National Technical University of Athens
School of Naval Architecture and Marine Engineering
Division of Ship Design and Maritime Transport

Diploma Thesis

Developing a Life Cycle Cost Analysis Tool for Floating Storage Regasification Unit (FSRU) Operations

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Abstract

In this thesis, a Life Cycle Cost Analysis model is developed in order to assess the acquisition, operation and disposal of Floating Storage and Regasification Units (FSRUs).

FSRUs are a special type of LNG vessel which can receive LNG, through ship to ship operation, store and regasify it in order to send it out to the shore. The FSRUs can be moved from site to site depending on the gas export demand and can even be operated as conventional LNG carriers in case required. The FSRU market has emerged as a cost effective and flexible alternative to the traditional land based storage and regasification plants. The FSRU market has also been fueled by the overall growth of the LNG market, largely driven by the move to cleaner fossil fuels, and the need of ship-owners to re-utilize excess shipping capacity as well as the necessity to satisfy seasonal gas demand. In certain markets-locations.

The Life Cycle Cost Analysis method LCCA takes into account all different costs accruing from an investment including the purchase, ownership, operation, maintenance and disposal of the various investment options in order to calculate the most profitable investment among different alternatives. The biggest challenge in an LCCA study is the precision of the future economic cash flows. This study takes into account the acquisition expenses and operational and disposal expenses of the investment. Additionally, driven by the increasingly strict environmental regulations, this study emphasizes the need to take into account the impact of the operation of the unit to the environment. The environmental impact of the asset is included in the study through estimating and expressing in monetized values the Green House Gases emissions of the unit with an option to include them into the financial analysis.

The tool developed is used to assess the investment of the Wilhelmshaven FSRU to be located in the Wilhelmshaven port in Germany which is planned to be owned, financed and operated by Mitsui O.S.K. Lines while Uniper will act as project developer. The Wilhelmshaven FSRU has a planned send-out capacity of 10 bcma and an LNG storage capacity of 263,000 cubic meters.

Results of the analysis revealed, amongst others, the importance of the gas export demand in the financial performance of the investment, particularly in case that the FSRU is not time chartered but operated on a charge per unit of gas exported basis. The influence of the monetized GHG emissions was also demonstrated.

KEY WORDS: LCCA, FSRU, LCA, GHG, LNG

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Glossary

bar g - unit of pressure close to 1 atmosphere
BCFD - Billion cubic feet per day
BCMA - Billion cubic meters per annum. A flowrate of natural gas commonly used
BOG - Boil Off Gas
BTU – British Thermal Units, heat to change the temperature of 1 pound of water 1 degree Fahrenheit
CAPEX - Industry term for Capital Expenses
Closed Loop - Circulation of heating medium (typically glycol/water) for LNG regasification in heat
DISPEX - Disposal Expenses
DSME - Daewoo Shipbuilding & Marine Engineering
EIB – European Investment Bank
ENVEX - Environmental Expenses exchangers
FLNG - Floating LNG liquefaction vessel
FPSO - Floating Production Storage & Offloading Vessel
FSRU - Floating Storage and Regasification Unit
FSRU - Floating storage and regasification vessel
FSU - Floating Storage Unit
FSU - Floating Storage Unit
GHG - Green House Gasses
HFO - Heavy Fuel Oil
IFO - Intermediate Fuel Oil
IFV - Intermediate Fluid Vaporization
IPCC - Intergovernmental Panel on Climate Change
IRR - Internal rate of return
ISO - International Organization for Standardization
km - kilometer
LCA - Life Cycle Analysis
LCCA - Life Cycle Cost Analysis
LDT- Lightweight of a vessel
LNG - Liquefied Natural Gas
LPG - Liquefied Petroleum Gas
m^3– cubic meters
m^3/h - Cubic meters per hour
MBtu -1,000,000 British thermal units
MCM - million cubic meters
Membrane- LNG thermal insulation method
MGO - Marine Gas Oil
MMSCF - Million Standard Cubic Feet

MMSCFA - Million standard cubic feet per annum
MMSFCD - Million standard cubic feet per day
Moss- Moss Maritime LNG tank design
MTPA - Million Tonnes Per Annum
MW - Megawatt
MWh - Megawatt-hour
NPC - Net present cost
NPV - Net present value
Open loop- direct vaporization of LNG using sea water in heat exchangers
OPEX - Operational Expenses
R&D - Research and development
Regas- Regasification or vaporization of LNG back into natural gas
RISKEX - Risk Expenses
Send-out - Production rate from an import terminal expressed as m^3/h, t/h, mtpa, mmscfd or Bcma
STS - Ship to Ship
TTP - Tank to Propeller emissions, the emissions from combustion and potential leakage
WRI - World Resources Institute
WTP - Well to Propeller emissions, TTP plus WTT emissions
WTT - Well to Tank, all the GHG emissions from the production, processing and delivery of a fuel

1. Introduction

1.1. Scope of the Thesis

The aim of this thesis is the development of a Life Cycle Cost Analysis tool for Floating Storage and Regasification Units (FSRUs). FSRU is a special type of ship used for LNG storage, where Liquified Natural Gas is regasified and transferred to the shore. The FSRU as a concept was first developed in 2005, driven by the need for a fast delivery and cost effective storage and regasification of LNG. Since then, the FSRU fleet has expanded, in line with the LNG market expansion. Life Cycle Cost Analysis (LCCA) is a tool utilized to determine the most cost-effective option, among alternative FSRU operating schemes, to purchase, own, operate, maintain and finally dispose of an object or process when each one is equally appropriate to be implemented on technical grounds. This thesis also explores the environmental impact of the operation of the FSRU, as would be done in a Life Cycle Analysis (LCA) study, in order obtain a more comprehensive insight into the overall FSRU operation. The model developed was used to study the Wilhelmshaven FSRU project.

1.2. Structure of the Thesis

In the introduction, the scope and structure of the thesis are discussed. Chapter 2 presents general information regarding LNG as a fuel and LNG market. Chapter 3 provides an insight the FSRU market, a technical overview of FSRUs as well as information on their operation, legal framework, classification and chartering amongst others. Financial aspects of FSRU operation are presented in further detail in chapter 5. Chapter 4 describes the Life Cycle Cost Analysis method and the challenges involved in this method. Chapter 6 describes the model developed as well as the data used for the development of the model. A case study using the model developed is presented in chapter 7. Chapter 8 includes comments and conclusions as well as future work arising from this study.

2. Liquified Natural Gas (LNG)

2.1. General Information

The first step towards studying LNG is the examination of its chemical and physical properties. Natural gas is considered a nonrenewable fossil fuel and is a complex mixture of hydrocarbon and non-hydrocarbon constituents existing in gas state under atmospheric conditions. LNG is natural gas which has been converted to liquid form to facilitate storage and transportation by means of a refrigerated cycle (compression, condensation, expansion, evaporation) that transforms the gas into a liquid at around -160°C decreasing its volume by 625:1.

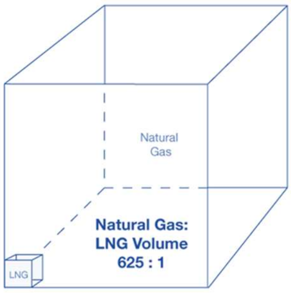


Figure 1. NG and LNG volume, source: IHRDC

Raw natural gas typically consists primarily of methane (CH_4), usually over 80% v/v which is the shortest and lightest hydrocarbon molecule in nature. LNG is the hydro-carbon fuel with the lowest carbon content. It also contains varying amounts of:

- Heavier gaseous hydrocarbons such as ethane (C_2H_6), propane (C_3H_8), normal butane (n-C_4H_{10}), iso-butane (i-C_4H_{10}), pentanes and even higher molecular weight hydrocarbons.
- Acid gases such as carbon dioxide (CO_2), hydrogen sulfide (H_2S) and mercaptans such as methanethiol (CH_3SH) and ethanethiol (C_2H_5SH).
- Other gases such as nitrogen (N_2) and helium (He).
- Water in vapor or liquid state
- Liquid hydrocarbons such as crude oil and/or gas condensates
- Mercury, in trace amounts

Table 1. Natural Gas Constituents

Chemical	Chemical Formula	Low	High
Methane	CH_4	87%	99%
Ethane	C_2H_6	<1%	10%
Propane	C_2H_8	>1%	5%
Butane	C_4H_{10}	>1%	>1%
Nitrogen	N_2	0.10%	1%

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. Natural gas is lighter than air and normally dissipates in case of leakage, which is one of its major advantages in terms of safety compared to Liquefied Petroleum Gas (LPG) or gasoline. The very properties that render LNG a good source of energy can also make it hazardous if inadequately dealt with and in order to accurately understand and predict

LNG behavior its properties as a liquid from its properties as a gas or vapor must be clearly distinguished.

Natural gas is produced in great depth underground under high pressure and temperature conditions. It is the product of the thermal dissolution of the initial high-molecular weight organic matter originating from trapped terrestrial or marine organic sediments. Gas deposits are created from the confinement of the methane produced to watertight geological formations on the bottom of which trapped oil is also commonly found. Natural gas extracted from different deposits differs in composition, sometimes significantly, since the composition of the gas is directly related to the species of the organic matter from which it originates and the conditions under which it was formed [1].

Once a potential natural gas field has been located by a team of exploration geologists and geophysicists, a team of specialists drills down to where the natural gas is thought to exist. After a well has been drilled and the presence of commercially viable quantities of gas has been verified, the next step is to extract the natural gas out of the ground and process it. At this point, the natural gas which is extracted from the ground is called “feed” gas. Before a commercial market for LNG existed, the gas associated with oil went unused and was wasted in a flare. Raw natural gas has to be purified during production prior to liquefaction before it can be used in homes and factories.

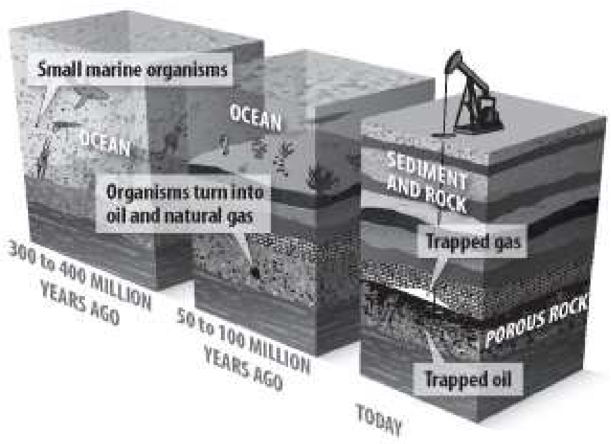


Figure 2. Liquefied Natural Gas formation source: IGU LNG report 2019

A majority of the world's LNG supply is exported from countries with large natural gas reserves. These countries include Qatar, Algeria, Australia, Indonesia, Malaysia, Nigeria, Trinidad, Brunei, Norway, UAE, Egypt, and Russia with Yemen. Other countries may produce natural gas for domestic use, like the US, but lack adequate supply to export on a large scale. In situations in which domestic gas supply is inadequate to meet intra-country demand, LNG is imported. The distance between these countries and their markets means that they lack sufficient gas production and/or it is not possible to import natural gas via pipelines. Another issue countered by LNG imports is the desire of a country to diversify its supply sources in order to increase its energy security in case of geopolitical risks. According to the aforementioned instances, an economical alternative to import LNG is via sea in LNG tankers [2]. Natural gas is liquefied through cooling and transformed to LNG in order to be transported via LNG vessels. LNG occupies a volume that is 600^{th}less of the fuel in its natural form. Nevertheless, the special processing and containment requirements to transport gas as LNG come at a significant cost. In liquid state, LNG will not ignite. The cargo is transported in heavy thermally insulated tanks, specially designed to maintain the natural gas in liquid form at -160°C [3]. LNG’s extremely low temperature makes it a cryogenic liquid.

2.2. The LNG Market

LNG is one of the fastest growing global commodities. According to International Gas Union 2019 LNG report LNG trade is expected to increase by nearly 7% through 2020. The LNG market has grown increasingly complex over the past decade, as a greater number of participants utilize a variety of trading strategies in order to enter and expand the LNG market [4]. The current number of supply projects under development is the biggest since market's establishment both in terms of spot and short-term trading as well as in terms of traditional long-term contracts. This growth of new business models has brought new participants into the market. The growing participation of short-term traders and the increasing unpopularity of destination clauses in LNG contracts has set LNG trade to become more dynamic. At the end of 2018, the LNG vessel order book contained 118 carriers expected to be delivered through 2022, 59 of which were ordered during 2018. This translated to a 195% increase from 2017 [4].

One important factor contributing to the growth of LNG market is the need to combat climate change acting as a pivotal factor of the economic development worldwide. Economic growth is a priority for nations, however, nowadays, this growth is gradually being measured by the effectiveness of the steps taken to protect the environment, including control of Greenhouse Gas emissions. As the international community promotes a global regime to price the use of carbon, some nations are already putting initiatives in place in order to develop low-carbon economies. Natural gas is one of the cleanest fossil fuels since its combustion produces CO_2 emissions that are 30% to 50% lower than those produced by other combustible fuels. A comparison of CO_2 emissions from different fuels is presented in Figure 3παρακάτω below, illustrating that LNG is one of the cleanest solutions in terms of CO_2 emissions, as far as fossil fuels are concerned. Given the above, as the decarbonization of the energy system is established so is the future of natural gas in the global energy economy [5].

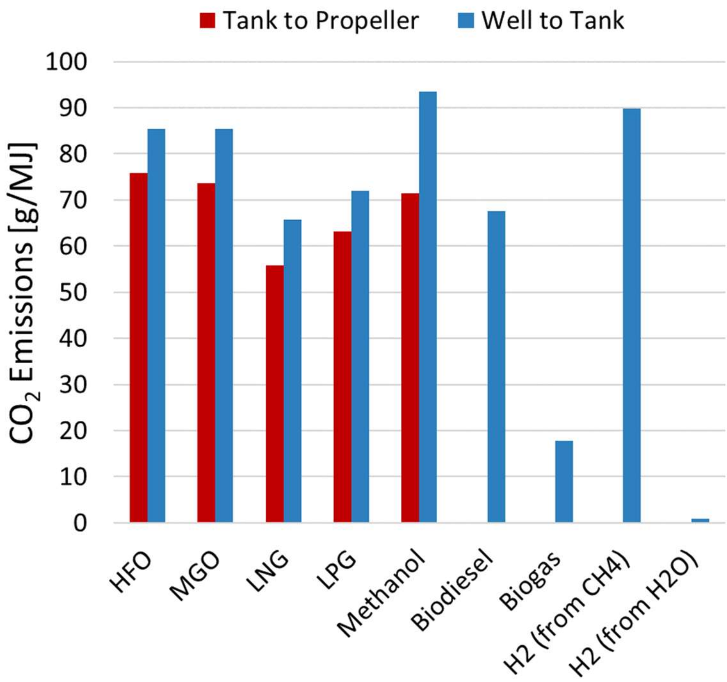
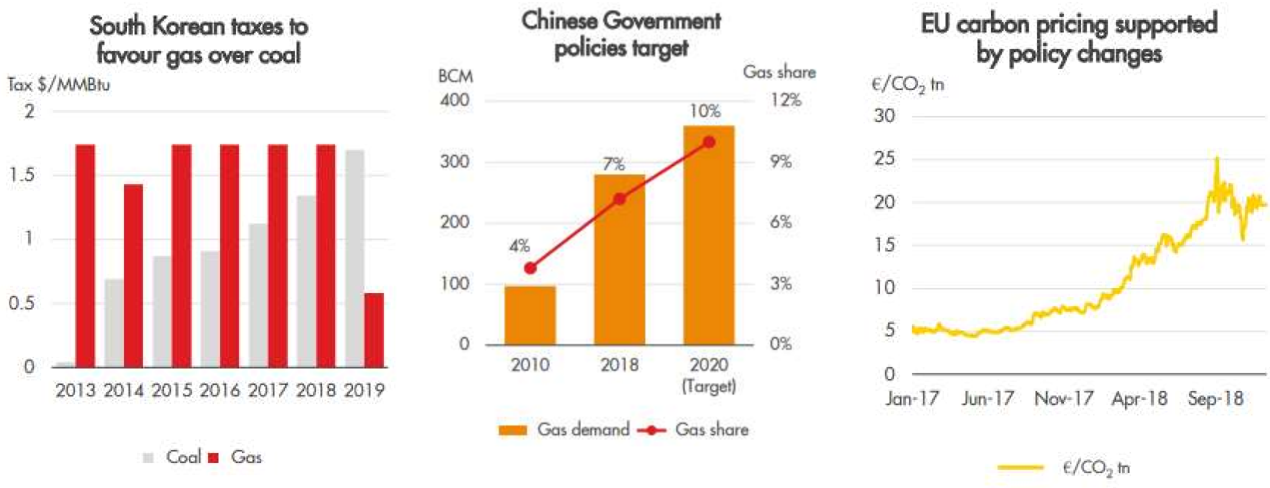


Figure 3: Comparison of TTP and WTT CO_2 emissions for different fuels (Source: DNV-GL)

In support of the above, 3 graphs showing government policies being implemented encouraging a cleaner energy mix, are presented below.



(a) (b) (c)

Figure 4: Government Policies encouraging cleaner energy mixes **[6]**

Figure (a) shows how the South Korean Government promotes the use gas over coal through favorable taxing in 2019 compared to previous years. Figure (b) illustrates the growth of gas demand in China for the period 2010 to 2019 as well as the targets set by the government in terms of the share of gas used in order to satisfy the energy needs of the country. Figure (c) depicts the evolution of the CO_2emissions financial penalty set by the European Union.

Promising as LNG may seem as a fuel, the economy of this emerging market is still volatile and as such future demand can be quite unpredictable. An overview of LNG fuel prices at different geographical locations and years as well as the respective prices of IFO an MGO are presented in Figure 5, giving the reader an idea of the variability in the LNG market as prices vary considerably not only with time but also with geographical location.

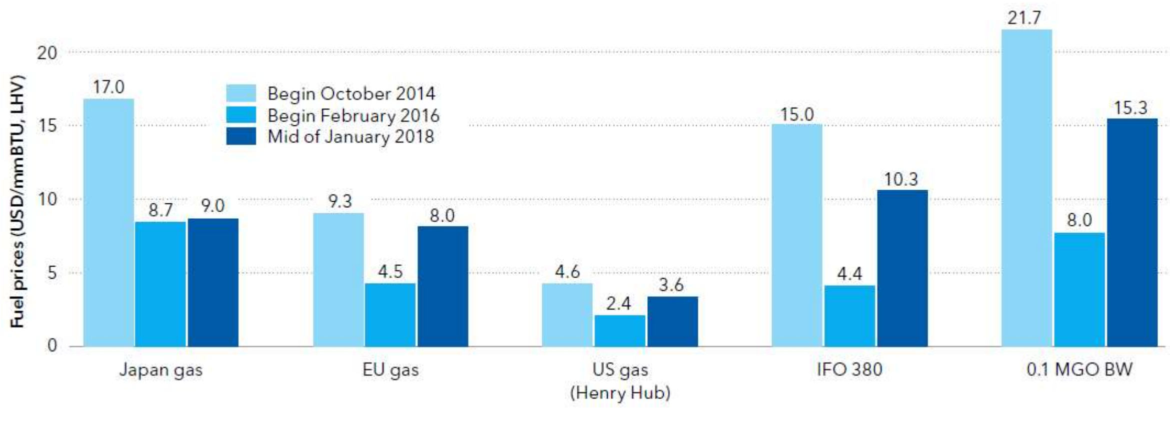


Figure 5 : Comparison between LNG price at different locations and IFO, MGO (source: DNV-GL)

At the same time, an LNG project represents a chain of investments, consisting of four to five links:

- field development
- the liquefaction facility,
- tanker or pipeline transportation
- receipt/regasification terminal

Each element is capital intensive and the investment is usually front-end loaded so that revenue does not begin to flow until the project is complete. As regards, LNG transportation, the special processing and handling requirements leads to significantly higher costs of moving natural gas compared to oil or coal. The relative costs of moving gas or oil by pipeline or by tanker differ substantially, which influences regional competition and thus natural gas markets. Due to the capital intensive nature of LNG investment links, breakdowns and delays in any part of the chain adversely affect capital recovery and project internal rate of return (IRR). However, in the past five to ten years, technology has made it possible to design new LNG liquefaction facilities and tankers with substantial cost reduction. Hence, trades that once seemed unprofitable are starting to become attractive [7].

At the same time, the LNG market has grown more complex over the past decade, as a greater number of participants utilize a broader variety of trading strategies and cargoes that were historically mainly delivered under long-term fixed destination contracts are being sold under shorter contracts or on the spot market. Over the past decade, this segment of the market has developed as a result of several key factors [4]:

- The growth in LNG contracts with destination flexibility, which has facilitated diversions to higher priced markets;
- The increase in the number of exporters and importers, which has amplified the complexity of the industry and introduced new permutations and linkages between buyers and sellers. In 2018, 30 markets (including re-exporters) exported spot volumes to 35 end markets. This compares to 6 spot exporters and 8 spot importers in 2000;
- The growth of companies with diverse marketing portfolios taking on an aggregator role, allowing long-term offtake contracts to satisfy a variety of short- and long-term buyer commitments.
- Sudden changes in supply or demand dynamics such as the Fukushima disaster in Japan or replacing pipeline supply in Jordan;
- The decline in competitiveness of LNG in international fuel competition such as coal in the power sector (chiefly in Europe) and shale gas (North America) that has freed up volumes to be re-directed elsewhere;
- Periods of large disparity between prices in different basins such as that from 2010 to 2014, which made arbitrage an important and lucrative monetization strategy;
- The large growth in the LNG fleet, especially vessels ordered without a long-term charter, which has at times allowed for low-cost inter-basin deliveries;
- The faster development timeline and lower initial capital costs of Floating Storage and Regasification Units compared to onshore regasification, which allow new markets to enter the LNG import market.

3. Floating Storage and Regasification Units (FSRUs)

3.1. Introduction in FSRUs

LNG is by its nature highly capital-intensive with substantial financial risks. Due to the capital intensive nature of the LNG marker, investors seek more flexible, low initial cost options to take advantage of the evolving market while mitigating their risks. During this present transitional period of LNG market establishment, new and often small markets emerge and often play a major role compared to their share on the market. As mentioned in chapter 3, the construction of extensive, permanent onshore facilities to receive LNG and regasify it, is a highly capital intensive and a relatively risky investment. On the other hand, a more viable and economically safe option to receive and send out LNG to the shore would be FSRUs, Floating Storage and Regasification Units.

The LNG fuel is transported via LNG carriers in a liquefied, cooled state of -160°C and needs to be transformed to its original gaseous form once it reaches its final destination in order to be sent out to the shore LNG network. The traditional way to do this is through an onshore LNG receiving terminal. A second option is the use of this special type of LNG vessel, an FSRU, which will receive LNG, through ship to ship operation, store and regasify it in order to send it out to the shore. FSRUs can be an advantageous alternative to onshore terminals, with the main benefits being the reduced cost and easier implementation but most importantly the great flexibility in terms of re-location when and if required. Another benefit of FSRUs is their ability to increase supply during seasonal peak demand across different regions.

