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USA-Asia LNG Shipping Route Optimization

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Statutory Declaration

"I hereby certify, that I did the work on my own, did not present it for any other purpose, specified all sources and resources I used during my research, and have indicated verbal and logical quotes."

Place and date: Madrid, 1st of February 2019

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(Thomas-Philipp Miksch)

Summary

The so called “shale-gas boom” led the USA from being a liquefied natural gas (LNG) importing nation to a net LNG exporting nation up from March 2016 and keeping this position year-on-year (YOY), with an exception during cold October 2017 when heating demand was high. This date marked the end of nearly 60 years in which more gas was imported into the USA than exported.
Existing regasification plants, mainly in the south with direct access to the Gulf of Mexico, are being modified to liquefaction plants, being Cheniere Energy´s operated Sabine Pass LNG the first of them that went commercially online in 2016 (trains T1 and T2).

On the other side, new global demand is mainly located in the Asia-Pacific basin, being China the biggest driver. Its demand for LNG grew by 12,7 million metric tonnes during 2017, the highest YOY increase ever seen by one single country [1, p.6]. This fact pushed the country to the second place of LNG importing countries, right behind Japan and overcoming South Korea. China´s demand has peaks during winter months from November until February, especially in its northern provinces, mainly because of heating. In general, analysts estimate a continuous growing demand for LNG in the upcoming years, apart from existing and new to come pipeline supply [2].

Also, other countries in the Asia or Asia-Pacific region are continuing to expand their regasification infrastructure or appear as new players: Beside the above-named Japan, world leader with 198 million tonnes per annum (MTPA) nameplate regasification capacity in March 2018 and 85 MTPA natural gas imports in 2017, and South Korea, the growing demands of India, Taiwan, Thailand and smaller markets like Singapore, Bangladesh or the Philippines will need to be satisfied. In addition, some exporting countries as Malaysia and Indonesia are increasing their gas consumption and recently have started to import.

In this context, this thesis´ focus shall to be set on one specific element of the LNG value chain: Shipping costs. Within the LNG value chain, shipping costs contribute to around 10-30 % of total Capital Expenditure (CAPEX) [3], depending on the passage, i.e. the distance between liquefaction plant and regasification terminal. As any other component along the value chain, they are subject to continuously price pressure.

With US liquefaction units mainly located at the southern coast (Gulf of Mexico) there exist four routes to bring gas to buyers in the Pacific basin: Either westwards through the Panama Canal or around Cape Horn (southern Argentina and Chile) or eastwards through the Suez Canal or the Cape of Good Hope (South Africa). While canal usage implicates a financial contribution in form of tariffs, it shortens the shipping time massively, saving daily operational costs.

The thesis is a practical approach to compare costs for different routes from the USA to buyers in the Pacific basin. It will be interesting to find the location, that defines the border between eastward and westward route. Furthermore, the results will be subject to enhanced examinations in terms of two different vessel sizes, changing prices for commodities (marine fuel oil, gas) and charter rates. Outlooks will also be given with respect to the Panama Canal as a possible bottleneck for LNG traffic and for shipping prices of several other LNG exporting countries. Qatar and Australia are strong LNG exporting markets that compete against US gas and will try to boost their exports to Asia, mainly China, favored by their closer location. Investigations on these topics will be done for a time frame of five years (2019 – 2023).

Table of content

Introduction into the LNG shipping business 1
1 The LNG value chain 2
1.1 Gas production, reserves and resources 2
1.2 Global gas and LNG trade and outlook 5
1.3 Properties of natural gas 8
1.4 Gas treatment 10
1.5 Liquefaction 11
1.5.1 Train size 11
1.5.2 Global developments 12
1.5.3 Global players 13
1.5.4 Liquefaction technologies 13
1.5.4.1 Expander based technologies (EBTs) 13
1.5.4.2 Mixed refrigerant based technologies (MRTs) 14
1.5.4.3 Cascade based technologies (CBTs) 15
1.5.4.4 Hybrid processes 16
1.6 Maritime transport: Costs 17
1.7 Storage 18
1.8 Regasification 19
1.8.1 Process technology 19
1.8.2 Global developments 20
1.9 Gas market applications 20
1.10 Investment costs 22
1.11 Vertically integrated supply chain 23
2 The USA as an LNG exporting country 25
2.1 The shale-gas phenomenon 27
2.2 US gas market and prospective resources 28
2.3 Development of US liquefaction capacities 30
3 LNG demand in Asia-Pacific and Middle East – A 5-year market outlook 33
3.1 Japan 33
3.2 China 33
3.3 South Korea 33
3.4 Other destinations: India, Taiwan, Pakistan, Kuwait, Thailand, Indonesia, Singapore, Bangladesh, the Philippines 34

4 LNG vessels 37
4.1 Vessel size 37
4.1.1 Size limitations 39
4.1.2 Gross tonnage and net tonnage 40
4.1.3 Gross tonnage to capacity relation and average vessel size 41
4.1.4 Small-scale LNG vessels and stationary offshore solutions 42
4.2 Containment types 43
4.2.1 Moss design 43
4.2.2 Membrane design 44
4.3 Propulsion types 45
4.3.1 DFDE/TFDE and alternative propulsion technologies that comply with future emission standards 46
4.3.2 The 2020 sulphur cap 48
4.4 Vessel lease 49
4.4.1 Seasonal differences 49
4.4.2 Leasing vs. buying 50
5 Routes 51
5.1 Westward routes 54
5.1.1 The Panama Canal 54
5.1.1.1 Tariffs 55
5.1.1.2 Tariff structure for LNG vessels 56
5.1.2 Cape Horn 56
5.2 Eastward routes 57
5.2.1 The Suez Canal 57
5.2.1.1 Tariffs 59
5.2.1.2 Tariff structure for LNG vessels 61
5.2.2 Cape of Good Hope 62
5.3 Competition between the Canals 63
5.4 Distances to destinations 64
5.5 Speed and travelling time 70
5.6 Chokepoints or bottlenecks of maritime transport 71
6 Expected USA-Asia shipping costs 72
6.1 Influence of fuel and charter costs 72
6.2 References from literature 73
7 USA-Asia shipping cost calculation 74

7.1 Input data 74
7.1.1 Low price scenario 76
7.1.2 Moderate price scenario 78
7.1.3 High price scenario 80
7.1.4 Comparison between scenarios 81
7.1.5 Comparison to results from literature 86
7.2 Focus: Panama Canal 87
7.2.1 The canal as a key access to the Pacific basin 87
7.2.2 Bottleneck analysis 89
7.2.3 Waiting vs. alternative routing 92
7.3 Competitors 94
8 Conclusion and outlook 99
References 100
List of figures 106
List of tables 108
Units 109
Conversions 109
Annex 110

Introduction into the LNG shipping business

Information in this chapter is based on [4], if not otherwise indicated.

The process of liquefying natural gas is not new. First intentions date back to 1820 when the famous British engineer and inventor Michael Faraday successfully chilled several gases and obtained their phase change into liquids. But it was the French physicist Louis P. Cailletet who first obtained liquified natural gas (LNG) in 1878. Later, Swiss chemist Raoul P. Pictet developed an improved cascade process. Carl von Linde´s inventions in refrigeration simplified the cooling process (1895) and are in principle still used in today's liquefaction plants.

The first experimental liquefaction plant of industrial scale was built in 1912 in West Virginia, USA. In 1940 the first liquefaction plant, constructed in Ohio, USA, produced LNG for three years. The first plants were not erected with the aim of international trade but to store gas in its liquefied form and later use for heating (demand peak shaving).

It was in 1959 when shipping became a part along the LNG value chain and the first cargo of LNG ever was shipped. A converted World War II freighter, then named *Methane Pioneer*, was used to convey 5.000 cm (cubic meters) of LNG from Lake Charles, Louisiana, USA, to Canvey Island, UK, in the Thames estuary. But there should follow only seven cargos more.

With the commissioning of 1 MTPA Arzew liquefaction plant in Algeria to long-term supply LNG to Canvey Island, UK, and later Spain, shipping took momentum and became integral part of the value chain (1964). This was possible using the first purpose-built LNG carrier, the *Methane Princess*.

There followed deliveries from Kenai liquefaction plant in Alaska, USA, to Tokyo (1969), with Kenai having been the longest time operational LNG plant so far (1969 – 2015). End of the 1970s Indonesia became the world´s biggest LNG exporter with Japan being the main buyer. Within the years more and more players came into the business, changing the focus to the Middle East, with Abu Dhabi becoming a big exporter and the USA mainland (or so called "Lower 48", excluding Alaska and Hawaii) the second largest consumer after Japan. The first US receiving terminal was located in Everett, Massachusetts, and came online in 1971. Within five years three more facilities began regasification: Cove Point, Elba Island (both in 1978) and Lake Charles (1982).

Routing and supply options expanded with the entry of Malaysia and Australia as big LNG suppliers in the 1980s. At the end of the decade the world´s fleet consisted of 70 vessels and trading volumes rounded up to 48 MTPA. The 1990s were marked by the entry of Qatar, being now the world´s top LNG producer since 2006.

Main driver of this expansion was the forecasted US demand: Supposedly only 75% of domestic gas demand could be covered by own production within the next decades – the rest would have to be imported as LNG. The US built eleven regasification facilities more and import peaked at 16 MTPA in 2007. Then unconventional gas resources were found, and within ten years the USA changed from being a gas importer to a gas exporter.

During the last years China has become the consumer with the biggest annual growth and is changing the focus again. In this context, the thesis is going to deal with shipping interconnections between the USA as a supplier that is expected to bring huge amounts of LNG online in the next years, and countries mainly of the Asian and Asian-Pacific region, where experts expect the world´s main demand.

1 The LNG value chain

The LNG value chain consists basically of three phases: Upstream, midstream and downstream processes. Apart from exploration, once the resource is localized and the source is developed, *upstream* processes can be considered as gas production, gas treatment, liquefaction and storage before transport. *Midstream* process can be characterized by transport by ship, storage at the receiving terminal and regasification. Distribution to the customer, gas trading, commercialization and marketing are typical parts of the *downstream* process. Natural gas is consumed by industry, for power generation, in the residential and commercial sector (heating) and for other applications.

Figure 1 LNG value chain.[1]

1.1 Gas production, reserves and resources

Natural gas can appear in different forms: Conventional gas can be found in a single gas field (non-associated) or associated together with crude oil. Shale gas, tight gas and coal-bed methane are indicated as unconventional gas resources. Shale is a fine-grained sedimentary rock that forms when silt and clay-size mineral particles are compacted, and it is easily broken into thin, parallel layers. Black shale contains organic material that can generate oil and natural gas, which is trapped within the rock's pores. Tight gas generally refers to low-permeable sandstone and carbonate reservoirs. Coal-bed methane is natural gas obtained from coal seams.

Another form of natural gas is natural biogas which is emitted in livestock farming or fermentation of biodegradable waste, fruits or vegetables (i.e. corn).

Apart from terrestrial appearance huge amounts of methane hydrate can be found in the oceans, enclosed in depths that provide certain temperature and pressure.

In all these forms, natural gas consists mainly of methane (CH4) and thus is a non-renewable energy source, a fossil fuel.

[1] Copyright by Wärtsilä: **Website** (Jan. 2019)

The following schematic shows all kids of terrestrial natural gas resources:

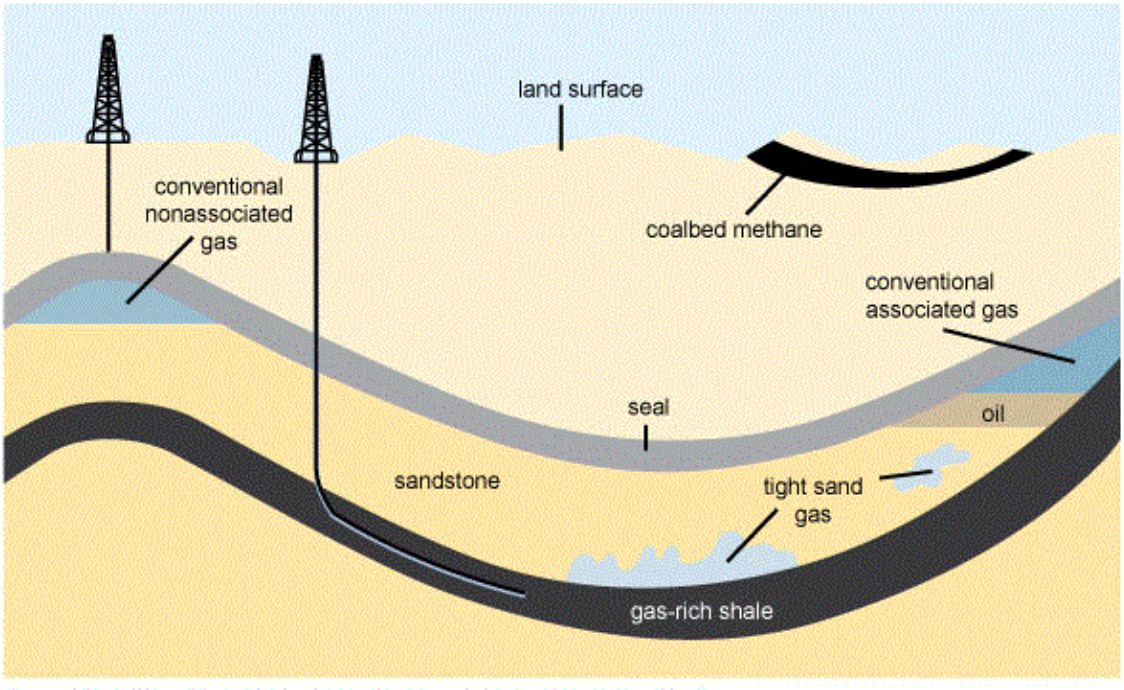


Figure 2 Schematic of terrestrial natural gas resources.[2]

Subterranean natural gas is called *conventional* when it flows "freely" from the well to the processing equipment using solely rotary drilling tools. This represents the easiest and cheapest way to obtain natural gas. On the contrary, natural gas is called *unconventional* when the drilling company needs more equipment than just rotary drilling tools to obtain the gas: For example, huge amounts of water and sand are needed to create access to rock-embedded gas (so called "fracking", which origins from "hydraulic fracturing"). The more complex processes get and the deeper the gas field is, the costlier it is to obtain the resource.

For further understanding it is necessary to explain the difference between resources and reserves: *Resources* are called those quantities of a raw material, that are geologically detected but not recoverable in a profitable, economic sense and / or expected in a certain area because of geological patterns. Raw material is called a *reserve* when it complies with three conditions: It must have been proved by drilling, exploitable with today´s technology (feasible) and extraction must be economically profitable at current commodity prices (profitable).

A good example how a resource can "transform" to a reserve are Canada´s oil sands, mainly located in the state of Alberta. Some time ago it was not technically feasible to exploit them. When technology advanced it was still not profitable. But when global oil prices peaked before the last world economic crisis in 2008, it became lucrative to use those sands for oil production, whereby they became a reserve.

There exist several methods for a closer classification, which all focus on an exacter prediction about resources and reserves. Basically, they are based on probabilities.

[2] Copyright by U.S. Energy Information Administration (eia): **Website** (Jan. 2019)

Table 1 Classification of reserves based on probabilities.

Probability	**Characteristics**	**Range of (un)certainty**
p90 or p100	Proved reserves, often with already existing pipeline infrastructure or construction underway	certain
p50	Probable reserves, lack of infrastructure	probable
p10	Possible or speculative reserves, more likely resources than reserves, might play an important role in future	uncertain

With additional drilling, proven long-term productivity for existing wells and technology improvements new information is continually gained and reserves may change their status from possible to probable and from probable to proven.

According to BP´s Statistical Review of World Energy 2018 [6], worldwide *proved* natural gas reserves are estimated 193,5 trillion cubic meters (1 tcm in American units equivales 1 bcm in standard SI units) at the end of 2017. With an annual production rate of 3.680,4 billion cubic meters (bcm) reserves could be used for another 52,6 years from 2018. US reserves contribute with 4,5% or 8,7 tcm to total proved reserves and would be depleted after 11,9 years from today at the current production rate of 734,5 bcm per annum.

This number might surprise considering the fact that experts foresee a golden age for US shale gas exports and construction for a multitude of liquefaction projects is underway or Front End Engineering and Design (FEED) has been completed, waiting for approval by the US Federal Energy Regulatory Commission (FERC) agency. But British Petrol´s (BP) numbers represent *proved* reserves only. In a commentary paper for the Annual Energy Outlook (AEO) the U.S. Energy Information Administration (eia) estimates *total technically recoverable resources* close to 70 tcm [5]. With this amount US gas could last for about 95 years. The truth might lay in between, as future technical improvements and market developments cannot be foreseen. Right now, the US are the world´s biggest producer of natural gas, followed by the Russian Federation and Iran.

Table 2 World´s top three natural gas producers [6].

In 2017	**Proved reserves**	**Production rate**	**Reserves-to-production ratio**	**Share of world production**
USA	8,7 tcm	734,5 bcm	11,9 y	20,0%
Russian Fed.	35 tcm	635,6 bcm	55 y	17,3%
Iran	33,2 tcm	223,9 bcm	148,4 y	6,1%
World	193,5 tcm	3.680,4 bcm	52,6 y	100%

1.2 Global gas and LNG trade and outlook

Nevertheless, shipping accounts just for a small share in global gas transport. The usual case is domestic gas use, which means production and use within the same country, connecting wells with centers of demand by pipelines. This activity is responsible for 69,2% of global gas consumption. The second share goes to international or cross-border commerce of gas by pipeline (onshore and offshore), which constitutes 20,1% of all gas trade. Here, gas is traded from one country to one or more other countries (i.e. Russian gas is sent to many European consumers or the USA satisfying Mexican gas demand). Pipelines have the advantage that they are very cheap in operation, highly automatized and can resist severe weather conditions or even pass oceans (i.e. from Algeria to Spain or Russia to Germany). But pipelines are fix connections, that often go through or come from political instable countries.
In contrast to pipeline gas, shipping of liquefied natural gas, which then holds the smallest share with 10,7% in global gas trade, allows the connection of islands and remote locations to the global gas market. Second, it brings flexibility of destinations and gas markets can be served on a spot basis. Transport via vessel becomes an option where supplier and consumer cannot be connected by pipeline or very long distances need to overcome, with skyrocketing costs for terrestrial buildout and operation.

Data for 2017, based on BP´s Statistical Review of World Energy 2018 [6], is given in the following diagram:

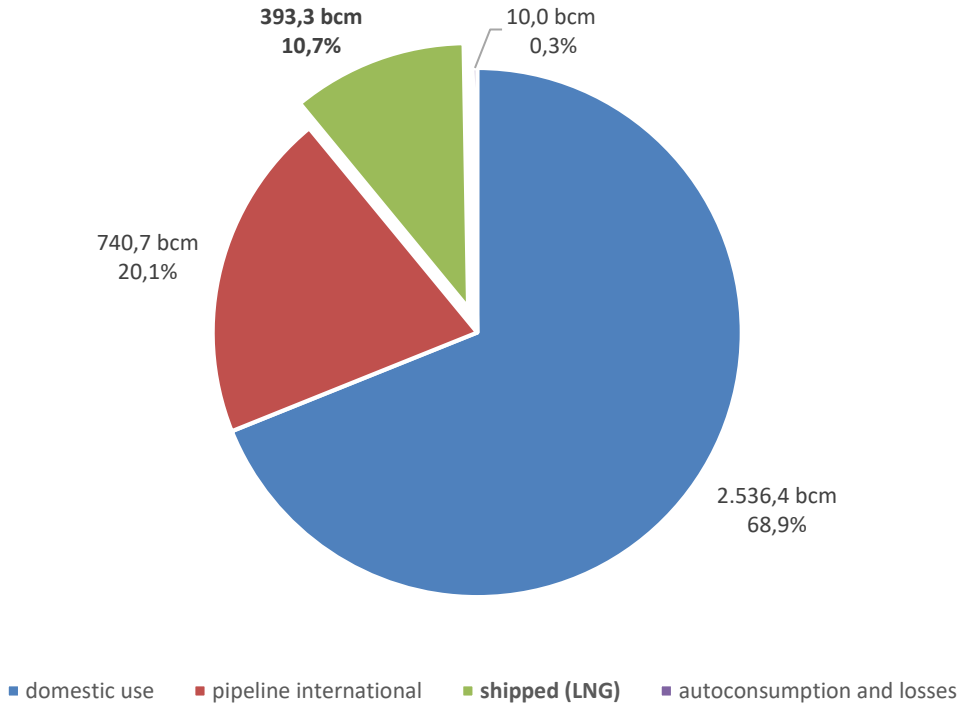


Figure 3 Worldwide gas movements. Data for 2017.

At the end of 2017, a volume of 293 mt (million tonnes) LNG[3] was traded between 19 exporting and 40 importing countries, using all kinds of vessels, from conventional LNG carriers to floating storage and regasification units (FSRUs) [1]. Shipping volumes have been grown constantly the last decades and are expected to keep on growing with the same pace or even faster, as BP estimates in its 2018 Energy Outlook [7, p.88]:

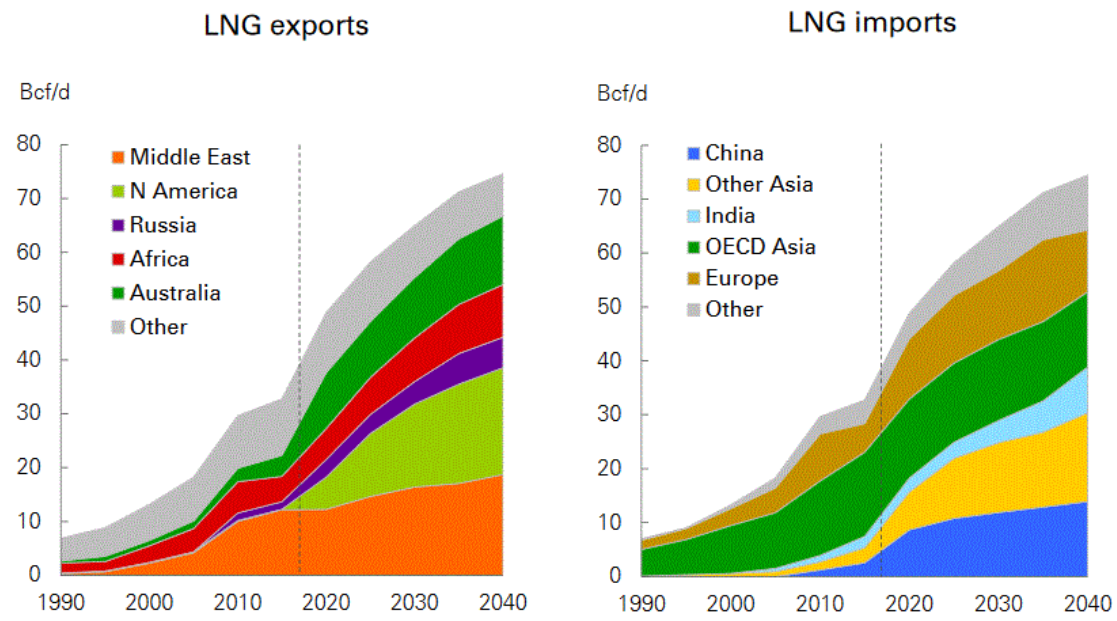


Figure 4 Prospect LNG volumes [7, p.88].

The graph shows a trading volume of around 38 bcf/d = 392,8 bcm/a = 302 MTPA in 2017. Until 2040 this volume could double to 76 bcf/d = 785,5 bcm/a = 604 MTPA. Obviously, total volumes of export and import are equal. The growing demand for gas as an energy source will lead to the construction of additional liquefaction and regasification plants and also in shipping capacities. The above standing figure also gives a hint about the regions that participate in LNG shipping trade.

[3] Groupe International des Importateurs de Gaz Naturel Liquéfié (GIIGNL) speaks of 290 MTPA in its annual report 2018 [8].
British Petrol (BP) names 302,6 MTPA in its Statistical Review of World Energy 2018 but includes re-exports [6].

Global interconnections can be concretized by the following figure:

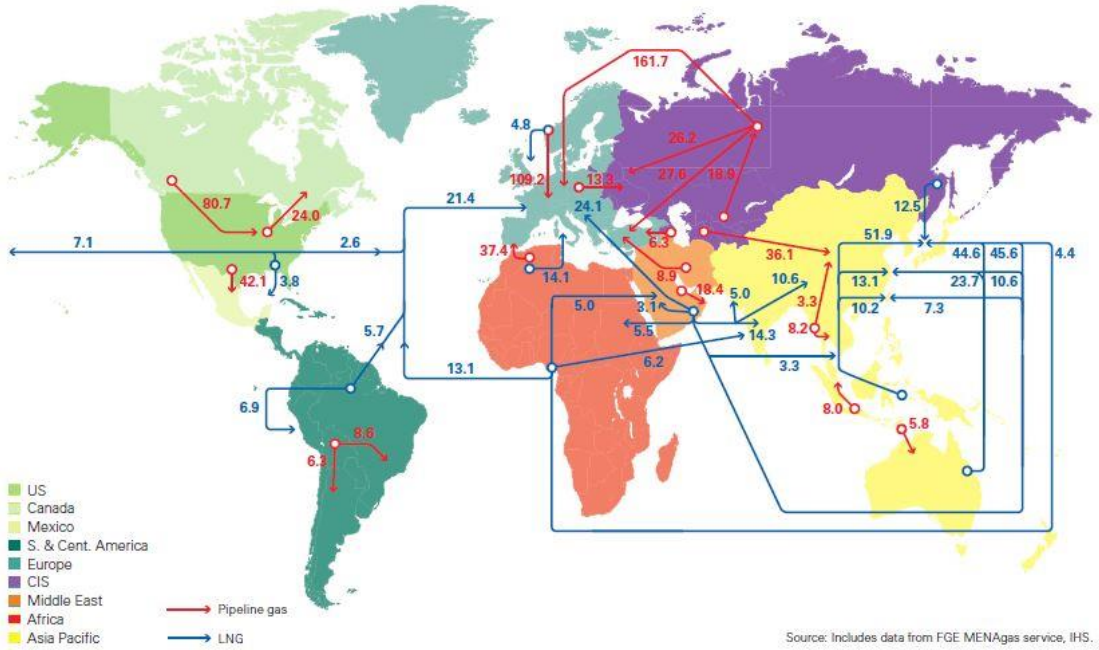


Figure 5 Major gas trade movements 2017 [6, p.35]. Blue lines=LNG, red lines=pipeline gas, numbers in bcm.

As this figure represents gas movements at the end of 2017, some newer liquefaction plants that shipped their first cargoes in 2018 could not have been included (i.e. Russia´s Yamal LNG plant or Cove Point in the U.S.). As one can notice, the epicenters of LNG demand (where the blue lines end) are Japan, China, South Korea, and India just starting to demand for more LNG as their pipeline infrastructure still needs to be extended and improved.
On the LNG supply side (where the blue lines begin) Qatar, Australia, Malaysia and Nigeria can be found, all with further potential to outperform current exports. Major development thus is expected to come from the United States of America.

Shipping trade is usually divided between the Atlantic and the Pacific basin[4], being separated by two important canals: The Panama Canal and the Suez Canal in Egypt. Both canals play a vital role in global marine trade, as they shorten by far the distances between the two basins, where shipping routes by nature would go around Cape Horn (south of Argentina and Chile) and Cape of Good Hope (south of South Africa). LNG trade was traditionally constrained to regional, inter-basin supply with fixed routes serving long-term point-to-point contracts. This tradition has been broken up by increase in short-term and spot[5] transactions and the recent extension of both the Panama and the Suez Canal. Inter-basin trade rose 35% between 2016 and 2017 (YOY) [1, p. 42]. Especially trade from the Atlantic to the Pacific basic might rise in the upcoming years, as new liquefaction volumes will come online in the United States. A special role might play the Panama Canal, as only a certain number of vessels can pass on a daily basis.

[4] The International Gas Union (IGU) also incorporates a Middle East basin, which includes Bahrein, Iran, Iraq, Israel, Jordan, Kuwait, Oman, Qatar, the United Arabic Emirates (UAE) and Yemen.
[5] Short-term trade refers to volumes traded on a spot (= immediate) basis or under contracts < 2 years. Medium-term trade means 2- to 5-year contracted volumes. Above 5 years is conventionally spoken of long-term trade.

1.3 Properties of natural gas

Natural gas is odorless, colorless, noncorrosive and nontoxic. It is practically equivalent to methane, which represents the simplest form of a hydrocarbon compound (C-H). Apart from methane (CH4), natural gas consists of some amounts of ethane (C2H6), propane (C3H8) and butane (C4H10). Further, it includes inert gases like nitrogen (N2) and carbon dioxide (CO2). For some natural gas plays, main chemical and physical are given in table 3 on the next page.

It can be observed that gas from Alaska has a very high share of CH4 and in consequence its gross calorific value (GCV) is one of the lowest. Gases with high volumetric concentrations (> 95%) of methane or ethane are called *dry* or *lean*, while gases with higher shares of longer-chained hydrocarbon compounds are called *wet* or *rich*. Other physical properties (density, expansion factor) are of interest when the gas shall be liquefied. The Wobbe Index divides the GCV by the relative density and describes the quality of different gases. Only gases with similar indexes should be mixed.

Origin	Nitrogen N2 %	Methane C1 %	Ethane C2 %	Propane C3 %	C4+ %	TOTAL	LNG Density[1] kg/m³	Gas Density[2] kg/m³(n)	Expansion ratio m³ (n)/m³ liq	Gas GCV[2] MJ/m³(n)	Wobbe Index[2] MJ/m³(n)
Australia - NWS	0.04	87.33	8.33	3.33	0.97	100	467.35	0.83	562.46	45.32	56.53
Australia - Darwin	0.10	87.64	9.97	1.96	0.33	100	461.05	0.81	567.73	44.39	56.01
Algeria - Skikda	0.63	91.40	7.35	0.57	0.05	100	446.65	0.78	575.95	42.30	54.62
Algeria - Bethioua	0.64	89.55	8.20	1.30	0.31	100	454.50	0.80	571.70	43.22	55.12
Algeria - Arzew	0.71	88.93	8.42	1.59	0.37	100	457.10	0.80	570.37	43.48	55.23
Brunei	0.04	90.12	5.34	3.02	1.48	100	461.63	0.82	564.48	44.68	56.18
Egypt - Idku	0.02	95.31	3.58	0.74	0.34	100	437.38	0.76	578.47	41.76	54.61
Egypt - Damietta	0.02	97.25	2.49	0.12	0.12	100	429.35	0.74	582.24	40.87	54.12
Equatorial Guinea	0.00	93.41	6.52	0.07	0.00	100	439.64	0.76	578.85	41.95	54.73
Indonesia - Arun	0.08	91.86	5.66	1.60	0.79	100	450.96	0.79	571.49	43.29	55.42
Indonesia - Badak	0.01	90.14	5.46	2.98	1.40	100	461.07	0.82	564.89	44.63	56.17
Indonesia - Tangguh	0.13	96.91	2.37	0.44	0.15	100	431.22	0.74	581.47	41.00	54.14
Malaysia - Bintulu	0.14	91.69	4.64	2.60	0.93	100	454.19	0.80	569.15	43.67	55.59
Nigeria	0.03	91.70	5.52	2.17	0.58	100	451.66	0.79	571.14	43.41	55.50
Norway	0.46	92.03	5.75	1.31	0.45	100	448.39	0.78	573.75	42.69	54.91
Oman	0.20	90.68	5.75	2.12	1.24	100	457.27	0.81	567.76	43.99	55.73
Peru	0.57	89.07	10.26	0.10	0.01	100	451.80	0.79	574.30	42.90	55.00
Qatar	0.27	90.91	6.43	1.66	0.74	100	453.46	0.79	570.68	43.43	55.40
Russia - Sakhalin	0.07	92.53	4.47	1.97	0.95	100	450.67	0.79	571.05	43.30	55.43
Trinidad	0.01	96.78	2.78	0.37	0.06	100	431.03	0.74	581.77	41.05	54.23
USA - Alaska	0.17	99.71	0.09	0.03	0.01	100	421.39	0.72	585.75	39.91	53.51
Yemen	0.02	93.17	5.93	0.77	0.12	100	442.42	0.77	576.90	42.29	54.91

(1) Calculated according to ISO 6578 [T = -160ºC]
(2) Calculated according to ISO 6976 [0ºC / 0ºC, 1.01325 bar]

**Last updated in 2012*

Table 3 Natural gas composition table [8, p. 27].

As table 3 lacks additional data for US “Lower 48” gas plays due to recent activities in this sector, information about the composition of natural gas in different US reservoirs is given in table 4:

Table 4 Composition of natural gas from selected US gas plays [9].

US gas play (State)	Methane (vol%)	Ethane (vol%)	Propane (vol%)	GCV (MJ/cm(n))
Utica (OH, PA, WV)	81,21	12,83	3,72	44,6
Marcellus (PA, WV, OH, NY)	76,75	12,58	5,06	46,0
Niobrara (CO, WY)	68,49	11,21	10,41	52,4
Eagle Ford (TX)	66,62	16,30	8,56	52,5
Bakken (ND, MT)	52,67	24,60	12,86	58,7

Here again it can be observed that a high concentration of methane correlates with a low calorific value (GCV), and vice versa. The wettest or richest gas (among this selection) can be found in the Bakken gas play in North Dakota and Montana.

Natural gas is the cleanest-burning fossil fuel. Due to its simple composition of short-chained hydrocarbons its reaction products are limited mainly to carbon dioxide (CO_2) and water vapor (H_2O). Small amounts of sulphur dioxide (SO_2) and nitrogen oxides (NO_x) can be detected.
Oil products and coals (bituminous coal, lignite) emit far more pollutants and particle matter when burnt because of their complex composition of long-chained hydrocarbons. Natural gas emits 117 lb CO_2eq/MMBtu, oil products 157-161 lb CO_2eq/MMBtu and coals 214-229 lb CO_2eq/MMBtu [10]. But as a greenhouse gas it is a strong promoter of climate change. Therefore, efforts must be undertaken to ensure tight and impermeable installations from the well to the user.

1.4 Gas treatment

Once the source is developed and natural gas flows to the surface, it needs to be treated. Gas treatment basically fulfils two necessities: The marketable gas needs to meet certain quality standards (purity) and it needs to comply with technical standards to protect further installations and equipment from corrosion, abrasion, or other detrimental impacts. Also, the purer the gas the more effective its liquefaction. That means that impurities and hydrocarbon liquids must be removed.

First, solid particles are separated in a slug catcher. Usually follows a three-phase separator, that separates water and gaseous hydrocarbons (C6 to C9 compositions) from the raw gas. Next, sulphur (S) and traces of carbon dioxide (CO_2) are removed (acid gas treatment) and rests of water will be eliminated (dehydration). The removal of mercury (Hg) might be necessary. Also, certain amounts of helium (He) will be made marketable as it is a very valuable gas and difficult to obtain. C2 to C5 compounds are called Natural Gas Liquids (NGLs) and are also sold separately to the petrochemical industry. Lean, dry natural gas can now enter the liquefaction trains or the pipeline network. It has now a purity of more than 90 vol% CH_4.

The following figure represents the mayor steps of raw natural gas treatment:

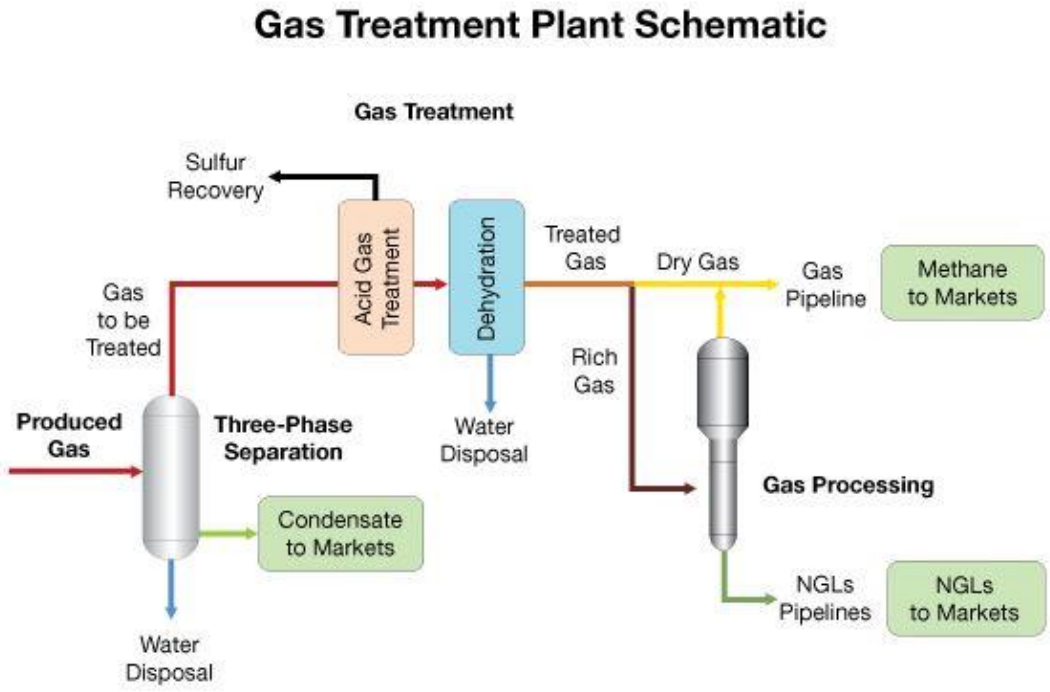


Figure 6 Raw natural gas treatment prior to liquefaction.[6]

1.5 Liquefaction

For shipping it is crucial to handle with liquified gases, because they require muss less space than gases under normal conditions, reduce potential risks that might occur transporting pressurized gas and hence decrease transport cost. Not only LNG is shipped, but other derivates and by-products of crude petroleum, such like liquefied petroleum gas (LPG).

The processed, pure natural gas, coming from the gas treatment plant, now enters the liquefaction trains where it will be liquefied. In principle, these are a series of huge heat exchangers, where the gas is cooled down by different refrigerants at almost atmospheric pressure (some millibar gauge) until around -162°C (-259°F), the boiling point of methane. During this phase change the gas reduces its volume to approximately 1/600th compared to its gaseous state. A disadvantage of liquified gas, compared to pipeline gas, is that it needs highly sophisticated insulation equipment during storage and transport.

1.5.1 Train size

Liquefaction train capacity has been grown from its early years until now, what can be observed in the following figure. Early liquefaction train size was within the range of 1-2 MTPA, but innovation in liquefaction technology, i.e. heat exchangers, compressors and gas turbines, has led to large single trains in commercial operation that reached a capacity of 7,8 MTPA (Qatar).

Since the US has been expanding its liquefaction capacity massively in 2016 and 2017, its new built trains span from 4 MTPA (Cameron train 1, under construction, online in 2019) to 5,1 MTPA (Freeport train 1, under construction, expected to be online in 2019), which are comparable to the

[6] Copyright by International Human Resources Development Corporation: **Website** (Jan. 2019)

size of trains built in Australia or Russia (see figure). An exception are Elba Island´s small-scale trains, based on a so called Moveable Modular Liquefaction System (MMLS) developed by Shell. The first six trains all together bring online just 1,5 MTPA (2018). Another four trains will serve 1 MTPA (2019).

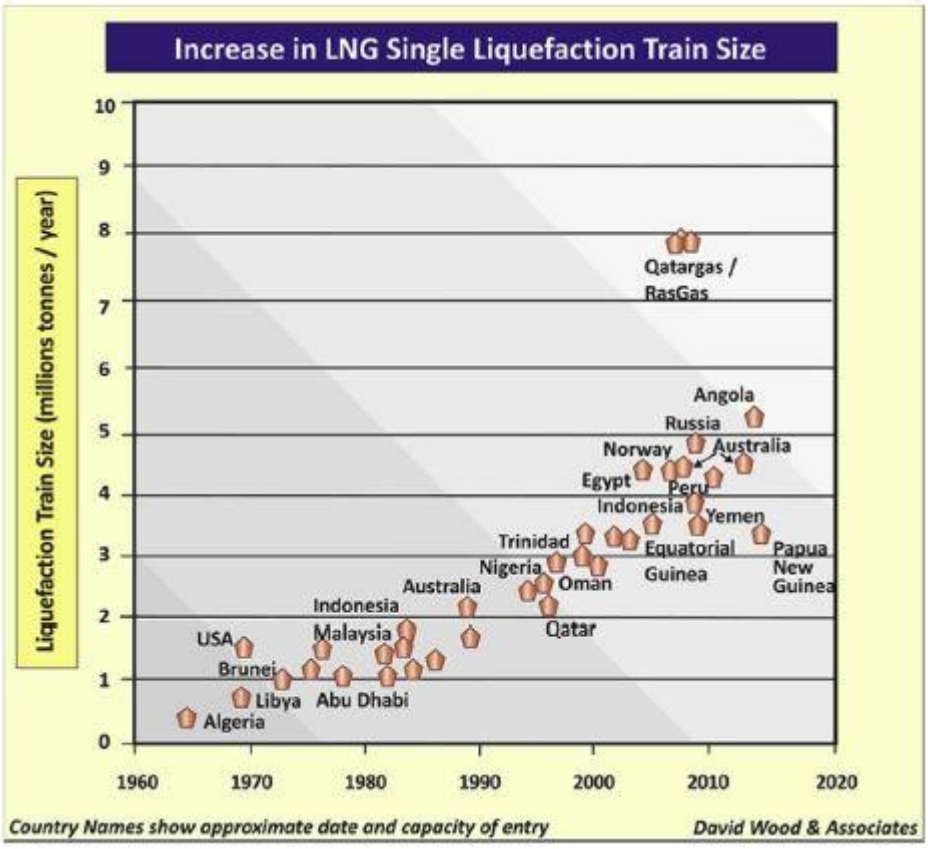


Figure 7 Development of LNG train size until approx. 2014.[7]

A clear global trend cannot be seen: Both smaller, flexible sized trains, so called small-scale LNG (ssLNG) and new proposed mega trains for Qatar, surpassing the "old" 7,8 MTPA single trains, are to be expected [1, p. 22].

1.5.2 Global developments

Worldwide, there were installed close to 370 MTPA liquefaction nameplate capacity as of March 2018 [1, p. 19]. Growth in 2017 was essentially driven by newbuilt facilities in Australia, the USA and Russia. 2017 was also the first year, a floating LNG (FLNG) platform began commercial operation (Malaysia). Another four floating projects have been sanctioned or are proposed and will be online between 2019 and 2022. Exact data for US projects will be provided in chapter 2.3.

Liquefaction units, unlike regasification plants, are designed to meet their nameplate capacity due to their high investment costs. Because of political decisions (Egypt) or military tensions (Yemen), some liquefaction plants have not been exporting during 2017 or even longer. Global utilization rate of all nameplate capacity thus was 84%, with little margin to improve [1, p. 20].

[7] Copyright by [11].

1.5.3 Global players

The liquefaction technology world market is dominated by two companies: Air Products and Chemicals Inc. (APCI) and ConocoPhillips (CP).
APCI liquefaction processes were used in 73% of all installed liquefaction plants in 2017 and remain the tender´s favorite processes, as more than 2/3rd of new capacities were awarded to it. A share of 21% is held by CP and is expected to expand, as its cascade process is more suitable to dry gas, which is typically found in the USA.
Linde and Shell have their own technologies but make up less than 6% of market share. Shell, for example, invented the above mentioned MMLS which is going to be used at the Elba Island´s LNG plant.
Another interesting liquefaction process is the PRICO process developed by Black & Veatch.

