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FUTURE LNG BUSINESS STRUCTURE: A COMPREHENSIVE REVIEW AND COMPARISON OF OIL AND LNG SECTORS

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ABSTRACT

The liquefied natural gas (LNG) trade provides the means of trading gas globally and represents about 10% of the gas trade. The forecasts show the LNG business will grow, over the next 20 years, at about twice the rate of the whole gas trade.

Although the current state of LNG trade is well studied, the literature on the future business structure of it is limited and conflictual. This work considers the future LNG business structure by comparing the development trajectories of the oil and LNG sectors. In addition, it assesses the conclusions drawn by researchers against this background and the current pattern of change in the industry.

The comparison involves three stages: (i) trade flows - oil and LNG trade flows are very similar, mainly due to the common distribution of the oil and gas reserves. (ii) Supply chain configuration - the international trade for both fuels is tanker based thus allowing for a similar market responsive trade policy, i.e. real-time destination selection (spot sale) at a global scale. (iii) Institutional developments - the current transparent and competitive global oil trade, with prices dominated by physical and paper markets, was driven previously by long-term contracts, in the same manner as the current LNG business.

This analysis, together with transaction cost economics, supports the argument that in future LNG spot trade will increase and give rise to a competitive and globally unified LNG market. Furthermore, LNG pricing will become transparent and would be dominated by physical and paper markets benchmark prices.

INTRODUCTION

Three fossil fuels currently dominate the world supply of primary energy: oil, coal, and natural gas. Their current roles in total primary energy supply, according to the International Energy Agency (IEA), are set out in Table 1. To allow a direct comparison of their quantitative roles in energy supply, the volumes are in million tonnes of oil equivalent (MTOE).

Table 1 - Total primary energy supply by fuel, 2013 (data extracted from: Ref 1).

Fuel	Supply (MTOE)
Oil	4,202
Coal	3,931
Natural gas*	2,982
Others: biofuels, nuclear, hydro, etc.	2,440
Total	13,555

* Share of liquefied natural gas (LNG) is 291 MTOE.[2]

Among the top three sources, gas is very important and has gained wide spread popularity as the fossil fuel of the new century; particularly in the light of the targets set by the Paris Agreement to reduce the greenhouse gas (GHG) emissions and the subsequent global warming (for details of the agreement see, e.g., Ref 3). The attractiveness of gas results from a set of economic and environmental benefits, including its abundancy, availability at scale, reliability and efficiency as a source of energy. In addition, gas is clean-burning (coal and oil often emit sulphur dioxide and nitrous oxides when burned) and has a lower carbon-intensity than both oil and coal (gas emits scarcely half as much carbon as coal does for each unit of energy produced).[4] According to Ref 5, using the levelised cost of electricity generation methodology, the cost of generating electricity per megawatt-hours (MWh) from gas is now competitive with coal in many parts of the world, and significantly below that of renewable sources. Gas consumption globally is forecast to grow faster than both oil and coal and at the rate of 1.9% per year for the next 20 years.[6]

There are two ways of supplying gas internationally: via pipelines for nearby markets, and via tankers in its liquid form, LNG, for more distant markets. Liquefying natural gas and exporting it by deep-sea vessels becomes economically more viable than the use of off-shore pipelines, if the gas market is farther than about 1,100 kilometres (km). In economic terms, the equivalent distance for on-shore pipelines is approximately 3,500 km.[7] According to Table 1, LNG represented 291 MTOE (2.2%) of the total primary energy supply in 2013. It was about 10% of the total natural gas supply and represented 31% of all the gas exported, since approximately 70% of gas is consumed locally.[8] LNG demand is anticipated to grow faster than the overall gas consumption, at the substantial rate of approximately 3.8% per year (double that of gas) for the next 20 years.[9] As a result, it will represent about 11% of world gas supply by 2020 and about 15% of supply by 2035, if these rates of growth continued. Total growth in LNG production from 2013 to 2035 would be about 127%, while local gas consumption would remain at about 70%. The high LNG export growth rate is due to economic reasons, as the prospects for further growth of pipelines as a means of export are limited and restricted to pipelines from Russia and Central Asia.[10]

LNG is currently traded mainly through long-term contracts (LTCs), but also via spot deals. Over the past dozen years, there have been several works analysing aspects of the current LNG business. Some researchers, including Refs 11-13 have examined the nature and essence of the LNG LTCs; while others, including Refs 14 and 15, have considered the effects of the gas market liberalization on the LTCs. Refs 16 and 17 investigated the LNG spot deals in detail.

However, an important aspect of the LNG trade less frequently discussed is the effect of an increase in global LNG trade on the business structure. The authors believe a comparison of the oil and LNG sectors provides some very useful insights and assists in answering this question. Factors in support of this approach include:

i. The international transport of LNG is waterborne, similar to the international transport of oil that is primarily maritime liquid bulk.

ii. LNG is an alternative energy source for efficient and relatively clean electricity generation. In addition, it is a candidate for direct substitution for oil (as well as coal) during the transitional period to a "low carbon economy", i.e., the period over the first half of this century when there will be a major switch to renewable sources.[3] For sea going vessels and larger vehicles, LNG can provide an efficient high pressure fuel system, using a heat exchanger to expand the gas without the necessity for a supercharger.

iii. In combination with appropriate well head measures to minimise emissions and carbon capture and storage (CCS) following combustion for electricity generation, LNG may have a longer term role as a substitute for oil.[18] In transport, the substitution may not always be direct as LNG is not as convenient a fuel as oil distillates for smaller vehicles. Nevertheless, the introduction of an electricity based private transport energy supply system, either through the direct distribution and storage of electricity or via hydrogen used in fuel cells, may increase the demand for centralised electricity generation for which gas coupled with CCS may be a more suitable fuel.

The primary role of LNG for the foreseeable future will continue to be the long distance maritime transport of gas, so the waterborne oil trade is a natural comparator.

To the knowledge of the authors, three works briefly try to foresee the future of the LNG business. Ref 16 attempts to foresee the future development of a global LNG market, but has serious reservations about the degree to which physical\spot and paper markets can hedge or diversify the risks, and hence materialize and produce benchmark prices. Refs 9 and 14 state that a globally unified LNG market and the emergence of liquid spot and paper markets with dominating benchmark prices at some time in the future, although not immediate, are bound to occur.

In this research a systemic perspective in predicting the future of LNG business is taken, considering the (i) LNG trade flows, (ii) LNG supply chain, and (iii) LNG trade's institutional developments, collectively. Furthermore, a thorough and up to date comparison of the oil and LNG sectors, on the aforesaid three factors, is carried out. The resulting insights, considering the LNG trade's expected growth and supply chain expenses, together with the transaction cost economics\TCE (for introduction to TCE, see; Refs 19-21) shape an exhaustive analysis on the future of the LNG business.

The central thesis of this paper, which is in line with that of Refs 9 and 14, is that a comparison with the oil sector indicates that the usage of LTCs will decline. Furthermore, the level of trade growth and the nature of LNG (as an exceptionally homogenous commodity) will allow and encourage the creation of a competitive and transparent global LNG market. The fall in the use of coal and fuel oil for electricity generation will lead to the decline of the LNG price indexation against substitute fuels. However, the high capital expenditures (CAPEX) and operating expenses (OPEX) of the trade, taking account of the physical and paper markets imperfections, may mean that these markets without the existence of medium-term contracts (MTCs) might not cover the whole risks for the LNG seller\producer enterprises. Such MTCs can be price indexed against physical and paper markets benchmark prices provided they are reliable and not subject to manipulation.

The remainder of this paper is organized as follows: in the first three sections, respectively, the oil and LNG trade flows and reserve distribution, the supply chains of oil and LNG, and the institutional developments in both sectors are studied and compared. The following section debates the future of the LNG business structure. The last section outlines the conclusions and provides some guidelines for further research.

TRADE FACTS AND FIGURES

Production and Export: Oil

The Middle East is the largest oil-producing region in the world and as a main producer has a critical role in the world oil supply (through export). This region's production would have been higher at various times, if it had not been for the market-balancing role played with varying degrees of success by the Organization of the Petroleum Exporting Countries (OPEC). Saudi Arabia, the biggest OPEC producer, has traditionally been the "swing supplier" to the global oil market, reducing its output as necessary to balance the supply and demand. The contribution of Middle East to the world oil supply is expected to continue to grow.

North America is now the second largest producing area after the Middle East, chiefly as a result of a surge in production of tight oil and synthetic crude extracted from oil sands in the US and Canada. However, it is expected that these new sources will peak sometime around 2030.[22] In Europe, the North Sea, between the UK and Norway, has been a key oil production region. Due to the maturity of its fields, the production in this area has been declining for over a decade. Norway and the UK are trying to control the decline in their production through the implementation of enhanced oil recovery (EOR) and by encouraging deep-water drilling with favourable financial measures.[23]

Finally, Africa (with its OPEC members, dominated by Nigeria), Russia, and Latin America (particularly Venezuela, an OPEC member) have been major players in producing and supplying international markets with crude oil; (the Venezuelan Orinoco Belt crude is heavy and high in sulphur, presenting particular extraction, transport, and refining problems and costs). The most visible new production and export prospect is the Caspian Sea area.

Due to the fear of losing its oil market share to non-OPEC producers, especially to the new North American oil sources, OPEC, and most visibly Saudi Arabia, has maximized its output resulting in the oil price crash of the late 2014 that has continued to this date. In the light of this development, some analysts (see, e.g., Ref 24) talk of a new order in the global oil trade, in which the market balancer will no longer be OPEC anymore, but rather the North American producers of tight oil and synthetic crude. Current low oil prices are favourable to OPEC countries, which produce cheaply from easily accessible conventional sources, while they will certainly be disadvantageous to and affect negatively the production of expensive North American tight oil and synthetic crude, Russian arctic oil, and North Sea deep-water oil.