Figure 6. Typical FSRU STS operation, source: LNG world news

The FSRU fleet consists of both converted LNG carriers and new-built vessels which rely on ship-to-ship (STS) transfers of LNG in order to maintain continuous supplies of gas send-out. The capital cost of a new FSRU terminal typically represent 60%of an onshore terminal and can be delivered in a shorter time. A conversion of a conventional vessel to a FSRU requires around 18-24 months and building a new FSRU requires 27-36 months. The greatest advantage of an FSRU in terms of time of delivery comes from readily available units e.g. already constructed on a speculative basis [4].

Additionally, while there is a significant cost differential between FSRUs and onshore regasification terminals, the preference towards FSRUs is also rooted in several other factors including the need to reutilize excess shipping capacity and the necessity to satisfy for seasonal gas demand. As explained in chapter 3.2., the growth of FSRUs is also largely driven by the move to cleaner fuels especially in certain jurisdictions such as China and Indonesia, where there has been an increased need to diversify the energy mix and switch away from crude and coal to cleaner fuels such as gas [8]. Additionally, depressed charter rates and uncommitted tonnage urges many shipowners to promote the conversion of their aging LNG carrier fleet to FSRUs in order to further benefit from their operation.

A comparison of the basic characteristics of onshore terminals and FSRU is shown on the following table and figure.

Table 2. Shore Terminal - FSRU comparison

Shore Terminal	FSRU
More permanent solution	Faster to build and put in operation
Greater capacity	Greater flexibility/ relocation ability
Lower OPEX	Lower CAPEX
Possibility of expansion	Requires less formalities

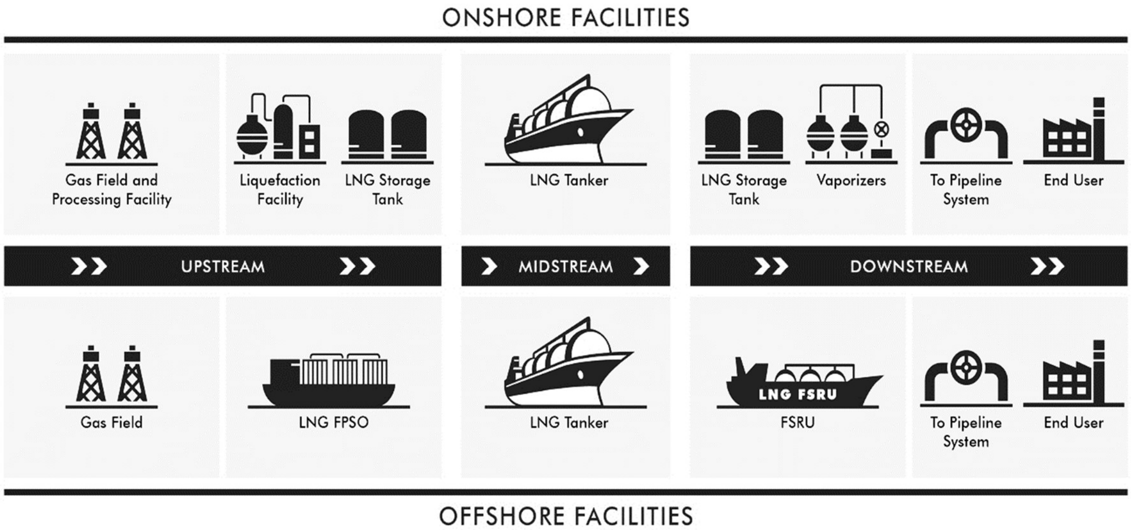


Figure 7: Comparison of Onshore and Offshore LNG facilities, source: Watson Farley and Williams, MITSUI Lines FSRU workshop

3.2. Brief History of FSRU

The FSRU as a concept was first developed in 2005, driven by the need for a fast delivery, storage and regasification of LNG. Since then, the FSRU fleet has expanded enabling the LNG industry to break into a wide range of developing gas markets, especially in the Middle East, Asia, and Latin America. As it was aforementioned, FSRUs have gained ground because they are typically cost-effective and flexible compared to the shore-based terminals.

The first FSRU projects, developed in 2005, were Gulf Gateway and Golar Spirit. Gulf Gateway was developed by Excelerate Energy using a new-build vessel. Golar Spirit was the conversion of a 26 year old LNG tanker decided on a speculative basis when Golar LNG sought to add value to the vessel and prolong its operational life by changing its primary function. These two experimental projects turned out to be successful and managed to open the market to a new and innovative way to access natural gas [9].

3.3. The FSRU Market

As of February 2019, nearly 85% of existing LNG terminals were located onshore. However, the ratio of onshore to offshore terminals has been shifting toward the latter in recent years. Nonetheless, five of the seven terminals that began operations in 2018 were onshore developments. This was largely caused by onshore additions to established markets in Asia, including China and Japan. What is interesting is that only seventeen of the twenty-nine terminals under construction as of early 2019 are listed as onshore proposals. The latest International Gas Union report estimated that the total FSRU capacity represents approximately 15% of the Global LNG regasification capacity and out of the total global LNG fleet, there are 31 FSRUs currently in operation. [4]In general, FSRUs contain substantially less storage capacity than onshore terminals. Onshore terminals generally contain between 260 and 700 mcm of storage capacity, whereas floating terminals typically utilize storage tanks between 125 and 170 mcm in size.

Four FSRUs were also completed in 2018, plus one floating storage unit and two more FSRUs were also ordered in 2018. Additionally, four FSRU terminals – in Argentina, Brazil, Egypt, and United Arab Emirates –were no longer required and thus departed from their mooring port, removing 16.6 MTPA (million tons per annum) from the market and resulting in only 6.2 MTPA of net regasification capacity worlwide growth. However, their departures confirm once again the inherent flexibility of FSRUs that can be added and removed relatively easily, which is crucial asset, particularly in markets that are characterized by significant demand oscillations [4].

As of February 2019, twelve FSRUs (including conversions) were on the order book of shipbuilding yards. In addition, multiple FSRUs were open for charter around the same time, with some being used as conventional LNG carriers, indicating sufficient near-term floating regasification capacity. Furthermore, as some floating terminal projects have been delayed or cancelled, the number of FSRUs being used as conventional carriers has increased. The number of proposed floating projects is steadily rising, confirming the speculated importance of FSRUs in establishing new LNG markets as illustrated in the below figure.

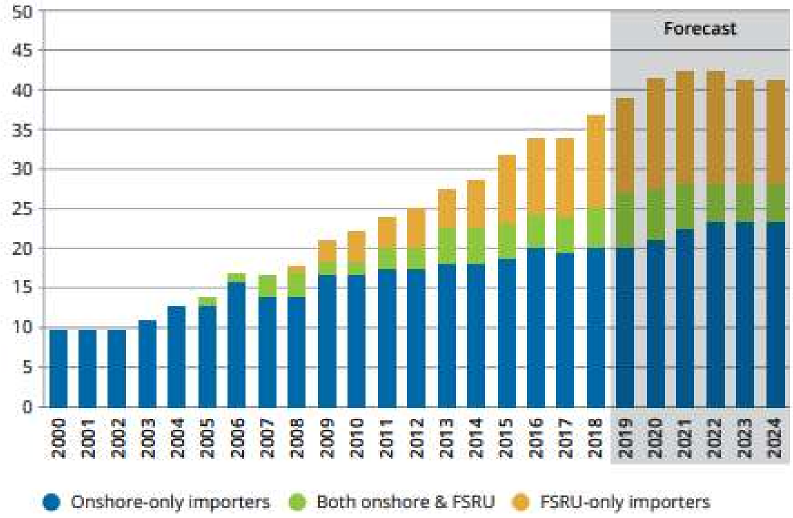


Figure 8. Rise of FSRUs among import markets, 2000 -2024, source: IGU LNG report 2019

The growth of the FSRU fleet since the first vessel entered service in 2005 can be divided into four main growth periods [10].

- 2005-2008 slow growth as the sector was developing;
- 2009-2013 rapid growth in 2009 and then a slow period until 2013;
- 2014-2017 again rapid growth in 2014 and then slow until 2016;
- 2017-2019 rapid growth with the fleet increasing by 60 per cent in just four years.

It is estimated that FSRU projects will continue to play an important part in energy delivery, especially in new markets for natural gas. However, after a surge in FSRUS over the past two decades, it is also speculated that the demand for new floating capacity may be reaching a balancing point. Small-scale floating projects are likely to emerge as specialized solutions to various issues in energy demand, such as industrial customers requiring stable and high compositional quality natural gas, isolated markets and to address various regulatory and logistical limits on pipeline supplies. Many of these specialized projects might never grow in scale to support traditional land-based terminal operations [4].

3.4. Technical Overview

3.4.1. General Information

The hull and structure of most FSRU vessels are almost identical to that of a typical LNG tanker. However, the design of an FSRU has additional requirements compared to a conventional vessel due to the continuous operation and the absence of regular dry-docking which translates to increased need for corrosion prevention and hull integrity requirements. Most FSRU designs incorporate the traditional double hull design and their storage tanks are either membrane or spherical Moss type tanks.

FSRUs can be constructed in two ways:

- <u>Newbuilt FSRU:</u>
  As a ship built similarly to an LNG carrier but on the purpose to operate as a floating storage and regasification unit for which reason it is also equipped with a regasification unit.
- <u>Converted LNG carrier:</u>
  By converting an old LNG carrier into a floating storage and regasification unit. That option is often appealing due to the high charter rates of FSRUs compared to old LNG carriers.

The decision of building an entirely new vessel or converting an existing one depends on many factors, one of which is the CAPEX and OPEX characteristics of each option. Conversion of LNG carriers to FSRU's usually requires less time and offers lower CAPEXs. However, new buildings are more flexible and have a longer operational life, especially when taking into account the limited capacity and age of the potential candidates to be converted [11]. Additionally, existing LNG carriers may face difficulties arranging the regasification facility in the cargo area because of their initial layout as explained below.

The main design issues of an FSRU are presented below: [12]

Key Design Considerations

1. **Size**
   a. Storage Capacity
   b. Send Out Capacity
2. **Environmental Impact**
   a. Open Loop regasification system or Closed Loop regasification system
   b. Temperature of sea water returning to sea compared to the inlet temperature
   c. Exhaust gas emissions
3. **Gas Management**
   a. During cargo transfer and periods of low gas send-out
   b. Installed HP Compressor/Recondenser
4. **Drydock Intervals**

5. **Mooring**

5. **Boil off Gas Management**

Despite that tank insulation is designed to limit the admission of external heat, even a small amount of it will cause slight evaporation of the cargo. This natural evaporation, known as boil-off is unavoidable and has to be removed from the tanks in order to maintain the cargo tank pressure. Typically, the Boil Off Gas is fed to re-liquefaction, fuel gas supply for auxiliary equipment. The main factors associated with boil-off gas generation are listed below [13]:

1. Heat ingress

The ingress of heat via the cargo tank insulation into cargo tanks is due to the difference between the temperature in the cargo tanks and the temperature of the environment surrounding it creates a warm boundary layer along the walls. The heat leads to evaporation when the layer reaches the surface as the cooled layer moves to the bottom of the tank. As the cargo reaches its boiling point according to cargo tank pressure, any heat ingress causes evaporation.

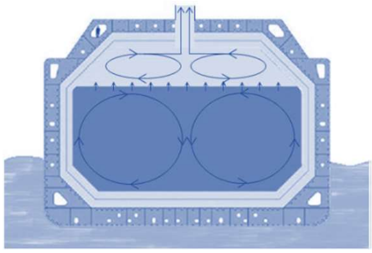


Figure 9. BOG, Heat Ingress

2. Sloshing of cargo

The liquid movement inside the tanks contributes to the evaporation through energy dissipation and turbulence. At the same time, it performs a partial cooling of the gas and the tank walls above the liquid level.

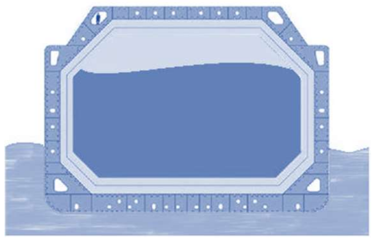


Figure 10. BOG, Cargo Sloshing

3. LNG loading and unloading

During loading, the difference between the operating pressure of the FSRU and the LNG vessel can greatly influence BOG generation. For instance, if the cargo is loaded at low pressure, the temperature of the LNG will decrease thus reducing BOG generated. Additionally, transfer of LNG using pumps may act as a source of heat as LNG is transferred.

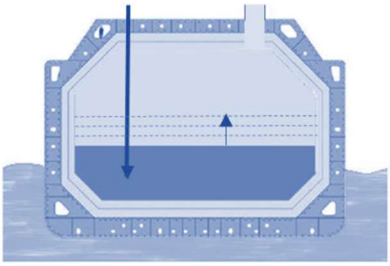


Figure 11. BOG, LNG loading and unloading

4. Cargo tanks pressure

Altering cargo tank pressure alters the boiling point of the LNG. As tank pressure increases, the LNG may become superheated and tend to evaporate at an increased rate until reaching the new boiling point.

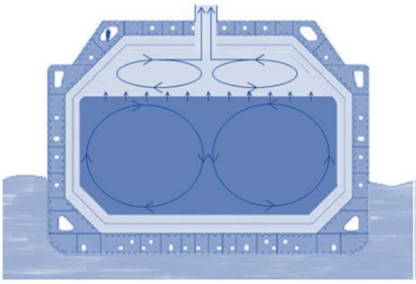


Figure 12. BOG, Tank Pressure

3.4.2. Main Equipment and Specification

The machinery equipment of an FSRU can be categorized in the following subsystems:

1. Powerplant
2. Regasification System
3. Transfer System
4. Cargo Containment System
5. Mooring System

Powerplant Alternatives

The type of the powerplant installed in an FSRU is a choice of significant importance. The similarity that the various alternatives share, is that they should all be able to burn boil off gas. The differences in BOG management, as a function of different powerplant alternatives is shown on the figure below.

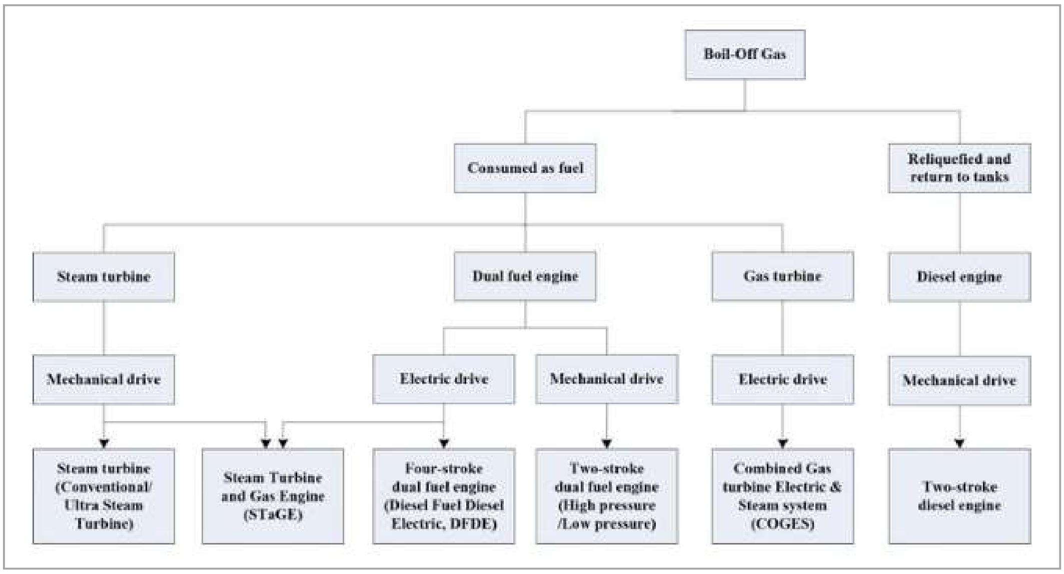


Figure 13. Boil Off gas management

Below figure shows the allocation of plant types of the currently operating FSRU fleet as per Table 14.

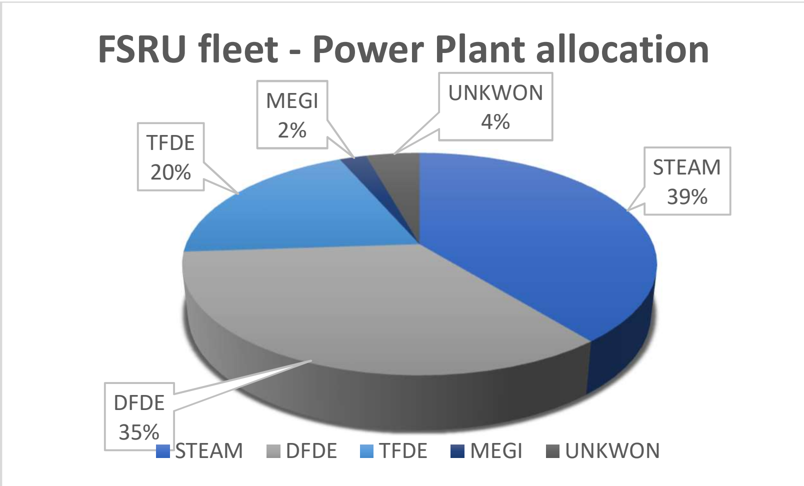


Figure 14. Power Plant allocation, source: author based on published data

Steam Turbine

The generation of electric energy on board is provided by two turbo generators which are fed by the steam generated in two boilers that produce enough superheated steam (P = 60 bar, t > 525 ˚C) to initially feed the high and then the low pressure turbines. The steam, once expanded in both turbines, is condensed in the main condenser and sent back to the boiler by means of pumps, after passing through a number of heaters which, by taking advantage of the residual heat, increase the thermal efficiency of the cycle. Once in the boiler, the corresponding change of state occurs again through the input of heat, returning again to steam phase, thus closing the cycle. The boilers are designed to simultaneously consume different fuel types such as HFO and Boil Off Gas, giving flexibility to the system. The excess of BOG generated may have to be burned in the boilers, producing steam which is sent directly to the condenser after passing through a laminating and tempering process known as "dumping". The purpose of this "no energy exploitation" process is to stabilize the pressure in the tanks [14].

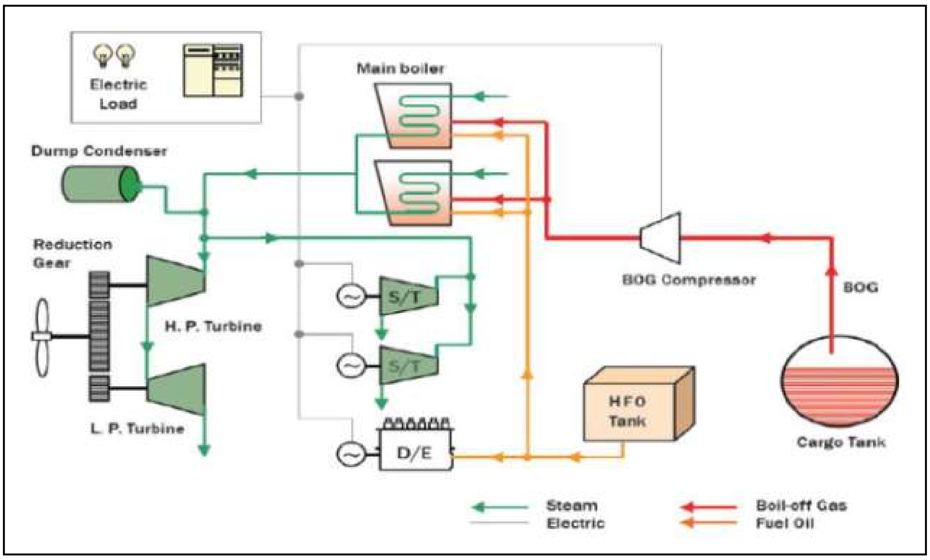


Figure 15. Steam Turbine configuration

The main advantages of steam turbines are listed below:

- The ability to burn several fuel types such as heavy fuel oil (HFO) and the BOG from the cargo;
- Above point, combined with the ease of use, increases the liability and reduces the maintenance costs;
- The easy control over the use of BOG;
- The low vibrations (compared for example with a large two-stroke marine engine);
- The reduced consumption of lubricating oil compared to other powerplant options.

The main drawbacks of steam turbine systems are:

- The poor efficiency which is around 35% at full load;
- The excessive emissions of CO_2;
- The large engine room required, compared with other systems;

The continuous rise in fuel prices together with stricter emissions regulations makes steam turbines a less and less attractive propulsion system.
1.

Ultra Steam Turbine

In an effort to improve the performance of steam turbines a system referred to as Ultra Steam Turbine (UST) has been developed. The key difference of the Ultra Steam Turbine systems is the introduction of a reheating stage which improves the thermodynamic efficiency, as well as the installation of an intermediate pressure turbine (IP) increasing the efficiency of the system by around 15%. However, the efficiency of USTs, remains lower than the one achieved by large two-stroke marine diesel engines. [14]

The main advantages of an Ultra Steam Turbine system compared to a conventional Steam Turbine system are shown below:

- The space in the engine room is not increased despite the increased number of elements;
- The efficiency is increased by around 15%;
- Highly reliable, comparable to the conventional system;

- Emissions of NO_x, SO_x and CO_2 are reduced by around 15%.

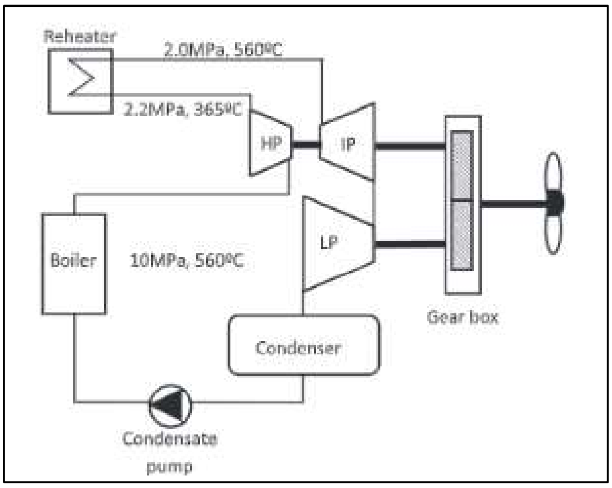


Figure 16. Ultra Steam Turbine configuration

Dual Fuel Diesel Electric

Another common powerplant alternative is the dual fuel diesel electric powerplants (DFDEs), which are installed on 35% of operating FSRUs. The DFDE configuration provides a more straightforward and simpler layout of the propulsion system. The DFDE propulsion system employs multiple engines of the same type, typically four or five, coupled to electrical generators to supply energy to the entire ship including propulsion, which is achieved by means of electric motors.

