INTERNATIONAL GAS UNION
UNION INTERNATIONALE DU GAZ

2016 World LNG Report

LNG 18 Conference & Exhibition Edition

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Gorgon LNG and domestic gas plant site.

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About the cover: Liquefied Natural Gas membrane system tank for a LNG carrier using GTT Membrane - No 96 Containment System.

Message from the President of the International Gas Union

Dear colleagues:

As we launch the 2016 IGU World LNG Report, I am struck by the remarkable changes in our industry over the past year. When we released last year's report we could see the writing on the wall – my predecessor noted "the spectacular and unexpected tumble in oil prices" – but today there is growing evidence of fundamental changes in the energy industry.

Global energy pricing has entered a new paradigm; while $70 (and higher) crude was the norm for many years, we're now uncertain about when to expect a rebound to historical trading ranges. Gas industry dynamics are also changing. Projects approved several years ago in a more robust pricing environment are now coming on stream. This supply abundance has affected gas hub and spot LNG pricing levels. LNG contract prices are trending downward, driven by traditional oil-linked formulas.

Nevertheless, the LNG industry remains vibrant, with four liquefaction projects reaching final investment decision in 2015, representing 20 MTPA of new capacity by the end of the decade. New regasification markets formed in Egypt, Jordan, Pakistan and Poland, just in time to benefit from near record-low prices. The United States is about to ride its shale technology revolution to increasing exports of both crude oil and LNG.

…the LNG industry remains vibrant, with four liquefaction projects reaching final investment decision in 2015, representing 20 MTPA of new capacity by the end of the decade.

In another development affecting the energy industry, the results of COP21 in Paris provided some uncertainty and hinted at some potentially exciting opportunities for natural gas. While the overall message of COP21 was a desire to move the world economy away from fossil fuels and toward renewables, news from Paris also highlighted a nearer term challenge, the detrimental effects of poor air quality on public health and economic development.

The global social and political groundswell illustrated by the COP21 agreements suggest that gas can be a critical part of the globe's future energy mix. Gas has many important benefits – it's abundant, flexible and is the perfect complement to intermittent renewables for electricity production. Gas provides clean affordable heating for industrial processes and for commercial and residential customers around the world. Natural gas also has benefits relative to coal and oil – in terms of lower carbon emissions of course, but also in terms of particulates and other emissions that contribute to poor air quality and ensuing health concerns.

IGU is strongly promoting the myriad benefits of gas, and the worldwide LNG industry is playing a key role in expanding access to this important energy resource that leads to a lower carbon future, cleaner air in metropolitan areas, and a prosperous economic future.

The *World LNG Report*, a flagship publication of IGU first published in 2010, provides key insights into LNG industry developments through the first quarter of 2016. While the *Report's* focus remains, as in years past, upon recent historical data on world LNG activity, the *Report* also provides key insights on issues addressing world LNG activity going forward. Now published on an annual basis, the *Report* serves many in the international energy business as a standard desk reference for information on the LNG industry.

Yours sincerely,

David Carroll
President of the International Gas Union

Gorgon. Photo courtesy Chevron

2. State of the LNG Industry[1]

244.8 MT
Global trade in 2015

Global Trade: Total LNG trade reached 244.8 MT in 2015, up 4.7 MT from 2014. This marks the largest year ever for LNG trade, surpassing the previous high of 241.5 set in 2011. The startup of several new projects in Australia and Indonesia drove higher supply, ramping up significantly enough to offset outages in Yemen, Egypt and Angola. Although the Pacific Basin remains the largest source of demand, growth was driven by Europe and the Middle East; both regions saw new countries become importers in 2015.

$9.77/MMBtu
Average LNG import price in Japan, 2015

Global Prices: The decline in oil prices and growing weakness in Pacific demand led all global LNG price markers to fall in 2015, from an average $15.60/MMBtu in 2014 to $9.77/MMBtu in 2015. Japanese import prices, which are primarily linked to oil, fell most dramatically, dropping 78% between January and December 2015. Northeast Asian spot prices also dropped sharply, which led the differential between the Pacific and Atlantic Basins to narrow to an average $1.32/MMBtu throughout the year, down from the average $6.80/MMBtu differential in 2014. As a result of this price signal, Atlantic to Pacific basin trade declined.

71.9 MT
Non long-term trade, 2015

Short-, Medium- and Long-term LNG Market (as defined in Chapter 8): In 2015, the start-up of new projects in Australia and Indonesia contributed meaningfully to the growth in non long-term trade (all those volumes traded under contracts of less than 5 years), as the delivery of commissioning cargoes plus the prevalence of more flexible contracts allowed short- and medium term trade to grow in both countries by over 3 MT year-on-year (YOY). In total, all non long-term LNG trade reached 71.9 MT in 2015, accounting for 29% of total gross LNG trade.

301.5 MTPA
Global nominal liquefaction capacity, January 2016

Liquefaction Plants: In 2015 global liquefaction nameplate capacity reached 301.5 MTPA as two new projects began commercial operations: the 8.5 MTPA Queensland Curtis LNG (QCLNG) project in Australia and the 2 MTPA Donggi-Senoro plant in Indonesia. Gladstone LNG (GLNG) in Australia also sent out commissioning cargoes in 2015, but commercial operations are stated to begin in 2016. Arun LNG in Indonesia transitioned to an import terminal in early 2015 after the final two trains were decommissioned in late 2014, while Algeria's Skikda plant decommissioned two trains in early 2014. A further 142 MTPA of liquefaction capacity was under construction world-wide as of January 2016. Final investment decisions (FID) occurred for a combined 20 MTPA at Sabine Pass T5, Corpus Christi T1-2, Freeport LNG T3, and Cameroon FLNG.

[1]The scope of this report is limited only to international LNG trade, excluding small-scale projects, unless explicitly stated. Small-scale projects are defined as anything less than 0.5 MTPA for liquefaction and less than 1.0 MTPA for regasification.

Prelude *FLNG. Courtesy Photographic Services, Shell International Limited*

890 MTPA
Proposed liquefaction capacity in new LNG frontiers

New Liquefaction Frontiers: Over the last several years, proposed liquefaction capacity has expanded dramatically and totalled 890 MTPA by January 2016. Only some of these projects will come to fruition as market demand expectations are much lower than that volume. Activity has already slowed considerably in 2015 as a result of market oversupply and demand uncertainty in key import markets. Key emerging regions include the US Gulf Coast and Canada (where proposals are spurred by the increase in shale gas production), East Africa (owing to large gas discoveries), floating LNG globally (to take advantage of stranded gas and potentially lower liquefaction unit costs), Asia Pacific brownfield expansions, and Arctic projects in Russia and Alaska.

757 MTPA
Global nominal regasification capacity, January 2016

Regasification Terminals: Global onshore and floating regasification capacity reached 757 MTPA in 2015. The year saw the majority of new terminals constructed in emerging markets, including Egypt, Jordan and Pakistan, though the world's largest importer – Japan – did bring online two new terminals. In addition to the three markets above, which brought the number of countries with regasification capacity to 33, Poland received its first commissioning cargo in December 2015 and its onshore terminal is expected to achieve commercial operations in early 2016. As of January 2016, 15 new terminals were reported to be under construction, 8 of which are located in China, for an increase in total global capacity of 73 MTPA expected online by 2019.

77 MTPA
FSRU capacity, end-2014

Floating Regasification: Floating regasification continued to gain popularity in 2015; 20.4 MTPA of new terminals were added during the year to bring total global floating capacity to 77 MTPA, which accounts for 10% of the total 757 MTPA in the market. Two floating storage and regasification units (FSRU) were added in Egypt, along with one in Jordan and one in Pakistan in 2015, as four out of the seven new terminals that started commercial operations in 2015 were FSRUs. Furthermore, five FSRU projects (in Ghana, Colombia, Puerto Rico, Uruguay and Chile) are in advanced stages.

410 Vessels
LNG fleet, January 2016

Shipping Fleet: The global LNG shipping fleet consisted of 410 vessels as of January 2016, with a total capacity of 60 mmcm. The 28 LNG vessels (including the FSRU *Golar Tundra* that initially acted as an LNG vessel) delivered in 2015 far outweighed the shipping requirements from the additional 4.7 MT of incremental LNG trade, exacerbating the oversupply in the LNG shipping market and leading charter rates to fall 49% between January and December 2015.

10% of Supply
Share of LNG in global gas supply

LNG Positioning: Natural gas accounts for roughly a quarter of global energy demand, of which 9.8% is supplied as LNG. Although LNG supply has grown faster than any other supply source – averaging 6% per annum from 2000 to 2014 – its market share growth has stalled since 2010 as growth in domestic production has accelerated. However, a major expansion of LNG supply through 2020 positions LNG to further expand its share.

3. LNG Trade

In 2015, global LNG trade reached 244.8 MT, marking the largest year for LNG trade in the industry's history and rising above the previous high of 241.4 MT set in 2011. Although no new exporters joined the market, several new plants delivered their first cargoes, contributing 6 MT of new supply. This was more than enough to counter the feedstock and domestic instability issues that led to sizeable declines from several existing exporters, namely Yemen, Angola and Egypt. Four new markets – Egypt, Jordan, Pakistan and Poland – began importing LNG in 2015, bringing the number of global LNG importers up to 33 .

Several emerging trends will shape the LNG market going forward. Over the next two years, significant new export capacity in the Pacific Basin is set to come online and further expand Intra-Pacific trade flows. Asia is still primed to remain the largest driver of demand growth given its expected contract ramp-ups, though the region began to show several potential signs of weakness in 2015. New LNG supplies combined with weaker economic growth, increased competition from competing fuels, and drastically lower oil prices will place downward pressure on LNG prices.

3.1 Overview

244.8 MT
Global LNG trade reached an historical high in 2015

In 2015, total globally traded LNG volumes reached 244.8 MT, a 4.7 MT increase over 2014. This marks an all-time high for total trade in the LNG market, surpassing the previous post-Fukushima high set in 2011 by 3.3 MT.

Only 17 countries exported LNG in 2015, down from 19 in 2014; Angola LNG was shut-down for extended repair work in early 2014, while Egypt exported its last cargo in late 2014 as rapid domestic demand growth diverted gas from its export plants. Furthermore, 10 countries re-exported cargoes in 2015. Three new countries joined the ranks of re-exporters in 2015, with India, Singapore and the United Kingdom sending out their first cargoes.

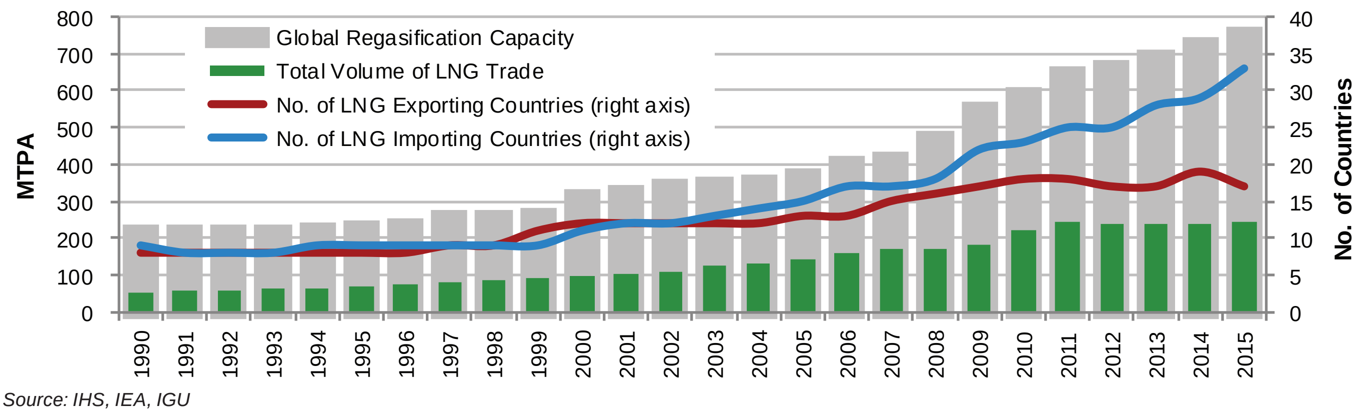
The Middle East's five-year reign as the largest exporting region was upheld in 2015, with the region accounting for 38% of total exports, but new supply from Australia and elsewhere in Asia-Pacific narrowed the gap significantly. The Middle East's market share fell from 40% in 2014 as domestic turbulence in Yemen forced first a brief *force majeure* in January, and then an extended shut-down starting in April; exports remain offline as of February 2016. Still, Qatar alone exported nearly one-third of global trade, and remains the world's largest exporter.

Asia-Pacific suppliers contributed 10.4 MT of supply growth in 2015 – primarily from Australia and Papua New Guinea (PNG) – enough to increase the region's market share from 31% to 34%. Both of the new project commercial start-ups in 2015 – QCLNG and Donggi-Senoro LNG – came from the Pacific Basin. GLNG sent out it's first cargo. Elsewhere, many traditional exporters had flat or minimally different exports in 2015, with the exception of two Atlantic suppliers: in Trinidad, feedstock declines resulted in lower exports of 1.9 MT, while Nigeria continued to show increased export resilience in the face of continued security risk, with exports up 1.0 MT.

Although Asia-Pacific and Asia markets (the distinction between these regions is illustrated in Section 8.3) continue to account for the majority of global demand, pulling in a combined 71.7% of total imports, weakness in the region's top markets – Japan, South Korea, and China – led this share to drop from 74.6% in 2014. The three importers were down a combined 7.5 MT YOY, but growth in smaller Pacific markets like Thailand helped to stem the total combined Asia and Asia-Pacific import decline to just 3.0 MT.

New importing countries also pulled market share away from traditional importers; with the addition of Egypt, Africa

Figure 3.1 LNG Trade Volumes, 1990–2015



Source: IHS, IEA, IGU

[1]Excluding Indonesia, which buys cargoes exclusively from domestic liquefaction plants.
[2]The United States is included in both totals, since it exports domestically-produced LNG from Kenai LNG in Alaska and re-exports LNG from regasification terminals in the Gulf of Mexico.

imported LNG for the first time in 2015, while three other markets (Pakistan, Jordan, and Poland) also took in their first cargoes this year. In total, these new markets pulled in 6.0 MT in 2015 as Egypt set a new record for the fastest import ramp-up ever. The four new markets added to the 29 existing markets in 2014 to bring the total number of importing countries to 33 (excluding Indonesia, which has only consumed domestically-produced LNG).

The decline in European LNG consumption that has occurred since 2011 appears to have ended, with 2015 imports rising by 4.6 MT as supply was redirected away from weaker Asian markets and Asia-NBP price differentials narrowed significantly. All but one European importer (France) registered a YOY gain in 2015, with the UK showing the third-largest gain overall at 1.3 MT), causing the region to have the highest global YOY growth. In contrast, imports in many North American and Latin American countries fell, owing to increased pipeline supply availability (Mexico), improved hydroelectric power generation (Brazil), and general economic weakness (Argentina and Brazil). The two regions were down a combined 1.8 MT.

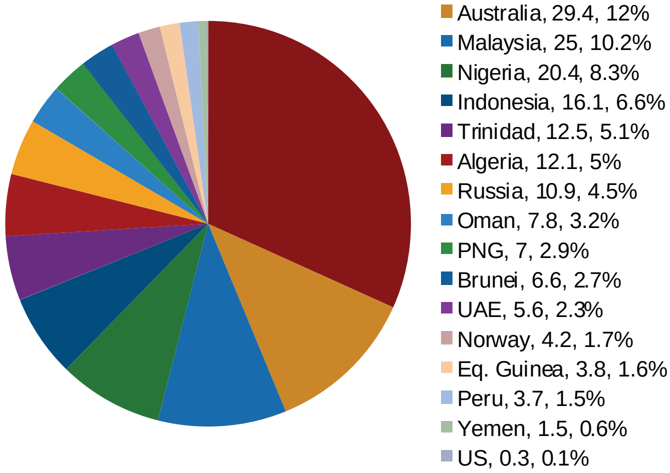
Near-term LNG demand will reflect many of the same trends that occurred in 2015. The Pacific basin will likely remain the primary driver of demand growth despite recent signs of weakness, owing to contracted supply ramp-ups. However there are potential downsides to the outlook from more nuclear restarts in Japan and additional economic weakness in Northeast Asia (particularly China). European demand fundamentals are set to remain weak, but a large increase in Intra-Pacific trade will likely shift more Atlantic and Middle East volumes to Europe, giving it significant growth potential. Downward pressure on LNG prices from an expected abundance of supply and lower oil prices could lead more countries – and potentially higher-risk countries – to quickly enter the market, particularly through the utilization of FSRUs.

On the supply side, the first cargoes from the US Gulf of Mexico will be exported in 2016, but the majority of the increase in supply will come from the Pacific Basin, particularly southeast Asia and Australia. The majority of under-construction capacity in the US is not expected to be completed until 2017 and later.

3.2. LNG Exports by Country

Only 17 countries exported LNG in 2015, down from 19 in 2014. This is owing to the suspension in exports from Angola and Egypt, which were shut down for repair work and feedstock loss, respectively. Despite the decrease in number of exporting countries, several new plants started up in 2015 which helped to increase total LNG trade by 4.7 MT. In Australia, QCLNG started commercial operations in early 2015 and GLNG delivered its first commissioning cargo in October. Indonesia's Donggi-Senoro LNG also began operations in the second half of 2015. In total, new plants added 6.0 MT to the market in 2015, which were delivered to Asia, Asia-Pacific, and the Middle East.

Figure 3.2. LNG Exports and Market Share by Country (in MTPA)

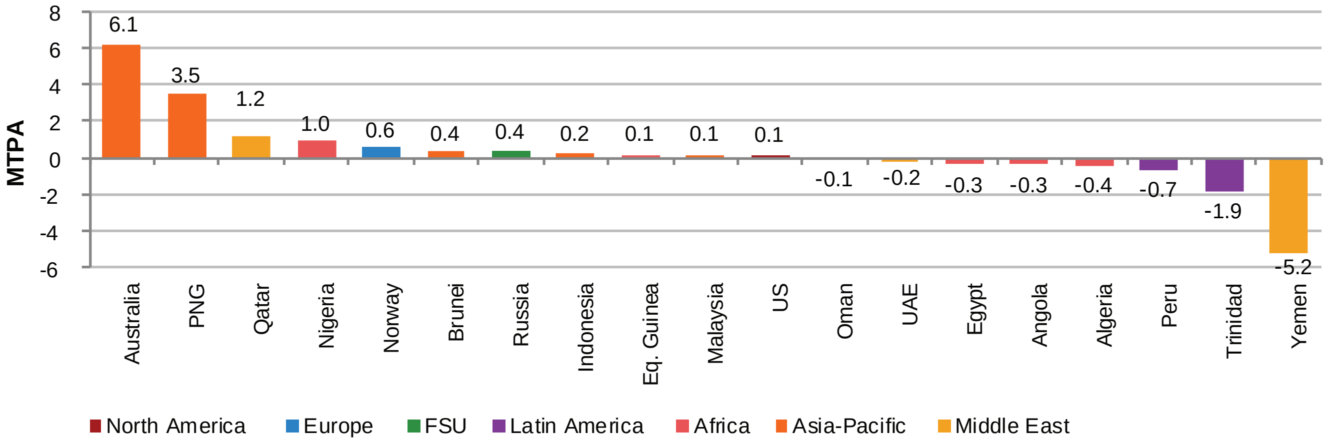


Note: Numbers in the legend represent total 2015 exports in MT, followed by market share. Sources: IHS, IGU

2014-2015 LNG Trade in Review

Global LNG Trade	LNG Exporters & Importers	LNG Re-Exports	LNG Prices
+4.7 MTPA Growth of global LNG trade	**+4** Number of new LNG markets in 2015	**-1.7 MT** Contraction in re-exports in 2015	**-$7.18** Change in average Northeast Asian spot price in MMBtu
Global LNG trade reached an all-time high of 247 MT, rising above the previous high of 242 MT set in 2011 For the first time since 2010, Europe led overall demand growth, followed by the Middle East	No new countries began exporting in 2015, but 4 new markets – Egypt, Jordan, Pakistan, and Poland – imported their first cargoes Two markets – Egypt and Angola – ceased sending out cargoes in 2015, though Angola is expected to return to the market in early 2016	Although three new markets re-exported cargoes in 2015, total re-exports fell owing to diminished cross-basin arbitrage potential The number of countries re-exporting LNG in 2015 rose to 12 with the addition of the UK, Singapore, and India	The drop in oil prices and a looser supply market led to a ~50% decline in Northeast Asian spot prices in 2015, falling from an average $15.01/MMBtu in 2014 to $7.83 Although the Pacific basin maintained its premium over Atlantic markets, differentials narrowed significantly

Figure 3.3. 2015 Incremental LNG Exports by Country Relative to 2014 (in MTPA)

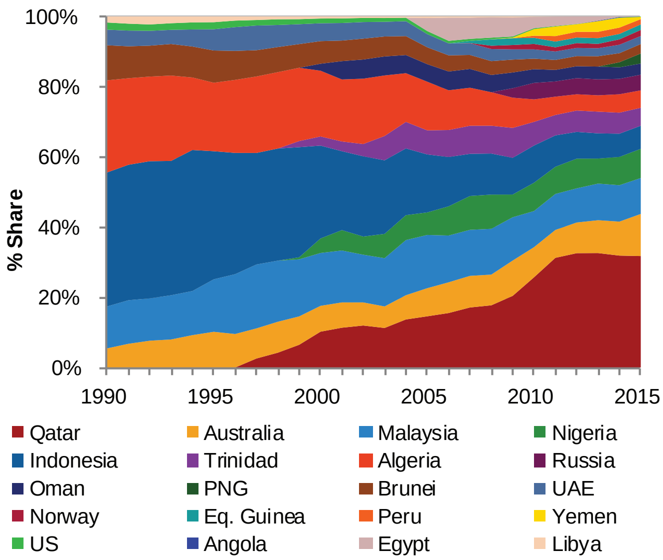


Sources: IHS, IGU

With exports of 77.8 MT, Qatar maintained its status as the largest LNG exporter, which it has now held for a decade. The country accounts for just shy of a third of global LNG supply. For the first time ever, Australia overtook Malaysia to become the second largest exporter in the world, at 29.4 MT. This trend is expected to continue; although both countries have multiple new projects under construction, Australia's projects are greater in both number and capacity. In addition to the 5.5 MT of supply added in 2015 from QCLNG and GLNG Train 1, an additional six projects (with 46 MTPA of capacity) will contribute to Australian supply growth through 2019. In comparison, Malaysia has three projects under construction, with a capacity of 6.3 MTPA. Elsewhere in Asia-Pacific, exports also increased, driven by the ramp-up of supply at new projects (PNG, Donggi-Senoro in Indonesia), which added an incremental 3.8 MT.

The largest YOY export decline in 2015 came from Yemen, where political instability caused Yemen LNG to declare *force majeure* in January 2015. Although the plant quickly resumed operations in February, it was again forced to shut down in April 2015 by the worsening domestic situation; it remains offline as of February 2016. In the Atlantic Basin, several producers also faced production declines, though primarily as a result of feedstock issues rather than above-ground risk. After Yemen, Trinidad showed the second largest YOY loss (-1.9 MT), while Algeria had a smaller but still significant 0.4 MT loss. In Angola, technical difficulties at the Angola LNG plant, commissioned in mid-2013, led the facility to be shut down in April 2014 for an extended period of repair work. The plant only exported five cargoes in 2014 (0.3 MT) and is expected to be back online in mid-2016.

Figure 3.4 Share of Global LNG Exports by Country, 1990-2015



Sources: IHS, IGU

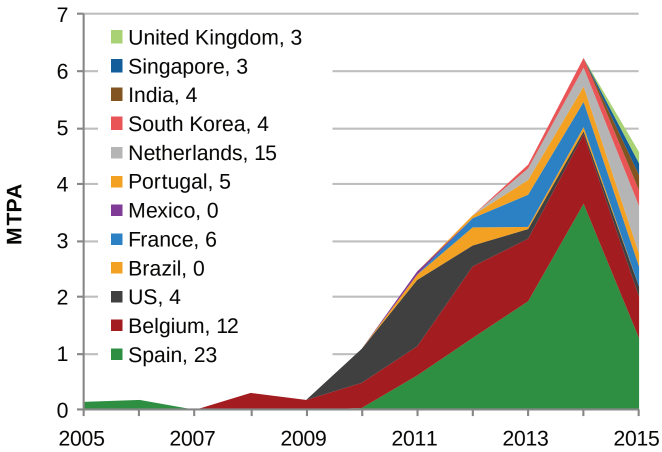
Only three of the eight Atlantic Basin exporters demonstrated production growth in 2015. Nigeria increased 1 MT, maintaining consistent output, even in the face of continued pipeline sabotage issues that caused a brief *force majeure* in December. Similarly, Norway was up 0.6 MT YOY as extended maintenance in 2014 at Snøhvit LNG have stemmed the technical issues that had plagued the plant since its 2007 start-up.

4.6 MT
Re-exported LNG volumes in 2015

Three new countries began to re-export LNG cargoes in 2015, including two more countries in the Pacific Basin – India and Singapore – and the United Kingdom. This brings the total number of re-exporters to 10 in 2015, which previously included: Belgium, France, the Netherlands, Portugal, Spain, South Korea and the US. The US is the only country to both re-export and regularly export cargoes, from the Kenai LNG plant in Alaska. In addition, Brazil and Mexico also have re-export capabilities, although they did not re-export cargoes in 2015.

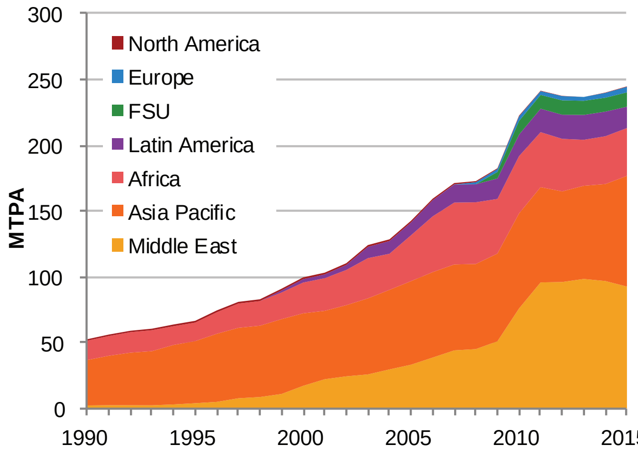
Despite the addition of three new markets, total re-export activity declined significantly in 2015 for the first time in six years as global price differentials narrowed. Total re-exports were only 4.6 MT, a 37% decline from 2015. Although Europe continues to dominate re-export activity at 3.6 MT (-2.3 MT), it was also responsible for essentially the entire decline in re-exported cargoes. After a big (90%) jump in 2014, Spain showed the biggest fall in 2015 (-65%, or -2.4 MT). This decline in re-exports was primarily a result of global factors, such as the increase in new Pacific supply and the decline in global arbitrage potential, rather than market-focused gas demand recovery in Europe.

Figure 3.5: Re-Exports by Country, 2005-2015



Note: Number in legend represents number of international re-exports in 2015. Re-exports figures exclude volumes that were reloaded and discharged within the same country. Source: IHS

Figure 3.6: LNG Exports by Region, 1990-2015



Note: FSU = Former Soviet Union. Sources: IHS, IGU

Looking ahead, the re-export trade may face even more pressure as new LNG supplies enter the market, exerting pressure on spot prices and limiting arbitrage opportunities. However, as traditional Asian markets face increased demand uncertainty ahead of major contracted supply ramp-ups, additional Pacific markets may add or increase their re-export capabilities.

Regionally, LNG trade is still dominated by the Middle East (92.7 MT), owing to Qatar's large role in the market. However, growth was driven by Asia-Pacific (84.1 MT), which increased by 10.4 MT YOY. As Yemen went offline for most of the year, the Middle East fell to a 38% market share, while new plants in Australia and Indonesia pushed Asia-Pacific up to a 34% market share – the closest the two regions have been since 2010. Although overall production was largely flat in Africa, growth elsewhere led its market share to fall slightly, to 14.8%.

3.3. LNG Imports by Country

In contrast to the declining number of exporters, the number of importers grew in 2015 as four new markets took in LNG cargoes. The addition of Jordan, Pakistan, Poland and Egypt – the first importer in Africa – brought the number of importing countries to 33.

Although Asia Pacific was still by far the largest market in 2015 at 139.8 MT, it also showed the biggest decline, falling by 5.1 MT to 57% of global LNG consumption. Japan is the largest market in the region (and globally), followed by South Korea and Taiwan. After narrowly outstripping Europe as the second largest LNG market in 2014, Asia once again fell to third place in 2015. Although both markets showed significant YOY growth. China, India, and Pakistan imported a combined 35.6 MT, just under 15% of global trade. European imports stood at 37.5 MT, up 4.6 MT from 2014 as re-export activity slowed.

In a strong reversal of recent trends, Europe had by far the largest growth globally in 2015 (+4.6 MT), as weaker Pacific

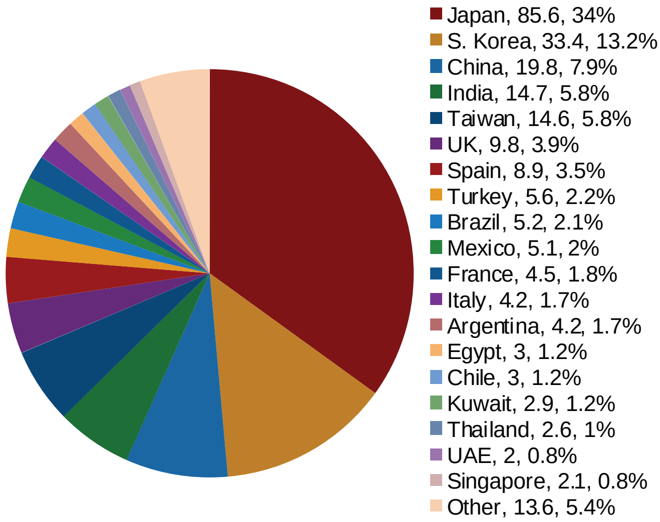
Musel LNG Terminal. Photo courtesy of Enagas

Table 3.1: LNG Trade between Basins, 2015, MT

Exporting Region / *Importing Region*	Africa	Asia-Pacific	Europe	Former Soviet Union	Latin America	Middle East	North America	Reexports Received	Reexports Loaded	**Total**
Africa	0.5	0.1	0.1		0.1	1.7		0.6		**3.0**
Asia	4.4	14.6	0.1	0.2	0.4	15.5		0.7	0.3	**35.6**
Asia-Pacific	9.7	68.5	0.3	10.7	0.4	49.4	0.3	1.1	0.5	**139.8**
Europe	15.8		2.3		2.1	20.8		0.2	3.6	**37.5**
Latin America	3.2		1.3		7.5	1.6		0.9		**14.6**
Middle East	1.2	0.8			0.9	3.0		1.0		**6.9**
North America	1.5	0.2	0.3		4.8	0.6		0.1	0.2	**7.4**
Total	**36.3**	**84.1**	**4.2**	**10.9**	**16.2**	**92.7**	**0.3**	**4.6**	**-4.6**	**244.8**

Sources: IHS, EIA, IGU

Figure 3.7. LNG Imports and Market Share by Country (in MTPA)



Note: Number legend represents total imports in MT, followed by market share %. "Other" includes countries with exports less than 2.0 MT: Belgium, US, Jordan, Malaysia, Puerto Rico, Portugal, Pakistan, Dominican Republic, Netherlands, Canada, Greece, Lithuania, Israel, and Poland. Sources: IHS, IGU

demand led Atlantic and Middle Eastern producers to supply more volumes into the region. This is the first year that Europe had positive LNG import growth since 2011 (which was only +0.2 MT); out of all 11 European importers, only France had a net YOY decline (-0.2 MT). Not including new markets, the UK had the largest YOY growth of any LNG importer, taking in an extra 1.3 MT over 2014 even as it began to re-export cargoes. It was followed closely by Belgium, which more than doubled its LNG imports to grow to 1.9 MT. New market entrant Poland added only very slightly to Europe's import gain, as it took its first LNG cargo at the end of December.

