Overview of the LNG industry

Anton Putter
September 2020

This is the first article in a series planned by OTC on natural gas (NG) and liquefied natural gas (LNG). It also ties in with previous articles published in late 2018 on the gas industry in southern Africa (Putter, 2018a & 2018b).

The planned NG and LNG series includes:

1. Overview of the LNG industry – September 2020
2. Gas logistics – November 2020
3. LNG technologies – January 2021
4. Comparison of inland gas and imported LNG – May 2021
5. Outlets for NG and LNG – June 2021
6. Gas for power generation – September 2021
7. Small scale versus large scale LNG – October 2021
8. Gas utilisation in transport – November 2021

These articles will be published over a period of 15 months and will be interspersed with articles related to aspects of project management.

Introduction

In this overview of the natural gas (NG) and liquefied natural gas (LNG) industries, the emphasis is on the global LNG industry. Where applicable, brief remarks are included on LNG in southern Africa.

The purpose of this article is to provide background on the LNG industry, as an introduction to the articles that follow. In this article a high-level overview is provided on the history of the LNG industry, the elements in the value chain, the main drivers of the LNG industry, and the status and potential of LNG in southern Africa.

History

Natural gas liquefaction dates back to the early nineteenth century when Michael Faraday (the same scientist of electromagnetism and electrochemistry fame and whose name is immortalised in concepts such as the Faraday cage and the SI unit of capacitance, the Farad) experimented with liquefying different types of gases. In 1820, Faraday succeeded in liquefying natural gas at a temperature of 113 Kelvin (-160°C).

Following are further highlights in the development of the LNG industry (most of the information extracted from Foss (2012)):

- German engineer, Karl von Linde, built the first industrial compressor refrigeration machine in Munich in 1873.
- The first commercial LNG liquefaction and regasification facilities started operating in Cleveland, Ohio, in 1941. This was a peak shaving plant which liquefies gas during periods of low demand, and then regasifies the LNG during periods of high demand for reintroduction into the pipeline system. There are now more than a hundred of these peak shaving facilities in the USA.
- The first bulk shipping of LNG took place in January 1959 when the world's first oceangoing LNG tanker, the Methane Pioneer, carried LNG from Lake Charles in Louisiana to Canvey Island in the United Kingdom. The Methane Pioneer was built in 1945 as a cargo ship named Marline Hitch, before being rebuilt in 1958 for the purpose of transporting LNG.
- Following the successful demonstration of LNG shipments by the Methane Pioneer, the British Gas Council initiated plans for the commercial importation of LNG. This commenced with the start-up of the "large" three-train Camel LNG plant in Algeria in 1964 (total capacity 0.9 million tpa). As a result, Algeria became the world's first LNG exporter and the United Kingdom the world's first LNG importer.
- The first imports of LNG into Asia (today the premier market for LNG imports) commenced in 1969 when Tokyo Electric and Tokyo Gas started purchasing LNG from Alaska.

Since this start of LNG production in 1941 and the start of LNG trade in 1964, the LNG industry has grown rapidly as demonstrated by the graph in Figure 1 from International Gas Union (IGU, 2020) showing that LNG capacity has grown eight-fold since 1990 to well over 400 million tpa. Further dramatic growth is forecast as shown in Figure 1.

Although LNG developments occurred across the globe, there were three specific areas developing strongly at different stages:

- Qatar's LNG capacity growth from 1995 to 2008 to reach 77 million tpa (and new plans to increase this to an ultimate 126 million tpa with the first of the six new trains planned for commissioning in 2025).

- Australian LNG capacity growth from 2009 to 2017 to reach 87 million tpa.
- USA export LNG capacity growth starting in 2016 with total capacity by end 2019 at 46 million tpa and a further 54 million tpa already sanctioned (either under construction or having achieved final financial approval).

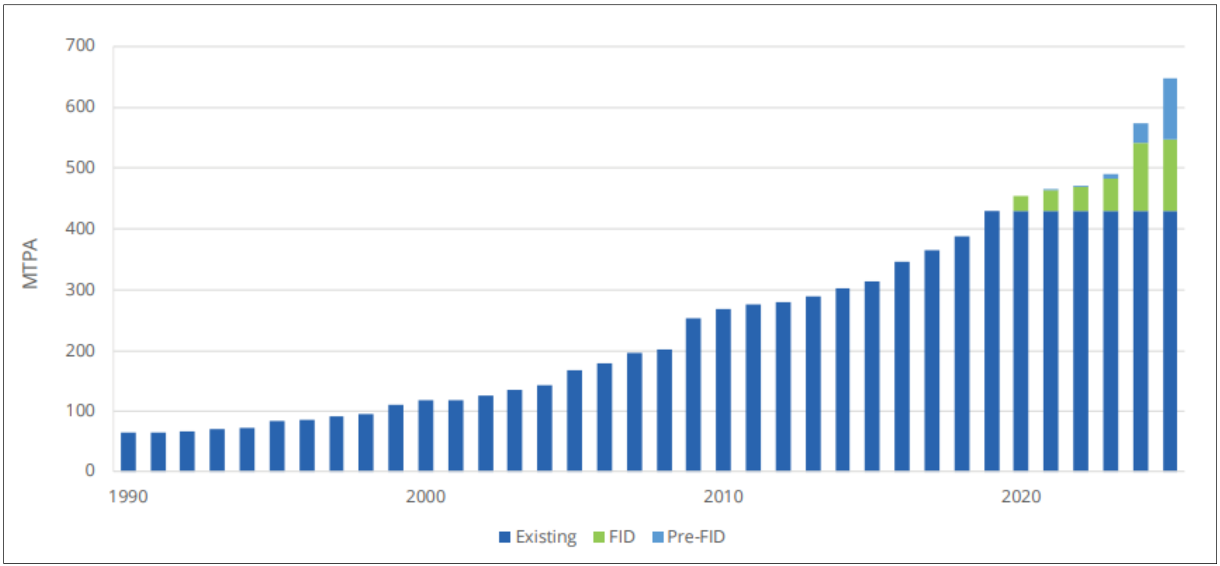

Figure 1: Growth in global LNG production capacity (IGU, 2020)

LNG value chain

Opening remarks

A typical LNG value chain is diagrammatically illustrated in Figure 2, with the value steps listed above the diagram.