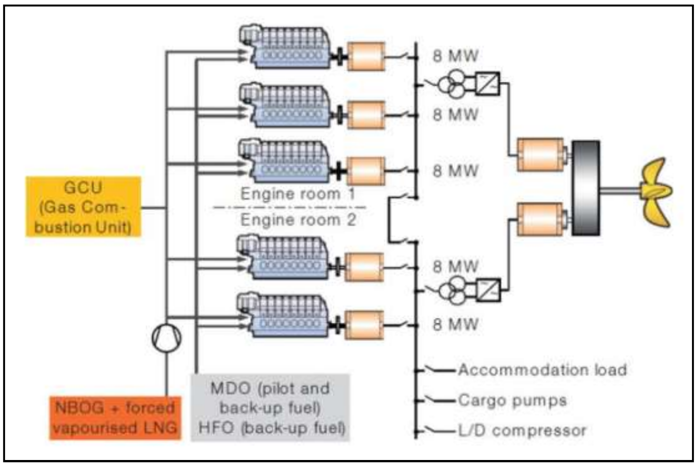


Figure 17. DFDE system configuration

Dual fuel engines can operate on BOG, MDO or HFO. They have have different operation modes depending on the fuel used. When gas is burned as fuel (gas mode), the engine adopts the concept of the lean Otto cycle. On the contrary, if MDO or HFO are used, the engine operates at diesel cycle (diesel mode). In Gas Mode, the BOG is injected to the air intake before each cylinder individually through a gas admission valve, where it is mixed with the charged air before entry to the combustion chamber. The mechanism enables the compression and injection of the BOG at a relatively low pressure, approximately 5–6 bar, which reduces the complexity of the fuel gas supply system and thus the risks using methane at high pressure in the engine room. A small amount of MDO (approx. 1%) is also required as a pilot fuel when operating on gas mode, giving a high-energy ignition source for the main fuel gas charge in the combustion chamber. Switching between the two operating modes can be conducted stably without interruption in power supply even though gas mode and diesel mode follow different operating principles, and as a result have different operating features. The diesel mode shows higher performance better in terms of thermal efficiency and dynamic response, while the Gas mode has advantages in terms of fuel cost and exhaust emissions.

2-Stroke slow speed diesel engine with re-liquefaction plant

Two-stroke slow speed diesel engines are the predominant propulsion plant in merchant shipping due to their high efficiency, capability of burning low-quality low cost fuels, and low maintenance costs. Since the two-stroke slow speed engine is a single fueled (HFO) propulsion plant without a BOG burning capability, the natural BOG from cargo tanks shall be liquefied and sent back to cargo tanks.

The BOG re-liquefaction principle is based on a closed cycle using nitrogen as a refrigerant, absorbing the heat from BOG. In this cycle, cargo boil off is suctioned from the LNG tanks and compressed to 5 bar by a low duty compressor, and then the vapor is cryogenically cooled to −160°C in a heat exchanger. This ensures condensation of all hydrocarbons in the BOG so they can be converted back to LNG, while the nitrogen and other non-condensable remain at gaseous state. These gas impurities are finally removed in a gas-liquid separator where the LNG is separated and delivered back to the cargo tanks with the nitrogen-rich non-condensable gases either discharged to the atmosphere or burnt in the GCU.

The operation of a re-liquefaction plant requires a high electric power supply by auxiliary generators composed of either 3 or 4 power generators.

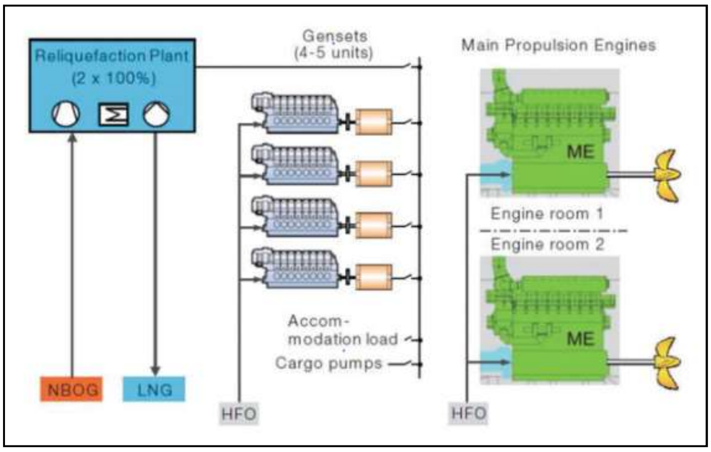


Figure 18. 2-Stroke slow speed diesel engine with re-liquefaction plant

Slow speed duel fuel engines

In general, internal combustion engines are the predominant propulsion system in all sectors of marine transport with the exclusion of LNG vessels due to their initial inability to burn different fuels. This, however, has changed during the recent years. Distinct technical routes were been adopted by the two main manufacturers. MAN Energy Solutions (former MAN Diesel and Turbo) utilize the high pressure concept while WinGD focuses on the low pressure concept.

MAN ME-GI (High pressure concept)

It should be noted that the MAN ME-GI engine is not usually used in FSRUs but rather in LNG carriers. The ME-GI high pressure gas engines operate on the diesel cycle. The BOG is pressurized through the fuel gas supply system (FGSS), and then directly injected at high pressure (250–300 bar) into the cylinder after the diesel pilot fuel has ignited near the top dead center. This concept makes it possible to utilize high compression ratio designs, thereby offering higher energy efficiency.

In terms of emissions, the high pressure two-stroke engines reduce the NOx emissions by 40% compared to HFO without exhaust gas treatment, which fulfills the IMO Tier II NOx limits. To achieve Tier III limits, ME-GI engine requires additional NOx reduction systems such as an SCR or EGR system. Furthermore, the CO_2 emissions are reduced by approximately 24% and methane emissions are at a very low level, due to the high in-cylinder temperatures that are developed during combustion.

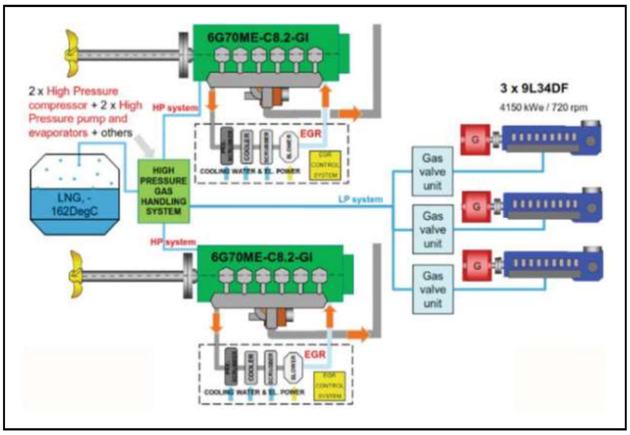


Figure 19.MAN ME-GI concept

MAN Energy Solutions Two-Stroke Business Unit has also announced that it has initiated the development of a low-pressure gas engine as a supplement to the existing dual-fuel ME-GI engine driven by strong LNG market demand. The development of the new engine is expected to be completed during the first half of 2022 and will be the main competitor against WinGD X-DF engine which is described below.

WinGD X-DF (Low-pressure concept)

The low pressure X-DF technology is based on the lean-burn Otto cycle, in which fuel and air are premixed and burned at a relatively high air-to-fuel ratio. When gas admission in the cylinder occurs, the piston is at about mid stroke of the compression phase and therefore the pressure in the combustion chamber is low. This allows the gas to be injected at low pressure, ranging from 5 to 16 bar. With the low-pressure gas injection, the gas-air mixtures need an ignition source to start the combustion. Combustion takes place with the aid of pilot fuel which ignites in a pre-chamber.

The most significant advantage of the low-pressure X-DF engine is the low level of emissions of any exhaust gas element and their lower CAPEX compared to their competitor. As the low-pressure X-DF engine has a pre-mixed homogeneous lean mixture of gas and air in the combustion chamber, the flame temperatures are relatively low. This results in low levels of NO_x production without any after treatment system, approximately 50% of the IMO Tier III limits. Besides, the weighted average of relative methane emission is about 3 g/kWh. However, this comes at a cost, since the efficiency of these engines is lower than traditional two-stroke engines due to the fact that they operate on the Otto Cycle and hence, they have lower compression ratios.

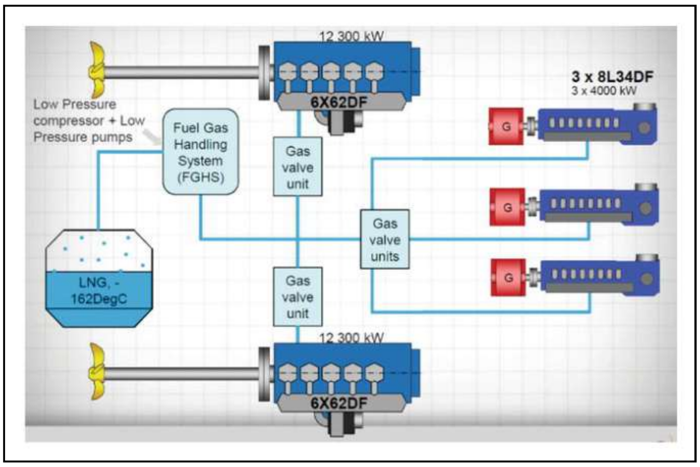


Figure 20. WinGD X-DF

Regasification System

The regasification systems of FSRUs can be:

1. Open Loop System
2. Closed Loop System
3. Intermediate Fluid System

Figure 21.The regasification unit of Golar Spirit between the vessel's two fore tank covers [15]

Open Loop System

The open loop system is the simplest regasification system. In this system, seawater is pumped in a shell and tube the heat exchanger and is discharged to the sea after vaporizing the LNG. The water used as the heating medium is returned directly to the sea approximately 10 °C colder. Open looped systems are preferred for warm seawater climates where the risk of freezing the seawater is reduced and are often subject to permitting issues in the same way as for onshore terminals. The power required to pump the sea water through the heat exchanger corresponds to a consumption of about 1.5% of the send out gas for power generation, similar to onshore terminals corresponding systems [16].

Closed Loop System

The closed loop system circulates a fresh water/glycol medium which is pre-heated by steam from the ship's boilers typically in a compact heat exchanger. This method uses an additional 1% of the send out gas to heat the circulating fluid to vaporize the LNG giving a total consumption of 2.5% [17].

Intermediate Fluid Vaporization System

The Intermediate Fluid Vaporization (IFV) system can be either in open loop or closed loop mode but the vaporization takes place in two stages – the first with propane vapor which condenses and the second with the seawater or heating medium which cools. The propane is re-vaporized using the warm seawater or the heating medium.

The IFV consists of three components:

a. Intermediate Fluid Vaporizer, where the Intermediate fluid, running in the shell side, is vaporized by the seawater running in the tubes;
b. LNG Vaporizer, where the LNG in tube side is vaporized by the heat from the condensation of the intermediate fluid in the shell. Intermediate fluid is condensed by LNG on the surface of the tubes and dropped to the bottom of the shell;
c. NG heater, where the LNG in the shell side is heated by seawater in the tube side up to the ambient temperature.

The main advantage of this system is that it reduces the risk of freezing by not contacting the LNG with sea water. It can also use compact heat exchangers reducing weight and size of the total unit. The major disadvantage is the introduction of highly flammable propane on to the FSRU. [18]

Cargo Transfer System

Gas can be exported via high pressure gas export arms or cryogenic flexible hoses

a. Cryogenic Flexible Hoses

Composite LNG hoses typically consist of multiple, unbonded, polymeric film and woven fabric layers encapsulated between two stainless steel wire helices—one internal and one external. Essentially, the film layers provide a fluid-tight barrier to the conveyed product, with the mechanical strength of the hose coming from the woven fabric layers. The number and arrangement of multiple polymeric film and woven fabric layers is specific to the hose size and application [19].

Figure 22. STS LNG transfer via Flexible Hoses, source: Excellerate Energy

b. Loading Arms

Loading takes place using articulated steel pipes that connect the LNG vessel to the FSRU. LNG is usually loaded temperatures below -159 ºC and since normal steel loading arms cannot withstand such cryogenic temperatures, the loading arms are usually made of alloys with special thermal expansion and contraction properties [20].

Figure 23. STS LNG transfer via loading arms
source: International Group of Liquefied Natural Gas Importers

Cargo Containment System

Similar to LNG conventional vessels, there are two kinds of cargo containment systems used on FSRUs, membrane systems and independent tanks.

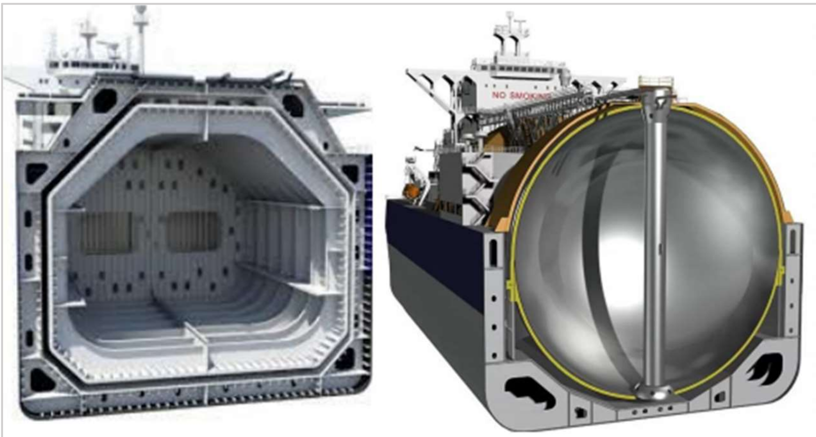


Figure 24. Membrane and Moss type LNG containment types, source: Glasgow Marine Academy

Membrane type

Membrane tanks are non-self-supported cargo tanks surrounded by a complete double hull ship structure. The membrane containment tanks consist of a thin layer of metal (primary barrier), insulation, secondary membrane barrier, and further insulation in a sandwich construction. The membrane is designed in such a way that thermal and other expansion or contraction is compensated without undue stressing of the membrane and in fact the vessel hull becomes the outer tank [4]. In general, membrane tanks offer better space utilization as their layout minimizes the unoccupied space of the hull.

Moss type

Moss type tanks are self-supporting as they do not constitute an integral part of the hull structure. Consequently, they do not contribute to the overall strength of the hull girder. Independent tanks fall into three categories as listed below:

Type A

Type 'A' tanks are constructed primarily of flat surfaces. The maximum allowable tank design pressure in the vapor space for this type of system is 0.7 bar which means that cargo has to transferred in the tank, in fully refrigerated condition near the atmospheric pressure.

The material used for Type 'A' tanks is not crack propagation resistant. Due to this a secondary containment system is required which can contain any leakage for at least 15 days at any given heel angle but at the same time comprises the space of the vessel's hull. The space between the cargo tank and the secondary barrier is known as the hold space which must be filled with inert gas when flammable cargoes are carried to prevent the formation of a flammable atmosphere in case of leakage [21].

Type B

Type 'B' tanks can be constructed of flat surfaces but usually are of the spherical type. Type 'B' systems are subject to more detailed stress analysis compared to Type 'A' systems since stress analysis is conducted for various temperatures and pressures and the fatigue life and crack propagation is also studied. The enhanced Type 'B' design requires a partial secondary barrier in the form of a drip tray where any leakage will accumulate. The temperature sensors on the drip tray will then detect the presence of LNG [21].

Type C

Type C is the dominant design in LNG carriers. Type 'C' tanks are normally spherical or cylindrical with design pressures higher than 4 bar. The cylindrical vessels may be vertically or horizontally mounted. This type of containment system is always used for semi-pressurized and fully pressurized gas carriers. In the case of the semi-pressurized tankers it can also be used for fully refrigerated carriage, provided appropriate low temperature steels are used in tank construction. Type 'C' tanks are designed and built to conventional pressure vessel codes and, as a result, can be subjected to accurate stress analysis. Furthermore, design stresses are kept low. Accordingly, no secondary barrier is required for Type 'C' tanks and the hold space can be filled with either inert gas or dry air and for fully pressurized tankers normal air may be allowed. Instead of detecting the leakage of cargo in the surrounding space of the tanks, the tanks are filled with inert gas or dry air and sensors monitor the change in the composition of the inert gas or dry air [21].

Thermal Insulation

Tank thermal insulation is a critical factor in LNG vessels, including FSRUs. Tank insulation must be fitted to refrigerated cargo tanks in order to minimize heat flow into cargo tanks, thus reducing boil-off and additionally to protect the tanker structure around the cargo tanks from the effects of low temperature.

In general, insulation materials for use on gas carriers should possess the following main characteristics:

- Low thermal conductivity;
- Ability to bear loads;
- Ability to withstand mechanical damage;
- Light weight;
- Unaffected by cargo liquid or vapor [21].

Thermal insulation may be applied to various surfaces, depending on the design of the containment system. For Type 'B' and 'C' containment systems, insulation is applied directly to the cargo tank's outer surfaces. For Type 'A' cargo tanks insulation can be applied either directly to the cargo tank or to the inner hull although its application to the cargo tank is more common [21].

Cargo Containment System choice

Lately, the membrane tanks have been favored as their shape eliminates the spaces between the storage tanks and provided higher storage capacity for the same overall size of the vessel. At the same time the flat deck provides a better platform for the regasification facilities. The spherical tanks configuration means that the regasification facilities cannot be located on the deck and have to be placed either between the tanks or on the bow. Nevertheless, many of the conversions are based on spherical tanks type vessels [9]. At the same time, moss tanks are preferred for FSRUs moored offshore or in exposed areas, due to their high structural strength against sloshing loads and lack of filling restrictions. At the same time, Moss tanks do not require modifications as membrane type tanks do in case a conventional LNG carrier is converted into an FSRU.

Mooring Arrangement

Special mooring systems are required for FSRU to handle ship to ship transfer at sea. Typical FSRU mooring arrangement are single berth, single point mooring and cross-dock [22].

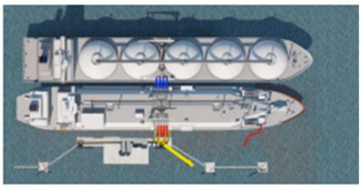


Figure 25. Single Berth, source: [22]

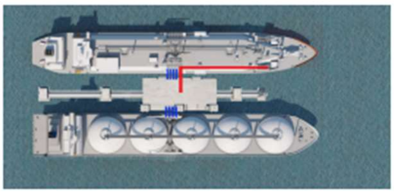


Figure 26.Cross-dock FSRUs, source: [22]

Figure 27. Singe Point Mooring FSRUs, source: [22]

Single Berth

LNG ships can moor alongside the FSRU and offload LNG for regasification and then supply directly into a pipeline. This option works best in protected harbors or near-shore with water depths of 15-30 meters and mild weather conditions.

Figure 28: STS FSRU-LNG operation, source: Mampaey offshore industries

Singe Point Mooring FSRUs

Weather-vaning solutions, where the vessel is allowed to spin in the direction of the current and wind, often allow the highest availability for offshore ship-to-ship transfer. There are numerous mooring options, depending on the site and conditions. Most have been tried and tested in the offshore oil industry. Some specific solutions include mooring towers, yokes, and turrets, internal or external to the FSRU.

Figure 29. FSRU Gateway and LNG vessel STS operation, source: Gateway

Cross-dock FSRUs

Segregated berths for LNG ships and FSRUs provide flexibility and improved availability. Such configuration allows for adding more vaporizer capacity and further berths for a Floating Storage Unit (FSU) or another FSRU.

Figure 30. Golar Spirit FSRU and LNG at Pecém, Brazil. source: courtesy of Petrobras

3.5. Pros and Cons of FSRUs compared to conventional onshore facilities

Onshore terminals and FSRUs both provide distinct benefits and drawbacks. However, these characteristics vary on a case by case basis and heavily rely on specific market requirements and conditions. However, in general, the advantages of offshore regasification units over onshore terminals that led to the rise of the former during the recent years are presented below.

3.5.1. Benefits of FSRUs over Onshore regasification facilities

Time to Build

FSRUs can constructed considerably faster than onshore terminals. This asset is of great importance for entering new markets driven by potential near-term demand growth. In fact, offshore regasification units can be built in half the time needed for the onshore terminals with equal capacities. The time required to construct an onshore terminal is typically around 36 to 50 months and is normally determined by the storage tanks. In general, onshore facilities can take between 5 and 7 years to be planned, constructed and brought online. New building FSRUs typically take 27-36 months to be built and conversions around 14 to 24 months. [9] [23], [9]

Flexibility/Relocation/Market Requirements

As aforementioned, the pivotal factor in the development of the FSRU market has been their inherent flexibility. FSRUs are movable from place to place which provides flexibility to release the vessel if regasification capacity is no longer required, as observed in Argentina, Brazil, Egypt, and the United Arab Emirates in 2018, or even deploy floating units to supplement the existing land based capacity. At the same time, FSRUs provide flexibility in terms of the location of the regasification process as they are characterized by fewer space constraints compared to onshore regasification solutions and limited onshore construction needs. In general, the capacity and overall characteristics of FSRUs can be tailored to the exact customer requirements. [9]

Cost

In general, FSRUs are less capital intensive compared to onshore solutions. This characteristic, together with their inherent flexibility, dramatically reduces the risk of the investment. Additionally, FSRUs are often leased to third parties which further mitigates the risk. Market data have shown that the cost of a new FSRU is typically only 50-60% of the cost of an onshore terminal.

Formalities

Due to being offshore and requiring limited onshore construction needs, FSRUs call for less formalities and bureaucracy. Additionally, regulatory approvals may be less time consuming due to the minimized onshore construction and environmental impact. Nonetheless, FSRU vessels may be classified as ships, which allows for more options in case the unit is no longer required and needs to be moved or even operated as a conventional vessel but also entails a lot of strict ship classification requirements and out of water drydocking surveys [24].

3.5.2. Drawbacks of FSRUs over Onshore regasification facilities

Despite the advantages of FSRUs compared to onshore facilities, it is also evident that there are many challenges in their operation. Additionally, onshore terminals also deliver a number of benefits over floating regasification units, depending on the market's specific requirements.

Storage Capacity

In general, FSRUs have capacity limitations offering substantially less storage capacity than onshore terminals. Onshore terminals generally offer between 260 and 700 mcm size of storage capacity whereas floating terminals are typically equipped with storage tanks between 125 and 180 mcm. Most FSRUs have a peak about 500-800 million cubic feet per day, though some of the newly built ones have adapted, reaching1 billion cubic feet per day. Due to the aforementioned capacity constraints, offshore units have less scope of expansion whereas onshore terminals typically offer the opportunity for larger storage tanks and expansions. This offers long term supply security and constitutes the onshore regasification facilities a more permanent solution. [25]

Location Challenges

Floating regasification units may also face several location related risks that are inherently absent in onshore projects. These risks include longer LNG delivery downtime, vessel performance, heavy seas and adverse weather conditions. In support of the above, Bangladesh's FSRU faced a number of these challenges while trying to reach its maximum operational capacity in 2018. The start of the project was delayed several months due to technical and infrastructure challenges, as well as rough seas during monsoon season. [4]

Lifespan Limitations

The FSRUs' lifespan is another critical issue. Usually the charter periods of FSRUs are ten to twelve years. Technically, an FSRU can be operative for 20 to 25 years which may be extended through appropriate maintenance. On the other hand, onshore terminals are designed to operate for 25 years and some of them can carry on for up to 40 years. This confirms once again the more permanent nature of onshore regasification facilities compared to floating units.

Legal Framework and existing infrastructure

FSRU vessels can be classified either as ships or offshore installations. Due to the relatively limited history of FSRUs an absence of clear local polices and regulations may be met in some countries which may lack the basic physical and organizational structures and facilities to accommodate FSRU projects. Furthermore, the deployment of floating regasification units as import terminals requires onshore infrastructure construction, such as pipeline, jetty, etc. All above requirements may complicate the development of FSRUs and offset their inherent flexibility which is one of their greatest assets. Additionally, FSRUs are often constrained by the demanding maritime regulations and maintenance requirements due to the harsher marine environment, although their deployment comes with less bureaucracy and formalities.