Figure 1 illustrates the export from OPEC countries in 2014. These countries collectively supplied 56.5% [22.644 million oil barrels per day (bbl/d)] of the oil traded internationally;[25] for production and export statistics on other countries see, e.g., the Statistical Review of World Energy[26] and the Annual Statistical Bulletin.[25]

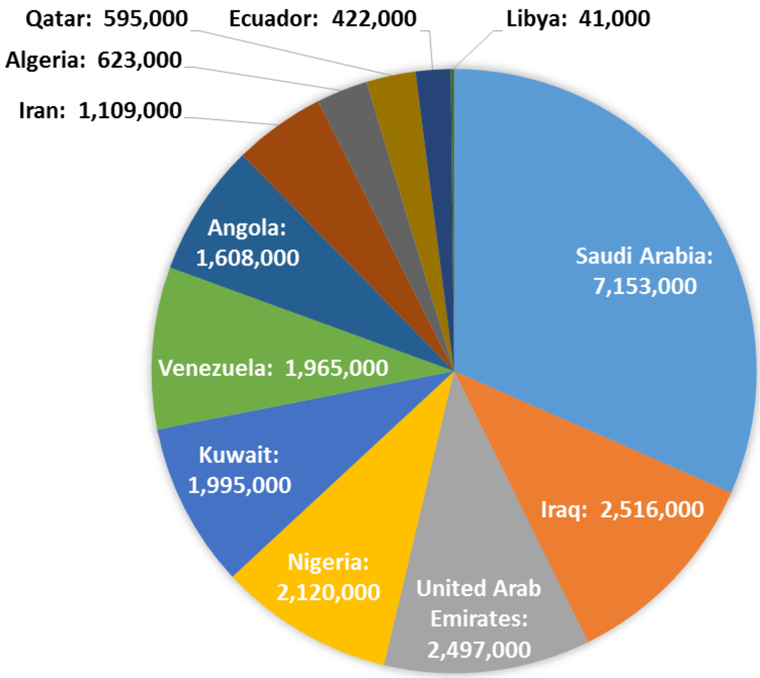
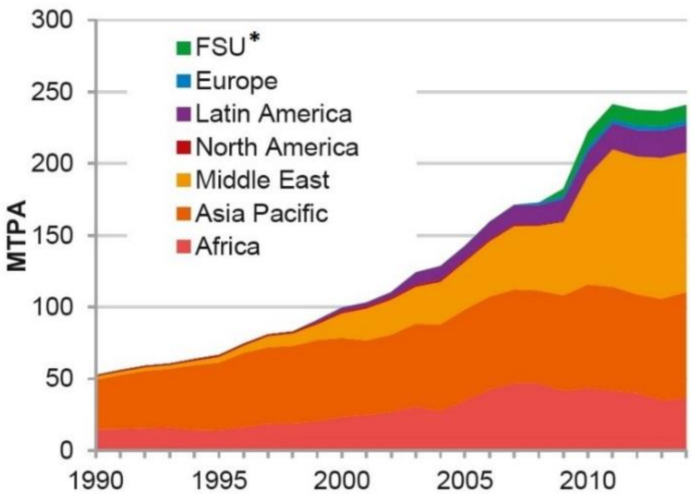


Figure 1 - Oil export from OPEC countries (bbl/d), 2014 (data extracted from: Ref 25).

Production and Export: LNG

In contrast to oil, where a significant part of extracted crude is retained for local refining and consumption, LNG has been produced almost entirely for the purpose of maritime export, as local markets for gas are supplied with compressed natural gas (CNG) through pipelines. Although local LNG consumption for use as a transport fuel and also for storage may rise, it will remain a minor component. Regionally, the Middle East (consisting of Qatar, Oman, Yemen, and United Arab Emirates) is the major LNG supplier in the world. This region surpassed Asia-Pacific, the other key regional supplier (including Australia, Malaysia, Indonesia, Brunei, and Papua New Guinea), in 2010-2011 and since then has put out more volumes into the market (Figure 2).



* Former Soviet Union Countries

Figure 2 - Regional LNG supply (million tonnes per annum\MTPA), 1990-2014 (source: Ref 27).

However, the situation is likely to change over the next decade and Asia-Pacific will probably become the major source again. This is due the rising domestic demand for gas in the Middle East, lack of policy and regulatory clarity in the region, absence of political and economic stability, and reserves that are more difficult to exploit. For the foreseeable future, the Middle East and Asia-Pacific will remain the major LNG supply regions.[28] However, Figure 2 shows the significant role of Africa in supplying LNG.

The top three LNG producers in 2014, respectively, Qatar, Malaysia, and Australia, exported 124.8 million tonnes (MT) of LNG (52% of global LNG supply); for more statistics on LNG exports see, e.g., Ref 29.

Consumption and Import: Oil

The transport sector, covering road, air, rail, domestic waterways and international bunkers, is by far the biggest oil consumer due to its relative ease of transport and high energy density; Figure 3 shows the share of crude oil consumption in the form of oil products by sector worldwide, in 2011 and 2040. The sectors' shares are forecast to be relatively static, considering the small fall in electricity generation portion, and transport is likely to remain dominant.

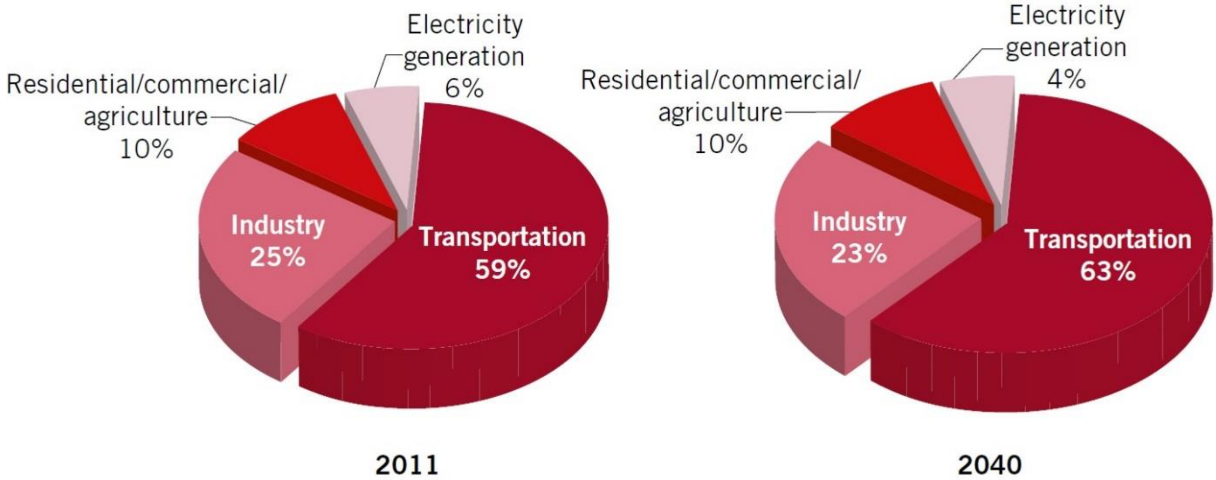


Figure 3 - Worldwide share (%) of oil demand by sector, 2014 and 2040 (source: Ref 22).

Regionally, the biggest consumers are, respectively, Asia Pacific (including countries such as China, India, Japan, and Australia), North America, and Europe (e.g. Germany, France and the UK). The US, with the highest rate of car ownership per capita, and China, with its remarkable thirst for oil because of its high economic growth rate, are the biggest consumption countries in the world. These countries in 2014 consumed 19.3 and 10.4 million bbl/d, respectively.[30] Asia Pacific and Europe are not among the big oil producers and given their considerable consumption are natural net-importers; but it is interesting to see that North America, despite being the second biggest regional oil producer, is a net-importer too.

Although consumption in these three regions is higher than in the other parts of the world, this should not be mistaken for inefficient usage of oil and other energy sources. On the contrary, energy intensity [total primary energy supply per unit of gross domestic product considering the purchasing power parity (TPES/GDP-PPP)] of the countries in these areas are generally among the lowest in the world (Figure 4). These regions are mostly made of developed countries from the Organization for Economic Cooperation and Development (OECD) with high-income economies, advanced technological infrastructures and very high human development indices (HDI).

