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Input to Potential study by introducing LNG into the German Market

Contents

1 Introduction

This study is concentrating on LNG terminals including land based installation of LNG tank farms with necessary utilities for LNG import, storage, re-gasification and compression meeting pipeline pressure at tie-in point.

There are different ways of handling the LNG from the LNG liquefaction plant to the end user. We are in this part of the study evaluating the processes marked in the green area, LNG import terminal with re-gassing, floating storage regasification unit (FSRU) with re-gassing both with possibilities for LNG transfer to small scale LNG carriers and LNG export with truck and rail cars.

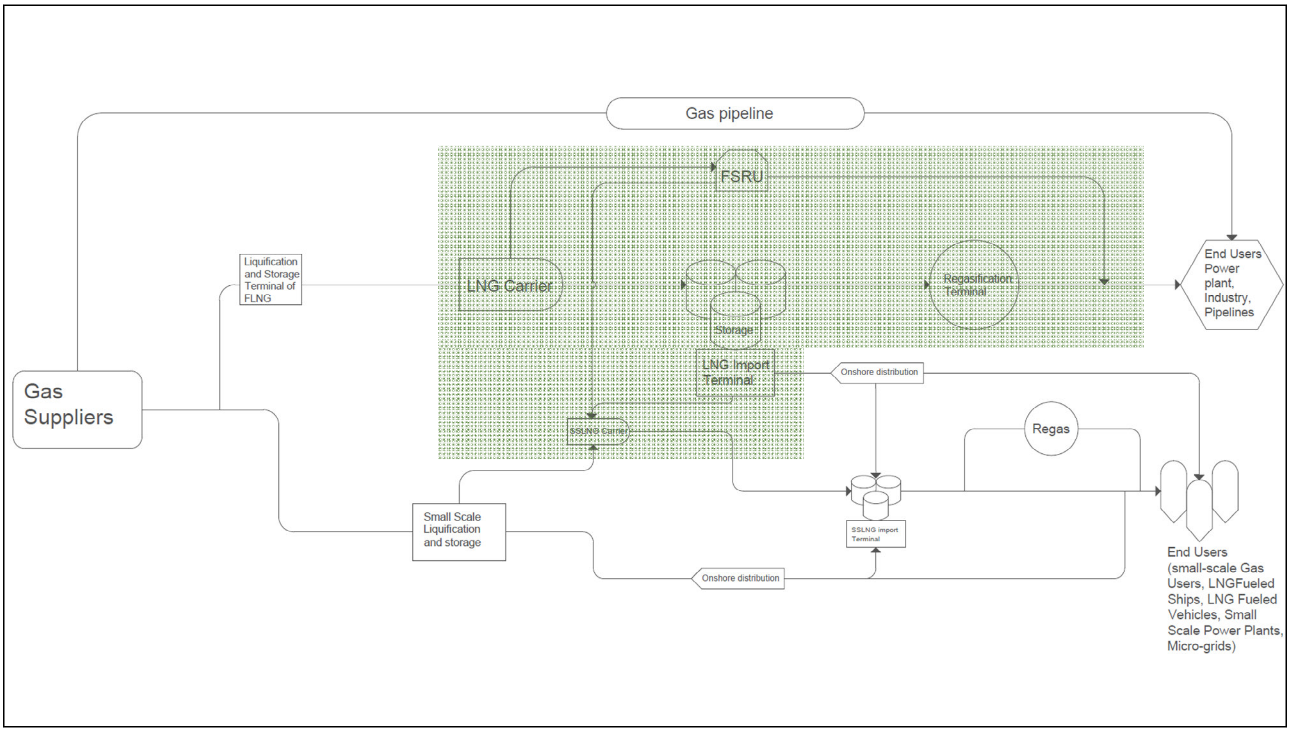

Figure 1, LNG value chain

The following alternatives are evaluated in this report:

- Large scale terminal with throughput of 14 billons Nm^3 gasified LNG per year
- Mid-scale terminal with throughput of 8 billons Nm^3 gasified LNG per year
- FSRU with throughput of 5 billons Nm^3 gasified LNG per year

All capacities calculated is based on LNG high heating value (gross heating value). The netto heat export is calculated based on the same conditions for all alternatives (re-gasification energy input based on 0.005% during summer period and 0.02% during winter period where supplementary firing is required).

The LNG storage volume in a standard FSRU is 170 000 m^3. There are no larger FSRU available on the market at the moment. If larger storage capacity or yearly trough put is required it is no problem to include two FSRUs at one location, pumping gas into the grid. This is done at the large LNG terminal in Egypt.

	Capacity $10^9 Nm^3/y$	Selected gross storage volume m^3 LNG	Netto heat export *) MWh/y	Heat export *) MWh/h
Large scale onshore LNG plant	14	450 000	160 549 565	18 328
Mid scale onshore LNG plant	8	300 000	91 742 608	10 473
Floating Storage Regas Unit	5	170 000	57 339 130	6 546
*) at 100% availability a				

Table 1, Capacity and energy export to grid

The study also includes the possibility for small scale LNG interfaces including LNG bunkering and LNG export to truck and rail cars.

The heat is preferably taken from the sea water at the location. In case of a FSRU the water intake is in sea chests on each side of the FSRU in order not to short circuit the inlet and outlet of process heating water (hot and cold water). The FSRU needs at least 3m additional water depth to ensure problem free water circulation.

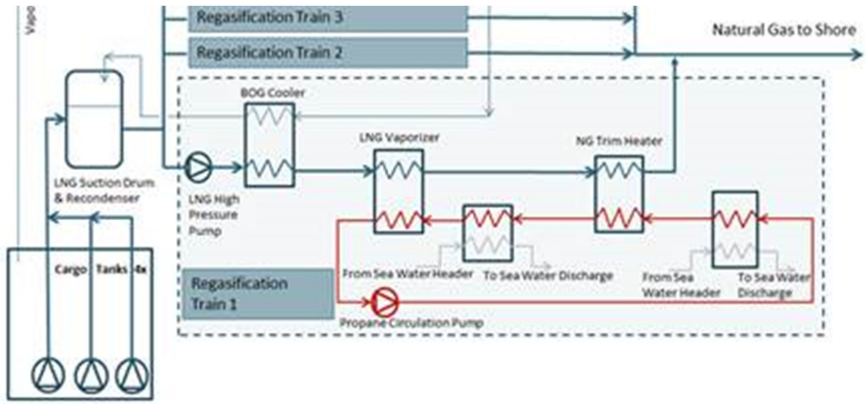

Figure 2, Typical re-gasification process flowsheet with propane as heating medium

The regasification process and calculations related hereto is based on a combination of open and closed loop heat transfer to the LNG. The open loop heating process is using sea water as a heating medium to the closed propane loop. Minimum inlet temperature to the process shall not be lower than 10^0C as the return temperature is estimated to be 7^0C lower than the inlet temperature. Other heat sources as waste heat from nearby process industry is ideal. For those periods of the year when the sea water temperature is lower than 10^0C a steam system must be used avoiding sea to freeze around the FSRU.

A typical temperature curve over the year for north-west Germany from Wilhelmshaven is used as guidance for selection of open /closed loop re-gasification. The closed loop regasification is based on heat from hot water/steam boilers and has a higher regasification cost.

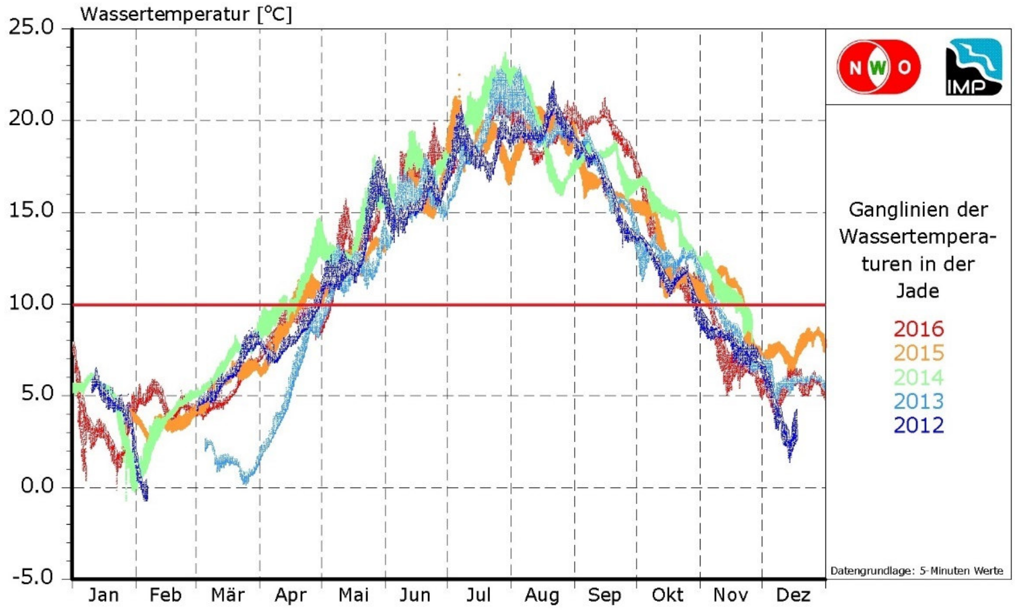

Figure 3, Water temperature at Wilhelmshaven over the year (2012 to 2016)

A consequence of the above temperature curve is that for the summer period (6 months) open cycle regasification process is used, for the winter period closed cycle regasification is used for balance of plant calculations. This is independent of land based terminal or FSRU.