Technical/Operational Challenges

FSRUs are generally more complex to operate and optimize in terms of performance requiring greater expertise. Another challenge in the operation of the FSRUs is their so called metocean performance as they are prone to weather interruptions and downtime when moored in unsheltered areas. [26]

Below table summarizes the strengths and weaknesses of FSRUs. [9]

Table 3. Strengths and Weaknesses of FSRUs

Strengths	Weaknesses
Lower (capital) cost and less capital outlay – better cash flow and return on Investment. Ideal for smaller independent energy companies where raising capital may be difficult	Storage and regasification capacity limited to maximum ship size – nominally 173,000 m^3 and 6 mtpa albeit larger vessels have been constructed but on a project dedicated basis
Shorter schedule - earlier gas to market improving competitiveness and securing the supply contract	Expansion is more difficult than onshore requiring a larger replacement unit or adding another FSRU
Option to lease (most are) improving cash flow and return of investment – not sunk cost as onshore but increased OPEX	Typically less buffer storage – most land terminals have 2 x 160,00 cm tanks
Can be relocated to meet seasonable gas demands	Offshore located FSRUs sensitive to weather windows – not an issue with inshore
Shipyard construction results in very high confidence on delivery cost and completion date	Limited local content during construction – onshore terminals are major civil engineering projects
Shipyard construction minimizes local disruption compared with onshore which are major civil engineering projects	No room on FSRU for nitrogen balancing to adjust heating value – could be onshore
FSRU can be reassigned to LNG tanker trading thus minimizing utilization risk if gas demand falls	

3.6. Classification, Insurance and Legal Framework

As mentioned in 3.5.2., FSRUs can be classified either as ships or offshore installations. Ship classification option is based on normal worldwide LNG trading operation with regular dry docking and international marine safety standards. In the case of offshore installations these can be sub classified as mobile or fixed, based on whether they are equipped with propulsion means or not. Offshore classified vessels are normally based on site specific conditions and regulated by national specifications and standards. Most FSRUs are classified as vessels to provide the flexibility to operate either as an FSRU or LNG tanker. While in general FSRUs are faster to deploy than onshore regasification, there is often a complex permitting regime requiring a number of different licenses and permits relating to environmental impact, trading and employment of shipboard personnel. Additionally, from a tax perspective the FSRU owner will typically have to apply for an import tax exemption, in some cases, an exemption from local employment laws in connection with shipboard personnel and a Value Added Tax (VAT) exemption in relation to the importation of goods and equipment in connection with the vessel. Such regulatory requirements vary significantly from project to project and may cause delays to the deployment of the FSRU in some cases [27].

As regards insurance, FSRUs require more complex charter parties and insurance covers compared to other traditional vessel types due their inherent risk prone nature and their relatively short history.

In general, risk and insurance issues will vary from project to project according to:

- Location and gas supply systems in place;
- Type of FSRU jetty;

• Proposed FSRU lease agreement;
• Gas off-take agreement, which is an agreement entered between a producer and a buyer to buy/sell a certain amount of the future production;
• Various other factors.

Risk management and protection of FSRUs, both for construction and operation phases, presents a complex combination of insurance and contractual responsibilities which are presented in the below table.

Table 4. FSRU insurance insight, source: Marsh Insights, FSRUS – A Guide To Risk And Insurance

Likely Events	Insurance Protection	Contractual Risk Mitigation
Weather related issues		
Description of event and consequences	**Property damage insurances**	**Contractual Risk mitigation steps**
– Windstorm with related tide/ swell forces. – Vessels moored to jetty systems. – Interruption of entire process for repairs/replacement.	**Pre-operational:** - FSRU marine risks conversion/ CAR policies. - Jetty CAR (construction all risks)/DSU (Delay in start up) policy. **Operational:** - Ships/FSRU marine hull risks policies - Business interruption and FSRU contingent BI. Liability insurances: - Pre-operational. - P&I risks – ships/FSRU. - Jetty/pipelines	Extent of force majeure clauses in FSRU lease agreements. •Responsibility for safe mooring. •Risk of loss provisions arising out of FSRU lease agreements. •Inter alia treatment of respective liability risk from FSRU. •Responsibilities defined for safe operation and weather related shutdown and emergency procedures.
Ship Collision		
Description of event and consequences	**Property damage insurances:**	**Contractual Risk mitigation steps**
– Damaging FSRU or jetty, with LNG/Gas escape and fire potential. – Liquefied Natural Gas Carriers (LNGCs) moored to jetties similarly at risk. – Interruption of entire process for repairs etc.	– Ships/FSRU – marine risks policies. – Jetty/pipelines – "all risks". Liability insurances: LNG ships/FSRU. – Jetty/pipelines. – Marine terminal operator's liability. – Charterers' liability.	•Review insurance requirements of LNG shippers. •Examine mutual inter alia liability caps between and third party LNG shippers and FSRU owners. •Ensure wide form business interruption wording includes vessel collision coverage. •Review tug services contract for safe berthing procedures
FSRU process issues		
Description of event and consequences	**Property damage insurances:**	**Contractual Risk mitigation steps**
Mechanical breakdown with fire. – Interruption for repairs etc.	– FSRU - marine risks policies. – LNG/gas – "all risks" cargo. – BI. – Terminal property damage. – Contingent BI insurance for FSRU.	Negotiate for continuing costs in the event of FSRU non-performance

The two main marine insurance categories are the Hull and Machinery (H&M) insurance and the Protection and Indemnity (P&I) Insurance. The H&M Insurance covers the physical aspects of the vessel, and the main driver for this cost is the value of the ship. However, as the ship ages, the insurance costs are increasing, due to the increased number of the H&M related problems, when in fact the value of the vessel may be dropping. Safer ships can achieve better insurance prices, and in that respect a preventive repairs and maintenance policy can play an important role in cost savings. The owner's records are also taken into account, as well as the number of vessels to be insured. Typical H&M claims include total loss of the vessel, damages to the vessel, engines or equipment, explosions and fires, striking, collisions, groundings amongst others. The P&I Insurance is provided by the P&I Club to cover the liability of the shipowner to third parties. Typical P&I coverage includes injury or death of crew members, passengers or visitors, damage to cargo, collision damage or pollution. P&I insurance cost depends on a number of factors such as the trading area of the vessel, the general safety level of the type of the vessel, e.g. bulk carriers have lower risk ratings compared to LNG vessels.

4. Life Cycle Cost Analysis

4.1. General Characteristics

Life Cycle Cost Analysis (LCCA) is a method to calculate the most profitable investment among different alternatives. LCCA takes into account all different costs accruing from the investment including the purchase, ownership (CAPEX), operation, maintenance (OPEX) and disposal (DISPEX) of the various investment options, given that each option fulfills the same requirements but varies in terms of capital and operational expenses. The Life Cycle Costs Analysis is a decision tool aiming to aid potential investors choose the investment that maximizes the net saving out of a pool of equivalent options which are similar but not identical. This method, among others, aims to minimize the total Life Cycle Cost of an asset, figure out the option which offers the optimal balance between CAPEX and OPEX. In short, Life Cycle Cost Analysis is used as a criterion in the search of the optimal compromise between cost, time and performance [28].

Life cycle costing can also consider the Risk Expenses (RISKEX) and Environmental Expenses (ENVEX) which refer to the costs related to the occupational accidents and fatalities and the environmental impact of the asset respectively. RISKEX are often not included in the LCCA since they involve estimates of the price of the human life and are not easily quantified. Similarly, ENVEX involve a great deal of uncertainty since they represent the quantified and monetized impact of the asset to the environment. The direct environmental impact of the operation of an FSRU includes the greenhouse gasses emissions and the low temperature discharge water which affects the marine life amongst others. Whereas the low temperature water effects are not long term but cease when the FSRU gets out of operation, the GHGs, especially carbon dioxide (CO_2), but also nitrous oxide (N_2O) and methane (CH_4) have a long lifetime in the atmosphere so that present emissions contribute to impacts in the distant future. It should be noted that in general, the impact of a project on climate does not only consist of the emissions produced during its operation but can also cover other phases of the investment, depending on the study. However, this study focuses on the emissions produced during the operation of the asset which directly affects the investor and also have the largest environmental impact.

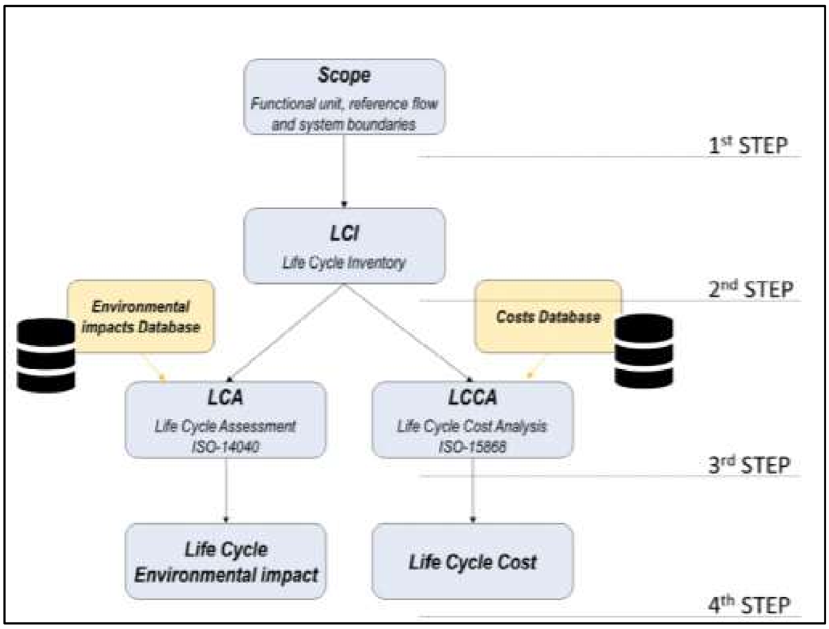


Figure 31.Life Cycle model for the assessment of maritime vessels [29]

The life cycle of an asset can be divided into four main stages:

1. The Conception Stage also known as Research & Development (R&D) stage. This stage includes all the activities necessary to develop the means for meeting the stated requirement of the investment including, research and development, design, contract specifications, identification of funding required and managerial structure for the acquisition.
2. Acquisition Stage also known as the Investment stage which comprises of all the activities necessary to acquire and provide support for the asset identified in the conception stage.
3. The In-Service Stage also known as the Operating and Support (O&S) stage. This stage is normally the longest one incorporating all the activities necessary for the operation, maintenance, support and modification of the asset throughout its life cycle.
4. The Disposal Stage which covers all the activities necessary to remove the asset and all relevant supporting materials from service.

Regarding the maritime industry, and specifically the life of a ship, four phases are distinguished: design, construction, operation/maintenance and scrapping phase. [29] It is worth mentioning, that the Life cycle of an asset does not necessarily coincide with the life span of the asset as it refers to the assessment period and is determined by the owner and may in fact include more than one life cycles. This is important especially for the shipping industry, as shipping assets often change ownership during their lifespan. In that sense they may have a number of lifecycles equal to the number of different owners. It should be noted that the greatest opportunities to reduce costs usually occur during the initial stages of an investment and as such it follows that the LCCA should be performed early in the design process while there is still room for improvement since most costs can hardly be changed once the initial design and investment decisions are done.

The impact of the analysis throughout the life of an asset is graphically represented in the figure below.

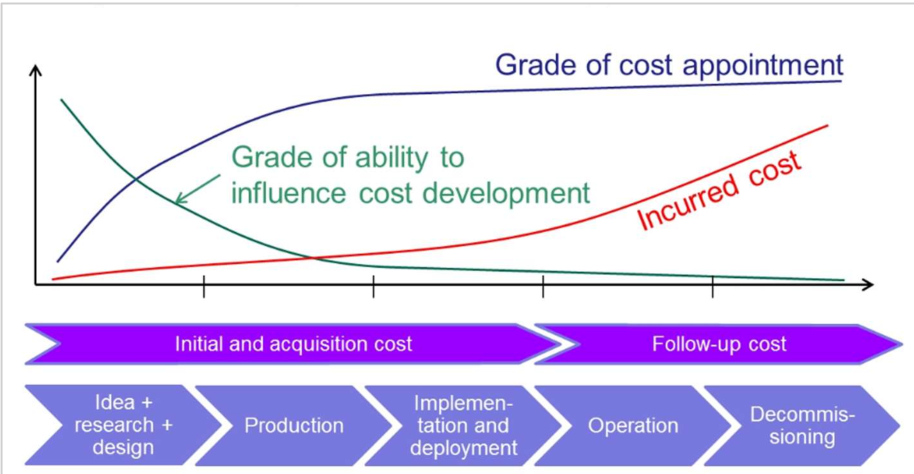


Figure 32. Life cycle costing phases and cost appointment, source: [30]

This study is oriented towards the acquisition, in service and disposal stage. It also takes into account the environmental impact of the asset through the investigation of GHG emissions of the unit. The environmental impact of the emissions is quantified and can be inserted in the economic analysis as a supportive element aiming to give a better understanding in the operation of the examined FSRUs which could affect the final choice of the investor.

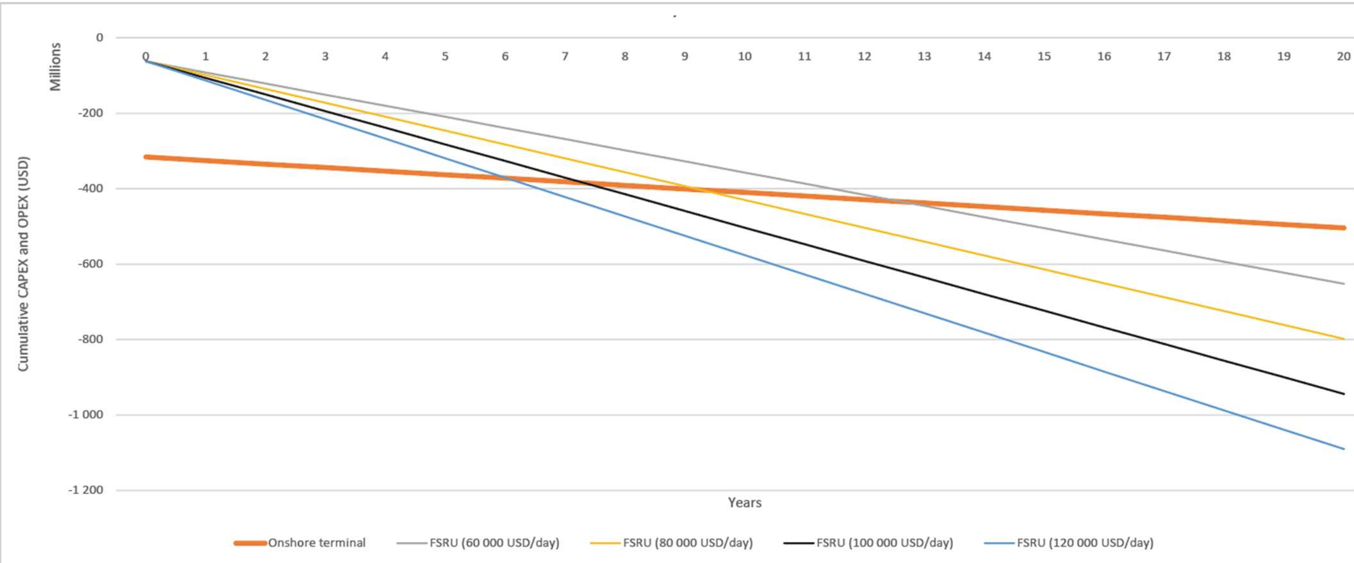
4.2. Challenges in the Life Cycle Cost Analysis Method

One of the biggest challenges of the LCCA is the determination of the economic effects of the alternative options and the quantification of such effects. In general, costs to be taken into account are those that differ for one alternative to another. At the same time these costs should be considerable and have a credible impact on the LCC of the project alternatives. The LCCA method sets all these amounts to their future year of occurrence and converts them to present values through the interest rate [31]. Predictions about investments typically involve a great deal of uncertainty in any analysis implemented. While performing an LCCA in the early stages of the investment increases the likelihood of choosing a cost effective project there may still be some uncertainties associated with the outcome. Because LCCAs are usually performed early when only estimates of costs and revenues are available, a certain degree of uncertainty in input values is always present. LCCA methodologies require availability of up-to-date data in order to provide safe estimations of lice cycle costs and the environmental footprint of a ship's life from its construction to its demolition [32]. The goal is to approach the actual expenses as much as possible in order to arrive to sound conclusions. There are methods that help estimate how uncertain input data affect the analysis outcome such as sensitivity analysis and breakeven analysis.

5. FSRU Economics

5.1. Capital Expenses

A major cost component for an FSRU is the initial investment which is substantially lower compared to more permanent land-based solutions. The capital cost of a new FSRU-based terminal can typically represent as low as 60% of a traditional onshore terminal capital cost. For example, an onshore 3 mtpa terminal with one 180,000 m^3 storage tank is likely to cost \$700-800m, depending on local construction labor costs, compared to \$300m for a similar capacity FSRU. The capital expenses for the acquisition of an FSRU vary from 250m USD to 400m USD and mainly depend of the storage and regasification capacity of the unit as well as on whether the unit is a converted LNG vessel or a newbuilt [9]. The choice between a new build and a conversion does not only determine the capital expenses for the acquirement of an FSRU but also the lead time for the operation of the unit. At the same time, even when the cost of a conversion is significantly lower than a new build the new-build vessels may often be preferred due to the cost savings associated with their superior boil-off efficiency which is crucial in terms of savings. The operation of an FSRU also requires investments in mooring and onshore receiving facilities and as such the capital cost an FSRU terminal comprises two major components, the FSRU vessel and the infrastructure required for the operation of the FSRU. It must be noted that the cost of inshore infrastructure is location-specific and heavily depends on the existing harbor facilities and the length of the pipeline from 50 to 150 million USD. Below figure illustrates the



CAPEX and OPEX lifecycle costs of FSRUs compared to onshore terminals and Floating Storage Units, FSUs.

Figure 33.Lifecycle cost comparison of FSRU, FSU and land-based terminal, source: Wartsila

5.1.1. FSRU vessel

New Build

As stated above, a newbuild FSRU may also introduce cost efficiencies, such as class exemptions from dry-docking during the start of the vessel's life, reduced boil-off rates and improved send-out rates and gas consumption which are all not negligible.

Conversion
If a nearly new tanker is purchased at $150m and assuming a typical $80m cost of conversion, the final cost of $230m will be similar to a new build FSRU but has the advantage of being completed in 18 months compared to 36 months for a new build vessel [9]. The cost of conversion covers the supply and installation of the regasification equipment including the high pressure pumps, vaporizers, metering station, gas export arms or hoses as well as any additional utility systems needed to meet the increased electrical power demand and water circulation for vaporization plus any modifications for permanent mooring. In the early stages of the FSRU market, conversions were very popular but demand for conversions has recently dropped in favor of new build vessels mainly due to the increased required capacity of the newest projects compared to the existing LNG vessels.

Choosing between the two options
It goes without saying that a single factor is not enough to determine the selection of a converted vessel over a new build and vise versa. However, the availability and cost are indeed the prime considerations when seeking for a candidate vessel. From a technical point of view, the older Moss tank type vessels are preferred since they are superior in terms of integrity and longevity. Older vessels tend to be slightly over-designed compared to more modern ones and they may therefore provide a safer foundation for major engineering modifications as those required in the LNG to FSRU conversion [15].

5.1.2. Infrastructure

The economic viability of any proposed FSRU project also depends on the costs associated with the supporting marine infrastructure. The existing harbor facilities, the technical solution chosen as explained in chapter 3.4. and the length of the pipeline required to connect the FSRU to the gas network will all affect the capital costs associated with the FSRU project. In that respect, unless the FSRU is to be located in an existing port, there may also be significant project development costs. For this reason, at the conception stage of any FSRU project, specialist contractors and consultants will be required to examine the proposed site location and subsea, metocean conditions and perform feasibility studies to ensure the optimum project configuration is selected [33].

Inshore
Inshore or Nearshore FSRUs are located in relatively benign water conditions with the protection of a harbor or breakwater and are not exposed to harsh open ocean sea states. An example of in shore configuration is shown in below figure with the vessel moored to a jetty. With these configurations the feedgas is normally supplied by pipeline from the producing field, which may be on- or offshore.

Figure 34. Inshore FSRU, source: Courtesy Höegh LNG

Offshore

Offshore FSRUs are located in open waters and are therefore much more exposed to the prevailing sea state conditions than the inshore facilities. An example of an offshore configuration is shown in below figure.

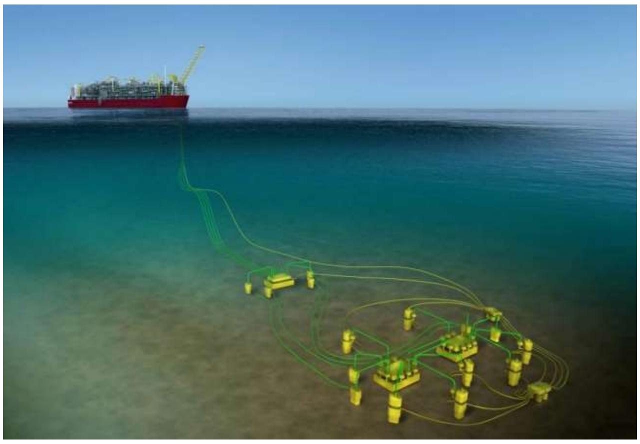


Figure 35. Offshore FSRU, source: Courtesy Shell International Ptd

The main limitation of the offshore location of an FSRU is the LNG offloading system. For relatively benign waters LNG will be exported using systems based on a proven hard arms design with the vessels located on a side-by-side basis. However, harsher conditions may require a tandem offloading arrangement with the vessels located one behind the other as used for oil offloading from FPSOs in harsh conditions [34].

5.2. Operational Expenses

Operating costs can be divided in five main categories:

1. Crew Cost
2. Repairs and Maintenance (R&M)
3. Consumables
4. Fuels Lubes Chemicals
5. Administration

5.2.1. Crew Cost

The crew cost of a vessel comprises by the below categories:

- Basic salaries and wages
- Social insurance
- Repatriation expenses, which are minimized for this type of vessel
- Victualling
- Recruitment and training

The FSRU manning typically varies between 20 and 28 members plus 4 located at the onshore interface similarly ton an LNG vessel. A typical LNG vessel needs a complement of 27 seafarers comprising five deck officers, five engineer officers and 17 crew members. Similarly, FSRUs classified as ships will require a full marine crew of typically 27 seafarers. FSRUs classified as offshore installations will probably only require 20 personnel [9].

The crew nationality plays an important role in the costs. Three nationality crewing models are assumed as presented below: [35]

A. Asian crew (officers, petty-officers and seamen)
B. North-European crew (North European officers, Asian officers and seamen)
C. South-European crew (South European officers, Asian officers and seamen)

The crew costs can be approximated by the below formula:

$$C_{crew} = k_1 * N_{crew}^{0.95} \quad (1)$$

Where C_{crew} is the annual crew cost, k1 is a factor obtained from the below table and N_{crew} is the number of crew members.

