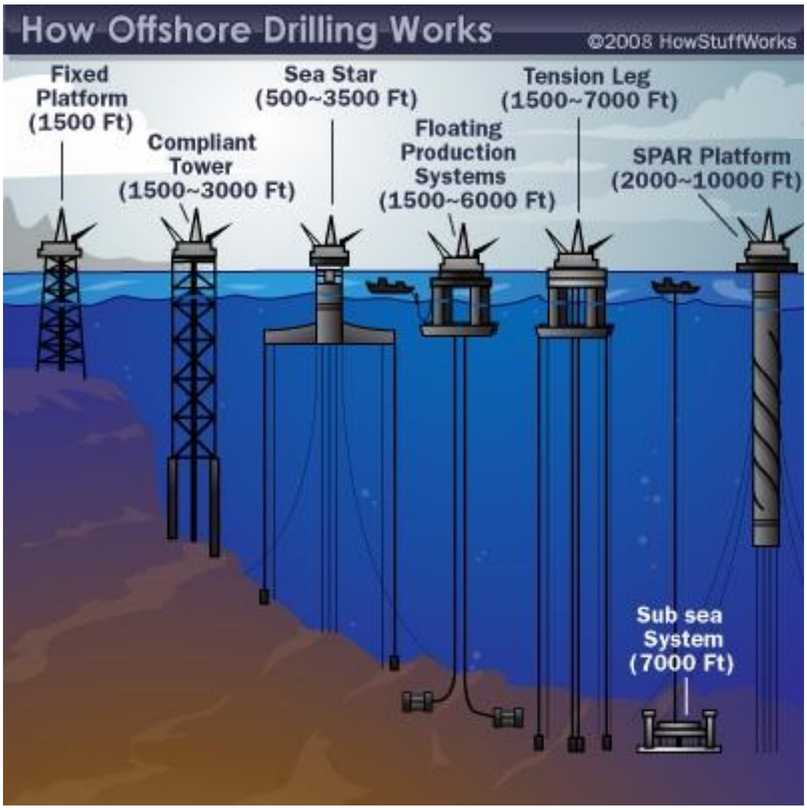



**Figure 3-4 Offshore drilling platforms (ROBERT LAMB, 2008)**

## 3.3 Production

The stage of production initiates in case of a productive well, where the drilling leads to natural gas deposits. More specifically, the natural gas is lifted out of the ground and goes through an initial treatment process. This process of refining is necessary due to the fact the raw natural gas that is being extracted from the ground contains oil, water and many unwanted compounds and gases. Processed natural gas that comes through the gas network to consumption (also known as "pipeline quality" dry natural gas) is comprised almost entirely of methane. The type of purity of the natural gas which is transferred through the pipeline networks is configured by specific standards (picture 3-6). ("Natural Gas Production," 2013)

**Picture 3-6 Liam Gas Treating (Processing) Plant ("Natural Gas Processing Plant Project – Ilam – Official Website of Hirbadan Company," 2017)**

It should be mentioned that raw natural gas is produced from three types of wells:

- Oil wells, which produce natural gas that is typically termed "associated gas". This gas can exist separate from oil in the formation (free gas), or dissolved in the crude oil (dissolved gas).
- Gas wells, which includes natural gas that has little or no crude oil and is termed "non-associated gas". Also, they typically produce raw natural gas by itself.
- Condensate wells, similarly to the gas wells contain "non-associated gas", but with the difference of producing free natural gas along with a semi-liquid hydrocarbon condensate. ("Processing Natural Gas NaturalGas.org," 2013)

At this point, the stage of processing natural gas will be analyzed (figure 3-5). It is a complicated procedure that usually involves four main processes to remove the various impurities:

- ✓ Oil and condensate removal, which is the case mainly for the "dissolved gas". It is most often done using equipment installed at or near the wellhead. The actual process used to separate oil from natural gas, as well as the equipment that is used, can vary widely. The most basic type of separator is known as a conventional separator. It consists of a simple closed tank, where the force of gravity serves to separate the heavier liquids like oil, and the lighter gases, like natural gas.
- ✓ Water removal, which is divided into two parts. The free water removal, which is a simple step and is done at or near the wellhead, while the other is the removal of the water vapor, which exists in solution in natural gas and is a more complex task. The last one, is practically the "dehydration" of the natural gas, and involves the processes of either absorption or adsorption. Absorption occurs when the water vapor is taken out by a dehydrating agent, an example of it being the Glycol Dehydration. Adsorption occurs when the water vapor is condensed and collected on the surface, and its primary form is Solid-desiccant dehydration.

- ✓ Separation of natural gas liquids, which is done because natural gas liquids (NGLs) have a higher value as separate products, and it is thus economical to remove them from the gas stream. The removal of natural gas liquids usually takes place in a relatively centralized processing plant, following two basic steps. First, the liquids are extracted from the natural gas. There are two principle techniques for removing NGLs from the natural gas stream: the absorption method and the cryogenic expander process. Second, these natural gas liquids are separated themselves, down to their base components. That is, the mixed stream of different NGLs must be separated out. The process used to separate the different NGLs down to their components is called fractionation, and the plant, where this process takes place is called Fractionator. Fractionation works based on the different boiling points of the different hydrocarbons in the NGL stream.
- ✓ Sulfur and Carbon Dioxide removal, which necessary by the type of natural gas some wells provide. This type of natural gas, because of the rotten smell provided by its sulfur content, is commonly called “sour gas”. It is undesirable, due to the lethal sulfur compounds it contains and the fact that it’s corrosive. Sulfur exists in natural gas as hydrogen sulfide ($H_2S$). The process for removing hydrogen sulfide from sour gas is commonly referred to as “sweetening” the gas. The primary process for sweetening sour natural gas is quite similar to the processes of glycol dehydration and NGL absorption and is called “amine process”, or alternatively as the Girdler process. It is also possible to use solid desiccants like iron sponges to remove the sulfide and carbon dioxide. (“Processing Natural Gas NaturalGas.org,” 2013)

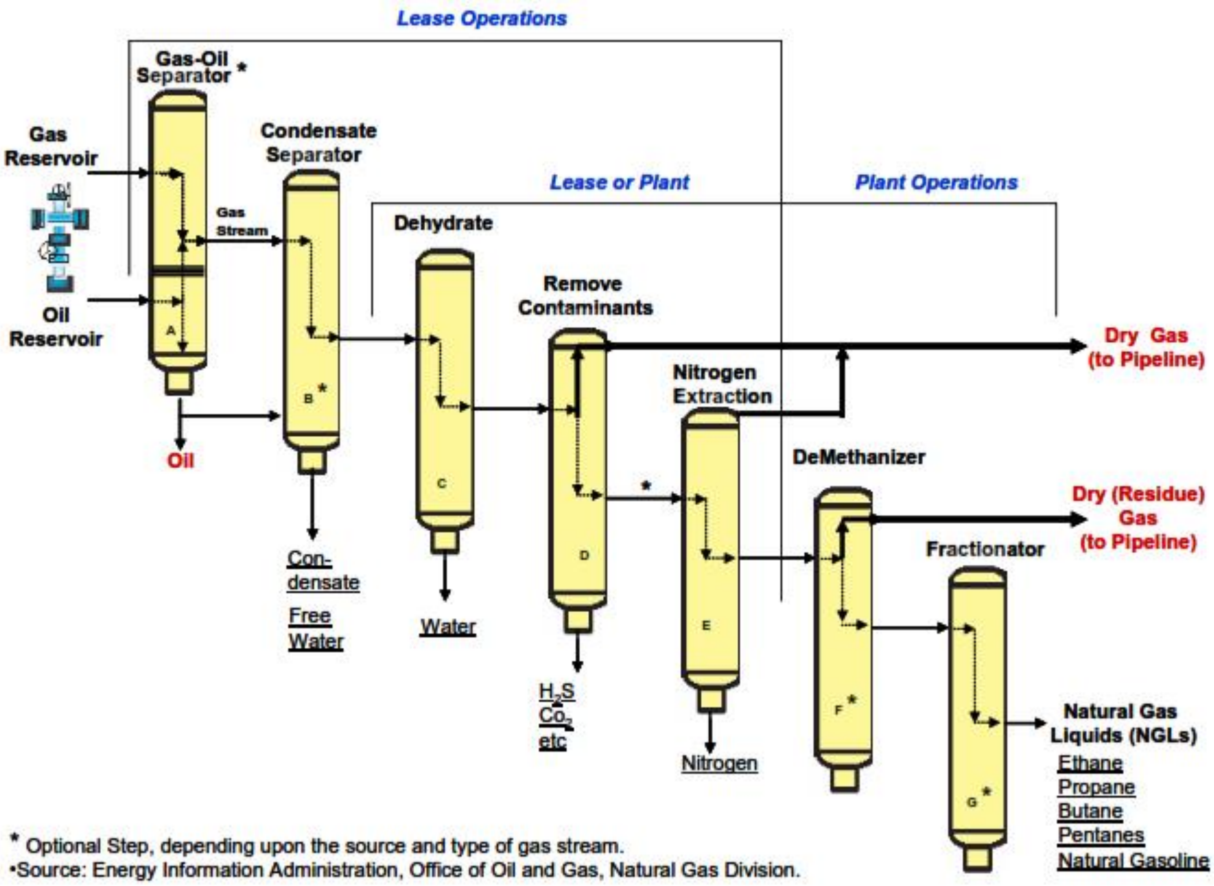



**Figure 3-5 Steps of processing the raw natural gas (Faramawy et al., 2016)**

## 3.4 Transportation

After the production of natural gas, the refined natural gas is ready to be transported in order to be supplied to local gas networks. The midstream part of the natural gas supply chain consists of two main modes of transportation: in gas form via the pipelines or in a liquid form (LNG) via specialized carrier ships (figure 3-6).

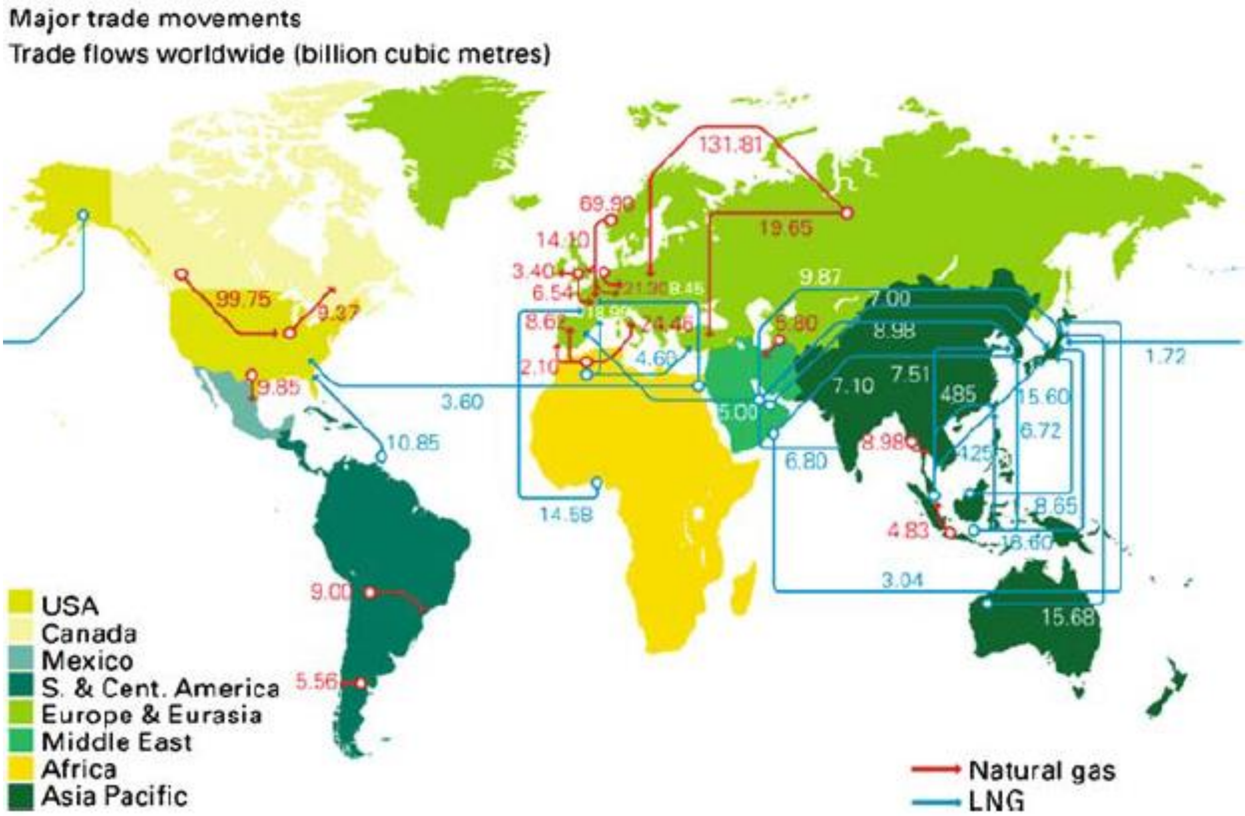



**Figure 3-6 The main trade flows of natural gas and LNG in the world. (Nunen et al., 2009)**

### 3.4.1 Pipeline transportation

As far as pipeline transportation is concerned, it can be used both offshore and onshore depending on the feasibility of its construction and operation. In this case, a central pipeline usually between 16 and 48 inches in diameter with larger capacity complemented by a complex network of smaller pipelines typically between 6 and 16 inches in diameter has to be used in order for natural gas to travel a great distance to reach its end users both quickly and efficiently. Furthermore, as natural gas must be highly pressurized to move along the pipeline compressor stations are placed along the pipeline along with metering stations in order to monitor and maintain the pressure. Moreover, there are three major types of pipelines along the transportation route: the gathering system, the interstate pipeline system, and the distribution system.

- The gathering system consists of low pressure, small diameter pipelines that transport raw natural gas from the wellhead to the processing plant. It's the link between the stage of extraction and production. Supposing natural gas from a particular well has high sulfur and carbon dioxide contents (sour gas), a specialized sour gas gathering pipe must be installed, because sour gas is corrosive, as said above.
- The interstate/intrastate pipelines are very similar to the highway systems. Interstate pipelines are similar to the interstate highway system, meaning they carry natural gas across state boundaries, or across the country. On the other hand, intrastate pipelines transport natural gas within a particular state (figure 3-7). However, this pipeline system may also run across different countries moving natural gas internationally (figure 3-8) In conclusion, this category

is the transportation system connecting the processing plant to the centers of natural gas consumption.

- The distribution system has the purpose of delivering gas to the end-consumers. In other words, while large interstate natural gas pipelines transport natural gas from the processing regions to the consuming regions and may serve large wholesale users such as industrial or power generation customers directly, it is the distribution system that actually delivers natural gas to most retail customers, including residential natural gas users. ("Natural Gas Transportation," 2013)

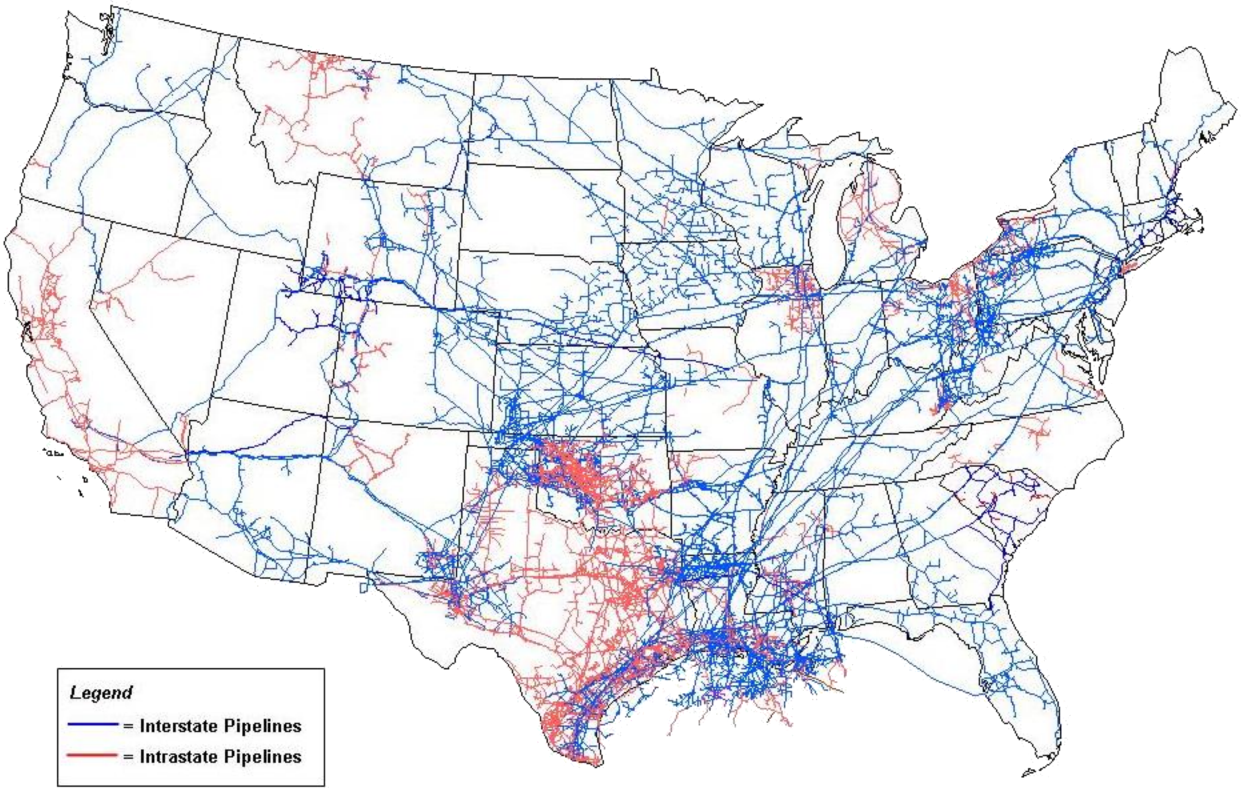



**Figure 3-7 U.S. Natural Gas Pipeline Network, 2009 ("EIA - Natural Gas Pipeline Network - U.S. Natural Gas Pipeline Network Map," 2009)**

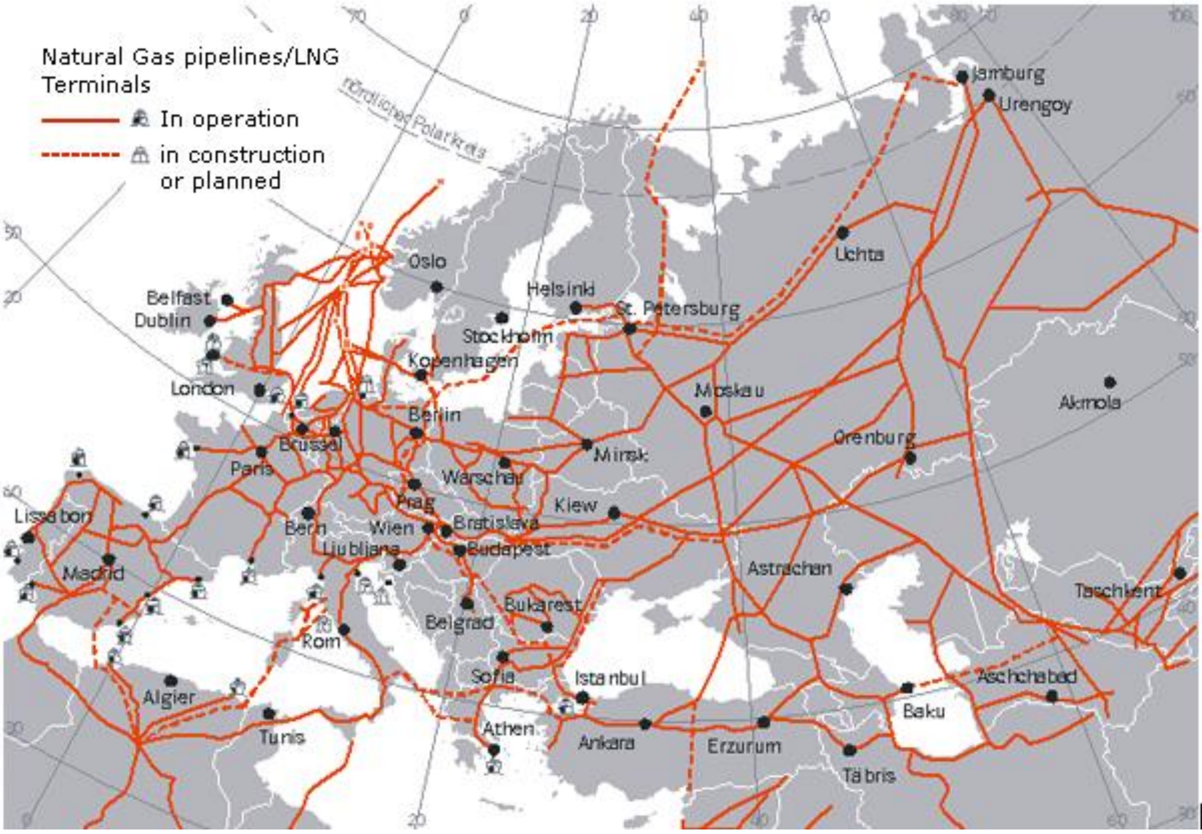



Figure 3-8 Natural Gas transportation system in Europe (Ioannis Michaletos, 2011)

The Greek National Gas Transmission System transports gas from the Greek-Bulgarian border and the Greek-Turkish border to consumers in continental Greece. Its main transmission pipeline has total length 521 km and design pressure 70 bar extends from the Greek-Bulgarian border at Promachonas to Attica. Also, there are transmission branches, which are 947 km long and extend from the main transmission pipeline and supply natural gas to the regions of Eastern Macedonia, Thrace, Thessaloniki, Platy, Volos, Trikala, Oinofyta, Antikyra, Aliveri, Korinthos, Megalopoli, Thisvi and Attica. Moreover, along the main transmission and the branches are used:

Line Valve Stations for isolating a segment of the transmission system in emergencies or maintenance

Scraper Stations or interior inspection devices

Cathodic protection system to avoid corrosion

Fiber Optic Cable for the remote supervision and control systems.

Adding to that, there are border metering stations near Serres and Evros river, a compression station At Nea Mesimvria, other metering and regulating stations, natural gas control and dispatching centers near Athens and Thessaloniki, operation and maintenance centers of Sidirokastro border station, Northern, Southern, Central and Eastern Greece and lastly, a remote control and communication system (figure 3-9). (“ΔΕΣΦΑ » Description,” 2015)


**Figure 3-9 Gas infrastructure of Greece 2014 (Jan Bartos and Andrew Robertson, 2014)**

### 3.4.2 Ship transportation

In the case that the natural gas has been identified and extracted offshore, the use of pipelines becomes a lot harder and complex (figure 3-10). The solution to this problem seems to by the liquefaction of the natural gas In order for the gas to be transported overseas to the mainland by ship (figure 3-11). Also, in its liquid form the natural gas takes up less volume, which makes it more economical to store and ship across larger distances. Furthermore, the ships in which LNG is carried are double-hulled with specially-built tanks for this particular reason (picture 3-7) and are among the safest in the shipping industry. The history of LNG trade spans over 40 years and contains 182 events. Of these events, 158 have occurred during regular service. (Aronsson, 2012)

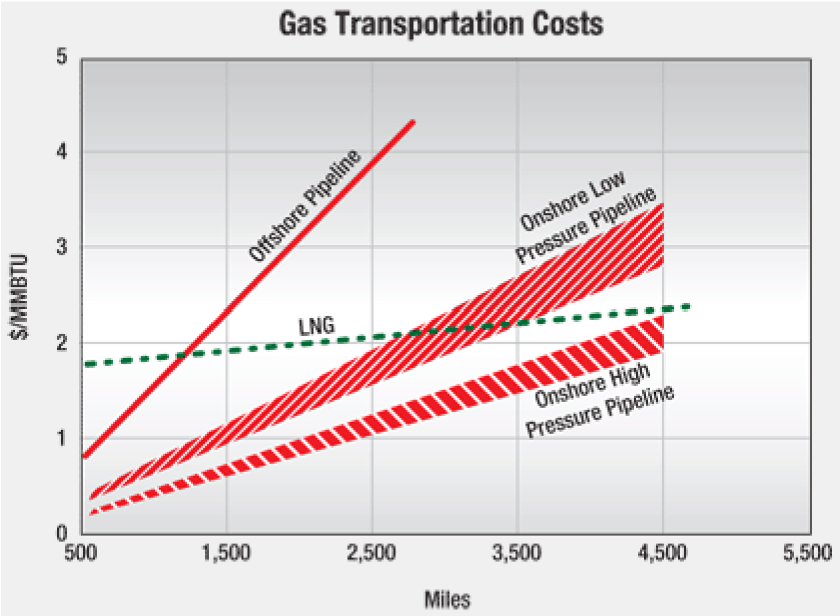



**Figure 3-10 Comparison of the cost of transporting gas via line as opposed to using LNG (Michael J. Economides and Saeid Mokhatab, 2007)**

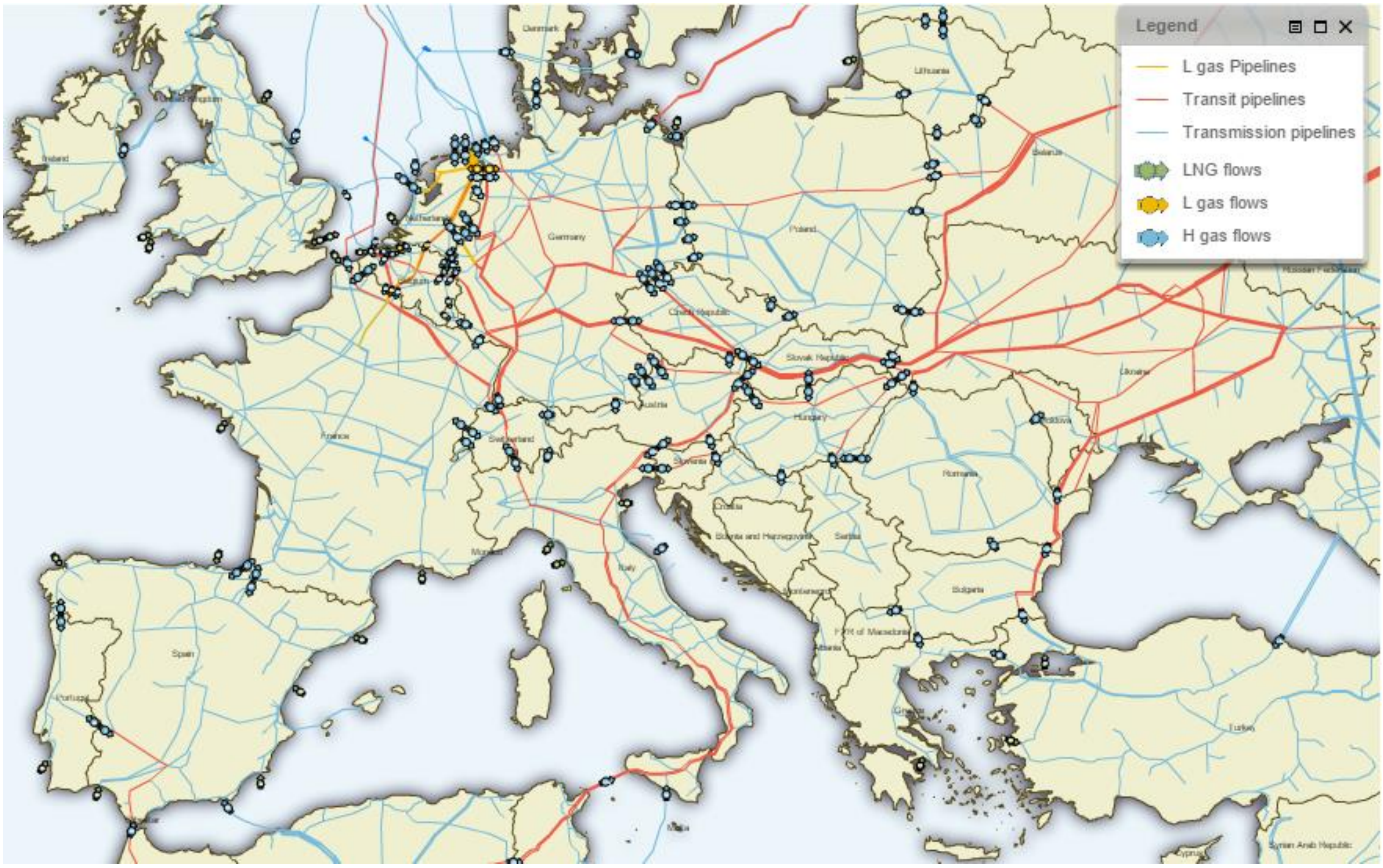



**Figure 3-11 Gas Trade flows in Europe, February 2017 ("IEA - Gas Trade Flows in Europe," 2017)**


**Picture 3-7 Section view of and LNG showing the internal space of the specially-built tank ("Xiamen Bags First LNG Carrier Order | World Maritime News," 2015)**

## 3.5 Liquefaction

An LNG producing infrastructure includes a gas pipeline leading to the seaside, a gas liquefaction plant (picture 3-8), storage facilities and special equipment used for the transfer to an LNG carrier (figure 3-12). This infrastructure may be built either near-shore or by retrofitting old LNG carriers turning them to what is called an LNG-FPSO (floating production storage and offloading) or Floating LNG (FLNG). FPSOs are moored in place by various mooring systems, which allow the vessel to rotate freely to best respond to weather conditions. Usually tied to multiple subsea wells, FPSOs gather hydrocarbons from subsea production wells through a series of pipelines. The processing equipment aboard the FPSO is similar to what would be found atop a production platform. Hydrocarbons are then transferred to the vessel's double-hull for storage. Permanently moored, FPSOs are viable development solutions for a number of different offshore field situations. Because FPSOs can be disconnected from their moorings, these offshore production vessels are optimal for areas that experience adverse weather conditions, such as cyclones and hurricanes. Additionally, because FPSOs can be moved, they are a more economical solution for more marginal fields, in that the vessel can be moved to another development and redeployed once the original field has been depleted. Also, FPSOs are an optimal choice for development when there are no existing pipelines or infrastructure to transfer production to shore (picture 3-9). ("How Do FPSOs Work? | Rigzone," 2017)

Picture 3-8 LNG Liquefaction Plant ("How Does LNG Work?," 2017)

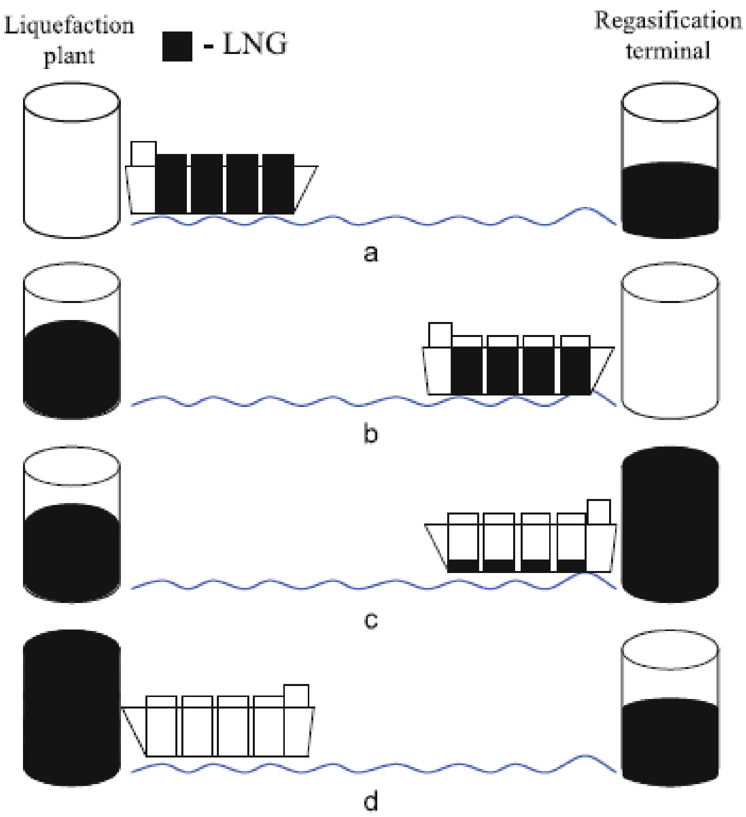



Figure 3-12 LNG infrastructure and optimized supply (Nunen et al., 2009)


**Picture 3-9 PETRONAS Floating Liquefied Natural Gas (PFLNG) SATU (“PETRONAS FLNG,” 2015)**

## 3.6 Regasification

When LNG reaches its destination it is gasified at the regasification plant at the terminal in order to be induced in the pipeline network or be transferred with specialized trucks (picture 3-10). The regasification can also be done on a specially retrofitted ship. These ships are called FSRU (floating storage regasification unit). FSRU act, in all aspects, similar to a land-based terminal and are permanently moored to a docking facility at a location close to a market access point. Also, they deliver natural gas through specially designed offshore and near-shore receiving facilities. Moreover, there are some advantages in using FSRU instead of land-based terminals. In most cases, a floating regasification solution is more cost effective per MMbtu than a traditional land-based solution. In addition, a floating solution can be implemented in one to three years versus a land-based terminal which typically takes four to six years to develop. Lastly, a dockside or offshore regasification facility requires less land use than a land-based terminal, thus minimizing environmental impacts to the surrounding environment. (picture 3-11). (“Excelerate Energy – FSRU Technology,” 2017; OLGA GERASIMCHUK, 2015)

Picture 3-10 Futtsu regasification plant and LNG Terminal (“Japan,” 2012)


Picture 3-11 Hoegh LNG FSRU (“Baker Botts Represents Hoegh LNG in Indonesia FSRU Deal,” 2012)

The midstream supply chain makes delivering natural gas all around the globe an achievable task, especially for countries where natural gas resources are not found near them. However, the transportation can be delayed due to unpredictable incidents, natural disasters or human errors, thus leaving these countries without gas.

