

H2020 – GASVESSEL 723030 - WP2

MILESTONE MS1 BY CHC – PARTNER 11

- **SCENARIO DESCRIPTION AND CHARACTERIZATION;**
- **DECISION SUPPORT MODEL DEFINITION**

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1 INTRODUCTION

This is the first report for the market analysis on the 3 Geologicistic Scenarios agreed to be reviewed as per the description of the Work Package 2 of the Gasvessel Project. This report also includes the description of the decision support model that will incorporate the data collected from the Geologicistic locations and to help designing a cost competitive vessel. The report is organized as per Geologicistic Scenario investigated and the last section describes the defined Decision Support Model.

2 EAST MEDITERRANEAN GEOLOGISTICS

2.1 TARGET MARKET SCREENING METHODOLOGY

2.2 OVERVIEW

This section outlines the methodology that will be used to identify the target markets for the various scenarios in EastMed Geolocation as part of the Gasvessel project.

2.3 OBJECTIVES

The objective of the target market methodology is to identify and propose potential markets in Eastern Mediterranean for the CNG Gasvessel project. The methodology takes into account key filtering parameters across the value chain of supply and delivery aiming to propose attractive markets for further techno-economic evaluation. A simplified description of the logic is described in the diagram below, however details for each parameter are presented in the following sections.

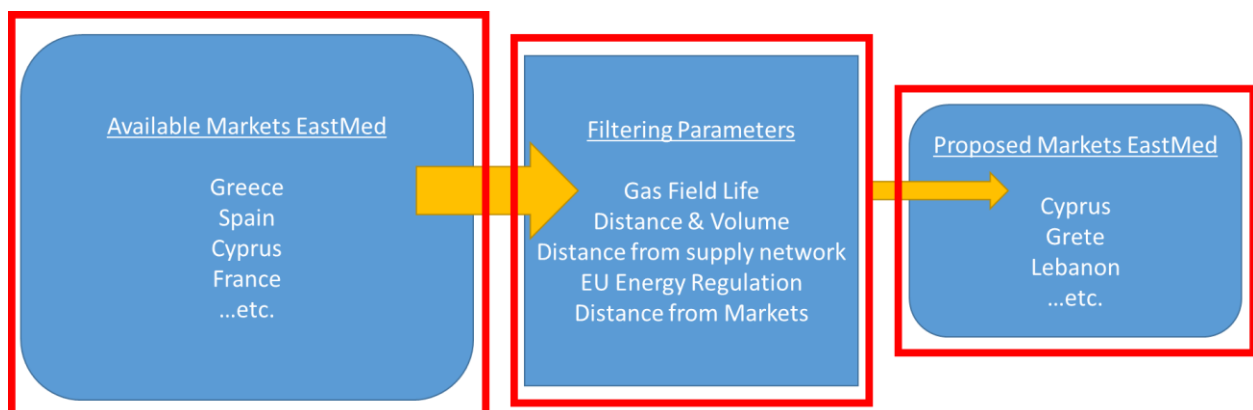


Figure 1. Schematic representation of screening methodology

2.4 TARGET MARKET METHODOLOGY

2.5 INPUTS

The following will need to be defined ahead of starting the generation of filtering the available markets to identify potential targets.

2.5.1 RESOURCE DESCRIPTION

A description of a potential hydrocarbon accumulation, including the following as a minimum:

- Location
- Amount of hydrocarbons that may be expected to be produced

2.5.2 DEMAND PROFILE OF POTENTIAL MARKETS

A demand profile will be required in order to ensure that the required infrastructure is appropriately sized for the required flowrates. This demand profile should include the following:

- Demand rate in mmscfd and in mscmd on an average annual basis
- Delivery location

We use the available information to calculate the demand in gas mmscfd today (2017), and project volumes in 2030 while having a view until 2040. Filtering criteria will be based on the projections of the year 2030, which we assume is the year of the CNG vessel production.

2.5.3 OTHER ASSUMPTIONS

Other assumptions made regarding the screening exercise include the following:

- One offshore gas loading location located offshore Cyprus in Block 4 with three potential field sizes of 1, 2 and 4 TCF of gas in place.
- One onshore gas loading location located onshore Cyprus at Vasilikos Energy Port, Cyprus.
- Power plant efficiency is assumed to be 50% for gas turbines and 40% for fuel oil engines, unless specific information is available for the power plants in question.
- The annual load factor for each power plant is assumed to be 30% on capacity throughout the year, unless specific information is available for the power plant in question.

2.5.4 FILTERING CRITERIA

The below criteria will be used to carry out a first-pass assessment of potential markets that will form part of an initial set of monetization scenarios for this study

2.6 VOLUME & DISTANCE PROFILES FOR CNG TECHNOLOGY

The below diagram was created by SeaNG, and illustrates the gas production rates and distances where CNG technology may theoretically have a competitive advantage against conventional technology such as pipelines and LNG. The Gasvessel partners do not have quantitative or qualitative information to confirm the validity of this diagram, however, based on the fact that similar diagrams have been generated by other proponents of Marine CNG technology, it will be used to filter out target markets that:

- Have a gas demand below 50 mmscfd or above 550 mmscfd
- Are a distance that is below 200 km or above 1750 km from the loading locations.

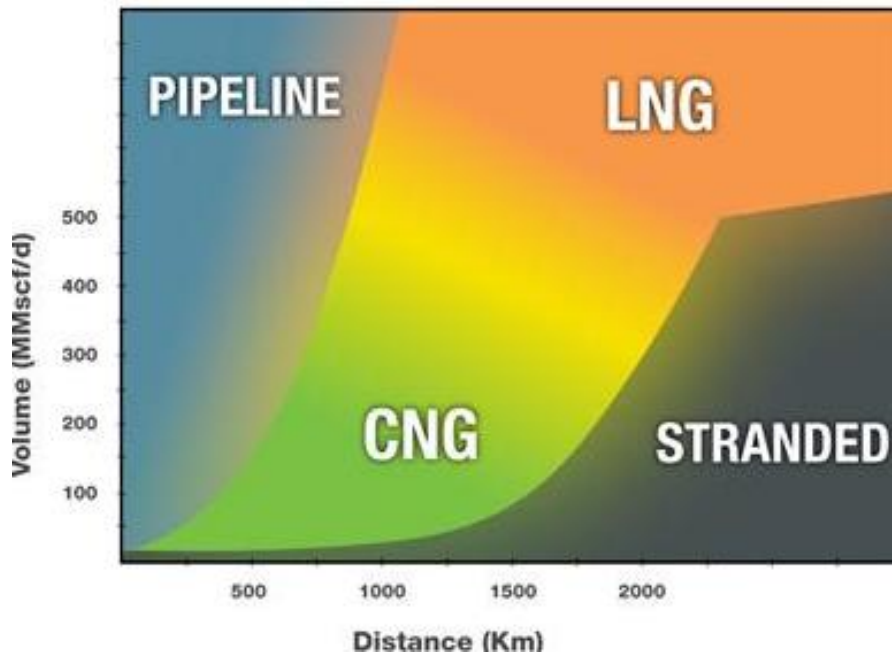


Figure 2. Marine Gas Transportation Market by SeaNG

2.7 GASVESSEL SIZING

Based on simulation data provided by Navalprogetti as part of the original Horizon 2020 proposal, there appears to be a range of gas flow rates for which the Gasvessel sizing results in favorable economics. The screening methodology will take into account whether the target market's demand and distance from the loading points are approximately similar to those presented in the previous Navalprogetti analyses.

Distance: 900 nm
Loading rate: 247.5 mmscf/d (7 mm scm/d)
Unloading rate: 247.5 mmscf/d (7 mm scm/d)

Results:

Pressure vessels diameter : 3.0 m
Optimal vessel speed: 18 kn
Optimal vessel size: 500 mmscf
Estimated tariff: 2.95 US\$/mmscf

The above results refer to a single vessel simulation, the values shall vary due to the fleet composition and possible presence of a storage.

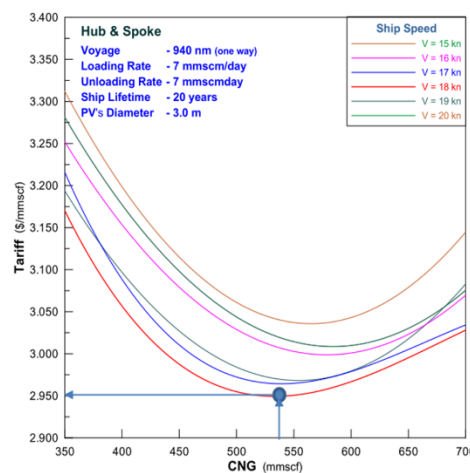


Figure 3. Optimum Gasvessel size for specific case study. Work by Navalprogetti.

2.8 MARKET ISOLATION

The current energy supply system in mainland Europe consists of a mature energy production and supply network, which allows gas to be procured at low gas prices due to deregulated access to existing infrastructure, sufficient distribution channels from the gas transmission lines and access to affordable gas

from both pipelines and LNG regasification terminals. Furthermore, European regulations that promote sustainable development support the investment in renewables and efficient utilization of energy thus energy in Europe is a dynamic system with many variables to consider. On the other hand, the Gasvessel concept supports European efforts in promoting green energy and the investment in low carbon fuels such as the use of natural gas over the use of liquid fuels. In addition, Gasvessel can be considered as an additional transport of energy thus enhancing Europe's energy security of supply.

Based on the above, CHC believes that for East Mediterranean geo-logistic scenario the Gasvessel concept is more likely to generate interest from gas buyers if isolated markets are targeted and/or buyers that have motives to switch to natural gas usage. For example, these buyers might be Power Plants, isolated from the gas network that run today with coal or diesel.

For this study we will consider a market as isolated if the distance from the main gas transmission line is over 100 km offshore and over 200 km onshore. These distances are generic and based on market research for various energy consumers at East Mediterranean.

Furthermore, the market analysis will focus only on potential gas buyers that operate near shore to allow direct access to the vessel without major infrastructure investments.

2.9 GAS FIELD LIFE

In this project the potential gas accumulations in Eastern Mediterranean are located offshore Cyprus, and are expected to be developed under the same production sharing contract (PSC) regime which is currently being implemented in licensed blocks the Cyprus EEZ. The model PSC contracts issued thus far by the Cypriot government indicate that an exploitation license is granted for up to 25 years. This number will be used in order to calculate minimum production thresholds per field, in order to filter out markets that are too small to enable gas recovery before an exploitation license expires. The diagram below shows the proposed gas field in terms of production rates and years of production per size of field in gas volume. In summary:

Offshore location:

- 28.3 bscm (1TCF) → potential markets higher than app. 2830 Msmd (100 mmscfd)
- 56.6 bscm (2 TCF) → potential markets higher than app. 220 mmscfd
- 113 bscm (4 TCF) → potential markets higher than app. 425 mmscfd

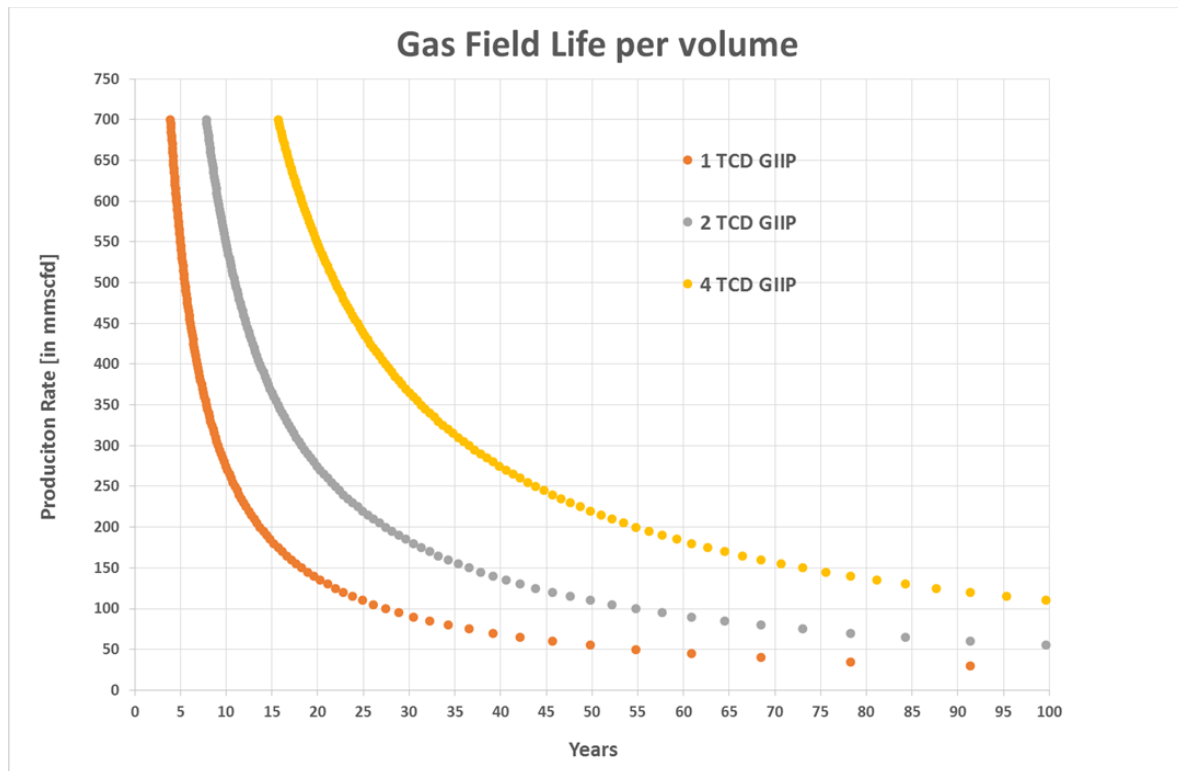


Figure 4. Gas Field life estimations based on three volume scenarios

2.10 COST ESTIMATING METHODOLOGY

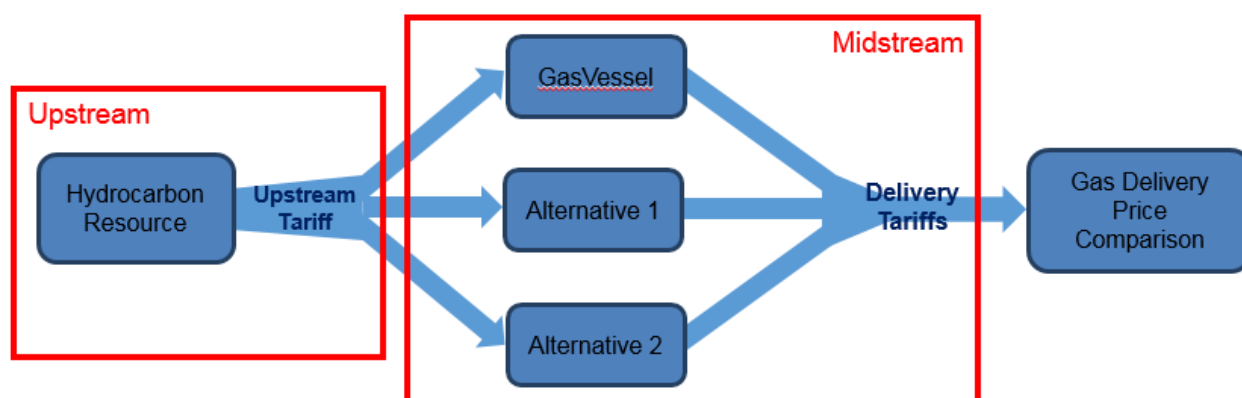
2.10.1 OVERVIEW

This document outlines the methodology that will be used to develop cost estimates and tariffs for the various scenarios for delivery of gas to identified markets as part of the Gasvessel project. In particular, this methodology applies to the activities included in Work Plan 2 (WP2).

2.10.2 OBJECTIVES

The overall objective of the work in WP2 is to develop end-to-end estimates for the delivery of gas from the identified source locations to the identified markets, for both the Gasvessel concept and for competing options.

This requires the development of cost estimates through the gas delivery chain, using consistent input assumptions, use of tools, and clarity of battery limits between each package and contributor. The flow chart below illustrates this logic



2.10.3 INPUTS

The following will need to be defined ahead of starting the generation of cost estimates for the various options.

2.10.4 RESOURCE DESCRIPTION

A description of the hydrocarbon reserves, including:

- Location
- Resource estimates (Gas Initially In Place)
- Gas composition
- Reservoir Temperature and Pressure
- Metocean data (wave, current, temperature)

2.10.5 DEMAND PROFILE

A demand profile will be required in order to ensure that the required infrastructure is appropriately sized for the required flowrates. This demand profile should include the following:

- Demand rate in mmscfd, on an average annual basis
- Gas Specification (Composition, temperature, pressure)
- Delivery location & existing infrastructure
- Taxes and/or royalty fees will not be incorporated in any cash flow calculations

2.10.6 OTHER ASSUMPTIONS

Other assumptions made regarding the cost estimation exercise include the following:

- Cost escalation at 2% per annum (OPEX and CAPEX)
- No tariff escalators, unless linked to underlying commodities prices
- No Decommissioning costs included

2.10.7 'UPSTREAM' COST ESTIMATING

Costs of delivering gas to the GasVessel will be calculated in USD. The following table summarizes the potential components of an upstream cost estimate, the estimating tools to be used, and the key assumptions made in generating the estimate.

Parameter	Estimate made using:	Notes / Assumptions
Drilling	Que\$tor	Assume N+1 wells are required Maximum well productivity of 150mmscfd
Subsea	Que\$tor	
Pipelines	Que\$tor	
Floating Production Unit	Que\$tor	Moored Units assumed Non-Leased Construction in Asian shipyard
Onshore Reception/Processing	Que\$tor	Land acquisition costs will not be included Onshore license will be available to CHC in late August
OPEX	Que\$tor	OPEX costs will not include any 'overhead' costs associated with the upstream entity

An exception to the above will be the Black Sea scenarios, where the upstream costs will be developed by VGT, and a gas tariff for a delivery point on the Georgian shore of the Black Sea will be provided.

2.10.8 CNG DELIVERY COST ESTIMATING

Parameter	Estimate made using	Notes
Risers	Navalprogetti to Advise	
Compression		
Offshore Floating Storage		
Onshore Storage		
Loading/Offloading Arms		
SAL/STL Systems		
Gas Storage system		
CNG Ship		
OPEX		

2.10.9 ALTERNATIVES COST ESTIMATING

Costs of delivering the gas to an identified market via alternative methods to the GasVessel will be calculated in USD. The following table summarises the potential components of such a 'midstream' cost estimate, the estimating tools to be used, and the key assumptions made in generating the estimate.

Parameter	Estimate made using	Notes
Pipelines	Que\$tor	
FLNG	Excel Based Tool	Existing/proposed FLNG units to be used to derive a \$/throughput metric
Regasification Units	Excel Based Tool	Excel tool to be built, calculating (F)SRU CAPEX based on throughput size
OPEX	Que\$tor, Excel	OPEX costs will not include any 'overhead' costs associated with the midstream entity

2.10.10 OTHER COSTS

Given the early stages of the project, is important to account for uncertainties and hidden costs in the estimate. The following is a summary of what additional costs should be considered in the cost estimates, for both 'upstream' and 'midstream' elements.

Parameter	Estimate made using	Notes
Contingency	30% of underlying base costs	Considered appropriate for concept selection level costs
Project Management	15% of underlying base cost	Includes Certification and Insurance. In line with typical oil and gas industry experience
Engineering and Design	5% of underlying base cost	

2.10.11 TARIFF CALCULATIONS

In order to calculate the tariff at each point of the value chain, the following need to be taken into account:

2.10.12 EXPENDITURE PROFILES

Capital and operational expenditure estimates for the all components of the development scenarios need to be calculated on a year by year basis, in order to allow for cash flows to be subsequently calculated when ma to be developed for the entirety of the project.

2.10.13 PAYBACK TIME

It is assumed that any investment in the Gasvessel project will require payback after 25 years.

2.10.14 EXPECTED RATE OF RETURN

The internal rate of return required for a capital investment will be dependent on the level of risk associated with the endeavor. IT is generally accepted that 'upstream' projects require a higher level of return than 'infrastructure' projects, because of the risks associated with the subsurface, and due to the expected steady return of an infrastructure investment. Thus, the following IRR assumptions are proposed:

- 'Upstream' IRR = 15%
- 'Midstream' IRR = 10%

2.11 DESCRIPTION OF GAS LOADING LOCATIONS

2.11.1 OVERVIEW

This document outlines the locations proposed by CHC as part of the Gasvessel project for monetization of potential offshore gas discoveries in the Eastern Mediterranean within the Cyprus EEZ.

2.11.2 OBJECTIVES

The objective of this report is to provide all the necessary information related to the gas loading locations that will help the Gasvessel partners to evaluate the design of the vessel, and the process of gas loading including logistics of delivery gas volumes to the gas unloading locations.

2.11.3 PROPOSED GAS LOADING SITES

CHC proposes two gas-loading sites for the Eastern Mediterranean geo-logistic scenarios, which includes onshore and offshore options. The offshore loading site is located within existing unlicensed blocks of exploration interest within Cyprus Exclusive Economic Zone, and the onshore gas loading site is located at Cyprus' proposed energy hub in the Vasilikos area. For the offshore loading site CHC will investigate the development of three production profiles based on 1, 2 & 4 TCF of gas in place. The onshore loading site is proposed when investigating the concept of transporting gas with an offshore pipeline from the offshore gas location to Cyprus to use the gas for domestic use and/or export by loading gas to the Gasvessel. The exact locations and description of the sites is part of A3 task of CHC internal WP2. Below a diagram, showing a map with the two gas loading locations as discussed above.



Figure 1. The offshore and onshore gas-loading locations proposed for Eastern Mediterranean Scenario

2.11.4 OFFSHORE SITE

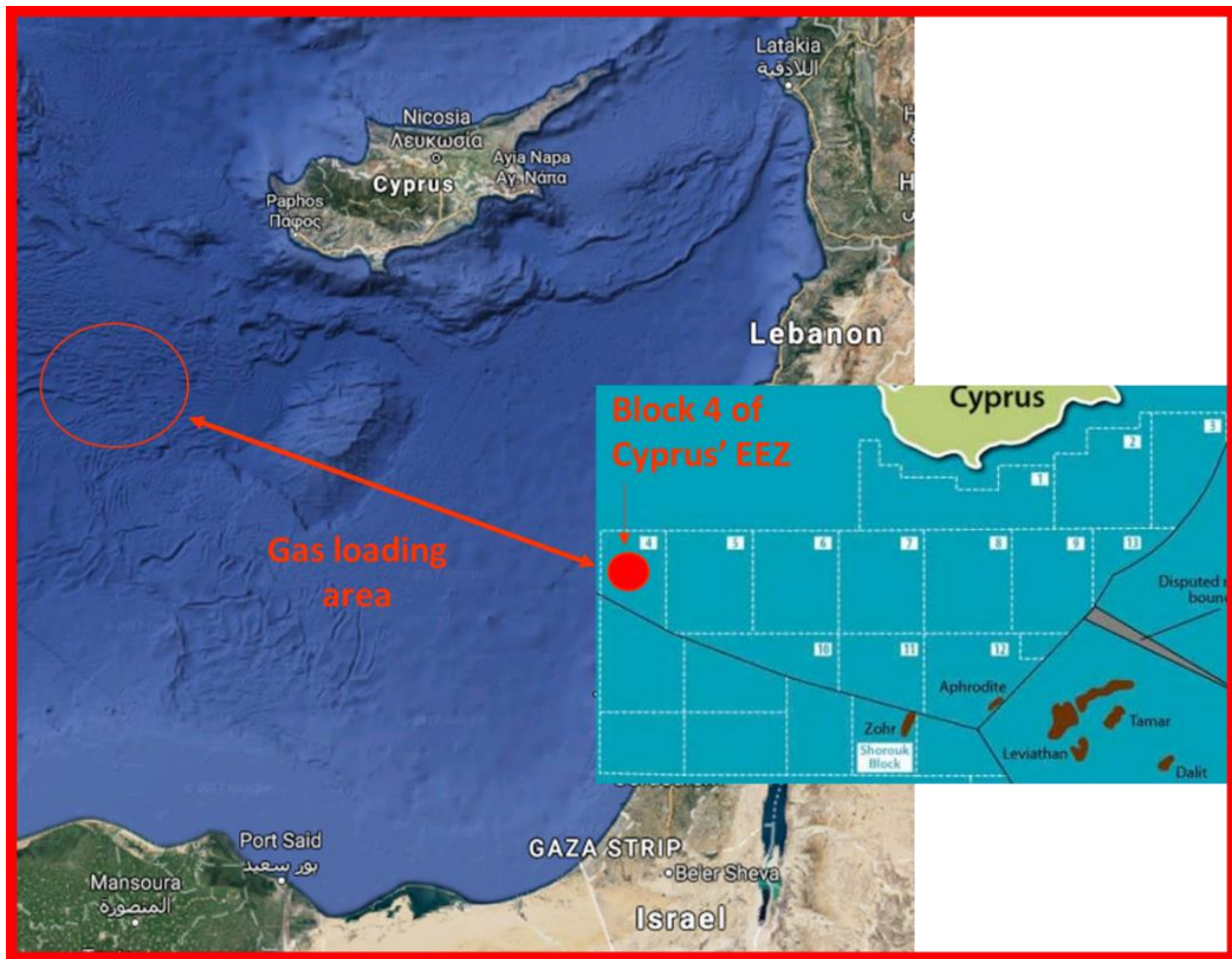


Figure 2. The offshore gas-loading locations and offshore Cyprus' offshore blocks

2.11.5 GAS LOADING LOCATION CHARACTERISTICS

The offshore gas-loading site is located at offshore Block 4 of Cyprus EEZ with coordinates 33.99 latitude. and 30.21 longitude. It is estimated to be 298 km (on a straight line) from Vasilikos proposed energy port at the Vasilikos Bay, which is proposed here as the onshore gas loading site. The depth at the specific location is estimated to be 2800 m with the soil at the seabed to be of extremely low and low strength clay within the top meter. In addition, below, the shallow sediments are expected to compromise clay.

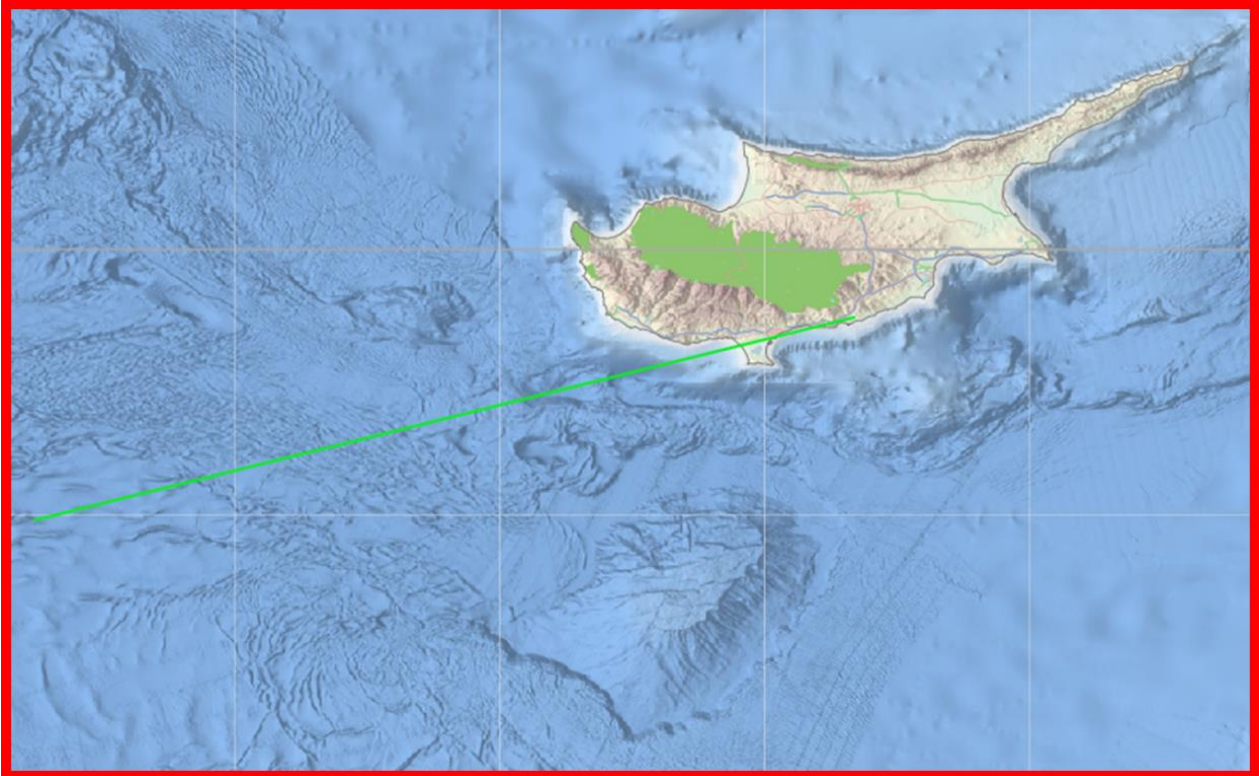


Figure 3. Distance of the offshore gas-loading locations and proposed Vasilikos Energy Port (straight line)

2.11.6 GAS COMPOSITION

The gas is characterized as very lean, consisting of app. 97-99% methane and of biogenic origin. Water saturated with no H₂S, no CO₂, no mercury. The condensates part of the gas stream is characterized with API 30° with CGR assumed at 1.9 bbl/MMscf. It is assumed that gas processing will be included as part of the development of the proposed gas field thus the Gasvessel will receive gas without the need of removing any condensates or any other components from the gas stream.

2.11.7 RESERVOIR CHARACTERISTICS

The reservoir depth is about 4800 meters from seabed and the size extends to about 5 km x 20 km of area. Pressure of the reservoir at 522 bar and temperature at 70°C. It is assumed here that the reservoir pressure and temperature will be reduced to the operating pressure and temperature of the offshore processing floating facility. The Gasvessel will receive the gas from an offshore CNG storage facility at a pressure and temperature similar to the pressure and temperature of the GasVessel specifications.

2.11.8 METOCEAN CONDITIONS

The Metocean conditions at the offshore gas loading site are more relevant for Block 12 of Cyprus EEZ and mainly for the area of Leviathan between Cyprus-Egypt-Israel, a location mainly East South of Cyprus. However, due to lack of information at Block 4 of Cyprus EEZ, CHC assumes for the Gasvessel project the same Metocean conditions. Please refer to figure 1 for the areas mentioned.

Extreme Conditions based on 10000 years

- Significant wave height, $H_s = 11\text{m}$
- Peak wave period, $T_p = 16\text{sec}$
- 1-hour wind speed = 30 m/s
- Associated current = 1.5. m/sec (surface)

Years	1	10	100	10000
Significant wave height (m)	4.8	6.5	8.5	11
Surface current (m/s)			1.2	1.5
WIND (m/s)	18	22.5	27	31

Operating Conditions

- Wind predominantly from the west avg. wind speed 5 m/s
- Waves predominantly due east (as wind is from the west) with 95% exceedance value for significant wave height is 1.5m
- Near surface current is predominantly west south west with mean current speed up to 0.25 m/s

Table 1. Significant wave heights and their frequency of occurrence in the Levantine Basin during the period from July 2005 to February 2008.

Wave Height Range ¹ (m)	Frequency (Occurrences Over Period of Record)	Percentage
0 to 0.2500	91	1.5230
0.5000	1,132	18.9456
0.7500	2,183	36.5356
1.0000	1,388	23.2301
1.2500	565	9.4561
1.5000	261	4.3682
1.7500	140	2.3431
2.0000	69	1.1548
2.2500	52	0.8703
2.5000	21	0.3515
2.7500	14	0.2343
3.0000	10	0.1674
3.2500	11	0.1841
3.5000	4	0.0669
3.7500	7	0.1172
4.0000	11	0.1841
4.2500	9	0.1506
4.5000	6	0.1004
4.7500	1	0.0167
Total	5,975	100%

¹ Upper limit of bin.

Figure 4: Significant wave height and their frequency during 2005-2008

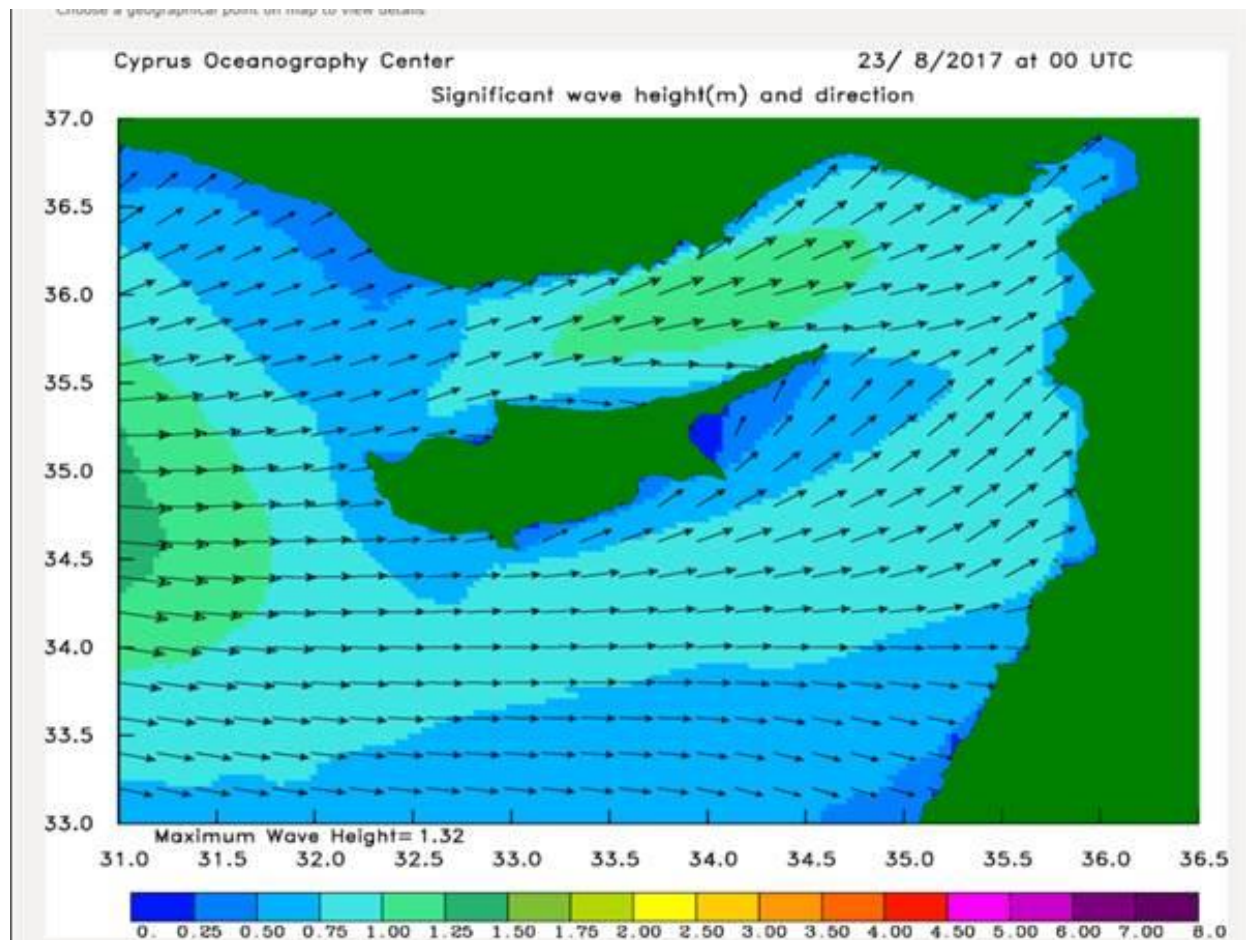


Figure 5. From Cyprus Oceanography Centre for wave direction. Similar direction for wind.

2.11.9 PROPOSED ONSHORE LOADING CONCEPTS



Figure 6. Onshore gas loading location of the proposed 'Vasilikos energy port' at Vasilikos Bay

2.11.10 GAS LOADING LOCATION CHARACTERISTICS

The onshore gas loading site is located at the proposed 'Vasilikos energy port' at Vasilikos bay, Cyprus with coordinates 34.73 latitude and 33.29 longitude. The location at Vasilikos bay provides a natural shelter for the marine industry. Vasilikos power plant is also located at the coast of the specific bay and in addition, at the area exists today a jetty owned by VTTI Vasilikos that operates for mooring ships and transport liquid fuels and store these products onshore on behalf of the company. At the same area exist several small ports that serve the local industry. The area between Vasilikos power plant and Zygi village along the coastline is planned for becoming an energy port for Cyprus thus facilitating several proposed projects such as onshore LNG, FSRU, etc. The figure below from google earth shows the details at Vasilikos area with the existing infrastructure. Figure 8 shows a technical drawing of Vasilikos power plant layout, which is located very near to the coordinates we have proposed for the onshore gas-loading site.

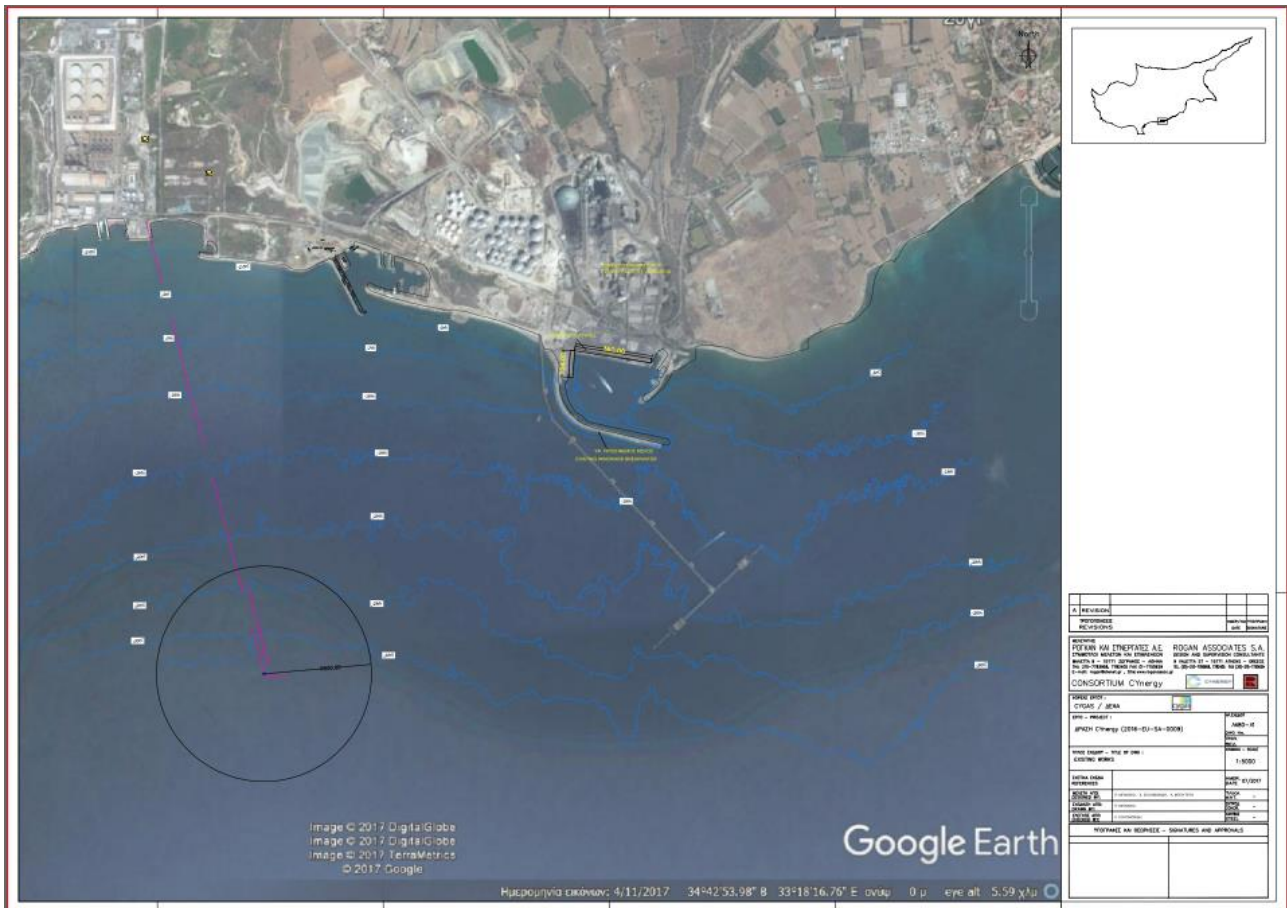


Figure 7. Photo showing part of Vasilikos bay with Vasilikos power plant on the left site and in the middle to right site the existing VTTI Jetty and its onshore storage tanks.

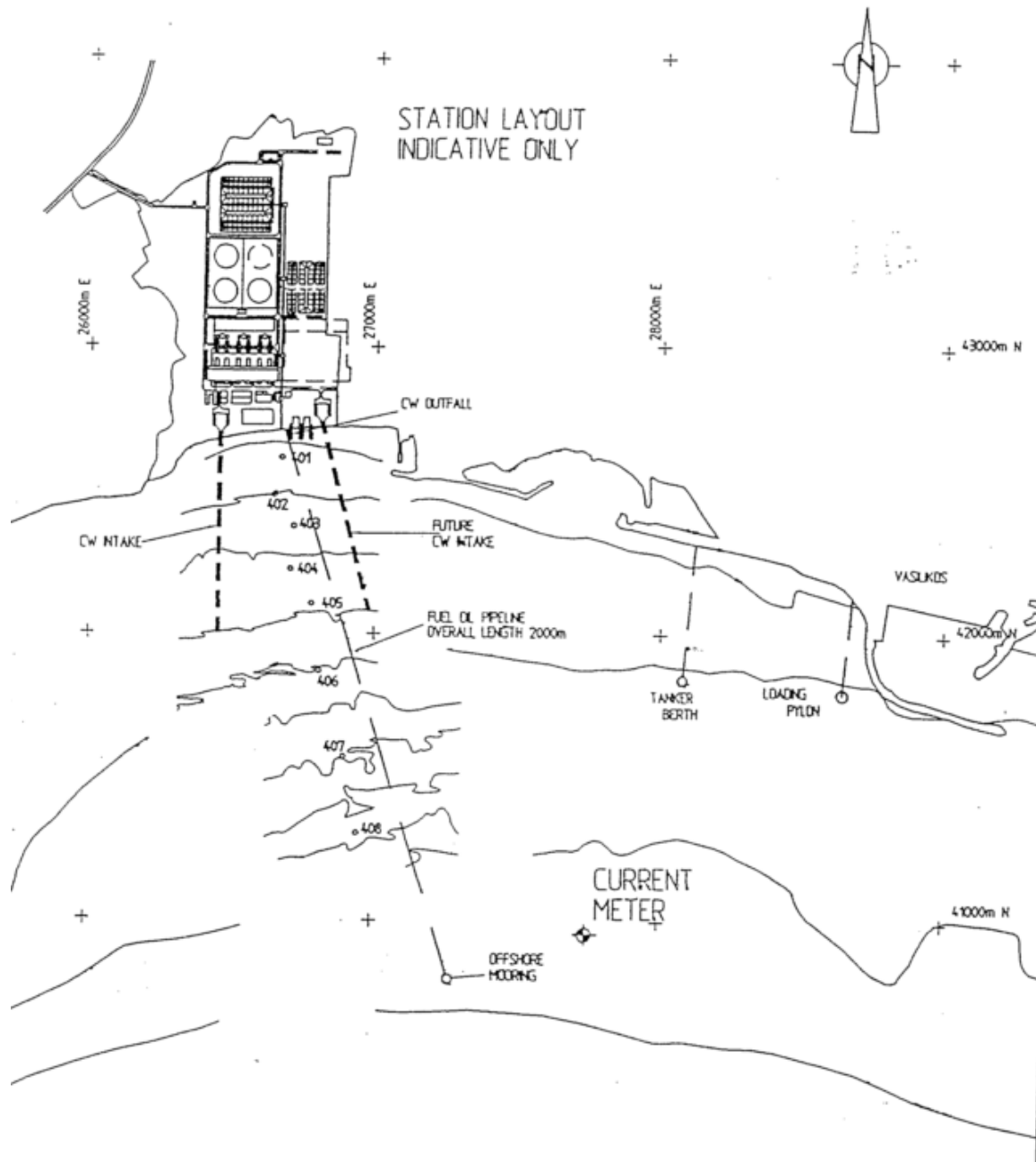


Figure 8. Layout of Vasilikos power plant near the proposed gas unloading and gas loading locations.

2.11.11 GAS COMPOSITION

Gas will be processed at similar specification as in the case of the offshore gas loading location.

2.11.12 METOCEAN CONDITIONS

Extreme conditions:

Winds profile

- The values for return periods of 1, 5, 10, 25 and 50 years computed assuming a storm duration of 6 hours are given below.