After Europe, the second and third largest demand increases came from emerging regions: Africa and the Middle East. Jordan added 1.8 MT of new imports in its first year in the market as it looked to alleviate both its own gas shortage as well as that of neighbouring Egypt. A portion of its imports went to feed the gas-short market in a reversal of historical pipeline flows. Existing importers Kuwait and the UAE also had significant incremental growth (+0.8 MT), as they capitalized on lower import prices to feed growing demand.

With the start-up of Egypt's two FSRU's, Africa imported LNG for the first time ever. Egypt had the fastest ramp-up of any importer ever, taking in over 1 MT within just four months of its first cargo in April, and reaching 3.0 MT by the end of the year. This is significantly higher than the previous record for fastest ramp-up, set by India in 2004 with 1.9 MT of imports in its first year.

The largest decline came from Asia-Pacific (-5.1 MT). The return of the first nuclear plant online in Japan since 2013, as well as weaker electricity demand and increased competition from competing fuels led to a 3.1 MT decline. Increased fuel competition in the power sector was also a major factor in South Korea's 4.5 MT drop, as coal is increasingly being favoured for new power generation. As additional nuclear and coal generation come online (or return) in Japan and South Korea, their LNG demand weakness can be expected to continue over the next several years.

Although Chinese LNG demand growth did not decline in 2015 (+0.02 MT), growth far underperformed expectations based on contracted supplies. Still, total Asia demand grew by 2.0 MT in 2015, propped up by the addition of Pakistan (+1.1 MT) as an importer and slightly higher imports in India (+0.2 MT). While contracted supplies from new projects in the Pacific Basin have positioned China for strong LNG import growth in 2016-17, uncertainty remains regarding China's ability to absorb the contracted supply ramp-up into its market. This could lead to additional volumes moving to the Atlantic Basin.

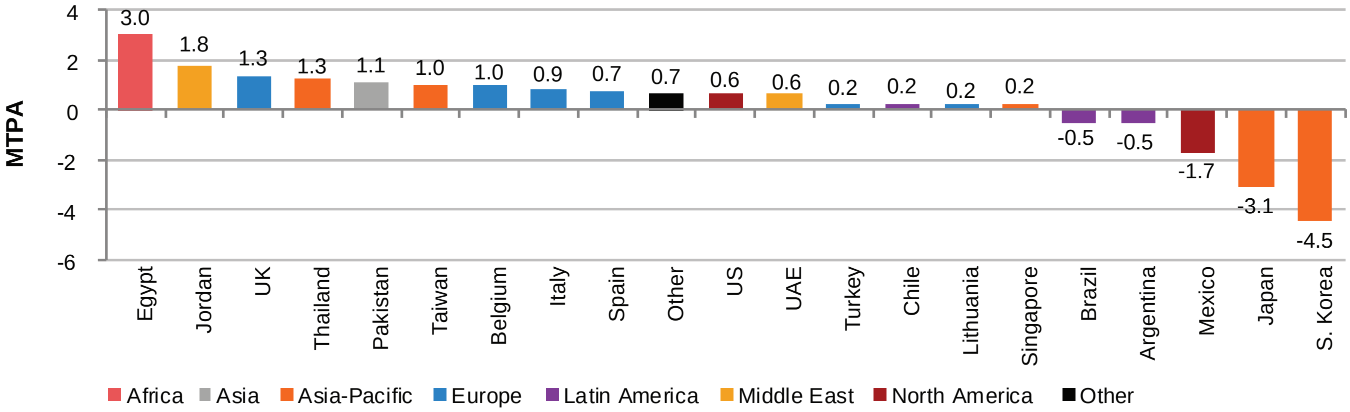
Both Latin American and North American LNG imports fell in 2015. In Latin America, economic performance and better hydroelectric stocks contributed to a 0.8 MT decline, though it still maintained a 7.1 MT lead over North America. A weak economic outlook for the region, particularly in Brazil, weighs heavily on Latin America's LNG outlook, and could usher in a further decline in LNG imports in the Americas. Mexico – since 2012 by far the largest importer in North America – had the third largest decline after Japan and South Korea. The completion of a new pipeline from the United States allowed for a ramp-up in pipeline imports, displacing 1.7 MT of LNG imports. Additional new midstream projects are set to allow for a further increase in low-cost pipeline supply from the US, pushing out more LNG in years ahead.

Globally, domestic production and pipeline trade still account for the majority of gas supplies, at 70.6% and 19.6% of the total, respectively. LNG made rapid gains in the late 1990s and 2000s, but its share has stabilized around 10% since 2010; in 2014 LNG accounted for 9.8% of global gas consumption. Still, LNG retains the highest growth rate of the three gas supply sources, expanding by an average 6.6% since 2000, though this dropped to just 2.2% between 2010 and 2014.

+ 6.6% p.a.
Average yearly growth rate of LNG demand since 2000

LNG imports have developed around the world for a variety of reasons. In the largest markets in Asia Pacific, geographic and geologic restrictions make LNG the only viable source of gas supply. Asia Pacific countries are by far the most dependent on LNG imports to meet gas demand, with LNG making up the majority of gas supply compared

Figure 3.8: Incremental 2015 LNG Imports by Country Relative to 2014 (in MTPA)



Note: "Other" includes countries with incremental imports of less than ±0.2 MT: Portugal, India, Kuwait, France, Netherlands, Poland, Canada, Puerto Rico, Dominican Republic, Malaysia, Greece, China, and Israel. Sources: IHS, IGU

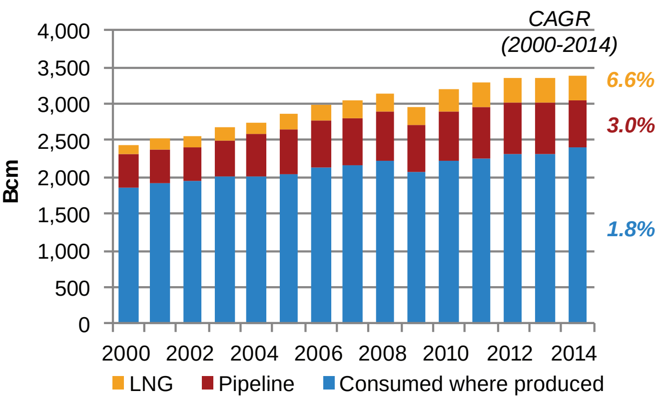
to Latin America and Europe. With little to no domestic production and no pipeline import capacity, Japan, South Korea and Taiwan – the three most important LNG markets in Asia Pacific – rely on LNG to meet nearly 100% of gas demand.

In other major gas markets, countries used LNG to offset maturing domestic gas production or pipeline supply, as has been the case in traditional gas producers like the UK, the Netherlands, Egypt and Argentina. Other markets without or with limited domestic production such as Belgium, Greece, and France have also turned to LNG chiefly to supplement pipeline imports. LNG imports have also evolved in gas-producing markets like Kuwait, Thailand and the UAE where stable or growing domestic production has been unable to keep up with rapidly increasing domestic demand.

In other markets, LNG is used to increase gas supply security. Italy and Turkey are examples of firmly established pipeline markets that have used LNG to augment gas supply diversity. LNG has also served to fortify supply for countries with historically unstable pipeline gas supply, such as Israel and Jordan, which have completely lost pipeline supply from Egypt.

Over the past few years, shifting market dynamics have changed the import requirements of several countries, allowing several markets to essentially wean off LNG imports. The US shale revolution has allowed the US to become self-sufficient in gas and sharply reduced the LNG requirements of Canada and Mexico owing to the interconnectivity of the North American grid.

Figure 3.9: Global Gas Trade, 2000-2014



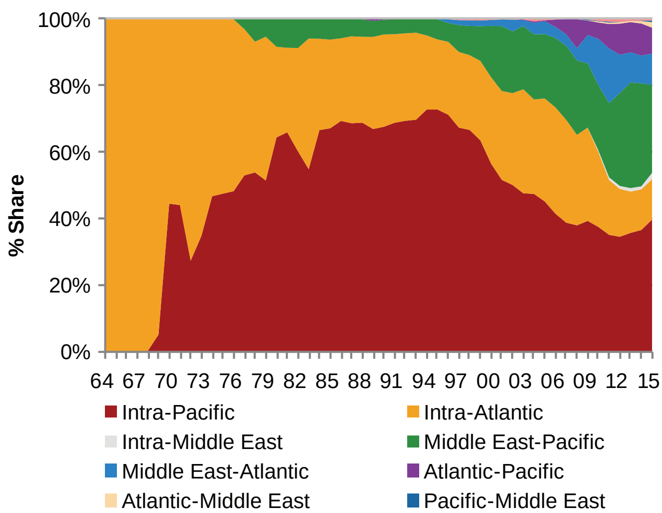
Note: CAGR = Compound Annual Growth Rate
Sources: IHS, BP Statistical Review of World Energy

3.4. LNG Interregional Trade

The largest global trade flow route is Inter-Pacific trade, which accounts for 39% of all global trade. Historically, this share was much higher (over 70% in the early 1990s), but supply from Qatar and other Middle East and Atlantic suppliers diminished the Pacific's share to hit a low of 34% in 2012. The start-up of PNG and new Australian projects added significantly to Inter-Pacific trade in 2015 (+9.4 MT) and will continue to do so over the next few years.

The biggest decline in regional flows in 2015 was in Middle East-Pacific trade, as new Pacific projects and stagnating Pacific demand combined to displace Qatari volumes from the Pacific Basin; as a result, Middle East-Atlantic and Intra-Middle East trade had the second and third highest annual growth, at 3.0 MT and 2.5 MT, respectively. Atlantic-Pacific trade declined considerably (-4.0 MT) with the fall in European re-exports. Once US projects ramp-up in 2017 and beyond, this trend may reverse.

Figure 3.10: Inter-Basin Trade Flows 1964-2015



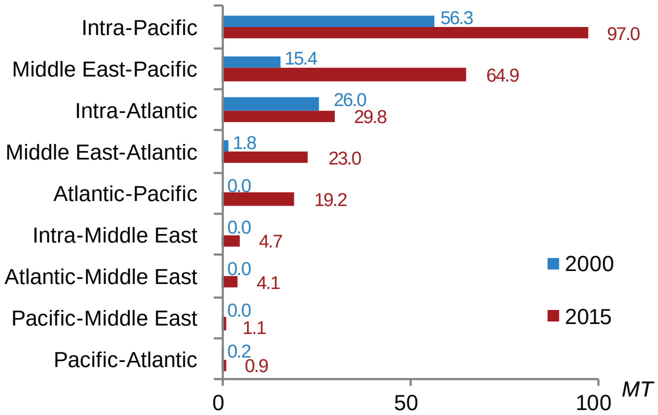
Sources: IHS, IGU

Table 3.2: LNG Trade Volumes between Countries, 2015 (in MTPA)

	Algeria	Angola	Australia	Brunei	Egypt	Equatorial Guinea	Indonesia	Malaysia	Nigeria	Norway	Oman	Papua New Guinea	Peru	Qatar	Russia	Trinidad	United Arab Emirates	United States	Yemen	Re-exports Received	Re-exports Loaded	2015 Net Imports	2014 Net Imports	2013 Net Imports	2012 Net Imports	2011 Net Imports
Egypt	0.35	-	0.07	-	-	0.13	-	-	0.07	0.06	-	-	-	1.70	-	0.06	-	-	-	0.59	-	3.02	-	-	-	-
Africa	0.35	-	0.07	-	-	0.13	-	-	0.07	0.06	-	-	-	1.70	-	0.06	-	-	-	0.59	-	3.02	-	-	-	-
China	0.38	-	5.73	-	-	0.20	2.90	2.98	0.44	0.06	0.06	1.47	-	4.93	0.19	0.06	-	-	0.30	0.14	-	19.83	19.81	18.60	14.77	12.84
India	-	-	0.84	-	-	0.79	0.32	0.13	2.22	-	0.59	0.07	0.07	8.81	-	0.24	0.12	-	0.32	0.41	(0.27)	14.67	14.48	12.92	13.99	12.74
Pakistan	-	-	0.19	-	-	0.19	-	-	0.19	-	-	-	-	0.41	-	-	-	-	-	0.13	-	1.11	-	-	-	-
Asia	0.38	-	6.76	-	-	1.18	3.22	3.11	2.85	0.06	0.65	1.53	0.07	14.15	0.19	0.30	0.12	-	0.63	0.69	(0.27)	35.61	34.29	31.52	28.76	25.58
Japan	0.75	-	18.71	4.30	-	0.46	6.02	15.56	4.56	0.06	2.36	3.97	0.15	14.59	7.78	0.06	5.42	0.16	0.22	0.46	-	85.58	88.69	87.79	87.26	78.76
Malaysia	0.40	-	0.33	0.19	-	0.06	-	-	0.19	0.14	0.13	-	-	0.13	-	-	-	-	-	-	-	1.57	1.60	1.62	-	-
Singapore	-	-	0.65	-	-	0.66	0.26	0.07	-	-	-	-	-	0.48	-	0.11	-	-	-	0.06	(0.21)	2.10	1.89	0.94	-	-
Korea	0.37	-	1.93	1.29	-	0.72	3.90	3.69	1.29	-	4.12	0.21	-	12.36	2.69	0.05	-	-	0.53	0.47	(0.28)	33.36	37.98	40.86	36.78	35.73
Taiwan	-	-	0.26	0.69	-	0.07	2.33	2.39	0.06	0.07	-	1.28	-	6.99	0.26	-	-	0.17	-	0.06	-	14.63	13.59	12.83	12.78	12.18
Thailand	-	-	0.20	-	-	-	0.07	0.13	0.13	-	-	-	-	2.06	-	-	-	-	-	-	-	2.58	1.31	1.42	0.98	0.72
Asia-Pacific	1.52	-	22.09	6.48	-	1.96	12.58	21.85	6.22	0.27	6.61	5.47	0.15	36.61	10.73	0.23	5.42	0.33	0.75	1.05	(0.48)	139.82	145.05	145.46	137.80	127.40
Belgium	-	-	-	-	-	-	-	-	-	-	-	-	-	2.62	-	-	-	-	-	-	(0.73)	1.89	2.13	1.10	1.91	4.45
France	3.27	-	-	-	-	-	-	-	0.80	0.35	-	-	0.20	0.28	-	-	-	-	-	-	(0.35)	4.54	5.17	5.80	7.48	10.68
Greece	0.27	-	-	-	-	0.06	-	-	0.09	-	-	-	-	-	-	-	-	-	-	-	-	0.42	0.40	0.51	1.07	0.95
Italy	0.03	-	-	-	-	-	-	-	-	-	-	-	-	4.13	-	-	-	-	-	0.04	-	4.21	3.35	4.25	5.23	6.43
Lithuania	-	-	-	-	-	-	-	-	-	0.33	-	-	-	-	-	-	-	-	-	-	-	0.33	0.11	-	-	-
Netherlands	0.17	-	-	-	-	-	-	-	-	0.70	-	-	-	0.60	-	-	-	-	-	-	(0.84)	0.63	0.80	0.32	0.61	0.56
Poland	-	-	-	-	-	-	-	-	-	-	-	-	-	0.08	-	-	-	-	-	-	-	0.08	-	-	-	-
Portugal	0.17	-	-	-	-	-	-	-	0.93	0.06	-	-	-	0.17	-	0.06	-	-	-	-	(0.23)	1.16	1.25	1.32	1.66	2.21
Spain	2.81	-	-	-	-	-	-	-	2.92	0.54	0.06	-	0.73	2.27	-	0.84	-	-	-	-	(1.27)	8.91	11.85	9.36	14.22	17.22
Turkey	2.86	-	-	-	-	-	-	-	1.10	0.14	-	-	-	1.20	-	0.12	-	-	-	0.13	-	5.55	5.32	4.24	5.74	4.58
United Kingdom	0.32	-	-	-	-	-	-	-	-	0.13	-	-	-	9.35	-	0.20	-	-	-	-	(0.20)	9.79	8.47	6.84	10.45	18.63
Europe	9.89	-	-	-	-	0.06	-	-	5.85	2.26	0.06	-	0.93	20.70	-	1.22	-	-	-	0.17	(3.63)	37.51	38.85	33.74	48.37	65.72
Argentina	-	-	-	-	-	0.12	-	-	0.83	0.50	-	-	-	0.31	-	1.94	-	-	-	0.50	-	4.19	4.68	4.93	3.82	3.19
Brazil	-	-	-	-	-	0.19	-	-	1.75	0.64	-	-	-	1.25	-	0.95	0.06	-	-	0.38	-	5.22	5.78	4.44	2.52	0.62
Chile	-	-	-	-	-	0.13	-	-	-	0.13	-	-	-	-	-	2.74	-	-	-	-	-	3.01	2.78	2.86	3.03	2.80
Dominican Republic	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.95	-	-	-	-	-	0.95	0.92	1.09	0.96	0.72
Puerto Rico	-	-	-	-	-	-	-	-	0.19	-	-	-	-	-	-	0.94	-	-	-	0.07	-	1.19	1.24	1.20	0.97	0.54
Latin America	-	-	-	-	-	0.44	-	-	2.77	1.27	-	-	-	1.56	-	7.52	0.06	-	-	0.94	-	14.56	15.41	14.51	11.30	7.88
Israel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.12	-	-	-	0.01	-	0.13	0.12	1.56	2.11	2.42
Jordan	-	-	0.07	-	-	-	-	-	0.71	-	-	-	-	0.58	-	0.20	-	-	-	0.25	-	1.81	-	-	-	-
Kuwait	-	-	0.20	0.13	-	0.07	0.07	0.07	0.42	-	0.46	-	-	0.69	-	0.41	-	-	-	0.40	-	2.90	2.73	1.08	1.24	1.18
United Arab Emirates	-	-	0.21	-	-	-	0.06	-	-	-	-	-	-	1.26	-	0.17	-	-	-	0.34	-	2.03	1.39	0.41	-	-
Middle East	-	-	0.47	0.13	-	0.07	0.13	0.07	1.12	-	0.46	-	-	2.53	-	0.90	-	-	-	1.00	-	6.88	4.24	3.06	3.35	3.61
Canada	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.41	-	-	-	0.06	-	0.47	0.42	0.75	1.28	2.42
Mexico	-	-	-	-	-	-	0.19	-	1.49	0.06	-	-	2.54	0.50	-	0.30	-	-	-	0.07	-	5.13	6.87	5.97	3.55	2.92
United States	-	-	-	-	-	-	-	-	-	0.25	-	-	-	-	-	1.60	-	-	0.15	-	(0.18)	1.82	1.23	1.83	3.26	5.93
North America	-	-	-	-	-	-	0.19	-	1.49	0.31	-	-	2.54	0.50	-	2.31	-	-	0.15	0.13	(0.18)	7.43	8.53	8.54	8.09	11.27
2015 Exports	12.14	-	29.39	6.61	-	3.84	16.12	25.03	20.36	4.23	7.78	7.00	3.68	77.75	10.92	12.53	5.60	0.33	1.53	4.57	(4.57)	244.84				
2014 Exports	12.58	0.34	23.25	6.18	0.33	3.72	15.88	24.90	19.37	3.68	7.86	3.49	4.33	76.57	10.57	14.38	5.78	0.25	6.68	6.23	(6.23)		240.13			
2013 Exports	10.90	0.33	22.18	7.05	2.81	3.89	17.03	24.68	16.89	2.97	8.63	-	4.26	77.18	10.76	14.63	5.40	-	7.23	4.59	(4.59)			236.83		
2012 Exports	11.03	-	20.78	6.85	5.08	3.75	18.12	23.11	19.95	3.41	8.08	-	3.89	77.41	10.92	14.40	5.57	0.19	5.13	3.45	(3.45)				237.67	
2011 Exports	12.59	-	19.19	6.84	6.42	3.89	21.43	24.99	18.75	2.86	7.90	-	3.76	75.49	10.49	13.94	5.85	0.33	6.65	2.33	(2.33)					241.39

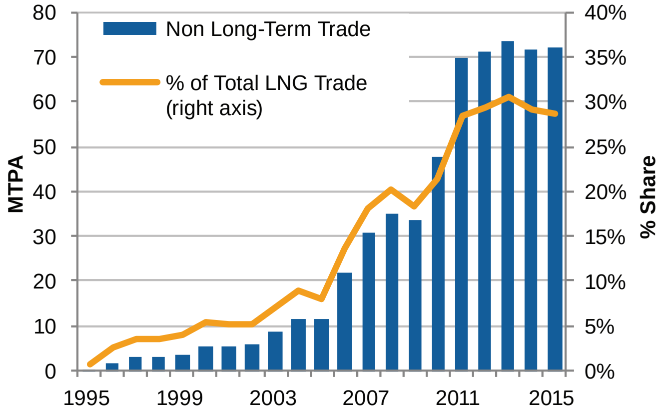
Note: Indonesia, Malaysia, and the UAE conducted domestic LNG trade in 2012- 2015. These volumes are not included above as they do not reflect international trade between countries. Sources: IHS, IGU

Figure 3.11: Inter-Basin Trade, 2000 v. 2015



Sources: IHS, IGU

Figure 3.13: Non Long-Term Volumes, 1995-2015



Sources: IHS, IGU

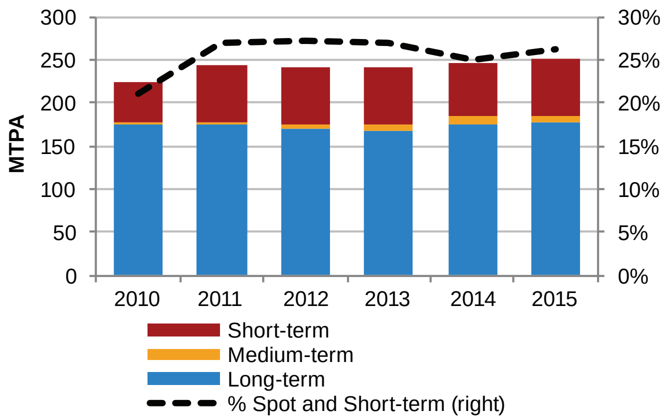
3.5. Spot, Medium and Long-Term Trade

For a large part of the industry's history, LNG was primarily traded under long-term, fixed destination contracts. In recent years, the proliferation of flexible-destination contracts and an emergence of portfolio players and traders has allowed for the growth of "non long-term" LNG trade, which was accelerated by shocks like those that resulted from the Fukushima crisis and the growth of shale gas in the United States.

71.9 MT
Non long-term trade in 2015; 29% of total gross trade

Of all volumes traded without a long-term contract, the majority of growth has come from short-term trade, here defined as all volumes traded under agreements of less than two years. In 2015, short-term trade reached 65.9 MT, or 26% of total gross traded LNG (including re-exports). Although price differentials between basins declined significantly in 2015, the emergence of several new importers, primarily dependent on spot imports, and the commissioning of three new liquefaction plants helped increase short-term trade by 4.1 MT over 2014.

Figure 3.12: Short, Medium and Long-Term Trade, 2010-2014



Sources: IHS, IGU

Medium-term contracts (between 2 and <5 years) have also become a more prevalent part of the non long-term LNG trade, though they remain small compared to short-term volumes. Volumes delivered under medium-term contracts actually declined, from 9.7 MT in 2014 to 6.0 MT in 2015, as several contracts expired and others were filled increasingly with short-term volumes. Medium term contracts offer countries with uncertain future LNG needs, more security of supply for their minimum requirements than would be provided by short-term imports. They are favoured by buyers hesitant to sign long-term contracts because of the availability of uncontracted and flexible supply.

In total, all non long-term LNG trade reached 71.9 MT in 2015 (+0.4 MT YOY) and accounted for 29% of total gross LNG trade. The non long-term market grew rapidly over the past decade; in 2005, only 8% of volumes were traded outside of long-term contracts. This fast growth is the result of several key factors:

- The growth in LNG contracts with destination flexibility, which has facilitated diversions to higher priced markets.
- The increase in the number of exporters and importers, which has amplified the complexity of the industry and introduced new permutations and linkages between buyers and sellers. In 2015, 28 countries (including re-exporters) exported spot volumes to 29 end-markets. This compares to 6 spot exporters and 8 spot importers in 2000.
- The lack of domestic production or pipeline imports in Japan, South Korea and Taiwan, which has pushed these countries and others to rely on the spot market to cope with any sudden changes in demand like the Fukushima crisis.
- The decline in competitiveness of LNG relative to coal (chiefly in Europe) and shale gas (North America) that has freed up volumes to be re-directed elsewhere.
- The large disparity between prices in different basins from 2010 to 2014, which made arbitrage an important and lucrative monetisation strategy.

[3] As defined in Section 8.

[4] "Non long-term" trade refers to all volumes traded under contracts of less than 5 years duration (spot/short-term + medium-term trade). To truly capture the size of the market, volumes are considered non long-term if at any point they were traded under anything other than a long-term contract (e.g., volumes procured from the spot market but delivered under a long-term portfolio contract would be considered spot).

- The faster development timeline and lower initial capital costs of FSRUs compared to onshore regasification, which allow new countries to enter the LNG market.
- The large growth in the LNG fleet, especially vessels ordered without a long-term charter, which has allowed low-cost inter-basin deliveries.

The start-up of new projects in Australia and Indonesia contributed meaningfully to the growth in non long-term trade in 2015, as the delivery of commissioning cargoes plus the prevalence of more flexible contracts allowed short- and medium-term trade to grow in both countries by over 3 MT YOY. The expiration of several contracts at older plants in Indonesia also contributed to its increase in short-term trade. The addition of reload capacity at several importers – India, Singapore and the UK – added a combined 0.7 MT of non long-term trade.

The outage at Yemen LNG was a major downside factor for the short-term market, but since over 55% of the plant's exports in 2014 were delivered under long-term contract, this only pulled 2.3 MT off the short- and medium-term market. European re-exports also had a 2.3 MT decline as they responded strongly to the sharp decline in price differentials between basins; this was strongly influenced by Spain, which accounted for only 35% of all European re-exports in 2015, down from 62% in 2014.

Among import markets, by far the largest gain relative to 2014 came from new market Egypt, which imported its entire 2.8 MT via short-term contracts. Similarly, Pakistan also imported its entire 1.1 MT from the short-term market, while Jordan's one long-term contract provided only 36% of its 1.9 MT total imports in 2015. Several countries in the Middle East and Asia Pacific took advantage of the loosening of the market and lower spot prices to increase their imports – the UAE, Singapore, Taiwan and Kuwait all had moderate YOY short-term gains of between 0.5 and 1.2 MT.

The biggest decline in non long-term imports came from Japan, as the start-up of new contracts plus lower overall LNG demand led it to pull back on short-term imports by 4.4 MT. The start-up of new contracts drove the second and third largest decrease in non long-term imports, in China (-1.9 MT) and Thailand (-0.8 MT), even though both countries had overall positive LNG growth in 2015. In contrast, despite a continued decline in LNG demand in South Korea, its short-term imports increased slightly (+0.2 MT) as several long-term contracts expired. In Latin America, weaker economic performance and hydropower recovery led to total import declines in Argentina and Brazil, which was reflected in their short-term imports (which fell by 0.5 MT and 0.7 MT, respectively) as both import exclusively from the non long-term market.

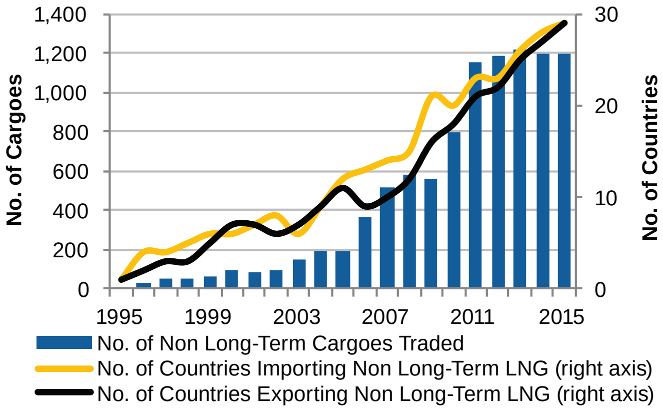
3.6. LNG Pricing Overview

Although the average prices of various regional LNG markets remain driven by different dynamics, they began to converge in 2015 as multiple factors exerted downward pressure on prices around the globe. Gas prices in North America are largely set at liquid trading hubs, the largest and most important of which is Henry Hub in Louisiana. In Europe, wholesale gas is sold mainly via long-term contracts.

These contracts variously take into account gas hub-based or oil-linked pricing, and often both. In Asia and many emerging markets without established and liquid gas trading markets, the price of LNG is for the most part set via oil-linkages, supplemented by a smaller share of spot imports.

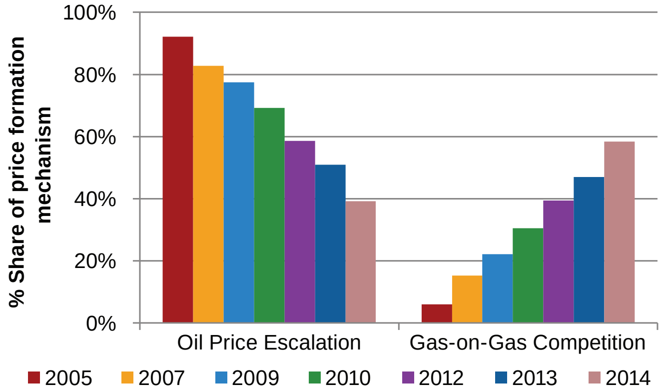
Following the events of the Fukushima disaster and the rise of global oil price benchmarks, oil-linked and spot prices rose rapidly, keeping arbitrage potentials between the Atlantic and Pacific basins high for most of 2011-2014. However, as oil prices fell in late 2014 and throughout 2015, traditionally oil-linked prices in Europe and Asia also declined. From an average of over $100/bbl in the first eight months of 2014, crude prices fell rapidly to below $50/bbl in January 2015. Given that most oil-indexed contracts have a three to six month time lag against the oil price, Asian term import prices remained relatively steady through the end of 2014, with Japanese imports holding at the $15/MMBtu level. However, by 2015 the impact of lower prices took effect; average Japanese import prices dropped more than $6/MMBtu throughout 2015, with December prices landing at $8.13/MMBtu.