1.5.4 Liquefaction technologies

Information in this chapter is primarily based on [11], if not otherwise indicated.

Objective of liquefaction is forced heat release from natural gas. To achieve this goal the gas must go through three stages to make a complete phase change: *Precooling*, *condensation* and *subcooling*. For a better understanding, highlights of these three stages are showed representative for a later discussed cascade process:

Table 5 Characteristics of cooling processes [12].

	Precooling	**Condensation**	**Subcooling**
Refrigerant	Propane C3H8	Ethylene C2H4	Methane CH4
Temperature change	≈ ambient to -40°C	≈ -40°C to -95°C	≈ -95°C to -170°C
Power required	≈ 10 MW	≈ 23 MW	≈ 17 MW

The cooler the average outside temperature, the less energy is required for the cooling process.
If the same liquefaction process is compared between a facility in Russia and another one in Nigeria, the Russian plant will need less power for the same output of LNG.

The following chapters will give a short view over state-of-the-art liquefaction processes:

1.5.4.1 Expander based technologies (EBTs)

Main characteristic of EBTs is, that the cooling fluid remains in its gaseous state. EBTs are mostly chosen for offshore applications where safety is an important issue because no hydrocarbons are needed (as in the other processes). They are simple in operation and permit compact installation, although relatively much rotating equipment is needed. Output is limited to around 1 MTPA.
The simplest configuration has only one refrigerant loop, using nitrogen (N2) as working gas. Compression and expansion of N2 generates low temperatures and provokes condensation of the feed gas. For heat exchange a main cryogenic heat exchanger (MCHE) is used. More complex EBT processes use a MCHE with two pressure stages and thus can save compression energy.
There exist also alternatives with both CO2 and N2 working as separate gases for pre- and subcooling, possible for one or two pressure levels. Intentions aim to optimize the known processes in terms of energy consumption, installation equipment or fluctuating feed gas conditions.

1.5.4.2 Mixed refrigerant based technologies (MRTs)

MRTs hold the highest share of all liquefaction technologies because of their high efficiency, proven-track record and many years of operational experience. The refrigerant consists of a blend of several liquefied hydrocarbons like methane (CH4), ethane (C2H6), propane (C3H8), butane (C4H10) and pentane (C5H12), mixed with nitrogen (N2). Higher efficiency than in EBT processes can be obtained by mixing the optimal composition of refrigerants, so that the cooling curve of natural gas is exactly matched by the evaporation curve of the refrigerant. This permits the liquefaction of feed gas from multiple sources. Different from EBTs, the cooling medium changes its phase from liquid to gas.
The single mixed refrigerant process (SMR) is the simplest variant of MR processes. The refrigerant does not evaporate gradually but at once, leaving the MCHE in a superheated state which causes high temperature differences between hot and cold side and reduces efficiency. It is capable to meet demands up to 1 MTPA only.
APCI´s propane pre-cooled MR process (APCI C3MR) is used for the majority of worldwide installed baseload liquefaction capacity and can cover single train ranges from below 1 MTPA to 6 MTPA. Contrary to the SMR process it is divided into two separate stages: In the first stage liquid propane precools the feed gas and in the second stage the MR provokes its condensation and subcooling. Working with closer temperature differences between hot and cold side, the MCHE does not need to withstand strong thermal tensions.

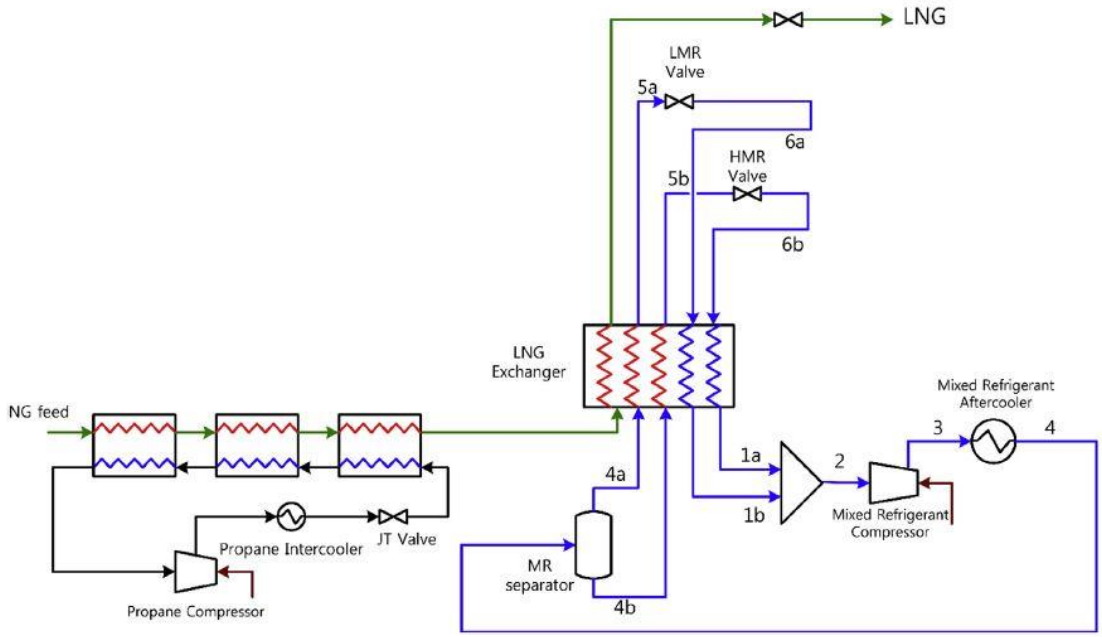


Figure 8 APCI´s C3MR process.[8]

[8] Copyright by [11].

In other modifications, different to the figure above, propane is also used to condensate the MR. Furthermore, instead of propane, ammonia can be used, what allows to take advantage of the plant´s residual heat, as the compressors and other equipment usually are driven by a gas turbine (cooling by heat absorption).
Shell´s dual MR (DMR) process takes advantage of a "warm" and a "cold" MR, removing the use of propane. This modification can take more advantage of the gas turbine´s power, because compression of propane solely needs more energy. Apart from this "standard" dual MR process, APCI has developed three more variants which are explained in detail in literature.
Korea Gas Corporation (KOGAS) developed a single MR (KSMR) process that divides the MR into a "light" and a "heavy" part (depending on the number of C-atoms). Supposedly, this modification shall improve efficiency and provide better matching of MR evaporating and NG condensation curves.
Last, APCI is able to deliver another process called Air Products Single Mixed Refrigerant (AP-SMR). Capacity and efficiency can be improved by using multiple gas turbines. As in the KSMR process MR splitting is involved.

1.5.4.3 Cascade based technologies (CBTs)

For CBTs pure refrigerants as well as mixed refrigerants can be used, with the natural gas entering a series of cascades that progressively reduce the gas temperature. Cascade based liquefaction provides several advantages over above named technologies:

- Losing one train does not cause total plant shutdown, only reduction in output
- Facilities can switch between feed gases; liquefaction of other gases like liquefied petroleum gases (LPG) is possible as well
- Broad range of suppliers and less specialized equipment

The first cascade-based process entering in commercial operation at the Kenai LNG plant, Alaska, in 1969 was ConocoPhillips´ Optimized Cascade Process (CP OPC). This design has three consecutive refrigeration cycles: Propane pre-cooling, ethylene liquefaction and methane subcooling. There are working two compressors on each stage, permitting high flexibility of operation and back-up in case of failure. Capacity can hit more than 5 MTPA for a single train and due to its modularity, this technology is very popular among plant manufacturers.

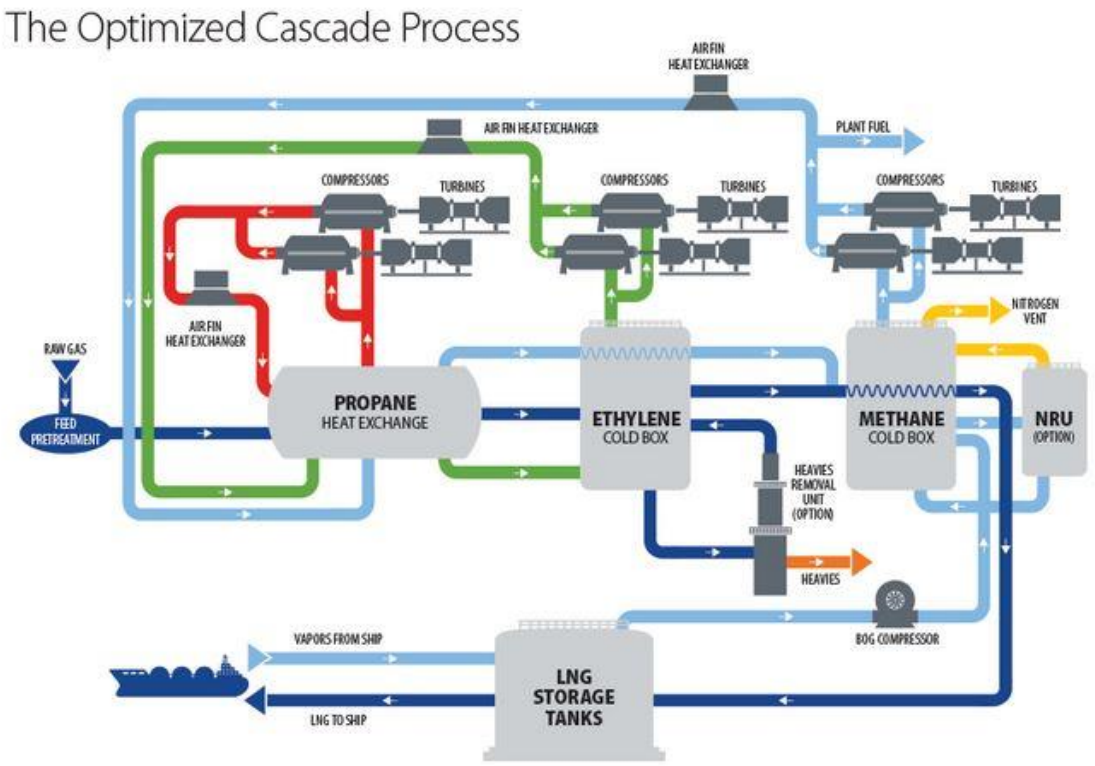


Figure 9 ConocoPhillips´ Optimized Cascade Process (CP OCP).[9] (NRU=Nitrogen Refrigeration Unit)

The German engineering group Linde developed a mixed refrigerant cascade process (Linde Cascade Process) which is said to work more efficiently because of closer matching between the refrigerants´ evaporating curves and natural gas condensation curve. However, implemented at Norway´s Snohvit 4,3 MTPA-plant, results have not been satisfying with several unplanned plant shutdowns.

1.5.4.4 Hybrid processes

Latest trends in liquefaction try to combine elements of the above explained technologies in order to increase efficiency, improve flexibility and diminish operating cost.
Former Axen Liquefin, a French research company that was acquired by Air Liquide in 2016/2017, engineered a hybrid process that uses two types of MR, which then can adapt better to feed gas composition. Contrary to other known processes, this Liquefin design supposedly remains the same efficiency over most of its production spectrum (from low to high output). However, this technology had not been proofed until end of 2016 and lacks experience and further optimization.
The last liquefaction technology to be described is Air Products and Chemicals Inc. AP-X process. The AP-X suits perfectly for large single train sizes up to 8 MTPA. It combines advantages of EBTs and MRTs. With the usage of a N2 expander cycle for sub-cooling, amounts of propane and mixed refrigerant can be reduced.

[9] Copyright by [13].

1.6 Maritime transport: Costs

A commonly known rule of thumb that compares the competitiveness of shipping to pipeline transport is shown in the following chart: For distances below 2.000 km onshore or offshore pipeline connection is the cheapest solution. Between 2.000 and 4.000 km transport by vessel is competitive to offshore gas, but still more expensive than onshore transport. From 4.000 km onwards, LNG is usually the most competitive and cost-efficient solution.

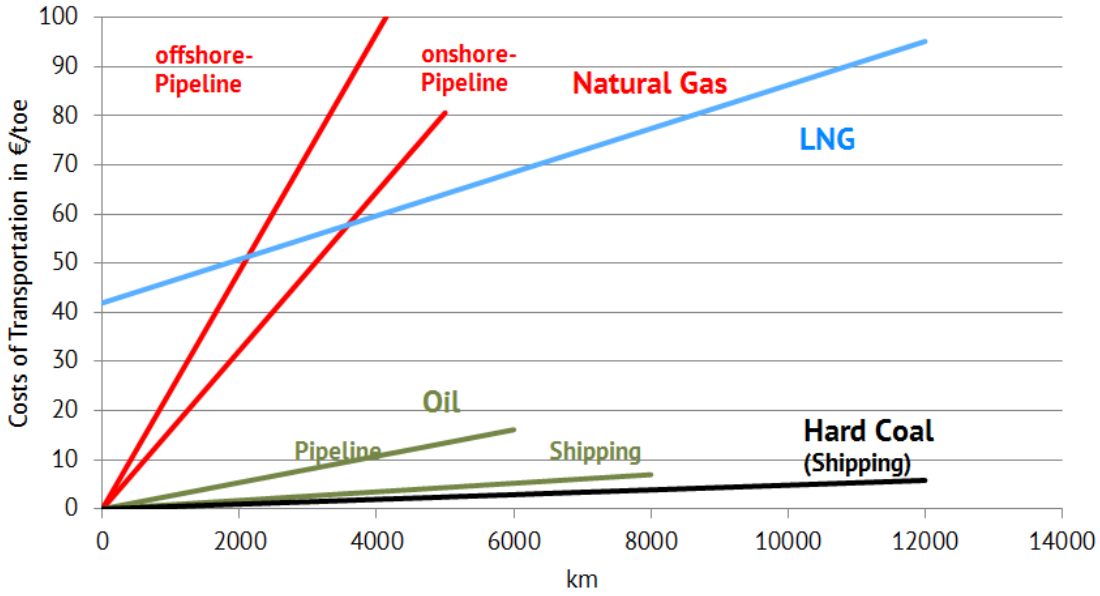


Figure 10 Transportation Costs over Distance.[10] (toe = tonnes of oil equivalent)

On the investment side, or CAPEX for capital expenditure, maritime transport is defined by the acquisition costs for an LNG carrier. Typical volume for the conventional class is 175.000 cm. With investment costs of about 1.100 USD/cm for tankers with newer propulsion technologies in 2017 [1, p. 43], today´s CAPEX reaches 190-200 million USD per tanker.

On the running expenses side, or OPEX for operating expenditure, can be found the transport costs that are created by bringing the product from A to B. LNG shipping costs are based on the carrier´s amortization cost, the size of the cargo and the distance to overcome. Later calculations will focus on US shipments to the Pacific basin and will shed light on costs per energy unit. The seller has the great incentive to choose the ideal shipping route to deliver its product to the lowest cost possible, thereby increasing its revenue.

Technical aspects of maritime transport will be given attention to in chapter 4, routing details will be discussed in chapter 5 and transport costs (part of OPEX) for selected routes will be presented in chapter 7.

[10] Copyright by Energy Brainpool: **Website** (Jan. 2019)

1.7 Storage

Having been shipped, the liquefied gas now enters a storage tank again, before it will be regasified. The principal functions of tanks at the receiving facility are to balance offer and demand, managing fluctuation between day and night or seasonally (i.e. more gas demand in winter for heating in the housing sector), economic reasons (i.e. pricing) and political-strategical reasons (i.e. long-term bunkering to be more independent from fluctuating supply). Transshipment (re-export) and truck-loading for further distribution are two more aspects for LNG storage.
Floating Storage and Regasification Units (FSRUs) are considered when a project demands for fast receiving erection, flexibility and cost reduction. Main obstacle for their use is their limitation in storage and regasification potential.

Global LNG storage capacity grew to 62,7 million metric cubic meters (mmcm) until end of 2017, being 424.000 cubic meters (cm) the average tank size. New built sites are found mostly in the Asia and Asia-Pacific, reflecting the region´s high demand. Japan (17,4 mmcm), South Korea (12,6 mmcm) and China (7,1 mmcm) are the triumvirate holding the main global storage capacities [1, pp. 51 & 52]. A typical single tank size is between 150.000 cm to 180.000 cm, which equivales to a conventional ship volume. Receiving terminals normally dispose of three to four tanks. Storage capacity is calculated as a product of demand, distance to market, ship size, average delivery time, back-up volume if the next cargo would be delayed and strategic reserves.
Inside the tank the liquid is not actively cooled but remains in its liquid state thanks to sophisticated wall insulation, that maintains the liquid at cryogenic temperature and is non-corrosive. The tank must be tight, especially its bottom, and must be built of a certain resistance to withstand the hydrostatic pressure of the LNG itself and possible external impacts (i.e. earthquakes in some regions). The tank´s wall is usually built using the following materials (from inside to outside):

- 1,2 mm stainless steel membrane (9% nickel alloy) with corrugations to absorb thermal tensions
- Insulating panel whose thickness is adaptable to consumer´s requirements. It consists of plywood, reinforced polyurethane foam (PU), an aluminum barrier impregnated with glass cloth and resin, again PU and plywood
- Mastic
- Post-tensioned concrete with moisture barrier

Filling of storage tanks depends on the composition of the arrived LNG and the required specifications of the receiving market. Tanks can be filled from above with “heavier” LNG or bottom-up with “lighter” LNG.[11] Then, the arriving LNG will mix in a natural way (by gravity) with the already stored LNG, in case of different suppliers or when necessary. Normal flow rates of LNG from the vessel to the tank are 12.000 cm/h but can reach up to 18.000 m3/h for large tankers.[12] Unloading a typical 175.000 cm vessel takes some 15 hours.

[11] See composition table in chapter 1.3
[12] Industry data provided by Naturgy.

1.8 Regasification

Next, LNG is processed in the regasification plant, where it is heated above its boiling point (up to 15°C or ambient temperature) to become gaseous again. Regasification is the reverse operation to liquefaction, but plant design and technology are much simpler and cheaper in service. In fact, regasification is the least costly step in the LNG value chain.

1.8.1 Process technology

Main component of the regasification plant are huge heat exchangers, called Open Rack Vaporizers (ORV), where LNG gets in thermal contact with sea water. OVRs are found in 70% of all installations. As regasification sites are erected usually near the coast sea water is the preferred source of heat. The only limitation of capacity is reinsertion of sea water in the ocean, as too cold temperatures could destabilize marine life around this place. Therefore, temperature decrease is limited to 5 degrees Celsius (or Kelvin or Fahrenheit).
To avoid this limitation in throughput (i.e. for peak demand) or in cold regions where more sea water would be needed, Submerged Combustion Vaporizers (SCV) can be used. The water circulates within a closed loop and gets heated by a combustion engine, usually a gas turbine. This kind of installation has lower capital costs but higher operation expenditures than OVRs. Negative aspects are emissions and around 1,5-2% of gas auto-consumption.
Shell and tube vaporizers (STV) can be used to regasify LNG when a power plant is directly connected. They have a higher throughput than plate heat exchangers and are more robust.
Where climate is favorable also air vaporizers can be used. They have low operation costs, but capacity depends on outside air temperature. Therefore, they usually receive backup from ORVs or SCVs.

The following schematic shows the typical ORV process:

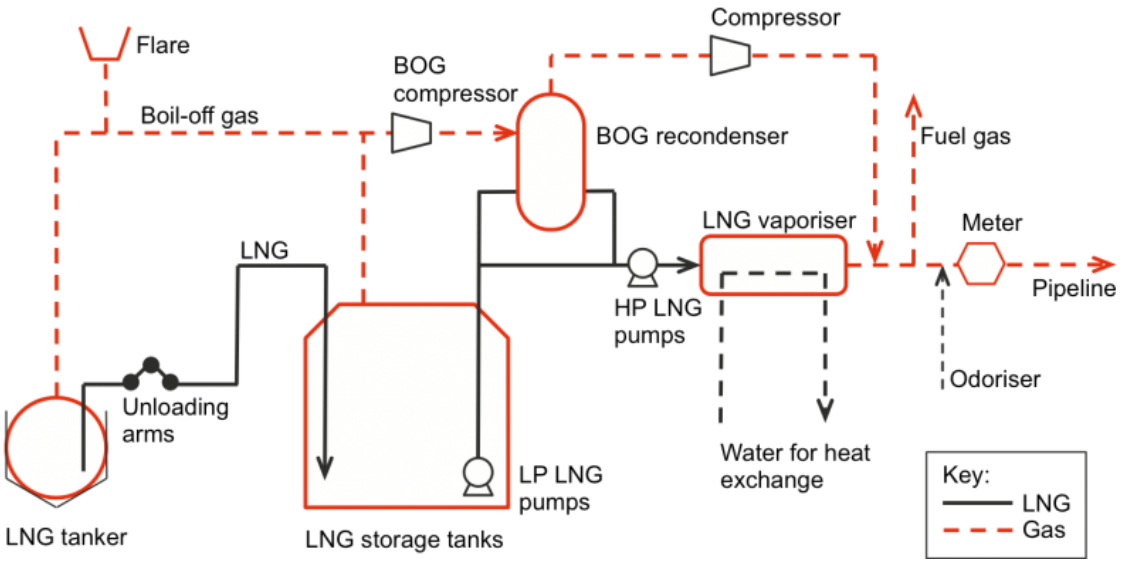


Figure 11 LNG regasification process schematic[13]

[13] Copyright by Broadleaf: **Website** (Jan. 2019)

As in a ship´s containment, in storage tanks also evaporates a small rate of LNG due to heat flow from the exterior to the interior. Also, during unloading and loading LNG evaporates and creates so called boil-off or boil-off gas (BOG). There are many forms to use BOG:

- During unloading and loading BOG is used to increase pressure in the ship´s tank respectively the storage tank to support LNG flow.
- BOG on ships can be used as a fuel or it is liquefied again by means of a separate reliquefaction unit.
- BOG in storage tanks is an unavoidable, unwanted side effect, that must be removed to maintain the (atmospheric) pressure. Therefore, it is reliquefied by a BOG recondenser (see figure above).
- Typical BOG rates are down to 0,1% LNG/d in a classic regasification terminal with flat bottom tanks [14].

Other solutions to the classic, shore-bound receiving terminal are Floating Storage and Regasification Units (FSRUs) and satellite terminals (terrestrial). Both can be erected in less time and with fewer costs but have limited ranges with respect to holding and regasification capacity. FSRUs could be solutions where a coastal area is densely populated but demand for LNG is high or where fast start-up is needed. Satellite terminals can be used for LNG supply expansion to remote areas, i.e. creating an LNG service station network throughout a country. They are associated with small-scale LNG (ssLNG) projects.
After being regasified, the natural gas is odorized to detect spills through odor within the further installations, and then its volume is metered before it enters a series of compressors that increase its pressure (80 bar(g) for transport and <16 bar(g) for distribution in cities) and is finally distributed to consumers by a pipeline network.

1.8.2 Global developments

Data in this chapter is mainly based on [1], if not otherwise indicated.

As of March 2018, there were installed 851 MTPA nameplate regasification capacities in 35 countries, with the majority in the Asian and Asia-Pacific region (compare to chapter 1.7).
In 2017 alone, nearly 45 MTPA of capacity was added. Compared to global liquefaction nameplate capacity (370 MTPA), regasification capacity more than doubles this number (2,3 times). Receiving capacity always exceeds liquefaction capacity due to the requirement to meet peak demand and ensure security of supply.
Onshore receiving terminals operate at an average of only 34%, meanwhile offshore floating units operate at 47% (smaller). If the huge, under false forecasts constructed and now unused, US regasification capacities are excluded, utilization of onshore facilities reaches 41%.

1.9 Gas market applications

With a growing population (between 9.5 and 10 billion people by 2050) and increasing global domestic product (GDP) energy demand is going to rise in the next decades (around a third by 2040). In the future energy mix, gas will play a stable and vital role and will probably be the second most used fossil fuel for electricity generation after coal by 2040 (≈ 20% share in power generation) according to BP [7]. As gas burns cleaner than oil or coal, (inter)national climate change goals could be achieved through switching from oil and coal to gas as a burning fuel in power plants. Currently, the most prominent driver is China. The USA have already advanced in this process and India is foreseen be the next big country to join.

Emissions from energy sources depend heavily on their supply chain, origin, heating value and the efficiency of the burning process, which results in life cycle analysis (LCA) for different kinds of fuels. The World Nuclear Association (WNA) compared over 20 LCA studies, showing that the average greenhouse gas emissions for natural gas reached 499 tonnes of $CO2_{eq}$ per GWh_{el} produced, meanwhile the burning of oil (733 t $CO2_{eq}/GWh_{el}$), coal (888 t $CO2_{eq}/GWh_{el}$) and lignite (1054 t $CO2_{eq}/GWh_{el}$) all outranged this number [15]. Power facilities burning gas are also an important back-up for renewable energies. Because renewables´ electricity production is intermittent by nature, fast start-up gas fired power plants are a commonly used option to guarantee electricity supply.

Apart from burning gas for power generation, the industrial sector will ask massively for gas. Industrial applications include gas use as a chemical feedstock (fertilizers), in-plant steam and electricity generation, heating and cooking. Major industries are pulp and paper (drying processes), steel and metal, petrochemical, glass and food industry.
Other sectors, apart from power generation, that rely on gas are transport and buildings. Within transport should be distinguished between the use of LNG and compressed natural gas (CNG): While LNG will mostly become interesting as marine fuel and as truck fuel for long-distance road haulage, CNG will gain market in smaller vehicles, mostly cars.
Typical gas applications in the building sector include heating and cooking. The building sector is not limited to residential housing, but incorporates office and commercial buildings, hospitals, public institutions, and so on.

The following graphic shows the described developments for the upcoming decades:

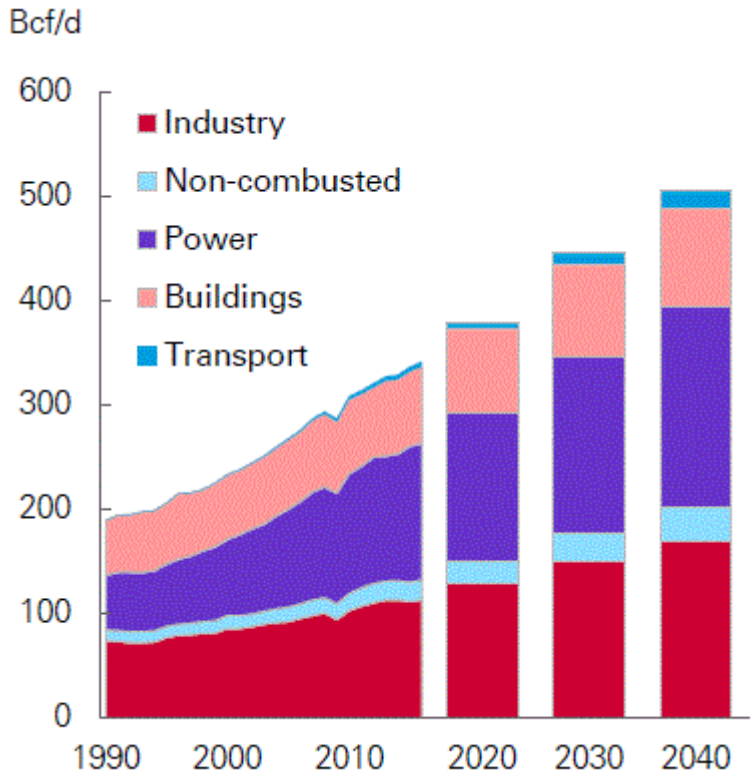


Figure 12 Gas consumption by sectors by 2040 [7].

1.10 Investment costs

Although updated data is not easy to find, former data still gives a good perception of capital expenditures (CAPEX) needed to realize an LNG project.

Table 6 Estimated relative CAPEX for different stages within an LNG project.

% of total CAPEX	Exploration & Production (E&P)	Liquefaction	Shipping	Storage & Regasification
[3] (not specified)	15-20	30-45	**10-30**	15-25
[16] (Nigeria – USA)	26	32	**32**	10
Data provided by Naturgy	20-30	50-60	**10-12**	8-10

As can be seen in the table above, liquefaction is roughly between 1/3rd and 2/3rd of CAPEX spent in LNG projects, while the production, shipping, and regasification components account for nearly equal portions of the remainder. [Songhurst 2014, 17, p. 29] concluded that liquefaction costs lie between 60-67% of total costs for "normal" cost projects and 67-71% for "high" cost projects. Obviously, liquefaction costs vary across projects and location, but have risen significantly over the past ten years. Some liquefaction plants have seen cost increases of 30-50% over FID [1, p. 25].

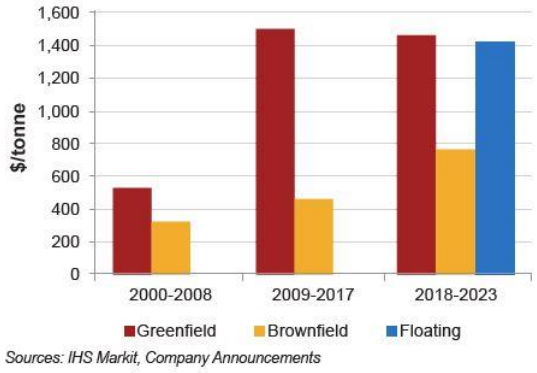
Between 1970 and 1990 investment cost in liquefaction plants averaged at 600 USD per tonne per annum (tpa), then dropping to 400 USD/tpa in the period from 1990 until 2008. Train and tanker sizes increased, reflecting the economy of scale and a "learning curve" effect was made up. However, up from 2008 costs grew and averaged at 1.200 USD/tpa between 2011 to 2015 [17, p. 6].

This anticyclical development was justified by bottlenecks in LNG supply, more (expensive) greenfield than brownfield projects, high commodity prices for bulk and raw materials like steel and metal alloys, low availability of engineering, procuring and construction (EPC) contractors due to a high level of ongoing projects in the oil & gas (O&G) sector worldwide, and a general lack of skilled workforce within the LNG industry. Projects at remote locations like in Papua New Guinea or Australia are almost expensive by nature.

In a recent paper [Songhurst 2018, 18, p. 7] showed that unit cost per tpa between 2014 and 2018 depended much on the site´s location, if it was a brownfield or greenfield project and on the gas quality (lean or rich). Costs were in the range from 700 USD/tpa for US-located brownfield projects handling lean gas to 2.000 USD/tpa for Australian greenfield projects liquefying rich gas. Brownfield liquefaction plants use existing infrastructure: There is no need to install new jetties, storage tanks and utilities. In the case of US-facilities, brownfield liquefaction plants are mostly converted regasification plants. Brownfield to greenfield liquefaction CAPEX costs are approximately 0,5 or even lower.

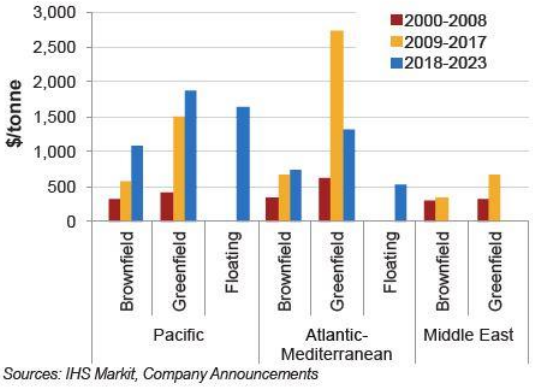
These trends are summarized in the figure given below: On the left side a split-up to years of installation and on the right side a furthermore split-up to basins can be found. Added are unit costs for floating liquefaction units.

Figure 4.10: Average Liquefaction Unit Costs in $/tonne (real 2016) by Project Type, 2000–2023



Sources: IHS Markit, Company Announcements

Figure 4.11: Average Liquefaction Unit Costs in $/tonne (real 2016) by Basin and Project Type, 2000–2023



Sources: IHS Markit, Company Announcements

Figure 13 Average liquefaction costs [1, p. 27].

1.11 Vertically integrated supply chain

Information in this chapter is mainly based on [19], if not otherwise indicated.

The LNG value chain is also a good example for a vertically integrated business. LNG can be shipped virtually to any coastal location in the world, but transport costs are high and thus a factor that is tried to maintain low. For a long time and still in the 1990s, this fact created primarily local and regional markets. Main actors along the value chain were national oil and gas companies (NOCs) with correspondent financial backup, excluding the participation of the private sector. Thus, markets were merely competitive and long-term contracts guaranteed financing of investments and revenue (security of demand and supply).

When gas markets became more and more deregulated at the beginning of this century, a movement forced primarily by Europe, NOCs partly gave place to the participation of internationally operating enterprises of the oil and gas (O&G) sector, cracking up the antique monopoles with governmental influence. Apart from bringing fresh capital and highly skilled workforce, the private sector is typically known to work more efficiently and be more open to innovations and improvements. Private companies in general are better vertically integrated than state owned actors and can cover theoretically the whole value and supply chain. This is especially true for the O&G sector, but also for other capital-intensive sectors like the steel industry or telecommunications. Main reason for vertical integration is to be active along the entire supply chain of a product. Further, it helps to internalize risks resulting from investments in capital-intensive infrastructure, i.e. liquefaction facilities.

Globally acting players try to diversify their LNG portfolio to gain both access to resources (upstream) and offer gas to the costumer to a competitive price (downstream). Flexible trading and optimized shipping routes are crucial (midstream), thus controlling transport capacities helps to benefit from price differences between different regions. It is also widely known that market players order ships without dedication to a project or route.

In their main research paper [Rüster and Neumann, 20] write: "*Private oil and gas companies join long-established state-owned entities in exporting countries securing (…) sources and connecting the fuel to high value markets, integrating downstream to benefit from marginal rents in the natural gas industry. In contrast, traditional downstream players integrate upstream, control transport capacities and secure access to liquefaction plants and reserves, to ensure supplies in times of a developing competition between importing regions. Global super majors diversify their portfolios by integrating along the whole value chain and into export and import regions worldwide.*"

Market players along the LNG value chain include governments, NOCs, majors, shipping providers, buyers, traders, financial institutions (banks), terminal operators, local stakeholders, regulators and environmental organizations; each entity with its own interests.

Next, a short overview for four different market players can be found:

- Qatar Petroleum is the state energy company of Qatar and example for a NOC. Its LNG portfolio comprises up to 70% of each of its liquefaction trains, which are operated by Qatargas, an own tanker fleet and acquisitions of floating LNG units, and both regasification equity stakes and own regasification capacities.
- British Petrol (BP) is a so called major or multinational O&G company. Its LNG activities include participation in feedstock production, liquefaction, shipping, contracting and trading, regasification capacities, up to marketing and distribution to the end consumer.
- Example for a utility enterprise is Naturgy from Spain: Participations in gas procurement, transport (pipeline and own vessel fleet), distribution, trading and own capacities in power generation ensure its revenues.
- The four largest European trading houses with LNG portfolio are Trafigura, Vitol, Gunvor and Glencore. Traders fulfil two main functions: They balance over- or undersupply of LNG by purchasing volumes from companies with surplus supply or by taking volumes from producers on a short-term basis to supply short-term tenders. Also, they are important intermediaries between project sponsors and higher risk markets that may not have sufficient credit ratings to support a liquefaction project. In the developing LNG market traders today need to find other niches, like increased participation in regasification facilities, and they are more willing to take also long-term agreements, as the 15-years 1 MTPA offtake of Trafigura from Cheniere in January 2018 showed [21, p.3].

A clear future trend concerning the global LNG market cannot be seen: Some trends indicate that there will be a shift towards more *commoditization* with increasing number of short-term agreements, growing liquidity and the entry of new players. Other trends suggest a more *consolidated* market, meaning that the bulk of trade, from the well to the customer, might be in the control of a few "super-majors".

2 The USA as an LNG exporting country

The first intentional exploitation of natural gas in the United States of America dates to 1821 when Mr. William Hart set a provisional "well" at Fredonia, New York. The soon founded Fredonian Gas Light Company is recognized to be the first American natural gas company. Later, industrial gas production was linked to the discovery of crude oil. The first known commercial oil well was set in Pennsylvania in the 1850s. In most cases being a side-product of oil, natural gas was sold very cheap. Still today, oil and gas production are usually interconnected, and all large US oil companies are also producing and marketing gas.

The US Energy Information Administration (EIA) is the statistical and analytical agency within the US Department of Energy (DOE) and collects, analyses, disseminates independent and impartial energy information. EIA was established in 1977 based on the DOE Organization Act, which was a political answer to the oil market disruptions of 1973 (so called first oil crisis, the second oil crisis was in 1979) [22].

On EIA´s website data for gas production and consumption can be found [23]. Data was converted to billion cubic meters (bcm) and is summarized in the following chart:

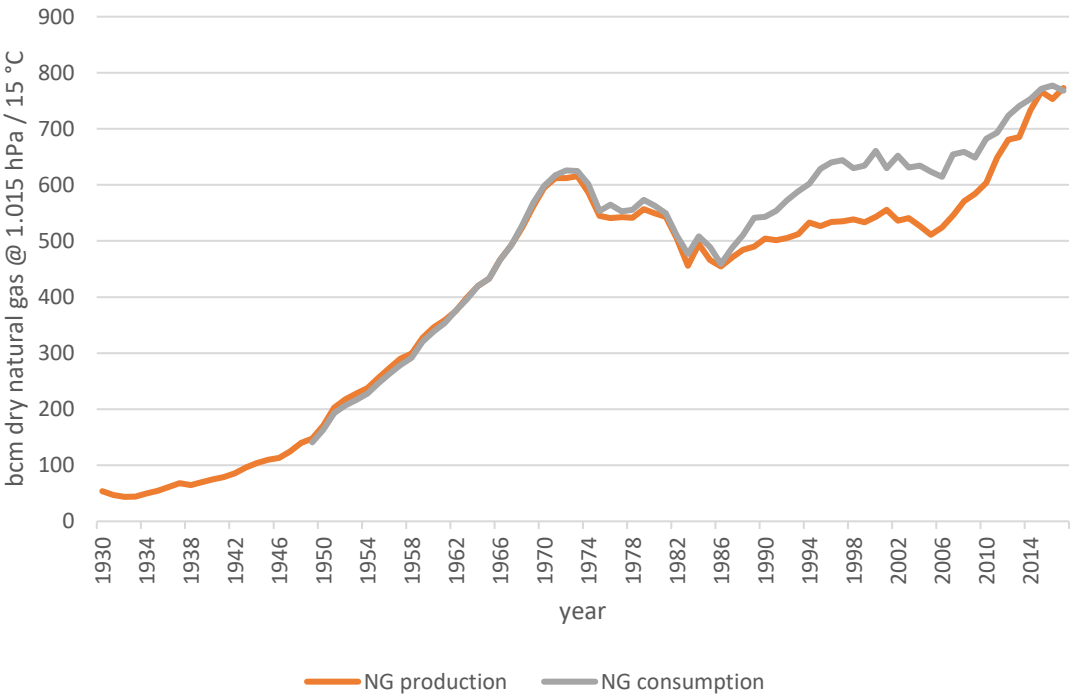


Figure 14 US dry gas production and consumption in bcm. (Dry natural gas @ 1.015 hPa and 15 °C)[14]

Until 1930 natural gas production (red line) was estimated and is therefore not considered here. Total natural gas consumption (grey line) was not measured up to 1949. Until the first oil crisis, production and consumption are equivalent. Both oil crises (in 1973 and 1979) can be clearly identified. From the mid-1980s onwards national production could not cover demand, resulting in a necessity of gas imports. The first LNG import terminal opened in Everett, Massachusetts, in 1971.

[14] Own elaboration based on [23].

Cove Point (1978), Elba Island (1978) and Lake Charles (1982) followed. Most of US gas, however, has been imported via pipeline from Canada [4, pp. 13, 14].

The next figure, with edited data from EIA [23], permits a closer look on the happenings since 1973:

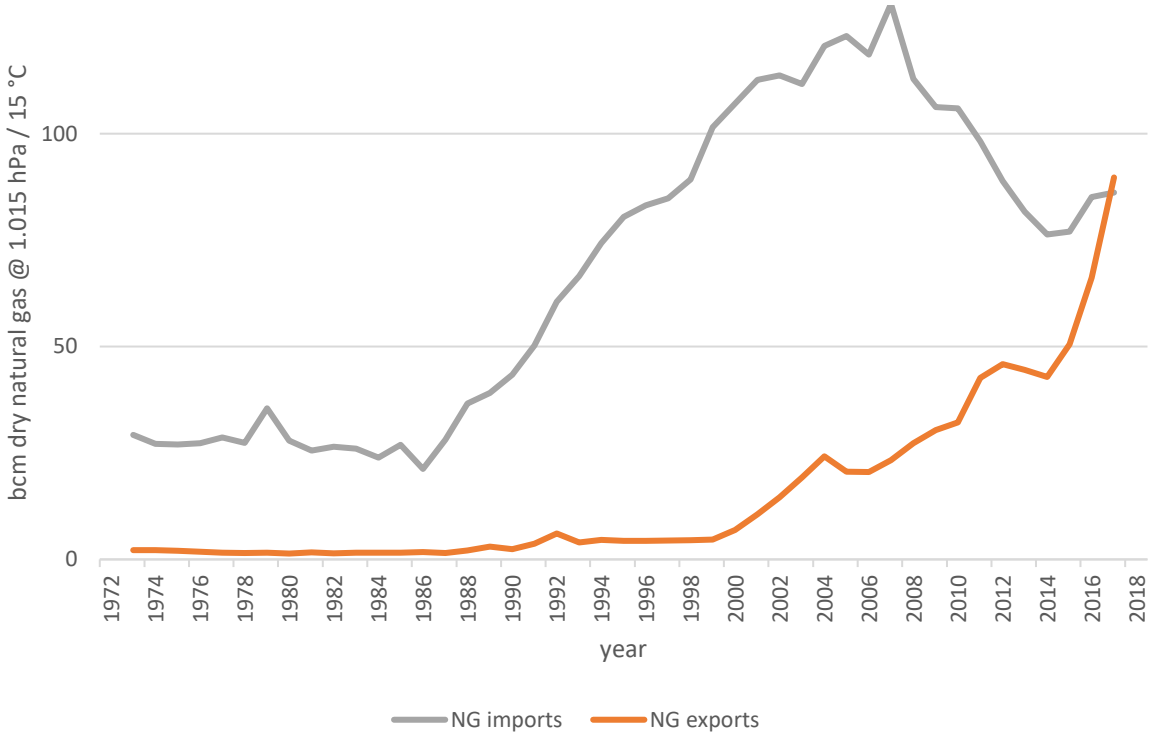


Figure 15 Total import, total export and net import (difference) of natural gas in bcm.[15]

Imports (grey line) began low at 30 bcm but peaked at 130 bcm in 2007. In 2003 the National Petroleum Council forecast that domestic gas production would only be able to meet 75% of US demand, with the balance having to be imported as LNG [4, p.16]. Eleven more LNG regasification terminals were in development or construction, but for many LNG never arrived.
When unconventional gas resources, especially shale gas, were made economically exploitable, import projects were stopped, and US exports (red line) increased, finally surpassing imports.

[15] Own elaboration based on [23].