Direction (°N)	Return period (years)				
	1	5	10	25	50
-15.: 15.	13.8	17.8	19.5	21.7	23.4
15.: 45.	14.7	18.2	19.6	21.5	22.9
45.: 75.	14.4	17.7	19.1	20.8	22.2
75.: 105.	14.5	17.9	19.3	21.1	22.4
105.: 135.	13.3	17.5	19.3	21.7	23.5
135.: 165.	12.7	16.4	18.0	20.1	21.6
165.: 195.	13.9	18.2	20.0	22.3	24.0
195.: 225.	16.5	20.6	22.3	24.4	26.0
225.: 255.	19.6	24.1	26.0	28.4	30.3
255.: 285.	19.0	22.9	24.7	26.9	28.7
285.: 315.	16.8	20.1	21.4	23.2	24.5
315.: 345.	16.7	20.4	22.0	24.0	25.6
Total	22.0	25.6	27.1	29.1	30.5

Table 3.4 Extreme wind speeds for each directional sector predicted from ship observations (in m/s)

Figure 9. Table is from a Metocean observation study at the area; however, it is not clear if this is applied for near shore Vasilikos Bay or open sea near Vasilikos Bay.

Wave profile

- Extreme waver heights were computed for return periods of 1, 5, 10, 25 and 50 years found in the table below.
- Most extreme conditions coming from southwestern directions. These conditions may be associated with storm depressions travelling east in the northern half of the Mediterranean causing western and southwestern winds at the south coast of Cyprus.
- We expect that in shallow water near the project site the extreme wave heights will be considerably lower to limitation of the wave height by the local depth.
- Extreme wave conditions in deep water near Zygi in the sector 75-255°C for various return periods are given in the table below. These extremes are mainly determined by the sector 195-255 °C. In the other sectors, the extreme wave heights are lower. It should be noted that near the port site the extreme wave conditions might be lower due to shallow water effects like refraction and breaking.

Return period (Years)	1	5	10	25	50
Significant wave height (m)	3.2	4	4.3	4.8	5.2

Operating conditions:

Winds profile

- The highest wind speeds in the northern sector will generally be lower at the coast than on open sea due to the sheltering effect of the mountain range close to the coast.

Nearshore Current Speed

- At 20 m depth (nearshore), near surface mean current speed about 0.1 m/s.

**TABLE 1 : Frequency table of current velocity and current direction -
Number of observations**

Current Direction (deg)	Current velocity (cm/sec)								Total
	0-5	5-10	10-15	15-20	20-25	25-30	30-35	35-40	
0-30	1037	356	37	2					1432
30-60	1744	1259	390	108	9	5	3		13518
60-90	1796	3532	2460	1385	426	107	15	6	9727
90-120	1256	1809	561	132	31				3789
120-150	583	735	144	21					1483
150-180	444	411	17	2					874
180-210	466	290	8						764
210-240	656	556	57	14	1	1			1285
240-270	1446	1894	816	351	152	52	20	7	4738
270-300	2343	3913	2092	744	379	133	45	5	9654
300-330	1859	1250	194	8	3				3314
330-360	1074	361	12			1			1448
Total	14704	16366	6788	2767	1001	299	83	18	42026

Notes

- (1) Current meter located at Lapertas Fish Farm in Vasilikos Bay; 34°42'.60N, 33°18'.16E.
- (2) Water depth 24 m, instrument 7 m below surface.
- (3) Record period 26/11/93 to 25/10/94.
- (4) Record interval 10 minutes.
- (5) Current direction is the direction towards which the current flows, measured in degrees from magnetic north.

Figure 10. Table is from a Metocean observation study at a fish farm near the area.

Waves Profile

- The nearshore (at Zygi area near Vasilikos) wave climate is considered representative for a water depth larger than about 20 m. In more shallow water the waves are further modified by bottom effects like refraction, bottom friction and surf breaking.
- The longer wave periods are mostly from southern to southeaster directions.

- Waves predominantly come from west with 95% exceedance value for wave height is 1.5m. Below the relevant measurements.
- In deep water near Zygi the sea is calm ($H_s < 0.25$ m) for near 50% of time, waves with a significant wave height over 2 m occur about 1% of time (3.5 days per year) and are almost frequent in the sector 195-25°C N.

Observed Wave Height (m)	Wave Direction (deg.N)												Total
	-15.: 15.	15.: 45.	45.: 75.	75.: 105.	105.: 135.	135.: 165.	165.: 195.	195.: 225.	225.: 255.	255.: 285.	285.: 315.	315.: 345.	
< .25	3.19	2.30	2.97	2.78	.88	.60	1.11	2.09	9.65	8.30	6.78	5.99	46.65
.25: .75	.29	.51	2.25	3.75	1.08	1.05	1.00	3.49	15.03	5.97	2.32	.58	37.32
.75: 1.25	.	.	.18	1.86	.61	.69	.76	1.95	5.15	.28	.06	.	11.54
1.25: 1.75	.	.	.02	.48	.27	.21	.12	.80	1.13	.	.	.	3.03
1.75: 2.25	.	.	.	.17	.10	.03	.11	.31	.27	.	.	.	.99
2.25: 2.75	.	.	.	.04	.03	.04	.03	.15	.06	.	.	.	.36
2.75: 3.25	.	.	.	.01	.	.	.01	.04	.01	.	.	.	.08
3.25: 3.75	.	.	.	.	.	.	.01	.	.	.	.	.	.02
3.75: 4.25	.	.	.	.	.	.	.	.01	.	.	.	.	.01
4.25: 4.75	.	.	.	.	.	.	.	.	.	.	.	.	.01
4.75: 5.75	.	.	.	.	.	.	.	.01	.	.	.	.	.01
5.75: 6.75	.	.	.	.	.	.	.	.01	.	.	.	.	.01
6.75: 7.75	.	.	.	.	.	.	.	.	.	.	.	.	.
7.75: 8.75	.	.	.	.	.	.	.	.	.	.	.	.	.
8.75: 9.75	.	.	.	.	.	.	.	.	.	.	.	.	.
9.75: 10.75	.	.	.	.	.	.	.	.	.	.	.	.	.
10.75: 12.75	.	.	.	.	.	.	.	.	.	.	.	.	.
12.75: 14.75	.	.	.	.	.	.	.	.	.	.	.	.	.
> 14.75	.	.	.	.	.	.	.	.	.	.	.	.	.
Total	3.48	2.81	5.41	9.09	2.96	2.62	3.16	8.87	31.32	14.56	9.16	6.58	100.00

Figure 11.5 Probability that sea waves occur in the given height and direction class in deep water near Zygi during the whole year (12,632 obs.)

Figure 11. Table is from a Metocean observation study near Zygi area.

2.12 PROPOSED TARGET MARKET AT MEDITERRANEAN

2.12.1 OVERVIEW

This document outlines the results of the first phase of the marketing analysis of the Mediterranean geologic scenario for the Gasvessel concept based on the target market screening methodology presented in a previous report.

2.12.2 OBJECTIVES

The objective of this report is to present the commercial and technical characteristics for the markets in Mediterranean collected during the marketing review for the area and using the target market screening methodology to identify the gas buyers suitable for the Gasvessel project. In addition, the proposed gas buyers will be analyzed further during the second phase of the marking analysis.

The second phase of the market analysis will focus on the identified gas markets and analyses in greater depth market characteristics such as supply/demand, pricing, regulations, infrastructure and market players.

2.12.3 MARKETS IN EAST MEDITERRANEAN

Market research for East Mediterranean geo-logistic scenario is divided into two phases. During the first phase CHC uses the target market screening methodology explained in a previous report to identify the most potential gas buyers in the area.

To identify which of the Mediterranean countries gather more potential to become targets for the Gasvessel project, CHC had an overview of the countries' power generation by gas and liquid fuel. The countries included were Cyprus, Greece, Italy, French Islands, Egypt and Lebanon. France mainland, Spain and Portugal, Morocco, Algeria, Tunisia and Libya were not included in the investigation because they were considered to be outside the distances for the Gasvessel technology having in mind that the loading sites are at the eastern site of the Mediterranean Sea. In addition, based on World Energy Council on world energy resources 2016 Tunisia and Libya are gas exporters and for this reason it is unlikely to be considered targets for Gasvessel.

To conclude, the first phase of the marketing analysis is based mostly on the energy consumed by power plants and it is assumed that targeted gas buyers are either the power plants or a wholesale gas distribution entities that re-sell gas to the power plants. CHC has used the Global Energy Observatory to mark the location and capacity characteristics of each power plant in the region and following the target screening methodology we have filtered out all the plants that are not located nearshore and not considered to be isolated markets. CHC also used data from several sources including The South East Europe Energy Outlook 2016/2017. This report present the analysis of the results and the recommendations by CHC for the primary targets for the Gasvessel project. As mentioned in the first paragraph, during the second phase of the marketing analysis CHC will focus on the proposed market areas and try to identify other gas potential buyers in each country investigated including household users or industrial users including fertilizer plants, cement plants, etc. thus open the market for the Gasvessel project.

2.12.4 CYPRUS

Cyprus has three power stations, however only 'Vasilikos' and 'Dhekelia' can operate today using gas feedstock. Furthermore, future increase in electricity demand in Cyprus can be covered with the addition of a third gas turbine at Vasilikos however, nothing is yet confirmed. The smaller power plants of 'Moni' may operate at a standby mode thus enhancing island's energy supply security by providing options in electricity production and/or fuel source diversification. Figure 1 show the location of the existing power plants.



Figure 1: Cyprus' Selected Power Plants

Table 1, 2 and 3 summarize the technical characteristics for each Power Plants and also provide other information such as the location of the power plant and distances from the gas loading locations.

Table 1: Moni Power Station Cyprus

Country	Cyprus
Mainland/Island	Island
Target Buyer	- Moni Power Station Cyprus Heavy Fuel Oil (HFO) - Design Capacity of 140 MWe - Existing turbines can not operate on gas
Location	- Location Coordinates: Latitude = 34.71056 / Longitude = 33.1825 - Description of the location: near shore, no gas pipeline network, no nearby port
Volume of gas based on 100 % gas conversion of the capacity	140 MWe = 3369 MWh/d = 11.464 mmscf/d = 324 mscm/d
Volume of gas using the 30% loading factor	= 8.60 mmscf/d

*Assuming diesel turbines 40% efficiency	= 242.92 mscm/d
Distance from gas loading locations (km) http://andrew.hedges.name/experiments/haversine/	1. Offshore location: 284.453 2. Vasilikos Port: 10.031 (onshore)

Table 2: Vasilikos Power Plant Cyprus

Country	Cyprus
Mainland/Island	Island
Target Buyer	Vasilikos Power Plant Cyprus Heavy Fuel Oil (HFO) Design Capacity of 868 MWe Possibility for Natural Gas Conversion
Location	- Location Coordinates: Latitude = 34.7286 Longitude = Ωασιλικός 3.29 - Description of the location: near shore no gas pipeline network nearby port
Volume of gas based on 100 % gas conversion of the capacity	868 MWe = 20832 MWh/d = 71.079 mmscf/d = 2008 mscm/d
Volume of gas using the 30% loading factor *Assuming gas turbines 50% efficiency	= 42.65 mmscf/d = 1204.88 mscm/d
Distance from gas loading locations (km)	1. Offshore location: 294.462 2. Vasilikos Port: -

Table 3: Dhekelia Power Plant Cyprus

Country	Cyprus
Mainland/Island	Island
Target Buyer	Dhekelia Power Plant Cyprus Heavy Fuel Oil (HFO) Design Capacity of 460 MWe Possibility for Natural Gas Conversion
Location	- Location Coordinates: Latitude = 34.98093 / Longitude = 33.74385 - Description of the location: near shore no gas pipeline network nearby port
Volume of gas based on 100 % gas conversion of the capacity	460 MWe = 11040 MWh/d = 37.668 mmscf/d = 1064 mscm/d
Volume of gas using the 30% loading factor *Assuming diesel turbines 40% efficiency	= 28.25 mmscf/d = 798.16 mscm/d
Distance from gas loading locations (km)	1. Offshore location: 342.171 2. Vasilikos Port: 50.038 (onshore)

The graph in the figure 2 shows the Cypriot power plants characteristics against the target market screening criteria. The y-axis represent the distance of the power plants in Cyprus from the closest European transmission line (in Greece) and the x-axis the mean average distance from the onshore and offshore gas loading sites. The bubble sizes represent the demand in mmscfd for each power plant based on the plants' capacities after assuming energy efficiency of 50% for gas turbines and 40% for diesel turbines while assuming also 30 % usage of power plants' capacities in a year. The 30% assumption is based on the ratio between total installed capacity and the actual demand in power in a year based on publicly available date of EAC website. The low load factor is something common at East-Mediterranean countries, especially at islands where demand in electricity is characterized by large demand swings because of seasonality between winter and summer months. Furthermore, the blue arrows show the distance battery limits based on the target market screening criteria while the yellow bubble is a dummy representation of 100 mmscfd used here as a reference to the smallest proposed production from the gas offshore loading site according to the upstream criteria.

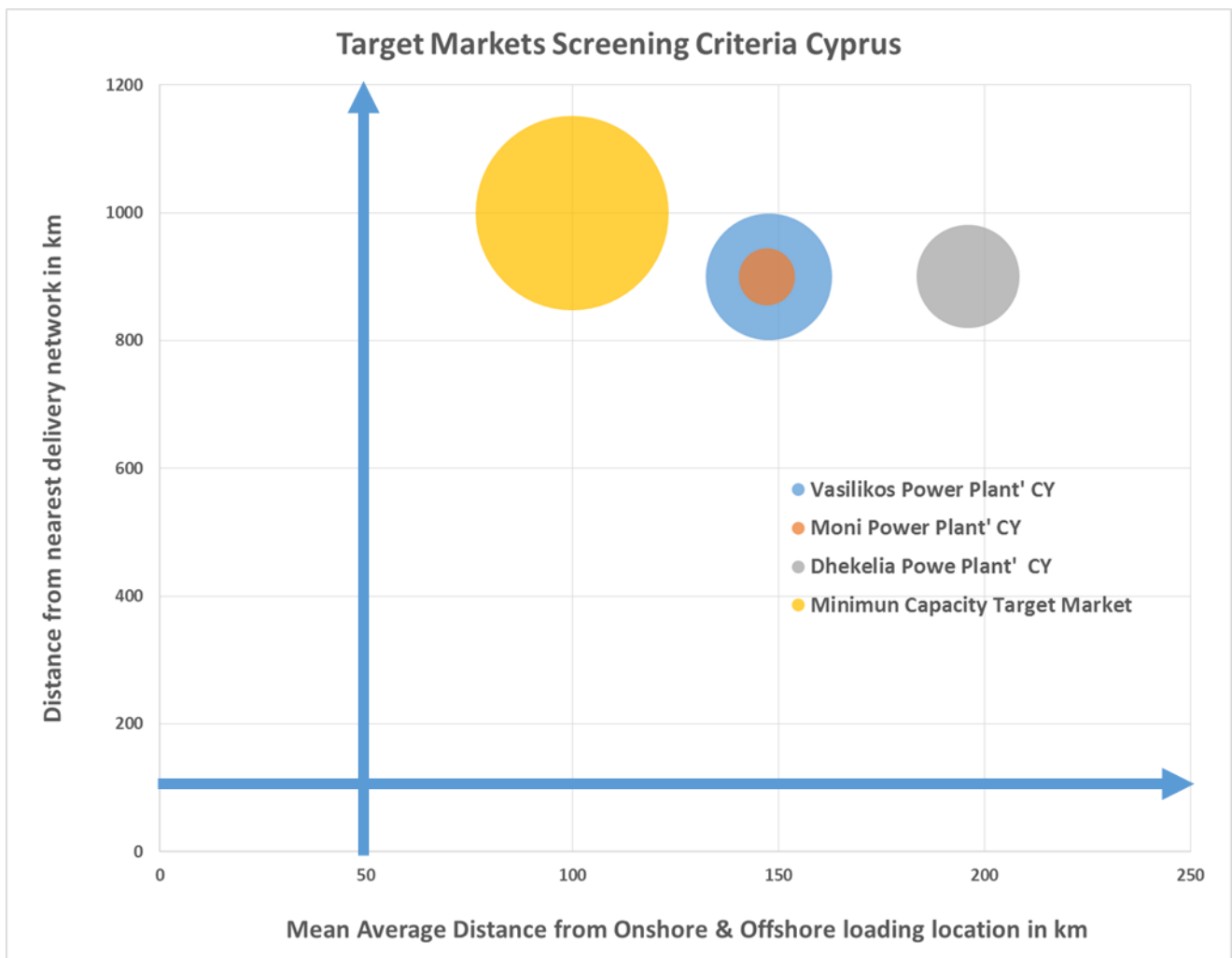


Figure 2: Power Plants in Cyprus based on market screening criteria

Figure 2 shows that even though all Cyprus' power plants make it through the screening criteria on isolated markets, none of the plants fulfill the minimum upstream criteria of 100 mmscfd. Vasilikos plant is estimated to be less than 50 mmscfd while the second biggest plant, Dhekelia, less than 40 mmscfd. However, due to

the close proximity of the plants (about 50 km onshore between Vasilikos and Dhekelia) we could combine the volumes to a total of 80 mmscfd. Furthermore, we can also assume one entry point at the proposed Vasilikos Energy Port[13] that would allow relatively easy CNG connection to feed Vasilikos plant and at the same time with an onshore connection of less than 50 km distance to feet Dhekelia. Moni Power Plant will not be considered as a targeted gas buyers in this report.

Even in the case of combining the demands of the two plants in Cyprus this does not meet the upstream criteria. However, CHC recommends Cyprus to be included in the target market list assuming that when the Gasvessel will be operated, i.e in the year of 2030, demand will grow towards 100 mmscfd. Detailed projections for prices and gas volumes for Cyprus will be part of the next phase of marketing analysis.

Table 4: Summary for Cyprus market

Wholesale Buyer	Application	Volume	Loading Location	Unloading Location
CYGAS	Gas for Power	100 mmscfd	Offshore location	Vasilikos Energy Port

Summary:

- Cyprus shall be listed as a target market for the Gasvessel project. It is considered a stranded market in terms distance from existing delivery network.
- **Supply:** Gas supply in Cyprus today is nonexistent and CHC believes that early gasification of Cyprus can be assisted by the Gasvessel project
- **Demand:** Demand for electricity in Cyprus has generally risen in line with economic growth, which was robust during the 2000s. However, as Cyprus's economic growth has slowed, due to the economic crisis and energy efficiency, demand growth has likewise slowed. Additionally, Cyprus is currently promoting other sources of energy, renewables and biomass and natural gas. By 2030 Cyprus total expected demand is 100 mmscfd, an important screening criteria is being met and Cyprus will be an important target of the subject project.

2.12.5 GREECE

Greece is a much bigger power consumer than Cyprus with the country's demand in electricity mostly covered today by different energy resources such as coal, oil, gas, wind and solar power. The gas main transmission line coming from Turkey and Bulgaria feed much of east site of the Greek mainland starting from the north and ending south covering the area around Athens. In addition, the existing transmission gas network is also supported in the south of Greece mainland by Revithousa LNG terminal thus enhancing security in supply. Furthermore, projects are under construction to expand the existing network into Peloponnese area, south of Greece mainland, while under development projects such as Greece-Italy interconnector is planned to feed the western site of Greece through pipeline gas. Based on today's infrastructure the power plants that can be considered as isolated gas buyers in Greece are the ones shown in Figure 3 which all happens to locate at Greek islands who are naturally disconnected from the existing infrastructure. Although Aliveri power plant is an oil operated plant with high installed capacity, it is not

included in the proposed list of the isolated buyers due to under construction project for extending the existing gas network at Athens to feed also Aliveri region. More information on the Power Plants' characteristics and locations are found in Tables 4-9.

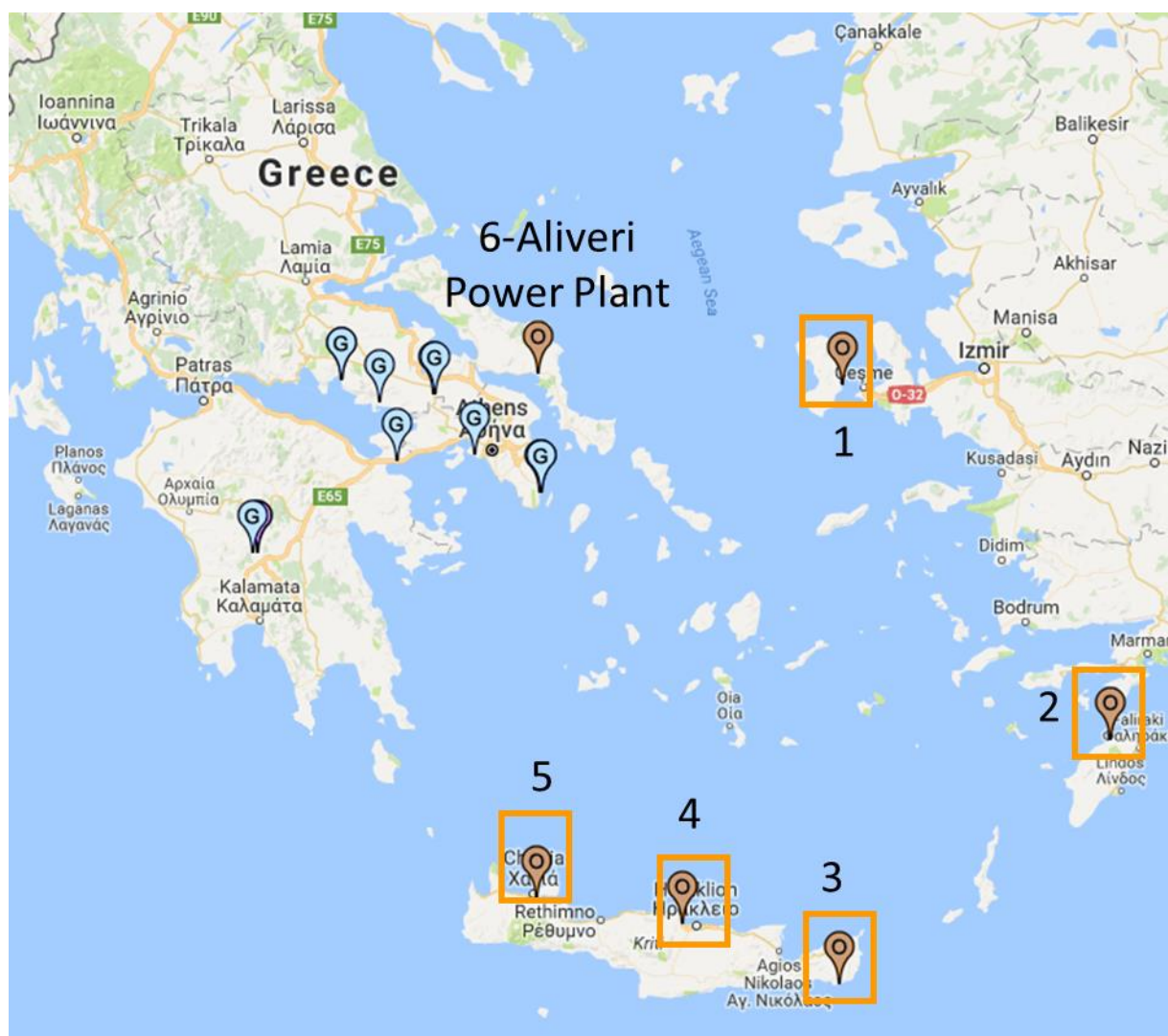


Figure 3: Greek's Selected Power Plants

Table 5: Chios Extension Power Plant Greece

Country	Greece
Mainland/Island	Island
Target Buyer	- Chios Extension Power Plant Greece Heavy Fuel Oil (HFO) - Design Capacity of 14.8 MWe - Possibility for Natural Gas Conversion
Location	- Location Coordinates: Latitude = 38.331 / Longitude = 26.154 - Description of the location: near shore - no gas pipeline network - nearby port

Volume of gas based on 100 % gas conversion of the capacity	14.8 MWe = 355 MWh/d = 1.212 mmscf/d = 34 mscm/d
Volume of gas using the 30% loading factor *Assuming diesel turbines 40% efficiency	= 0.91 mmscf/d = 25.68 mscm/d
Distance from gas loading locations (km)	- Offshore location: 604.503 - Vasilikos Port: 752.867

Table 6: Soroni Rhodes Power Plant Greece

Country	Greece
Mainland/Island	Island
Target Buyer	- Soroni Rhodes Power Plant Greece Heavy Fuel Oil (HFO) - Design Capacity of 84 MWe - Possibility for Natural Gas Conversion
Location	- Location Coordinates: Latitude = 36.37887 Longitude = 28.01857 - Description of the location: near shore no gas pipeline network nearby port
Volume of gas based on 100 % gas conversion of the capacity	84 MWe = 2016 MWh/d = 6.879 mmscf/d = 194 mscm/d
Volume of gas using the 30% loading factor *Assuming gas turbines 50% efficiency	= 5.16 mmscf/d = 145.75 mscm/d
Distance from gas loading locations (km)	- Offshore location: 331.907 - Vasilikos Port: 511.035

Table 7: Chania Power Plant Crete Greece

Country	Greece
Mainland/Island	Island
Target Buyer	- Chania Power Plant Crete Greece Heavy Fuel Oil (HFO) - Design Capacity of 345 MWe - Possibility for Natural Gas Conversion
Location	- Location Coordinates: Latitude=35.488/Longitude=24.0384 - Description of the location: near shore - no gas pipeline network - nearby port
Volume of gas based on 100 % gas conversion of the capacity	345 MWe = 8280 MWh/d = 28.25 mmscf/d = 798 mscm/d
Volume of gas using the 30% loading factor *Assuming diesel turbines 40% efficiency	= 21.19 mmscf/d = 598.62 mscm/d

Distance from gas loading locations (km)	- Offshore location: 587.99 - Vasilikos Port: 845.745
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Table 8: Linoperamata Power Plant Crete Greece

Country	Greece
Mainland/Island	Island
Target Buyer	- Linoperamata Power Plant Crete Heavy Fuel Oil (HFO) - Design Capacity of 272 MWe - Possibility for Natural Gas Conversion
Location	- Location Coordinates: Latitude = 35.34 / Longitude = 25.0523 - Description of the location: near shore - no gas pipeline network - nearby port
Volume of gas based on 100 % gas conversion of the capacity	272 MWe = 6528 MWh/d = 22.27 mmscf/d = 629 mscm/d
Volume of gas using the 30% loading factor *Assuming diesel turbines 40% efficiency	= 16.71 mmscf/d = 471.96 mscm/d
Distance from gas loading locations (km)	- Offshore location: 495.006 - Vasilikos Port: 753.111

Table 9: Atherinolakkos IC Power Plant Greece

Country	Greece
Mainland/Island	Island
Target Buyer	- Atherinolakkos IC Power Plant Greece Heavy Fuel Oil (HFO) - Design Capacity of 195 MWe - Possibility for Natural Gas Conversion
Location	- Location Coordinates: Latitude = 35.0038 Longitude = 26.1397 - Description of the location: near shore - no gas pipeline network - nearby port
Volume of gas based on 100 % gas conversion of the capacity	195 MWe = 4680 MWh/d = 15.97 mmscf/d = 451 mscm/d
Volume of gas using the 30% loading factor *Assuming diesel turbines 40% efficiency	= 11.98 mmscf/d = 338.35 mscm/d
Distance from gas loading locations (km)	- Offshore location: 389.672 - Vasilikos Port: 653.135

The analysis of the power plants' characteristics show that none of the proposed plants satisfy the minimum upstream criteria of 100 mmscfd in gas demand. Unfortunately, even the combination of all the plants together is less than 50 mmscfd based on today's installed capacity and the assumptions of energy efficiency

conversion and the load factor we used for Cyprus case study. Based on figure 4, CHC does not recommend these power plants to be included in the proposed target buyers as a stand-alone case. CHC recommends using only the three power plants located at the island of Crete and in combination with the demand in Cyprus, thus increasing the total demand for CNG transportation by ship. This proposal could be investigated in different two case studies;

- a) when gas from offshore gas location is transported to Cyprus by offshore pipeline to feed Cyprus' domestic needs and surplus of this gas to be converted into CNG and shipped from the proposed Vasilikos Energy Port to Crete
- b) By using the offshore gas loading location to serve directly both Cyprus and Crete under the Gasvessel concept by optimizing the intermediate value chain that the number of vessel, using storage facilities, etc.

Because of the close proximity of the three power plants at Grete, CHC will assume a single entry point near Heraklion area to feed the nearby power plant at Linoperamata and with an onshore gas connections the two other plants on the east and west site of the island. CHC assumes about 50 mmscfd in gas demand is an adequate approximation to cover the island's need today.

Table 10: Summary for Crete market

Application	Volume	Loading Location	Unloading Location
Gas for Power	50 mmscfd	Offshore location	Linoperamata Port 35.346299 Latitude 25.050034 Longitude
Gas for Power	50 mmscfd	Vasilikos Energy Port	Linoperamata Port 35.346299 Latitude 25.050034 Longitude

In similar manner, we could propose a concept to include Chios or Rodos power plants and even to create a case to combine all the power plants of the different islands together, however CHC believes that at this stage using only Crete as an example is good enough to collect the information needed for Gasvessel project.

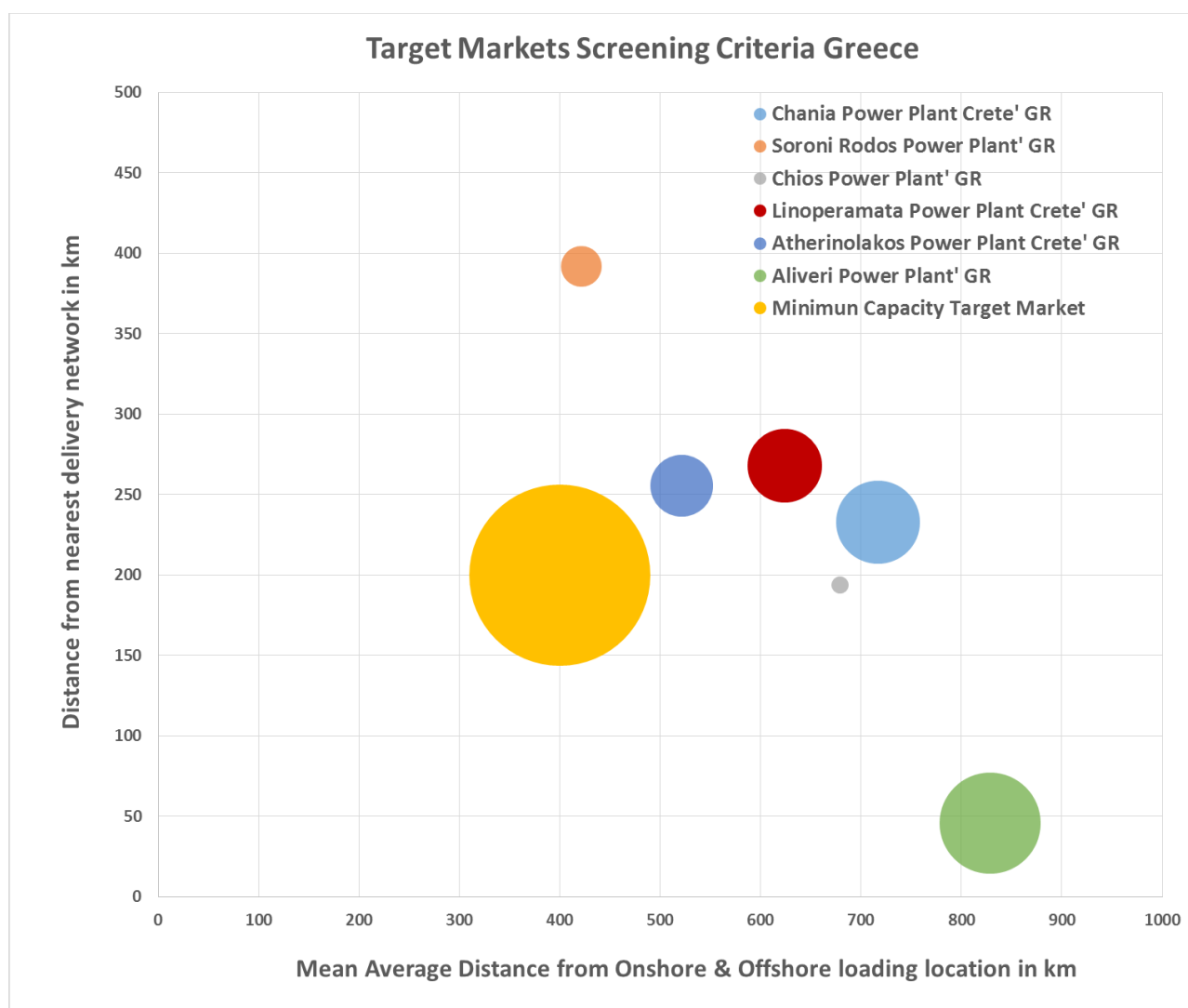


Figure 4: Power Plants in Greece based on market screening criteria

Summary:

- Greece, although the mainland is sufficiently gasified and well supplied by pipelines and waterborne LNG, the target islandic regions identified above shall be listed as target markets for the Gasvessel project. Crete, Chios and Rhodes are considered isolated from the existing grid but the challenge here is to either combine those regions or select to work with the largest market, which naturally fails our screening criteria, for progressing the project. For this research, we are focusing on the island of Crete because it is the biggest isolated demand center in the country.
- Supply:** Crete has no existing gas supplies, neither local gas production. Only waterborne LNG can land on this island as of today. Nevertheless, things might take another turn in the near future as Exxon, has recently requested exploration licenses for the South West region of the island.
- Demand:** As described above the demand is limited for Crete, only about 50 mmscfd, nevertheless for the purposes of this project, CHC will run some scenarios where the demand in Crete will be combined with Cyprus'.

2.12.6 ITALY

Located just opposite traditional gas exporters such as Algeria, Tunisia and Libya, Italy is among the well-gasified countries in Europe that introduced natural gas in its energy mix. The national gas network is supported from the north by gas pipelines coming from north, central and west Europe and on the south by North Africa countries. Italy has also three regasification terminals connected to the network that allow flexibility of supply especially when during demand swings. The existing gas transmission lines such as Trans-Mediterranean and Greenstream provide gas to Italy entering from the island of Sicily and then continue to the north until the other end of the country. In addition, Italy is producing oil and gas that partially feeds its domestic power plants thus is another element to consider when evaluating Italy as a potential gas buyer. Furthermore, the Island of Sardinia will potentially receive gas very soon from two proposed projects i.e Galsi gas pipeline that crosses through the island and its opponent Sardinia small-scale regasification terminal. Figure 5 shows the power plants have been evaluated for the first phase of the marketing analysis and tables 11-18 present their technical characteristics.



Figure 5: Italian Power Plants

Table 11: ENEL Porto Tolle Thermal Power Plant Italy

Country	Italy
Mainland/Island	Mainland
Target Buyer	ENEL Porto Tolle Thermal Power Plant Italy Heavy Fuel Oil (HFO) Design Capacity of 2640 MWe Possibility for Natural Gas Conversion
Location	- Location Coordinates: Latitude = 44.9569 Longitude = 12.4883 - Description of the location: near shore available gas pipeline network nearby port
Volume of gas based on 100 % gas conversion of the capacity	2640 MWe = 63360 MWh/d = 216.184 mmscf/d = 6108 mscm/d
Volume of gas using the 30% loading factor *Assuming diesel turbines 40% efficiency	= 162.14 mmscf/d = 4580.75 mscm/d
Distance from gas loading locations (km)	1. Offshore location: 1942.595 2. Vasilikos Port: 2100.03

Table 12: ENIPOWER S.P.A. Stabil. Di Brindisi Italy

Country	Italy [13]
Mainland/Island	Mainland
Target Buyer	ENIPOWER S.P.A. Stabilimento di Brindisi Italy Heavy Fuel Oil (HFO) Design Capacity of 1321 MWe Possibility for Natural Gas Conversion
Location	- Location Coordinates: Latitude = 40.629278437948 Longitude = 18.003287315369 - Description of the location: near shore available gas pipeline network nearby port
Volume of gas based on 100 % gas conversion of the capacity	1321 MWe = 31704 MWh/d = 108.174 mmscf/d = 3056 mscm/d
Volume of gas using the 30% loading factor *Assuming diesel turbines 40% efficiency	= 81.13 mmscf/d = 2292.11 mscm/d
Distance from gas loading locations (km)	1. Offshore location: 1306.141 2. Vasilikos Port: 1494.41

Table 13: Enel Marzocco Oil Power Plant Italy

Country	Italy
Mainland/Island	Mainland
Target Buyer	Enel Marzocco Oil Power Plant Italy Heavy Fuel Oil (HFO) Design Capacity of 310 MWe Possibility for Natural Gas Conversion
Location	- Location Coordinates: Latitude = 43.56727 Longitude = 10.31 - Description of the location: near shore available gas pipeline network nearby port
Volume of gas based on 100 % gas conversion of the capacity	310 MWe = 7440 MWh/d = 25.385 mmscf/d = 717 mscm/d
Volume of gas using the 30% loading factor *Assuming diesel turbines 40% efficiency	= 19.04 mmscf/d = 537.89 mscm/d
Distance from gas loading locations (km)	1. Offshore location: 2019.802 2. Vasilikos Port: 2202.602

Table 14: ENEL Piombino Thermal Power Plant Italy

Country	Italy
Mainland/Island	Mainland
Target Buyer	ENEL Piombino Thermal Power Plant Italy Heavy Fuel Oil (HFO) Design Capacity of 1280 MWe Possibility for Natural Gas Conversion
Location	- Location Coordinates: Latitude = 42.9565 Longitude = 10.6034 - Description of the location: near shore available gas pipeline network nearby port
Volume of gas based on 100 % gas conversion of the capacity	1280 MWe = 30720 MWh/d = 104.817 mmscf/d = 2961 mscm/d
Volume of gas using the 30% loading factor *Assuming diesel turbines 40% efficiency	= 78.61 mmscf/d = 2220.97 mscm/d
Distance from gas loading locations (km)	1. Offshore location: 1970.014 2. Vasilikos Port: 2158.908

Table 15: Sarlux (Cagliari) IGCC Power Plant Italy

Country	Italy
Mainland/Island	Island
Target Buyer	Sarlux (Cagliari) IGCC Power Plant Italy Heavy Fuel Oil (HFO) Design Capacity of 550 MWe Possibility for Natural Gas Conversion
Location	- Location Coordinates: Latitude = 39.1037 Longitude = 9.0063 - Description of the location: near shore available gas pipeline network nearby port
Volume of gas based on 100 % gas conversion of the capacity	550 MWe = 13200 MWh/d = 45.038 mmscf/d = 1272 mscm/d
Volume of gas using the 30% loading factor *Assuming gas turbines 50% efficiency	= 27.02 mmscf/d = 763.46 mscm/d
Distance from gas loading locations (km)	1. Offshore location: 1972.864 2. Vasilikos Port: 2206.566

Table 16: Ottana Oil CHP Power Plant

Country	Italy
Mainland/Island	Island
Target Buyer	Ottana Oil CHP Power Plant Heavy Fuel Oil (HFO) Design Capacity of 140 MWe Possibility for Natural Gas Conversion
Location	- Location Coordinates: Latitude = 40.2387 Longitude = 9.0176 - Description of the location: near shore available gas pipeline network nearby port
Volume of gas based on 100 % gas conversion of the capacity	140 MWe = 3369 MWh/d = 11.464 mmscf/d = 324 mscm/d
Volume of gas using the 30% loading factor *Assuming diesel turbines 40% efficiency	= 8.60 mmscf/d = 242.92 mscm/d
Distance from gas loading locations (km)	1. Offshore location: 1997.928 2. Vasilikos Port: 2220.352

Table 17: Edipower San Filippo del Mela Thermal Power Plant Italy

Country	Italy
Mainland/Island	Island
Target Buyer	Edipower San Filippo del Mela Thermal Power Plant Italy Heavy Fuel Oil (HFO) Design Capacity of 1280 MWe Possibility for Natural Gas Conversion
Location	- Location Coordinates: Latitude = 38.2049 Longitude = 15.2818 - Description of the location: near shore available gas pipeline network nearby port
Volume of gas based on 100 % gas conversion of the capacity	1280 MWe = 30720 MWh/d = 104.817 mmscf/d = 2961 mscm/d
Volume of gas using the 30% loading factor *Assuming diesel turbines 40% efficiency	= 78.61 mmscf/d = 2220.97 mscm/d
Distance from gas loading locations (km)	1. Offshore location: 1419.136 2. Vasilikos Port: 1653.687

Table 18: ISAB Priolo Gargallo IGCC Power Plant Italy

Country	Italy
Mainland/Island	Mainland
Target Buyer	ISAB Priolo Gargallo IGCC Power Plant Italy Heavy Fuel Oil (HFO) Design Capacity of 562.6 MWe Possibility for Natural Gas Conversion
Location	- Location Coordinates: Latitude = 37.1399 Longitude = 15.2158 - Description of the location: near shore available gas pipeline network nearby port
Volume of gas based on 100 % gas conversion of the capacity	562.6 MWe = 63360 MWh/d = 216.184 mmscf/d = 6108 mscm/d
Volume of gas using the 30% loading factor *Assuming diesel turbines 40% efficiency	= 162.14 mmscf/d = 4580.75 mscm/d
Distance from gas loading locations (km)	1. Offshore location: 1399.411 2. Vasilikos Port: 1647.129

From a preliminary research the Italian national gas network existing today seems to reach all the major buyers in Italy leaving no room for the Gasvessel concept. Figure 6 below proves that the combination of

long distances from the proposed gas loading locations in Cyprus and the short distances from the gas network eliminates the markets that initially thought to be isolated from the network. The only power plant that fulfills all target market-screening criteria is the one located near Brindisi area named Stabil Di Brindisi power plant. However, even in this case CHC does not propose this plant as a potential buyer because the specific area is planned to be gasified by the Trans Adriatic Pipeline project, which is already under construction. The specific project will cross Northern Greece, Albania and the Adriatic Sea before coming in Southern Italy to connect to Italy's national network.

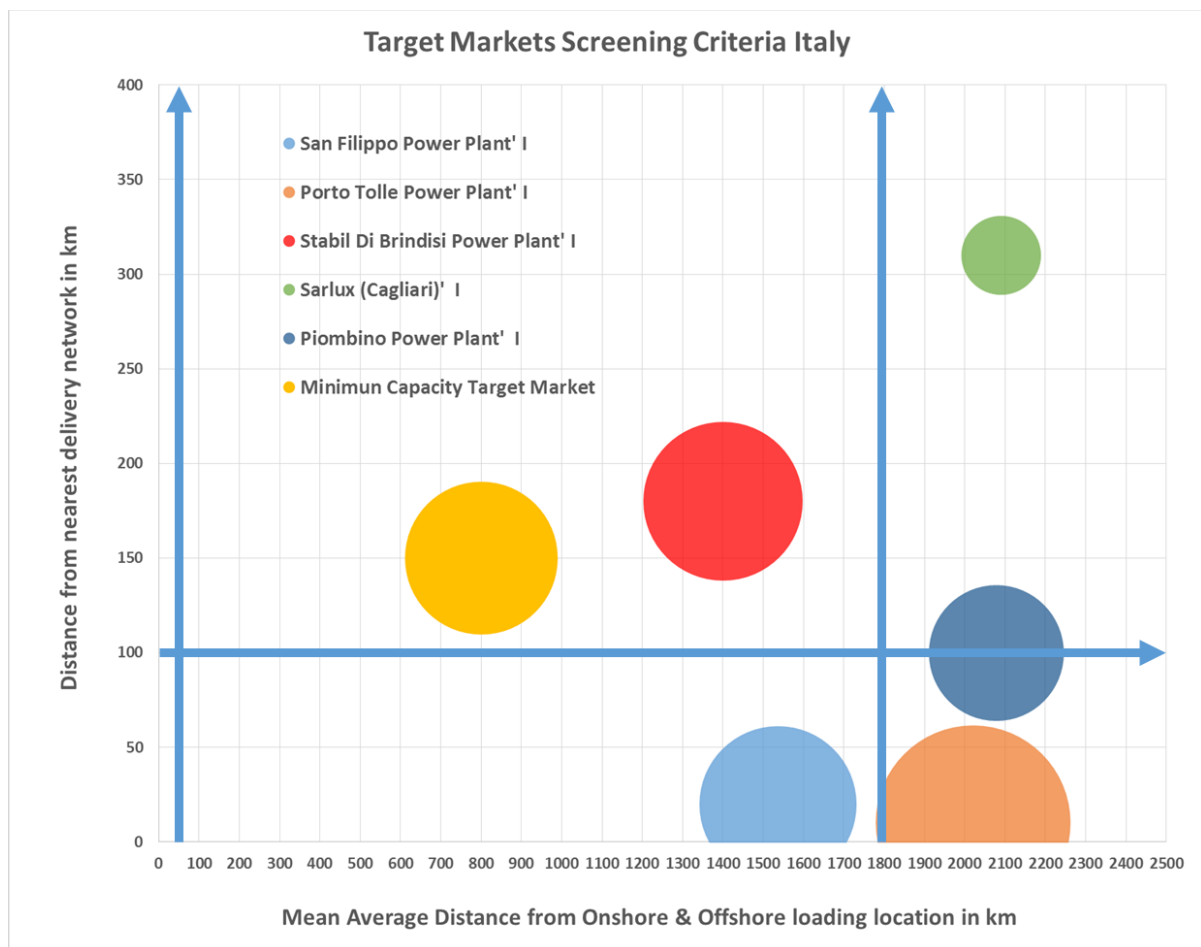


Figure 6: Power Plants in Italy based on market screening criteria

SUMMARY

- Stabilimento di Brindisi power plant, although being the only plant that fulfills screening criteria and is located near Brindisi area, it is not considered as a potential target because the specific area is planned to be gasified by the Tran Adriatic Pipeline project which is underway as well as it's proximity to the existing grid.
- **Supply:** Abundant supply options in terms of the Italian market both from pipelines and LNG regasification sources. Italy in general is a highly gasified country and the islandic regions of the country can easily be accessed by extending the gas grid.