Figure 3.14: Non Long-Term Cargo Market Development, 1995-2015



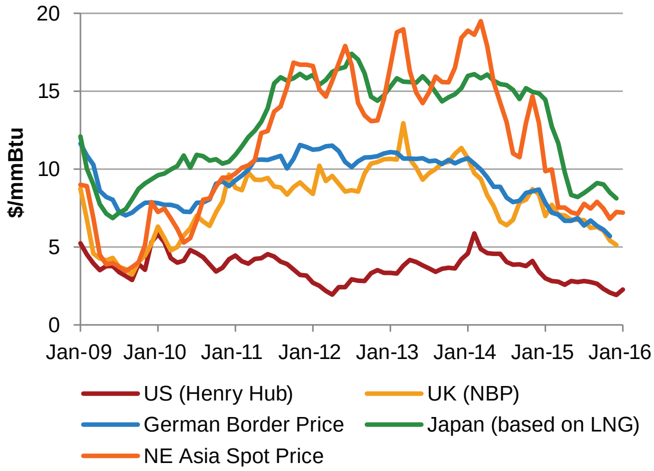
Sources: IHS, IGU

Figure 3.15: European Import Price Formation, 2005 to 2014



Note: Oil Price Escalation = prices linked, usually through a base price and an escalation clause, to competing fuels, typically crude oil, gas oil and/or fuel oil. Gas-on-Gas Competition = prices determined by the interplay of supply and demand – gas-on-gas competition – that are traded at physical or notional hubs.
Sources: IGU Wholesale Gas Price Survey - 2015 Edition

Figure 3.16: Monthly Average Regional Gas Prices, 2009 - January 2016



Sources: IHS, Cedigaz, US DOE

Additionally, the increased availability of LNG – particularly flexible Pacific LNG – in conjunction with stalled demand growth in China and demand loss in Japan began to draw down average Asian short-term prices as well. These two drivers helped to push short-term prices in Northeast Asia down to a low of $6.81/MMBtu in November, a level not seen since early 2010, after the global financial crisis. Lower oil prices, increased LNG supply, and lower demand growth will be key factors in shaping LNG prices.

The majority of Asian gas contracts are linked to oil prices at a multi-month lag. Over the past five years, Asian buyers have increasingly sought to diversify the pricing structures of their LNG portfolios, shifting away from the traditional fixed-destination, long-term, oil-linked LNG contract. Over the past five years, the sustained growth of shale gas production in North America has seen Henry Hub trade at a discount to other major gas benchmarks in the Pacific Basin and Europe, and as a result, Japanese, South Korean and Indian companies signed a number of offtake agreements based on Henry Hub pricing. However, a lower priced oil environment may alter the economic rationale driving buyers to secure US LNG contracts, and contracting activity from the US had already slowed in 2014 and 2015. While Henry Hub linked LNG contracts will continue to offer buyer's portfolio diversification, the perception that these contracts will result in lower priced LNG relative to oil-linked contracts is less assured.

Since 2009, European gas contracts have increasingly been signed or renegotiated to include hub gas price indexation (particularly in the Northwest), dropping the historically dominant links to crude and fuel oil. Due to European Union energy policies and market dynamics, major gas suppliers have since increased the share of hub pricing in the formulation of pipeline export prices for certain contracts.

Similar to contracted Japanese LNG prices, the German border gas price – a proxy for contracted European gas import prices – began to reflect the fall in oil prices in 2015, averaging $6.80/MMBtu for the year. This is a continuation of the declining trend from 2014, though the two periods were driven by different factors; the multi-month lag built into oil-linked contracts meant that 2014's fall from $10.7/MMBtu in January to around $8/MMBtu at year-end represented not oil price weakness but the greater presence of European hub indexing.

As weakness in Pacific demand and new Pacific supply combined to move more Atlantic and Middle Eastern volumes into the United Kingdom, which has one of Europe's most liquid trading hubs, the National Balancing Point (NBP), saw gas prices decline significantly in the second half of 2015. A normal 2014-15 winter left NBP averaging around $7/MMBtu in the first half of the year; meanwhile, the decline in Northeast Asian spot prices brought the average differential between the two to a low of just $0.37/MMBtu by June 2015. By December, NBP began to reflect the influx of new LNG supply, falling sharply to $5.14/MMBtu – a five-year low – and with Asian spot prices at $7.25/MMBtu, the basis differential ended the year at $2.11/MMBtu. Although higher than the summer low, this still represents a significant drop from differentials in 2014, which averaged $6.80/MMBtu during the year.

In North America, overall market fundamentals drive gas price movements much more than changes in the oil price. Although lower activity in oil and wet gas plays resulting from weaker oil prices is set to reduce the growth of associated gas production, the effect will be minimal relative to the size of US gas production. Further, reduced liquids activity has and will continue to reduce the costs of rigs, crews and equipment, which will benefit operators. Moreover, Henry Hub prices are expected to be primarily determined by gas supply and demand fundamentals such as improved pipeline access to growing Marcellus shale and Utica shale production and end-market fuel competition with coal or renewables in the power sector, all of which put downward pressure on prices. For the first time in over 15 years, Henry Hub prices averaged below $3.00/MMBtu in every month in 2015, with an annual average of $2.61/MMBtu. Lower oil prices may have decreased the spread between oil-linked and US LNG contracts in the near-term, but the lower starting point of US prices and abundant downside market fundamentals risks mean that US LNG contracts may offer buyers reduced price volatility over the next few years.

Offshore Platform in Qatar. Photo courtesty RASGAS

Looking Ahead

Considerable new LNG supplies will enter the market in 2016 and beyond. The supply growth from new plants that already happened in 2015 will be amplified by additional production capacity commissioned in 2016-2018. Supply growth will mainly come from the Pacific Basin in 2016 and early 2017, filling Pacific markets with intra-basin supply and reducing arbitrage potential for Atlantic and Middle-East suppliers, particularly re-export markets. However, starting in mid-2017 and beyond, the ramp-up of currently under-construction US capacity will start to balance out the new Pacific push with more flexible Atlantic supply.

How much of an impact will economic weakness have on LNG demand in 2016? Going into 2015, China was set to be the main driver of LNG demand based on its contracted ramp-up, but weak economic performance left it with very limited demand growth. Contract ramp-ups are expected to increase in 2016, but sustained economic uncertainty could dampen the country's ability to absorb these new supplies. Similarly, 2014 may have been a near-term peak year for LNG demand in Latin America, as Brazil has recession risk in 2016. In addition to these macroeconomic factors, financial difficulties and related payment risks in emerging markets may mute demand growth in some of the bigger new entrants in 2015.

Will low LNG prices usher in another set of new LNG importing countries? After adding four new importers in 2015, the expansion of the LNG market is set to slow in 2016. Only one new large-scale market – the Philippines – currently expects to complete construction of new LNG import infrastructure. Low prices helped to bring 2015's new markets like Egypt and Pakistan online mostly according to schedule. If global demand proves to be weaker than expected, placing further downward pressure on prices, other proposed markets may accelerate their plans to add import capacity, potentially providing an unexpected outlet for new flexible LNG supply.

Artistic rendition of LNG Bunkering Ship. Courtesy ENGIE.

4. Liquefaction Plants

Marking the beginning of a wave of new supply expected online over the next several years, global nominal liquefaction capacity increased by approximately 10.5 MTPA in 2015. As of January 2016, 141.5 MTPA of projects were under construction, primarily in the United States and Australia. Though Qatar remained the largest liquefaction capacity holder as of January 2016, Australia is expected to become the largest source of capacity by 2018.

The majority of new LNG proposals stem from North America, where 670 MTPA of capacity has been announced in the US and Canada, excluding 62 MTPA of projects already under construction in the United States. Many proposals in North America as well as globally, particularly high-cost greenfield developments, will face significant challenges in reaching FID in the medium-term due to impending market oversupply and the slower pace of contracting activity. As a result, the actual capacity buildout will likely be significantly lower than announced, though some lower-cost projects, such as brownfield expansions or small-scale floating liquefaction projects, may be able to secure buyers and move forward in 2016. Nevertheless, the LNG business is long term in nature and there will be demand growth in the future due to market rebalancing.

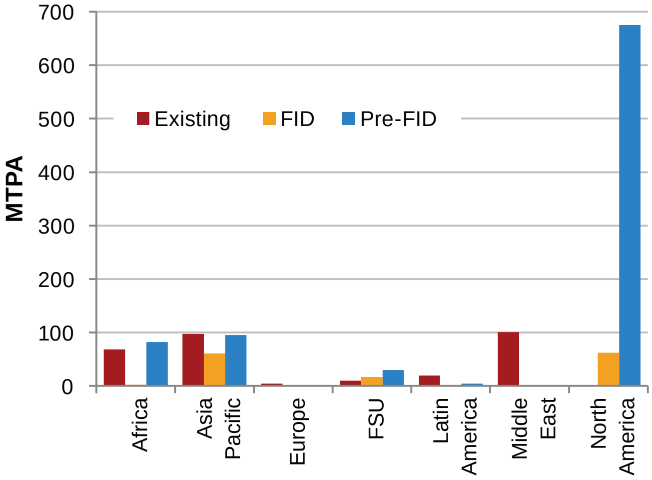
4.1. Overview

301.5 MTPA
Global nominal liquefaction capacity, January 2016

As of January 2016, global nominal liquefaction capacity totalled 301.5 MTPA, an increase from 291 MTPA at end-2014. In 2015, two new projects began commercial operations: the 8.5 MTPA QCLNG project in Australia and the 2 MTPA Donggi-Senoro plant in Indonesia. GLNG in Australia also sent out commissioning cargoes in 2015, with commercial operations beginning in 2016.

The pace of the capacity ramp-up that began in 2015 will accelerate in 2016 as a series of under-construction projects in Australia and the first of the US projects begin operations. Based on announced start dates, 41.5 MTPA of nominal capacity is expected to come online in 2016 in the US, Australia and Malaysia. Under-construction LNG capacity stood at 141.5 MTPA as of January 2016, with four projects (20.3 MTPA of capacity) reaching FID in 2015. Three – Freeport LNG T3, Corpus Christi LNG T1-2, and Sabine Pass LNG T5 – are located on the US Gulf Coast, with the fourth being Cameroon FLNG in West Africa.

Figure 4.1: Nominal Liquefaction Capacity by Status and Region, as of January 2016



Note: "FID" does not include the 10.8 MTPA stated to be under construction in Iran, nor is the project included in totals elsewhere in the report. Sources: IHS, Company Announcements

With 53.8 MTPA under construction, Australia is likely to become the largest LNG exporter by the end of the decade. Growth in the US, where 62 MTPA is under construction, will follow a few years behind Australia.

141.5 MTPA
Global liquefaction capacity under construction, January 2016

The number of proposed liquefaction projects has increased significantly over the last several years and now totals 890 MTPA. The vast majority of this capacity (75%) has been proposed in the US and Canada. However, many of these projects face considerable hurdles and have made limited commercial progress, with only 36% of proposed capacity at or beyond the pre-front end engineering and design (FEED) stage.

Outside the US and Canada, significant liquefaction capacity has also been proposed in Australia, East Africa, and Russia. Timelines for many of these projects – especially those with higher costs – have been pushed back due to market oversupply, weaker demand growth in key import markets, and decreased capital budgets owing to lower oil prices.

Feedstock availability and security concerns impacted several projects in 2015. Both liquefaction projects in Egypt, Egyptian LNG (ELNG) and Damietta LNG, remained offline due to limited feedgas production. Egypt became an LNG importer in 2015 and is not expected to resume exports in the near term. In Yemen, LNG production was halted in early 2015 and remains offline as of January 2016 as a result of political instability.

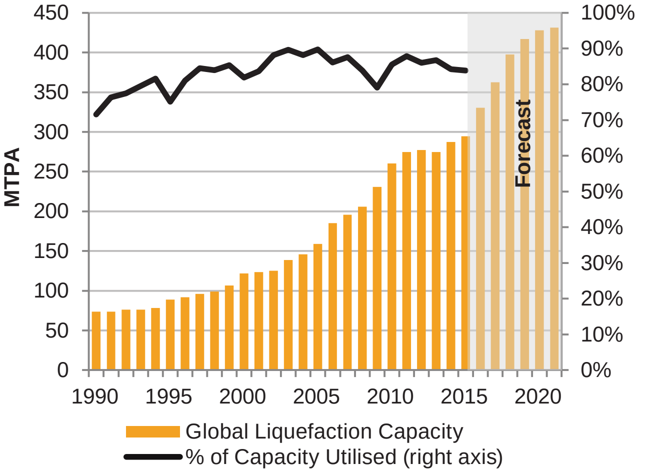
4.2. Global Liquefaction Capacity and Utilisation

In 2015, global liquefaction capacity utilisation averaged 84%[2]. Utilisation has remained relatively consistent over the last several years, averaging 86% since 2010.

Slightly lower rates in 2014 and 2015 were driven by three main factors. Egypt reduced exports in 2014, stopping LNG production fully in 2015, to meet growing domestic demand.

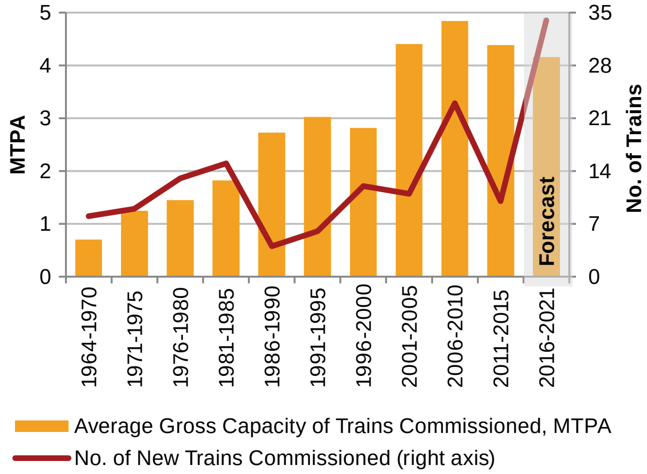
[1]Nominal liquefaction capacity refers to projects' nameplate capacities and is not prorated based on project start dates.
[2]Includes exports within Indonesia, as well as offline capacity in Angola, Egypt, and Yemen. If offline capacity is excluded, average 2015 utilisation is 92%.

Figure 4.2: Global Liquefaction Capacity Build-Out, 1990-2021



Sources: IHS, Public Announcements

Figure 4.3: Number of Trains Commissioned vs. Average Train Capacity, 1964-2021



Sources: IHS, Company Announcements

No timeline has been established for the resumption of Egyptian exports. A *force majeure* at Yemen LNG owing to increased political violence forced the stoppage of exports in mid-2015. The project remained offline as of January 2016. In Angola, the 5.2 MTPA project experienced a series of technical difficulties and produced only a few cargoes in 2014 before being taken offline for repairs. The project did not export cargoes in 2015 but is expected to resume exports in 2016.

These losses were offset by significant production growth and high utilisation from new projects in Australia (+6.1 MTPA) and Papua New Guinea (+3.5 MTPA) as well as continued strong output from legacy producers Qatar, Malaysia, Russia, and Nigeria, all of which operated at or near full capacity in 2015.

4.3. Liquefaction Capacity by Country

Existing

Nineteen[3] countries held LNG export capacity as of January 2016. No countries became new exporters in 2015. Papua New Guinea, the newest exporter, joined the list in 2014. Sixty percent of the world's nominal liquefaction capacity is held in just five countries: Qatar, Indonesia, Australia, Malaysia, and Nigeria. Qatar alone holds 25% of the total capacity. While aging trains in Algeria have been taken offline over the past few years, the country recently added new replacement trains to offset the decline in capacity.

+46% by 2021
Expected growth in global liquefaction capacity

Under Construction

As of January 2016, 141.5 MTPA of liquefaction capacity was under construction. The majority of this capacity is being constructed in the US (62 MTPA) and Australia (53.8 MTPA). Additional projects are under construction in Russia (16.5 MTPA), Malaysia (6.3 MTPA), Indonesia (0.5 MTPA), and Cameroon (2.4 MTPA)[4].

Australia retained its position as the second-largest LNG capacity holder in 2015, behind only Qatar, and will be a major source of incremental supply growth over the next two years. Six projects are under construction in the country and all are expected online by 2018.

With five projects (62 MTPA) under construction on the US Gulf of Mexico and East Coast, the United States will be the predominant source of new liquefaction capacity over the next five years[5]. Through 2016, the US only exported small volumes from the Kenai LNG project in Alaska. This will change soon as Sabine Pass T1 produced it's commissioning cargo in February 2016. Three of the under-construction projects, both expansions and new-builds, were sanctioned in 2015, and all are expected online by 2019. Apart from Corpus Christi LNG, the under-construction projects are brownfield developments associated with existing regasification terminals.

In Russia, Yamal LNG has been under construction since late 2013. The first train is announced to come online in 2017, with all trains scheduled to be operational by 2019. The project is challenged by the difficult Arctic environment as well as possible financing issues related to sanctions against Russia, which may cause delays. However, once completed, it will bring Russia's total liquefaction capacity to 26.1 MTPA[6].

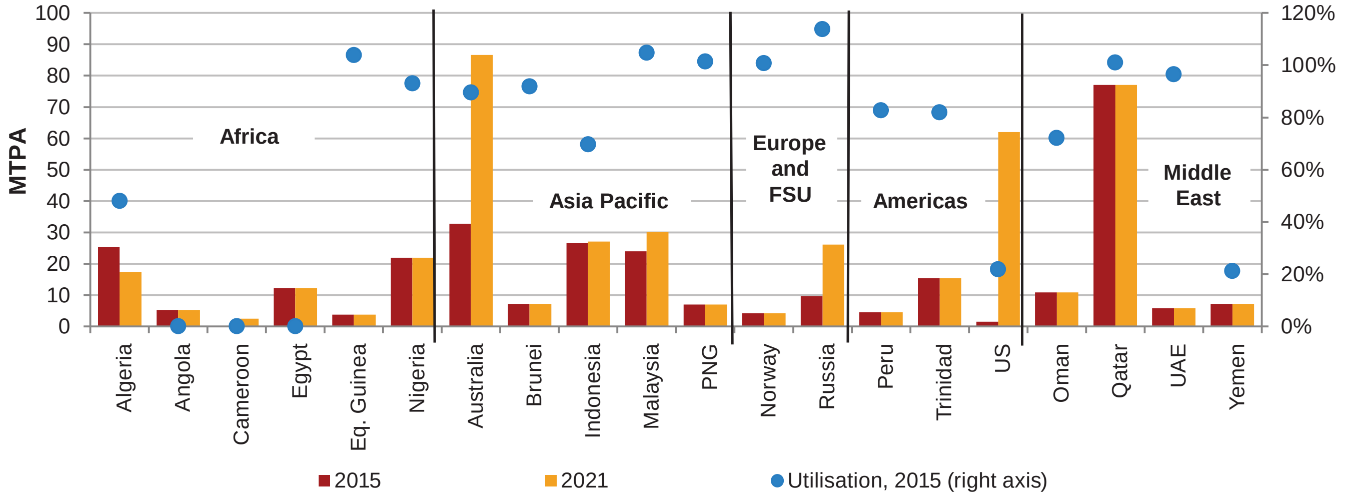
Proposed

Over the last several years, proposed liquefaction capacity has expanded significantly and totalled 890 MTPA by January 2016. Proposal activity slowed considerably in 2015 as a result of market oversupply and demand uncertainty in key import markets.

North America accounts for the bulk of this proposed capacity, where more than 60 liquefaction projects or expansion trains have been announced totalling nearly 680 MTPA[7]. Despite aggressive development timelines put forward by project sponsors, the actual capacity buildout will likely be significantly

[3]Includes Angola and Egypt, which did not export cargoes in 2015.
[4]See Appendix II for a detailed list of under-construction liquefaction projects.
[5]Excludes proposed liquefaction capacity with announced start dates prior to 2021 that has not been sanctioned as of January 2016.
[6]Excludes proposed liquefaction capacity with announced start dates prior to 2021 that has not been sanctioned as of January 2016.
[7]See Tables 4.3 through 4.7 for a breakdown of proposed projects in North America, including the US Lower 48 (4.3), Alaska (4.4), Western Canada (4.5), Eastern Canada (4.6), and Mexico (4.7).

Figure 4.4: Nominal Liquefaction Capacity by Country in 2015 and 2021



Sources: IHS, Company Announcements

lower than expected as only a limited number of projects have made meaningful commercial progress.

Most of the 330 MTPA of proposed capacity in the US is located on the Gulf of Mexico coast and will face significant competition for a limited number of offtakers in an oversupplied market.

Most of the proposed 340 MTPA of capacity in Canada is planned for British Columbia on the country's West coast. Though several of these projects have large LNG buyers as equity partners, their interest in securing large volumes in a weak market environment may wane. Furthermore, many of these projects, unlike those in the US, require large upstream and pipeline investments, adding to project costs.

Several projects have also been proposed in eastern Canada and Mexico. Apart from market supply and demand dynamics, these projects face feedstock availability challenges. In the case of Canada, they will likely require pipeline reversal and capacity expansion in order to proceed. In Mexico, surging gas demand has prompted an increased reliance on US pipeline (and, to a lesser extent, LNG) imports as domestic production declines. As a result, the country's two proposed liquefaction projects (7 MTPA) are longer-term opportunities.

The discovery of large gas reserves offshore East Africa has resulted in multiple liquefaction proposals in Mozambique (44 MTPA) and Tanzania (20 MTPA). Due to additional clarity in 2015 on field development plans and commercial momentum, some East African projects could begin operations in the first half of the next decade. However, project risks in both countries include evolving domestic demand requirements, a lack of infrastructure, and regulatory uncertainty.

Kenai plant. Photo courtesy ConocoPhillips.

Proposed projects in the Arctic and sub-Arctic face a difficult operating environment, high cost estimates, and lengthy construction timelines. The approximately 20 MTPA Alaska LNG project is estimated to cost $45-65 billion and requires the construction of an 800-mile pipeline. Partners are targeting a start date in the mid-2020s. In Russia, Gazprom and Shell signed a Memorandum to construct a third production train within Sakhalin II, with an early 2020's start date. Additional projects in the Russian sub-Arctic are targeting later start dates.

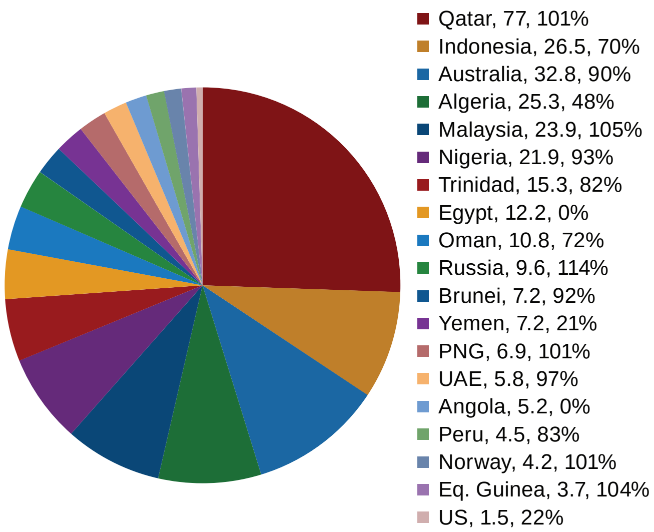
In Asia Pacific, 96 MTPA of capacity has been proposed and is based primarily on offshore reserves. Given the high costs associated with the projects under construction in the region, especially in Australia, as well as competition with the large queue of proposed projects elsewhere, these projects are planned as post-2020 opportunities. Furthermore, project sponsors have not announced start dates for more than half of proposed capacity (51 MTPA) in the region. More than 35% (35 MTPA) of proposed capacity is composed of brownfield expansions of existing or under-construction capacity, while nearly half (44.1 MTPA) of proposed capacity is predicated on floating liquefaction (FLNG) technology.

Decommissioned

No projects were officially decommissioned in 2015, and relatively few projects are expected to be taken offline in the coming years. Arun LNG in Indonesia transitioned to an import terminal in early 2015 after the final two trains were decommissioned in late 2014. Two trains at the Skikda complex in Algeria were decommissioned in early 2014, and the country may decommission several other aging trains in the next few years as two new trains (totalling 9.2 MTPA) were brought online in 2013 and 2014.

While Kenai LNG in the US was also set be decommissioned in 2016, it received a two-year extension of its export authorization in early 2016. Due to declining feedstock, the project was shut down in 2012 but resumed summer operations in 2014 after receiving US Department of Energy (DOE) approval.

Figure 4.5: Nominal Liquefaction Capacity and Utilisation by Country, 2015



Sources: IHS, IGU

While ELNG in Egypt has not been officially decommissioned, it did not export cargoes in 2015 and exports are unlikely to resume in the near future due to declining domestic gas production and rising demand. The country's other export project, Damietta LNG, was taken offline in 2012. However, the Zohr discovery (30 Tcf) made in the Egyptian Mediterranean and the announced $11 billion gas development in the West Nile Delta in 2015 may rebalance the domestic market and revive its LNG export potential. This would be especially true if further exploration success occurs and/or the Leviathan discovery in Israel is partly monetized via Egypt's LNG infrastructure through a shared arrangement.

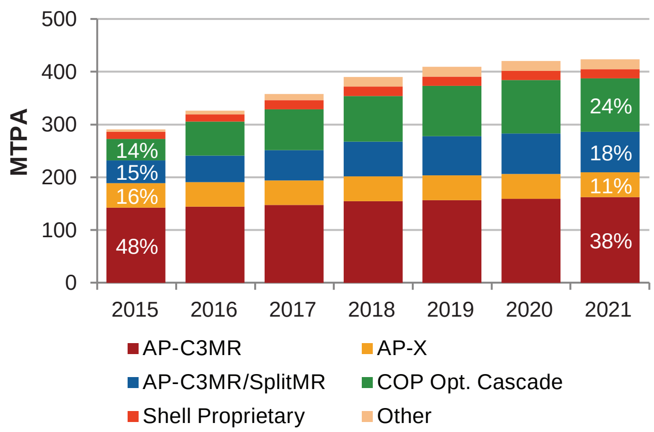
In the longer term, Oman has announced it intends to decommission its export projects by 2024 in order to meet domestic demand. However, the recent announcement of a potential 1 Bcfd gas agreement with Iran may backfill a portion of Qalhat LNG. The UAE is also considering various options to decommission some of the ADGAS trains to meet growing demand when the project's long-term contracts expire in 2019.

4.4. Liquefaction Processes

An array of liquefaction designs is available to project developers. In recent years, a number of designs focused on new concepts, like smaller and floating liquefaction trains, have been developed.

Processes marketed by Air Products account for roughly 80% of installed plants: the AP-C3MR process holds the greatest share at 49%, followed by the AP-X® (16%) and AP-C3MR/SplitMR® (15%) processes. Several under-construction projects have also selected Air Products' processes. Cameron LNG and Yamal LNG will utilise the AP-C3MR process, while Cove Point, Freeport LNG, Gorgon LNG, Ichthys LNG, and MLNG T9 will use the AP-C3MR/SplitMR process. PFLNG 1 will use the AP-N™ process. Combined, these projects account for 76.2 MTPA (54%) of the 141.5 MTPA of capacity under construction as of January 2016. The large-scale AP-X process has thus far been used exclusively in Qatari projects.

Figure 4.6: Liquefaction Capacity by Type of Process, 2015-2021



Source: IHS

The PETRONAS FLNG SATU has been completed and is expected to commence production in 2016. Photo courtesy PETRONAS.

As a result, Air Products is expected to retain a large percentage through 2021. The ConocoPhillips Optimized Cascade® process will see strong growth with thirteen trains (57.2 MTPA of capacity) under construction using the process as of January 2016. As a result of its suitability to dry gas, the process has been the top choice for coal-bed methane (CBM) projects in Australia as well as some projects in the US, given their connection to the dry gas grid.

Other and increasingly smaller-scale processes make up a limited portion of existing and under-construction capacity but may see an increase in market share going forward. In North America, multiple projects have been proposed based on small-scale modular liquefaction processes. The use of these processes would allow developers to begin constructing liquefaction trains offsite, which may help to reduce costs.

171 MTPA
Proposed FLNG capacity as of January 2016[8]

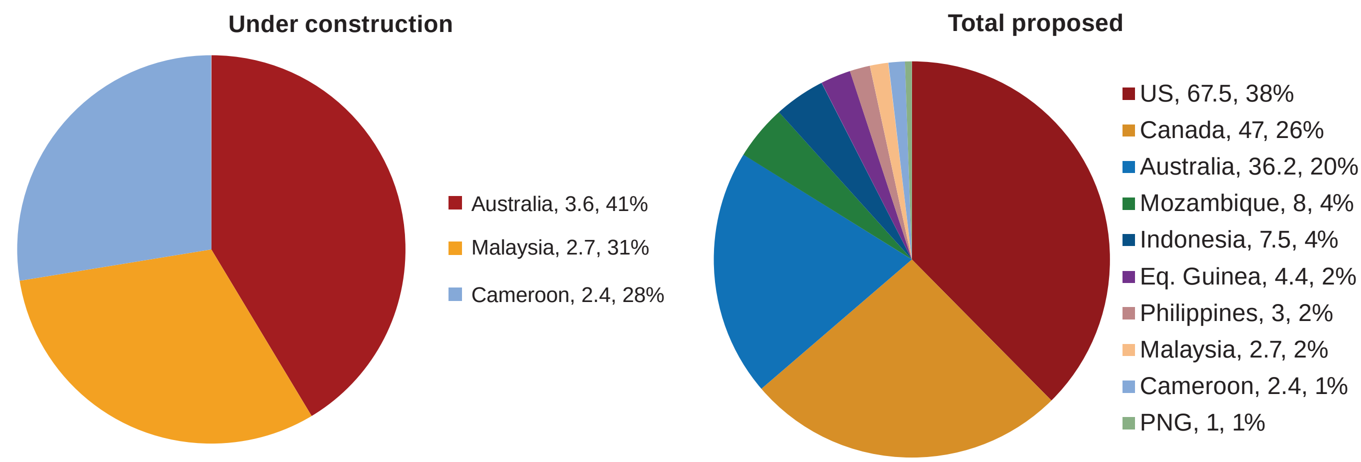
4.5. Floating Liquefaction

As the pace of onshore liquefaction proposals has slowed, numerous floating proposals have emerged. Four FLNG projects in Australia, Malaysia, and Cameroon totalling 8.7 MTPA were under construction as of January 2016. The first two projects are expected to begin operations in 2016, with all four scheduled to come online by 2018. Beyond the projects under construction, twenty-four FLNG proposals totalling 171 MTPA have been announced as of January 2016, mostly in the US, Canada, and Australia. Projects have also been proposed in Equatorial Guinea, Indonesia, Mozambique, Papua New Guinea, and the Philippines.

Based on several different development concepts – purpose-built, near-shore barge, and conversions – FLNG projects typically seek to commercialize otherwise stranded gas resources, avoid much of the lengthy permitting and regulatory approvals associated with onshore proposals, and reduce costs with offsite construction. Relative to onshore proposals, they are generally smaller-scale and, in some instances, reportedly have lower cost estimates. As these projects have not yet been commissioned, cost escalation remains an uncertainty.

Three of the four under-construction FLNG projects – Prelude (3.6 MTPA), PFLNG 1 (1.2 MTPA), and PFLNG 2 (1.5 MTPA) – are utilising purpose-built vessels. The proposed 3 MTPA Coral FLNG project offshore Mozambique would use a similar approach and made meaningful progress in 2015 as offtake

Figure 4.7: Under Construction and Total Proposed FLNG Capacity by Country in MTPA and Share of Total, as of January 2016



Notes: "Total proposed" capacity is inclusive of under-construction capacity. Source: IHS

[8] Excludes the 8.7 MTPA of FLNG capacity currently under construction.