Table 5. Crew Cost

Vessel Type	Crew A	Crew B	Crew C
Oil Tankers	34,000	48,000	56,000
Bulk Carriers	30,000	40,000	45,000
Container Vessels	30,000	38,000	41,000

5.2.2. Repairs and Maintenance

Maintenance and inspection covers the routine tasks plus inspections if required. If the vessel is classed as an offshore installation, it is unlikely that it will require dry dock inspection during its contract period and underwater inspections will be undertaken. If the vessel is classified as a ship then dry docking may be required. This is dependent on the class of the particular vessel. Spare parts costs cover the provision of ongoing spares for maintenance. This is the same for chemicals and lubricants required for ongoing operation and maintenance.

5.2.3. Fuel, Lubricants and Chemicals

For a send-out rate of 5 mtpa this consumption is 6.2 t/h (150 t/d) for open loop and 14.8 t/h (335 t/d) for closed loop. Using an LNG price of $10/mmbtu ($500/t) this adds $72,000/d and $167,000/d respectively to the operating costs. The cost is directly proportional to the send out rate except for the small 0.5 t/h (12 t/d) for general vessel use. This consumption is generally accounted for as shrinkage i.e. the difference between LNG supplied to the FSRU and that exported as sales gas [9].

5.2.4. Insurance

Determining aforehand the insurance cost of a vessel, let alone of an FSRU, is not a simple task due to the lack of market data on insurance prices as well as the variability of the price, which is affected by many factors including but not limited to the type, age, trade and background of the vessel. Various studies have shown that the total insurance costs of a vessel may vary from 9 to up to 30% of the OPEX, but typically insurance accounts for 15% of operating expenses [36].

5.3. Income

FSRUs can be chartered from 5 to 20 years depending on the gas market demand. Nevertheless, the units are usually charted for a 10 to 15 year period which acts as a reassurance to the owners that they will be recovering the capital expenditure and finance charges over the charter period. Further analysis shows that the minimum charter period in order for the risk to be minimized and the asset to make considerable profit is 10 years. The day rate for that period is usually to be estimated considering that the capital and finance costs should be recovered in the first say 8 years of the operation of the asset with the remaining 2 years as profit. Although obtaining charter rates is difficult due to their confidential nature, the agreed durations are typically easier to be obtained and are sometimes listed by the units' owners, possibly in an effort to advertise the future availability of their assets. Below is a list of some published contract leasing durations as obtained by the "outlook on Floating Storage and Regasification Units published by the Oxford institute for Energy Studies. In the column stating the contract term the '+' refers to possible extensions

Table 6. FSRU contracts

Owner	Vessel	Terminal	Charterer	Contract years
Excelerate Energy	Explorer	Mina Al-Ahmadi	KNPC	5
	Experience	Guanabar Bay	Petrobras	15
	Various (GasPort)	Aguirre	PREPA	15+5
	Excelerate	Ruwais	GASCO	Longterm
Golar LNG	Golar Spirit	Pecem	Petrobras	15+5
	Golar Winter	Rio de Janeiro	Petrobras	15
	Golar Winter	Bahia,Salvador	Petrobras	15
	Golar Freeze	Jebel Ali	Dubai Supply Authority	10
	NusantaraRegas Satu	Jakarta Bay	PTNR	11
	Golar Igloo	Mina Al Ahmadi	KNPC	5
	Golar Eskimo	Aqaba	Hashemite K of Jordan	5
	Golar Arctic	Kingston	New Fortress Energy	2
	Golar Tundra	Tema	West Africa Gas Ltd.	5
Hoegh LNG	Grace	Cartagena	SPEC	20
	Gallant	Ain Sokhna	EGAS	5
	Independence	Klaipeda	Klaipedos Nafta	10
	PGN Lampung	Lampung	PGN LNG	20
	GdF Suez Anne	Tianjin	Engie	5
	FSRU#9	Port Qasim 3	GEIL	20+5+5
MOL	GNL Del Plata	Punta deSayago	Gas Sayago	20
BW Offshore	BW Singapore	Ain Sokhna	EGAS	5
	TBA	Port Qasim 2	EGAS	15
Teekay LNG	Bahrain LNG	Bahrain FSU	Bahrain LNG (JV)	20
Bumi Armada	Armada LNG Mediterrana	Marsaxlokk Bay FSU	Electrogas Malta	18

6. Model Description

The model developed implements the LCCA method as explained in chapter 4. and is oriented towards the acquisition, in service and disposal stage. It also takes into account the environmental impact of the asset through the investigation of GHG emissions of the studied unit.

Three scenarios are studied:

1. Bareboat charter
2. Time charter
3. Self Operation

For those three scenarios, the costs and benefits allocation per year is presented in below tables.

It is assumed that the unit operates for 25 years and the acquisition of the unit is partially covered by a loan which is repaid in the first 10 years of the operation of the unit. The purchase of the unit takes place in two equal doses, two and one year prior to unit's commencement of operation.

As mentioned above, years 2020 and 2021are assumed to be spent building the FSRU, so no revenue is assumed during that period. From 2021 onwards, the undiscounted annual revenue for the three aforementioned scenarios for NPV=0 are calculated using GoalSeek Tool in Excel.

Table 7. Costs and Benefits Allocation

Costs and Benefits Allocation							
CHARTER SCENARIO		BAREBOAT CHARTER		TIME CHARTER		SELF OPERATION	
Project cycle	**YEAR**	**COSTS**	**BENEFITS**	**COSTS**	**BENEFITS**	**COSTS**	**BENEFITS**
-2	2020	CAPEX/2	LOAN	CAPEX/2	LOAN	CAPEX/2	LOAN
-1	2021	CAPEX/2	-	CAPEX/2	-	CAPEX/2	-
1	2022	LOAN	FREIGHT	LOAN + OPEX	HIRE	LOAN + OPEX	FREIGHT
2	2023	LOAN	FREIGHT	LOAN + OPEX	HIRE	LOAN + OPEX	FREIGHT
3	2024	LOAN	FREIGHT	LOAN + OPEX	HIRE	LOAN + OPEX	FREIGHT
4	2025	LOAN	FREIGHT	LOAN + OPEX	HIRE	LOAN + OPEX	FREIGHT
5	2026	LOAN	FREIGHT	LOAN + OPEX	HIRE	LOAN + OPEX	FREIGHT
6	2027	LOAN	FREIGHT	LOAN + OPEX	HIRE	LOAN + OPEX	FREIGHT
7	2028	LOAN	FREIGHT	LOAN + OPEX	HIRE	LOAN + OPEX	FREIGHT
8	2029	LOAN	FREIGHT	LOAN + OPEX	HIRE	LOAN + OPEX	FREIGHT
9	2030	LOAN	FREIGHT	LOAN + OPEX	HIRE	LOAN + OPEX	FREIGHT
10	2031	LOAN	FREIGHT	LOAN + OPEX	HIRE	LOAN + OPEX	FREIGHT
11	2032	OPEX	FREIGHT	OPEX	HIRE	OPEX	FREIGHT

12	2033	OPEX	FREIGHT	OPEX	HIRE	OPEX	FREIGHT
13	2034	OPEX	FREIGHT	OPEX	HIRE	OPEX	FREIGHT
14	2035	OPEX	FREIGHT	OPEX	HIRE	OPEX	FREIGHT
15	2036	OPEX	FREIGHT	OPEX	HIRE	OPEX	FREIGHT
16	2037	OPEX	FREIGHT	OPEX	HIRE	OPEX	FREIGHT
17	2038	OPEX	FREIGHT	OPEX	HIRE	OPEX	FREIGHT
18	2039	OPEX	FREIGHT	OPEX	HIRE	OPEX	FREIGHT
19	2040	OPEX	FREIGHT	OPEX	HIRE	OPEX	FREIGHT
20	2041	OPEX	FREIGHT	OPEX	HIRE	OPEX	FREIGHT
21	2042	OPEX	FREIGHT	OPEX	HIRE	OPEX	FREIGHT
22	2043	OPEX	FREIGHT	OPEX	HIRE	OPEX	FREIGHT
23	2044	OPEX	FREIGHT	OPEX	HIRE	OPEX	FREIGHT
24	2045	OPEX	FREIGHT	OPEX	HIRE	OPEX	FREIGHT
25	2046	OPEX	FREIGHT + SCRAP	OPEX	HIRE + SCRAP	OPEX	FREIGHT + SCRAP

The minimum charter rate can then be altered by the user and the investment may be re-assessed using the NVP, IRR and CRF criteria.

The model provides the following user defined variables:

6.1. Model Variables and assumptions

6.1.1. Chartering Options

Time Charter

On time charter, the charterer hires the ship for a stated period of time. In such contracts the charterer pays for fuels and lubricants, port charges, commissions, and a daily hire to the owner of the vessel. The biggest item of charterers expenditure in a time charter after the daily hire is the bunkers provision. Under time charter party contracts, the shipowner remains responsible for the technical operation of the vessel, but commercial control and exploitation of the vessel is handled by the charterer while covering all costs associated with the repairs and maintenance of the vessel insurance and manning.

Bareboat Charter

Bareboat charter is a hiring agreement which does not include any administration or technical maintenance as part of the expenses covered by the owner of the asset. In such contracts, the charterer has the full control of the vessel including its legal and financial responsibility. Apart from fuel, all operational expenses are covered by the charterer including hull insurance, P&I coverage and crew opposed to time chartering.

Self Operation

In this case the owner does not charter the vessel but operates the vessel inhouse undertaking both the technical and commercial management. It follows that all costs accruing from the operation of the asset are directly covered by the owner-operator who is also the beneficiary of the asset.

Expenses and Revenues depending on the charter option

Each one of the above scenarios comes with a certain allocation of income and expenses among the owner and charterer. From the owner's point of view, the income and expenses for the above three described exploitation options are presented in the below table and are presented in more detail in chapter 6.

Table 8. Cost and Benefit Allocation, Owner's Perspective

	INCOME	EXPENSES
BAREBOAT	Freight	CAPEX, disposal fees
TIME CHARTER	Hire	CAPEX, OPEX, disposal fees
SELF OPERATION	Tariff Charge	CAPEX, OPEX, disposal fees

6.1.2. Technical Aspects

Origin of the vessel

Whether the vessel under consideration is a newbuild or a converted conventional LNG carrier is left as a user defined variable.

As mentioned above, the choice between a new build and a conversion affects capital, operational costs as well as lead time for the delivery of the asset. The choice between a newbuild and a conversion is discussed in more detail in chapter 5.1.

Send out capacity of the vessel

The send out capacity of the FSRU is a technical aspect with direct impact on the profitability of the investment since it affects the amount of fuel transferred ashore which is directly translated to profit.

Storage Capacity of the vessel

The storage capacity of the FSRU is also left as a user defined variable which, amongst others, affects the CAPEX of the unit.

6.1.3. Loan and Payback period

The loan amount is also left as a user input. The user determines the percentage of the capital expenses covered by the loan. The payback period of the loan is also left as a user defined parameter as well as the payback method, which can either be balloon payment or annual payment.

6.1.4. Revenues

The revenues are directly affected by the charter scenario. In any case, the minimum charter rate is estimated assuming NPV equal to zero. The revenues can also be a user defined parameter in case actual market data are available.

6.2. Criterions Applied

The criterions that will be applied in this feasibility study are the following:

- Net Present Value (NPV)
- Internal Rate of Return (IRR)
- Capital Recovery Factor (CRF)

6.2.1. Net Present Value

Net Present Value (NPV) is the sum of all future cash flows, both incoming and outgoing, over the entire life of an investment discounted to the present. In other words, the NPV refer as an amount of investment required today to meet future financial requirement over a specified period.

The mathematical formula of this criterion is the following:

$$\boldsymbol{NPV\ (i,N)\ =\sum_{t}^{N}\frac{R_t}{(1+i_k)^t}}$$

i_t: is the discount rate for a given time period t. Discount rate is a rate at which the future cash flows are discounted to find present value and therefore is 0 when t=0. It is one of the most significant factors in the economic evaluation of an investment;
N: Is the expected period of the time during which the asset is useful. The economic life and physical life may differ depending on the study;
$\mathrm{R_t}$: Is the cash inflow minus cash outflow in a given time period also known as the net cash flow.

The costs of an asset are calculated until the client's or the organization's interest on the use and ownership of the structure stops [37].

6.2.2. Internal Rate of Return

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

The mathematical formula of this criterion is the following:

$$\boldsymbol{NPV\ (i,N)\ =\sum_{t}^{N}\frac{R_t}{(1+i_k)^t}}$$

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

The discount rate plays a big role in the IRR criterion since there may be multiple discount rate values that lead to NPV = 0, so IRR is not defined unilaterally and additionally the criterion works only when i_t = constant.

6.2.3. Capital Recovery Factor

The Capital Recovery Factor (CRF) is a ratio used to calculate the present value of a series of equal annual cash flows. The mathematical formula of this criterion is the following:

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

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.

Loan

A loan is money, property, or other material goods given to another party in exchange for future repayment of the loan value, along with interest or finance charges.

If a loan is used, then it should be taken into account when using the NPV criterion by considering the initial sum of the money as cash inflow and the payments of the loan plus the interest as part of the losses annually incurred. It is evident that the use or not of a loan changes the NPV of an investment. Different scenarios have to examined to arrive to the most cost effective choice. In general, below 3 factors gravely affect the economic impact of a loan.

1. The interest rate r. Interest rate is the proportion of a loan that is charged as interest to the borrower and is not to be confused with the discount rate i. Generally, the loan is a preferable choice when the interest rate is lower than the discount rate;
2. The ease of the beneficiary company or individual to meet their financial obligations with the liquid assets available also known as liquidity. Understandably, the higher the liquidity of the company the lower the need for a loan;
3. The payment terms of the loan. One of the most crucial payment terms of a loan is the payment period and the intervals of the payments.

6.3. Environmental Impact

The environmental impact of the investment is taken into account through the calculation of its carbon footprint. The greenhouse gases (GHGs) included in the footprint assessment include the seven gases listed in the Kyoto Protocol, namely: carbon dioxide (CO_2), methane (CH_4) which is the major component of Natural Gas, nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), sulphur hexafluoride (SF_6), and nitrogen trifluoride (NF_3).

Over the past decade, a global practice has emerged leading to categorizing GHG emissions into three major scopes, which comprise of:

- Direct GHG Emissions that occur from sources that are owned or controlled by the company. Source: GHG Protocol Figure 9. Categories of Company's Operations by Scopes
- Indirect GHG Emissions attributable to purchased electricity, purchased heat/steam, and purchased cooling water.
- Other Indirect GHG Emissions due to emission sources that are not owned or operated by the company but are essential for conducting the company's business and are not accounted for in above 2 emissions categories [38].

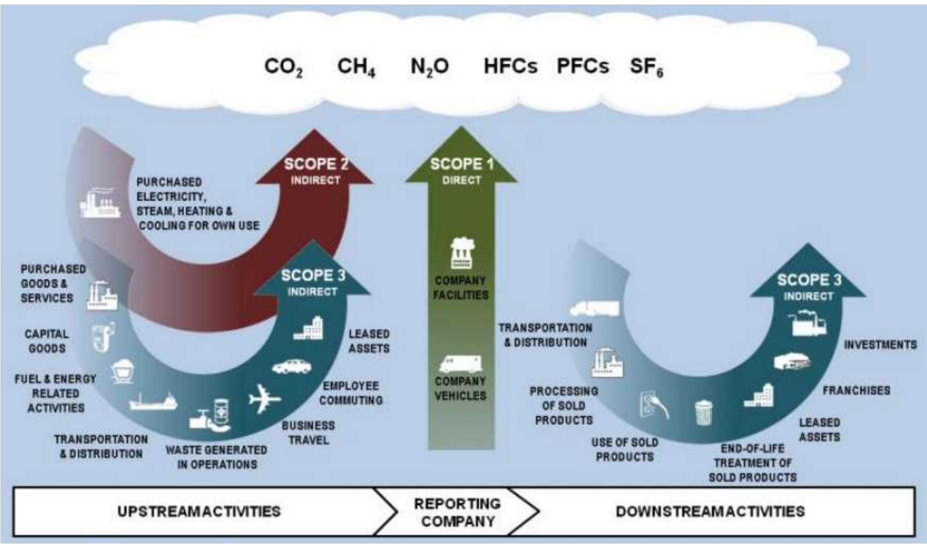


Figure 36. Categories of emissions, source: [38]

LNG operations and its associated GHG emissions fall into five stages:

1. Liquefaction
2. Storage
3. Loading and Unloading
4. Shipping
5. Regasification

Out of which, FSRU operations are associated with Storage, Loading and Unloading and regasification. GHG emissions from the LNG segments consist primarily of CO_2, CH_4 and N_2O:

• Carbon Dioxide (CO_2) - from process CO_2 in addition to combustion of fuels in engines, boilers, heaters, turbines and other and compressor drivers;
• Methane (CH_4) – from venting and equipment leaks in all segments of the LNG operations chain;
• Nitrous Oxide (N_2O) - from combustion devices, of primary importance for stationary engines including gas turbines and combustion of non-gaseous fuels.

6.3.1. Methodology

This study focuses on direct emissions with emphasis to the operation of the unit. As stated above, in its operational phase, the FSRU will have two direct emission GHG sources, combustion of fuel to provide auxiliary power to the FSRU and fugitive emissions also known as methane slip. As regards power, the GHG emissions depend on the amount of fuel combusted to provide auxiliary power. As regards fugitive emissions, the transferring of LNG in any state is connected to the potential of fugitive releases of natural gas. Since the methane contained in natural gas is a GHG, the fugitive emissions are included in the overall environmental impact of the project. All other GHGs are of lower significance though they should be considered if they are relevant for specific circumstances or are subject to local requirements. Emissions associated with the delivery of LNG to the FRSU are considered to be outside of the control of the Project and are not direct sources of emissions and therefore will not be considered in the assessment [39].

As mentioned above, the environmental impact of the methane slip and combustion emissions is quantified with an option to be inserted in the economic analysis, as would be done in a Life Cycle Analysis. However, this study focuses on a Life Cycle Cost Analysis using the investigation and quantification of the emissions of the asset as a supportive element in the decision process.

The environmental impact of the asset is assessed using a combination of guidelines and data. The European Commission guide to integrate climate change externalities into the economic appraisal of a project serves as the basis of the environmental impact calculations. The guide is based on the EIB Carbon Footprint Methodology and is consistent with the EU Decarbonisation Roadmap 2050 which are in turn based on other international standards and methodologies including IPCC, ISO 14064 parts 1 & 2, WRI GHG Protocol. The GHG calculation consists of the following steps:

a. **Quantification of the volume of emissions additionally emitted, or saved, in the atmosphere because of the project.** Emissions are quantified on the basis of project-specific emission factors (e.g. t-CO_2 per unit of fuel burnt, kg-CO_2 per kilometre travelled, etc.) and are expressed in tonnes per year. In the absence of project-specific data, default emission factors from the economic literature can be used. It should be noted that the emissions from a project can be further categorized as absolute emissions, baseline emissions and relative emissions. Absolute emissions (Ab) concern a project's emissions during a typical year of operation i.e. not including commissioning or unplanned shutdowns. Baseline emissions (Be)are defined as the expected GHG impact of alternative means to meet the output supplied by the proposed project. As such, they are clearly theoretical and hence incorporates an additional level of uncertainty beyond those involved in estimating absolute emissions. Relative emissions (Re) are defined as the actual emissions minus baseline emissions and as such can be both positive and negative, where negative, the project is expected to result in a savings in GHG emissions relative to the baseline and vice versa.

$$\boldsymbol{Relative\ Emissions\ =\ Absolute\ Emissions\ -\ Baseline\ Emissions}$$

or

$$\boldsymbol{Re\ =\ Ab - Be}$$

b. **Calculation of total CO_2-equivalent (CO_2) emissions using Global Warming Potentials (GWP).** GHGs other than CO_2 are converted into CO_2 by multiplying the amount of emissions of the specific GHG with a factor equivalent to its GWP. An emissions factor is a representative value that attempts to relate the quantity of a pollutant released to the atmosphere with an activity associated with the release of that pollutant. These factors are usually expressed as the weight of pollutant divided by a unit weight, volume, distance, or duration of the activity emitting the pollutant (e.g., kilograms of particulate emitted per megagram of coal burned).The greenhouse gases (GHGs) included in the footprint include the seven gases listed in the Kyoto Protocol, namely: carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), sulphur hexafluoride (SF_6), and nitrogen trifluoride (NF_3).

Below table includes the global warming potential factors as presented in [40]

Table 9. Global Warming Potential Factors

Gas	Chemical formula	Global warming potential
Carbon dioxide	CO_2	1
Methane	**CH_4**	**25**

Nitrous oxide	N_20	265
Hydrofluorocarbons (HFCs)		
HFC-23	CHF_3	12,400
HFC-32	CH_2F_3	677
HFC-41	CH_3F	116
HFC-43-10mee	$C_5H_2F_{10}$	1,650
HFC-125	C_2HF_5	3,170
HFC-134	$C_2H_2F_4$ (CHF_2CHF_2)	1,120
HFC-134a	$C_2H_2F_4$ (CH_2FCF_3)	1,300
HFC-143	$C_2H_3F_3$ (CHF_2CH_2F)	328
HFC-143a	$C_2H_3F_3$ (CF_3CH_3)	4,800
HFC-152a	$C_2H_4F_2$ (CH_3CHF_2)	138
HFC-227ea	C_3HF_7	3,350
HFC-236fa	$C_3H_2F_6$	8,060
HFC-245ca	$C_3H_3F_5$	716
Hydrofluoroethers (HFEs)		
HFE-449sl (HFE-7100)	$C_4F_9OCH_3$	421
HFE-569sf2 (HFE-7200)	$C_4F_9OC_2H_5$	57
Perfluorocarbons (PFCs)		
PFC-14	CF_4	6,630
PFC-116	C_2F_6	11,100
PFC-2180	C_3F_8	8,900
PFC-3-1-100	C_4F_{10}	9,200
PFC318	c-C_4F_8	9,540
PFC-4-1-12	C_5F_{12}	8,550
PFC-5-1-14	C_6F_{14}	7,910
Sulfurhexafluoride	SF_6	23,500

Since LNG is a commonly used fuel Default Emission Factors are provided which incorporate the global warming potential factors [40].

Table 10. LNG Emission Factor

Fuel Name	Amount of fuel	Units	kg CO_2	kg CH_4	kg N_2O	kg CO_2e
Natural gas	1	m^3	1.9	0.0	0.0	1.9

Above default emission factor is based on typical LNG quality. In reality, the properties of the fuel consumed affect the emission volume and composition and consequently the fuel emission factor. One particular fuel characteristic which affects the GHG emissions is the heating value of the fuel which describes the quantity of energy released when a fuel is completely combusted. In general, the heating value per unit volume of a fuel is calculated as the volume, or mass, weighted average of the heat generated in the combustion of the individual components of the gas. The heat of combustion of hydrocarbons per volume or mass increases with the addition of carbon atoms to the hydrocarbon chain [41].

c. **Evaluation of externality using a unit cost of CO_2-equivalent.** Total tonnes of CO_2 emissions are multiplied by a unit cost expressed in Euro/tonne Due to the global effect of global warming, there is no difference between how and where in Europe GHG emissions take place. For this reason, the same unit cost factor applies to all countries. However, the cost factor is time-dependent in the sense that emissions in future years will have greater impacts than emissions today as the atmospheric concentration of carbon increases. EIB Carbon Footprint Methodology assumesa central estimate for the damage associated with an emission in 2010 of EUR25 per tonne of carbon dioxide equivalent, plus a high and low estimate of EUR40 and 10, respectively. As mentioned above, the marginal damage of emissions increase in function of the atmospheric concentrations of carbon and in that respect annual "adders" are applied after 2010as presented in below table.