- **Demand:** As described above although the ENIPOWER S.P.A. Stabilimento di Brindisi power plant has nameplated capacity which could equate to 108 mmscfd of gas and fulfills the criteria, for the reasons described earlier we will not take into account any targets in Italy.

2.12.7 CORSICA (FRENCH ISLAND)

CHC considers France outside the feasible distances for the Gasvessel concept when gas is loaded from offshore Cyprus. Based on the target market screening criteria, distances at 1750 km may already be a borderline for the technology. France is located more than 2300 km away from Cyprus offshore gas loading location. Even though the island of Corsica is located at the very east-south site of France mainland is still about 2000 km away from Cyprus offshore gas loading location. However, CHC decided to have a closer look at the island of Corsica since based on the target market screening criteria it can be seen at a first look as isolated market. Furthermore, it is considered to be the largest island in the Mediterranean after Sicily, Sardinia, Cyprus and Crete. However, by looking closer at its potential gas demand, Corsica has two rather small power oil plants to cover its daily needs and recently (2012) a cable connection of equivalent of 300MW was installed between Italy mainland-Corsica-Sardinia to cover any additional needs in power. The long distance from loading location in combination with the very small potential in gas demand led CHC not to propose Corsica as a potential gas buyer for the Gasvessel concept. Figure 7 shows the location of the two oil power plants at the island and tables 19 and 20 provide their technical characteristics. Furthermore, the graph in figure 8 shows the power demand of the two power plants against the target market screening criteria.

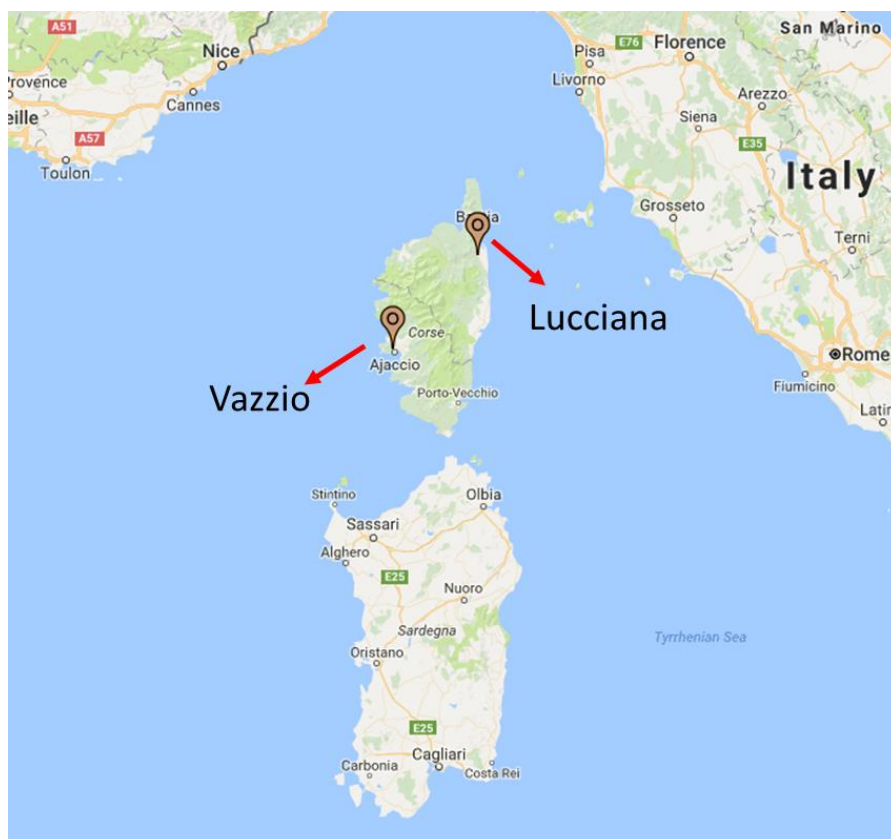


Figure 7: Corsica's Oil Power Plants

Table 19: Lucciana Thermal Power Plant France

Country	France
Mainland/Island	Island
Target Buyer	Lucciana Thermal Power Plant France Heavy Fuel Oil (HFO) Design Capacity of 131 MWe Possibility for Natural Gas Conversion
Location	- Location Coordinates: Latitude = 42.527341483252 Longitude = 9.449872970581 - Description of the location: near shore no available gas pipeline network nearby port
Volume of gas based on 100 % gas conversion of the capacity	131 MWe = 3144 MWh/d = 10.727 mmscf/d = 303 mscm/d
Volume of gas using the 30% loading factor *Assuming gas turbines 50% efficiency *Assuming diesel turbines 40% efficiency	= 8.05 mmscf/d = 227.3 mscm/d
Distance from gas loading locations (km)	1. Offshore location: 2039.007 2. Vasilikos Port: 2236.117

Table 20: Vazzio Thermal Power Plant France

Country	France
Mainland/Island	Island
Target Buyer	Vazzio Thermal Power Plant France Heavy Fuel Oil (HFO) Design Capacity of 135.5 MWe Possibility for Natural Gas Conversion
Location	- Location Coordinates: Latitude = 41.932087233061 Longitude = 8.720440864563 - Description of the location: near shore no available gas pipeline network nearby port
Volume of gas based on 100 % gas conversion of the capacity	135.5 MWe = 3252 MWh/d = 11.096 mmscf/d = 313 mscm/d
Volume of gas using the 30% loading factor *Assuming gas turbines 50% efficiency *Assuming diesel turbines 40% efficiency	= 8.32 mmscf/d = 235.11 mscm/d
Distance from gas loading locations (km)	1. Offshore location: 2073.522 2. Vasilikos Port: 2278.83

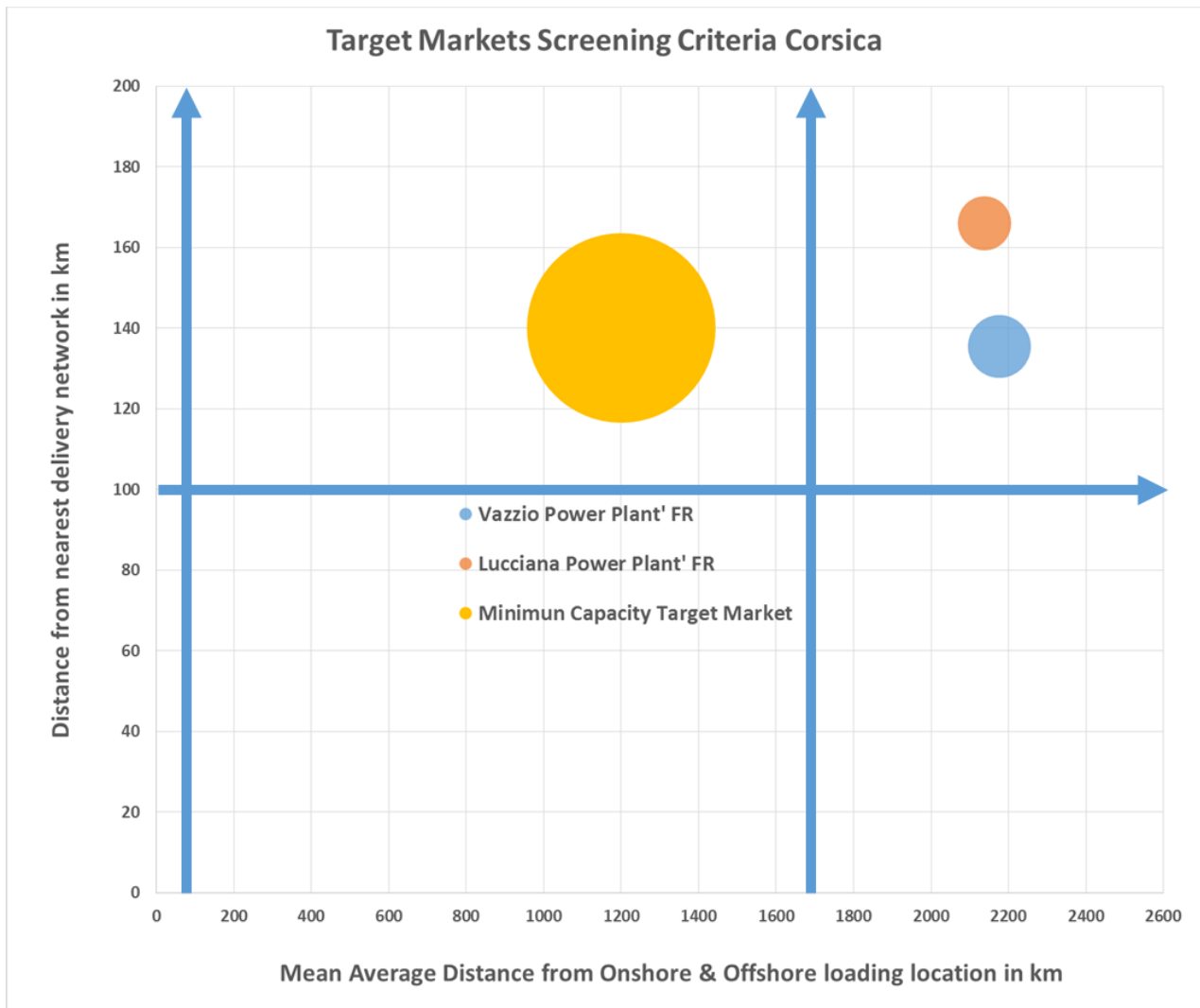


Figure 8: Power Plants in Corsica based on market screening criteria

SUMMARY

- Although Mediterranean France and the near shore French Power facilities fall off the screening criteria we have selected to progress the prospect, CHC decided to further investigate the island of Corsica because its distance from the proposed gas fields is not prohibitive for the Gasvessel project. In conclusion though, the two rather small power plants of the island, currently running on Fuel Oil, do not accumulate enough demand to justify the inclusion of Corsica in our target markets.
- **Supply:** Although there is no Gas supply in the island of Corsica, a power supply cable of 300 MWh is currently connecting the island to Italy through which the power demands are being met.
- **Demand:** A combined demand of 21 mmscfd (10 +11 mmscfd) from the two power plants of Corsica, does not accumulate sufficient demand to be included in the target markets for the Gasvessel project.

2.12.8 LEBANON

Lebanon has seven power plants that operate today using liquid fuels. Even though, European regulations for switching oil power plants to gas for environmental mainly incentives may not apply for Lebanon, the country has introduced gas in its energy mix by converting four of its power plans to burn gas due to a combination of reasons including economic and energy security in supply motives. The move of partially gasifying the market was a concept started to develop in Lebanon during the operation of Arab pipeline that connected Lebanon, Syria and Jordan to the Egyptian gas export network. Furthermore, when the export production from Egypt stopped in 2011 Lebanon continued its plans to introduce gas into the market by evaluating the option of investing in regasification terminal. The below figure shows the location of the power plant that CHC included in the list of proposed target buyers. In addition, tables 21-26 gather characteristics of the proposed power plants such as distances from the gas loading sites and their power demand in gas.

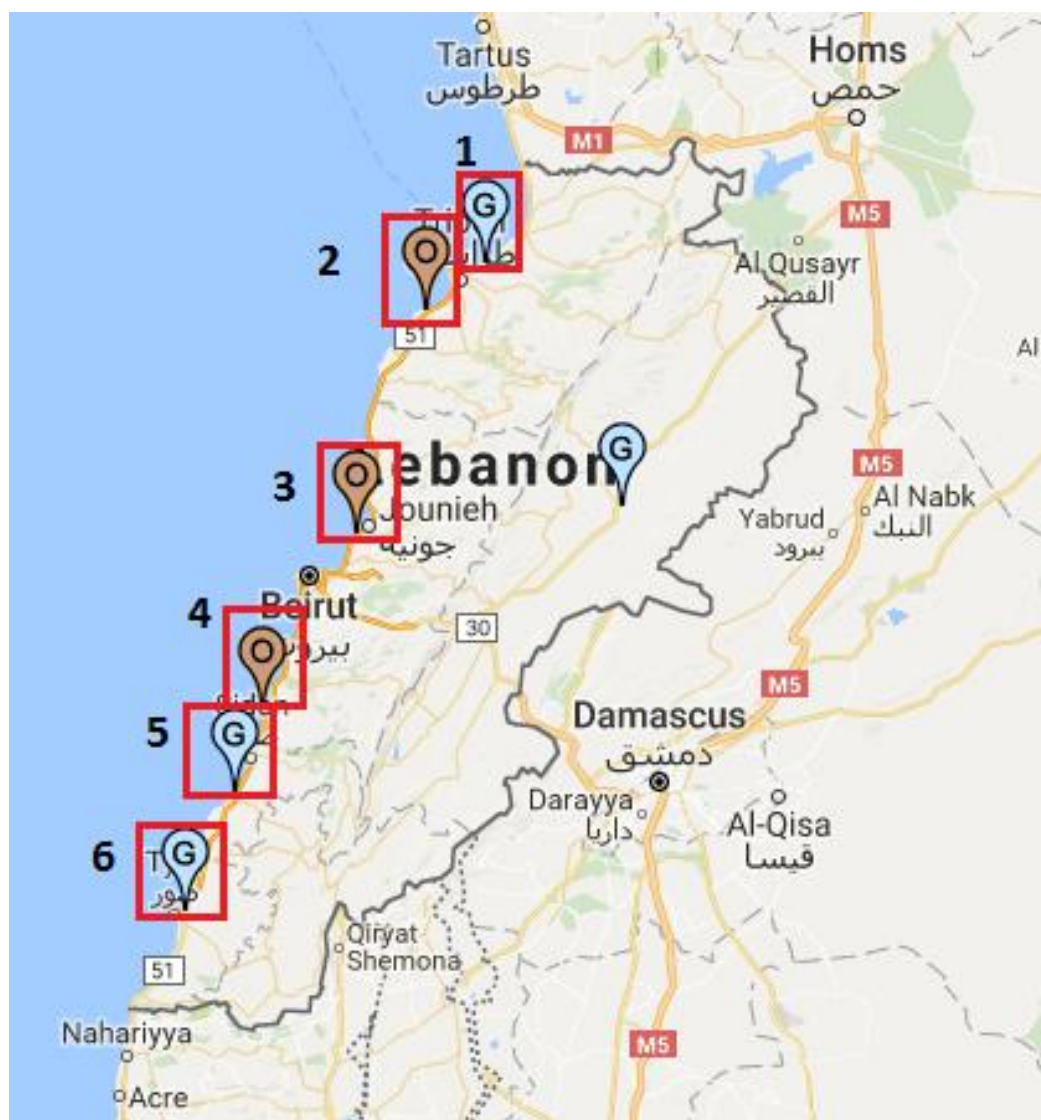


Figure 9: Lebanon's Power Plants

Table 21: Deir-Ammar CCGT Power Plant Lebanon

Country	Lebanon
Mainland/Island	Mainland
Target Buyer	Deir-Ammar CCGT Power Plant Heavy Fuel Oil (HFO) Design Capacity of 470 MWe Possibility for Natural Gas Conversion
Location	- Location Coordinates: Latitude = 34.465036762176 Longitude = 35.894179344177 - Description of the location: near shore available gas pipeline network nearby port
Volume of gas based on 100 % gas conversion of the capacity	470 MWe = 11280 MWh/d = 38.487 mmscf/d = 1087 mscm/d
Volume of gas using the 30% loading factor *Assuming gas turbines 50% efficiency *Assuming diesel turbines 40% efficiency	= 23.09 mmscf/d = 652.41 mscm/d
Distance from gas loading locations (km)	1. Offshore location: 525.351 2. Vasilikos Port: 240.229

Table 22: Al-Hreesha (Hreishi) Thermal Power Plant Lebanon

Country	Lebanon
Mainland/Island	Mainland
Target Buyer	Al-Hreesha (Hreishi) Thermal Power Plant Lebanon Heavy Fuel Oil (HFO) Design Capacity of 75 MWe Possibility for Natural Gas Conversion
Location	- Location Coordinates: Latitude = 34.379544341883 Longitude = 35.758395195007 - Description of the location: near shore available gas pipeline network nearby port
Volume of gas based on 100 % gas conversion of the capacity	75 MWe = 1800 MWh/d = 6.142 mmscf/d = 174 mscm/d
Volume of gas using the 30% loading factor *Assuming gas turbines 50% efficiency *Assuming diesel turbines 40% efficiency	= 4.61 mmscf/d = 130.14 mscm/d
Distance from gas loading locations (km)	1. Offshore location: 512.303 2. Vasilikos Port: 229.427

Table 23: Zouk Thermal Power Plant Lebanon

Country	Lebanon
Mainland/Island	Mainland
Target Buyer	Zouk Thermal Power Plant Lebanon Heavy Fuel Oil (HFO) Design Capacity of 607 MWe Possibility for Natural Gas Conversion
Location	- Location Coordinates: Latitude = 33.969 Longitude = 35.604 - Description of the location: near shore no available gas pipeline network nearby port
Volume of gas based on 100 % gas conversion of the capacity	607 MWe = 14568 MWh/d = 49.706 mmscf/d = 1404 mscm/d
Volume of gas using the 30% loading factor *Assuming gas turbines 50% efficiency *Assuming diesel turbines 40% efficiency	= 37.28 mmscf/d = 1053.23 mscm/d
Distance from gas loading locations (km)	1. Offshore location: 497.496 2. Vasilikos Port: 228.675

Table 24: Jieh Thermal Power Plant Lebanon

Country	Lebanon
Mainland/Island	Mainland
Target Buyer	Jieh Thermal Power Plant Lebanon Heavy Fuel Oil (HFO) Design Capacity of 346 MWe Possibility for Natural Gas Conversion
Location	- Location Coordinates: Latitude = 33.647475074694 Longitude = 35.399601459503 - Description of the location: near shore no available gas pipeline network nearby port
Volume of gas based on 100 % gas conversion of the capacity	346 MWe = 8304 MWh/d = 28.333 mmscf/d = 800 mscm/d
Volume of gas using the 30% loading factor *Assuming gas turbines 50% efficiency *Assuming diesel turbines 40% efficiency	= 21.25 mmscf/d = 600.36 mscm/d
Distance from gas loading locations (km)	1. Offshore location: 481.071 2. Vasilikos Port: 228.326

Table 25: Zahrani CCGT Power Plant Lebanon

Country	Lebanon
Mainland/Island	Mainland
Target Buyer	Zahrani CCGT Power Plant Lebanon Heavy Fuel Oil (HFO) Design Capacity of 470 MWe Possibility for Natural Gas Conversion
Location	- Location Coordinates: Latitude = 33.496089832825 Longitude = 35.337975025177 - Description of the location: near shore no available gas pipeline network nearby port
Volume of gas based on 100 % gas conversion of the capacity	470 MWe = 11280 MWh/d = 38.487 mmscf/d = 1087 mscm/d
Volume of gas using the 30% loading factor *Assuming gas turbines 50% efficiency *Assuming diesel turbines 40% efficiency	= 23.09 mmscf/d = 652.41 mscm/d
Distance from gas loading locations (km)	1. Offshore location: 477.463 2. Vasilikos Port: 233.153

Table 26: Tyre (Sour) Thermal Power Plant Lebanon

Country	Lebanon
Mainland/Island	Mainland
Target Buyer	Tyre (Sour) Thermal Power Plant Lebanon Heavy Fuel Oil (HFO) Design Capacity of 70 MWe Possibility for Natural Gas Conversion
Location	- Location Coordinates: Latitude = 33.276090203352 Longitude = 35.228991508484 - Description of the location: near shore no available gas pipeline network nearby port
Volume of gas based on 100 % gas conversion of the capacity	70 MWe = 1680 MWh/d = 5.732 mmscf/d = 162 mscm/d
Volume of gas using the 30% loading factor *Assuming gas turbines 50% efficiency *Assuming diesel turbines 40% efficiency	= 3.44 mmscf/d = 97.17 mscm/d
Distance from gas loading locations (km)	1. Offshore location: 471.55 2. Vasilikos Port: 240.968

Lebanon gas power plants are all within the battery limits on distances according our screening criteria. However, by analyzing Lebanon potential gas demand, based on its power plant installed capacities and assuming the energy efficiencies and load factor as for the cases in Cyprus and Crete, figure 10 shows that none of the plants alone can match the minimum upstream criteria. However, all the proposed power plants are located along the coastline of Lebanon thus reducing complexity when investigating the idea of combining the demand of the plants together. It becomes more interesting the fact that with only one gas entry point near Zouk terminal port, at the middle of Lebanon seaside can serve the biggest power plant, that of Zouk and with onshore gas connection running along the coastline in the north and south of the country can feed the remaining plants. Furthermore, due to the close proximity with Cyprus CHC proposes to investigate Lebanon market together with the gas feeding Cyprus market.

This proposal could be investigated in different two case studies;

- a) when gas from offshore gas location is transported to Cyprus by offshore pipeline to feed Cyprus' domestic needs and surplus of this gas to be converted into CNG and shipped from the proposed Vasilikos Energy Port to Lebanon
- b) by using the offshore gas loading location to serve directly both Cyprus and Lebanon under the Gasvessel concept by optimizing the intermediate value chain that the number of vessel, using storage facilities, etc.

Apart the proposed power plants Lebanon has other power plants (not near shore) and also industrial players that may present gas opportunities for the Gasvessel concept, however due to the lack of adequate distribution channels it is not recommend to investigate Lebanon industrial players independent from the existing gas infrastructure. CHC recommends to concentrate more on the coastal areas to allow easy access for the Gasvessel. The greater potential of Lebanon gas market will be investigated during the second phase of market analysis. At this stage, CHC proposes volume of 130 mmscfd in gas demand to be used for our research study.

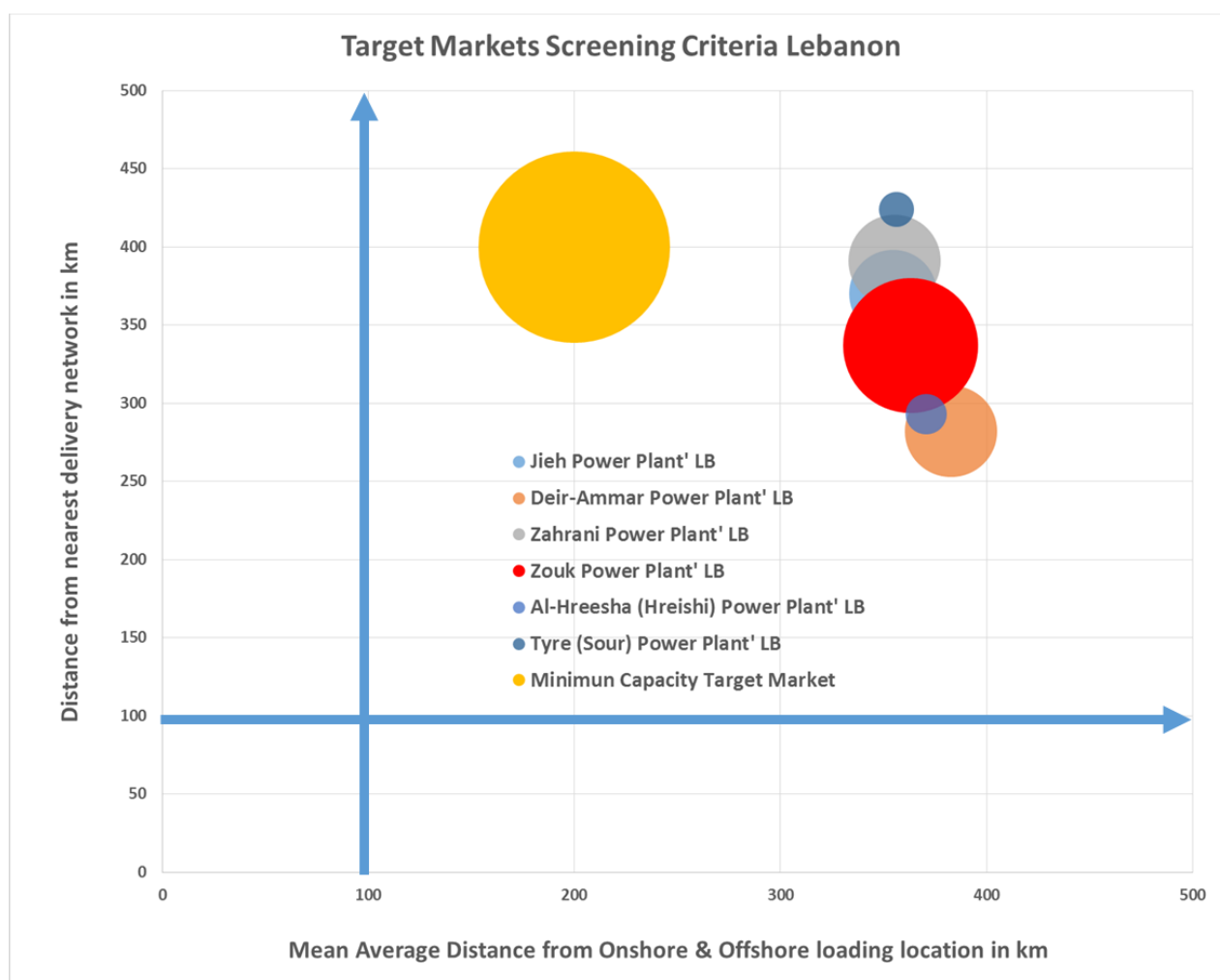


Table 27: Summary for Lebanon market

Application	Volume	Loading Location	Unloading Location
Gas for Power	130 mmscfd	Offshore location	Zouk Port 33.973828 Latitude 35.602965 Longitude
Gas for Power	130 mmscfd	Vasilikos Energy Port	Zouk Port 33.973828 Latitude 35.602965 Longitude

SUMMARY

- Lebanon's has no upstream production, however, there regulatory actions that may enable the kick-start the Upstream sector. The government has announced that five out of the ten offshore blocks in its EEZ will be available for licensing in the first licensing round expected to be competed in 2017. Initial seismic exploration in 2012 estimated that at least 25tcf of gas could be found. Having appointed a new president in 2016, the Lebanese parliament rekindled efforts to commence exploration.

- **Supply:** the Arab Gas pipeline 1200 km long used to export Egyptian natural gas to Jordan, Syria and Lebanon. Lebanon is now short of gas also as their gas-hungry neighbors. Given the current lack of regionally available pipeline gas supply options, importing liquefied natural gas (LNG) is the most realistic and practical option. The government has announced plans to import LNG to replace fuel oil in power generation, although at present the country has no regasification terminal and no contract to build and operate one has been signed.
- **Demand:** 130 mmscfd accounts for the total power demand needs of Lebanon in gas measurements. Despite the fact that Lebanon has lined up an exploration strategy and planning to tender its offshore blocks to the IOCs. CHC believes that Lebanon is a market we should include in our Gasvessel scenarios. It faces a significant barrier to extracting gas reserves – the more than 800 kilometers of contested maritime borders, it shares with Israel are being disputed for quite some time now.

2.12.9 EGYPT

Egypt is a gas producer who historically covered its domestic needs and also exported gas in the form of LNG. Its growing domestic demand in combination with decline of gas production has reversed Egypt from an exporter to a Gas importer. The above situation as well as its close proximity to Cyprus makes the Egyptian market an interesting target to look in terms of Power demand as well as demand from heavy industries.

Figure 11 shows the proposed oil-fired power plants following the target screening methodology thus emphasizing at power plants located at Mediterranean coastline and along Suez Canal, while tables 28–34 represent their technical characteristics.

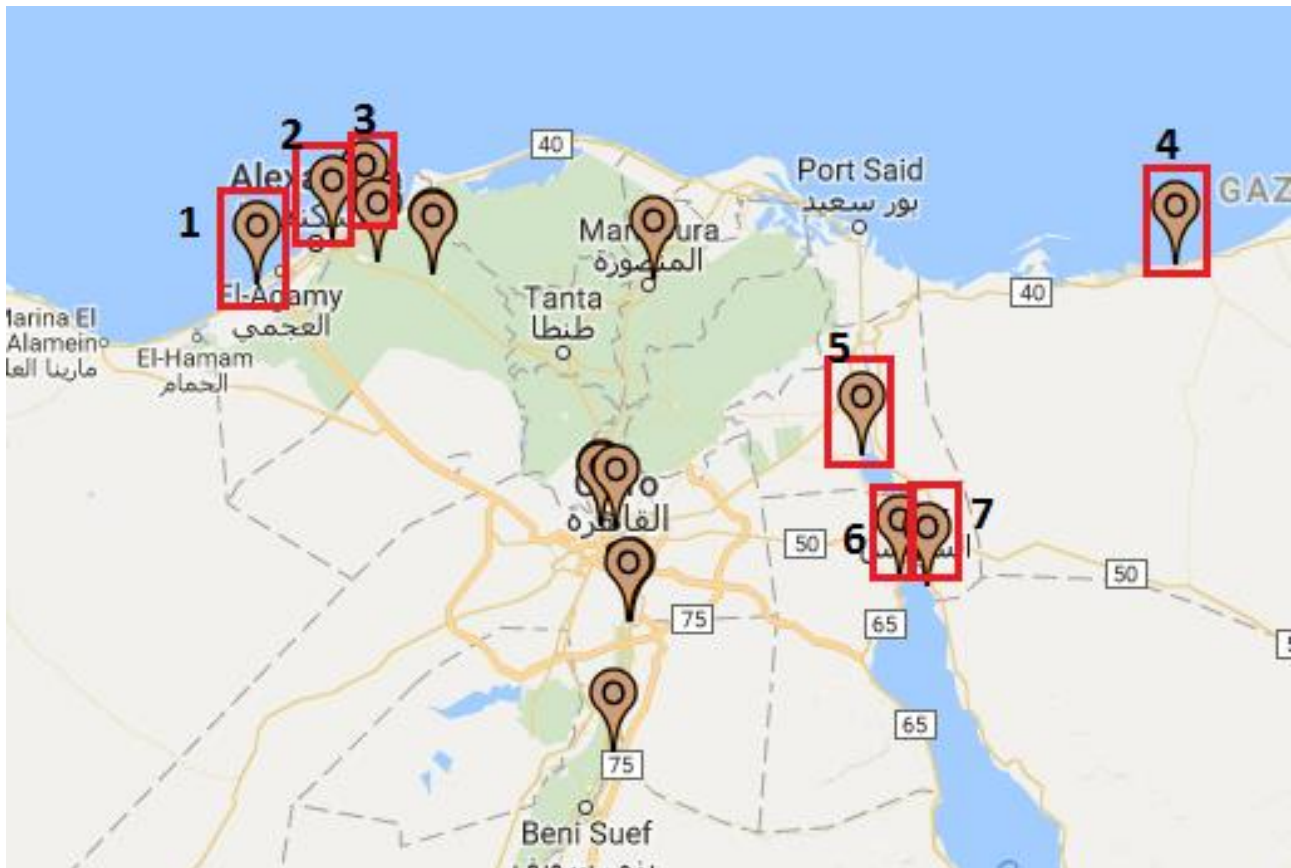


Figure 11: Egypt's Oil Power Plants

Table 28: Sidi Krir 1 and 2 Thermal Power Plant Egypt

Country	Egypt [13]
Mainland/Island	Mainland
Target Buyer	Sidi Krir 1 and 2 Thermal Power Plant Heavy Fuel Oil (HFO) Design Capacity of 640 MWe Possibility for Natural Gas Conversion
Location	- Location Coordinates: Latitude = 31.04475 Longitude = 29.66014 - Description of the location: near shore available gas pipeline network nearby port
Volume of gas based on 100 % gas conversion of the capacity	640 MWe = 15360 MWh/d = 52.408 mmscf/d = 1481 mscm/d
Volume of gas using the 30% loading factor *Assuming gas turbines 50% efficiency *Assuming diesel turbines 40% efficiency	= 39.31 mmscf/d = 1110.49 mscm/d
Distance from gas loading locations (km)	1. Offshore location: 331.814 2. Vasilikos Port: 531.743

Table 29: El-Seiuf Thermal Power Plant Egypt (Shutdown)

Country	Egypt
Mainland/Island	Mainland
Target Buyer	El-Seiuf Thermal Power Plant Egypt (Shutdown) Heavy Fuel Oil (HFO) Design Capacity of 200 MWe Possibility for Natural Gas Conversion
Location	- Location Coordinates: Latitude = 31.2159 Longitude = 29.9974 - Description of the location: near shore available gas pipeline network nearby port
Volume of gas based on 100 % gas conversion of the capacity	200 MWe = 4800 MWh/d = 16.378 mmscf/d = 463 mscm/d
Volume of gas using the 30% loading factor *Assuming gas turbines 50% efficiency *Assuming diesel turbines 40% efficiency	= 12.28 mmscf/d = 347.03 mscm/d
Distance from gas loading locations (km)	1. Offshore location: 309.391 2. Vasilikos Port: 496.977

Table 30: Abu Qir (Kir) Thermal Power Plant Egypt

Country	Egypt
Mainland/Island	Mainland
Target Buyer	Abu Qir (Kir) Thermal Power Plant Heavy Fuel Oil (HFO) Design Capacity of 2211 MWe Possibility for Natural Gas Conversion
Location	- Location Coordinates: Latitude = 31.2694 Longitude = 30.1409 - Description of the location: near shore available gas pipeline network nearby port
Volume of gas based on 100 % gas conversion of the capacity	2211 MWe = 53064 MWh/d = 181.054 mmscf/d = 5115 mscm/d
Volume of gas using the 30% loading factor *Assuming gas turbines 50% efficiency *Assuming diesel turbines 40 % efficiency	= 135.79 mmscf/d = 3836.38 mscm/d
Distance from gas loading locations (km)	1. Offshore location: 302.869 2. Vasilikos Port: 484.023

Table 31: Arish Thermal Power Plant Egypt

Country	Egypt
Mainland/Island	Mainland
Target Buyer	Arish Thermal Power Plant Egypt Heavy Fuel Oil (HFO) Design Capacity of 66 MWe Possibility for Natural Gas Conversion
Location	- Location Coordinates: Latitude = 31.1162 Longitude = 33.6824 - Description of the location: near shore available gas pipeline network nearby port
Volume of gas based on 100 % gas conversion of the capacity	66 MWe = 1584 MWh/d = 5.405 mmscf/d = 153 mscm/d
Volume of gas using the 30% loading factor *Assuming gas turbines 50% efficiency *Assuming diesel turbines 40% efficiency	= 4.05 mmscf/d = 114.52 mscm/d
Distance from gas loading locations (km)	1. Offshore location: 456.338 2. Vasilikos Port: 403.472

Table 32: Abu Sultan Thermal Power Plant Egypt

Country	Egypt
Mainland/Island	Mainland
Target Buyer	Abu Sultan Thermal Power Plant Egypt Heavy Fuel Oil (HFO) Design Capacity of 600 MWe Possibility for Natural Gas Conversion
Location	- Location Coordinates: Latitude = 30.40245 Longitude = 32.30864 - Description of the location: near shore available gas pipeline network nearby port
Volume of gas based on 100 % gas conversion of the capacity	600 MWe = 14400 MWh/d = 49.133 mmscf/d = 1388 mscm/d
Volume of gas using the 30% loading factor *Assuming gas turbines 50% efficiency *Assuming diesel turbines 40% efficiency	= 36.85 mmscf/d = 1041.08 mscm/d
Distance from gas loading locations (km)	1. Offshore location: 445.409 2. Vasilikos Port: 489.903

Table 33: Ataka (Suez) Thermal Power Plant Egypt

Country	Egypt
Mainland/Island	Mainland
Target Buyer	Ataka (Suez) Thermal Power Plant Egypt Heavy Fuel Oil (HFO) Design Capacity of 900 MWe Possibility for Natural Gas Conversion
Location	- Location Coordinates: Latitude = 29.93619 / Longitude = 32.47192 - Description of the location: near shore - available gas pipeline network - nearby port
Volume of gas based on 100 % gas conversion of the capacity	900 MWe = 21600 MWh/d = 73.699 mmscf/d = 2082 mscm/d
Volume of gas using the 30% loading factor *Assuming gas turbines 50% efficiency *Assuming diesel turbines 40% efficiency	= 55.27 mmscf/d = 1561.62 mscm/d
Distance from gas loading locations (km)	1. Offshore location: 499.015 2. Vasilikos Port: 538.568

Table 34: Oyoun (Ayoun) Moussa Thermal Power Plant Egypt

Country	Egypt
Mainland/Island	Mainland
Target Buyer	Oyoun (Ayoun) Moussa Thermal Power Plant Egypt Heavy Fuel Oil (HFO) Design Capacity of 640 MWe Possibility for Natural Gas Conversion
Location	- Location Coordinates: Latitude = 29.91153 / Longitude = 32.5948 - Description of the location: near shore available gas pipeline network nearby port
Volume of gas based on 100 % gas conversion of the capacity	640 MWe = 15360 MWh/d = 52.408 mmscf/d = 1481 mscm/d
Volume of gas using the 30% loading factor *Assuming gas turbines 50% efficiency *Assuming diesel turbines 40% efficiency	= 39.31 mmscf/d = 1110.49 mscm/d
Distance from gas loading locations (km)	1. Offshore location: 506.548 2. Vasilikos Port: 539.767

All the proposed plants meet the screening criteria on distances from the loading sites and the distances from an established gas network (the distance here was estimated from the transmission lines passing south of Turkey) however only one plant meets the upstream criteria of the minimum target capacity in gas demand. Abu Qir power plant is located by the Mediterranean coastline, west of Alexandria and very near to the Port of El Maadiya. This is the only plant that could be a single gas buyer for the Gasvessel project. Furthermore, we could combine the capacities of all the proposed plants in Egypt as in previous cases, however, at this point we should deviate from the initial approach and look Egypt as a potential gas buyer at a bigger scale because of the extensive domestic gas transmission network and the regulatory changes that are currently underway regarding the gas market.

Table 35: Summary for Egypt – Power Plants

Egypt	Application	Volume	Loading Location	Unloading Location
Abu Qir power plant	Gas for Power	135 mmscfd	Offshore location	Latitude = 31.2694 Longitude = 30.1409

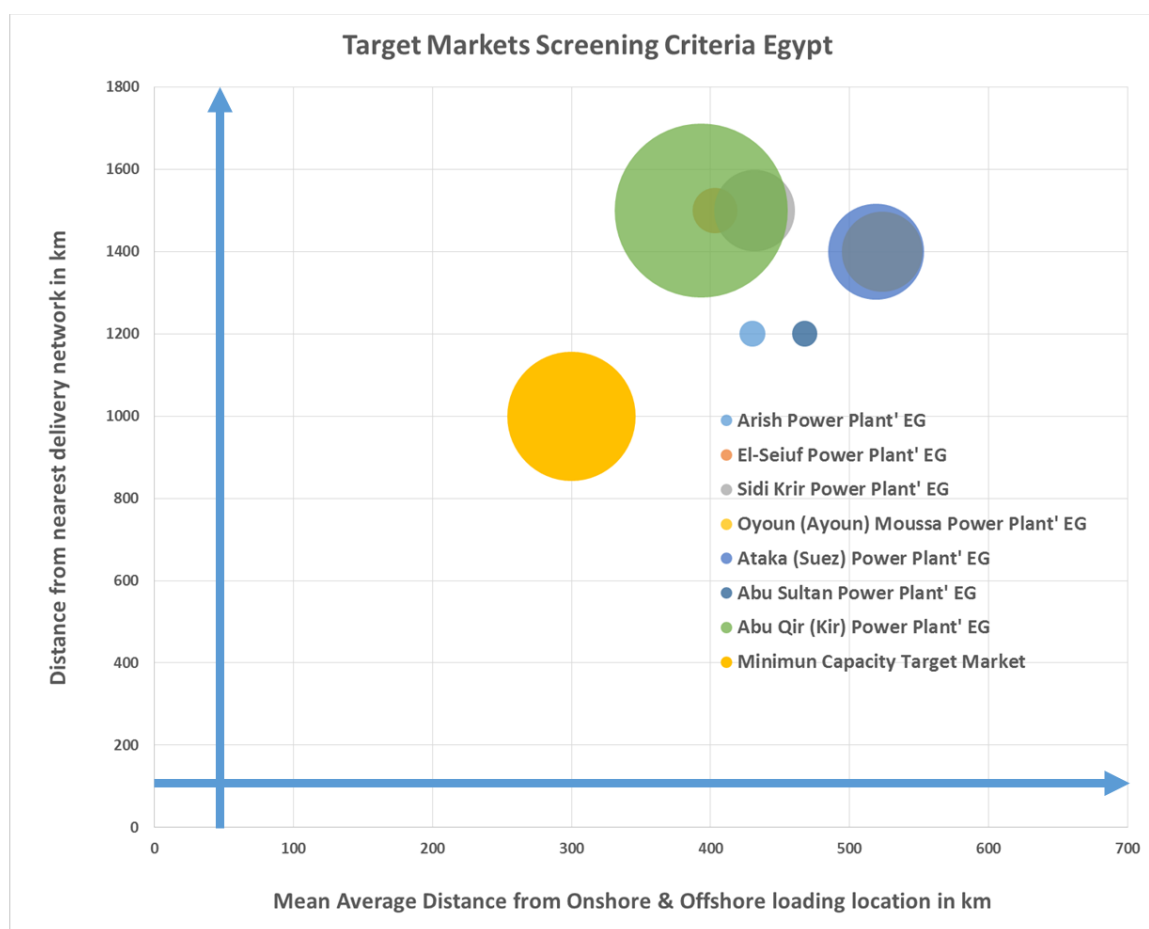


Figure 12: Power Plants in Egypt based on market screening criteria

Egypt today is considered to be net a gas importer. Between the years 2000-2010 gas was exported from Egypt through its two LNG liquefaction facilities located at Damietta and Idku and through the Arab pipeline. Exports declined to zero due to the combination of several economic and political setbacks that started in 2011 and had a negative impact on oil and gas industry. In addition, decline of production in existing fields and lack of investment to increase production while having population growing (currently 92 million people with) at app. 4% per annum has created a sizable deficit between the supply and demand. To address the deficit, the government of Egypt started to import LNG cargos using its two regasification terminals and at the same time by prioritizing gas for power and household users leaving industrial players without feedstock. The priority for gas per sector and subsidies on gas prices created a gap on gas pricing between the different sectors.

The announcement of new discoveries such as the Zohr gas field, new investments in the energy sector and governmental strategies to eliminate energy subsidies and to create a fully functioning wholesale gas market show that energy sector is moving to the right direction. Taking into account current gas production, imports through LNG terminals and gas available in the region, supply is expected to increase around 2020 and then start to drop gradually until 2035 due to continues decline of the domestic production. Subject to no other significant additional discoveries in Egypt, the domestic gas deficit will continue to grow until 2040.

Industrial Customers use gas in order to produce cement, fertilizers and other chemicals which are mainly used for exports. These plants have been paying significantly higher prices for the gas compared to power plants and households. Today several industrial players fail to secure feedstock gas for their operational due.

Due to gas shortages in Egypt, the government has prioritized the allocation of volumes to power plants and households and decided to curtail the volumes going to the industrial plants, which means that they are either not operating or using alternative sources of fuel.

The fact that Industrial customers are not a priority for Egypt, combined with the fact that historically they have been paying significantly higher prices for gas, make the Egyptian Industrial customers a good fit for potential CNG deliveries. Having in mind the above trends in Egyptian energy sector (Domestic Deficit, Power Demand, status of industrial customers and regulatory reforms underway), CHC recommends that Egypt should be seen as a whole sale buyer with a demand that can satisfy different volume case studies for the Gasvessel project. Taking into account the upstream criteria we recommend that these volumes could be in the range of 100 mmscfd to 600 mmscfd and therefore suggest 3 scenarios: 100 / 300 / 600 mscfd.