2.1 The shale-gas phenomenon

Although commonly spoken as of a "phenomenon", the development of shale-gas in the United States was a long process that began in the late 1970s. [Wang and Krupnick, 24] write that "*price ceilings on interstate natural gas were set at levels below the equilibrium prices that would arise in a competitive market, thus stimulating demand and discouraging supply*" and being an essential factor the severe natural gas shortage at that time. As a response the "*US government adopted a series of policies to promote the development of new sources of natural gas, including unconventional sources. These policies set the stage for the increased production of tight gas and coalbed methane and, later, the boom in shale gas. The major natural gas policies include incentive pricing, tax credits, and R&D programs for unconventional natural gas and policies promoting industry restructuring (…).*" Focus was especially laid on unconventional gas resources (shale gas, tight gas and coalbed methane) because decline in production of conventional gas resources was prospected. Political sanctions like the Natural Gas Policy Act of 1978 (incentive pricing, tax credits) and DOE´s Eastern Gas Shale Program (1978 – 1992) with federal investments of 137 million USD, together with technological innovations from private industries, mainly Mitchell Energy on the Barnett Shale, were crucial to overcome the crisis and set the path for the extraction of unconventional gas resources.
[Wang and Krupnick, 24] emphasize the outstanding importance of three technological methods that made unconventional gas resources economically exploitable: Horizontal drilling, fracturing technology and 3D seismic imaging.

However, the development of any energy resource, indifferent if conventional or unconventional, bears (new) risks and challenges. These include for shale gas and hydraulic fracturing:

- Increased consumption of fresh water
- Induced seismicity, although hardly detectable
- Potential ground water and surface water contamination
- Impacts on air quality
- Local impacts like noise, dust and land disturbance

2.2 US gas market and prospective resources

The following figure, from 2015, underlines the immense importance of unconventional gas in the United States. It was taken from EIA´s Annual Energy Outlook (AEO) 2016 with latest data from 2015 and projections until 2040 (Reference Case) [25]. Shale gas is estimated to grow both in absolute and in relative numbers and might represent 69% of all produced dry natural gas in 2040. Tight gas plays could be source for 16% of produced dry natural gas by then. “Other” resources refer to associated and non-associated conventional gas: This type of source is projected to decline from today 24% to 11% in future. Offshore gas resources, coal-bed methane and Alaska´s natural gas resources only represent marginal parts with declining importance.

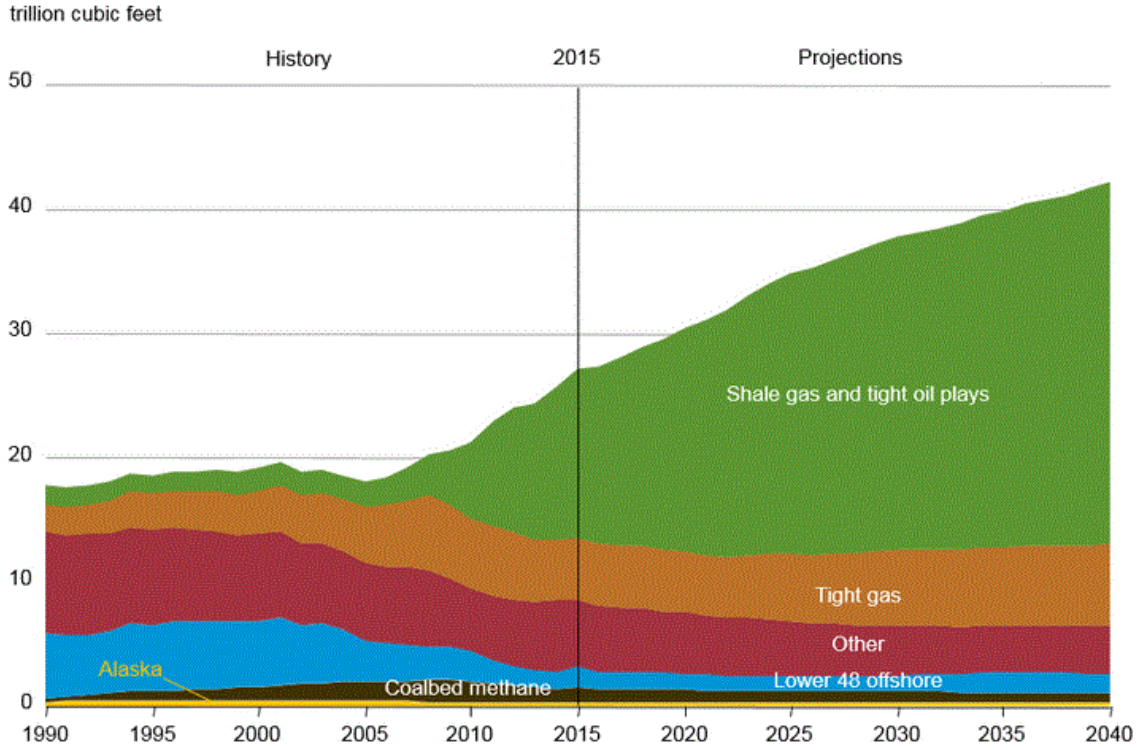


Figure 16 US dry natural gas production by source [25, Reference Case].

It is expected that future demand will be driven by electric power generation (39%) and industrial applications (31%. Natural gas as feedstock in the production of methanol and ammonia). The residential (15%) and commercial sector (12%) could demand to equal parts, but much less. Transportation (2%) would be the fifth sector with necessities for gas [25, pp. 155-157, data for Reference Case, year 2040].

Resources of shale gas can be found in 30 of the "Lower 48" states [26]. The most important plays are found in the next image. Some gas plays have been producing gas for a long time, others are known for decades, but exploitation was not economically and/or technically feasible until recently. Ultimately, gas production depends on natural gas prices and production costs with the consequence that proved reserves can grow or shrink or a gas play is given up and later restarted again.

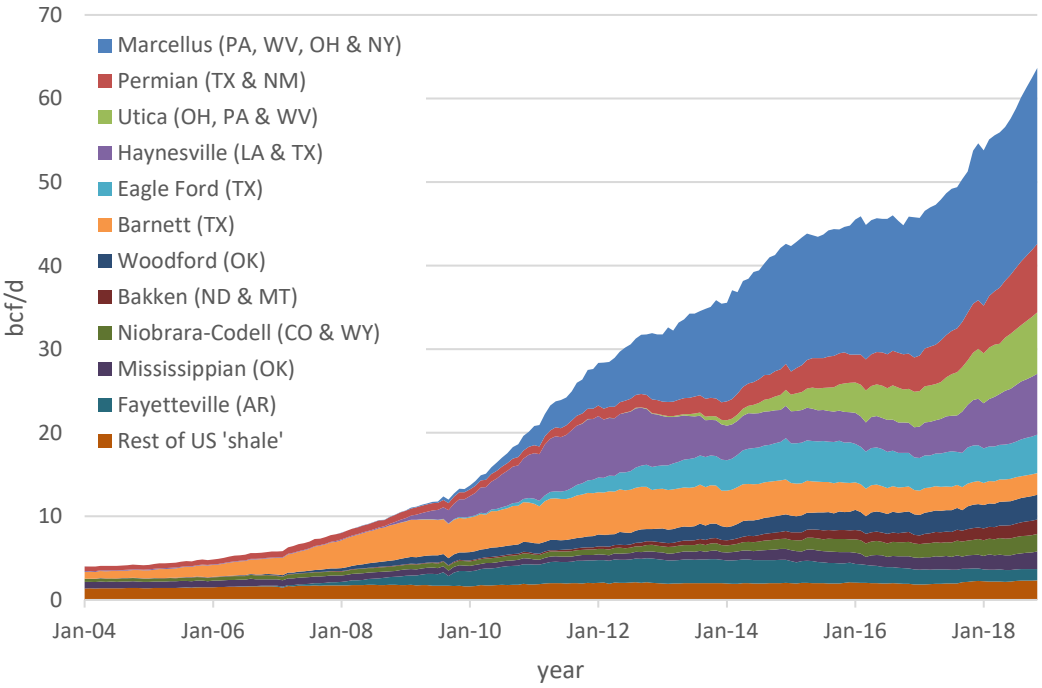


Figure 17 Dry shale gas production estimates by play. December 2018.[16]

In a 2013 published paper EIA estimated the potential for *unproved*, technically recoverable resources for 137 shale gas formations in 41 countries. On a global scale, US share could represent some 8,2% of all shale gas resources. Global shale resources are estimated to be 7.576,6 tcf or 214,6 tcm [27]. Huge quantities are expected in China, Argentina, Algeria, Canada, Mexico and Australia. As these are *unproved resources* this number obviously exceeds the total *proved reserves* in BP´s Statistical Review of World Energy 2018 of 193,5 tcm. But it gives a taste of what might be recoverable in future and that global gas reserves are still a very abundant source of energy.
On the other side some shale gas is prohibited to be extracted due to current political decisions: For example, in France and Germany fracking is forbidden.

[16] Own elaboration based on [23].

2.3 Development of US liquefaction capacities

Equipped with plenty of gas resources the USA changed from a net importer of natural gas to a net exporter in 2017. Exports in the past were existent but scarce and mainly based on pipeline exports to Canada and Mexico and LNG shippings from Kenai, Alaska, to Japan. When in 2016 the first two trains of Sabine Pass liquefaction facility came online, LNG exports gained momentum: LNG share on exports was only 2% in 2015, mainly because of re-exports from other countries, but then it rose to 8% in 2016 and 22% in 2017 [28]. Numbers for 2018 might be available at February 2019 with expected higher LNG share on US gas exports. Within pipeline exports, 63% go to Mexico and 37% to Canada [29].

Until January 2019 four of the expected six trains of Sabine Pass, Louisiana, and the Cove Point facility in Maryland came online. Kenai liquefaction plant in Alaska, the first and oldest on US territory, has not been exporting LNG since 2015 and future remains unclear. At the moment, all LNG exports leave either from the Gulf of Mexico or the US east coast, and therefore are located within the "Lower 48".

With data from IHS Markit the current status of nameplate capacity was summarized [30].
In January 2019 23 MTPA were online, another 44 MTPA under construction, and 204 MTPA were "in FEED" or "FEED completed" status (FEED = Front End Engineering and Design).

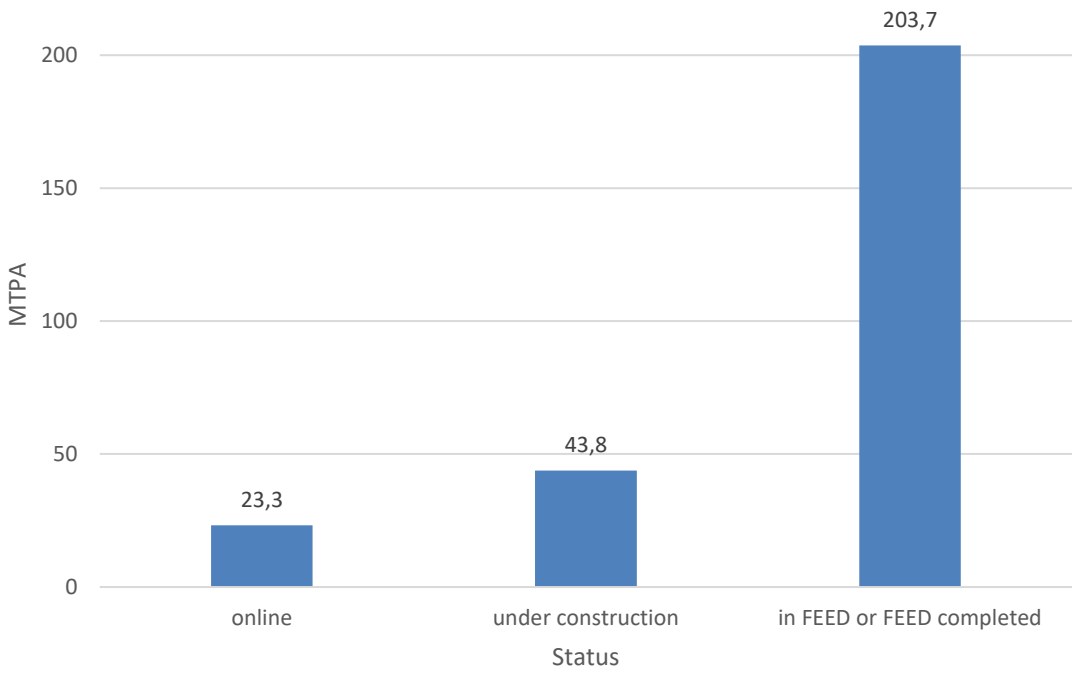


Figure 18 US nameplate liquefaction capacity status as of 01/2019.[17]

[17] Own elaboration based on [30].

However, a project being “in FEED” or even with “FEED completed” does not necessarily mean that the liquefaction plant is going to be constructed. LNG projects are complex undertakings that take up to 10 years from the first conceptual designs until commercial production, including roughly four years from final investment decision (FID) until first shipment (construction time). This ten-year time frame is packed with the following milestones (among other issues): Feasibility studies or conceptual design, permit obtaining, shareholders and financial agreements, front end engineering design (FEED), detailed engineering, feed gas supply contracts, shipping agreements, site construction and installation and final test runs. An example for the Cameron liquefaction plant (Houston, TX) can be found in the annex.

For LNG projects on US territory several approvals from federal agencies, among other permits like environmental impact statements, are obligatory:
The Federal Energy Regulatory Commission (FERC) is responsible for authorizing the siting and construction of onshore and near-shore LNG import or export facilities, issues certificates of necessity for LNG facilities engaged in interstate natural gas transportation by pipeline and reviews facilities during their lifetime [31].
In contrast, the Maritime Administration (MARAD), an agency within the Department of Transportation, handles issues with waterborne transportation including shipping and port operations. For example, projects involving floating LNG platforms or vessels need MARAD authorization [32, 33].
A third important authorization, which directly affects the export of LNG, must be obtained from the US Department of Energy (DOE): It is checked where the LNG will be shipped and whether with these countries exist or not a free trade agreement (FTA). Evaluation for non-FTA countries usually takes more time. Where trade is explicitly prohibited by law or policy, or is against national interests, DOE denies the export. This is an important step for most project in their path towards financing and construction [34].

Therefore, future projects were analyzed in detail within the thesis´ 5-year outlook (2019-2023):

- Current 44 MTPA under construction are expected to come online between 2019 and 2021.
- New capacities for 2022 and 2023 were “in FEED” or “FEED completed” but with a high probability to be constructed (additional trains at Corpus Christi and Sabine Pass in 2022, Calcasieu Pass in 2023).
- Projects “in FEED” or “FEED completed” were reduced to those probable to come online between 2024 and 2030 (called “post 2023”, as these projections exceed this thesis´ outlook).
- Most projects are located in the “Lower 48” states and the Atlantic basin.

The findings are presented in the following chart:

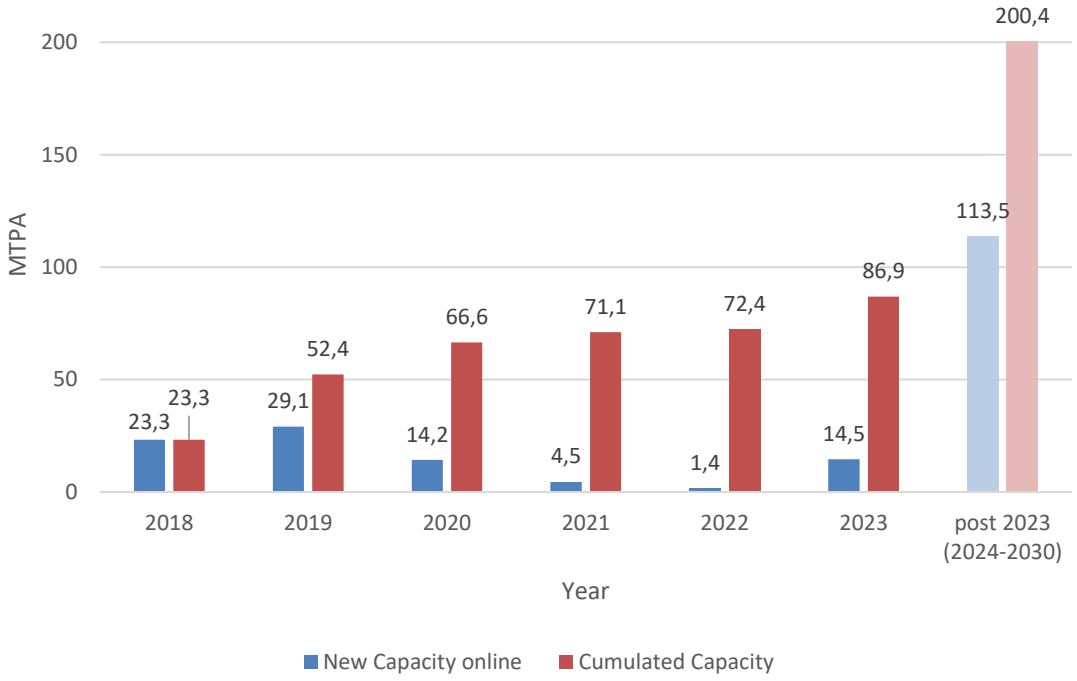


Figure 19 Liquefaction capacity to come online in the upcoming years as of 01/2019.[18]

Until 2023 some 87 MTPA of liquefaction nameplate capacity could be in commercial operation. Within ten years today´s liquefaction capacity could almost increase tenfold.

To finish this chapter, its content is summarized:

- For a long time, the USA was dependent on foreign gas imports.
- Production of unconventional gas was initiated and co-financed by the government to overcome gas shortages. The private industry contributed with technological innovations like horizontal drilling, development of hydro-fracturing ("fracking") and 3D seismic imaging.
- Shale gas is nowadays and in future the resource with the highest share of all US gas resources.
- In 2016 the first "Lower 48" liquefaction plant came online and since 2017 the USA are a net gas exporter. LNG share was 22% in 2017 and is expected to increase.
- 23 MTPA of liquefaction capacity are online today and 87 MTPA are projected to be in operation until this thesis´ outlook at the end of 2023. Further capacities cannot be forecasted with high reliability.

[18] Own elaboration based on [30] and own assumptions.

3 LNG demand in Asia-Pacific and Middle East – A 5-year market outlook

In the following passages market demands for the Asia-Pacific region and the Middle East will be analyzed. Whenever possible, estimations are given within the timeframe of five years: From 2019 to 2023. Countries are listed according their imported volumes of LNG in March 2018 (from high to low) as they are listed in [1], without further references in text.

3.1 Japan

Japan was one of the first LNG importing countries, being delivered from Alaska´s Kenai liquefaction site from 1969 onwards. End of the 1970s and in the 1980s close to 80% of globally traded LNG was delivered to Japan. With the economic impossibility of pipeline gas supply, Japanese buyers traditionally contracted LNG on a long-term basis from Alaska and countries within the Asian-Pacific region like Indonesia, Malaysia, Australia, Brunei and the United Arab Emirates (UAE).
With the nuclear disaster at the Fukushima power plant in 2011 all nuclear power plants were shut down for detailed inspection. The gap was mostly compensated by LNG, using existing infrastructure. Within the last years some reactors have been restarted but future remains uncertain for nuclear power generation in Japan, also due to strong public opposition.
As of March 2018 Japan was the world´s biggest LNG importer with a regas nameplate capacity of 198 MTPA and an average utilization rate of 43% or 85 MTPA. 17 different countries ensure Japan´s supply, resulting in a diverse mix with a relatively high level of redundancy. Analysts estimate that by 2020 US gas could make up about 20% of LNG imports [35, p. 3]. With a slowly declining demand of 80 MTPA by the mid-2020s, this would be equivalent to some 16 MTPA.

3.2 China

In 2017 China surpassed South Korea as the world´s second market for LNG imports with expected growing demand. Today, it is the fastest growing market for LNG in absolute and relative terms. This is mainly driven by two factors: A governmental initiative to reduce pollution in Chinese cities as well as objectives to meet CO2 emission targets. For both actions coal-to-gas switching is the medium of choice. Furthermore, most industry is located at the shore and pipeline supply from Russia and Central Asia is not enough to cover demand.
By March 2018 a nameplate capacity of 57 MTPA was installed. Level of utilization was 73% or 42 MTPA. This is half of what Japan regasified in 2017. Further coal-to-gas switching could result in 63 MTPA by 2023 (end of this thesis´ outlook) [36, p. 5].
Due to uncertainty related to the ongoing trade dispute with the USA, it is unclear to what extend US gas might be used for Chinese imports. In 2017, this rate was around 4% only [6, p. 34]. But until end of July 2018 US imports to China already grew to 7%. Another source states that US-share on Chinese imports was already 6% in 2017 and might rise to 20% in future without naming an exact year [37]. This might be possible because closely situated, traditional Chinese suppliers (Australia, Malaysia and Indonesia) might feel forced to limit their gas exports due to changing political conditions, making US gas more competitive for Chinese buyers. For further calculations a share of 10% of US gas is supposed. This would result in 6,3 MTPA of LNG in 2023.

3.3 South Korea

From 1995 to 2016 South Korea was the world´s second-highest importer of LNG after Japan. In 2017 and 2018 it was surpassed by China´s imports and ranks third since then. South Korea finds itself with inaccessibility to pipeline supply due to difficult political relations with its northern neighbor North Korea. The country´s primary energy mix is based very much on oil and coal. The share of LNG within primary energy was 19% in 2013 but fell to close to 16% in 2017. US gas imports were ranked sixth in

2017 but gained ground from January to August 2018 pushing US gas to the third rank (10%) after Qatar (33%) and Australia (16%) [38, p. 2].
In spring 2018 127 MTPA of regas capacities had been installed. Utilization rate was only 30% resulting in 38 MTPA of regasified LNG. On the one hand, clean energy policies are expected, favoring gas and setting higher taxes on coal. However, capacities of coal-fired and nuclear power plants, which have been under maintenance, are going to come online again in the next few years. Thus, LNG demand might remain stable until 2023 between 35 and 40 MTPA. With a 10% share US imports would remain at 3,8 MTPA.

3.4 Other destinations: India, Taiwan, Pakistan, Kuwait, Thailand, Indonesia, Singapore, Bangladesh, the Philippines

India´s demand for LNG is growing fast and has pushed the country on world rank number four with respect to LNG imports. Many construction projects (pipelines and regasification plants) have been started recently but gas supply of inland demand centers still is a challenge. First LNG imports date back to 2004. Qatar has been one of the main low-cost suppliers and still covers 53% of Indian LNG imports. In 2018 new contracts were made with Cheniere (Sabine Pass) and Dominion (Cove Point), among others. Holding a share of just 2% in 2017 US imports rose to close to 5% in 2018 (January to November) [6, p. 34 and 39, p. 5]. Imports are said to increase from 21 MTPA in 2017 to 28 MTPA in 2023. Considering a constant quote, US share might be 1,4 MTPA then.

Taiwan´s primary energy sources are oil and coal. Nevertheless, gas comes third with a share of 13% of the island´s energy supply mix. Thereof, 98% are LNG and 2% domestic gas production [40, p. 2]. US contribution to this has been practically inexistent (0,9% of 17 MTPA in 2017). Main suppliers are situated in the Asian-Pacific region or the Middle East (Qatar). Demand is foreseen to remain at 17 MTPA until 2023. Assuming 1% share this would result in 0,17 MTPA coming from the USA.

Pakistan is one of the newest LNG importing countries with its first shipment received in 2015. Although possessing a well-equipped gas infrastructure, Pakistan suffers ongoing difficulties in project financing and foreign investors are worried about its ability to pay. While in 2017 only 5 MTPA of LNG had been imported, this number is prospected to almost triplicate until 2023 (14 MTPA) [41, p. 3]. For 2017 BP saw 1,6% of Pakistani LNG imports coming from the USA but data from IHS Markit show that these were single spot shippings and not based on continuous contracting. Pakistan might remain a marginal market for US gas in the next five years. If spot cargos remain at this low level, in 2023 some 0,22 MTPA could have US origin.

Originally being an oil and gas exporting nation, Kuwait became a net importer of gas in 2008. A remarkably high energy consumption per capita and remaining difficulties in making accessible gas from non-associated gas fields led to this curiosity. Demand reflects seasonal dependency with peaks from April to October. With Shell being one of the main suppliers, also shipments from Sabine Pass can be found in the supply portfolio. A utilization rate of 75% in 2017 Kuwait´s single regasification plant (a second is under construction) led to LNG imports of 5 MTPA in 2017. It is estimated that 7,5 MTPA would be needed in 2023 to satisfy demand and a share of 8% could have US-origin (0,6 MTPA) [42, p. 3].

Thailand´s Map Ta Phut regas facility is the country´s only opportunity to receive LNG. Its workload was at 39% in 2017 resulting in 4 MTPA. US gas plays a minor role: Only Shell contributed with spot shipments to LNG import [43, p. 4]. BP states 1,9% in its Statistical Review of World Energy 2018. Supposing a need of 10 MTPA in 2023 0,19 MTPA could be delivered from the United States.

From the late 1970s onwards, Indonesia has been an important gas exporting nation and second-largest producer in Southeast Asia. Its reserves could easily permit to satisfy domestic demand. But self-supply is a challenge due to the high number of islands (limited pipeline infrastructure) and centers of demand do not necessarily comply with those of production, which led to the construction of three regasification facilities. Apart from receiving domestic LNG, international deliveries are going to play an important role in future [44, p. 2]. In 2017 2,9 MTPA of LNG were imported. Until 2023 this number could double to 6 MTPA. US imports are said to come from the Corpus Christi liquefaction plant and deliver 0,4 MTPA from 2020 onwards, with the option to increase up to 1 MTPA. This would result in close to 17% of imported LNG in 2023 coming from the US Gulf Coast.

Although Singapore has 11 MTPA of installed nameplate regas capacity, it was poorly used in 2017 (21%). Singapore is mainly focused on storing and re-exporting LNG, creating the first Asian LNG hub as a counterpart to the existing ones and establishing LNG as marine fuel. Due to its small size energy supply is easily manageable. The 2017 imported 2,3 MTPA are expected to rise to 5,7 MTPA in 2023. Until now US gas does not play any role for the country´s gas supply but future volumes are expected to come from the Freeport and Cameron facilities [45, p. 3]. For this thesis´ approach it will be assumed that only few spot cargos with US gas might deliver to Singapore (excluding re-exports, i.e. own consumption), making up 5% or 0,29 MTPA.

The Bangladeshi and the Philippines´ regasification terminals had been under construction in 2017. The former is said to have a regas capacity of 3,75 MTPA, the latter of 1,5 MTPA. Assuming an average regasification utilization rate of 35% (world average) because of lack of data, this would result in 1,3 and 0,5 MTPA in 2023, respectively. Also, US gas imports can only be estimated. This is done with the same rate as for Singapore (5%) resulting in 0,07 MTPA for Bangladesh and 0,03 MTPA for the Philippines. Both markets play a minor role and are not thoroughly developed.

The findings are summarized in the following figure:

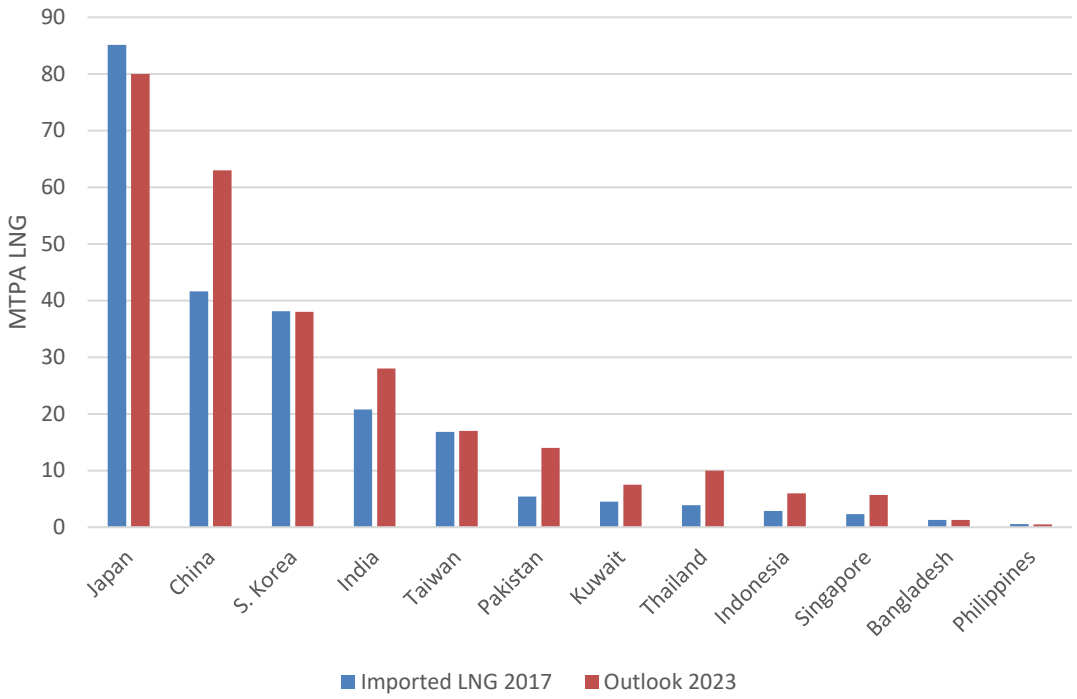


Figure 20 LNG demands 2017 and 2023 for selected countries in Asia-Pacific and the Middle East.[19]

The only LNG importing country which could suffer a decline is Japan. But as nuclear power generation remains unclear, outlook for 2023 is uncertain. Though it is commonly accepted that Japan will remain the world´s leading importing nation for the next few years. South Korea is expected to receive the same amount of LNG than in 2017 (approx. 40 MTPA). All other countries, notably China, are supposed to increase their LNG imports until 2023. The Bangladeshi and the Philippine´s market play only minor roles. Altogether, this would result in a demand of 271 MTPA in 2023 from 223 MTPA at the end of 2017. This represents an increase of more than 21%.

Furthermore, for each country future US share was estimated. In total, this would result in the import of 30 MTPA LNG with US origin or 11% of demand. Especially Japan and China could be very interesting markets for US gas: Japan, because many contracts will need to be renewed and China, because it is still unclear what companies might fill the future demand-supply-gap with the lion´s share still needed to be negotiated.
On the long-term also India might surpass South Korea as the third-ranked importing country and might be a promising market for US gas, but progress needs to be made in regasification construction and pipeline networks need to be extended in a faster pace to reach inland centers of demand.

[19] Own elaboration based on [1] and [35] – [45].

4 LNG vessels

Very special ships have been developed since the first ever shipped LNG cargo in 1959. Those ships can load large volumes of LNG and their insulation permits maintaining the load´s cryogenic temperature of about -162°C (-259 F). This chapter tries to give an overview of main characteristics like vessel size, containment and propulsion type and financial aspects in hiring an LNG tanker.

4.1 Vessel size

According to IHS Markit database from October 2018 [46] the following chart was created:

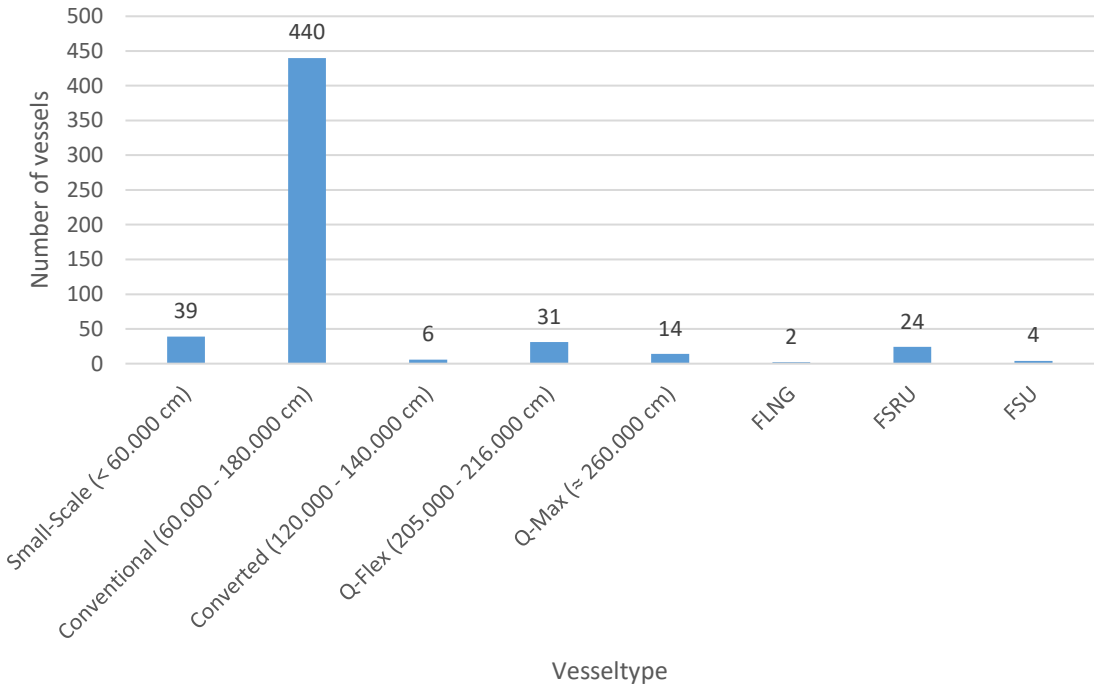


Figure 21 LNG fleet as of October 2018, ordered by vessel types.[20]

In October 2018 there existed a total of 560 vessels that could handle LNG in any kind of sense. 530 (94,6%) of them were for transport usage. The rest (5,4%) were floating, stationary units with the purposes to liquefy (FLNG), storage and regasify (FSRU) or only storage (FSU).

The 530 vessels that are used for LNG transport, can be classified corresponding their transportable volume in cubic meters (cm), as shown in the diagram above: Below of 60.000 cm they are called small-scale vessels. Between 60.000 and 180.000 cm the conventional carriers are found. The Q-Flex class fits between 205.000 to 216.000 cm and the biggest LNG vessels ever built belong to the Q-Max class with around 260.000 cm.

Size is a result of prospective purpose, in terms of destination and route. While the conventional class virtually can enter every known LNG liquefaction and receiving port, Q-Flex and Q-Max are Qatari developments that correspond to their large liquefaction units built in the 1990s. Q-Flex and Q-Max have very low price per unit costs and are the most efficient option to transport liquefied

[20] Own elaboration based on [46].

natural gas. But because of their size they are not able to pass the Panama Canal, and neither can access some regasification terminals, which limits their application to serve the global LNG market.

Small-scale carriers are a newer trend. They are deployed in regions with a high number of islands that have a developed and mature gas market or use gas for electricity generation, for example Japan, the Philippines, Indonesia or some Caribbean islands. Usually, a conventional LNG vessel moors at a larger receiving port and LNG is reloaded to smaller vessels that will be send to remote regasification plants.

As of October 2018, there were 11 small-scale and 103 conventional vessels on order for the upcoming years until 2022. Furthermore, two FLNG and eight FSRU have been booked. Orders are not only given by shareholders in the LNG value chain, like international O&G companies that hold equity in LNG plants, but there is a growing part of speculative orders by shipowners that reflects trade under short-term and spot aspects (< 2 years or “immediately”). The limitation to conventional vessels in actual orderbooks coincides with the size limits set by the Panama Canal locks.

A relatively new class, which is not defined by its size but its special requirements for harsh weather conditions, are vessels with winterized design. With more and more LNG projects coming online in arctic waters like Statoil´s operated Snohvit LNG plant on Melkoya Island, close to Hammerfest, or Novatek´s Yamal LNG plant, located on Russia´s Yamal Peninsula, shipyards are confronted with special ship equipment. As climate change reduces the ice pack in the Arctic Ocean, the Northern Sea Route (NSR) is shippable eastwards (direct link from Russia to Asia) during summer due to lower ice thickness and westwards in winter (passing Europe and the Suez Canal) when ice thickness impedes direct vessel transit towards the east. If vessels want to avoid the operation of additional, costly, icebreaker escorts, their design needs to be improved [47]. Classification ranges from *Ice1* to *Ice3* and from *Arc4* to *Arc9* for arctic-proof ships. Up to date, *Arc7* is the highest ice-class and can independently break through ice of 2,1 m thickness. *Arc8* and *Arc9* vessels have not been built yet. Winterized design includes:

- Both-directional driving mode: Bow-ahead under normal conditions and ice-thickness up to 1,5 m and astern to crush ice of up to 2,1 m thickness
- Ice-strengthened hull structure
- Double-hull engine rooms, center bulkhead dividing two engine rooms (redundancy), special ice chip removal and melting for engine cooling water
- Winterization on deck and in living quarters to withstand temperatures down to -50°C
- Redundant heating applications (electric and oil heated)

Icebreaking-speed is only 5,5 knots (10,2 km/h) for ice-thickness of 1,5 m. Due to special equipment, redundancy and longer transportation time, both investment costs and transportation costs are higher for Arc-class vessels.[21]

[21] Investment costs make up approx. 320 mUSD, compared to 180-200 mUSD for a same-sized conventional vessel acc. to [1, p. 46].

4.1.1 Size limitations

As mentioned above, size is the result of the vessel´s prospective purpose regarding destination and route. Its dimensions are set firstly by the size capacity of the building shipyards and the ports where the ship would probably operate, secondly by the Panama and the Suez Canal as arteries of global marine transport and thirdly by economics, as 50% of its voyage the vessel is empty (return to homeport after unloading) with corresponding fuel costs.

The Panama Canal extension from two to three lanes was realized between 2009 and 2016 and permits new capacities, called NeoPanamax class, to cross from the Atlantic to the Pacific ocean and vice versa. As most of the LNG vessels have been wider than the former Panamax class, hardly any LNG carrier could pass the Panama Canal before its amplification.

Table 7 Maximal vessel dimensions for the both types of Panama Canal locks.

(in laden condition)	**Length**	**Width (Beam)**	**Depth (Draft)**
Panamax class	294,1 m / 965 ft	32,3 m / 106 ft	12 m / 39,5 ft
NeoPanamax class	365,7 m / 1.200 ft	49 m / 161 ft	15,2 m / 50 ft

Also, the Suez Canal received several extensions since its inauguration in 1869, the last finished in 2015, now permitting the transit of ships in both directions simultaneously, which was not the case before. Unlike the Panama Canal, the Suez Canal has no locks, so that ships are not limited due to their length.

Table 8 Maximal vessel dimensions for the Suez Canal.

(in laden condition)	**Width (Beam)**	**Depth (Draft)**
Suezmax	50 m / 164 ft	20,1 m / 66 ft
or[22]	77,5 m / 254 ft	12,2 m / 40 ft

More facts about the both canals will be given later in chapter 5.

[22] Due to the canal´s trapezium shape.

4.1.2 Gross tonnage and net tonnage

Gross tonnage (GT) and net tonnage (NT) are of special interest because they serve in particular to calculate canal and berthing dues. For example, NT is needed to calculate transit cost for the Suez Canal. This will be explained later in chapter 5.2.1.1.

Gross tonnage (GT) is a logarithmic function of spaces within a vessel according to the International Convention on Tonnage Measurement of Ships (ICTM). Here, one ton is *not* a number in terms of weight but equivales to a volume of 100 cubic feet (cf) or 2,83 cubic meters (cm). It includes, in theory, the total volume of "*spaces bounded by the under surface of the uppermost complete deck, the side frames, and the floor frames or the inner bottom if it rests on the floor or if the double water is for ballast water, plus closed-in space are available for cargo or stores or for the berthing or accommodation of passengers or crew*" [48].

$GT = V * (0,2 + 0,002 * \log_{10}(V))$

with V = capacity of enclosed spaces.

Apart from GT exists also the NT, which excludes accommodation spaces for crew, machinery, engine room and fuel. Simplifying, it is the cargo´s stowage space.

$NT = (0,2 + 0,002 * \log_{10}(V)) * V_c * (4d/3D)^2 + 1,25 * ((GT+10.000)/10.000)) * (N1 + N2/10)$

with V_c = capacity of enclosed cargo space, d = molded draught amidships, D = molded depth amidships, N1 = number of passengers with not more than 8 berths, N2 = number of other passengers [49].

[Cridland, 49] describes the determination of NT as a "*black-art, even worse than (the calculation of) GT and too complicated to be calculated by shipyards*". Meanwhile GT can be found in some internet databases with open access[23], NT indeed seems to be a mysterious number and is only calculated by shipyards or constructors on order. It is almost impossible to find any reasonable estimation or how to deduce NT from GT within open accessible websites. According to the International Maritime Organization (IMO) a "*net tonnage shall not be taken as less than 30 per cent of the gross tonnage*" [50]. This statement might be true for other kinds of vessels but not LNG carriers. Solely for small liquified petroleum gas (LPG) tankers with capacities less than 60.000 cm it could be verified by the author.[24] For bigger LNG carriers this number was not satisfying. For this reason, examples from Naturgy´s fleet were taken, and their NT and GT were set in relation to each other. The result can be expressed as

$NT \approx 0,67 * GT$.

This factor of 0,67 (67%) seems much more reliable, logical and probable, as LNG carriers dispose of large containments that surmount their uppermost deck.

As has been mentioned in the beginning of this passage, net tonnage is an important parameter that will play a role later for calculating canal tariffs.

[23] For example www.vesselfinder.com or www.marinetraffic.com (both Jan. 2019)
[24] https://horizonship.com/ship-category/tankers-for-sale/gas-carriers-for-sale/ (Jan. 2019)

4.1.3 Gross tonnage to capacity relation and average vessel size

Vessel size, in terms of cubic meters, that means holding capacity, can be expressed in relation to gross tonnage (GT). The following graph was created on basis of IHS Markit´s Fleet Database of October 2018 [46] and the online database www.vesselfinder.com. In this case, small-scale vessels (< 60.000 cm) and floating, stationary units in a total number of 69 were excluded. Another 30 ships could not be found in the online database. This results in 461 of 560 records, or 82,3%.

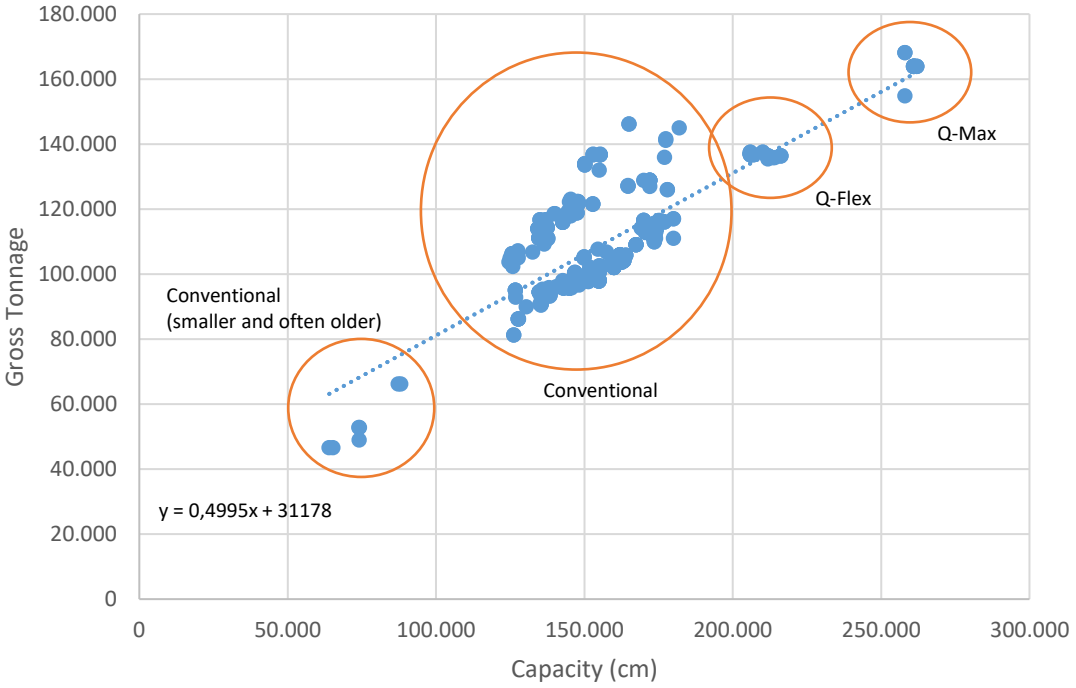


Figure 22 Gross Tonnage over capacity (cm).[25]

The figure shows the relation between GT and capacity of LNG vessels. The different sizes "Conventional", "Q-Flex" and "Q-Max" can be seen very clearly. There are some ships belonging to the conventional class that are smaller than the majority of this class and therefore stand apart (left circle). Still, their containment can hold more than 60.000 cm and they are not small-scale.
As a result, this graphic permits the generation of a mathematic formula, a simple line, that expresses GT in relation of capacity. The formula can be seen in the lower left corner of the figure and can be simplified to

*GT = 0,5*CAP + 30.000*

with GT the gross tonnage (without unit) and CAP the capacity in cm. So, for any given capacity the gross tonnage can be calculated, and vice versa. Once GT was calculated, NT and other factors can be deduced (see chapter 5.2.1.1).