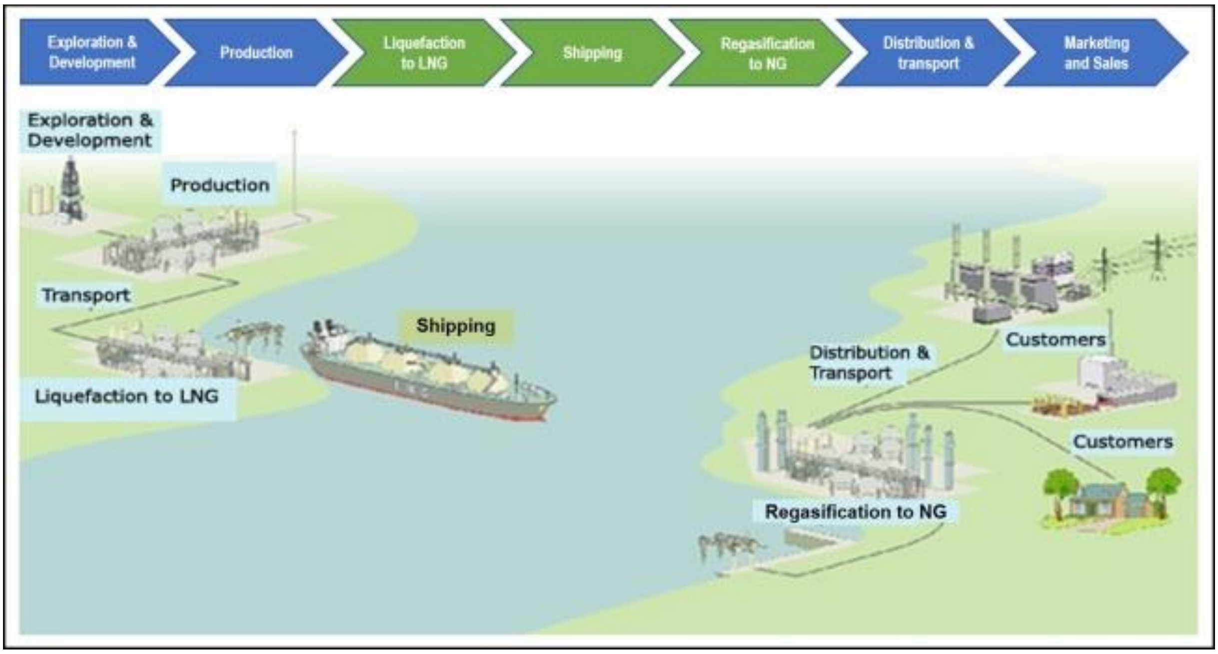

Figure 2: LNG value chain (Adapted from Oman LNG, 2020)

The value chain elements that are specific to LNG, namely liquefaction to LNG, shipping transport, and gasification to NG, are dealt with in the rest of this section (illustrated with a dark green background in Figure 2). The other elements are part of the value chain of any gas sales, and not specific to LNG.

Liquefaction

Liquefaction is the heart of the LNG industry and the most expensive part of the value chain to get the gas from source to consumer (in cases where liquefaction is employed). The logistics of getting natural gas from the source to the consumer is often the biggest challenge in the development of a natural gas resource. Liquefaction and LNG transport fulfils a growing role in solving natural gas logistic challenges and is extensively used for sea-borne transport, together with specialised LNG tankers.

The global liquefaction capacity at end 2019 is illustrated in Figure 3, which shows that half of the world's LNG capacity is concentrated in Australia, Qatar, and the USA.