## 3.7 Storage

Building LNG storage facilities to maintain a reserve becomes very important. The storage tanks can be constructed at underground, surface facilities or in a LNG vessel chartered as floating storage.

The LNG reserve can service the demand for natural gas on several seasonal occasions. More specifically, the natural gas demand increases during the colder months, as the natural gas serves the purpose of heating in residential and commercial buildings, which is not the case for the summer period. As a result, the storage of excess gas supply delivered during summer months is utilised during the winter. Additionally, the recent trend towards natural gas used for electric power generation translates into increased demand for natural gas during the summer months. ("Natural Gas Storage," 2013)

As far as underground storage facilities are concerned, they are quite complex to build. First, it has to be reconditioned to create a sort of storage tank underground. During the injection of natural gas into the facility, more and more pressure is being created by its addition to the closed space. So, the underground formation serves the purpose of a pressurized natural gas container and the higher the pressure, the gas will be extracted. The extraction, then, stops once the pressure of the storage equalize with or is less than that of the wellhead. Because of the necessary pressure difference in order for natural gas to be extracted and as more and more of it being extracted, the pressure of the storage lowers, so there is a certain amount of gas that may never be extracted, this is called "unrecoverable gas". In addition, there is the "base gas" or "cushion gas", which is the volume of gas that must remain in the facility in order to provide the minimum required level of pressurization to extract the remaining gas, but a portion of it may be extracted using special equipment at the wellhead. Lastly, the volume of gas which is the one that needs to be stored is called "working gas" and its capacity is called "working gas capacity". When the storage is full, the withdrawal rate is at its highest, due to the high amount of pressure. However, as more and more gas is being extracted, pressure diminishes, and so does the withdrawal rate. ("Natural Gas Storage," 2013)

Commonly, natural gas is stored in one of the following three principal types of large underground storage systems (figure 3-13). These are:

1. Depleted natural gas reservoirs, which make up more than 80% of natural gas storage capability (figure 3-14). They are easy to convert to storage facilities after use and are typically located near consumption centers and existing pipeline systems. As an example, there is a natural gas field at South Kavala which is used to extract gas. The operation is organized by the company "Energean" and the company plans to recover 98.5% of the gas by 2019. In addition, the depleted field is suitable to be

converted into an Underground Gas Storage (UGS) linked to the Trans Adriatic Pipeline (TAP) (figure 3-15) that will transit Greece 2km from Energean's onshore processing plant. Energean has submitted on 1st July 2011 to the Regulatory Authority of Energy (RAE) an application for the acquisition of a license that permits the installation of the storage and the conversion of the almost depleted field into a UGS. This development is on hold awaiting approval from the Greek government. Conversion to UGS would require an investment of approximately initially estimated at US $400 million (figure 3-16). ("Energean Oil & Gas Operations," 2017)

2. Natural aquifers, which are suitable for gas storage if the water-bearing sedimentary rock formation is overlaid with an impermeable cap rock. Deliverability rates, which are the rates at which gas inventory can be withdrawn, may be enhanced by the presence of an active water drive, which supports the reservoir pressure through the injection and production cycles.
3. Salt caverns, which provide very high withdrawal and injection rates relative to their working gas capacity. Also, cavern construction is more costly than depleted field conversions when measured on the basis of dollars per thousand cubic feet of working gas capacity. However, once created, a salt cavern offers an underground natural gas storage vessel with very high deliverability. In addition, cushion gas requirements are the lowest of all three storage types, with salt caverns only requiring about 33 percent of total gas capacity to be used as cushion gas. ("The Basics of Underground Natural Gas Storage - U.S. Energy Information Administration," 2015)

Lastly, due to the introduction of Federal Energy Regulatory Commission's (FERC) Order 636 in 1992 natural gas storage became available to anyone seeking storage for commercial purposes or operational requirements. Prior to Order 636 storage used to serve only as a buffer between transportation and distribution, to ensure adequate supply of natural gas for the filling of the seasonal or unexpected demand. However, now, apart from the above, gas storage can be used from the industrial section for commercial reasons, meaning when gas's price is low more of it being stored and when its price returns to higher levels more of it being sold. ("Natural Gas Storage," 2013)

The Greek regulatory framework is characterized by a gradual movement towards an integrated and liberalized natural gas market. Since 1998, where the first natural gas EU directive (Directive 98/30/EC) was introduced, the Greek regulatory framework has been evolving in line with European Union legislation. In this context, most recently, Greece implemented the third EU energy legislation package which mainly aims to unbundle the energy suppliers from network operators, strengthen the independence of regulators and increase the transparency in retail markets to benefit consumers. (BERNITSAS, 2016)

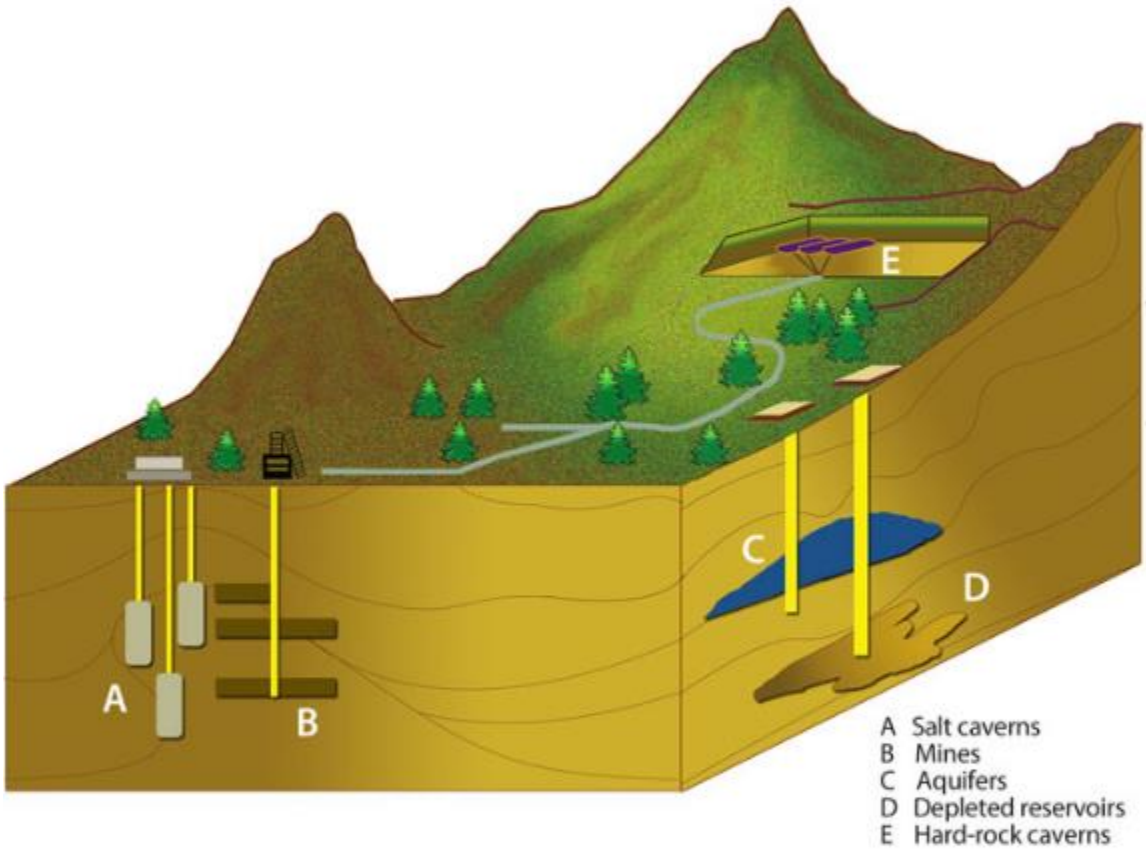



**Figure 3-13 Types of underground natural gas storage facilities ((“The Basics of Underground Natural Gas Storage - U.S. Energy Information Administration,” 2015)**

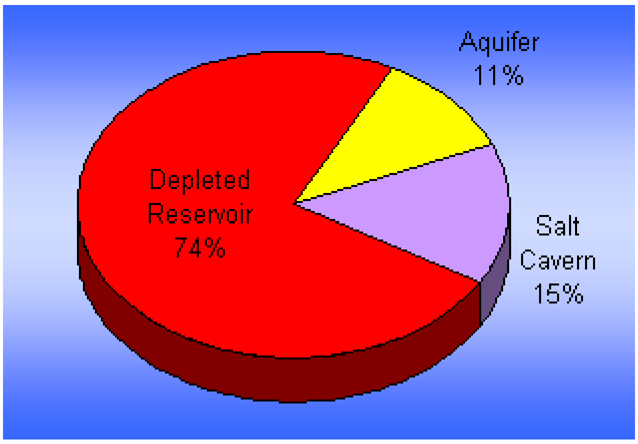



**Figure 3-14 Working Gas Capacity by Type of Storage (“Natural Gas Storage,” 2013)**

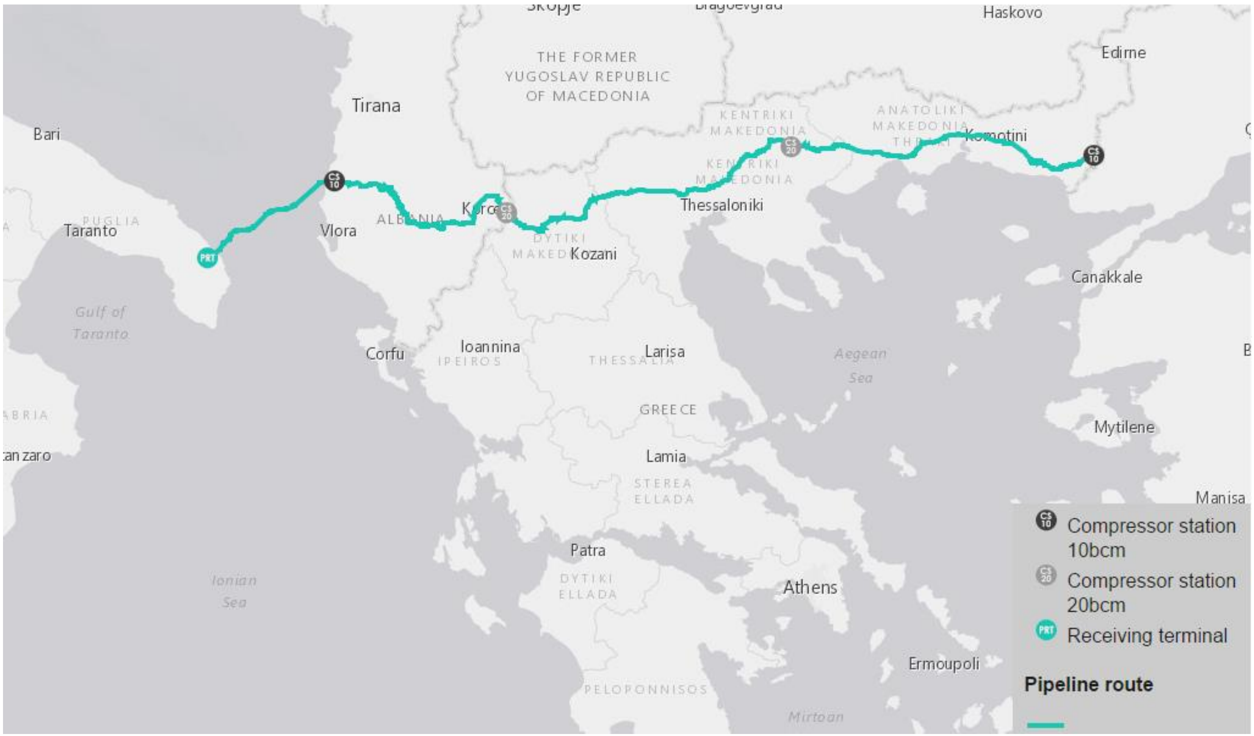



Figure 3-15 Trans Adriatic Pipeline (Trans Adriatic Pipeline, 2017)

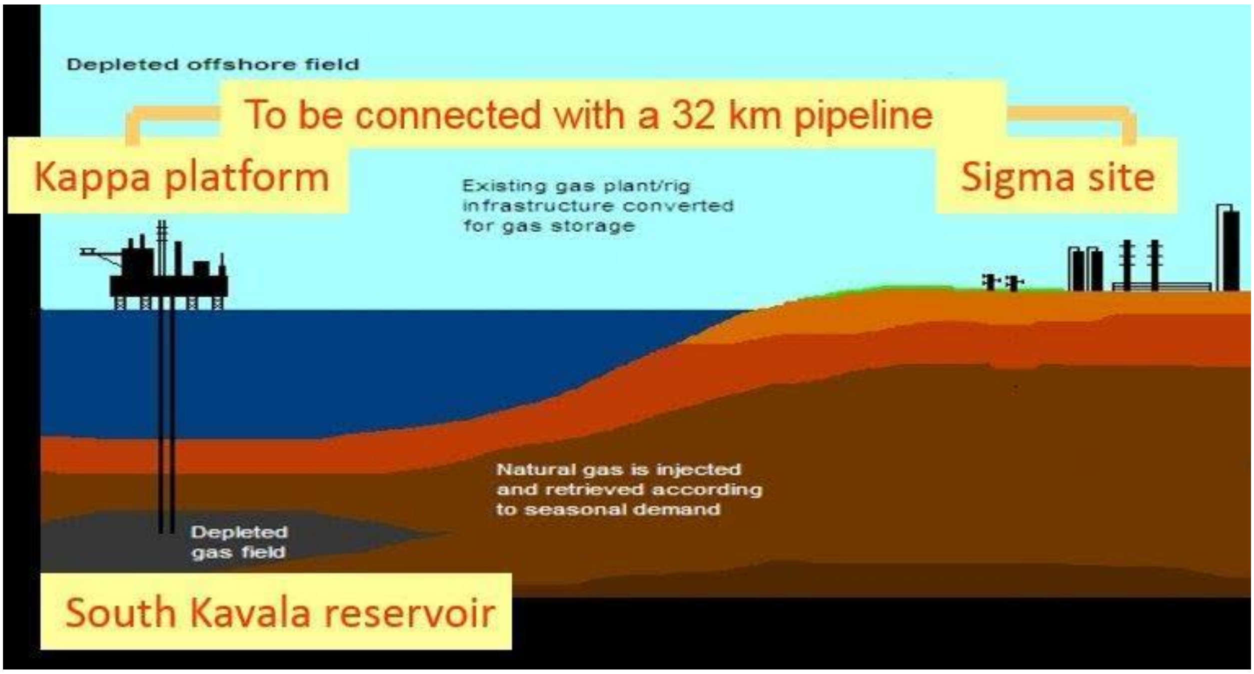



Figure 3-16 The project to make South Kavala depleted natural gas reservoir an underground storage (HHRM, 2017)

## 3.8 Distribution

As previously written, the downstream supply chain ends with the distribution pipeline network to end users. In contrast with large industrial, commercial and electric generation customers, who receive natural gas directly from interstate/intrastate pipelines, most other users receive it from their local gas utility, called "local distribution company" (LDC). These are regulated utilities and are divided into two categories: the ones owned by investors and public gas systems owned by local governments. Also, the distribution pipeline system is smaller in diameter than the intrastate pipelines and they connect to them through delivery points across the latter. The delivery point is also called "citygate", and is an important market center for the pricing of natural gas in large urban areas. Usually, civil services get ownership of the natural gas at the citygate, and deliver it to each individual customer's meter. Due to the fact that the gas is moved to many different customers across a wide area, a large amount of small-diameter pipeline is needed. Although, large pipelines could reduce unit costs by transmitting large volumes of natural gas, distribution companies must deliver relatively small volumes to many more different locations. So, the distribution system becomes very expensive. In fact, it makes up half of the amount of the natural gas costs for households and small volume customers (figure 3-17). ("Natural Gas Distribution," 2013)

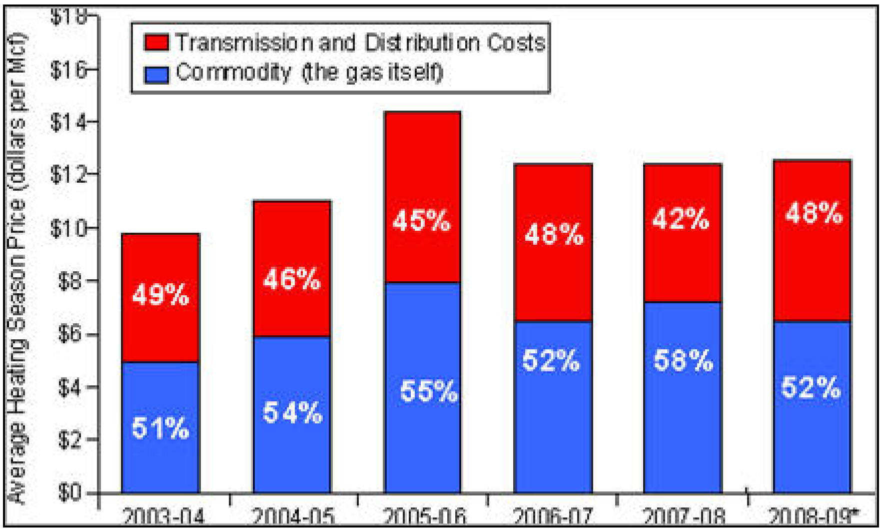



**Figure 3-17 Average Heating Season Price (dollars per Mcf) ("Natural Gas Distribution," 2013)**

***Mcf – Thousand cubic feet**

# 4 Description of FSRU, technical information and factors affecting investment in it

## 4.1 General Information on FSRUs

Although, the LNG cargo is transported in a slushy state of -162°C, at destination it is required to be heated up to the atmospheric temperature (20 °C) and its original gaseous state. This procedure happens at the beginning of the downstream LNG supply chain and the process is called regasification. Alternative means of executing this procedure have been presented:

- Via onshore LNG regasification terminals
- Via offshore Gravity Based Structure (GBS) LNG regasification terminals, which is a new concept and only one has been built. It's located in Adriatic Sea, Italy and is made by the company Adriatic LNG.
- Via floating terminals named Floating Storage Regasification Units (FSRUs) (*IGU 2017 World LNG Report*, 2017)

As shown in the first chapter, natural gas is on the rise this past decade and it is considered by experts to climb even more on the popularity list of fuels. This leads to the increase of LNG carrier shipbuilding and thus regasification terminals. (figure 4-1).

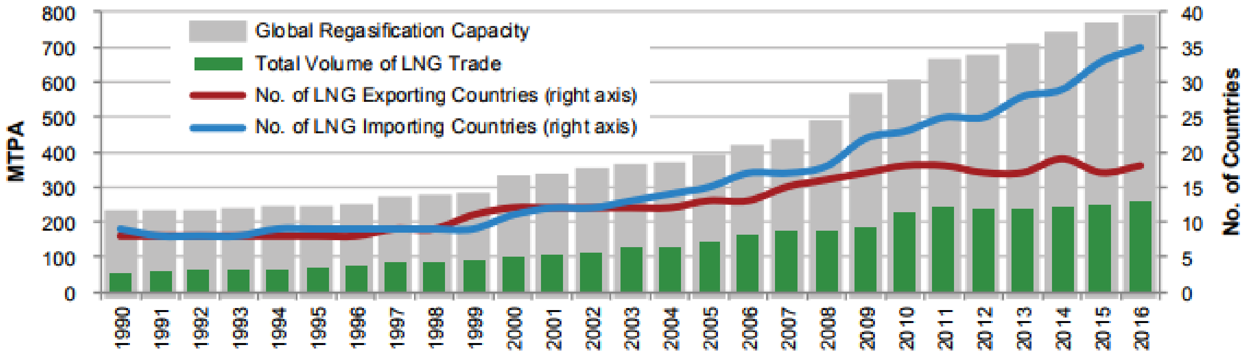



**Figure 4-1 Total global LNG regasification capacity (IGU 2017 World LNG Report, 2017)**

As far as FSRUs are concerned, the first was deployed on 2005 by Exmar and ever since many more have been in service (figure 4-2) and planned (figure 4-3).

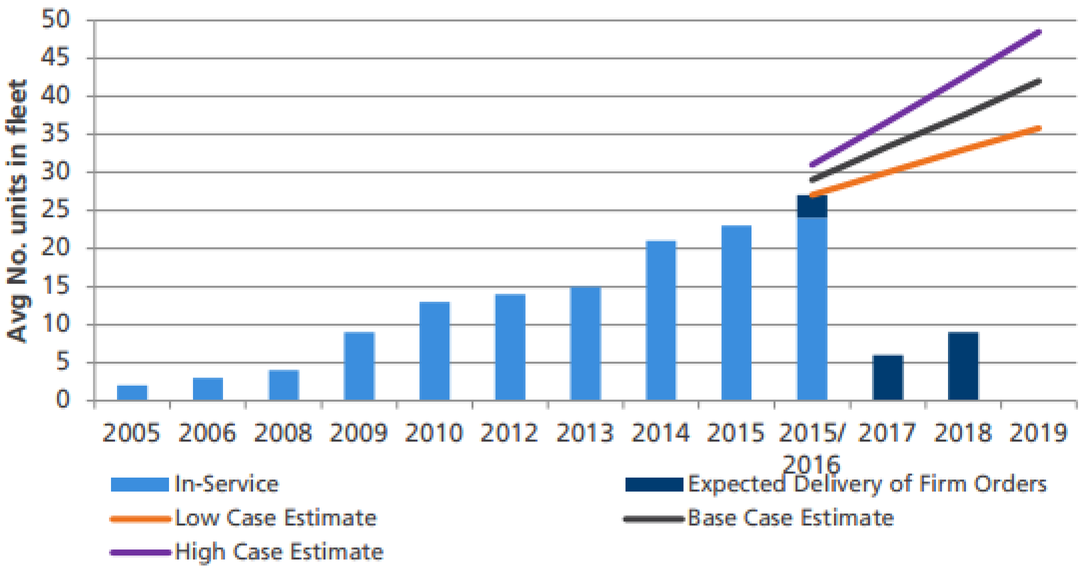



**Figure 4-2 Global FSRU demand outlook (Lloyd's Register, 2016)**

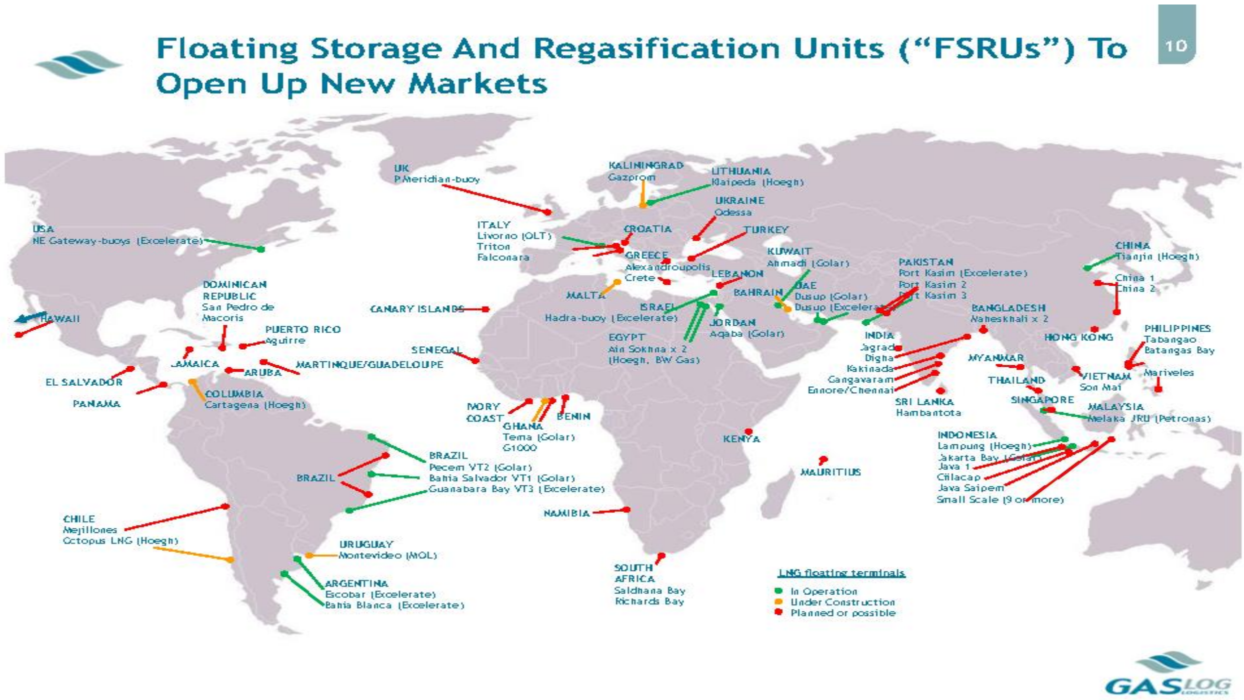



**Figure 4-3 FSRUs around the globe (GASLOG LTD., 2017b)**

However, there are advantages in favor of offshore regasification units over onshore terminals, which lead to the rise of the former during the recent years. More specifically, till the beginning of 2017 there is only one offshore regasification terminal (Adriatic LNG/ Rovigo), 93 onshore terminals, 13 onshore terminals under construction, 20 floating terminals, 6 floating terminals under construction, 23 FSRUs built and 7 under construction. These are: (*IGU 2017 World LNG Report*, 2017)

- They're faster to build. In fact, offshore regasification units can be built in half the time needed for the onshore terminal, when capacity is equal. (Manos Migadis, 2017)
- They're a lot cheaper, reaching up to a third of the price of a land based terminal (figure 4-4). In figure 2 SRV (LNG Shuttle and Regasification Vessel System) is appeared, which is an LNG vessel with onboard LNG vaporizers. (Larsen and Markussen, 2004)

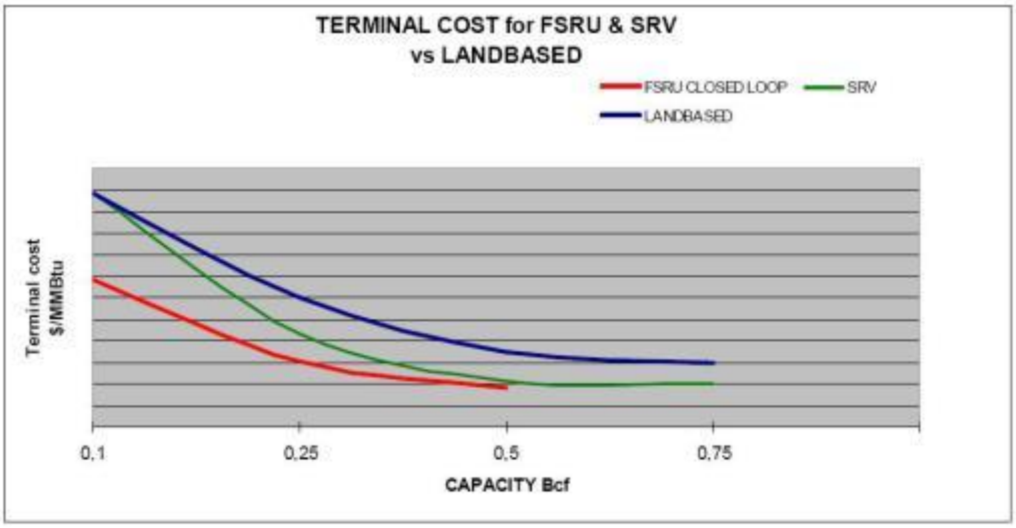



**Figure 4-4 Terminal costs for FSRU versus Onshore terminals ("What is FSRU?," 2009)**

- Due to being offshore, the offshore ones need less shore licenses, bureaucracy and land infrastructures
- They are floating, so they are movable from place to place. That increases terminal availability.
  (Manos Migadis, 2017)
- They have easier decommissioning. (Dino Ettore Cervetto, Head of RINA Technical Services, n.d.)
- A dockside or offshore regasification facility requires less land use than a land-based terminal, thus minimizing environmental impacts to the surrounding environment. ("Excelerate Energy – FSRU Technology," 2017)
- They can be deployed to supplement existing land-based capacity.