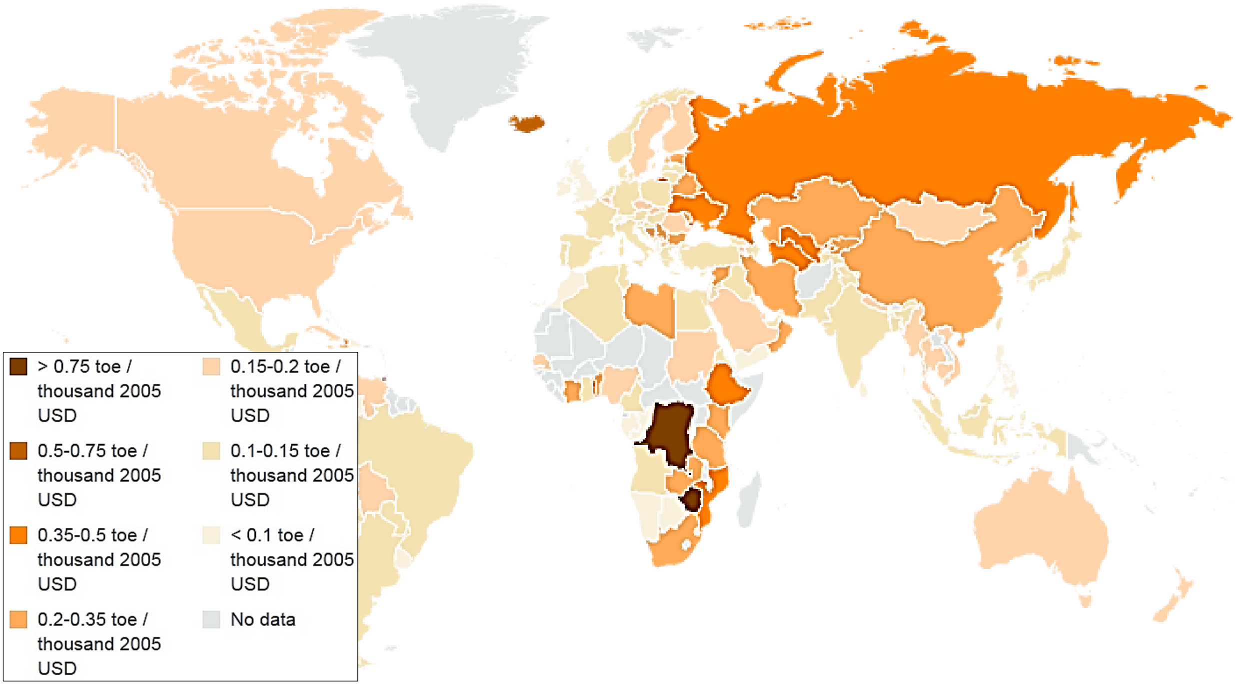


Figure 4 - World energy intensity [tonnes of oil equivalent/thousand 2005 US dollars (toe/thousand 2005 US$)], 2012 (source: Ref 31).

It is predicted that consumption and import of crude oil to Europe and North America will fall due to the decline in demand created by a transition to a low carbon economy, resulting from higher efficiency in using fossil fuels and exploiting renewable energy sources. But in the Asia Pacific, growing consumption in rapidly developing countries, particularly China and India, will result in higher consumption in and import to the whole region. The crude oil consumption in developing countries, in areas such as Africa, Middle East, and Latin America is expected to increase too. In the long-term, it is forecast that the rise in local demand in Africa and Latin America will surpass the increase in production, resulting in a decrease in exports from these regions. A considerable portion of the increase in consumption in all the regions with growing consumptions will come from the escalating oil demand for transport. For example, the Chinese passenger vehicle fleet grew at the extraordinary rate of 21% per annum in 2000-2011 and this growth is expected to be sustained.[22] For detailed statistics on consumption in and import to the countries see, e.g., Refs 25 and 30.

Consumption and Import: LNG

There were 29 LNG importers in 2014 (Figure 5) that imported approximately 238 MT of LNG.[29] Although Lithuania was the only new LNG consumer in this year, it is expected that Jordan, Egypt, Pakistan, and Poland will begin importing LNG shortly.

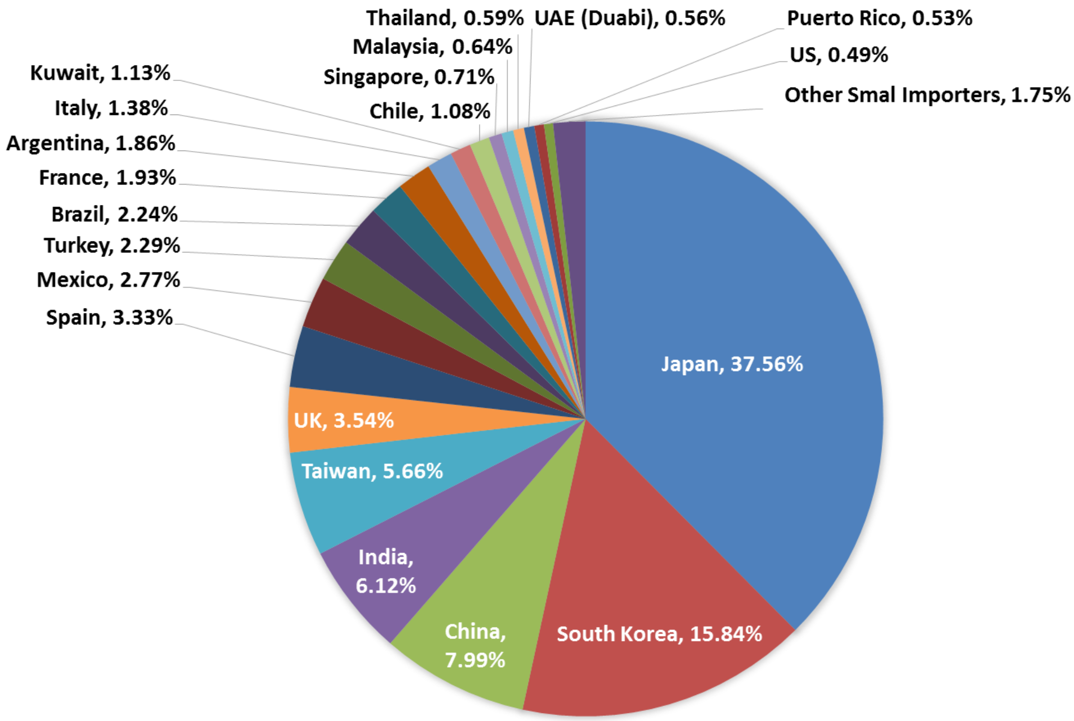


Figure 5 - Share (%) of LNG imports by country, 2014 (data extracted from: Ref 29).

Asia Pacific is expected to remain as the biggest LNG consumer region. In 2014, this area absorbed nearly 75% of the LNG globally traded.[27] Japan, South Korea and Taiwan have been the major traditional LNG consumers; with little to none local gas production and pipeline import capacity, these countries have been relying on LNG for satisfying nearly all their gas demand. China and India are newer LNG importers in comparison to the aforementioned trio, but recently have been experiencing considerable growth in their demand. In 2014, India and China, respectively, increased their imports by 1.5 and 0.5 MT.[29]

Europe is the second largest LNG importing area. However, over the past few years due to economic stagnation and growing competition from both coal and renewable energy sources in power generation, the imports to this region have decreased. In 2014, Europe imported approximately 33 MT of LNG, down from a peak of 66 MT in 2011.[27]

An increasingly important area for LNG consumption is Latin America. The surge in energy demand (e.g., in Brazil) and decline in domestic gas production (e.g., in Argentina) has pushed Latin America toward LNG import.

Finally, North America used to be considered a potentially major LNG import area. However, since 2008-2009, because of the rapid rise of shale gas production in the US, the LNG import to this area has decreased substantially. The shale gas production has now increased to a level where LNG import facilities in the US are being converted to export facilities so that the surplus gas can be exported as LNG.[32]

Comparative Comments on Trade

Figure 6 depicts the major interregional trade flows of oil and LNG. It is interesting to notice that the trade flows in both cases are, to a great extent, similar. This rises from two facts: (i) the distribution of the oil and gas proved reserves are largely the same. Table 2 lists the significant oil and gas reserve-holders in the world. Aside from the fact that Iran, Saudi Arabia, and Russia are listed in both oil and gas columns, it should be considered that nine out of the 14 countries mentioned in the two columns are Middle Eastern and/or OPEC countries. Middle East is by far the richest region for both oil and gas, with, respectively, 47.7% (810.7 thousand million bbl) and 42.7% [79.8 trillion cubic meters (m^3)] of the world proven reserves. OPEC holds 71.6% (1216.5 thousand million bbl) of the world oil proved reserves.[26] This concentration of the world oil and gas reserves has an important implication for market development that is addressed later. (ii) The developed countries (generally OECD countries) that rely on natural gas imports to satisfy their energy demand, also have high import demands for oil, and try to diversify imports by energy type to decrease the risk of dependency on foreign supply.

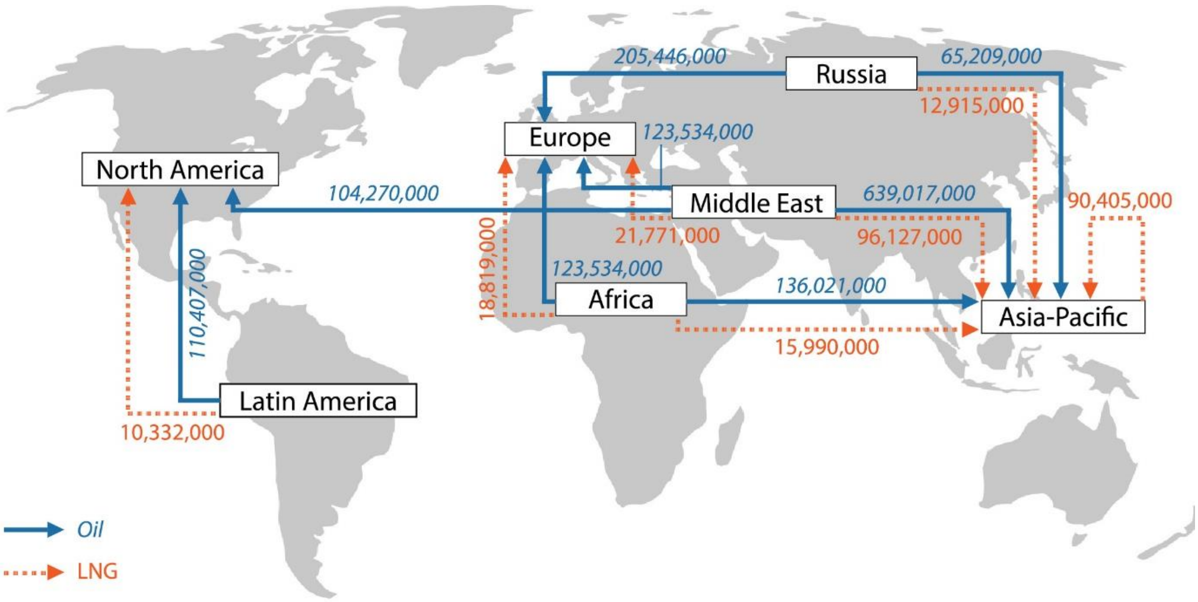


Figure 6 - Major interregional trade flows of oil and LNG (TOE), 2014 (adapted from: Refs 25 and 27).