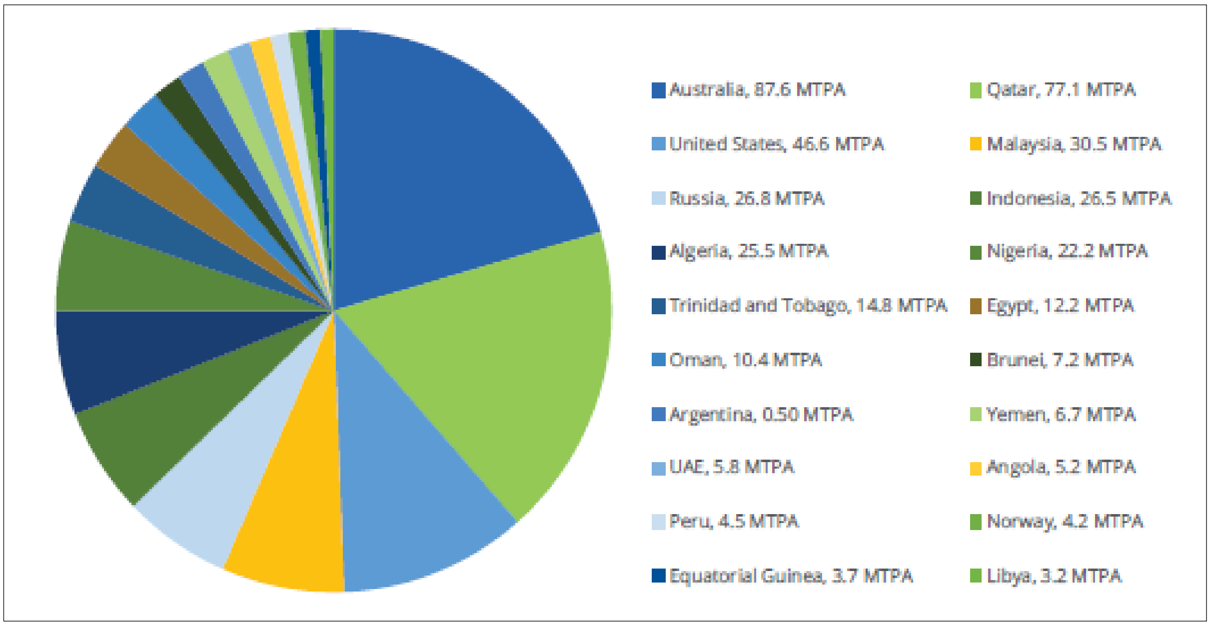

Figure 3: Global LNG liquefaction capacity (IGU, 2020)

From the start of the Camel LNG plants in Algeria, the scale of the LNG developments around the world has grown dramatically. As shown in Figure 1, the compound capacity growth over the last 20 years has been more than 10% per annum with further strong growth in the forecast.

Single-train LNG capacity has increased dramatically from the 0.3 million tpa Camel trains with single train capacities of 4,5 to 5,5 million tpa now quite common. Even larger trains are planned such as the two train Rovuma LNG project in Mozambique (each train at 7,6 million tpa) and the planned Qatar trains at 8 million tpa each.

The utilisation rate of global LNG capacity has varied between 80% and 85% over the past number of years (actual utilisation rate in 2019 at 81.4%). At an approximate LNG utilised volume in 2019 of 350 million tons, this means that LNG played a role in over 12% of NG consumed in the world. Although this ratio is growing, it still indicates that LNG is only involved in a small fraction of the gas value chains worldwide. The bulk of NG logistics occurs via pipeline. Even NG value chains that include LNG facilities, normally also include pipelines along the way.

A variety of liquefaction technologies are available from companies such as Air Products, Shell, ConocoPhillips, Black & Veatch, Baker Hughes/GE, and Linde. There are also operator self-developed technologies in use, such as by CNPC. The dominant technology supplier to date has been Air Products and according to IGU (2020), 70% of the global operational capacity by end 2019 was based on Air Products technology.

Liquefaction projects are highly capital intensive. For the large LNG plants the capital cost per unit of installed capacity varies from \$600/tpa to \$2000/tpa over the past 10 years. The variation in unit capital costs for liquefaction is shown in Figure 4.

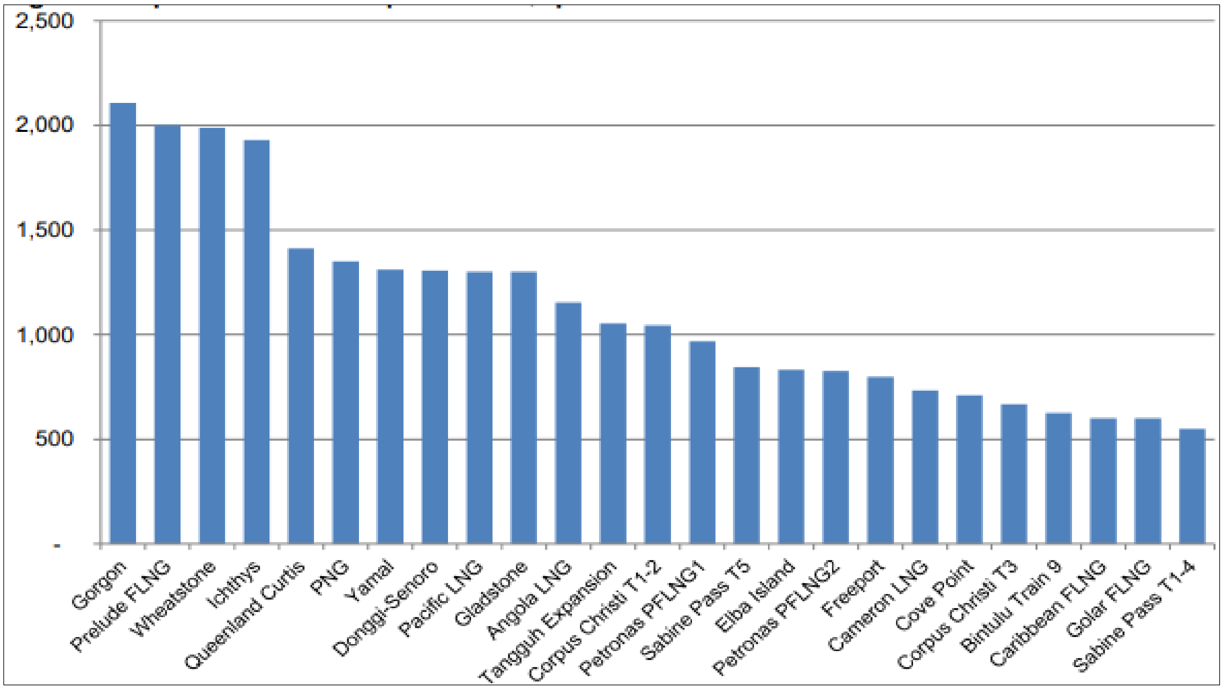

Figure 4: Unit capital cost for liquefaction in \$/tpa (Songhurst, 2018)

The big variation in unit capital cost is driven by several factors. As is common in the petrochemical industry, the scale of the trains has a significant impact on the unit capital cost. Other factors that play a significant role, are the following:

- Whether the feed gas is lean gas (such as shale gas in the USA) or rich gas which will require feed processing.
- Whether the project is a greenfield facility or a brownfield expansion.
- The location of the liquefaction facility, with lowest cost being in the USA and most expensive in Australia.