[25] Own elaboration based on [46].

According to the created database, the *average* non-small-scale LNG vessel of today (end of 2018) is of the following characteristics:

Table 9 Average LNG vessel characteristics.[26] (L=length, W=width/beam, D=depth/draft)

CAP (cm)	GT	NT	L (m)	L (ft)	W (m)	W (ft)	D (m)	D (ft)	Speed (kt)
158.700	110.500	74.000	290	953	46	150	10,3	34	19,1

4.1.4 Small-scale LNG vessels and stationary offshore solutions

The International Gas Union (IGU) considers small-scale (ss-)vessels as of loading capacities below 60.000 cm. This accordance was adopted also within this thesis. As shown in figure 21 in chapter 4.1, today exist 39 ss-vessels, a share of 7,4% of the global vessel fleet (floating, stationary units excluded). Another 11 ss-carriers are on order and will start service until 2022. Apart from conventional sized tankers, which are the vast majority, this is currently the only category to bring new capacities in service.
After booming in the 2010s, demand for Qatari´s Q-class vessels has declined. Meanwhile, market needs have gradually seen a change, not only in the sense of transporting capacities, but with new, innovative, integrated ss-solutions all along the LNG value chain.
As an integral part of this chain, small-scale vessels are aimed to serve gas markets within short distances and remote locations, for example in regions with a high proportion of islands like Japan, the Philippines, Indonesia or the Caribbean. Small-scale solutions yet exist in Norway, whose unique geography of mountains and fjords make shipping preferable to road transportation. Due to their lower draft of around 5,8 m (= 19 ft)[27] those ships can enter smaller ports, and because loading and unloading is faster, they can be used to ship capacities on a spot-basis and help to shave peak demand. They can deliver LNG to power plants, land-based industries and may play an active role as supplier of a (still to build and expand) global gas station network for the use of LNG as a long-distance road haulage and marine fuel to represent a cleaner alternative to traditional fuels like marine diesel oil. Bunkering infrastructure is already existing in Zeebrugge, Rotterdam and Singapore. Small-scale vessels are less expensive than the conventional class[28], but unitary cost is higher because of missing economy of scale.

Apart from this newer class of shipping capacities, floating LNG concepts have begun to be an interesting solution for certain small-market applications. Floating units are offshore-based but close to the shore, stationary vessels whose purpose might be liquefaction (FLNG), storage and regasification (FSRU) or only storage (FSU). Often, laid-up vessels that would be inefficient for LNG transport or would need costly repairing are modified into floating units. Those innovations are characterized by reduction in investment and operation costs, construction time, regulation and permitting complexity. Floating units, although principally thought to be stationary, can be relocate easily when a project comes to an end or even when it gets bigger and onshore facilities have been constructed. Also, their built-up time is shorter than for “classic”, land-based receiving terminals.

[26] Own elaboration based on [46] and www.vesselfinder.com
[27] Mean average of 10 randomly chosen ss-LNG vessels from www.vesselfinder.com
[28] Mean average of 12 *existing* ss-LNG vessels with known investment cost is 63 mUSD [46].
Small-scale carriers *on order* cost 50,5 mUSD at an average.

In conjunction with floating units, ss-transportation can show its whole strength in the sense of flexibility and dynamic [1, p. 46]: Solutions in Jamaica included a series of ship-to-ship loadings from conventional vessels to smaller ones for further distribution, using an FSU. In Chile a FSU helped to import LNG before completion of the actual receiving terminal (less construction time). And Malta became the last LNG importing country in 2017 by using a converted carrier as FSU and then sending volumes onshore to a small regasification plant (0,4 MTPA).
Companies like Naturgy or Wärtsilä have developed solutions specifically for ss- or floating-technologies along the LNG value chain and operate very successfully within these niches. Wärtsilä offers engineering, procurement and construction (EPC) concepts that include satellite terminals for small power plants or bunkering of LNG as a fuel [14]. Naturgy has developed the world´s first floating LNG transferring system that is equipped with a universal connection for loading and unloading a great range of vessels offering great flexibility ("LNG Direct Link"). It is a mobile solution that can be erected within a short timeframe [51].

4.2 Containment types

LNG vessel containment systems have made huge advances since the first LNG shipping in 1959 with the converted World War II freighter *Methane Pioneer*. Nevertheless, considering the technological possibilities 60 years ago, the aluminum prismatic tanks with balsa wood supports and insulation of plywood and urethane was highly developed engineering and still today´s repositories use some of those materials. The containment´s principle function is to remain the liquefied natural gas under cryogenic condition at -162°C and to protect it from heat transfer from outside, what would result in evaporation of the product.

Essentially, todays´ LNG carrier fleet uses two types of containment systems, which will be presented in the following passages. Any variation of these types (prismatic, cylindrical or "Bilobe" design) is not part of this summary and appropriate literature should be consulted for a deeper study.

4.2.1 Moss design

Moss or Moss-Rosenberg tanks have a spherical design and their structure is self-supporting, which means that their containment systems are built apart and then inserted into the ship´s body.
At the end of 2017 26% of active LNG vessels used the Moss design and share is declining: As of October 2018, the orderbook counts only 10 of 82 conventional tankers to the Moss or related prismatic IHI SPB design [1, p. 37 & 51].
The Moss or Moss-Rosenberg design was developed in Norway and introduced in 1973. Since then, around 140 vessels have been built. Their flexibility permits volumes between small-scale and Q-Max size and boil-off rates (BOR) can reach levels down to 0,07%/d [52]. Because of the spherical construction sloshing of LNG is not a problem.
The self-supporting design requires more material than for the same volume of transported LNG than alternative designs, resulting in a heavy rigid construction. As they do not dispose of a secondary barrier, a detailed stress and fatigue analysis is obligatory.

Shipyards specialized in the Moss design are Mitsubishi Heavy Industries, Kawasaki Heavy Industries and Japan Marine United Corporation.

4.2.2 Membrane design

The membrane structure is not self-supporting, which means that the vessel´s inner hull forms the load bearing structure. This type made up 74% of 2017-active LNG carriers [1, p. 37]. Future orders for membrane-type containment systems even increase this number with 72 of 82 vessels within the conventional class [46].
French corporations Technigaz (1964) and Gaztransport (1969) developed the first membrane-type LNG vessels. They merged in 1994 to form GTT. GTT´s No. 96 and Mark III are the most sold membrane-type systems. They basically differ in the implemented insulation and layer technology. As well as Moss-type carriers, they can be constructed in virtually every size. Because sloshing is a problem in membrane-type containment systems, the inner hull is fitted with a corrugated structure that breaks waves of moving LNG.
The different layers of the containment system are a specialized “lightweight” construction (compared to Moss). For the same volume only around 1/10th of material is required. In contrast to Moss-type carriers, membrane-type tankers need a second barrier (consisting of membrane and insulation), as can be observed in the figure below.
Advantages are a better usage of the vessels inner hull, with fewer unused spaces, and a better navigation visibility, as they are usually constructed lower than Moss-type carriers.

Shipyards specialized in the membrane design are Daewoo, Samsung Heavy Industries, Hyundai Heavy Industries and some Chinese shipyards.

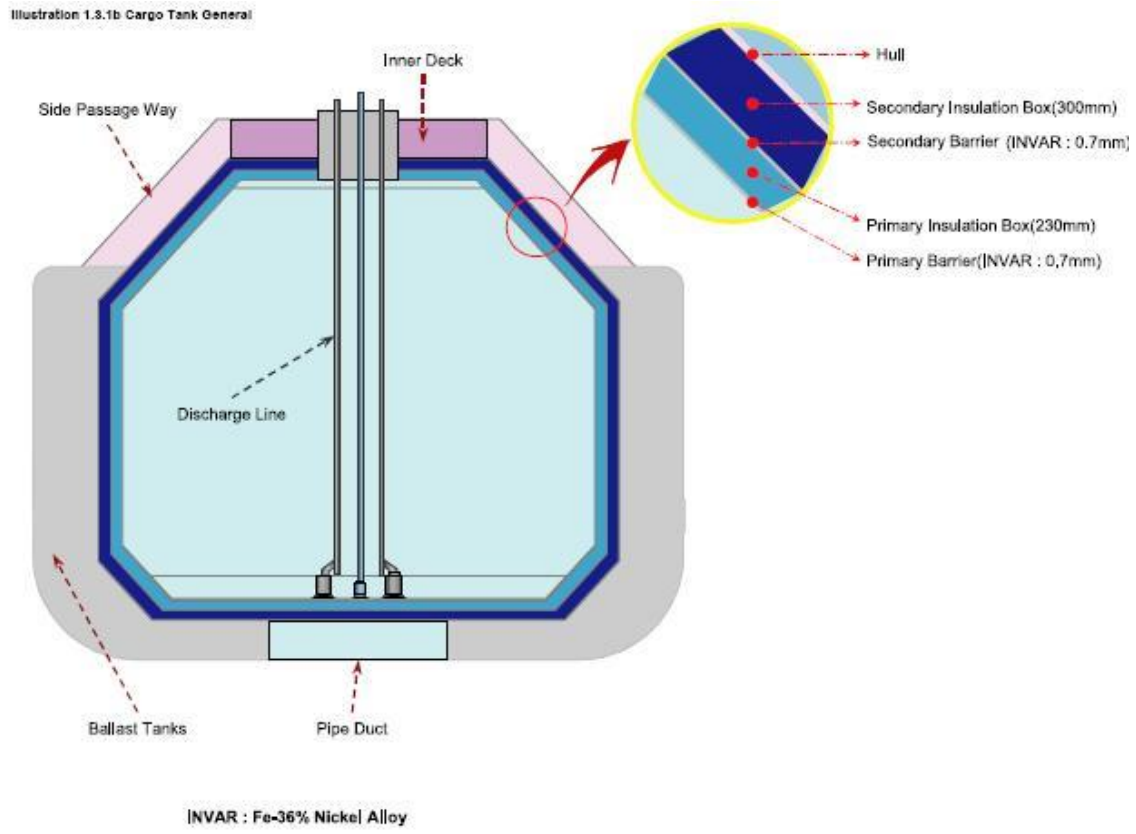


Figure 23 Schematic of a membrane-type containment system.[29]

[29] Copyright by Liquefied Gas Carrier: **Website** (Jan. 2019)

4.3 Propulsion types

Propulsion technologies are defined by economic and environmental factors. Choosing the appropriate combustion system has direct impacts on transportation cost and needs to be conform with existing exhaust emission standards.

To date steam propulsion is still the most used propulsion system among LNG vessel owners. Its share is about 50% of the active fleet. Developed from the very beginning in the 1960s, steam has been the medium of choice for most of the fleet since then because of its simplicity, reliability, low maintenance costs and the versatility to burn both marine fuel oil (MFO) and boil-off gas (BOG). To remove latter from the containment systems is necessary to remain pressure stable, i.e. to avoid overpressure and possible material fractures. The normal case is to force BOG (in contrast to natural boil-off) with a rate of 50 t/d at a service speed of 17,5 kt [53]. Major drawback of steam propulsion is the low efficiency of around 35%, which is the usual efficiency of any combustion system based on the Rankine cycle. Although improvements have been made and Ultra Steam Turbines (UST) with an efficiency of 50% have been developed [54], future orders do not consider steam propulsion any more due to tightened exhaust emission regulations. Vessel owners, who want to use their steam-driven carriers, must improve their exhaust system up from 2020 in order to comply with new emission standards.

The propulsion systems of the active fleet and of the order book, as of October 2018, are summarized below:

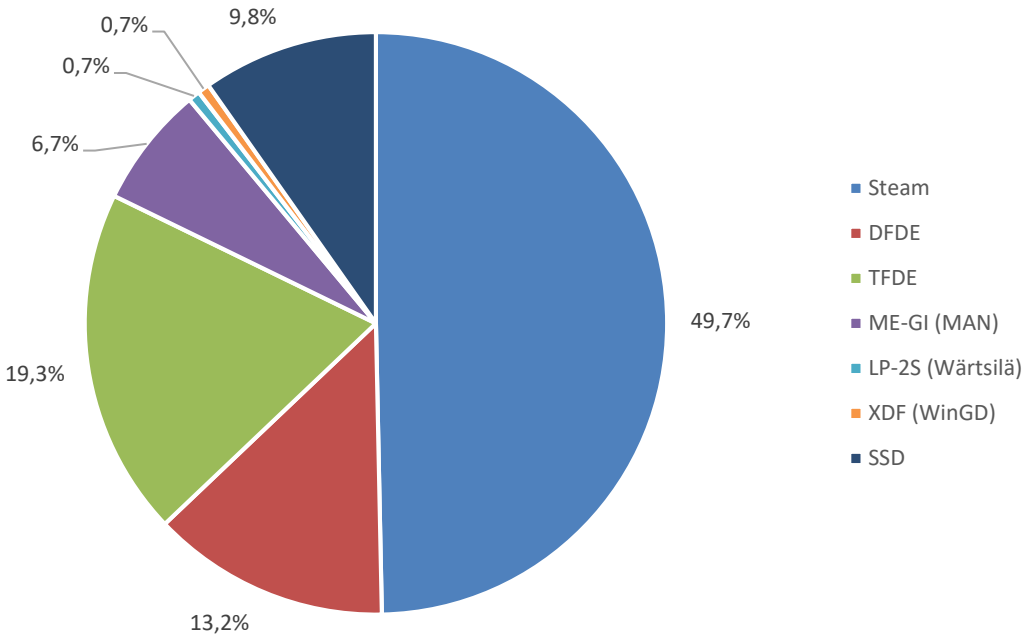


Figure 24 Propulsion types active fleet, October 2018.[30] (DFDE = Dual-fuel diesel electric, TFDE = Tri-fuel diesel electric, ME-GI = M-type electronically controlled gas-injection, LP-2S = Low-pressure 2-stroke, XDF = X-Dual-fuel (low-speed 2-stroke), SSD = Slow-speed diesel)

[30] Own elaboration based on [46].

While 50% of the active fleet consist of steam driven vessels, the other half is equipped with newer technologies. Over 30% of the ship owners trust dual- or tri-fuel diesel electric propulsion systems (DFDE, TFDE) and another 7% use the M-type electronically controlled gas injection drives engineered by MAN (ME-GI), which are suspected to have an essential future market share.
10% use slow-speed diesel engines (SSD).

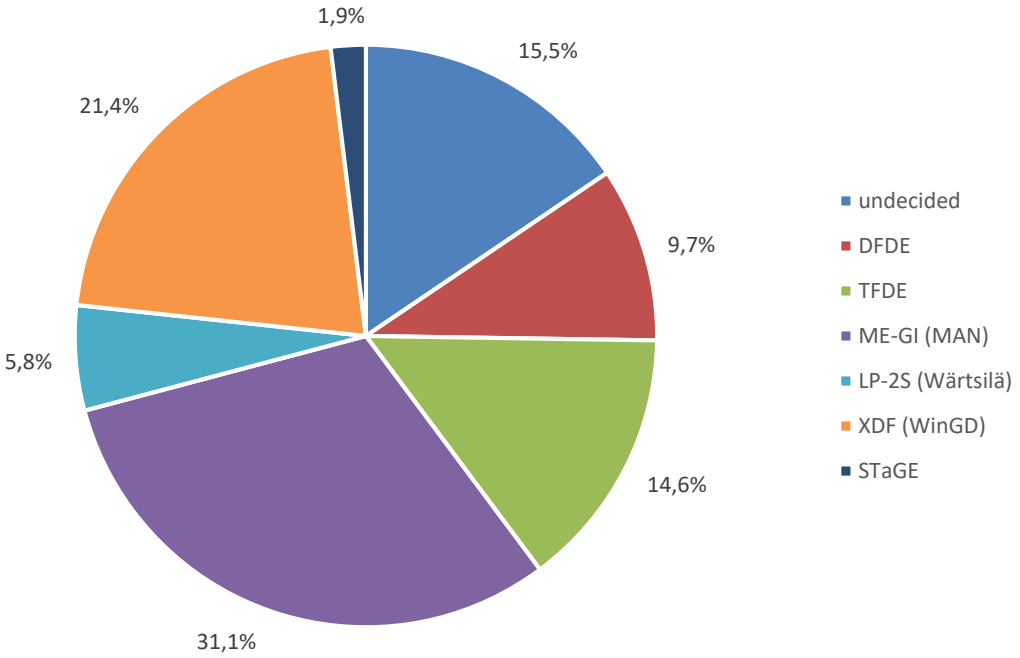


Figure 25 Propulsion types order book, October 2018.[31] (StaGE = Steam turbine and gas engine)

New orders for LNG tankers do not contain steam propulsion. MAN´s ME-GI and WinGD´s X-Dual-fuel engines (XDF) will have the highest shares among new built vessels, but DFDE and TFDE are still demanded.

4.3.1 DFDE/TFDE and alternative propulsion technologies that comply with future emission standards

This passage gives a short synopsis of propulsion types different than steam based on [Fernandez et al., 54].

Dual- and Tri-fuel diesel electric engines can burn both boil-off gas (BOG) and one (DFDE) or two (TFDE) additional liquid fuel(s) like marine fuel oil (MFO) or heavy fuel oil (HFO). In gas mode, which is the normal case, these engines run on low-pressure natural gas with a small amount of liquid fuel used as ignition spark. D/TFDE engines can run 19 kt with natural boil-off with no need to burn any fuel oil [55]. The engine operators can switch to traditional MFO at any time. With the option to burn a second liquid fuel, TFDEs offer even more operational flexibility at different speeds (service speed, maneuvering, etc.) and different fuel costs. Their efficiency is said to be 25-30% over traditional steam driven vessels with very low sulphur oxides (SO_x) emissions because the consumed BOG is

[31] Own elaboration based on [46].

practically sulphur-free [1, p. 38]. Major drawback of these technologies is the additional equipment necessary to treat BOG, what increases their maintenance costs compared to steam propulsion.

The following figure gives an example of a DFDE arrangement:

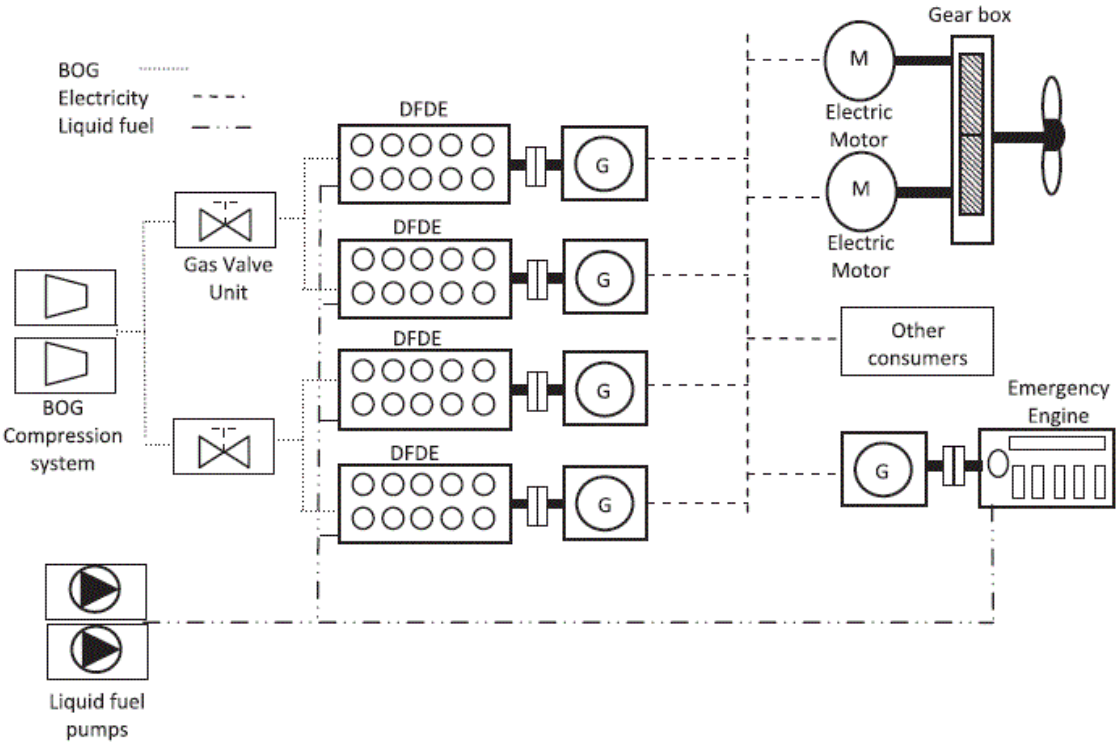


Figure 26 DFDE configuration schematic [54].

MAN´s M-type electronically controlled gas injection system (ME-GI) could be one of the mostly used propulsion systems for future LNG vessels, as sales volumes look promising until now. Slow-speed, two-stroke engines use a high pressure (250-300 bar) fuel injection system to burn any desired or requested fuel oil-to-gas ratio once a small amount of MFO or HFO ignited the gas. Consumption is expected to undercut TFDE propulsion systems by 15-20% [1, p. 38]. To comply with future emission standards an exhaust gas recirculation (EGR) or selective catalytic reduction (SCR) system is required.

Another innovative solution is presented by Winterthur Gas & Diesel (WinGD): In contrast to MAN, their slow-speed, two-stroke, dual-fuel engine (XDF) runs on low pressure below 16 bar. This fact lowers investment costs for the fuel gas supply system (FGSS), electrical power consumption and maintenance. Also, WinGD´s XDF permits operation in gas mode down to 5% power, meanwhile limit for ME-GI is 10% engine power [56].

Typical consumptions in t/d for a service speed of 18 kt are given in the following table. Port consumption is around 1/4th.

Table 10 Typical fuel consumption in t/d.

Propulsion type	Industry data (Naturgy)	IGU World LNG Report 2018	fairplay.ihs.com (Internet)	Average
Steam / Ultra Steam	145	175	170	163
DFDE / TFDE	105	130	140	125
ME-GI / XDF	80	110	-	95

The most important ship engine manufacturers are MAN, Wärtsilä and WinGD. Their propulsion systems are under constant development due to economic market tendencies and environmental regulations. Manufacturers are in the difficult situation to find solutions that unify high efficiency with low consumption and meet legal emission standards.

4.3.2 The 2020 sulphur cap

Like any transport sector shipping must comply with existing exhaust gas regulations and emission standards. Those are set and controlled by the International Convention for the Prevention of Pollution from Ships, or short MARPOL (for marine pollution). The agreement was developed by the International Maritime Organization (IMO), a department within the United Nations Organization (UNO). MARPOL Annex VI, first adopted in 1997, handles issues concerning the main pollutants contained in ships exhaust gas and their progressive reduction: Sulphur oxides (SOx) Nitrous oxides (NOx) and ozone depleting substances (ODS).

According to the agreement, ODS are completely prohibited. To reduce NOx to the mandatory level, ship owners and operators usually install well-proven EGR or SCR cleaning technologies. The latest restriction concerns sulphur / sulphur oxides and is going to enter into force from 1st of January 2020.

The main types of marine fuels, also called “bunker”, derive directly from crude oil distillation and, by nature, contain certain amounts of sulphur. When burned in the vessel, SOx are emitted. Those are known to be harmful to human health and lead to acid rain. While current bunker must be concordant with the current limit of 3,5% m/m (mass by mass) sulphur content, marine fuels sold from the 1st of January 2020 onwards will need to comply with the new 0,5% m/m limit [57].
This limit is a global agreement and is going to affect approximately 70.000 vessels [58]. In already existing emission control areas (ECA) an even stricter limit of 0,1% m/m will be applicable. Those ECAs are (until now): The Baltic Sea, the North Sea, North American sea territories (coastal areas off the USA and Canada) and US Caribbean territories (Puerto Rico and the Virgin Islands). Future areas might include the Mediterranean Sea, the Norwegian coastline, the Japanese sea territories and some of China´s notoriously busy coastal hotspots.

Ship owners and operators have the following options to deal with the so called “2020 sulphur cap”:

- Switch to cleaner marine fuels or compliant fuel blends.
- Keep using “standard” bunker but install a scrubber to clean the exhaust gas.
- Use alternative fuels, for example LNG.

Every alternative has its advantages and disadvantages. Cleaner fuels and blends instead of "standard" bunker will increase operating costs, but the installation of a scrubber is tied to capital expenses. Using the laden LNG is form of BOG is already reality for virtually the whole LNG vessel fleet, but further capitally-expensive modification and retrofitting concerning the ship´s engines will be necessary.

Vessel age, operating and capital costs, fuel availability, technology solution availability and reliability and the primary trading areas are factors that will need to be considered by ship owners and operators to comply with this exhaust gas reform.

4.4 Vessel lease

Traditionally, vessels are built project-related, dedicated to a particular charterer and serve usually an LNG supply-agreement for lifetime (20 to 30 years). This is called time-charter.

Contrary to time-chartering, spot-chartering can occur when a shipyard builds vessels without order or owners order capacities without dedication to a specific project. In both cases the tanker is available on the market, for the owner itself or for traders and portfolio players. Data for 2018 showed that 19 of 107 vessels on the orderbook (18%) remained available for charter. Out of the 107 vessels 17% were tied to LNG producers (i.e. Nigeria LNG, Yamal LNG), 45% belonged to buyers or traders (i.e. Mitsui, Chubu Electric) and 38% were owned by companies with activities along different parts of the LNG value chain (producer, buyer or trader, i.e. Shell and BP) [59, p. 5].

Non time-chartering accounted for nearly 30% of all delivery contracts in 2017, almost doubling its share within a decade, and close to 370 spot fixtures were made during the same year, which represents a 36% YOY increase [1, pp. 15 & 40]. Those numbers highlight, that the LNG spot market is highly liquid, and its importance keeps growing.

4.4.1 Seasonal differences

The following figure shows the high price sensitivity of spot charter rates for steam and DFDE/TFDE-driven vessels. As can be observed for the modern, fuel-efficient DFDE/TFDE carriers (yellow line), spot charter rates ranged between 30.000 USD/d in summer 2015 and 160.000 USD/d in winter 2012. Steam carriers (green line) can be spot-chartered at reduced rates, as they are not so demanded because of higher operating costs. On the contrary, leasing rates are even higher for vessels using the newest ME-GI or XDF propulsion technologies.

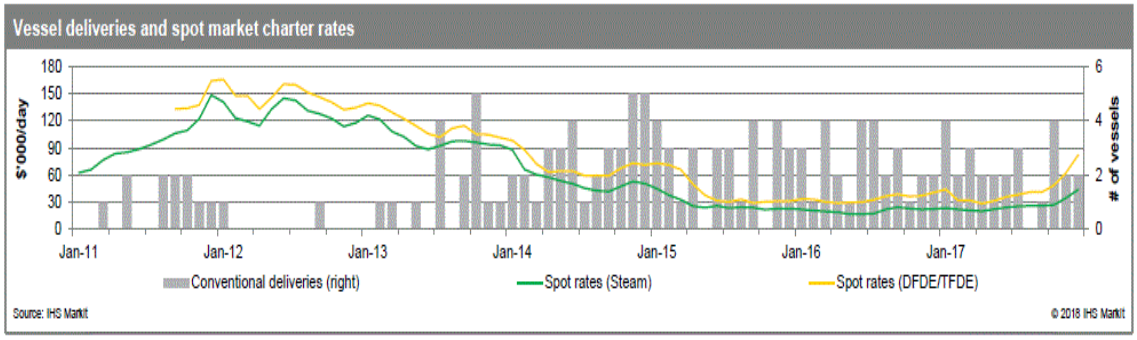


Figure 27 Spot charter rates for DFDE and steam driven vessels between Jan. 2011 and Dec. 2018 [59, p. 3].

Current numbers for November 2018 show, that in the Asia-Pacific basin day rates hit an all-time high of 190.000 USD/d, with an average of 183.000 USD/d for the whole month [60].

Two factors that affect charter rates are seasonal demand and the current stock of vessels. First effect could be observed during winter 2017/18 when China´s demand for gas (coal-to-gas switching due to clean air policy) led to a high number of spot cargos and charter rates skyrocketed. Apart from the seasonal demand, the number of available transport capacities is a crucial element that defines higher or lower charter costs. Construction of new liquefaction plants should go hand in hand with expansion of the vessel fleet to remain charter rates at "acceptable" levels.

With growing importance for international LNG trade, the impact of different time-charter rates will be part of the analysis of shipping costs in chapter 7. With time-charter rates always being lower that spot-charter rates, calculations will be done for a spread between 60.000 and 150.000 USD/d.

4.4.2 Leasing vs. buying

In a paper for the International Journal of Coastal & Offshore Engineering [Kamalinejad et al., 61] investigated the cashflow of shifting from charter transportation to LNG tanker purchase. Although their calculations were made on behalf of the Iranian gas industry, they are purely hypothetical and can serve basically for any LNG producer.

They write: "*The owner of a ship of between 135,000 m3 and 145,000 m3, costing $200 to $220 million*[32] *is estimated to require a payment of between $45,000/day and $55,000/day to cover the capital cost of the vessel (interest payments, repayment of capital, and return on the equity part of the total capital cost), with the actual rate depending on such factors as interest rates, the share of the investment in the ship covered by loans, and the period over which the cost of the ship is amortized. Adding the $9,000/day to $16,000/day needed to cover fixed operating costs, gives a total charter rate of between $54,000/day and $71,000/day.*"

Among their assumptions, and surely not true for every case, this statement gives an interesting insight about the margin vessel owners achieve by leasing their carrier(s).

[32] These numbers exceed the numbers from chapter 1.6 by around 400 USD/cm because construction costs in 2014/15 were higher than in 2017.

5 Routes

Shipping routes from the USA to countries in Asia-Pacific and the Middle East, as those named before in chapter 3, can take a westward or an eastward direction. With main liquefaction capacity located in Louisiana and Texas, Cheniere operated Sabine Pass liquefaction plant (Louisiana) shall be taken exemplar for volumes leaving the USA from this region. On the other side, Dominion´s operated Cove Point plant will represent gas that is shipped from Maryland, located at the US east coast. Both plants are the only ones in commercial operation during this thesis´ elaboration. The following map shows the position of both sites:

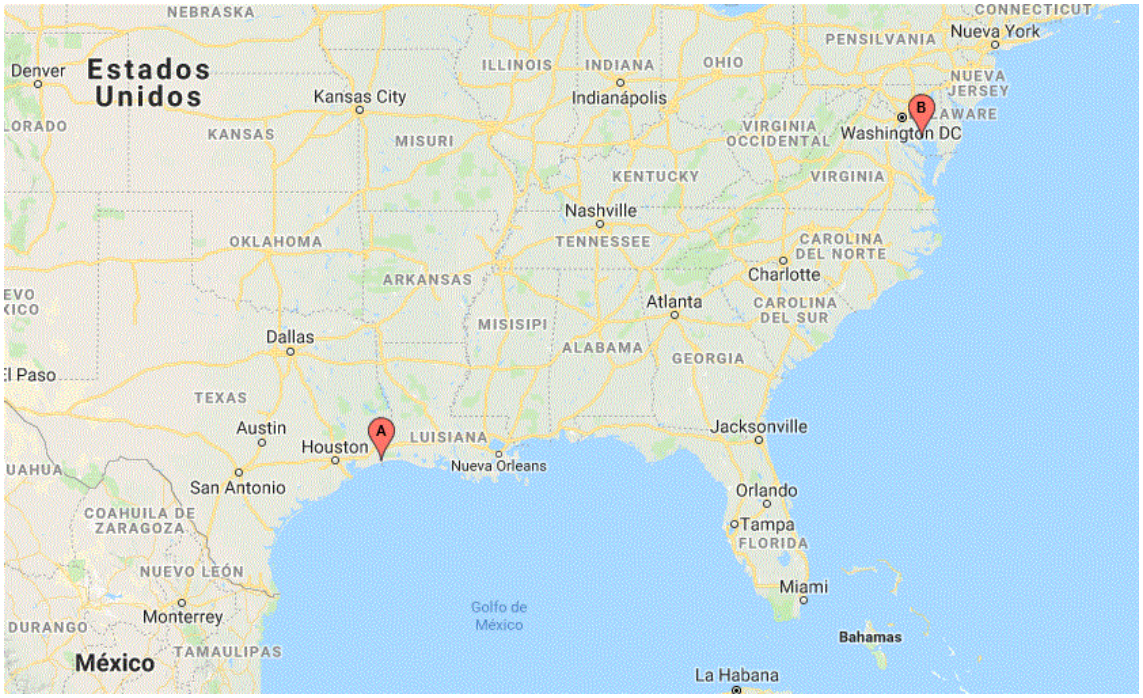


Figure 28 Locations of US-based liquefaction terminals Sabine Pass (A) and Cove Point (B).[33]

As receiving countries were chosen the locations given in the following table, as they cover a broad range of regions and possible routes. Some already receive US gas, others might be prospect candidates, and even others still are constructing regasification capacities. Essentially, they stand representative for Asian and Arab markets and thus are basis for further calculations.

The sites are listed according their country (condition 1) and within the country according their longitude (condition 2), beginning with Japan as the country furthest eastwards from Greenwich meridian, London. Nameplate regasification capacity is given as a reference to compare between import terminals (whole facility, not single trains).

[33] Created with https://de.batchgeo.com/ (Jan. 2019)

Table 11 List of regasification terminals.

Regasification terminal	Indication on maps	Longitude from Greenwich (east)	Status	Nameplate capacity (MTPA) acc. to [1]
Japan, Ishikari	A (first map)	141°17'32.1"	existing	1,4
Japan, Tobata	B	130°51'07.1"	existing	6,8
South Korea, Incheon	C	126°36'28.0"	existing	43,3
Philippines, Pagbilao FSRU	D	121°45'29.7"	under construction	3,0
China, Dalian (north of Peking, close to N. Korea)	E	121°39'15.9"	existing	6,0
China, Shanghai	F	121°37'23.4"	existing	3,0
China, Shandong, Qingdao (betw. Peking and Shanghai)	G	120°14'36.8"	existing	3,0
China, Fujian, Putian (on a level with Taiwan)	H	119°09'25.6"	existing	5,0
China, Beihai	I	109°02'34.1"	existing	3,0
Taiwan, Yong an	J	120°12'03.6"	existing	9,5
Indonesia, Nusantara (Cilegon) FSRU	A (second map)	105°56'14.6"	existing	3,8
Indonesia, Arun	B	97°05'56.3"	existing	3,0
Singapore, Jurong Island	C	103°43'53.7"	existing	11,0
Thailand, Map Ta Phut	D	101°09'16.3"	existing	10,0
Bangladesh, Moheshkhali FSRU	E	91°50'23.5"	under construction	3,8
India, Ennore / Chennai	F	80°18'09.3"	under construction	5,0
India, Kochi	G	76°13'40.4"	existing	5,0
India, Dahej	H	72°30'34.7"	existing	15,0
Pakistan, Port Qasim (Karachi) FSRU	I	67°18'40.1"	existing	5,7
Kuwait, Mina Al-Ahmadi	J	48°10'23.4"	existing	5,8

The 20 chosen receiving terminals are showed on the following two maps[34]:

Figure 29 Locations of 10 regasification terminals in Japan, South Korea, Philippines, China and Taiwan.

Figure 30 Locations of 10 regasification terminals in Indonesia, Singapore, Thailand, Bangladesh, India, Pakistan and Kuwait.

[34] Created with https://de.batchgeo.com/ (Jan. 2019)

There shall be considered four routing options for marine traffic from the US to Asia: Going westwards using the Panama Canal or Cape Horn, or shipping eastwards crossing the Suez Canal or Cape of Good Hope. Other routes, like the Northern Sea Route (NSR) or passing north of Canada are not considered because they do not represent standard shipping routes and are not shippable all year long or only under extraordinary conditions using vessels of the Arctic ice-class.

5.1 Westward routes

Westward routes include either the usage of the Panama Canal or shipping around Cape Horn, which would mean to go all around southern Argentina and Chile and crossing the Pacific Ocean from southeast to northwest to reach Asian gas markets.

5.1.1 The Panama Canal

Most information in this chapter was taken from [Rodrigue, 62, and 63]. Further references are indicated separately.

Panama´s location has been for strategic interest for a long time, as it represents the shortest land bridge connection between the Atlantic and the Pacific Ocean, and because it is situated relatively central between North and South America. The canal´s construction was driven by US-American interests of creating a shortcut to transport minerals (mainly gold) from California to the hot spots of demand at the east coast, and, as an emerging superpower controlling both the Atlantic and the Pacific Ocean, to permit the transfer of military capacities. First, ships took the Cape Horn or Magellan passage, sailing around southern Chile and Argentina. Considering also Nicaragua and even Mexico, finally Panama was chosen to receive one of an outstanding masterpiece of civil engineering projects in modern history. In 1903 construction began and ended successfully in 1914. During the first decades the canal was controlled by the Americans. It was in 1979 when the canal´s operation and maintenance was entrusted to the State of Panama. Until the end of 1999 both countries administrated the canal, when it was finally transferred to the Panama Canal Authority (PCA) which now is responsible for operation, maintenance and financial issues (tolls).

The canal reduces the journey from San Francisco to New York from some 11.300 nm (21.000 km) to around 4.300 nm (8.000 km). That´s a reduction of 62%, compared to the larger passage around South America.

The Panama Canal needs locks to elevate vessels to the level of Lake Gatún. This means to overcome 59 meters at the Atlantic side (northern entry) and 63 meters at the Pacific side (southern entry) by using locks.

Between 2009 and 2016 the canal received its last expansion works. They included the build-up of new locks, which were added to the existing capacities. Old locks can be passed by vessels called “Panamax class”, although practically every conventional LNG vessel already exceeds this limit because they use to be wider than 32,3 m (compare to chapter 4.1.1). New locks can handle vessels called “NeoPanamax class”, which means the inclusion of any sized LNG vessel, but not the Q-class. The expansion was an answer to growing traffic and bigger ship sizes. Transit in number and in shipped volumes have been rising since its completion in 2016. This resulted in higher income due to transit fees.

The following table shows YOY-changes for total number of transits and LNG tankers:

Table 12 Panama Canal transit statistics [64].

PCA Fiscal year[35]	Total no. of transits	YOY-change	No. of LNG vessels (bidirectional)	YOY-change
2016	13.114	basis	-	-
2017	13.548	+3,3%	163	basis
2018	13.795	+1,8%	290	+78%

In the yearly census for fiscal years (FY) 2017 and 2018 shipping segments were analyzed: LNG vessel traffic was on last position in FY 2017 and on position number nine out of eleven in FY 2018.
With a total of 290 transits in FY 2018 LNG vessels represented only 2,4% of all segment movements. This could also be expressed as one LNG vessel every 30,2 hours or 5,5 vessels a week.
In total, number of laden LNG vessels increased 78% YOY (from 163 to 290) between fiscal years 2017 and 2018 (October 2016 until September 2018). This represents the increasing importance of LNG traffic to the canal.

5.1.1.1 Tariffs

In principle, every ship that wants to cross Panama must pay a canal fee to the Panama Canal Authority (PCA). This fee serves several purposes: A part of it is utilized to repay for the construction of the canal or is saved for future projects and unforeseen repairs. The authority not only manages operation of the canal itself (locks, tug boats, mooring) but is also responsible for issues like water management, water traffic safety, reliability and accessibility of adjacent ports, infrastructure (operation of railway and pipeline), sale of fuel and electricity to the ships, telecommunication infrastructure, environmental protection of canal-affected areas, payment of employees and so on. A part of the income is also redirected to social projects and education. In general, the canal creates employment and adds positive value to national income by taxing all its related businesses.

Tariffs are structured according type of vessel: Container ships, dry bulk carriers, tankers, vehicle carriers, passenger ships, and so on. LNG vessels are also a separate category. Every category might be taxed differently, for example using the ships deadweight tonnes (DWT) for dry bulk carriers or according the “Panama Canal Universal Tonnage Measurement System” called CP/SUAB in Spanish (“Canal de Panamá – Sistema Universal de Arqueo de Buques”) for tankers. There also might exist differences if the old or the new locks are used.

Prices were adjusted in the course of the last expansion and entered into force as from 1st of October 2017. They slightly raised for LNG carriers (+4,2%) [65]. Adjusted tariffs try to reflect change in demand, level of utilization and productivity of new locks (“NeoPanamax”), but they also are an instrument to maintain the passage´s competitiveness to alternative routes. For LNG vessels calculation is simple, as it only depends on their storage volume.

[35] The Panamanian fiscal year starts October 1st.

5.1.1.2 Tariff structure for LNG vessels

Canal fee for LNG vessels has a four-level structure that is related to the vessel´s containment capacity: First 60.000 cm, next 30.000 cm, next 30.000 cm and the rest. Furthermore, it depends on the vessel´s cargo status: Full (laden) or empty (ballast). To remain the ship´s tanks cool, usually a small rest of LNG always remains inside. For vessels carrying less than 10% of its storage volume (for cooling reasons) the ballast tariff is applied. A special rebate is granted for vessels returning ballast within 60 days to the last lock they passed. This could be interesting for US-Asia deliveries investigated in this thesis. As in Panama historically the US-Dollar has been an accepted mean of payment (in co-existence with the Panamanian Balboa), tariff is set in USD/cm.

The next table resumes the tariff structure for LNG vessels (valid from 1st of October 2017):

Table 13 Tariff structure Panama Canal.

	Laden	**Ballast**	**Ballast (fast return)**
First 60.000 cm	2,88 USD/cm	2,56 USD/cm	2,30 USD/cm
Next 30.000 cm	2,47 USD/cm	2,16 USD/cm	2,01 USD/cm
Next 30.000 cm	2,38 USD/cm	2,07 USD/cm	1,84 USD/cm
Rest (> 120.000 cm)	2,25 USD/cm	1,97 USD/cm	1,73 USD/cm

Example: Laden carrier with 175.000 cm storage capacity.
60.000 cm x 2,88 USD/cm + 30.000 cm x 2,47 USD/cm + 30.000 cm x 2,38 USD + (175.000 cm – 120.000 cm) x 2,25 USD/cm = 442.050 USD.
This would result in 442.050 USD + 388.850 USD = 830.900 USD for a "normal" round-trip or 442.050 USD + 348.650 USD = 790.700 USD for a "fast" round-trip (return to the last lock passed within 60 days).