Table 2 - Major oil and gas reserve-holders (data extracted from: Ref 26).

No.	Oil			Gas		
	Country	Proved reserve (thousand million bbl)	Share of total world proved reserves (%)	Country	Proved reserve (trillion m^3)	Share of total world proved reserves (%)
1	Venezuela*	298.3	17.5	Iran*	34.0	18.2
2	Saudi Arabia*	267	15.7	Russia	32.6	17.4
3	Canada	172.9	10.2	Qatar*	24.5	13.1
4	Iran*	157.8	9.3	Turkmenistan	17.5	9.3
5	Iraq*	150.0	8.8	US	9.8	5.2
6	Russia	103.2	6.1	Saudi Arabia*	8.2	4.4
7	Kuwait*	101.5	6.0	United Arab Emirates*	6.1	3.3
Sum		1250.7	73.6		132.7	70.9

* Middle Eastern and/or OPEC countries.

Note that Figure 6 shows that Africa and Middle East, due to their strategic geographical position, supply both the Asia-Pacific and European markets with oil and LNG; while Latin America's major market for oil and LNG is North America.

Russia's push for further diversifying its oil export markets by increasing its supply capacity to Asia-Pacific is the key change foreseen in the trade flows depicted above. Currently, efforts are being made in this country to expand the "eastern vector". Russia needs and counts on foreign investment from Asia-Pacific, particularly China, for developing new oil supply sources and building pipelines to Asia-Pacific.[33] Assuming this country manages to obtain and absorb such investments, a significant part of the volumes of the oil previously exported to Europe is expected to be redirected to Asia-Pacific. That in turn will encourage Africa to decrease its oil supply to Asia-Pacific and focus on Europe; a move that from an overall cost perspective, is optimal for Africa, as exporting African crude to Europe is cheaper than to Asia-Pacific.

A major difference between the oil and LNG sectors is the magnitude of trade. The reason being that LNG is a growing sector while oil is a mature one. Note that the numbers reported in Figure 6 are TOE scaled and thus are comparable. Another difference is the nature of demand for each fuel; oil primarily fuels transport, while LNG is primarily utilised in power generation. Although LNG has started penetrating the transport sector as well, with fuelling trucks (in China, Europe, and the US) and deep-sea vessels, as previously noted in the introduction.

SUPPLY CHAIN

Configuration: Oil

The oil supply chain consists of three phases: upstream, midstream, and downstream. The upstream, also known as the extraction, includes the search for potential oil sources (underground or underwater, conventional or unconventional), the drilling of exploratory wells, and the subsequent operation of the wells to extract the crude. The midstream phase consists of the storage and international transport of the oil. Finally, the downstream phase includes petroleum refinement and retail outlets (Figure 7).

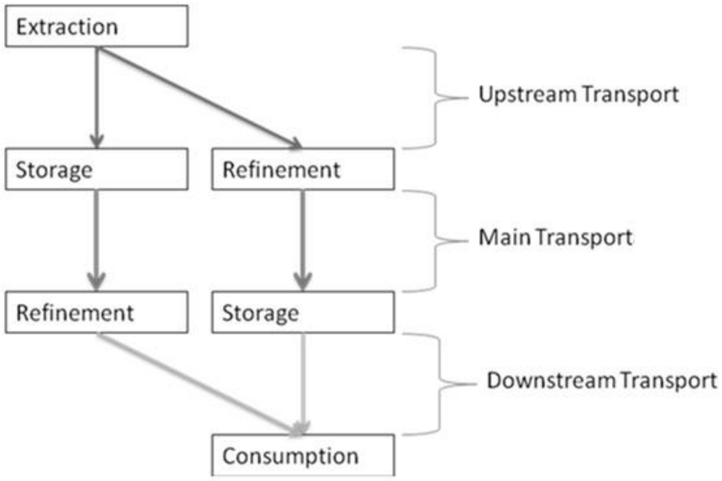


Figure 7 - Oil supply chain, with the main configuration on the left.

The international transport of crude is carried out waterborne, as oil tankers are low cost, efficient, and extremely flexible; while building pipelines for such long distances is uneconomic. Furthermore, pipelines could cross multiple countries that creates geopolitical risk. Table 3 presents the world tanker fleet.

Table 3 - World oil tanker fleet by categories in 2014 (adapted from: Ref 25).

Type	Range of capacity (1,000 dwt*)	Total	
		No.	1,000 dwt
General purpose carrier	16.5–24.9	714	11,888
Medium range carrier	25.0–44.9	1,166	46,199
Large range 1 carrier	45.0–79.9	1,304	72,846
Large range 2 carrier	80.0–159.9	1,296	158,060
Very large crude carrier	160.0–319.9	674	193,982
Total		5,153	482,975

* Deadweight tonnage.

Note that when the transport in midstream is transregional and in close distance, e.g. in North America, it is carried out by pipelines, as in such cases it is the most cost efficient solution. Inland pipelines are at least an order of magnitude cheaper than any alternative such as rail, barge, or road. Moreover, political vulnerability is a small or non-existent issue within a nation's border or between neighbours, such as the US and Canada. Pipelines are critical for export from landlocked countries, e.g., in the Caspian Sea area, and also complement maritime tankers at certain key locations by relieving bottlenecks or providing shortcuts.

In addition to the oil transport in midstream (main transport), there are less visible transport operations in the upstream and downstream phases. The upstream transport component corresponds to the movement of crude from the extraction site to the closest node for storage. The distance covered here can vary, however, pipelines are often used. The downstream transport relates to the distribution of oil products from the refineries to the outlet stores. Downstream transport is a complex and diverse business, which due to the large range of oil products (including but not limited to gasoline, diesel, jet fuel, heating oil, asphalt, and lubricants) and the small distances encountered is, usually, conducted by road or rail networks.

Crude oil dominates the world oil trade as the risk-weighted economics and differences between the mix of refined products by region clearly favour refineries to be located close to consumers rather than to the wellhead. This policy takes advantage of the economies of scale of large crude tankers; especially as local quality specifications are increasingly fragmenting the oil product market. It increases the refiner's ability to tailor the product output to the market's short-term surges, such as those caused by weather, equipment outages, etc.

There are a limited number of refining centres that appear to conflict with this general rule, having been developed to serve particular export markets (see Figure 7 and the alternative supply chain configuration on the right). These export-refining centres (Singapore, the Caribbean, and the Middle East) give rise to some regular interregional oil product transport by product tankers. Nonetheless, they are the exception as the long distance oil products trade is largely a temporary market-balancing function. For detailed statistics on distribution of refinery facilities across the world see, e.g., Ref 30.

Configuration: LNG

Figure 8 depicts the LNG supply chain and the chain's main by-products. In the LNG sector, extraction and liquefaction are usually considered the upstream, shipping the midstream, and regasification the downstream of the supply chain. Final distribution of gas is usually performed by way of national pipeline networks.

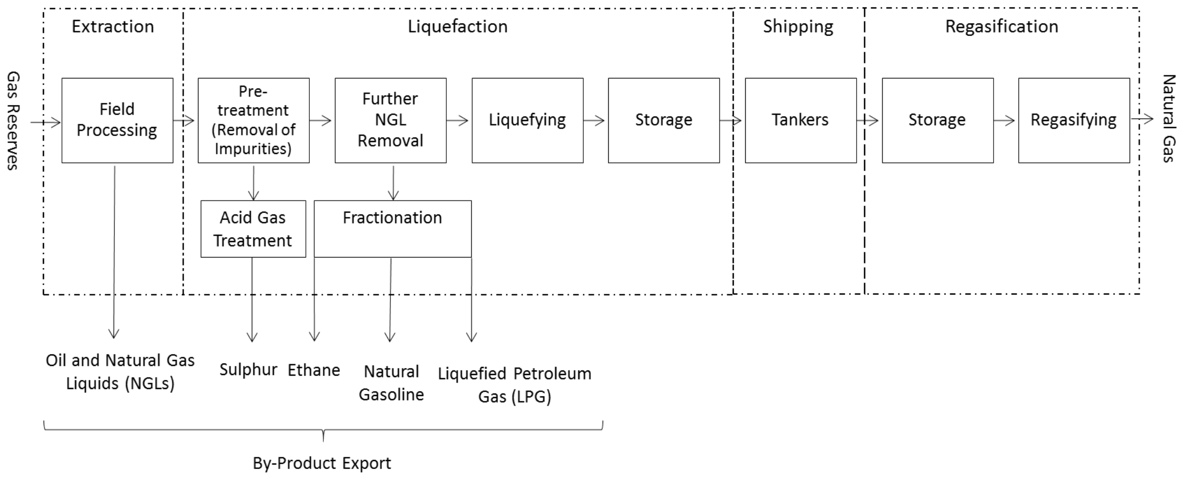


Figure 8 - Detailed LNG supply chain.