The fact is that LNG plants are expensive to construct. Extreme examples of this are the Gorgon project in Australia with a total capital cost of $53 billion (three trains and a total LNG capacity of 15,6 million tpa) and the Yamal project in Russia with a total capital cost of $27 billion (three trains and a total capacity of 16,6 million tpa). Even smaller expansion projects such as Bintulu train 9 with a capacity of 3,6 million tpa carries a price tag of $2,5 billion.

Although these large conventional LNG plants get all the attention, there are also other variations of LNG plants. Increasing use is made of floating LNG (FLNG) facilities which are constructed offshore. Interesting to note from Figure 4 is that the unit costs of these FLNG facilities are not necessarily higher than the capital cost of the land-based plants.

Small-scale LNG plants (roughly classified as capacities below 500 000 tpa) are constructed in increasing numbers. Even micro-scale LNG plants (capacities below 50 000 tpa) are constructed in specific circumstances, such as treatment of biogas from waste-dumps (where capacities as low as 5 000 tpa are used). These smaller LNG plants are often modularised skid-mounted units.

Apart from the capital cost for constructing an LNG plant, the energy efficiency of the LNG plant is probably the most important consideration in making decisions on the life-cycle economics of the facility. Liquefaction of NG is a highly energy intensive process, driven primarily by large refrigeration requirements. Should the energy required be solely sourced from gas, typically 8 to 10% of the feedstock to an LNG plant will be consumed as energy for the liquefaction process. If the feed gas is only available at atmospheric pressure (such as from coal-bed methane), this energy consumption increases significantly.

According to IGU (2020), more than 40 large LNG plants (capacity over 1 million tpa) were operating at the end of 2019. Most of these plants had multiple trains with Qatargas and Rasgas in Qatar now both up to seven trains each. Four of these facilities are FLNGs. In 2014, there were close to 100 small-scale LNG facilities operating with a total capacity of approximately 20 million tpa. The exact current number of small-scale facilities is unknown but is expected to be approximately 150.

Shipping

LNG shipping is employed to facilitate logistics of gas across large bodies of water where gas pipelines are not practical or not feasible. According to the BP Statistical Review (BP Energy Review, 2020), 240 million tons of LNG was moved in interregional trade in the world in 2019, all of this probably done via LNG shipping. Other uses of LNG to make up the total production of 350 million tpa mentioned above, would be intraregional trade of LNG such as within Asia Pacific (mainly still done by means of shipping), inland LNG facilities, peak shaving LNG facilities, and exploitation of stranded pockets of gas (such as flared associated gas in the Permian basin).

LNG carriers are specially designed and constructed refrigerated ships. These ships store LNG at atmospheric pressure (unlike LPG carriers which operate at elevated pressures) and transport the LNG in individual insulated tanks. Typically, 0,1% to 0,25% of the LNG boils off daily. The new carriers have onboard liquefaction systems to reliquefy the boil-off, but most of the older carriers just use the boil-off as fuel for their engines.

According to IGU (2020), the global operating fleet of LNG carriers total 503 vessels. The carrier capacities are typically between 140 000 m^3 and 210 000 m^3 of LNG, with very few carrier capacities below 130 000 m^3 and a few large carriers of 266 000 m^3 capacities. Vessels are designed with specific criteria in mind, such as the ability to fit through the Panama canal, to limit their draughts for access to specific berths, to withstand sea-ice (in the case of vessels serving the Yamal LNG facility in Russia), and means of dealing with LNG boil-off. LNG carriers are expensive vehicles and the capital cost for an individual vessel can exceed $300 million. The delivery time from the placement of an order is typically 30 to 50 months.

The carriers complete an average of 11 to 12 voyages per year (total of 5 701 voyages in 2019). Figure 5 shows the number of LNG voyages to Asia and Europe in 2019 together with the associated tonnage of LNG delivered.