However, the use of onshore units still plays a big role in LNG transfer, because it is needed when:

- Significant volumes for storage and regasified gas are in demand.
- Land-based terminal construction is well under way.
- Existing land facilities have been designed to meet future increases in regasification demand. (Lloyd's Register, 2016)

An (FSRU) (figure 4-5) is a vital component of the LNG supply chain required in order to transform natural gas back into its gaseous form and feed it to a regional, a national gas network or even directly to a power station. A FSRU is a special type of ship which is used for the storage and the regasification of LNG. Lastly, the gas is transported via pipeline to the Grid. Rarely a FSRU unit can combine the two aforementioned operations with the transportation of LNG, these are called LNG Regasification Vessels (RV). ("What is Floating Storage Regasification Unit (FRSU)?," 2012a)

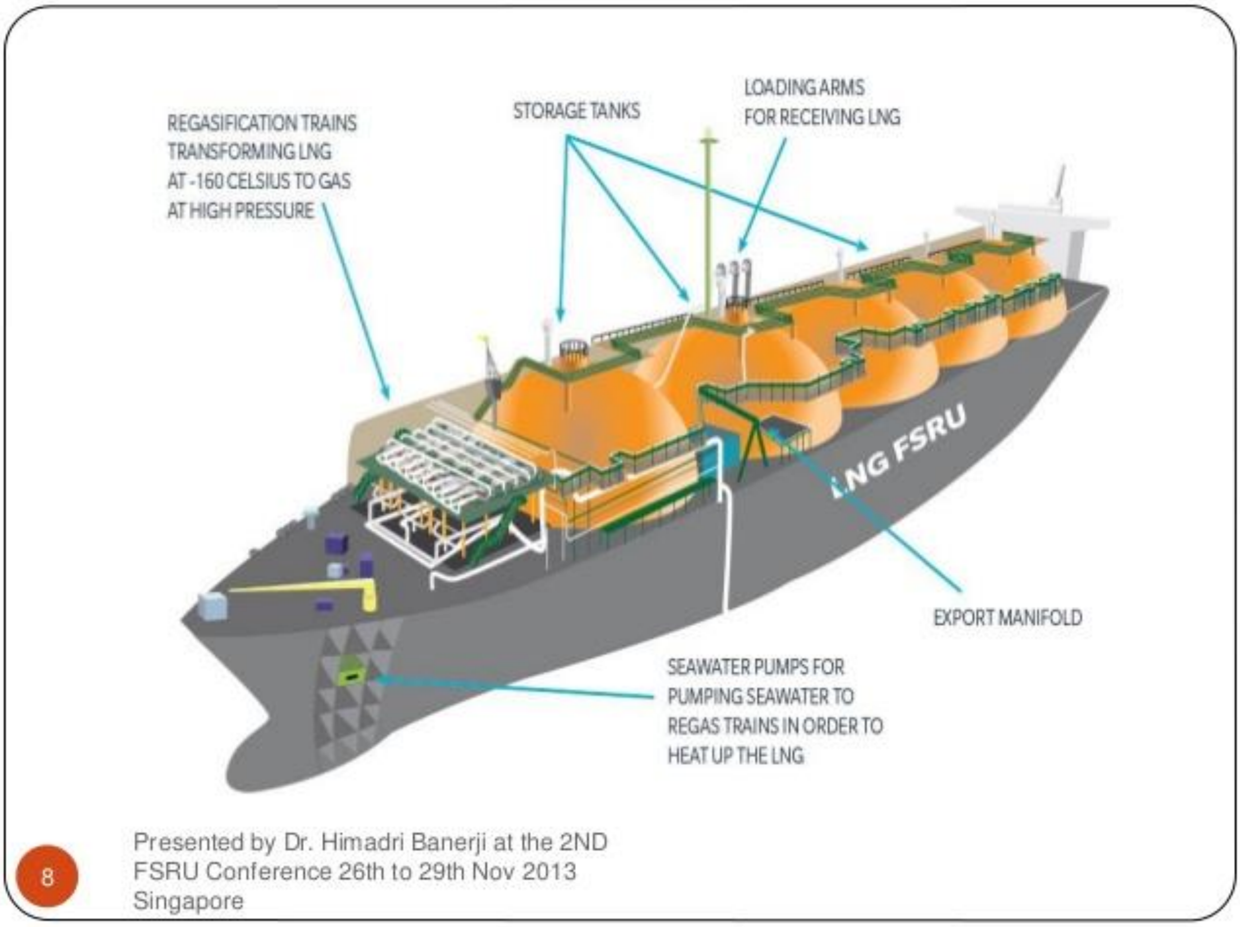



**Figure 4-5 FSRU overview (Dr. Himadri Banerji, 2013)**

So, they are two main types of offshore regasification units. These are:

- LNG RV (regasification vessel), which is a ship based on the conventional LNG carrier design with onboard LNG regasification facilities and internal turret for the sub-sea pipe connection (picture 4-1). The LNG RV can take the role of the conventional LNG carrier during the voyage, and at the same time it is used for an offshore regasification terminal when connected to a submerged buoy. The regasification process is mainly composed of the LNG feeding pumps, high pressure pumps, vaporizers, and send-out equipment, which is similar to that of a land-based LNG receiving terminal (figure 4-6). (Kim and Lee, 2005)

Picture 4-1 LNG RV (Kim and Lee, 2005)

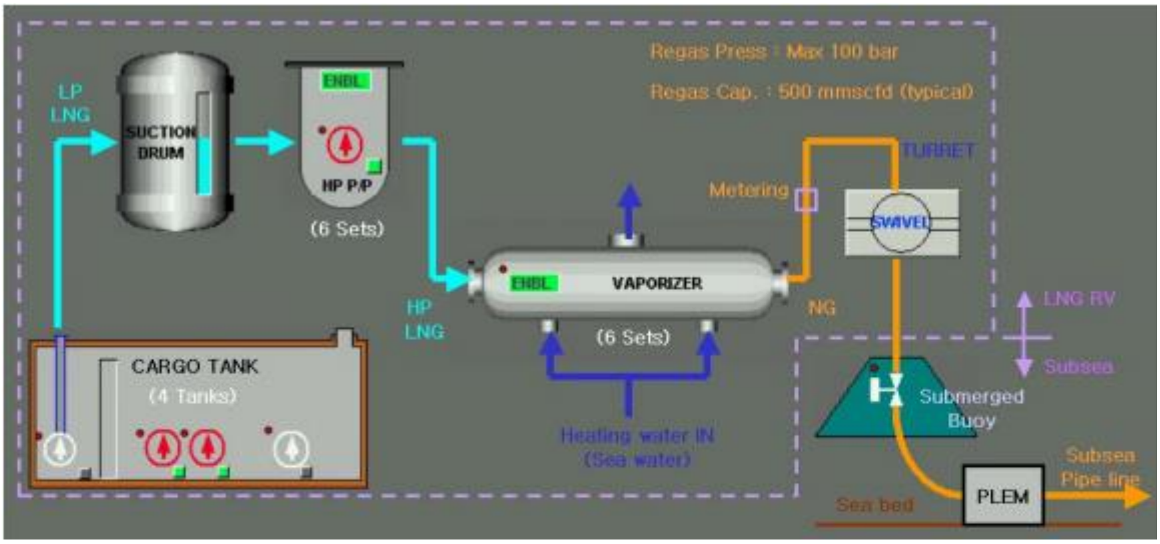



Figure 4-6 LNG RV Process Overview (Kim and Lee, 2005)

- FSRU, which is a floating LNG import terminal moored offshore or to a jetty allowing energy companies to store and regasify LNG close to markets with limited impact on land (picture 4-2). (Ragnar Wisløff, n.d.)

Picture 4-2 Different types of mooring of FSRU (Ragnar Wisløff, n.d.)

Between these two offshore regasification units, the advantages of the one over the other have to be carefully examined for each specific project. These pros and cons are the following:

- ✓ FSRU sails at a speed of 18 kn or lower, whereas LNG RV sail at 19,5 kn with 21% sea margin as conventional LNG carriers
- ✓ Installed power of FSRU is reduced compared to LNG RV.
- ✓ There are FSRUs without propulsion system.
- ✓ LNG RV is more expensive to build than FSRU given the same carrying and regasification capacity.

  (Manos Migadis, 2017)

There are no general requirements about FSRUs and each unit has to meet the specific needs of the charterer.

FSRUs can be constructed in three ways:

- As a new-built ship, that is built similarly to an LNG carrier, but has a regasification unit aboard. In this case, the process of regasification can be carried out within the vessel itself without having to unload the fuel in its semi-frozen slushy state.
- By using an old LNG carrier and converting it into an independent unit, which is finally placed in a particular destination. That option promises to be more viable, because even if LNG carriers are employed, their day rates and contract durations are significantly lower than those of FSRUs. Thus, conversion still appears to be a more lucrative alternative. It is also expected that LNG carriers that were built in 1970/1980 and which are now laid up could be revived as floating unit conversion prospects. ("What is Floating Storage Regasification Unit (FRSU)?," 2012b)
- Using regasification barges with LNG FSUs (FSRB). This option is developed for cases when the amount of LNG being transferred to land is low. In fact, FSRB have storage capacity from 7500 to 30,000 m³, while the smallest FSRU today has around 120,000 m³. So, if limited demand cannot support a large-scale fixed facility or a conventional large-scale FSRU, FSRB is used (figure 4-7). ("Floating storage and regasification barges," 2017)

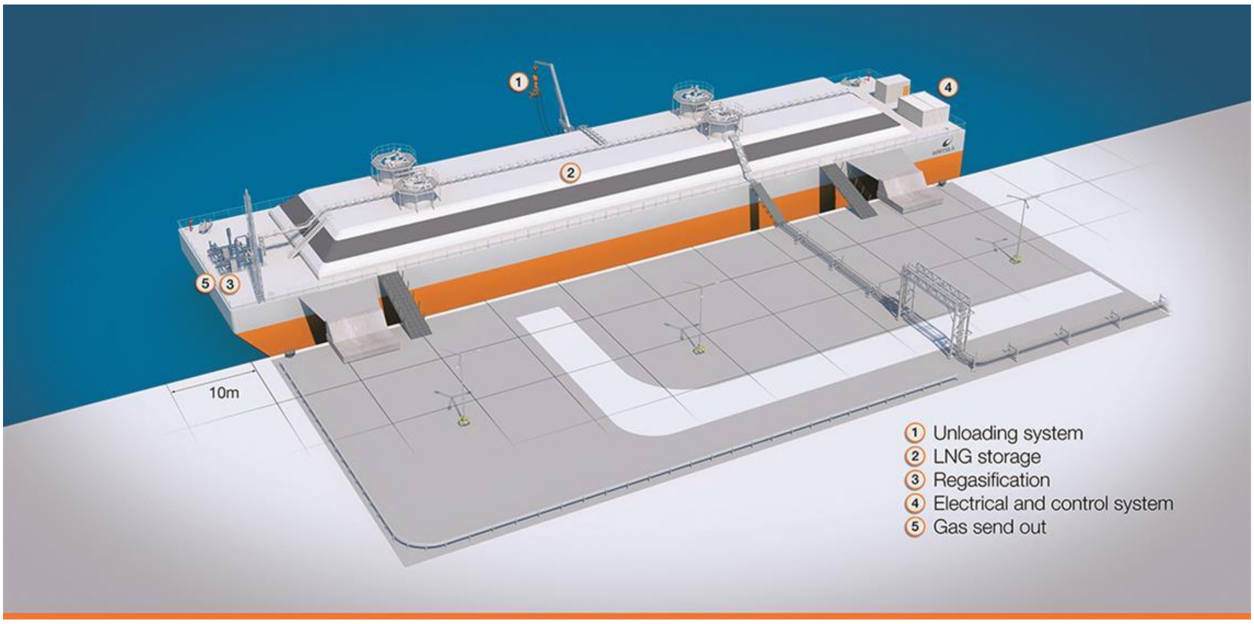



**Figure 4-7 FSRB overview ("Floating storage and regasification barges," 2017)**

The advantages and disadvantages of these types of construction are displayed on the following table. (table 4-1)

| | Barge and FSU | Conversion | Newbuilding |
|---|---|---|---|
| **Delivery Time** | 18 months | 20-22 months | 28-32 months |

| | | | |
|---|---|---|---|
| **Capacity** | 100-750 mmscfd* 20000-170000 $m^3$ | 250-750 mmscfd 145000-170000 $m^3$ | 500-1000 mmscfd 170000-266000 $m^3$ |
| **Designed For** | Protected sites 0,5-1 mtpa** | Calm sites 2,0-3,5 mtpa | Harsh weather sites 3,5-5,0 mtpa |
| **Key aspects** | 1) Built at most shipyards 2) Scalable as market grows 3) FSU candidates available | 1) Time to market 2) Lower upfront capex 3) Candidates available | 1) Purpose built 2) Low technical risk 3) Compatible with newer tonnage |
| **Cost** | $60-80 million + FSU | $70-90 million + vessel | $250-300 million |

**Table 4-1 Comparison between methods of building floating units (GASLOG LTD., 2017b)**

***Mmscfd: million standard cubic feet per day**
****Mtpa: million tonnes per annum**

## 4.2 Technical Characteristics

The technical characteristics of the various types of offshore unit (FSRU, FSU or LNGRV) may address the procedure of the regasification, albeit each in a distinct way utilizing different technologies. The main components of these technologies are the below:

### 4.2.1 Cargo containment system

It is one of the most crucial parts of LNG operations, as the liquid form of natural gas and its cryogenic temperature makes storing it a hard and expensive task. IMO has established regulation in regards to cargo containment by the application of the International Code for the Construction and Equipment of ships carrying liquefied gases in bulk (IGC CODE). These regulations impose, in short, that the design life of the cargo containment system shall not be less than the design life of the ship, its structural strength should be assessed against failure modes, including but not limited to plastic deformation, buckling and fatigue and it should meet specific criteria about collision, fire and flooded compartment causing buoyancy on tank. Two main systems have been developed for the storage of LNG:
(International Maritime Organization, 2016)

- Independent tanks, which are divided into three categories, type A, B and C. Type B are selected for large-scale floating units. Moss Type B technology is well established with a very good track record and service experience on LNG carriers constructed with spherical, independent tanks of either aluminum or 9% nickel steel, allowing for unrestricted operation alongside cargo tank filling limits (figure 4-8). Most Moss Type B aluminum FSRUs are conversions of relatively old steam turbine conventional LNG carriers. The SPB technology can be considered an alternative to Type B for FSUs (figure 4-9). Tanks bare arranged independent of the inner hull structure, being supported and held in place by a system of supports, anti-roll, anti-pitching/collision and anti-flotation chocks. (Lloyd's Register, 2016)


**Figure 4-8 Moss tank overview (Saurabh Agrawal, 2016)**

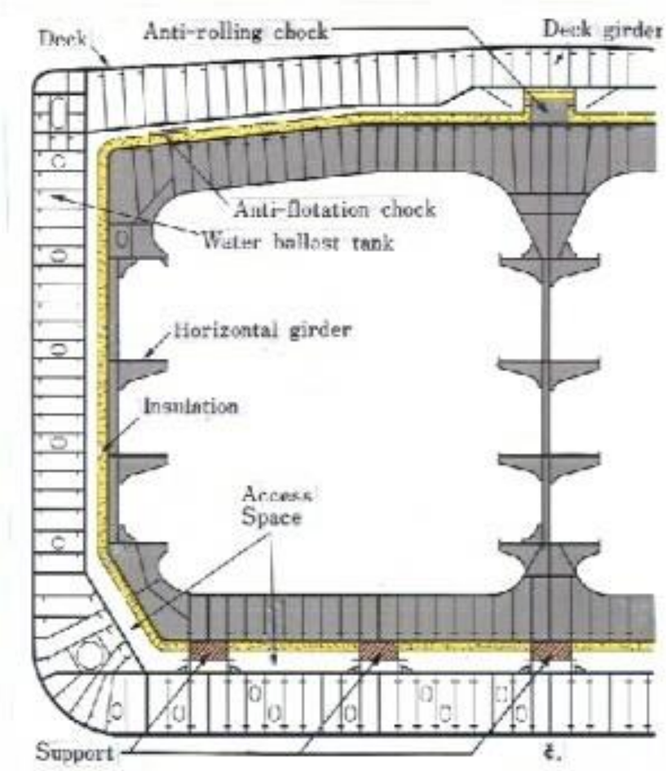



**Figure 4-9 SPB tank overview ("what is SPB," 2000)**

- Membrane systems, in which the LNG is stored at a temperature of -163°C for a cargo density of 0.470 to 0.500 tons per cubic metre and in atmospheric conditions. It is common, however, to establish a maximum vapour pressure of 0.7 bar in the FSRU mode (figure 4-10). The company Gaztransport & Technigaz (GTT) is the most known in the market of membranes (picture 4-3). The function of the membrane system is to prevent leakage, while the insulation supports and transmits the loads and, in addition, minimizes heat exchange between the cargo and the inner hull. The secondary membrane, sandwiched between the two layers of insulation, not only provides a safety barrier between the two layers of insulation, but also reduces convection currents within the insulation. This technology has the advantage of additional storage compared to the moss type tanks, as it is placed directly on the inside of the hull. (Lloyd’s Register, 2016)

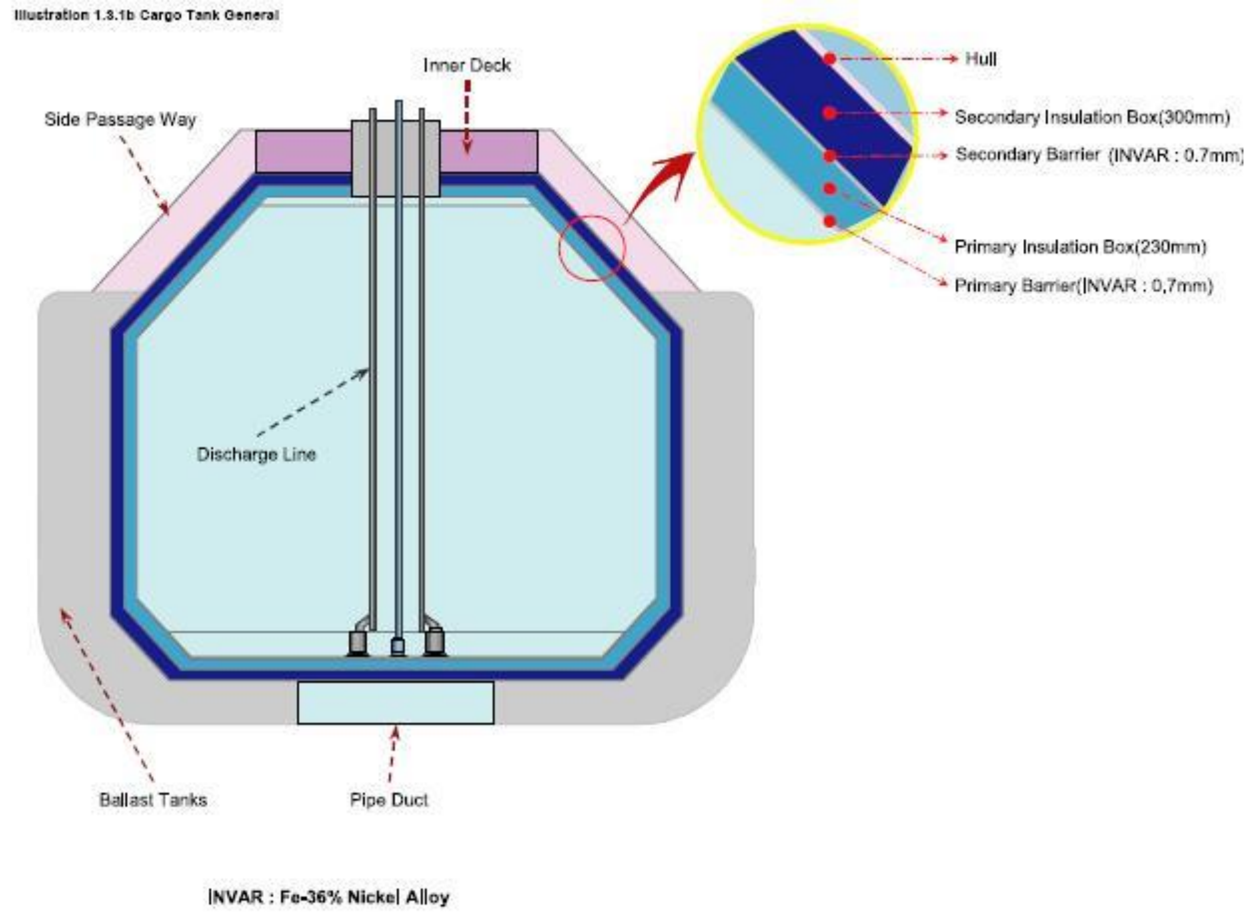
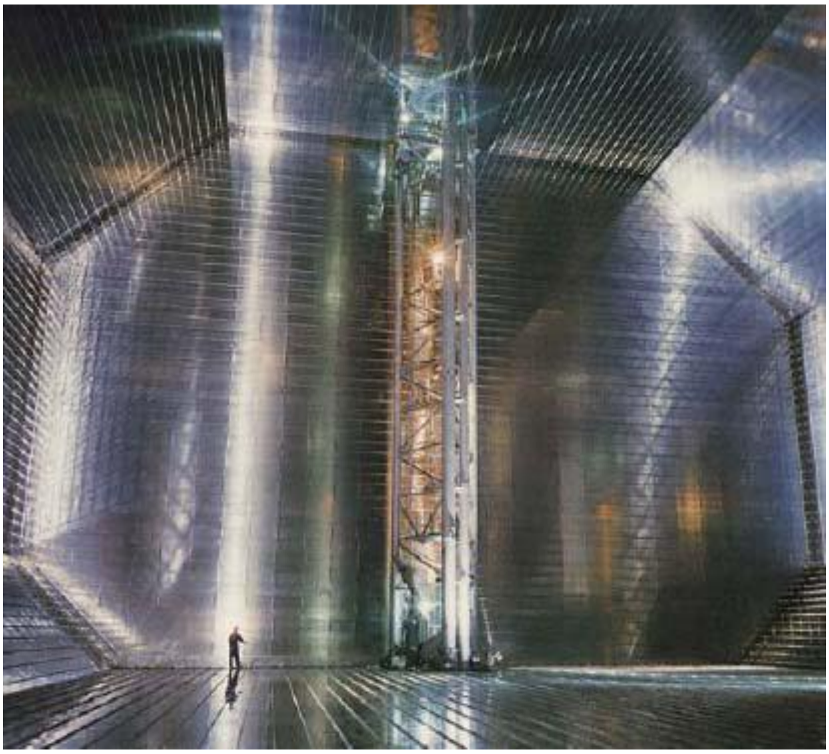



**Figure 4-10 Membrane design overview (“LNG vessel construction -Advantages of membrane technology,” 2017)**



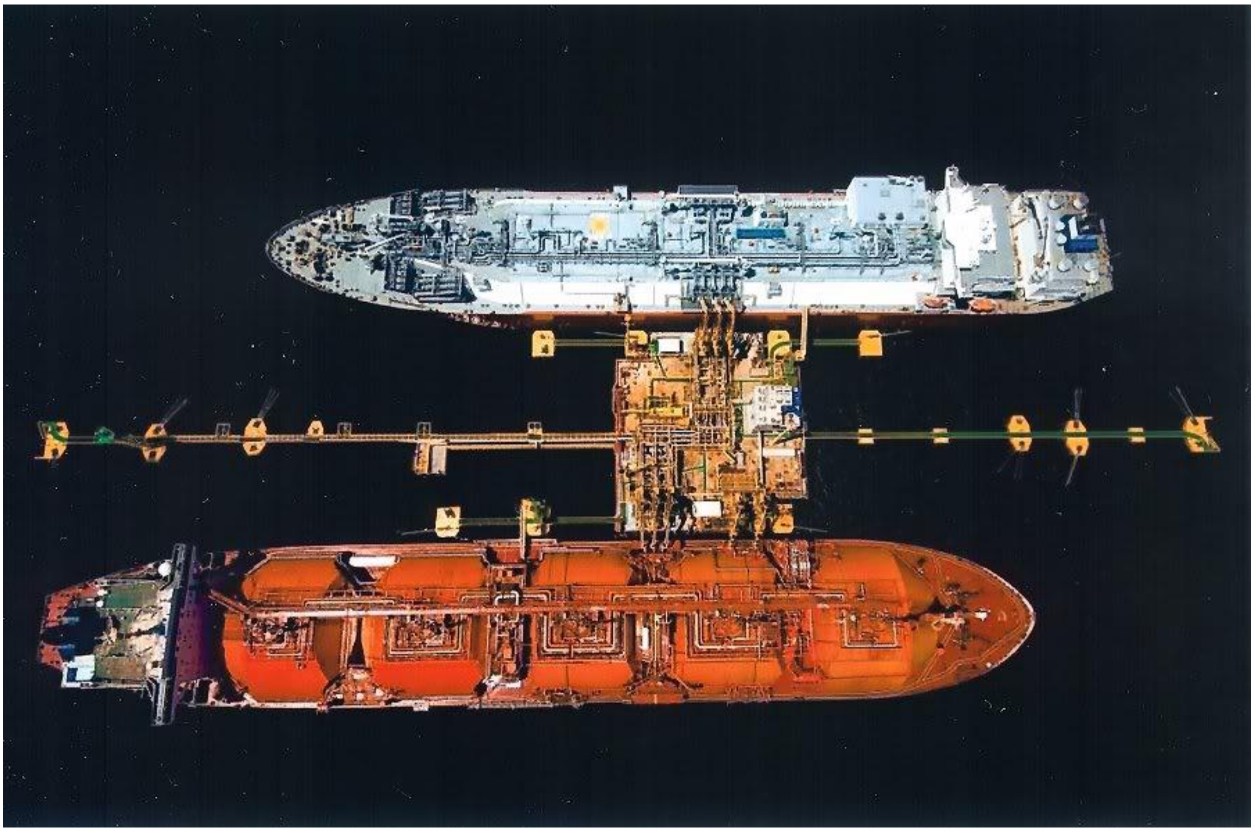
**Picture 4-3 MEMBRANE DESIGN - GAS TRANSPORT TECHNIGAZ (GTT) - GT96 ("LNG vessel construction -Advantages of membrane technology," 2017)**

Both containment systems have pros and cons. As far as the membrane system is concerned, the assessment for sloshing and the ways in which partial filling can be achieved is extremely crucial and the endurance of the containment depends on it. However, there are no filling restrictions at sheltered water of Hs ~ 2.0 m. On the other hand, MOSS and SPB tanks are preferred for moored FSRUs due to the higher durability to sloshing loads they have and the fact that they have no filling restrictions. (Manos Migadis, 2017)

### 4.2.2 Cargo loading/discharging system

It refers to the system that links and transfers the LNG from the LNG carrier to the floating unit. In order for the connection to be possible, applying the right offshore systems, monitoring relative movements between the two vessels, doing frequent maintenance and inspection and having an efficient emergency release system are crucial. The following connections are possible:

- Ship to jetty connection: The process of transferring LNG from the carrier to the FSRU through a jetty (picture 4-4). By the use of loading arms fixed on the jetty, the two vessels connect to the jetty. Moreover, the jetty may provide a regasification unit, when the floating unit doesn't afford it (as in case of FSUs), in which case the regasification is done there and the natural gas arrives to the unit in gas phase. (Lloyd's Register, 2016)



**Picture 4-4 FSRU to jetty to LNG carrier connection ("Some details of the FSRU 'Golar Spirit,'" 2003)**

- Side by side connection: The discharging of LNG utilizes flexible hoses, which is the result of double-banking between the LNG carrier and the FSRU and is most often selected over the others methods (picture 4-5). The side connection can also be performed through loading arms, which as the name implies is done using fixed loading arms and is usually used in cases of floating unit with a mooring turret system or a mooring dolphin and a breasting dolphin. The arms are fully balanced in all positions and are designed to allow the structure to absorb mechanical stresses (picture 4-6). (Lloyd's Register, 2016)

**Picture 4-5 STS flexible hoses ("Excelerate Energy – STS LNG Transfer," 2017)**

**Picture 4-6 STS loading arms (Mike Corkhill, 2013)**

### 4.2.3 Power systems/Propulsion arrangements

The power requirements for the FSRUs vary between 1,500 kW and 40,000 kW, depending on its designation (table 4-2). That range can be explained due to the fact that the floating unit may or may not provide a regasification unit and it may or may not be propelled. For propelled FSRUs the requirements are similar to most common LNG carriers of similar sizes (steam turbine, dual-fuel diesel electric (DFDE), dual-fuel direct driven). (Lloyd's Register, 2016)

| Cargo carrying capacity (cubic metres) | Designation | Propulsion type | No. of Screws | Engines | Total generated power ('000) |
|---|---|---|---|---|---|
| 112–332,000 | FSU | Non-propelled | - | 2 to 6 aux engines | 1.6–7.0 kW |
| 26,000 | Small FSRU | Non-propelled | - | Unknown | Unknown |
| | | Direct driven | | | n/a |
| 120–376,000 | FSU | Steam turbine | 1 | 1 steam turbine | 26–33 kW |
| 44–330,000 | FSU | Direct driven | 1 to 2 | 1 to 2 two-stroke engines and 3 aux engines | 8–36.4 kW |

**Table 4-2 FSU and FSRU power requirements (Lloyd's Register, 2016)**

LNG is used as fuel in many FSRUs in order to exploit the boil-off effect of the LNG cargo, thus minimizing energy losses while maximizing economic gains. The boil-off happens due to heat entering the cryogenic tank during storage and transportation, thus a part of the LNG in the tank continuously evaporates creating a gas called "Boil-Off Gas" (BOG), which changes the quality of LNG over time. Also, the use of dual fuel technologies can force a portion of the cargo to be "boiled-off" as this would be beneficial especially for units that locate on areas with restricted on SOx and NOx emissions. The main arrangements for FSRU propulsion are: (Lloyd's Register, 2016)

- Genset – DFDE (dual fuel diesel electric), in which case the number and size of the engines will depend on the power requirements and the size of the unit will also influence whether a single or twin skeg setup is required (figure 4-11). (Lloyd's Register, 2016)

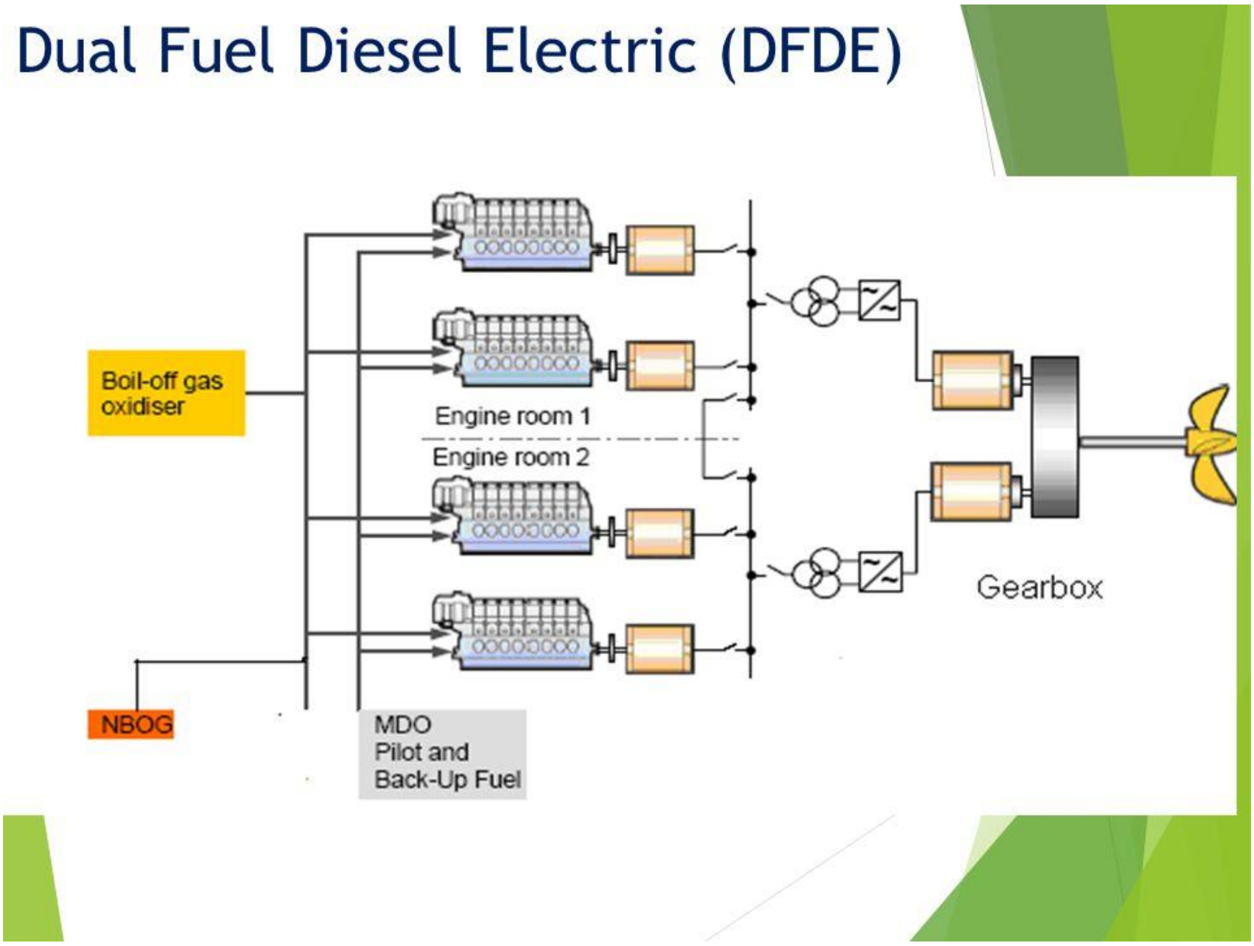



**Figure 4-11 DFDE propulsion (Anissa Knighton, 2015)**

- Genset – Gas turbines. This technology has not yet been applied to either LNG carriers or FSUs, but it has been shown it allows total power generation to meet the requirements of an FSRU both at sailing/manoeuvring periods and regasification times (figure 4-12). (Lloyd's Register, 2016)

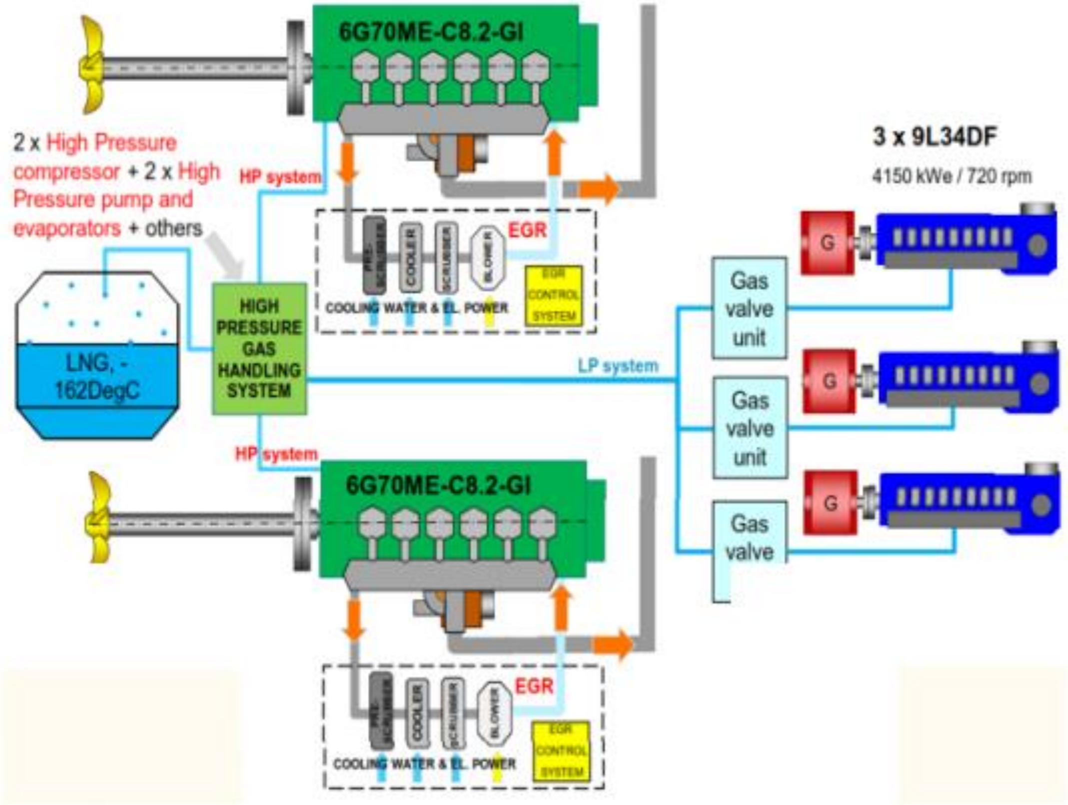



**Figure 4-12 Dual fuel gas turbine propulsion (Lloyd's Register, 2016)**

- Direct driven, which method includes the used of dual fuel and 2-stroke engines. Although it is shown to be very productive for LNG carriers, it's not essential for floating units, because of the diminished need for propulsion compared to the former. (Lloyd's Register, 2016)

### 4.2.4 Regasification systems

These systems are necessary for the regasification process that takes places on the floating units. The regasification plant's specification and capacity is derived from both the ship's characteristics (in case of retrofitting) and its requirements as a gas-receiving terminal. The main part of this system is the vaporizer, while there are also other minor yet necessary parts, such as the injection of a stenching agent and dehumidification or blending to ensure a constant calorific value in case the gas is being pumped or supplied directly to the shore-side distribution network. Also, the quality and volume of the gas being supplied would also require monitoring and recording for operational and safety reasons.