All assumptions and conversions factors used in the study are included and tabulated inn Attachment no. 1.

An alternative to seawater as heating source for the regasification process, is to utilize excess heat from other plant(s) within reasonable distance. A pre-requisite for this alternative is stable availability of heat over the year, if not, a double system must be implemented into the design. The heat requirements for the regasification is proximately 0.5 % of the energy throughput of the regasification capacity when heat source has higher temperature than +10 ^{0}C. If the closed loop regasification is used the regasification requires proximately 2.0 % of the energy throughput of the regasification capacity.

Pipeline pressure at the connection point is expected to be 105 bar. All LNG terminals and FSRU design will meet this requirement. It is further recommended to have a positive export pressure margin of at least 5 bar above the pipeline pressure out from the LNG terminal/FSRU.

2 LNG terminal

LNG terminals involve cryogenic equipment for LNG storage and regasification processes in addition to equipment directly involved in the import and export facilities for both gas and LNG. When the LNG terminal is connected to pipeline network the LNG terminal shall have the possibility to design the process to meet the required pipeline pressure for problem free connection and export. The LNG terminal shall further be designed for continuous operation with high degree of redundancy of equipment and power supply.

A typical terminal set-up is presented in the figure below. The LNG is unloaded from large LNG carriers at a high rate, typically 9,000 – 12,000 m^3/hr. Typical storage capacity for LNG carrier is from 145 000 m^3 to 266 000 m^3. The net volume is less as there always must be some LNG rest left in the tank in order to keep the tank temperature as low as possible. In this study 90% of gross volume is used for import to the terminals or FSRU. This allows normal unloading to occur in about 12 to 24 hours. The LNG is pumped directly to storage, multiple pressurized tanks or to a larger flat bottom atmospheric pressure tank. During unloading process, a large quantity of LNG vapour (Methane) is generated. Vapour is returned to the tanker for replacement of exported LNG volumes, and the surplus vapour is normally compressed in the boil-off system for use as fuel or re-liquefied and returned as a LNG product in the tanks. During normal operation, the Methane slip to the atmosphere shall be kept to an absolute minimum.

At gas export facilities, the LNG is pumped to export pressure by submerged LNG pumps. The LNG will be vaporized to natural gas at the export pressure. The vaporization system can be based on several different technologies conditioned the necessary capacity and environmental conditions. The vaporisation process can be based on systems with fired equipment, seawater or air vaporizers as well as intermediate (closed loop) fluid (i.e. Propane) systems. The system should be designed for import of waste heat if found economical beneficial.

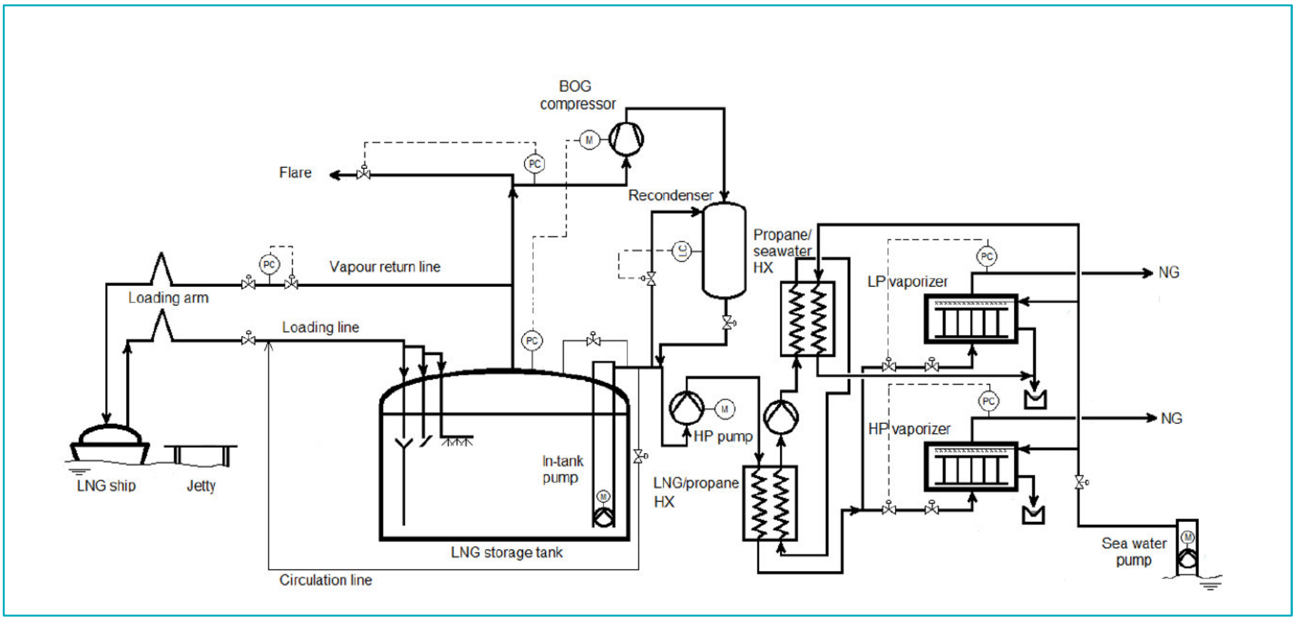

Figure 4, Typical schematic flowchart of LNG terminal

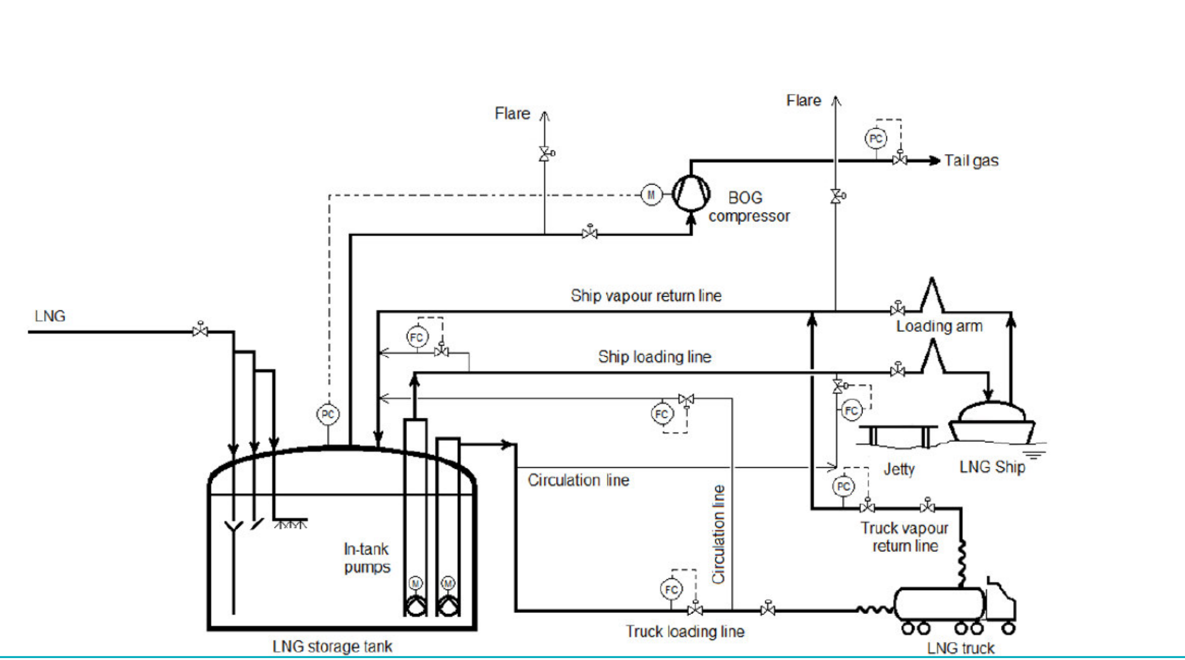

Figure 5, Typical small-scale LNG export terminal flowchart

The following alternatives have been evaluated:

- Large scale terminal with throughput of 14 billons Nm^3 gasified LNG per year
- Mid-scale terminal with throughput of 8 billons Nm^3 gasified LNG per year

The LNG storage capacity for the different alternatives have been based on totally 7days consumption of energy at peak capacity. The following high-level comparison is established

	Capacity $10^9 Nm^3/y$	Selected gross storage volume m^3 LNG	Netto heat export *) MWh/y	Heat export *) MWh/h
Large scale onshore LNG plant	14	450 000	160 549 565	18 328
Mid scale onshore LNG plant	8	300 000	91 742 608	10 473
Floating Storage Regas Unit	5	170 000	57 339 130	6 546
*) at 100% availability				

Table 2, Capacity and energy export to grid

The regasification process needs heat to increase temperature of the LNG from -162 ^{0}C to ambient temperature. Based on the temperature curve (ref Figure 1) it is considered that during a 6-month period in the summer open cycle re-gasification process is selected for operation. The remaining 6-month will be operated as a hybrid (combining open/closed cycle) process balancing the outlet temperature from the re-gasification process to not be lower than +3^{0}C. The calculation above is conservative and is based on 100% closed regasification process during the winter season.

The following assumptions is made:

- Open cycle re-gasification heat required: 0,5% of heating value of product *)

- Closed cycle re-gasification heat required: 2.0 % of heating value of product *)
- Hybrid operation is a combination of the two-above, meeting minimum outlet temperature of $+3^0$C
- Availability estimated to 98%

*) Information received by FSRU operator, Höegh LNG, Norway

Gas delivery supplying gas into a country's main grid shall meet high expectations both to availability and reliability. Therefor high degree of redundancy should be included in the design where found necessary. Specially rotating equipment shall be spared and constructed to meet n+1 requirements for critical items. This requirement shall apply independent of the location of the plant, land based or FSRU based. The goal is to meet 98% availability during normal operation with scheduled maintenance every 2nd or 3rd year for a period of up to 3-4 weeks.

2.1 LNG berthing of carrier

The berthing of an LNG carrier is the same with respect to time consumption independent of terminal/jetty berthing or ship to ship berthing and offloading. The following assumptions are estimated based on a standard LNG carrier up to 145 000 m^3 -170 000 m^3 LNG:

1.	All lines fast, Pre-transfer meeting;	2	hours
2.	Connections and cool down of transfer equipment;	5	hours
3.	LNG transfer typical 9 000 m^3/h to 13 000 m^3/h;	17-20	hours
4.	Drain/purge/disconnect LNG equipment;	3	hours
5.	Total berth duration	27 to 30 hours	

In addition to the above identified durations, the tugging assistance for the carrier turning and berthing operations.

2.2 Large scale terminal

For study purposes, a 14 billons Nm^3 gasifier LNG per year throughput has been selected.

The necessary land area has been evaluated based on a green field assessment. Small scale LNG export equipment to smaller LNG carriers are included in the cost estimate. Necessary land area allocated to LNG export by truck and rail cars have not been included neither in the layout nor in the cost estimates.

The time for offloading the Q-Max LNG load is estimated to 36 operating hours. The birthing for each call is estimated to 2x7 hours by assistance of necessary tugs and tugs availability must be included in the evaluation. This gives a total duration of each call of proximate 2 days total in berthing conditions.

The throughput of a terminal of this size is enormous and requires a storage capacity of 7 days at maximal/peak regasification capacity in the low end. If a Q-Max LNG carrier is selected with maximum transport capacity of 266 000 m^3 LNG the maximum offloading volume is 240 000m^3 of LNG at a maximum offloading ratio of 90%, the average loading sequence is 3.7 days between each call. Loading frequency is 98 calls per year by the Q-max carrier. If estimated sailing time from Qatar to NW Germany is estimated to 7 + berthing 3 days in each end making one transport sequence to 20 days, the supply chain requires more than 5 Q-Max LNG carriers only servicing this import terminal.

The land required for such terminal is estimated to minimum 90 000 m^2 and will cover a land of proximate 300 m x 300 m plus the offshore installations of jetty and jetty bridge. Due to the relatively long duration of the offloading process it is recommended to include two berthing positions at the jetty. Estimated length of jetty is set to proximate 1000 m. (Length of Q-max 345 m + berthing margins of 50% of length of vessel).

The area described above does not include small scale LNG export by rail car or by truck. If such LNG export facilities shall be included the depth of the area will increased by proximate 100m. There are specific rules for driving and operating the large LNG caring trucks. During normal operation, it is not acceptable to reverse the long vehicle and the complete turning radius must be included inside the fenced area. The weighing cells for both LNG rail cars and LNG trucks shall also be located inside the fenced area.

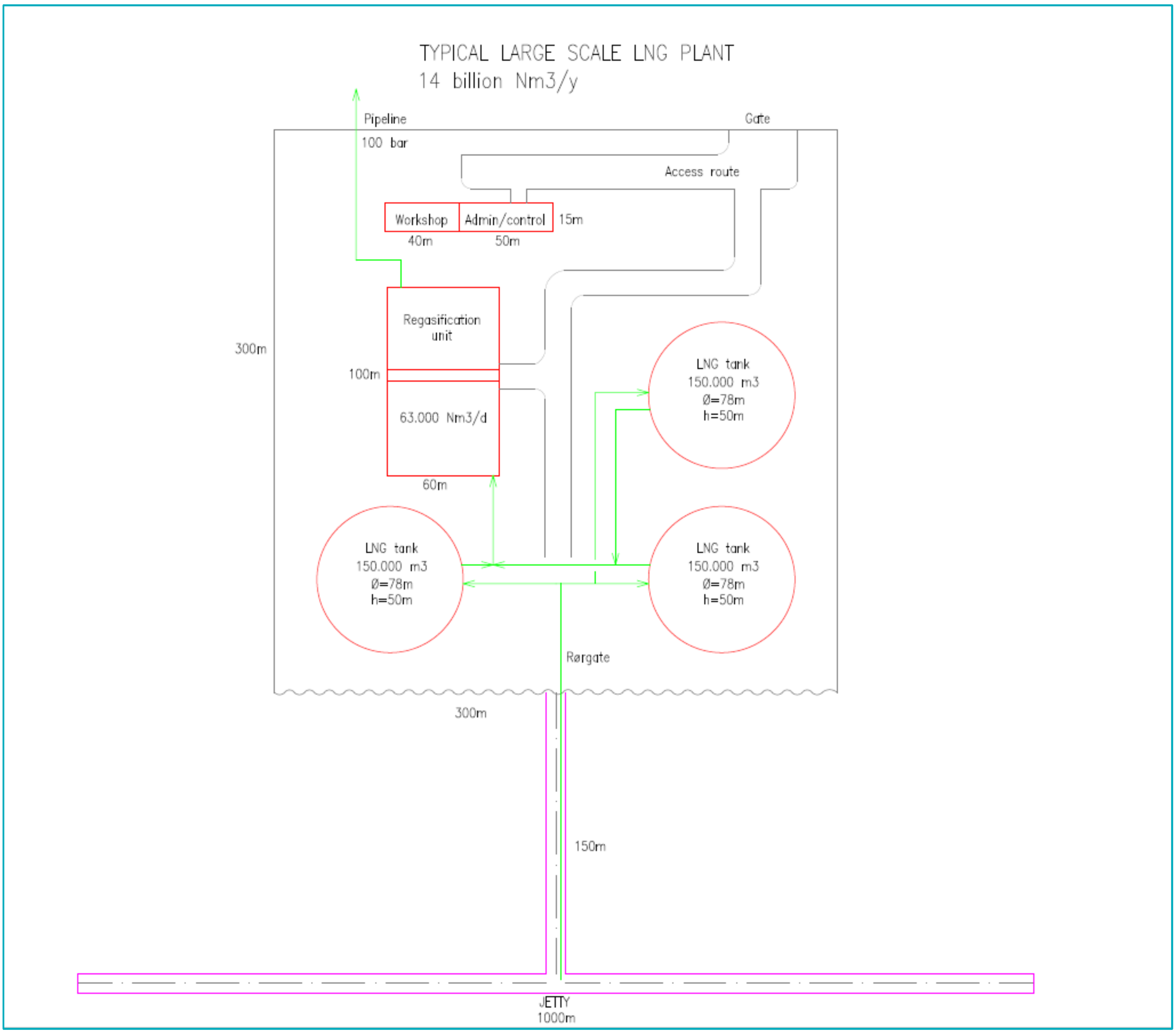

Figure 6, High level large scale LNG land terminal with 3x150 000 m³ storage volume

For this large-scale LNG terminal with throughput of 14 billons m³ of re-gasified LNG the storage volume of 3x150 000m³ is selected. This is based on CAPEX minimization. To increase the flexibility for LNG supply and trading there is an option to increase the storage with one additional tank of 150 000m³ LNG making the total capacity 4x150 000m³. If constructed it will increase the necessary land requirement from 300mx300m to 300mx370m.