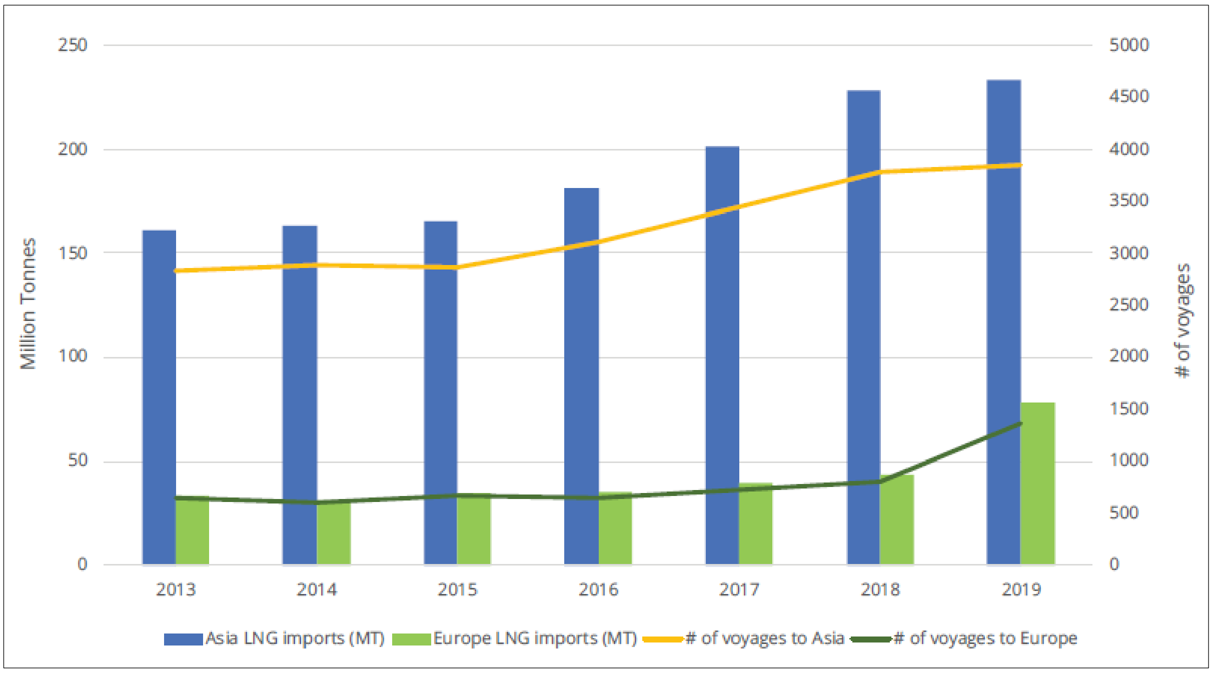

Figure 5: LNG imports and voyages to Asia and Europe (IGU, 2020)

Figure 5 clearly illustrates the following:

- **The dominance of Asia in the global LNG trade**: Although the ratio has been declining over the past few years, the LNG carrier deliveries into Asia in 2019 represented more than 65% of the global LNG market.

- **The sharp increase in LNG imports into Europe in 2019**: This was largely driven by LNG exports from the newly completed USA LNG plants and the low global spot LNG prices in 2019. The future of these European LNG imports is uncertain as LNG spot prices recover from their current low levels and gas pipeline projects such as Nordstream 2 and Turkstream come online.

Regasification

Regasification refers to the receiving terminals where the LNG from the LNG carriers are received, stored, and vaporised for supply to customers by pipeline (even if the customer is an electricity generator adjacent to the receiving terminal). On paper there is substantial slack capacity in these facilities with the global regasification capacity at over 800 million tpa at the end of 2019.

As already mentioned, Asia represents roughly two thirds of the global LNG market. This is also reflected in the LNG receiving terminal capacity. Japan has the largest import terminal capacity by far, but China is catching up fast in terms of actual LNG import quantities. High growth rates are evident in LNG import terminal capacity in China and India. Figure 6 shows the LNG regasification capacity by country and the regasification utilisation capacity in 2019.

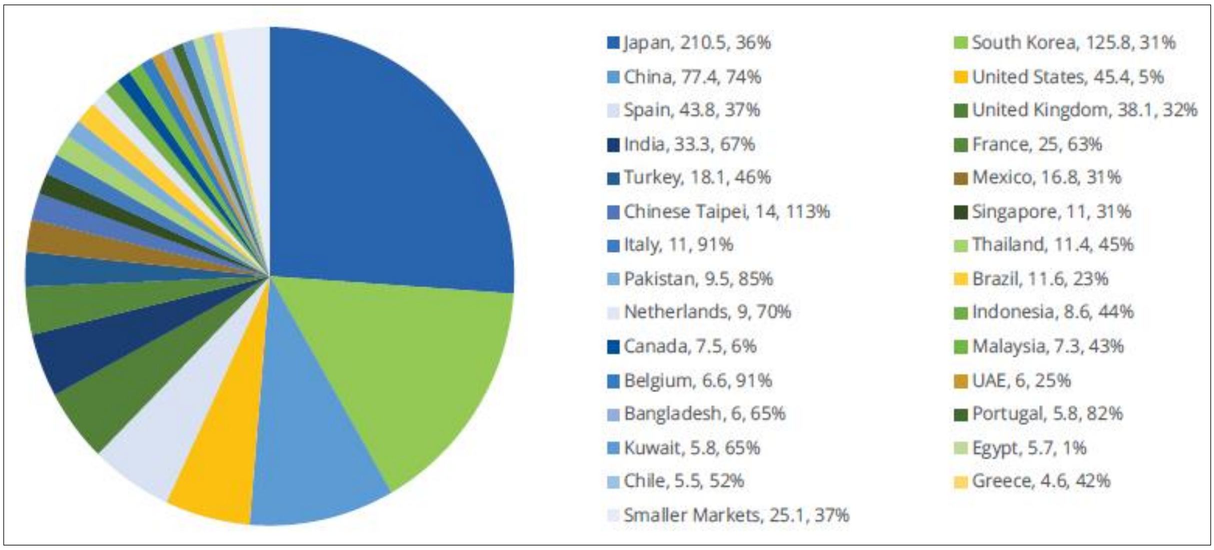

Figure 6: LNG regasification capacity (million tpa) and utilisation rate (IGU, 2020)

Traditionally all regasification terminals were land-based. Since 2005, a new type of regasification facility has emerged and today represents approximately half of all new developments. These are floating storage and regasification units (FSRUs). FSRUs can be custom built, but they are often converted LNG carriers. Although many factors play a role when deciding between a shore-based and floating facility, the main advantages offered by FSRUs are their lower capital cost and the shorter schedules involved.