There are four main categories of these systems:

- The closed-loop propane with seawater as heating medium, where propane is supplied in liquid phase around the regasification loop, thus heating the LNG up order to change it to gas phase. The propane is supplied by the pump at a high pressure of approximately 4.7 bar, vaporized and at 0 °C. Lastly, after the LNG is warmed, the propane is sent back to the propane tank at a temperature of -5 ºC (figure 4-13). (Lloyd's Register, 2016)

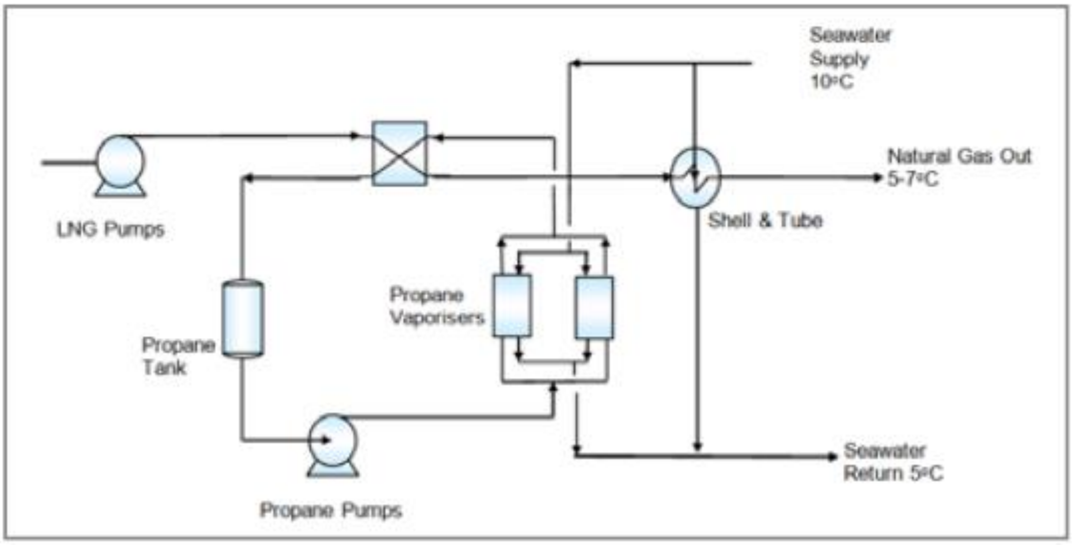



**Figure 4-13 closed-loop propane with seawater as heating medium method overview (Lloyd's Register, 2016)**

- Direct seawater vaporizers, which involve only one heat exchange process and one set of pumps in addition to the LNG supply pumps. Sea water is used in order to warm the LNG up and seawater pumps raise seawater's pressure to the required levels. After warming the LNG, the seawater is dumped overboard (figure 4-14). (Lloyd's Register, 2016)

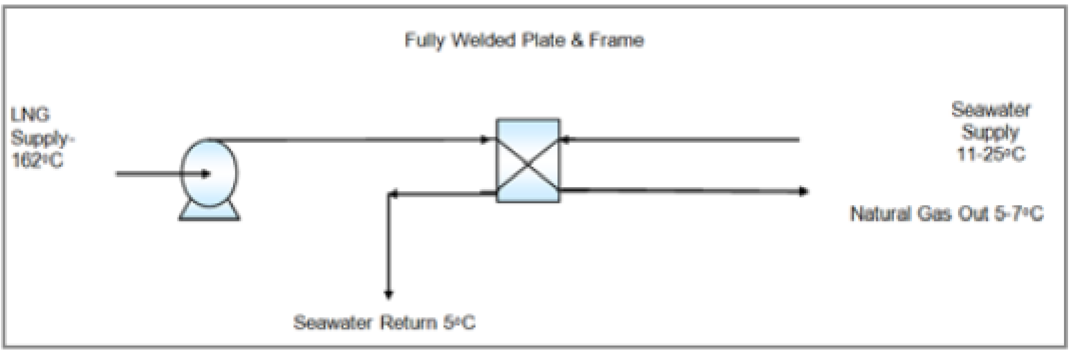



**Figure 4-14 Direct seawater vaporizers method overview (Lloyd's Register, 2016)**

- Closed-loop TEG/water and steam, in which tri-ethylene glycol (TEG) and fresh water are mixed together (approximately 35% TEG and the rest fresh water) at a temperature of 90 ºC in order to heat up the LNG. A centrifugal pump is used to supply the mixture and steam supplied at a pressure of 23 bars warms up the mixture in the shell and tube heat exchanger. The main heat exchanger that is needed for the heating up of the LNG is printed circuit heat exchanger (PCHE) is typically made of 316L Stainless Steel (SS), and the shell and tube from carbon steel (figure 4-15). (Lloyd's Register, 2016)

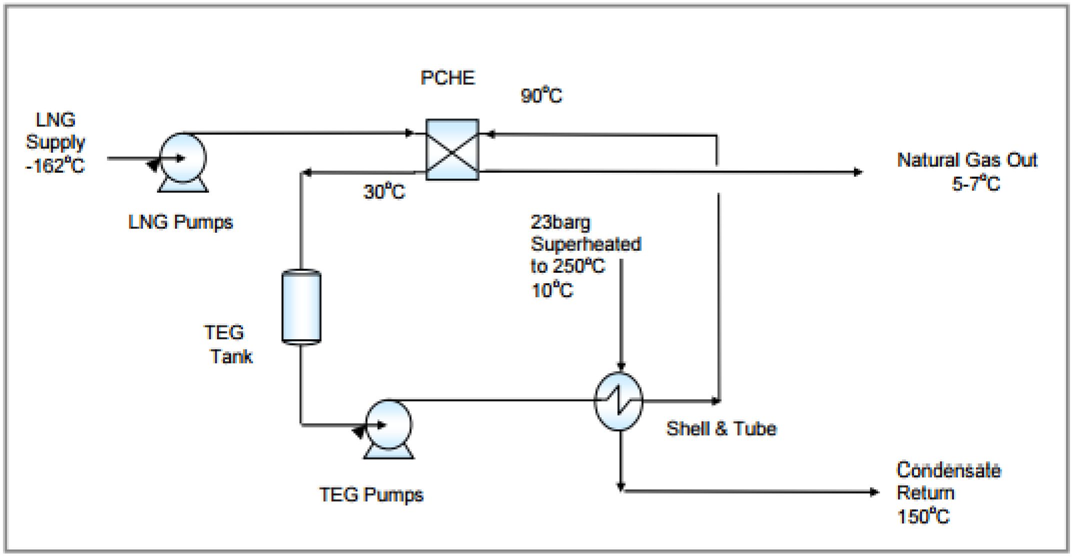



**Figure 4-15 Closed-loop TEG/water and steam method overview (Lloyd's Register, 2016)**

- Closed-loop TEG/water and seawater, where a mixture of TEG and fresh water is used in order to warm up LNG, as the above method. However, instead of steam, the heating medium for the TEG–fresh water mixture is seawater. The main PCHE is also made of 316 SS, whereas this Shell & Tube must be constructed from a corrosion-resistant alloy such as 22% chromium super duplex stainless steel (figure 4-16). (Lloyd's Register, 2016)

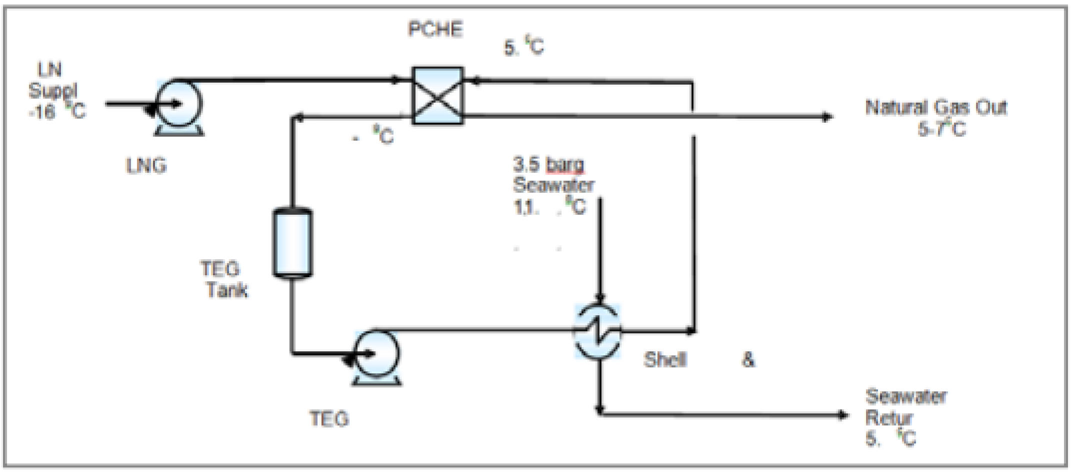



**Figure 4-16 Closed-loop TEG/water and seawater (Lloyd's Register, 2016)**

### 4.2.5 Mooring arrangements

The mooring of a FSRU also depends on the unit's designation. More specifically, they vary depending on the method by which the LNG will be unloaded to the floating unit and the way in which the send-out (LNG in the case of FSU, and gas in case of FSRU) will be exported from the unit to the terminal. Also, the design of the mooring is affected by environmental factors such as the water depth or the wind and current (figure 4-17).

These arrangements are mainly the following: (Lloyd's Register, 2016)

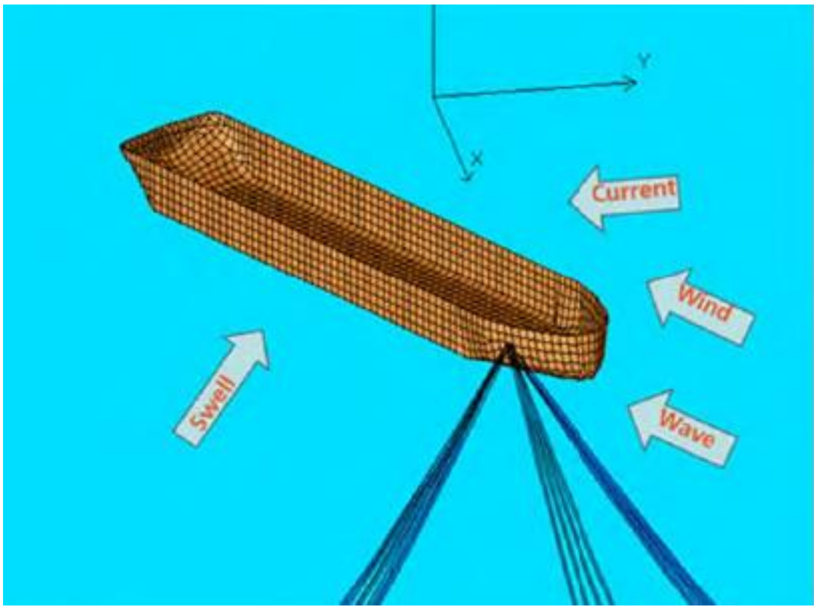
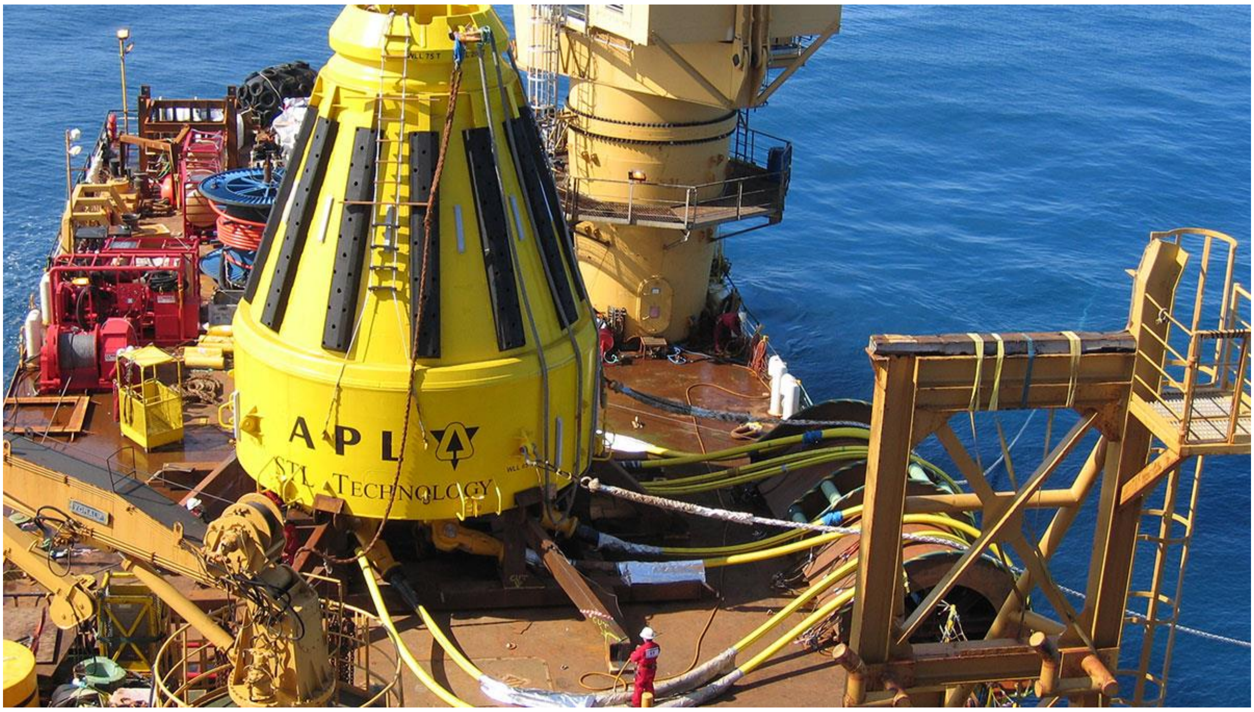



**Figure 4-17 Naturally occurring forces and moments straining a floating unit (Jose Navarro, 2013)**

- Mooring at a jetty, which may be part of the onshore terminal or not which then is referred to as "island jetty" (picture 4-7). The link between the floating unit and the LNG carrier is then accomplished by the aforementioned methods. (Manos Migadis, 2017)

**Picture 4-7 Island jetty mooring ("Aguirre Offshore Gasport," 2017)**

- Single point mooring through a turret (picture 4-8), which allows 360° movement using a swivel bearing. Side by side connection for transferring the gas is primarily done when the floating unit is moored like that and the turret allow the ships to remain double-banked. Also, the turret is usually connected to the front of the ship, so a special infrastructure needs to be created there and may be internal (figure 4-18) or external (picture 4-9). Lastly, the send-out gas from the regasification plant is sent through the turret via subsea pipes. (Lloyd's Register, 2016)




**Picture 4-8 Submerged Turret for mooring ("Submerged Turret Loading," 2017)**

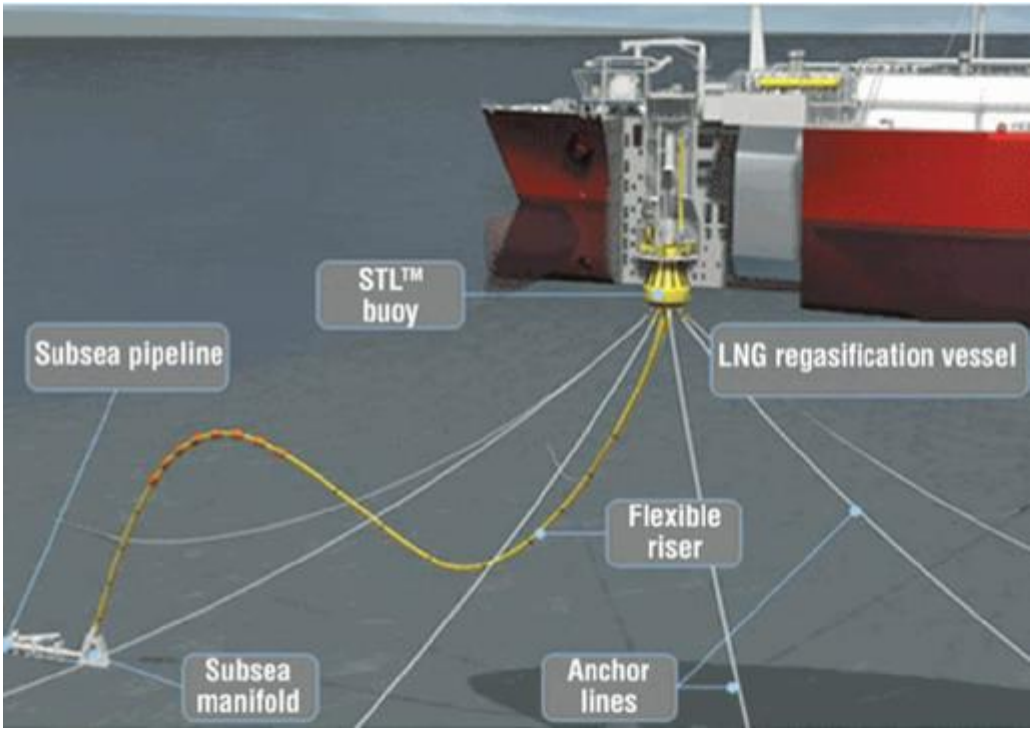



**Figure 4-18 Internal turret mooring (Manos Migadis, 2017)**


**Picture 4-9 External turret mooring ("Turret Mooring Solutions for FPSO & FSO," 2014)**

- Single point mooring through the soft yoke system, where a yoke tower is used to moor the unit (picture 4-10). It's a suitable method for shallow waters and the tower includes a ballast water tank to increase its stability and thus decrease the unit's excessive movement. Lastly, this method, as the previous one, is more commonly used when the unit and the carrier connect side by side. (Lloyd's Register, 2016)

**Picture 4-10 Yoke system mooring (Manos Migadis, 2017)**

## 4.3 Operational integration with floating terminals

Lloyds Register (LR) has been involved for over 10 years trying to come up with safety regulations for the regasification business. This integration can be achieved through a risk-based approach by performing studies in the form of:

- Hazard Identification (HAZID)
- Hazard and Operability (HAZOP)
- Navigation Simulations
- Quantified Risk Assessment (QRA)
- Reliability, Availability and Maintainability (RAM)

(Lloyd’s Register, 2016)

# 5 Feasibility study methodology

In this chapter, the methodology with which the feasibility study will be conducted is presented. To perform a feasibility study different financial criterions are being used. The criterions that will be discussed further and applied in this thesis are the following: Net Present Value (NPV), Internal Rate of Return (IRR), Capital Recovery Factor (CRF), Payback Period (PP) and Profitability Index (PI).

## 5.1 Net Present Value

The Net Present Value (NPV) is defined as the sum of the present values of the individual cash flows (both incoming and outgoing) of a series of cash flows. The Present Value is defined as the current worth of a future sum of money or stream of cash flows at a certain discount rate. (Naiyer Jawaid, 2013)

The mathematical formula of this criterion is the following:

$$\mathbf{NPV\ (i,N)} = \sum_{t=0}^{N} \frac{R_t}{\prod_{k=0}^{t}(1+i_k)}$$

$i_t$: It's the discount rate in a given time period t. By definition, when referring to the present (t = = 0), $i_0$ = 0. Discount rate is a rate at which the future cash flows are discounted to find present value. (Psaraftis, 2005)

N: It's the economic life of the investment. Economic life is the expected period of time during which an asset is useful to the average owner. The economic life of an asset could be different than its actual physical life. (Staff, 2010)

$R_t$: It's the net cash flow (cash inflow minus cash outflow) in a given time period t. Also, when t = 0 then $R_0<0$, because in the beginning of the investment a large sum of money has to be expended in order for the project to begin, thus creating negative cash flow initially. (Psaraftis, 2005)

In case of multiple projects being considered on the same period it is beneficial to use the combination of projects that give the largest NPV. For example, when two projects are proposed, A and B, there are four options:

1. Run no project.
2. Run only project A.
3. Run only project B.
4. Run both projects.

In order to choose one of the above four scenarios the discount rate has to be known. After that, the scenario with the largest NPV is the one to choose. So, it is obvious that the most significant factor of this criterion is the discount rate $i_t$.

Lastly, there are cases where the projects proposed are not independent. So, it would be wrong to assume that the net cash flow of the "A&B" scenario would be the same as the sum of the cash flow of project A plus the cash flow of project B, if each project was run alone. (Staff, 2010)

In addition, some specific scenarios about the projects should be analyzed. These are:

#### 5.1.1 Loan

In case of getting a loan, it is necessary to add that when using the NPV criterion. More specifically, the initial sum of money given as loan is added to the gains and then the payment of the loan plus the interest are part of the losses. As a result, the value of NPV would differ between a project with a loan or not. So, studying both scenarios is essential for finding the right solution.

There are three main factors determining the right choice. These are:

1. The interest rate r, which is different from the discount rate i. Interest rate is the proportion of a loan that is charged as interest to the borrower. In particular, the comparison between the two rates is the method leading to the right choice and the loan is preferred when r is lower than i.
2. The liquidity of the company or public service which is responsible for the project. Liquidity measures the ease with which an individual or company can meet their financial obligations with the liquid assets available to them and cash is the most liquid asset. So, the higher the liquidity of the company the lower the need for loan. (Liquidity)
3. The payment terms, mainly the payment period and the number of payments during that period. There are many ways to divide they payment, such as equal installments of the capital, equal installments of capital plus interest or balloon payment, in which case all of the capital is paid at the end. (Psaraftis, 2005)

#### 5.1.2 Taxes

Taxes are also included in the calculation of NPV as losses. In particular, taxes are a percentage of the taxable income during a period, and the percentage depends on the legislation of the country where the project takes place. The taxable income is usually different from the net cash flow. More specifically, it consists of the net cash inflow without the money earned from the loan, minus expenses, such as operational expenses, interest payment. Also, in case of a balloon loan, the sum of money earned or paid at the end is not added to the taxable income. Lastly, depreciation may occur to the asset of the project after some time and that is again added as a minus value in the taxable income. Depreciation refers to a reduction in the value of an asset over time, due in particular to wear and tear. (Psaraftis, 2005)

### 5.2 Internal Rate of Return

The Internal Rate of Return (IRR) is a rate of return at which the project's NPV becomes zero. It is usually used for large scale investments.

The mathematical formula of this criterion is the following:

**If $i_t$ = i = constant, then NPV (i) = $\sum_{t=0}^{N} \frac{R_t}{(1+i)^t}$**

**If NPV (i) = 0, then i = IRR**

The way this criterion works, is that between different projects, the one with the biggest IRR is the best option to run. That can be explained due to the fact that bigger IRR means that future cash flows can be discounted to a higher level and still NPV would be positive.

This criterion derives from the formula of NPV, but there are completely independent. For example, when choosing between two projects, the first one may be preferred as a better choice when using the NPV criterion, whereas when using IRR the second might appear to be the right choice. This phenomenon occurs depending on the discount rate being examined.

Lastly, there are a number of flaws in this criterion, these are:

1. There may be multiple discount rate values that lead to NPV = 0, so IRR is not defined unilaterally.
2. It's a dimensionless criterion, thus it ignores the scale of the investment.
3. As shown above, this criterion works only when $i_t$ = constant.

(Psaraftis, 2005)

## 5.3 Capital Recovery Factor

The Capital Recovery Factor (CRF) is a ratio used to calculate the present value of an annuity (a series of equal annual cash flows). ("Capital Recovery Factor," n.d.)

The mathematical formula of this criterion is the following:

**CRF = $\frac{IRR * (1+IRR)^N}{(1+IRR)^N - 1}$ & CRF = $\frac{E}{K}$**

E: It's the cash flow each time period. As said above, it's the same every time period t.

K: It's the initial cash outflow that is necessary in order to run the investment.

The CRF criterion is similar to the IRR. When following this criterion, the project with the highest CRF is chosen, because there is need for less equal cash flows in order to achieve capital recovery, which is the earning back of the initial funds put into an investment. (Psaraftis, 2005; Staff, 2011)

## 5.4 Payback Period

The criterion of Payback Period refers to how fast the total cash inflow from a running project will reach up to the initial investment value. Following this criterion the project to choose is the one with the smaller payback period.

Obviously, it's a flawed criterion, because it doesn't take into account the value of money during the future years as well as the scale of the investment. So, it will not be as significant as the others methods in examining the profitability and longevity of the project that is analyzed in the case study. (Psaraftis, 2005)

## 5.5 Profitability index

The profitability index (PI) is an index that attempts to identify the relationship between the costs and benefits of a proposed project through the use of a ratio calculated as:

$$\textbf{PI} = \frac{\textit{PRESENT VALUE OF FUTURE CASH FLOWS}}{\textit{INITIAL INVESTMENT REQUIRED}} = \mathbf{1} + \frac{\textit{NET PRESENT VALUE}}{\textit{INITIAL INVESTMENT REQUIRED}}$$

PRESENT VALUE OF FUTURE CASH FLOWS (PV): It's the current worth of future cash flows at a discount rate. However, it's not the same as NPV, because in PV the initial sum of money being invested is not taken into account. The mathematical formula connecting PV with NPV is the below:

**PV = NPV + INITIAL INVESTMENT**

(Obaidullah Jan, n.d.)

PI cannot be negative and must be converted to a positive figure before it's a useful criterion. A ratio of 1,0 is logically the lowest acceptable measure on the index, as any value lower than 1,0 would indicate that the project's PV is less than the initial investment. As values on the profitability index increase, so does the financial attractiveness of the proposed project. If PI is equal to one, it is situation of indifference where any gains or losses from a project are minimal.

When comparing between two projects, the one with the highest PI is the one to run. However, in some cases, when examining the application of two projects using both NPV and PI criterions, though they may be similar methods, they could give opposing results. In that situation, usually the project with the highest PI would be preferred. (Staff, 2004)

## 5.6 Real Data Used

It is essential to collect some data in order to conduct an economic feasibility study. These data are divided into two main categories: the costs and benefits per time period.

### 5.6.1 Costs

First of all, the operating expenses must be calculated. This category is defined as the sum of the costs of paying the crew, provision costs, insurance costs, cost of fuels, travel costs to transport the FSRU to the place that the project will be run and maintenance and repair costs. Also, in order to start the project a loan is usually used, so the payment must be added. In addition, taxes must be taken into account in the study. (Konstantinidis Dimitios et al., n.d.)

### 5.6.2 Benefits

As a project for investment, the FSRU project should bring economic benefits. That is the payout or in other words the expected financial return from an investment over a given period of time; it may be expressed on an overall or periodic basis as either a percentage of the investment's cost or in a real dollar amount.

Lastly, the liquidity of the company or public service that will run the project matters, as the money could be spent as initial investment. (Konstantinidis Dimitios et al., n.d.)

# 6 Case study. Feasibility Study of Alexandroupolis FSRU

In this chapter, a feasibility study will be conducted. In the study a project is considered, in which an FSRU is operated at Alexandroupolis along Greece's national NG grid. Moreover, the study is divided into two scenarios. The first explores the option of a joint company with shareholders a shipping company and a public NG company owning and operating the FSRU. The second one examines the project from two independent scopes, the one of the shipping company as owner and manager of the FSRU and that of the NG company chartering the FSRU from the shipping company and charging its use as a point of entry of NG.

Also, some information should be provided about the project, which is the base of the study. Firstly, the FSRU's storage is assumed 180,000 m$^3$ and its send-out capacity 6.1 bcm/year. In addition, the FSRU is being built between 2017-2018, its commercial activity starts at year 2019 and the study examines its operation for 20 years. (King & Spalding LLP, 2016)

## 6.1 First scenario

As mentioned above, this scenario is the study of collaboration of the shipping company (owning 60% of total shares) and NG company (owning 40% of the total shares). Thus it's assumed that each contributes respectively to the total annual cashflow. (figure 6-1) (figure 6-2)

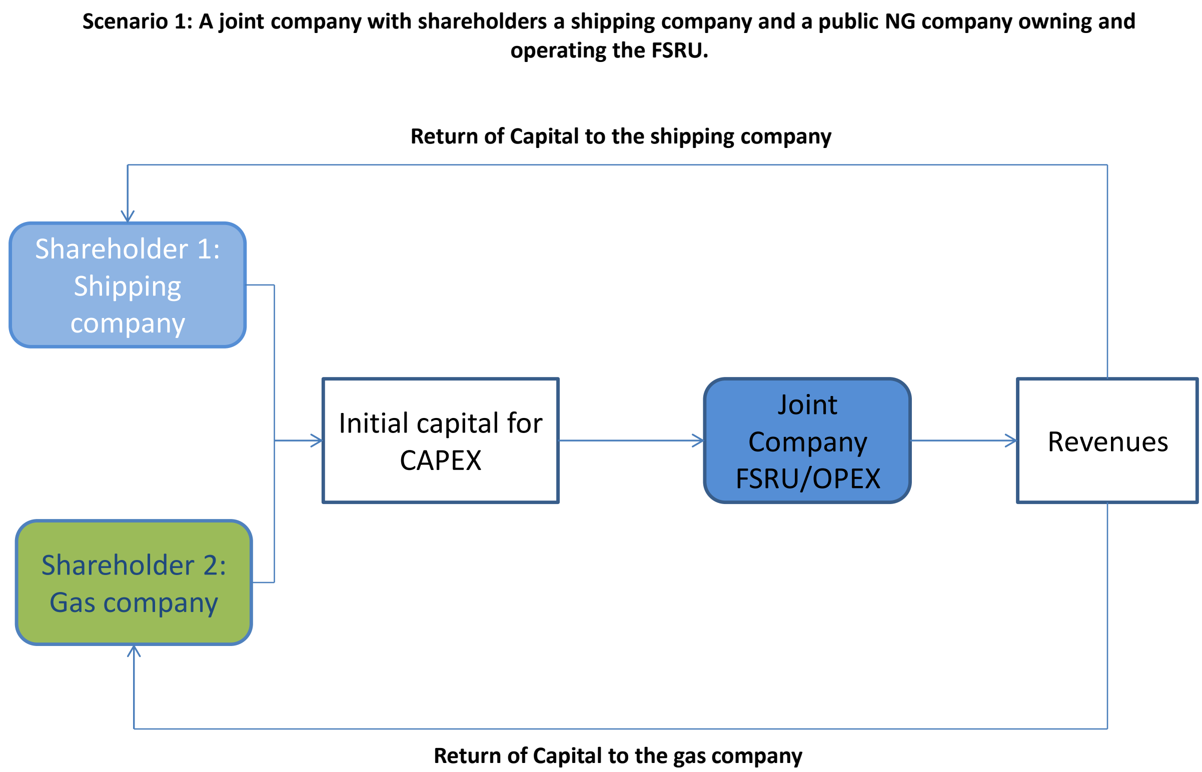



**Figure 6-1 General idea of the study of the 1st scenario**

**Scenario 1: A joint company with shareholders a shipping company and a public NG company owning and operating the FSRU.**

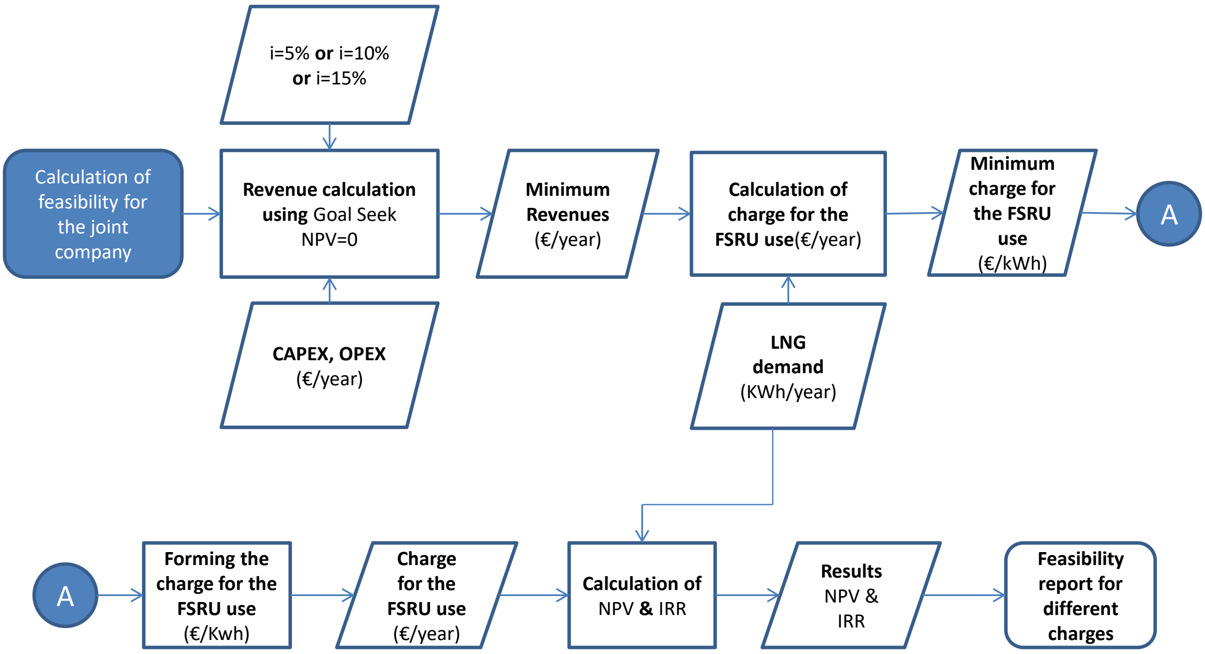



**Figure 6-2 Analytical plan of the study of the 1st scenario**

At the beginning, the annual cashflow had been calculated in total and then the appropriate division was done. The first part of the calculation was setting values for the annual expenses. This category consists of capital expenditures (CAPEX) (Table 5) and operation expenditures (OPEX). (Table 6-1)

| Component | FSRU (new build) [m €] * |
|---|---|
| Jetty including piping | 70 |
| Unloading lines | N/A |
| Tanks 3x60,000 m³ | in FSRU |
| FSRU Vessel | 225 |
| Process plant | in FSRU |
| Utilities | in FSRU |
| Onshore interface/infrastructure | 30 |
| **CAPEX** | 325 |
| Contingency 30% Onshore, 10% FSRU | 30 |
| Owners' Costs | 45 |
| **Total CAPEX** | 400 |

**Table 6-1 CAPEX's components (Songhurst, 2017)**
*** [m €]: million euros**

As shown above, total CAPEX are equal to 400 € and it is assumed to be paid in two equal annual installments of 200 mil. €, interest free. Annual OPEX occurs when FSRU is commercially active, so for the construction period of 2018-2018 the OPEX are zero. Moreover, OPEX consist of a wide variety of costs:

- Provision of personnel – onboard and located on the onshore interface
- Ongoing head office support to operations
- Fuel gas and oil for power generation and steam generation
- Maintenance and inspection
- Spare parts
- Chemicals and lubricants
- Insurance
- Harbour fees
- Tugs for supply tanker maneuvering
- Service boats for offshore located FSRUs
- Dredging
- Financing costs

Lastly, annual OPEX are assumed equal to 6.25% of total CAPEX.