Figure 4.8: Global Liquefaction Plants, 2015

Note: Further information on each of these plants can be found in Appendix I, identified by reference number in parenthesis. Source: IHS

2014-2015 Liquefaction in Review

Capacity Additions	New LNG Exporters	US Build-out Begins	Floating Liquefaction
+10.5 MTPA Year-over-year growth of global liquefaction capacity in 2015	**1** Number of new LNG exporters since 2014	**5** US projects sanctioned since 2014	**8.7 MTPA** FLNG capacity under construction as of January 2016
Global liquefaction capacity increased from 291 MTPA in 2014 to 301.5 MTPA in 2015 141.5 MTPA was under construction as of January 2016 890 MTPA of new liquefaction projects have been proposed as of January 2016, primarily in North America	PNG joined the list of countries with LNG export capacity in 2014 A number of project proposals in emerging regions such as Canada and Sub-Saharan Africa could lead to the emergence of several new exporters in coming years	Previously expected to be one of the largest LNG importers, 62 MTPA of export capacity was under construction in the US as of January 2016 Several additional US projects made regulatory and commercial progress. In total, 332 MTPA of capacity is proposed in the US, excluding under-construction projects	Since 2014, 69 MTPA of floating liquefaction capacity has been proposed. Four projects have been sanctioned, totalling 8.7 MTPA Many proposals announced in the past few years aim to market gas from smaller, stranded offshore fields

discussions reached an advanced stage. The developer is seeking to sanction the project in 2016 and have the purpose-built vessel online by 2020.

Smaller-scale FLNG projects based on vessel conversions gained particular momentum in 2015 due to their reportedly lower cost, shorter development timelines, and ability to commercialize a wide range of smaller resources. The most recent project, floating or otherwise, to take FID in 2015 was Cameroon FLNG, a 2.4 MTPA FLNG conversion design that was first proposed in mid-2014. The Fortuna FLNG project in Equatorial Guinea, also based on a vessel conversion, is being developed in a similar manner. The project developer aims to reach FID in 2016 and expects the project online in mid-2019.

Near-shore barge-based FLNG developments generally seek to commercialize onshore reserves while minimizing onshore infrastructure. Being permanently moored without navigation ability reduces project complexity and thus potentially reduces costs, though, like other floating development designs, the potential for cost overruns exists.

The 0.5 MTPA Caribbean FLNG project offshore Colombia was originally slated to be the first floating project online in mid-2015, though in early 2015 project developers announced delays due to the low oil price environment. Developers are reportedly working to place the vessel elsewhere for liquefaction work.

Though several FLNG projects are in advanced discussions with offtakers, only two under-construction projects have announced binding agreements so far. Given estimated construction timelines and weak market fundamentals, a significant buildout beyond the four FLNG projects under construction is unlikely before 2020. That said, despite an increasingly oversupplied LNG market, floating projects have a smaller parcel size, and may find it easier to secure offtakers and reach FID in 2016, than large land-based projects.

4.6. Project Capital Expenditures (CAPEX)[9]

With market oversupply likely to increase in 2016 and oil prices expected to remain weak in the near term, cost will be a major factor in determining which proposed LNG projects are ultimately sanctioned.

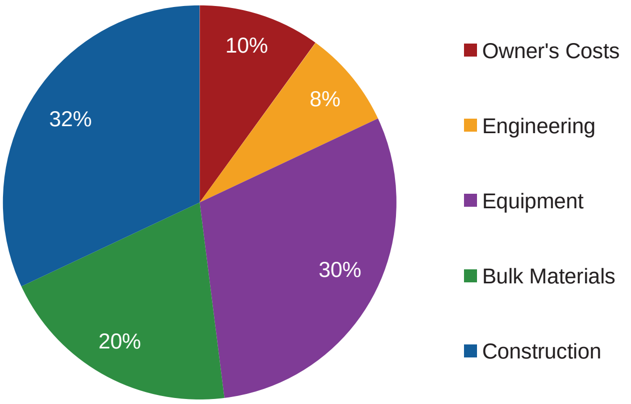
Liquefaction projects have faced considerable cost escalation since 2000, with several projects reporting cost overruns in the range of 30-50%. Unit costs[10] for liquefaction plants increased from an average of $379/tonne in the 2000-2007 period to $807/tonne from 2008-2015. Between the same time periods, greenfield projects have increased from $495/tonne to $1,162/tonne, while brownfield projects have only increased to $502/tonne, up from $297/tonne, due to the advantage of existing infrastructure.

Plant costs vary widely and depend on location, capacity, liquefaction process (including choice of compressor driver), the number of storage tanks, access to skilled labour, and regulatory and permitting costs. Large amounts of steel, cement, and other bulk materials are required. Investment in gas processing varies depending on the composition of the upstream resource. Gas treatment includes acid gas, natural gas liquids (NGL), and mercury removal; and dehydration. Figures 4.9 and 4.12 include additional information on average liquefaction project costs by construction component and expense category.

Higher input and labour costs became common over the last decade due to global competition for engineering, procurement and construction (EPC) services as many projects began construction simultaneously. Cost escalation has been pervasive in both the Atlantic and Pacific Basins, but

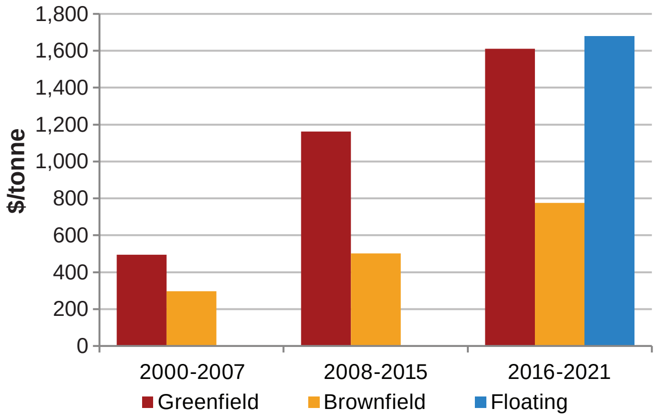
[9] CAPEX figures reflect the complete cost of building the liquefaction facilities, including site preparation, gas processing, liquefaction, LNG storage, and other related infrastructure costs. Upstream and financial costs are excluded.
[10] All unit costs are in real 2014 dollars.

Figure 4.9: Average Cost Breakdown of Liquefaction Project by Construction Component



Source: Oxford Institute for Energy Studies

Figure 4.10: Average Liquefaction Unit Costs in $/tonne (real 2014) by Project Type, 2000-2021



Sources: IHS, Company Announcements

Australia has been particularly affected due to exchange rate fluctuations and skilled labour shortages.

Several completed or sanctioned projects over the last few years have been located in difficult operating environments and are associated with complex upstream resources, including CBM in Eastern Australia, deepwater fields in Asia Pacific, and Arctic environments in Norway and Russia. The complexity has resulted in considerable delays, which have further driven up costs.

However, costs may begin to stabilize going forward due to significant technological advancements that have reduced upstream costs by improving well productivity. Steel costs have fallen dramatically over the last several years and may reduce overall capital expenditure requirements. EPC costs may also face downward pressure if the pace of FIDs slows over the next several years.

$1,611/tonne
Weighted average expected cost for greenfield projects announced to come online between 2016 and 2021

The average unit cost for Atlantic Basin LNG projects increased to $1,292/tonne from 2008-2015, compared to $441/tonne from 2000-2007. Projects in Asia Pacific fared only marginally better, with costs increasing from $293/tonne to $1,011/tonne between the same periods. Comparatively, Middle Eastern projects averaged $456/tonne from 2008-2015, largely due to the lower cost of brownfield expansions in Qatar and Oman.

Based on announced costs, greenfield projects will remain at a significant cost premium to brownfield projects. Greenfield projects expected to come online from 2016-2021 have an average unit cost of $1,611/tonne.

Brownfield developments offer much more favourable project economics. Notably, four of the five liquefaction projects under construction in the US are brownfield projects associated with existing regasification terminals. Unit costs for these brownfield projects average $862/tonne, well below the $1,569/tonne associated with under-construction greenfield projects globally.

Most US projects will source dry gas, which will reduce costs by limiting the need for gas treatment infrastructure. In addition, US projects may be less exposed to cost escalation because most EPC contracts associated with the projects were signed on a lump-sum turnkey basis as opposed to the cost-plus contracts used for some global projects.

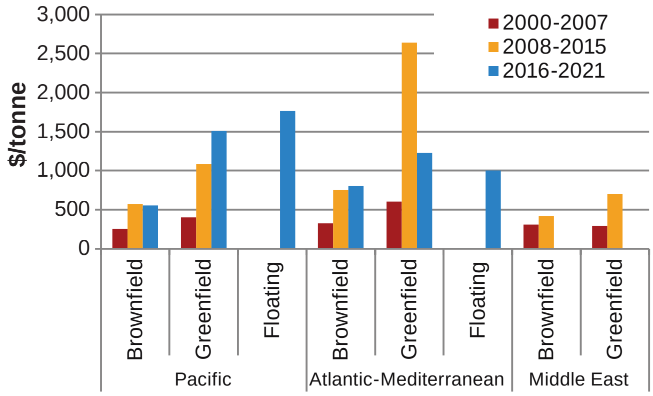
Numerous greenfield proposals that have not yet been sanctioned have high project costs with economics that are challenged by low oil prices. For most greenfield projects to move forward, developers will need to secure long-term contracts to underpin project financing. Low oil prices and weaker demand growth in major import markets make this task a more difficult undertaking. As a result, high costs are expected to be a major source of delay for future projects.

Apart from high liquefaction costs, greenfield projects proposed in Western Canada and Alaska require lengthy (300 miles or more) pipeline infrastructure. Fully integrated Western Canadian projects have announced cost estimates of up to $40 billion, while in Alaska the estimate ranges from $45-65 billion.

4.7. Risks to Project Development

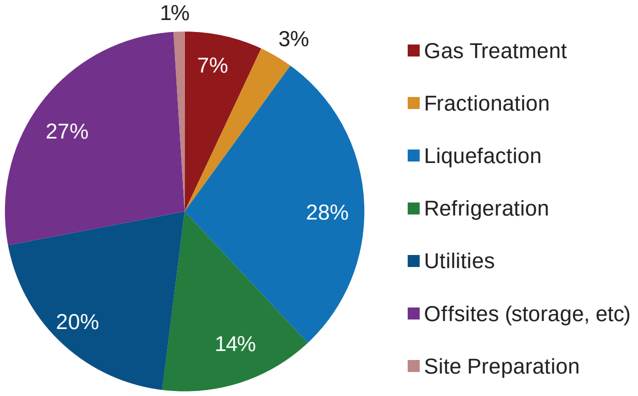
Although liquefaction projects face a variety of risks common with other types of large infrastructure projects, low oil prices and challenging LNG market fundamentals have exacerbated

Figure 4.11: Average Liquefaction Unit Costs in $/tonne (real 2014) by Basin and Project Type, 2000-2021



Sources: IHS, Company Announcements

Figure 4.12: Average Cost Breakdown of Liquefaction Project by Expense Category



Source: Oxford Institute for Energy Studies

several of these risk factors, especially project economics and contracting. Timelines for a number of projects, particularly those with high cost estimates and no buyers, have been pushed back by several years. Several projects face such high risks that they are likely to be delayed or cancelled.

Major liquefaction project risks include project economics, politics and geopolitics, environmental regulation, partner priorities and partners' ability to execute, business cycles, domestic gas needs and fuel competition, feedstock availability, and marketing and contracting challenges.

Project Economics

As noted in Section 4.6, high cost estimates have been a leading obstacle to project development, particularly as the LNG market has become increasingly oversupplied and oil prices remain low. Adding to this is the risk associated with uncertain fiscal and regulatory regimes, especially in emerging liquefaction regions.

Politics, Geopolitics, and Environmental Regulation

The permitting and regulatory approval processes, even in developed markets such as the US, can be time consuming and costly. Gaining full regulatory approval remains a critical challenge for many proposed projects. Even for US brownfield developments, environmental permitting is likely to continue to take nearly two years or more. However, with several projects having now moved through the process, greater certainty has emerged on expected timelines and costs.

Canada's environmental approval process is well established but still takes nearly two years to complete. Only a few projects have been approved; the majority of proposals have not yet begun the process. Furthermore, project developers in Canada need to secure approvals from First Nations groups impacted by the project, including those along associated pipeline routes, which can prove difficult as an agreement must be negotiated with each group separately. The British Columbia government has been persistent in its support for LNG development. It provided clarity on taxation in 2014 and 2015 via a new LNG export-specific tax and royalty regime, which was previously a major uncertainty. Similarly,

Wheatstone. Photo courtesy Chevron

in Sub-Saharan Africa, both the Mozambican and Tanzanian governments support the development of liquefaction projects and have actively worked to establish new gas-specific legislation in 2015, though this has been a lengthy process, particularly in Tanzania.

Persistent political volatility can pose a serious risk to project development, and it can continue to impact steady operations after construction has completed. Political instability has hampered existing projects, such as in Yemen, and has delayed the development of additional liquefaction capacity in Nigeria and several other countries.

Iran's LNG sector has been hampered by the imposition of US and European Union (EU) sanctions. The country has not been able to do business with most firms operating in the LNG industry, nor has it been able to access US liquefaction processes, which maintain a majority of market share. Although many nuclear-related sanctions were lifted in January 2016, there is a possibility that sanctions could be reintroduced depending on political developments, and most non-nuclear sanctions remain in place. These uncertainties may impact the development of Iran's several proposed large-scale liquefaction projects that were previously abandoned due to the imposition of sanctions.

Partner Priorities, Ability to Execute, and Business Cycles

Divergent priorities among project partners, even in established liquefaction regions, have resulted in project delays, especially for large-scale projects. Not all partners are equally committed to a project. Smaller companies may be unable or unwilling to commit to investments on that scale, while larger players are frequently in the position of high-grading opportunities in their respective portfolios.

Though project proposals slowed in 2015, the number of projects under consideration has nonetheless increased considerably over the past several years. However, many are being developed by project sponsors with no experience in liquefaction, particularly in North America. This is an emerging theme as new players enter the LNG business. Developers must have the technical, operational, and logistical capabilities to execute a project. Concerns over a company's ability to execute on any component of an LNG project will also make it more difficult for that company to secure sufficient project financing.

Even for experienced developers, their ability or willingness to sanction a liquefaction project may be impacted by overarching business cycles. Low oil prices have caused many companies to reduce capital spending, resulting in numerous project

Table 4.1: Liquefaction Project Development Risks

Risk Factors	Impact on LNG Project Development
Project Economics	High project costs require developers to sign long-term sales contracts that will allow for a sufficient return. Cost overruns and changing market prices can have a large impact on when or if a project is sanctioned.
Politics & Geopolitics	Permitting may be time consuming. Federal or local governments may not be supportive of exports and could levy additional taxes on LNG projects or establish stringent local content requirements. Political instability or sanctions could inhibit project development or operations.
Environmental Regulation	Regulatory approval may be costly and extends to the approval of upstream development and pipeline construction. Local environmental opposition, including from indigenous groups, may also arise.
Partner Priorities	Not all partners are equally committed to a project and face different constraints depending on their respective portfolios. Ensuring alignment in advance of FID may be difficult.
Ability to Execute	Partners must have the technical, operational, financial, and logistical capabilities to fully execute a project. Certain complex projects may present additional technical hurdles that could impact project feasibility.
Business Cycle	Larger economic trends (e.g., declining oil prices, economic downturns) could limit project developers' ability or willingness to move forward on a project.
Feedstock Availability	The overall availability of gas to supply an LNG project may be limited by technical characteristics of the associated fields or the requirement of long-distance pipelines.
Fuel Competition	Interest in a project may wane if project developers or end-markets instead seek to develop or consume competing fuels, including coal, oil, or renewables.
Domestic Gas Needs	Countries with high or rising gas demand may choose to use gas domestically rather than for exports. This often results in new or existing liquefaction projects being required to dedicate a share of production to meet domestic demand.
Marketing/Contracting	Project developers need to secure LNG buyers for a large portion of project capacity before sanctioning a project. Evolving or uncertain market dynamics may make this task more difficult.

Source: IHS

deferments pending a price recovery. Coinciding with the beginning of market oversupply, shifts in demand fundamentals due to economic country-specific factors (e.g., economic downturn in China or structural changes in the Japanese power sector) have reduced several countries' LNG import requirements, which may also slow the pace of project sanctioning.

Many Asian buyers have equity stakes and offtake from proposed projects in Western Canada, East Africa, and Russia. Weakening demand in their home markets may reduce their willingness to commit to higher-cost offtake.

Feedstock Availability, Domestic Gas Needs, and Fuel Competition

The prioritization of gas for domestic consumptions remains strong in several countries, especially in those with declining feedstock production.

In Egypt, the domestic market has increasingly diverted feedstock from the country's export plants, resulting in the closure of Damietta LNG in late 2012, and the cessation of exports at ELNG in 2014. Production from fields associated with these projects is set to continue to decline over time, although the $11 billion West Nile Delta development and the large discovery Zohr made in 2015 offer the potential for longer-term domestic production growth.

While not as immediate as the situation in Egypt, Indonesia, UAE, Malaysia, Oman, and Trinidad also face rising domestic demand that may combine with declining feedstock production to eventually result in lower LNG exports. New or brownfield export proposals, including those in Malaysia, Mexico, and Algeria may also be impacted.

Moreover, the competitiveness of LNG relative to alternate fuels – both in terms of project returns and downstream economics – remains a major factor that can affect liquefaction project investment decisions worldwide as other commodity prices, including coal and oil, remain depressed.

Marketing and Contracting

A major challenge to the development of future projects is the looming supply from Australia and the US set to come online over the next five years. With 141.5 MTPA under construction and announced to come online before 2020, LNG supply is expected to expand considerably during this time, making it more difficult for project developers to secure commitments from long-term buyers.

Some under-construction projects have not yet signed offtake contracts for their full capacities. The inability to secure buyers has also been a major impediment to the development of many LNG projects in Western Canada.

In the US, most projects are being developed as tolling facilities, in which the market risk is shifted to the tolling customer. In reserving capacity, the tolling customer agrees to pay a flat liquefaction fee to the terminal owner for the life of the contract, regardless of whether it elects to actually offtake volumes. While this take-or-pay model offers developers and lenders greater revenue certainty, tolling customers may face difficulties in marketing volumes if demand fundamentals shift in their domestic markets or globally.

Flexible short-term contracts have become increasingly common over the last several years. If this trend continues, proposed projects may find it difficult to secure foundational buyers, particularly those that are established and creditworthy players.

4.8. Update on New Liquefaction Plays

In 2015, construction continued at eleven projects in Australia (53.8 MTPA) and the US (62 MTPA), representing the largest sources of incremental supply over the next several years. A substantial capacity buildout in either country beyond what is already under construction is unlikely in the near term.

As of January 2016, an additional 670 MTPA of capacity has been proposed in the US and Canada, another large emerging liquefaction region, though proposal activity in both countries dropped off in 2015. Given the lengthy timelines associated with receiving regulatory approval, finding LNG buyers, and securing financing, it is likely that only a few more advanced projects with committed buyers will come online by the early 2020s. While several new projects and brownfield expansion trains in Australia have also been proposed, the country's high-cost environment and the challenges of CBM-to-LNG production make it unlikely many of these proposals will advance in the near term.

There was limited momentum elsewhere in 2015, as proposals stagnated or faced delays due to marketing constraints, high project costs, and regulatory hurdles. Once a key emerging liquefaction region, progress has slowed in the Eastern Mediterranean due to regulatory uncertainty and market conditions. However, regulatory and fiscal certainty improved in several supply regions, including Canada and East Africa.

In contrast, notable progress was made on several FLNG projects in West Africa, with Cameroon FLNG reaching FID during the year. While small in terms of capacity, this commercial momentum indicates the ability of some projects to move forward in an oversupplied market.

Project Economics and Marketing

Sustained low oil and LNG prices continue to test the competitiveness of many LNG projects as margins become compressed and impact project economics.

The US has been widely touted as among the lowest-cost sources of LNG due to the brownfield nature of many developments[11] and inexpensive feedstock. However, the arbitrage potential between US Henry Hub-linked supply and other global gas hubs diminished in 2015. Furthermore, the price of oil-linked contracts has fallen, narrowing the price differential with Henry Hub-linked contracts.

These shifts present a major development risk for US projects that have yet to make contracting progress. Around 112 MTPA[12] of binding and non-binding agreements have been signed for offtake from US projects, of which only 9.5 MTPA were signed in 2015. Given market conditions, it may be difficult for additional projects to secure customers in the near term.

[11]Four of the five projects under construction are brownfield projects associated with existing regasification terminals, while the fifth is a former regasification proposal.
[12]Excludes contracts deemed to have been canceled or lapsed.

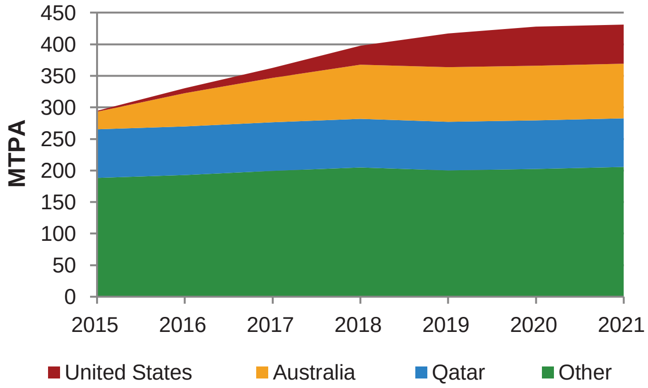
Compared to the US, Canadian projects – all greenfield proposals and mostly integrated developments – face the additional costs of considerable upstream and lengthy pipeline infrastructure. Several projects have offtakers as upstream and liquefaction equity partners. However, pressure on companies to reduce capital spending over the next few years combined with the availability of potentially more cost-effective sources of supply and weakened demand growth in buyers' home markets may reduce momentum at these projects. As a result, only a few binding offtake contracts have been signed to date. One project, Pacific Northwest LNG, reached only a conditional FID in 2015.

Several LNG projects, totalling 55 MTPA of capacity[13], have also been proposed in Eastern Canada. Given long shipping distances to Asia, most project sponsors appear to be targeting European importers. However, few have achieved significant commercial momentum, and the projects may find it difficult to secure LNG buyers in the near term. Most of the East Coast projects will also depend on pipeline reversal and expansion, subject to regulatory approval from both Canada and the US.

In Australia, additional projects and brownfield expansion trains have been proposed at both east and west coasts, based on CBM and conventional off-shore resources, respectively. With costs likely to remain high, partly due to expected greater competition for EPC services, as well as impending market oversupply, many proposals face marketing challenges; several have been delayed or cancelled. Apart from Prelude FLNG, most floating proposals are considered longer-term options.

Although large dry gas discoveries offshore Mozambique and Tanzania transformed the region into a new frontier for LNG supply, no binding contracts have been announced. High midstream costs and dry gas reserves will likely translate to higher breakeven costs, which could make projects more challenged as new supply comes online. Potentially divergent

Figure 4.13: Post-FID Liquefaction Capacity Build-Out, 2016-2021



Note: This build-out only takes into account existing and under construction projects. Sources: IHS, Company Announcements

partner priorities in a low-price environment may slow progress in Tanzania.

Regulatory and Fiscal Certainty
Contracting activity will continue to be the major driver of commercial momentum, but regulatory certainty generally improved in major liquefaction regions in 2015.

US LNG export projects need to receive two major sets of regulatory approvals to move forward: environmental/ construction approval, primarily from the Federal Energy Regulatory Commission (FERC), and export approval from the DOE. The US regulatory approval process, particularly FERC, remains time-consuming and costly. However, several projects have now moved through the process, and greater certainty has emerged regarding expected timelines and costs. Lake Charles LNG received FERC approval in late 2015, with several more expected in 2016. DOE approval has two phases. Approval to export to countries with which the US holds a free trade agreement (FTA) is issued automatically.

Ras Laffan Industrial City. Photo courtesy RASGAS

[13]See Table 4.6 at the end of this chapter.

For non-FTA approved countries, a permit will be issued only after the project receives full FERC approval. Some expansion trains at projects already under construction in the US may be able to move more quickly through the regulatory process.

In Canada, projects must receive environmental and export approval from the Canadian Environmental Assessment Agency (CEAA) and the National Energy Board (NEB), respectively, among others. The process is fairly well established but is nonetheless rigorous and requires approval from First Nations groups impacted by the projects, which has emerged as a significant hurdle in some instances. The British Columbia government provided clarity on taxation in 2014 and 2015 via an LNG export-specific tax and royalty regime. Although important, these steps are unlikely to have a major impact on the overall pace of project development.

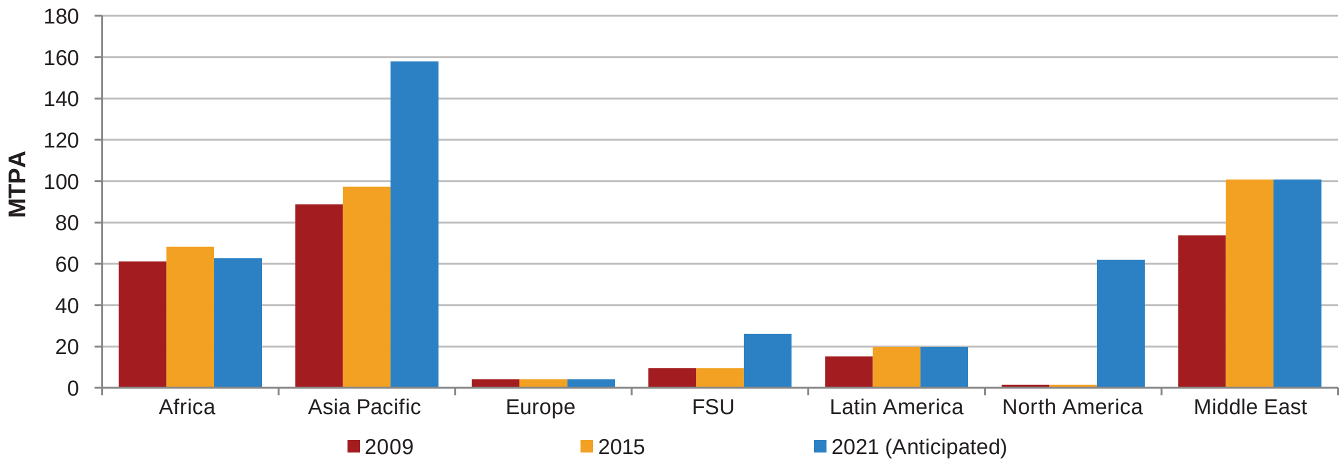
Projects in Mozambique gained some momentum in 2015 due to additional clarity on field development plans. Multiple floating and onshore projects have been proposed based on standalone Area 1 and Area 4 reserves as well as one that draws from both blocks. The Mozambique government in 2014 set out favourable taxation terms and required companies developing LNG proposals to submit plans for unitization, which occurred in late 2015 as discussions with offtakers continued to advance. As of January 2016, independent developments appear to have been prioritized, though a joint development is still proposed as well.

LNG exports from Tanzania are a longer-term opportunity. In 2015, the country enacted the first of a series of policy and regulatory reforms to the oil and gas sector, which must be implemented before projects can reach FID. The Petroleum Bill, passed in 2015, provides more regulatory independence and establishes royalty and profit-sharing rates; additional bills are still under consideration.

The Yamal LNG (16.5 MTPA) project is under construction in Russia. Despite having buyers for most of its offtake, the project has faced financing challenges due to the imposition of US and EU sanctions on Russia. Alternative sources of debt and equity financing have been sought to fund the remaining balance of the project cost; in December 2015, Silk Road Fund (China) acquired a 9.9% equity stake. Several other proposals in the country remain longer-term opportunities and may face similar challenges if sanctions remain in place.

Previously considered a large new LNG export frontier, momentum in the Eastern Mediterranean has slowed due to a greater focus on pipeline exports, significant regulatory uncertainty over upstream licenses, and the prioritization of gas for domestic uses.