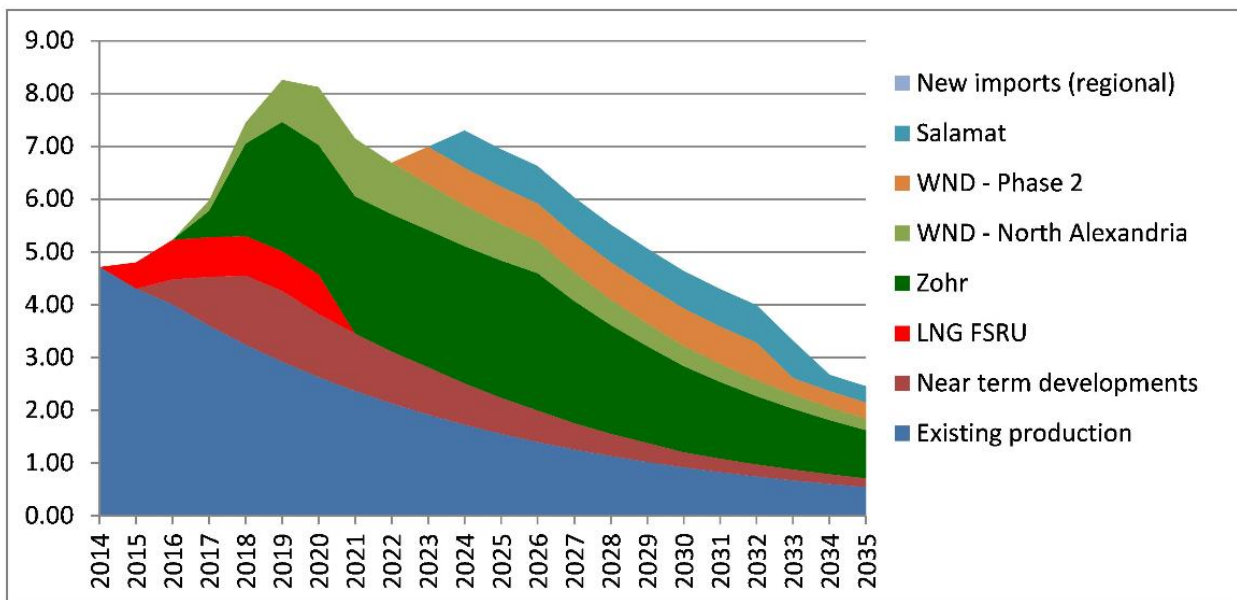


Figure 13: GCA's gas supply forecast for Egypt (mid-case scenario) in Bcf

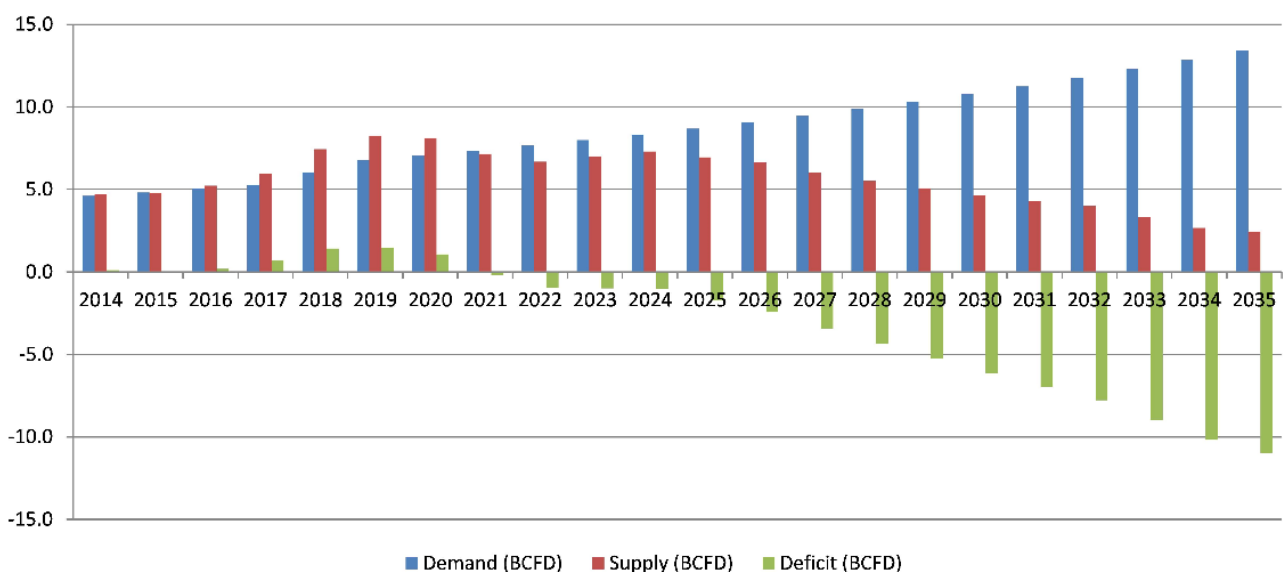


Figure 14: GCA's Mic case Supply / Demand forecast for Egypt in Bcf

Several characteristics of the Egyptian energy market enhance CHC proposal to approach Egypt as a whole sale buyer. These characteristics are:

A) The Egyptian gas grid is considered to be the largest and longest in Africa and in the Middle East providing gas from the north to the south, and extending east to Sinai and along the coast of the red sea capable of feeding power plants, household users, CNG for transportation, industrial players as well as petrochemical industries.

B) The existence today of fifteen companies in Egypt operate today as wholesale gas buyers to re-sell and distribute gas quantities to individual buyers. The list below shows those potential whole buyers for the CNG gas.

C) Government efforts to de-regulate the energy market and to allow access to its national gas network thus attracting new gas imports and open the industrial gas market [ref].

D) Different entry points to the national grid located at the Mediterranean seaside allowing easy access for the Gasvessel concept. Port Side is a possible entry point for unloading gas to the national grid. The area is considered to be an gas hub for Egypt with adequate gas infrastructure to support the Gasvessel concept.

Table 36: Summary for Egypt – Power Plants

Egypt	Application	Volume	Loading Location	Unloading Location	Distances from loading locations
Wholesale buyer i.e EGAS	Gas for Power	100 mmscfd 300 mmscfd 600 mmscfd	Offshore location and Onshore location	Port Side 31.317 Latitude 32.156 Longitude	Port Side from offshore loading location : 348 km Port Side from onshore loading location : 392 km

SUMMARY

- The main challenge for Egypt is internal. The country has high domestic gas consumption, estimated at 50bcm per year (and growing) is proceeding unchecked due to heavy government subsidies that artificially lower the price of electricity for end-consumers. As Egypt began defaulting on its commitment to export a minimum amount of gas through its LNG terminals, Unión Fenosa, Eni, Shell and others incurred heavy losses. Lengthy discussions ensued between these international corporations and the Egyptian government to resolve outstanding liabilities owed by the Egyptian state. By 2016, Egypt had racked-up a total debt of approximately \$3.6 billion to foreign companies. Expanding consumption and falling production, driven largely by the absence of government investment in further exploration activities or existing ones drove Egypt to develop its import infrastructure to meet the energy shortfall as the state went on a purchasing spree on the LNG markets.

- The discovery of Zohr injected much needed gas into Egypt's energy balance, as it is projected to produce between 20- 30 bcm per year for two decades. Given Egypt's domestic demand, the bulk of Zohr's gas will probably be directed to internal markets. Yet the size of the gas field suggests that, at maximum production, a surplus could be set aside for export, allowing Egypt to resume its role as a regional exporter by 2020-2021, after the current LNG glut has passed.
- **Supply:** Between 1999 and 2006, gas production grew by an average 19% per year, allowing Egypt to not only fulfill its domestic gas needs, but also to develop both LNG and pipeline gas export infrastructure. However, production growth slowed significantly toward the end of the 2000s, and began to consistently decline starting in 2012. Production fell from a peak of 6.1 Bcf/d in 2009 to 4.0 Bcf/d in 2016, forcing Egypt to divert most of its gas away from exports in order to meet its growing domestic needs. Zohr's development raised government hopes will allow Egypt to cease imports, and possibly return to net exporter status, by 2021.
- **Demand:** Egyptian gas demand more than doubled in a little over a decade, growing at an average rate of 10% per year between 2002 and 2009. However, growth slowed starting in the 2010s, due to reduced production, consumption fell 10% by 2015 from its peak in 2013, although initial reports suggest availability increases have since prompted a rebound. The power sector has historically been the largest consumer of gas in Egypt's economy, currently making up more than 60% of all consumption, and reaching 2.9 Bcf/d in FY 2013 and FY 2015. Its share declined throughout the 2000s as gas use in the industrial sector expanded, owing both to industrial demand growth and as a replacement for fuel oil, but the industrial sector saw a 27% decrease in gas demand between FY 2013 and 2015 amid domestic tightness.

2.13 CONCLUSION

Based on the above analysis of the different countries, it is recommended that the below scenarios can be used for further techno economic analysis for the Gasvessel project.

Table 37: Summary for Markets

Target market	End User	Volume Demand
EGYPT	Power Plant / Industrial	100 mmscfd (scenario 1)
		300 mmscfd (scenario 2)
		600 mmscfd (scenario 3)
CYPRUS	Power Plant	100 mmscfd
CRETE	Power Plant	50 mmscfd
LEBANON	Power Plant	130 mmscfd

Table 38: Summary for Scenarios proposed for evaluation at East Mediterranean

Target Market Entry Point	Offshore gas loading	Onshore gas loading	Number of Scenarios
Cyprus Vasilikos Area	YES	NO	1
Crete Linoperamata Area	YES (in combination with Cyprus)	YES (in combination with Cyprus)	2
Livanos Zouk Area	YES	YES	2
Livanos Zouk Area	YES (in combination with Cyprus)	YES (in combination with Cyprus)	2
Egypt Port Said (1)	YES	YES	2
Egypt Port Said (2)	YES	YES	2
Egypt Port Said (3)	YES	YES	2
Total Scenarios Proposed			13

Market Analysis PHASE II

As described above, Phase I of the market analysis maintained a helicopter view of the individual markets in the region in order to filter out those markets for which certain market fundamentals clearly do not fit with Gasvessel and identify those markets who make a better match. Having done that, we have finalized a list of potential target markets that fulfill the prerequisites to be a successful destination for the proposed Gas Vessel.

Phase II of market analysis will focus on the above four markets and perform a deeper analysis of the key market fundamentals. Further analysis will specifically focus:

- Energy Demand: Additional information will be provided for the existing demand as well as forecasted volumes.
- Infrastructure: Provide more detail on existing infrastructure and also provide an overview of under-construction and proposed infrastructure that might be relevant for the project.
- Pricing: provide insights related to pricing
- Regulations: A high level status of current market functioning and anticipated developments in this space.
- Market Players: a description of the key market players involved in each market.

3 BARENTS SEA GEOLOGISTICS

As part of WP2, during August-December 2017, SINTEF conducted information search on Barents Sea discoveries, gas distribution infrastructure and market screening around the Northern European region. The purpose was to identify few relevant and feasible scenarios for monetization of stranded or associated gas by use of CNG vessel. For the region identified as Barents Sea / Northern region, 3 scenarios are proposed and summarized below. These are within the feasible distances and volumes previously identified by the Gasvessel consortium as niche area for CNG-vessel transportation concepts. These scenario are not exhaustive, but complementary, and suggested for conducting comparison analysis and feasibility study of the Gasvessel concept.

Scenario:	LOADING POINT	UNLOADING POINT	Gas facility + pipeline entry			Gas storage facility	Gas tariff	Alternatives
			NYHAMNA	KOLLSNES	KÅRSTØ			
SCENARIO 1 Offshore (associated gas) to onshore gas	JOHAN CASTBERG	Distance (1)	686	800	896		\$0,31 /Sm3 (0,01/scf)	LNG ship
	Gas reserve: 10,9 M Sm3 (0,353 bscf)	Delivery quantities / day (2)	1,44 (51)	1,09 (39)	1,42 (50)			
SCENARIO 2 Offshore (gas field) to onshore gas	ALKE	Distance (1)	645	743	805		Not identified	LNG ship
	Gas reserve: 11,37 MSm3 (0,401 bscf)	Delivery quantities / day (2)	1,44 (51)	1,09 (39)	1,42 (50)			
SCENARIO 3 Onshore gas production to Onshore	KÅRSTØ	Distance (1)				244	\$0,05-0,14 /Sm3 (\$0,002-0,005 /scf)	LNG ship Pipeline
	Gas production capacity:	Delivery quantities / day (3)				1,6 – 4,5 (56 - 158)		

	95							
	MSm3/day							
	(3,35 bscfd)							

3.1 CONCEPT DESCRIPTION

The objective of this document is to provide necessary information for setting up a scenario for monetization of gas from Barents Sea based on the Gasvessel CNG-ship concept. For the region Barents sea / Norway, 3 concept scenarios are proposed, based on information collected on both gas fields, gas markets, distribution network available and previous feasibility studies performed in the region: 2 from offshore loading to near shore unloading (scenario 1 and 2), and one from near shore gas processing facility to near shore unloading (Scenario 3).

- Scenario 1: offshore loading from green gas field to unloading at onshore (gas facility)
- Scenario 2: offshore loading from associated gas field to unloading at onshore (gas facility)
- Scenario 3: onshore loading at gas processing plant to unloading near shore

These 3 scenarios and the loading / unloading locations are illustrated in the map below (*Figure 15*):

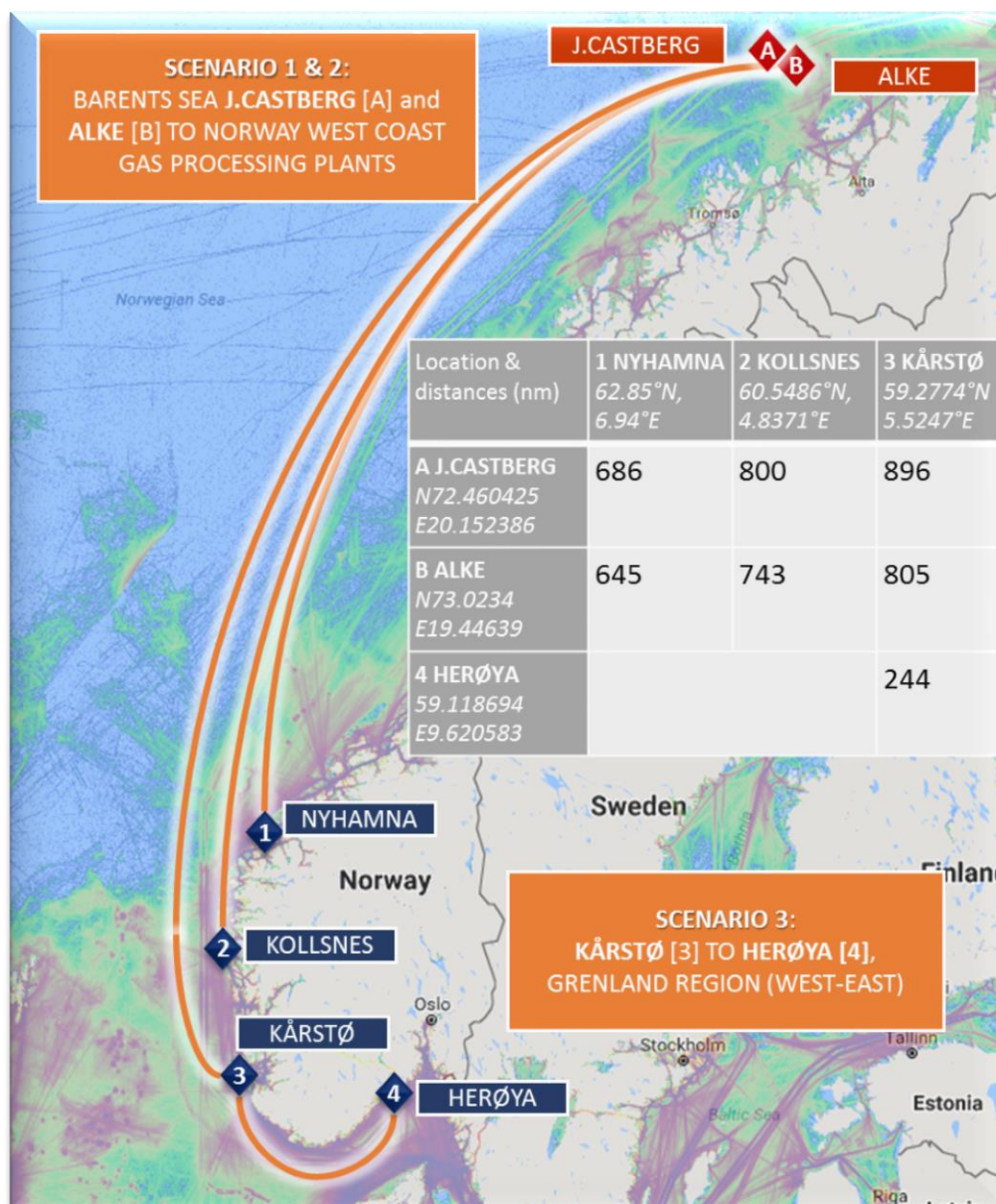


Figure 15: Map illustrating the 3 Gasvessel scenarios selected for the region Barents sea / Norway

These three scenarios display two unloading / loading concepts, illustrated below (A and B mark the battery limits for each concept):

- **Offshore Gas loading to onshore unloading** (scenario 1 and 2) (Figure 16).
In this concept, the gas originates from the identified offshore oil/gas field and is delivered to a gas facility with access to pipeline for exporting gas to Northern Europe.
- **Onshore loading to near shore unloading** (scenario 3) (Figure 17)
In this concept, the gas originates from a gas processing plant. The daily processing capacity is of 95 million Sm³ of rich gas, currently exported by pipeline.

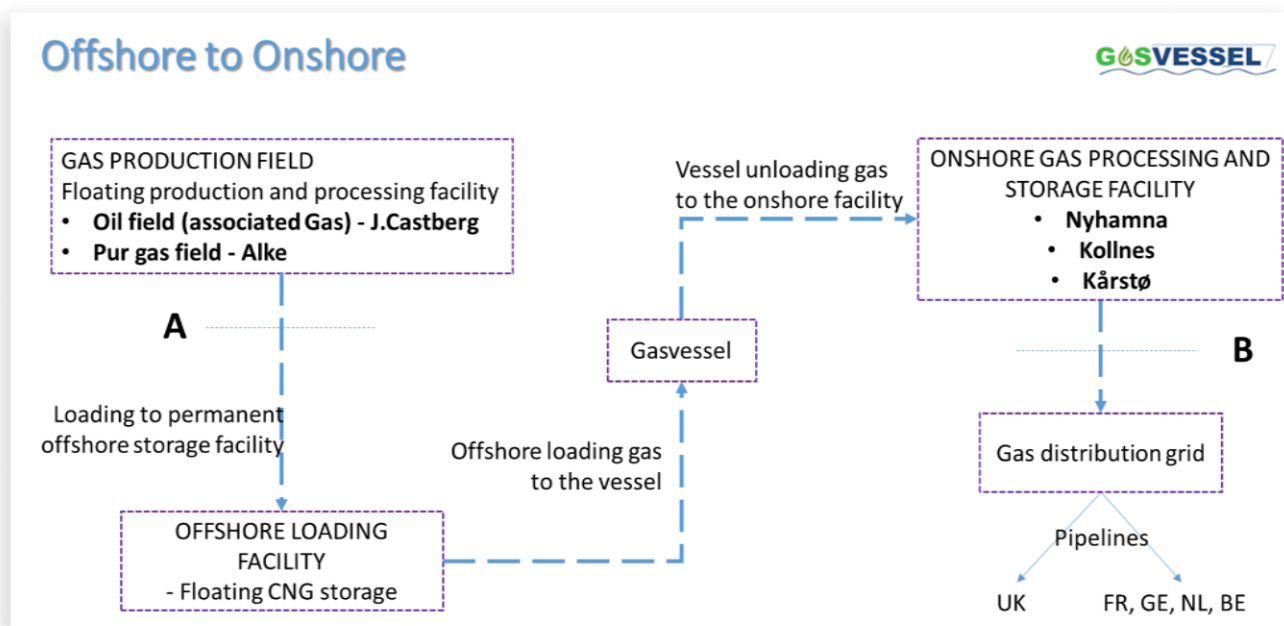


Figure 16: concept description offshore loading to onshore unloading

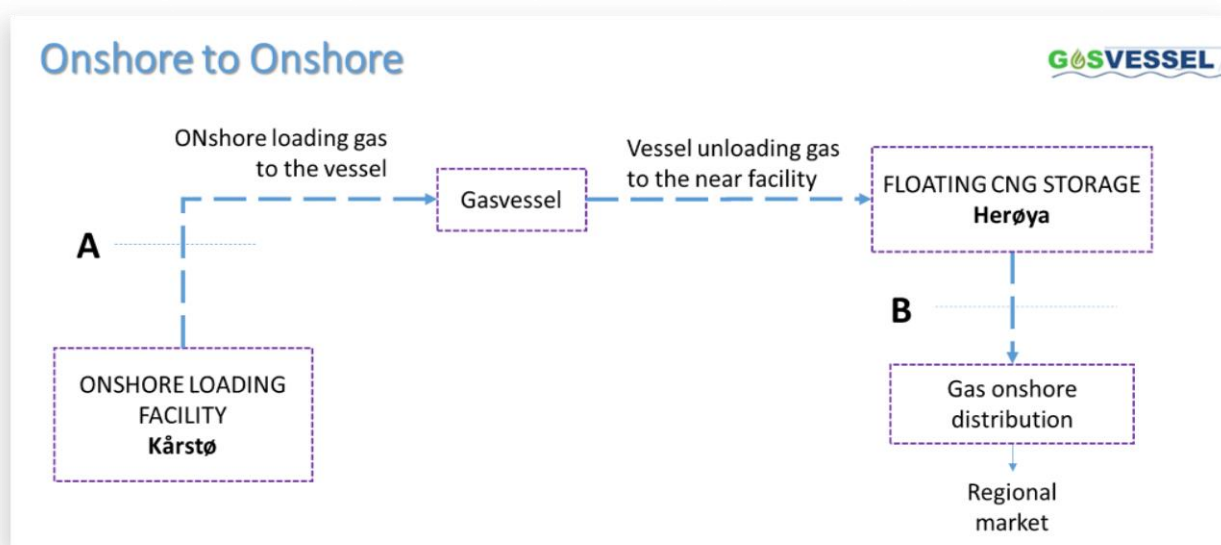


Figure 17: concept description onshore loading to nearshore unloading

These proposed loading and unloading concepts correspond to the ones described by CHC in report.

3.2 TARGET MARKET SCREENING METHODOLOGY

The objective of the market screening was to identify and characterize potential target markets in North Europe for a Gasvessel-based gas export scenario. Countries included in the review were Norway and other Northern Europe countries where gas distribution is enabled by available capacity in offshore pipelines originating from Norway) or where direct gas delivery by CNG vessel was considered realistic. Information collected per market includes; energy demand, current fuel type and energy prices, competing plans to satisfy the demand (including future government plans), Metocean and near shore characteristics of

receiving gas terminal/network or at location of the entry point in pipeline network, and distances from gas loading locations.

Priority was given to identify realistic cases, although under high uncertainty due to no exploitation plan published or known, markets and distribution scenarios in the Northern region. Given the large quantity of fields under production, the well established network and distribution infrastructure, the market analysis has not served to screen the entire potential market available for Norwegian gas, but rather interesting niches for CNG distribution by ship. The market analysis for this region has therefore focused on identifying opportunities today not exploited due to lack of infrastructure or transport solutions.

The two factors for identifying target markets during the screening work were distance from loading to unloading point, and potential market size (delivery quantity).

- **Location**

Targeted distance of 500-2500 km (270-1350 nm) from loading sites (Barents Sea southwest). The distance from Barents Sea was estimated from reference point: the Goliat field. The reason for focusing on the Barents sea is that it presents clear potential for monetizing stranded and associated gas due to lack of infrastructure and small volumes of gas discovered. The North Sea has not been considered (well established and served by pipelines). To identify relevant markets for gas from the Barents Sea south-west fields, the area shown in the map below was considered. Later in the project, an additional scenario based on loading point from gas production plant (onshore near Kårstø) was considered more realistic than with loading from gas field in Barents sea, and still within the distance limits targeted by Gasvessel. The CNG market considered is located on the East coast of Norway (point of unloading: Herøya, in the Grenland region, with further distribution to the region and Oslo district).

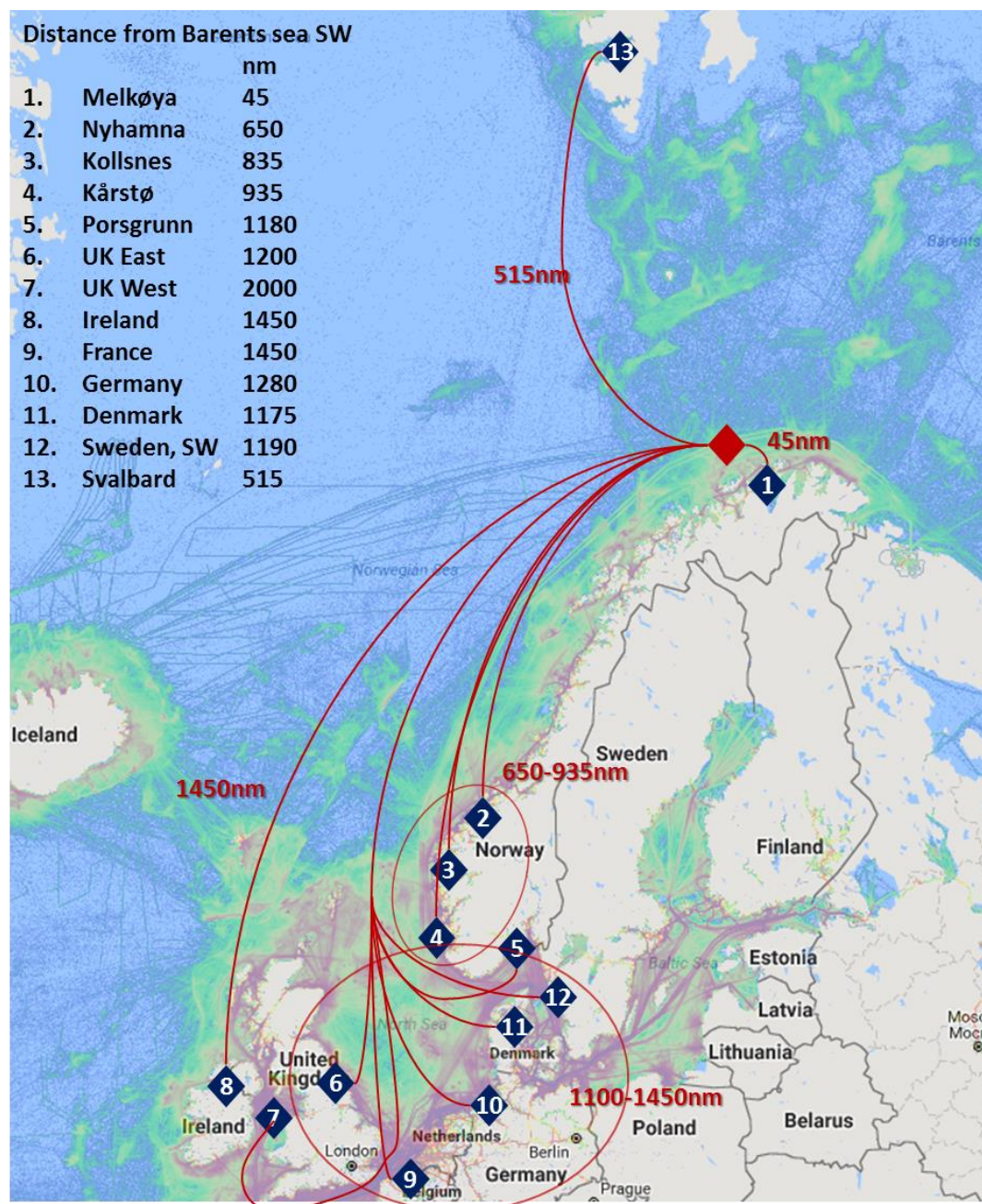


Figure 18: Potential CNG markets / delivery points considered in the market screening and distance (in nm) from Barents sea gas fields identified.

- **Potential market size**

Targeted volume of gas 50 – 500 mmscfd. Most of the work has been focusing on identifying potential local markets and specific annual demand / consumption. Information on energy consumption, forecast, energy price and on country energy dependency and energy strategy was reviewed. Potential customer analysis was based on a review of existing gas processing facilities, gas distributor, power plant (with potential for switching to gas, from coal or oil), and manufactures with potential to switch for gas as energy source. Despite some isolated market (power plants) identified, it was commonly agreed with project partners that these isolated markets were less realistic than delivery to pipeline entry point for further distribution from Norway to Northern Europe. Three distribution points were identified at gas processing plants, based on a review of their distribution network and capacity.

As an input to market screening, given the small size of the reserves identified, the size of market demand has been compared to the theoretical estimated production rate of the gas fields. The figure below shows the estimated daily production rate as function of number of years of field production. To anticipate a production over a period of 20 years (as the oil field Goliat), the minimum daily gas production rate must be 50 mmscfd for both Alke and J. Castberg (proposed for scenario 1 and 2). As a comparison, the minimum daily rate must be 100 mmscfd for the pure gas field Pingvin (largest theoretical reserve amount), and 20 mmscfd for the field Kramnsnø.

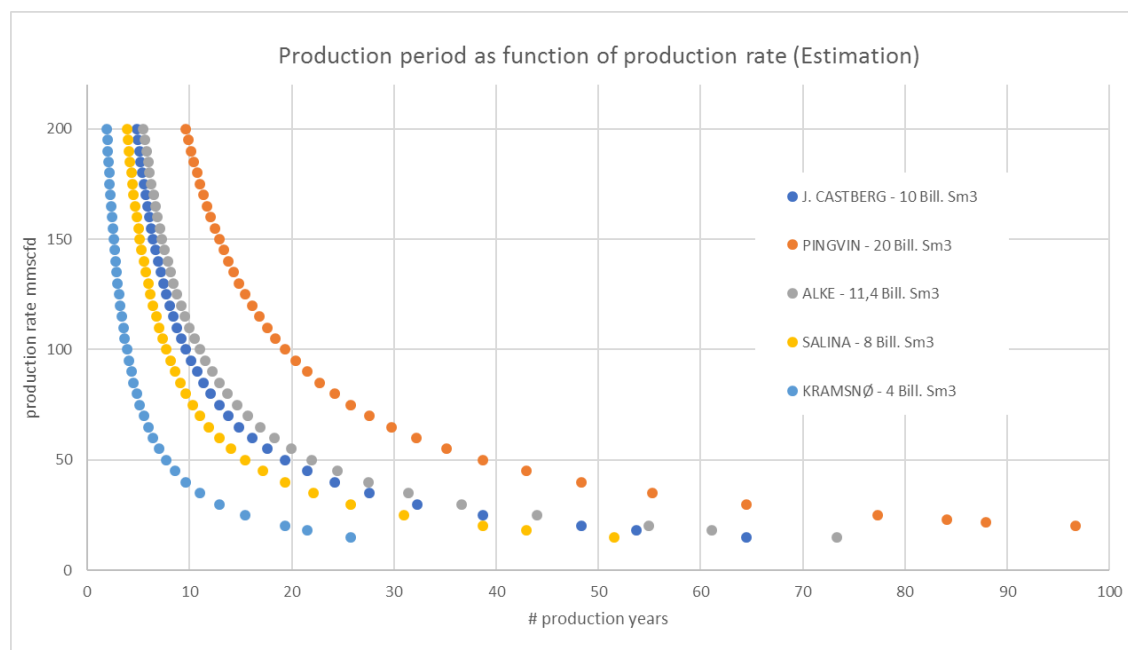


Figure 19: estimation of production period as function of daily production rate for distinct Barents sea fields.

3.2.1 SUMMARY OF MARKET SCREENING

After a first screening work, the conclusions were the following: Most of the markets are well deserved already by the gas pipeline network of the Norwegian shelf (UK, France, Benelux, Germany), which implies two main distribution scenarios: direct delivery by Gasvessel, or delivery to a pipeline entry point on the Norwegian West coast then further distribution by pipeline.

For direct delivery, the UK market (largest market for Norwegian and relatively more isolated than continental Europe) was reviewed extensively, in terms of coal-fueled power plants, gas distribution network, energy policy. Concrete case for direct delivery included 2 power plants located at a 2000 nm distance from Barents sea. Another direct delivery case was identified in Svalbard, but this was rather a highly theoretical scenario of CNG delivery to two power plants currently fueled by coal.

Other potential international markets not connected to the subsea gas network were reviewed but not potential future demand for CNG distribution by ship was identified (Denmark, Sweden, and Ireland).

Regarding delivery to pipeline entry point, potential reception points include gas processing facilities on the west coast of Norway (Nyhamna, Kollsnes, and Kårstø), all connected to gas pipeline for receiving gas from offshore gas fields, and exporting by pipeline to Northern Europe. Regarding Norway, a potential market

considered in the South East coast of Norway was identified, not connected to any sub-sea gas pipeline, but with gas facilities that may enable the supply of gas by CNG ship.

After a workshop with project partners, it was advised to abandon the scenarios with unloading points in markets already served by pipeline (UK, FR, GE, NL, IR), and rather to focus on point of entry of pipeline: Nyhamna, Kollsnes, Kårstø on the west coast of Norway (points (2)(3)(4) on the map of *Figure 15*). The Svalbard scenario was also abandoned due to the existing competing options for phasing out of coal, as well as the physical and meteorological challenges associated. A new scenario was selected, switching from Barents Sea field to a gas processing plant (Kårstø) as loading point.

3.3 DESCRIPTION OF GAS LOADING LOCATIONS

2 offshore fields and one gas processing plant have been selected for the set-up of Gasvessel Barents Sea/Norway scenarios. These are presented below, together with the offshore gas fields considered as interesting and potentially suitable for a CNG project. The assessment of the monetization of potential of these offshore gas discoveries is based on the discovery status, exploitation plan, volume of recoverable gas, and field location with regards to distribution infrastructure. Information reported include field characteristics such as location, operator, reservoir characteristics, gas composition, and Metocean data.

In terms of gas composition, and to some extent reservoir characteristics, it has proven challenging to find information available to the public. During the preparation of this report, public information from NPD and divers industrial and research reports has been used. The authors have also carried interviews with the operator of the pipeline distribution network for Norwegian gas – Gassco, and been in close contact with the Norwegian Petroleum Directorate. Valuable advice and information assessment has been received from Edoardo Cainer from Navalprogetti.

3.3.1 SCREENING OF FIELDS

Detailed information of the screening of gas fields and fields with associated gas in the Barents Sea can be found in report A4.

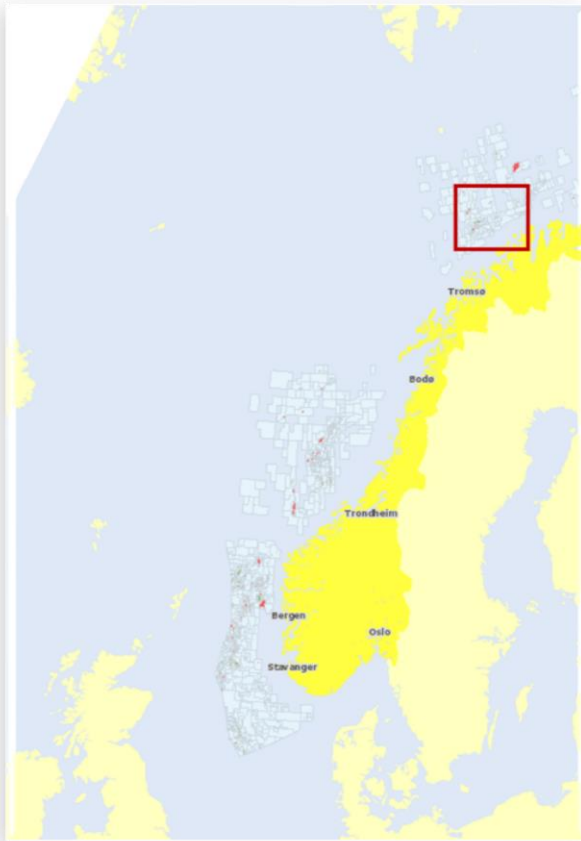


Figure 20: Barents Sea south-west

The screening of fields consisted of a review of all discoveries containing gas made in Barents Sea, based on data from the Norwegian Petroleum Directorate and from previous feasibility on Barents Sea gas production and transport infrastructure (Gassco, 2012, 2014).

The following approach for data gathering and assessment has been applied:

- Scope / area: Barents sea, stranded and associated gas; discoveries with not access to pipeline infrastructure; complementary to the cases identified in the two other regions in Gasvessel (Med and Black Sea)
- Distance: Scenarios Barents Sea to Northern Europe need to fulfil the CNG feasibility distance criteria established by Gasvessel, ca. 500-2500km.
- Volumes: the potential supply from selected loading points (offshore fields) must fulfil the CNG feasibility volume criteria established by Gasvessel: 0,7-7 bcm/year.

Figure 21 and Table 39 summarise the fields and discoveries considered. The discovery/field name underlined are the ones considered realistic and relevant for a CNG case. In the figure, the red quadrants are pure gas fields, and green are oil/gas fields. The quadrants with thick black border are categorised as "production unlikely" by the NPD (Norwegian Petroleum Directorate). In these cases, information from the discovery and wellbore report(s) has been reviewed.

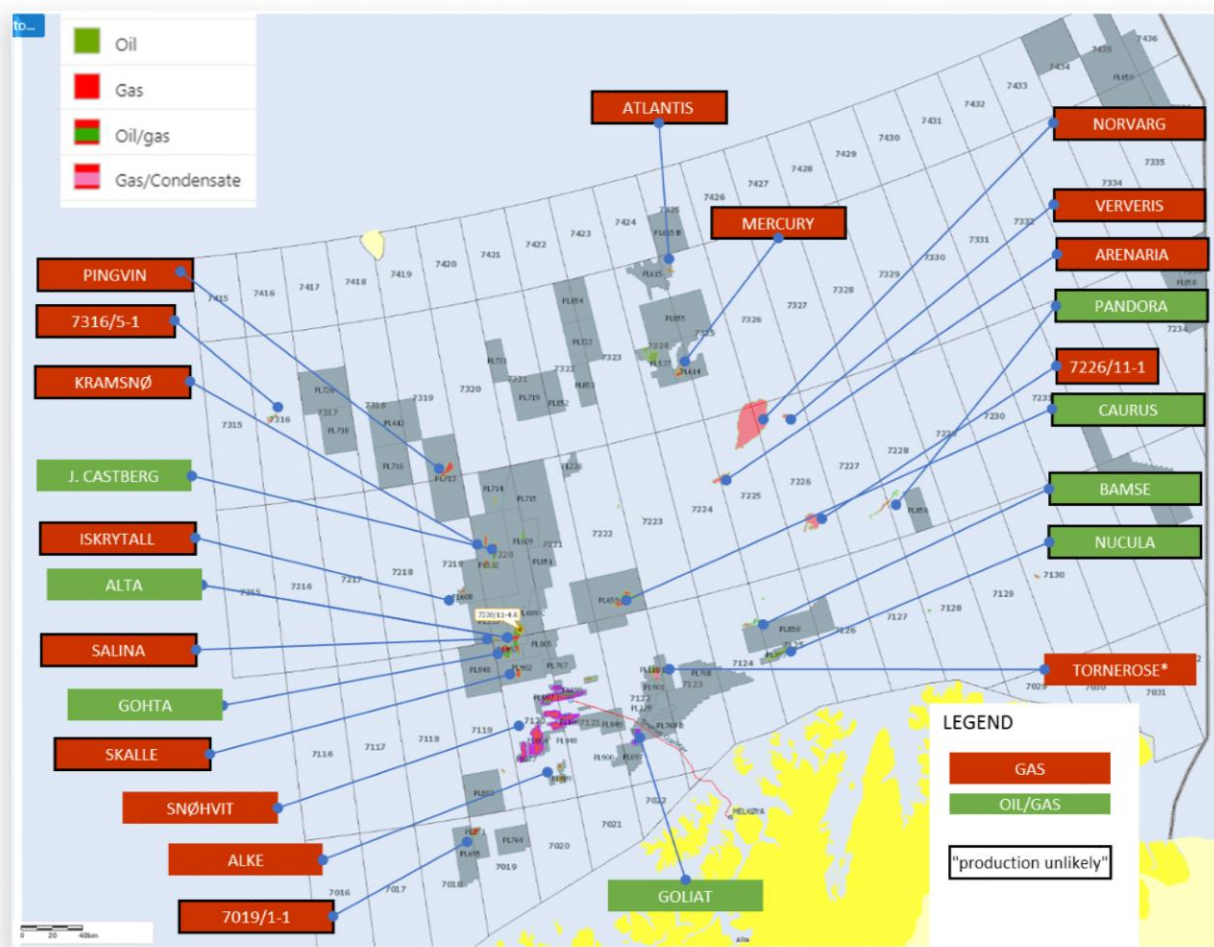


Figure 21: Map of gas and oil/gas discoveries and fields from Barents Sea reviewed as potential loading fields for Gasvessel.

Table 39: List of Barents Sea South-West oil and gas discoveries and production (SINTEF Ocean, 2017 based on various data sources)

Field	Status	Year	content	Resources – Recoverable Gas: bill Sm3 (bcf)	Location	Water depth
<u>ALKE (nor, Sør)</u>	Production likely, but not identified	Discov. 1981	GAS/ CONDENSATE	11,4 bSm3 (402 bscf)	71.1°N 22.7°E	164 /185 m
<u>GOLIAT</u>	Producing (Oil)	Start prod. 2000	OIL / GAS	10,70 bSm3 associated gas (377bcf)	71.30°N 22.30°E	400 m
SNØHVIT	Producing	Start prod. 2007	GAS	Remaining 182 bSm3 (6422 bscf) Orig. Reciverable 223 bSm3 (7869 bscf)	71.56°N 21.23°E (Pipeline entry)	340 m
<u>SKALLE</u>	Production unlikely	Discov. 2011	GAS	2,5 - 7,9 bSm3 (88-278 bscf) [1]	71.71°N 20.37°E	327 m
GOHTA	Production likely, but unclarified	Discov. 2013	OIL / GAS	6.22 bSm3 (219bscf)	71.93°N 20.19°E	342 m
ALTA	Production likely, but unclarified	Discov. 2014	OIL/GAS	9.70 bSm3 (342 bscf)	72.0°N 21.55°E	388 m
<u>SALINA</u>	Production unlikely	Discov. 2012	GAS	6-8 bSm3 (211-282 bscf)	72.0°N 20.0°E	341 m

ISKRYSTALL	Production unlikely	Discov. 2013	GAS	2,3 bSm3 (81bscf) [2]	72.32°N 19.60°E	344 m
<u>KRAMSNØ</u>	Production unlikely	Discov. 2014	GAS	2 – 4 bSm3 (70-140 bscf) [1]	72.59°N 20.22°E	403 m
<u>Johan CASTBERG</u>	Production in clarification phase	Discov. 2011	Oil/Gas	10.90 bSm3 [384bscf]	72.5°N 20.33°E	370 m
PINGVIN	Production unlikely	Discov. 2014	GAS	5-20 bSm3 (176-705bscf) [3]	73,0°N 19,74°E	422 m
<u>NORVARG</u>	Production unlikely [4]	Discov. 2011	GAS	5-10 bSm3 (175-352bscf) [4]	72,9°N 25,9°E	377 m
VERVERIS	Production unlikely	Discov. 2008	GAS	3,5 bSm3 (124bscf) [5]	72,8°N 26,6°E	341 m
ARENARIA	Production unlikely	Discov. 2008	GAS	0,5 bSm3 (18bscf) [5]	72,6°N 25,0°E	415 m
PANDORA	Production unlikely	Discov. 2001	OIL/GAS		72,2°N 27,9°E	
CAURUS	Production unlikely	Discov. 2008	OIL/GAS	2-14 bSm3 (70-494bscf) [5]	72,0°N 22,6°E	
BAMSE	Production unlikely	Discov. 1987	OIL/GAS			
NUCULA	Production unlikely	Discov. 2007	OIL/GAS			293 m
<u>TORNEROSE</u>	Production in clarification phase	Discov. 1987	GAS/condensate	3.69 bSm3 (130bscf)	71,6°N 22,85°E	400 m
SNØHVIT	Producing	Start prod. 2007	GAS	Remaining 182,40 (5,2) Orig. Recoverable 223,80 (6,3)	71.56°N 21.23°E ⁽⁷⁾	340 m

Table notes / info and data sources:

Main data source: <http://factpages.npd.no>

Data source: http://subseaiq.com/data/Project.aspx?project_id=928&AspxAutoDetectCookieSupport=1

<http://www.npd.no/Global/Norsk/2-Tema/Ressursregnskap-og-analyser/Norsk/RNB2013/Publiserte-tabeller-RNB2014.pdf>

<http://www.npd.no/en/news/Exploration-drilling-results/2014/731912-1/>

poor permeability & well productivity <http://www.speworkshop.no/wp-content/uploads/2015/03/SPE-Workshop-Arctic-Norway-2015-Norvarg-DST-Final-presentation.pdf>

<http://www.cleanenergyinvest.no/wp-content/uploads/2016/05/DN-14-mai-2013.pdf>

Reservoir: Depth: 1500 – 2050 m MSL • Fair porosity (12 – 18 %) • Low permeability (0.1 – 10 mD) • Reservoir Pressure: 175-180 bar • Dry gas with low CO2 content

Pipeline entry

Max production rate: 48000sm3

Snøhvit is listed as information purposed, but not selected obviously because already in production. Snøhvit infrastructure has been considered for alternative distribution scenario, but all information available confirms that the infrastructure (pipeline and storage at Melkøya) is at its full capacity until 2040 and not expansion plan are known to date.