In summary, annual expenses of the project are shown below. (Table 6-2)

| Years | CAPEX [m €] | OPEX [m €] |
|---|---|---|
| 2017 | 200 | 0 |
| 2018 | 200 | 0 |
| 2019 | 0 | 25 |
| 2020 | 0 | 25 |
| 2021 | 0 | 25 |
| 2022 | 0 | 25 |
| 2023 | 0 | 25 |
| 2024 | 0 | 25 |
| 2025 | 0 | 25 |
| 2026 | 0 | 25 |
| 2027 | 0 | 25 |
| 2028 | 0 | 25 |
| 2029 | 0 | 25 |
| 2030 | 0 | 25 |
| 2031 | 0 | 25 |
| 2032 | 0 | 25 |
| 2033 | 0 | 25 |
| 2034 | 0 | 25 |

| | | |
|---|---|---|
| 2035 | 0 | 25 |
| 2036 | 0 | 25 |
| 2037 | 0 | 25 |
| 2038 | 0 | 25 |

**Table 6-2 Annual CAPEX & OPEX**

After that, using the NPV criterion, the minimum annual revenue is calculated for the project's NPV=0, using three different discount rates:

- [A]: 5%
- [B]: 10%
- [C]: 15%

As mentioned above, years 2017 and 2018 were spent building the FSRU, so it is reasonable to suggest that no revenue occurs during that period. From 2018 onwards, the undiscounted annual revenue calculated for the three aforementioned scenarios of NPV=0 are calculated using GoalSeek Tool in Excel® is shown in the table below. (Table 6-3)

| | [A] | [B] | [C] |
|---|---|---|---|
| **Minimum Annual Revenue [m €]** | **57.90** | **74.33** | **93.70** |

**Table 6-3 Minimum Annual Revenues**

Thereinafter, the minimum LNG charge for the use of the FSRU is calculated using an assumed LNG demand serviced by the FSRU. The basis of the assumed demand is the LNG imported quantity in Greece for the year 2016, which is measured 0.53 MTPA (million tonnes per annum). The total LNG imported is considered to rise in the following years due to the benefits of NG as main fuel, which is split in half between Revithousa's and Alexandroupolis' terminals. Consequently, the year 2019 is considered to end with 1.1 MTPA LNG imports, half of which is delivered to the Alexandroupolis FSRU, 0.55 MTPA. After year 2019, an increase equal to 4% of the imported LNG is assumed and the LNG demand is calculated as shown in Table 6-4. (figure 6-3) (*The LNG industry GIIGNL ANNUAL REPORT 2017*, 2017)

| YEAR | LNG imported to Alexandroupolis [MTPA] | LNG imported to Alexandroupolis [m kWh per annum] |
|---|---|---|
| 2017 | 0 | 0 |
| 2018 | 0 | 0 |
| 2019 | 0.55 | 7945.962733 |
| 2020 | 0.572 | 8263.801243 |
| 2021 | 0.59488 | 8594.353292 |
| 2022 | 0.6186752 | 8938.127424 |
| 2023 | 0.643422208 | 9295.652521 |
| 2024 | 0.669159096 | 9667.478622 |
| 2025 | 0.69592546 | 10054.17777 |

| | | |
|---|---|---|
| 2026 | 0.723762479 | 10456.34488 |
| 2027 | 0.752712978 | 10874.59867 |
| 2028 | 0.782821497 | 11309.58262 |
| 2029 | 0.814134357 | 11761.96592 |
| 2030 | 0.846699731 | 12232.44456 |
| 2031 | 0.88056772 | 12721.74234 |
| 2032 | 0.915790429 | 13230.61204 |
| 2033 | 0.952422046 | 13759.83652 |
| 2034 | 0.990518928 | 14310.22998 |
| 2035 | 1.030139685 | 14882.63918 |
| 2036 | 1.071345273 | 15477.94475 |
| 2037 | 1.114199083 | 16097.06254 |
| 2038 | 1.158767047 | 16740.94504 |

**Table 6-4 LNG demand**

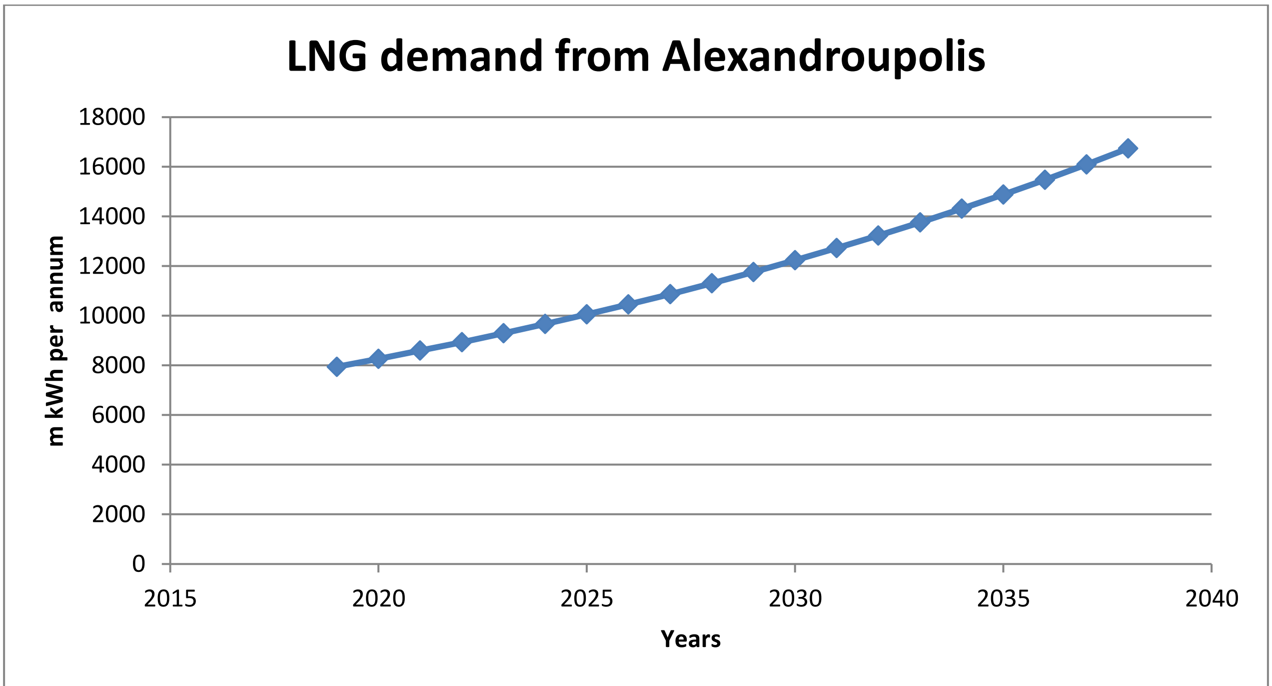



**Figure 6-3 LNG demand from Alexandroupolis**

The minimum charge for the FSRU use is calculated as € per year by dividing the minimum annual revenue to the LNG demand for three NPV scenarios. (Table 6-5) (figure 6-4)

| YEAR | Minimum Charge for the FSRU use per year [A] [€/KWh] | Minimum Charge for the FSRU use per year [B] [€/kWh] | Minimum Charge for the FSRU use per year [C] [€/kWh] |
|---|---|---|---|
| 2017 | 0 | 0 | 0 |
| 2018 | 0 | 0 | 0 |
| 2019 | 0.007286651 | 0.009354819 | 0.011791829 |
| 2020 | 0.007006396 | 0.008995018 | 0.011338297 |

| | | | |
|---|---|---|---|
| 2021 | 0.006736919 | 0.008649056 | 0.010902209 |
| 2022 | 0.006477807 | 0.0083164 | 0.010482893 |
| 2023 | 0.00622866 | 0.007996538 | 0.010079705 |
| 2024 | 0.005989096 | 0.007688979 | 0.009692024 |
| 2025 | 0.005758746 | 0.007393249 | 0.009319254 |
| 2026 | 0.005537256 | 0.007108894 | 0.008960821 |
| 2027 | 0.005324285 | 0.006835475 | 0.008616174 |
| 2028 | 0.005119505 | 0.006572572 | 0.008284783 |
| 2029 | 0.004922601 | 0.00631978 | 0.007966137 |
| 2030 | 0.00473327 | 0.006076712 | 0.007659747 |
| 2031 | 0.004551221 | 0.005842992 | 0.007365141 |
| 2032 | 0.004376174 | 0.005618262 | 0.007081867 |
| 2033 | 0.00420786 | 0.005402175 | 0.006809487 |
| 2034 | 0.004046019 | 0.005194399 | 0.006547584 |
| 2035 | 0.003890403 | 0.004994614 | 0.006295754 |
| 2036 | 0.003740772 | 0.004802514 | 0.006053609 |
| 2037 | 0.003596896 | 0.004617802 | 0.005820778 |
| 2038 | 0.003458554 | 0.004440194 | 0.005596902 |

**Table 6-5 LNG demand from Alexandroupolis**

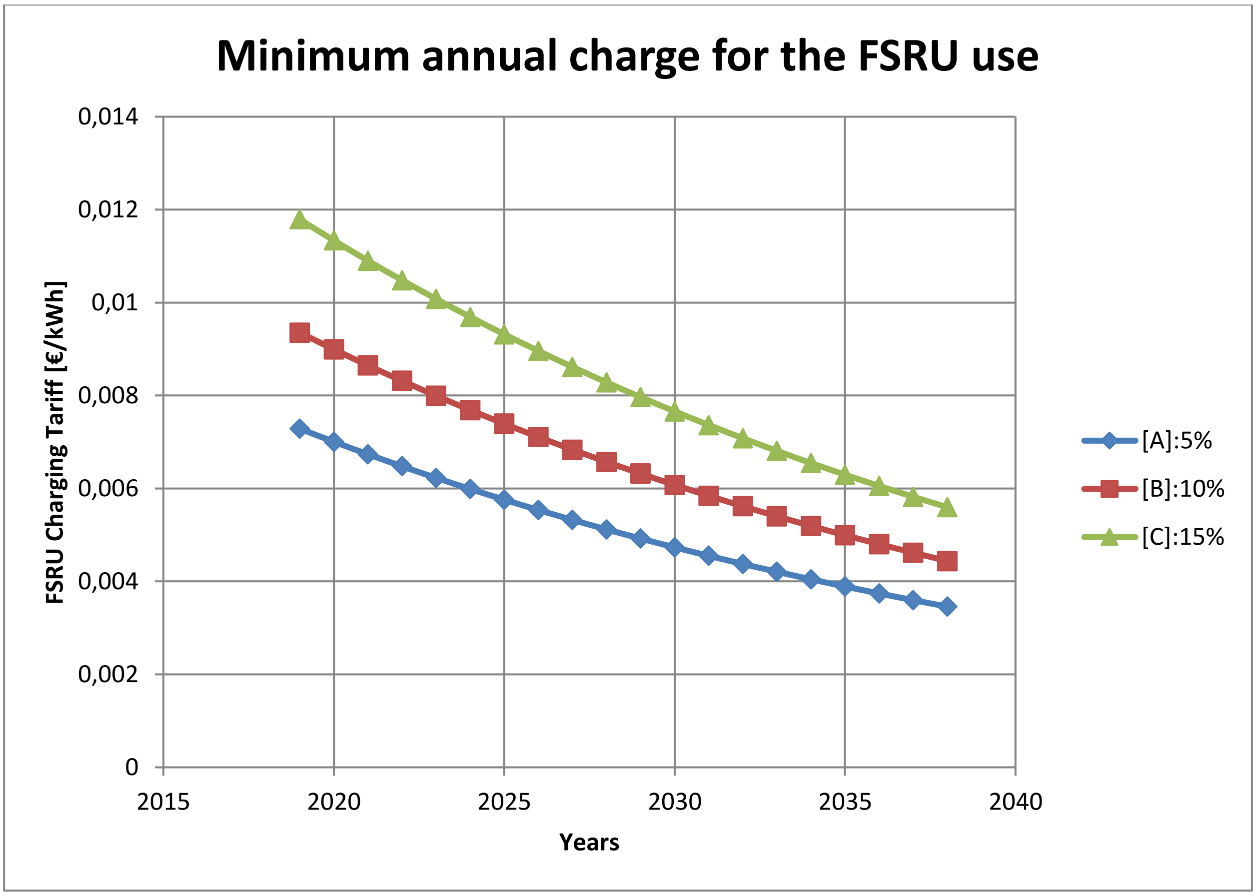


**Figure 6-4 Minimum annual charge for the FSRU use**

After the calculation of minimum FSRU tariffs, a reverse calculation is performed to produce the NPV and IRR for a commercial annual charge increased by 15% in a comparison with the minimum. (Tables 6-6,6-7,6-8)

| YEAR | Annual charge for the FSRU use [A] [€/KWh] | Real Revenue [A] [m €] |
|---|---|---|
| 2017 | 0 | 0 |
| 2018 | 0 | 0 |
| 2019 | 0.008379649 | 66.58437986 |
| 2020 | 0.008057355 | 66.58437986 |
| 2021 | 0.007747457 | 66.58437986 |
| 2022 | 0.007449478 | 66.58437986 |
| 2023 | 0.007162959 | 66.58437986 |
| 2024 | 0.006887461 | 66.58437986 |
| 2025 | 0.006622558 | 66.58437986 |
| 2026 | 0.006367845 | 66.58437986 |
| 2027 | 0.006122928 | 66.58437986 |
| 2028 | 0.00588743 | 66.58437986 |
| 2029 | 0.005660991 | 66.58437986 |
| 2030 | 0.00544326 | 66.58437986 |
| 2031 | 0.005233904 | 66.58437986 |
| 2032 | 0.0050326 | 66.58437986 |
| 2033 | 0.004839039 | 66.58437986 |
| 2034 | 0.004652922 | 66.58437986 |
| 2035 | 0.004473963 | 66.58437986 |
| 2036 | 0.004301888 | 66.58437986 |
| 2037 | 0.00413643 | 66.58437986 |
| 2038 | 0.003977337 | 66.58437986 |

**Table 6-6 Annual charge for the FSRU use assuming 5% discount rate**

| YEAR | Annual charge for the FSRU use [B] [€/kWh] | Real Revenue [B] [m €] |
|---|---|---|
| 2017 | 0 | 0 |
| 2018 | 0 | 0 |
| 2019 | 0.010758042 | 85.48299877 |
| 2020 | 0.010344271 | 85.48299877 |
| 2021 | 0.009946414 | 85.48299877 |
| 2022 | 0.00956386 | 85.48299877 |
| 2023 | 0.009196019 | 85.48299877 |
| 2024 | 0.008842326 | 85.48299877 |
| 2025 | 0.008502237 | 85.48299877 |

| | | |
|---|---|---|
| 2026 | 0.008175228 | 85.48299877 |
| 2027 | 0.007860796 | 85.48299877 |
| 2028 | 0.007558457 | 85.48299877 |
| 2029 | 0.007267748 | 85.48299877 |
| 2030 | 0.006988219 | 85.48299877 |
| 2031 | 0.006719441 | 85.48299877 |
| 2032 | 0.006461001 | 85.48299877 |
| 2033 | 0.006212501 | 85.48299877 |
| 2034 | 0.005973559 | 85.48299877 |
| 2035 | 0.005743806 | 85.48299877 |
| 2036 | 0.005522891 | 85.48299877 |
| 2037 | 0.005310472 | 85.48299877 |
| 2038 | 0.005106223 | 85.48299877 |

**Table 6-7 Annual charge for the FSRU use assuming 10% discount rate**

| YEAR | Annual charge for the FSRU use [C] [€/kWh] | Real Revenue [C] [m €] |
|---|---|---|
| 2017 | 0 | 0 |
| 2018 | 0 | 0 |
| 2019 | 0.013560603 | 107.7520471 |
| 2020 | 0.013039041 | 107.7520471 |
| 2021 | 0.01253754 | 107.7520471 |
| 2022 | 0.012055327 | 107.7520471 |
| 2023 | 0.01159166 | 107.7520471 |
| 2024 | 0.011145827 | 107.7520471 |
| 2025 | 0.010717142 | 107.7520471 |
| 2026 | 0.010304944 | 107.7520471 |
| 2027 | 0.0099086 | 107.7520471 |
| 2028 | 0.0095275 | 107.7520471 |
| 2029 | 0.009161058 | 107.7520471 |
| 2030 | 0.008808709 | 107.7520471 |
| 2031 | 0.008469913 | 107.7520471 |
| 2032 | 0.008144147 | 107.7520471 |
| 2033 | 0.00783091 | 107.7520471 |
| 2034 | 0.007529722 | 107.7520471 |
| 2035 | 0.007240117 | 107.7520471 |
| 2036 | 0.006961651 | 107.7520471 |
| 2037 | 0.006693895 | 107.7520471 |
| 2038 | 0.006436438 | 107.7520471 |

**Table 6-8 Annual charge for the FSRU use assuming 15% discount rate**

Then, using the new annual revenue, NPV and IRR were calculated. (Table 6-9)

| | **[A]** | **[B]** | **[C]** |
|---|---|---|---|
| **IRR:** | **7.8%** | **13.0%** | **18.3%** |

| FINAL NPV [m]: | 103.08 € | 86.30 € | 76.50 € |
|---|---|---|---|

Table 6-9 Final NPV and IRR

It seems that IRR is bigger in scenario C than B, and in scenario B is bigger than in A. The opposite appears to be true for the final NPV. That can be explained due to the fact that in scenario C we assume a discount rate bigger than A or B. So, IRR obviously would be larger. Also, it appears that in scenario A the discount rate increases the most as a percentage of the initial discount rate (from 5% to 7.8%), next is B (from 10% to 13.0% ) and the smallest raise appears in C (from 15% to 18.3%). This can be explained due to the fact that the increase in revenue was the almost the same for the three scenarios (same percentage and similar initial revenues), but the higher initial discount rate is the lower the NPV change and the discount rate change as a percentage will be.  From the above, the results of final NPV are explained.

Lastly, in the frame of the simplified analysis by the present Thesis, the results of the performed financial analysis are apportioned 60% to the shipping company (Table 6-10) and 40% to the gas company, based on each one's shareholding capital ownership. (Table 6-11)

| **Shipping company** | | | |
|---|---|---|---|
| **YEAR** | **Total Annual Cashflow [A] [m €]** | **Total Annual Cashflow [B] [m €]** | **Total Annual Cashflow [C] [m €]** |
| 2017 | -120 | -120 | -120 |
| 2018 | -120 | -120 | -120 |
| 2019 | 24.95062792 | 36.28979926 | 49.65122827 |
| 2020 | 24.95062792 | 36.28979926 | 49.65122827 |
| 2021 | 24.95062792 | 36.28979926 | 49.65122827 |
| 2022 | 24.95062792 | 36.28979926 | 49.65122827 |
| 2023 | 24.95062792 | 36.28979926 | 49.65122827 |
| 2024 | 24.95062792 | 36.28979926 | 49.65122827 |
| 2025 | 24.95062792 | 36.28979926 | 49.65122827 |
| 2026 | 24.95062792 | 36.28979926 | 49.65122827 |
| 2027 | 24.95062792 | 36.28979926 | 49.65122827 |
| 2028 | 24.95062792 | 36.28979926 | 49.65122827 |
| 2029 | 24.95062792 | 36.28979926 | 49.65122827 |
| 2030 | 24.95062792 | 36.28979926 | 49.65122827 |
| 2031 | 24.95062792 | 36.28979926 | 49.65122827 |
| 2032 | 24.95062792 | 36.28979926 | 49.65122827 |
| 2033 | 24.95062792 | 36.28979926 | 49.65122827 |
| 2034 | 24.95062792 | 36.28979926 | 49.65122827 |
| 2035 | 24.95062792 | 36.28979926 | 49.65122827 |
| 2036 | 24.95062792 | 36.28979926 | 49.65122827 |
| 2037 | 24.95062792 | 36.28979926 | 49.65122827 |
| 2038 | 24.95062792 | 36.28979926 | 49.65122827 |

Table 6-10 Shipping Company's annual cashflow

| Gas company | | | |
|---|---|---|---|
| YEAR | Total Annual Cashflow [A] [m €] | Total Annual Cashflow [B] [m €] | Total Annual Cashflow [C] [m €] |
| 2017 | -80 | -80 | -80 |
| 2018 | -80 | -80 | -80 |
| 2019 | 16.63375194 | 24.19319951 | 33.10081885 |
| 2020 | 16.63375194 | 24.19319951 | 33.10081885 |
| 2021 | 16.63375194 | 24.19319951 | 33.10081885 |
| 2022 | 16.63375194 | 24.19319951 | 33.10081885 |
| 2023 | 16.63375194 | 24.19319951 | 33.10081885 |
| 2024 | 16.63375194 | 24.19319951 | 33.10081885 |
| 2025 | 16.63375194 | 24.19319951 | 33.10081885 |
| 2026 | 16.63375194 | 24.19319951 | 33.10081885 |
| 2027 | 16.63375194 | 24.19319951 | 33.10081885 |
| 2028 | 16.63375194 | 24.19319951 | 33.10081885 |
| 2029 | 16.63375194 | 24.19319951 | 33.10081885 |
| 2030 | 16.63375194 | 24.19319951 | 33.10081885 |
| 2031 | 16.63375194 | 24.19319951 | 33.10081885 |
| 2032 | 16.63375194 | 24.19319951 | 33.10081885 |
| 2033 | 16.63375194 | 24.19319951 | 33.10081885 |
| 2034 | 16.63375194 | 24.19319951 | 33.10081885 |
| 2035 | 16.63375194 | 24.19319951 | 33.10081885 |
| 2036 | 16.63375194 | 24.19319951 | 33.10081885 |
| 2037 | 16.63375194 | 24.19319951 | 33.10081885 |
| 2038 | 16.63375194 | 24.19319951 | 33.10081885 |

**Table 6-11 Gas company's annual cashflow**

As a result, in the frame of the simplified analysis by the present Thesis, it's assumed that the NPVs of the shareholding companies of the joint company are a percentage of the total NPV of the company, as calculated by the performed financial analysis, based on each one's shareholding capital ownership (table 6-12).

| | Shipping company | | Gas company | |
|---|---|---|---|---|
| | **NPV** | **IRR** | **NPV** | **IRR** |
| **[A]** | **61.85 €** | **7.8%** | **41.23 €** | **7.8%** |
| **[B]** | **51.78 €** | **13.0%** | **34.52 €** | **13.0%** |
| **[C]** | **45.90 €** | **18.3%** | **30.60 €** | **18.3%** |

**Table 6-12 NPV & IRR of each shareholding company**

Lastly, assuming constant FSRU charging price per year, the project's NPV is calculated for the three aforementioned discount rates. The values of zeroing the NPV for these rates are emphasized (Figure 6-5) (Table 6-13).

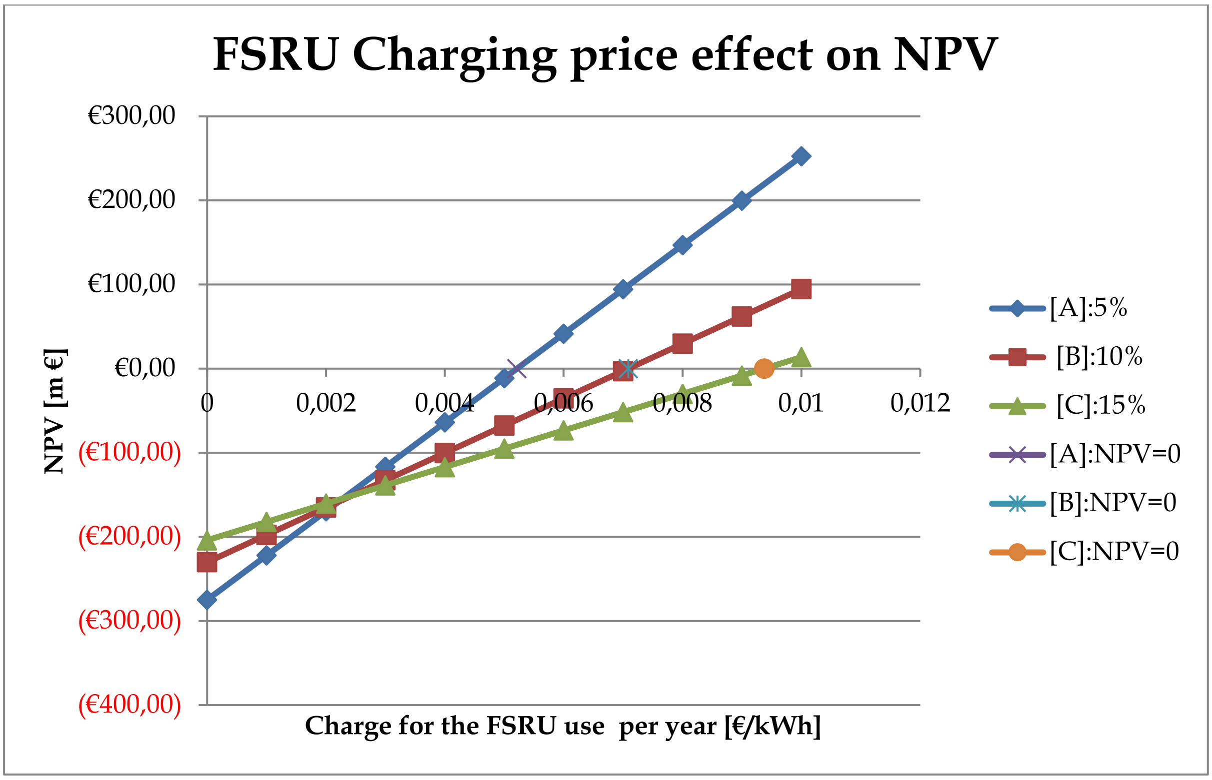



**Figure 6-5 FSRU charge effect on the project's NPV from the joint company's standpoint**

| NPV=0 | [A]:5% | [B]:10% | [C]:15% |
|---|---|---|---|
| Charge for the FSRU use per year [€/kWh] | 0.0052 | 0.0071 | 0.0094 |

**Table 6-13 FSRU charging price resulting to NPV=0**

## 6.2 Second scenario

In this scenario, the project's feasibility is analyzed from two different perspectives, those of the shipping company and the gas company. (figure 6-6) (figure 6-7) (figure 6-8)

**Scenario 2: A Shipping company owning and operating the FSRU charters it to a gas company**

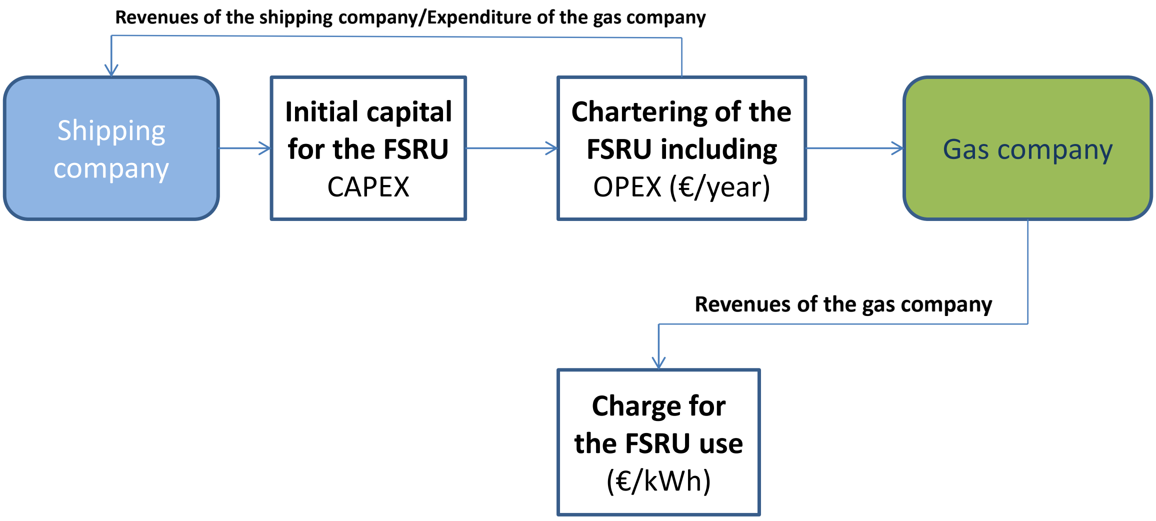



Figure 6-6 General idea of the second scenario

**Scenario 2: A Shipping company owning and operating the FSRU charters it to a gas company**

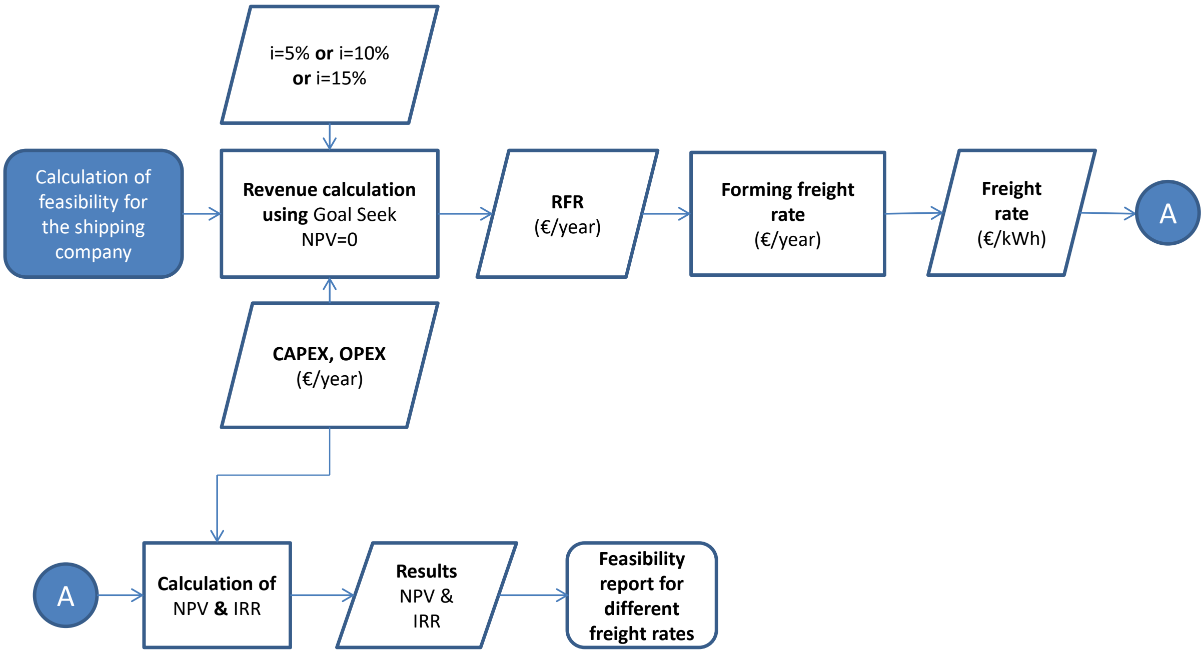



**Figure 6-7 Analytical plan of the study of the 1st scenario from shipping company perspective**

Scenario 2: A Shipping company owning and operating the FSRU charters it to a gas company