An overview of each applicable tariff, according to the category of the ship, can be found on the websites of the PCA, as well as an online calculator for canal fees.[36]

5.1.2 Cape Horn

Cape Horn, in the context of routing, shall be regarded same as the Strait of Magellan, as both are located relatively close to each other in southern Chilean waters, linking the Atlantic and the Pacific Ocean. Cape Horn is the most southern point of South America and was discovered to be a passage by chance in the 16th century. Then it was used, together with the already known Strait of Magellan, for commercial trade between Europe and Australia during the 17th and until the beginning of the 20th century. When the Panama Canal opened in 1914, trade around South America dropped sharply. Nowadays modern freighters are not seen frequently, but the Cape remains a destination for sport sailing challenges and yachting. Weather is said to be extremely windy, with large waves, strong currents and occasionally icebergs.
Whenever possible, the Strait of Magellan is preferred for commercial shipping, but has also lost in importance since the Panama Canal opened. Only few LNG shippings have been made, for example

[36] https://micanaldepanama.com/wp-content/uploads/2017/09/1010-0000.pdf and https://peajes.panama-canal.com/wclng.aspx (both Jan. 2019)

from Peru to Europe. But the Strait is then an alternative, when congestions at the Panama Canal are expected. It is called after the Portuguese explorer Ferdinand Magellan, who discovered the passage in 1520. It is approximately 600 km long and its width ranges between 3 to 35 km. Due to this fact and because of its inhospitable climate, navigation is difficult.
Even if transit for both Cape Horn and the Strait of Magellan is free of charge compared to the Panama Canal, and modern navigation and communication systems could handle the harsh conditions, their importance for international freight shipping is negligible. The Panama Canal provides a safer alternative, that shortens the distance for most of the routes.

The following picture helps to localize Cape Horn and the Strait of Magellan:

Figure 31 Cape Horn and Strait of Magellan.[37]

5.2 Eastward routes

Within the eastward routes can be chosen between usage of the Suez Canal or the passage around Cape of Good Hope, that means a longer journey passing the extreme south of the African continent to serve Middle or Far East LNG buyers.

5.2.1 The Suez Canal

Information in this chapter is mainly based on [Rodrigue, 62]. Other references are always indicated.

The Suez Canal represents, together with the Panama Canal, one of the most significant, artificial maritime shortcuts. It connects the Mediterranean Sea with the Red Sea and separates the Sinai Peninsula from Egypt´s mainland. As both waters have the same water level and country is flat, locks are not needed. With a length of about 190 km it is the longest artificial waterway without locks in the world.

[37] Copyright by Google Maps.

When it was opened in 1869 it reduced a journey from London to the southern point of India by about 3.240 nm (6.000 km) by avoiding the longer journey all around the African continent. During its history it was first under British authority between 1874 and 1956. Then the canal was nationalized by Egypt. Political tensions between Israel and Egypt in the 1950s and 1960s led to its closure for maritime transport from 1967 until 1975, with massive impacts on international transport, as ships were forces to take the longer passage around Cape of Good Hope. Today the Suez Canal Authority (SCA) is responsible for operation and maintenance and handles financial issues (tolls).

As like other canals, it was widened and dredged various times during its existence. Last improvements were finished in 2015 within only one year of construction work, now allowing northbound and southbound convoys of ships to pass simultaneously within a length of 113 km, which increases capacity and reduces waiting time to not more than three hours. Therefore, the existing canal was deepened along 37 km to a uniform depth of now 66 ft (24 m) and an additional canal of a length of 35 km was created. Expansion projects are a response to shipping demand. It is estimated that the daily average of transiting vessels will increase from some 50 ships nowadays to close to 100 in 2023, thus doubling vessel numbers.
As mentioned in chapter 4.1.1 the Suez Canal has a trapezoidal shape, so maximum ship size depends on total weight (deadweight plus load). In theory, ships with 240.000 DWT represent the allowed limit. Indeed, it is not unusual to reload part of the load to the parallel constructed rail line or pipeline to reduce maximum draft during passage.
On the SCA´s website can be found the "Traffic Statistics Annual Report 2017" which reveals some interesting statistics [66]. This report does *not* refer to fiscal years, but calendar years.

The following table shows YOY-changes for total number of transits and LNG traffic:

Table 14 Suez Canal transit statistics [66].

Year	Total no. of transits	YOY-change	No. of LNG vessels (bidirectional)	YOY-change
2015	17.438	basis	670	basis
2016	16.833	-3,5%	575	-14,2%
2017	17.550	+4,3%	567	-1,4%

Compared to the results of the Panama Canal, these numbers are essentially higher and represent the huge importance of the Suez Canal for international transport. Among shipping segments, LNG vessels were listed on position number six in both 2016 and 2017. This underlines that other sectors, but not shipping of LNG, are economically more important to the Suez Canal. In fact, LNG trade has reduced in number of vessels within the last three years (2015 to 2017).
The lion´s share of LNG trade is being handled within the Asia-Pacific basin: Supply comes from Qatar, Australia and Malaysia and goes to Japan, China and South Korea with no need to cross the Suez Canal. LNG vessels that cross the canal are directed mostly to other destinations like Jordan, Egypt, India or Kuwait when they come from the Mediterranean Sea or Italy, the United Kingdom, Spain or France, closely followed by Turkey, with Qatar by far sending the highest volumes northbound (99%).

5.2.1.1 Tariffs

As it is the case for Panama, the SCA by offering generates income through its canal-related services, which is then reinvested in maintenance or future expansion projects. The duties of this canal authority are in principle the same as for their Panamanian counterpart and imposing fees on transit are a world-wide accepted, usual means to guarantee a safe passage for their clients. Thereby, the SCA creates opportunities for local population and contributes positively to the national income.

Tariffs are set depending on vessel type, which is a similar method used by the Panama Canal Authority (PCA). This tries to consider the earning capacity of the transiting vessel, given market conditions and developments and compares costs of the passage to alternative routes. As a result, tankers, dry bulk carriers, container ships, vehicle carriers, passenger ships and other categories are subjects to different rates of fee, which are staggered into a seven-level scheme. The toll table can be found online.[38]

Toll calculation for the Suez Canal is more complex than for the Panama Canal, as more input data is required. In the following, Suez Canal Gross and Net Tonnage (SCGT and SCNT) and Special Drawing Rights (SDR) will be explained, as these are factors that are required for toll calculation:
SCGT and SCNT are historically evolved shipping measurement units, which have been particularly applied for Suez Canal transit. As anticipated in an earlier chapter GT and NT are important factors, when it comes to canal and berthing fees. In that chapter was also concluded, that NT ≈ 0,67 * GT as an approximation for the non-small-scale LNG fleet and with GT being a known dimension.
According to [Stopford, 67, p. 171] "*The SCNT of a vessel is calculated either by the classification society or by an official trade organization, which issues a Suez Canal Special Tonnage Certificate. For vessels wishing to transit the canal that do not have a certificate, the SCNT is provisionally calculated by adding together the gross and the net tonnage, dividing by two and adding ten per cent*".

This results in

*SCNT = (GT + NT) / 2 * 1,1*

SCGT can then be calculated by the rule of three:

*SCGT = GT * SCNT / NT*

The average LNG vessel characteristics given in table 10 in chapter 4.1.3 can then be completed:

Table 15 Average LNG vessel SCNT and SCGT.

CAP (cm)	GT	NT	SCNT	SCGT
158.700	110.500	74.000	101.500	151.400

[38] https://www.suezcanal.gov.eg/English/Tolls/Pages/TollsTable.aspx (Jan. 2019)

Another required data is the Special Drawing Right (SDR) because canal fee is expressed in SDR/SCNT and it is more convenient to pass it to USD/SCNT. SDR is an international reserve asset, created by the International Monetary Fund (IMF) in 1969 to supplement its member countries´ official reserves. It is based on five currencies: The USD, the Euro, the Chinese Renminbi, the Japanese Yen and the British Sterling Pound. Closer explanation can be found on the websites of the IMF.[39] A factor of 1,40 USD/SDR is a good approximation. Up-to-date exchange rates can be obtained online.[40]

The below given chart shows the currency fluctuation of XDR to USD within the last five years:

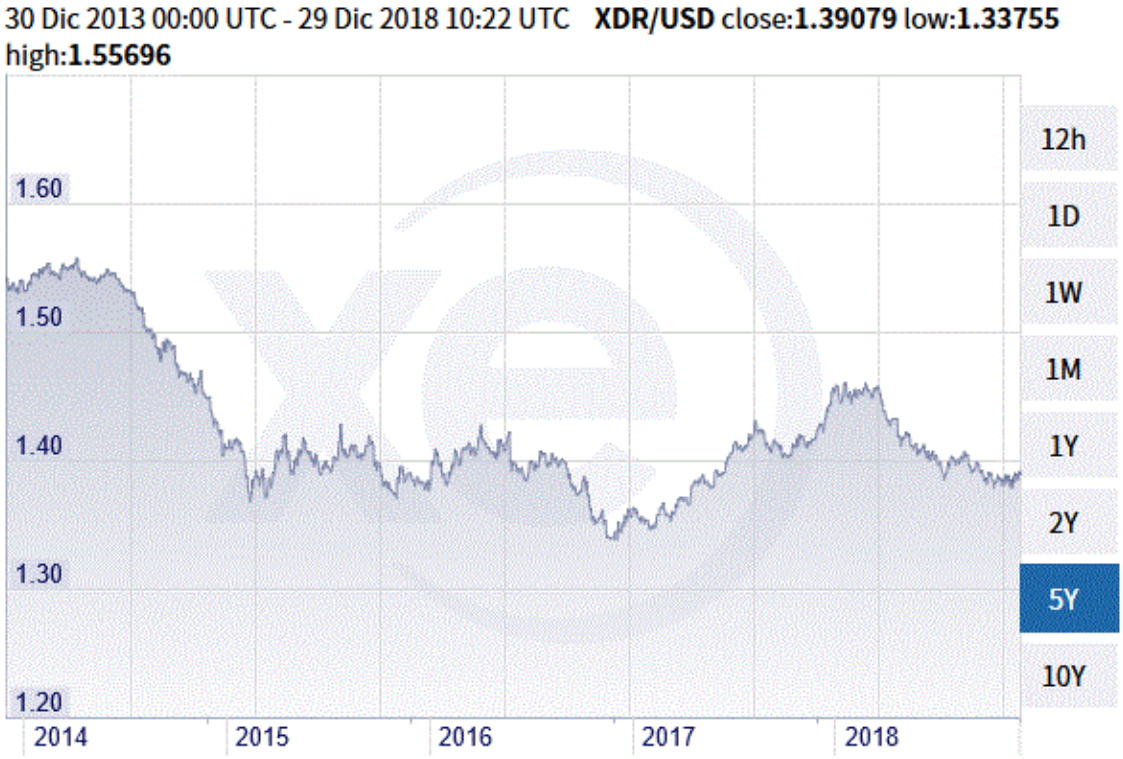


Figure 32 XDR to USD conversion within the last 5 years.[41]

Knowing all these parameters, canal fees for virtually any type of vessel can be calculated.[42]

[39] https://www.imf.org/en/About/Factsheets/Sheets/2016/08/01/14/51/Special-Drawing-Right-SDR (Jan. 2019)
[40] https://www.xe.com/es/currencyconverter/convert/?Amount=1&From=XDR&To=USD (Jan. 2019)
[41] Copyright by XE: **Website** (Jan. 2019)
[42] Official SCA toll calculator: **Website** (Jan. 2019)

5.2.1.2 Tariff structure for LNG vessels

As of 1st of May 2018 tariffs for LNG vessels were determined in the seven-level structure as represented in the following table:

Table 16 Tariff structure Suez Canal.

	Laden	**Ballast**
First 5.000 SCNT	7,88 SDR/SCNT	6,70 SDR/SCNT
Next 5.000 SCNT	6,13 SDR/SCNT	5,21 SDR/SCNT
Next 10.000 SCNT	5,30 SDR/SCNT	4,51 SDR/SCNT
Next 20.000 SCNT	4,10 SDR/SCNT	3,49 SDR/SCNT
Next 30.000 SCNT	3,80 SDR/SCNT	3,23 SDR/SCNT
Next 50.000 SCNT	3,63 SDR/SCNT	3,09 SDR/SCNT
Rest (> 120.000 SCNT)	3,53 SDR/SCNT	3,00 SDR/SCNT

Trying to give an example (comparable to that of the Panama Canal), now it is not enough to define a laden carrier by its storage capacity. More parameters need to be known to define SCNT. Storage capacity can result in a wide range of gross tonnage and thereby (Suez Canal) net tonnage. This was described in chapter 4.1.3, where both dimensions were related to each other. Therefore, the simplified formula to calculate GT from capacity shall be used:

*GT = 0,5*CAP + 30.000*

For a 175.000 cm vessel this would result in a gross tonnage of 117.500. With the factor 0,67 this leads to a net tonnage of 78.725 and a SCNT of 107.924 (GT, NT, SCNT and SCGT without units). Rounding up to 108.000 SCNT the ship would have to pay:

[5.000 SCNT x 7,88 SDR/SCNT + 5.000 SCNT x 6,13 SDR/SCNT + 10.000 SCNT x 5,30 SDR/SCNT + 20.000 SCNT x 4,10 SDR/SCNT + 30.000 SCNT x 3,80 SDR/SCNT + (108.000 SCNT – 70.000 SCNT) x 3,63 SDR/SCNT] x 1,40 USD/SDR **≈ 639.800 USD in laden condition and ≈ 544.300 USD in ballast condition, thus resulting in 1.184.100 USD for a round-trip**.

Interestingly, the SCA grants a rebate of 25% to any LNG carrier, thus reducing the fee to 888.075 USD. This number exceeds the Panamanian examples (normal / fast return) by 57.175 / 97.375 USD or 6,9 / 12,3 %.

In chapter 5.3 it will be shown how the authorities try to attract more LNG vessels by different policies.

5.2.2 Cape of Good Hope

As Cape Horn for the Panama Canal, Cape of Good Hope is the equivalent free-of-charge, but much longer alternative for the Suez Canal passage. It is *not* the most southern point of Africa, but very close to it (it is Cape Agulhas, some 200 km southeast). It became important to global trade in the 15th century, when the Dutch established a commonly used route from Europe to India and Far East. In this region the Atlantic and the Indian Ocean meet, and their cold and warm currents mix, respectively. Contrary to Cape Horn it is not feared of its inhospitable conditions and frequently used by marine traffic, although the Suez Canal, as far as applicable, surely is the safer option for most of the traffic. Nevertheless, LNG shippings from Angola or Nigeria usually use the Cape route to deliver liquefied gas to Asian markets.

The following picture gives an orientation about the ubication of the Cape:

Figure 33 Cape of Good Hope.[43]

[43] Copyright by Google Maps.

5.3 Competition between the Canals

To attract more vessels, especially within the LNG segment, the canals´ authorities use different policies. It was described above, that LNG vessels recently were on ninth place of vessel types using the Panama Canal and on sixth place with respect to the Suez Canal. But after their recent expansions both canals have capacities to handle more cargo. So, for some routes, they are in direct competition to each other some routes. Advantage of the Panama Canal is its proximity to the USA as an emerging LNG supplier. Distance from Sabine Pass to Colón (northern lock of the Panama Canal) is 1.471 nm and from Cove Point 1.774 nm. Respective distances to Port Said at the northern entry of the Suez Canal are 6.603 nm and 5.268 nm.

As mentioned before, 5,5 times a week an LNG tanker passed the canal according last census [64]. This was due to PCA self-imposed daylight and encounter restrictions after inauguration of the new locks in 2016. A higher demand for LNG shipping slots led the PCA to change its policy to elevate LNG carrier number: Since the 1st of October 2018 two vessels are allowed to use the canal simultaneously in two different directions (southbound and northbound) within 24 hours [68]. So, in theory, four LNG tankers can cross the canal daily, rising, but also limiting, transit numbers to 28 a week or 1.460 within a year.

The SCA, conscious of rising LNG export volumes from the USA, takes a different approach: Apart from the a priori 25% rebate for any LNG carrier, independent from its origin and destination, the 1st of October 2017 have been applied special rebates for LNG vessels operating between the American south coast west of Miami (thus excluding the Cove Point facility at the US east coast) and the Arabian Gulf zone, India and Far East ports [69]. These offers are only granted if the ship does not call any other port in between for commercial reasons (for example reloading of LNG) and cannot be combined with other rebates (like the a priori 25%). With beginning of October 2018, the tariffs were slightly adjusted and can be resumed as follows:

Table 17 Discounts Suez Canal.

Route	Discount
Standard discount for any LNG vessel	-25%
US-ports west of Miami to destinations west of Kochi, India	-30%
US-ports west of Miami to destinations between Kochi and Singapore	-40%
US-ports west of Miami to destinations east of Singapore	-65%

Discount is applicable on the basic canal due, not on additional canal costs like extra pilots or escorting tugs.

Future developments will show to what extend both policies are functional or need to be adjusted. For now, these seem to be appropriate means to boost LNG transits, guarantee free flow of future gas volumes and ensuring income to the responsible authorities.

5.4 Distances to destinations

Now that the four routing options are known, distances between origin and destination, that means liquefaction and regasification plant, can be calculated. For that purpose, a free online tool named "Sea-Distances"[44] is used. This website allows to calculate not only the distance, but also the time for a maritime journey, if vessel speed is entered.

Major drawback of this tool is, that it does not *show* the route, just the outcome. The user does not know how calculation is exactly done and has not the opportunity to modify the route (like it can be easily done using Google Maps for road traffic navigation). Surely not considered are sea currents, seasonal patterns (stormier sea in winter), delay using the Panamanian locks or slower speed in the Suez Canal.

"Sea-Distances" has more than 4.000 ports in its database. In the case a port was not found, the closest neighbor port was searched. Next standing, the cases are listed where the exact port could not be found. The deviation to the closest neighbor port was estimated using Google Maps.

- Japan, Ishikari: The website does not indicate Ishikari port correctly compared to Google Maps. The distance was assumed to be right.
- Philippines, Pagbilao FSRU: Port / FSRU not listed, probably because still under construction. Closest port is Batangas port, ca. 65 nm (120 km) western.
- Indonesia, Nusantara (Cilegon) FSRU: Port / FSRU not listed. Closest port found is Jakarta, ca. 59 nm (110 km) eastern.
- Indonesia, Arun: Port not listed. Closest port found is Pangkalan Susu, ca. 162 nm (300 km) south-eastern.
- Thailand, Map Ta Phut: Port not listed. Closest port found is Sattahip, ca. 11 nm (20 km) western.
- Bangladesh, Moheshkhali FRSU: Port / FSRU not listed, probably because still under construction. Closest port is Chittagong, ca. 49 nm (90 km) northern.
- India, Dahej: Port not listed. Closest port found is Mumbai, ca. 189 nm (350 km) southern.

As a resume of this chapter, two tables were created, showing the distances (in nautical miles and in kilometers, 1 nm = 1,852 km) from Sabine Pass and Cove Point to the destinations listed in chapter 5:

[44] https://sea-distances.org/ (Jan. 2019)

Table 18 Distances from Sabine Pass to each destination.

From Sabine Pass, Louisiana, USA	Westward Routes				Eastward Routes			
	Panama Canal		Cape Horn		Suez Canal		Cape of G. Hope	
	nm	km	nm	km	nm	km	nm	km
Japan, Ishikari	9960	18446	16795	31104	13724	25417	14922	27636
Japan, Tobata	9591	17763	17006	31495	14147	26200	15286	28310
South Korea, Incheon	9998	18516	17402	32229	14169	26241	15416	28550
Philippines, Pagbilao FSRU	10893	20174	16604	30751	12961	24004	14088	26091
China, Dalian	10137	18774	17537	32479	14236	26365	15478	28665
China, Shanghai	10081	18670	17248	31943	13854	25658	15098	27961
China, Shandong, Qingdao	10086	18679	17472	32358	14080	26076	15327	28386
China, Fujian, Putian	10454	19361	17093	31656	13270	24576	14517	26885
China, Beihai	10936	20253	17399	32223	12936	23957	14208	26313
Taiwan, Yong an	10459	19370	16935	31364	13238	24517	14485	26826
Indonesia, Nusantara (Cilegon) FSRU	12080	22372	16507	30571	11877	21996	12581	23300
Indonesia, Arun	12404	22972	17324	32084	11269	20870	12662	23450
Singapore, Jurong Island	12013	22248	16962	31414	11609	21500	13002	24080
Thailand, Map Ta Phut	12017	22255	17667	32719	12371	22911	13741	25448
Bangladesh, Moheshkhali FSRU	13522	25043	18405	34086	11342	21005	12936	23957
India, Ennore / Chennai	13591	25171	18102	33525	10640	19705	12234	22657
India, Kochi	13858	25665	18098	33517	9840	18224	11761	21781
India, Dahej	14440	26743	18680	34595	9649	17870	11998	22220
Pakistan, Port Qasim (Karachi) FSRU	14892	27580	19132	35432	9462	17524	12070	22354
Kuwait, Mina Al-Ahmadi	15830	29317	20063	37157	9889	18314	12548	23239

Table 19 Distances from Cove Point to each destination.

From Cove Point, Maryland, USA	Westward Routes				Eastward Routes			
	Panama Canal		Cape Horn		Suez Canal		Cape of G. Hope	
	nm	km	nm	km	nm	km	nm	km
Japan, Ishikari	10263	19007	16231	30060	12389	22944	14283	26452
Japan, Tobata	9894	18324	16442	30451	12812	23728	14747	27311
South Korea, Incheon	10301	19077	16838	31184	12834	23769	14777	27367
Philippines, Pagbilao FSRU	11196	20735	16040	29706	11626	21531	13449	24908
China, Dalian	10440	19335	16973	31434	12901	23893	14839	27482
China, Shanghai	10384	19231	16684	30899	12519	23185	14459	26778
China, Shandong, Qingdao	10389	19240	16908	31314	12745	23604	14688	27202
China, Fujian, Putian	10757	19922	16529	30612	11935	22104	13878	25702
China, Beihai	11239	20815	16835	31178	11601	21485	13569	25130
Taiwan, Yong an	10762	19931	16371	30319	11903	22044	13846	25643
Indonesia, Nusantara (Cilegon) FSRU	12383	22933	15943	29526	10542	19524	11942	22117
Indonesia, Arun	12707	23533	16760	31040	9934	18398	12023	22267
Singapore, Jurong Island	12316	22809	16398	30369	10274	19027	12363	22896
Thailand, Map Ta Phut	12320	22817	17103	31675	11036	20439	13102	24265
Bangladesh, Moheshkhali FSRU	13825	25604	17841	33042	10007	18533	12297	22774
India, Ennore / Chennai	13894	25732	17538	32480	9305	17233	11595	21474
India, Kochi	14161	26226	17534	32473	8505	15751	11122	20598
India, Dahej	14743	27304	18116	33551	8314	15398	11359	21037
Pakistan, Port Qasim (Karachi) FSRU	15195	28141	18568	34388	8127	15051	11431	21170
Kuwait, Mina Al-Ahmadi	16133	29878	19499	36112	8554	15842	11909	22055

The following two charts represent the distances in nautical miles given in the tables:

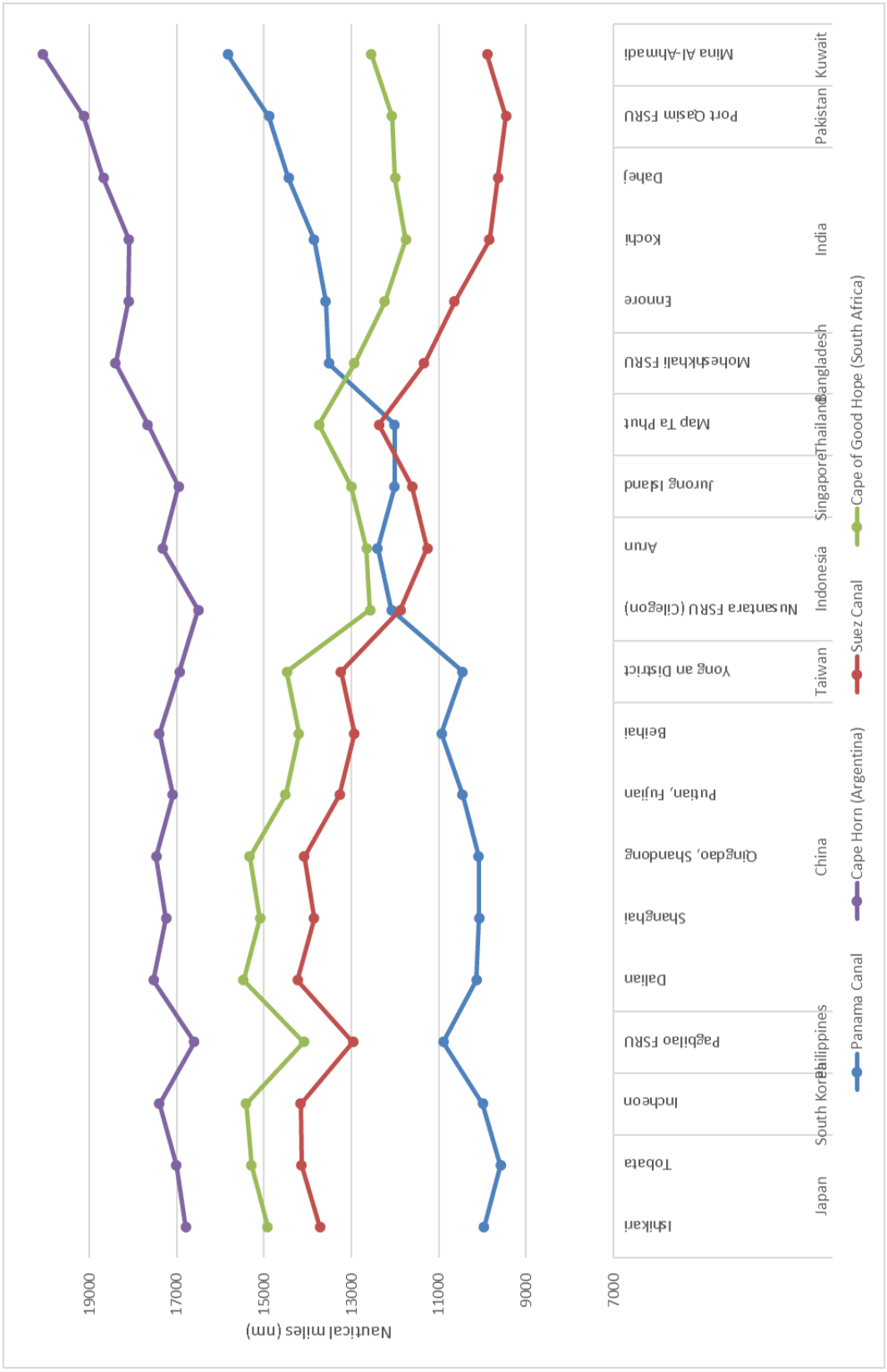


Figure 34 Distances (nm) from Sabine Pass, Louisiana.

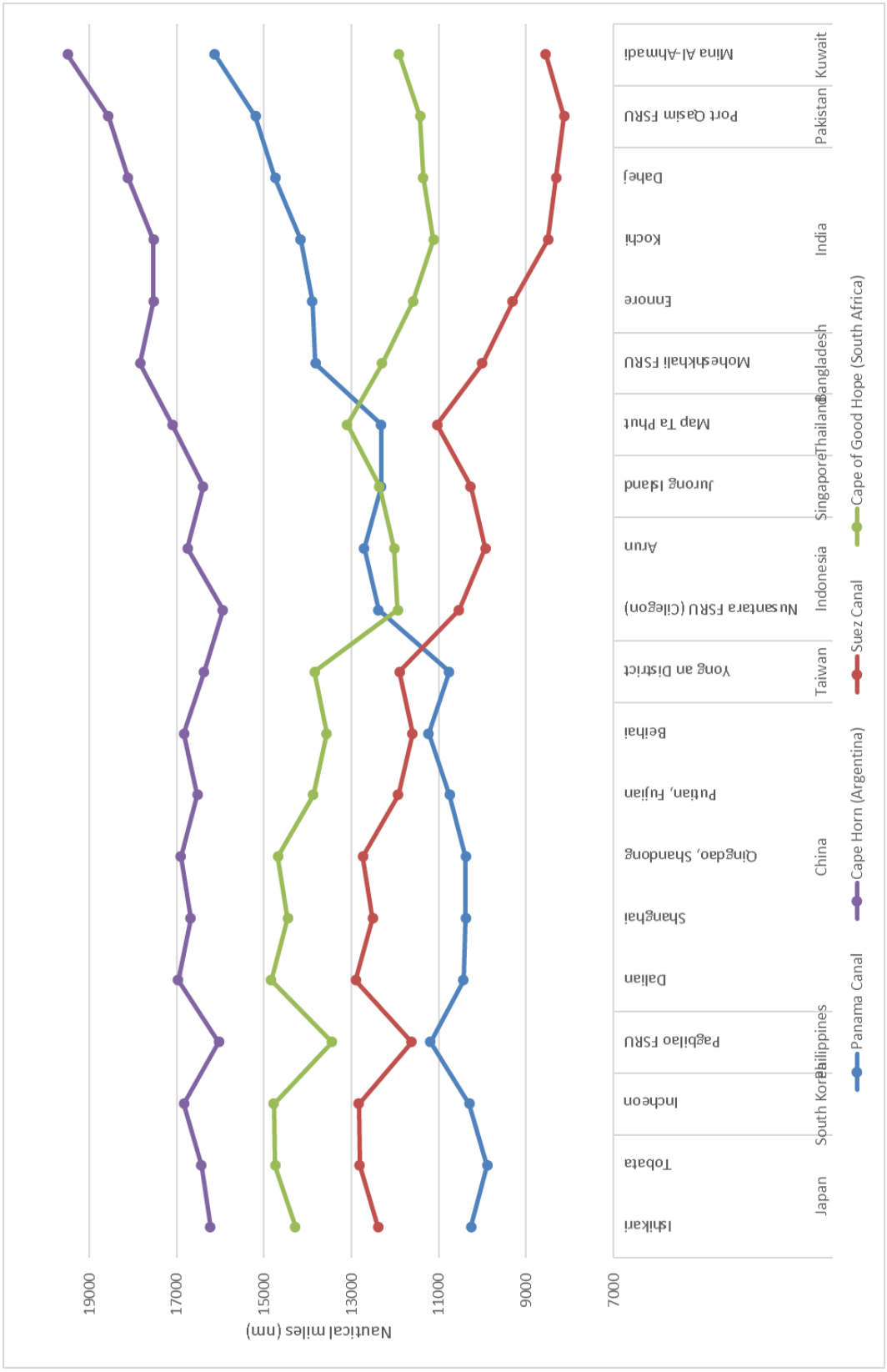


Figure 35 Distances (nm) from Cove Point, Maryland.

Destinations are listed from left to right according their eastward longitude from Greenwich meridian, beginning with the Japanese regasification plants and ending with the one in Kuwait.

First, it can be observed that the Cape Horn passage always represents the longest route. A change from Cape Horn to the Strait of Magellan would have been indifferent in this regard. The journey around South America is always be the largest, never competing with any other route. This results in being the Panama Canal the only option for westward routing in terms of shipping time, assumed that there are no congestions at the entry locks. All cost-related factors will be explained later.

Second, the trends of Cape of Good Hope and Suez Canal follow the same patterns and never cross each other, obviously being the journey around South Africa always the longer option. Trends become interesting when Panama Canal crosses Suez Canal and Cape of Good Hope. This gives a prediction of when taking one or another route to minimize travelling distance, time and costs (assuming a constant travel speed).

For vessels leaving Sabine Pass, Indonesia´s Nusantara FSRU is the point of equality, where it does virtually not matter to go westward using the Panama Canal or to go eastward using the Suez Canal. Also, Singapore´s Jurong Island and Thailand´s Map Ta Phut regasification plants are within an “equal range”, where distances from both US liquefaction sites are relatively close to each other.
For departures from Sabine Pass the split between the Panamanian route and shipping through the Suez Canal regarding Indonesia´s Arun facility can be explained by the sloped shape of Indonesia, being Arun located closer to the Suez Canal. In fact, this regasification plant could be reached within similar timeframes using the Panama Canal or shipping around Cape of Good Hope (point of equality). The Bangladeshi plant is where travelling distances for both routes finally change and going westward would always be the worse option.

In general, the patterns described are mostly the same for vessels leaving Cove Point. This liquefaction plant is located at the US east coast, close to Washington D.C., giving an advantage to the eastern routes (Suez Canal or Cape of Good Hope). Destinations in Japan, South Korea, the Philippines, China and Taiwan are closer to Cove Point going westwards. But among these, Philippines´ Pagbilao FSRU and China´s Beihai are very close to the Suez route. Then, between Taiwan and Indonesia comes a clear cut, giving advantage to both eastward routes. The only both exceptions are Singapore´s Jurong Island being an equal point for the Panamanian route or shipping around South Africa and Thailand´s Map Ta Phut, which again is closer going westward because of Thailand´s long, vertical shape discriminating the Cape route (but still giving advantage to the Suez route).

This chapter only highlighted *distances* from point A to point B. Normally, assuming constant travel speed, distance correlates with travel time and with travel costs, as it requires less fuel. Costs will be subject in later investigations.

5.5 Speed and travelling time

Travelling time from origin to destination is the quotient of distance by average cruising speed. In maritime navigation speed has been measured historically in knots (kt), being 1 knot equal to 1 nautical mile per hour (1 kt = 1 nm/h = 1,852 km/h).
Average cruising speed in this thesis is the entirety of operating or service speed and maneuvering speed. The operating or service speed is an essential part of the contract between manufacturer and buyer and constitutes safe maneuvering within conditions and circumstances in open water. Maneuvering speed is used within ports, canals or narrow passages with a higher probability of accidents.

According to a MAN factsheet [70], average cruising speed is a function of ship size in terms of capacity (cubic meters):

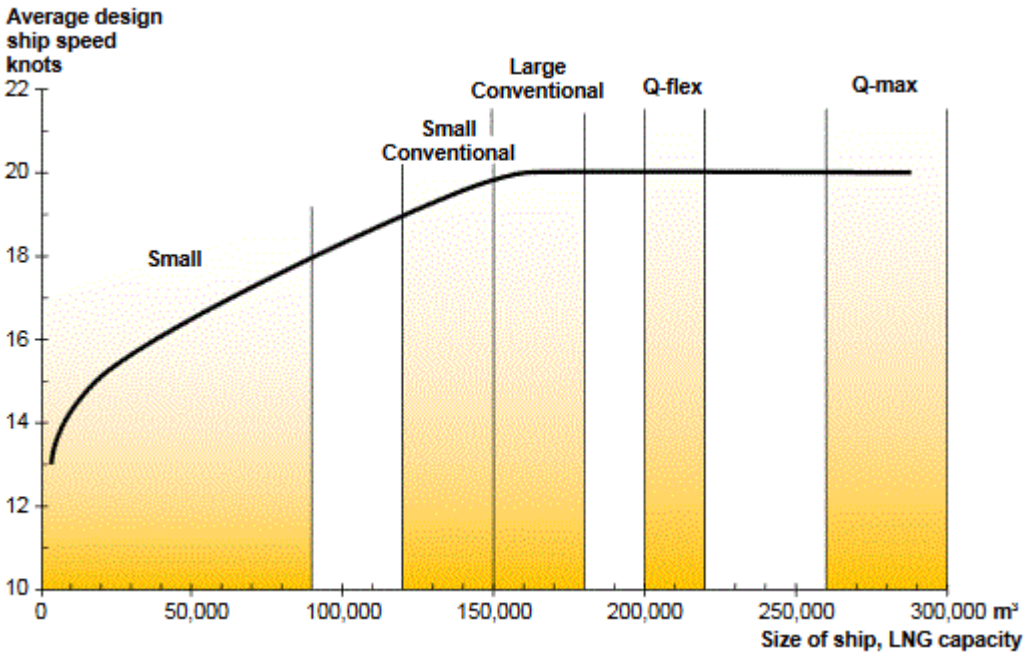


Figure 36 Average design ship speed of LNG carriers [70].

Speed is directly linked to propulsion, and thus to fuel consumption and emission of exhaust gases. In recent years speeds had been adjusted (slow steaming) mainly because of rising fuel prices and to comply with national and international emission restrictions (compare chapter 4.3.2).

For the purpose of this thesis, average shipping speed was defined to be 18 kt. This number represents an optimum between velocity and consumption of marine fuel. IHS Markit´s average of the current fleet is 19,1 kt [46], but it does not include maneuvering in ports or reduced speed in a canal. Furthermore, trend goes towards slower, fuel-saving speed.

For the routes considered in this thesis, the travelling times in days can be calculated by dividing the nautical miles given in the distance tables in the previous chapter by 18 kt and by 24 h.
From Sabine Pass the shortest journey would be to Port Qasim, Pakistan, via Suez Canal and take 21,9 days and the longest journey would be to Mina Al-Ahmadi, Kuwait, via Cape Horn and take 46,4 days. Shortest and longest travelling times from Cove Point would be to the same destinations using the same routes but could be achieved within 18,8 and 45,1 days, respectively.

5.6 Chokepoints or bottlenecks of maritime transport

Chokepoints, in a nautical sense, tend to be narrow passages making navigation difficult or forcing to reduce speed. Usually, they are strategic places, whose open access must be guaranteed to allow free flow of goods. Natural chokepoints for example are straits, like the Strait of Magellan or the Strait of Malacca, where ships are exposed to prevailing coasts, winds, currents, depth, reefs, ice and even political interests. On the contrary, canals might be called “artificial chokepoints”: Their waters are calm, but they suffer high traffic and it might happen that cargo weight needs to be reduced and transported partially by pipeline or train to lift maximum keel draft.

Both the Panama and the Suez Canal are known as chokepoints or bottlenecks of maritime transport, as a relatively high number of vessels tries to cross these canals in the same time frame. This can lead to undesirable congestion and results in waiting time, for example when a ship´s arriving was not announced in time to the responsible canal authority.

As a natural bottleneck, the Strait of Malacca might be of additional interest. It is located between the Indian Ocean and the South China Sea, partly belonging to Malaysia and Indonesia, with Singapore at its south-eastern end. According to [62, p. 38] ”*it measures about 800 km in length, has a width between 50 and 320 km (2,5 km at its narrowest point) and a minimal channel depth of 23 meters (about 70 feet). It represents the longest strait in the world used for international navigation and can be transited in about 20 hours*.”
For the routes discussed in this thesis, it would be crossed by ships from Sabine Pass delivering to Singapore´s Jurong Island and Thailand´s Map Ta Phut. Unclear is, if Indonesia´s Nusantara FSRU would be reached using the Strait or passing Indonesia´s southern coastline. Ships leaving Cove Point would use the Strait of Malacca for a variety of destinations: Potentially Philippines´ Pagbilao FSRU and China´s Beihai, and surely Singapore´s Jurong Island and Thailand´s Map Ta Phut. Again, for Indonesia´s Nusantara FSRU it remains unclear, if the strait would be used or not.

The Strait of Malacca handles the bulk of maritime transport between the Asia-Pacific region, Europe and Arabian countries: Around 25% of global shipping fleet and 30% of global petroleum trade [62]. This flow must remain stable for world economic reasons, but open access for ships is not self-evident. For example, the strait would require dredging at some point, but cost share has not been agreed between Indonesia, Malaysia and Singapore. Another example are political tensions in the Southern Chinese Sea. With proved oil and gas resources, groups of islands are claimed in whole or in part by different nations, over all by China. Hopefully access remains guaranteed for all participants to keep ongoing international freight distribution without taking detours.

6 Expected USA-Asia shipping costs

It is expected that shorter routes, that means less delivery time, correlate directly with lower shipping costs. Direct linking of distance and costs means that there will be a point “halfway” where it will be more beneficial to take this or that route, with special focus on both canals.

Furthermore, it is assumed that using the Cape Horn route will always be the worst choice, because of its long journey. Daily expenses for fuel (MFO and BOG) might exceed savings from canal-bound costs.

Deliveries from Sabine Pass might be cheaper for deliveries to Japan, South Korea, the Philippines, China, Taiwan and Thailand going westwards through the Panama Canal. For vessels starting from Cove Point, it might be the same pattern, except the delivery to Thailand. This can be observed in figures 34 and 35 in chapter 5.4.

For all other destinations, the Suez route might be slightly preferred but with a close run between the Suez Canal and Cape of Good Hope, especially for deliveries leaving Sabine Pass because distances to Egypt and South Africa are more similar than from Cove Point.

6.1 Influence of fuel and charter costs

While fixed expenses for route-bound journeys cannot be changed, three variables will have great impact in further calculations: Marine fuel oil (MFO) cost, gas price for liquefied natural gas and charter rate. The second affects the costs of evaporated gas, that is BOG used for propulsion. The latter is a daily expense that is set by the contract between deliverer and vessel loaner, respectively, if the shipper is the vessel owner, daily costs that reflect his payments to cover the capital costs of the tanker.

More important is the influence of MFO, as different propulsion types consume different quantities of MFO (chapter 4.3.1). In this thesis D/TFDE vessels are considered only, as they make up 32% of today’s fleet and at least 24% of the ordered carriers (chapter 4.3). Also, it is supposed that the natural BOG will be used for propulsion, with no BOG being reliquefied. With a more sophisticated propulsion technology, less MFO is needed, and with a bigger vessel size more BOG is created. Thus, net MFO consumption varies with propulsion system and ship size. For considerations within this thesis applies:

- Steam-powered vessels < 193.000 cm still have net MFO consumption, above not.
- **D/TFDE-powered vessels < 148.000 cm still have net MFO consumption, above not.**
- ME-GI/XDF-powered vessels < 113.000 cm still have net MFO consumption, above not.

This circumstance has an effect on later results: For a vessel size of 135.000 cm both gas price and MFO price have an influence, meanwhile for 175.000 cm tankers fuel costs are determined by the gas price only.

6.2 References from literature

Calculation of LNG shipping costs usually have been made by market players with own fleets and are not publicly available. Nevertheless, probably due to a growing interest of researchers and among decision-makers, some approaches were found and serve as a base for later comparison:

- Not only with respect to the spot shipping market, but also for long-term shipping contracts, calculation of shipping costs gets more and more important. Looking at the project economics of the Sabine Pass and Cove Point liquefaction plants, IHS Markit expects shipping costs between 2,17 USD/MMBtu for **Sabine Pass and** 2,24 USD/MMBtu for **Cove Point** for deliveries **to Incheon, South Korea via the Panama Canal** [71, p. 53 and 82, p. 34].
- In a paper for The Oxford Institute of Energy Studies [Rogers 2018, 55] highlights the fact, that there exists also niche market for spot cargoes without fixed destination. Brokers might be interested in selecting a destination that permits high profit. His results for December 2017 show that for DFDE-driven vessels the average shipping cost from the **US Gulf Coast to China (via Panama)** would be 1,93 USD/MMBtu. For the early 2020s with rising stock of DFDE vessels he estimates falling charter prices and delivery costs of 1,52 USD/MMBtu. Due to the fact, that many long-term shipping contracts are bound to the oil price, [Rogers 2018, 55] argues that "*the final investment decision (FID) of many of the next wave LNG projects may have to be taken on the assumption of volumes sold on spot, short or medium-term basis (…) in the market destination region, rather than on the basis of an oil-linked formula. (…) If price-sensitive LNG demand starts to diminish once the price is above 6 USD/MMBtu and more so above 8 USD/MMBtu, then this should be a warning sign to LNG project investors who require higher destination prices than these to break even*."
- Another example is given by [Ripple, 73]. Being a professor of Energy Business and Finance at the University of Tulsa, USA, he investigates the economic viability of US cargos. He believes that only small spot volumes of US-LNG will be traded profitably to Asia and Far East for charter rates below 65.000 USD/d. Regardless the ongoing low HH gas price delivered costs are remarkably close to what Asian buyers are willing to pay. LNG spot prices for Japan have fallen from 18,30 USD/MMBtu in April 2014 to 6,80 USD/MMBtu in March 2016, leaving virtually no benefit margin and narrowing the window of profitable opportunity. He calculated scenarios for three different charter rates from **Sabine Pass to Tokyo (via Panama)** with resulting shipping rates spanning from just 0,88 USD/MMBtu to 2,25 USD/MMBtu.
  (Author´s note: The low Japanese spot prices have not fallen below 7 USD/MMBtu since November 2017 and seem to remain stable between 8 and 11 USD/MMBtu.[45])

Looking at these three examples, a wide variety of shipping costs is presented and will serve as a comparison for results in this thesis. Probably, IHS Markit has the best market insights what makes it an acknowledged and important reference.
Depending on the author, input data varies widely and not always can be verified. To give an example, [Rogers 2018, 55] and [Ripple, 73] roughly estimated Panama Canal fees and IHS Markit neither applied special discounts for LNG shipments for Suez Canal nor considered additional canal costs for tug boats, mooring, electricity and so on. Later, differences between the findings will be discussed.