Goliat is a highly relevant field and has been subject to previous feasibility studies of monetization of its associated gas. The current strategy is reinjection of gas and no plans for gas production are known.

Most of the fields identified have been, so far, classified at "not likely for production", has a relatively low level of gas reserve identified compared to what is necessary to justify infrastructure investment and lack of information about reservoir composition. Filtering of potential fields for the Barents Sea Gasvessel scenario was based on a review of the reservoir and wellbore reports, the size of the discovery (gas reserves), localisation of the field (not too far North East, and not too close to Snøhvit infrastructure which may represent a potential competing transport channel).

The fields/discoveries considered interesting and feasible for a CNG case are underlines in the table. These are:

- **J.Castberg**: oil & gas field approved for development field, with start oil production planned for 2022 (operator: Statoil). The field is retained for Gasvessel scenario based on associated gas. It resembles Goliat in terms of gas reserves, but still under development, and therefore still subject for feasibility study of monetization of associated gas.
- **Kramsnø** (discovery 7220/4-1) and **Salina** (7220/10-1) due to the size of the identified reserves and their localization nearby J- Castberg.
- **ALKE** Nor and Sør: classified as "production likely but unclarified". The identified gas reserve is comparable to that of J. Castberg. Despite its localization rather close to Snøhvit infrastructure (pipeline), ALKE is considered the most realistic pure gas field for a CNG case.
- **Tornerose** is also of interest, classified as "production likely", and retained as feasible in the Gassco study (2014¹) but lacks some information about the reservoir, and is located far north east in the area.
- In a longer-term perspective, **Skalle** (7120/2-3) and **Norvarg** (7225) (retained as feasible in the Gassco study (2014²)) are also to be considered as interesting for CNG case.

In the case of **Pingvin** (7319-12), although the amount of reserve has been estimated as up to 20 billions sm³ (705 bscf), the review of the wellbore report concludes otherwise. The net pay looks small (14m 967-953m) which indicates relatively low reserves; in addition, with a very well defined gas/water contact (GWC 967m), one would expect fingering of water and early shut-in of wells.

3.3.2 SELECTED OFFSHORE FIELDS / LOADING POINTS

It was agreed with project partners to select 2 fields: one of associated gas and one pure gas field.

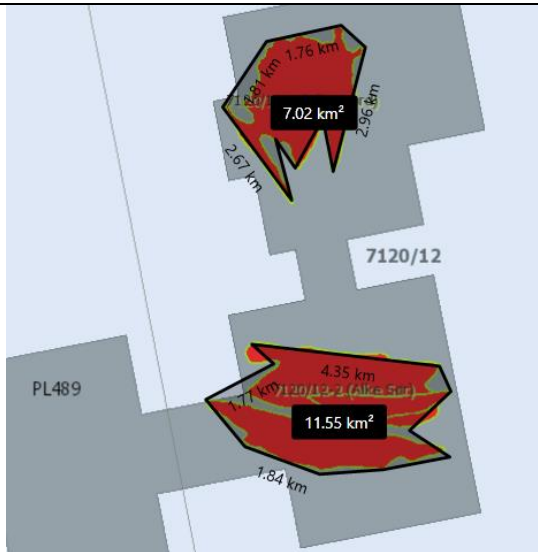
3.3.2.1 Pure gas field - ALKE

Among the 6 gas fields identified as interesting for a CNG case, **ALKE** is retained as the most realistic. Not too close to Snøhvit infrastructure (entry to pipeline), defendable size of reserve identified, and high likeliness for field development (which also implies more detailed information available on the field).

Name	ALKE
Type of Field	GAS/CONDENSATE
Block (licence)	7120/12-2 (Alke South) and 7120/12-3 (Alke North)
Operator	Eni Norway
Year discovery	1981 (Alke North 1983)
Status	Production likely, but not identified
Reservoir	Limited information available
Recoverable gas	Wellbore/exploration: 1 gas (Alke Nord), 1 gas/condensate (Alke south) Reserves: Alke North: 11.4 bill. Sm ³ (= 55 mmscfd) (20 years)
Localisation	71° 7' 30.3" N

<https://www.gassco.no/globalassets/099808.pdf>

<https://www.gassco.no/globalassets/099808.pdf>

	20° 48' 19" E
Water depth	Alke North: 185 m Alke South: 164 m
Size	 Total area Alke Sør + Nor: outreach 27 km², 11 km x 5 km
Depth	Alke North: 2523 m Alke South: 4680 m
Pressure	Alke North: Unspecified Alke South: Unspecified
Temperature	Alke North: 118 °C (at 2523m) Alke South: 115 °C (4680m), 77 °C (2568m), 66 °C (1985m) Sea water: 5-8 degrees at seabed
Reservoir characteristics; Gas composition	Alke (North + South): • Gas: 11,4 Bill Sm³ • NGL: 0,6 Bill Ton • Condensate: 0,4 Bill Sm³ • 2562 m to 2568 m: 25.1 Sm³/day condensate of gravity 55.92° API • 1944 m to 1950 m: 52.5 Sm³/day condensate of gravity 64.4° API, See detailed reservoir information on discovery wellbore reports Alke Nord online info, Alke Sør online info Additional sources for field information: • Discovery wellbore: • Barents sea studies: - Rajan, et al., 2013. - NPD.no, Gas hydrates in the Barents Sea - Vadakkepuliambatta, 2014. • Alke specific: Well 7120/12-2 completion report

3.3.2.2 Associated gas field – JOHAN CASTBERG

The consideration of associated gas for Barents Sea scenario is highly recommended for a CNG Gasvessel scenario. In a producing oil field especially offshore, associated gas represents a challenge: oil production implies gas production. When no easily accessible infrastructure is available (pipeline), the first step is to

utilize the gas as a source of energy for the offshore facilities. In case of authorization or no restriction, the associated gas is being flared.

However, at present the majority of the countries do not allow the flaring of the associated gas being it a waste of energy, waste of money and cause of pollution. In the North Sea the oil companies have built a dense gathering system to collect the associated gas from various fields (Ekofisk, Forties, Sleipner etc..) and to transport it by pipeline to the consumers.

A complete different situation is in the Barents Sea for the fields already developed or in the phase of being developed. The Goliat field is a typical case, in which gas is used for the facilities but the remaining produced gas estimated around 250mmscf/day (to be checked) is currently reinjected. Three alternatives are possible: Building a pipeline is too expensive; building an LNG infrastructure would require higher gas quantity and is too expensive. Consequently, the only suitable alternative is to inject the associated gas into the producing formation. Reinjection of gas is used to maintain reservoir pressure and displace the oil, thus increasing effectiveness of oil recovery. In that way, the gas is stored for possible future gas recovery.

However this requires deep and complex simulation studies knowing that the immiscible gas to oil displacement is an inefficient process because the gas, compared to the oil, is a highly mobile fluid resulting in a production characterized by continuous increase of the GOR (gas -oil ratio) due to fingering of the gas at the producing wells (Gas cycling). Not to mention the cost of drilling the injection wells as well as the high investment for compressors and the incremental operating cost. On the other side, immiscible gas inject technique is used as secondary recovery process in fields containing under saturated oil, since by the swelling of the oil in contact with the injected gas, it might result in a high recovery factor for the field.

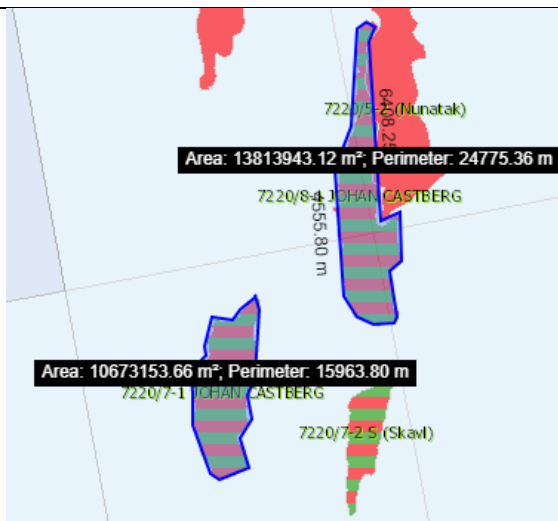
To conclude, in the petroleum industry, to increase the recovery factor of an oil or condensate field a lot of improvement have been done since the first in immiscible gas injection in 1930 in US, Nowadays there are other EOR processes that could be applied successfully instead of utilizing associated gas which could much better valorized through our CNG project.

Valuation of associated gas is difficult, but gas reinjection is not for free. The following aspects of economics of reinjection can be mentioned (source: Nja, 2008³): although injection wells are cheaper than production wells, gas has to be cleaned and conditioned before being compressed and reinjected, which necessitates compressors normally driven by gas turbine (typically 3% of reinjected gas is used as fuel) or electrical motor.

The field suggested is **Johan Castberg**.

Name	JOHAN CASTBERG (Consisting of the fields Skrugard, Havis and Drivis)
Type of Field	Oil/Gas
Block (licence)	7220/7 AND 7220/8

Steinar Nja (Norway Petroleum Directorate) 2008 (<https://www.slideshare.net/EPetrilli/pres-sn-carbon-limit-workshop-31208-presentation>)

Operator	Statoil Petroleum AS
Year discovery	2011
Status	Production in clarification phase
Reservoir	Johan Castberg consists of three discoveries Skrugard, Havis and Drivis, proven in 2011 to 2013 in Lower to Middle Jurassic sandstone. The discoveries are planned to be developed together and the decision to continue (BoV) was taken in December 2016. The development concept includes a production, storage and offloading vessel (FPSO), with gas turbines as energy providers. The plan for development and operation (PDO) is planned to be submitted to the authorities in late 2017. The production of oil is current based on reinjection of produced gas and water, in addition to treated seawater ⁴ .
Recoverable gas	10.90 bill. Sm ³ (1,49 million sm ³ day = 52 mmscfd) (20 years)
Localisation	72.29°N 20.20°E
Water depth	370 m
Size	 Distances: 7 km * 17 km, 130 square kilometres
Depth	7220/7-1: 2230 m 7220/8-1: 2222.0m
Pressure	Unspecified – estimated to be low.
Temperature	7220/7-1: 72 °C (bottom hole) Sea water: 5-8 degrees at seabed
Reservoir characteristics; Gas composition	- Oil: 88,1 mill Sm³ - Gas: 10,9 Bill Sm³ - NGL and Condensate: 0 See detailed reservoir information on discovery wellbore reports: 7220/7-1 online info, 7220/8-1 online info

<https://www.statoil.com/content/dam/statoil/documents/impact-assessment/johan-castberg/statoil-pl532-johan-castberg-pud-del-ii-konsekvensutredning-30-juni-2017.pdf>

	Additional sources for field information: • Barents sea studies: - Rajan, et al., 2013. - NPD.no, Gas hydrates in the Barents Sea - Vadakkepuliambatta, 2014. • Targeted studies: Gas from Johan Castberg is composed on light components (C2 to C4) (NILU, Statoil, 2017)
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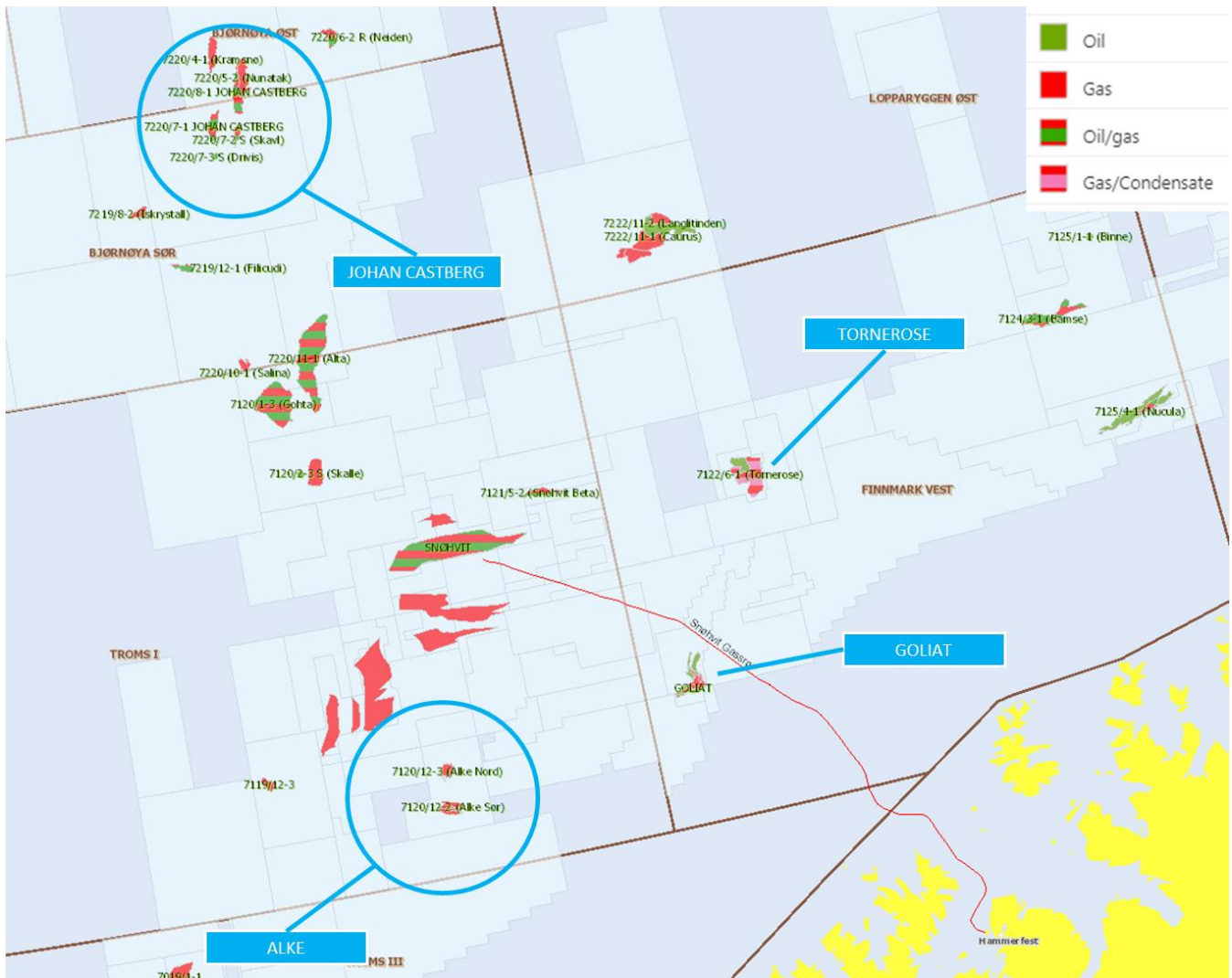


Figure 22: Map of the 2 suggested loading sites for Gasvessel Barents Sea scenario: JOHAN CASTBERG and ALKE.

3.3.3 METOCEAN (BARENTS SEA SOUTHWEST)

The following information is to be considered for both J.Castberg and Alke.

The area on focus (Hammerfest Basin, Barents Sea Southwest⁵) is characterised by shallow waters 300-400 m, cold climate, challenging conditions during winter including darkness, severe wind and waves, and fog during summer season. The flow of Atlantic (Gulf Stream) and Coastal waters is responsible for absence of ice formation and relatively middle temperatures. Average air temperature varies from -2°C to 6°C, with min/max of approximately -15°C to +25°C. Sea water temperature lies in the range of 5-8 degrees at seabed and in the range of 1-10 degrees at sea level.

Map of meteorological stations in Barents sea : http://eklima.met.no/Help/Stations/toDay/all/no_Stations.html

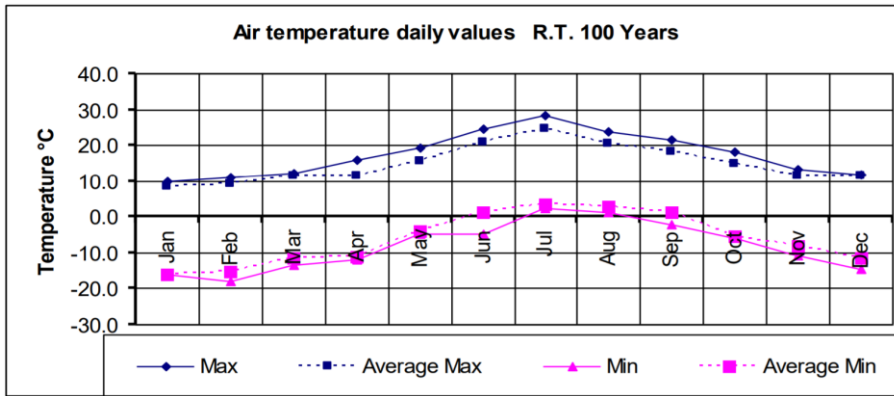


Figure 23: Air temperature Goliat FPSO (Source: ENI Norge, 2014 (Liv Nielsen, Norsk Olje og gass seminar))

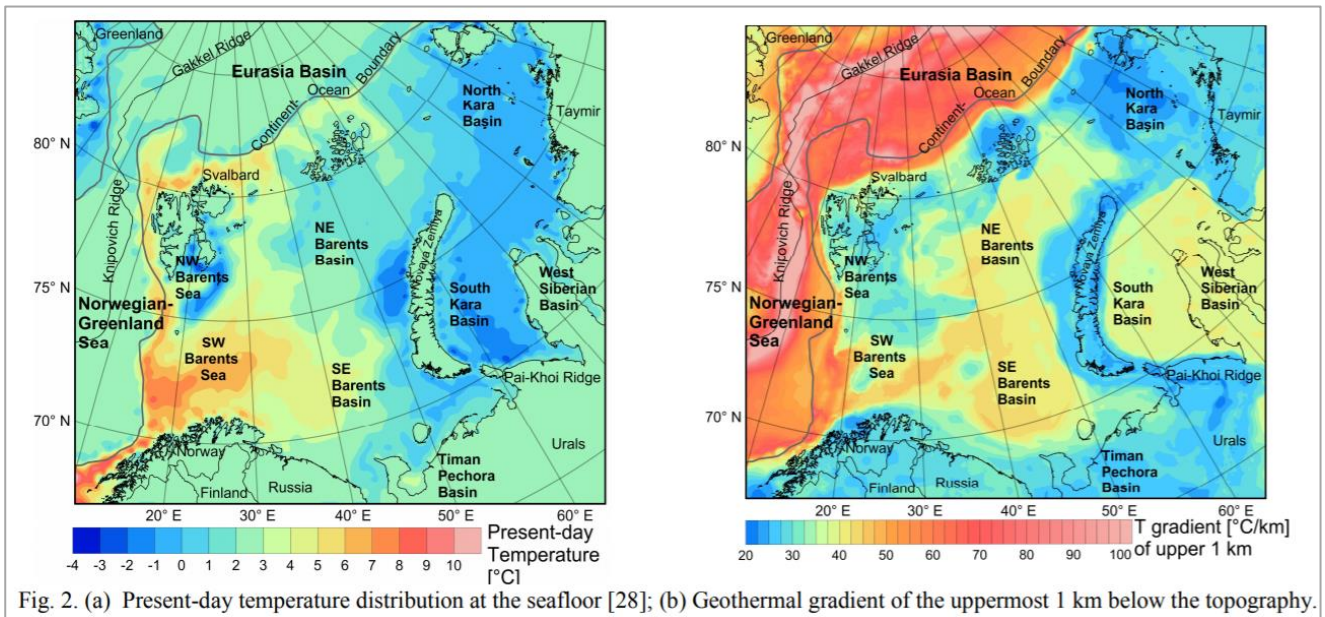


Figure 24: Temperature distribution at seafloor, Barents Sea (Source: Klitzke et al., 2016)

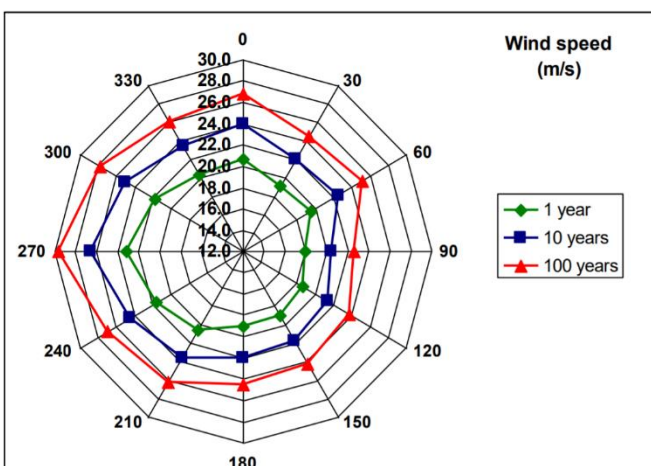


Figure 25: Wind speed, Goliat FPSO (Source: ENI Norge, 2014 (Liv Nielsen, Norsk Olje og gass seminar))

The average wind speed in the Barents Sea southwest varies from 5 to 10m/s. With peaks at, fr instance 28 m/s registered at GOLIAT FPSO (corresponding wind direction 260 degrees).

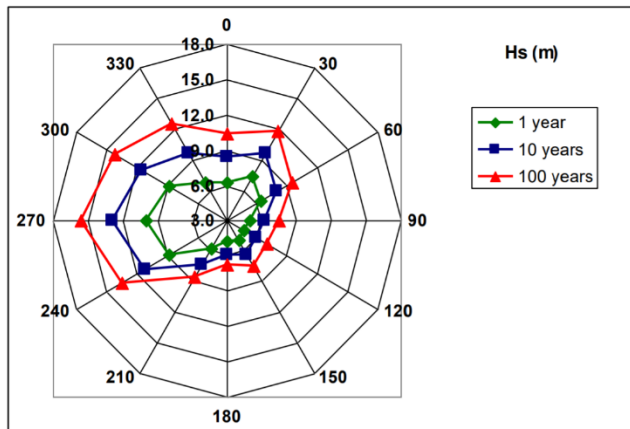


Figure 26: Significant Wave height, GOLIA FPSO (Source: ENI Norge, 2014 (Liv Nielsen, Norsk Olje og gass seminar))

Average significant wave height in Barents Sea Southwest varies from 1,5m to 3,3m. Significant wave height is generally higher in Norwegian Sea than Barents Sea.

3.3.4 ONSHORE LOADING POINT - KÅRSTØ

Independently of the Barents Sea fields reviewed, a **third loading point location** has been identified in Kårstø, as a result of a potential case of coastal CNG sea transport from production in Kårstø to distribution point nearby Porsgrunn (Grenland region on the east coast). A previous feasibility study (NVE, 2004, MARINTEK 2005, 2004) of gas transport from Kårstø to the East coast identify gas tariff at Kårstø around 39-102 øre/Sm³ (\$0,002-0,005 /scf)), and transport costs by CNG vessel around 54 øre/Sm³ (\$0,02 / scf) for a minimum viable volume around 150 MSm³/year (5 bscf/y).

KÅRSTØ is a gas and condensate processing plant.

Location: 59.2774°N 5.5247°E

Kårstø receives rich gas and un-stabilised condensate (light oil), which are separated into liquid products and dry gas. The dry gas is transported by pipeline to continental Europe. The liquid stream is separated into six different products and shipped out on special carriers. The plant has a capacity of about 90 million Sm³ rich gas every 24 hrs, 6.3 million tonnes wet gas per year and about 4.5 million tonnes condensate per year. The plant holds a central position in the export to Europe, handling approximately 25% of the total volumes (Source: Kårstø Fact Sheet).



Figure 27: Picture of the gas and condensate processing plant at Kårstø (Source: Norwegian Petroleum, Photo: Øyvind Hagen-Gassco)

The local / national market of the plant includes:

- Pipeline from Kårstø to Haugesund.
- CNG from Kårstø to Bergen region by truck.
- LNG to national, international market by ship.

For Metocean information, see **chapter 3.4.2.3**.

3.4 FIRST PHASE OF MARKETING ANALYSIS

3.4.1 SUMMARY OF UNLOADING POINTS AND ASSOCIATED MARKETS

Four unloading points are identified:

- 3 on the west coast (Nyhamna, Kollsnes, Kårstø), for gas originating from Barents sea fields
- 1 on the East coast (Herøya) for gas from gas processing plant.

3.4.1.1 Nyhamna, Kollsnes, Kårstø

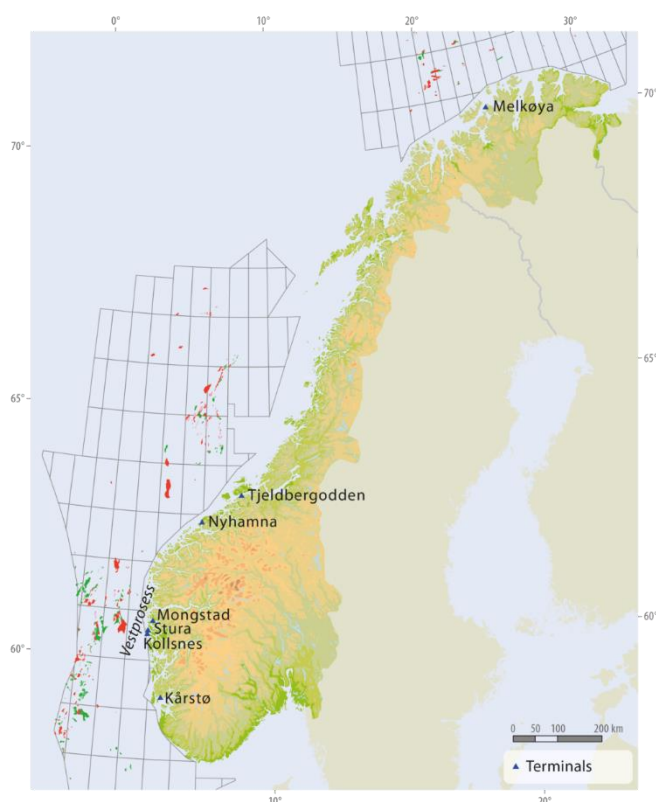
These gas facilities are able to accommodate process and export gas, mostly through pipeline to UK, France, Benelux, Germany. Although some local market is identified (pipeline, CNG, LNG), the suggested targeted markets are the European markets served by subsea pipelines.

For the markets served by pipeline, the potential quantity of gas to be delivered at entry point has not been based on market demand forecast, but calibrated by on pipeline capacity and estimated daily production rate⁶. In each case, 2% of the pipeline capacity is the best match with the fields' daily production rate.

To put things in perspectives, one can compare the size of the relevant gas markets with the total size of the gas reserve under consideration. For instance, UK's annual gas consumption is about 66 mtoe / 70 bcm, which equals 7 times the total recoverable gas of Castberg or Alke. Looking more closely at one specific power plant with potential for switching from coal to gas, *Fiddlers ferry*, its potential yearly demand of 40 bmscf (1,1 billion MSm3) represents 10% of the total recoverable gas of the Castberg or Alke. Due to these large differences between market size and field's gas reserves, it does not seem relevant to calibrate the gas production based on end market size, but rather of the capacity of gas export at the delivery point, i.e. the pipeline capacity out of Nyhamna, Kollsnes, Kårstø. The annual export capacity being still significantly higher than the field's total gas reserve, it is suggested to study several cases of volumes based on a percentage of the pipeline capacity - 1, 2, 3% - closer to the estimated daily production rate of the fields (as in Figure 19).

FACILITY	NYHAMNA	KOLLSNES	KÅRSTØ
LOCALISATION	62.2664°N 5.4460°E	60.5486°N 4.8371°E	59.2774°N 5.5247°E
DISTANCE FROM J.Castberg / Alke	686 nm / 645 nm	800 nm / 743 nm	896 nm / 805 nm
CAPACITY	70 million Sm ³ dry gas per day	143 million Sm ³ rich gas per day	95 million Sm ³ rich gas per day
Export, distribution	Pipeline to Easington, UK	Pipeline to: Zeebrugge, Dornum, Emden, Easington, Dunkerque	- Pipeline to Dornum, Emden, Dunkerque. - LNG world
Pipeline capacity			
- Total 1% 2% 3% in million sm ³ /day (mmscfd)	72,1 0,721 (25) 1,44 (51) 2,163 (77)	54,8 0,548 (19) 1,09 (39) 1,64 (58)	71 0,71 (25) 1,42 (50) 2,13 (75)

Melkøya LNG terminal, although with a capacity of 6 bcm L NG/year, was not considered a potential delivery point. This is based on information on no available capacity before 2040, and no information of future infrastructure and capacity expansion available.



Distance between unloading points
(scenario 1 & 2)

Unit: nm

	NYHAMNA	KOLLSNES	KÅRSTØ
NYHAMNA	-	148	182
KOLLSNES	148	-	104
KÅRSTØ	182	104	-

3.4.1.2 Herøya (Grenland region)

The corresponding market spans from local (Grenland region) to regional market (Oslo region and vicinity). Reference information, estimated around 570 MSm³/year (20 bscf) up to 1 630 MSm³/year (60 bscf) (highest estimate including regional transport by pipelines).

The marked is characterized by its industrial activity, including chemicals, plastics, fertilizers, aluminum. Industrial actors have studied the possibility of building a pipeline from West gas production to the Grenland

region, but no concrete construction plans until now. The main gas distributor in the region is Skagerrak Naturgass (<http://www.skageraknaturgass.no>), originally Naturgass Grenland AS established for distribution of natural gas in the region, owned Statoil, Hydro, Skagerrak Energi and Gasnor. Today, the downstream market of Skagerrak Naturgass consists of manufactures, industrial buildings, public building and transport actors (road and sea). The company exploits both natural gas and biogas, which can use the same thus existing infrastructure as natural gas. The company has 9 gas terminals in the regions, established during the period 2006-2012.

3.4.2 DELIVERY POINTS FOR GAS DELIVERY FROM OFFSHORE

3.4.2.1 Nyhamna

Capacity

70 million Sm³ dry gas per day (2,47 bcfd)

Distribution / export

DELIVERY POINT: ENTRY POINT: Nyhamna	Easington, UK
Pipe(s) name	Langled North + South
Pipeline Capacity to end destination (mill. Sm ³ /day)	74,7 and 72,1
Tariff (entry exit, €/Sm ³)	0,0126
Destination	Easington, UK

Localization

62.2664°N 5.4460°E

Distance from J.Castberg and Alke: 686 nm and 645nm

Estimated delivery quantity

Nyhamna supplies 20% of UK gas, through Langled pipeline with daily capacity of 72,1 million sm³ (=2550 mmscf/day). This is app. 26365 million sm³ per year, twice as much as the total estimated field/discovery reserve (up to 12 Billion sm³). Therefore, it is necessary to determine the quantity /market size arbitrarily. Using "available capacity" as reference is not relevant because this seems to vary continuously and deliveries can be booked almost on the spot following regulations set by Gassco. (<https://www.gassco.no/en/our-activities/capacity-management/gassled-booking-eng/>). No minimum quantity required (info not found), but gas shipper must honour the quantity agreed in the contract. **1 to 3 % of the pipeline capacity** would give the following:

1% of the daily pipeline capacity would represent 0,721 million sm³/day (=25 mmscf/day)

2% => 1,44 million sm³/day (=51 mmscf/day)

3% => 2,163 million sm³/day (=77mmscf/day)

MetOcean

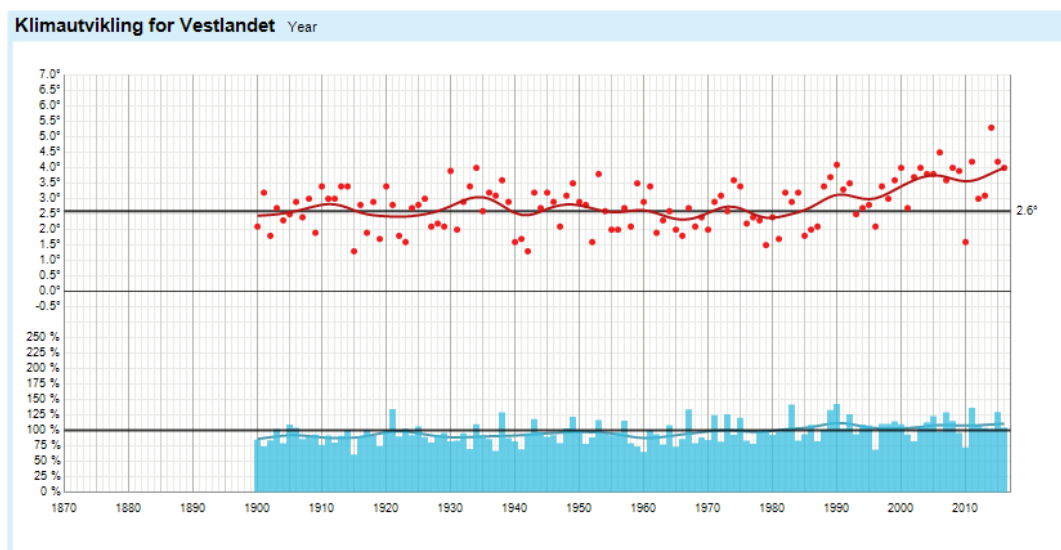


Figure 28: Temperature and precipitation, Vestlandet region (Source: yr.no)

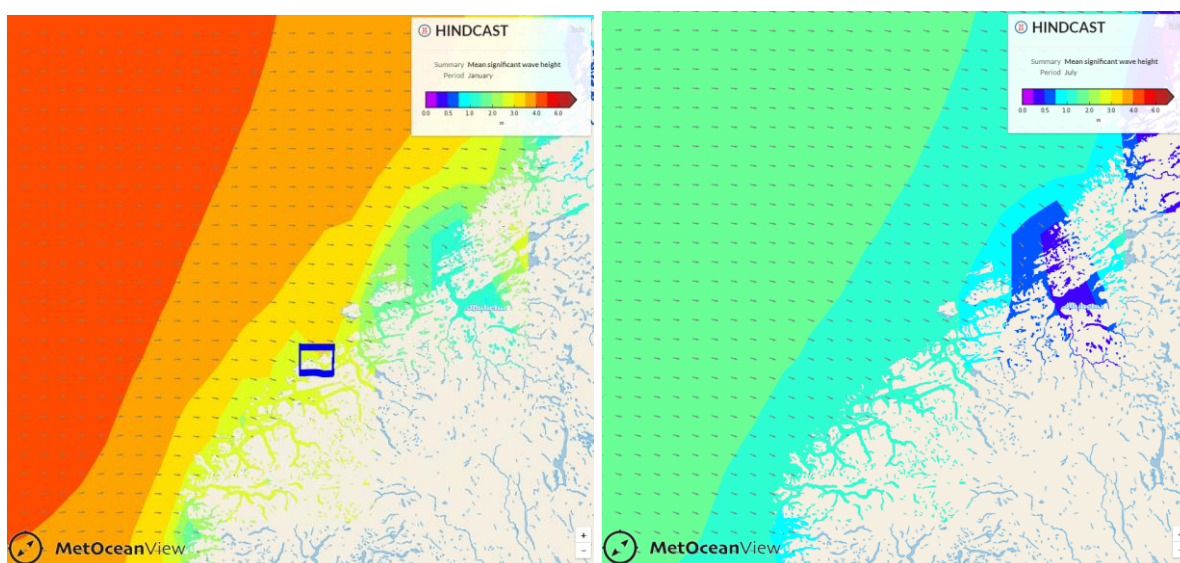


Figure 29: Mean significant wave height, Norwegian sea (Nyhamna blue quadrant), July and January (Source: metoceanview.com)

- Wind:
 - Mean wind speed, annual: 10-12 knots
 - 50% 10m wind speed: 12-14 knots
 - 99% 10m wind speed: 25-30 knots
 - RPV 10 year wind speed: 50-60 knots
 - RPV 100 year wind speed: 50-60 knots

3.4.2.2 Kollsnes

Capacity

143 million Sm³ rich gas per day

Distribution / export

- 8-10 MSm³ annually to the local region by CNG trucks
- Pipeline to Belgium, Germany, France, UK

DELIVERY POINT:	Zeebrugge	Dornum, Emden	Easington	Dunkerque	Emden
ENTRY POINT: KOLLSNES					
Pipeline(s) name and capacity to end destination (mill. Sm ³ /day)	Zeepipe II B: 77 + Zeepipe: 42,2	Zeepipe II B: 75 + Europipe: 45,7	Zeepipe II A: 77 + Langed South: 72,2	Zeepipe II B: 75 + Norpipe: 54,8	Zeepipe II B: 75 + Statepipe: 44,4 + Norpipe: 44
Tariff (entry+exit, €/Sm ³)	0,027	0,027	0,027	0,027	0,0395
Destination	Zeebrugge be	Dornum, Emden GE	Easington	Dunkerque	Emden

Localization

60.5486°N 4.8371°E

Distance from J.Castberg and Alke: 800 nm / 743 nm

Estimated delivery quantity

Kollsnes supplies both UK and Northern Europe through distinct pipelines with max capacity spanning from 42.2 to 54.8 million sm³/day (=1494 to 1940 mmscf/day)

Using the same approach as above; **% of the pipeline with highest capacity** (delivery to Dunkerque):

1% of the daily pipeline capacity would represent 0,548 million sm³/day (=19 mmscf/day)

2% => 1,09 million sm³/day (=39 mmscf/day)

3% => 1,64 million sm³/day (=58mmscf/day)

MetOcean

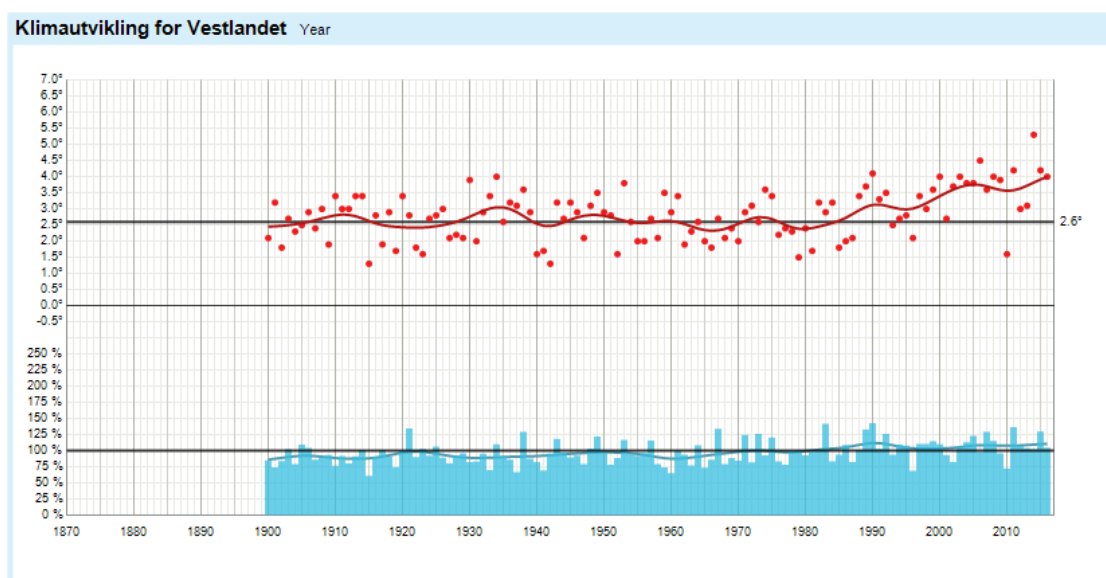


Figure 30: Temperature and precipitation, Vestlandet region (Source: yr.no)

Temperature: The dots indicate average yearly temperature. The line is a 10 year Gaussian distribution. The normal is drawn as a thick horizontal line. Precipitation: The blue bars at the bottom of the picture indicate the average yearly precipitation compared to the normal — which is drawn as a thick line through the bars. The line is a 10 year Gaussian distribution.