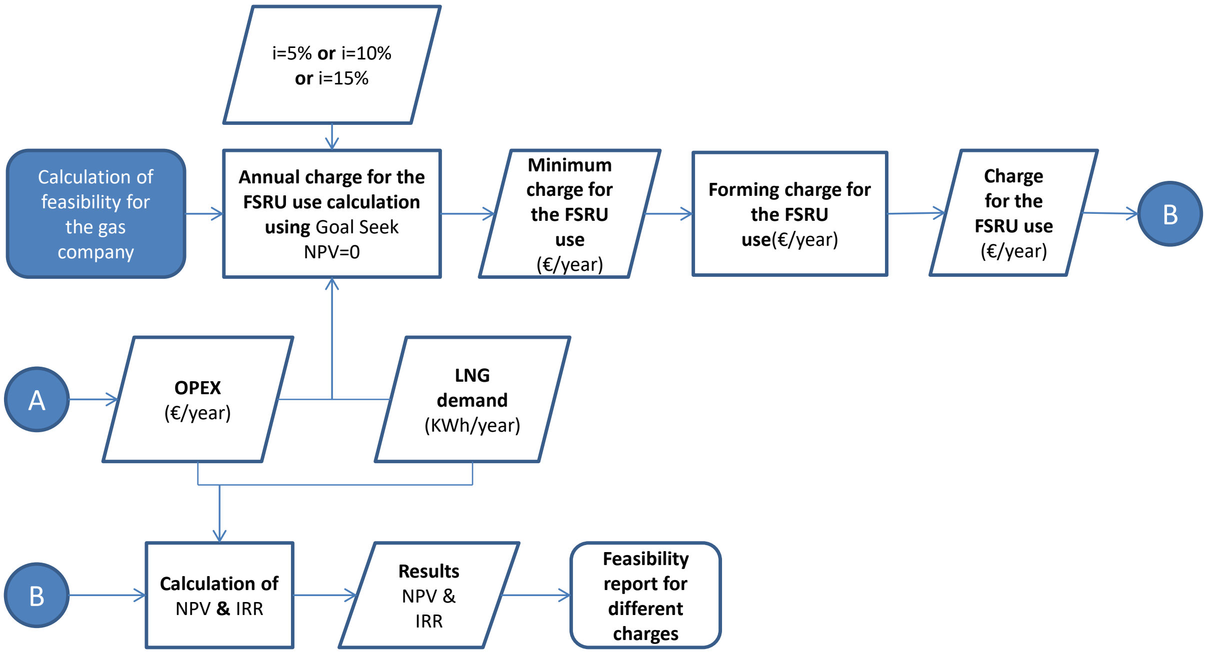



Figure 6-8 Analytical plan of the study of the 1st scenario from gas company perspective

### 6.2.1 Shipping company's perspective

For each perspective, the total annual expenses will be presented, divided into CAPEX and OPEX as mentioned above. The shipping company is responsible for the payment for the FSRU's construction. This payment is done in two installments of equal value and interest free as in the first scenario. The shipping company's OPEX are the same as in the first scenario except from the fuel to generate heat and power for the regasification process, which is expense of the gas company along with other costs such as financial, cost for chemicals and lubricants and other (Songhurst, 2017; "Time charter," n.d.). Gas company's OPEX are assumed to be 4250 €/day or 1.55 m €/year (Bjørn K. Markussen, 2004). (Table 6-14)

| YEARS | CAPEX (-) [m €] | OPEX ship (-) [m €] |
|---|---|---|
| 2017 | 200 | 0 |
| 2018 | 200 | 0 |
| 2019 | 0 | 23.45 |
| 2020 | 0 | 23.45 |
| 2021 | 0 | 23.45 |
| 2022 | 0 | 23.45 |
| 2023 | 0 | 23.45 |
| 2024 | 0 | 23.45 |

| | | |
|---|---|---|
| 2025 | 0 | 23.45 |
| 2026 | 0 | 23.45 |
| 2027 | 0 | 23.45 |
| 2028 | 0 | 23.45 |
| 2029 | 0 | 23.45 |
| 2030 | 0 | 23.45 |
| 2031 | 0 | 23.45 |
| 2032 | 0 | 23.45 |
| 2033 | 0 | 23.45 |
| 2034 | 0 | 23.45 |
| 2035 | 0 | 23.45 |
| 2036 | 0 | 23.45 |
| 2037 | 0 | 23.45 |
| 2038 | 0 | 23.45 |

**Table 6-14 Shipping Company's CAPEX & OPEX**

On the other hand, the shipping company's revenue is generated by the chartering of the FSRU, namely, the gas company pays a daily freight rate to the shipping company, according to a specific time charter in order to provide and operate the unit. Also, the possibility of selling or using the FSRU for scrap is taken into consideration (Table 6-15). It is assumed that the vessel depreciates at almost 5 per cent on a straight line basis during the 20 years of the project. (Stopford, 2009)

| YEARS | Scrapping Value (+) [m €] |
|---|---|
| 2017 | 0 |
| 2018 | 0 |
| 2019 | 0 |
| 2020 | 0 |
| 2021 | 0 |
| 2022 | 0 |
| 2023 | 0 |
| 2024 | 0 |
| 2025 | 0 |
| 2026 | 0 |
| 2027 | 0 |
| 2028 | 0 |
| 2029 | 0 |
| 2030 | 0 |
| 2031 | 0 |
| 2032 | 0 |
| 2033 | 0 |
| 2034 | 0 |
| 2035 | 0 |
| 2036 | 0 |

| | |
|---|---|
| 2037 | 0 |
| 2038 | 16 |

**Table 6-15 FSRU's Scrapping Value**

After that, using the NPV criterion the required freight rate (RFR) is calculated. RFR is the minimum freight rate that the company earns, in order to nullify the project's Present Value. Also, three different discount rates of return were used in the calculations:

- [A]: 5%
- [B]: 10%
- [C]: 15%

As mentioned above, years 2017 and 2018 were spent building the FSRU, so it is reasonable that no revenue occurs during that period. Furthermore, equal annual revenue is assumed. So, the resulting freight rate is shown in the table below. (Table 6-16)

| | [A] | [B] | [C] |
|---|---|---|---|
| **RFR (+) [m €] :** | 55.87 | 72.50 | 91.99 |

**Table 6-16 RFR**

Then, a freight rate profitable for the shipping company is considered and so it is assumed that a freight rate increased by 15% using RFR as a basis is proposed. (Table 6-17)

| YEARS | Freight rate (+) [A] [m €] | Freight rate (+) [B] [m €] | Freight rate (+) [C] [m €] |
|---|---|---|---|
| 2017 | 0 | 0 | 0 |
| 2018 | 0 | 0 | 0 |
| 2019 | 64.24541626 | 83.37924167 | 105.7899361 |
| 2020 | 64.24541626 | 83.37924167 | 105.7899361 |
| 2021 | 64.24541626 | 83.37924167 | 105.7899361 |
| 2022 | 64.24541626 | 83.37924167 | 105.7899361 |
| 2023 | 64.24541626 | 83.37924167 | 105.7899361 |
| 2024 | 64.24541626 | 83.37924167 | 105.7899361 |
| 2025 | 64.24541626 | 83.37924167 | 105.7899361 |
| 2026 | 64.24541626 | 83.37924167 | 105.7899361 |
| 2027 | 64.24541626 | 83.37924167 | 105.7899361 |
| 2028 | 64.24541626 | 83.37924167 | 105.7899361 |
| 2029 | 64.24541626 | 83.37924167 | 105.7899361 |
| 2030 | 64.24541626 | 83.37924167 | 105.7899361 |
| 2031 | 64.24541626 | 83.37924167 | 105.7899361 |
| 2032 | 64.24541626 | 83.37924167 | 105.7899361 |
| 2033 | 64.24541626 | 83.37924167 | 105.7899361 |
| 2034 | 64.24541626 | 83.37924167 | 105.7899361 |
| 2035 | 64.24541626 | 83.37924167 | 105.7899361 |

| | | | |
|---|---|---|---|
| 2036 | 64.24541626 | 83.37924167 | 105.7899361 |
| 2037 | 64.24541626 | 83.37924167 | 105.7899361 |
| 2038 | 64.24541626 | 83.37924167 | 105.7899361 |

**Table 6-17 Real Freight Rate**

Finally, using the new annual revenue, NPV and IRR were calculated. (Table 6-18)

| | **[A]** | **[B]** | **[C]** |
|---|---|---|---|
| **IRR:** | **7.6%** | **12.9%** | **18.2%** |
| **FINAL NPV [m]:** | **99.46 €** | **84.17 €** | **75.10 €** |
| **Daily Freight Rate [th €]*** | **175.89** | **228.28** | **289.64** |

**Table 6-18 Final NPV & IRR of shipping company**

***[th €]: thousand euros**

As in the first scenario, it seems that IRR is bigger in scenario C than B, and in scenario B is bigger than in A. The opposite appears to be true for the final NPV. That can be explained due to the fact that in scenario C we assume a discount rate bigger than A or B. So, IRR obviously would be larger. Also, it appears that in scenario A the discount rate increases the most as a percentage of the initial discount rate (from 5% to 7.6%), next is B (from 10% to 12.9% ) and the smallest raise appears in C (from 15% to 18.2%). This can be explained due to the fact that the increase in revenue was the almost the same for the three scenarios (same percentage and similar initial revenues), but the higher initial discount rate is the lower the NPV change and the discount rate change as a percentage will be.  From the above, the results of final NPV are explained.

### 6.2.2 Gas company's perspective

The second part of the second scenario is the study of the project from the scope of the gas company. As with the former scenario, total annual expenses are calculated. As the gas company charters the FSRU, the CAPEX are zero. However, the freight rate paid to the shipping company, along with fuel costs are paid by the gas company. Fuel cost is thought to be around 4250 €/day or 1.55 m €/year. (Table 6-19)

| YEARS | OPEX (-) [A] [m €] | OPEX (-) [B] [m €] | OPEX (-) [C] [m €] |
|---|---|---|---|
| 2017 | 0 | 0 | 0 |
| 2018 | 0 | 0 | 0 |
| 2019 | 65.79541626 | 84.92924167 | 107.3399361 |
| 2020 | 65.79541626 | 84.92924167 | 107.3399361 |
| 2021 | 65.79541626 | 84.92924167 | 107.3399361 |
| 2022 | 65.79541626 | 84.92924167 | 107.3399361 |
| 2023 | 65.79541626 | 84.92924167 | 107.3399361 |
| 2024 | 65.79541626 | 84.92924167 | 107.3399361 |
| 2025 | 65.79541626 | 84.92924167 | 107.3399361 |
| 2026 | 65.79541626 | 84.92924167 | 107.3399361 |

| | | | |
|---|---|---|---|
| 2027 | 65.79541626 | 84.92924167 | 107.3399361 |
| 2028 | 65.79541626 | 84.92924167 | 107.3399361 |
| 2029 | 65.79541626 | 84.92924167 | 107.3399361 |
| 2030 | 65.79541626 | 84.92924167 | 107.3399361 |
| 2031 | 65.79541626 | 84.92924167 | 107.3399361 |
| 2032 | 65.79541626 | 84.92924167 | 107.3399361 |
| 2033 | 65.79541626 | 84.92924167 | 107.3399361 |
| 2034 | 65.79541626 | 84.92924167 | 107.3399361 |
| 2035 | 65.79541626 | 84.92924167 | 107.3399361 |
| 2036 | 65.79541626 | 84.92924167 | 107.3399361 |
| 2037 | 65.79541626 | 84.92924167 | 107.3399361 |
| 2038 | 65.79541626 | 84.92924167 | 107.3399361 |

**Table 6-19 Gas company's expenses**

Next, using the NPV criterion the minimum revenues are calculated. However, in this case the process is a bit more complicated, because the demand for LNG imports via the Alexandroupolis FSRU must be taken into account. Specifically, a constant charge for the FSRU use [€/kWh] is assumed, the demand data is given, so the minimum annual revenue is calculated. (Tables 6-20, 6-21, 6-22)

| YEARS | Minimum Charge for the FSRU use per year [A] [€/KWh] | Calculated Revenues (+) [A] [m €] |
|---|---|---|
| 2017 | 0 | 0 |
| 2018 | 0 | 0 |
| 2019 | 0.005924124 | 47.07286814 |
| 2020 | 0.005924124 | 48.95578286 |
| 2021 | 0.005924124 | 50.91401418 |
| 2022 | 0.005924124 | 52.95057474 |
| 2023 | 0.005924124 | 55.06859773 |
| 2024 | 0.005924124 | 57.27134164 |
| 2025 | 0.005924124 | 59.56219531 |
| 2026 | 0.005924124 | 61.94468312 |
| 2027 | 0.005924124 | 64.42247045 |
| 2028 | 0.005924124 | 66.99936927 |
| 2029 | 0.005924124 | 69.67934404 |
| 2030 | 0.005924124 | 72.4665178 |
| 2031 | 0.005924124 | 75.36517851 |
| 2032 | 0.005924124 | 78.37978565 |
| 2033 | 0.005924124 | 81.51497708 |
| 2034 | 0.005924124 | 84.77557616 |
| 2035 | 0.005924124 | 88.1665992 |
| 2036 | 0.005924124 | 91.69326317 |
| 2037 | 0.005924124 | 95.3609937 |
| 2038 | 0.005924124 | 99.17543345 |

**Table 6-20 Minimum charge for the FSRU use per year assuming 5% discount rate [€/KWh]**

| YEARS | Minimum Charge for the FSRU use per year [B] [€/KWh] | Calculated Revenues (+) [B] [m €] |
|---|---|---|
| 2017 | 0 | 0 |
| 2018 | 0 | 0 |
| 2019 | 0.008096885 | 64.33754269 |
| 2020 | 0.008096885 | 66.91104439 |
| 2021 | 0.008096885 | 69.58748617 |
| 2022 | 0.008096885 | 72.37098562 |
| 2023 | 0.008096885 | 75.26582504 |
| 2024 | 0.008096885 | 78.27645804 |
| 2025 | 0.008096885 | 81.40751636 |
| 2026 | 0.008096885 | 84.66381702 |
| 2027 | 0.008096885 | 88.0503697 |
| 2028 | 0.008096885 | 91.57238449 |
| 2029 | 0.008096885 | 95.23527987 |
| 2030 | 0.008096885 | 99.04469106 |
| 2031 | 0.008096885 | 103.0064787 |
| 2032 | 0.008096885 | 107.1267379 |
| 2033 | 0.008096885 | 111.4118074 |
| 2034 | 0.008096885 | 115.8682797 |
| 2035 | 0.008096885 | 120.5030108 |
| 2036 | 0.008096885 | 125.3231313 |
| 2037 | 0.008096885 | 130.3360565 |
| 2038 | 0.008096885 | 135.5494988 |

**Table 6-21 Minimum charge for the FSRU use per year assuming 10% discount rate [€/KWh]**

| YEARS | Minimum Charge for the FSRU use per year [C] [€/KWh] | Calculated Revenues (+) [C] [m €] |
|---|---|---|
| 2017 | 0 | 0 |
| 2018 | 0 | 0 |
| 2019 | 0.010738818 | 85.33024965 |
| 2020 | 0.010738818 | 88.74345964 |
| 2021 | 0.010738818 | 92.29319803 |
| 2022 | 0.010738818 | 95.98492595 |
| 2023 | 0.010738818 | 99.82432299 |
| 2024 | 0.010738818 | 103.8172959 |
| 2025 | 0.010738818 | 107.9699877 |
| 2026 | 0.010738818 | 112.2887873 |
| 2027 | 0.010738818 | 116.7803387 |
| 2028 | 0.010738818 | 121.4515523 |
| 2029 | 0.010738818 | 126.3096144 |

| | | |
|---|---|---|
| 2030 | 0.010738818 | 131.361999 |
| 2031 | 0.010738818 | 136.6164789 |
| 2032 | 0.010738818 | 142.0811381 |
| 2033 | 0.010738818 | 147.7643836 |
| 2034 | 0.010738818 | 153.6749589 |
| 2035 | 0.010738818 | 159.8219573 |
| 2036 | 0.010738818 | 166.2148356 |
| 2037 | 0.010738818 | 172.863429 |
| 2038 | 0.010738818 | 179.7779662 |

**Table 6-22 Minimum charge for the FSRU use per year assuming 15% discount rate [€/KWh]**

After that, the final annual charge for the FSRU use is calculated. A raise to annual charge for the FSRU use from the calculated minimum equal to 15% is assumed. (Tables 6-23, 6-24, 6-25)

| YEAR | Charge for the FSRU use per year [A] [€/KWh] | Real Revenues [A] [m €] |
|---|---|---|
| 2017 | 0 | 0 |
| 2018 | 0 | 0 |
| 2019 | 0.006812743 | 54.13379836 |
| 2020 | 0.006812743 | 56.29915029 |
| 2021 | 0.006812743 | 58.5511163 |
| 2022 | 0.006812743 | 60.89316096 |
| 2023 | 0.006812743 | 63.32888739 |
| 2024 | 0.006812743 | 65.86204289 |
| 2025 | 0.006812743 | 68.49652461 |
| 2026 | 0.006812743 | 71.23638559 |
| 2027 | 0.006812743 | 74.08584101 |
| 2028 | 0.006812743 | 77.04927465 |
| 2029 | 0.006812743 | 80.13124564 |
| 2030 | 0.006812743 | 83.33649547 |
| 2031 | 0.006812743 | 86.66995529 |
| 2032 | 0.006812743 | 90.1367535 |
| 2033 | 0.006812743 | 93.74222364 |
| 2034 | 0.006812743 | 97.49191258 |
| 2035 | 0.006812743 | 101.3915891 |
| 2036 | 0.006812743 | 105.4472526 |
| 2037 | 0.006812743 | 109.6651428 |
| 2038 | 0.006812743 | 114.0517485 |

**Table 6-23 Real charge for the FSRU use per year assuming 5% discount rate [€/KWh]**

| YEAR | Charge for the FSRU use per year [B] [€/kWh] | Real Revenues [B] [m €] |
|---|---|---|
| 2017 | 0 | 0 |

| | | |
|---|---|---|
| 2018 | 0 | 0 |
| 2019 | 0.009311417 | 73.98817409 |
| 2020 | 0.009311417 | 76.94770105 |
| 2021 | 0.009311417 | 80.02560909 |
| 2022 | 0.009311417 | 83.22663346 |
| 2023 | 0.009311417 | 86.5556988 |
| 2024 | 0.009311417 | 90.01792675 |
| 2025 | 0.009311417 | 93.61864382 |
| 2026 | 0.009311417 | 97.36338957 |
| 2027 | 0.009311417 | 101.2579252 |
| 2028 | 0.009311417 | 105.3082422 |
| 2029 | 0.009311417 | 109.5205718 |
| 2030 | 0.009311417 | 113.9013947 |
| 2031 | 0.009311417 | 118.4574505 |
| 2032 | 0.009311417 | 123.1957485 |
| 2033 | 0.009311417 | 128.1235785 |
| 2034 | 0.009311417 | 133.2485216 |
| 2035 | 0.009311417 | 138.5784625 |
| 2036 | 0.009311417 | 144.121601 |
| 2037 | 0.009311417 | 149.886465 |
| 2038 | 0.009311417 | 155.8819236 |

**Table 6-24 Real charge for the FSRU use per year assuming 10% discount rate [€/KWh]**

| YEAR | Charge for the FSRU use per year [C] [€/kWh] | Real Revenues [C] [m €] |
|---|---|---|
| 2017 | 0 | 0 |
| 2018 | 0 | 0 |
| 2019 | 0.012349641 | 98.1297871 |
| 2020 | 0.012349641 | 102.0549786 |
| 2021 | 0.012349641 | 106.1371777 |
| 2022 | 0.012349641 | 110.3826648 |
| 2023 | 0.012349641 | 114.7979714 |
| 2024 | 0.012349641 | 119.3898903 |
| 2025 | 0.012349641 | 124.1654859 |
| 2026 | 0.012349641 | 129.1321053 |
| 2027 | 0.012349641 | 134.2973896 |
| 2028 | 0.012349641 | 139.6692851 |
| 2029 | 0.012349641 | 145.2560565 |
| 2030 | 0.012349641 | 151.0662988 |
| 2031 | 0.012349641 | 157.1089508 |
| 2032 | 0.012349641 | 163.3933088 |
| 2033 | 0.012349641 | 169.9290411 |
| 2034 | 0.012349641 | 176.7262028 |

| | | |
|---|---|---|
| 2035 | 0.012349641 | 183.7952509 |
| 2036 | 0.012349641 | 191.1470609 |
| 2037 | 0.012349641 | 198.7929434 |
| 2038 | 0.012349641 | 206.7446611 |

Table 6-25 Real charge for the FSRU use per year assuming 15% discount rate [€/KWh]

Eventually, using the new annual revenue, NPV and IRR were calculated. (Table 6-26)

| | [A] | [B] | [C] |
|---|---|---|---|
| **IRR:** | **19.4%** | **29.7%** | **46.3%** |
| **FINAL NPV [m]:** | **117.14 €** | **98.60 €** | **87.64 €** |

Table 6-26 Final NPV & IRR of gas company

Again, it seems that IRR is bigger in scenario C than B, and in scenario B is bigger than in A. The opposite appears to be true for the final NPV. This is explained by the reasons mentioned above.

Finally, assuming constant FSRU charging price per year, the gas company's NPV is calculated for the three aforementioned discount rates. The values of zeroing the NPV for these rates are emphasized (Figure 6-9)(Table 6-27).

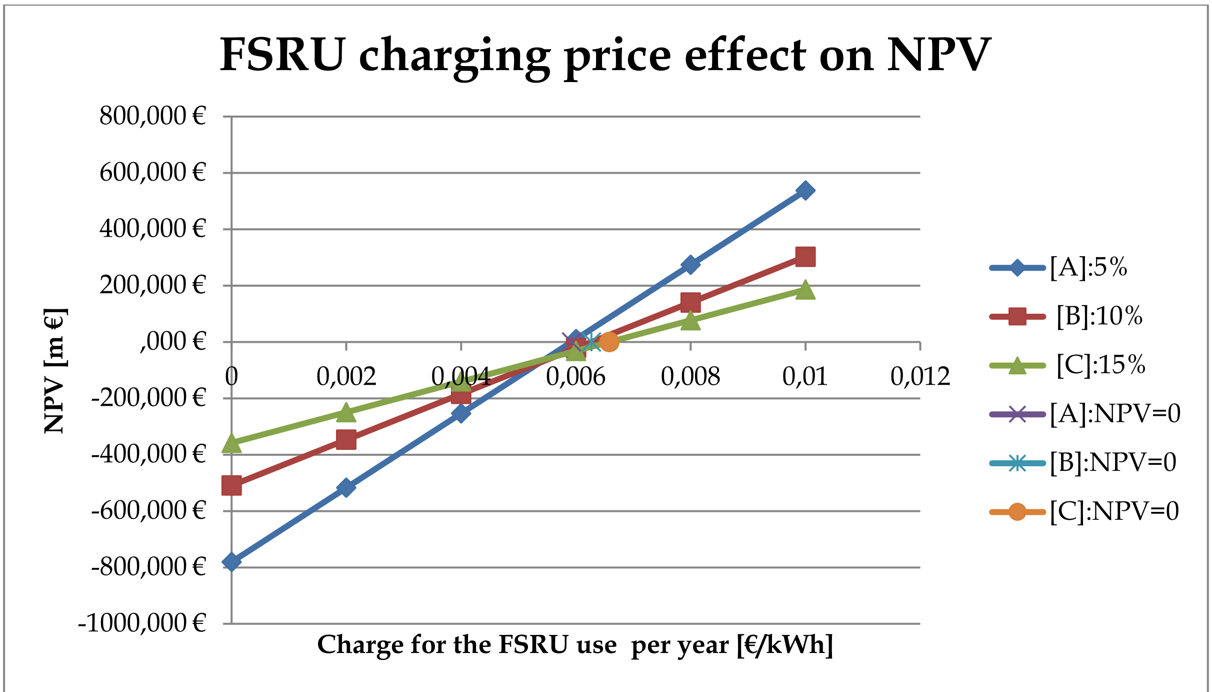



Figure 6-9 FSRU charge effect on the project's NPV from the Gas company's standpoint

| NPV=0 | [A]:5% | [B]:11% | [C]:15% |
|---|---|---|---|
| | | | |

| | | | |
|---|---|---|---|
| **Charge for the FSRU use per year [€/kWh]** | **0.0059** | **0.0063** | **0.0066** |

**Table 6-27 FSRU charging price resulting to NPV=0**

# 7 Conclusion

In this thesis the main subjects are natural gas (NG) and FSRU. Initially, technical description and uses of LNG are mentioned. In summary, LNG is a clear, colorless and non-toxic liquid which forms when NG is cooled to -162°C, which shrinks the volume of the gas 600 times, making it easier and safer to store and ship and it's used by: a) the electric power sector, b) the industrial sector, c) the residential sector, d) the commercial sector and e) the transportation sector (figure 2-1). Moreover, arguments in favor of NG over other traditional fuels are made, e.g. a) that gas plants are cheaper to build and operate in comparison to using other types of fuel (figure 2-8), b) that its emission of pollutants is far lower than coal emissions (figure 2-9) causing better local air quality and c) that NG is emitting less $CO_2$ (figure 2-10) thus contributing far less to climate change than coal, which explain its rise on the list of the most commonly used types of fuel (figure 2-7). Also, LNG global demand and its rise are explained in detail (figure 2-12) as well as regulations and policies aiding to the rise of the NG as main fuel (table 2-2). Lastly, the European Union's (EU) strategy aiming to exploit the potential of LNG and gas storage to make the EU gas system more diverse and flexible is mentioned.

After that, the NG's supply chain from its natural underground reservoirs to people's residences and companies is displayed, analyzing each and every different stage of it numbering various ways of fulfilling them (figure 3-1). Before the initiation of the chain, the stage of exploration is needed, where companies identify and explore regions onshore and offshore for reserves and specific deposits of NG that can be commercially exploited. The biggest breakthrough in NG exploration came through the use of basic seismology, the study of how energy, in the form of seismic waves, moves through the Earth's crust and interacts differently with various types of underground formations. Seismology is divided into two categories depending on the area, in which the exploration takes place, the offshore (figure 3-2) and the onshore (figure 3-3). In case of indications of a NG reservoir, the stage of extraction takes place, which is the procedure of drilling by a team of experts using special drilling equipment where the NG is located. The extraction can be done either onshore or offshore depending on where NG resources have been located. In case of a successful extraction, where the drilling leads to NG deposits, the stage of production initiates. In this stage, the NG is lifted out of the ground and goes through refining process, which is necessary due to the fact the raw NG that is being extracted from the ground contains oil, water and many unwanted compounds and gases (figure 3-5). After the production of NG, the refined NG is ready to be transported via pipelines ("pipeline quality") or via ships in order to be supplied to local gas networks. The midstream part of the NG supply chain consists of two main modes of transportation: in gas form via the pipelines or in a liquid form (LNG) via specialized carrier ships (figure 3-6). There are three major types of pipelines along the transportation route: the gathering system, the interstate/intrastate pipeline system, and the distribution system. In the case that the NG has been identified and extracted offshore NG is usually liquefied in order to be transported overseas to the mainland by ship (figure 3-11). Furthermore, the ships in which LNG is carried are double-hulled with specially-built tanks for this particular reason (picture 3-7). The liquefaction process is executed by an LNG producing infrastructure, which includes a gas pipeline leading to the seaside, a gas liquefaction plant (picture 3-8), storage facilities and special equipment used for the transfer to an LNG carrier (figure 3-12). When LNG reaches its destination it is gasified at the regasification plant at the terminal in order to be induced in the pipeline network or be transferred with specialized trucks (picture 3-10). The regasification can also be done on a specially retrofitted ship. These ships are called FSRUs. They act, in all aspects, similar to a land-based terminal and are permanently moored to a docking facility at a location close to a market access point. Also, tanks are built as storage facilities to maintain an NG or LNG reserve and these can be constructed at underground, surface facilities or in an LNG vessel chartered as floating storage. Commonly, NG is stored in one of the following three principal types of large underground storage systems (figure 3-13): a) Depleted natural gas reservoirs, b) Natural aquifers, c) Salt caverns. At last, the downstream supply chain ends with the distribution pipeline network to end users. The distribution pipeline system is smaller in diameter than the intrastate pipelines and they connect to them through delivery points across the latter. The delivery point is also called "citygate", and is an important market center for the pricing of NG in large urban areas. Also, this system becomes very expensive making up half of the amount of the NG costs for households and small volume customers (figure 3-17).

On the second part of this thesis, information about the FSRU is mentioned. There are advantages in favor of offshore regasification units over onshore terminals, which lead to the rise of the former during the recent years. These are, in summary: a) they're faster to build, b) they're a lot cheaper, due to being offshore, c) they need less shore licenses, bureaucracy and land infrastructures, d) they are floating, so they are movable from place to place, e) they have easier decommissioning and f) they require less land use than a land-based terminals, thus minimizing environmental impacts to the surrounding environment. On the other hand, the land-based units are favored, because: a) significant volumes for storage and regasified gas may be in demand, b) land-based terminal construction is well under way and c) the existing land facilities have been designed to meet future increases in regasification demand. FSRUs are a special type of ships which are used for the storage and the regasification of LNG. Rarely FSRUs can combine the two aforementioned operations with the transportation of LNG; these are called LNG Regasification Vessels (RV). Between these two offshore regasification units, the advantages of the one over the other have to be carefully examined for each specific project. Also, FSRUs can be constructed in three ways: a) As new-built ships, b) By using old LNG carriers and converting them into independent units, c) Using regasification barges with LNG FSUs (FSRB) and the choice of way of construction is dependent on the project's requirements (table 4-1). In addition, the containment process of LNG is analyzed. This is a complicated procedure, due to the liquid's temperature and two types of tanks exist: a) Independent tanks (figure 4-8), b) Membrane systems (figure 4-10) both regulated by the IMO. Also, the connections for loading/discharging between the LNG carrier and the offshore unit are: a) Ship to jetty connection, b) Side by side connection. The power requirements for the FSRUs vary between 1,500 kW and 40,000 kW, depending on its designation (table 4-2). The main arrangements for FSRU propulsion are: a) Genset – DFDE (dual fuel diesel electric) (figure 4-11), b) Genset – Gas turbines (figure 4-12), c) Direct driven. Moreover, there are four main categories of regasification systems: a) The closed-loop propane with seawater as heating medium (figure 4-13), b) Direct seawater vaporizers (figure 4-14), c) Closed-loop TEG/water and steam (figure 4-15), d) Closed-loop TEG/water and seawater (figure 4-16). Lastly, the mooring arrangements are mainly the following: a) Mooring at a jetty (picture 4-7), b) Single point mooring through a turret (picture 4-8).

The main takeaway is that FSRU is new technology of floating plant with benefits over traditional land-based plants. Over the last decade, more and more ship-owners invest in them, either as new-build FSRUs or by converting old LNG carriers to FSRUs. This recent increase in demand on them leads to a geometrically rise in their price.