[45] http://www.meti.go.jp/english/statistics/sho/slng/index.html (Jan. 2019)

7 USA-Asia shipping cost calculation

Shipping costs were calculated at the utmost precision and with the best up-to-date data. Focus is strictly set on US shipping movements to Asia and Middle East. Routes from Sabine Pass and Cove Point to different consumers were analyzed and compared within three scenarios: A low, moderate and high-price scenario.

7.1 Input data

The three main variables are marine fuel oil (MFO) cost, gas price for liquefied natural gas and the charter rate.

- Cost for MFO varied widely within the last years. Historic data for different hubs (or as global average) can be found online. Usually, Intermediate Fuel Oil (IFO) with 180 or 380 centistokes or Marine Gas Oil (MGO) is tanked. For this thesis, historic IFO 380 prices between 350 and 500 USD/t MFO were used. The current development indicates a steep fall for Houston-linked IFO380 prices. Nevertheless, for the low-price scenario limit was set to 350 USD/t because oil-linked products may not remain too low-priced in future and long-term trends indicate they might increase moderately.

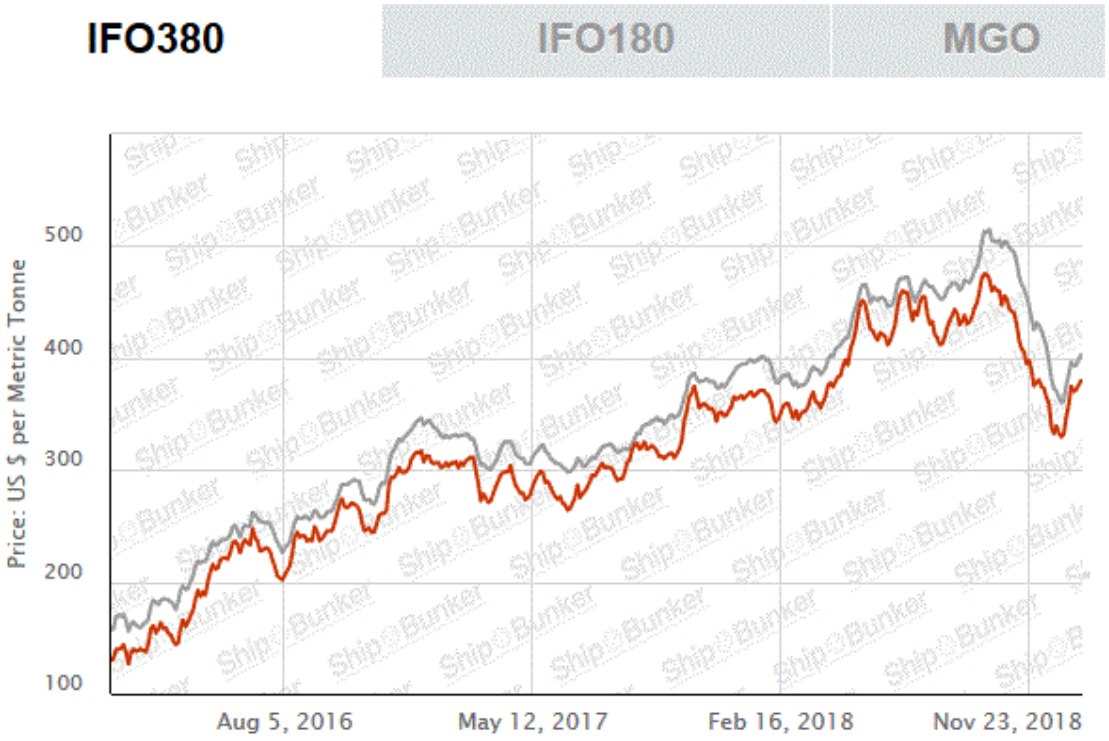


Figure 37 Houston (red) and global (grey) IFO 380 price history.[46]

[46] Copyright by Ship & Bunker: **Website** (Jan. 2019)

- Natural gas trade is usually based on the Henry Hub (HH) gas price. Henry Hub is the main gas distribution hub in Louisiana, United States. With its high liquidity it serves as a benchmark for commodity trade and a pricing point for "Futures" traded at the New York Mercantile Exchange (NYMEX) and Over the Counter (OTC) swaps traded on the International Exchange (ICE) [74]. The hub is connected to four domestic gas pipelines and nine international ones. Gas price at the liquefaction factory is usually 115% * HH, with annual average HH price according to current NYMEX futures at around 3 USD/MMBtu.[47] This lower limit is unlikely to be surpassed in the near future (see next figure). For the moderate and high-price scenario gas prices (HH) of 4 and 5,50 USD/MMBtu were determined.

  Liquefaction cost is 2,25 to 3,00 USD/MMBtu for Cheniere operated Sabine Pass trains and 2,50 USD/MMBtu for the Dominion operated Cove Point facility, according to IHS Markit insights [71, p. 42 and 82, p. 33]. Costs depend on the contracts made between plant owner and purchaser (quantity, time frame, etc.). Liquefaction cost of 2,50 USD/MMBtu was considered (included) in all calculations.

  Thus, gas prices for LNG were set within a range from 5,50 to 8 USD/MMBtu.

Figure 38 Historic and future HH gas (blue) and LNG (red) price at a monthly average.[48]

[47] Industry data provided by Naturgy. Updated prices can be found online, for example at: https://www.theice.com/products or https://www.cmegroup.com/trading/energy/natural-gas/natural-gas_quotes_settlements_futures.html (both Jan. 2019). Some websites may require active subscription.
[48] Own elaboration based on industry data provided by Naturgy.

- Differences in charter rates had been explained earlier this document. For the scenarios time charter rates between 60.000 to 150.000 USD/d were supposed.

The following table gives an overview over the scenario-specific data:

Table 20 Input data for shipping cost calculations. Three scenarios.

Variable (specification note)	**Low**	**Moderate**	**High**
Price MFO USD/t (IFO380)	350	380	500
Gas price USD/MMBtu (115% HH + liquefaction)	5,50	6,50	8,00
Charter rate USD/d (D/TFDE, time charter)	60.000	80.000	150.000

Fixed input data comprised the propulsion type (D/TFDE), the travel speed (18 kt) and SDR to USD conversion (1,40 SDR/USD). Discounts (fast return to Panama Canal, Suez Canal policies for LNG vessels according destination) or additional costs (10% punitive tariff on US imports to China) had also been considered, according to the specific route.

Every scenario was applied to vessels of 135.000 cm and 175.000 cm, as they represent common vessel sizes of the conventional class and form the lion´s share of today's LNG vessel fleet (compare figures 21 and 22 in chapter 4). An analysis of small-scale or Q-class sized vessels was not included, although they could be calculated as well with the same method.

7.1.1 Low price scenario

The low-price scenario is based on an MFO price for IFO 380 of 350 USD/t, a gas price (115% * HH + liquefaction) of 5,50 USD/MMBtu and a vessel charter rate of 60.000 USD/d.

First of all, calculations showed that in *every scenario* the Cape Horn route (equal to Strait of Magellan) is the most expensive and can never compete with any of the three other routes. Distance is simply too long with corresponding expenses for fuel oil, respectively gas. Day-bound costs for charter, operation, administration and insurance exceed savings from avoided canal fees. It is between 0,67 and 1,66 USD/MMBtu more expensive for all routes amongst all scenarios compared to the second most expensive route (Cape of Good Hope). For this reason, the Cape Horn route will not be regarded any further, neither in the moderate nor the high-price scenario.

Following characteristics were made up:

135.000 cm and 175.000 cm vessels leaving Sabine Pass should take the Panamanian route for destinations to Japan, South Korea, the Philippines, China and Taiwan. Also, Thailand can be reached with less expenses compared to the other options because of minor distance. Shipping costs range from 2,11 to 2,61 USD/MMBtu for the smaller vessel and 1,72 to 2,13 USD/MMBtu for the bigger one. This is due to economies of scale resulting in more unloadable volume, so the unit price is lower. The lowest price within this range has to be paid by customers in Tobata, Japan, and the highest price by the gas purchaser of China´s Beihai plant.

Regasification plants in Indonesia, Singapore, Bangladesh, India, Pakistan and Kuwait should be reached taking the Suez route. Here, shipping costs range from 2,11 to 2,50 USD/MMBtu and from 1,72 to 2,02 USD/MMBtu, corresponding to the different vessel sizes. Pakistan can be found at the lower end and Singapore at the upper end of this range.

As China could become one of the main purchasers of US-LNG, average shipping cost to China are of interest. Furthermore, many studies, as could be been in the preceding chapter, take US-China trading relations as an example for shipping costs to the Asian market and a comparative value. A 135.000 cm vessel taking the Panama Canal could deliver to Chinese destinations for around 2,48 USD/MMBtu, meanwhile the bigger tanker could do this route for around 2,03 USD/MMBtu.

Average deviation from Cape of Good Hope to Suez Canal is only 0,10 USD/MMBtu for the smaller vessels and practically inexistent (0,06 USD/MMBtu) for the bigger class. For example, Indonesia Arun, Singapore Jurong Island and Thailand Map Ta Phut can be reached at equal costs taking the Suez or the Cape of Good Hope route.

Table 21 Interesting data for shippings leaving Sabine Pass. Low-price scenario.

Sabine Pass (in USD/MMBtu)	**135.000 cm**	**175.000 cm**
Panama route between Japan and Taiwan + Thailand	From 2,11 (Tobata, Japan) to 2,61 (Beihai, China)	From 1,72 (Tobata, Japan) to 2,13 (Beihai, China)
Suez route between Indonesia and Kuwait	From 2,11 (Pakistan) to 2,50 (Singapore)	From 1,72 (Pakistan) to 2,02 (Singapore)
Av. shipping to China	2,48 (Panama) 3,12 (Suez)	2,03 (Panama) 2,51 (Suez)
Av. deviation between CGH and Suez	0,10	0,06

Shipping costs from Cove Point show similar patterns, but three developments can be seen:

- The Panamanian route gets marginal more expensive (0,06 USD/MMBtu for 135.000 cm and 0,05 USD/MMBtu for 175.000 cm).
- The Cape of Good Hope route differs more to the Suez route than before. Average deviation is now 0,24 USD/MMBtu for the smaller tankers and 0,18 USD/MMBtu for the bigger ones.
- Thailand is now cheaper to deliver via the Suez Canal.

All effects can be explained by Cove Point´s location on the US east coast, its position to the canals and thus favoring the eastern route(s).

Like for Sabine Pass, the Panama Canal route should be chosen for shippings between Japan and Taiwan, with the exception that the Philippine and China´s Beihai plants are deliverable with same expenses either via the Panama or the Suez Canal. Shipping costs range from 2,17 to 2,68 USD/MMBtu for 135.000 cm tankers and from 1,77 to 2,18 USD/MMBtu for ships with 175.000 cm capacity, with Japan´s Tobata and China´s Beihai setting the limits.

Between Indonesia and Kuwait clearly the Suez Canal is the cheaper option. For Thailand even shipping around Cape of Good Hope has a little advantage against the Panama Canal. Costs range from 1,86 to 2,39 USD/MMBtu for smaller vessels and from 1,51 to 1,93 USD/MMBtu for bigger ones, being Pakistan at the lower end of this scale and Thailand at the upper end.

The five investigated Chinese plants can still be reached cheaper taking the Panama Canal, but differences between both canals converge compared to the Sabine Pass results.

Because of the more favorable location of Cove Point with respect to the Suez Canal, the average costs between the Suez and the Cape of Good Hope route differ more now.

Table 22 Interesting data for shippings leaving Cove Point. Low-price scenario.

Cove Point (in USD/MMBtu)	**135.000 cm**	**175.000 cm**
Panama route between Japan and Taiwan	From 2,17 (Tobata, Japan) to 2,68 (Beihai, China)	From 1,77 (Tobata, Japan) to 2,18 (Beihai, China)
Suez route between Indonesia and Kuwait	From 1,86 (Pakistan) to 2,39 (Thailand)	From 1,51 (Pakistan) to 1,93 (Thailand)
Av. shipping to China	2,55 (Panama) 2,82 (Suez)	2,08 (Panama) 2,27 (Suez)
Av. deviation between CGH and Suez	0,24	0,18

7.1.2 Moderate price scenario

The moderate price scenario is based on an MFO price for IFO 380 of 380 USD/t, a gas price (115% * HH + liquefaction) of 6,50 USD/MMBtu and a vessel charter rate of 80.000 USD/d.

Following characteristics were made up:

For vessels loaded at Sabine Pass optimum routes are the same as in the low-price scenario. Nevertheless, mean average costs for the canal routes increase by 0,48 USD/MMBtu (Panama) and 0,49 USD/MMBtu (Suez) compared to the original scenario.

Shippings to China, using the Panama Canal, in average cost 0,44 USD/MMBtu more than in the low-price scenario for both types of vessels.

And meanwhile discrepancy between the Cape of Good Hope route compared to the Suez route is 0,17 USD/MMBtu for smaller vessels, it is now doubling (from 0,06 to 0,12 USD/MMBtu) for the 175.000 cm class.

Table 23 Interesting data for shippings leaving Sabine Pass. Moderate-price scenario.

Sabine Pass (in USD/MMBtu)	**135.000 cm**	**175.000 cm**
Panama route between Japan and Taiwan + Thailand	From 2,52 (Tobata, Japan) to 3,13 (Beihai, China)	From 2,06 (Tobata, Japan) to 2,55 (Beihai, China)
Suez route between Indonesia and Kuwait	From 2,52 (Pakistan) to 3,01 (Singapore)	From 2,04 (Pakistan) to 2,43 (Singapore)
Av. shipping to China	2,97 (Panama) 3,78 (Suez)	2,42 (Panama) 3,04 (Suez)
Av. deviation between CGH and Suez	0,17	0,12

Cove Point-bound vessels neither show “surprises”, as the routing options remain the same. Canal-bound cost increases are 0,49 USD/MMBtu for the Panama and 0,43 USD/MMBtu for the Suez Canal.

Deliveries to Chinese destinations surpass the original scenario by 0,46 USD/MMBtu for both vessel types.

Table 24 Interesting data for shippings leaving Cove Point. Moderate-price scenario.

Cove Point (in USD/MMBtu)	**135.000 cm**	**175.000 cm**
Panama route between Japan and Taiwan	From 2,60 (Tobata, Japan) to 3,22 (Beihai, China)	From 2,12 (Tobata, Japan) to 2,62 (Beihai, China)
Suez route between Indonesia and Kuwait	From 2,21 (Pakistan) to 2,87 (Thailand)	From 1,79 (Pakistan) to 2,41 (Thailand)
Av. shipping to China	3,06 (Panama) 3,41 (Suez)	2,49 (Panama) 2,75 (Suez)
Av. deviation between CGH and Suez	0,35	0,26

7.1.3 High price scenario

The high-price scenario is based on an MFO price for IFO 380 of 500 USD/t, a gas price (115% * HH + liquefaction) of 8,00 USD/MMBtu and a vessel charter rate of 150.000 USD/d.

Following characteristics were made up:

Shippings from Sabine Pass show the same pattern as for the first scenario. The same destinations can be reached this or that way, as it was explained in the first example. Mean average costs for the canal routes, compared to the original scenario, rise substantially by 1,94 USD/MMBtu (Panama) and 2,02 USD/MMBtu (Suez).

The higher charter rate discriminates the longer day-bound routes via Cape of Good Hope, resulting in higher deviation to the Suez Canal (quadruplicating for smaller vessels and quintuplicating for bigger vessels, compared to the low-cost scenario).

Table 25 Interesting data for shippings leaving Sabine Pass. High-price scenario.

Sabine Pass (in USD/MMBtu)	**135.000 cm**	**175.000 cm**
Panama route between Japan and Taiwan + Thailand	From 3,82 (Tobata, Japan) to 4,76 (Beihai, China)	From 3,07 (Tobata, Japan) to 3,82 (Beihai, China)
Suez route between Indonesia and Kuwait	From 3,80 (Pakistan) to 4,60 (Nusantara, Indonesia)	From 3,04 (Pakistan) to 3,67 (Nusantara, Indonesia)
Av. shipping to China	4,51 (Panama) 5,85 (Suez)	3,62 (Panama) 4,66 (Suez)
Av. deviation between CGH and Suez	0,39	0,30

Cargos leaving Cove Point suffer an average price increase of 2,00 and 1,78 USD/MMBtu with respect to the canal-bound routes (averages for both vessel sizes).

Other aspects remain the same as for the previous price scenarios with the same destinations reachable by one or another route.

Again, the longer Cape-journey is being discriminated due to higher costs of charter and MFO.

Table 26 Interesting data for shippings leaving Cove Point. High-price scenario.

Cove Point (in USD/MMBtu)	**135.000 cm**	**175.000 cm**
Panama route between Japan and Taiwan	From 3,93 (Tobata, Japan) to 4,89 (Beihai, China)	From 3,16 (Tobata, Japan) to 3,92 (Beihai, China)
Suez route between Indonesia and Kuwait	From 3,30 (Pakistan) to 4,36 (Thailand)	From 2,64 (Pakistan) to 3,48 (Thailand)
Av. shipping to China	4,64 (Panama) 5,26 (Suez)	3,72 (Panama) 4,19 (Suez)
Av. deviation between CGH and Suez	0,67	0,51

Figures for all six scenarios, representing the shipping costs, can be found in the annex.

7.1.4 Comparison between scenarios

To summarize results, figures 39 and 40 show the shipping costs for all three scenarios and both vessel sizes. With major US-liquefaction capacities located at the Gulf coast, Sabine Pass stands representative for all the other liquefaction facilities, as this region will become America´s main LNG exporting hub.

Shown are only shippings via the canals. The Cape Horn route is never competitive, and the Cape of Good Hope route is always slightly more expensive than the Suez alternative (between 0,06 and 0,30 USD/MMBtu).

A look at the figure gives a quick impression under what circumstances which route should be chosen.

(Note: It should be considered that in 2019 Chinese buyers still suffered a 10% premium on US-imports due to the ongoing trade conflict between the USA and China. This might change in future and thus reduce shipment costs to China slightly.)

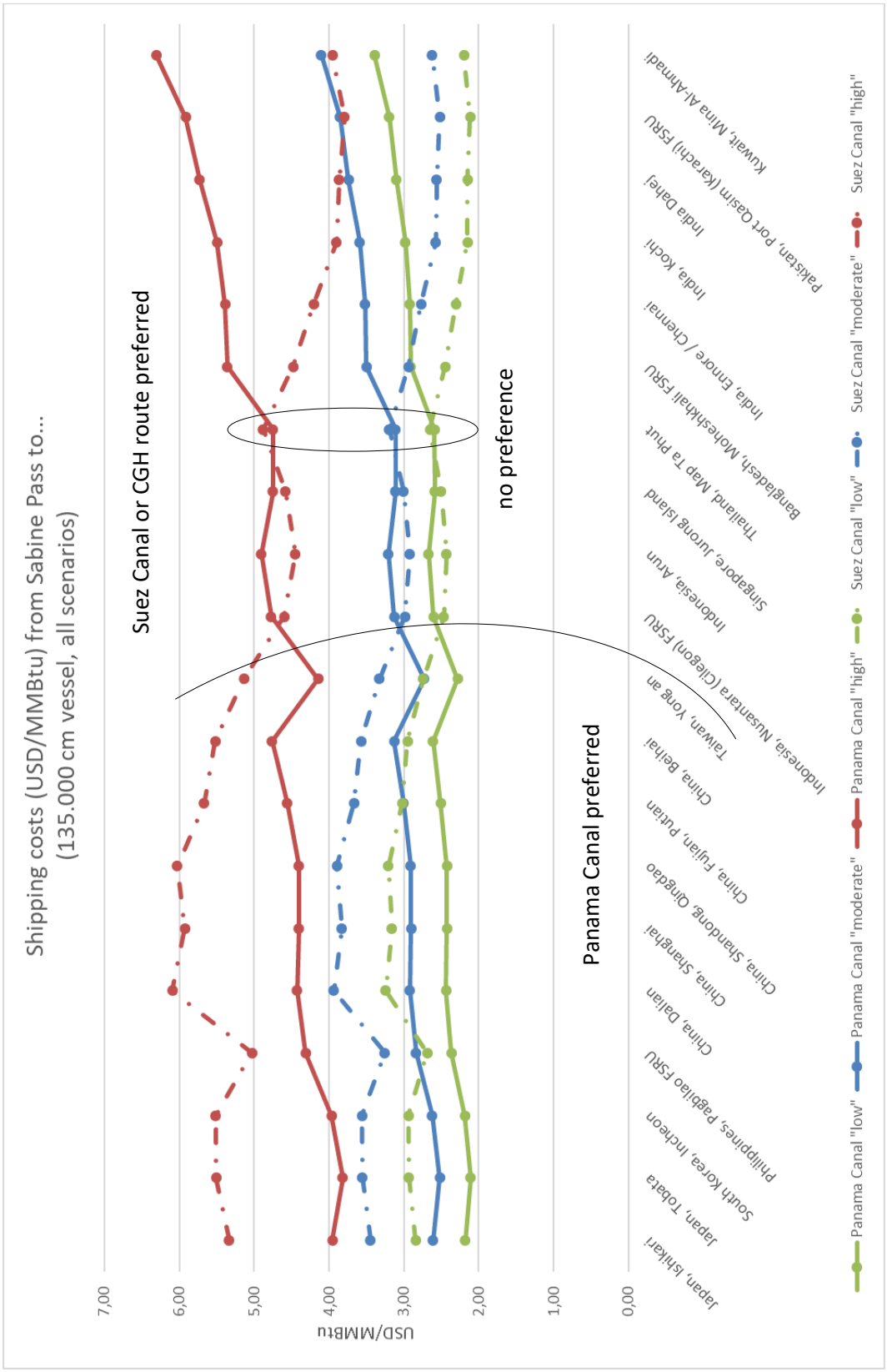


Figure 39 Shipping costs from Sabine Pass for 135.000 cm vessels. Canals only. All three scenarios.

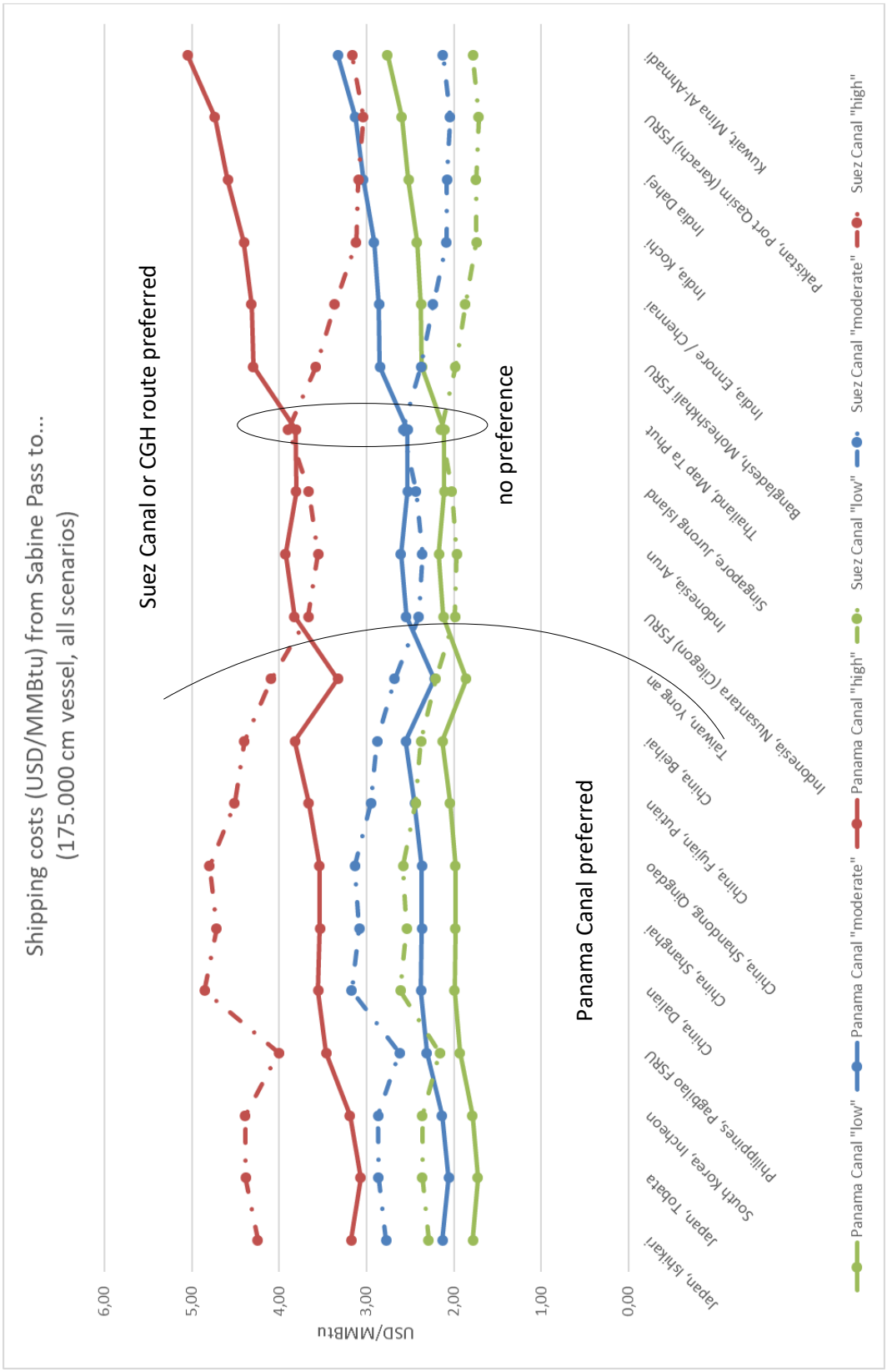


Figure 40 Shipping costs from Sabine Pass for 175.000 cm vessels. Canals only. All three scenarios.

Another interesting chart can be obtained by splitting up the individual costs for both vessel types and the three scenarios. This permits a closer look on how far changes in the variables rise or lower the transport costs.

To emphasize the growing importance of China on future global LNG trade, and to remain calculations simple, this was done solely for the five Chinese destinations (mean average). Here again, Sabine Pass stands representative for all the other US-liquefaction facilities. Costs were split up to the canal fee (shipments to China would prefer the Panama Canal only), the charter rate, fuel costs for both BOG and MFO, and fixed costs for loading and unloading, daily operation, administration and insurance. It is known, that a 10% premium is charged for US-imports.

Following observations can be made:

- The canal fee changes only marginally between the two vessel sizes.
- Fixed costs remained the same per vessel size and changed alter between them due to economies of scale.
- The additional tariff on US-imports is fixed to 10% but relative due to the sum of the other costs.
- Fuel costs change only little, too. As it was described earlier, 175.000 cm vessels do (practically) not use MFO for service speed propulsion. Thus, the alternation between the three scenarios is led back to gas price variation only. This is not the case for the 135.000 cm tanker: There, also MFO price affects the change.
- The most impact can be attributed to the different charter rates (60.000, 80.000 and 150.000 USD/d): Correspondent to the scenario, they make up between 43% and 59% of the total cost for the smaller-sized carriers and between 40% and 57% for the bigger ones.
- Economy of scale, that means switching from a small to a big carrier, can safe between 0,45 and 0,89 USD per energy unit, although obviously total round trip expenses are higher.

A low (time-) charter rate is thus crucial for stable revenue and has more impact than varying commodity prices. Also, choosing bigger vessels generates great savings due to economies of scale (more unloadable product).

It should be indicated again, that calculations were made for D/TFDE-driven vessels only, as this fact directly affects the charter rate and the consumption of the ship.

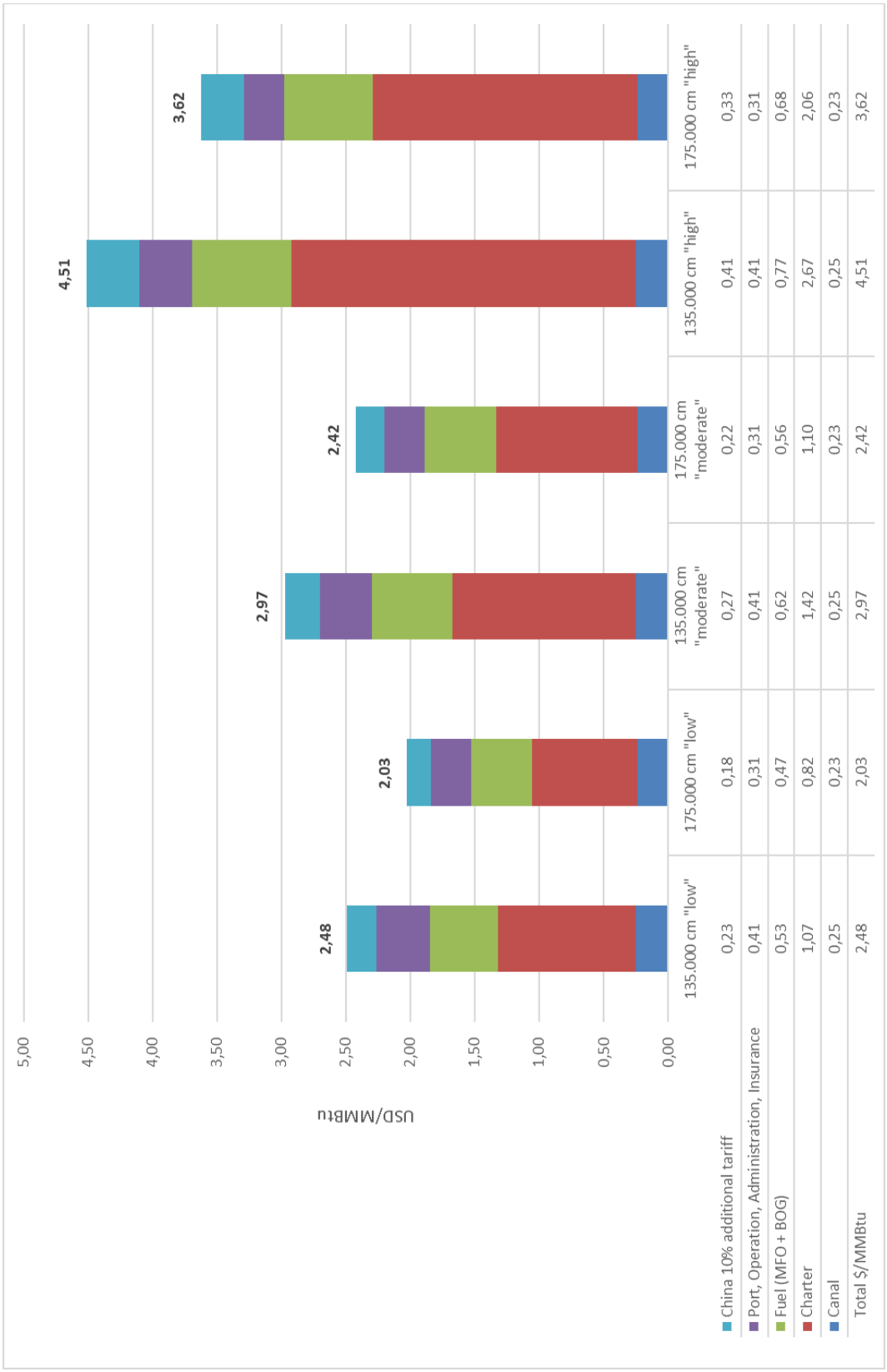


Figure 41 Sabine Pass – China cost split-up (USD/MMBtu) for D/TFDE-driven vessels.

7.1.5 Comparison to results from literature

IHS Markit´s input data are [71, 72]: 170.000 cm vessel, MFO price of 350 USD/t, gas prices of 6,76 USD/MMBtu for shippings leaving Sabine Pass and 6,26 USD/MMBtu for those casting off Cove Point and a charter rate of 75.000 USD/d. This is close to the moderate price scenario.
For a trip from Sabine Pass to Incheon, South Korea, using the Panama Canal IHS Markit calculates 2,17 USD/MMBtu and from Cove Point 2,24 USD/MMBtu. Using their assumptions in the thesis´ calculation sheet, results are 2,13 USD/MMBtu and 2,15 USD/MMBtu, respectively. This gives a congruence of around 98% for the first and 96% for the second example and proofs the thesis´ calculation approach.

[Rogers 2018, 55] in his work for The Oxford Institute for Energy Studies examines shipping costs from the US Gulf Coast to China, especially Shanghai, by using the Panama Canal. In his paper he gives results for three different calculations, varying MFO, gas price and charter rate.

Table 27 [Rogers´, 55] assumptions.

Variable (specification note)	**Example 1**	**Example 2**	**Example 3**
Price MFO USD/t	350	350	380
Gas price USD/MMBtu (115% HH + liquefaction)	5,50	9,20	9,20
Charter rate USD/d (D/TFDE)	33.000	78.400	55.000

His further assumptions differ essentially from the input data used for this thesis. They can be found in the annex. Nevertheless, applying his hypotheses, his calculations were proofed with exactitudes of 97%, 96% and 99% (from left to right according to the table) by applying his data on the thesis´ Excel sheet. Here again, the thesis´ calculations could be verified.

Last, calculations done by [Ripple, 73] for the International Association for Energy Engineers (IAEE) Energy Forum magazine were checked: His calculations were based on three different scenarios with results for shippings from Sabine Pass to Tokyo between 0,88 and 2,25 USD/MMBtu. The only variable is the charter rate for the vessel.
His calculations cannot be verified because some of his assumptions remain unclear. Deviation is between 22% for the low-cost scenario and 17% for the higher charter rate. He writes that "*an LNG tanker with 160.000 cubic meters of capacity*" carries "*approximately 3.000.000 MMBtu of deliverable natural gas*". This would result in a gross calorific value (GCV) of only 18,75 MMBtu/cm, but GCV for LNG is 24 MMBtu/cm.
In addition, he underestimates the Panamanian canal fee (635.500 USD to 831.000 USD, even the fast return discount considered). He states MFO cost to 35 USD/nm, that is far under 90 USD/nm for a calculation made for a shipping to Tobata, Japan (close to Tokyo). Furthermore, he ignores operating, administrative and insurance costs.
Paradoxically, if the GCV is changed to 24 MMBtu/cm and all other input data remain the same, results get close to his calculations within a range of 94% for the low charter rate and 91% for the high charter rate.

All three examples used Sabine Pass as point of origin, named destinations in Asia, and examined shippings via the Canal of Panama. Meanwhile comparison to IHS Markit could definitely proof not only the Excel calculations but also congruence with respect to shippings to Incheon, South Korea, Rogers´ examples did not fit well in any of the thesis´ scenarios but his method of resolution could be verified. Only Ripple´s calculations could not be proofed and were unusually low compared to the author´s and IHS Markit´s results. Clearly, modifications in the charter rate or the gas price have a huge impact on the output. Depending on the paper´s approach (considering time or spot charter, estimation of future gas price development) quite different outcomes are presented.

7.2 Focus: Panama Canal

It was explained earlier that the Panama Canal is a chokepoint or bottleneck for global marine transport: A high number of different kinds of vessels, paired with an inefficient reservation system for free slots, frequently forces carriers to wait or even take another route. Nearly all slots are reserved a year in advance under the premise “first-come, first-served”, but approximately 40% are unused due to minimal cancellation penalties (ca. 35.000 USD) [75]. Many cancellations are received so close to the transit date that most other shippers cannot utilize the slots. IHS Markit estimated 19 laden vessels not able to cross the canal and instead having taken a longer route only between November 2017 and January 2018, with correspondent financial losses for the seller [75].

Although the Panama Canal Authority (PCA) has made improvements with respect to LNG vessels, the implemented four daily slots could not be sufficient for cross-basin LNG traffic within the 5-year-outlook of this thesis, when more and more US liquefaction capacities are expected to come online. Today, two LNG vessels can use the canal in both directions daily, indifferently if they are moving laden or in ballast. This permits 120 transits per month (30 days) or 1.460 (4x365) per year.

7.2.1 The canal as a key access to the Pacific basin

In chapter 3.4 it was showed that US gas could make up some 30 MTPA or 11% of imports in the Asia-Pacific and Middle East region until 2023 (within the 5-year time frame of this thesis). The total demand for the twelve countries (Japan, South Korea, the Philippines, China, Taiwan, Indonesia, Singapore, Thailand, Bangladesh, India, Pakistan and Kuwait), that are subject of this investigation, was estimated to be 271 MTPA.

With the intention to investigate until what extend the Panama Canal could be a bottleneck for future US supply to the Pacific basin, the following assumptions were made:

- In equal parts 135.000 cm and 175.000 cm vessels (50/50)
- starting from the US Gulf Coast, i.e. Sabine Pass
- with a usable volume of 98,5%
- and an average usage of 10% gas as marine fuel (losses) for the total journey

This would result in unloadable volumes of 120.000 and 155.000 cm LNG in the receiving country, depending on the tanker´s size. The annually expected volume to be imported to a country was divided through the unloadable volume of a single shipment to obtain the total number of ships that would be needed to satisfy each demand.

In accordance with the results of the preceding chapter, shipping via the Panama Canal would be preferred for the following consumers: Japan, China, South Korea, Taiwan and the Philippines (100%). Shippings to Thailand can be done to virtually equal costs via any of both canals. Thus, deliveries to Thailand´s were considered with 50%.

Receiving countries must be extended by two other countries with regasification terminals in the Pacific basin: Mexico and Chile. Further information was obtained by IHS Markit reports on both countries [76, 77]. Although bulk of US gas is transported to Mexico by pipeline, a small share is shipped to the regasification facilities Costa Azul (7,5 MTPA) and Manzanillo (3,5 MTPA) on the Mexican west coast.
In Chile also exist two regasification plants: The 1,5 MTPA Mejillones terminal in the northern part of the country and the 2,5 MTPA Quintero plant close to Santiago. In analogy to the countries investigated in chapter 3.4 expectations are made for the US share of LNG imports for Mexico and Chile, as for these four purchasers the preferred route is via the Panama Canal, and therefore affecting this analysis.

The Mexican LNG market disposes of an installed nameplate capacity of 16,4 MTPA, including 11 MTPA on its west coast. Utilization rate in 2017 was only 30% among the three import terminals (two on the west coast, one on the east coast) [1, p. 47]. With growing gas demand but decreasing domestic production, volumes are foreseen to be mainly imported by pipeline from the United States. Mexico´s pipeline network is being renewed and expanded. This implicates that LNG imports are going to decline after 2020. The US has become the country´s principal LNG supplier, accounting for nearly 75% of LNG imports in 2018 (January to September). Applying this share on the forecasted 2023 demand of 2 MTPA for the west coast situated terminals results in 1,5 MTPA coming from the United States. Compared to the results from chapter 3.4 this would be nearly equivalent to the future deliveries to India.

With an installed nameplate capacity of 4 MTPA and total imports of 3,1 MTPA in 2018, utilization rate for both Chilean LNG terminals was 78%. The market is expected to growth – but not until 2023. Within the next years, demand is said to remain stable. Nevertheless, US share on imported LNG is expected to increase with the expansion of new liquefaction facilities on the US Gulf coast. In 2018 60% of LNG imports came from Trinidad and Tobago and 40% from both Equatorial Guinea and the USA. It can be supposed that until 2023 50% could have US origin, resulting in 1,6 MTPA. This would be almost equivalent to the future Mexican or Indian volumes.

The following chart summarizes the forecasted demands for Japan, China, South Korea, India, Pakistan, Kuwait, Thailand, Indonesia, Singapore, Bangladesh, the Philippines, Mexico and Chile, together with the expected US share on imports, the possible volumes sent through the Panama Canal and the numbers of vessels sent outwards to transport these volumes, respectively.

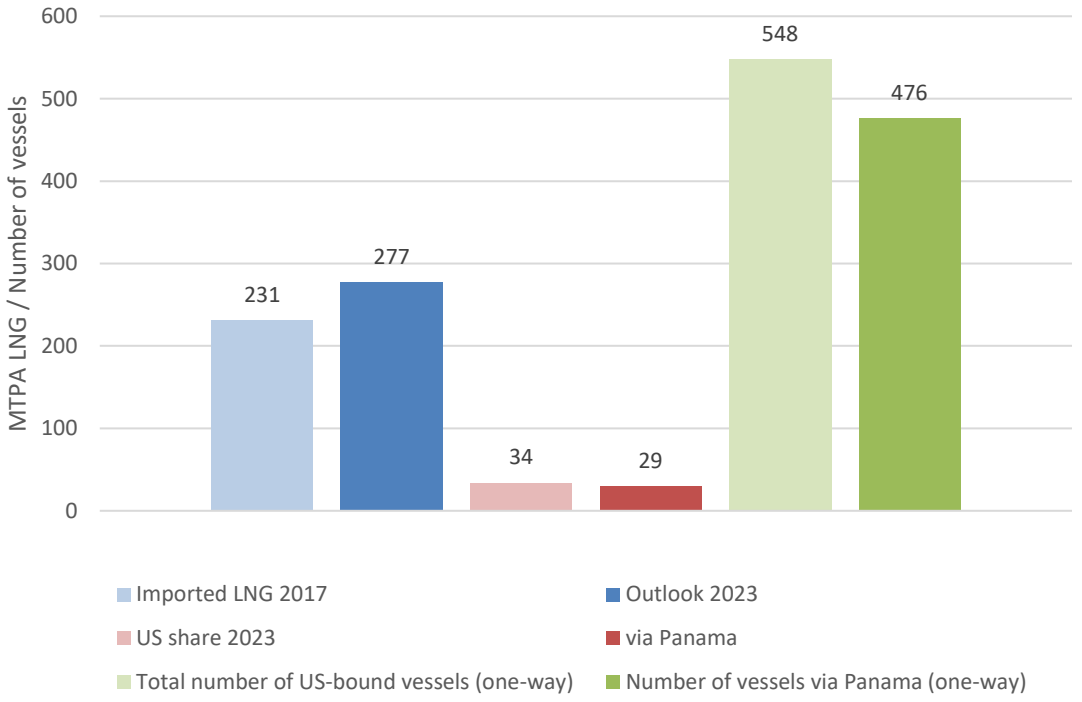


Figure 42 LNG imports Asia-Pacific, Middle East, Mexico and Chile (MTPA) in 2017 and forecast to 2023, US share 2023 (MTPA) and Panama Canal usage (no. of vessels).