In upstream, gas is recovered from commercially viable natural gas sources and is almost always transferred to the LNG liquefaction plant by pipeline. Note that the natural gas components that are liquid at atmospheric pressure (NGLs) and the oil (in the case of associated gas reserves) are separated from the gas at the wellhead.

In the liquefaction plant, the gas is liquefied by the use of refrigerants in heat exchangers. Usually plants consist of several parallel liquefying units, each termed a “train”. The trains remove the impurities (water, mercury, carbon dioxide, nitrogen, oxygen and sulphur compounds[34]) and the remaining NGLs (heavier alkanes) to prevent the formation of solids in the heat exchangers that can damage the equipment. As the result of the removal process, LNG is mostly composed of methane. Therefore, while LNG supplies from different sources do differ, it is a much more homogenous commodity than crude oil, where differences between grades can affect transport costs, as well as refining costs.

The LNG produced is stored in cryogenic tanks at atmospheric pressure until it makes its way to the midstream and is off-taken by the tankers to be shipped internationally. The world LNG fleet in 2014 consisted of 421 vessels, of which, in terms of containment system, 112 were Moss-type, 289 Membrane-type, and the rest other types.[29] Until a decade ago the number of Moss-type tankers was higher than Membrane-type tankers. A key reason for the change in the pattern of the fleet is that the carriers in using the Suez Canal pay tolls based on gross tonnage, which causes the Moss-type to pay higher fees than Membrane-type for the same volume of LNG carrying capacity. Membrane-type continues to lead the LNG fleet order book as the preferred containment option. To create value for the earlier Moss-type vessels, which are out of favour and gradually are being retired, they are often converted to floating storage and regasification units (FSRUs), i.e., mobile and floating LNG regasification terminals. FSRUs are well suited to seasonal markets since they can be relocated for new employment opportunities. Figure 9 shows the range of LNG tankers capacity and the number of vessels in each range. The largest vessels are employed for the most part on long distance high volume supply routes such as Qatar-Japan.

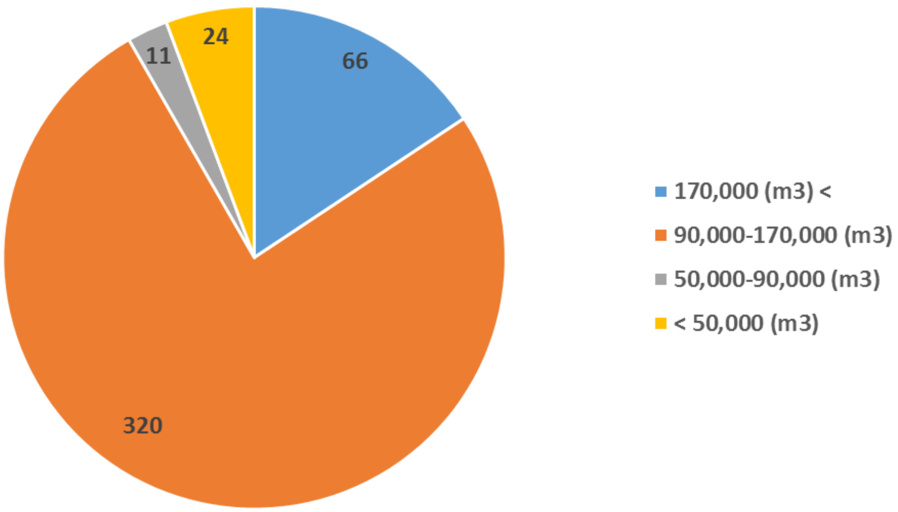


Figure 9 - Number of vessels in the LNG fleet by range of cargo capacity, 2014 (data extracted from: Ref 29).

Along with the rapid expansion of the global LNG trade and the LNG fleet, there is currently a demand for larger vessels. It is foreseen that with the expansion of the Panama Canal in 2016, which will permit the canal to accommodate LNG carriers with carrying capacity of up to 180,000 m^3, the standard capacity for new tanker orders will grow to Post Panamax vessels (170,000-180,000 m^3). The largest LNG tankers at present are the Q-max size, with the capacity of 266,000 m^3 and a deadweight of 125,000 dwt.[27] For comparison, this is about a third of the size of the largest crude oil tankers currently in use. However, since the volumetric thermal value density of LNG is only about half of that of crude oil, an LNG vessel double the capacity of an equivalent oil tanker is required to transport the same amount of energy as measured in million British thermal unit (MMBtu).

Finally, in the last stage of the LNG supply chain, the regasification terminal, the vaporizers transform the LNG received and stored back to gas, following which the gas is distributed via the trunk gas supply grid to be used in power plants or reach the commercial and residential consumers. For statistics on the world liquefaction and regasification capacities, see, e.g., Ref 27.

Comparison of Supply Chains
There are substantial similarities between the supply chains of oil and LNG. They are both fossil fuels that need to be extracted and recovered from buried sources. Oil and LNG are both liquids that are distributed worldwide, hence the need for storage to buffer the supply and demand, and waterborne transport as the most cost effective choice of product transfer.

Among the similarities, waterborne trade is particularly important, since it provides for the same market responsive trade policy with change of destination in real-time, a.k.a. spot sale, in a global scale. Spot sales are a central factor, as seen later, in shaping the global oil and LNG markets.

But there are differences too. An important one is the spread of the supply chains across the world; it is obvious from Table 3 and Figure 9 that the LNG trade is still far smaller than that of oil. The total number of oil tankers is several thousand whilst the number of LNG tankers is merely a few hundred despite the lower thermal value of LNG. Apart from that, LNG is a much more homogenous product than crude oil.

INSTITUTIONAL DEVELOPMENTS

Pricing Mechanisms and Contractual Structures: Oil
Oil is a global commodity today, essential for production and for quality of life in most societies; it is tightly related to economic growth. The expansion of the oil sector has gone through three main stages, each with its specific pricing mechanism. Table 4 outlines the major eras of the sector.

Table 4 - Timeline of the oil sector’s main eras.

Period (year)	Eras
1920-1972	Majors\Seven-Sisters (buyer cartel price setting)
1973-1987	OPEC (producer cartel price setting)
1988-	Spot and paper markets (market price setting)

During the primary era of the sector, the Majors, a.k.a. the Seven-Sisters, (including: BP, Shell, Chevron, Exxon, Gulf, Mobil, and Texaco) managed the oil business through vertically integrated supply chains. These companies withheld long-term concession agreements with host countries (typically developing Middle Eastern countries) and used to sell the oil through LTCs predominantly to their affiliates, i.e. refineries. Crude price in a Major’s sale to its affiliates was often an internal transfer price between the oil production subsidiary and the refining\marketing subsidiary, and was kept artificially low to minimize the rent-taking (royalty) of the host country.

When it came to pricing the oil products, the Seven-Sisters, who had colluded through the Achnacarry agreement of 1928, each having a specific quota of sales to segments of the market out of the US, calculated the price of the crude through a formula included as a principal clause of the agreement. This formula was known as the "Gulf plus freight" formula (Gulf refers to the Gulf of Mexico). Here, the oil price was calculated as the high free-on-board (FOB) US Gulf of Mexico oil price plus the freight rate from the Gulf to the delivery point, independent of the factual origin of the delivery.[35] This proved to be a lucrative trade arrangement for the Seven-Sisters. The US oil prices in this period were however regulated and were kept artificially high to preserve the financial viability of the great many non-integrated local American crude producers. This way, despite their high marginal costs, allowing them to compete in the market. The regulated prices were "marginal cost-plus" and provided the local producers with an acceptable profit, although certainly not anywhere near the Seven-Sisters.

After World War II, the US and British administrative investigations, whose Navies had both been buying bunker fuel expensively from the Majors during the war, forced the Seven-Sisters to enhance the pricing formula to dampen the prices. Through a modification to the Achnacarry agreement the "two Gulf plus" formula for oil pricing was introduced. Under this formula, the freight rates were calculated either from the Mexican Gulf or from the Persian Gulf (whichever was closer). Nonetheless, in all the sales the oil price used for the calculation was the FOB US Gulf of Mexico. This, to a degree, decreased the profit of the Majors by diminishing the virtual transport cost; nevertheless, their profits were still substantial given the difference between the transfer prices and the high FOB US Gulf of Mexico prices.

The nationalization of the oil companies in OPEC countries in the 1970s, following the rise of the concept of "permanent sovereignty over natural resources", is an important turning point in the oil history, associated with and defining the second era of the oil sector. Through nationalization, the concession agreements were terminated. Furthermore, the vertically integrated supply chain of oil was broken-down and the producer countries gained control over the upstream (extraction\sale) phase, thus changing rent sharing to their advantage.

OPEC countries began selling the oil on LTCs, mostly to the Majors, given the quota assigned to each member and with the official selling price (OSP), both decided in OPEC meetings. The OSP, de facto the world oil price in this era, was largely based on the price of the benchmark crude of the time, the Saudi Arabian Light crude, FOB Persian Gulf (Ras-Tanura), while OPEC took into account the developments in the prices in the rising oil physical\spot and paper markets as well. Each OPEC member adjusted the OSP for its sales according to the differentials. The differentials were based on the physical properties of the oil sold, and the distance to the destination markets.