Furthermore, a case study is conducted in this thesis examining the feasibility of operating an FSRU outside of Alexandroupolis along Greece's national NG grid from an economic standpoint, which is divided into two scenarios. The first explores the option of a joint company with shareholders a shipping company and a public NG company owning and operating the FSRU. The second one examines the project from two independent scopes, the one of the shipping company as owner and manager of the FSRU and that of the NG company chartering the FSRU from the shipping company and charging its use as a point of entry of NG. The purpose of the study is to determine whether a joint company favors any of the aforementioned companies or not.

From the results of the first scenario (table 6-9) it seems that IRR is bigger in scenario C than B, and in scenario B is bigger than in A. The opposite appears to be true for the final NPV. That can be explained due to the fact that in scenario C we assume a discount rate bigger than A or B. So, IRR obviously would be larger. Also, it appears that in scenario A the discount rate increases the most as a percentage of the initial discount rate (from 5% to 7.8%), next is B (from 10% to 13.0% ) and the smallest raise appears in C (from 15% to 18.3%). This can be explained due to the fact that the increase in revenue was the almost the same for the three scenarios (same percentage and similar initial revenues), but the higher the initial discount rate is the lower the NPV change and the discount rate change as a percentage will be. From the above, the results of final NPV are explained.

Considering the second scenario, both from the shipping company's perspective (table 6-18) and the gas company's perspective (table 6-26) it seems that IRR is bigger in scenario C than B, and in scenario B is bigger than in A. The opposite appears to be true for the final NPV. Again, that can be explained due to the fact that in scenario C we assume a discount rate bigger than A or B. So, IRR obviously would be larger. Also, it appears that in scenario A the discount rate increases the most as a percentage of the initial discount rate (from 5% to 7.6% for the shipping and from 5% to 19.4% for the gas company), next is B (from 10% to 12.9% for the shipping company and 10% to 29.7% for the gas company) and the smallest raise appears in C (from 15% to 18.2% for the shipping company and from 15% to 46.3% for the gas company). This can be explained due to the fact that the increase in revenue was the almost the same for the three scenarios (same percentage and similar initial revenues), but the higher initial discount rate is the lower the NPV change and the discount rate change as a percentage will be. Also, the above explain the results of final.

As far as the shipping company is concerned, the first scenario gives slightly higher IRR results (table 6-9) than that of the second one (table 6-18) and NPV results almost equal to 60% of the NPV calculated in the second scenario. However, for the first two years of the project, when expenses are high and there is no revenue, it is observed that in the first scenario (table 6-10) the expenses are only 60% the ones calculated in the second scenario (table 6-14).

As far as the gas company is concerned, the second scenario gives way higher IRR and NPV results (table 6-26). Also, from the graph of FSRU charging price effect on the project from the gas company's standpoint the following observations are made (figure 6-5) (figure 6-9):

- For discount rate equal to 5%, NPV is zeroed for a lower price in the first scenario than in the second.
- For discount rates equal to 10% or 15%, NPV is zeroed for a higher price in the first scenario than in the second.

In addition, for the first two years in the second scenario (table 6-19) there are no expenses, whereas expenses are high in the first one (table 6-11).

Finally, the above results are taken into account in order to determine which scenario favors which company. It is obvious, that the gas company is favored by the second scenario, due to the expense free first two years, higher NPV and IRR and effect of FSRU charging price on NPV for two of the three discount rates used in the study. So from the gas company's standpoint the two companies shouldn't work as a joint company.

On the other hand, the shipping company's choice of scenario is a bit more complicated. Depending on the NPV and IRR criterions the second scenario is a better choice. However, the first scenario results in expenses way lower than the ones in the second for the first two years. The first years of a project pay a big role, because the higher the initial costs are the more difficult it is to initiate it. In that case, a loan is usually inevitable and this would definitely lower the project's NPV and IRR, compared to the ones calculated in this study. So, it is proposed that in case of the shipping company owning a large capital for investment the second scenario is preferable. Whereas in case of the company not owning a sizable sum of money before initiating the project, which in real world application would result in getting a loan, the first scenario is proposed.

Although the feasibility study may be adequate for a diploma thesis, there is still room for improvement in order to simulate a real world application. Firstly, a number of assumptions are made in order to make this thesis simpler, as it should for an undergraduate student and not a major shipping or natural gas company. Some examples of this are the assumption of constant annual OPEX and the steady annual increase of the imported LNG after year 2019. In order to make a more thorough estimation of the feasibility of such a project, these assumptions should be more accurate. Lastly, a large amount of capital is paid for the construction of the ship, so in real world a loan would be advised. This dynamic was not added in this thesis, but it would be an essential part of an optimal economic study.

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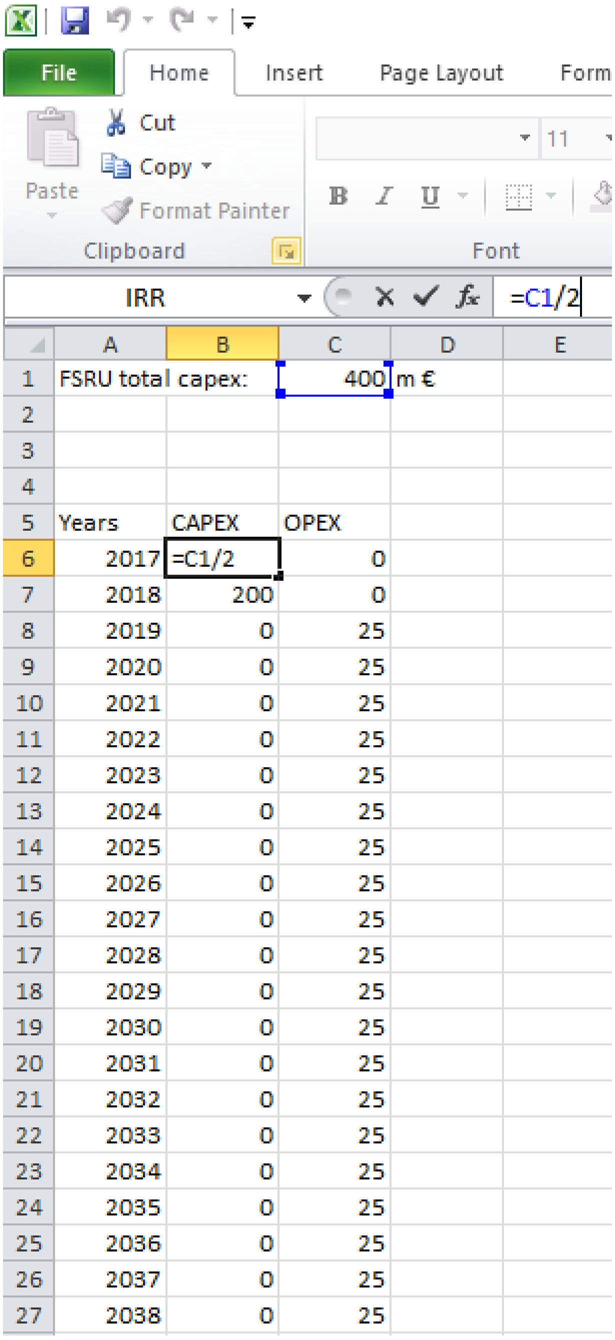
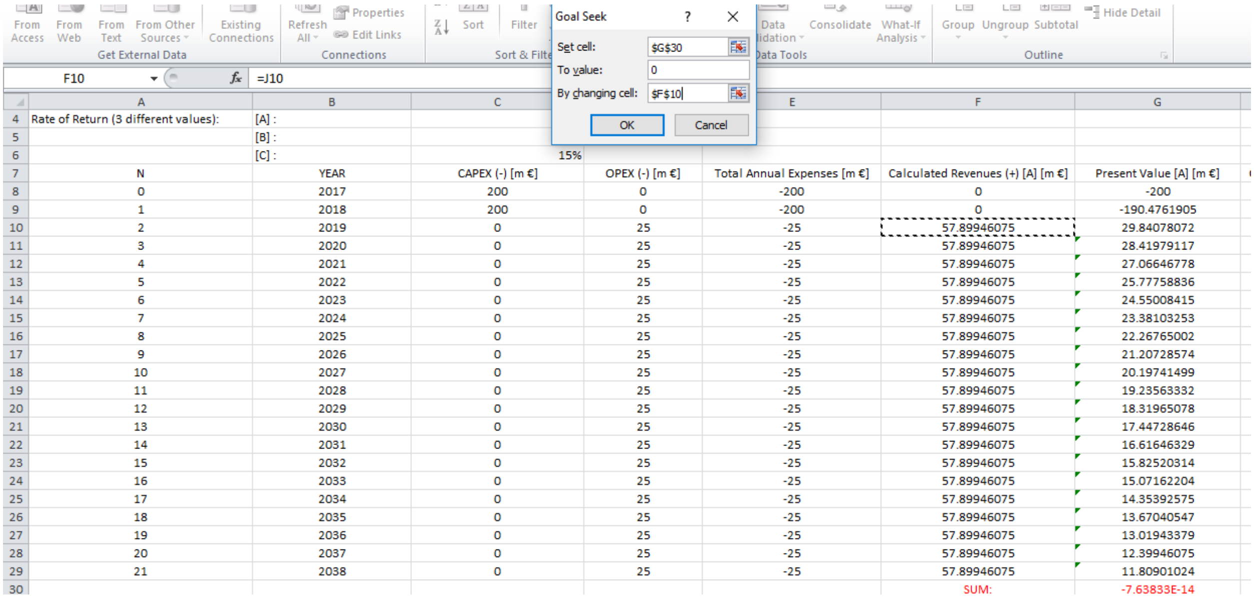
# 9 Annex - Analytical calculation process

## 9.1 First Scenario



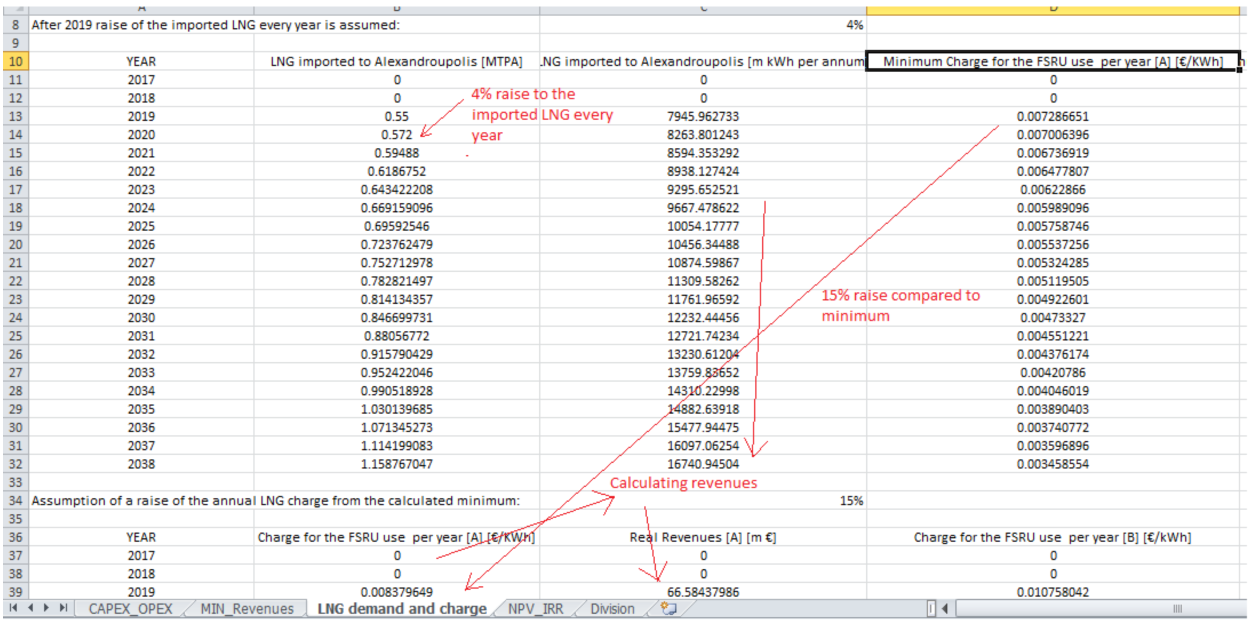

| | A | B | C | D | E |
|---|---|---|---|---|---|
| 1 | FSRU total capex: | | 400 | m € | |
| 2 | | | | | |
| 3 | | | | | |
| 4 | | | | | |
| 5 | Years | CAPEX | OPEX | | |
| 6 | 2017 | =C1/2 | 0 | | |
| 7 | 2018 | 200 | 0 | | |
| 8 | 2019 | 0 | 25 | | |
| 9 | 2020 | 0 | 25 | | |
| 10 | 2021 | 0 | 25 | | |
| 11 | 2022 | 0 | 25 | | |
| 12 | 2023 | 0 | 25 | | |
| 13 | 2024 | 0 | 25 | | |
| 14 | 2025 | 0 | 25 | | |
| 15 | 2026 | 0 | 25 | | |
| 16 | 2027 | 0 | 25 | | |
| 17 | 2028 | 0 | 25 | | |
| 18 | 2029 | 0 | 25 | | |
| 19 | 2030 | 0 | 25 | | |
| 20 | 2031 | 0 | 25 | | |
| 21 | 2032 | 0 | 25 | | |
| 22 | 2033 | 0 | 25 | | |
| 23 | 2034 | 0 | 25 | | |
| 24 | 2035 | 0 | 25 | | |
| 25 | 2036 | 0 | 25 | | |
| 26 | 2037 | 0 | 25 | | |
| 27 | 2038 | 0 | 25 | | |

Picture 9-1 Final NPV & IRR of gas company




| | A | B | C | D | E | F | G |
|---|---|---|---|---|---|---|---|
| 4 | Rate of Return (3 different values): | [A] : | | | | | |
| 5 | | [B] : | | | | | |
| 6 | | [C] : | 15% | | | | |
| 7 | N | YEAR | CAPEX (-) [m €] | OPEX (-) [m €] | Total Annual Expenses [m €] | Calculated Revenues (+) [A] [m €] | Present Value [A] [m €] |
| 8 | 0 | 2017 | 200 | 0 | -200 | 0 | -200 |
| 9 | 1 | 2018 | 200 | 0 | -200 | 0 | -190.4761905 |
| 10 | 2 | 2019 | 0 | 25 | -25 | 57.89946075 | 29.84078072 |
| 11 | 3 | 2020 | 0 | 25 | -25 | 57.89946075 | 28.41979117 |
| 12 | 4 | 2021 | 0 | 25 | -25 | 57.89946075 | 27.06646778 |
| 13 | 5 | 2022 | 0 | 25 | -25 | 57.89946075 | 25.77758836 |
| 14 | 6 | 2023 | 0 | 25 | -25 | 57.89946075 | 24.55008415 |
| 15 | 7 | 2024 | 0 | 25 | -25 | 57.89946075 | 23.38103253 |
| 16 | 8 | 2025 | 0 | 25 | -25 | 57.89946075 | 22.26765002 |
| 17 | 9 | 2026 | 0 | 25 | -25 | 57.89946075 | 21.20728574 |
| 18 | 10 | 2027 | 0 | 25 | -25 | 57.89946075 | 20.19741499 |
| 19 | 11 | 2028 | 0 | 25 | -25 | 57.89946075 | 19.23563332 |
| 20 | 12 | 2029 | 0 | 25 | -25 | 57.89946075 | 18.31965078 |
| 21 | 13 | 2030 | 0 | 25 | -25 | 57.89946075 | 17.44728646 |
| 22 | 14 | 2031 | 0 | 25 | -25 | 57.89946075 | 16.61646329 |
| 23 | 15 | 2032 | 0 | 25 | -25 | 57.89946075 | 15.82520314 |
| 24 | 16 | 2033 | 0 | 25 | -25 | 57.89946075 | 15.07162204 |
| 25 | 17 | 2034 | 0 | 25 | -25 | 57.89946075 | 14.35392575 |
| 26 | 18 | 2035 | 0 | 25 | -25 | 57.89946075 | 13.67040547 |
| 27 | 19 | 2036 | 0 | 25 | -25 | 57.89946075 | 13.01943379 |
| 28 | 20 | 2037 | 0 | 25 | -25 | 57.89946075 | 12.39946075 |
| 29 | 21 | 2038 | 0 | 25 | -25 | 57.89946075 | 11.80901024 |
| 30 | | | | | | SUM: | -7.63833E-14 |

**Picture 9-2 Goal Seek method to calculate the minimum annual revenues**




| | A | B | C | D |
|---|---|---|---|---|
| 8 | After 2019 raise of the imported LNG every year is assumed: | | 4% | |
| 9 | | | | |
| 10 | YEAR | LNG imported to Alexandroupolis [MTPA] | LNG imported to Alexandroupolis [m kWh per annum | Minimum Charge for the FSRU use per year [A] [€/KWh] |
| 11 | 2017 | 0 | 0 | 0 |
| 12 | 2018 | 0 | 0 | 0 |
| 13 | 2019 | 0.55 | 7945.962733 | 0.007286651 |
| 14 | 2020 | 0.572 | 8263.801243 | 0.007006396 |
| 15 | 2021 | 0.59488 | 8594.353292 | 0.006736919 |
| 16 | 2022 | 0.6186752 | 8938.127424 | 0.006477807 |
| 17 | 2023 | 0.643422208 | 9295.652521 | 0.00622866 |
| 18 | 2024 | 0.669159096 | 9667.478622 | 0.005989096 |
| 19 | 2025 | 0.69592546 | 10054.17777 | 0.005758746 |
| 20 | 2026 | 0.723762479 | 10456.34488 | 0.005537256 |
| 21 | 2027 | 0.752712978 | 10874.59867 | 0.005324285 |
| 22 | 2028 | 0.782821497 | 11309.58262 | 0.005119505 |
| 23 | 2029 | 0.814134357 | 11761.96592 | 0.004922601 |
| 24 | 2030 | 0.846699731 | 12232.44456 | 0.00473327 |
| 25 | 2031 | 0.88056772 | 12721.74234 | 0.004551221 |
| 26 | 2032 | 0.915790429 | 13230.61204 | 0.004376174 |
| 27 | 2033 | 0.952422046 | 13759.83652 | 0.00420786 |
| 28 | 2034 | 0.990518928 | 14310.22998 | 0.004046019 |
| 29 | 2035 | 1.030139685 | 14882.63918 | 0.003890403 |
| 30 | 2036 | 1.071345273 | 15477.94475 | 0.003740772 |
| 31 | 2037 | 1.114199083 | 16097.06254 | 0.003596896 |
| 32 | 2038 | 1.158767047 | 16740.94504 | 0.003458554 |
| 33 | | | | |
| 34 | Assumption of a raise of the annual LNG charge from the calculated minimum: | | 15% | |
| 35 | | | | |
| 36 | YEAR | Charge for the FSRU use per year [A] [€/KWh] | Real Revenues [A] [m €] | Charge for the FSRU use per year [B] [€/kWh] |
| 37 | 2017 | 0 | 0 | 0 |
| 38 | 2018 | 0 | 0 | 0 |
| 39 | 2019 | 0.008379649 | 66.58437986 | 0.010758042 |

**Picture 9-3 Minimum and commercial annual charge and revenues of the joint company**

IRR | =IRR(G5:G26)

| | A | B | C | D | E | F | G |
|---|---|---|---|---|---|---|---|
| 3 | | | | | | | |
| 4 | N | YEAR | CAPEX (-) [m €] | OPEX (-) [m €] | Total Annual Expenses [m €] | Real Revenues [A] [m €] | Total Annual Cashflow [A] [m €] |
| 5 | 0 | 2017 | 200 | 0 | -200 | 0 | -200 |
| 6 | 1 | 2018 | 200 | 0 | -200 | 0 | -200 |
| 7 | 2 | 2019 | 0 | 25 | -25 | 66.58437986 | 41.58437986 |
| 8 | 3 | 2020 | 0 | 25 | -25 | 66.58437986 | 41.58437986 |
| 9 | 4 | 2021 | 0 | 25 | -25 | 66.58437986 | 41.58437986 |
| 10 | 5 | 2022 | 0 | 25 | -25 | 66.58437986 | 41.58437986 |
| 11 | 6 | 2023 | 0 | 25 | -25 | 66.58437986 | 41.58437986 |
| 12 | 7 | 2024 | 0 | 25 | -25 | 66.58437986 | 41.58437986 |
| 13 | 8 | 2025 | 0 | 25 | -25 | 66.58437986 | 41.58437986 |
| 14 | 9 | 2026 | 0 | 25 | -25 | 66.58437986 | 41.58437986 |
| 15 | 10 | 2027 | 0 | 25 | -25 | 66.58437986 | 41.58437986 |
| 16 | 11 | 2028 | 0 | 25 | -25 | 66.58437986 | 41.58437986 |
| 17 | 12 | 2029 | 0 | 25 | -25 | 66.58437986 | 41.58437986 |
| 18 | 13 | 2030 | 0 | 25 | -25 | 66.58437986 | 41.58437986 |
| 19 | 14 | 2031 | 0 | 25 | -25 | 66.58437986 | 41.58437986 |
| 20 | 15 | 2032 | 0 | 25 | -25 | 66.58437986 | 41.58437986 |
| 21 | 16 | 2033 | 0 | 25 | -25 | 66.58437986 | 41.58437986 |
| 22 | 17 | 2034 | 0 | 25 | -25 | 66.58437986 | 41.58437986 |
| 23 | 18 | 2035 | 0 | 25 | -25 | 66.58437986 | 41.58437986 |
| 24 | 19 | 2036 | 0 | 25 | -25 | 66.58437986 | 41.58437986 |
| 25 | 20 | 2037 | 0 | 25 | -25 | 66.58437986 | 41.58437986 |
| 26 | 21 | 2038 | 0 | 25 | -25 | 66.58437986 | 41.58437986 |
| 27 | | | | | | | |
| 28 | | [A] | [B] | [C] | | | |
| 29 | IRR: | =IRR(G5:G26) | 13.0% | 18.3% | | | |
| 30 | FINAL NPV [m]: | 103.08 € | 86.30 € | 76.50 € | | | |

CAPEX_OPEX | MIN_Revenues | LNG demand and charge | NPV_IRR | Division

Picture 9-4 IRR of the joint company

IRR | =G5+NPV(0.05;G6:G26)

| | A | B | C | D | E | F | G |
|---|---|---|---|---|---|---|---|
| 3 | | | | | | | |
| 4 | N | YEAR | CAPEX (-) [m €] | OPEX (-) [m €] | Total Annual Expenses [m €] | Real Revenues [A] [m €] | Total Annual Cashflow [A] [m €] |
| 5 | 0 | 2017 | 200 | 0 | -200 | 0 | -200 |
| 6 | 1 | 2018 | 200 | 0 | -200 | 0 | -200 |
| 7 | 2 | 2019 | 0 | 25 | -25 | 66.58437986 | 41.58437986 |
| 8 | 3 | 2020 | 0 | 25 | -25 | 66.58437986 | 41.58437986 |
| 9 | 4 | 2021 | 0 | 25 | -25 | 66.58437986 | 41.58437986 |
| 10 | 5 | 2022 | 0 | 25 | -25 | 66.58437986 | 41.58437986 |
| 11 | 6 | 2023 | 0 | 25 | -25 | 66.58437986 | 41.58437986 |
| 12 | 7 | 2024 | 0 | 25 | -25 | 66.58437986 | 41.58437986 |
| 13 | 8 | 2025 | 0 | 25 | -25 | 66.58437986 | 41.58437986 |
| 14 | 9 | 2026 | 0 | 25 | -25 | 66.58437986 | 41.58437986 |
| 15 | 10 | 2027 | 0 | 25 | -25 | 66.58437986 | 41.58437986 |
| 16 | 11 | 2028 | 0 | 25 | -25 | 66.58437986 | 41.58437986 |
| 17 | 12 | 2029 | 0 | 25 | -25 | 66.58437986 | 41.58437986 |
| 18 | 13 | 2030 | 0 | 25 | -25 | 66.58437986 | 41.58437986 |
| 19 | 14 | 2031 | 0 | 25 | -25 | 66.58437986 | 41.58437986 |
| 20 | 15 | 2032 | 0 | 25 | -25 | 66.58437986 | 41.58437986 |
| 21 | 16 | 2033 | 0 | 25 | -25 | 66.58437986 | 41.58437986 |
| 22 | 17 | 2034 | 0 | 25 | -25 | 66.58437986 | 41.58437986 |
| 23 | 18 | 2035 | 0 | 25 | -25 | 66.58437986 | 41.58437986 |
| 24 | 19 | 2036 | 0 | 25 | -25 | 66.58437986 | 41.58437986 |
| 25 | 20 | 2037 | 0 | 25 | -25 | 66.58437986 | 41.58437986 |
| 26 | 21 | 2038 | 0 | 25 | -25 | 66.58437986 | 41.58437986 |
| 27 | | | | | | | |
| 28 | | [A] | [B] | [C] | | | |
| 29 | IRR: | 7.8% | 13.0% | 18.3% | | | |
| 30 | FINAL NPV [m]: | =G5+NPV(0.05;G6:G26) | 86.30 € | 76.50 € | | | |

CAPEX_OPEX | MIN_Revenues | LNG demand and charge | NPV_IRR | Division

Picture 9-5 Final NPV of the joint company

B5 =0.6*NPV_IRR!G5

| | A | B | C | D | E | F |
|---|---|---|---|---|---|---|
| 1 | It's assumed that the shipping company contributes to 60% of total annual cashflows and the gas company to the rest. | | | | | |
| 2 | | | | | | |
| 3 | | | Shipping company | | | Gas company |
| 4 | YEAR | Total Annual Cashflow [A] [m €] | Total Annual Cashflow [B] [m €] | Total Annual Cashflow [C] [m €] | Total Annual Cashflow [A] [m €] | Total Annual Cashflow [B] [m €] |
| 5 | 2017 | -120 | -120 | -120 | -80 | -80 |
| 6 | 2018 | -120 | -120 | -120 | -80 | -80 |
| 7 | 2019 | 24.95062792 | 36.28979926 | 49.65122827 | 16.63375194 | 24.19319951 |
| 8 | 2020 | 24.95062792 | 36.28979926 | 49.65122827 | 16.63375194 | 24.19319951 |
| 9 | 2021 | 24.95062792 | 36.28979926 | 49.65122827 | 16.63375194 | 24.19319951 |
| 10 | 2022 | 24.95062792 | 36.28979926 | 49.65122827 | 16.63375194 | 24.19319951 |
| 11 | 2023 | 24.95062792 | 36.28979926 | 49.65122827 | 16.63375194 | 24.19319951 |
| 12 | 2024 | 24.95062792 | 36.28979926 | 49.65122827 | 16.63375194 | 24.19319951 |
| 13 | 2025 | 24.95062792 | 36.28979926 | 49.65122827 | 16.63375194 | 24.19319951 |
| 14 | 2026 | 24.95062792 | 36.28979926 | 49.65122827 | 16.63375194 | 24.19319951 |
| 15 | 2027 | 24.95062792 | 36.28979926 | 49.65122827 | 16.63375194 | 24.19319951 |
| 16 | 2028 | 24.95062792 | 36.28979926 | 49.65122827 | 16.63375194 | 24.19319951 |
| 17 | 2029 | 24.95062792 | 36.28979926 | 49.65122827 | 16.63375194 | 24.19319951 |

Picture 9-6 Division of the cashflow of the joint company

TREND =B5+NPV(5%;B6:B26)

| | A | B | C | D | E |
|---|---|---|---|---|---|
| 13 | 2025 | 24.95062792 | 36.28979926 | 49.65122827 | 16.63375194 |
| 14 | 2026 | 24.95062792 | 36.28979926 | 49.65122827 | 16.63375194 |
| 15 | 2027 | 24.95062792 | 36.28979926 | 49.65122827 | 16.63375194 |
| 16 | 2028 | 24.95062792 | 36.28979926 | 49.65122827 | 16.63375194 |
| 17 | 2029 | 24.95062792 | 36.28979926 | 49.65122827 | 16.63375194 |
| 18 | 2030 | 24.95062792 | 36.28979926 | 49.65122827 | 16.63375194 |
| 19 | 2031 | 24.95062792 | 36.28979926 | 49.65122827 | 16.63375194 |
| 20 | 2032 | 24.95062792 | 36.28979926 | 49.65122827 | 16.63375194 |
| 21 | 2033 | 24.95062792 | 36.28979926 | 49.65122827 | 16.63375194 |
| 22 | 2034 | 24.95062792 | 36.28979926 | 49.65122827 | 16.63375194 |
| 23 | 2035 | 24.95062792 | 36.28979926 | 49.65122827 | 16.63375194 |
| 24 | 2036 | 24.95062792 | 36.28979926 | 49.65122827 | 16.63375194 |
| 25 | 2037 | 24.95062792 | 36.28979926 | 49.65122827 | 16.63375194 |
| 26 | 2038 | 24.95062792 | 36.28979926 | 49.65122827 | 16.63375194 |
| 27 | | | | | |
| 28 | | Shipping company | | Gas company | |
| 29 | | NPV | IRR | NPV | IRR |
| 30 | [A] | =B5+NPV(5%;B6:B26) | 7.8% | 41.23 € | 7.8% |
| 31 | [B] | 51.78 € | 13.0% | 34.52 € | 13.0% |
| 32 | [C] | 45.90 € | 18.3% | 30.60 € | 18.3% |

Picture 9-7 NPV of each shareholding company

TREND =IRR(B5:B26)

| | A | B | C | D | E |
|---|---|---|---|---|---|
| 13 | 2025 | 24.95062792 | 36.28979926 | 49.65122827 | 16.63375194 |
| 14 | 2026 | 24.95062792 | 36.28979926 | 49.65122827 | 16.63375194 |
| 15 | 2027 | 24.95062792 | 36.28979926 | 49.65122827 | 16.63375194 |
| 16 | 2028 | 24.95062792 | 36.28979926 | 49.65122827 | 16.63375194 |
| 17 | 2029 | 24.95062792 | 36.28979926 | 49.65122827 | 16.63375194 |
| 18 | 2030 | 24.95062792 | 36.28979926 | 49.65122827 | 16.63375194 |
| 19 | 2031 | 24.95062792 | 36.28979926 | 49.65122827 | 16.63375194 |
| 20 | 2032 | 24.95062792 | 36.28979926 | 49.65122827 | 16.63375194 |
| 21 | 2033 | 24.95062792 | 36.28979926 | 49.65122827 | 16.63375194 |
| 22 | 2034 | 24.95062792 | 36.28979926 | 49.65122827 | 16.63375194 |
| 23 | 2035 | 24.95062792 | 36.28979926 | 49.65122827 | 16.63375194 |
| 24 | 2036 | 24.95062792 | 36.28979926 | 49.65122827 | 16.63375194 |
| 25 | 2037 | 24.95062792 | 36.28979926 | 49.65122827 | 16.63375194 |
| 26 | 2038 | 24.95062792 | 36.28979926 | 49.65122827 | 16.63375194 |
| 27 | | | | | |
| 28 | | Shipping company | | Gas company | |
| 29 | | NPV | IRR | NPV | IRR |
| 30 | [A] | 61.85 € | =IRR(B5:B26) | 41.23 € | 7.8% |
| 31 | [B] | 51.78 € | 13.0% | 34.52 € | 13.0% |
| 32 | [C] | 45.90 € | 18.3% | 30.60 € | 18.3% |

Picture 9-8 IRR of each shareholding company

## 9.2 Second scenario

### 9.2.1 Shipping company's perspective

From Access | From Web | From Text | From Other Sources | Existing Connections | Get External Data | Refresh All | Edit Links | Connections | Sort

IRR =C9-1.55

| | A | B | C | D | E |
|---|---|---|---|---|---|
| 1 | FSRU total capex: | | 400 | m € | |
| 2 | fuel cost: | 4250 | €/day | Hoegh-FSRU | |
| 3 | fuel cost: | 1.55 | m €/year | | |
| 4 | | | | | |
| 5 | | | | | |
| 6 | YEARS | CAPEX (-) [m €] | OPEX sc 1 (-) [m €] | OPEX ship (-) [m €] | |
| 7 | 2017 | 200 | 0 | 0 | |
| 8 | 2018 | 200 | 0 | 0 | |
| 9 | 2019 | 0 | 25 | =C9-1.55 | |
| 10 | 2020 | 0 | 25 | 23.45 | |
| 11 | 2021 | 0 | 25 | 23.45 | |
| 12 | 2022 | 0 | 25 | 23.45 | |
| 13 | 2023 | 0 | 25 | 23.45 | |
| 14 | 2024 | 0 | 25 | 23.45 | |
| 15 | 2025 | 0 | 25 | 23.45 | |