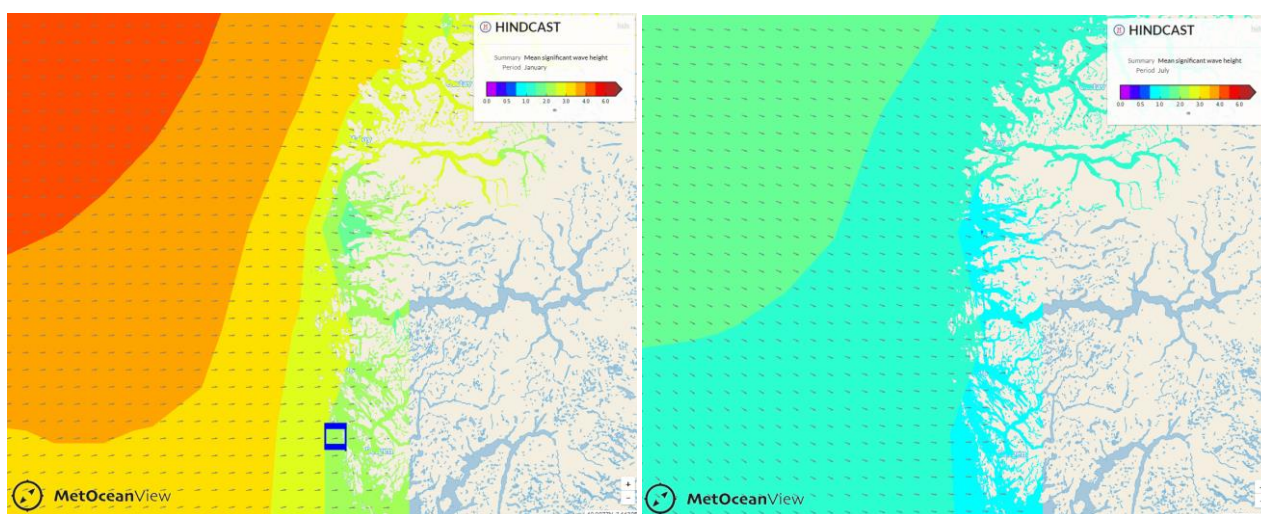


Figure 31: Mean significant wave height, Norwegian Sea (Kollsnes blue quadrant), July and January (Source: metoceanview.com)

3.4.2.3 Kårstø

Capacity

95 million Sm³ rich gas per day

Distribution / export

- LNG World; Norway
- CNG to Bergen region
- Pipeline to Germany, France

DELIVERY POINT:	Dornum GE	Dornum, Emden	Emden GE	Dunkerque
ENTRY POINT: KÅRSTØ				
Pipe(s) name	Europipe II	Statepipe Europipe	+ Statepipe Statepipe Norpipe	+ Statepipe + Franpipe
Pipeline Capacity to end destination (mill. Sm3/day)	71	21; 45,7	21; 44,4; 44	21; 54,8
Tariff (entry exit, €/Sm3)	0,0155	0,028	0,040 ?	0,028
Destination	Dornum GE	Dornum, Emden	Emden GE	Dunkerque

Localization

Localization 59.2774°N / 5.5247°

Distance from J.Castberg / Alke: 896 nm / 805 nm

Estimated delivery quantity

Kårstø supplies both France and Germany through distinct pipelines with max capacity spanning from 21 to 71 million sm3/day (=743 to 2500 mmscf/day)

Using the same approach as above; **% of the pipeline with highest capacity 71msm3day** (delivery to Dornum GE):

1% of the daily pipeline capacity would represent 0,71 million sm3/day (=25 mmscf/day)

2% => 1,42 million sm3/day (=50 mmscf/day)

3% => 2,13 million sm3/day (=75mmscf/day)

Metocean / Hindcast

Site: North Sea 59.25N 5.5E, Source: metoceanview.com

- Temperature:
 - Mean Air temperature 6-7 °C
 - Mean Sea surface temperature 8-9 °C
- Wave & wind:

Extremes	Return period [years]		
	10	100	10000
Significant Wave Height [m]	5.3	6.7	9.3
Wind speed [knots]	44	51	63

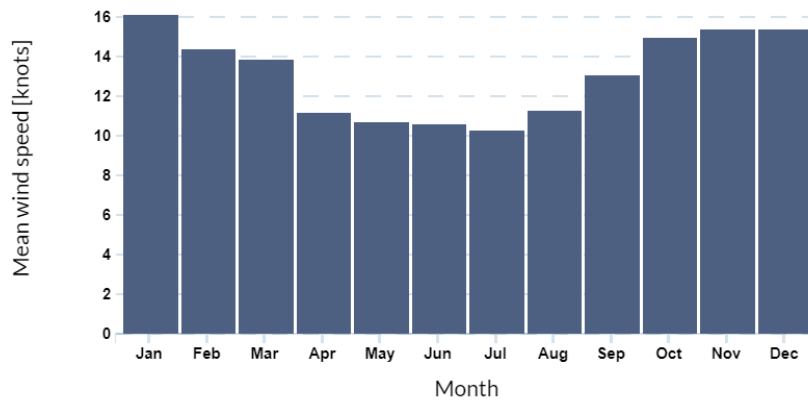


Figure 32: Mean wind speed, knots (Wind data source: MSL WRF, metoceanview.com)

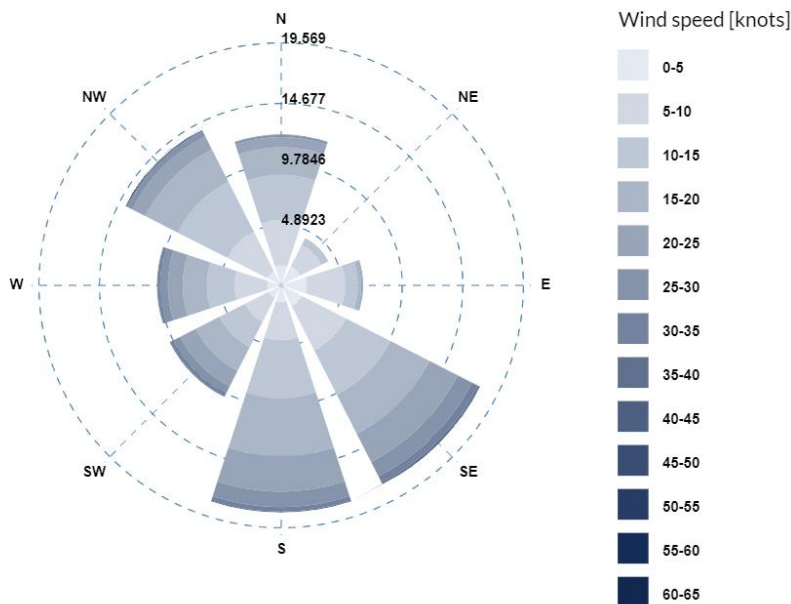


Figure 33: Wind speed and direction (annual) (Wind data source: MSL WRF, metoceanview.com)

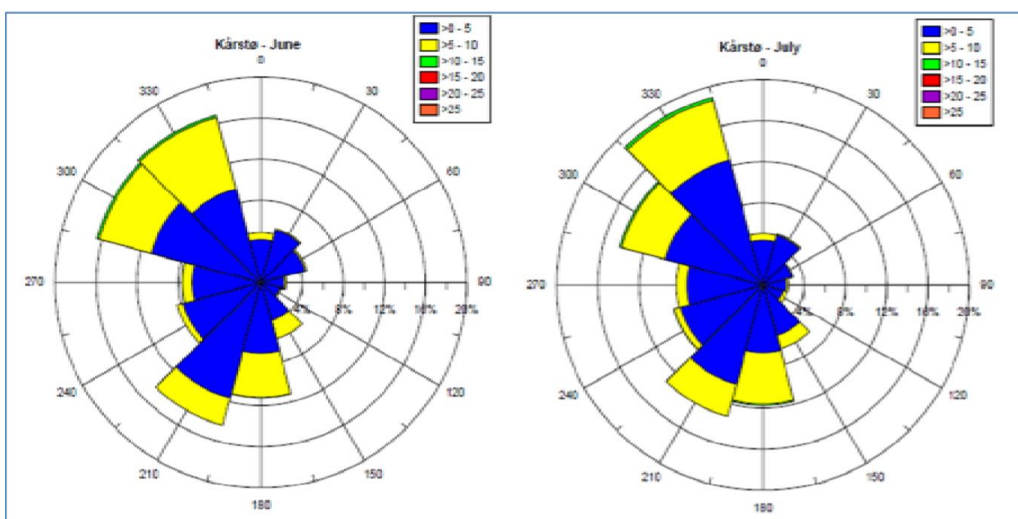


Figure 34: Wind speed and direction Kårstø area 1979-2005, June and July (Source: NIVA, 2012)

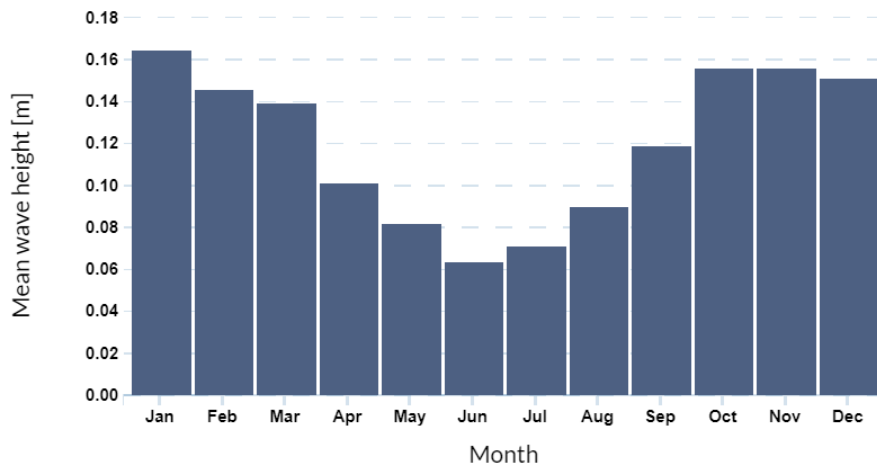


Figure 35: Mean wave height, m (Wind data source: MSL WRF, metoceanview.com)

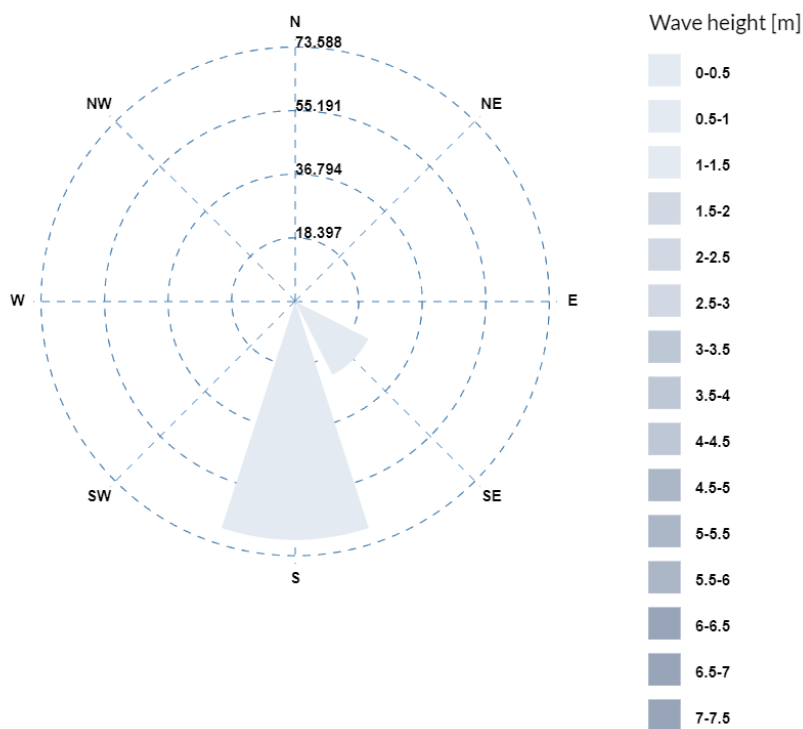


Figure 36: Wave speed and direction, annual (Wind data source: MSL WRF, metoceanview.com)

- Current

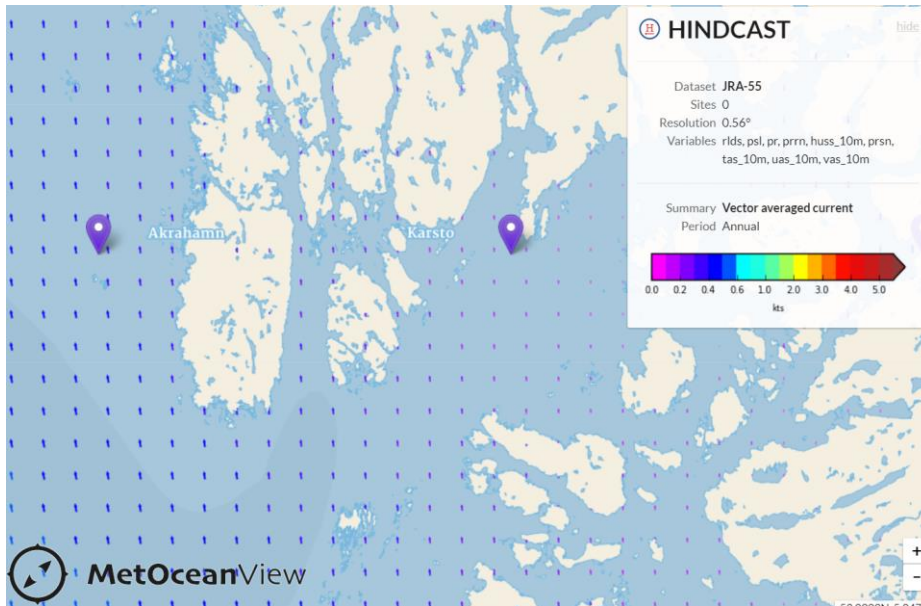


Figure 37: Vector averaged current, annual (source: metoceanview.com)

- Precipitations

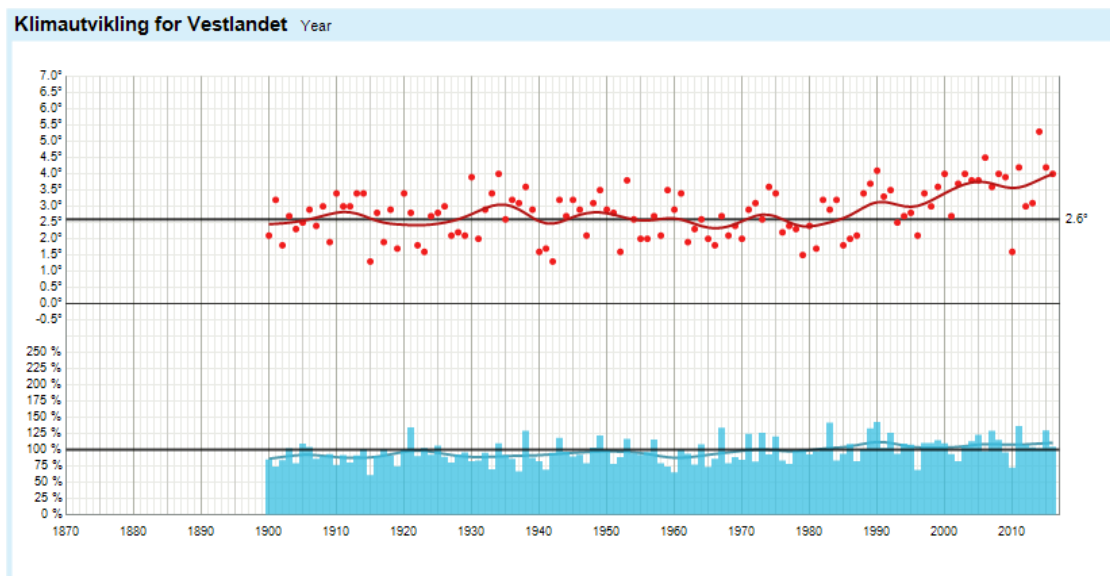


Figure 38: The graph shows long term statistics for yearly temperature and precipitation

3.5 DELIVERY POINT FOR GAS DELIVERY ONSHORE

- Distance from loading point Kårstø: 244nm.
- Delivery point: Herøya Skagerak Naturgass Gas terminal Herøya (as is the scenario from the NVE 2004 study). Sea terminal: Deep-water quay in port of Porsgrunn (Dypsvannkaia Porsgrunn havn) <http://grenland-havn.no/havneterminaler/dypvannskaia-porsgrunn/>.

Deep water quay:

- Berth length: 175m
- Depth 9.7m

Metocean information

Area at entrance of Grenland district:

- Air temperature:
 - Average annual Temperature: 6,7 °C

Mean temperature (Month normal 1961 – 1990), °C													
Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year	
-2,0	-2,1	0,8	4,6	9,8	14,4	16,0	15,6	12,2	8,2	3,2	-0,1	6,7	

Source: eKlima; data from Langøytingen Lat 58.9917, Long 9.7570; 1972-1990

Ice formation in winter in areas with weakest current, typically around Langesund and Fugløya.

- Sea surface temperature (Source: metoceanview.com)
 - Annual average: 9 °C
 - January: 2-3 °C
 - July: 16 °C
- Rain

Precipitation (Month normal 1961 – 1990), mm													
Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year	
69	47	61	46	64	61	65	85	95	114	102	71	880	

Source: eKlima; data from Langøytingen Lat 58.9917, Long 9.7570; 1972-1990

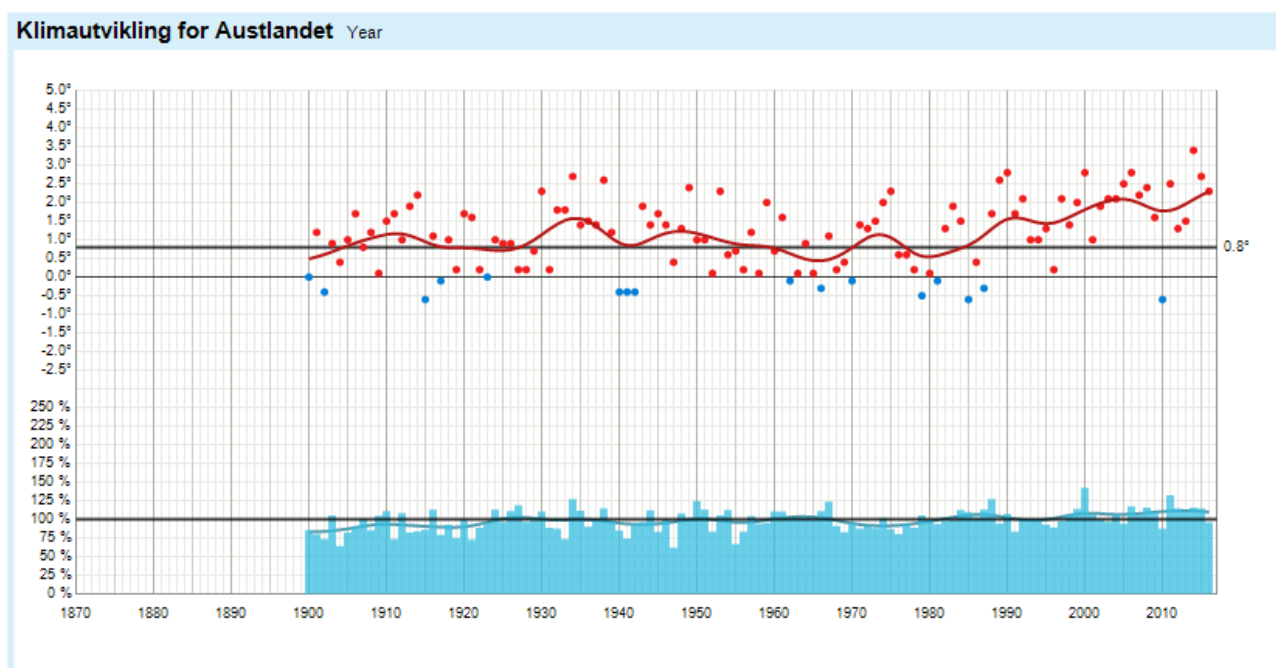


Figure 39: Temperature and precipitation, Austlandet region (Source: yr.no)

Temperature: The dots show average monthly temperature. The line is a 10-year Gaussian distribution. The monthly normal is drawn as a thick horizontal line.

Precipitation: The blue bars in the bottom of the picture shows the amount of precipitation compared to the normal —, which is drawn as a thick line through the bars. The line is a 10-year Gaussian distribution.

- Wind (Source: metoceanview.com)
 - Average Wind Speed: 10 knots/s
 - January: 15 knots
 - July: 9 knots

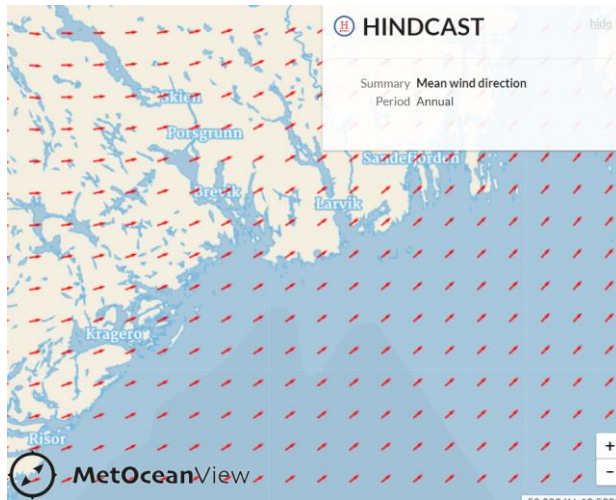


Figure 40: Mean wind direction, annual (Source: MetoceanView)

- Wave
 - RPV 100 year wave height: 4-6m
 - 99% significant wave height: 2m
 - Mean significant wave height: 0,5-1m

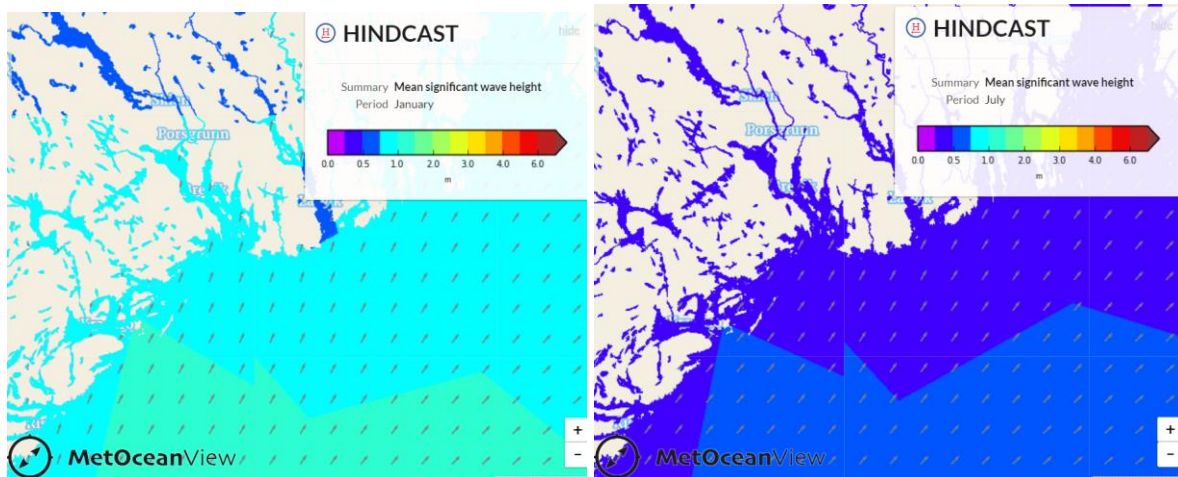


Figure 41: Wave direction and mean significant wave height January, July (Source: MetoceanView)

- Current: Average current speed, annual: 6-12 cm/s (max 25-36 cm/s)
- Sea temperature: 7-19°C

Area in focus: entrance to Grenland district (towards gas terminal in Porsgrunn).

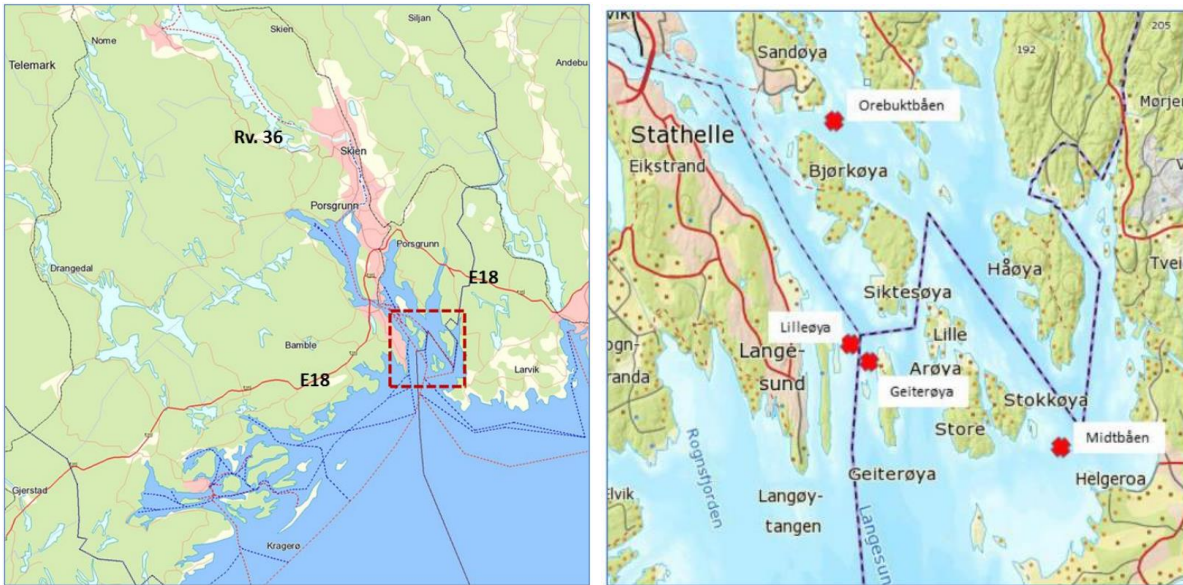
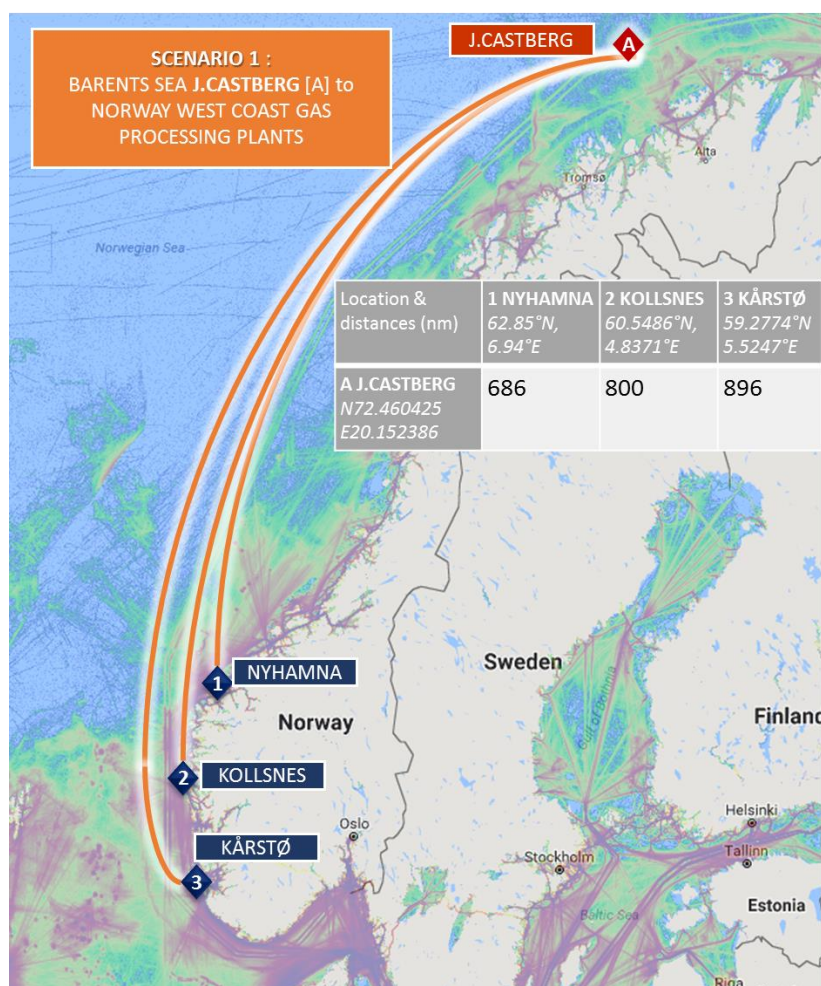


Figure 42: Map of the area considered for Metocean and traffic information and the measurement points Orebuktbåen, Lilleøya, Geiterøya, Midtbåen

3.6 SUMMARY OF SCENARIOS

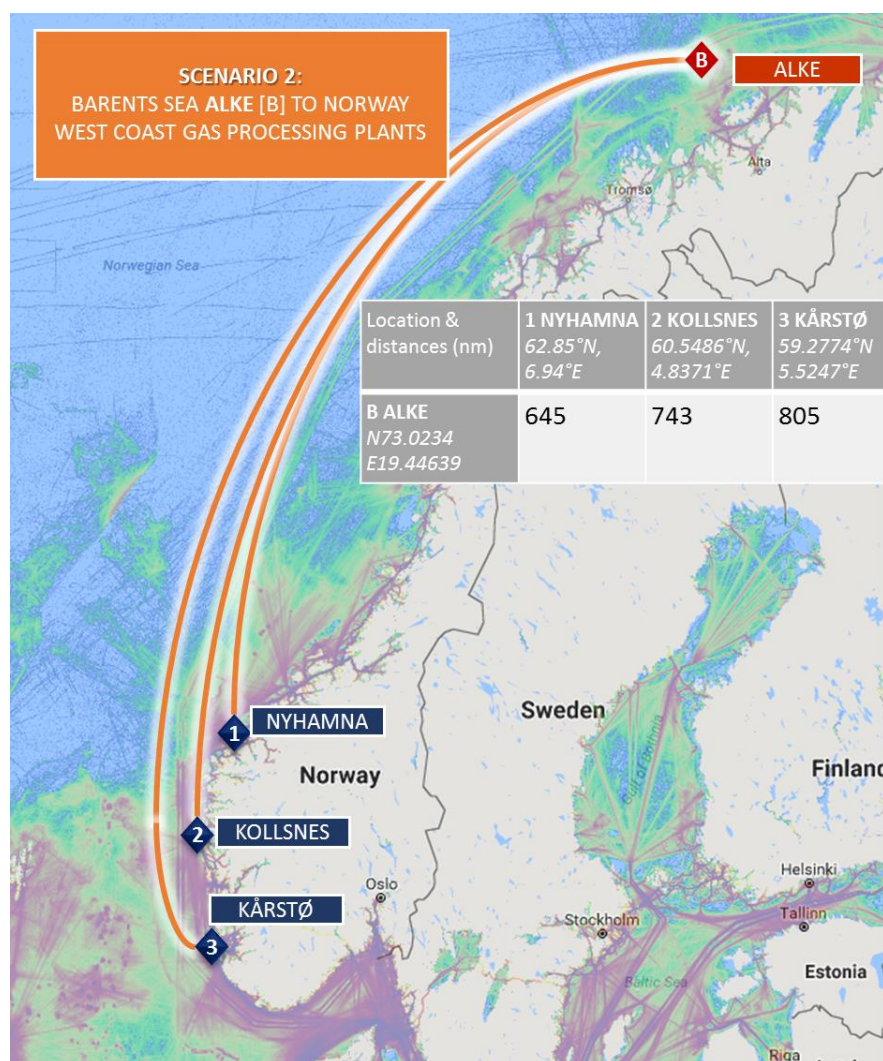
3.6.1 SCENARIO 1: OFFSHORE (J.CASTBERG) TO ONSHORE PIPELINE ENTRY POINT (NYHAMNA, KOLLSNES, KÅRSTØ)



Delivery quantity estimation:

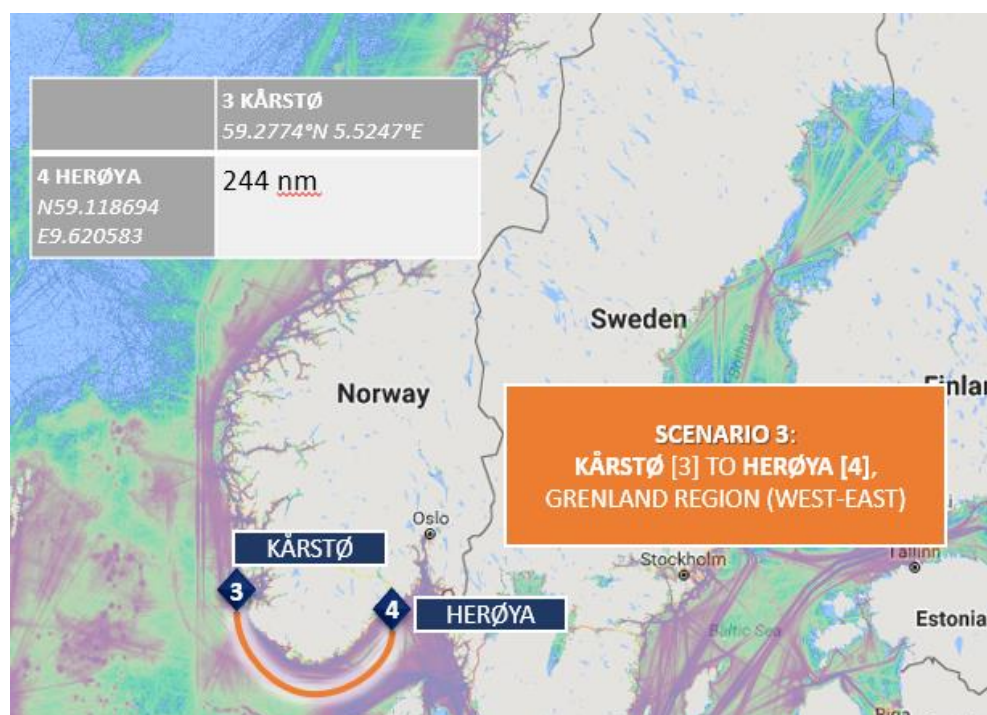
LOADING POINT ↓	UNLOADING POINT ⇒	NYHAMNA	KOLLSNES	KÅRSTØ
JOHAN CASTBERG	DISTANCE TO UNLOADING POINT [Nm]	686	800	896
GAS RESERVE 10,9 Bill. Sm3 (353 bscf)	DELIVERY QUANTITIES / DAY [million sm3/day (mmscfd)]	1,44 (51)	1,64 (58)	1,42 (50)

3.6.2 SCENARIO 2: OFFSHORE (ALKE) TO ONSHORE PIPELINE ENTRY POINT (NYHAMNA, KOLLSNES, KÅRSTØ)



LOADING POINT ↓	UNLOADING POINT ⇨	NYHAMNA	KOLLSNES	KÅRSTØ
ALKE	DISTANCE TO UNLOADING POINT [Nm]	645	743	805
GAS RESERVE 11,37 Bill. Sm3 (401 bscf)	DELIVERY QUANTITIES / DAY [million sm3/day (mmscfd)]	1,44 (51)	1,64 (58)	1,42 (50)

3.6.3 SCENARIO 3: ONSHORE GAS PLANT (KÅRSTØ) TO NEARSHORE DELIVERY GAS TERMINAL (HERØYA)



LOADING POINT ↓	UNLOADING POINT ⇔	HERØYA
KÅRSTØ	DISTANCE TO UNLOADING POINT [Nm]	244
GAS PRODUCTION CAPACITY 95 M Sm ³ /day (3352 mmscfd)	DELIVERY QUANTITIES / DAY [million sm ³ /day (mmscfd)]	1,6 – 4,5 (56-158)

3.6.4 COST OF UPSTREAM COST

3.6.5 ASSOCIATED GAS FIELD: JOHAN CASTBERG

Little information available: high sensitivity and confidentiality.

No infrastructure available yet, but field under development, so infrastructure supporting oil production shall be considered as existing by the time Gasvessel is to enter in operation. No information yet available about the decision to reinject or produce the gas, the assumption is that no gas production is planned.

Estimated gas upstream tariff for associated gas: 0,23 €/Nm³. (2,2 NOK/Sm³; source GASSCO, 2012)

3.6.6 GREEN FIELD PROJECT: ALKE

- Field ref / name: Alke Nor + Alke Sør
- Coordinates: 71° 7' 30.3" N, 20° 48' 19" E
- Water depth [m] 164 – 185
- Total depth (MD) [m RKB] 4680.0

- Final vertical depth (TVD) [m RKB] 4667.0
- Recov. Gas: 11,37 bill. Sm³

3.6.7 ONSHORE GAS FACILITY

A previous feasibility study (NVE, 2004, MARINTEK 2005, 2004) of gas transport from Kårstø to the East coast identify gas tariff at Kårstø around 39-102 øre/Sm³ (\$0,002-0,005 /scf), and transport costs by CNG vessel around 54 øre/Sm³ (\$0,02 / scf) for a minimum viable volume around 150 MSm³/year (5 bscf/y).

3.7 ALTERNATIVE CONCEPTS

For alternatives, only FLNG is realistic to consider for the Barents Sea fields (associate + pure gas), while pipeline can be considered for the 3rd scenario agreed upon (the coastline scenario).

- **Scenario 1:** Johan Castberg (associated gas) to west coast gas terminal (pipeline entry): Nyhamna, Kollsnes, Kårstø => pipeline seems unrealistic to consider (between 590 and 900 nautical miles), but **FLNG** could very well be considered, although it would require to set-up necessary infrastructures without disturbing the oil production (at the loading site).
- **Scenario 2:** Pure Gas field **Alke**. Same localization, same story and 3 delivery points possible. Pipeline seems unrealistic, but **FLNG** yes, also requiring the development of infrastructure today not existing (at the gas field site)
- **Scenario 3:** From Kårstø west coast to Grenland on the East, coast. Both **FLNG** and **pipeline** could be considered as options.

In the NVE study, dry gas pipelines of dim16" and combi-pipeline of dim 18" were considered. The foreseen route was following the coast line from west to east, at a 4 nm distance from coast. The depth would be 300-500 meter, with a relatively flat seabed. The end point would be Herøya. The total pipeline distance would be 475 km / 255 nm. We use the same estimates / baseline info for the Gasvessel Barentssea-scenario3 (should be called Norway scenario).

3.8 CONCLUSION

As part of WP2, during August-December 2017, SINTEF conducted information search on Barents Sea discoveries, gas distribution infrastructure and market screening around the Northern European region. The purpose was to identify few relevant and feasible scenarios for monetization of stranded or associated gas by use of CNG vessel. For the region identified as Barents Sea / Northern region, 3 scenarios are proposed and summarized below. These are within the feasible distances and volumes previously identified by the Gasvessel consortium as niche area for CNG-vessel transportation concepts. These scenarios are not exhaustive, but complementary, and suggested for conducting comparison analysis and feasibility study of the Gasvessel concept.

Scenario:	LOADING POINT	UNLOADING POINT	Gas facility + pipeline entry			Gas storage facility	Gas tariff	Alternatives
			NYHAMNA	KOLLSNES	KÅRSTØ			
SCENARIO 1 Offshore (associated gas) to onshore gas	JOHAN CASTBERG	Distance (1)	686	800	896		\$0,31 /Sm3 (0,01/scf)	LNG ship
	Gas reserve: 10,9 M Sm3 (0,353 bscf)	Delivery quantities / day (2)	1,44 (51)	1,09 (39)	1,42 (50)			
SCENARIO 2 Offshore (gas field) to onshore gas	ALKE	Distance (1)	645	743	805		Not identified	LNG ship
	Gas reserve: 11,37 M Sm3 (0,401 bscf)	Delivery quantities / day (2)	1,44 (51)	1,09 (39)	1,42 (50)			
SCENARIO 3 Onshore gas production to Onshore	KÅRSTØ	Distance (1)				244	\$0,05-0,14 /Sm3 (\$0,002-0,005 /scf)	LNG ship Pipeline
	Gas production capacity: 95 M Sm3/day (3,35 bscfd)	Delivery quantities / day (3)				1,6 – 4,5 (56 - 158)		

4 BLACK SEA GEOLOGISTICS

4.1 CONCEPTION DESCRIPTION

Between the several tasks for Natural Gas supply using the GASVESSEL in the Black Sea water area is the definition of sites for placement of loading and unloading terminals.

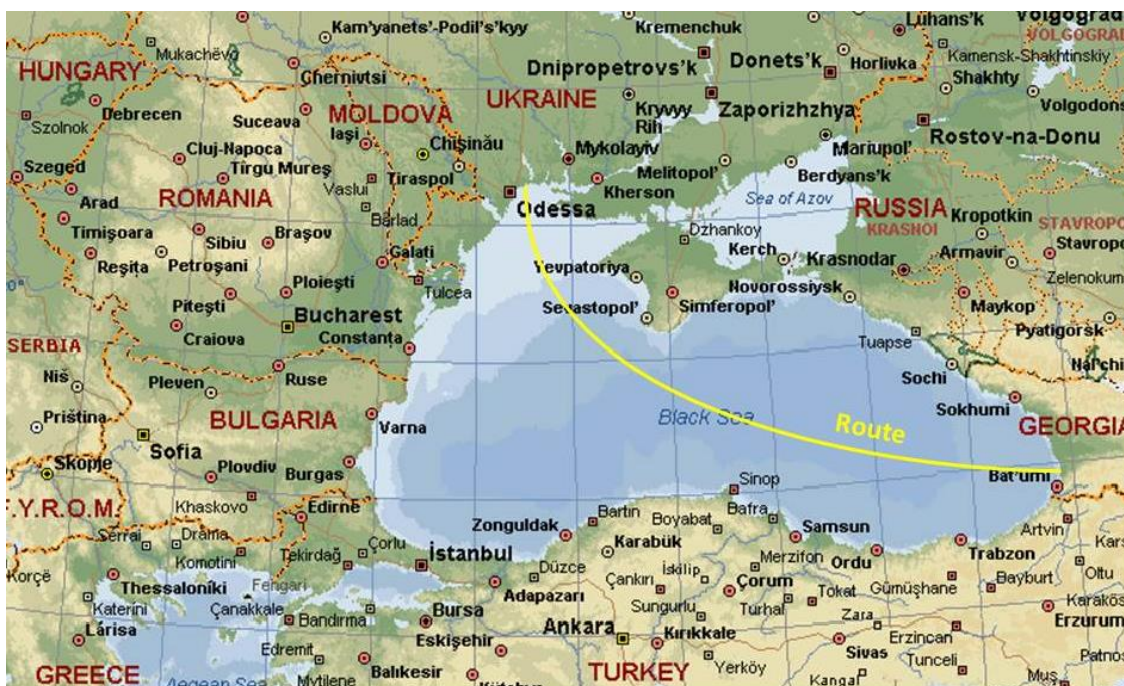
VTG conducted a search for information in open sources to study the presence of the developed Gas infrastructure in the coastal zones of Black Sea countries in order to ensure the loading and unloading of GASVESSEL.

At the meetings on the implementation of WP2, a potential source of the Natural Gas was identified - the Shah Deniz field in Azerbaijan. From this source, Gas is transported through the territory of Azerbaijan, Georgia and further through the territory of Turkey. The shortest routes of the existing Gas pipelines from the Shah Deniz field to the Black Sea coast were the Baku-Tbilisi-Erzurum and TANAP Gas pipelines on the territory of Georgia. Thus, the country where the boot terminal was located was selected.

Ukraine was chosen as the country of the location of the unloading terminal as the state most dependent on Natural Gas imports.

Thus, to realize the possibility of loading and unloading GASVESSEL, it is necessary to create a certain infrastructure connecting the existing Gas transportation systems of Georgia and Ukraine with terminal sites. This report considers the variant of placing the Gas loading terminal in the most optimal variant near the existing infrastructure of the Baku-Tbilisi-Erzurum Main Gas pipeline. Such a site for the Gas loading terminal was chosen in the area of the Poti port in Georgia.

As a site for the unloading terminal, among several of the investigated sites, was chosen a site near the Yuzhny port in Ukraine.



Pic.1. the map of Gas transport concept to Ukraine.

4.2 PROPOSED GAS LOADING PROCESS

4.2.1 GAS SUPPLY SOURCE

Considering the fact that near the existing ports in Georgia there is no necessary infrastructure of the Main Gas pipelines, it is necessary to envisage the creation of such an infrastructure.

In the text below describes the options for connecting a loading Gas terminal to existing Main Gas pipelines and selected the best option for terminal placement.

4.2.2 DESCRIPTION OF THE EXISTING GEORGIAN GAS INFRASTRUCTURE

The Georgian Oil and Gas Corporation (GOGC) is a state-owned company (under the Partnership Fund) committed to ensuring the energy security of Georgia. GOGC holds the legal status of the National Oil Company (NOC) and represents the state's interests in upstream oil and natural Gas projects in Georgia. GOGC was established to consolidate Georgia's energy assets under single management.

Georgia's auspicious strategic location is a transport corridor for natural Gas supplies to European markets. The transport corridor through Georgia allows the EU to diversify its supply, increasing energy security. Georgia's favourable location has prompted significant investments in its Oil and Gas sector. To that end, GOGC represents the state in international energy transit projects. Georgia's main natural Gas pipelines are:

- Main Gas Pipeline System (MGPS) that stretches across the country and is comprised of:
 - North-South Gas Pipeline (NSGP), extending 235km and transporting Gas from Russia to Armenia;
 - East-West Gas Pipeline (EWGP);
 - Southern branch;
 - Kakheti branch;
- South Caucasus Pipeline (SCP) that stretches 692km (249km in Georgia) and transports natural Gas from Azerbaijan to Turkey through Georgia and from Turkey further to the EU. The Southern Gas Corridor Project, aimed at improving the security and diversity of the EU energy supply, will bring additional volumes of natural Gas from the Caspian region to Europe. It is comprised of several separate energy projects, including the expansion of the SCP pipeline, which should bring additional volumes to GOGC as the pipeline capacity is 2021.

Approved CNG supply chain in the Black Sea basin (area) assumes Georgia to be the potential transit country for such CNG.

Actually, no Gas is produced today in Georgia. However, its favourable geographical position makes it possible to play a role in the regional transit partner.

See below considerations with regard to the natural Gas supply routes within the territory of Georgia, whereby the ports of Georgia and further countries of the Black Sea basin are accessible.



Source: Company data, Galt & Taggart Research

Pic. 2 Pipelines in Georgia – existing Routes to potential loading terminals.

4.2.3 DESCRIPTION OF THE MAIN GAS PIPELINE BAKU-TBILISI-ERZURUM (BTE, SCP)

The Main Gas pipeline Baku-Tbilisi-Erzurum, (Project TRA-N-1138, Gas Pipeline Future Expansion including CS, Commissioning Year 2021, also known as South Caucasus pipeline, BTE pipeline, or Shah Deniz pipeline) is a natural Gas pipeline from the Shah Deniz Gas field in the Azerbaijan sector of the Caspian Sea to Turkey. The pipeline runs parallel and proximate to Baku-Tbilisi-Ceyhan (BTC) crude Oil pipeline. The BTE originates at the Sangachal Terminal, which is located approximately at 45 km to the south of Baku and traverses to Azerbaijan and Georgia before terminating at Erzurum in eastern Turkey. The lengths of Georgia's and Turkey's sections are 442 km and 248 km respectively. The total pipeline length is 980 km, Its diameter is 42 inches.

The pipeline is buried throughout the route and is designed for an operational life of 30 years. It has a diameter of 42 inches and is designed to transmit 7 billion cubic meters of Gas annually. It is protected against corrosion by applying a combination of three-layer polyethylene (PE) coating system and an impressed current cathodic protection (CP) system.

In addition to the pipeline's construction, the BTE project involved a number of above ground installations including two compressor stations (one each in Azerbaijan and Georgia), an intermediate pigging station (cleaning and inspection) and 11 small block valves.

The SCP Expansion (SCPX) Project is designed to increase the capacity of the South Caucasus pipeline from the existing 7 billion m³/year to 23 billion m³/year, to transmit the Gas that will be produced by the second stage of Shah Deniz, which is currently under development.

In order to increase the transmission capacity, a new 56 inches diameter pipeline will be laid beside the existing pipeline. The new pipeline will originate from the Georgian border and will be reconnected to the existing pipeline after running for 56 km.

Other components of the project include a new block valve (BV) at kilometer point (KP) 27, a pigging station at KP56 (the point where the new pipeline will be reconnected to the existing line), two new compressor stations and a new pressure reduction and metering station (PRMS) at the Georgian-Turkish border. The expanded pipeline is likely to be fully operational in the fourth quarter of 2021.



Pic. 3 Baku – Tbilisi – Erzurum Main Gas Pipeline (brown).

Therefore, it is obvious that the said Gas line may be used for Gas supplies to the onshore loading terminal.

4.2.4 THE TECHNICAL DATA OF MAIN GAS PIPELINE BAKU-TBILISI-ERZURUM (BTE, SCP)

Transportation and Transfer Capacity after rehabilitation: 20,0 billion m³/year

Daily Transfer Capacity: 55,6 million m³/day

Plan/Design Factor: (as per ASME B31.8)

System Design Pressure: 56,5 bar

Design/Diameter of the Line Pipe: API 5L X 70 I 42+56"

A number of locations for the loading terminal installation within the Black Sea coast of Georgia have been considered.

4.2.5 LOADING PORT: POTI

The seaport of Poti lies at the southern periphery of the oceanic climate, but it is classified as humid subtropical according to Köppen's classification. The city's climate is heavily influenced by the Black Sea and is subject to the effects of the effects of the onset of the Black Sea, resulting in significant rainfall over the most part of the year.