In 1973-74 OPEC raised prices unilaterally from 3 US$/bbl to 12 US$/bbl ("the first oil shock"). This was parallel to the oil embargo that Arab members of OPEC, in the light of the US support for Israel in the 1973 Arab-Israeli War, imposed on the US. Later, in 1979-80 and in the aftermath of the Iranian revolution, prices rose again from 12 US$/bbl to 30 US$/bbl ("the second oil shock"). The embargo and the Iranian revolution created a widespread fear of crude scarcity; crude buyers wanted oil at any price. This sparked the investment in and extraction of oil in the non-OPEC countries, which was then sold in the physical and paper markets. The prices in these markets rose to such heights that even some OPEC members bypassed the LTCs and started selling some volumes in these markets. The share of physical and paper markets in the global crude business rose from 5%-8% at the beginning of 1970s to at least 40%-50% in the mid-to-late 1980s.[14]

In response to these developments, Saudi Arabia, the swing supplier within OPEC, decreased its output to compensated for the over quota production of other OPEC members, such that the total output of the organization would remain within the designated accumulated quotas. This way defending the OSP and the OPEC cartel dominated oil business. The Saudi Government voluntarily shut down about 75% of its production capacity between 1981 and 1985.[36] However, by the mid-1980s it was becoming increasingly clear that OSP was not working and the OPEC era was coming to its end. Partly, as a result of the rapid rise of oil prices from 1970s to mid-1980s, the overall world oil consumption had decreased; combined with the additional production of oil from the non-OPEC countries, this had created a supply glut. Under this circumstances, the oil buyers were finding the OPEC-LTCs with OSP unacceptable.

Finally, in the summer of 1985 Saudi Arabia that felt the policy of keeping the oil prices high was causing crude to be pushed out of the global energy mix, and had suffered by playing the role of the swing supplier, decided to reclaim its market share. The Saudis introduced the netback pricing formula as an instrument for increasing their production and recovering their market share; [Crude oil price (FOB) = gross oil product worth (GPW) in the physical and/or paper markets – fixed refining margin – transportation costs (from the terminal in the oil exporting country to the refinery in the oil importing country)]. This was a very effective tool for Saudi Arabia, since refineries that had unstable and low profits found it very attractive. This was followed by the oil price crush of 1986 ("the counter oil shock"), to approximately 10 US$/bbl, for which (despite the oil supply glut and non-OPEC export) the netback pricing\Saudi Arabia was blamed.[37] In 1987, OPEC (including Saudi Arabia) briefly tried to reinstate the OSP regime. But, by then, the oil buyers were more interested in the main elements of the pricing formula contained in their LTCs with OPEC, being the benchmark crude prices in the progressively liquid physical markets and later also the paper markets. The reason was that this pricing was in the longer run more competitive than the OSP. As a result, in 1988 OPEC gave up setting the OSP. The Brent (influential globally), West Texas Intermediate\WTI (prominent in the US), and Dubai/Oman (influential in Asia) since then have risen as the dominant benchmark crude prices in the physical and paper markets. Recently, the decrease in liquidity of Dubai/Oman physical market has created calls for establishing a new oil benchmark for Asia. In this respect, a debate has started on the suitability of the exports via the Eastern Siberia-Pacific Ocean (ESPO) oil pipeline, distributing overwhelming volumes of Russian crude to the Asia-Pacific markets, to act as a benchmark price. However, the risk of benchmark manipulation by Russia, and concerns about the rule of law and independent legal and reliable fiscal systems in this country are major obstacles for ESPO volumes to become the dominant Asian benchmark crude.[38]

In 2007, more than 50% of total oil traded globally was carried out on MTCs (shortened LTCs with the typical duration of one year).[14] It is extremely difficult to obtain reliable figures on the magnitude of the oil physical market, paper markets, and MTCs over the last ten years. Ref 38 has suggested that the size of the physical market may have fallen to as low as 15%. However, there is agreement that the duration of LTCs has decreased to MTCs, with the latter having their price adjustment clauses based on the physical and paper markets benchmark prices.

Paper markets were developed, with a few years of delay, following the growth of the oil physical market. The buyers were wary of the price fluctuations of 1970s and were aware of the low price elasticity of demand for oil, especially in the short-term. They recognised that the concentration of the oil reserves principally in the OPEC countries, despite the supply diversity from many but mostly small non-OPEC reserve-holders\producers, created, to a degree, an oligopolistic supply structure with the possibility of high prices. Note that the share of OPEC in total proven oil reserves since the 1960s has been relatively static at 70-80%.[25] Therefore, buyers wished to hedge the price risk, as the volume risk was absorbed, to a great degree, by the increasingly liquid physical market. To that end and taking account of the developments in information technology and financial theory, in addition a political climate favouring markets over governmental solutions and administration, oil paper markets (including forward, futures, and options markets) were established.

By the end of the 1980s the current sophisticated contractual structure of the oil sector was in place. Nevertheless, there are still concerns about the nature of the physical and paper markets benchmark prices that are used to adjust the MTCs, the relevance and the liquidity of the markets on which the benchmark prices are based, and the process of price discovery.[38]

Pricing Mechanisms and Contractual Structures: LNG

In comparison to oil, LNG is a considerably younger energy source since its extensive use originates just in the 1960s. Following the first commercial cargo of LNG from the US Louisiana Gulf to the UK Canvey Island in the River Thames in 1959, a term deal was struck between Algeria (as the LNG producer) and the UK and France. These two European importers were followed by Spain and Italy, which began importing LNG from Africa. At the end of the 1960s Japan entered the business by importing the first transpacific LNG shipment from Alaska. Finally, in 1972 the US became active in the LNG sector as an importer by developing four LNG importing terminals.[14]

The entry of the US to the sector was followed by several unprecedented changes in the international energy trade. These included the two oil price shocks of the 1970s, the widespread nationalization of the Majors' concession areas within OPEC countries, and the restructuring of the North American gas market. As a result, the LNG trade in the US collapsed and, despite initial positive predictions, the trade growth in the whole Atlantic Basin faltered. The LNG trade hence moved to the Pacific Basin. It was only in the late 1990s that the Atlantic Basin became seriously active again.

The LNG trade has since its expansion in the 1960s been based on take-or-pay LTCs, with very long durations (20 to 25 years).[9] These contracts distribute the main risks, i.e., price and volume risks, between the LNG sellers\producers and the buyers (both commercial enterprises), where the seller takes the price risk and the buyer takes the volume risk. The important contract clauses in LNG LTCs are:

i. *Destination clause:* by this clause the LTC prohibits a buyer from selling the LNG, which is delivered to the principally identified market, to any alternative market. This clause essentially preserves the territorial separation for the LNG seller.

ii. *Take-or-pay clause:* this clause sanctions a buyer to take a minimum quantity of LNG each year and forces the buyer to pay for that minimum quantity whether or not it is actually taken. Often more than 90% of the annual production of a liquefaction plant is sold under this clause, while the remainder is sold in the spot\physical market.[16]

iii. *Price clause:* LTCs do not have a fixed price over the life of the contract, but rather a formula that relates the price of the LNG to competitive energy sources at the time of delivery; sometimes with a minimum price to protect the seller from a complete collapse in prices and a maximum price to protect the buyer from exceedingly high prices. This price adjustment process differs from that in mature commodity markets, such as oil, where physical and paper markets declare the benchmark prices for the commodity. Furthermore, paper markets hedge the price risk.

In the absence of liquid physical and paper markets to absorb the volume and price risks, these clauses make sure that there is a minimum steady revenue for both the sellers and the buyers using which they can service their debts, pay their operating expenses, and have a reasonable profit. Note that in the LNG sector, the seller usually owns and controls the upstream (extraction and liquefaction) and the buyer owns and manages the downstream (regasification), while the tankers for transport could be owned and organized by either of them (in many cases the seller).

With reactivation of the Atlantic-Basin in LNG trade in the late 1990s, a problem rose in supply of LNG to the US and the UK. These two countries had liberalized their local gas markets, thus creating competition in the marketplace as opposed to the previously existing monopolistic markets.

With a competitive local gas market, the UK and the North-American LNG buyers could no longer take the volume risk without a market responsive pricing clause. But with such a clause, a redistribution of risk in favour of the buyer takes place, since the buyer can easily sell the unwanted LNG volumes in the progressively liquid local gas market. Thus, in essence, risk has moved from the downstream\buyer to the upstream\seller.

The reaction of the LNG sellers to these developments has been increasingly toward vertical integration through self-contracting (contrasting the traditional LNG LTCs discussed above) in sales principally destined for to the US and the UK. Here, an equity-holder in the LNG seller enterprise signs an LTC with the enterprise, becomes the buyer, and markets the LNG with an open-hand for arbitrage; the margin of arbitrage is divided among the enterprise equity-holders. Note that the LNG enterprises are often made of the national oil company (NOC) of the host country, and one or several international oil companies (IOCs). The buyer-equity-holder, often an IOC, through booking capacity in LNG regasification terminals in North-America and the UK, which due to liberalization are open to third-party-access (TPA), sells the LNG directly to the consumers, or might sell the product to other buyers across the world. Some IOCs with self-contracts (e.g., BP and Shell) have made LNG portfolios for themselves, combining the supply of LNG from several liquefactions plants and using their tankers to feed into their regasification capacity.[39] Such portfolio players try to optimize their profit through the commercialization of their flexibility. Due to the beginning of liberalization in the Continental European gas markets, self-contracting has started penetrating these markets too. With liberalization of the Asia-Pacific gas markets in the long horizon, in-time, self-contracting in these markets is expected as well. In 2008, about 18% of world LNG supply was self-contracted and about 75% was sold on traditional LTCs.[15] It appears that the traditional LTCs are still the main LTC type in place in the LNG sector.