The Gate LNG terminal in Netherland is of the same magnitude of the large-scale LNG terminal in this study and has increased the storage capacity by one additional large LNG tank making total stage capacity of 540 000m³ and 2 (increasing to 3) jetties at a throughput of 12 billion m³ per annum.

2.3 Mid-scale terminal

For study purposes, a 8 billons Nm^3 gasified LNG terminal capacity per year throughput has been selected.

The necessary land area has been evaluated based on a green field assessment. Small scale LNG export equipment to smaller LNG carriers are included in the cost estimate. Necessary land area allocated to LNG export by truck and rail cars have not been included neither in the layout nor in the cost estimates.

The same design criteria have been selected for the LNG tank capacities. 7 days gas consumption equalise to 255 $000m^3$ LNG, the LNG storage is selected to 2x150 000 m^3 LNG tanks. The LNG storage capacity is slightly oversized since one full Q-max LNG carrier could empty the full cargo into the onshore storage tanks. Construction cost of a 100 000 m3 storage tank or a 150 000 m3 tank is not significant, but to by a full Q-max cargo load is significant cheaper than importing part loads only.

Loading capacity from Q-max carrier of 266 $000m^3$ with maximum offloading of 90% equalise 240 $000m^3$. Loading frequency is a carrier of this Q-max size every 6.5 day. Loading frequency is 57 calls per year by the Q-max carrier. If estimated sailing time from Qatar to NW Germany is estimated to 7 + berthing 3 days in each end making one transport sequence to 20 days, the supply chain requires 4 Q-Max LNG carriers only servicing this import terminal. Alternatively, a smaller size LNG carrier of gross storage of 170 000 m^3 with maximum offloading of 90% equalise 153 $000m^3$. Loading frequency is every 4.1 day. This is rather similar the large-scale LNG terminal loading frequency but with smaller LNG carrier.

However, for an 8 billion m^3 LNG terminal based on CAPEX minimization. To increase the flexibility for LNG supply and trading there is an option to increase the storage with one additional tank of 150 $000m^3$ LNG making the total capacity 3x150 $000m^3$. If constructed, it will give a loading frequency more in line with normal LNG loading frequencies and giving more flexibility for LNG trading.

The land required for a 2x150 $000m^3$ terminal is estimated to minimum 70 000 m^2 and will cover a land of proximate 300 m x 230 m plus the offshore installations of jetty and jetty bridge. Due to the relatively long duration of the offloading process it is recommended to include two berthing positions at the jetty. Estimated length of jetty is set to proximate 1000 m. (Length of Q-max 345 m + berthing margins of 50% of length of vessel). If a 3x150 000m3 LNG tank solution is selected the jetty length could be shortened and the necessary capacity of 1xQ-max at a time. Length would be less than 600m. Reference is given to figure 4.

To information the Polish Świnoujście LNG Terminal has a storage capacity of 2x160 $000m^3$ and 2 jetties at a through put of 5 billion m^3 per annum, possible to increase capacity to 7.5 billion m^3 per annum

The area described above does not include small scale LNG export by rail car or by truck. If such LNG export facilities shall be included the depth of the area will increased by proximate 100m.

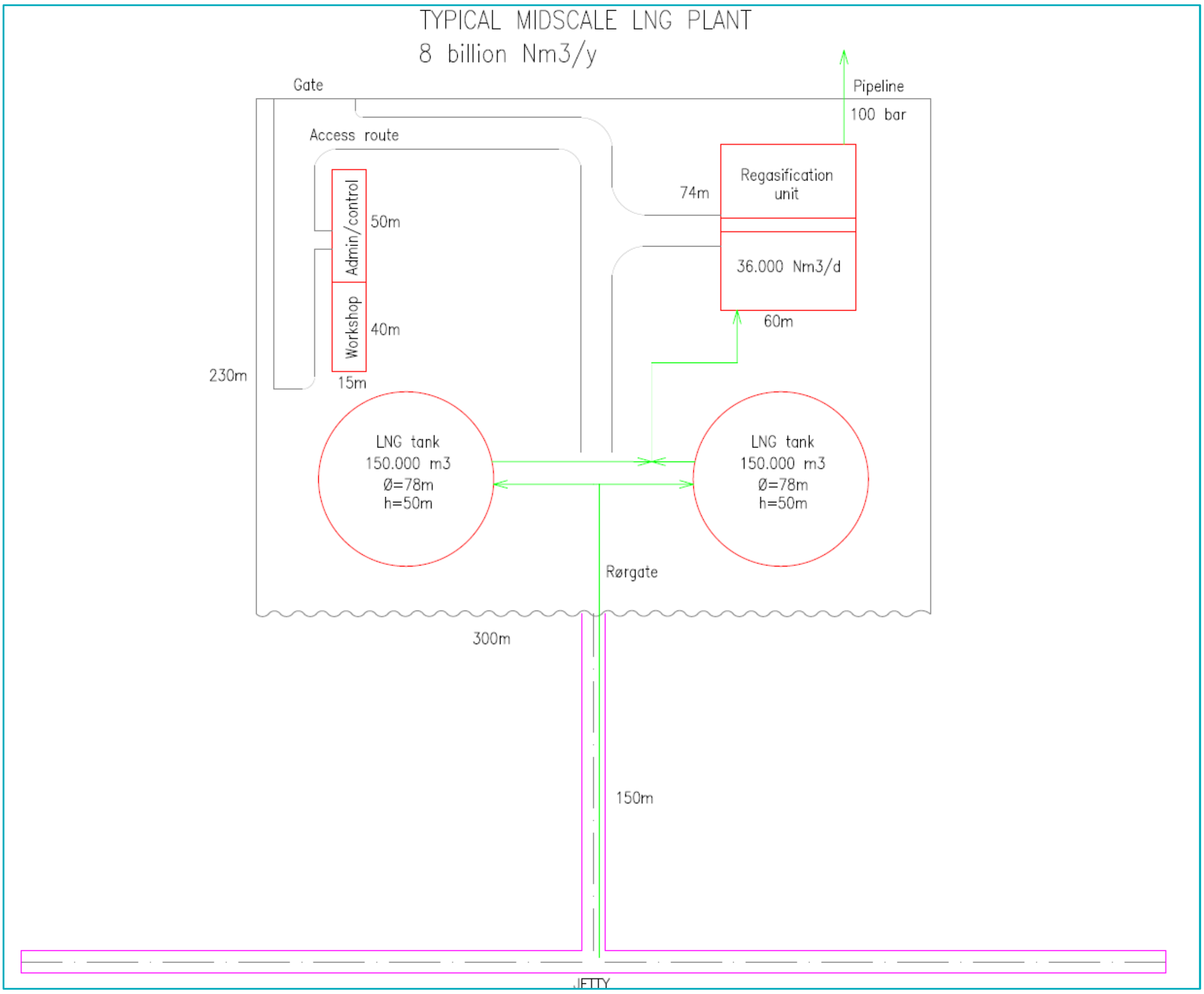

Figure 7, High level arrangement for mid-scale LNG land terminal with 2x150 000 m3 storage volume

3 FSRU alternative

For study purposes, a 5 billons Nm^3 gasified LNG terminal capacity per year throughput has been selected for FSRU alternative.

Figure 8 Typical FSRU berthing (170 000m^3) and LNGC offloading

The same design criteria as for land based terminal have been selected for the FSRU. 7 days gas consumption equalise to 160 000m^3 LNG, the LNG storage is selected to 1x170 000 m^3 LNG tanks included in the FSRU hull.

A normal LNG carrier of LNG storage of 170 000 m^3 with maximum offloading of 90% equalise 153 000m^3. Loading frequency is every 6.7 day. Loading frequency is 55 per year.

The FSRU could handle ship-to-ship, side by side offloading up to and including a Q-Max carrier. Loading frequency will be every 10.5 days making 35 calls per year. If this large carrier size is selected the time for offloading must be increased by 24 hours, from normal 36 hours to 72 hours. The FSRU cannot absorb more than 170 000 m^3 LNG. The surplus volume up to Q-Max offloading capacity of 240 000m3 must be absorb by the export gas capacity of FSRU. It shall be said that the re-gassing capacity of the FSRU could be increased to meet peak loads by proximately 50% well within the standard design. A consequence is that Q-Max offloading can only be utilised during peak season.