With expected 34 MTPA to be shipped annually to Asian and Arabian customers, Mexico and Chile, 29 MTPA would be transported preferentially through the Panama Canal. This would add up to 476 conventional vessels in 2023 (one-way). For the rest (72 carriers) the Suez route would be the preferred option. Panama Canal usage would be far higher than Suez Canal usage because the top three consumers Japan, China and South Korea would be delivered westwards.

7.2.2 Bottleneck analysis

For a deeper analysis, the total traffic of LNG vessels shipping the Panama Canal needs to be extended to returning tankers and those leaving from non-US territory. IHS Markit estimates that US ballast slot requirements are 75% of laden slots and that 75 annual slots are needed for non-US cargos [75].

Then, a bottleneck analysis was done for six scenarios: A 10% US share of China´s LNG imports (1), a 20% US share of China´s LNG imports (2), the annual Panama Canal limit (3), an imaginative example in which all US liquefaction capacity by 2023 (87 MTPA) would be sent through the Canal (4) and two peak case analyses which refer to high monthly demands in winter (November to February), one with 10% US share (5) and one with 20% US share with respect to China´s LNG imports (6).

	Base case (10% US gas)	Scenario 20% (20% US gas)	Limit Panama Canal (49 MTPA)	"All-in" (87 MTPA)	Monthly peak (10% US gas)	Monthly peak (20% US gas)
Outward via Panama	476	578	791	1.408	50	63
75% return	357	434	594	1.056	38	48
75 non-US vessels	75	75	75	75	25 (estimated)	25 (estimated)
Total	908	1.087	1.460	2.539	113	136
Limit Panama Canal	1.460	1.460	1.460	1.460	120	120
Remaining vessels	552	373	0	-1.079	7	-16

Table 28 Panama Canal bottleneck analysis (table).

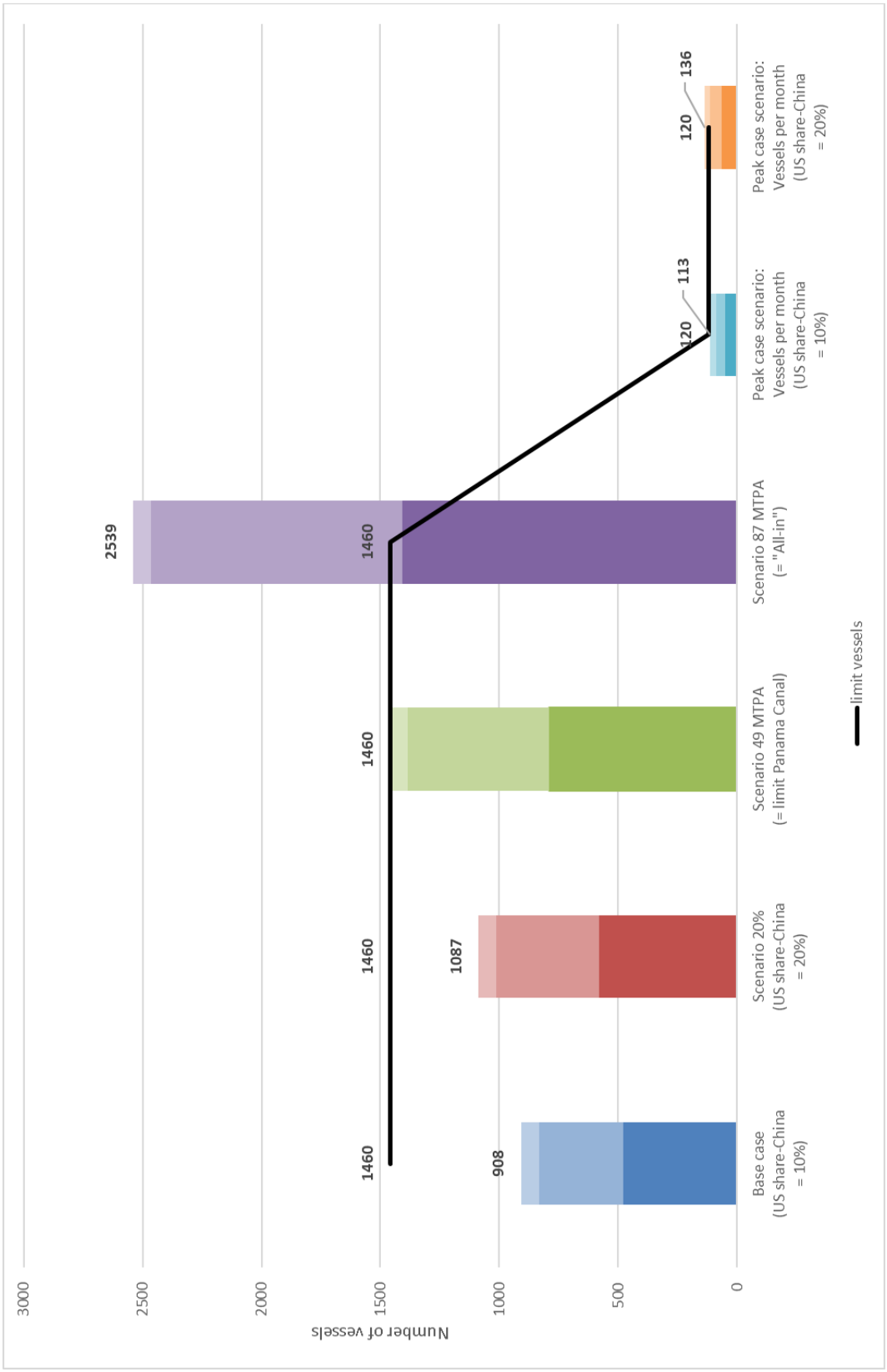


Figure 43 Panama Canal bottleneck analysis (chart). Dark colored = outward US vessels, half-lightly colored = returning US vessels, lightly colored = non-US vessels.

Under “normal” circumstances, presuming a uniform distribution during the year and that most of the LNG charterers meet their reserved slots, no congestion is to be expected: In the base case scenario (1) there would be buffer for 552 vessels and 373 shipments could still be processed in the 20% scenario (2). Even if 100% of outgoing ships would return through the Panama Canal and number for non-US vessels would be raised from 75 to 100, there would be capacity for another 204 shipments in the 20% scenario. Obviously, these calculations change quickly for another relation between 135.000 and 175.000 cm vessels.

The canal´s limit are 1.460 vessels (3), what would equal to approximately 49 MTPA under the given split between the two vessel sizes (50/50) and the assumptions taken in the beginning of the chapter.

Evidently, but unrealistic for 2023, the shipping of 87 MTPA through the canal would by far exceed its capacity (4).

Meanwhile the first four examples are based on uniform demands during a year, the latter two breakdowns were done for monthly peak demands. In Asia a strong 2017/18 winter led to increased LNG imports and regasification utilization was much higher than the annual average. For this purpose, some further conditions had to be considered:

- The average monthly demand from November 2017 until February 2018 was taken and
- complemented by the prospective annual variation (2023/2017) for each country.
- Non-US vessels were supposed to be 25 in a peak month (33% of 75 vessels annually)

Scenario (5) and (6) are more significant as they show clearly that in times of high demand in the Pacific basin the canal could represent a bottleneck for LNG transport not just until 2023, but even earlier. With a monthly capacity for 120 LNG vessels (4 per day and assuming a month with 30 days) the Panama Canal Authority is not really prepared to take up with a share of more than 10% US gas on China´s LNG imports. This could force vessels to take another route. It was not even considered that every reserved slot would be taken, respectively that all required slots would had been reserved in advance.

7.2.3 Waiting vs. alternative routing

It might occur that a tanker cannot use its reserved slot due to any kind of circumstance. This leads to the question, until what time it is cheaper for the seller to let the vessel wait for the next free slot, or take one of the other three routes (Cape Horn, Suez Canal or Cape of Good Hope)?

Calculation was done for:

- 135.000 cm and 175.000 cm vessels
- starting from the US Gulf Coast, i.e. Sabine Pass
- under the assumptions of the “moderate scenario” with a gas price for LNG of 6,50 USD/MMBtu and an MFO price of 380 USD/t
- and for three different time-charter rates: 60.000, 80.000 and 150.000 USD/d

Number of receiving terminals was reduced to eight. Only countries were considered where shipments would be done preferably via the Panama Canal:

Table 29 Reduced number of receiving terminals for "waiting vs. alternative routing-analysis".

Regasification plant	**Longitude (east)**	**Status**	**Regas nameplate capacity (MTPA)**
Japan, Tobata	130°51'07.1"	existing	6,8
South Korea, Incheon	126°36'28.0"	existing	43,3
Philippines, Pagbilao FSRU	121°45'29.7"	under construction	3,0
China, Shanghai	121°37'23.4"	existing	3,0
Taiwan Yong an	120°12'03.6"	existing	9,5
Thailand, Map Ta Phut	101°09'16.3"	existing	10,0
Mexico, Manzanillo	-	existing	3,5
Chile, Quintero	-	existing	2,5

As the difference of round-trip costs between the Panama Canal and the other three alternatives (Cape Horn, Suez Canal, Cape of Good Hope) was originally calculated to obtain the main results, this can be compared to the running costs per day waiting to enter the Panama Canal in case of congestion. It is known, that the Suez route is the option with the second less expenses. Only for Mexico and Chile the Cape Horn route would be the next alternative. The daily running costs were calculated according to the following equation:

*No. of days * [(vessel capacity in cm * GCV 24 MMBtu/cm * load level 98,5% * BOG rate 0,15% * * gas price 6,50 USD/MMBtu) + (port consumption DFDE vessel t/d * MFO price 380 USD/t) + + (charter rate + operating costs + administrative costs + insurance costs)]*

Table 30 Maximum days waiting time instead of taking the alternative route. 135.000 cm vessels.

Daily charter rate for 135.000 cm	**60.000 USD**	**80.000 USD**	**150.000 USD**
Daily running costs for 135.000 cm	**121.000 USD**	**141.000 USD**	**211.000 USD**
Thailand, Map Ta Phut	1 day	1 day	1 day
Philippines, Pagbilao FSRU	7 days	7 days	8 days
Taiwan Yong an	10 days	10 days	11 days
South Korea, Incheon	16 days	17 days	18 days
China, Shanghai	16 days	16 days	17 days
Chile, Quintero	16 days	17 days	19 days
Japan, Tobata	18 days	18 days	20 days
Mexico, Manzanillo	35 days	36 days	39 days

Table 31 Maximum days waiting time instead of taking the alternative route. 175.000 cm vessels.

Daily charter rate for 175.000 cm	**60.000 USD**	**80.000 USD**	**150.000 USD**
Daily running costs for 175.000 cm	**130.000 USD**	**150.000 USD**	**220.000 USD**
Thailand, Map Ta Phut	1 day	1 day	1 day
Philippines, Pagbilao FSRU	6 days	6 days	7 days
Taiwan Yong an	9 days	9 days	11 days
Chile, Quintero	14 days	16 days	18 days
South Korea, Incheon	15 days	16 days	17 days
China, Shanghai	15 days	15 days	17 days
Japan, Tobata	17 days	17 days	19 days
Mexico, Manzanillo	33 days	34 days	37 days

Three effects can be observed:

- The daily running costs for a 175.000 cm vessel outstrip those for the smaller tanker by 9.000 USD. This reduces the “permitted” maximum waiting time between one and two days according to the destination.
- The number of days, which a carrier could wait and still use the Panama Canal, results of the high difference between the total round trip costs of this route and the route with the second lowest expenses.
- For deliveries to Thailand a maritime traffic jam should be immediately avoided by taking the Suez route.

It should be noted that this is merely a careful approach to estimate the “breakeven” between daily running costs (resulting from waiting time) compared to the next cheapest shipping route.

7.3 Competitors

Although bulk of global liquefaction capacities is being constructed at the US Gulf coast and US-Asian LNG shippings are expected to increase in the next few years, LNG trade has been mainly constrained to separate basins. It was mentioned in chapter 1.2 that with Qatar and Australia important suppliers are not located within the Atlantic basin but situated much closer to the centers of future demand, especially to China with its growing demand for LNG. Also, exporters from the African east coast compete with the USA to gain customers.

To confirm this assumption, a short look at global trade is helpful. *Interregional* trade in 2017 was much lower than *intraregional* trade, which show data for the Pacific basin: While 58% of all in the Pacific region demanded LNG came from within the same basin (intraregional), only 10% came from the Atlantic basin (interregional). The rest came from suppliers in the Middle East region [1, p. 13].

But this actuality might change in future. Comparative data for 2023 show that expansion projects in other countries (Australia, Russia, Indonesia and Malaysia) are not likely to be developed within the next five years, and most additional capacity will come from US liquefaction projects. Even Qatar is probably not bringing new capacities online until 2023 [1, p. 21]. This might restrict intraregional trade and intensify interregional trade.

Without a deeper study of future liquefaction capacities and expected political or economic decisions, this chapter merely compares shipping costs from competing locations to those from the US Gulf coast.

On the supply side the following locations were chosen:

- A: Los Angeles, located at the US west coast, and serving as a theoretical example[49]
- B: Kitimat, Canada (future LNG export facility, positive FID in November 2018)
- C: Gorgon, Australia (existing)
- D: Doha, Qatar (existing)
- E: Bonny Island, Nigeria (existing)

The following map shows the position of the five facilities (A – E):

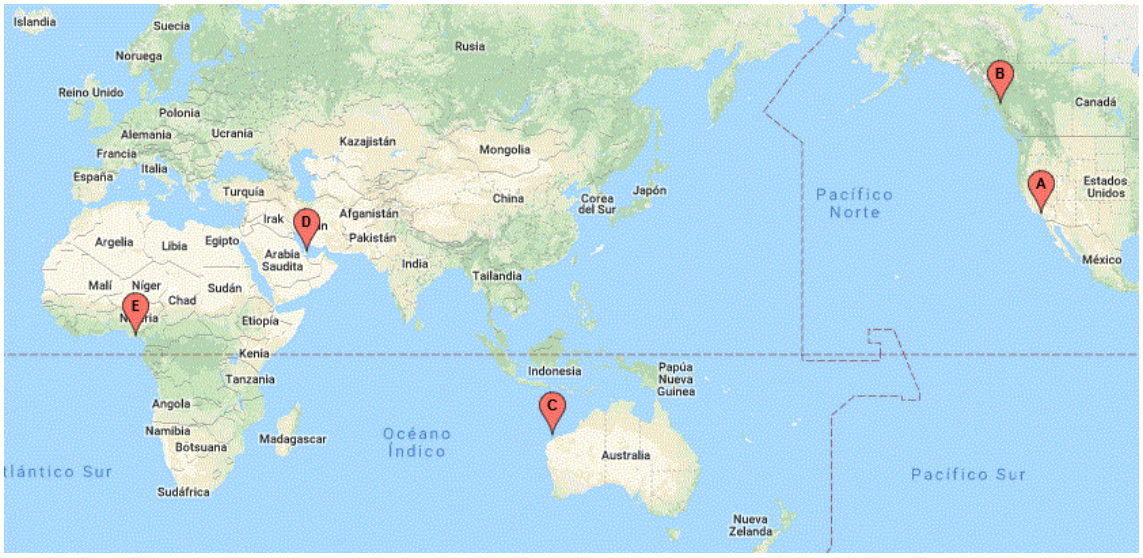


Figure 44 Alternative suppliers.[50]

[49] Jordan Cove LNG in the state of Oregon is supposed to be constructed, although IHS Markit estimates commercial export not before the mid 2030s [30].
In Mexico, Sempra is considering converting its Costa Azul import facility into an export facility. Although it is located in Baja California, Mexico, US gas would be exported. In September 2018 the project received FTA export approval from DOE [76, pp. 3 & 6].
Los Angeles is located (more or less) between Oregon and Baja California and stands representative for the US west coast.

[50] Created with https://de.batchgeo.com/ (Jan. 2019)

The number of receiving countries was reduced to eight. Remaining locations are:

Table 32 Reduced number of regasification terminals for "competitive analysis".

Regasification plant	**Longitude (east)**	**Status**	**Regas nameplate capacity (MTPA)**
Japan, Tobata	130°51'07.1"	existing	6,8
South Korea, Incheon	126°36'28.0"	existing	43,3
China, Shanghai	121°37'23.4"	existing	3,0
China, Beihai	109°02'34.1"	existing	3,0
Singapore, Jurong Island	103°43'53.7"	existing	11,0
India, Ennore / Chennai	80°18'09.3"	under construction	5,0
India, Dahej	72°30'34.7"	existing	15,0
Pakistan, Port Qasim (Karachi) FSRU	48°10'23.4"	existing	5,7

Exact locations of the receiving facilities can be reviewed in chapter 5 (map).

Shipping cost calculations were made for a 175.000 cm vessel and under the assumptions of the moderate scenario (MFO price = 380 USD/t, gas price (115% * HH + liquefaction) = 6,50 USD/MMBtu, vessel time-charter rate = 80.000 USD/d).

None of the new routes includes a canal passage and all destinations are reached on the shortest way via the "open sea". Deliveries leaving Bonny Island, Nigeria, take the Cape of Good Hope route due to shorter distances to all eight receiving terminals, with the positive side-effects of avoiding canal fees and possible congestion.

The following chart shows the shipping costs from the five different liquefaction facilities to the eight chosen receiving terminals. Results were then compared to the cheapest shipping options from Sabine Pass. According to the findings in chapter 7.1.2 shippings from Japan to China would be done using the Panama Canal and deliveries from Singapore to Pakistan via the Suez Canal. The 10% extra charge for US-cargos to Chinese destinations was applied.

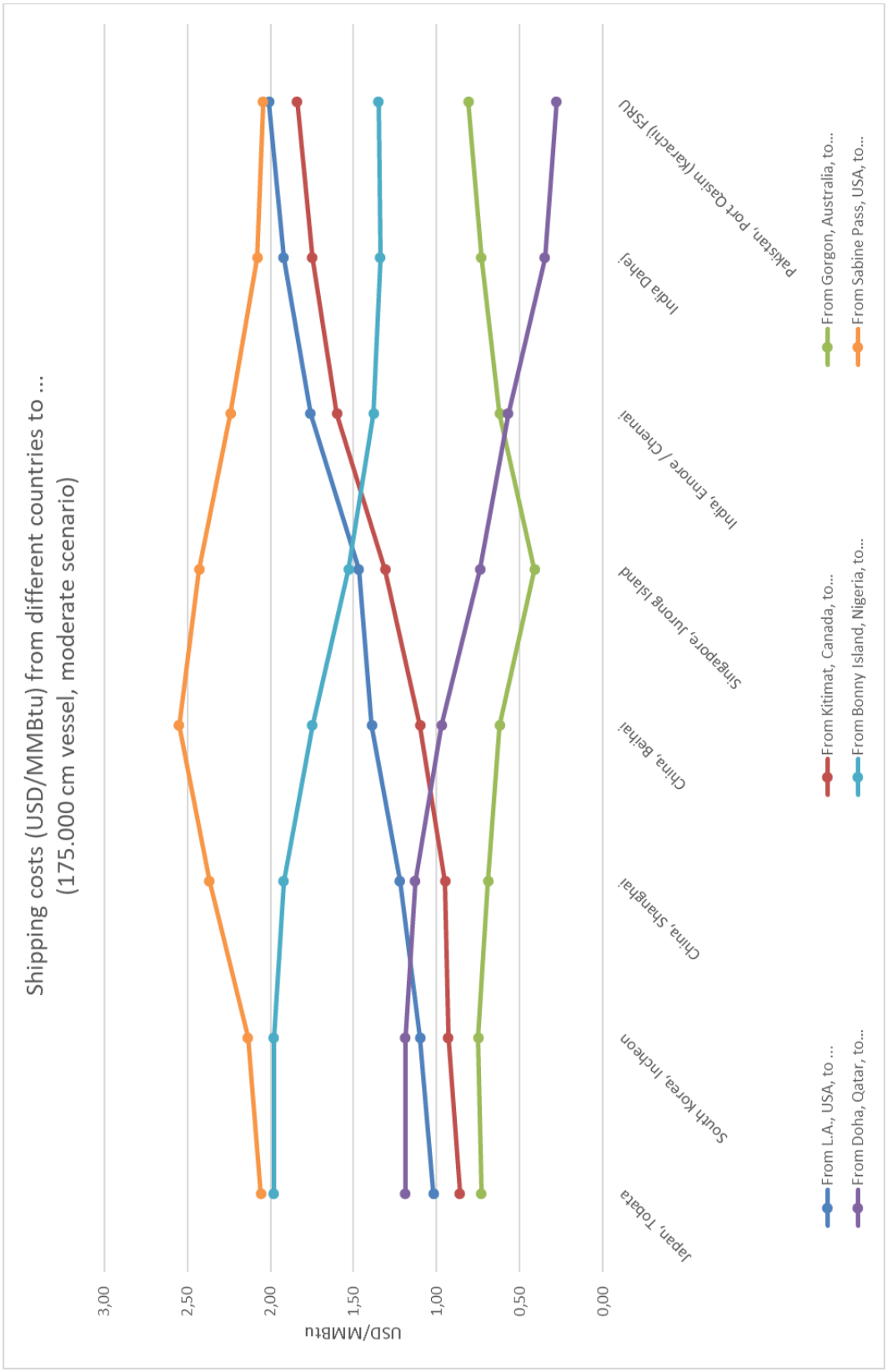


Figure 45 Shipping costs for "competitive analysis". 175.000 cm vessel. Moderate scenario.

It can be observed that shipments from Sabine Pass (from Japan to China via Panama, from Singapore to Pakistan via Egypt) are more expensive than the other alternatives. This phenomenon can be explained by the fact that for these eight destinations Sabine Pass is located very unfortunate, with the necessity for vessels to always cross a canal. Even that some other routes were longer (i.e. US or Canadian west coast to Indian west coast or Pakistan, Nigeria to Japan or South Korea), the impact of canal costs on shipping costs outweighed this advantage.

Shipments from the US or Canadian west coast (dark blue and red) are close together with costs roughly between 1 and 2 USD/MMBtu, with a light advantage for vessels leaving Canada (savings between 8% and 15%).

For most of the possible deliveries, Australian LNG from Gorgon, located at the continents´ northwest cost, would be the most economical choice. They never pass 1 USD/MMBtu and are only undercut by shippings from the Middle East with destinations between Pakistan and the eastern side of the Indian subcontinent.

Shipments from Qatar are competitive until the Chinese south coast, but for supply of South Korea or Japan exist cheaper alternatives.

Nigeria, located at the African west coast, has always an advantage compared to Sabine Pass. Also, benefits can be made up for deliveries between the Middle East and the Indian subcontinent when compared to senders located on America´s west coast. But for the lion´s share of the destinations other competitors can offer lower transportation costs.

Nonetheless it must be observed, that for a detailed analysis the respective gas prices in each country must be considered. This calculation was done with the unitary approach for US gas, which is 115% * HH + liquefaction. In other regions, and corresponding to the contracts between buyer and supplier, the gas price might be linked to another index, and liquefaction costs could be higher or lower.

8 Conclusion and outlook

After giving an overview of the LNG value chain, this thesis focused on the USA as one of the upcoming natural gas exporters and LNG demand in the Pacific basin; for both parts within a time frame of 5 years (2019-2023). Then, technical aspects of vessels were explained, which were important for the further understanding of the calculations. Afterwards, the four possible routes from US territory to a variety of buyers were analyzed and their distances presented. Attention was given to the different policies of the canal authorities to attract more LNG vessels.
Principal point of this practical work was the calculation of shipping costs from the USA to a wide range of destinations. The correctness of the approach and the results were verified by examples from available literature. In the end, focus was laid on the Panama Canal as a possible bottleneck for LNG traffic and it was found, that, at least until 2023, annual transit should be possible in a non-critical manner, but monthly peaks could lead to congestions.
To give a possible outlook and topic for further investigation, the situation between US LNG exports and those from other exporting countries was touched: It showed, within very narrow conditions, that US shale gas is not necessarily the cheapest option for the Asian consumers – but future restrictions in other countries could give US-gas an advantage.

Although all calculations were done with the utmost precision, it should be taken into account that small variances could lead to big changes. With new records for spot charter rates in November 2018, this variable could have much more influence for future investigations. As the LNG shipping market evolves, this type of calculations will always be necessary for industry. Thus, input data should be updated from time to time. Apart from that, market players should practice continuous monitoring of vessel consumption and expenses. It was said, that a clear future trend concerning the global LNG market cannot be seen: While some trends might indicate a more commodity-based market, others show clues of consolidation. Wherever the trend might go: Actors should be aware to reduce their shipping costs and react as fast as possible to external factors.

Shipping of LNG is expected to rise due to the facts that many big cities, especially in Asia, are located close to the shore making them well accessible for seaborne deliveries, huge resources of (shale) gas exist, new to build trans- and international pipeline networks often take longer to come into service than a vessel fleet, and because gas is the cleanest burning fossil fuel and commonly seen as the transition energy source towards a future based on renewable energies.

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List of figures

Figure 1 LNG value chain. 2
Figure 2 Schematic of terrestrial natural gas resources. 3
Figure 3 Worldwide gas movements. Data for 2017. 5
Figure 4 Prospect LNG volumes [7, p.88]. 6
Figure 5 Major gas trade movements 2017 [6, p.35]. Blue lines=LNG, red lines=pipeline gas, numbers in bcm. 7
Figure 6 Raw natural gas treatment prior to liquefaction. 11
Figure 7 Development of LNG train size until approx. 2014. 12
Figure 8 APCI´s C3MR process. 14
Figure 9 ConocoPhillips´ Optimized Cascade Process (CP OCP). (NRU=Nitrogen Refrigeration Unit) .. 16
Figure 10 Transportation Costs over Distance. (toe = tonnes of oil equivalent) 17
Figure 11 LNG regasification process schematic 19
Figure 12 Gas consumption by sectors by 2040 [7]. 21
Figure 13 Average liquefaction costs [1, p. 27]. 23
Figure 14 US dry gas production and consumption in bcm. (Dry natural gas @ 1.015 hPa and 15 °C) 25
Figure 15 Total import, total export and net import (difference) of natural gas in bcm. 26
Figure 16 US dry natural gas production by source [25, Reference Case]. 28
Figure 17 Dry shale gas production estimates by play. December 2018. 29
Figure 18 US nameplate liquefaction capacity status as of 01/2019. 30
Figure 19 Liquefaction capacity to come online in the upcoming years as of 01/2019. 32
Figure 20 LNG demands 2017 and 2023 for selected countries in Asia-Pacific and the Middle East. .. 36
Figure 21 LNG fleet as of October 2018, ordered by vessel types. 37
Figure 22 Gross Tonnage over capacity (cm). 41
Figure 23 Schematic of a membrane-type containment system. 44
Figure 24 Propulsion types active fleet, October 2018. (DFDE = Dual-fuel diesel electric, TFDE = Tri-fuel diesel electric, ME-GI = M-type electronically controlled gas-injection, LP-2S = Low-pressure 2-stroke, XDF = X-Dual-fuel (low-speed 2-stroke), SSD = Slow-speed diesel) 45
Figure 25 Propulsion types order book, October 2018. (StaGE = Steam turbine and gas engine) 46
Figure 26 DFDE configuration schematic [54]. 47
Figure 27 Spot charter rates for DFDE and steam driven vessels between Jan. 2011 and Dec. 2018 [59, p. 3]. 49
Figure 28 Locations of US-based liquefaction terminals Sabine Pass (A) and Cove Point (B). 51
Figure 29 Locations of 10 regasification terminals in Japan, South Korea, Philippines, China and Taiwan. 53
Figure 30 Locations of 10 regasification terminals in Indonesia, Singapore, Thailand, Bangladesh, India, Pakistan and Kuwait. 53
Figure 31 Cape Horn and Strait of Magellan. 57
Figure 32 XDR to USD conversion within the last 5 years. 60
Figure 33 Cape of Good Hope. 62
Figure 34 Distances (nm) from Sabine Pass, Louisiana. 67
Figure 35 Distances (nm) from Cove Point, Maryland. 68
Figure 36 Average design ship speed of LNG carriers [70]. 70
Figure 37 Houston (red) and global (grey) IFO 380 price history. 74
Figure 38 Historic and future HH gas (blue) and LNG (red) price at a monthly average. 75
Figure 39 Shipping costs from Sabine Pass for 135.000 cm vessels. Canals only. All three scenarios.. 82

Figure 40 Shipping costs from Sabine Pass for 175.000 cm vessels. Canals only. All three scenarios.. 83
Figure 41 Sabine Pass – China cost split-up (USD/MMBtu) for D/TFDE-driven vessels. 85
Figure 42 LNG imports Asia-Pacific, Middle East, Mexico and Chile (MTPA) in 2017 and forecast to 2023, US share 2023 (MTPA) and Panama Canal usage (no. of vessels). 89
Figure 43 Panama Canal bottleneck analysis (chart). Dark colored = outward US vessels, half-lightly colored = returning US vessels, lightly colored = non-US vessels. 91
Figure 44 Alternative suppliers. 95
Figure 45 Shipping costs for “competitive analysis”. 175.000 cm vessel. Moderate scenario. 97
Figure 46 Exemplary LNG project timeline with major milestones for Cameron LNG, Houston. 110
Figure 47 Input data part 1, example from [Rogers, 55]. 123
Figure 48 Input data part 2, example from [Rogers, 55]. 124

List of tables

Table 1 Classification of reserves based on probabilities. 4
Table 2 World´s top three natural gas producers [6]. 4
Table 3 Natural gas composition table [8, p. 27]. 9
Table 4 Composition of natural gas from selected US gas plays [9]. 10
Table 5 Characteristics of cooling processes [12]. 13
Table 6 Estimated relative CAPEX for different stages within an LNG project. 22
Table 7 Maximal vessel dimensions for the both types of Panama Canal locks. 39
Table 8 Maximal vessel dimensions for the Suez Canal. 39
Table 9 Average LNG vessel characteristics. (L=length, W=width/beam, D=depth/draft) 42
Table 10 Typical fuel consumption in t/d. 48
Table 11 List of regasification terminals 52
Table 12 Panama Canal transit statistics [64]. 55
Table 13 Tariff structure Panama Canal. 56
Table 14 Suez Canal transit statistics [66]. 58
Table 15 Average LNG vessel SCNT and SCGT. 59
Table 16 Tariff structure Suez Canal 61
Table 17 Discounts Suez Canal. 63
Table 18 Distances from Sabine Pass to each destination. 65
Table 19 Distances from Cove Point to each destination. 66
Table 20 Input data for shipping cost calculations. Three scenarios. 76
Table 21 Interesting data for shippings leaving Sabine Pass. Low-price scenario. 77
Table 22 Interesting data for shippings leaving Cove Point. Low-price scenario 78
Table 23 Interesting data for shippings leaving Sabine Pass. Moderate-price scenario. 79
Table 24 Interesting data for shippings leaving Cove Point. Moderate-price scenario. 79
Table 25 Interesting data for shippings leaving Sabine Pass. High-price scenario 80
Table 26 Interesting data for shippings leaving Cove Point. High-price scenario. 81
Table 27 [Rogers´, 55] assumptions. 86
Table 28 Panama Canal bottleneck analysis (table). 90
Table 29 Reduced number of receiving terminals for “waiting vs. alternative routing-analysis”. 93
Table 30 Maximum days waiting time instead of taking the alternative route. 135.000 cm vessels. 93
Table 31 Maximum days waiting time instead of taking the alternative route. 175.000 cm vessels. 94
Table 32 Reduced number of regasification terminals for “competitive analysis”. 96

Units

cf = cubic feet
mmcf or MMcf = million metric cubic feet
bcf or Bcf = billion cubic feet

cm = cubic meter
mmcm = million metric cubic meters
bcm = billion cubic meters (10^6 cm in SI units)
tcm = trillion cubic meters (10^9 cm in SI units)

tpa = tonne per annum
MTPA = million tonnes per annum

MMBtu = million British thermal units
lb CO2eq/MMBtu = pound CO2 equivalent per million British thermal units

Conversions

1 t LNG = 2,22 cm LNG = 1.300 cm gas = 45.909 cf gas = 53,38 MMBtu
(For 1 MTPA LNG multiply by 10^6)

1 cm LNG = 0,45 t LNG = 585 cm gas = 20.659 cf gas = 24,02 MMBtu
(For 1 mmcm LNG multiply by 10^6)

1 MMBtu = 1.055 MJ = 0,293 MWh

Liquefaction capacity example: 1.000 MMcf/d = 4,7 MTPA

Heating value example: 1.400 Btu/cf = 52,2 MJ/cm

Annex

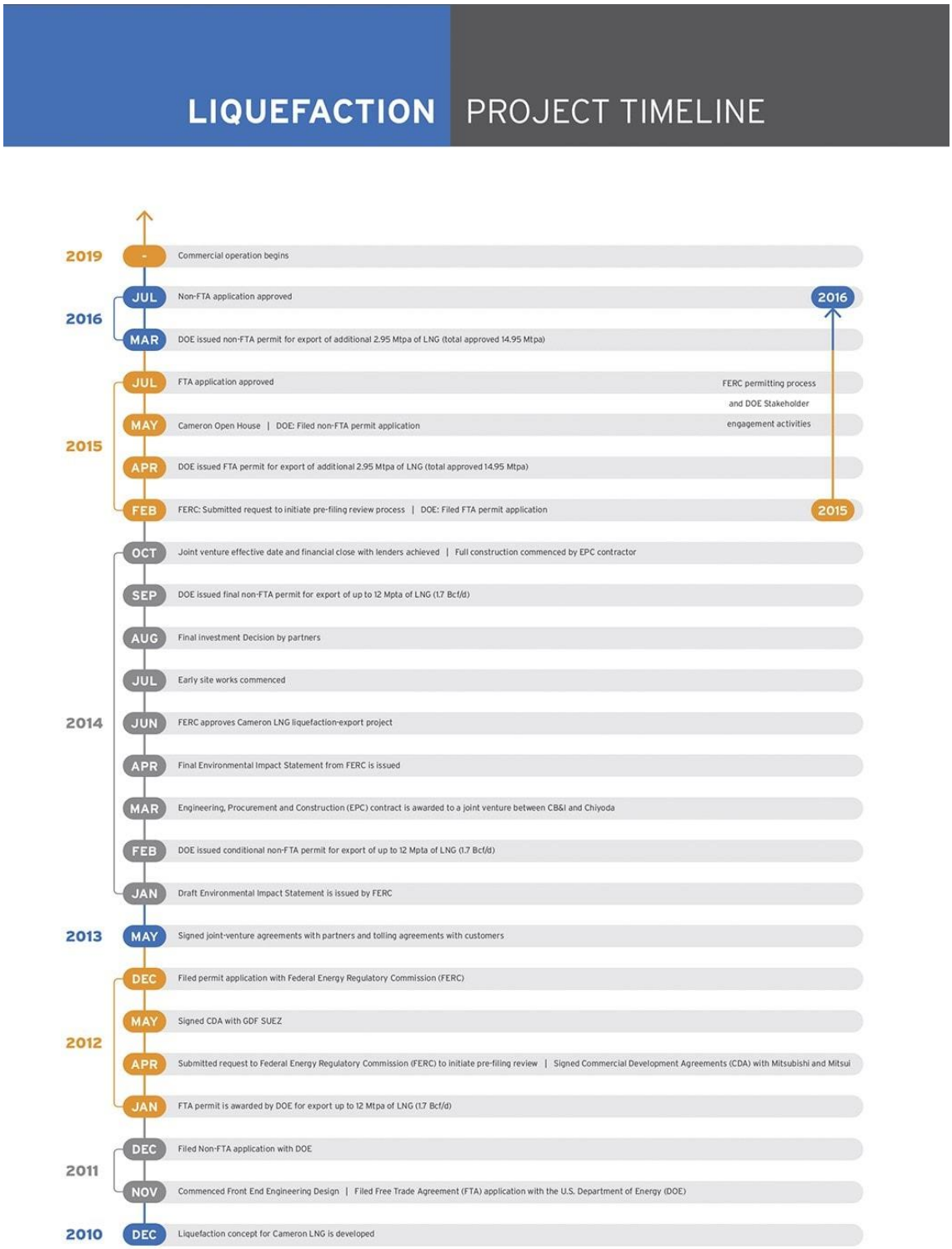
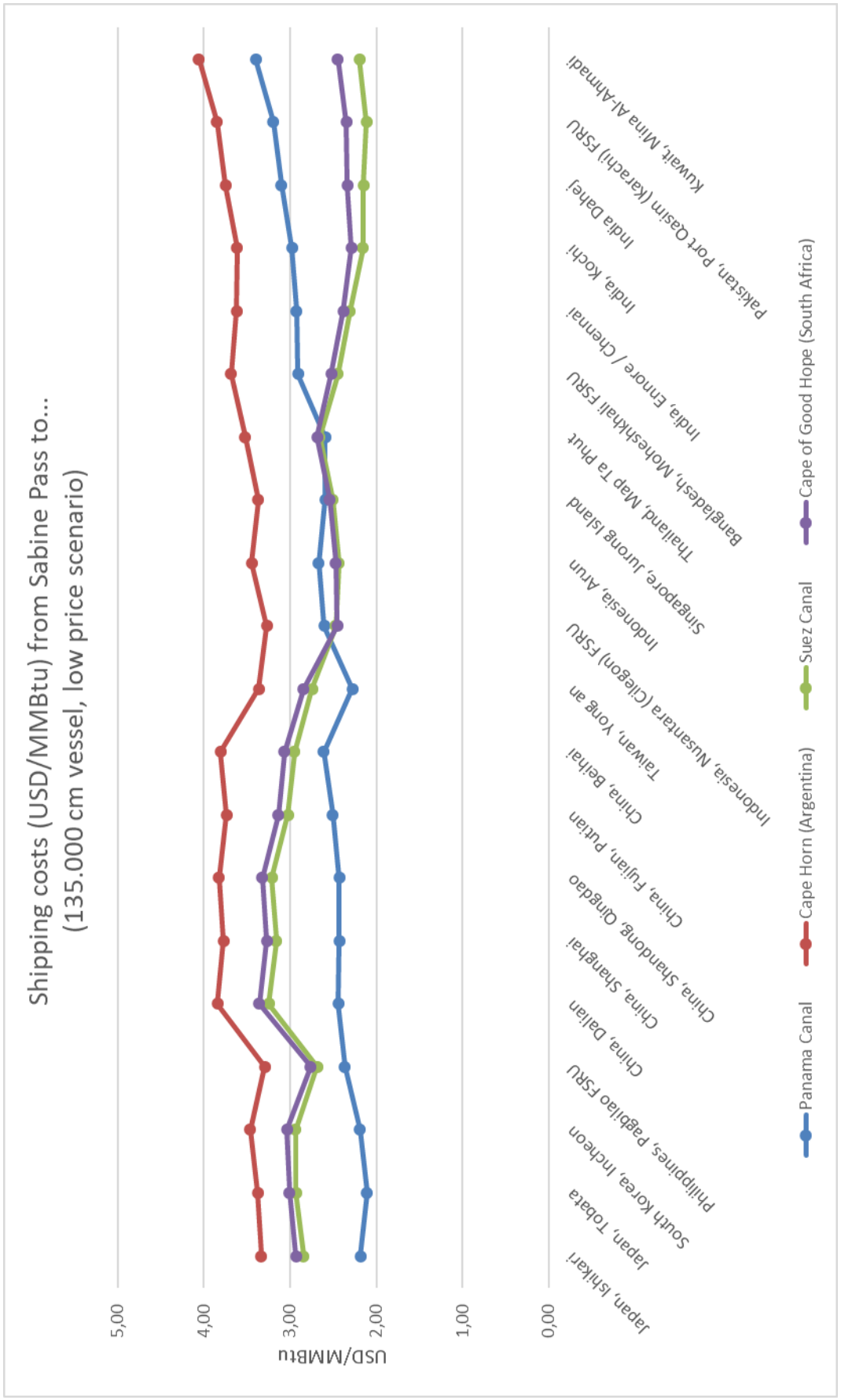
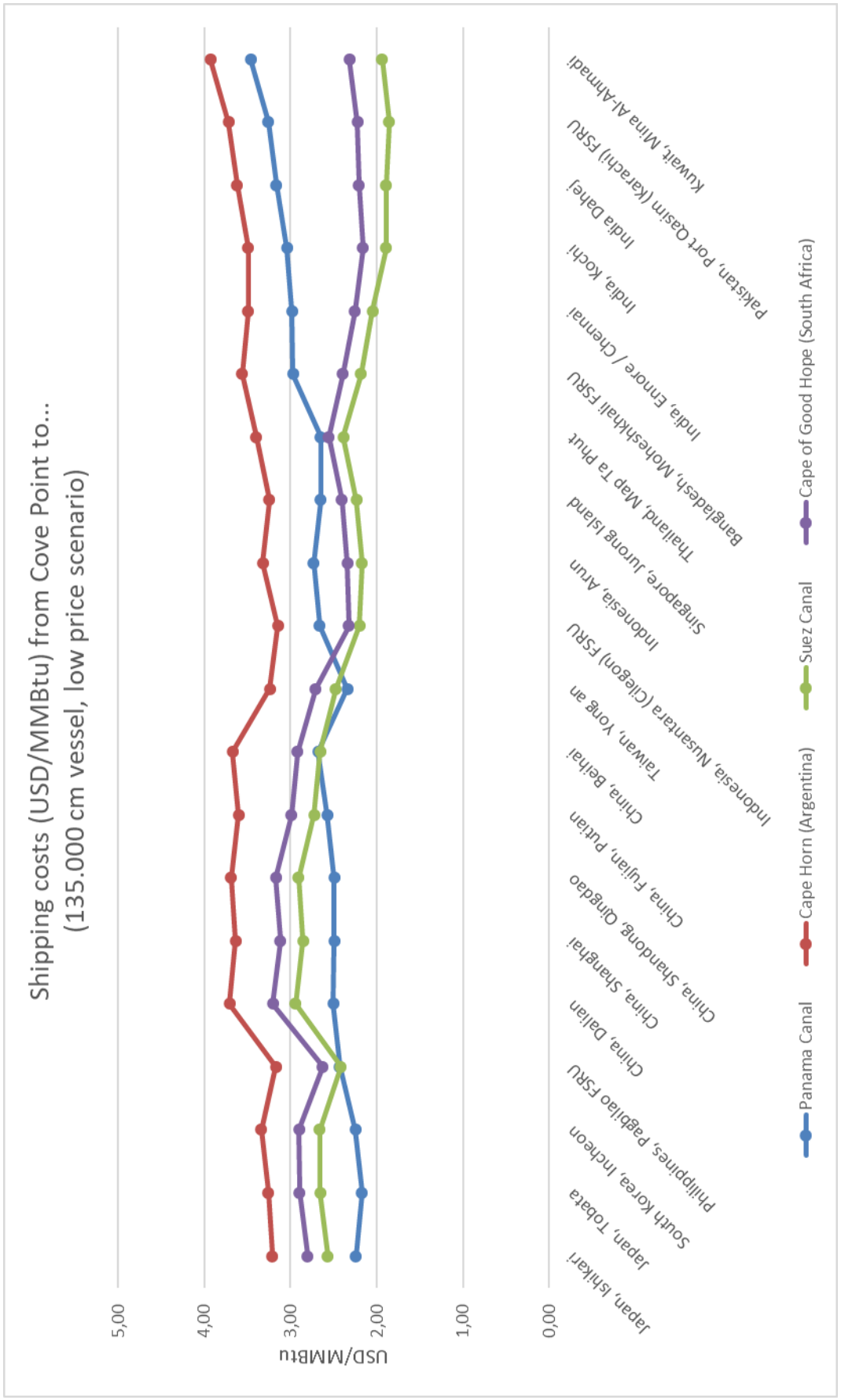