Picture 9-9 CAPEX & OPEX of the shipping company

G13 =SUM(H11:H32)

| | A | B | C | D | E | F | G | H |
|---|---|---|---|---|---|---|---|---|
| 10 | N | YEARS | CAPEX (-) [m €] | OPEX ship (-) [m €] | Total Annual Expenses [m €] | Scrapping Value (+) [m €] | RFR (+) [A] [m €] | Present Value [A] [m |
| 11 | 0 | 2017 | 200 | 0 | -200 | 0 | 0 | -200 |
| 12 | 1 | 2018 | 200 | 0 | -200 | 0 | 0 | -190.4761905 |
| 13 | 2 | 2019 | 0 | 23.45 | [illegible] | 0 | 55.86557935 | 29.40188603 |
| 14 | 3 | 2020 | 0 | 23.45 | [illegible] | 0 | 55.86557935 | 28.00179622 |
| 15 | 4 | 2021 | 0 | 23.45 | [illegible] | 0 | 55.86557935 | 26.66837736 |
| 16 | 5 | 2022 | 0 | 23.45 | [illegible] | 0 | 55.86557935 | 25.39845462 |
| 17 | 6 | 2023 | 0 | 23.45 | [illegible] | 0 | 55.86557935 | 24.1890044 |
| 18 | 7 | 2024 | 0 | 23.45 | [illegible] | 0 | 55.86557935 | 23.03714705 |
| 19 | 8 | 2025 | 0 | 23.45 | -23.45 | 0 | 55.86557935 | 21.94014005 |
| 20 | 9 | 2026 | 0 | 23.45 | -23.45 | 0 | 55.86557935 | 20.89537148 |
| 21 | 10 | 2027 | 0 | 23.45 | -23.45 | 0 | 55.86557935 | 19.90035379 |
| 22 | 11 | 2028 | 0 | 23.45 | -23.45 | 0 | 55.86557935 | 18.95271789 |
| 23 | 12 | 2029 | 0 | 23.45 | -23.45 | 0 | 55.86557935 | 18.05020752 |
| 24 | 13 | 2030 | 0 | 23.45 | -23.45 | 0 | 55.86557935 | 17.19067382 |
| 25 | 14 | 2031 | 0 | 23.45 | -23.45 | 0 | 55.86557935 | 16.37207031 |
| 26 | 15 | 2032 | 0 | 23.45 | -23.45 | 0 | 55.86557935 | 15.59244791 |
| 27 | 16 | 2033 | 0 | 23.45 | -23.45 | 0 | 55.86557935 | 14.84995039 |
| 28 | 17 | 2034 | 0 | 23.45 | -23.45 | 0 | 55.86557935 | 14.1428099 |
| 29 | 18 | 2035 | 0 | 23.45 | -23.45 | 0 | 55.86557935 | 13.46934276 |
| 30 | 19 | 2036 | 0 | 23.45 | -23.45 | 0 | 55.86557935 | 12.82794549 |
| 31 | 20 | 2037 | 0 | 23.45 | -23.45 | 0 | 55.86557935 | 12.21709094 |
| 32 | 21 | 2038 | 0 | 23.45 | -23.45 | 16 | 55.86557935 | 17.37840254 |
| 33 | | | | | | | SUM: | 3.19744E-14 |
| 34 | | | | | | | | |

Goal Seek
Set cell: H33
To value: 0
By changing cell: $G$13
OK Cancel

CAPEX_OPEX | RFR | Final_Freight_Rate
Point

Picture 9-10 Goal Seek method to calculate the RFR

IRR | =IRR(H4:H25)

| | A | B | C | D | E | F | G | H |
|---|---|---|---|---|---|---|---|---|
| 3 | N | YEARS | CAPEX (-) [m €] | OPEX ship (-) [m €] | otal Annual Expenses [m € | crapping Value (+) [m € | Freight rate (+) [A] [m €] | otal annual Cashflow [A] [m € |
| 4 | 0 | 2017 | 200 | 0 | -200 | 0 | 0 | -200 |
| 5 | 1 | 2018 | 200 | 0 | -200 | 0 | 0 | -200 |
| 6 | 2 | 2019 | 0 | 23.45 | -23.45 | 0 | 64.24541626 | 40.79541626 |
| 7 | 3 | 2020 | 0 | 23.45 | -23.45 | 0 | 64.24541626 | 40.79541626 |
| 8 | 4 | 2021 | 0 | 23.45 | -23.45 | 0 | 64.24541626 | 40.79541626 |
| 9 | 5 | 2022 | 0 | 23.45 | -23.45 | 0 | 64.24541626 | 40.79541626 |
| 10 | 6 | 2023 | 0 | 23.45 | -23.45 | 0 | 64.24541626 | 40.79541626 |
| 11 | 7 | 2024 | 0 | 23.45 | -23.45 | 0 | 64.24541626 | 40.79541626 |
| 12 | 8 | 2025 | 0 | 23.45 | -23.45 | 0 | 64.24541626 | 40.79541626 |
| 13 | 9 | 2026 | 0 | 23.45 | -23.45 | 0 | 64.24541626 | 40.79541626 |
| 14 | 10 | 2027 | 0 | 23.45 | -23.45 | 0 | 64.24541626 | 40.79541626 |
| 15 | 11 | 2028 | 0 | 23.45 | -23.45 | 0 | 64.24541626 | 40.79541626 |
| 16 | 12 | 2029 | 0 | 23.45 | -23.45 | 0 | 64.24541626 | 40.79541626 |
| 17 | 13 | 2030 | 0 | 23.45 | -23.45 | 0 | 64.24541626 | 40.79541626 |
| 18 | 14 | 2031 | 0 | 23.45 | -23.45 | 0 | 64.24541626 | 40.79541626 |
| 19 | 15 | 2032 | 0 | 23.45 | -23.45 | 0 | 64.24541626 | 40.79541626 |
| 20 | 16 | 2033 | 0 | 23.45 | -23.45 | 0 | 64.24541626 | 40.79541626 |
| 21 | 17 | 2034 | 0 | 23.45 | -23.45 | 0 | 64.24541626 | 40.79541626 |
| 22 | 18 | 2035 | 0 | 23.45 | -23.45 | 0 | 64.24541626 | 40.79541626 |
| 23 | 19 | 2036 | 0 | 23.45 | -23.45 | 0 | 64.24541626 | 40.79541626 |
| 24 | 20 | 2037 | 0 | 23.45 | -23.45 | 0 | 64.24541626 | 40.79541626 |
| 25 | 21 | 2038 | 0 | 23.45 | -23.45 | 16 | 64.24541626 | 56.79541626 |
| 26 | | | | | | | | |
| 27 | | | | | | | | |
| 28 | | | | | | | | |
| 29 | | | | | | | | |
| 30 | | [A] | [B] | [C] | | | | |
| 31 | IRR: | =IRR(H4:H25) | 12.9% | 18.2% | | | | |
| 32 | FINAL NPV [m]: | 99.46 € | 84.17 € | 75.10 € | | | | |
| 33 | Daily Freight Rate [th €] | 175.89 | 228.28 | 289.64 | | | | |
| 34 | | | | | | | | |

CAPEX_OPEX | RFR | Final_Freight_Rate

Picture 9-11 IRR of the shipping company

IRR | =H4+NPV(0.05;H5:H25)

| | A | B | C | D | E | F | G | H |
|---|---|---|---|---|---|---|---|---|
| 2 | | | | | | | | |
| 3 | N | YEARS | CAPEX (-) [m €] | OPEX ship (-) [m €] | otal Annual Expenses [m € | crapping Value (+) [m € | Freight rate (+) [A] [m €] | otal annual Cashflow [A] [m € |
| 4 | 0 | 2017 | 200 | 0 | -200 | 0 | 0 | -200 |
| 5 | 1 | 2018 | 200 | 0 | -200 | 0 | 0 | -200 |
| 6 | 2 | 2019 | 0 | 23.45 | -23.45 | 0 | 64.24541626 | 40.79541626 |
| 7 | 3 | 2020 | 0 | 23.45 | -23.45 | 0 | 64.24541626 | 40.79541626 |
| 8 | 4 | 2021 | 0 | 23.45 | -23.45 | 0 | 64.24541626 | 40.79541626 |
| 9 | 5 | 2022 | 0 | 23.45 | -23.45 | 0 | 64.24541626 | 40.79541626 |
| 10 | 6 | 2023 | 0 | 23.45 | -23.45 | 0 | 64.24541626 | 40.79541626 |
| 11 | 7 | 2024 | 0 | 23.45 | -23.45 | 0 | 64.24541626 | 40.79541626 |
| 12 | 8 | 2025 | 0 | 23.45 | -23.45 | 0 | 64.24541626 | 40.79541626 |
| 13 | 9 | 2026 | 0 | 23.45 | -23.45 | 0 | 64.24541626 | 40.79541626 |
| 14 | 10 | 2027 | 0 | 23.45 | -23.45 | 0 | 64.24541626 | 40.79541626 |
| 15 | 11 | 2028 | 0 | 23.45 | -23.45 | 0 | 64.24541626 | 40.79541626 |
| 16 | 12 | 2029 | 0 | 23.45 | -23.45 | 0 | 64.24541626 | 40.79541626 |
| 17 | 13 | 2030 | 0 | 23.45 | -23.45 | 0 | 64.24541626 | 40.79541626 |
| 18 | 14 | 2031 | 0 | 23.45 | -23.45 | 0 | 64.24541626 | 40.79541626 |
| 19 | 15 | 2032 | 0 | 23.45 | -23.45 | 0 | 64.24541626 | 40.79541626 |
| 20 | 16 | 2033 | 0 | 23.45 | -23.45 | 0 | 64.24541626 | 40.79541626 |
| 21 | 17 | 2034 | 0 | 23.45 | -23.45 | 0 | 64.24541626 | 40.79541626 |
| 22 | 18 | 2035 | 0 | 23.45 | -23.45 | 0 | 64.24541626 | 40.79541626 |
| 23 | 19 | 2036 | 0 | 23.45 | -23.45 | 0 | 64.24541626 | 40.79541626 |
| 24 | 20 | 2037 | 0 | 23.45 | -23.45 | 0 | 64.24541626 | 40.79541626 |
| 25 | 21 | 2038 | 0 | 23.45 | -23.45 | 16 | 64.24541626 | 56.79541626 |
| 26 | | | | | | | | |
| 27 | | | | | | | | |
| 28 | | | | | | | | |
| 29 | | | | | | | | |
| 30 | | [A] | [B] | [C] | | | | |
| 31 | IRR: | 7.6% | 12.9% | 18.2% | | | | |
| 32 | FINAL NPV [m]: | V(0.05;H5:H25) | 84.17 € | 75.10 € | | | | |
| 33 | Daily Freight Rate [th €] | 175.89 | 228.28 | 289.64 | | | | |

Daily freight rate is equal to the annual freight rate divided by 365.25 (avg number of days per year

CAPEX_OPEX | RFR | Final_Freight_Rate

Picture 9-12 Final NPV and daily FR paid to shipping company

### 9.2.2 Gas company's perspective

Get External Data | Connections | Sort & Filter | Data Tools

IRR | ='C:\Users\jimmy\Desktop\FSRU thesis\[FSRU_NPV sc.2 ship.xlsx]Final_Freight_Rate'!$G$6 +1.55

| | A | B | C | D |
|---|---|---|---|---|
| 3 | YEARS | OPEX (-) [A] [m €] | OPEX (-) [B] [m €] | OPEX (-) [C] [m €] |
| 4 | 2017 | 0 | 0 | 0 |
| 5 | 2018 | 0 | 0 | 0 |
| 6 | 2019 | ='C:\Users\jimmy\ | 84.92924167 | 107.3399361 |
| 7 | 2020 | 65.79541626 | 84.92924167 | 107.3399361 |
| 8 | 2021 | 65.79541626 | 84.92924167 | 107.3399361 |
| 9 | 2022 | 65.79541626 | 84.92924167 | 107.3399361 |
| 10 | 2023 | 65.79541626 | 84.92924167 | 107.3399361 |
| 11 | 2024 | 65.79541626 | 84.92924167 | 107.3399361 |
| 12 | 2025 | 65.79541626 | 84.92924167 | 107.3399361 |
| 13 | 2026 | 65.79541626 | 84.92924167 | 107.3399361 |
| 14 | 2027 | 65.79541626 | 84.92924167 | 107.3399361 |
| 15 | 2028 | 65.79541626 | 84.92924167 | 107.3399361 |
| 16 | 2029 | 65.79541626 | 84.92924167 | 107.3399361 |
| 17 | 2030 | 65.79541626 | 84.92924167 | 107.3399361 |
| 18 | 2031 | 65.79541626 | 84.92924167 | 107.3399361 |
| 19 | 2032 | 65.79541626 | 84.92924167 | 107.3399361 |
| 20 | 2033 | 65.79541626 | 84.92924167 | 107.3399361 |
| 21 | 2034 | 65.79541626 | 84.92924167 | 107.3399361 |
| 22 | 2035 | 65.79541626 | 84.92924167 | 107.3399361 |
| 23 | 2036 | 65.79541626 | 84.92924167 | 107.3399361 |
| 24 | 2037 | 65.79541626 | 84.92924167 | 107.3399361 |
| 25 | 2038 | 65.79541626 | 84.92924167 | 107.3399361 |

**Picture 9-13 OPEX of the gas company**

E11 | =SUM(G9:G30)

| | B | C | D | E | F | G |
|---|---|---|---|---|---|---|
| 4 | [A] : | 5% | | Assuming constant charge for the FSRU use | Calculating revenues from FSRU charge | |
| 5 | [B] : | 10% | | | | |
| 6 | [C] : | 15% | | | | |
| 7 | | | | | | |
| 8 | YEARS | LNG imported to Alexandroupolis [m kWh per annum] | OPEX (-) [A] [m €] | Minimum Charge for the FSRU use per year [A] [€/KWh] | Calculated Revenues (+) [A] [m €] | Present Value [A] [m €] |
| 9 | 2017 | 0 | 0 | 0 | 0 | 0 |
| 10 | 2018 | 0 | 0 | 0 | 0 | 0 |
| 11 | 2019 | 7945.962733 | 65.79541626 | 0.005924124 | 47.07286814 | -16.98190306 |
| 12 | 2020 | 8263.801243 | 65.79541626 | 0.005924124 | 48.95578286 | -14.54670847 |
| 13 | 2021 | 8594.353292 | | 0.005924124 | 50.91401418 | -12.24296632 |
| 14 | 2022 | 8938.127424 | | 0.005924124 | 52.95057474 | -10.06426943 |
| 15 | 2023 | 9295.652521 | | 0.005924124 | 55.06859773 | -8.004517138 |
| 16 | 2024 | 9667.478622 | | 0.005924124 | 57.27134164 | -6.057900683 |
| 17 | 2025 | 10054.17777 | | 0.005924124 | 59.56219531 | -4.218889289 |
| 18 | 2026 | 10456.34488 | | 0.005924124 | 61.94468312 | -2.482216912 |
| 19 | 2027 | 10874.59867 | | 0.005924124 | 64.42247045 | -0.842869628 |
| 20 | 2028 | 11309.58262 | | 0.005924124 | 66.99936927 | 0.703926389 |
| 21 | 2029 | 11761.96592 | 65.79541626 | 0.005924124 | 69.67934404 | 2.162716317 |
| 22 | 2030 | 12232.44456 | 65.79541626 | 0.005924124 | 72.4665178 | 3.53782758 |
| 23 | 2031 | 12721.74234 | 65.79541626 | 0.005924124 | 75.36517851 | 4.833380232 |
| 24 | 2032 | 13230.61204 | 65.79541626 | 0.005924124 | 78.37978565 | 6.053296847 |
| 25 | 2033 | 13759.83652 | 65.79541626 | 0.005924124 | 81.51497708 | 7.201311932 |
| 26 | 2034 | 14310.22998 | 65.79541626 | 0.005924124 | 84.77557616 | 8.280980896 |
| 27 | 2035 | 14882.63918 | 65.79541626 | 0.005924124 | 88.1665992 | 9.295688589 |
| 28 | 2036 | 15477.94475 | 65.79541626 | 0.005924124 | 91.69326317 | 10.24865744 |
| 29 | 2037 | 16097.06254 | 65.79541626 | 0.005924124 | 95.3609937 | 11.14295519 |
| 30 | 2038 | 16740.94504 | 65.79541626 | 0.005924124 | 99.17543345 | 11.9815023 |
| 31 | | | | | | 2.79398E-06 |

Goal Seek
Set cell: G31
To value: 0
By changing cell: $E$11
OK | Cancel

Using Goal Seek we calculate the minimum FSRU charge

OPEX | Min_Revenues | LNG demand & charge | NPV_IRR

**Picture 9-14 Goal Seek method to calculate the minimum charge for the FSRU use**

E7 MTPA

| | A | B | C | D | E |
|---|---|---|---|---|---|
| 10 | YEAR | Minimum Charge for the FSRU use per year [A] [€/KWh] | linimum Charge for the FSRU use per year [B] [€/KWh | Minimum Charge for the FSRU use per year [C] [€/KWh] | .NG imported to Alexandroupolis [m k |
| 11 | 2017 | 0 | 0 | 0 | 0 |
| 12 | 2018 | 0 | 0 | 0 | 0 |
| 13 | 2019 | 0.005924124 | 0.008096885 | 0.010738818 | 7945.962733 |
| 14 | 2020 | 0.005924124 | 0.008096885 | 0.010738818 | 8263.801243 |
| 15 | 2021 | 0.005924124 | 0.008096885 | 0.010738818 | 8594.353292 |
| 16 | 2022 | 0.005924124 | 0.008096885 | 0.010738818 | 8938.127424 |
| 17 | 2023 | 0.005924124 | 0.008096885 | 0.010738818 | 9295.652521 |
| 18 | 2024 | 0.005924124 | 0.008096885 | 0.010738818 | 9667.478622 |
| 19 | 2025 | 0.005924124 | 0.008096885 | 0.010738818 | 10054.17777 |
| 20 | 2026 | 0.005924124 | 0.008096885 | 0.010738818 | 10456.34488 |
| 21 | 2027 | 0.005924124 | 0.008096885 | 0.010738818 | 10874.59867 |
| 22 | 2028 | 0.005924124 | 0.008096885 | 0.010738818 | 11309.58262 |
| 23 | 2029 | 0.005924124 | 0.008096885 | 0.010738818 | 11761.96592 |
| 24 | 2030 | 0.005924124 | 0.008096885 | 0.010738818 | 12232.44456 |
| 25 | 2031 | 0.005924124 | 0.008096885 | 0.010738818 | 12721.74234 |
| 26 | 2032 | 0.005924124 | 0.008096885 | 0.010738818 | 13230.61204 |
| 27 | 2033 | 0.005924124 | 0.008096885 | 0.010738818 | 13759.83652 |
| 28 | 2034 | 0.005924124 | 0.008096885 | 0.010738818 | 14310.22998 |
| 29 | 2035 | 0.005924124 | 0.008096885 | 0.010738818 | 14882.63918 |
| 30 | 2036 | 0.005924124 | 0.008096885 | 0.010738818 | 15477.94475 |
| 31 | 2037 | 0.005924124 | 0.008096885 | 0.010738818 | 16097.06254 |
| 32 | 2038 | 0.005924124 | 0.008096885 | 0.010738818 | 16740.94504 |
| 33 | | | Calcullating revenues | | |
| 34 | Assumption of a raise of the annual LNG charge from the calculated minimum: | | 15% | | |
| 35 | | | | | |
| 36 | YEAR | Charge for the FSRU use per year [A] [€/KWh] | Real Revenues [A] [m €] | Charge for the FSRU use per year [B] [€/kWh] | Real Revenues [B] [m € |
| 37 | 2017 | 0 | 0 | 0 | 0 |
| 38 | 2018 | 0 | 0 | 0 | 0 |
| 39 | 2019 | 0.006812743 | 54.13379836 | 0.009311417 | 73.98817409 |
| 40 | 2020 | 0.006812743 | 56.29915029 | 0.009311417 | 76.94770105 |
| 41 | 2021 | 0.006812743 | 58.5511163 | 0.009311417 | 80.02560909 |

15% raise of charge for the FSRU compared to minimum

OPEX / Min_Revenues / LNG demand & charge / NPV_IRR

Picture 9-15 Minimum and commercial annual charge and revenues of the gas company

IRR =IRR(E4:E25)

| | A | B | C | D | E |
|---|---|---|---|---|---|
| 3 | N | YEAR | OPEX (-) [A] [m €] | Real Revenues [A] [m €] | Total Annual Cashflow [A] [m €] |
| 4 | 0 | 2017 | 0 | 0 | 0 |
| 5 | 1 | 2018 | 0 | 0 | 0 |
| 6 | 2 | 2019 | 65.79541626 | 54.13379836 | -11.6616179 |
| 7 | 3 | 2020 | 65.79541626 | 56.29915029 | -9.496265963 |
| 8 | 4 | 2021 | 65.79541626 | 58.5511163 | -7.244299952 |
| 9 | 5 | 2022 | 65.79541626 | 60.89316096 | -4.902255299 |
| 10 | 6 | 2023 | 65.79541626 | 63.32888739 | -2.466528861 |
| 11 | 7 | 2024 | 65.79541626 | 65.86204289 | 0.066626635 |
| 12 | 8 | 2025 | 65.79541626 | 68.49652461 | 2.70110835 |
| 13 | 9 | 2026 | 65.79541626 | 71.23638559 | 5.440969335 |
| 14 | 10 | 2027 | 65.79541626 | 74.08584101 | 8.290424758 |
| 15 | 11 | 2028 | 65.79541626 | 77.04927465 | 11.2538584 |
| 16 | 12 | 2029 | 65.79541626 | 80.13124564 | 14.33582938 |
| 17 | 13 | 2030 | 65.79541626 | 83.33649547 | 17.54107921 |
| 18 | 14 | 2031 | 65.79541626 | 86.66995529 | 20.87453903 |
| 19 | 15 | 2032 | 65.79541626 | 90.1367535 | 24.34133724 |
| 20 | 16 | 2033 | 65.79541626 | 93.74222364 | 27.94680738 |
| 21 | 17 | 2034 | 65.79541626 | 97.49191258 | 31.69649633 |
| 22 | 18 | 2035 | 65.79541626 | 101.3915891 | 35.59617283 |
| 23 | 19 | 2036 | 65.79541626 | 105.4472526 | 39.65183639 |
| 24 | 20 | 2037 | 65.79541626 | 109.6651428 | 43.8697265 |
| 25 | 21 | 2038 | 65.79541626 | 114.0517485 | 48.25633221 |
| 26 | | | | | |
| 27 | | | | | |
| 28 | | [A] | [B] | [C] | |
| 29 | IRR: | =IRR(E4:E25) | 29.7% | 46.3% | |
| 30 | FINAL NPV [m]: | 117.14 € | 98.60 € | 87.64 € | |

Picture 9-16 IRR of the gas company

IRR | =E4+NPV(0.05;E5:E25)

| | A | B | C | D | E |
|---|---|---|---|---|---|
| 3 | N | YEAR | OPEX (-) [A] [m €] | Real Revenues [A] [m €] | Total Annual Cashflow [A] [m €] |
| 4 | 0 | 2017 | 0 | 0 | 0 |
| 5 | 1 | 2018 | 0 | 0 | 0 |
| 6 | 2 | 2019 | 65.79541626 | 54.13379836 | -11.6616179 |
| 7 | 3 | 2020 | 65.79541626 | 56.29915029 | -9.496265963 |
| 8 | 4 | 2021 | 65.79541626 | 58.5511163 | -7.244299952 |
| 9 | 5 | 2022 | 65.79541626 | 60.89316096 | -4.902255299 |
| 10 | 6 | 2023 | 65.79541626 | 63.32888739 | -2.466528861 |
| 11 | 7 | 2024 | 65.79541626 | 65.86204289 | 0.066626635 |
| 12 | 8 | 2025 | 65.79541626 | 68.49652461 | 2.70110835 |
| 13 | 9 | 2026 | 65.79541626 | 71.23638559 | 5.440969335 |
| 14 | 10 | 2027 | 65.79541626 | 74.08584101 | 8.290424758 |
| 15 | 11 | 2028 | 65.79541626 | 77.04927465 | 11.2538584 |
| 16 | 12 | 2029 | 65.79541626 | 80.13124564 | 14.33582938 |
| 17 | 13 | 2030 | 65.79541626 | 83.33649547 | 17.54107921 |
| 18 | 14 | 2031 | 65.79541626 | 86.66995529 | 20.87453903 |
| 19 | 15 | 2032 | 65.79541626 | 90.1367535 | 24.34133724 |
| 20 | 16 | 2033 | 65.79541626 | 93.74222364 | 27.94680738 |
| 21 | 17 | 2034 | 65.79541626 | 97.49191258 | 31.69649633 |
| 22 | 18 | 2035 | 65.79541626 | 101.3915891 | 35.59617283 |
| 23 | 19 | 2036 | 65.79541626 | 105.4472526 | 39.65183639 |
| 24 | 20 | 2037 | 65.79541626 | 109.6651428 | 43.8697265 |
| 25 | 21 | 2038 | 65.79541626 | 114.0517485 | 48.25633221 |
| 26 | | | | | |
| 27 | | | | | |
| 28 | | **[A]** | **[B]** | **[C]** | |
| 29 | **IRR:** | **19.4%** | **29.7%** | **46.3%** | |
| 30 | **FINAL NPV [m]:** | **=E4+NPV(0.05;E5:E25)** | **98.60 €** | **87.64 €** | |

OPEX | Min_Revenues | LNG demand & charge | **NPV_IRR**

**Picture 9-17 Final NPV of the gas company**

Clipboard | Font | Alignment | Number

TREND | =0.002*C11-D11

| | A | B | C | D |
|---|---|---|---|---|
| 7 | | | | |
| 8 | N | YEARS | LNG imported to Alexandroupolis [m kWh per annum] | OPEX (-) [A] [m €] |
| 9 | 0 | 2017 | 0 | 0 |
| 10 | 1 | 2018 | 0 | 0 |
| 11 | 2 | 2019 | 7945.962733 | 65.79541626 |
| 12 | 3 | 2020 | 8263.801243 | 65.79541626 |
| 13 | 4 | 2021 | 8594.353292 | 65.79541626 |
| 14 | 5 | 2022 | 8938.127424 | 65.79541626 |
| 15 | 6 | 2023 | 9295.652521 | 65.79541626 |
| 16 | 7 | 2024 | 9667.478622 | 65.79541626 |
| 17 | 8 | 2025 | 10054.17777 | 65.79541626 |
| 18 | 9 | 2026 | 10456.34488 | 65.79541626 |
| 19 | 10 | 2027 | 10874.59867 | 65.79541626 |
| 20 | 11 | 2028 | 11309.58262 | 65.79541626 |
| 21 | 12 | 2029 | 11761.96592 | 65.79541626 |
| 22 | 13 | 2030 | 12232.44456 | 65.79541626 |
| 23 | 14 | 2031 | 12721.74234 | 65.79541626 |
| 24 | 15 | 2032 | 13230.61204 | 65.79541626 |
| 25 | 16 | 2033 | 13759.83652 | 65.79541626 |
| 26 | 17 | 2034 | 14310.22998 | 65.79541626 |
| 27 | 18 | 2035 | 14882.63918 | 65.79541626 |
| 28 | 19 | 2036 | 15477.94475 | 65.79541626 |
| 29 | 20 | 2037 | 16097.06254 | 65.79541626 |
| 30 | 21 | 2038 | 16740.94504 | 65.79541626 |
| 31 | | | | |
| 32 | | | | |
| 33 | | | | |
| 34 | | | | |
| 35 | | **[A]** | **[B]** | **[C]** |
| 36 | **Minimum Charge of LNG per year [€/KWh]** | **0.0059241** | **0.0080969** | **0.0107388** |
| 37 | | | | |
| 38 | | | | |
| 39 | 0 | 0 | 0 | 0 |
| 40 | 1 | 0 | 0 | 0 |
| 41 | 2 | -65.79541626 | =0.002*C11-D11 | -34.01156532 |
| 42 | 3 | -65.79541626 | -49.26781377 | -32.74021129 |
| 43 | 4 | -65.79541626 | -48.60670967 | -31.41800309 |
| 44 | 5 | -65.79541626 | -47.91916141 | -30.04290656 |

Calculating the annual cashflow for FSRU charging price from 0 to 0.1 EUR/kW using the assumed LNG demand

OPEX | **Min_Revenues** | LNG demand & charge | NPV_IRR

Picture 9-18 Gas company's total annual cashflow calculation depending on FSRU charge

Clipboard | Font | Alignment | Number | Styles

TREND =B39+NPV(5%;B40:B60)

| | A | B | C | D |
|---|---|---|---|---|
| 44 | 5 | -65.79541626 | -47.91916141 | -30.042906 |
| 45 | 6 | -65.79541626 | -47.20411121 | -28.612806 |
| 46 | 7 | -65.79541626 | -46.46045901 | -27.125501 |
| 47 | 8 | -65.79541626 | -45.68706072 | -25.578705 |
| 48 | 9 | -65.79541626 | -44.8827265 | -23.970036 |
| 49 | 10 | -65.79541626 | -44.04621891 | -22.297021 |
| 50 | 11 | -65.79541626 | -43.17625102 | -20.557085 |
| 51 | 12 | -65.79541626 | -42.27148441 | -18.747552 |
| 52 | 13 | -65.79541626 | -41.33052713 | -16.865638 |
| 53 | 14 | -65.79541626 | -40.35193157 | -14.908446 |
| 54 | 15 | -65.79541626 | -39.33419218 | -12.872968 |
| 55 | 16 | -65.79541626 | -38.27574322 | -10.756070 |
| 56 | 17 | -65.79541626 | -37.1749563 | -8.5544963 |
| 57 | 18 | -65.79541626 | -36.0301379 | -6.2648595 |
| 58 | 19 | -65.79541626 | -34.83952676 | -3.8836372 |
| 59 | 20 | -65.79541626 | -33.60129119 | -1.4071661 |
| 60 | 21 | -65.79541626 | -32.31352618 | 1.1683638 |
| 61 | | | | |
| 62 | | | | |
| 63 | | | | |
| 64 | | | NPV | |
| 65 | **Charge for the FSRU use per year [€/kWh]** | **[A]:5%** | **[B]:10%** | **[C]:15%** |
| 66 | **0** | =B39+NPV(5%;B40:B60) | -509.23 € | -358.12 € |
| 67 | **0.002** | -517.27 € | -346.87 € | -249.31 € |
| 68 | **0.004** | -253.64 € | -184.50 € | -140.50 € |
| 69 | **0.006** | 10.00 € | -22.14 € | -31.69 € |
| 70 | **0.008** | 273.64 € | 140.22 € | 77.12 € |
| 71 | **0.01** | 537.28 € | 302.59 € | 185.93 € |

Picture 9-19 Gas company's project NPV depending on FSRU charge

TREND =TREND(A68:A69;B68:B69;0)

| | A | B | C | D |
|---|---|---|---|---|
| 53 | 14 | -65.79541626 | -40.35193157 | -14.9084468 |
| 54 | 15 | -65.79541626 | -39.33419218 | -12.8729681 |
| 55 | 16 | -65.79541626 | -38.27574322 | -10.7560701 |
| 56 | 17 | -65.79541626 | -37.1749563 | -8.55449633 |
| 57 | 18 | -65.79541626 | -36.0301379 | -6.26485954 |
| 58 | 19 | -65.79541626 | -34.83952676 | -3.88363727 |
| 59 | 20 | -65.79541626 | -33.60129119 | -1.40716611 |
| 60 | 21 | -65.79541626 | -32.31352618 | 1.16836389 |
| 61 | | | | |
| 62 | | | | |
| 63 | | | | |
| 64 | | | NPV | |
| 65 | **Charge for the FSRU use per year [€/kWh]** | **[A]:5%** | **[B]:10%** | **[C]:15%** |
| 66 | **0** | -780.91 € | -509.23 € | -358.12 € |
| 67 | **0.002** | -517.27 € | -346.87 € | -249.31 € |
| 68 | **0.004** | -253.64 € | -184.50 € | -140.50 € |
| 69 | **0.006** | 10.00 € | -22.14 € | -31.69 € |
| 70 | **0.008** | 273.64 € | 140.22 € | 77.12 € |
| 71 | **0.01** | 537.28 € | 302.59 € | 185.93 € |
| 72 | | | | |
| 73 | 0 | =TREND(A68:A69;B68:B6 | | |
| 74 | 0 | 0.00627 | | |
| 75 | 0 | 0.00658 | | |
| 76 | | | | |
| 77 | | | | |
| 78 | NPV=0 | [A] | [B] | [C] |
| 79 | Charge for the FSRU use per year [€/kWh] | 0.0059 | 0.0063 | 0.0066 |

Picture 9-20 FSRU charging price zeroing gas company's project NPV