Below are two alternatives for FSRU berthing. One for side-by side offloading and one for across jetty offloading. Both alternatives shall include LNG offloading onto small-scale LNG carriers of the size 1000 m^3 to 15 000 m^3 transport capacity. Simultaneous operations of large carrier offloading and small carrier loading are possible. For figure 9 arrangement the small-scale carrier has to be located inside of the jetty. For figure 10 arrangements the small-scale carrier berths on the free side of the FSRU. For LNG loading of the small scale LNG carriers the transfer shall be made by FSRU export pumps of capacity from 150 m^3/h up to 2000 m^3 /h pending on vessel capacity. The low capacity pumps will be used for up to 1000m3 LNG carriers giving a loading time of 6.5 hours. A carrier of 7000m3 LNG volume could be loaded by using the main export pump giving a loading time down to 3.5 hours.

The FSRU re-gassing systems are constructed as modules each having an export capacity of 2900 MWh/h (250 MSCFD). To meet the n+1 philosophy it is necessary to install 3 re-gassing modules. Two is required to meet the daily demand. The third is there for meeting the sparing requirement. By this design the FSRU can in peak periods increase the capacity by 50%. There is space large enough on the FSRU deck for a forth unit if that is found necessary.

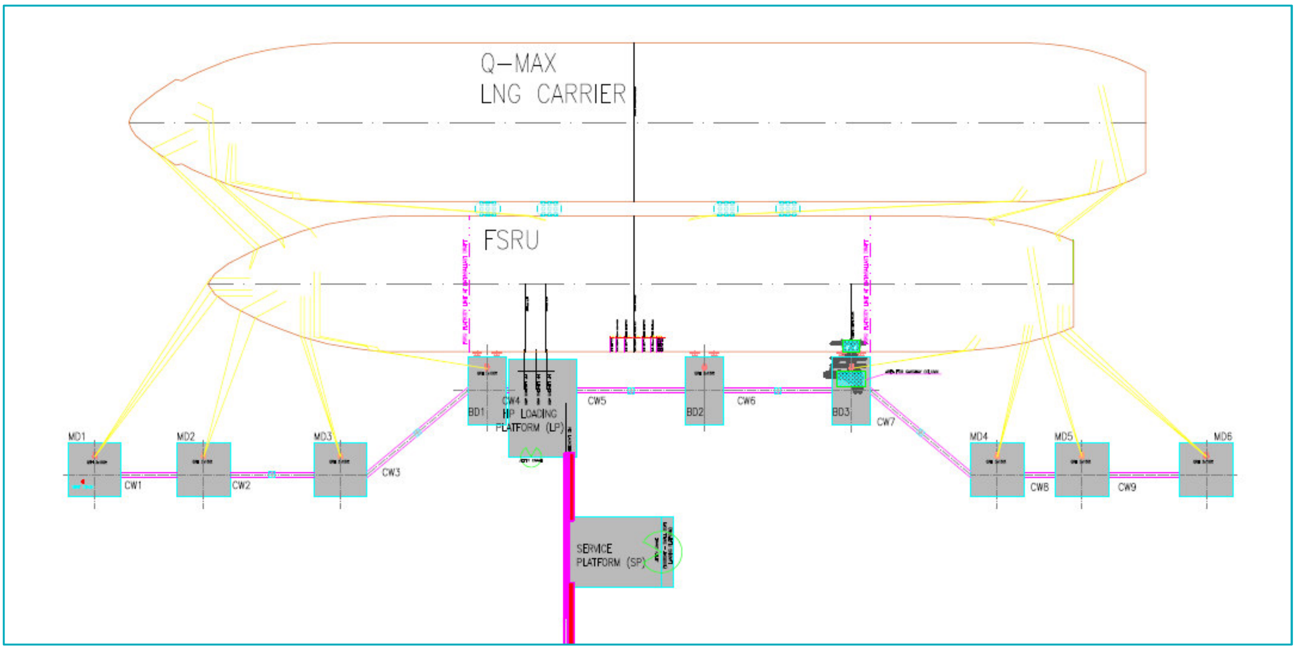

Figure 9, FSRU side-by-side offloading

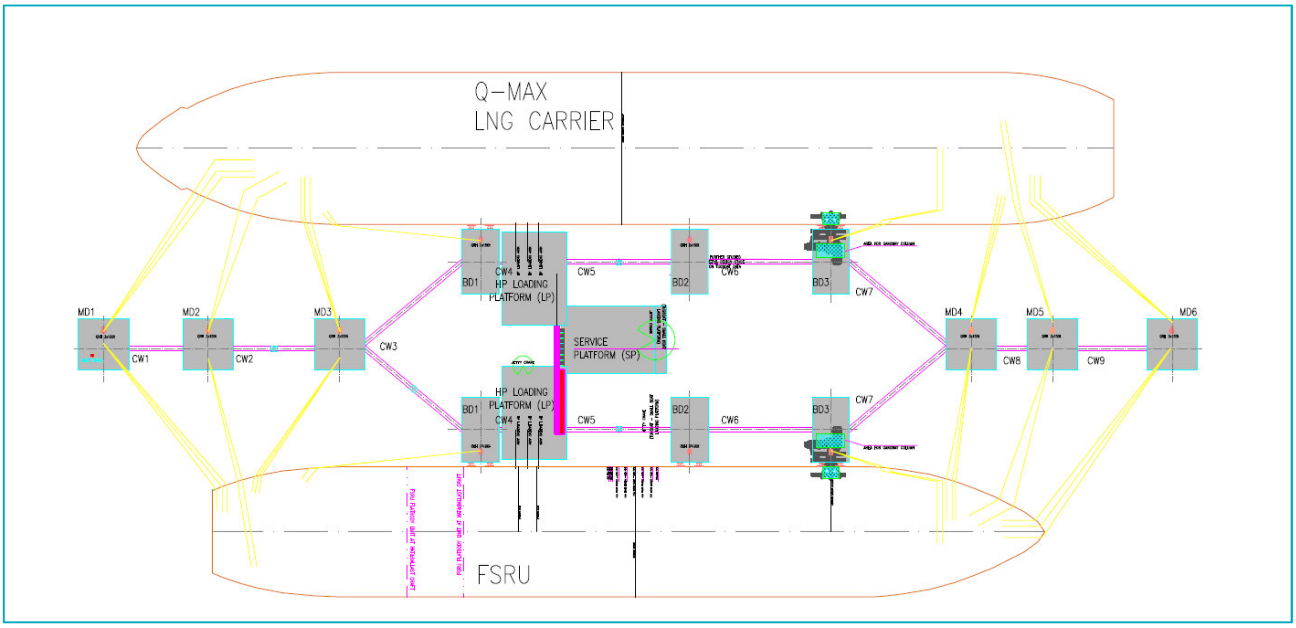

Figure 10, FSRU across jetty offloading

Furthermore the berthing arrangement in figure 10 allows the berthing of other large carrier like e.g. crude oil tankers at that site of not utilised by LNG carriers.

The different berthing concepts require the same equipment, but the equipment is located on different locations. In figure 9 the FSRU contains all necessary facilities for ship-to-ship LNG transfer by flexible hoses. When loading from large LNG carriers the carrier's export pumps are used, for small-scale carrier filling from the FSRU low capacity pumps onboard the FSRU is used. No additional equipment is need for loading operations.

High pressure gas loading arms are installed on the jetty with all necessary control and monitoring system ensuring safe transfer and export of the re-gasified LNG to the pipeline.

There is a standard design of FSRU that includes the berthing and loading on starboard side of the vessel (berthing on backboard side is possible and must be specified by customer) and regasification system meeting pipeline pressure of up to 90 bara to 110 bara. In order to meet the export pressure at NWG the high pressure application shall be selected. The FSRU will be equipped with all relevant interfaces necessary for the operation independent of the type of berthing arrangement and will include increased export pressure to meet the pipeline pressure without including any gas compressor station onshore. LNG transfer could also be included if specified.

When cross jetty berthing is utilised as indicated on figure 11, there will be installed thermal insulated LNG transfer pipe with necessary safety valves and quick release valves as indicated on the sketch below.