Self-contracts, the leading LTC type in North-America and the UK, have their pricing formula based on the local gas market benchmark prices, respectively, Henry Hub (HH) and the National Balancing Point (NBP). The pricing of the LTCs destined for the Continental Europe is for the most part connected to the price of substitutes–oil, or oil products and coal, depending on the country. The long-term contracted volumes for the Asia-Pacific have their prices linked to the Japan Customs-cleared Crude oil price (JCC). JCC pricing is the most common type of pricing since the biggest LNG consumers are in Asia-Pacific and considerable volumes are sold into this region on LTCs.

Over the past two decades, particularly since the surge of the shale gas in the US, arbitrage has become an acceptable practice in the LNG sector. Whereby LNG cargoes on LTCs with principally identified markets, with the mutual agreement of the seller and the buyer, are diverted to other markets to be sold on the spot.[17] This has substantially increased the share of LNG physical market in the worldwide LNG trade (Figure 10). The price of spot sales in the US and the UK that have gas market benchmark prices (HH and NBP) follows these indicators, while in markets without such benchmark prices the spot price could be much higher or lower than LTC prices.

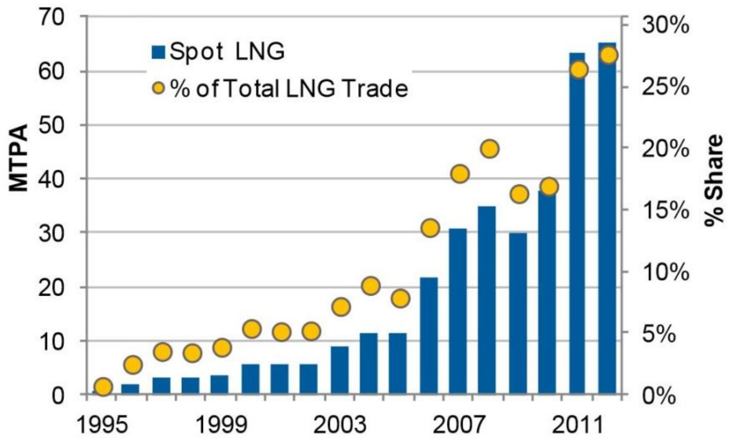


Figure 10 - Volume of LNG trade in physical market (MTPA) and its share (%) of total LNG trade, 1995-2012 (adapted from: Ref 40).

Comparative Remarks on Pricing Mechanisms and Contractual Structures in Oil and LNG Sectors

Comparing the oil sector's various eras with the traditional LNG LTCs, which dominate the global LNG trade, it appears that the OPEC era of oil and the current state of global LNG trade are similar. The upstream and downstream are controlled by different parties, in both sectors, and the LTCs are the main economic instrument in selling the product. Meanwhile, non-LTC trade (physical and paper markets) emerged in oil during the OPEC era and is now emerging in LNG (physical market).

Nevertheless, there are two key differences. While oil in OPEC era was priced based on the OSP and the supplier countries fixed the prices, the LNG price is not fixed; rather, it is linked to other factors out of the producer countries' control. This comes from the fact that major oil suppliers in the OPEC era (and since then) were united as a cartel (OPEC), while the LNG producers do not have such an organization, hence coordinating action among them is relatively difficult. Recently, some of the gas exporting countries (including LNG exporters) have created a discussion forum, named the Gas Exporting Countries Forum (GECF), headquartered in Qatar. The expanding forum involves many top gas\LNG producers and reserve-holders; Iran, Qatar, United Arab Emirates (from Middle East), and Russia are members, while Turkmenistan has participated in some meetings. The combined share of the GECF members in total proven world gas reserves is about 67%.[41] The idea is transforming this forum into the Organization for Gas Exporting Countries (OGEC) with the goal of consolidating the supply and dominating the global gas trade. It remains to be seen whether the forum manages to do so.

The other difference is in the nature of developing non-LTC trade. While in the oil sector the non-LTC trade used to come from the upstream projects that were developed without LTCs (spot sale of uncommitted product), the spot volumes in LNG trade come from arbitrage, since over 90% of the liquefaction plants capacity is covered by LTCs. It seems that LNG sellers are not fully confident in the marketplace to develop a plant without LTC protection, although this may be changing. The volume of MTCs (term contracts up to 5 years long) has grown steadily since 2010 and by 2014 represented nearly 5% of the trade.[27]

DISCUSSION: A COMPARISON OF THE WATERBORNE TRADES OF OIL AND LNG

Trade Scale and Supply Chain CAPEX

The business structure in commodity trading, among other things, is influenced by two important factors: the scale of trade and the supply chain CAPEX. It is instructive to compare these two for the LNG and oil sectors.

The LNG trade in 2013 was 291 MTOE. Estimates of the future growth of the global LNG trade[9] indicate that the volume of LNG to be exported by 2035 will have risen to about 661 MTOE.

It is difficult to obtain historical data for the international waterborne trade of crude oil as pipelines are used for oil exports too. However, the domination of the maritime liquid bulk over pipeline in the global crude trade allows using exports as a surrogate. Comparisons between the world production and export figures between 1980-2010 allow an approximate estimate to be made for the earlier maritime export between 1960 and 1970 (see, e.g., Ref 25). This leads to figures of about 550 MT in 1960, 1,250 MT in 1970, rising to 1,625 MT in 1980, before falling to 1,450 MT in 1990. Hence, given that the volumetric thermal value of LNG is half of that of oil, the forecast LNG trade over the period from 2013 to 2035 will be similar in volume to the maritime crude trade during the last decade of the Majors' era (1960-1970).

Looking at the supply chain of LNG, it is observed that a considerable portion of LNG chain CAPEX, i.e., at least extraction and liquefaction that is about 77% of the chain investment (Table 5) falls on the seller creating a sizable investment risk (majorly made of volume and price risks) for him. In comparison, to the knowledge of the authors, the CAPEX for a single player in the oil supply chain, at least since the OPEC era has never been so high, neither in absolute ($/MMBtu) nor in relative (%) terms.

Table 5 - LNG supply chain CAPEX (source: Ref 42).

Item	CAPEX ($/MMBtu)
Extraction	1.0-3.0
Liquefaction	3.0-4.5
Shipping	0.8-1.5
Regsification	0.4-0.8
Total	5.2-9.8

Ref 16 takes the view that the high CAPEX of LNG supply chain, as well as its concentration in the upstream in the hands of the seller, means that the LNG business structure will not converge with that of oil. As evidence, the author points out the collapse (Enron) and near collapse (e.g., Dynegy) of gas trading companies in early 2000s, advocating the use of derivatives instead of LTCs for hedging the high CAPEX risks. Although, it should be mentioned that the financial troubles of the US gas traders were not because of that advocacy, but rather the result of unhealthy competition among the rivals, leading to the use of accounting limitations to misrepresent earnings and modifications to the balance sheet to indicate favourable performance (for an analysis of the downfall of Enron, see, e.g., Ref 43). Therefore, the reasoning of Ref 16 does not seem to be that strong in its core. Ref 9, however, takes the strong contrary view that the development of a globally unified LNG market and the rise of spot and paper markets with dominating benchmark prices is certain.

In considering the discussed two factors, one should contemplate that the greater degree of homogeneity of LNG compared to crude oil should allow a global market to develop at a lower volume of trade. Moreover, the growth of the LNG sector is taking place in an era when physical and paper markets are accepted means for handling the price and volume risks. Nonetheless, the high CAPEX for the sellers should be considered in any prediction of the future business structure.

Future LNG Business Structure: An Argument

As previously noted, when discussing the institutional developments, there is a tendency among the sellers for vertical integration of the LNG supply chain through self-contracting. This is in effect a move of the seller enterprises to the right pole of the spectrum of governance structures in managing their transactions\deals (Figure 11). It is in the opposite direction to that suggested by Ref 14, who forecast a movement towards spot trade where liquefaction plants are developed without LTC coverage. Given this and the continuing links between LNG prices and those of other energy sources in markets such as Japan, one wonders whether LNG business will follow in the oil sector footsteps during and post OPEC era and develop to a competitive and transparent market where prices are determined by a bargaining system.

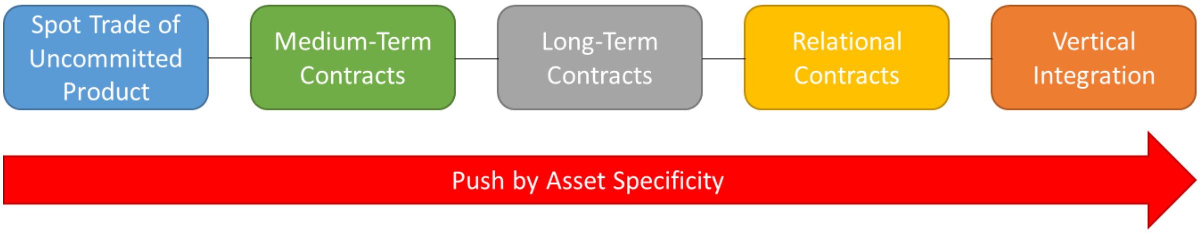


Figure 11 - Spectrum of governance structures for transactions (adapted from: Ref 44).

The authors believe the answer is positive and LNG trade will eventually produce a global market with all the pricing mechanisms typical of the commodity markets. Transaction cost economics (TCE) can assist in explaining the current LNG business structure and suggesting future developments in the sector.