Table 11. CO_2 unit prices estimation scenarios

Carbon Unit Price Estimation				
Estimate	2010 emission value	2011 - 2030 annual adder	2031 - 2040 annual adder	2041 - 2050 annual adder
High	40	2	4	8
Central	25	1	2	4
Low	10	0,5	1	2

Below figure and table present the CO_2 unit price through years 2020 to 2050 for the central, high and low CO_2 impact scenarios.

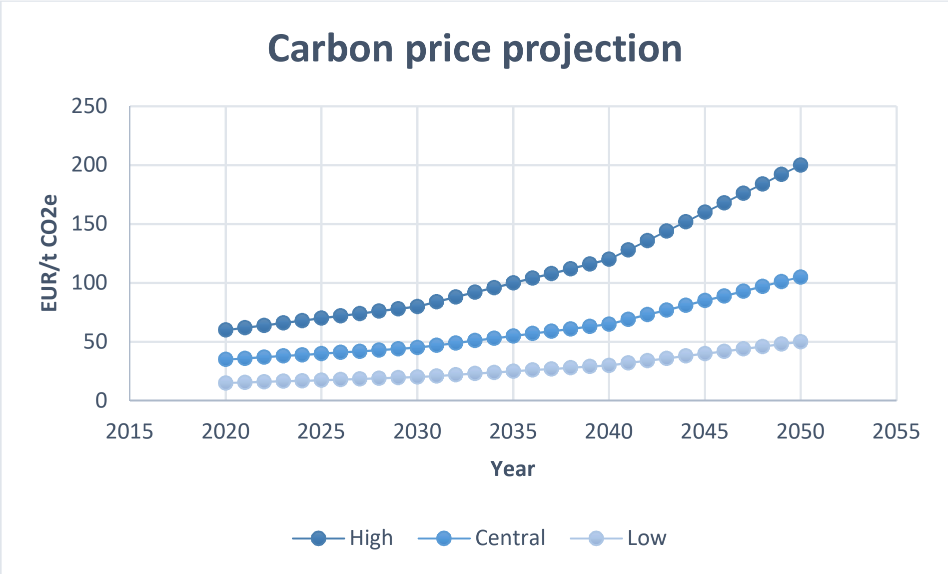


Figure 37. CO_2 EU unit price

The CO_2 unit cost for the running year of the project are presented in the below table.

Table 12. CO_2 EU unit prices projection

Carbon Unit Price Projection						
	HIGH		*CENTRAL*		*LOW*	
year	€	$	€	$	€	$
2020	60	65,40	35	38,15	15	16,35
2021	62	67,58	36	39,24	15,5	16,90
2022	64	69,76	37	40,33	16	17,44
2023	66	71,94	38	41,42	16,5	17,99
2024	68	74,12	39	42,51	17	18,53

2025	70	76,30	40	43,60	17,5	19,08
2026	72	78,48	41	44,69	18	19,62
2027	74	80,66	42	45,78	18,5	20,17
2028	76	82,84	43	46,87	19	20,71
2029	78	85,02	44	47,96	19,5	21,26
2030	80	87,20	45	49,05	20	21,80
2031	84	91,56	47	51,23	21	22,89
2032	88	95,92	49	53,41	22	23,98
2033	92	100,28	51	55,59	23	25,07
2034	96	104,64	53	57,77	24	26,16
2035	100	109,00	55	59,95	25	27,25
2036	104	113,36	57	62,13	26	28,34
2037	108	117,72	59	64,31	27	29,43
2038	112	122,08	61	66,49	28	30,52
2039	116	126,44	63	68,67	29	31,61
2040	120	130,80	65	70,85	30	32,70
2041	128	139,52	69	75,21	32	34,88
2042	136	148,24	73	79,57	34	37,06
2043	144	156,96	77	83,93	36	39,24
2044	152	165,68	81	88,29	38	41,42
2045	160	174,40	85	92,65	40	43,60
2046	168	183,12	89	97,01	42	45,78
2047	176	191,84	93	101,37	44	47,96
2048	184	200,56	97	105,73	46	50,14
2049	192	209,28	101	110,09	48	52,32
2050	200	218,00	105	114,45	50	54,50

It should be noted that the unit cost of CO_2 used in this study is the one stipulated by the EU guidelines. This assumption was made based on the fact that EU has started to implement a strong environmental policy and provides clear guidelines on the calculation and quantification of GHG emissions. The use of EU unit cost of CO_2 does not affect the applicability of the study or the feasibility of the project since the same unit cost is applied to all studied projects. Additionally, all projects can be separately compared in terms of environmental impact and cost effectiveness. Different unit costs for implementation of the project in different parts of the world would alter the monetized environmental impact value of the assets but would still lead to the same conclusion regarding the most fit choice in terms of environmental impact. The tool developed for the assessment of the investment gives the user the option to alter the unit cost of the emissions in case the user wishes to conduct a more location specific analysis. It is important to mention however, that, in general, carbon footprinting involves many forms of uncertainty and GHG estimates are in principle approximate [40].

The cost of GHG calculation can be summarized as:

$$\boldsymbol{Cost\ of\ GHG\ emission = V_{GHG} * C_{GHG}}$$

where:

– V_{GHG} is the incremental volume of GHG emissions produced by the project, expressed in CO_2 equivalents
– C_{GHG} is the unit price or damage cost of CO_2, actualised and expressed at prices of the year at which the analysis is carried out.

6.3.2. Calculation of volume of GHG emissions produced

This Emission Factor approach requires information about the amount of fuel used. In actual projects, such information can be obtained from on-site measurements, manufacturers' emission factors and fuel consumption monitoring. For calculating CH_4 non-combustion emissions published or manufacturers' emission factors based on equipment type and its expected leakage rate can be used.

This particular study correlates the average annual send out gas to power requirement in order to derive the annual LNG quantity consumed and translate it to CO_2 equivalent emissions. As per [9]the consumption of an FSRU is proportional to the send out of the unit and in the case of a 5 mpta send out rate the average daily consumption will be 6.5 t/h. This gives a ratio of LNG consumption to average send out activity of 31.2 tn/day/mtpa. Assuming 365 days operation with an average 3 mtpa send out, the yearly LNG consumption will be approximately 35,000 tns. As regards methane emissions, knowing the number of valves, compressors, flanges and pumps as well as the emission factors and the operational profile of the equipment, can be used to estimate the methane slip of the unit. However, in absence of that data, it was assumed that the methane emissions are 100 tonnes CH_4based on [42]. In case real consumption data are available they can be inserted in the calculations and incorporated in the final results.

Based on the above below table is filled for each year of operation of the unit in order to assess the annual environmental impact of the unit and express it in monetized values.

Table 13. Environmental Impact assessment

year	CO_2unit price	Average MTPA	LNG (t/Y) consumption	Fugitive (t/Y) Emissions	CO_2e (LNG/Y)	CO_{2e}e (Methane/Y)	total CO_2e/y	CO_2e/Y monetized

6.3.3. Other sources of environmental impact

Apart from airborne emissions, FSRUs impact the local environment though:

i. Noise
The FSRU is an industrial plant and as such will generate some noise. Most of the audible noise coming from the ship when it is operating is from engine room vent fans. There is some additional noise from the flow of water through heat exchangers when they are in operation. The FSRU is designed to minimize the impact of noise, including to the crew that stays on board.

ii. Cool water discharge
The use of sea water to heat LNG results in seawater being returned at sea at a temperature lower than seawater than can vary from -4 to -10°C cooler than the ambient temperature. The time the water returns to ambient temperature and the potential impacts on the local marine ecology shall be investigated prior to the implementation of the investment. If the impacts cannot be managed effectively there are alternate heating methods that can be used on the ship such as burning some of the cargo to drive the regasification process.

iii. Plant defouling processes

The intake of seawater into any pipe or plant system will lead to biofouling of the system. Biofouling is the accumulation of microorganisms, plants, algae, or animals from sea water on the internal seawater piping systems. To combat this hypochlorite may be used to disinfect pipe and plant systems. Hypochlorite is produced by running an electric current through seawater, a process known as electrochlorination. This process can produce residual chloride content in this water, which decays upon return to the sea [43].

6.4. Data Used

In order to conduct the economic feasibility study, the collection of various data is required. These data are divided into two main categories, the expenses and the benefits per time period.

6.4.1. Costs

Capital Expenses

The capital expenses for the acquisition of an FSRU, as mentioned in chapter 5.1.1., vary from 250,000,000 USD to 400,000,000 USD and mainly depend of the storage and regasification capacity of the unit as well as on whether the unit is a converted LNG vessel or a newbuilt. In this study, CAPEX market data are used in order to extract formulas linking the CAPEX with the storage and regasification capacity of the unit.

Below table contains information of the currently operating FSRUs. Source: [6], [4], [44], [9]

Table 14. FSRU market data, source: author based on published data

NO	SHIP NAME	SHIPONWER	SHIPBUILDER	DELIVERY YEAR	STORAGE CAPACITY (m3)	PROPULSION TYPE	CAPEX (USD)	REGASIFICATION CAPACITY (mmscf/day)
1	ARMADA LNG MEDITERRANA	EEKAY	MITSU	2016	127,209	TFDE	300,000,000	
2	BAHRAIN SPIRIT	BW	DAEWOO	2018	173,400	DFDE		
3	BW INTEGRITY	BW	SAMSUNG	2017	170,000	STEAM	310,000,000	750
4	BW SINGAPORE	HOEGH MOL	SAMSING	2015	170,000	TFDE	310,000,000	750
5	CAPE ANN	EXMAR EXCEERATE	SAMSUNG	2010	145,130	STEAM	300,000,000	750
6	EXCELERATE	EXCELERATE ENERGY	DAEWOO	2006	135,313	STEAM		690
7	EXCELSIOR	EXCELERATE ENERGY	DAEWOO	2005	138,124	STEAM		690
8	EXEMPLAR	EXCELERATE ENERGY	DAEWOO	2005	138,000	STEAM		690
9	EXPEDIENT	EXCELERATE ENERGY	DAEWOO	2010	151,072	STEAM		690
10	EXPERIENCE	EXCELERATE ENERGY	DAEWOO	2010	147,994	STEAM	280,000,000	690
11	EXPOLRER	EXCELERATE ENERGY	DAEWOO	2014	173,660	STEAM		1200
12	EXPRESS	EXCELERATE ENERGY	DAEWOO	2008	150,900	STEAM		960
13	EXQUISITE	EXCELERATE ENERGY	DAEWOO	2009	151,035	STEAM		690
14	FSRU TOSCANA	OLT OFFSHORE LNG TOSCANA	HYUNDAI	2004	137,500	STEAM		745
15	GOLAR ESKIMO	GOLAR LNG	SAMSUNG	2014	160,000	TFDE		450
16	GOLAR FREEZE	GOLAR LNG PARTENRS	HDW	1997	126,000	STEAM		728
17	GOLAR FROST	GOLAR LNG	SAMSUNG	2014	160,000	TFDE	330,000,000	475
18	GOLAR GLACIER	ICBC	HYUNDAI	2014	162,500	TFDE		
19	GOLAR GRAND	GOLAR LNG PARTENRS	DAEWOO	2005	145,700	STEAM		
20	GOLAR ICE	GOLAR LNG	SAMSUNG	2015	160,000	TFDE		
21	GOLAR IGLOO	GOLAR LNG PARTENRS	SAMSUNG	2014	170,000	TFDE		
22	GOLAR NANOOK	GOLARPOWER	KAWASAKI	2018	138,000	DFDE		728
23	GOLAR SPIRIT	GOLAR LNG PARTENRS	SAMSUNG	1981	170,000	STEAM	277,000,000	
24	GOLAR TUNDRA	GOLAR LNG	DAEWOO	2015	129,000	TFDE		242
25	GOLAR WINTER	GOLAR LNG PARTNERS	HYUNDAI	2004	170,000	STEAM		728
26	HOEGH ESPERANZA	HOEGH MOL	HYUNDAI	2018	138,000	DFDE		500
27	HOEGH GALLANT	HOEGH	HYUNDAI	2014	170,000	DFDE	250,000,000	
28	HOEGH GANNET	HOEGH	HYUNDAI	2018	170,000	DFDE	236,000,000	
29	HOEGH GIANT	HOEGH	HYUNDAI	2017	166,630	DFDE	236,000,000	1000
30	HOEGH GRACE	HOEGH	HYUNDAI	2016	170,000	DFDE	250,000,000	750
31	INDEPENDENCE	HOEGH	HYUNDAI	2014	170,000	DFDE	275,300,000	500
32	MARSHKAL VASILEVSKIY	GAZPROM JSC	HYUNDAI	2018	170,132	TFDE	330,000,000	384
33	MOL FSRU CHALLENGER	MOL	DAEWOO	2017	174,000	DFDE	300,000,000	600
34	NEPTUNE	HOEGH MOL TLTC	SAMSUNG	2009	263,000	STEAM		800
35	NUSANTARA REGAS	GOLAR LNG PARTNERS	ROSENBERG	1977	145,130	DFDE	290,000,000	750
36	PGN FSRU LAMPUNG	HOEGH	HYUNDAI	2014	125,003	STEAM	385,000,000	485
37	TENAGA EMPAT	MISC	CNIM	1981	170,000	STEAM		360
38	TENAGA SATU	MISC	DUNKERQUE	1982	130,000	MEGI		
39	BW COURAGE	BW	CNIM	2021	130,000			
40	DAEWOO 2487	MARAN GAS MARITIME	DUNKERQUE	2019	173,400	DFDE	223,600,000	750
41	HOEGH GALLEON	HOEGH	DAEWOO	2019	170,000	DFDE	270,000,000	
42	HUDONG ZHONGHUA H1786A	DYNAGAS	DAEWOO	2021	174,000	DFDE		750
43	HUDONG ZHONGHUA H1787A	DYNAGAS	SAMSUNG	2021	174,000	DFDE	325,000,000	
44	HYUNDAI ULSAN	TURKIYE PETROLLERI	HYUNDAI	2020	170,000			
45	TURQUOISE	KOLIN/KALYON	HYUNDAI	2019	167,042	DFDE	195,000,000	
46	VASANT	TRIUMPH OFFSHORE PVT LTD	HYUNDAI	2019	180,000	DFDE		

For vessels that data are available for both CAPEX and regasification capacity or for both CAPEX and storage capacity, the associated CAPEX/storage capacity and CAPEX/regasification capacity are calculated as presented in the below tables.

CAPEX depending on Storage capacity:

Vessels for which both CAPEX and storage capacity data are available are presented below.

Table 15. CAPEX as a function of storage capacity data

CAPEX as a function of storage capacity data			
NO	**SHIP NAME**	**STORAGE CAPACITY (m^3)**	**CAPEX ($)**
1	PGN FSRU LAMPUNG	125,003	**385,000,000**
3	ARMADA LNG MEDITERRANA	127,209	**300,000,000**
4	NUSANTARA REGAS	145,130	**290,000,000**
5	CAPE ANN	145,130	**300,000,000**
10	EXPERIENCE	147,994	**280,000,000**
17	GOLAR FROST	160,000	**330,000,000**
23	HOEGH GIANT	166,630	**236,000,000**
27	TURQUOISE	167,042	**195,000,000**

28	HOEGH GANNET	170,000	**236,000,000**
29	HOEGH GALLANT	170,000	**250,000,000**
30	HOEGH GRACE	170,000	**250,000,000**
31	HOEGH GALLEON	170,000	**270,000,000**
32	INDEPENDENCE	170,000	**275,300,000**
33	GOLAR SPIRIT	170,000	**277,000,000**
35	BW INTEGRITY	170,000	**310,000,000**
36	BW SINGAPORE	170,000	**310,000,000**
40	MARSHKAL VASILEVSKIY	170,132	**330,000,000**
41	DAEWOO 2487	173,400	**223,600,000**
43	MOL FSRU CHALLENGER	174,000	**300,000,000**
45	HUDONG ZHONGHUA H1787A	174,000	**325,000,000**
mean value:		161,784	283,645,000
Ratio CAPEX/Storage Capacity		1,753.238124	

CAPEX depending on Regasification capacity:

Vessels for which both CAPEX and regasification capacity data are available are presented below.

Table 16. CAPEX as a function of regasification capacity data

CAPEX as a function of regasification capacity data			
NO	**SHIP NAME**	**REGASIFICATION CAPACITY (mmscf/day)**	**CAPEX ($)**
32	MARSHKAL VASILEVSKIY	384	**330,000,000**
17	GOLAR FROST	475	**330,000,000**
36	PGN FSRU LAMPUNG	485	**385,000,000**
31	INDEPENDENCE	500	**275,300,000**
33	MOL FSRU CHALLENGER	600	**300,000,000**
10	EXPERIENCE	690	**280,000,000**
3	BW INTEGRITY	750	**310,000,000**
4	BW SINGAPORE	750	**310,000,000**
5	CAPE ANN	750	**300,000,000**
30	HOEGH GRACE	750	**250,000,000**
35	NUSANTARA REGAS	750	**290,000,000**
40	DAEWOO 2487	750	**223,600,000**
29	HOEGH GIANT	1000	**236,000,000**
mean value:		664	293,838,462
Ratio CAPEX/Regasification Capacity		442,425.3	

As mentioned in the bibliography, the capital expenses for the construction of an LNG vessel are proportional to the storage and regasification capacity of the unit [45] [46]. The CAPEX are finally estimated as the mean value of:

$$\boldsymbol{CAPEX = mean\ (storage\ ratio * storage\ capacity + regas\ ratio * regas\ capacity)}$$

Finally, the infrastructure cost is left as a user defined variable and assumed to be between 50 and 150 million USD.

Operational Expenses

This category is defined as the sum of the costs of paying the crew, provision costs, insurance and classification costs, cost of fuels lubricants and chemicals, travel costs to locate the FSRU its operation place as well as maintenance and repair costs as set out in section 5.2. A loan is also used, the payment of which is added to the cash outflow as explain above. The operational expenses were drawn from various feasibility studies and published data as set out in the bibliography.

Operating costs are estimated to be similar to costs of operating standard LNG carriers typically, in the range of 1-3% of total capex per annum which translates to daily OPEX at 20,000 to 45,000 USD [9]. The operational expenses vary depending on the operational profile, location, age and many other factors. As regards the age of the units, older units, and especially converted vessels tend to have slightly higher OPEX compared to newer, newbuilt vessels. The OPEX for converted vessels are calculated to be approximately 10% higher compared to newbuilts [47].

This study assumed that the OPEX are 1-3% of the CAPEX, with an option to alter the percentage, a decision which is made by the user. If a vessel is assumed to be converted a 10% increase is applied to the yearly OPEX. The rate or the daily value of the OPEX can be altered by the user in case more specific data are available.

The OPEX of an FSRU are broken down as follows as further explained in chapter 5.2.

1. Crew Cost
2. Repairs and Maintenance (R&M)
3. Consumables
4. Fuels Lubes Chemicals
5. Administration

6.4.2. Benefits

The expected financial return of the investment over the studied period of time was also assessed. The profits of the operation of the unit were defined through the charter rate which was assessed assuming return of the capital expenses and finance expenses over a certain period depending on the input of the user of the model using the NPV criterion. The calculated charter raters were then compared to available market data. The revenues can also be a user defined parameter in case actual market data are available.

Income

The minimum annual revenue is calculated for the project's net present value equal to zero. Then, based on the charter scenario, the charter rate is estimated and compared to market data. The user may then increase the charter rate re-running the criteria.

Sale of the asset

This refers to the disposal expenses as set out in chapter 4. It is assumed that the vessel is sold for scrap at the end of the studied operational life of the unit, which is assumed to be 25 years.

Lightship calculation

In any case, whether the vessel is converted or a newbuild, it is assumed that the asset is sold at scrap iron prices at the end of her operational life. This assumption was based on the duration of the examined life cycle, 25 years, which means that at the end of this period the asset will be at least 25 years old and as such will be reaching the end of its life. In general end-of-life vessel economics are difficult to predict since the end of the life of the vessel is the furthest phase in the future from the time of the analysis, and therefore it is affected by a great degree of uncertainty. [48] In addition, the volatility of the demolition market further implicates the prediction of the demolition price of the asset.

The ship-demolition market plays an important role in the maritime industry, as it mitigates imbalances between supply and demand by adjusting the merchant fleet size. When a vessel is sold for scrap the price is usually calculated through a fixed scrap iron price per light displacement (LDT). A vessel that is sold for scrap can be either sold as "as is, where is" or "upon delivery". In an "as is, where is" sale, the ship owner sells the ship exactly how it is and where it is at the point in time defined in the contract. The cash buyer then takes care of moving, managing and crewing the ship on its last voyage and dealing with the required paperwork and authorities at the breaking site. In an "upon delivery" sale, the ship owner delivers the vessel to an agreed location, usually in the proximity of the yards, for instance at anchorage point outside a beaching destination. Sometimes ships can be delivered in a port which may not be in the country of breaking [49]. The sale price heavily depends on the type of sale, "as is, where is" or "upon delivery" since in the first case the cost of fuels, crewing, possibly towage as well as any other operational expense as well as the risk of travelling the vessel to its final destination are deducted from the final scrap price.

Since the sale price of the vessel is a function of the lightship of the vessel, the estimation of the lightship of the asset under examination is required. The lightship is estimated through the deadweight coefficient which is defined as the fraction of the deadweight of the vessel and the displacement of the vessel. Knowing the displacement of the vessel and the deadweight coefficient, the lightship can then be estimated.

$$\boldsymbol{C_D = \frac{deadweight}{displacement} = \frac{DWT}{LDT}}$$

A typical value of the C_D for LNG carriers is 0.620 [50]. It is assumed that the deadweight coefficient of FSRUs does not substantially vary from the coefficient of LNG carriers.

Typical C_D values for various vessel types are presented in the below table.

Table 17. Deadweight Coefficients

Deadweight Coefficients			
Ship Type	C_D	Ship Type	C_D
Oil Tanker	0.80-0.86	Container ship	0.60
Ore Carrier	0.82	Passenger Liners	0.35-0.40
General Cargo Ship	0.70	Ro-Ro vessel	0.30
LNG or LPG vessels	0.62	Cross-channel	0.20

Scrap vessel Prices

The prices of the ship recycling industry depend on the freight rates and type of vessel, the age of the ship, the location of the recycling shipyard but also the internal and global demand for steel and hence scrap, the growth and the exchange rates of the countries in which demolition takes place.Third world countries offer the best scrap prices per LDT due to the cheap labor and the lower safety and technical standards. In general, the world's largest ship recycling markets are Bangladesh, India, China, Pakistan, and Turkey, who are also the largest importers of steel in the world. However, during the past few years EU has implemented a strict ship recycling policy through the EU SRR regulation which stipulates that commercial vessels above 500 GT must be recycled in safe and environmentally sound ship recycling facilities that are included on the European List of approved ship recycling facilities. The scrap prices offered by these yards are typically lower than those offered by 3rd word countries shipyards.