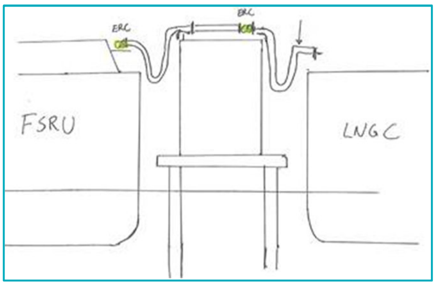

Figure 11, Cross jetty LNG transfer arrangement

General FSRU technical information

The jetty is designed to receive an LNG tanker from which LNG is transferred to the moored FSRU, so that the regasification equipment on the FSRU generates gas with the required pressure in accordance with demand at the time, and the high-pressure loading arm sends out the gas into the pipeline. The following are the pieces of equipment used in the process:

- Imported LNG receiving loading flexible pipes, 2 manifolds with 4 flexible LNG pipes, and vapour return flexible pipe
- LNG transfer loading flexible pipe for LNG transfer to small scale LNG carriers and return line
- Cross jetty loading/unloading piping arrangements
- High pressure natural gas send-out loading arms
- Valve manifold related to the above
- Emergency shutdown system
- Nitrogen connections and piping
- Loading arm operation system
- Knock-out drums for vapour
- Drain pump
- Electric power distribution panel and system (utilities and power source will be received from the FSRU. The FSRU has standard 60 Hz power system and cannot be directly connected to shore power)
- Communication systems for same operation

The following pieces of equipment will be in place as part of the jetty facilities:

- Breasting dolphins
- Mooring dolphins
- Navigation aid
- Radio communications, etc.

As stated in the section that explores the capacity of an FSRU, the size of the LNG tanker receiver is unidentified at this stage. Hence, the team considered the size that ranges between 145 000 m3 and 170 000 m3 (up to 260 000 m3 for Q-Max) to envisage the structures of the jetty and the dolphins.

The system flow of the equipment and the schematic diagram are as shown below:

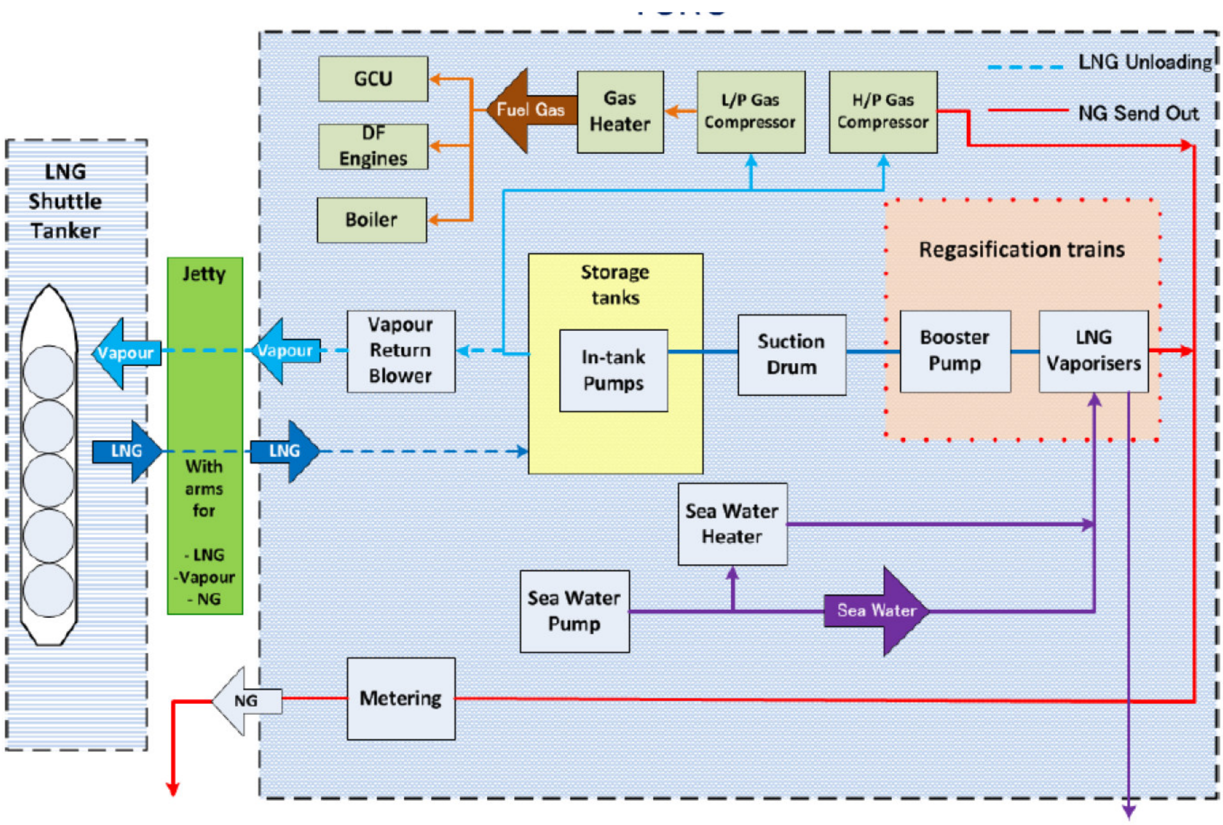

Figure 12, FSRU system flow and main equipment

3.1 Small-scale LNG terminal

A land based terminal will have the possibilities to export LNG to truck and rail transport. The FSRU as it is berthed out from shore needs facilities onshore to compensate for this. In this study, there is included cost for such terminal for the FSRU alternative and a typical layout arrangement. It is selected a storage capacity of 5000 m3 LNG with export facilities for truck and rail, a vacuum insulated LNG pipeline from the FSRU and a vapour return line back to the FSRU as well as a gas production to the local grid. The storage capacity can be reduced to 500 m^3 to 1000 m^3 LNG pending of truck loading daily throughput. The filing of such truck loading station from an FSRU or land based LNG terminal will be made in batches in order to reduce the vapour losses between the large storage tanks and the small loading stations.

In case of small-scale LNG infrastructure at a land-based LNG import terminal the storage capacity is not necessary hence reducing the investment costs.