4.2.6 SELECTION OF THE LOADING TERMINAL SITE LOCATION

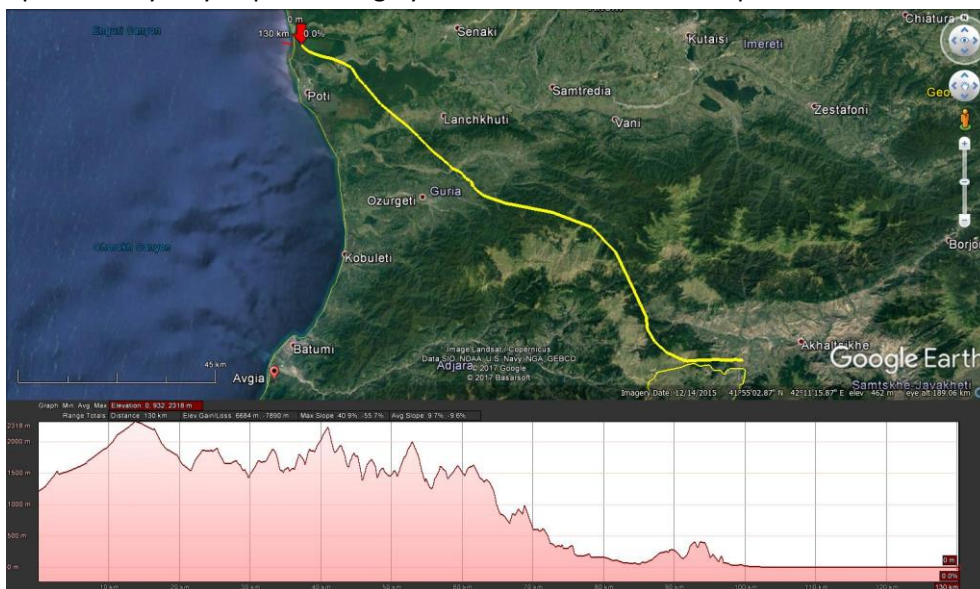
The territory to the South of Poti seaport have the recreational meaning, while from the North it is restrained by the Rioni river, it has been resolved to install the Gas loading terminal to the North of Poti. In particular behind the river Rioni, in which case the terminal location will be equally distanced from both Poti seaport

and Kulevi Oil terminal. Besides, the territory for the Gas loading terminal near Poti seaport has been selected taking into account the underwater streams, as well as sludge from by Rioni and Khobi rivers.

4.2.7 CONSTRUCTION OF THE GAS INTERCONNECTION LINE BETWEEN THE TERMINAL AND THE EXISTING MAIN GAS PIPELINE BAKU-TBILISI-ERZURUM

For the purpose of connection of the existing Main Gas pipeline Baku-Tbilisi-Erzurum with the Gas loading terminal, the special connecting line shall be constructed. Estimated connecting Gas line data shall be calculated in the Section “Main Gas Lines”. This section will be developed by VTG in the work package WP6. According to a preliminary study, the approximate length of the Gas interconnector will be about 140 km, the diameter will be determined in accordance with the need to fulfil scenarios for Gas supply to Ukraine. The Gas interconnector pipeline is proposed to be connected to the existing line of the SCP Main Gas pipeline at the Gas measuring point No 80, located about 3 km to the south-west from the village of Vale. Preliminary calculations show that the construction of a Gas Compressor station is necessary at the beginning of the Interconnector. The capacity of the Compressor station will be determined depending on the loading schedule of GASVESSEL.

The optimization of the parameters of the designed Gas interconnector (diameter, pressure), will be optimized by way of performing hydraulic calculations of its operation modes with the Gas loading terminal.

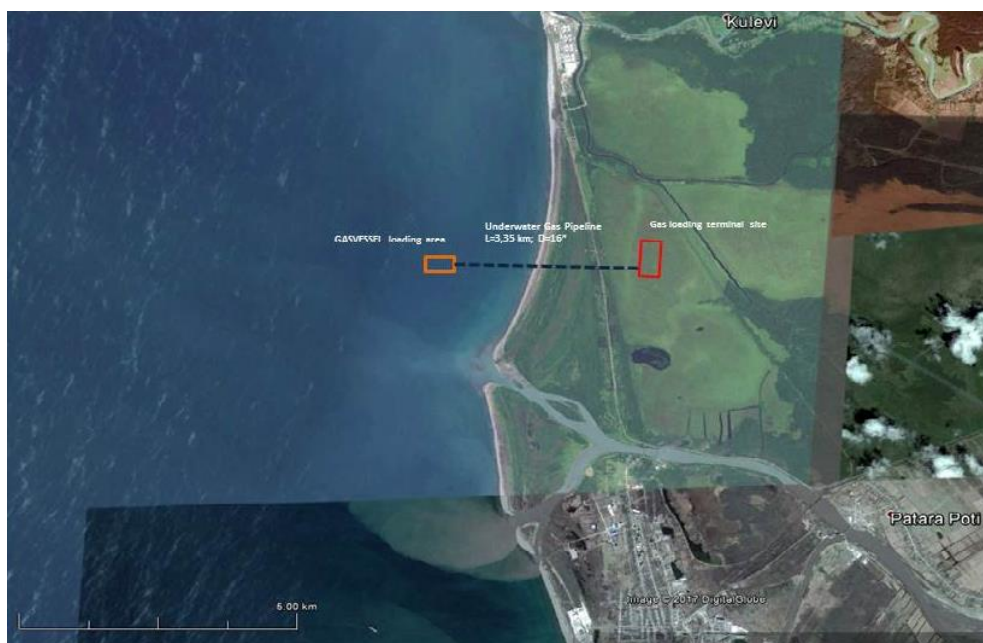


Pic. 4. The map of Gas interconnector line route to the loading terminal near the port of Poti and connection point to BTE.

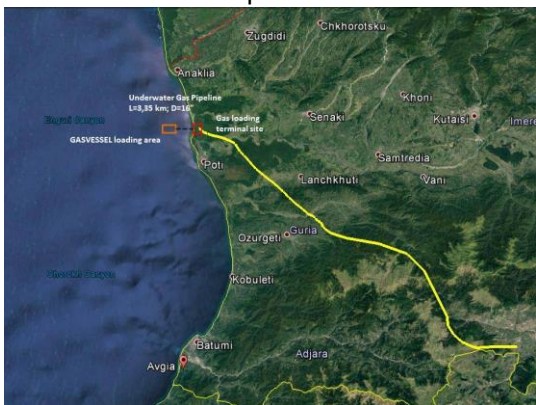
4.2.8 CONSIDERATIONS REGARDING ON-SHORE LOADING TERMINAL (POTI)

The location of the on-shore loading terminal is suggested due to the following considerations:

- Availability of necessary infrastructure in the region (power supply, roads etc.);
- Easy access for GASVESSEL to loading zone;
- Sea depth in loading zone;
- All Year-round navigation and the ice-free sea in the area of the terminal;
- Acceptable marine climate conditions and height of waves nearby.

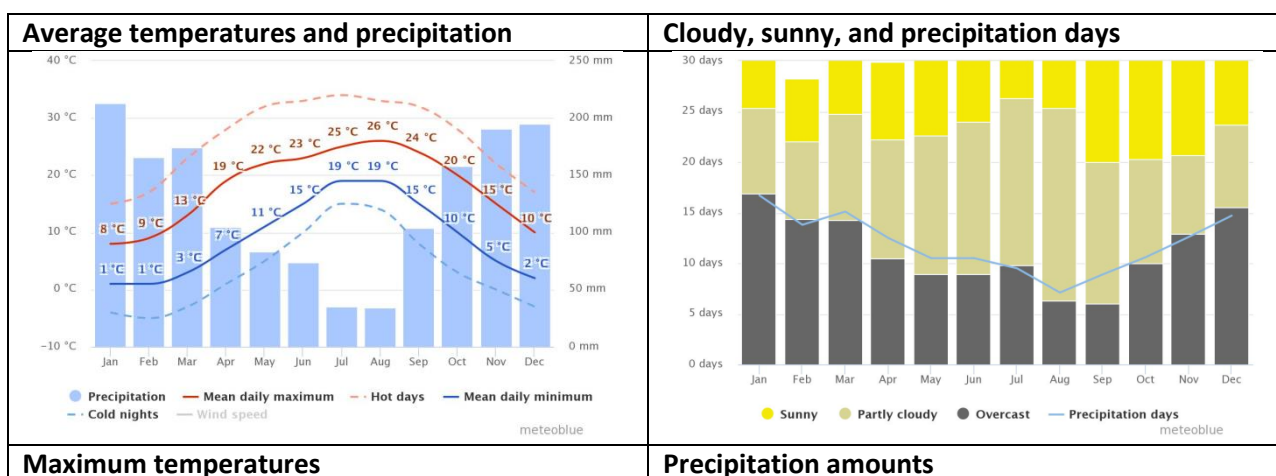


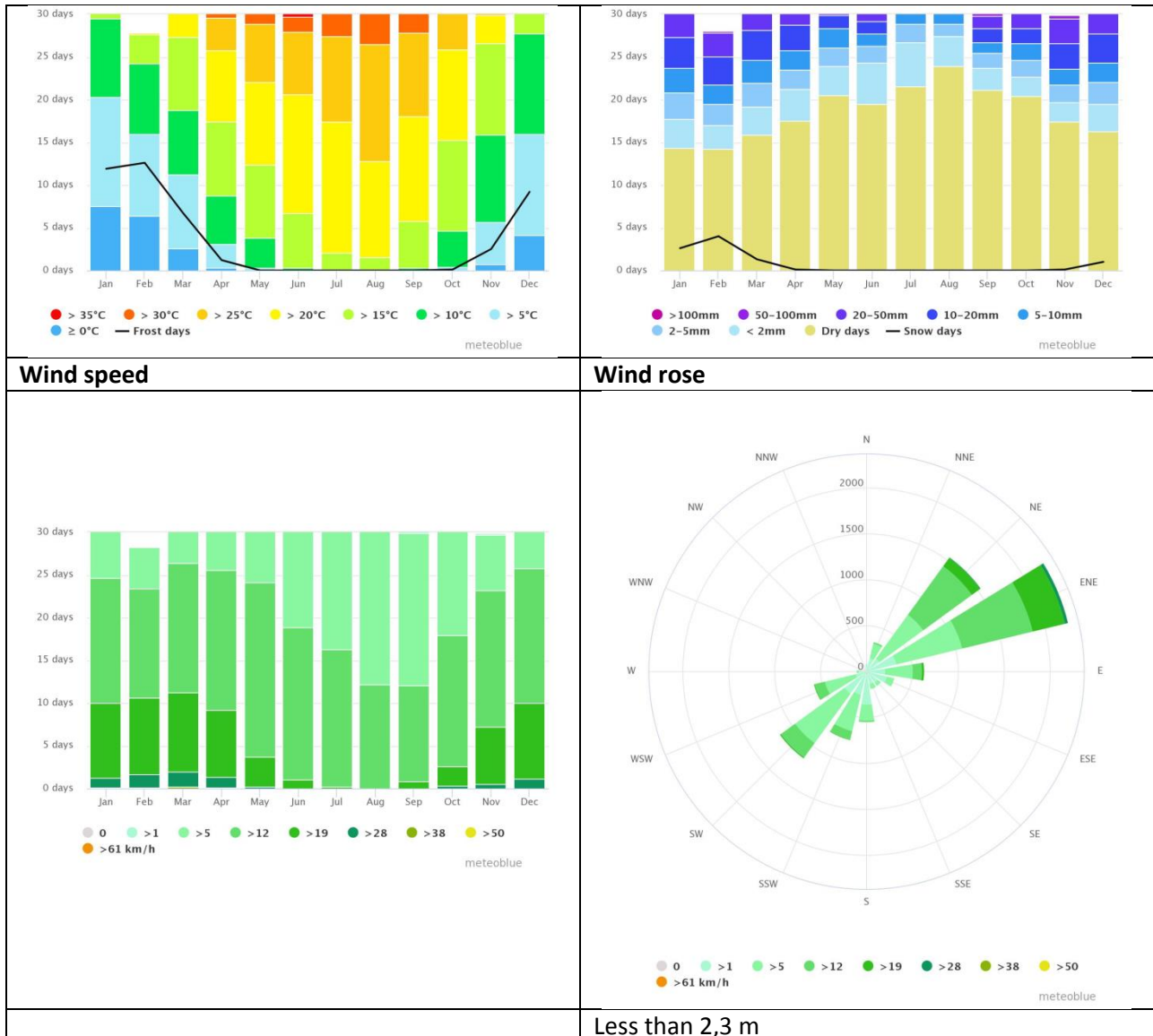
Pic. 5 The location of the loading terminal site and GASVESSEL loading area in the north of Poti port.

Name: Loading Terminal near port of Poti, Georgia	Location: Onshore
Type of Gas source: Gas Interconnector SCP-Loading Terminal	Gas source: Shah-Deniz Gas Fields
• Interconnector Characteristics: • Diameter • Length • Pressure • Capacity	• To be determined • 130 km - To be determined • As per 3 scenarios 
Location and coordinates of Gas loading terminal:	Latitude: 42°14'13.32"N Longitude: 41°39'47.55"E

	
Location and coordinates of Gas loading point:	Latitude: 42°14'24.98"N Longitude: 41°37'11.18"E 
Water Depth of loading point	34 m
Gas composition	87-90 % Methane - no H₂S, no CO₂, no mercury
Distance from delivery port Port of Yuzne, Ukraine)	578 nm

Climatic characteristics of the territory near the port of Poti:





4.3 PROPOSED GAS UNLOADING PROCESS

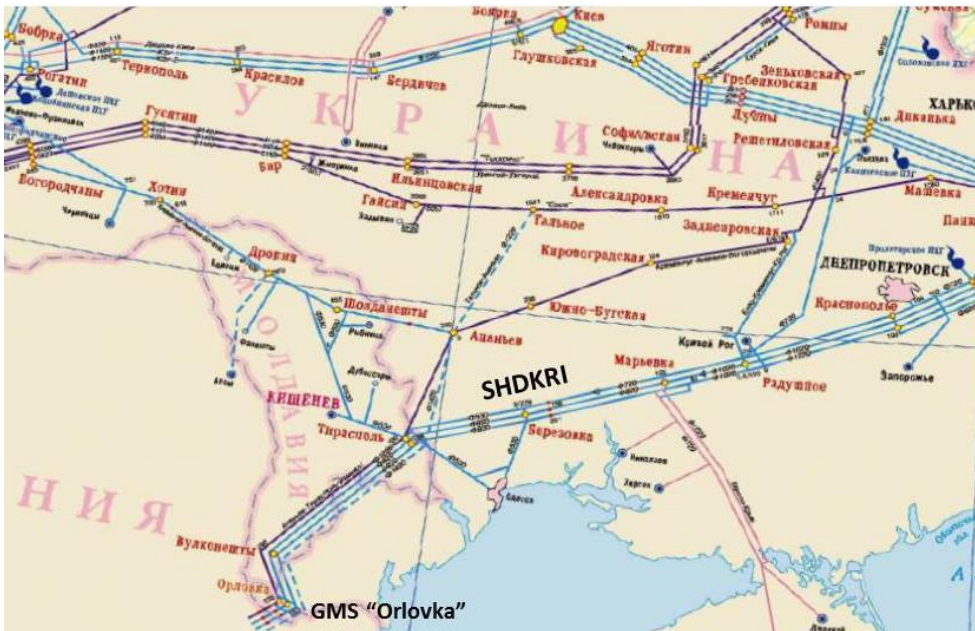
4.3.1 GAS SUPPLY SOURCE

Considering the fact that near the existing ports in Ukraine there is no necessary infrastructure of the main Gas pipelines, it is necessary to envisage the creation of such an infrastructure. After considering several options for placing the site of the unloading terminal in Ukraine, the option of locating the terminal near the port of Yuzhny was chosen.

The existing infrastructure of the Ukraine Gas transportation system is divided into sectors limited by the existing Main Gas pipelines and is aimed at Gas consumption by all consumers located in such sectors. The southern regions of Ukraine are tied to the main Gas pipeline SHDKRI. The volume of Gas consumption in Ukraine at the actual location of the main Gas pipelines in the southern regions of Ukraine may be limited due to the possibility of Gas consumption by existing consumers in the region.

4.3.2 DESCRIPTION OF THE UKRAINIAN GAS INFRASTRUCTURE IN SOUTHERN REGION OF UKRAINE

The main Gas pipeline network in Odessa region is pretty extensive. It is based on the multiple Gas line system of Shebelinka - Dnepropetrovsk - Krivoy Rog - Izmail (SHDKRI), which actually consists of several Gas lines: Shebelinka - Dnepropetrovsk, Shebelinka – Dnepropetrovsk – Odessa, first and second branches, Shebelinka - Dnepropetrovsk - Krivoy Rog - Izmail, Razdelnaya – Izmail. The mentioned Gas pipelines have a various number of lines (from 2 to 4) and different diameters in different sections – DN 500 to DN 1200. The Gas transport system map in Ukrainian South is shown in Pic. 6.



Pic.6. The map of Gas transport system in South Ukraine.

The Gas pipeline system of Shebelinka - Dnepropetrovsk - Krivoy Rog – Izmail supplies Gas to the consumers in Kharkov, Dnepropetrovsk, Zaporozhye, Kherson, Nikolayev, and Odessa regions, as well as ensures Gas transit to the Republic of Moldova and the Balkan Countries. The Gas deliveries to the Autonomous Republic of Crimea at this time have been completed.

The sources of Gas supply to this system are the Ostrogozhsk-Shebelinka, Novo Pskov-Shebelinka Gas pipelines that supply Gas from the territory of the Russian Federation to the initial point of the Gas pipeline, as well as the Kremenchuk-Krivoy Rog junction in Gas pipeline. These supplies Gas from the transit Gas system Yelets-Kremenchuk-Krivoy Rog Gas transportation system Ananyev-Izmail (EKKRAI), and the Ananyev-Tiraspol- Izmail (ATI) Gas pipeline through the existing point of Gas reduction at the Grebeniki Gas-measuring station.

The design capacity of the SHDKRI Gas pipeline system (excluding the adding Gas pipelines) makes up 33 b m³/year in its initial point and 7,3 b m³/year in its endpoint. The rated operating pressure is 55 kg/cm².

In a post-Soviet period, the Ukrainian consumers used to consume up to 25 b m³ of Gas per year from this system. The Gas transit to Moldova amounted to up to 2 b m³/year, the transit to the Balkan Countries amounted to up to 7 b m³/year.

The SHDKRI Gas system includes 9 compressor stations ("Shebelinka", "Pavlograd", "Krasnopolye", "Radushnoye", "Maryevka", "Berezovka", "Tiraspol-1", "Vulkaneshty", "Orlovka"), two of them: "Tiraspol-1" and "Vulkaneshty" are located in the territory of Moldova. The capacity of the compressor stations corresponds to the capacity of the linear part past the respective CS (7,3 to 33 b m³/year), developed pressure: 55 kg/cm², the most of Compressor Stations are equipped with electric drive units, which makes this system independent of Gas supplies for process needs.

The (only one of 12) underground Gas storage "Proletarskoe UGS" is integrated into the SHDKRI Gas system; the storage capacity is 1 b m³, which compensates the seasonal irregularity of Gas delivery through the Gas

pipelines. The Gas transportation system operator plans to increase the storage capacity of this UGS by 2,6 times.

Basing on the designed and actual Gas transportation volumes, the mentioned seasonal storage capacities are insufficient, so it is necessary to find the possibilities to construct additional UGS's.

The issue of a particular relevancy is the deficiency of operative control over the irregular Gas supply, which is better to compensate by new storages in the rock salt deposits. Such storages with the operating storage capacity of 1-2 bm^3 each may be constructed in future in the area of Kiliya and Izmail.

Due to insufficient Gas storage capacity, the Moldavian consumers (except for Pridnestrovye) get switched to Gas supply from the Ananyev-Bogorodchany Gas pipeline (in the reverse mode), connected via the "Bogorodchany" compressor station (CS) to the system of western Ukrainian UGS's for the winter season.

In the final section of the SHDKRI Gas system, which crosses the territory of Odessa region with partial intervention into the territory of Moldova, the twin line Razdelnaya - Izmail (RI) - SHDKRI system (two lines DN800) performs the transit of Russian natural Gas to Bulgaria, Romania, Turkey and other Balkan Countries (Serbia, Macedonia, Bosnia and Herzegovina) since 1974. The design volume of supplies is 7 bm^3/year .

Considering the construction of the larger ATI line (Ananyev – Tiraspol - Izmail, 1985) and its further expansion with 70 km loopings and the "Tarutino" CS (1998-2002), the SHDKRI Gas system became less important for the "Southern" Gas transit, serving as a looping in the section of Tiraspol - Izmail, which was used mainly in winter. As of today, this Gas line delivers 17 - 23 bm^3/year , design system capacity – 26,8 bm^3/year . It is important to admit that considering significant reduction of Russian Gas transit through Ukraine (by 30-40% in 2012 – 2016, in comparison with the previous years), the "Southern" transit remains pretty stable last 10-15 years.

On the border of Ukraine and Romania in the area of the KS "Orlovka" (before passing through the Danube River), gas is distributed to three gas pipelines:

- The DN1000 gas pipeline to Romania (only for Romanian consumers with annual topping of up to 6 billion m^3 / year),
- DN1000 to Bulgaria (only for consumers in Bulgaria with an annual topping of up to 6.5 billion m^3 / year),
- DN1200 for Turkey (for consumers in Turkey, Greece, Macedonia and others with an annual topping of up to 14 billion m^3 / year)

"Ukrtransgaz" PJSC performs the operation of the main gas pipelines in the territory of Odessa region, in particular by its branches:

- Main Gas Line Operation Directorate UMG Kharkovtransgaz – the section from Shebelinka to the "Ryasnopol" GMS (the border between Nikolayev and Odessa regions);
- Main Gas Line Operation Directorate UMG Prykarpattyatransgaz – the section from the "Ryasnopol" GMS to the "Orlovka" GMS (the border between Ukraine and Romania).

The SHDKRI Gas system involves many connected and operating distribution Gas lines, branch lines, and Gas distribution stations (GDS) of different capacity. The biggest ones are Maryevka - Kherson – Crimea Gas pipeline DN700, branch pipelines to Dnepropetrovsk, Zaporozhye, Nikolayev, and Odessa.

The branch pipeline to Odessa and overall SHDKRI Gas transportation system (see Pic. 3) starts at the "Berezovka" CS as the twin system DN 500 and goes 23 km to the South-West. Then it splits into two separate Gas pipelines DN 500. The first one of 39 km goes towards the Adzhalykyskiy Liman to the Odessa Port Plant and ends with the "Vizirka" GDS. The second one with the looping DN500 reaches the "GDS-1" and the "GDS-2" in Odessa, which have the junction with the branch pipeline and the "GDS-3", coming from Moldova (at the moment, no Gas is transported from Moldova to Odessa, all three GDS are fed from the SHDKRI Gas system).

The pipeline capacity of the system of branch lines to Odessa, connected to the SHDKRI Gas system, is estimated at 3 bm^3/year .

The SHDKRI system has been operated for over 50 years. Since that, the admissible operating pressure was reduced in several sections due to various defects.

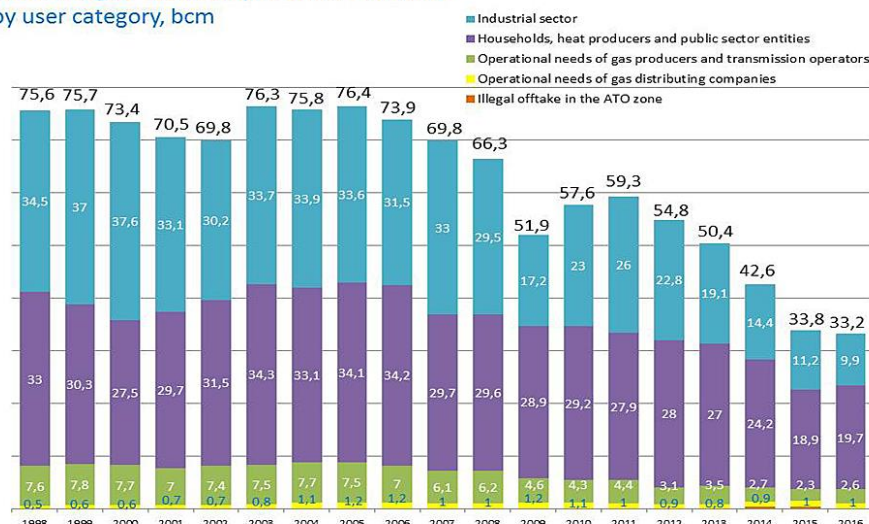
The Operator of the Gas transportation system of Ukraine "Ukrtransgaz" PJSC performed a series of rehabilitation and major repair work over the past ten years and continues repairing separate SHDKRI system

sections. Such repairs include replacement of pipes and installation of pig launcher and receiver traps, allowing performing in-line diagnosis and monitoring technical condition of Gas lines. All limitations regarding the admissible operating pressure (PN55) are cancelled now. All compressor stations are functional and able to ensure the design capacity of the Gas lines.

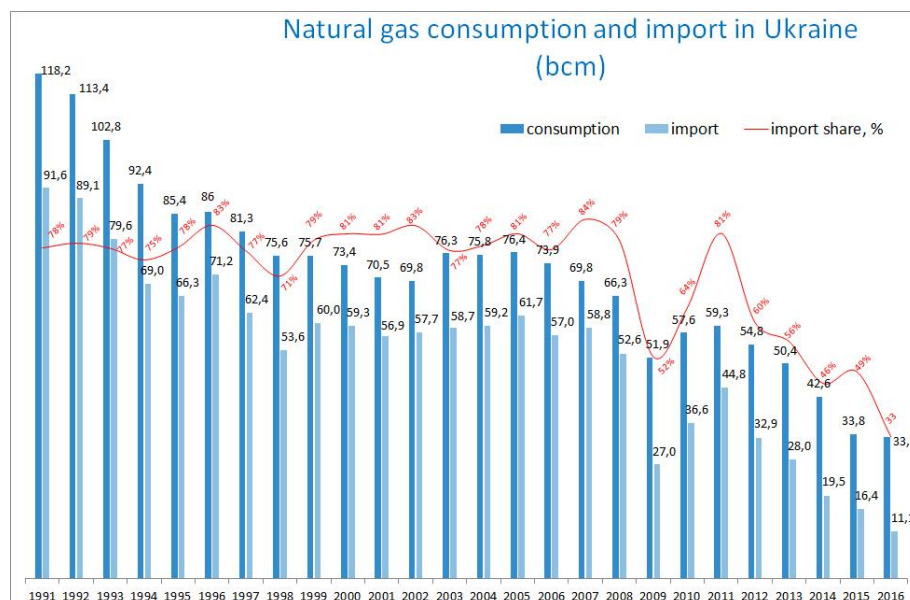
4.3.3 DESCRIPTION OF THE GAS CONSUMPTION IN UKRAINE

Last years there is a drop in Gas demand by industry and in the domestic consumption sector.

Natural gas consumption in Ukraine
by user category, bcm



Pic. 7 Natural Gas consumption in Ukraine of different consumers



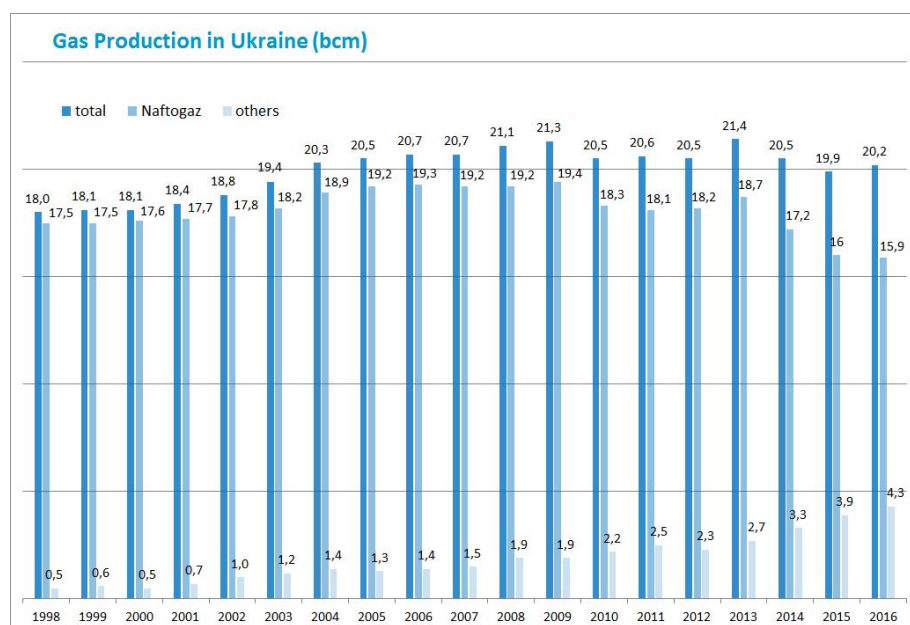
Pic. 8 Natural Gas consumption and import in Ukraine

At the same time, Ukraine is increasing its own Gas production.

Although the increase in Natural Gas production is currently proceeding at a slow pace due to a lack of sufficient investment.

Nevertheless, the government of Ukraine made a number of decisions on increasing its own natural Gas production. This is partly dictated by the situation when natural Gas received by Ukraine from Europe is, in

fact, is also Russian and any possible restrictions on Gas supplies for Europe may have risks for Ukraine. It is not a question of excluding Gas supplies for Europe, but of reducing Gas supplies to the level only of necessary consumption in the European Union. However, such a scenario may not be implemented.



Pic. 9 Natural Gas production in Ukraine

	Fact, tcm
Total production	57175
UkrGasvydobuvannya	42202
Ukrnafta	2907
Others	12066

Pic. 10 Supply from Gas producers of Ukraine for 01.01.2018

For the GASVESSEL project, consideration of the most probable and viable scenarios is necessary, so we will consider the Ukrainian market not only from the point of view of natural Gas consumption but also from the point of view of Gas transit to Moldova, Bulgaria and Romania. According to the Gas transportation company "Ukrtransgaz" PJSC, such transit through the Gas measuring station "Orlovka" (on the border with Moldova) is approximately 65.85 million cubic meters per day. At the same time, the reserve capacity of transit is about 15.55 million cubic meters per day. The table below shows the transit possibilities of Gas transit via Gas measuring station "Orlovka"

#	Gas measuring station	Technical capacity	Nomination	Flow	Free capacity
1	2	3	4	5	6
1	Uzhgorod	281.90	121.30	120.52	161.38
2	Orlovka	81.40	65.20	65.85	15.55
3	Beregovo	67.77	26.30	25.21	42.56
4	Drozdovichi	14.50	14.20	14.14	0.36
5	Tekovo	13.70	3.00	2.97	10.73
6	Moldova (summary)	16.70	12.20	9.98	6.72

Pic. 11 Operational data at GMS of "UKRTRANSGAZ" PJSC for 01.01.2018 (mcm at 20°C)

Ukraine in January-November 2017 increased natural Gas imports by 39% (by 3 billion 676.1 million cubic meters) compared to the same period in 2016 - up to 13 billion 95.2 million cubic meters, according to the

announcement of PJSC "Ukrtransgaz". According to the calculations of the agency Interfax-Ukraine, including from Slovakia in January-November-2017 received 9 billion 239.3 million cubic meters of Gas, from Hungary - 2 billion 702.2 million cubic meters, from Poland - 1 billion 153.6 million cubic meters. In November-2017, imports amounted to 1 billion 316.8 million cubic meters of Gas, which is 14.9% less than in November-2016 (1 billion 546.6 million cubic meters). At the same time, Ukraine has not imported natural Gas under a contract with PJSC Gazprom for more than two years (since November 26, 2015), purchasing a resource exclusively on its western border. As reported, Ukraine in 2016 reduced the import of natural Gas by 32.7% (by 5 billion 375.6 million cubic meters) compared to 2015 - up to 11 billion 78.4 million cubic meters.

Ukraine in January-November 2017 increased natural Gas consumption by 1,8% (by 0,504 billion cubic meters) compared to the same period in 2016 - up to 28,1billion cubic meters.

As reported by the Ministry of Energy and Coal Industry:

- The **Industry** consumed 9,5 billion cubic meters of Gas (+11,3% against January- November 2016).
- The **Domestic and Budget Enterprises** consumed 10 billion cubic meters of Gas (-2,9%),
- The **Power and Heating plants** consumed 5 billion cubic meters of Gas (-13,6%).
- The **Production and technological expenses** amounted to 3,6 billion cubic meters of Gas (+21,1%).

As reported, Ukraine in 2016 reduced the consumption of Natural Gas by 4.1% (by 1.366 billion cubic meters) compared to 2015 - up to 32.361 billion cubic meters. In particular:

- The **industry** consumed 9.599 billion cubic meters (-15.9% against 2015),
- The **Domestic and Budget Enterprises** - 12.457 billion cubic meters (+2.3%),
- The **Power and Heating plants** - 7.034 billion cubic meters (+ 1.4%),
- The **Production and technological expenses** amounted to 3.271 billion cubic meters (+2.4%).

Ukraine in January-November 2017 increased transit of Natural Gas through its Gas transportation system (GTS) by 15.9% (by 11 billion 725.9 million cubic meters) compared to the same period in 2016 - up to 85 billion 504.8 million cubic meters, according to the operating data of PJSC "Ukrtransgaz". According to calculations by the agency Interfax-Ukraine, including the transit of Gas through Ukraine to Europe for 11 months amounted to 83 billion 138.4 million cubic meters, to Moldova - 2 billion 366.4 million cubic meters. Because of the November-2017 transit of Gas decreased by 4.1% (by 352 million cubic meters) compared to the same month in 2016 - up to 8 billion 134.7 million cubic meters. Including transit of Gas through Ukraine to Europe in the past month amounted to 7.825 billion cubic meters, to Moldova - 309.7 million cubic meters. November-2017 was the third of 11 months of this year, which recorded a negative trend compared to the same months in 2016. As reported, Ukraine in 2016 increased the transit of Natural Gas through its Gas transportation system (GTS) by 22.5% (by 15 billion 121.1 million cubic meters) compared to 2015 - up to 82 billion 200.1 million cubic meters.

The production of natural Gas in Ukraine in January-November 2017 increased by 4.1% (by 754.2 million cubic meters) compared to the same period in 2016 - up to 19 billion 34.2 million cubic meters, according to the data of PJSC "Ukrtransgaz". According to calculations by the Interfax-Ukraine agency, including Gas production by PJSC "UkrGasvydobuvannya" amounted to 13 billion 929.3 million cubic meters (4.3% compared to January-November-2016), PJSC "Ukrnafta" - 1 billion 12.2 million cubic meters (-15%), other companies - 4 billion 92.7 million cubic meters. m (+ 9.4%). In November-2017, Gas production amounted to 1 billion 743.8 million cubic meters (+ 6% by November-2016), incl. the extraction of "UkrGasvydobuvannya" amounted to 1 billion 275.4 million cubic meters (+ 6%), "Ukrnafta" - 80.9 million cubic meters (-23.7%), other companies - 387.6 million cubic meters (+ 15.3%). As reported, Natural Gas production in Ukraine in 2016 increased by 0.5% (by 91.1 million cubic meters) compared to 2015 - up to 19 billion 987.1 million cubic meters. The enterprises of "Naftogaz of Ukraine" last year reduced Gas production by 0.8% (by 131.8 million cubic meters) to 15 billion 900.2 million cubic meters including the "UkrGasvydobuvannya" increased Gas production by 0.5% (by 74.7 million cubic meters) - to 14 billion 602.7 million cubic meters, whereas "Ukrnafta" decreased by 13.7% (by 205.5 million cubic meters), to 1 billion 297.5 million cubic meters. Other

Oil and Gas producing companies operating in the country increased Gas production by 5.8% (by 222.9 million cubic meters) in 2016, compared to 2015, to 4 billion 86.9 million cubic meters.

4.3.4 GAS INTAKE CAPACITY OF THE GAS TRANSPORTATION SYSTEM.

It is suggested to implement the concept of Gas delivery from the Gas carriers to the Gas Transportation System of Ukraine in two steps:

1. Considering that the pipeline capacity of the existing system of Gas branch pipelines is limited to 3 bm^3/year , it would be feasible to transmit Gas from its delivery point near the “Yuzhnyi” Seaport through the separate Gas line to the area of the “Berezovka” CS, where it then can be delivered to the consumers through the existing SHDKRI Gas system:
 - Westwards – through two pipelines DN800 and one DN500 to consumers of Moldova, the south of the Odessa region and, possibly, even to consumers in Romania and Bulgaria;
 - Eastwards – through two pipelines DN800 and one DN700 to consumers of the north of the Odessa region, Mykolayiv, Kherson and Dnepropetrovsk regions.

As there are no large Gas consumers within the Berezovka - Tiraspol – Orlovka direction, the main volume of Gas probably will be delivered from the CNG terminal eastwards (reverse flow), which estimated pipeline capacity is 15 bln m^3/year . With this purpose, it is suggested to perform the reverse flow at the “Berezovka” CS and the “Maryevka” CS in future, ensuring their reverse operation by performing rehabilitation of junction points with the installation of additional valves and crossovers.

2. In the future, in case of construction of UGS facilities in the Izmail area, or in case of a reduction in the volumes of Russian Gas transit, the need for winter peak Gas flows in the Tiraspol-Orlovka section will decrease, and the need for Gas inflow from the Berezovka, this Gas through the existing Gas reduction unit on the GIS “Grebeniki” can be fed from the ATI Gas pipeline to the SHDKRI Gas system in the eastern (reverse) direction only.
3. In this case, the Gas from the terminal will also be supplied exclusively in the east direction, which will eliminate the heterogeneity of Gas flows at the Berezovka compressor station and simplify the reconstruction of the connection unit on it. At the same time, there is no longer a need to feed the SHCDRI system from the ECRAI system, focusing the latter exclusively on the southern transit of Gas, if such is maintained at that time.

The design capacity of the “Berezovka” CS (forward flow) is 8 bm^3/year , of the “Maryevka” CS – 12 b m^3/year . In order to ensure the Gas intake at the “Berezovka” CS and its transportation eastwards, it is necessary to expand the capacity of this CS or perform its complete rehabilitation and replace the GCU with more efficient ones.

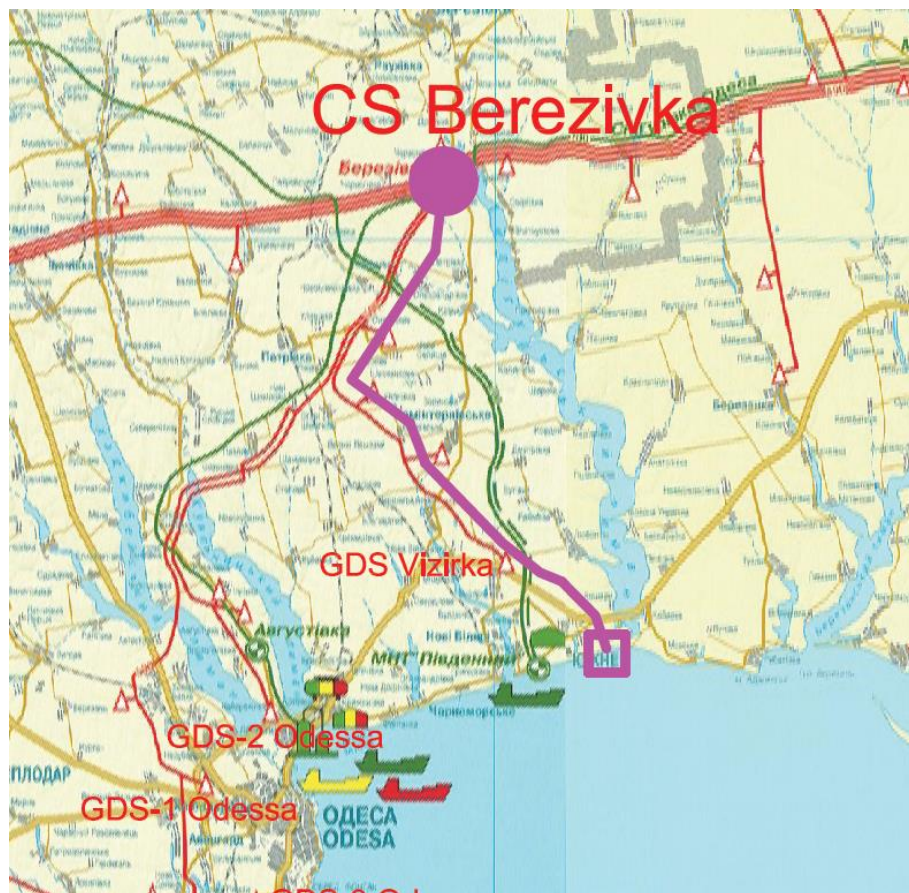
Thus, the existing Gas transportation system is able to accept about 10 b m^3/year of Gas in the area of the “Berezovka” CS.

4.3.5 UNLOADING SITE LOCATION

The choice of the location of the unloading terminal was dictated by the inherent stable market of natural Gas consumption. After analyzing possible situations of Gas consumption in the southern region of Ukraine, the volumes of Gas supplies were determined. These numbers are about 3-3.5 billion cubic meters per year for the consumption of the southern region and about 5.5-6,0 billion cubic meters per year, taking into account exports to Romania at the Gas measuring station Orlovka.

The possibility of Gas reception is based on the multiple Gas line system of Shebelinka - Dnepropetrovsk - Krivoy Rog - Izmail (SHDKRI), which actually consists of several Gas lines: It is planned to make a tie-in to a Gas pipeline near Berezovka compressor station (see Pic. 12).

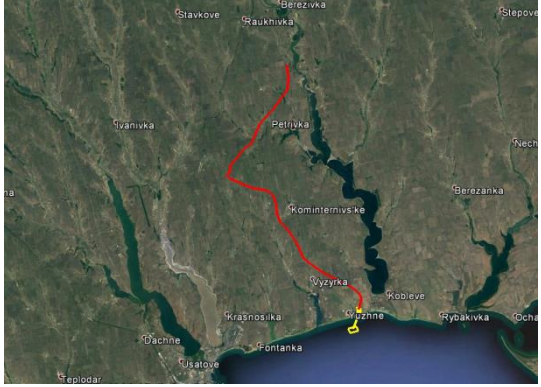
4.3.6 UNLOADING TERMINAL NEAR THE PORT OF YUZNE, UKRAINE



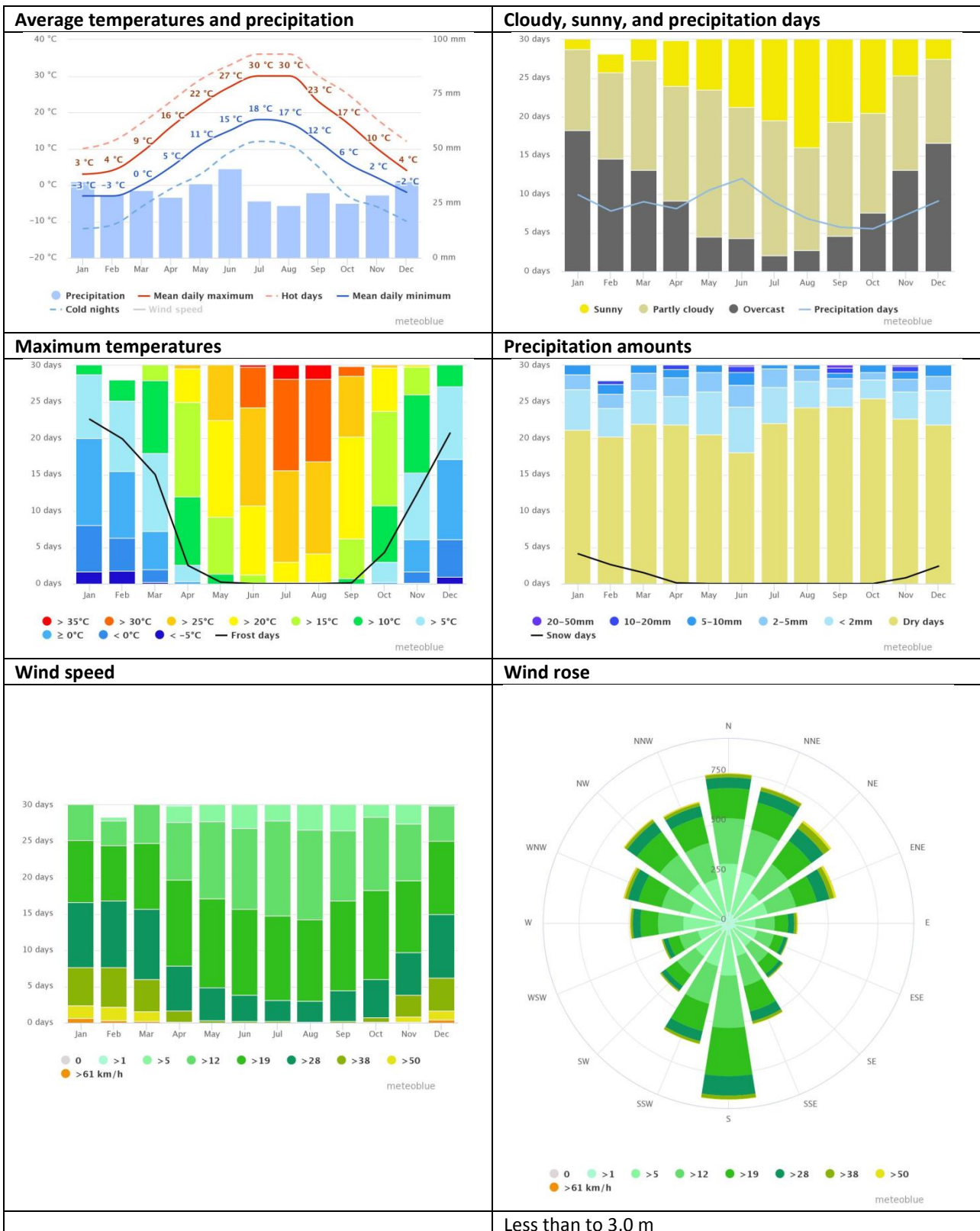
Pic. 12. The map of connecting Gas pipeline route between the unloading terminal near the port of Yuzne, Ukraine and Gas compressor station Berezivka.