Some goods and services can be produced more efficiently, i.e., the value of the items produced is maximized net of the associated expenses of transaction (the costs involved in market exchanges) and production, if one of the parties invests in "transaction-specific" assets that cannot be easily put to other uses if the seller\producer-buyer relationship breaks down.[44] This has been the case in traditional LNG LTCs where the sellers have been responsible, at least, for creating the upstream facilities and buyers have been in charge of developing the regasification terminals.

It was discussed that the investment in LNG supply chain is high (see Table 5), e.g., the upstream CAPEX in an average chain with the capacity of five million tonnes per annum is 8-16 US$ billion, while the CAPEX of regasification facilities for such a chain is 1-1.5 US$ billion. To be assured of realizing the full value of these investments and protecting them, the LNG sellers and buyers have been entering into traditional LTCs, which tie the parties together and guarantee the continuity of the relationship for a specified period.

However, with liberalization of the gas markets in the US and the UK, which in the LNG sector provides TPA to the regasification terminals, and a significant rise in arbitrage (Figure 10), the asset specificity of regasification terminals in these countries has reduced. There are now many market participants downstream who would like to book capacity in these terminals and bring the arbitraged LNG to the local gas market. Thus, there is a good chance the terminals can achieve high levels of utilisation without traditional LTCs.

The decrease in asset specificity has reduced the interest of the US and the UK regasification terminal owners (the traditional LNG buyers) in LTCs; now they are leaning toward the left pole of the spectrum of governance structures. This combined with the escalation in gas demand worldwide convinced the sellers to connect the fuel to the high value markets themselves and to integrate the downstream through self-contracting to benefit from the marginal rents.[45]

In the future, it is expected that along with the increasing demand for LNG, the technological advancement will make the LNG supply chain cheaper, although not in a transformational way. This would be a continuation of current trends. According to Ref 46 between 1990 and 2008 the investment per unit of output in the LNG supply chain decreased from 4.50 US$/MMBtu to 3 US$/MMBtu (in 2004 US$). The surge in demand will also stimulate the development of gas reserves including smaller reserves and in smaller gas reserve-holder countries (buyers are concerned with the security of supply and prefer to import from a diversified set of sources),[47] liquefaction plants, LNG fleet, and the regasification terminals; (note that gas market liberalization in major LNG consumption regions, i.e., Europe and Asia-Pacific, will provide TPA to all the regasification terminals in these regions). This would lead to a greater number of LNG market participants and more flexibility.[48]

These developments, according to Ref 9, are anticipated in turn to enhance the opportunities for spot trade and competition, necessitate the gas trading firms that would provide the service of allowing buyers and sellers to access efficiently to a broad array of counterparts, and generate the need for price reporting agencies\PRAs (such as Platts) to provide transparency in the growing physical market. The developments are also forecast to reduce the volume of capacities in liquefaction plants that are long-term contracted prior to investing in these facilities. A higher number of market participants reduces the asset specificity for the LNG sellers, which will move them to the left of the spectrum of governance structures. Consequentially, an increase in the LNG physical market liquidity is expected.[49] Note that maturity, i.e., reaching the full depreciation threshold, of liquefaction plants makes the sellers more interested in the rewards of an open and competitive market.[16] Since then, the CAPEX has been fully recovered and the bottom line of revenue, where the asset owners financial position is secure, has reduced. The revenue now needs merely to cover the OPEX (Table 6), although generating profit might require the sellers to seek higher revenues. Therefore, the older the LNG business becomes, the larger the number of sellers that are inclined toward spot sale. This too results in escalation of the LNG physical market liquidity.

Table 6 - LNG supply chain OPEX after recovery of CAPEX (data extracted and estimated from: Ref 42).

Item	OPEX ($/MMBtu)
Extraction	0.5-1.6
Liquefaction	1.6-2.6
Shipping (from Middle East to Europe or North East Asia)	0.9
Regsification	0.2-0.3
Total	3.2-5.4

It should be mentioned that, although the physical market is expected to develop, the high CAPEX and relatively high OPEX (most of which is fixed) in upstream, imply the need for guaranteed base supply volumes from the liquefaction plants. Therefore, leading the sellers to MTCs (base volume), although with smoothed prices, i.e., price variation clauses indexed against physical market. This has happened in oil, as discussed before, that has lower expenses. Another example for such developments is the iron ore trade (a major commodity), which has high expenses. Up to 2010, the Australian iron ore business was based primarily on term contracts with renegotiated annual prices. The system collapsed due to the inability of the pricing system to match rapid changes in demand and to the high volatility in global markets. By 2012, approximately half the Australian iron ore production was sold on the physical market.[50] But the other 50% appears to have been sold on MTCs with prices adjusted by shipment based on physical market benchmark prices such as Platts Iron Ore Index\IODEX.[51]

The iron ore and oil experiences suggest that over time and parallel to the LNG trade growth, LTCs with periods of 20-25 years will disappear to be replaced by a combination of spot trade, as predicted using TCE, and MTCs with price variation clauses set by the physical market (and later perhaps paper markets) benchmark prices. However, if sellers resist the move away from LTCs and are unwilling to invest without the risk distribution that these contracts offer, changes may be slow.

This hypothesis can be assessed against the statistics provided by Ref 27 in the World LNG Report. Between 2004 and 2014, the total non-LTC LNG trade grew by seven times to almost 32% of the exported LNG. But between 2011 and 2014, the percentage of spot remained approximately constant at 27%, whereas MTCs grew from about 1% to nearly 5% of the total trade. The LTC component appears to have fallen steadily from about 72% to 68%. This provides evidence of a slow move away from LTCs, against the pressures from sellers to retain them and the overhang of existing LTCs, in addition to the preference for MTCs, for at least part of the trade, rather than a complete reliance on spot sale.

The development of benchmark prices is necessary not only for facilitating the spot trade but also for the price adjustment of MTCs. Benchmark price development in commodity markets is a complex subject, see, e.g., Ref 38's analysis of oil benchmark prices. However, it is clear that reliable benchmark prices, not subject to easy manipulation, are needed. In addition, the authors are confident that link between LNG prices and oil and coal prices will fade away, as coal and fuel oil, for environmental reasons, are phased out from power generation. Thus, it is expected that the LNG sector becomes decoupled from them. Ref 9 even predicts an inflection point (similar to the occurrences in oil sector in 1986-1987) in pricing the LNG and a rapid tipping to price indexation to physical and paper markets benchmark prices, including in LTCs. Note that the flexibility of the spot trade will link the currently segmented world LNG markets (supplied from dedicated liquefaction plants) and result in convergence of benchmark prices around the world, according to the "law of one price", thus creating a global LNG market.

LNG has a low price elasticity of demand. This, along with the concentration of gas reserves in a handful of countries (Iran, Russia and Qatar together hold approximately 50% of the proven world gas reserves; see Table 2), which despite the progressively liquid physical LNG market provides a fairly oligopolistic supply structure, will generate a situation where high LNG prices cannot be precluded by the physical market (transformation of GECF to OGEC, subject to occurring, will intensify the oligopoly). There will be need for derivatives for managing the price risk. Hence, it is anticipated that LNG will be monetized and paper markets will grow beside the LNG physical market. Paper markets will increase the transparency of the global LNG trade. The New York Mercantile Exchange (NYMEX) and the Intercontinental Exchange (ICE) both have launched LNG swap futures contracts recently.[52]

To further clarify, note that the physical and paper markets are supposed to hedge the volume and price risks. But these markets are fully effective when they are immensely competitive and transparent. The shortcomings of reality from theory, resulting in imperfect markets, necessitates the above discussed guaranteed base supply volumes for covering the expenses, and therefore the MTCs for the LNG sellers.

CONCLUSIONS AND FURTHER RESEARCH

In conclusion, the authors believe that there is now good evidence that growth in the global LNG trade will lead to the development of a global LNG market. However, the existence of a large overhang of LTCs and the resistance to change may slow this development.

The chief changes forecast, which appear to be supported by current changes in the sector, are:

i. A steady reduction in the role of LTCs in LNG trade

ii. Further growth in the role and volume of MTCs.

iii. The development of paper markets to complement the LNG physical market.

iv. The rise of physical and paper markets benchmark prices that would dominate the LNG pricing. This would be parallel to a decline in the use of coal and oil prices in pricing of LNG, as, for environmental reasons, the use of coal and fuel oil in power generation deteriorates.

Further research is needed to support and flesh out these ideas and in particular, to place a timescale on the likely rate of development. This is itself dependent on the degree to which countries execute their commitments to climate change policies which favour the wider use of imported gas rather than cheaper domestic fuels.

Another important avenue of research is the interaction between the geographically constrained pipeline gas trade (domestic and international) and the LNG business. Some researchers, such as Ref 53, believe that the inherent flexibility of the future LNG trade will not only link the LNG markets but also the pipeline gas markets and give rise to a globally unified gas market. The idea is interesting, but before being accepted it needs to be analysed thoroughly and the obstacles in its way addressed. The authors have intentionally left out commenting on possible dealings between the pipeline and LNG trades from the paper. The major obstacles to integration of gas and LNG markets are: (i) the different CAPEX magnitude and structure of many gas pipelines and LNG trade. (ii) The regulated gas markets in numerous producer\reserve-holder countries, particularly those in OPEC and/or Middle East. Given that 70% of the gas produced globally is used domestically,[10] without liberalization of the regulated markets of the producer countries, a free flow of the gas across the world resulting in a global gas market seems inconceivable. The pricing for gas used locally in such countries is relatively neutral, based on social arguments, as long as costs are covered, and hence much different with LNG prices.

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