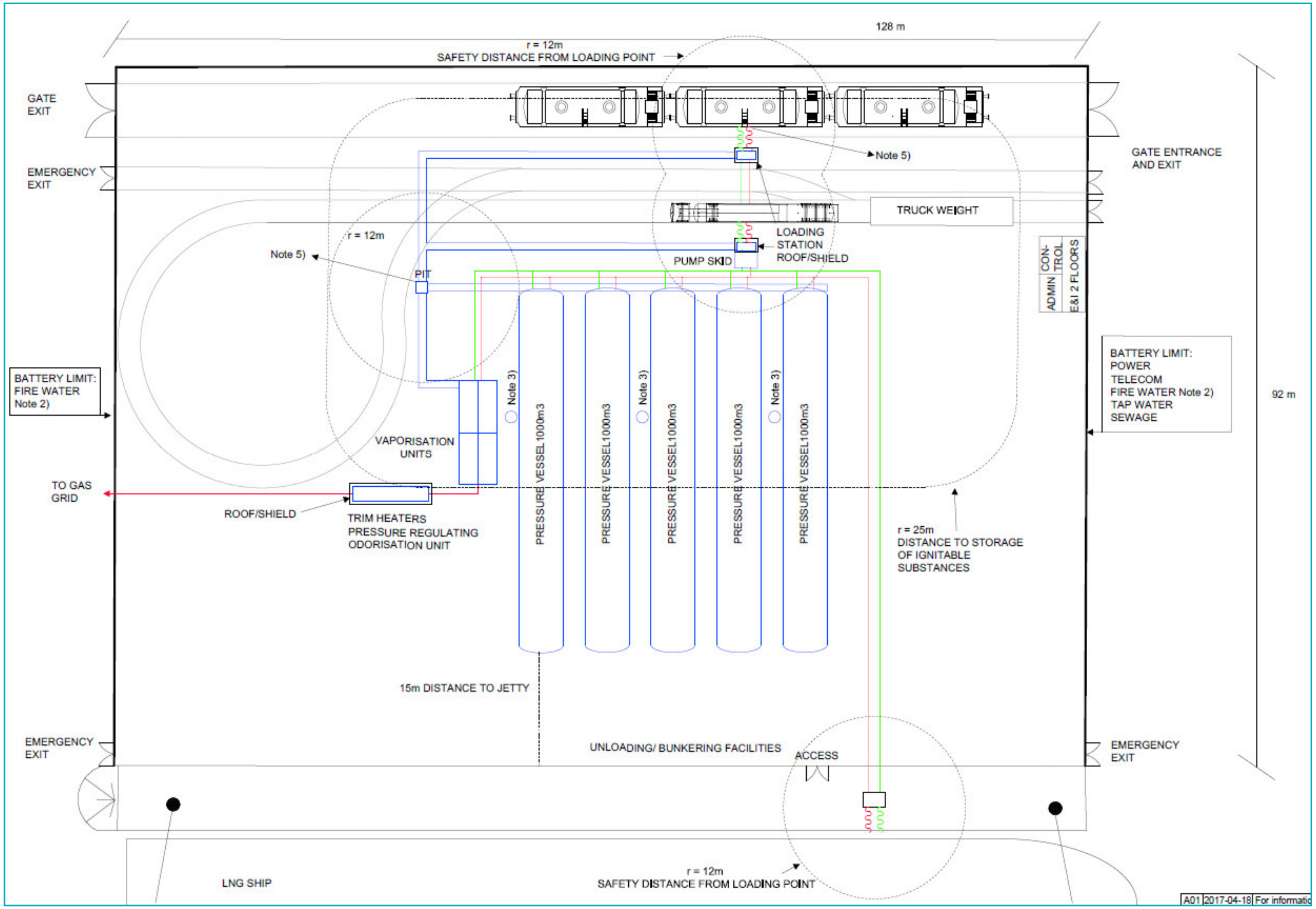

Figure 13, Typical Small-scale LNG terminal, 5000 m3

3.2 Benefits of choosing a floating LNG import terminal

The following highlights the advantages of a floating import terminal solution as opposed to an onshore solution:

- Half the time to construct (FSRU maximum construction time 26 months, land based installation 5-8 year construction time)
- significant less cost
- Less risk of cost overruns, through constructing a significant portion of the terminal on fixed price and delivery time at a shipyard which is specialised on such construction
- Less environmental impact, as the installation is located in the sea and not on land
- Flexibility to relocate the FSRU or use it as an LNGC (LNG carrier)
- Capacity increase by introduce a second FSRU to double the capacity

Using a FSRU as an alternative to land based installations is interesting seen in view of the following arguments:

- Short construction time (proximate 28 months for tailor made design)
- Standardised and well proven technical concept for both storage and regasification
- Open or closed re-gasification loops adapted to summer and winter sea water temperature variations
- Constructed in accordance with international codes and regulations
- Meeting DNV-GL and ILO rules, approved and certified accordingly
- Design is based on self-propelled, ship shape design, and can operate as commercial LNG carrier

3.3 Limitations by using FSRU

The FSRU is a complete self-standing industrial application installed on a ship shape hull or on a barge. To shorten the delivery time, the FSRU is very often financed by the ship owner on speculation. Delivery time for a standard FSRU can come down to 12-month due to this fact, and standard design is delivered. Tailor made FSRU could be delivered on proximately 24-26 months.

- There is some limitations connected to the use of FSRU compared to onshore LNG terminals.
- Power from shore is limited as the standard FSRU is driven by 60 Hz onboard generators.
- Limited use of excess heat from other plants

The re-gasification process is standardised and are bringing all LNG components to gas conditions in one step. There is not possible to differentiate the heating process for extraction of C_2+ components.

4 Safety considerations

An LNG installation in the scale that have been evaluated in this study will have impact on the neighbouring areas as a consequence of the stored flammable goods when installed onshore as a land terminal. In case of fire, the heat load exposed to the areas outside of the designated area could have significant impact on buildings and equipment at the neighbouring areas.

In a case where FSRU is selected and the jetty is located away from shore, the impact is limited to the jetty itself and not to the surroundings due to the distance. There is not expected any consequences on onshore buildings or equipment in this case. Normal distance for such jetty is 150 m distance from shore or more.

It is recommended that heat load analyses and QRA* is performed in the upcoming project phases. The studies must include measures to limit the heat load effect on the surroundings by different firefighting principles and heat shielding to minimise the effect on surroundings. This is applicable both for onshore LNG terminal and FSRU cases.

*A QRA is a formal and systematic approach to estimating the likelihood and consequences of hazardous events, and expressing the results quantitatively as risk to people, the environment or business. It also assesses the robustness and validity of quantitative results, by identifying critical assumptions and risk driving elements.

5 Cost estimation

5.1 CAPEX

In this chapter, there is not included any optimisation on the delivery logistic related to the delivery of LNG. We know from other projects that the logistic of LNG supply is crucial for lowering the operational costs. There are two methods of optimising the LNG chain.

- Optimise based on Lowest possible CAPEX
- Optimise based on lowest OPEX

The consequence of optimising based on OPEX could end up in larger investment in storage capacity at the LNG terminal due larger freedom of trading LNG from carriers and are not sensitive to smaller variations in delivery frequencies. As stated, this has not been evaluated at this stage, but could be included in the upcoming phases of the project when more details are available.

The cost estimation is based on sources of information from:

- EU Agency for the corporation of Energy Regulators, gas infra structure dated 20.07.2015
- Cost investigations and information collection based on available through official channels

The scope in the EU document was to prepare analysis to specify by defining minimum thresholds for the value of investment (total cost) and for selected technical specifications as well as by defining the time period under consideration, in order to improve the consistency of the data by leaving very small or very old investments out of the scope of the Report. The analysis also takes into consideration the impact of outliers, i.e. observed values of unit investment costs which are very distant from other observed values. For transmission infrastructure, data were provided on the investment cost and other necessary parameters of 293 transmission pipelines and 101 compressor stations put in service during the last 10 years (2005-2014). Similarly, data for 19 UGS and 31 LNG infrastructure projects (new facilities and expansions) commissioned over the last 15 years (2000-2014) were collected. The total value of the investment in such facilities over the reviewed period is about €32 billion, of which €15 billion in transmission pipelines, €8 billion in LNG facilities, €5 billion in UGS and €4 billion in compressor stations.

The results from costs estimated based on the EU report was validated against information official available from different operators or owners of LNG terminals. The following LNG terminals were investigated:

- Świnoujście LNG Terminal, Poland
- Gate LNG terminal, Netherland
- Dunkerque LNG terminal, France

By using the Polish Świnoujście LNG Terminal cost data and capacities fully developed to its maximum capacity with the construction of the third tank its capacity is due to expand to reach 7.5 billion m^3 per annum. The total cost of the terminal is EUR 950 million (PLN 3.5billion). The first LNG delivery to the terminal is expected on December 2015.

Reference is given to: http://www.wow.com/wiki/%C5%9Awinouj%C5%9Bcie_LNG_terminal

On Maasvlakte in Rotterdam, Gate terminal has built the first LNG import terminal in the Netherlands. The terminal has an initial throughput capacity of 12 billion m^3 per annum and will consist of three storage tanks, two jetties and a process area where the LNG will be re-gasified. Annual throughput capacity can be increased to 16 billion m3 per annum in the future.

The estimated cost in 2006 was EUR 800 million. The Gate terminal has not official noticed the final cost of the plant, but estimated by using industrial index from 2006 to 2016. The industrial index in 2006 was 808 and the index 2016 1006. This indicate an estimated cost increase of (1008-808)/808=0.25

http://www.turnerconstruction.com/content/files/ci4q2006.pdf

This indicate a final cost of the Gate import/export of EUR 800 million x1.25= EUR 1 000 million for a throughput of 12 billion m^3 per annum. Based on experience from this type of an overrun during construction is expected, but the Gate terminal has not reported any.

If an overrun of 20% is assumed the cost will be EUR 1 200 million.

LNG TERMINAL at Dunkerque

The LNG terminal at Dunkerque is a complete LNG import terminal and natural gas export provider with a storage capacity 3 x 190 000 m^3 LNG (gross volume 570 000 m^3 LNG) with a regasification capacity of 13 billion m^3 of gas, representing around 20% of France and Belgium's annual natural gas consumption.

The investment for the LNG plant is proximate 1 000 million EUR, 150 million EUR for port construction and 80 million EUR to connect the terminal to the compressor station. This indicates a total cost of 1 230 million EUR.

Reference is given to: https://www.edf.fr/en/the-edf-group/industrial-provider/production-map/dunkerque-lng-terminal/introduction

By this exercise, the following cost evaluations is prepared

- Mid-scale LNG terminal 7.5 billion m3 per annum at a cost of EUR 1000 million
- Large scale LNG terminal 12 billion m3 per annum at a cost of EUR 1300 million

None of the cost estimates includes any type of nitrogen injection systems or operational cost connected hereto to reduce the heating value to meet pipeline distribution specification. It is considered that the LNG imported to the terminals or FSRU meets the pipeline specification and other requirements.