Figure 4.14: Liquefaction Capacity by Region in 2009, 2015, and 2021



Note: Liquefaction capacity only refers to existing and under-construction projects. Sources: IHS, Company Announcements

Table 4.2: Nominal Liquefaction Capacity by Region in 2009, 2015, and 2021

Region	2009	2015	2021 (Anticipated)	% Growth 2009-2015 (Actual)	% Growth 2015-2021 (Anticipated)
Africa	61.2	68.3	62.8	12%	-8%
Asia Pacific	88.8	97.3	157.9	10%	62%
Europe	4.2	4.2	4.2	0%	0%
FSU	9.6	9.6	26.1	0%	172%
Latin America	15.3	19.8	19.8	29%	0%
North America	1.5	1.5	62.0	0%	4030%
Middle East	73.8	100.8	100.8	37%	0%
Total Capacity	**254.4**	**301.5**	**433.5**	**19%**	**44%**

Note: Liquefaction capacity only refers to existing and under construction projects. Sources: IHS, Company Announcements

Table 4.3: Proposed Liquefaction Projects in the US Lower 48, as of January 2016

Project		Capacity	Status	Latest Company Announced Start Date	DOE/FERC Approval	FTA/non-FTA Approval	Operator
United States Lower 48							
Sabine Pass LNG	T1-2	9	UC**	2016	DOE/FERC	FTA/ non-FTA	Cheniere Energy
	T3-4	9	UC**	2016-17	DOE/FERC	FTA/ non-FTA	
	T5	4.5	UC**	2019	DOE/FERC	FTA/ non-FTA	
	T6	4.5	Pre-FID	2019	DOE/FERC	FTA/ non-FTA	
Freeport LNG	T1-2	8.8	UC**	2018	DOE/FERC	FTA/ non-FTA	Freeport LNG Liquefaction
	T3	4.4	UC**	2019	DOE/FERC	FTA/ non-FTA	
Cameron LNG	T1-3	12	UC**	2018	DOE/FERC	FTA/ non-FTA	Sempra Energy
	T4-5	8	Pre-FID	2019-21	DOE	FTA	
Cove Point LNG		5.25	UC**	2017	DOE/FERC	FTA/ non-FTA	Dominion Resources
Elba Island LNG T1-2		2.5	Pre-FID	2017	DOE	FTA	Kinder Morgan
Corpus Christi LNG	T1-2	9	UC**	2019	DOE/FERC	FTA/ non-FTA	Cheniere Energy
	T3	4.5	Pre-FID	2020	DOE/FERC	FTA/ non-FTA	Cheniere Energy
Magnolia LNG T1-4		8	Pre-FID	2019	DOE	FTA	LNG Limited
Jordan Cove LNG T1-4		6	Pre-FID	2019	DOE	FTA/ non-FTA	Veresen
Calcasieu Pass LNG T1-2		10	Pre-FID	2019	DOE	FTA	Venture Global Partners
Texas LNG T1-2		4	Pre-FID	2020	DOE	FTA	Texas LNG
Annova LNG T1-6		6	Pre-FID	2020	DOE	FTA	Exelon
Downeast LNG		3	Pre-FID	2020	N/A	N/A	Downeast LNG
CE FLNG T1-2 (OS)		8	Pre-FID	2020	DOE	FTA	Cambridge Energy Holdings
Main Pass Energy Hub FLNG T1-6		24	Pre-FID	2020	DOE	FTA	Freeport-McMoran Energy
Delfin FLNG 1-4		13	Pre-FID	2020	DOE	FTA	Delfin FLNG
Plaquemines LNG		20	Pre-FID	2020	N/A	N/A	Venture Global Partners
Oregon LNG T1-2		9	Pre-FID	2020-21	DOE	FTA/ non-FTA	Oregon LNG
Lake Charles LNG T1-3		15	Pre-FID	2020-21	DOE/FERC	FTA/ non-FTA	Energy Transfer/ BG
Golden Pass LNG T1-3		15.6	Pre-FID	2020-21	DOE	FTA	Golden Pass Products
Gulf LNG T1-2		10	Pre-FID	2020-21	DOE	FTA	Gulf LNG
Rio Grande LNG		27	Pre-FID	2020-21	N/A	N/A	NextDecade International
G2 LNG		13.4	Pre-FID	2020-21	DOE	FTA	G2 LNG
Mississippi River LNG T1-4		2	Pre-FID	2021	DOE	FTA	Louisiana LNG
Live Oak LNG		5	Pre-FID	2021	N/A	N/A	Parallax Energy
Barca FLNG 1-3		12	Pre-FID	2021	DOE	FTA	Barca LNG
Gulf Coast LNG T1-4		21	Pre-FID	2021	DOE	FTA	Gulf Coast LNG
Eos FLNG 1-3		12	Pre-FID	2021	DOE	FTA	Eos LNG
General American LNG T1-2		4	Pre-FID	2022	N/A	N/A	General American LNG
Port Arthur LNG		10	Pre-FID	2022-23	DOE	FTA	Sempra Energy
Monkey Island LNG T1-6		12	Pre-FID	N/A	DOE	FTA	SCT&E

Project	Capacity	Status	Latest Company Announced Start Date	DOE/FERC Approval	FTA/non-FTA Approval	Operator
United States Lower 48						
Alturas LNG	1.5	Pre-FID	N/A	N/A	N/A	WesPac
Waller Point FLNG	1.3	Pre-FID	N/A	DOE	FTA	Waller Marine, Inc
Pelican Island LNG	6	Pre-FID	N/A	N/A	N/A	NextDecade International
Lavaca Bay FLNG	8	Cancelled	N/A	DOE	FTA	Excelerate Energy
South Texas FLNG T1-2	8	Cancelled	N/A	DOE	FTA	NextDecade International
Gasfin LNG	1.5	Cancelled	N/A	DOE	FTA	Gasfin Development

*Note: UC** denotes under construction. Sources: IHS, Company Announcements*

Table 4.4: Proposed Liquefaction Projects in Alaska, as of January 2016

Project	Capacity	Status	Latest Company Announced Start Date	DOE/FERC Approval	FTA/non-FTA Approval	Operator
Alaska						
REI Alaska	1	Pre-FID	2020	N/A	N/A	Resources Energy Inc.
Alaska LNG T1-3	20	Pre-FID	2024-25	DOE	FTA/ non-FTA	BP, ConocoPhillips, ExxonMobil

*Note: UC** denotes under construction. Sources: IHS, Company Announcements*

Table 4.5: Proposed Liquefaction Projects in Western Canada, as of January 2016

Project		Capacity	Status	Latest Company Announced Start Date	NEB Application Status	Operator
Western Canada						
LNG Canada	T1-2	12	Pre-FID	2021-22	Approved	Royal Dutch Shell
	T3-4	12	Pre-FID	N/A	Approved	
Kitimat LNG	T1	5	Pre-FID	N/A	Approved	Chevron
	T2	5	Pre-FID	N/A		
Pacific Northwest LNG	T1-2	12	Pre-FID	2020-21	Approved	PETRONAS
	T3	6	Pre-FID	N/A	Approved	
WCC LNG	T1-3	15	Pre-FID	2024	Approved	ExxonMobil
	T4-6	15	Pre-FID	N/A	Approved	
Prince Rupert LNG T1-3	T1-2	14	Pre-FID	N/A	Approved	BG Group
	T3	7	Pre-FID	N/A	Approved	
Woodfibre LNG		2.1	Pre-FID	2017	Approved	Pacific Oil and Gas
Douglas Channel FLNG		0.55	Pre-FID	N/A	Approved	AltaGas
Kitsault FLNG 1-2		8	Pre-FID	2018-19	Approved	Kitsault Energy
Orca FLNG	T1	4	Pre-FID	2019	Approved	Orca LNG
	T2-6	20	Pre-FID	N/A	Approved	
Malahat FLNG		6	Pre-FID	N/A	Approved	Steelhead Group

Project		Capacity	Status	Latest Company Announced Start Date	NEB Application Status	Operator
Western Canada						
Sarita Bay LNG		24	Pre-FID	N/A	Approved	Steelhead Group
Aurora LNG T1-4	T1-2	12	Pre-FID	2023	Approved	Nexen (CNOOC)
	T1-4	12	Pre-FID	2028	Approved	
Stewart Energy LNG	T1	5	Pre-FID	2018	Approved	Stewart Energy Group
	T2-6	25	Pre-FID	2020-25	Approved	
Discovery LNG T1-4		20	Pre-FID	2021-24	Approved	Quicksilver Resources
Grassy Point LNG T1-4		20	Pre-FID	2021	Approved	Woodside
Cedar FLNG		6.4	Pre-FID	N/A	Approved	Haisla First Nation
Tilbury LNG		3	Pre-FID	N/A	Approved	WesPac LNG
NewTimes Energy LNG		12	Pre-FID	2019	Approved	NewTimes Energy LNG
Triton FLNG		2	Pre-FID	N/A	Approved	AltaGas
SK E&S LNG		N/A	Pre-FID	N/A	Not Filed	SK E&S
Watson Island LNG		N/A	Pre-FID	N/A	Not Filed	Watson Island LNG Corp.

Sources: IHS, Company Announcements

Table 4.6: Proposed Liquefaction Projects in Eastern Canada, as of January 2016

Project	Capacity	Status	Latest Company Announced Start Date	NEB Application Status	Operator
Eastern Canada					
Goldboro LNG T1-2	10	Pre-FID	2019-20	Approved	Pierdae Energy
Bear Head LNG T1-6	12	Pre-FID	2019-24	Approved	LNG Limited
Canaport LNG	5	Pre-FID	N/A	Approved	Repsol
AC LNG T1-3	15.5	Pre-FID	2020	Approved	H-Energy
Saguenay LNG T1-2	11	Pre-FID	2020	Approved	GNL Quebec
North Shore LNG	1	Pre-FID	2018	Approved	SLNGaz

Sources: IHS, Company Announcements

Table 4.7: Proposed and Under Construction Liquefaction Projects in Mexico, as of January 2016

Project	Capacity	Status	Latest Company Announced Start Date	Operator
Mexico				
PEMEX LNG	5	Pre-FID	2021	PEMEX
Costa Azul LNG	2	Pre-FID	N/A	Sempra Energy

Sources: IHS, Company Announcements

Table 4.8: Proposed and Under Construction Liquefaction Projects in Australia, as of January 2016

Project		Capacity	Status	Latest Company Announced Start Date	Operator
Eastern Australia (CBM)					
Australia Pacific LNG T1-2		9	UC**	2016	ConocoPhillips
GLNG T1-2		7.8	UC**	2016	Santos
Abbot Point LNG	T1-2	1	Pre-FID	2020	EWC
	T3-4	1	Pre-FID	N/A	
Fisherman's Landing LNG T1-2		3.8	Pre-FID	N/A	LNG Limited
Offshore Australia					
Gorgon LNG	T1-3	15.6	UC**	2016-17	Chevron
	T4	5.2	Pre-FID	N/A	
Wheatstone LNG	T1-2	8.9	UC**	2017	Chevron
	T3-5	13.35	Pre-FID	N/A	
Prelude FLNG		3.6	UC**	2017	Royal Dutch Shell
Ichthys LNG T1-2		8.9	UC**	2017-18	INPEX
Scarborough FLNG		6.5	Pre-FID	2021	ExxonMobil
Browse FLNG 1-3		11.7	Pre-FID	2021-24	Woodside
Bonaparte FLNG		2	Pre-FID	N/A	ENGIE
Crux FLNG		2	Pre-FID	N/A	Shell
Darwin LNG T2		3.6	Pre-FID	N/A	ConocoPhillips
Poseidon FLNG		3.9	Pre-FID	N/A	ConocoPhillips
Sunrise FLNG		4	Pre-FID	N/A	Shell/Woodside
Timor Sea FLNG		2.5	Pre-FID	N/A	ConocoPhillips
Timor Sea LNG		3	Pre-FID	N/A	MEO

** UC denotes "Under Construction" Sources: IHS, Company Announcements

Looking Ahead

How will shifts in market fundamentals impact FIDs in 2016? Project sanctioning is expected to remain relatively muted in 2016. With CAPEX budgets under pressure due to low oil prices, project developers will likely hesitate to commit to capital-intensive liquefaction projects. The prospect of inadequate margins on oil-linked LNG sales will give developers further pause until greater certainty is established over long-term price expectations. Buyers, particularly those with weak demand in their home markets, may be equally hesitant to commit to costly long-term offtake agreements and may instead choose to opt for increasingly flexible short-term contracts. That said, security of supply remains a priority for some buyers who may seek additional long-term volumes. Projects with compelling economics that are able to offer competitive contract terms in an oversupplied market are more likely to reach FID in 2016.

Will floating projects be cost-competitive in a low price environment? FLNG projects are utilising various development concepts, each of which offers certain advantages. In terms of project economics, smaller-scale FLNG projects, including those based on barges or vessel conversions, have reportedly lower cost structures and the potential ability to be diverted to other markets. As a result, FLNG projects in Cameroon and Equatorial Guinea based on the vessel conversion concept have made commercial progress, with Cameroon FLNG reaching FID in 2015. Numerous other floating proposals, especially those in North America, have yet to find buyers and are longer-term opportunities. The commissioning and operational timelines of the several larger FLNG vessels under construction will closely inform the industry as to the scale and pace at which FLNG could progress.

How will exporters adjust to low LNG prices? Despite lower LNG term and spot prices, outages in Yemen and Angola in 2015, and longer-term suspension of exports from Egypt, global LNG trade grew by 2% and utilisation remained consistent at 84%. Output from legacy producers Qatar, Malaysia, Russia, and Nigeria remained particularly strong, with Australia and Papua New Guinea contributing substantial new volumes. In response to downward pressure on prices, legacy assets – many of which are at least partially depreciated and have low breakeven costs – have maintained high utilisation.

5. LNG Carriers

There have been significant changes in the LNG sector over the past decade that affected LNG shipping, particularly in the Pacific Basin. The LNG shipping sector, like most shipping markets, is cyclical in nature and 2015 marked a new depth of the oversupply in tonnage.

Estimated average spot charter rates fell as low as ~$20,000/day for steam vessels and $27,000/day for dual-fuel diesel electric (DFDE)/ tri-fuel diesel electric (TFDE) tankers in 2015 as demand for Atlantic volumes in the Pacific Basin weakened and re-exports subsequently declined. The continuous wave of newbuilds hitting the market in 2016 will further push the LNG shipping market deeper into a period of oversupply, maintaining the current trend for spot charter rates in the near term. Additionally, the charter market evolved into a clear two tier market, with older steam vessels competing with more efficient newbuilds to find fixtures. However, with the deflation of oil prices, the cost spread between the propulsion systems narrowed, diminishing the competitive advantage of the more fuel-efficient vessels.

5.1. Overview

The 29 LNG carriers[1] (including the FSRU *Golar Tundra* that initially acted as an LNG carrier) delivered in 2015 far outweighed additional shipping requirements from the additional 4.7 MT of incremental LNG trade, exacerbating the oversupply in the LNG shipping market. In addition, inter-basin trade diminished due to a narrowed arbitrage, reducing the number of extra-long haul deliveries. In total, the active global fleet comprised 410 vessels – excluding vessels equal to or less than 60,000 cm in capacity – for a combined capacity of 63 mmcm by the end of 2015.

A new wave of newbuild orders began in late 2012 and 2013. Unlike LNG demand factors that drove orders in past years, LNG supply factors largely led to the current cycle, with newbuild orders primarily tied to projects in Australia and the United States. The delayed ramp-up of new liquefaction plants led to the deepening of the tonnage glut in the shipping market in 2015. Speculative building was also a major contributor to the oversupply. Many vessels ordered in 2012 and 2013 had no specific work at the time of order, and today more than 40 vessels remain unchartered to a specific project or have other means of long-term employment.

Appetite for larger LNG carriers has increased the average capacity of delivered newbuild vessels since 2012. The average capacity of vessels delivered in 2015 was 163,813 cm, a 10% increase over vessels delivered in 2012. Based on the current orderbook, the average capacity of a delivered vessel is set to increase to 175,000 cm (+7%) by 2020.

With the expansion of the Panama Canal expected in 2016, conventional carriers with capacities between 170,000 cm and 180,000 cm (also known as New Panamax carriers) have become the new standard for newbuild LNG vessels. Out of the 23 vessels ordered in 2015, 87% are registered as the New Panamax class. These ships will be able to pass through the expanded Panama Canal and will offer greater flexibility – especially compared to the Q-Class – when it comes to accessing the main discharge ports, particularly in Asia.

As of January 2016, 146 LNG carriers were in the orderbook with deliveries stretching to 2022. About 75% of the vessels in the orderbook are associated with charters that extend beyond a year. By contrast, 46 vessels are open for charter upon delivery (i.e. available).

For 2016 specifically, another 46 tankers, including FSRU's, are scheduled to be delivered from the shipyards, though only 10.5 MTPA of additional liquefaction is slated to come online. With significant supply ramp-up delayed, the oversupply conditions in the LNG tanker market will persist given the additional tonnage. With the orderbook representing around 40% of the existing fleet, this state of affairs is unprecedented and this oversupply will impact the LNG shipping spot market for years to come.

To create value from the older vessels, ships considered for retirement have often been converted to FSRUs or even used as units for floating storage purposes. Additionally, companies – specifically Golar LNG – are exploring the value of converting Moss-type steam designs into FLNG units for smaller (0.5-2.5 MTPA) export projects.

Shipowners long on tonnage may be pinning their hopes on vessel retirements via scrappage or conversions to FSRUs

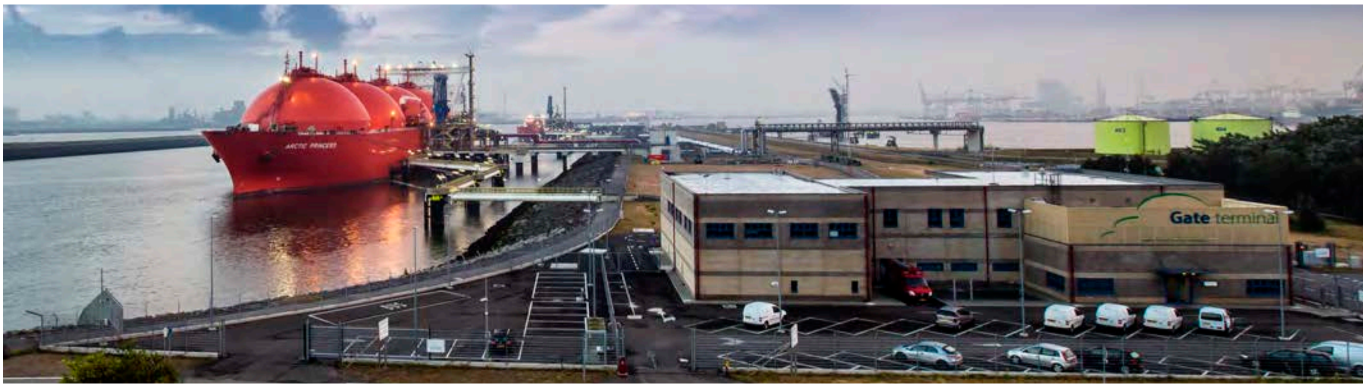
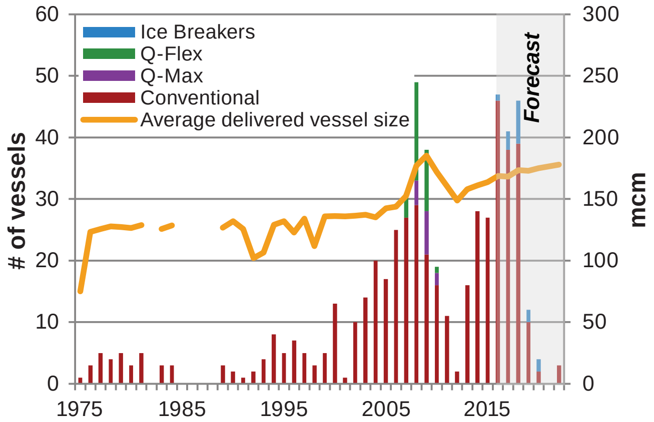


Photo courtesy GATE Terminal B.V.

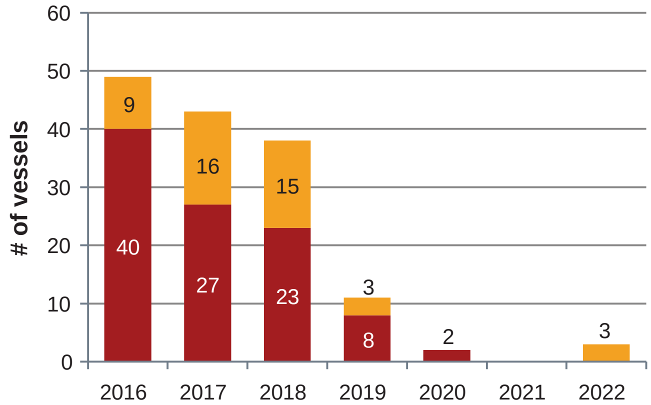
[1]A tank ship designed for transporting LNG can interchangeably be referred to as an LNG carrier, tanker, or vessel.

Figure 5.1: Global LNG Fleet by Year of Delivery versus Average Vessel Size



Source: IHS

Figure 5.2: Estimated Future Conventional Vessel Deliveries, 2016-2022



Note: Available = currently open for charter. Source: IHS

or FLNG units. Moreover, the shipping needs of US LNG associated with LNG traders, international oil companies, or European utilities could provide some upside – albeit minimal – to an otherwise weak market. Some of the offtakers of US exports, particularly for the projects slated to be online by 2019, have yet to fully order the necessary shipping capacity. The pace of contracting newbuilds has drastically slowed down from second half 2014. In 2015, only 16 vessels have been ordered with ties to US offtake, compared with 33 in only the fourth quarter of 2014.

5.2. Vessel Characteristics

Containment Systems. Two different designs were initially developed for LNG containment on vessels: the Moss Rosenberg design and the membrane-tank system using thin, flexible membranes supported only by the insulated hull structure. The Moss Rosenberg design started in 1971 and is well known by its independent spherical tanks that often have the top half exposed on LNG carriers. The Membrane-type has multiple designs from different companies, though the most common have been designed by Gaztransport and Technigaz (GTT)[3] . A new version of the membrane containment design has been developed by Samsung Heavy Industries; it will be installed on two vessels ordered by SK Shipping. By the end of 2015, 76% of the active fleet had a Membrane-type containment system, which continues to lead the orderbook as the preferred containment option.

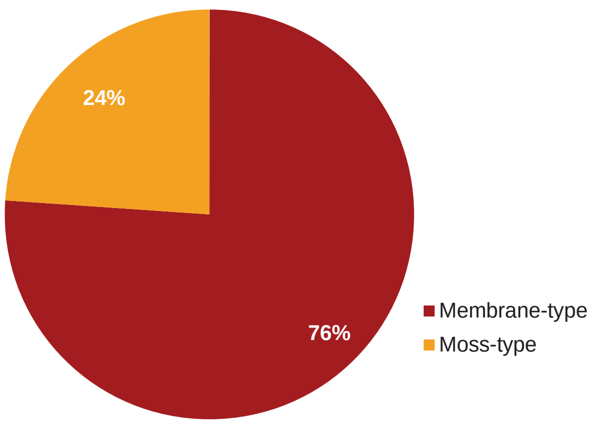
Both tank systems rely on expensive insulation to keep the LNG cold during the voyage and minimize evaporation. Nevertheless, an amount equivalent up to roughly 0.15% of the cargo evaporates per day. However, the rate of the boil off gas (BOG) is ultimately determined by the insulation of the LNG carrier, which in turn varies according to the containment system. Newer vessels are designed with lower BOG rates, with the best-in-class purporting rates as low as 0.08%.

Propulsion Systems. To keep the tank pressure close to atmospheric conditions per design conditions, this boil-off gas has to be released from the tanks, and has generally been used for fuelling the ships' steam-turbine propulsion systems which are reliable, but inefficient. Since the turn of the millennium, however, these systems specific to LNG carriers have undergone major innovations and enhancements, particularly to reduce fuel cost during an LNG voyage.

With a rise in bunker costs during the 2000's, the issue of fuel cost became ever more critical. Attempting to reconcile the objective of low fuel consumption with the necessity of consuming the BOG, innovative systems have taken a variety of approaches, depending on the specific transport concept, such as the carrying capacity, vessel speed, the duration of its potential voyages, and other voyage-specific factors. Any comparison of alternative concepts of LNG carrier propulsion and auxiliary energy generation must consider the overall complexity of LNG transport. Today, LNG carrier operators can choose between the following systems:

Steam Turbines. Steam turbines are the traditional propulsion system of LNG carriers. Usually two boilers generate sufficient steam for the main propulsion turbines and auxiliary engines. The boilers can also be partially or fully fuelled with heavy fuel oil. One important advantage of the steam turbine system is the fact that no gas combustion unit is necessary; all BOG is used in the boilers. The maintenance and other operating costs are considerably lower with steam propulsion systems

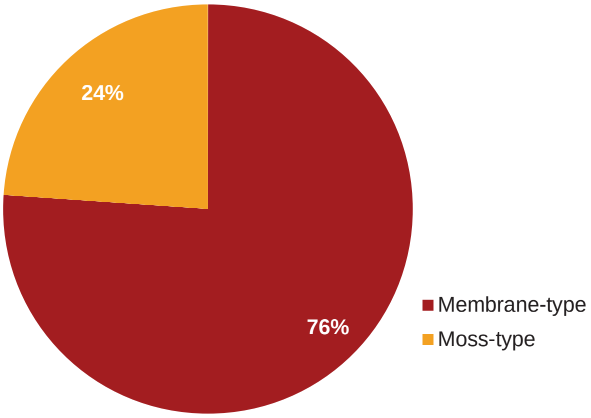
Figure 5.3: Existing Fleet by Containment Type, end-2015



Source: IHS

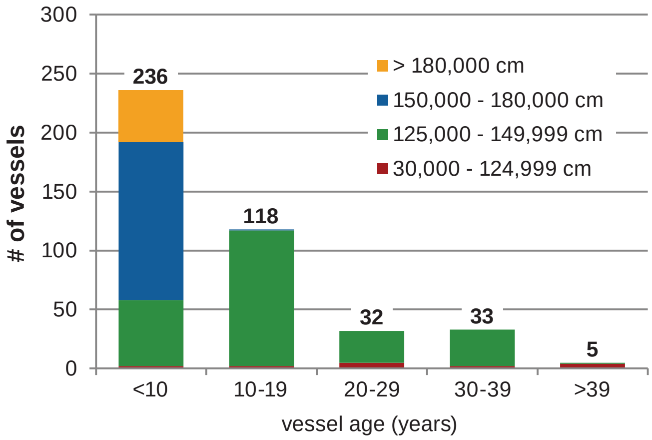
[2] As a general rule, one conventional LNG carrier is necessary to transport 1 MT of LNG.
[3] GTT was formed in 1994 out of the merger between Gaztransport and Technigaz. Both companies had previous experience in designing and developing LNG carrier technologies.

Figure 5.4: Existing and On Order LNG Fleet by Propulsion Type, end-2015



Source: IHS

Figure 5.5: Active Global LNG Fleet by Capacity and Age, end-2015



Source: IHS

when compared to other systems due to the simple design with BOG from the LNG.

On the other hand, low thermal efficiency and resulting higher cargo transport costs are clear disadvantages. Large LNG carriers require more power than existing steam turbine designs can deliver. Moreover, manning the vessels with engineers that are qualified to operate steam-turbine systems is getting more difficult as this technology has lost market share and fewer seamen are pursuing this qualification.

Dual-Fuel Diesel Electric (DFDE). After almost forty years of the LNG fleet consisting entirely of steam turbine propulsion systems, GDF SUEZ (now ENGIE) ordered the first two LNG carriers – GDF SUEZ *Global Energy* and *Provalys* – to be powered by dual-fuel diesel-electric propulsion (DFDE) systems in 2001. DFDE systems are able to burn both diesel oil and BOG improving vessel efficiency by around 25-30% over the traditional steam-turbines. DFDE propulsion systems are equipped with an electric propulsion system powered by dual-fuel, medium-speed diesel engines. In gas mode, these dual-fuel engines run on low-pressure natural gas with a small amount of diesel used as a pilot fuel. The engine operators can switch to traditional marine diesel at any time.

These propulsion systems must be equipped to handle excess BOG. In contrast to steam propulsions, a Gas Combustion Unit (GCU) is necessary as it offers an appropriate means to burn the BOG when necessary. In addition, a GCU is needed to dispose of residual gas from the cargo tanks prior to inspection. The additional equipment needed for the BOG increases the amount of maintenance.

Table 5.1: Propulsion Type and Associated Characteristics

Propulsion Type	Fuel Consumption (tonnes/day)	Average vessel capacity	Typical Age
Steam	175	<150,000	>10
DFDE/TFDE	130	150,000-180,000	<10
ME-GI	110	150,000-180,000	<1
Steam Re-heat	140	150,000-180,000	Not Active

Source: IHS

Tri-Fuel Diesel Electric (TFDE). Shortly after the adoption of DFDE systems, TFDE vessels – those able to burn heavy fuel oil, diesel oil, and gas – offered a further improvement to operating flexibility with the ability to optimize efficiency at various speeds. While the existing fleet is still dominated by the legacy steam propulsion system, almost 25% of active vessels are equipped with TFDE propulsion systems. Additionally, the orderbook has over 31% of the TFDE vessels.

Slow-Speed Diesel (SSD) with a BOG Re-liquefaction Plant. Another propulsion system was introduced to the LNG shipping industry in the mid-2000s, primarily developed in tandem with the Qatari megatrain projects. Instead of using BOG to generate propulsion and/or electric energy, vessels are propelled by conventional low-speed diesel engines consuming heavy fuel oil. Electric power is supplied by conventional heavy fuel oil or marine diesel oil generator sets.

The boil-off gas is instead entirely re-liquefied and fed back into the cargo tanks. An additional GCU allows BOG to be burned when necessary. This system permits LNG to be transported without any loss of cargo, which is advantageous when burning HFO/MDO is comparatively cheaper than burning BOG for propulsion fuel.

During ballast voyages, the cargo tank temperature is maintained by spraying re-liquefied LNG back into the cargo tanks. This helps reduce the initial increase of BOG on laden voyages. The entirety of the Q-Class is equipped with this propulsion type.

M-type, Electronically Controlled, Gas Injection (ME-GI). Around 37% of vessels in the orderbook are designated to adopt the newest innovation in LNG carrier engine design: the ME-GI engine, which utilize high pressure slow-speed gas-injection engines. Unlike the Q-Class which cannot accept BOG in the engine, ME-GI engines optimize the capability of slow speed engines by running directly off BOG – or fuel oil if necessary – instead of only reliquefying the gas. This flexibility allows for better economic optimization at any point in time.

A 170,000 cm, ME-GI LNG carrier – operating at design speed and fully laden in gas mode – may consume around

15-20% less fuel than the same vessel with a TFDE propulsion system. While there is an improvement in fuel consumption, the reliability and extent of operational flexibility is still to be determined as the first LNG carrier with a ME-GI propulsion system was only delivered in the second half of 2015.

Others. In order to improve the performance of a traditional steam-turbine propulsion system, the Steam Reheat engine design was developed. The design is based on a reheat cycle, where the steam used in the turbine is reheated to improve its efficiency. This improvement in the steam adaptation maintained the benefits of the simple steam-turbine while improving overall engine efficiency.

Wärtsilä introduced its low-speed 2-stroke dual-fuel engine in 2014. This alternative to DFDE propulsion systems offers capital expenditure reductions of 15-20% via a simpler and lower cost LNG and gas handling system. On the operating expenditure side of the equation, significant gains can be achieved because no high pressure gas compression system external to the engine needs to be operated onboard the vessel, and NOx abatement systems are not required.

Vessel Size. Conventional LNG vessels typically vary significantly in size, though more recent additions to the fleet demonstrate a bias toward vessels with larger capacities. Prior to the introduction of the Q-Class in 2008-2010, the standard capacity of the fleet was between 125,000 cm and 150,000 cm. As of end-2015, 56% of active LNG carriers had a capacity within this range, making it the most common vessel size in the existing fleet.

Conversely, the Q-Flex (210,000-217,000 cm) and Q-Max (261,700-266,000 cm) LNG carriers that make up the Qatari Q-Class offer the largest available capacities. The Q-Class (43 vessels in total) accounted for 16% of the active tonnage at the end of 2015.

The cargo capacity of the vessels has continued to progress and is now focused above 170,000 cm. This is partly related to the upcoming expansion of the Panama Canal, which will accommodate vessels of up to 180,000 cm and redefine the Panamax vessel class known as the New Panamax. By the end of 2015, 31% of the active global fleet was in the 150,000 to 180,000 cm[4] range. This share will grow rapidly in the years ahead with the average capacity in the orderbook standing at approximately 170,000 cm at the end of 2015.

Vessel Age. At the end of 2015, 55% of the fleet was under 10 years of age, a reflection of the newbuild order boom that accompanied liquefaction capacity growth in the mid-2000s, and again in the early 2010s. Generally, shipowners primarily consider safety, reliability and operating economics when considering whether to retire a vessel after it reaches the age of 35, although some vessels have operated for approximately 40 years. Around 9% of active LNG carriers were over 30 years of age in 2015; these carriers will continue to be pushed out of the market as the younger, larger, and more efficient vessels continue to be added to the existing fleet.

Typically, as a shipowner considers options for older vessels – either conversion or scrappage – the LNG carrier is laid-up. However, the vessel can re-enter the market. At the end of 2015, 19 vessels (all Moss-type steam tankers with a capacity of under 150,000 cm) were laid-up. Approximately 80% of these vessels were over 30 years old, and all were older than 10.

As the newbuilds are delivered from the shipyards, shipowners can consider conversion opportunities to lengthen the operational ability of a vessel if it is no longer able to compete in the charter market. In 2015, only three vessels were retired from the fleet by selling the tanker for scrap. However, four vessels were flagged for conversion to liquefaction production units, while an additional tanker underwent maintenance to solely operate as a floating storage unit for employment in Malta.

2014-2015 LNG Trade in Review

Global LNG Fleet	Propulsion systems	Charter Market	Orderbook Growth
+27 Conventional carriers added to the global fleet in 2015	**~30%** Active vessels with DFDE/TFDE propulsion systems	**$30,000** Spot charter rate per day in 2015	**+24** Conventional carriers ordered in 2015
The active fleet expanded to 410 carriers in 2015 The average ship capacity increased by 2% to 164,000 cm compared to the average in 2014 Seven vessels – all over 35 years of age – were either retired or flagged for conversion in 2015	In 2014, over 75% of the fleet was steam-based; by 2015, DFDE/TFDE ships accounted for almost 30% of the fleet The orderbook has a variety of vessels with new propulsion systems including ME-GI, and Steam Reheat designs	The increase in cross-basin trade following the years after the 2011 Fukushima crisis prompted spot charter rates to skyrocket in 2013 to over $100,000/day In 2014-15, +55 vessels entered the market during a period of minimal incremental growth in LNG supply, pushing charter rates almost to operating costs	Newbuild orders skyrocketed in 2014 (68 vessels ordered) as buyers moved to secure shipping tonnage for the upcoming growth in LNG supply, primarily from the US However, in 2015, only 24vessels were ordered as liquefaction project sanctions dropped off

[4]The New Panamax is defined by length, breadth, and draught. The maximum capacity which still fits these dimensions has thus far come to about 180,000cm, but there is no specific limitation on capacity.