Figure 46 Exemplary LNG project timeline with major milestones for Cameron LNG, Houston.[51]

[51] http://cameronlng.com/lng-import-export/timeline/


Shipping costs (USD/MMBtu) from Sabine Pass to...
(135.000 cm vessel, low price scenario)
USD/MMBtu
5,00
4,00
3,00
2,00
1,00
0,00
Panama Canal
Cape Horn (Argentina)
Suez Canal
Cape of Good Hope (South Africa)
Japan, Ishikari
Japan, Tobata
South Korea, Incheon
Philippines, Pagbilao FSRU
China, Dalian
China, Shanghai
China, Shandong, Qingdao
China, Fujian, Putian
China, Beihai
Taiwan, Yong an
Indonesia, Nusantara (Cilegon) FSRU
Indonesia, Arun
Singapore, Jurong Island
Thailand, Map Ta Phut
Bangladesh, Moheshkhali FSRU
India, Ennore / Chennai
India, Kochi
India Dahej
Pakistan, Port Qasim (Karachi) FSRU
Kuwait, Mina Al-Ahmadi


Shipping costs (USD/MMBtu) from Cove Point to...
(135.000 cm vessel, low price scenario)
USD/MMBtu
5,00
4,00
3,00
2,00
1,00
0,00
Panama Canal
Cape Horn (Argentina)
Suez Canal
Cape of Good Hope (South Africa)
Japan, Ishikari
Japan, Tobata
South Korea, Incheon
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China, Shanghai
China, Shandong, Qingdao
China, Fujian, Putian
China, Beihai
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Singapore, Jurong Island
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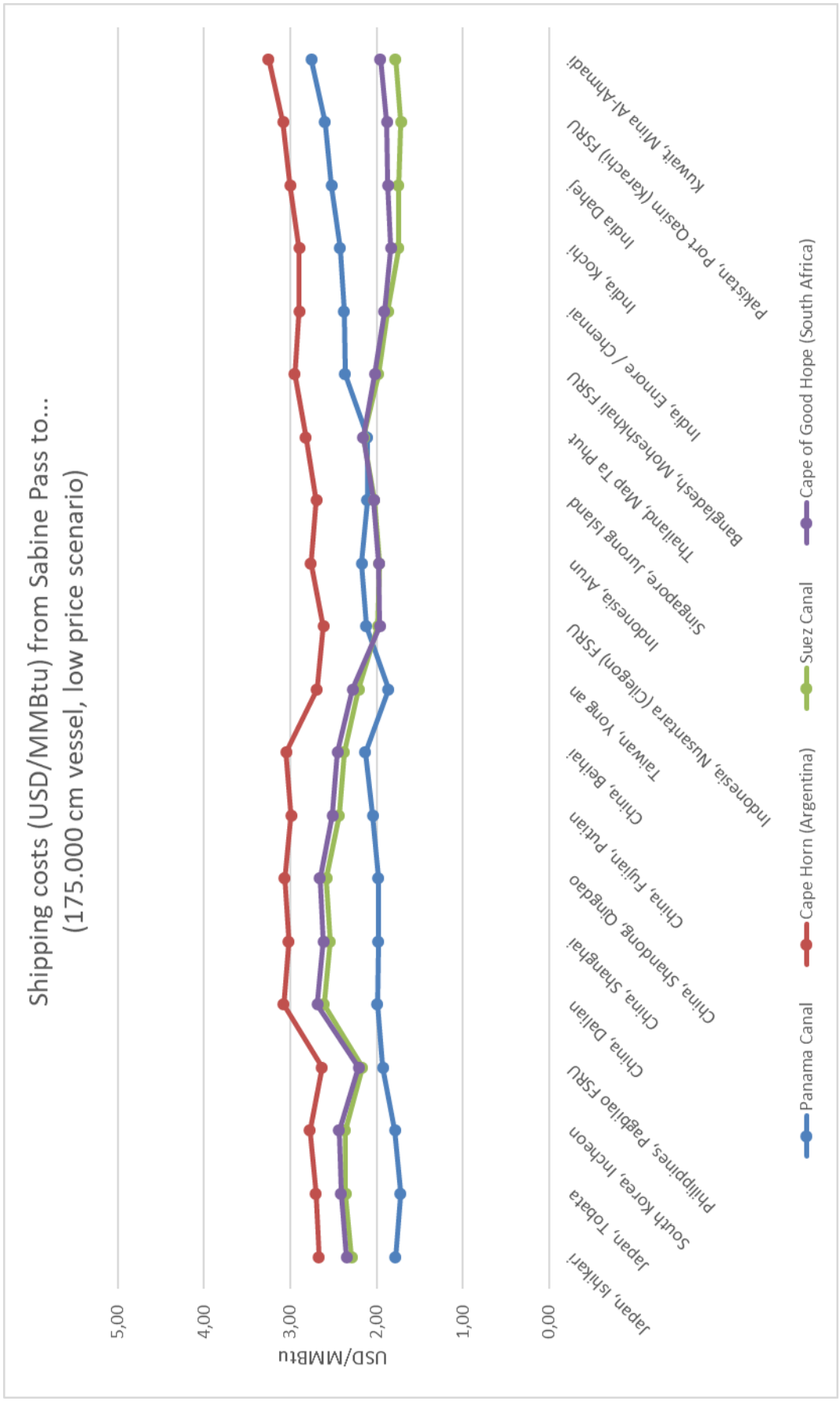
India, Ennore / Chennai
India, Kochi
India Dahej
Pakistan, Port Qasim (Karachi) FSRU
Kuwait, Mina Al-Ahmadi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USD/MMBtu
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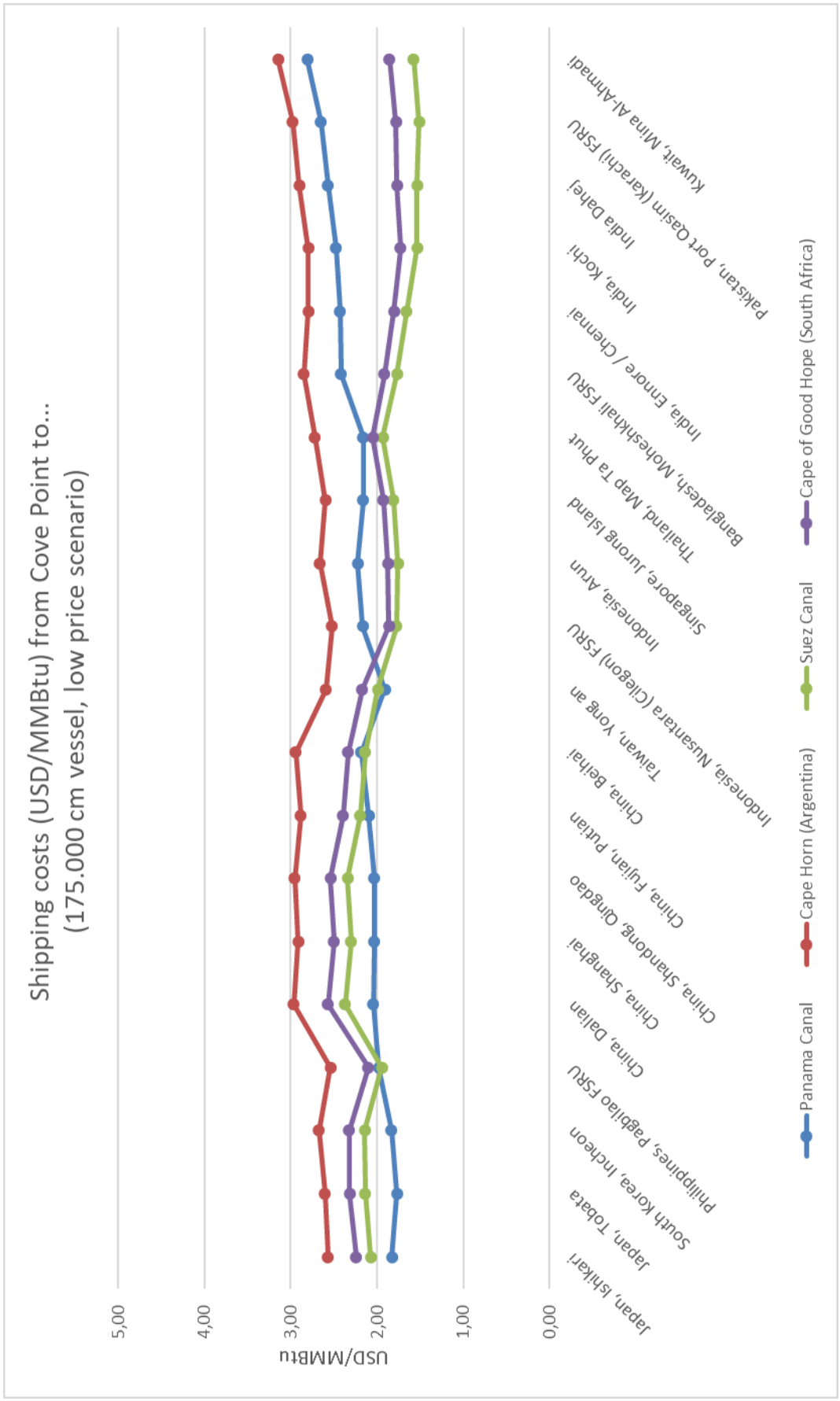
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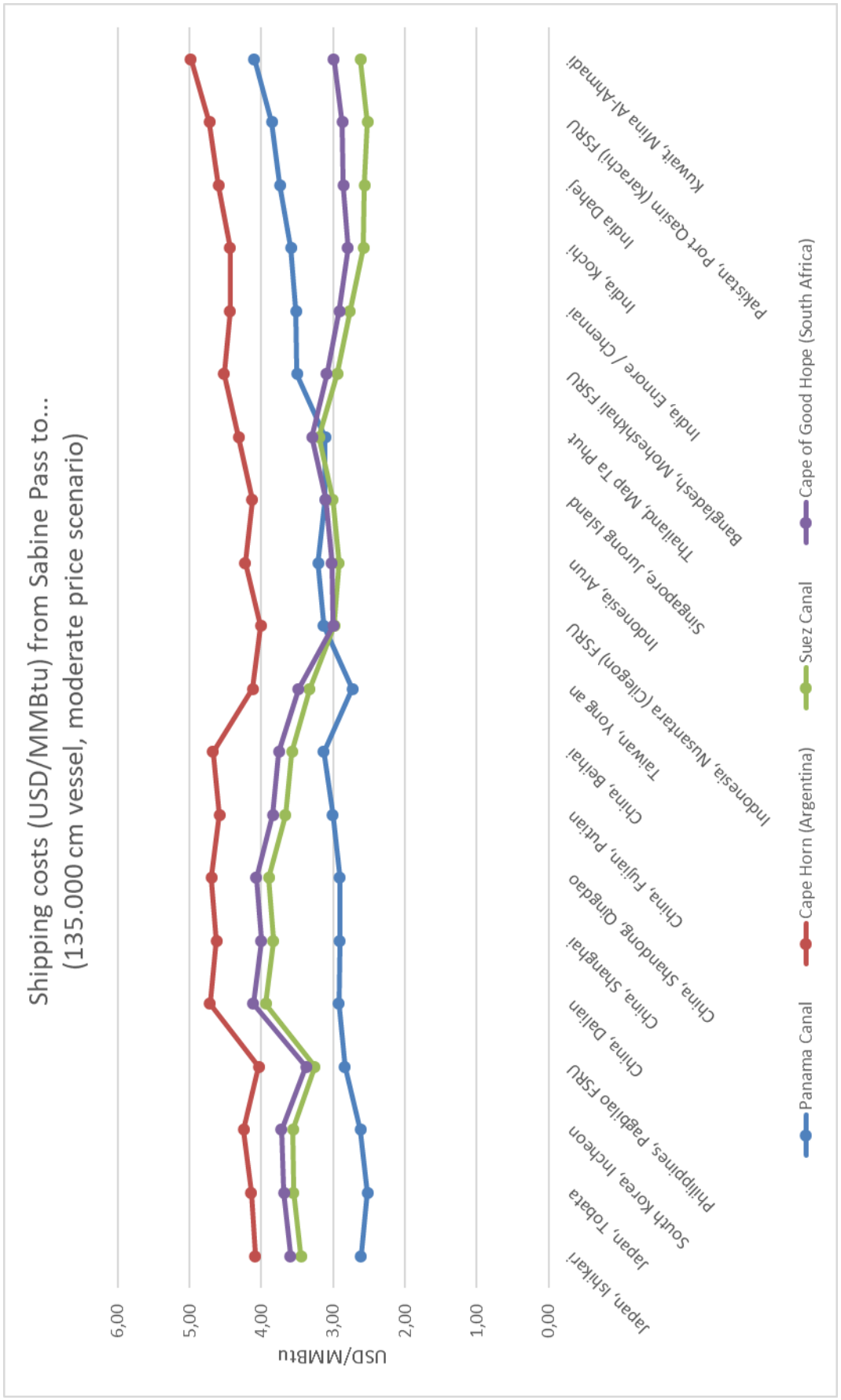
Kuwait, Mina Al-Ahmadi


Shipping costs (USD/MMBtu) from Sabine Pass to...
(135.000 cm vessel, moderate price scenario)
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Cape of Good Hope (South Africa)
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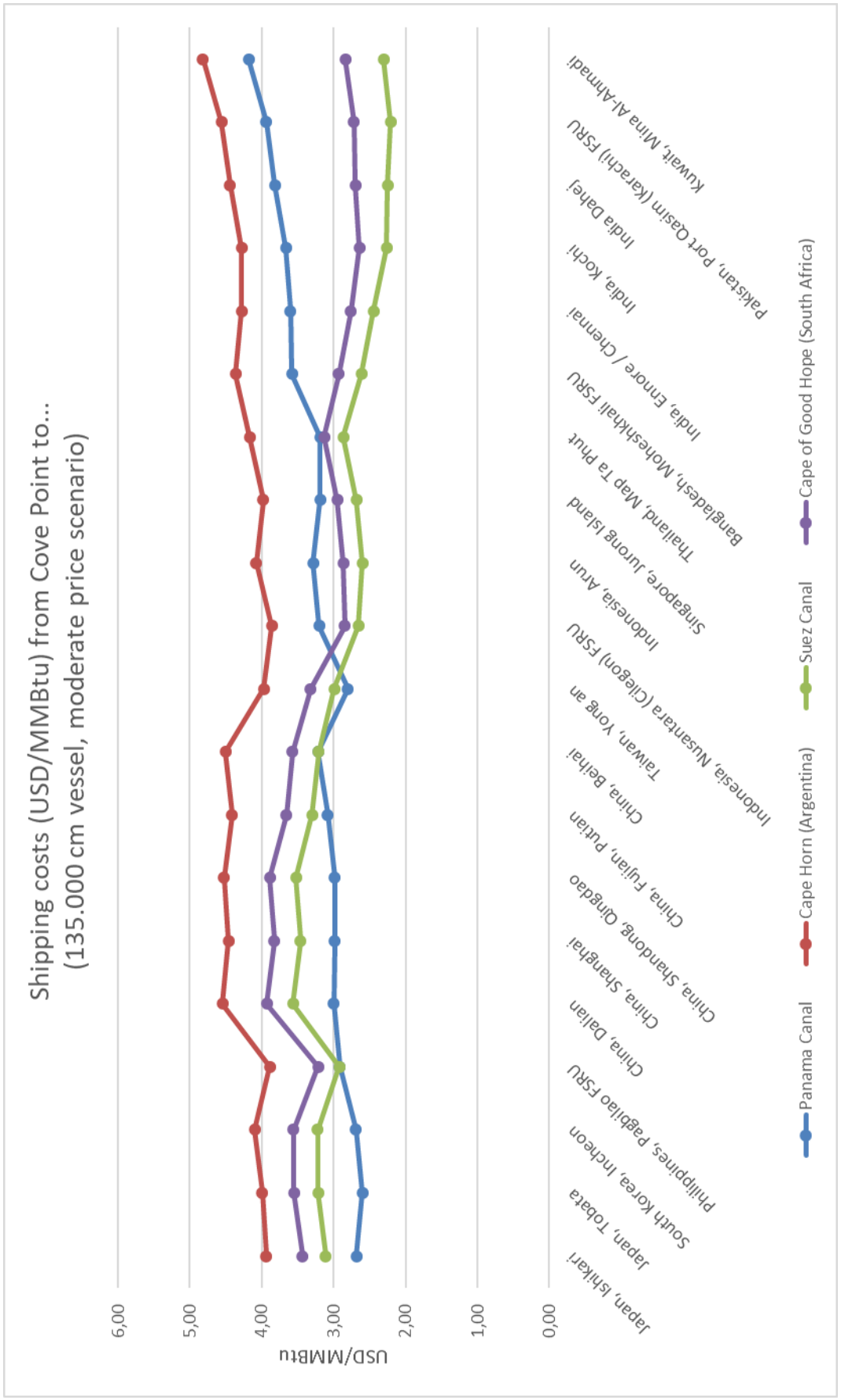
Kuwait, Mina Al-Ahmadi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(135.000 cm vessel, moderate price scenario)
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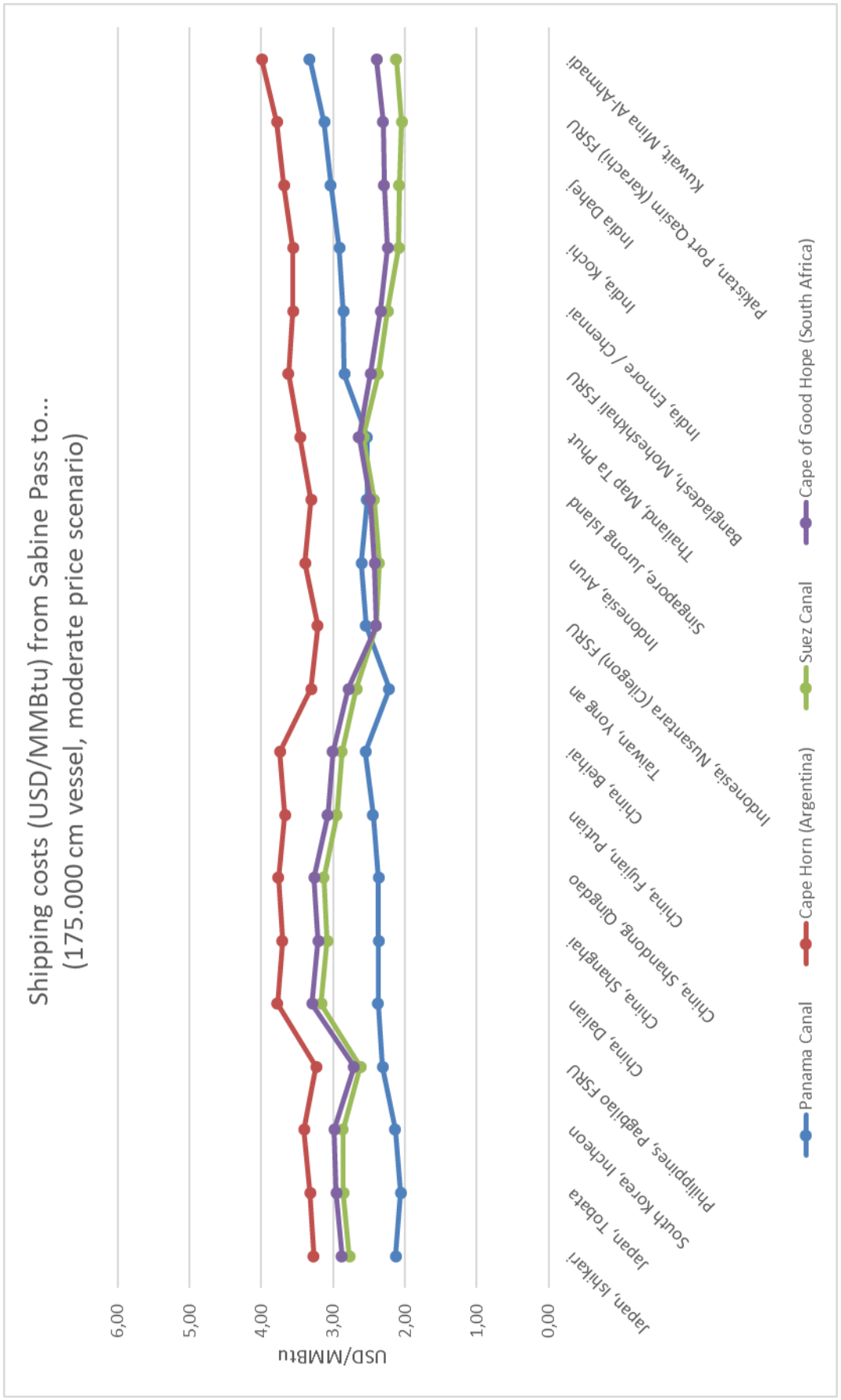
Shipping costs (USD/MMBtu) from Sabine Pass to...
(175.000 cm vessel, moderate price scenario)
USD/MMBtu
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Panama Canal
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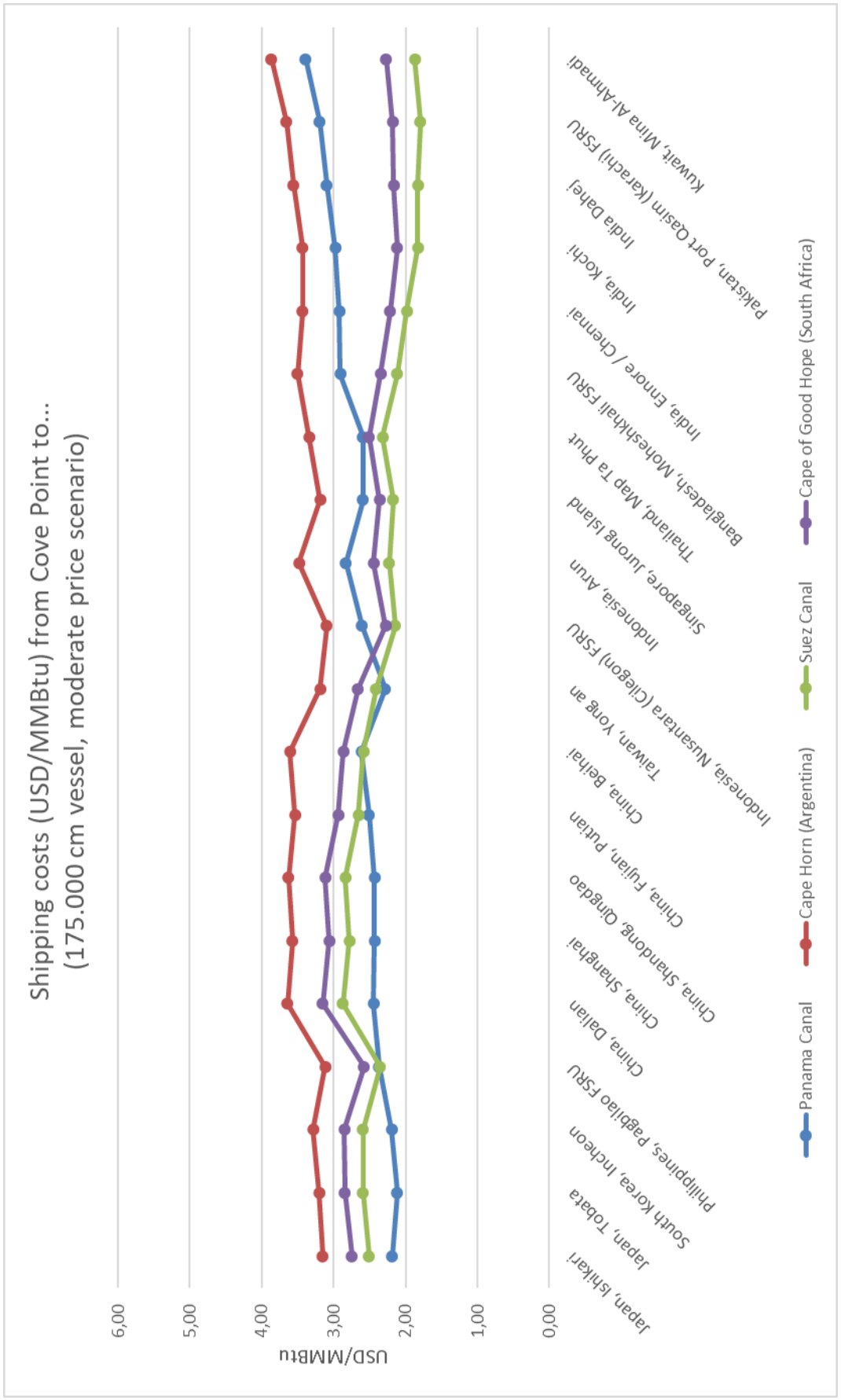
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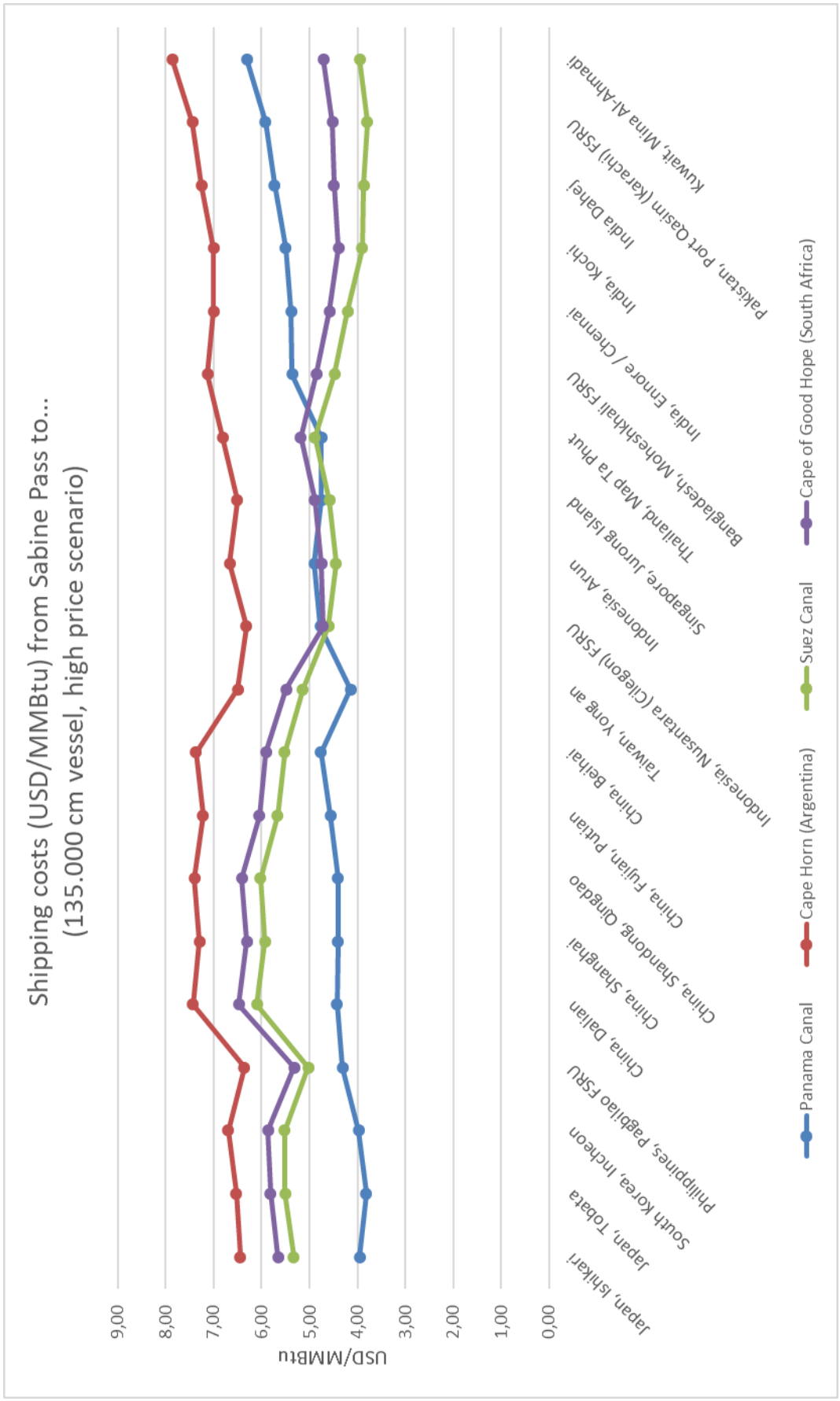
Shipping costs (USD/MMBtu) from Sabine Pass to...
(135.000 cm vessel, high price scenario)
USD/MMBtu
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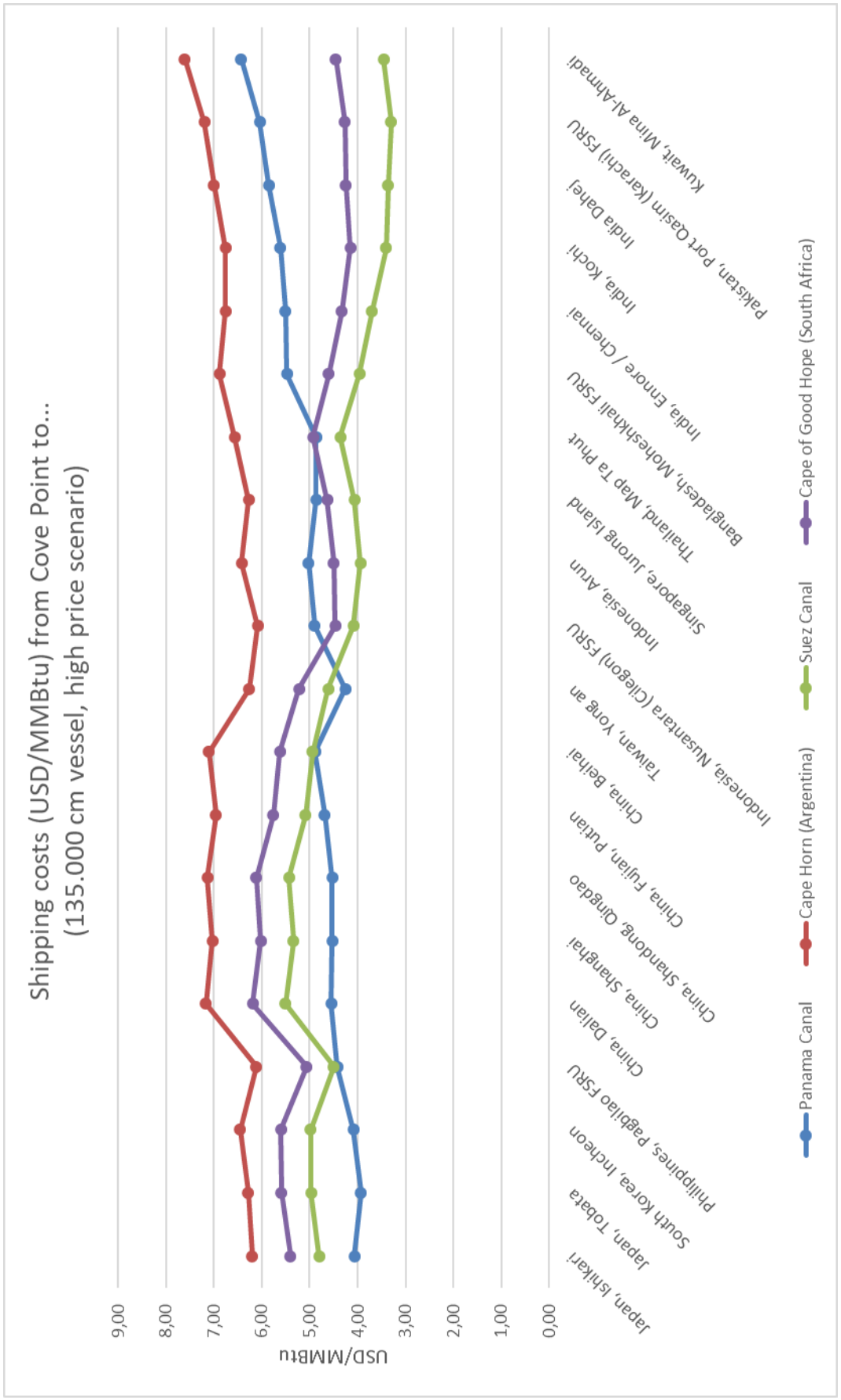
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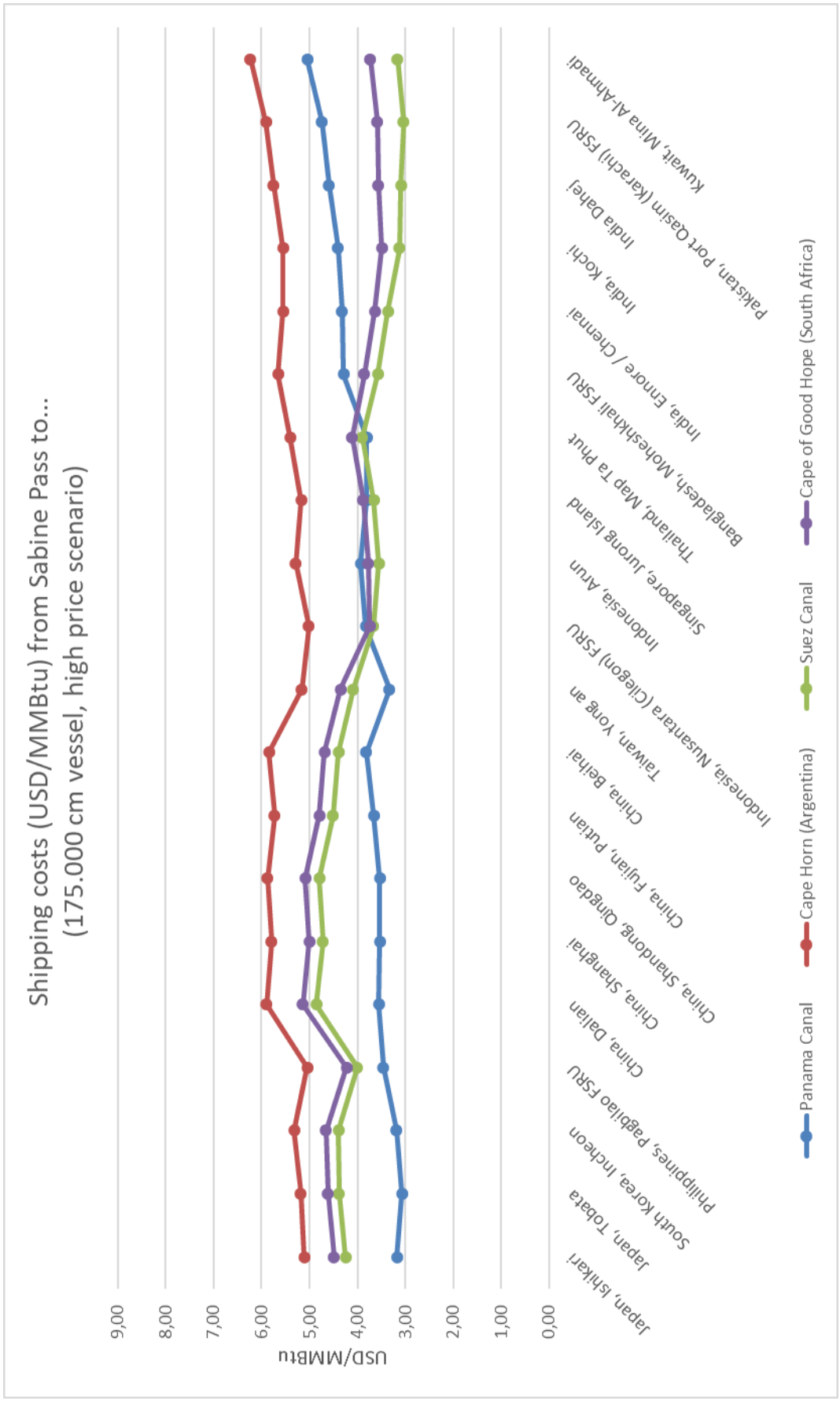
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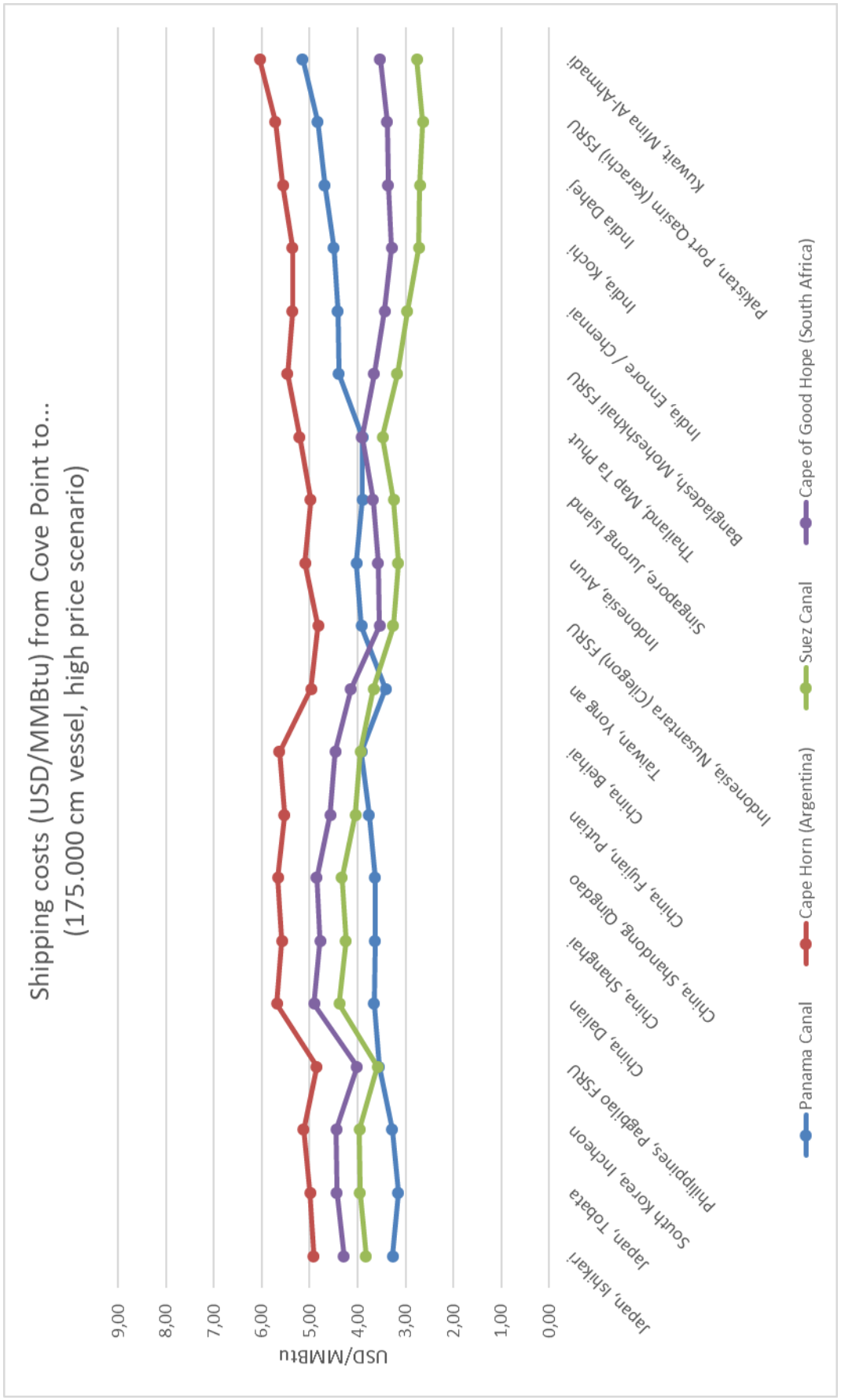
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Calculation example by [Rogers, 55]: Part I – Key assumptions

Nominal Carrier Size:160,000 cubic metres

LNG liquid cubic metres to MMBtu: 23.12 (GIIGNL 2017 Annual Report, Page 36)

Fuel oil price: taken from *Argus Global LNG* 'Competing Fuel' 1pc fuel oil NW Europe series. In December 2017 this was $348.80/tonne. Future prices are scaled with crude forward curve prices based on current fuel oil – North Sea dated crude relationship.

Opportunity cost of gas (for boil off fuel cost calculation): Either European hub price or Asian LNG spot price.

Average carrier speed: 19 knots for DFDE and ST.

Fuel Consumption: 72 Tonnes/day LNG equivalent[18] for DFDE; 145 Tonnes/day LNG equivalent for ST – comprising LNG boil-off and Heavy Fuel Oil for ST).

Boil-off assumptions: around 0.1% of cargo per day for DFDE, 0.15% of cargo per day for ST.

LNG heel: for the assumed return leg of the journey the LNG storage compartments/tanks need to be kept cool; hence there is a need to keep back some of the original cargo. It has been assumed that 4% of the cargo is retained as the heel..

Port costs: difficult to quantify and needs to be separated from re-gas charges. Assume $100,000 per cargo based on non-unloading costs at Montoir and Fos Tonkin terminals[19].

Suez Canal costs: Timera Energy suggests a range of $300,000 to $500,000/LNG ship[20]. Assume $400,000.

Panama Canal costs: The US Energy Information Administration (EIA) estimate a cost of $0.20/MMBtu for a round trip voyage (outbound and return transit)[21].

Other costs: broker's and ship agent's costs are assumed at 2% of the total charter fee; insurance appears to average some $2,600/day, based on averaging data in Argus Global LNG, January 2018, Page 26.

Figure 47 Input data part 1, example from [Rogers, 55].

Calculation example by [Rogers, 55]: Part II – Example calculation for a DFDE carrier

Example route: Sabine Pass to Shanghai (via Panama Canal) is 10,081 nautical miles (one way).

Average carrier speed: 19 nautical miles/hour.

Nominal vessel size: 160,000 m3 liquid LNG.

At 98% loading: 156,800 m3 liquid LNG (3,625,216 MMBtu). Assume heel left at end of return (ballast) voyage (4%) = 145,009 MMBtu.

Charter rate: $33,286/day (July 2017 figure).

Daily LNG boil-off: 3,673 MMBtu/day.

Opportunity cost of LNG boil-off: $20,204/day (assuming destination price of $5.5/MMBtu).

Voyage days: 22.1 days each way.

Port days: 3, outbound port, destination port and return destination port.

Charter costs: 44.22+3=47.2 days at $33,286/day = $1,571,596 (allowing for rounding).

Fuel costs: LNG boil-off for 44.22 days: 20,204x44.22 = $893,315 (allowing for rounding).

LNG delivered at destination: 3,317,787 MMBtu (initial loading less boil-off on outward voyage, less boil-off and heel reserved for return (ballast voyage)).

Panama Canal fee: outbound and return voyage is $0.2/MMBtu = $663,557 based on size of delivered cargo.

Port costs: 3 days at $100,000/day = $300,000.

Agents and broker fees, and insurance: 2% of charter cost plus $2,600/day for insurance. This equates to $154,191 (allowing for rounding).

Summarising:

Charter costs:	$1,571,596
Fuel costs:	$893,315
Panama Canal fee:	$663,557
Port costs:	$300,000
Agents and broker fees plus insurance:	$154,191
Total:	**$3,582,658**

Based on the delivered cargo of 3,317,787 MMBtu, the total cost is $1.08/MMBtu.

Figure 48 Input data part 2, example from [Rogers, 55].