By using the data from the EU Agency for the corporation of Energy Regulators (ACER) document the following cost estimation is prepared:

Average value 2000-2014 escalated to base year 2015			
LNG cost distribution	**Mid scale LNG terminal size 300 000 m^3**	**Large scale LNG terminal size 450 000 m^3**	**FSRU 170 000 m^3**
Storage	239	359	345
Civil works and other costs	284	426	15
Regasification	177	266	0
LNG costs not informed by cost category	168	253	14
Jetty	18	27	35
Sum	887	1 330	409
Values in Mill EUR			

Table 3, Estimated total CAPEX for mid-scale, large scale LNG terminals based on ACER report and FSRU alternative based on ship owner input.

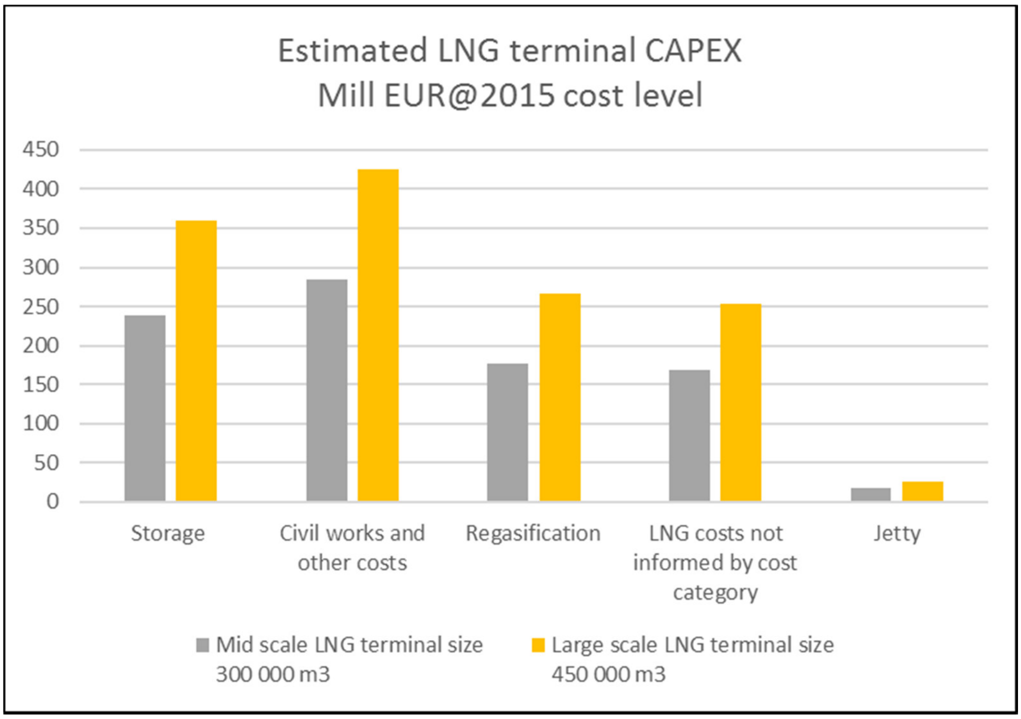

Table 4, Estimated LNG terminal CAPEX

All costs are based on 2015 price and are including escalation from relevant construction year up to 2015. Totally 9 plants are evaluated located both onshore and offshore. The tabulations in the report identify an average value and a median value for the period. As the costs are reflecting different type of onshore/offshore plants a mean value has been used for the calculation reflecting the cost of docking terminal, jetty w/equipment, un-loading arms and natural gas transfer lines. The value used in calculations are 2 955 EUR total terminal cost/m^3 LNG. The costs include complete installation, construction follow up and supervision and long lead spare parts.

The investment cost for the FSRU includes cost for an upgraded FSRU to meet the specific requirements for north-west Germany natural gas grid connections with relatively high export pressure 105-110 bar and specific berthing arrangement as described in this report.

The most use type of financing FSRU solutions based on lease and operate contract to the ship owner. This indicates that the FSRU owner takes all the risks including commercial, financially and technically responsibility up to berthing to the jetty and the infrastructure. The normal long-term charter rates in 2017 for a typical FSRU is proximately 130 000 USD per day in production. The charter rate is normally constant for the charter period. Typical variables are LNG cost as the boil of gas from the tanks are metered and used as fuel for generators and regas system (only during cold period). The cost includes all necessary manning onboard 24/7 365 days a year, operational costs, spare part, fuel consumption for regasification and maintenance, fuel cost at 7USD/MBTU and open cycle re-gasification system. This is independent of the re-gasification stream taken out. A consequence of this is that a higher re-gasification rate exported to the pipeline the lower cost per Nm^3 exported.

For the cost estimation of the FSRU alternative there is included a small-scale land based LNG terminal connected by a LNG pipeline from the FSRU for exporting LNG to trucks and to rail cars in addition to the natural gas export to pipeline. It is considered a LNG terminal based on bullet tanks of 5 x 1000 m3 each, complete with all necessary infrastructure. The cost is estimated based a green field installation:

Estimated small scale onshore LNG terminal		
	8000 m3	5000 m3
Civil works	950 000	653 125
Mechanical	1 800 000	1 237 500
LNG tanks	10 200 000	7 012 500
Piping, Piperack to FSRU	3 065 000	2 107 188
Metering, weighing	140 000	96 250
Electro instrumentation	550 000	378 125
Fire and safety	27 000	18 563
Eng. follow up, rig etc.	1 300 000	893 750
Rig & services	2 100 000	1 443 750
Sum	20 132 000	13 840 750

Values in EUR

Table 5, Estimated cost for small scale onshore LNG terminal

5.2 Operational cost, OPEX

A high-level evaluation of LNG terminal operational cost is to use a percentage of the investment cost per operating year. For LNG terminals, the percentage is in the magnitude of 4% to 7% of the total investment cost. The operating cost includes energy consumption, staffing, manning and necessary maintenance activities. The operational cost does not include financial costs on the investments.

The cost given below includes those cost elements considered relevant. Financial costs are not included. Utility costs include the cost of fuel for regasification, and are subject to change according to the number of regasification facilities in operation. The basis for the calculation is a LNG cost of 7 USD per MBTU or 23,9 USD per MWh.

As can be seen from the calculating below the heat input to the regasification process is proximate 50% of the total operation expenses over the year. This makes the operation cost substantial sensitive to LNG cost variations. If excess heat from other process industry is available this could have significant influence on the operation cost of the plant (pending on the price of the access heat available). The cost of the heat available from other nearby process industry must be competitive to the LNG alternative including necessary installation cost and availability.

	Mid scale LNG terminal MEUR/y	Large scale LNG terminal MEUR/y
Labour cost	17,6	21,1
Utility, fuel/heat cost	27,9	48,9
Repair cost	9,3	11,2
General management cost	5,7	6,8
Insurance	2,6	3,9
Sum	**63,1**	**91,9**
Operational cost per MWh	0,688	0,572
Percentage of investment cost	7,12	6,91

The above operating costs are subject to the LNG purchase contract, and are based on the assumption that the contract is to purchase LNG at the CIF price, and does not include costs related to the handling of jetty docking/undocking of LNG carriers (tug boats chartering costs, etc.). If the local Port Authority does not own enough tug boats to handle LNG carriers, and the cost of purchasing tug boats is not included.

For FSRU all operational costs, maintenance, spare parts, manning, accommodation and financial cost are included in the daily charter rate. The day rate breakdown has not been given to the study group by any of the possible ship owners.

5.2.1 Financial cost

The two concepts of LNG terminals have rather different approaches to the investment costs during the construction period.

LNG land based terminal has an average construction time of proximate 5 years. During this construction time, the complete project must be financed by the owner with loans to a certain interest rate. With an investment of 1 000 MEUR or more upfront of start of production is crucial for the economic success of the complete project.

In the case of FSRU the ship owner will carry the risk and cost during the construction time. The charter rate will start when the ship is moored to the jetty and is ready for receiving the first cargo of LNG and start degassing and exporting the natural gas to the grid. The construction time is estimated to proximate 28 months.

This study has not evaluated the differences and benefits of the different two options from a financial cost perspective. This could be subject for a follow-on study.

6 Attachments

6.1 Technical data used in the study

6.1.1 Physical data FSRU

• LNG storage capacity	170 000 m^3
• length	294 m
• Width	46.4 m
• Draft maximum	12.6 m
• Minimum clearance to sea bottom	3.0 m (due to open cycle water intake)
• Berthing and offloading side (Starboard/Backboard)	

6.1.2 Physical data LNG carrier

	Normal carrier	**Q-max LNG carrier**
• LNG storage capacity	145 000 m^3	266 000 m^3
• Length	288 m	345 m
• Width	49.0 m	53.8 m
• Draft maximum	11.7 m	12.0 m