The scrap prices also depend on the type of the vessel sold, but a firm conclusion on the effect of the type of the vessel cannot be extracted since the prices heavily depend on the market level of each ship type at the time of the demolition. The parameters which play a major role in the scrap prices and scarp market in general are presented diagrammatically in the below figure.

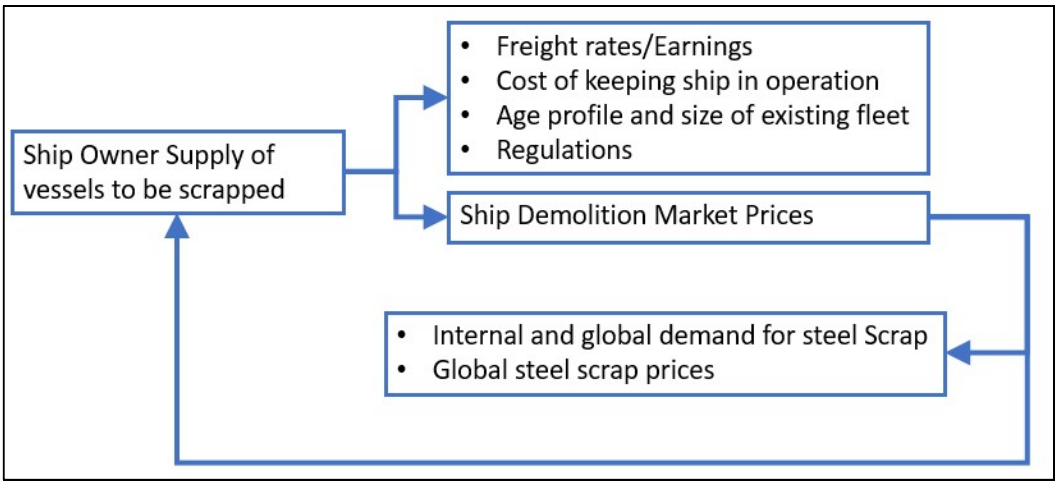


Figure 38. Scrap Market Diagram, source: author

Representative scrap prices for the main four ship demolition markets as of January 2020 are presented below [51].

Table 18. Ship Demolition Scrap Prices

Ship demolition Scrap Prices				
No.	Country	Wet USD$/LDT	Dry USD$/LDT	Container USD$/LDT
1	Bangladesh	370/380	360/370	380/390
2	Pakistan	360/370	350/360	370/380
3	India	365/375	355/365	370/380
4	Turkey	265/275	245/255	265/275
	Mean value	***345***	***332.5***	***351.25***

Based on the above, the value that will be regained when the vessel is sold for scrapping will be:

$$\boldsymbol{Scrap\ Value = LDT \cdot 345 \frac{USD}{LDT}}$$

7. Case Study - FSRU Wilhelmshaven

As Germany is phasing out the use of nuclear energy and coal power, the country's electricity generation capacity is set to halve within the foreseeable future. Liquefied natural gas can cover a large part of the demand and ensure an affordable energy supply. Uniper SE and Mitsui O.S.K. Lines, Ltd. have reached an agreement on a project to install a Floating Storage and Regasification Unit (FSRU) at Uniper site in Wilhelmshaven, Germany. Mitsui O.S.K. Lines plans to own, operate and finance the FSRU whereas Uniper will act as project developer. The FSRU has a planned send-out capacity of 10 bcma and an LNG storage capacity of 263,000 cubic meters and is set to begin its operation in 2022. The project benefits from its location since Wilhelmshaven is closely located to existing pipeline and gas storage infrastructure. The FSRU will be supplied by LNG companies from the United States, but also other countries from around the world, with the opportunity to deliver LNG into the German and European markets, diversifying away from pipeline gas arriving from Russia, Norway and the Netherlands. This study examines its operation for 25 years, for time charter and self operation, since the FSRU is designed to operate for a period of 25 years, without having to leave the port [52].

7.1. Details on the project

The Wilhelmshaven LNG project will comprise a FSRU permanently moored to an extension of the existing jetty at Jade Bay near Wilhelmshaven. The length, breadth, and draught of the FSRU will be 345m, 55m, and 12m, respectively. The LNG from the LNG carriers will be loaded into the FSRU through flexible hoses at a rate of 10,000m³/h. The LNG storage capacity of the FSRU will be 263,000m³. The LNG will be regasified onboard using seawater as the heat source. After regasification, the natural gas will be discharged from the FSRU via three discharge arms and then delivered through a pipeline to a gas measurement station onshore. The project will involve the construction of a 30km-long onshore pipeline to inject natural gas from the Wilhelmshaven import facility to the existing natural gas transmission grid. The Wilhelmshaven floating LNG import terminal is also planned to be developed with manifolds for loading LNG onto bunker barges as well as small LNG seagoing vessels for further transportation to the liquid-gas markets in north-west Europe [53].

Figure 39. Wilhelmshaven FSRU still image, source: [54]

The CAPEX of the investment is calculated to be 500 million USD according to the CAPEX calculation as per chapter 5.1. The estimation of the CAPEX is confirmed by various sources estimating the total CAPEX of the project, including the jetty and infrastructure at 650 million USD. The infrastructure cost is not included in the economic calculations since in late March, Germany's federal cabinet approved a plan that aims to make it easier for LNG project companies to invest in terminals. The draft legislation would require LNG companies to pay only 10 percent of the costs of connecting the terminal to the German natural gas network [55] [54] [56]. The OPEX are calculated as 3% of the CAPEX as explained in 5.4.1.2. The calculated OPEX figure is 40,000 USD per day since the vessel is a newbuilt.

7.2. Time charter Scenario

As mentioned above, both time charter and self operation scenarios are examined. Using the model developed the minimum hire rates estimated for three discount rates scenarios, 5%, 10% and 15%. The cost and benefits allocation, as also presented in chapter 6.1., can be seen below:

Table 19. Time charter scenarios cash flows

TIME CHARTER	
COSTS	**BENEFITS**
CAPEX/2	LOAN
CAPEX/2	-
LOAN + OPEX	HIRE
LOAN + OPEX	HIRE
LOAN + OPEX	HIRE
LOAN + OPEX	HIRE
LOAN + OPEX	HIRE
LOAN + OPEX	HIRE
LOAN + OPEX	HIRE
LOAN + OPEX	HIRE
LOAN + OPEX	HIRE
LOAN + OPEX	HIRE
OPEX	HIRE
OPEX	HIRE
OPEX	HIRE
OPEX	HIRE
OPEX	HIRE
OPEX	HIRE
OPEX	HIRE
OPEX	HIRE
OPEX	HIRE
OPEX	HIRE
OPEX	HIRE
OPEX	HIRE
OPEX	HIRE
OPEX	HIRE
OPEX	HIRE + SCRAP

7.2.1. Minimum hire calculation

The minimum daily hire was calculated basis three discount rate scenarios. At first, the calculations did not include the GHG costs. The minimum hire for the first year of operation of the unit was extracted. The hire amount is considered to be fixed for the whole operational life of the asset, it is however discounted to its present value so the absolute hire amount per year increases as the project year increases.

Table 20. Minimum Hire time charter scenario, GHG costs not included

Minimum Hire Calculation, Environmental Impact not included	
Discount rate	**minimum daily hire $**
5%	131,392
10%	176,978
15%	227,427

As expected, the minimum hire increases with the increase of the discount rate.

7.2.2. Reverse calculation

Assuming 20% increase in the minimum hire rates, the results of the NPV, IRR and CRF criteria are presented below.

Table 21. Reverse calculation results, time charter scenario, GHG costs not included

Criteria results for 20% increase in minimum hire			
Discount rate	**NPV**	**IRR**	**CRF**
5%	128,746,413	7.96%	0.0922
10%	106,609,072	13.54%	0.1406
15%	93,320,694	19.28%	0.1948

7.2.3. GHG emissions

The calculations were repeated taking into account the environmental impact of the asset as explained in chapter 6.3. In order to quantity the effect of the unit on the environment it was assumed that the average yearly send out of the unit is 5 MTPA.

The minimum hire calculations are presented below:

Table 22. Minimum Hire time charter scenario, GHG costs included

Minimum Hire Calculation, Environmental Impact included	
Discount rate	**minimum daily hire $**
5%	157,164
10%	200,823
15%	249,906

As expected the minimum hire increases if the environmental cost is also taken into account since the extra hire has to offset the GHG costs inserted into the cash flow.

Below comparative figure illustrates the minimum hire, for year 2022, as a function of discount rate with and without considering the environmental impact.

Figure 40. Minimum Hire time charter scenario

NPV, IRR and CRF criteria were also applied taking into account the environmental impact of the unit. The results are presented below.

Table 23. Reverse calculation results, time charter scenario, GHG costs included

Criteria results for 20% increase in minimum hire			
Discount rate	**NPV**	**IRR**	**CRF**
5%	153,999,678	8.673%	0.0980
10%	119,183,396	14.089%	0.1456
15%	102,544,465	19.780%	0.1996

The results of the analysis with and without including the GHG costs are presented diagrammatically below.

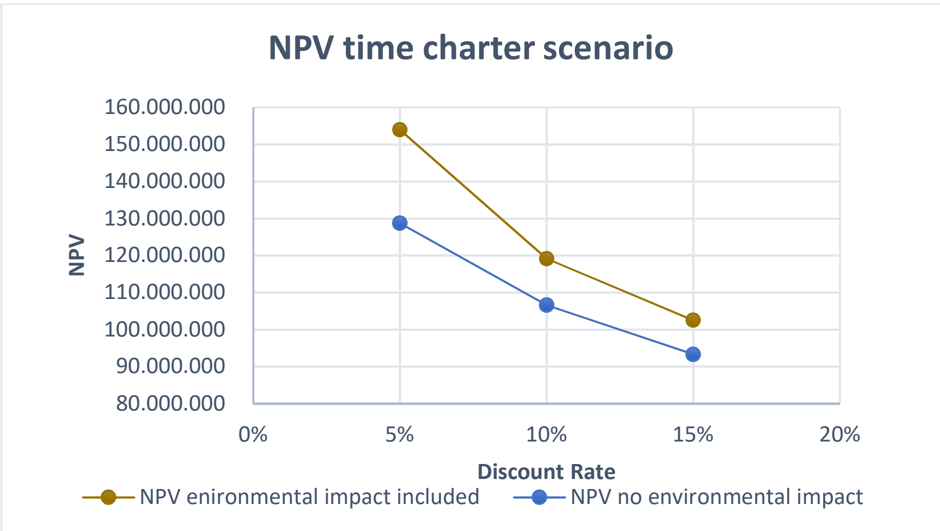


Figure 41. NPV comparison, time charter scenario

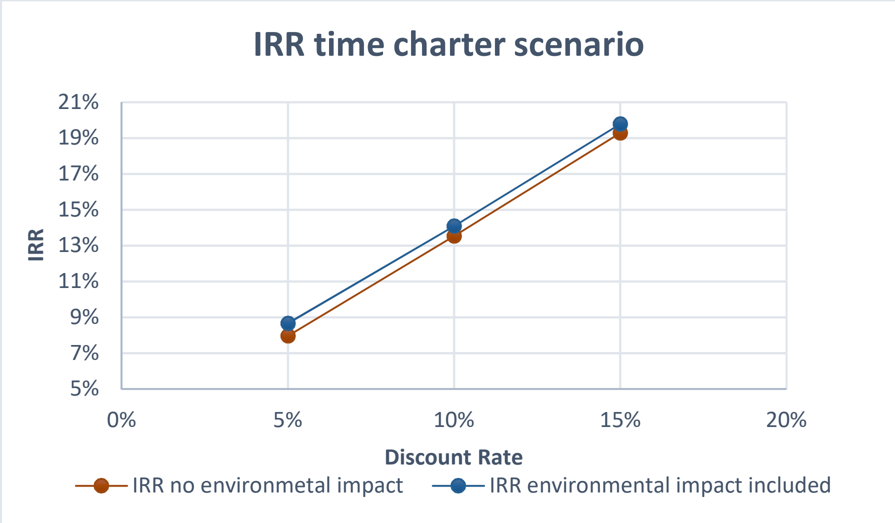


Figure 42. IRR comparison, time charter scenario

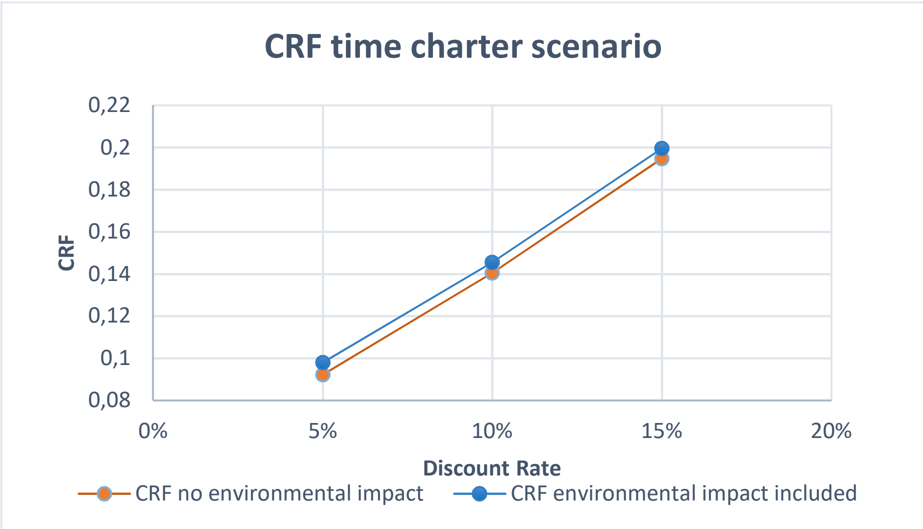


Figure 43. CRF comparison, time charter scenario

7.3. Self Operation Scenario

For the self operation scenario, the minimum tariff per mmsfcd was calculated basis three discount rates and three average annual send out scenarios:

i. 3 MPTA
ii. 5 MTPA
iii. 7 MTPA

The cost and benefits allocation, as also presented in chapter 6.1., can be seen below:

Table 24. Self Operation scenario cash flows

SELF OPERATION	
COSTS	**BENEFITS**
CAPEX/2	LOAN
CAPEX/2	-
LOAN + OPEX	FREIGHT
LOAN + OPEX	FREIGHT
LOAN + OPEX	FREIGHT
LOAN + OPEX	FREIGHT
LOAN + OPEX	FREIGHT
LOAN + OPEX	FREIGHT
LOAN + OPEX	FREIGHT
LOAN + OPEX	FREIGHT
LOAN + OPEX	FREIGHT
LOAN + OPEX	FREIGHT
OPEX	FREIGHT
OPEX	FREIGHT
OPEX	FREIGHT
OPEX	FREIGHT
OPEX	FREIGHT
OPEX	FREIGHT
OPEX	FREIGHT
OPEX	FREIGHT
OPEX	FREIGHT
OPEX	FREIGHT
OPEX	FREIGHT
OPEX	FREIGHT
OPEX	FREIGHT
OPEX	FREIGHT
OPEX	FREIGHT + SCRAP

7.3.1. Minimum tariff calculation

Similar to the time charter scenario, the minimum charge per mmsfcd of gas exported is calculated so that investment's NPV becomes zero. As expected the minimum tariff decreases as the send out demand increases and vice versa. The results of the calculations for the three scenarios are presented in the below tables.

3 MTPA scenario

Table 25. Minimum Tariff Calculation for 3 MTPA, Environmental Impact not included

Minimum Tariff Calculation for 3 MTPA, Environmental Impact not included	
Discount rate	**minimum tariff per mmsfcd**
5%	306.58
10%	412.95
15%	530.66

5 MTPA scenario

Table 26. Minimum Tariff Calculation for 5 MTPA, Environmental Impact not included

Minimum Tariff Calculation for 5 MTPA, Environmental Impact not included	
Discount rate	**minimum tariff per mmsfcd**
5%	183.95
10%	247.77
15%	318.40

7 MTPA scenario

Table 27. Minimum Tariff Calculation for 7 MTPA, Environmental Impact not included

Minimum Tariff Calculation for 7 MTPA, Environmental Impact not included	
Discount rate	**minimum tariff per mmsfcd**
5%	131.39
10%	176.98
15%	227.43

Results for the three scenarios are presented diagrammatically below:

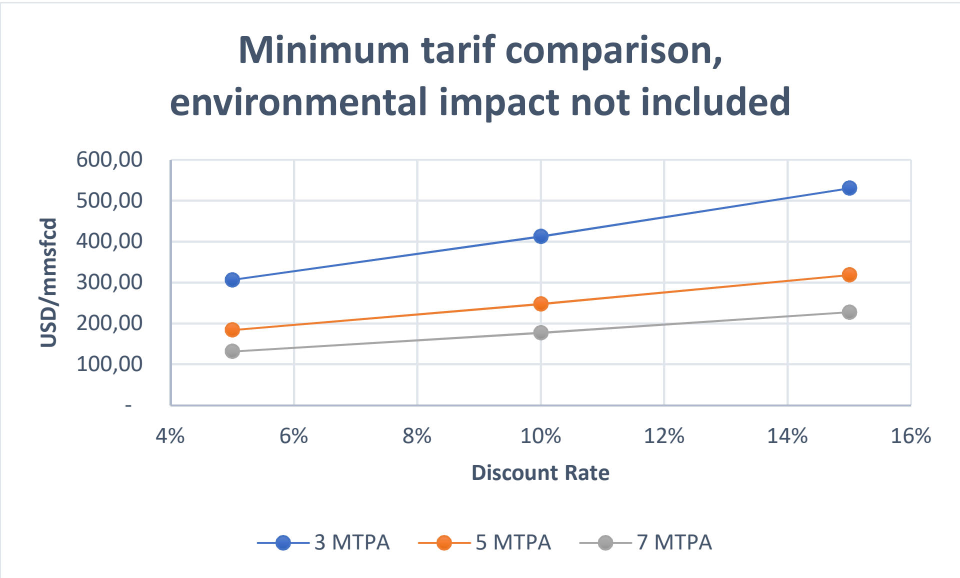


Figure 44. Minimum tariff comparison, environmental impact not included

7.3.2. Reverse calculation

Assuming that the minimum annual send out requirement in order to reach minimum annual revenues so that NPV becomes zero is met and applying a 20% increase in the minimum tariff, NPV, IRR and CRF criteria for the three discount rate scenarios yield the following results.

Table 28. Criteria results for 20% increase in minimum tariff, no GHG costs included

Criteria results for 20% increase in minimum tariff			
Discount rate	**NPV**	**IRR**	**CRF**
5%	128,746,413	7.963%	0.0922
10%	106,609,072	13.544%	0.1406
15%	93,320,694	19.282%	0.1948

7.3.3. GHG emissions

The calculations were repeated taking into account the environmental impact of the asset as explained in chapter 6.3. The gas export scenario plays an important role on the environmental impact of the unit since the send out rate is directly connected to the consumption and as such the emissions produced. The results for the three scenarios are presented below.

As expected the minimum tariff decreases as the send out demand increases and vice versa. However, it should be noted that an increase in MTPA leads to an increase in GHG emissions and as such leads to an increase in the minimum tariff which however, is offset and overcome by the increased demand.

3 MTPA scenario
Minimum tariff calculations:

Table 29. Minimum Tariff Calculation for 3 MTPA, Environmental Impact included

Minimum Tariff Calculation for 3 MTPA, Environmental Impact included	
Discount rate	**minimum tariff per mmsfcd**
5%	428.57
10%	446.66
15%	562.44

Reverse Calculations:

Table 30. Criteria results for 20% increase in minimum tariff, 3 MTPA

Criteria results for 20% increase in minimum tariff, 3 MTPA			
Discount rate	**NPV**	**IRR**	**CRF**
5%	$ 144,048,149	8.3884%	0.0957
10%	$ 115,312,580	13.8904%	0.1438
15%	$ 98,909,663	19.5824%	0.1977

5 MTPA scenario

Minimum tariff calculations:

Table 31. Minimum Tariff Calculation for 5 MTPA, Environmental Impact included

Minimum Tariff Calculation for 5 MTPA, Environmental Impact included	
Discount rate	**minimum tariff per mmsfcd**
5%	220.03
10%	281.15
15%	349.87

Reverse Calculations:

Table 32. Criteria results for 20% increase in minimum tariff, 5 MTPA

Criteria results for 20% increase in minimum tariff, 5 MTPA			
Discount rate	**NPV**	**IRR**	**CRF**
5%	$ 153,999,678	8.6733%	0.098
10%	$ 120,972,931	14.1204%	0.1459
15%	$ 102,544,465	19.7803%	0.1996

7 MTPA scenario

Minimum tariff calculations:

Table 33. Minimum Tariff Calculation for 7 MTPA, Environmental Impact included

Minimum Tariff Calculation for 7 MTPA, Environmental Impact included	
Discount rate	**minimum tariff per mmsfcd**
5%	167.32
10%	210.22
15%	258.76

Reverse Calculations:

Table 34. Criteria results for 20% increase in minimum tariff, 7 MTPA

Criteria results for 20% increase in minimum tariff, 7 MTPA			
Discount rate	**NPV**	**IRR**	**CRF**
5%	$ 163,951,207	8.965%	0.1004
10%	$ 126,633,283	14.354%	0.1481
15%	$ 106,179,268	19.980%	0.2016

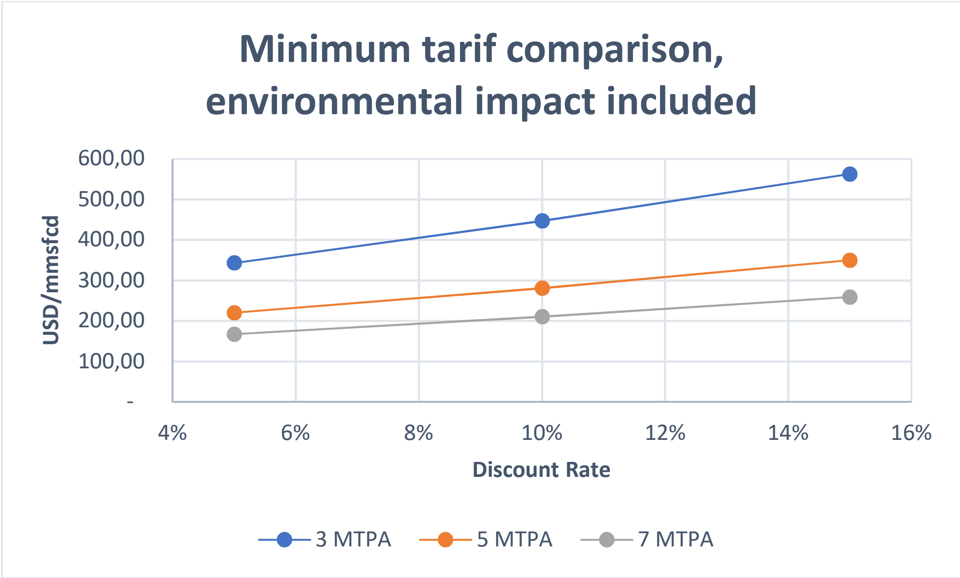


Figure 45. Minimum Tariff Calculation including GHG emissions impact

8. Conclusions and Future Work

In this thesis, LCCA method was implemented in order to assess the acquisition, operation and disposal of FSRUs. The tool developed for the LCCA takes into account the acquisition (CAPEX), operation (OPEX) and disposal (DISPEX) of the asset. In addition, the environmental impact of the asset is estimated, quantified and inserted into the analysis. The environmental expenses of an investment, (ENVEX), are typically part of Life Cycle Analysis (LCA) method, however, they were included in this LCCA study in order to give a better understanding on the operation of FSRUs taking into account the fact that environmental legislation worldwide is becoming increasingly stringent.