The advantage in capital costs enjoyed by FSRUs are significant. According to Songhurst (2017), the typical capital costs for a 3 million tpa gasification and 180 000 m^3 storage facility would be $750 million for a shore-based facility and $450 million for an FSRU.

The rate-determining step for a shore-based regasification terminal is the storage tank construction which typically takes 36 to 40 months. According to Songhurst (2017), a new-build FSRU would take 27 to 36 months, but a conversion of an LNG carrier could be done in 18 to 24 months. Even quicker is relocating an existing FSRU when a project could be completed within six months, largely determined by the land-based infrastructure that needs to be put in place.

LNG economics

It is clear from the above discussion on the LNG value chain that large investments are required to put the liquefaction, LNG carriers and regasification terminals in place. This meant that traditionally long-term contracts (typically 15 to 20 years) and contract pricing had to be established before project financing could be obtained for LNG liquefaction projects. Long-term contract pricing for LNG with some indexation remains the norm today, although spot and short-term contracts have grown relatively strongly over the past 10 years and today probably accounts for more than 30% of the global LNG trade. This is especially prevalent amongst USA LNG exporters where volumes are currently growing strongly.

Historically the price indexation in the contracts were linked to crude oil pricing since most LNG sales originally replaced oil in energy applications. These pricing formulas included a crude linkage slope and a constant. The crude linkage slope was traditionally 16%, but some deviations started occurring once an oversupply of LNG began developing and spot prices started declining far below contract prices. Since 2013, this crude linkage slope declined from 15% in 2013 to 11% in 2019. Following the strong oil price declines in the 1980s, most LNG contracts also incorporated a floor and ceiling, the floor to protect producers during periods of low oil prices and a ceiling to protect customers during periods of high oil prices.

Pricing from USA LNG producers are not linked to oil pricing at all, but typically to the Henry Hub gas price. Added to the Henry Hub gas price is then the cost of transport to the liquefaction facility, an LNG liquefaction facility cost, and shipping costs to arrive at a price in the port of delivery. Figure 7 shows this price build-up as well as calculated prices and some actual prices for 2013.

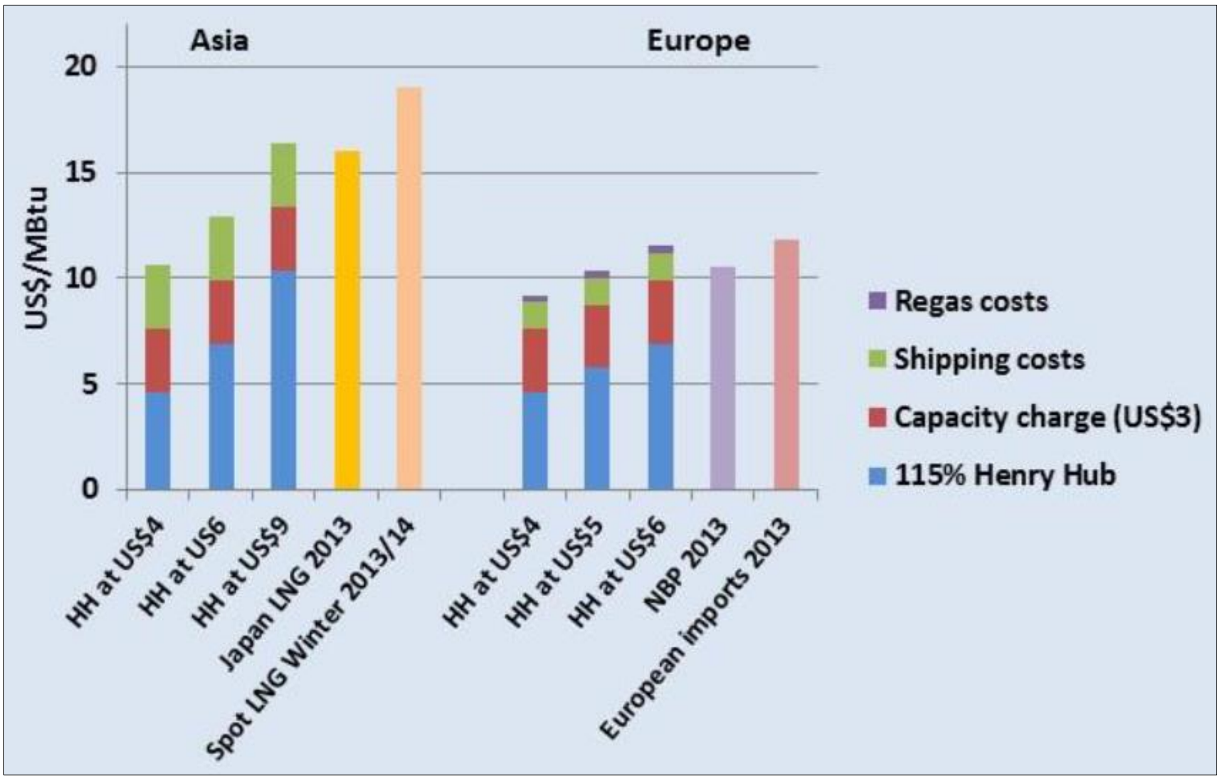

Figure 7: Delivered price of US LNG to Asia and Europe (Cornot-Gandolphe, 2014)

The gas prices to customers are typically much higher in cases where the value chain includes a liquefaction facility than in cases where gas is simply delivered by pipeline. This limits the cost competitiveness of LNG-derived gas with other sources of energy. LNG-derived gas can often still compete with refined oil products such as diesel and LPG, but hardly ever with other fossil fuel options. On the other hand, pipeline delivered gas (which does not include any LNG facility) can be at such a low price that it can even compete with coal as source of primary energy in some jurisdictions, such as the USA and Russia.