The unloading terminal site near the port of Yuzne in Ukraine will be located 0,7 km to the south-east from the village of Sychavka, and about 1,46 km from the village of Yuzne. This is dictated by the necessity to place the object out of environmentally protected areas on the sea coast. In the table below shows the part of the Gas interconnector, the site of loading terminal, the underwater Gas pipeline and the area of GASVESSEL docking.

Name: Unloading Terminal near port of Yuzne, Ukraine	Location: Onshore
Type of Gas source: GASVESSEL	Gas source: Shah-Deniz Gas Fields
- Interconnector Characteristics: - Diameter - Length - Pressure - Capacity	- To be determined 70 km - As per 3 scenarios 10 billion meter cub per year

	
Location and coordinates of Gas unloading terminal:	Latitude: 46°37'38.96"N Longitude: 31° 7'38.01"E 
Location and coordinates of Gas unloading point:	Latitude: 46°35'32.06"N Longitude: 31° 6'42.74"E 
Water Depth of loading point	• 27 m
Gas composition	• 87-90 % Methane • no H₂S, no CO₂, no mercury

Climatic characteristics of the territory near the port of Yuzne:



Less than to 3,0 m

4.4 TARIFFS AND COST ESTIMATION

The structure of tariff includes the retail price of Gas in Shah Deniz field, Gas transportation from the Shah Deniz field through the territory of Azerbaijan and Georgia to the loading terminal, CAPEX, OPEX of Gas interconnector, CAPEX, OPEX of Gas loading terminal.

The same structure of tariffs must be shown in unloading system in Ukraine. The structure of tariff includes the retail price of Gas in GASVESSEL, CAPEX, OPEX of Gas unloading terminal, CAPEX, OPEX of Gas interconnector, the tariff for entry point (Compressor station “Berezivka”) into the Gas transportation system of Ukraine.

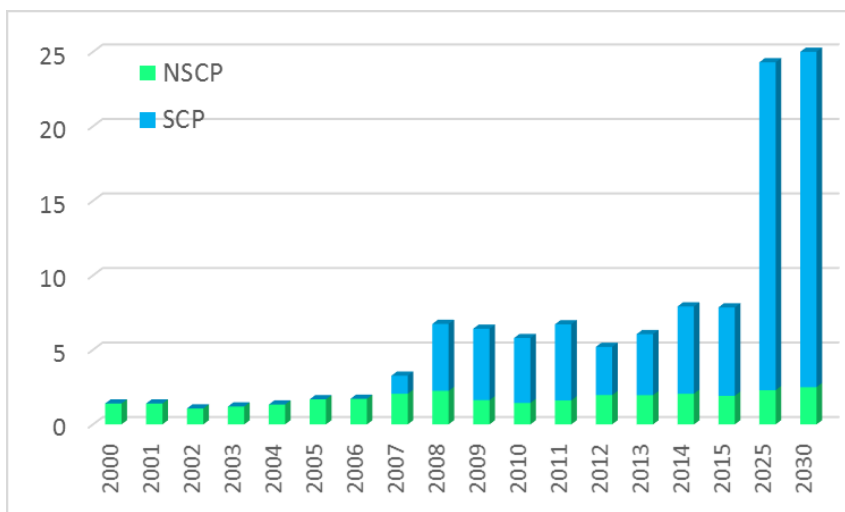
At present time, there is a steady trend of increasing the cost of Gas for consumers of all categories in Ukraine.

4.4.1 COST OF GAS TRANSPORTATION TO THE GAS LOADING TERMINAL IN GEORGIA

In this document, Georgia is not seen as a Gas consumer, but only as a transmitter for the GAZVESSEL Project, so we will consider only the transport tariff for Gas pipelines owned by Georgian State companies. Gas pipelines are the sources of Gas supplies to the loading terminal in the Poti region, and they are also considered as the state Gas transportation system, so the tariffs for Gas transportation will be the same.

Here we make an assumption that the Gas price offered in the market in Georgia will be adequate of Gas price for Gas supplied via the BTE Gas pipeline since the Gas source is the same, this is Shah Deniz fields.

The possibility to increase of volumes of Gas transiting via the Gas transportation System of Georgia is envisaged through the upgrading of the whole system. Despite the fact that attraction of the resources required thereto is set forth by plans of the National operator of the Gas Transportation System of Georgia, we consider only main gas lines, which may potentially transport gas to the GASVESSEL loading terminal. Required adjustments and corrections may be made to the Project upon determination of potential volumes of gas supplies via GASVESSEL system.



Pic. 13 Natural Gas transit, bm^3 per year through Georgian GTS.

Natural gas consumer price has increased.

Before gas consumer price growth, gas transportation tariff was also raised and it effected final price. Natural gas transportation tariff rose by 0.5 Tetri. GNERC members took a unanimous decision. Starting July 20, gas distributor companies will pay 1.9 Tetri for transporting one cubic meter. According to GNERC information,

tariff increased because of increased operational costs that are necessary for keeping the network in order. At the same time, gas companies expected the tariffs to rise more.

Transportation is one of the components of consumer tariff. GNERC will discuss the final price of natural gas. The commission does not make comments on whether the natural gas price will rise for consumers, while experts expect the tariff to grow further.

After determination of a new price of natural gas, Ministry of Energy should take one more decision. Namely, the Ministry plans to annul the decree by former Energy Minister Aleko Khetaguri regarding gas tariff regulation. This signifies that in regions a unified tariff has been terminated for all subscribers by GNERC. Before price growth, old subscribers used to pay 45 Tetri per cubic meter (who joined the network before 2008), while the new ones used to pay 5 Tetri. Under the new decision, Kaztransgas Tbilisi subscribers in Tbilisi will pay 46 Tetri and 56-57 Tetri in regions.

New tariffs of natural gas, starting July 20:

KazTransGas Tbilisi – 46.153 Tetri

SOCAR Georgia Gas – regions – 56.94 Tetri

SakOrgGas – Gori – 57.015 Tetri

The total cost of Gas in Georgia (supply from Azerbaijan) will be **192,5 USD/1000 cub m**. In this includes all costs for the Gas retail price and all transportation costs for the Georgian territory.

4.4.2 COST OF GAS TRANSPORTATION FROM THE GAS UNLOADING TERMINAL IN UKRAINE

As indicated below, it is possible the realization of natural Gas both on the domestic market of Ukraine and Gas export to outside from Ukraine.

4.4.2.1 Tariffs on Gas transportation in Ukraine.

According to GTS Code - approved by the Resolution of NERC on 30.09.2015 No. 2493 (registered in the Ministry of Justice of Ukraine on 06.11.2015 No. 1378/27823) - UKRTRANSGAZ PJSC informs that the **Gas reference price (GRP) is: for September 2017 – 6822,08 UAH*** excluding VAT for 1000 cubic meters, VAT – 1364,42 UAH, **totally 8186,50 UAH (246,8 €)**, including VAT *(is used in the calculation of financial security from October 16, 2017, and in calculating the cost of balancing services and in calculating the additional payment for failure to comply with the natural gas quality parameters in September 2017)*

PJSC UKRTRANSGAZ reported that according to the Resolution of the National Energy and Utilities Regulatory Commission of Ukraine No. 3158 dated 12.29.2015 new tariffs for entry/exit points, located at the state border of Ukraine and unit commodity charge to cover own use Gas for exit point were introduced from 1 January 2016.

4.4.2.2 Transportation to cross-border entry/exit points

PJSC UKRTRANSGAZ reported that according to the Resolution of the National Energy and Utilities Regulatory Commission of Ukraine No. 3158 dated 12.29.2015 new tariffs for entry/exit points, located at the state border of Ukraine and unit commodity charge to cover own use gas for exit point were introduced from 1 January 2016.

No.	Name of entry/exit point	Tariff for entry point, USD/1000m ³	Tariff for exit point, USD/1000m ³	Unit commodity charge to cover own use gas, %
13	Orlivka	-	23,12	2,11

For the GASVESSEL Project, it is interesting the point of export (exit) of Gas in the Gas transportation system of Ukraine. There is the "Orlivka" Gas Measuring Station.

PJSC UKRTRANSGAZ reported that according to the decision of the National Energy and Utilities Regulatory Commission of Ukraine dated 12.29.2015 №3159 starting from 1 January 2016 introduced new tariffs for services of natural gas transportation to DSO.

4.4.2.3 Transportation to DSO

Differentiated tariffs for transportation of natural Gas via high-pressure pipelines of PJSC UKRTRANSGAZ according to the licensed territory of DSO (see. tab.):

No.	Name of licensed territory	Tariff excluding VAT, UAH/1000 m ³
23	PJSC "Odessagaz"	363,60 (10,70 €)

For the GASVESSEL Project, it is interesting the DSO in Odessa region

4.4.2.4 Tariff for transportation to exit point to directly connected clients

For consumers directly connected to the main pipelines of PJSC UKRTRANSGAZ - the tariff for transportation of natural gas is:

615,10 UAH (18,10 €) for 1000 m³ excluding the VAT.

4.4.2.5 Tariff for injection, storage and withdrawal of gas

Name of service	Tariff excluding VAT, UAH/1000 m ³
Injection	32,9 (0,96 €)
Storage	46,2 (1,36 €)
Withdrawal	32,9 (0,96 €)
Overall storage service	112 (3,30 €)

For the GASVESSEL Project, it is interesting the Injection

In addition, the PJSC UKRTRANSGAZ provides information about the range of services provided to consumers that are included to the tariffs for transportation of Natural Gas, Gas reception to the transmission system in entry points (at the sites of production, border Gas stations, underground gas storages), control the volume

and quality of Gas supplied; transmission of gas to exit points using gas pumping units and gas mains networks; provision of Gas, which is transmitted to the Gas distribution stations and Gas supply companies with gasification or clients directly connected to the high-pressure pipelines ; odorization of Gas in case of need; balancing natural Gas volumes (correspondence between the intake and consumption of Gas).

4.4.2.6 Scenarios of Gas supply to Ukraine

Scenario:	LOADING POINT ↓	UNLOADING POINT ⇒	Gas facility + pipeline entry	Gas storage facility	Gas tariff & cost estimate	Alternative transport options
			Yuzne	Poti		
SCENARIO 1 Gas consumption of 200 mmscfd	Loading terminal near port of Poti, Georgia	Distance (1)	578 nm	To be updated	Not identified	LNG ship
SCENARIO 2 Gas consumption of 400 mmscfd	Loading terminal near port of Poti, Georgia	Distance (1)	578 nm	To be updated	Not identified	LNG ship
SCENARIO 3 Gas consumption of 600 mmscfd	Loading terminal near port of Poti, Georgia	Distance (1)	578 nm	To be updated	Not identified	LNG ship
SCENARIO 4 Gas consumption of 800 mmscfd	Loading terminal near port of Poti, Georgia	Distance (1)	578 nm	To be updated	Not identified	LNG ship

4.4.2.7 Calculation of CAPEX in variants of different Scenarios

Scenario, mmscfd	No	Transportation system	New Infrastructure Facilities	Gas price, €/1000 cub m	CAPEX, mln €	Transport Tariff	Notes
200	Gas loading terminal in Georgia, near the port of Poti (source - Shah Deniz Gas fields)						
	1	Main Gas pipeline Baku-Tbilisi-Erzurum (BTE, SCP)	Existing	167,39			Shah Deniz - Gas measuring point No 80
	2	Main Compressor Station	New		18,82		To be updated
	3	Gas interconnector to Gas loading terminal	New (L=140 km, D=28")		66,64		Gas measuring point No 80 - Gas loading terminal
	4	Gas loading terminal with Gas storage	New		36,45		To be updated
	5	Underwater gas pipeline	New (L=2,5 km, D=28")		1,68		Gas loading terminal - Underwater PLEM
	6	PLEM with SAL system	New		0,68		To be updated
400	Gas loading terminal in Georgia, near the port of Poti (source - Shah Deniz Gas fields)						
	1	Main Gas pipeline Baku-Tbilisi-Erzurum (BTE, SCP)	Existent	167,39			Shah Deniz - Gas measuring point No 80
	2	Main Compressor Station	New		24,91		To be updated
	3	Gas interconnector to Gas loading terminal	New (L=140 km, D=32")		76,16		Gas measuring point No 80 - Gas loading terminal
	4	Gas loading terminal with Gas storage	New		48,4		To be updated
	5	Underwater gas pipeline	New (L=2,5 km, D=32")		1,92		Gas loading terminal - Underwater PLEM
	6	PLEM with SAL system	New		0,68		To be updated
600	Gas loading terminal in Georgia, near the port of Poti (source - Shah Deniz Gas fields)						
	1	Main Gas pipeline Baku-Tbilisi-Erzurum (BTE, SCP)	Existent	167,39			Shah Deniz - Gas measuring point No 80
	2	Main Compressor Station	New		37,29		To be updated

	3	Gas interconnector to Gas loading terminal	New (L=140 km, D=32")		76,16		Gas measuring point No 80 - Gas loading terminal
	4	Gas loading terminal with Gas storage	New		64,31		To be updated
	5	Underwater gas pipeline	New (L=2,5 km, D=32")		1,92		Gas loading terminal - Underwater PLEM
	6	PLEM with SAL system	New		0,68		To be updated
800	Gas loading terminal in Georgia, near the port of Poti (source - Shah Deniz Gas fields)						
	1	Main Gas pipeline Baku-Tbilisi-Erzurum (BTE, SCP)	Existent	167,39			Shah Deniz - Gas measuring point No 80
	2	Main Compressor Station	New		49,81		To be updated
	3	Gas interconnector to Gas loading terminal	New (L=140 km, D=40")		95,2		Gas measuring point No 80 - Gas loading terminal
	4	Gas loading terminal with Gas storage	New		82,1		To be updated
	5	Underwater gas pipeline	New (L=2,5 km, D=40")		2,41		Gas loading terminal - Underwater PLEM
	6	PLEM with SAL system	New		0,68		To be updated
200	Gas unloading terminal in Ukraine, near the port of Yuzne (source - GASVESSEL)						
	1	Main Gas pipeline SHKDRI	Existent	246,8			SHDKRI
	2	Gas interconnector from Gas unloading terminal	New (L=70 km, D=40")		33,6		Gas loading terminal - Compressor station "Berezivka"
	3	Gas unloading terminal	New		16,2		To be updated
	4	Underwater gas pipeline	New (L=3,54 km, D=20")		1,7		Underwater PLEM - Gas loading terminal
	5	PLEM with SAL system	New		0,68		To be updated
400	Gas unloading terminal in Ukraine, near the port of Yuzne (source - GASVESSEL)						
	1	Main Gas pipeline SHKDRI	Existent	246,8			SHDKRI
	2	Gas interconnector from Gas unloading terminal	New (L=70 km, D=40")		33,6		Gas loading terminal - Compressor station "Berezivka"
	3	Gas unloading terminal	New		16,2		To be updated
	4	Underwater gas pipeline	New (L=3,54 km, D=20")		1,7		Underwater PLEM - Gas loading terminal
	5	PLEM with SAL system	New		0,68		To be updated
600	Gas unloading terminal in Ukraine, near the port of Yuzne (source - GASVESSEL)						
	1	Main Gas pipeline SHKDRI	Existent	246,8			SHDKRI
	2	Gas interconnector from Gas unloading terminal	New (L=70 km, D=40")		33,6		Gas loading terminal - Compressor station "Berezivka"
	3	Gas unloading terminal	New		16,2		To be updated
	4	Underwater gas pipeline	New (L=3,54 km, D=20")		1,7		Underwater PLEM - Gas loading terminal
	5	PLEM with SAL system	New		0,68		To be updated
800	Gas unloading terminal in Ukraine, near the port of Yuzne (source - GASVESSEL)						
	1	Main Gas pipeline SHKDRI	Existent	246,8			SHDKRI
	2	Gas interconnector from Gas unloading terminal	New (L=70 km, D=40")		33,6		Gas loading terminal - Compressor station "Berezivka"

3	Gas unloading terminal	New	16,2	To be updated
4	Underwater gas pipeline	New (L=3,54 km, D=20")	1,7	Underwater PLEM - Gas loading terminal
5	PLEM with SAL system	New	0,68	To be updated

4.5 CONCLUSION

This report describes the Ukrainian Gas market as the main consumer of Natural Gas in the water area of Black Sea, technical feasibility of supplies and engineering aspects of the GASVESSEL loading in the Black Sea, also outline the methodology applied to identify the target markets in the Black Sea area.

Since Ukraine was chosen as the main Gas consumer because of a number of existing political-economic problems in the region, the concept of the organization of natural Gas deliveries to the existing Ukrainian Gas transportation system was considered. Also, the possibility of supplying of Natural Gas from existing stable sources - Main Gas pipelines passing through Azerbaijan and Georgia was considered. The filling of these Gas pipelines comes from the development of the second stage of the Gas field in Azerbaijan - Shakh-Deniz.

The objective of this report is to present the technical possibilities of the existing Gas transportation system in Ukraine to receive the required volume of Gas on the market. Both domestic Gas consumers and transit Gas consumers outside of Ukraine are considered, but to which the existing GTS of Ukraine is connected.

According to the preliminary analysis of the routes of the proposed Gas interconnection pipelines to the site of the loading terminals near the port of Poti, and interconnection pipelines from the site of unloading terminal near the port of Yuzne in Ukraine, also the preliminary calculation of CAPEX, the following conclusionsto can be drawn:

- The route to the loading site terminal near the port of Poti is the best way of Gas transportation to coast of Black Sea;
- Ukraine increased the natural Gas imports.
- Ukraine increased the natural Gas consumption.
- Ukraine increased the natural Gas transit.
- For the GASVESSEL Project, the Ukrainian Gas market will be promising in relation to the growth of Gas consumption.
- Taking into account the fact that in the event of a reduction or cessation of Russian Gas supplies to the largest Gas main in southern Ukraine the SHKDRI, the GAZVESSEL Project will play a major role both for supplying Gas to the southern region of Ukraine and for exporting Gas to Moldova and Romania.

5 SCENARIO DECISION SUPPORT MODEL (MODEL)

5.1 OVERVIEW

This document outlines the methodology employed to develop the Scenario Decision Support Model (Model) for the gas delivering to the identified markets as part of the Gasvessel project. In particular, this methodology applies to the activities included in Work Plan 2 (WP2).

Esteco using the optimization software modeFRONTIER develops the Scenario Decision Support Model.

5.2 OBJECTIVES

The main goal is to develop a tool (Scenario Decision Support Model) to optimize the delivery of gas from the identified source locations to the identified markets using the Gasvessel concept in different scenarios.

The outcome of the model is an estimation of the CNG transportation for the identified scenarios, providing essential information like the optimal ship size, the ship speed and the fleet size in order to reach the lowest gas transport costs per unit volume.

Three geographic areas have been chosen as they establish early take-up potential for the Gasvessel concept.

- **Barents Sea Offshore Oil Field**
- **East Mediterranean Gas Fields**
- **Black Sea Region**

In any case, the model developed by Esteco can be applied in the future to other scenarios, not yet defined at this stage, including exploitation and supply to Europe of stranded, associated and flared gas resources from outside of the European geographical area.

5.3 METHODOLOGY DESCRIPTION

5.3.1 THE CONCEPT BEHIDE THE MODEL

The Scenario Decision Support Model (Model) is developed using the optimization software modeFRONTIER. modeFRONTIER is an integration platform for multi-objective and multi-disciplinary optimization, it offers a seamless coupling with third party engineering tools or any in house/generic code enables the design process automation and facilitates analytic decision making.

For the Work Package 2 an in house script code is developed to calculate, within the modeFRONTIER platform, the proper output variables starting from selected input variables. For each scenario the input and output variables are identified by the partners (CHC, SINTEF, VTG and Navalprogetti) and provided to Esteco. The Model collects information from different parts of the Gasvessel transportation system and the optimization algorithms available in modeFRONTIER drive the process into an iterative loop (Figure 1) to reach the lowest costs per unit volume of the proposed technology.

The Model is also able to analyze the relationship between inputs and outputs and in particular to assess the effect of each input variable on the relevant outputs (sensitive analysis).

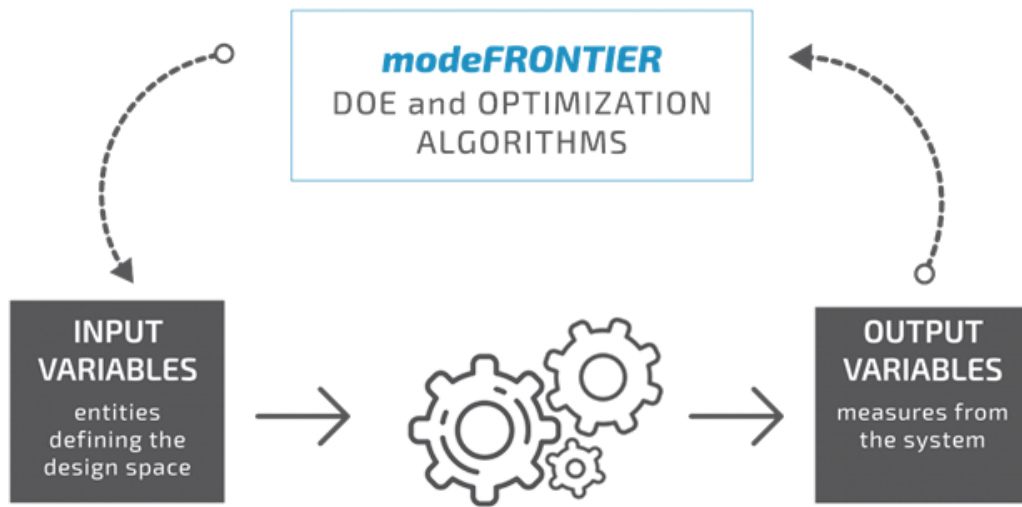


Figure 1. Optimization loop scheme

5.3.2 MODEL DESCRIPTION

5.3.2.1 Overview

As mentioned before the Model is designed to be flexible, generic and easily suitable for any further scenario in new areas. The flow chart below (Figure 2) shows the logic:

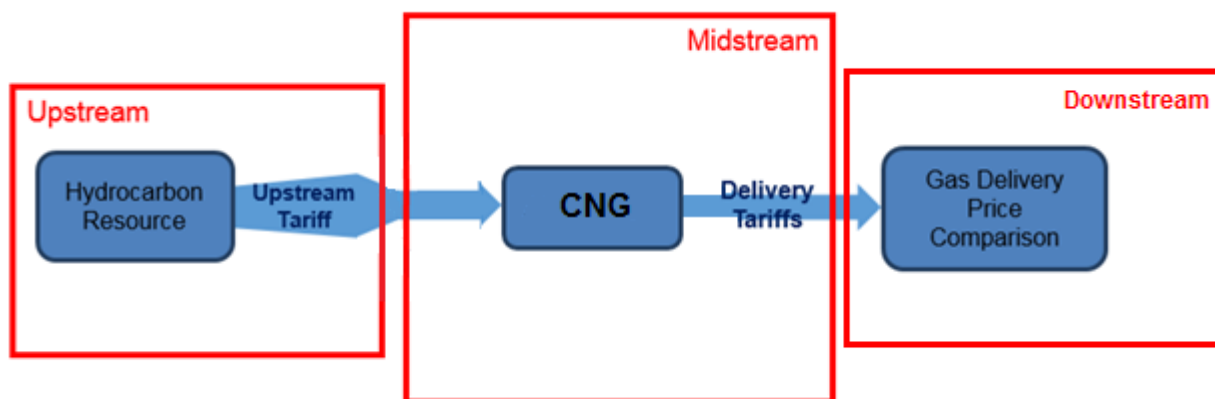


Figure 2. Gas transportation flow chart

The Model will optimize only the Midstream CNG transportation cost; gas Upstream tariff calculation and gas Downstream cost estimation are to be provided by the partners for each scenario. The model provides the transportation tariff but it can report separately the following contributes.

- CNG transportation tariff

- Gas source and delivery facilities cost
- Gas downstream tariff (Upstream tariff + CNG transportation tariff + facilities cost, including unloading cost)

Other alternative tariff options can be provided by the partners for comparison but are not calculated by the Model.

For each identified scenario, the Model will find the optimal ship size, ship speed and fleet size in order to fulfill the estimated gas demand in the area at the lowest costs per unit volume (Gasvessel transportation tariff), given the geographical characteristic and the facilities at departure and destination.

This kind of information is an important input for the entire Gasvessel project, in particular the results of the scenarios analysis will be used in the design processes of WP3 (pressure vessel), WP4 (pre-industrial prototyping of pressure vessels) and WP5 (ship design). WP7 will afterward perform an analysis of the markets to identify where the CNG concept is competitive compared to other monetization options.

5.3.2.2 INPUT VARIABLES

The input variables included in the Model are listed in the following table:

Parameter name	Description	Notes / Assumptions
Total gas demand [Nm ³ /year]	Gas demand in the identified market or total gas produced in a specific gas field. Note that the total demand can be provided to different destination ports in the same geographical area; in such a case the gas rate demand to each destination port must be given.	This quantity is considered in general as a constant datum, not as an optimization parameter (but the impact of the different total demand on the final cost can be estimated). The gas volume loaded in each ship considers also the gas engine consumption for the transport.
Ship capability [Nm ³]	Gas capability using cylinder (Pressure Vessel). It is the gas amount the ships can transport in each trip, it is a parameter to be optimized (the allowed ship sizes number can however be discrete within a certain range).	Optimization parameter. The transport by containers option can be made also available if requested
Costal storage autonomy [day]	The minimum quantity of gas necessary at each port to guarantee the autonomy of the market express in days. It is basically the maximum time interval without receiving gas that the destination port can bear; this may be related to the capacity of storage at destination if present. In some cases however there is no need to set this quantity explicitly.	It is a fixed or an optimization parameter. In some scenario the storage is not required, for example if the delivery point is a pipeline or a network grid that guarantees continuously the demand
Ports distances matrix [Nautical Miles]	It represents the distance between the departure and the destination port(s). The distance is computed along the typical route from departure to destination.	It is a fixed parameter (no optimization). For each scenario the data are reported in a matrix with all the distances between source ports and delivery ports.
Ship velocity [knots]	The ship speed is an important parameter for the gas delivery tariff. It is the average ship velocity during the trips over one year in that geographical area.	Metoccean conditions can influence the ship velocity and fuel condition.
Working days per year [day]	It is the number of days that a ship is available over one year (considering all the	Metoccean conditions of a certain route may affect this

	stops for ordinary and extraordinary maintenance).	input. It is a fixed parameter (no optimization).
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Other input parameters to estimate the CNG transportation tariff:

Parameter name	Description	Notes / Assumptions
Gas loading time [hours]	Gas loading time from the gas source to the Gasvessel.	An accurate enough formula to estimate gas loading time as function of gas volume and pressure is given.
Gas unloading time [hours]	Gas unloading time from Gasvessel to the delivery port.	An accurate enough formula to estimate gas unloading time as function of gas volume and pressure is given.
Operational time [hours]	The operational times necessary for the ship at each arrival port.	It may be different for each port.
Ship CAPEX [€]	Ship CAPEX cost express in Euro.	Estimated the CAPEX cost as function of ship size.
Ship OPEX [€/Year]	Ship OPEX cost per year express in Euro.	Estimated the OPEX cost as function of ship size.
Activity years [year]	Life cycle of a ship for the scenario.	it is a fixed parameter (no optimization).
Mortgage period [year]	It is the period that it shall be returned on payment of the debt (investment).	it is a fixed parameter (no optimization).
Interest rate [%/year]	it is the amount of interest due per period (one year) as a proportion of the amount lent.	it is a fixed parameter (no optimization).

Moreover, in order to estimate also the gas downstream tariff, it is necessary to include this additional information:

Parameter name	Description	Notes / Assumptions
Gas Upstream tariff [€/Nm ³]	Gas tariff at source field.	If this data is not available only the transportation tariff can be computed.
Loading/Unloading facility cost [€]	Loading and Unloading facility cost at the port.	If this data is not availed the downstream tariff estimation is not computed.
Other costs [€]	Indirect cost, Tax, Port fee etc.	Analyze whether it may be worth considering other not mentioned costs for the tariff estimation.

The Model can take into account even other parameters and data necessary for the correct tariff estimation. These data are parameterized into the Model and can be assumed as constant based on either on-field experience or somehow computed by estimation.

5.3.2.3 ASSUMPTIONS

The Model considers the following as assumptions.

- Gas composition (Pure gas)
- Gas pressure (Upstream gas pressure 240 bar)
- One ship can transport gas to more than one destination port (the model automatically check if this is possible and convenient) however each ship always goes back to the same departure port for the loading (this in case there were more than one departure port).
- In case there is a certain maximum autonomy period that has to be fulfilled, (i.e. the coastal storage autonomy quantity is greater than zero) the ship capability is enough to guarantee that autonomy period, for example if the ship capacity was 900.000 m³ and the autonomy period was 7 days then the maximum gas demand over that 7 days period could not be greater than 900.000 m³. If this condition is not fulfilled, an error will be generated, in such a case it will be necessary to increase the ship capacity or to decrease the maximum allowed autonomy period.
- All the ships in a certain geographical area are identical (i.e. it is not possible to have ships of different size or characteristics in the same area).

All the assumptions can anyway be adjusted anytime in the Model at the best convenience.

5.3.2.4 SCENARIO DATA AND DESCRIPTION

Three different scenario cases were identified and characterized, representing both existing and new upcoming gas exploitations.

- **Barents Sea Offshore Oil Field** (unused gas due to limited pipeline availability and flared associated gas from the oil platform)
- **East Mediterranean Gas Fields** (new discovered gas field to be exploited)
- **Black Sea Region** (unreachable since there are no near existing gas pipelines)

In these cases the Gasvessel technology may be a valid alternative opportunity.

1) BARENTS SEA OFFSHORE OIL FIELD

Scenario 1: J.Castberg oil&gas field to Nyhamna, Kollsnes or Kårstø

Gas production: 507 Millions Nm³/year (associate gas)

Distance matrix [NM]:

Ports	J.Castberg
Nyhamna	686
Kollsnes	800
Kårstø	896

Scenario 2: Alke gas field to Nyhamna, Kollsnes or Kårstø

Gas production: 568,5 Millions Nm³/year

Distance matrix [NM]:

Ports	Alke
Nyhamna	645
Kollsnes	743
Kårstø	805

Scenario 3 Kårstø gas production field to Herøya

Gas demand: 1,1 Millions Nm³/year

Distance matrix [NM]:

Ports	Herøya
Kårstø	244

2) EAST MEDITERRANEAN GAS FIELD

Scenario 1: Cyprus Aphrodite gas field to Cyprus Vasilikos and Crete Linoperamata

Gas demand: 1445 Millions Nm³/year

Vasilikos = 962 Millions Nm³/year,

Linoperamata = 483 Millions Nm³/year

Distance matrix [NM]:

Ports	Aphrodite gas field	Vasilikos
Vasilikos	159	-
Linoperamata	267	407

Scenario 2: Cyprus Aphrodite gas field to Cyprus Vasilikos

Gas demand: 962 Millions Nm³/year

Distance matrix [NM]:

Ports	Aphrodite gas field
Vasilikos	159

Scenario 3: Cyprus Aphrodite gas field to Lebanon Zouk

Gas demand: 1252 Millions Nm³/year

Distance matrix [NM]:

Ports	Aphrodite gas field
Zouk	269

Scenario 4: Cyprus Aphrodite gas field to Cyprus Vasilikos and Lebanon Zouk

Gas demand: 2214 Millions Nm³/year

Vasilikos = 962 Millions Nm³/year,

Zouk = 1252 Millions Nm³/year

Distance matrix [NM]:

Ports	Aphrodite gas field	Vasilikos
Vasilikos	159	-
Zouk	269	123

Scenario 5: Cyprus Aphrodite gas field to Egypt

Gas demand: The gas demand for Egypt is very big, CNG can transport part of this demand, here we consider 3 different volume.

Gas demand (1): 962 Millions Nm³/year

Gas demand (2): 2890 Millions Nm³/year

Gas demand (3): 5781 Millions Nm³/year

Distance matrix [NM]:

Ports	Aphrodite gas field
Egypt	188

3) BLACK SEA REGION

Scenario 1: Shah-Deniz gas field to POTI-Georgia, delivery to YUZNE-Ukraine

Gas demand: 10 Billions Nm³/year is the gas demand for Ukraine, CNG can transport part of this demand, also here we can consider 3 different demand

Gas demand (1): 962 Millions Nm³/year

Gas demand (2): 2890 Millions Nm³/year

Gas demand (3): 5781 Millions Nm³/year

Distance matrix [NM]:

Ports	POTI-Georgia
YUZNE-Ukraine	308

5.3.3 SHIP NUMBER AND SIZE ASSESSMENT PLATFORM

The model developed in modeFRONTIER contains the input variables described in the paragraph above; any of the previously mentioned inputs can be exposed, and all the necessary computations are implemented by a proper generic script. The output variables are then extracted and made available; see the workflow scheme below (Figure 3):

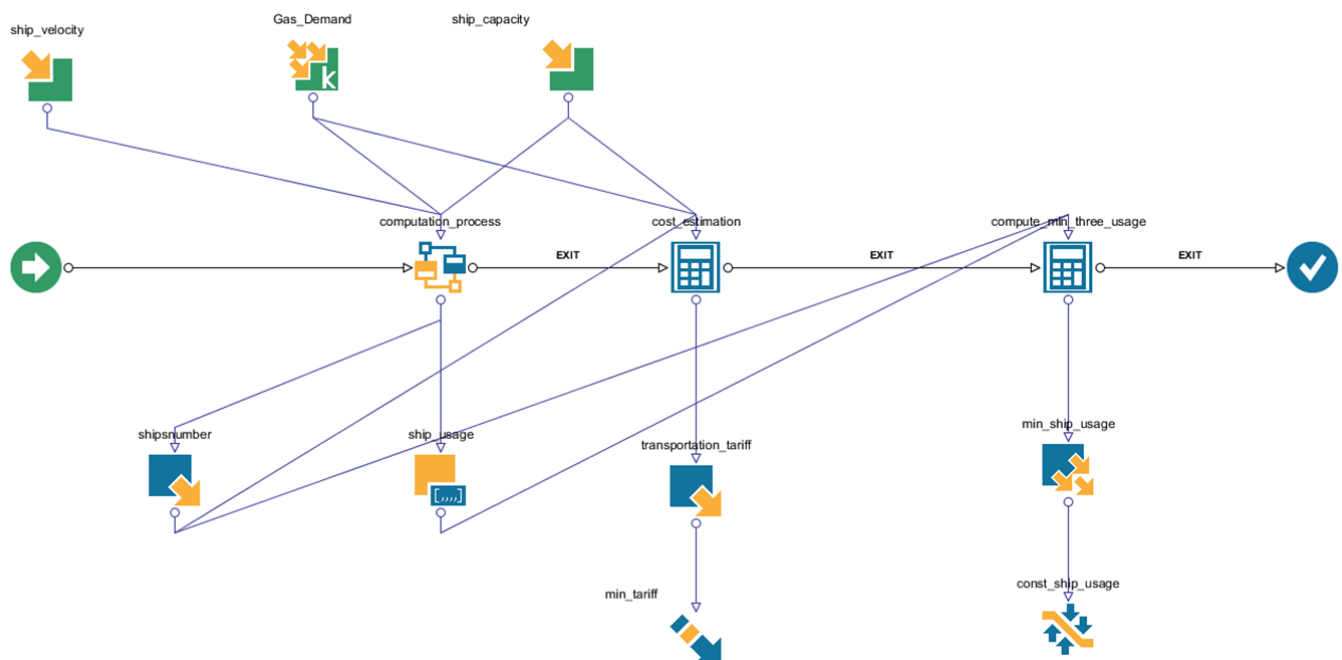


Figure 3. Model Workflow Scheme

Similar workflows are created for each scenario or variant, these workflows are intended as an independent sub-process below the main platform. In this way the final Model is flexible and easily adaptable for any new case.

A specific procedure has been implemented to find the optimal number of ships and size to satisfy the gas demand of the considered geographical areas.

The optimal solution considers the size and the number of ships necessary to fulfil the given gas demand trying at the same time to maximize the usage of the ships (the percentage of time the ship is on mission) reducing finally the cost/tariff. Possible scenario solution schemes:

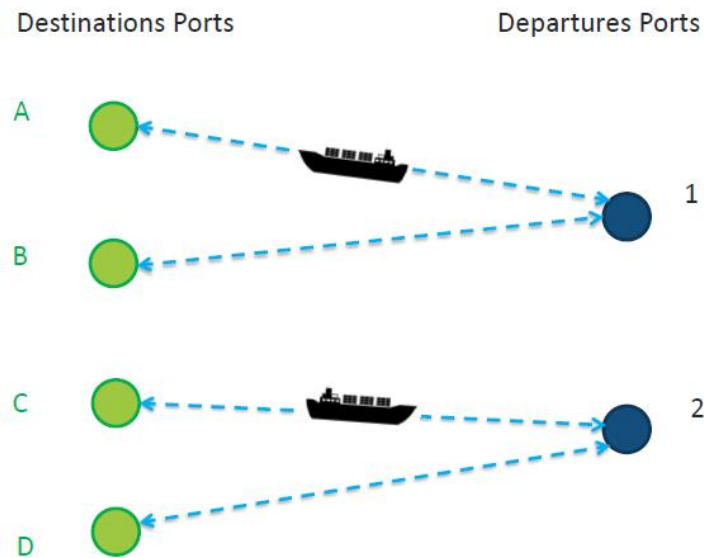


Figure 4. Source 1 is convenient for ports A and B, and Source 2 is convenient for ports C and D

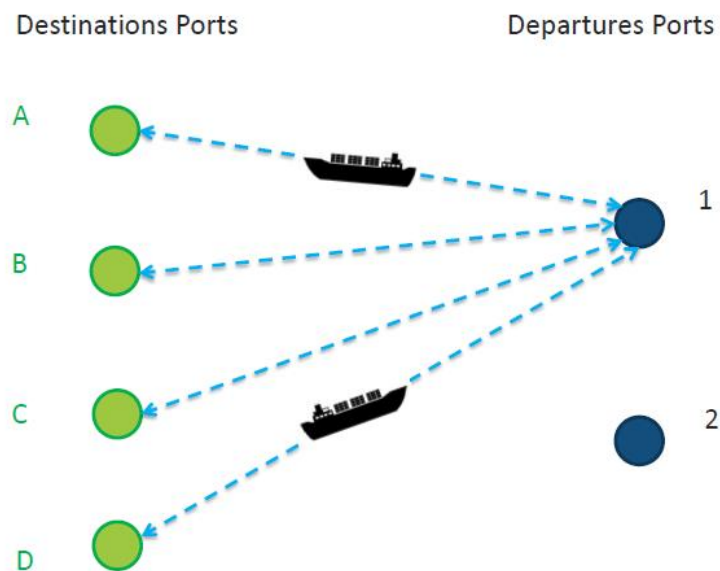


Figure 5. Source 2 is not convenient for ports A, B, C and D

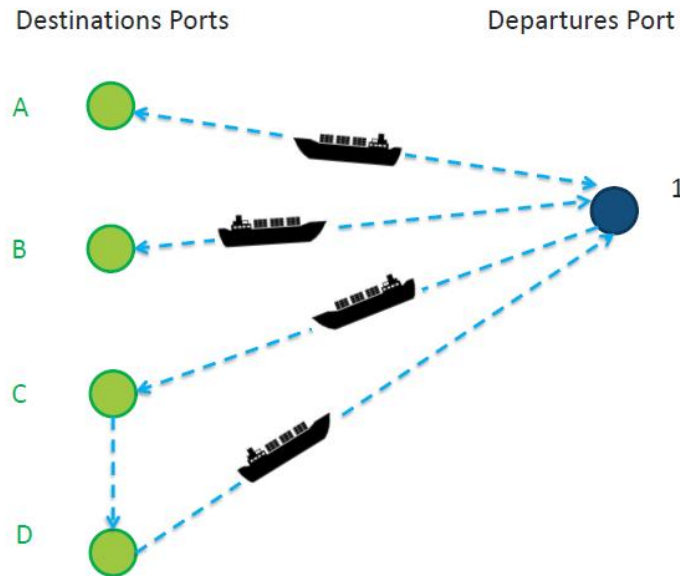


Figure 5. The optimal solution combines ports C and D with one triangle route (partial gas unloading)

5.3.4 MODEL OUTCOMES

For each set of the previously mentioned input parameters the following quantities are provided as output parameters:

- Number of ships fleet: it is the number of ships necessary to fulfil the gas requirement in the geographical area, the ship number is computed considering the number of trips necessary during one year, the maximum autonomy at the destination (if provided), the distances and the ship velocity;
- Ship usage: it is a vector that reports for each ship the percentage of time the ship would be on mission over the entire working year
- Total days per cycle: it is the number of days necessary for a complete return trip from a destination to an arrival, including loading and unloading procedures and operational times

The optimization procedure will automatically set the input parameters for a certain number of designs in order to optimize the desired quantities (the percentage of ship usage for now, the total cost and the gas tariff estimation finally). Of course in this methodology it is also considered the possibility that the same ship be used to transport gas to more than one destination whenever it is possible.

For the first Model version the cost of the ships is considered as a fixed parameter, in any case the total cost optimization, in terms of Capex and Opex, is something that will be implemented once the costs estimation is provided as a function of the ship characteristics. Hence, the final outcome of the platform will be actually the gas tariff estimation [€/Nm³] in the considered geographical areas, by the Gasvessel technology.

5.3.5 IMPROVEMENTS

At this stage, the SCENARIO DECISION SUPPORT MODEL is ready and complete, the Model can calculate all the desired outputs for each identified scenario, however there are still some points that may be improved in the next months to obtain a more flexible and accurate Model, suitable for any scenario.

Here are the pending points and the partners that can contribute to each.

1. How to consider Metocean data? (Could impact the average ship velocity and ship consumption or, more simply, the actual ship working days per year) – *SINTEF, CHC, NP, HLL*
2. Ship Consumption (to quantify the ship total loading gas volume) - *NP*
3. Loading and Unloading times are currently estimated using a simplified formula provided by Cenergy, a more accurate formula could be employed – *VTG, Cenergy*
4. Estimated ship building cost for different sizes (at this stage we have only a fixed cost for two ship sizes) – *NP*
5. Opex cost for different ships (at this stage we have only a fix cost for one ship size) – *NP, HLL*
6. Are there other indirect costs? – *CHC, SINTEF, NP*
7. Facilities costs at the departure and arrival ports should be provided to be included in the final gas tariff. At moment the platform can estimate the CNG transportation tariff but not the gas downstream tariff since the provided gas upstream tariff does not include gas loading and storage cost at the departure port. The unloading facilities cost at the arrival port is indeed necessary to estimate the gas downstream tariff – *NP, CHC, VTG, SINTEF, Cenergy, HLL*
8. The total Ukraine gas demand value is very big, a proper portion should be considered for the scenario (in case the Model can find which could be the portion that makes the Gasvessel option still convenient in that area)– *NP, VTG*

5.4 CONCLUSIONS

The Decision Support Model developed in modeFRONTIER is a flexible workflow to calculate the CNG transportation tariff for any geologist scenario.

The model allows the end user to have an easy tool to estimate the CNG cost and then the gas tariff. The flexible modular concept and parametrization can explore different combinations, options and locations by adding or removing modules, inputs and outputs suitable for the specific case study.

Moreover, the post process tools available in modeFRONTIER design space can be helpful to analyzed data and results, in order to understand which would be the most effective set of input parameters.

The modeFRONTIER optimization algorithms are used to locate the best option in an automatic way; the platform can be made available to all the Gasvessel partners and published as a web service by the Volta architecture developed at Esteco.