5.3. Charter Market

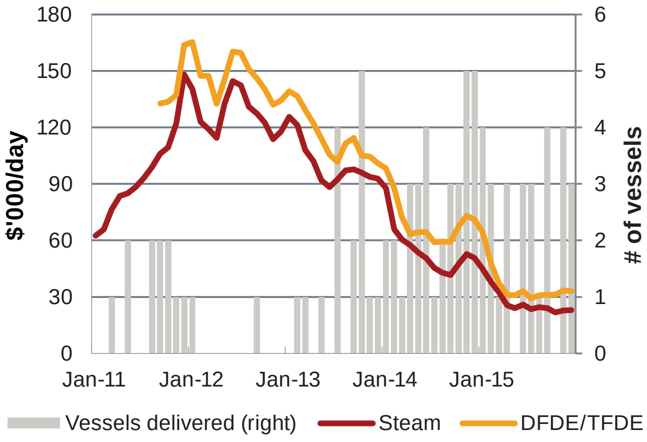
Charter rates fell and stayed low for the entirety of 2015. Older ships with higher costs (smaller capacity and less efficient steam turbine propulsion) often received lower rates; thus, there has been an emergence of a "spot" charter market at two distinct levels – the "premium" younger DFDE/TFDE vessel market (which is also typically associated with a larger capacity) and the steam based market with vessels associated with a smaller cargo capacity (i.e. <150,000 cm).

A total of 27 conventional LNG tankers and 2 FSRUs (temporarily open for charter) were delivered from the yard in 2015, yet 22 tankers were laid-up or scrapped. Only two liquefaction projects supported additional demand for shipping tonnage during the year – QCLNG and Donggi-Senoro LNG. However, these projects required minimal tonnage from the spot charter market since the majority of vessels used to deliver the additional volumes were already ordered and chartered on a long-term basis. Spot charter rates continued their downward trajectory in 2015 as growth of shipping supply far outpaced demand growth due to:

- The 2014 addition of 28 new vessels into the global fleet plus another 27 by end-2015 was far more than the supply growth of only 5.7 MT.
- Lower call for long-distance shipping caused both by the overall weakness of Northeast Asian spot purchasing in 2015 and additional LNG volumes introduced to the Pacific basin.
- Delays in the completion of new LNG projects plus shut-ins at Yemen and Angola led the vessels tied to those projects to seek employment in the short-term market, further increasing available shipping supply.

After the first quarter of 2015, estimated average monthly charter rates for steam vessels fell to about $20,000/day as Northeast Asian spot demand weakened while shipyards continued to deliver vessels. Although the majority of DFDE/TFDE vessels have been able to outperform their steam counterparts in the majority of the charter market due to their better fuel efficiency, a growing number of recently delivered DFDE/TFDE tankers were forced to remain idle because of insufficient charter opportunities. Many shipowners who had

Figure 5.6: Average LNG Spot Charter Rates versus Vessel Deliveries, 2011 – December 2015



Source: IHS

hoped to secure premium rates for their newer and more fuel efficient tankers found it difficult to charter their respective carriers in a 'warm' state. Instead, the vessels were forced to load cool-down volumes and accept rates below the already weak market day-rate.

Otherwise, without cold tanks, the vessels were market-limited, reducing the number of ships that were available on short notice. Also, the number of tankers with expired Ship Inspection Report documents continued to grow, which prevented some of these vessels from loading and unloading cargoes entirely, even if the demand for the tankers emerged. This reduced the number of tankers available on short notice, yet charter rates continued to remain low.

The oversupplied carrier market provided traders additional flexibility to bid on short-term Free On Board (FOB) supply tenders. In contrast, during periods of shipping shortages, LNG suppliers typically require the buyer to nominate a tanker before being able to bid on an FOB cargo. With plenty of shipping tonnage available for short-term chartering, traders were able to bid on tenders without specified shipping capacity.

Al Khuwair. Photo courtesy RASGAS.

By June 2015, short-term charter rates rose, albeit only to $26,000/day for steam and $33,000/day for DFDE/TFDE vessels. With short-term tenders from Egypt, Jordan, Pakistan, and Argentina, commodity traders and some additional LNG portfolio players without sufficient LNG tonnage sought short-term shipping capacity to fulfill their short positions for the tenders. This increase in short-term shipping fixtures temporarily boosted the charter rate given the minimal amount of available tankers with cold tanks. In turn this reduced the available vessel pool for spot cargo charters.

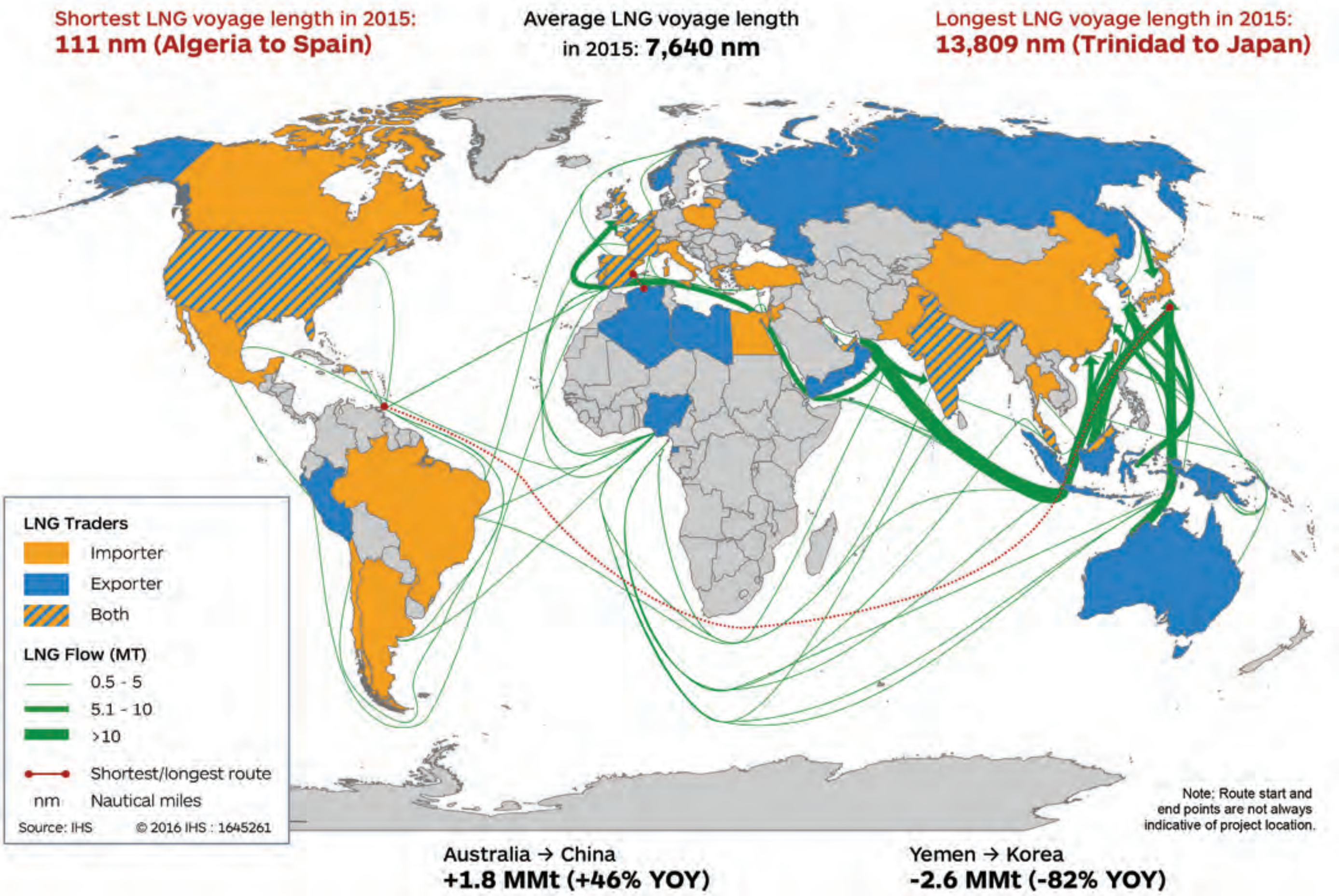
In August 2015, as a reaction to the low charter rates and the recently delivered vessels sitting idle, Dynagas, GasLog, and Golar LNG created an LNG tanker pool to help market their vessels that are trading on the spot market. Pools are frequently used in commodity shipping, including oil tankers and dry bulk, but had yet to be employed in the LNG arena. A tanker pool allows the owners to be operationally more flexible, spread risk across a larger group of owners, stabilize the income stream, and ultimately have more influence on charter rates by controlling a larger share of the shipping capacity. The new tanker pool is referred to as the “Cool Pool,” and is managed by Dynagas. At the time of the announcement, 14 tankers were participating in the pool, which focuses on charter durations of 12 months or less.

By fourth quarter 2015, average short-term charter rates (for both steam and DFDE/TFDE) slid back down, despite an increase in voyage distances travelled as Asia Pacific supply searched for markets outside Northeast Asia, especially the Middle East and India. Shipping rates also started to firm up on bid activity of traders’ participating in supply tenders. Most supply tenders require traders to nominate a tanker in order to submit a bid. The nominated tanker will then be chartered to the trader that wins the supply tender. This process gives the impression that there is more shipping demand than there really is, since only one tanker out of many nominated will be chartered at the end of a supply tender process.

Since all of the new-build tankers were delivered either from Japan, South Korea, or China, the Pacific Basin was particularly long on LNG tonnage. However, in the Atlantic Basin, shipping fixtures for short-term charters were at times able to fetch rates around $40,000/day for TFDE tankers with cold tanks. Despite the premium in Atlantic spot shipping rates due to an unbalanced market between basins, shipowners were hesitant to reposition vessels west of the Suez owing to the expense and risk of relocating to a lower-volume market.

Newbuilds expected to hit the market in 2016 will further push the LNG shipping market into oversupply. Early 2016 will see minimal growth in LNG production to absorb the new vessels. The capacity surplus is likely to continue until at least 2018 when the US Lower-48 liquefaction capacity ramps up to full production, supporting additional demand for tonnage.

Figure 5.7: Major LNG Shipping Routes, 2015



Source: IHS.

5.4. Fleet Voyages and Vessel Utilisation

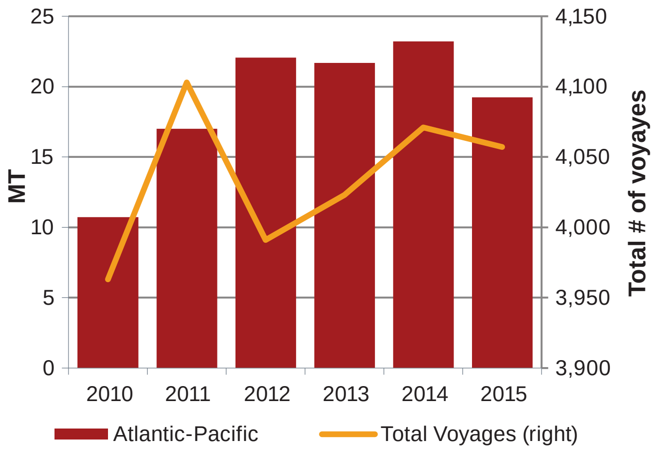
With short-term demand weak in northeast Asia, the demand for long-haul one-off voyages decreased in 2015. A total of 4,057 voyages were completed during 2015, a slight decrease of 1.2% compared to 2014. Trade was traditionally conducted on a regional basis along fixed routes serving long-term point-to-point contracts, though the rapid expansion in LNG trade over the past decade has been accompanied by an increasing diversification of trade routes. However, 2015 was the first year when total volume of LNG trade increased, yet total voyages decreased. This inverse relationship suggests that regional trade increased, particularly in the Pacific Basin with the onset of Australian volumes hitting the market. Despite the entry of new importers and exporters combined with growing destination flexibility in LNG supply contracts and greater short-term trade, the increase in intra-Pacific basin trade led to a concentration on regional trade and the demand for volumes sent from the Atlantic to the Pacific fell by 17%.

4,057 Voyages
Number of voyages of LNG trade voyages in 2015

Given the increased regionalisation of trade in 2015 and the reduction in European reloads, the average distance of LNG deliveries decreased. In 2015, the longest voyage – from Trinidad to Japan around the Cape of Good Hope – was taken by only one vessel. Conversely, the shortest voyage – a more traditional route from Algeria to the Cartagena terminal in Spain – occurred only twice; however, Algeria to Spain's four southern terminals occurred almost 80 times in 2015. The most common voyage was from Australia to Japan, with about 300 trips completed during the year.

In 2015, the amount of LNG delivered on a per tanker basis dropped to 0.6 MT from 0.7 MT in 2011 as many newbuilds sat idle in Asia Pacific and Middle East as shipowners struggled to charter them. In contrast, vessel utilisation was at its highest in 2011 following Japan's Fukushima disaster, which required significant incremental LNG volumes sourced from the Atlantic Basin. This demand shock in the Pacific Basin strained the global LNG tanker fleet. Strong Atlantic to Pacific trade continued in the following three years as traders capitalised on the arbitrage opportunity between basins.

Figure 5.8: Atlantic-Pacific Trade versus Total Number of Voyages per year, 2011-2015



Source: IHS

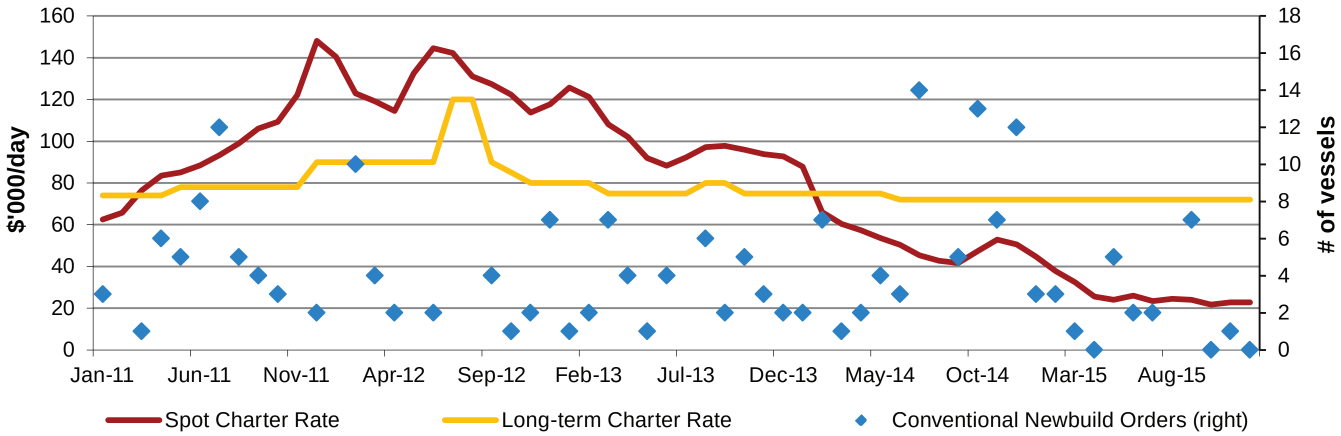
With the influx of newbuilds in 2014 and 2015 without a substantial increase in total LNG volume traded, the list of available tankers remained high throughout 2015. A portion of the available tankers had higher utilisation rates than the rest; this is due to owners early on offering their tankers at below market price to maintain cold tanks, build up an operational history for the tanker, and be compatible at multiple ports. As a result, many of the same tankers were picked up for single voyages or backhauls while the rest sat idle.

5.5. Fleet and Newbuild Orders

At the end of 2015, 146 conventional vessels were on order. Around 70% of vessels in the orderbook were associated with charters that extend beyond a year. By contrast, 40 vessels were ordered on a speculative basis.

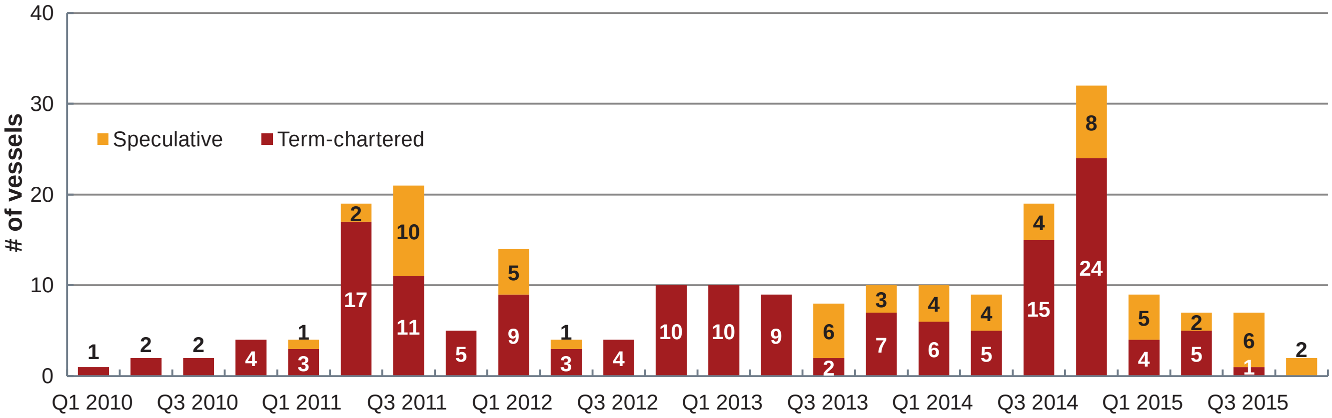
In 2015, newbuild vessel orders decreased by 65% YOY to 24, though 2014 was a record year in terms of newbuild orders with 70 contracts signed for conventional carriers. Orders in 2015 were also tied to the upcoming US LNG build-out, particularly with Asian buyers. The majority of orders in 2015 are slated for delivery by late 2018 or early 2019. Out of the vessels ordered in 2015, almost 100% will have a capacity greater than or equal to 170,000 cm. As these larger, more

Figure 5.9: Estimated Long-term and Spot Charter Rates versus Newbuild Orders, end-2015



Source: IHS

Figure 5.10: Firm Conventional Newbuild Orders by Quarter



Sources: IHS, Shipyard Reports

efficient newbuilds are added to the active fleet, older smaller vessels will be increasingly retired.

Many independent shipping companies made moves to dramatically grow their fleet sizes in the aftermath of the Fukushima nuclear crisis. While Golar ordered newbuilds primarily on a speculative basis, competitors such as Maran Gas Maritime and GasLog LNG chiefly placed orders based on term charter agreements with international oil companies.

Out of the 100 vessels on charter in the orderbook, 35% are tied to companies that are considered an LNG producer (e.g., Nigeria LNG, Yamal LNG, etc.). LNG buyers are driving a third of the new-build orders as the companies gear up for their Australian and US offtake. The remaining charters comprise companies that span multiple market strategies, particularly IOCs and portfolio players.

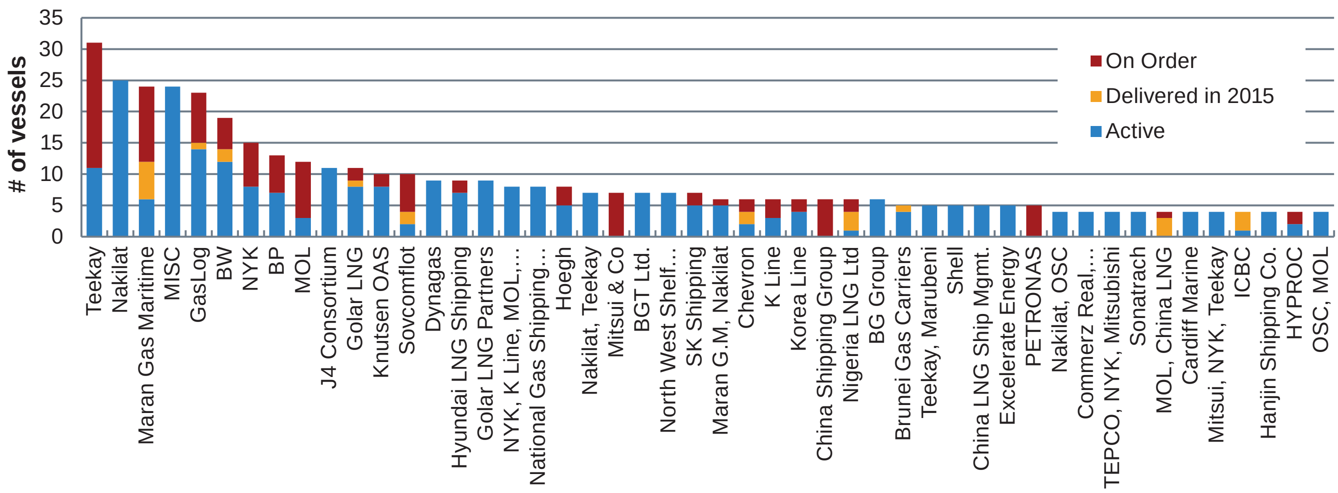
5.6. Vessel Costs and Delivery Schedule

During the 2000s, LNG carrier costs remained within a narrow range once controlled for capacity. However, the rapid growth in demand for innovative vessels in 2014 pushed average vessel costs, particularly vessels with TFDE propulsion, to rise from $1,300/cm in 2005 to $1,770/cm in 2014. This was mainly driven by the Yamal LNG icebreakers vessels which are more expensive than a typical carrier. However, in 2015, the costs for TFDE vessels dropped back to $1,420/cm.

With few exceptions, vessels have historically been delivered between 30 and 50 months after the order is placed. However, the delivery timeline has varied depending on overall demand and the type of propulsion system. For instance, when DFDE vessels were first ordered in the early 2000s, the time to delivery was expanded as shipyards had to adapt to the new ship specifications and had to do so with limited shipyard capacity. DFDE tankers delivered in 2006 saw an average time of 60 months between order and delivery.

Yamal's three liquefaction trains are under construction. Upon completion, the project will require up to 17 ice-breaker LNG carriers, and 15 have already been ordered. Eventually, these ships will have the capacity to transport LNG in summer via the North Sea Route (NSR) and in winter by the western route to European terminals, including Zeebrugge and Dunkirk. The 15 under construction ice-class tankers each cost approximately $320 million. The first of these vessels commenced its initial sea trials in January 2016.

Figure 5.11: LNG Fleet by Respective Company Interests



Source: IHS

5.7. Near-Term Shipping Developments

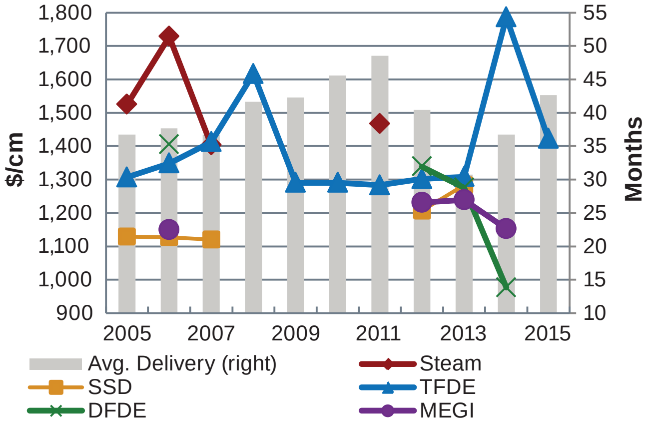
New charter contract structure – LNGVOY. A new contract for voyage chartering of LNG vessels is expected to be published in May 2016. As most of the chartering agreements within the LNG space are based on a day charter rate, the LNG Carrier Voyage Charter Party (LNGVOY) was developed specifically for the spot LNG market which typically only includes a single voyage.

Traditionally, a time charter agreement stipulates that the voyage can use the natural boil-off as fuel up to a certain amount; under this contract type, the loss of gas is typically allocated between both the charterer and shipowner if the cap is exceeded. The new LNGVOY contract, stipulates provisions for cost allocation of fuel oil/gasoil and/or forced boil-off to best meet the charterer's needs. Conversely, at loading and discharging ports, any additional boil-off beyond that cap will be on the charterer. Provisions relating to heel[5] vary in importance. When a charter is spot, or for a single voyage, owners will want to know more precisely the quantity of heel that will be returned in order to plan for the vessel's next employment opportunity.

The contract adds flexibility to the spot market and gives parties alternative means to manage the associated risks, and more importantly, control costs. The flexibility and effectiveness of LNGVOY will be tested in 2016 once the new contract structure is finalized and made available for the LNG space.

Propulsion. Shipowners may increasingly convert their previous orders to include the new propulsion system, as was done in 2015. The flexibility to burn gas or fuel oil depending on market conditions could offer ME-GI propulsion vessels a distinct competitive advantage in the market. In early 2015, Flex LNG notably opted to convert its DFDE propulsion for two newbuilds to ME-GI types. Additionally, one Q-Max vessel was retrofitted and converted to ME-GI propulsion in 2015 during a

Figure 5.12: Average Delivery and Cost per Cubic Meter in Ordered Year by LNG Carrier Type, 2005-2015



Source: IHS

dry docking. If the retrofit proves economical and reliable over the following months, all the Q-Class is under consideration to be converted to ME-GI.

Suez Canal. In 2015, Suez Canal transit tolls for LNG carriers were increased, as the 35% historical discount was reduced to 25%. The previous discount rate had been in place since 1994. The discount specifically for LNG tankers was determined based on formula – which measures the height and length of the tanker to determine cargo space – that dictates the fee. The toll gross tonnage causes the Moss-type to pay 25% to 30% higher fees than the Membrane-type when comparing on the same cubic meter carrying capacity since the non-cargo space between the tanks would mistakenly be considered cargo space. The original discount attempted to normalize this issue since the majority of tankers in 1994 had spherical tanks. Since membrane-type vessels are now the majority of the fleet, the discount has been adjusted accordingly.

Asia Excellence. Photo courtesy Chevron.

[5]Heel = LNG remaining on board in tanks.

Table 5.2: Tariff Structure for LNG Vessels Travelling via the Suez Canal

Proposed LNG vessel toll structure			
Bands in cm	Laden	Ballast	Ballast (roundtrip)
First 60,000	$2.50	$2.23	$2.00
Next 30,000	$2.15	$1.88	$1.75
Next 30,000	$2.07	$1.80	$1.60
Remaining Volume	$1.96	$1.71	$1.50

Note: A vessel is considered to be in a ballast voyage if it has LNG from its previous cargo equal to no more than 2% of the ship's Summer Deadweight (different from SCNT). Prices are reported in Special Drawing Rights (SDRs), not US Dollars (SDRs per currency unit are published by the International Monetary Fund). Tug fees must be added for an LNG vessel that does not provide a Gas Free Certificate. Sources: IHS, Suez Canal

Table 5.3: Announced Tariff Structure for LNG Vessels Travelling via the Panama Canal

LNG vessel toll structure (without discount)		
Bands in cm	Laden	Ballast
First 5,000	$7.88	$6.70
Next 5,000	$6.13	$5.21
Next 10,000	$5.30	$4.51
Next 20,000	$4.10	$3.49
Next 30,000	$3.80	$3.23
Next 50,000	$3.63	$3.09
Remaining tonnage	$3.53	$3.00

Note: A vessel is considered to be in ballast unless it has an excess of 10% of its cargo carrying capacity as heel. To be considered a roundtrip voyage, vessels must transit on ballast passage within 60 days of completion of the laden passage. There could be other additional costs not factored in like security, tugboats, and reservation fees. Sources: IHS, Panama Canal Authority

Panama Canal. The $5.25 billion expansion of the Panama Canal – which will allow around 90% of the existing LNG fleet to transit the canal – was reported to commence operations in April 2016. But some of the newly installed locks began to leak in the second half of 2015, and repairs are announced to be extensive. However, the canal authority has said Grupo Unidos Por el Canal, the consortium building the locks, has not changed the opening date for the new locks, despite seepage in a sill tied to a problem with steel enforcement.

Although the start-up will come years behind the initial schedule, the 48-mile artery of the Panama Canal connecting the Atlantic and Pacific oceans will become the primary inter-basin route for US LNG exports. For shipowners from Gulf Coast LNG projects, the attractiveness of the canal is clear. The trip from the US Gulf Coast to Japan and back through Panama will take 43 days, shaving almost 20 days off the roundtrip voyage compared to going through the Suez Canal.

The Panama Canal Authority (PCA) released the LNG vessel tariff structure in early 2015. The tariffs are to be calculated based on cargo volume and not vessel tonnage or length. This tariff structure removes any inherent transit pricing differential between Moss-type and Membrane-type vessels that is considered when passing through the Suez Canal.

Based on those announcements, the fee charged to a laden[6] 173,000 cm LNG vessel will equal $380,480. Additionally, the PCA outlined its proposal to incentivize vessels to also use the Panama Canal on its return voyage, by charging around $34,000 less than the standard ballast[7] fee for a 173,000 cm vessel. Importantly, a vessel will be considered to be in ballast unless it has in excess of 10% of its cargo carrying capacity as heel.

The canal widening will accept LNG vessels as large as 180,000 cm based on current length, width, and draught dimension for vessels of this volume. This excludes the passage of only the Q-Class. Initially, the expanded Panama Canal will support the transit of six to eight vessels per day – of all vessel types – in both directions. Slot nomination will need to be scheduled months in advance. This notification requirement could make scheduling LNG trade more challenging.

Yamal ice-breaking vessels. The Azimutal Thruster system – where the electric motor is mounted inside the propulsion unit and the propeller is connected directly to the motor shaft – has been adopted by the 15 Yamal LNG project-specific vessels. These powerful units (3 units of 15 MW each) allow the vessels to navigate the Arctic conditions along the Northern Sea Route (NSR) with greater hydrodynamic and mechanical efficiency which will be needed in addition to the ice-breaking abilities.

Blue Amazon. BG Group developed a new generation of LNG carrier design. Codenamed Blue Amazon, the project involves the adjustment of the shape of the hull and cargo tanks which is crucial in reducing resistance through the water, reducing theoretical fuel consumption. According to BG, the new design should cut fuel use and corresponding emissions by between 3% and 5%. The final design, which is undergoing review by Korean shipyards, should emerge in March 2016.

[6]Laden = a vessel that is loaded with a cargo.
[7]Ballast = a vessel that does not have a delivery cargo onboard.

Looking Ahead

When will the shipping market recover from the current oversupply in tonnage? Aside from the near-term oversupply dynamics, a tightening in the shipping market may still occur by the turn of the decade as liquefaction capacity is set to increase by nearly 50% by 2021, particularly from the US Gulf Coast. These volumes required significant shipping tonnage based on the long-haul voyages to Asia via the Panama Canal.

When LNG carriers with ME-GI propulsion systems are delivered, will the spot charter market evolve into a three-tier market? With the potential growing number of ME-GI tankers being delivered from the shipyards, a three-tiered charter rate system, instead of the current two-tier system, could develop. In 2015, TFDE held a consistent premium in the spot charter market over steam tankers, despite the fall in the price of oil derivatives. However, as the global fleet becomes more diverse in propulsion systems and other key characteristics, rates may break out further to include ME-GI systems. The varying degrees of propulsion system efficiency in the global fleet – which provides potential charterers with more operational flexibility – will drive more options in the LNG charter market over the coming years.