Most LNG sales are not driven by the cost competitiveness of the gas, but by regulation on environment and safety. The bulk of LNG is consumed in Asia where LNG-derived gas is used in power generation to reduce emissions, e.g. in China where it replaces coal, and to reduce safety risks (in Japan where it replaces nuclear power).

Due to the magnitude of the investments in every element of the LNG value chain, a certain base load is required for justification of these investments (apart from the long-term contracts discussed above). This is similar to gas pipeline investments where a certain committed base load is required before an expensive pipeline is built. For large liquefaction facilities, these committed base loads are at least 50% of the liquefaction capacity, and usually substantially higher than that.

One of the advantages of an FSRU is that it does not require long-term contracts. The reason for this is that the FSRU can be moved to another location if there is no further demand for its services at a specific location. Whereas initial lease periods for FSRUs were a minimum of 10 to 15 years, there are now many five-year leases in place. However, the base load requirement for an FSRU still remains. According to Songhurst (2017), the minimum base load for a smaller FSRU would be 1,7 million tpa, or the equivalent of a 1200 MW base load power station.

LNG in southern Africa

There are currently only large-scale exports of LNG taking place from Angola with a substantial LNG exports planned for Mozambique. There is, however, no commercial consumption of LNG in place yet.

The existing LNG export facility is Angola LNG, a 5.2 million tpa plant commissioned in 2013 with its own dedicated fleet of seven LNG carriers. The biggest shareholder of Angola LNG is Chevron, with the other shareholders being Sonangol, BP, Total, and ENI. The planned LNG export facilities are all based on the substantial Rovuma gas basin in the north of Mozambique, being:

- Coral Sul FNLG developed by ENI on behalf of all the shareholders/concessionaires in the Coral field. The FNLG project priced at $8 billion and with a capacity of 3,4 million tpa reached financial closure in December 2017 and start-up is expected in 2022. All the LNG is sold to BP under a 20-year contract with an optional 10-year extension.
- Mozambique onshore LNG developed by Total (initially by Anadarko) on behalf of several partners will use gas from the offshore Golfinho and Atum NG fields. The project will have a total capacity of 13 million tpa from two trains. The total capital cost is estimated at $20 billion. Financial closure is expected before the end of 2020 with a major financing deal ($14,9 billion) recently concluded. Commissioning is planned for 2024.
- Rovuma onshore LNG project developed by Exxon on behalf of the partners and based on offshore gas from Area 4. The project envisages a total capacity of 15 million tpa from two trains with a capital cost estimate of $30 billion. Financial closure was planned for March 2020 but has been postponed to 2021.

Various LNG import options have been considered for southern Africa over the past 10 years. Some examples of initiatives considered are as follows:

- The South African government considered importation of LNG at various ports for power generation to assist with the chronic power shortages experienced in South Africa over the past 12 years. An enquiry to this effect was issued by the government in May 2015 which created a bout of excitement in the LNG industry and elicited numerous responses. Although this option has not been abandoned officially, it seems unlikely that anything will come from it.
- PetroSA has over the years investigated various options of importing LNG to replace their dwindling feedstock supply to their Mossel Bay GTL plant. None

of these investigations has led to anything, either due to environmental or economic constraints.

- Currently, Gigajoule and Total are jointly developing a project to import LNG via an FSRU into the port of Matola in Mozambique. The base load of this project will be provided by a 2000 MW power station in Maputo and the possibility of providing gas into the existing South African market to replace the dwindling supplies from the Pande/Temane fields (from 2023 onwards) via the ROMPCO pipeline. This seems to be the most realistic plan to date, but it still remains to be seen if the developers can secure a power purchase agreement at power prices that will probably be much higher than the power utilities in southern Africa are used to, or if they can convince the ROMPCO customers to source gas at prices much higher than that which they are currently paying.

Little-known is that there is a small LNG plant on the PetroSA site in Mossel Bay. This was installed in the early 1990s to provide back-up for the gas supply from the deep-sea platforms to the processing plant in case of an unexpected interruption to the gas supply. It has a small liquefaction capacity, but reasonably sized storage and regasification. As such, it is similar to the LNG peak shaving facilities in the USA.

It is interesting that FFS recently brought an isotainer of LNG into South Africa. This is the first physical imports of LNG into South Africa. They used this LNG for proof of concept in several LNG applications such as power generation via a gas engine and fuelling a dual-fuel heavy duty road vehicle.

Several smaller LNG projects in southern Africa are at various stages of development. Some of these are as follows:

- Renergen is developing LNG capability together with their helium recovery from biogenic gas in the northern Free State. A capacity of almost 20 000 tpa is mentioned with first product expected towards the end of 2021. An agreement has been reached with Total to market the LNG to vehicles travelling along the N3 route between Johannesburg and Durban.
- A prefeasibility study was completed on a 60 000 tpa LNG facility off Botswana's coal-bed methane (CBM) resources. The study showed acceptable economics and further progress is expected once commercial production of CBM is proven.
- Several investigations have been launched into LNG production from pipeline gas in South Africa. It is not clear if any of these are progressing.