To sum up the main steps of the study, initially capital expenses are estimated using published market data to extract the capital costs as a function of the storage and send out capacity of the units. Since the LCCA methods takes place at the beginning of the investment, one of the biggest challenges of this method is the prediction of the future cash flows. Future cash flows consist primarily of the operational expenses, loan pay off and income. The operational expenses are estimated as a percentage of capital expenses depending on whether the asset is a newbuilding or a conversion. The OPEX percentages were found in literature. The user of the model has the option to insert more detailed operational expenses data in case same are available. The model takes into account the loan pay-of giving the user the option to choose annual or balloon payment. The loan amount as a percentage of the total CAPEX, the interest rate and payback period are also user defined variables. As regards the income, it is estimated assuming NPV equal to zero.

The income in case of time chartering of the asset is expressed as a hire amount and is not dependent of the send out demand. If self operation is assumed then, the income is calculated as the charge per unit of gas exported, also known as tariff, multiplied by the amount of gas exported. In both cases, the minimum hire and tariff are calculated so that the NPV of the investment becomes zero. Then these minimum amounts are multiplied by a user defined factor and the financial criteria are re-run in order to assess the economic performance of the investment.

The disposal of the asset at the end of its operational life is taken into account assuming the vessel is sold for scrap and using current scrap market prices. The environmental impact of the unit throughout its operational life is also taken into account through the calculation of the GHG emissions and their conversion to USD amounts.

The model developed was used to study the Wilhelmshaven FSRU project in Germany which is set to begin its operation in 2022. CAPEX and some basic technical data of the unit were available. OPEX, disposal and environmental impact were estimated using the model developed. Assuming time charter and self operation scenarios, the minimum hire and tariff, for three different send out demand scenarios, were calculated. The calculations were repeated in order to include the environmental impact of the unit and compared to the initial calculations. The minimum charge results are presented in the below tables.

Table 35. Time Charter Scenario Final Results

FINAL RESULTS TIME CHARTER SCENARIO			
Minimum Hire Estimation			
Discount rate	No Enviromental Impact assumed	**Discount rate**	Enviromental Impact assumed
5%	131.392,03	**5%**	157.164,22
10%	176.978,19	**10%**	200.823,15
15%	227.426,77	**15%**	249.905,52

Table 36. Self Operation Scenario Final Results

FINAL RESULTS SELF OPERATION SCENARIO					
Minimum Tariff Calculation					
No Enviromental Impact assumed					
Discount rate	3 MTPA	**Discount rate**	5 MTPA	**Discount rate**	7 MTPA
5%	306.58	**5%**	183.95	**5%**	131.39
10%	412.95	**10%**	247.77	**10%**	176.98
15%	530.66	**15%**	318.40	**15%**	227.93
Enviromental Impact assumed					
Discount rate	3 MTPA	**Discount rate**	5 MTPA	**Discount rate**	7 MTPA
5%	428.57	**5%**	220.03	**5%**	167.32
10%	446.46	**10%**	281.15	**10%**	210.22
15%	562.44	**15%**	349.87	**15%**	258.76

For the self operation scenario, one factor that greatly affects the minimum income is the mean annual demand of gas export. As discussed in the relevant chapter, the increase in the mean annual LNG export translates to a decrease in the minimum charge per unit of gas exported and an increase in the NPV of the investment. In case that the environmental impact is also taken into account, then the increase in gas export of the unit is accompanied by an increase in the GHG emissions costs. This increase however, is not enough to offset the positive effect of the rise in the gas demand export. In general, it seems that the inclusion of GHG emissions costs in the analysis has a positive impact on the NPV of the projects since the minimum hire or tariff calculated increases in order to offset the extra costs.

The biggest challenge in an LCCA study is the accuracy and quality of the quantification of the future economic effects. Given this, possibilities for future work are listed below.

a. Future demand estimation for each year of operation of the asset. Present study assumes a fixed send out demand for the whole operational period of the unit. However, the demand will in fact fluctuate in real projects. As discussed above, the gas demand is one of the most important factors in the investment and as such the estimation of the mean annual demand fluctuation would help produce more accurate results. A more detailed estimation of the gas export quantity per year would also help predict more accurate OPEX figures.

b. In addition to the above, having available the technical characteristics of the unit as well as its operational profile, it would be possible to more accurately predict the environmental impact of the unit's operation. As regards the environmental impact, baseline emissions can also be included in future studies so as to take into account the GHG impact of alternative means to meet the output supplied by the proposed project. Since environmental impact calculations involve a great deal of uncertainty, especially when baseline emissions are concerned, it would be useful to also conduct a sensitivity analysis. Additionally, an assessment of the risk expenses (RISKEX) could also be conducted rendering the model developed a hybrid LCA and LCCA model.

c. Lastly, such extensive and expensive projects usually involve cost allocation between different shareholders as well as state funding and complex chartering contracts. In that respect, it would prove useful to conduct the financial analysis for each party concerned.

Appendix A: Conversion Factors

Conversions included in the study were based on below table.

Table 37. LNG volume Conversion Factors

LNG volume conversion factors	
MMSCFD to MTPA	0.007
MMSCF to TONNES	20.32
TONNES to MMSCF	0.049
Liquid m^3 to MMSCF	0.027

In addition, a few more useful LNG conversion factors as obtained by PLATTS can be found below.

Table 38. LNG conversion factors, source: PLATTS

LNG conversion factors								
	kWh	Gj	therm	MMBtu	cf	cu m	mt LNG	cu m LNG
1 kWh		0	0.03	0.003	3.337	0.095	6.67E-05	0.000684
1 Gj	277.8		9.479	0.95	909	26.25	0.019	0.4
1 therm	29.3071	0.1055		0.1	97.47	2.762	0.0019	0.0042
1 MMBtu	293.1	1.055	10		974.659	27.62	0.019	0.042
1 cf	0.2997	0.0011	0.0102	0.001		0.0283	0.000021	0.000047
1 cu m	10.58	0.0381	0.362	0.0362	35.3147		0.00073	0.00164
1 mt LNG	15	52	517	52	48,690	1,379		2.2
1 cu m LNG	7,001	25	239	24	21,500	609	0.46	

Appendix B: Calculations Example

Some extracts of the model developed in Excel® are presented below.

CAPEX

The capital expenses are estimated as the sum of the cost of the FSRU vessel and infrastructure. As explained in chapter 6.4.1., the cost of acquisition of the unit is estimated as a function of its storage and regasification capacity based on market data analysis.

B	C	D	E	F	G	H	I
					CAPEX CALCULATION		
						10	bcm/a
mmscfd/day	966,7822466		FSRU VESSEL	444.415.273,77 USD		3,28	from m to feet
Storage Capacity	263000	m3	INFRASTRUCTURE	150.000.000,00 USD			
CAPEX	$ 500.000.000,00						
				MARKET DATA ANALYSIS			
Column1	Column2	Column3	Column4	Column5	Column6	Column7	Column8
SHIP NAME	SHIPONWER	SHIPBUILDER	TYPE	DELIVERY YEAR	STORAGE CAPACITY (m3)	PROPULSION TYPE	SEND OUT RATE
ARMADA LNG MEDITERRANA	EEKAY	MITSU	FSRU	2016	127.209	TFDE	
BAHRAIN SPIRIT	BW	DAEWOO	FSRU	2018	173.400	DFDE	

Figure 46. CAPEX tab

OPEX

The annual operational expenses are estimated to be similar to the costs of operating LNG carriers and are assumed to be 1% to 3% of the CAPEX expenditure. This approached was adopted based on a plethora of literature sources. The OPEX calculation depends on whether the vessel is a newbuilt or a conversion.

			OPEX CALCULATION				
OPEX	15.000.000,00	CHECK CELL					Operating costs are estimated to be similar to
		opex calc based on newbuilt capex	1% year	5.000.000,00	3% year	15.000.000,00	costs of operating standard LNG carriers in the
			day	13.698,63	day	41.095,89	range of 1-3% of total capex per annum
newbuilt/onverted OPEX ratio extraction				min	max		
based on King and Spandling opex data,			NEW BUILT	18000	30000		
https://www.marinemoney.com/system/files/media/2017-			CONVERTED	20000	35000		
12/1435%20King%20and%20Spalding.PDF			new/conv	0,9	0,857142857	0,878571429	
OPEX CALCULATION				1%	3%		
opex for newbuilt and conv using 1% and 3% rates			OPEX NEW	13.698,63	41.095,89	27.397,26	
			OPEX CONVERTED	15.591,94	46.775,81		

Figure 47. OPEX tab

Loan

The investment is assumed to be partially financed through a loan which can be paid of either by annual payment or balloon payment. In any case the annual cash flows of the loan tab are inserted into the final calculations tab depending on the payment method choice.

LOAN CALCULATION

CAPEX	$ 500.000.000,00
% of CAPEX covered by loan	0,3
LOAN:	**$ 150.000.000**

Annual Payment

LOAN	$ 150.000.000,00	USD
repayment perio	10	years
rate	0,02	

LOAN PAYMENT

YEAR	YEAR BEG BALANCE	ANNUAL PAYMENT	INTEREST COMPONENT	FIXED YEARLY PAYMENT	YEAR END BALANCE
1	$ 150.000.000,00	$ 24.000.000,00	$ 9.000.000,00	$ 15.000.000,00	$ 135.000.000,00
2	$ 135.000.000,00	$ 17.700.000,00	$ 2.700.000,00	$ 15.000.000,00	$ 120.000.000,00
3	$ 120.000.000,00	$ 17.400.000,00	$ 2.400.000,00	$ 15.000.000,00	$ 105.000.000,00
4	$ 105.000.000,00	$ 17.100.000,00	$ 2.100.000,00	$ 15.000.000,00	$ 90.000.000,00
5	$ 90.000.000,00	$ 16.800.000,00	$ 1.800.000,00	$ 15.000.000,00	$ 75.000.000,00
6	$ 75.000.000,00	$ 16.500.000,00	$ 1.500.000,00	$ 15.000.000,00	$ 60.000.000,00
7	$ 60.000.000,00	$ 16.200.000,00	$ 1.200.000,00	$ 15.000.000,00	$ 45.000.000,00
8	$ 45.000.000,00	$ 15.900.000,00	$ 900.000,00	$ 15.000.000,00	$ 30.000.000,00
9	$ 30.000.000,00	$ 15.600.000,00	$ 600.000,00	$ 15.000.000,00	$ 15.000.000,00
10	$ 15.000.000,00	$ 15.300.000,00	$ 300.000,00	$ 15.000.000,00	$ -

This method assumed fixed interest rate and fixed yearly payment

Balloon Payment

LOAN	150.000.000,00 USD	USD
interest rate	0,02	
repayment period	10	years
% ballon payment	0,6	
ballon payment	- 90.000.000,00 USD	USD
YEAR PAYMENT	**- 8.479.591,67 USD**	**using PMT formula**
YEAR PAYMENT*YEARS	- 84.795.916,72 USD	

LOAN PAYMENT

YEAR	annual payment	final balloon payment
1	8.479.591,67 USD	
2	8.479.591,67 USD	
3	8.479.591,67 USD	
4	8.479.591,67 USD	
5	8.479.591,67 USD	
6	8.479.591,67 USD	
7	8.479.591,67 USD	
8	8.479.591,67 USD	
9	8.479.591,67 USD	
10	8.479.591,67 USD	*90.000.000,00 USD*

Figure 48. LOAN tab

Disposal

The disposal of the asset involves the calculation of the lightweight of the vessel which shall then be multiplied by the scrap value price.

SCRAP PRICE CALCULATION

APPROXIMATION OF LS OF THE VESSEL	
DWT	100.000
LS	62000
USD/LS	345
MONEY PAID BACK	**21.390.000,00 USD**

No.	Country	Wet USD$/LDT	Dry USD$/LDT	Container USD$/LDT
1	Bangladesh	370/380	360/370	380/390
2	Pakistan	360/370	350/360	370/380
3	India	365/375	355/365	370/380
4	Turkey	265/275	245/255	265/275
	Mean value	345	332,5	351,25

Figure 49. Disposal Tab

GHG Emissions

The GHG emissions calculations are repeated for the three export demand scenarios. The relevant calculations for the 5 MPTA scenario are presented below as an example.

GHG EMISSIONS CALCULATION 5 MTPA											
#	year	co2 unit price E	co2 unit price $	exchange rate E/$	AVERAGE MTPA	LNG CONSUMED T/Y	FUGITIVE EMISSIONS T/Y	CO2E LNG/Y	CO2E METHANE/Y	TOTAL CO2Et/y	CO2E/Y MONETIZED
1	2022	37	40,33	1,09	5	56940	100,0	166.105,4	2.500,00	168.605	6.799.854 USD
2	2023	38	41,42		5	56940	100,0	166.105,4	2.500,00	168.605	6.983.634 USD
3	2024	39	42,51		5	56940	100,0	166.105,4	2.500,00	168.605	7.167.414 USD
4	2025	40	43,6		5	56940	100,0	166.105,4	2.500,00	168.605	7.351.194 USD
5	2026	41	44,69		5	56940	100,0	166.105,4	2.500,00	168.605	7.534.974 USD
6	2027	42	45,78		5	56940	100,0	166.105,4	2.500,00	168.605	7.718.754 USD
7	2028	43	46,87		5	56940	100,0	166.105,4	2.500,00	168.605	7.902.534 USD
8	2029	44	47,96		5	56940	100,0	166.105,4	2.500,00	168.605	8.086.313 USD
9	2030	45	49,05		5	56940	100,0	166.105,4	2.500,00	168.605	8.270.093 USD
10	2031	47	51,23		5	56940	100,0	166.105,4	2.500,00	168.605	8.637.653 USD
11	2032	49	53,41		5	56940	100,0	166.105,4	2.500,00	168.605	9.005.213 USD
12	2033	51	55,59		5	56940	100,0	166.105,4	2.500,00	168.605	9.372.772 USD
13	2035	53	57,77		5	56940	100,0	166.105,4	2.500,00	168.605	9.740.332 USD
14	2036	55	59,95		5	56940	100,0	166.105,4	2.500,00	168.605	10.107.892 USD
15	2037	57	62,13		5	56940	100,0	166.105,4	2.500,00	168.605	10.475.452 USD
16	2038	59	64,31		5	56940	100,0	166.105,4	2.500,00	168.605	10.843.011 USD
17	2039	61	66,49		5	56940	100,0	166.105,4	2.500,00	168.605	11.210.571 USD
18	2040	63	68,67		5	56940	100,0	166.105,4	2.500,00	168.605	11.578.131 USD
19	2041	65	70,85		5	56940	100,0	166.105,4	2.500,00	168.605	11.945.690 USD
20	2042	69	75,21		5	56940	100,0	166.105,4	2.500,00	168.605	12.680.810 USD
21	2043	73	79,57		5	56940	100,0	166.105,4	2.500,00	168.605	13.415.929 USD
22	2044	77	83,93		5	56940	100,0	166.105,4	2.500,00	168.605	14.151.049 USD
23	2045	81	88,29		5	56940	100,0	166.105,4	2.500,00	168.605	14.886.168 USD
24	2047	85	92,65		5	56940	100,0	166.105,4	2.500,00	168.605	15.621.287 USD
25	2048	89	97,01		5	56940	100,0	166.105,4	2.500,00	168.605	16.356.407 USD

Figure 50. GHG emissions tab

Calculation

The calculations take place in 3 different tabs per chartering scenario, for the three studied discount rates. Each tab includes the calculations with and without the GHG costs. For example, an extract from a calculation tab is presented below.

CASH FLOWS AND CRITERIA / NO ENVIRONMENTAL IMPACT INCLUDED									
		NET PRESENT VALUE GOAL SEEK							
interest rate r	0,02	t/year		Hire	Income	Expenses	net cash flow R	Π(1+iκ)	NPV
discount rate It	0,05	-2	2020	0	$ 150.000.000,00	$ 250.000.000,00	$ -100.000.000,00	1,000	$ -100.000.000,00
initial investement	500.000.000 USD	-1	2021	0	$ -	$ 250.000.000,00	$ -250.000.000,00	1,050	$ -238.095.238,10
		1	2022	$ 47.958.090	$ 47.958.090,30	$ 30.000.000,00	$ 17.958.090,30	1,103	$ 16.288.517,28
		2	2023	$ 47.958.090	$ 47.958.090,30	$ 30.000.000,00	$ 17.958.090,30	1,158	$ 15.512.873,60
HIRE	$ 47.958.090	3	2024	$ 47.958.090	$ 47.958.090,30	$ 30.000.000,00	$ 17.958.090,30	1,216	$ 14.774.165,33
		4	2025	$ 47.958.090	$ 47.958.090,30	$ 30.000.000,00	$ 17.958.090,30	1,276	$ 14.070.633,65
EXTRA CHARGE	0,200	5	2026	$ 47.958.090	$ 47.958.090,30	$ 30.000.000,00	$ 17.958.090,30	1,340	$ 13.400.603,47
		6	2027	$ 47.958.090	$ 47.958.090,30	$ 30.000.000,00	$ 17.958.090,30	1,407	$ 12.762.479,50
		7	2028	$ 47.958.090	$ 47.958.090,30	$ 30.000.000,00	$ 17.958.090,30	1,477	$ 12.154.742,38
		8	2029	$ 47.958.090	$ 47.958.090,30	$ 30.000.000,00	$ 17.958.090,30	1,551	$ 11.575.945,12
		9	2030	$ 47.958.090	$ 47.958.090,30	$ 30.000.000,00	$ 17.958.090,30	1,629	$ 11.024.709,64
		10	2031	$ 47.958.090	$ 47.958.090,30	$ 30.000.000,00	$ 17.958.090,30	1,710	$ 10.499.723,47
		11	2032	$ 47.958.090	$ 47.958.090,30	$ 15.000.000,00	$ 32.958.090,30	1,796	$ 18.352.297,91
		12	2033	$ 47.958.090	$ 47.958.090,30	$ 15.000.000,00	$ 32.958.090,30	1,886	$ 17.478.378,96
		13	2034	$ 47.958.090	$ 47.958.090,30	$ 15.000.000,00	$ 32.958.090,30	1,980	$ 16.646.075,20
		14	2035	$ 47.958.090	$ 47.958.090,30	$ 15.000.000,00	$ 32.958.090,30	2,079	$ 15.853.404,95
		15	2036	$ 47.958.090	$ 47.958.090,30	$ 15.000.000,00	$ 32.958.090,30	2,183	$ 15.098.480,91
		16	2037	$ 47.958.090	$ 47.958.090,30	$ 15.000.000,00	$ 32.958.090,30	2,292	$ 14.379.505,63
		17	2038	$ 47.958.090	$ 47.958.090,30	$ 15.000.000,00	$ 32.958.090,30	2,407	$ 13.694.767,26
		18	2039	$ 47.958.090	$ 47.958.090,30	$ 15.000.000,00	$ 32.958.090,30	2,527	$ 13.042.635,49
		19	2040	$ 47.958.090	$ 47.958.090,30	$ 15.000.000,00	$ 32.958.090,30	2,653	$ 12.421.557,61
		20	2041	$ 47.958.090	$ 47.958.090,30	$ 15.000.000,00	$ 32.958.090,30	2,786	$ 11.830.054,87
		21	2042	$ 47.958.090	$ 47.958.090,30	$ 15.000.000,00	$ 32.958.090,30	2,925	$ 11.266.718,92
		22	2043	$ 47.958.090	$ 47.958.090,30	$ 15.000.000,00	$ 32.958.090,30	3,072	$ 10.730.208,49
		23	2044	$ 47.958.090	$ 47.958.090,30	$ 15.000.000,00	$ 32.958.090,30	3,225	$ 10.219.246,19
		24	2045	$ 47.958.090	$ 47.958.090,30	$ 15.000.000,00	$ 32.958.090,30	3,386	$ 9.732.615,41
		25	2046	$ 47.958.090	$ 69.348.090,30	$ 15.000.000,00	$ 54.348.090,30	3,556	$ 15.284.896,86
									$ -0,00

Figure 51. Calculations Tab example

Final Results

The final results are gathered in the relevant tab so as to extract the relevant graphs and tables.

FINAL RESULTS

TIME CHARTER SCENARIO

No Enviromental Impact assumed

	min hire
5%	131.392,03
10%	176.978,19
15%	227.426,77

20% increase in min hire

	NPV	IRR	CRF
5%	128.746.413	7,963%	0,0922
10%	106.609.072	13,544%	0,1406
15%	93.320.694	19,282%	0,1948

Enviromental Impact assumed

	min hire
5%	157.164,22
10%	200.823,15
15%	249.905,52

20% increase in min hire

	NPV	IRR	CRF
5%	153.999.678	8,673%	0,0980
10%	119.183.396	14,089%	0,1456
15%	102.544.465	19,780%	0,1996

SELF OPERATION SCENARIO

No Enviromental Impact assumed

	min tarif mmsfcd assuming 3 MTPA	min tarif mmsfcd assuming 5 MTPA	min tarif mmsfcd assuming 7 MTPA
5%	306,58	183,95	131,39
10%	412,95	247,77	176,98
15%	530,66	318,40	227,43

20% increase in min tarif

	NPV	IRR	CRF
5%	128.746.413	7,963%	0,0922
10%	106.609.072	13,544%	0,1406
15%	93.320.694	19,282%	0,1948

Enviromental Impact assumed

	min tarif mmsfcd assuming 3 MTPA	min tarif mmsfcd assuming 5 MTPA	min tarif mmsfcd assuming 7 MTPA
5%	428,57	220,03	167,32
10%	446,66	281,15	210,22
15%	562,44	349,87	258,76

20% increase in min tarif (3 MTPA)

	NPV	IRR	CRF
5%	$ 144.048.149	8,388%	0,0957
10%	$ 115.312.580	13,890%	0,1438
15%	$ 98.909.663	19,582%	0,1977

20% increase in min tarif (5 MTPA)

	NPV	IRR	CRF
5%	$ 153.999.678	8,673%	0,0980
10%	$ 120.972.931	14,120%	0,1459
15%	$ 102.544.465	19,780%	0,1996

20% increase in min tarif (7 MTPA)

	NPV	IRR	CRF
5%	$ 163.951.207	8,965%	0,1004
10%	$ 126.633.283	14,354%	0,1481
15%	$ 106.179.268	19,980%	0,2016

Figure 52. Final Results Tab

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