Do commodity traders in the LNG market have more opportunity to participate in supplying volumes given the lower barriers of entry in shipping? With the LNG vessel market saturated with speculatively ordered tonnage, a healthy supply of LNG, and buyers looking for shorter contract durations, the environment is set for traders to grow in their participation of the market, potentially aiding the development of a more prolific spot charter system. These players need spot tonnage as they typically do not have their own tankers or charter on a long-term basis. The oversupplied LNG tanker market has provided traders additional flexibility to bid on short-term FOB supply tenders from liquefaction projects, being certain they could charter a vessel at short notice, if they had the winning bid. In contrast, LNG projects previously required the prospective buyer to nominate a tanker before being able to bid on an FOB cargo, propping up spot charter rates as a result. This trading pattern will ultimately boost much needed demand for spot tonnage, though the magnitude will ultimately depend on the buyer's appetite for uncontracted cargoes.

Photo courtesy Chevron.

6. LNG Receiving Terminals

Regasification capacity continues to expand, both for existing LNG importers as well as in emerging markets. Import capacity grew world-wide to 757 MTPA by end-2015. In 2015, three new countries added regasification capacity: Egypt, Pakistan and Jordan. Poland received its first commissioning cargo in December 2015, but commercial capacity has not yet started. The prospects of sustained low prices allowed these new markets to fast-track their projects, as they could secure regasification capacity relatively quickly, through the utilisation of offshore FSRUs. Many established LNG import markets have focused on growing import, storage and vessel berthing capacities through the development of larger onshore terminals and expansion projects. Further, many terminals are expanding services to include small-scale reloading and bunkering.

As multiple new liquefaction plants come online in the 2016-2018 time frame, a well-supplied market with lower prices could provide benefits to some LNG importers, potentially replacing competing fuels. Further, market conditions could continue to unlock more demand from new, less mature LNG markets. Onshore regasification projects are the key consideration for new markets like Croatia, Panama, or Morocco that are looking to add LNG import capacity over the longer term. In addition, Colombia, Ghana, Bangladesh, Benin and Uruguay all have proposals to bring their first regasification terminals online via FSRUs over the next two years. With new markets able to secure supply quickly by chartering FSRUs, producers may face challenges predicting LNG demand moving forward.

6.1. Overview

Although Japan, the world's largest LNG importer, brought two new regasification terminals online in 2015, the year saw the majority of new terminals constructed in emerging markets, including Egypt, Jordan, Pakistan and the UAE, which added a much larger FSRU to replace an existing vessel at Dubai LNG. In January 2015, Indonesia successfully converted a former liquefaction plant, Arun LNG, into a regasification terminal. Poland received its first commissioning cargo in December 2015 and its onshore terminal is expected to achieve commercial operations in early 2016. Overall, total global regasification capacity grew by 24 MTPA (+3.3% YOY) in 2015, bringing total capacity worldwide to 757.1 MTPA in 33 countries.[1]

757 MTPA
Global LNG receiving capacity, end-2015

The Asia and Asia Pacific regions have continued to maintain the global LNG market's largest regasification capacities in recent years, as capacity has grown in both established markets, such as Japan and South Korea, and in rising LNG importers, including China and India. Outside of North America, all other regions have increased regasification capacity over the last few years, especially through the development of FSRUs in the Middle East and Latin America. FSRUs are expected to continue playing an important role for bringing new importing countries to the LNG market quickly provided there is sufficient pipeline and offloading infrastructure in place. However, onshore regasification terminals offer the stability of a permanent solution when there is less of a rush to add LNG import capacity.

6.2. Receiving Terminal Capacity and Utilisation Globally

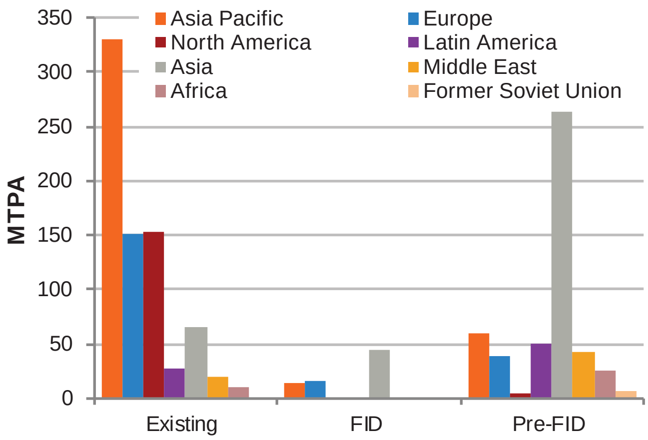
The LNG market continues to grow, particularly as new import countries have access to floating vessels for regasification and flexible trade increases amid falling global prices, unlocking demand in markets previously unable to secure LNG supply. The number of LNG importing countries has tripled over the past 15 years. Although countries in some traditional importing regions like Europe continue to join the global LNG market, countries in emerging, higher credit risk markets comprise the majority of the next round of new LNG importers.

7 terminals
Number of new receiving terminals brought online in 2015

In 2015, a total of 7 new regasification terminals were completed worldwide. Three of these were onshore terminals: in Japan (Hachinohe and Shin-Sendai) and Indonesia (Arun, which was converted from a decommissioned liquefaction plant). The other four were FSRUs completed in new LNG markets: in Egypt (Ain Sokhna BW and Ain Sokhna Hoegh), Jordan (Aqaba) and Pakistan (Engro). In addition, China is expected to complete the Yuedong LNG (Jieyang) terminal in early 2016.

Two existing importers completed capacity expansions in 2015. Chile brought online a 1.3 MTPA expansion project at its Quintero LNG project in March 2015. The Dubai LNG project

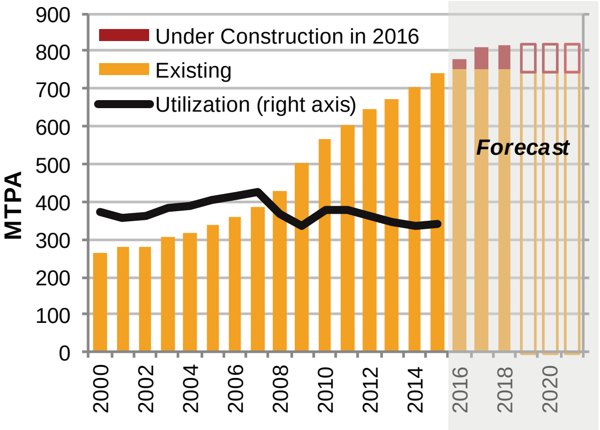
Figure 6.1: LNG Receiving Capacity by Status and Region, as of January 2016



Sources: IHS, Company Announcements

[1]This count, along with all other totals within this section, only includes countries with large-scale LNG import capacity (1 MTPA and above). This includes countries that only import domestically-produced LNG, which may cause totals to differ from those reported in Chapter 3. Refer to Chapter 8 for a description of the categorization of small-scale versus large-scale LNG.

Figure 6.2: Global Receiving Terminal Capacity, 2000-2021



Note: The above forecast only includes projects sanctioned as of end-2015. Owing to short construction timelines for regasification terminals, additional projects that have not yet been sanctioned may still come online in the forecast period, as indicated by the diagonal bars. Although several FSRU contracts will expire over this time period, this forecast assumes that the capacity will remain in the global market. Sources: IHS, Public Announcements

in UAE received a new FSRU capable of handling 6 MTPA in April 2015, which replaced the existing vessel's 3 MTPA throughput. Furthermore, a 3 MTPA expansion project at the Rudong Jiangsu LNG terminal in China is expected to come online in early 2016.

As of January 2016, 16 new terminals were reported to be under construction, 8 of which were located in China, (including the Yuedong LNG (Jieyang) terminal, expected online in early 2016). Two countries, Poland and the Philippines, were set to begin commercial operations at their first regasification terminals, with onshore projects expected in both countries in the first half of 2016. Existing importers France, India, Japan and South Korea all had onshore regasification projects under construction as well, with two each in India and Japan. Five capacity expansion projects were also under construction, including two projects in China and one each in Greece, India and Thailand. In total, 73 MTPA of onshore regasification capacity, including expansion projects, was under construction, 95% of which is located in existing LNG import markets.

Furthermore, five FSRU projects (in Ghana, Colombia, Puerto Rico, Uruguay and Chile) are in advanced stages as developers have selected an FSRU provider.[2] These projects have a total combined capacity of 18.9 MTPA. Only 40% of this figure stems from countries with established regasification capacity.

54.9 MTPA
New receiving capacity under-construction, Q1 2016

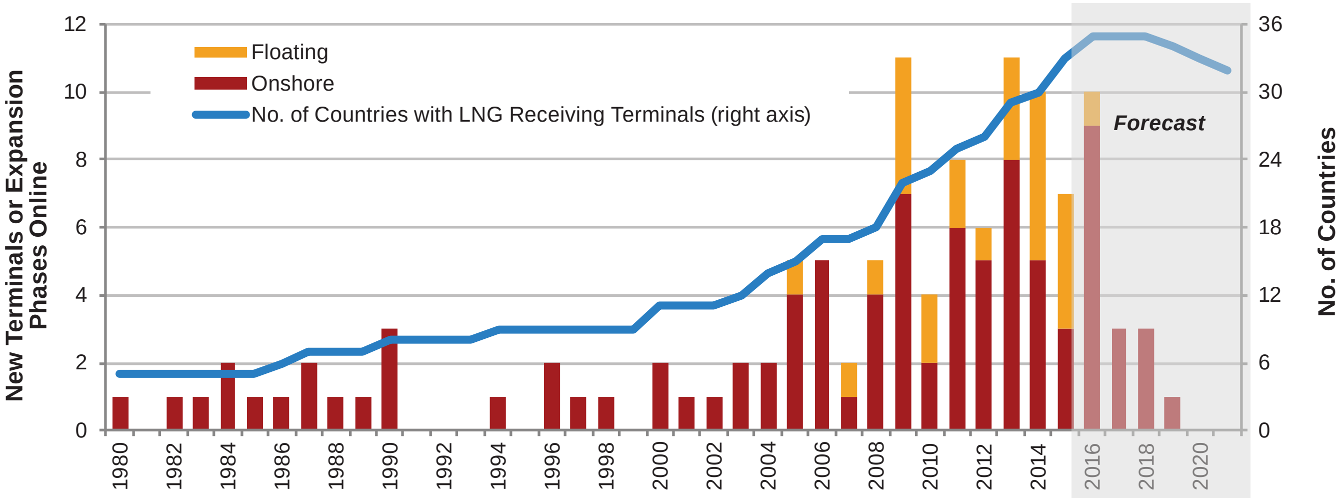
Global LNG regasification utilisation rates averaged 33% in 2015, essentially equal to 2014 levels. If mothballed terminals[3] are excluded, this number would reach 35% in 2015. Due to the requirement to meet peak seasonal demand and ensure security of supply, regasification terminal capacity far exceeds liquefaction capacity, causing average utilisation rates below 50%. Global utilisation levels have stayed flat, despite adding 24 MTPA of new receiving capacity in 2015. However, if the US is removed, global utilisation reached 39% in 2015. The United States' imported LNG volumes in 2015 equated to just 1% of the country's 129 MTPA capacity as the availability of domestic shale gas has led to a dramatic fall in US LNG imports.

Over the past few years, average peak send-out capacity at global regasification terminals has declined, from 12.2 bcm/yr (8.9 MTPA) in 2011 to 10.9 bcm/yr (7.9 MTPA) in 2015. This is largely a result of small to medium-sized terminals coming online in smaller markets, as well as the growing use of floating terminals, whose capacity is generally below 6 MTPA.

6.3. Receiving Terminal Capacity and Utilisation by Country

The LNG market's largest importer, both in terms of capacity and actual imports, continues to be Japan. The country comprises 26% of the world's total regasification capacity in

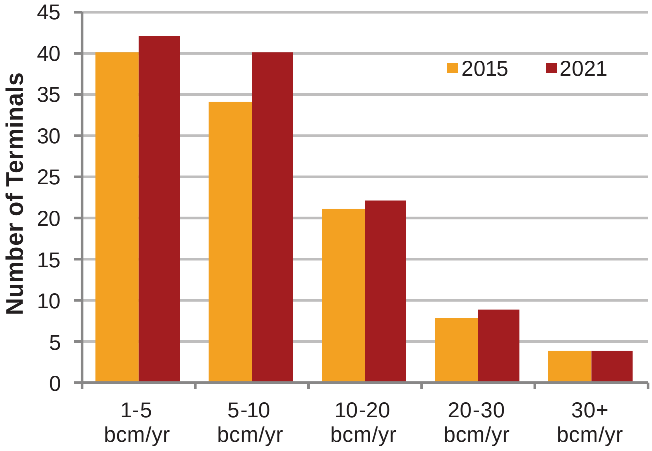
Figure 6.3: Start-Ups of LNG Receiving Terminals, 1980-2021



Note: The decline in number of countries with LNG receiving terminals is the result of FSRU charter expirations. Sources: IHS, Company Announcements

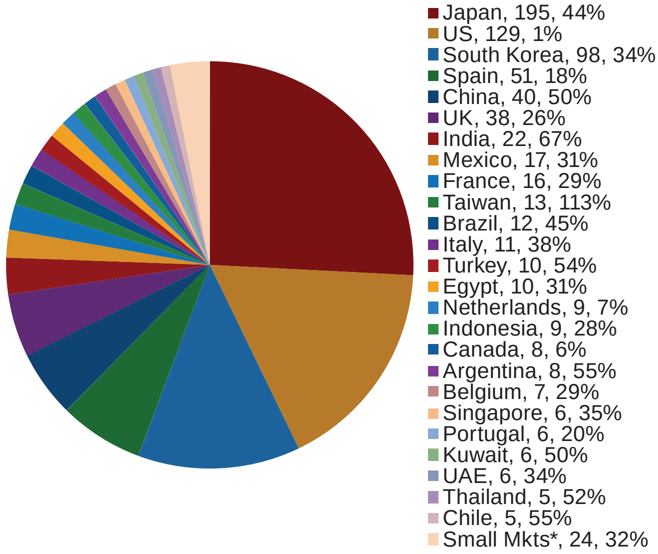
[2]Although these projects technically have binding agreements in place with FSRU providers, they are still considered as "Pre-FID" until on-site construction is confirmed.
[3]Including El Musel, Cameron, Golden Pass, Gulf LNG, and Lake Charles.

Figure 6.4: Annual Send-out Capacity of LNG Terminals in 2015 and 2021



Sources: IHS, Company Announcements

Figure 6.5: LNG Regasification Capacity by Country (MTPA) and Utilisation, 2015



Note: "Smaller Markets" includes Jordan, Pakistan, the Dominican Republic, Greece, Israel, Lithuania, Malaysia, and Puerto Rico. Each of these markets had 4 MTPA or less of nominal capacity in 2015. Sources: IHS, IGU

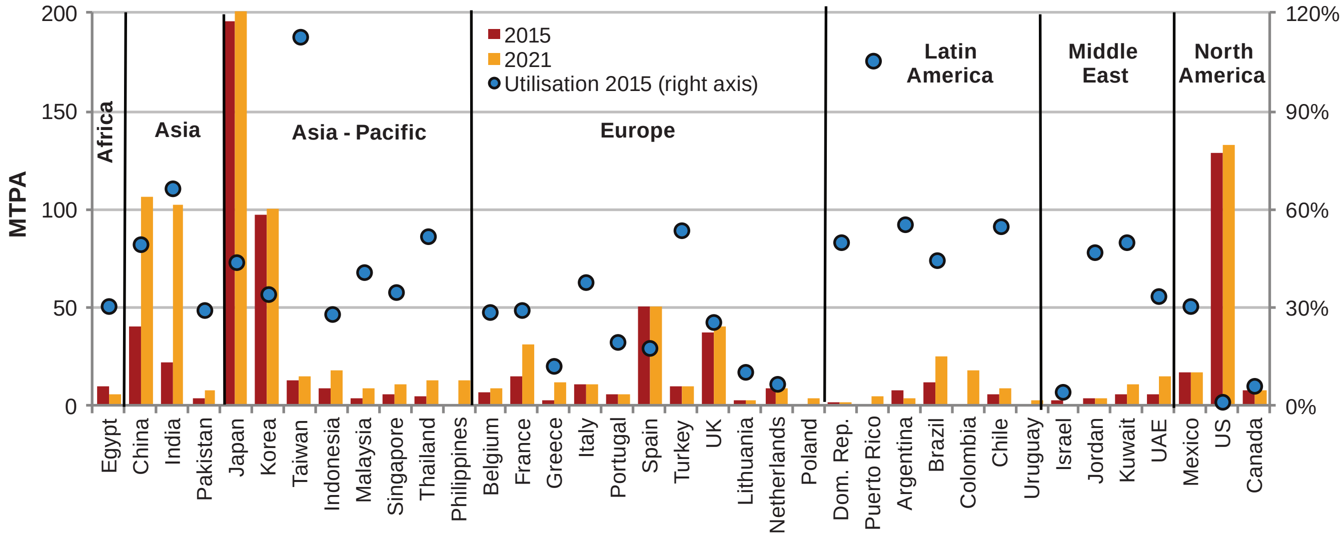
2015. Japan's receiving capacity grew to 195 MTPA in 2015, after bringing the 1.5 MTPA Hachinohe terminal online in April 2015 and the 1.5 MTPA Shin-Sendai terminal in December 2015. Japan had two terminals under construction as of January 2016, Hitachi and Soma LNG, anticipated to begin commercial operations in 2016 and 2018, respectively. Japan's leading import position is not expected to change. Capacity utilisation stood at 44% in 2015, a minor decrease from 47% in 2014. Annual average utilisation rates in Japan have typically averaged around 50% due to import seasonality, yet LNG demand growth could weaken as more nuclear capacity is brought back online.

South Korea, the world's second largest LNG importer in 2015, has 98 MTPA of regasification capacity, behind only Japan and the US. South Korea experienced a utilisation rate of 34% in 2015 (-4% YOY). The country had one project under construction as of January 2016, Boryeong, with a capacity of 3 MTPA. The terminal is expected online in 2017.

Over the past five years, the fastest growing LNG market in terms of regasification capacity was China, despite not adding any new terminals in 2015, growing to 5.3% of the market. China has 18.8 MTPA of under-construction regasification capacity due to come online in 2016 (and 10 MTPA under construction for 2017-2018). However, regasification development activity may slow down as natural gas demand growth has been weakened by macroeconomic challenges and the falling competitiveness of gas over competing fuels such as coal. Although China was the world's fifth largest regasification market by capacity as of end-2015 at 40 MTPA, up from 6 MTPA in 2008, and remains the third largest importer by volume, LNG demand growth remained below expectations in 2015. China's average terminal utilisation

Cartagena Terminal. Photo courtesy Enagas.

Figure 6.6: Receiving Terminal Import Capacity and Utilisation Rate by Country in 2015 and 2021



Sources: IHS, IGU, Company Announcements

steadied at 50% in 2015, falling 1% YOY from 2014. As a result of the high number of regasification projects coming online in 2016-2017, coupled with slowing demand growth, China's regasification utilisation is expected to decline in this period.

India, forecasted to be a significant growth market for LNG imports, had 22 MTPA of regasification capacity as of January 2016. Although the country did not add any new terminals in 2015, it is reported to complete a 5 MTPA expansion project at the Dahej terminal and potentially add a 4.5 MTPA FSRU at Kakinada in end-2016. Indeed, India's regasification capacity could reach as high as 100 MTPA by 2020 based on the number of announced project proposals. Eastern India requires additional supply since domestic upstream projects have been delayed considerably relative to expectations. However, there was consolidation in terms of the number of terminals proposed in eastern India in 2015; a few proposals have been cancelled or consolidated with other projects. Despite this strong activity behind new regasification developments, new pipeline connections will be needed to maximize gas penetration in this part of the country. The lack of connectivity near the Kochi terminal has severely limited throughput thus far.

Utilisation rates have been low across Europe, reaching an average of only 25% in 2015 (+3% YOY), ranging between 7% and 54% by country. Despite holding 20% of global LNG import capacity, imports have been down in recent years as LNG has faced competition from pipeline gas, coal and renewables. However, European imports in 2015 grew significantly, as sustained low LNG prices are increasing Europe's role as an LNG importing region, which could lead to higher utilisation

2014-2015 Receiving Terminals in Review

Receiving Capacity **+24 MTPA** Growth of global LNG receiving capacity	Number of LNG Import Markets **+7** Number of new LNG import terminals	New LNG Importers **+3** New regasification markets	Offshore Terminals **+4** Number of new offshore LNG terminals
Regasification capacity grew by 24 MTPA (+3.3%), from 733.1 MTPA in 2014 to 757.1 MTPA in 2015. New importers Egypt, Jordan and Pakistan led capacity growth in 2015.	New terminals in Indonesia and Japan (existing markets), and Egypt, Jordan and Pakistan (new importers) brought the total number of active regasification terminals from 101 to 108.	The number of LNG importing countries increased from 30 to 33 as Egypt, Pakistan and Jordan added new terminals. Poland is expected to begin commercial operations at its first terminal in early 2016. Ghana, Colombia and the Philippines plan to bring their first regasification capacity online in 2016, though not all have reached official FID.	Two FSRUs were added in Egypt, along with one in Jordan and one in Pakistan in 2015, as four out of the seven new terminals that started commercial operations in 2015 were FSRUs. FSRUs have offered a cost-effective solution to bring online regasification capacity quickly and potentially temporarily, making them an attractive option for new and less-mature import markets

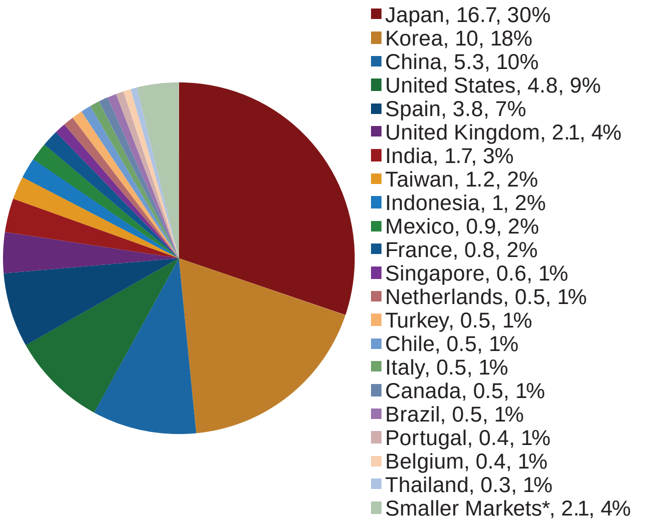
levels. Yet with low utilisation rates at existing regasification terminals, Western Europe may not require significant amounts of new regasification capacity despite the expected increase in LNG imports. Indeed, out of the 10 existing LNG importing markets in Europe, only France is currently constructing a new regasification terminal. France's 10 MTPA Dunkirk LNG terminal, set to reach commercial operations in 2016, will be one of the largest import terminals to come online in recent years. Still, new import markets, particularly in Southeast Europe, could continue to develop as countries attempt to diversify their natural gas supply away from pipeline imports, supported by the EU commission's LNG strategy. In addition, Lithuania began LNG imports in 2014, and Poland received a commissioning cargo in December 2015 with commercial operations expected to commence in early 2016.

Behind Japan, the US still holds the second most regasification capacity in the world. However, the country's terminals remain minimally utilised, if at all; the country averaged 1% utilisation in 2015. In fact, four regasification terminals in the US were completely unutilised in 2015. The prospect of ample, price-competitive domestic gas production means that this is unlikely to change going forward. Many terminal operators have focused on adding export liquefaction capacity to take advantage of the shale gas boom. Canada had one of the lowest utilisation levels in 2015 (6%), also due to the availability of domestic production. Taiwan (113%) and Puerto Rico (105%) registered the highest regasification terminal utilisation in 2015.

6.4. Receiving Terminal LNG Storage Capacity

Global LNG storage capacity grew marginally in 2015 to 55 mmcm on the back of seven new terminals starting up over the course of the year. The average storage size for the 108 existing terminals worldwide is slightly under 500 mcm. The strategic importance of gas storage is set to grow, given the current market environment, particularly in Europe as US volumes come online.

Figure 6.7: LNG Storage Tank Capacity by Country (mmcm) and % of Total, as of Q1 2016



Note: "Smaller Markets" includes Egypt, Pakistan, Jordan, Lithuania, Argentina, the Dominican Republic, Greece, Israel, Kuwait, Malaysia, Puerto Rico and the UAE. Each of these markets had 0.3 mmcm or less of capacity as of January 2016. Sources: IHS, Company Announcements

Many of the largest terminal LNG storage capacities are in Asia, where developers have prioritized LNG supply security and flexibility through greater storage capacity to manage seasonal demand cycles. Importers like China, Japan, India and South Korea also have little gas storage available outside of LNG terminals. Capacity at the 20 largest LNG storage terminals range from 0.5 to 3.3 mmcm and account for 44% of the world's total. Fourteen of these terminals are located in South Korea and Japan. South Korea's Samcheok LNG terminal, which started operations in the third quarter of 2014, is undergoing a storage expansion project to add to the 0.8 mmcm currently in operation. An additional 1.0 mmcm of storage is expected online by mid-2016. The final phase of the project, which is expected to be completed in 2017, will add another 0.8 mmcm in three tanks of 270,000 cm each – the world's largest capacity for a single storage tank. The final capacity of Samcheok will be 2.62 mmcm.

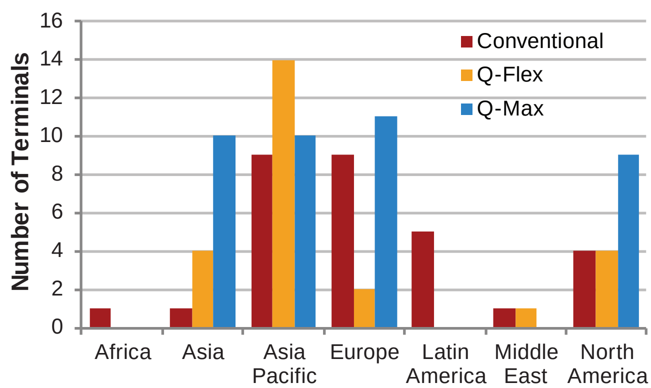
Although LNG storage capacity in traditional countries continues to grow, particularly in Asia, emerging markets utilising FSRUs generally have lower storage capacity. Figures for floating projects usually stand between 125 to 170 mcm, compared to 200 to 600 mcm observed in most established onshore terminals. With a storage capacity of 263 mcm, Uruguay's GNL del Plata FRSU – reported to come online in 2017 – will become the world's largest FSRU to enter operations.

6.5. Receiving Terminal Berthing Capacity

Ship berthing capacities at LNG terminals experienced two separate trends over the last few years, as observed with the evolution of LNG storage capacity. Newer importing countries, and those with lower-demand, generally have smaller berthing capacities, only capable of receiving conventional ships (under 200,000 cm capacity). More established markets with higher demand have worked to expand the berthing capacities of their terminals to accommodate Q-Class carriers with capacities over 217,000 cm.

Q-Max vessels, the largest of LNG carriers, have capacities of 261,700-266,000 cm. Fifteen different import markets (40 out of 108 existing regasification terminals) were known to be capable of receiving Q-Max ships as of January 2016. Twenty of these terminals were located in Asia and Asia Pacific, and none in Latin America, Africa or the Middle East.

Figure 6.8: Maximum Berthing Capacity of LNG Receiving Terminals by Region, 2015[4]



Sources: IHS, Company Announcements

[4]Terminals that can receive deliveries from more than one size of vessel are only included under the largest size that they can accept.

Seventeen out of thirty-three import markets were confirmed to have at least one terminal capable of receiving Q-Class vessels. Notably, Taiwan, the world's fifth largest LNG importer in 2015, is only able to receive conventional vessels. Of the 46 terminals that are reported to be limited to receive conventional vessels, 17 are FSRUs. Some terminals are capable of receiving even smaller LNG ships as small-scale LNG facilities continue to develop worldwide.

6.6. Receiving Terminals with Reloading and Transshipment Capabilities

LNG re-exports developed as importers with access to sufficient piped natural gas were able to use LNG to capture arbitrage opportunities between basins. Additionally, re-exports have developed for logistical reasons. Spain continues to be the world's largest re-exporter, owing to its insufficient connectivity with mainland Europe and available pipeline gas supply from North Africa. All seven of the country's regasification terminals are equipped with re-export infrastructure. Out of 24 regasification terminals in Europe, 54% have re-export capabilities.

Three terminals re-exported cargoes for the first time in 2015, all from countries new to re-exports: Grain (UK), Kochi (India) and Singapore LNG. Additionally, China reloaded a cargo from its Zhuhai terminal, for delivery within the domestic market. This brings the total number of terminals able to reload cargoes to 23 in 13 different countries.

Although three of the four new reloading countries in 2015 were located in Asia, non-European reloads remain limited, at only a few cargoes per year. For example, South Korea's Gwangyang terminal, which has had reloading capacity since 2013, re-exported only four cargoes in 2015. Other facilities, such as Cove Point in the US or Canaport in Canada, have been authorized to re-export, but decided not to pursue this option as they have instead focused on adding liquefaction capacity.

Some regasification terminals that have two jetties, such as the Montoir-de-Bretagne (France) terminal, can complete direct transhipments and bunkering services. GATE LNG in the Netherlands has also been offering this functionality since the second half of 2015 (for ships as small as 5,000 cm).

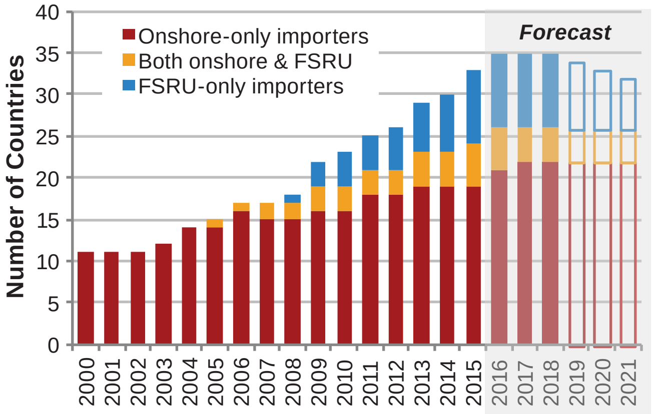
Beyond the ship unloading and reloading capabilities, several terminals have also added truck loading capabilities, such as the Isle of Grain terminal, since the summer of 2015. LNG continues to grow as a transportation fuel and LNG consumption has increased on a small-scale basis for consumers in remote areas or not connected to the main pipeline infrastructure. For more information on this topic, see the 2015 edition of the IGU World LNG Report.