Environment and safety

No article on NG and LNG would be complete without some discussion on the safety and environmental impacts of these commodities. Most NG is burnt for its energy value and the resultant carbon emissions is an important element of the global climate change debate. Furthermore, methane, the primary component of NG, is a potent greenhouse gas (GHG) and any fugitive emissions of methane must be avoided. From a safety perspective, gas is highly flammable and under the right circumstances, also explosive.

Although gas-generated power typically leads to roughly half the volume of carbon emissions of similar coal-fired power stations (and almost none of the other harmful emissions of coal combustion such as nitrogen oxides and particulates), natural gas is still a fossil fuel, and gas combustion does lead to carbon emissions. These carbon emissions will continue to attract attention from a climate-change perspective and pressure to reduce and/or eliminate these emissions, will continue. Gas-fired power is ideally suited for peaking power as opposed to coal-fired and nuclear power that can only serve as base power. As such, gas power in combination with renewable power offers the best of both worlds, with these combinations being less carbon emission intensive than gas power on its own and more economical than renewable power on its own (which then requires expensive energy storage additions).

In most countries LNG is classified as a hazardous material, even though most of the safety issues associated with LNG only arises once the LNG vaporises to the gaseous phase. The primary intent of managing the safety issues of LNG is to prevent a containment failure. In the unlikely event that a containment failure occurs, it could lead to jet or pool fires (if an ignition source is present), or a methane vapour cloud (with the associated risk of a flash fire, or vapour cloud explosion).

Closing remarks

The global LNG industry has grown at a rapid pace of 10% per annum over the past 20 years which is expected to continue into the foreseeable future. This growth is primarily driven by Asia (with China and India leading the charge) and to replace coal for power generation.

Although LNG is currently in a strong growth phase, this will not be the case indefinitely. The current two big drivers for LNG growth (replacement of less desirable fossil fuels and strong growth in China and India) will probably both turn against LNG over the next 10 to 20 years. Fossil fuel usage is currently still growing as renewable energy is striving to reach critical mass whilst gas is replacing the other fossil fuels. However, the fossil fuel growth is expected to reverse in approximately 15 years as renewable energy becomes a bigger part of the global energy equation, although natural gas growth might continue as replacement of other fossil fuels. The natural gas consumption in China and India is currently mainly supplied in the form of LNG, but as long-distance pipelines reach these markets, this growth driver for LNG will also slow down. The Power of Siberia pipeline from eastern Siberia to north-eastern China was commissioned at the end of 2019 and further pipelines are planned.

The current method of global LNG pricing is probably not sustainable. There are two ongoing discrepancies that will drive a change in the LNG pricing. Firstly, spot LNG prices have been significantly lower than LNG contract prices for at least five years. Secondly, contract prices from the USA exporters are significantly lower than contract prices from any other exporter. Both these discrepancies are placing significant pressure on contract exporters from the rest of the world, leading to significant increases in spot LNG sales and in new contracts with significantly improved terms for buyers. On the other hand, long-term contracts will probably continue to form a substantial part of the overall LNG sales to provide certainty to financiers of liquefaction as well as LNG carrier and regasification projects.

In southern Africa, the production of LNG has commenced with further development plans in place, but no market for LNG yet. It is the author's contention that small- and micro-scale LNG production and markets have a much higher probability of taking hold rather than large-scale LNG imports. There is a possibility that large-scale LNG imports might be required for emergency power generation in the region, but there is also a strong probability that LNG imports will not occur at all.

References

BP Energy Review. (2020) *BP Statistical Review of World Energy.* Available from: https://www.bp.com/content/dam/bp/business-sites/en/global/corporate/pdfs/energy-economics/statistical-review/bp-stats-review-2020-full-report.pdf. Accessed on 28 June 2020.

Cornot-Gandolphe, S. (2014) *Gas and coal competition in the EU power sector*. Cedigaz, Rueil Malmaison, France.

Foss, M.M. (2012) *Introduction to LNG: An Overview on Liquefied Natural Gas (LNG), its Properties, the LNG industry, and safety considerations.* Available from http://www.beg.utexas.edu/files/energyecon/global-gas-and-lng/INTRODUCTION TO LNG Update 2012.pdf. Accessed on 25 June 2020.

IGU (International Gas Union). (2020). *2020 World LNG Report.* Available from www.igu.org/research/2020-world-lng-report. Accessed on 23 June 2020.

Oman LNG. (2020) *Oman LNG value chain*. Available from https://omanlng.co.om/en/OmanLNGValueChain/Pages/GasValueChain.aspx. Accessed on 30 August 2020

Putter, A.H. (2018a) *Natural Gas in Southern Africa, Part 1: Current natural gas supply and demand.* Available from https://www.ownerteamconsult.com/natural-gas-in-southern-africa-part-1-current-supply-and-demand/ . Accessed on 23 June 2020.

Putter, A.H. (2018b) *Natural Gas in Southern Africa, Part 2: Available gas resources and future development.* Available from https://www.ownerteamconsult.com/natural-gas-in-southern-africa-part-2-available-gas-resources-and-future-development/ . Accessed on 23 Jun 2020.

Songhurst, B. (2017) *The Outlook for Floating Storage and Regasification Units (FSRUs).* Available from https://www.oxfordenergy.org/wpcms/wp-content/uploads/2017/07/The-Outlook-for-Floating-Storage-and-Regasification-Units-FSRUs-NG-123.pdf. Accessed on 15 August 2020.

Songhurst, B. (2018) *LNG Plant Cost Reduction 2014 - 18.* Available from https://www.oxfordenergy.org/wpcms/wp-content/uploads/2018/10/LNG-Plant-Cost-Reduction-2014–18-NG137.pdf. Accessed on 5 August 2020.