Table 6.1: Regasification Terminals with Reloading Capabilities in 2015

Country	Terminal	Reloading Capability	Storage (mcm)	No. of Jetties	Start of Re-Exports
Belgium	Zeebrugge	4-5 mcm/h	380	1	2008
Brazil	Rio de Janeiro	10.0 mcm/h	171	2	2011
Brazil	Bahia Blanca	5 mcm/h	136	1	N/A
Brazil	Pecém	10 mcm/h	127	2	N/A
France	FosMax LNG	4.0 mcm/h	330	1	2012
France	Montoir	5.0 mcm/h	360	2	2012
India	Kochi	N/A	320	1	2015
Mexico	Costa Azul	N/A	320	1	2011
Netherlands	GATE LNG	10 mcm/h	540	2	2013
Portugal	Sines	3.0 mcm/h	390	1	2012
Singapore	Singapore LNG	8.0 mcm/h	540	2	2015
S. Korea	Gwangyang	N/A	530	1	2013
Spain	Cartagena	3.5 mcm/h	587	2	2011
Spain	Huelva	3.7 mcm/h	620	1	2011
Spain	Mugardos	2.0 mcm/h	300	1	2011
Spain	Barcelona	3.5 mcm/h	760	2	2014
Spain	Bilbao	3.0 mcm/h	450	1	2015
Spain	Sagunto	6.0 mcm/h	300	1	2013
Spain	El Musel	6.0 mcm/h	300	1	N/A
UK	Isle of Grain	Ship-dependent	960	1	2015
USA	Freeport	2.5 mcm/h*	320	1	2010
USA	Sabine Pass	1.5 mcm/h*	800	2	2010
USA	Cameron	0.9 mcm/h*	480	1	2011

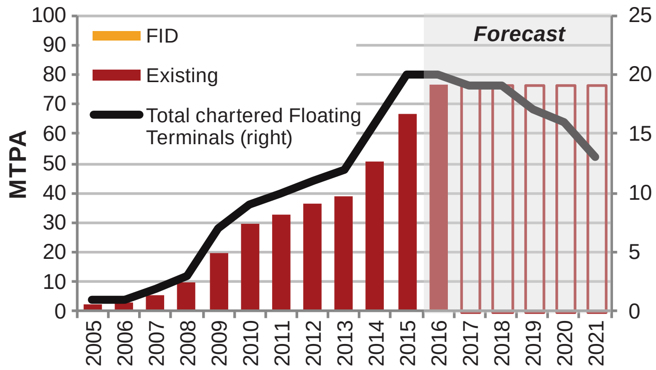
**Reloading capacity permitted by the US DOE. Sources: IHS, IGU*

Figure 6.9: Rise of FSRUs among Import Markets, 2000-2021



Note: The above graph only includes importing countries that had existing or under construction LNG import capacity as of end-2015. Owing to short construction timelines for regasification terminals, additional projects that have not yet been sanctioned may still come online in the forecast period, as indicated by the diagonal bars. The decline in number of countries at the end of the forecast period is the result of short FSRU contract expirations. Sources: IHS, Company Announcements

Figure 6.10: Floating Regasification Capacity by Status and Number of Terminals, 2005-2021



Note: The above forecast only includes floating capacity sanctioned as of end-2015. Owing to short construction timelines for FSRUs, additional projects that have not yet been sanctioned may still come online in the forecast period, as indicated by the diagonal bars. The decline in number of chartered floating terminals at the end of the forecast period is the result of short FSRU contract expirations. Sources: IHS, Company Announcements

6.7. Comparison of Floating and Onshore Regasification

While onshore terminals continue to be developed, particularly in established LNG markets, FSRUs have been the most common pathway for new markets to enter the LNG market recently. Egypt, Jordan and Pakistan joined the ranks of LNG importing countries in 2015 via the commissioning of FSRUs. Fourteen out of 33 current import markets had floating capacity as of January 2016. Five of these 14 had onshore capacity as well. In 2016, three FSRU projects have already selected an FSRU contractor and plan to come online, totaling 12.3 MTPA (in Colombia and Ghana, both new LNG markets, and Puerto Rico). A number of other projects have been proposed for 2016, including in India and Egypt. Furthermore, multiple FSRUs have been announced for 2017, particularly in Bangladesh, Benin and Uruguay, all of which would be new import markets if the terminals were to come online. Nevertheless, there are still several new importers, such as Croatia, Panama and Morocco, which plan to enter the LNG market using onshore proposals in order to establish a more permanent solution for gas imports.

Four new FSRUs began operations in 2015: Pakistan's Engro LNG in May, Jordan's Aqaba LNG in June and Egypt's Ain Sokhna Hoegh and Ain Sokhna BW in May and October, respectively. Moreover, one other terminal completed an expansion of floating capacity: a larger FSRU replaced a smaller unit at the Dubai LNG terminal in UAE. At the end of January 2016, total active floating import capacity stood at 77 MTPA at 20 terminals.

There are several advantages for implementing floating regasification in comparison to onshore projects. FSRUs allow for more rapid fuel switching, as projects can often be brought online faster than an onshore option. Furthermore, these projects are typically less expensive (see Section 6.8. for further information). Without the need to construct significant onshore facilities, floating solutions in many cases offer greater flexibility when there are either space constraints onshore or no suitable ports. FSRU vessels can also be linked to an offshore buoy that connects into a subsea gas pipeline system and can therefore operate further offshore than conventional terminals. Additional advantages include a possibly easier and shorter permitting process, as well as much lower CAPEX as FSRUs are normally chartered from a third party. However, onshore terminals offer a number of benefits as well, such as providing significantly more storage capacity, which could be strategically important given the current market environment.

On the other hand, FSRUs face potential risks related to the terminal's operability, including vessel performance, heavy seas or meteorological conditions, and a longer LNG deliverability downtime. There are also limitations in terms of both send-out and storage capacity, which for FSRUs are typically much lower than for larger onshore facilities – and can thus create impediments and limitations for onloading operations. In addition, despite generally lower capital expenditure, operating expenditure can be significantly greater, simply because of the vessel's time charter assigned to the project.

Table 6.2: Onshore Regasification Terminals and FSRUs

Onshore Terminals	FSRUs
Provides a more permanent solution	Allows for quicker fuel switching
Offers longer-term supply security	Greater flexibility if there are space constraints or no useable ports
Greater gas storage capacity	Capable of operating further offshore
Generally requires lower operating expenditures (OPEX)	Generally requires less CAPEX
Option for future expansions	Less land regulations

Floating terminals can be separated into two functional groups based on engine capability. The first FSRUs came in the form of converted old vessels with limited propulsion that are permanently moored and act as long-term regasification terminals. Other floating terminals are mobile vessels which can be contracted for short periods. These FSRUs can function as standard LNG carriers when not under contract, and also have the possibility to come to a port loaded and stay only for the time required to regasify their cargo.

As of January 2016, eight FSRUs (greater than 60,000 cubic meters) were in the orderbook. However, there are only a few existing FSRUs that could become available in the near term, including the sub-charter from Dubai LNG (the *Golar Freeze*) and the *Golar Tundra*, though this is earmarked for Ghana. Excelerate typically keeps one of its vessels in order to support its trading activities; however, its only open vessel may be sent to Puerto Rico's under-development floating terminal, Aguirre GasPort. Based on the limited immediate availability of FSRUs, significant near-term expansions in regasification capacity via FSRU employment beyond what is already delivered and on order is limited through mid-2017. Given the near-term limitations, shipping companies have been open to ordering newbuild FSRUs and converting existing conventional vessels on a speculative basis, underlining the perceived importance of FSRUs in supporting new markets enter the LNG market in the long term.

6.8. Project Capex

CAPEX for regasification terminals typically consists of costs associated with vessel berthing, storage tanks, regasification equipment, send-out pipelines and metering of new facilities. Between 2006 and 2012, CAPEX for new regasification capacity remained fairly steady. However, CAPEX costs have increased significantly since this time, nearly doubling for onshore terminals. Floating projects experienced a large jump in CAPEX costs in 2009 and 2010 as the active number of floating terminals increased from four to ten, a few of which were capital intensive projects.

$245/tonne
Average costs of new onshore LNG import capacity in 2015

In 2015, the weighted average unit cost of onshore regasification capacity that came online during the year was $245/tonne (based on a three-year moving average). While this value is somewhat lower than the 2014 average ($276/tonne)[5], it was still significantly higher than the average for onshore regasification terminals between 2006 and 2012 ($115/tonne). The rise in onshore regasification costs is closely associated with the trend of increased LNG storage capacity. As countries – mainly in high-demand regions like Asia and Asia Pacific – add larger storage tanks to allow for higher imports and greater supply stability, the storage capacity size per unit of regasification capacity has increased. However, several new onshore terminals with smaller storage units are expected online in 2016 and 2017, bringing down overall costs. CAPEX for onshore capacity under construction are set to fall to $235/tonne in 2016 and $172/tonne in 2017. However, a number of proposed projects that may soon reach construction milestones have higher CAPEX, which could ultimately bring these averages higher.

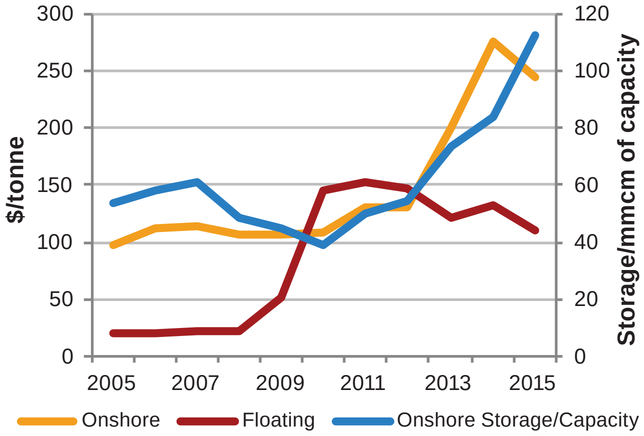
CAPEX for floating terminals are considerably lower than onshore facilities simply owing to the limited infrastructure developments involved in bringing an FSRU online. Furthermore, project developers consider the vessel charter as an OPEX instead of including it in CAPEX. It is generally accepted that OPEX for FSRUs is higher than for onshore terminals.

New floating terminals' CAPEX have remained roughly steady over the past three years, declining from a high of $153/tonne in 2011. In 2015, the weighted average unit cost of floating regasification based on a three-year moving average was $109/tonne. As of January 2016, there were no FSRUs considered to be under construction, but three of the five forthcoming FSRU projects that have selected an FSRU provider have notably high CAPEX, particularly the Uruguay and Chile proposals, indicating that average FSRU costs

BBG Terminal (Bilbao). Photo courtesy Enagas.

[5]Revised from the 2015 edition of the IGU World LNG Report

Figure 6.11: Regasification Costs Based on Project Start Dates, 2005-2015



**Indicates the size of onshore storage relative to onshore terminal capacity.*
Sources: IHS, Company Announcements

could be rising moving forward. As with onshore terminals, larger vessels – and thus greater storage and send-out capacity – have accompanied higher CAPEX. Still, overall CAPEX for floating terminals are generally less volatile than for onshore facilities, which is partly a reflection of fewer variations in capacity and storage size for vessel-based terminal solutions.

6.9. Risks to Project Development

Regasification projects face a number of risks throughout the development process, albeit generally on a smaller scale in comparison to the challenges of liquefaction plants. Particularly with FSRUs, new regasification projects can reach commercial operations without substantial land-based construction and at a significantly faster pace. However, developers of regasification terminals still must deal with factors that can obstruct or delay the successful implementation of planning and construction schedules, similar to those that typically affect liquefaction projects. This includes:

- Project and equity financing, which are required for terminal plans to advance. Bangladesh's Petrobangla FSRU project has faced multiple delays, largely due to financing challenges given the country's low sovereign credit rating. The latest announcement indicated a 2017 target start date for commercial operations.
- Permitting, approval and fiscal regime. New regasification terminals can face significant delays in countries with complicated government approval processes or lengthy permit authorization periods. The Port Ambrose floating regasification project, proposed for offshore US, experienced numerous regulatory delays and was stalled indefinitely in November 2015 after the Governor of New York vetoed the project.
- Challenging conditions in the surrounding environment could lead to delays or cancellations of regasification projects. A floating terminal was cancelled in South Africa in 2014 following FEED studies indicating intricate met-ocean conditions in Mossel Bay.
- Reliability and liquidity of contractors and engineering firms during the construction process. Uruguay's FSRU project, the first for the country, was initially set to come online in late 2015. However, the project has encountered challenges stemming from financial issues plaguing the Brazilian contractor chosen to construct the project, pushing the target start date back multiple times. The latest announced start date is in 2017.
- Securing long-term regasification and offtake contracts with terminal capacity holders and downstream consumers, particularly as the market shifts toward shorter-term contracting. As of January 2016, Lithuania's Klaipeda LNG has booked only 0.4 MTPA of the terminal's 3 MTPA capacity; securing offtake from domestic consumers has been challenging since LNG faces competition from oil-linked Russian pipeline imports. The terminal has been under-utilised, and as a result, its owners were seeking to reduce operation costs and secure re-export capabilities. For the development of new terminals, political support could be needed if long-term commitments are not secured.
- Associated terminal and downstream infrastructure including pipelines or power plant construction required to connect a terminal with end-users, which are often separate infrastructure projects that are not planned and executed by the terminal owners themselves. The Penco Lirquen FSRU planned for Chile in 2018 could have a slow ramp-up as the project waits for the completion of a new gas-fired power plant and associated infrastructure to absorb the imported volumes. The Kochi terminal in India continues to limit receiving capabilities due to the lack of completed pipeline connections to downstream users.

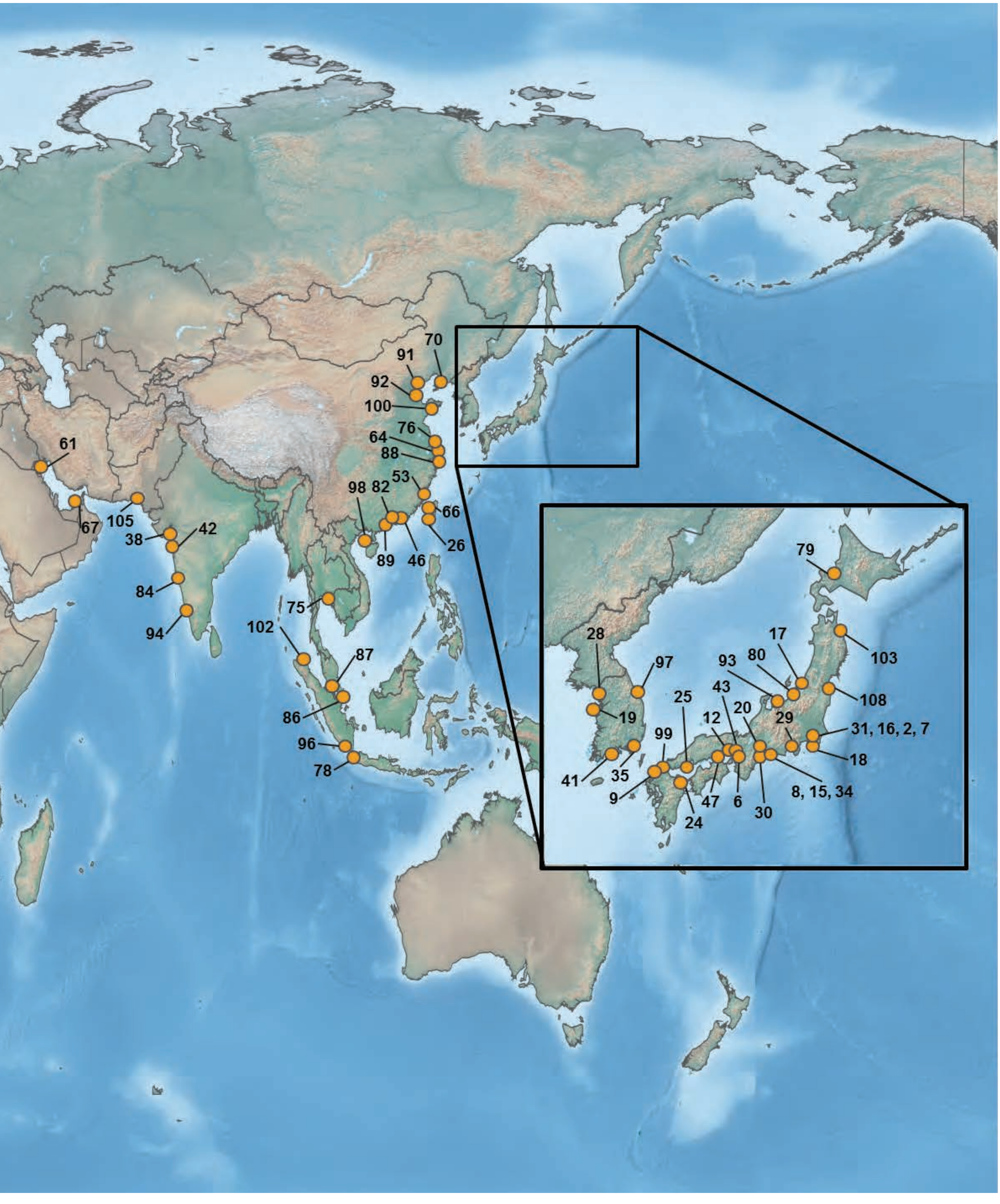
Looking Ahead

Will the majority of new regasification markets continue to be emerging markets? Egypt, Jordan and Pakistan joined the ranks of LNG import markets in 2015 by adding FSRUs in a relatively short period of time, fast-tracked by the prospects of low LNG prices. Despite recent capacity additions and proposals from established gas markets, such as Lithuania, Poland, and Croatia, the majority of expected new LNG importers continue to be emerging markets. Indeed, Colombia, Ghana, Panama, the Philippines and Uruguay all have projects in advanced phases of development. Further down the road, Bangladesh, Bahrain, Benin, Myanmar, Morocco and Ukraine all have proposals for regasification capacity in the medium to long term.

Will the recent growth in floating regasification capacity continue to gain momentum? Egypt, Jordan and Pakistan became LNG importers in 2015 through floating regasification, and of the seven countries with proposed projects to become new importers in 2016-2017, five will have an FSRU as their first import terminal. While it is clear that FSRUs have played a vital role in bringing new countries to the global LNG markets, floating terminals also face constraints: their storage and berthing capacity is generally much lower than that of onshore facilities and OPEX are much higher because of the time charter vessel. As nascent LNG markets mature, they may ultimately seek to move to onshore solutions. In spite of this, demand for floating regasification capacity will persist, particularly for countries in emerging markets securing LNG for the first time.

Figure 6.12: Global LNG Receiving Terminal Locations

Note: Terminal numbers correspond to Appendix III: Table of LNG Receiving Terminals. Source: IHS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7. The LNG Industry in Years Ahead

What factors will impact short-term LNG activity?

With gas price benchmarks around the world facing pressure, supply-demand fundamentals will continue to adjust. Globally, macroeconomic decline has impacted most importing countries, reducing the need for energy, including natural gas. In particular, buyers in northeast Asia are finding that they are overcommitted in terms of contracted LNG relative to demand. Several emerging market countries demonstrated a healthy appetite for LNG as short-term prices collapsed in 2015, which partially offset the imbalance caused by weaker-than-anticipated Northeast Asian LNG demand. However, these new importers are less established as buyers and are not likely to have sufficient growth to offset the imbalance.

Another key determinant of buyers' response to low gas prices is inter-fuel competition with coal, and to some extent oil. Low oil prices have resulted in low oil-linked LNG contract prices. However, despite lower LNG prices, countries that use oil products and coal in power and industry may be slower to substitute for gas.

Given current LNG price levels, suppliers will face lower revenue generation than in the recent past. The gradual trend toward more flexible trade arrangements, coupled with the supply-demand imbalance, means that variable cost may be the price setting mechanism in the short-term market. Contract prices may see a dislocation to this level if Brent and/or Henry Hub, as the key indices, see appreciation. These are key contracting considerations of both buyers and sellers.

Will under-construction projects stay the course?

Most under-construction projects remain active toward planned schedules. There are four key reasons:

- Many project builders – the engineering, construction, and procurement contractors – have committed to construction schedules and could incur a penalty if they are late.
- Similarly, many projects have coordinated upstream feedstock arrangements that would incur higher costs or take-or-pay penalties if production is not received.
- The sponsors of new projects are eager to start generating cash flow to start recovery of large capital outlays. New projects have the signal to produce so long as the price is above variable cost, even if they do not achieve full cost recovery.
- LNG project owners have a long-term time horizon when viewing an asset's performance. Near-term revenue challenges might put pressure on operators, but should be viewed in the context of a 20-30 year project life.

However, there could be some setbacks to timely start-up due to technical issues. More broadly, failure of any single project to meet its scheduled start-up would not fundamentally alter the supply-demand imbalance.

How will trade optimization evolve in 2016?

The world's short-term gas price benchmarks all fell substantially in 2015, shaping cross-basin LNG trade. The entry of new Australian capacity in 2015 has put downward pressure on Asian short-term LNG demand as more Asian customers are meeting their portfolios with newly online contracted supply. This trend will continue in 2016 with the commercial start-up of APLNG and Gorgon LNG, as well as the continued ramp-up of GLNG. Atlantic Basin and Middle East cargoes that had been moving east to meet this Asian demand in recent years will have more incentive to remain in the Atlantic Basin, which among other factors will contribute to European hub price formation.

While this paints a picture of partitioned LNG markets in the Atlantic and Pacific basins, there are some notable trends that could make this trade balance more uncertain. First, if Henry Hub stays at current low levels, some US LNG sales to Asia may become attractive, especially under sunk cost treatment of capacity.

Second, LNG portfolio players, and to a lesser degree traders, will be forced to bring in supply from their respective portfolios in another basin to meet contractual end-market obligations. For the largest portfolio players in 2016, 60% of their contracted supply is sourced from Atlantic Basin producers, but 60% of their re-contracted volumes are with Asian buyers (and this rises to 75% if Middle Eastern buyers are also included).[1] To optimize shipping costs, market participants are more actively engaging in cross-basin swap agreements, minimizing long-haul physical flows.

How will Europe's role in the LNG market evolve?

European LNG imports are poised for a second year of growth following three years of declines from 2011 to 2014. Europe's role as a key backstop for excess cargoes in the global LNG market is likely to expand as other consuming regions are unable to absorb new demand as quickly as supply is being added.

The introduction of US LNG in 2016 marks the launch of another supply source for Europe given that the Pacific Basin is better balanced in the second part of this decade, and US LNG is regarded as highly flexible. Reaction by established pipeline gas and LNG suppliers to Europe will be of interest. Will supply continue to flow at unhindered rates, or will a low price see reduced deliveries? Will gas demand rebound due to low prices?

EU policy formation regards energy security as a cornerstone and is expected to call on more gas and LNG. New policies by the European Commission regarding "Security of Gas Supply Regulation" and "Strategy for Liquefied Natural Gas and Storage," will address the role of LNG in helping to meet EU energy security. The final strategy document is anticipated to call on expanded use of LNG, particularly in eastern and southern Europe, where markets are less diversified, to promote a more liquid gas market. This may require new import terminals, pipeline connections and a diversified portfolio of sellers.

Preparing for the influx of LNG into the market, several European utilities and aggregators sought direct and re-contracted volumes from US LNG offtakers in 2015 to lock in expected deliveries for the upcoming years.

Will there be any new liquefaction FIDs? What types of projects might be able to move forward?

Low prices and weak demand have caused buyers to take a wait-and-see approach to long-term contracts, which does not bode well for reaching FID at new, large-scale LNG projects. Historically, having contracts for the majority of the project's capacity was a pre-requisite to reach FID. Under the current supply-demand imbalance, this continues to be very important to project developers.

In the current environment, the largest LNG consumers appear to be over-committed with several new contracts ramping up and are thus not aggressively searching for new contract positions. In recent years, the most attractive supply source has been the United States, owing to the economics of Henry Hub-based pricing. However this commercial impetus has significantly faded now that US LNG is not as cheap as most oil-indexed supply. Thus US FIDs are unlikely to occur at the same pace as in 2015. Three US projects – Freeport LNG T3, Sabine Pass LNG T5, and Corpus Christi LNG T1-2 – reached FID earlier in 2015, but these were well advanced, with marketing arrangements locked in before the fall in oil prices began in November 2014. While there are several projects that are relatively advanced in the regulatory queue, offtake obligations have yet to be finalized.

In Canada, Pacific Northwest LNG reached conditional FID in 2015 and may reach full FID in 2016 pending the clearance of all remaining regulatory permits. Cameroon FLNG took FID in 2015 as a relatively low-cost development based on a tanker conversion. The projects that proceed will be cost competitive and likely to have committed buyers.

Will Northeast Asian LNG demand recover?

Japan and South Korea, the world's two largest consumers of LNG, reduced their imports by 7 MT in 2015. This decline offset all growth from the rest of the Pacific Basin, leading to the first year-on-year fall in Asian LNG demand since the 2009 recession. How these major markets develop in 2016 is critical not only for short-term oversupply, but also for LNG project seeking long-term contracts to underpin new developments. Overall, it appears unlikely that demand in this region will fully recover in the near term.

Japanese buyers face great uncertainty in assessing their LNG needs, even just a few months ahead. While uncertainty about the nuclear power plant re-starts depends greatly on regulatory and legislative issues, weakening electricity consumption growth remains a chief structural threat to LNG demand in the years to come. Japan is increasingly focused on improving energy efficiency. The LNG demand loss is also due to weak manufacturing growth. Moreover, solar power continues to expand, both displacing thermal generation and bringing intermittency factors. In response to the near-term LNG oversupply in the Japanese market, buyers have begun re-selling LNG volumes both domestically and internationally to reduce their individual exposure.

Following rapid growth through 2013, expectations for South Korea's LNG demand have been reset. The Ministry of Trade, Industry and Energy's 7th Basic Plan for Long-term Electricity Supply and Demand, published in July 2015, confirmed the favoured role of coal in meeting incremental electricity needs over the next five years. Around 7–8 GW of new coal capacity is due to come online by the end of 2016. With power consumption growth below expectations, and high nuclear availability, utilization of gas-fired generation plants is expected to continue to fall. In addition, economic growth has slowed more than anticipated, further impacting overall power demand. These factors suggest that the decline in South Korea's LNG imports in 2015 is unlikely to be reversed over the next decade.

Taiwan provides a bright spot for LNG demand in Northeast Asia – but not enough to offset the weak outlook for Japan

[1] This analysis is based on a grouping of Shell, BG Group, BP, TOTAL, ENGIE, Gas Natural Fenosa, and Gazprom.

and South Korea. With less reliance on nuclear power, Taiwan plans LNG imports to drive power sector growth. Imports increased in 2015 with further plans to increase short and medium-term buying activity in light of opportunistic market conditions for relatively cheap LNG.

How are China and India responding to the LNG oversupply?

LNG contract ramp up are already in full swing for China. However this occurs at a time when natural gas demand growth has been significantly weakened by broad macroeconomic challenges as well as reforms that have increased local gas prices. As a result, the NOC buyers will need to employ several different strategies to minimise their exposure to potentially large financial losses if enough local demand cannot be created. In response, the National Development and Reform Council (NDRC) has already lowered domestic wholesale prices to incentivise demand.

- In 2015, the most effective tactic was working with existing suppliers to adjust contract terms. Already, Chinese NOCs have been successful in delaying delivery to later points in the year – particularly pushing summer deliveries to the winter months.
- Companies have also resorted to selling LNG on the international market. The profitability of doing this in 2016 with a weak spot price may not be as attractive and would not do much to minimise losses.
- The Chinese NOCs are also able to optimise between domestic supplies in their home market. The domestic gas producers have reportedly limited production at several major conventional fields in the past year. In terms of pipeline imports, China imported noticeably less from its Central Asian suppliers. However, there are contractual and financing terms that will prevent such extreme deferments from occurring consistently in the future.

India's LNG demand has fared relatively well despite general economic weakness in Asia. The underutilised gas-fired power sector saw much improved performance in 2015 on the back of subsidies for LNG imports. Although how long this can be sustained is a major uncertainty. Nevertheless, in a low short-term price environment, Indian consumers have absorbed additional volumes from the global LNG market.

Will the LNG shipping market begin to recover?

Little relief to the oversupplied LNG shipping market is expected in 2016 with the growth in new LNG supply from Australia. These new volumes will target mostly Asian buyers and are likely to decrease the average global delivery route. One counter-argument – though less likely – is the idea that buyers and portfolio players seeking to divert cargoes due to weak demand, could cause average distances to increase in search of a new buyer in farther markets. Nevertheless, more collaboration between parties is starting to increase shipping efficiency, which decreases shipping demand. Also, 2016 will see 48 vessel deliveries, 40 on charter and 8 available for employment – which would tie the largest number ever delivered (in 2008) – are the largest harbinger of continued low day-rates.

Recovery might come through continued deceleration of new vessel orders and the large ramp-up of US volumes, which requires more shipping tonnage per ton of LNG delivered because of the longer distance from markets. However, these factors are not expected to outweigh the large number of ship deliveries through the second half of 2017. In the meantime, some vessels could be used for alternative uses such as FSRU conversions and floating storage.

How much more regasification capacity is needed globally? Three key factors will promote new regasification terminals around the world. First, the growth of new flexible liquefaction capacity mainly from the United States adds to an abundance of uncommitted supply that could find delivery in previously under-served markets. Second, the growth in global liquefaction capacity will put downward pressure on prices making LNG imports more affordable not only for emerging markets, but also for new industries and regions in mature markets. Lastly, for countries that have short-term visibility in terms of their own natural gas demand requirements, FSRUs could be quickly procured to provide import capacity for as little or as long as needed. One possible limitation on how much new capacity is actually brought online is potentially higher credit risks in emerging markets. In any case, emerging markets will play an increasing role in development of new regasification capacity.

8. References Used in the 2016 Edition

8.1. Data Collection

Data in the 2016 World LNG Report is sourced from a variety of public and private domains, including the BP Statistical Review of World Energy, Cedigaz, the International Energy Agency (IEA), the Oxford Institute for Energy Studies (OIES), the US Energy Information Agency (EIA), the US Department of Energy (DOE), GIIGNL, IHS, company reports and announcements. This report should be read in conjunction with the 2014 and 2015 World LNG Reports, available on the IGU website at www.igu.org.

The data and associated comments have been reviewed and verified by IGU.

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- TOTAL, France
- Osaka Gas, Japan
- RasGas, Qatar
- Anadarko, USA
- Bureau Veritas, France
- GIIGNL, France

8.2. Definitions

Brownfield Liquefaction Project: A land-based LNG project at a site with existing LNG infrastructure, including but not limited to storage tanks, liquefaction facilities and regasification facilities.

Forecasted Data: Forecasted liquefaction and regasification capacity data only takes into account existing and under construction capacity (criteria being FID taken), and is based on publically announced start dates.

Greenfield Liquefaction Project: A land-based LNG project at a site where no previous LNG infrastructure has been developed.

Large-Scale vs. Small-Scale LNG: IGU defines the large-scale LNG industry as every LNG business above 1 MTPA of LNG production and/or consumption. Conversely, small-scale LNG is any business under 1 MTPA.

Liquefaction and Regasification Capacity: Unless otherwise noted, liquefaction and regasification capacity throughout the document refers to nominal capacity. It must be noted that re-loading and storage activity can significantly reduce the effective capacity available for regasification.

LNG Carriers: For the purposes of this report, only Q-Class and conventional LNG vessels with a capacity greater than 30,000 cm are considered part of the global fleet discussed in the "LNG Carriers" chapter (Chapter 5). Vessels with a capacity of under 30,000 cm are considered small-scale LNG carriers.

Northeast Asian Spot Prices: Northeast Asian spot prices are calculated based on the observed average price for spot cargoes imported into Japan and South Korea in a given month.

Project CAPEX: Liquefaction plant CAPEX figures reflect the complete cost of building the facilities, including site preparation, gas processing, liquefaction, LNG storage and other related infrastructure costs. Regasification terminal CAPEX figures are based on company announcements and may therefore only include selected infrastructure components.

Short-term, Medium-term and Long-term Trade:

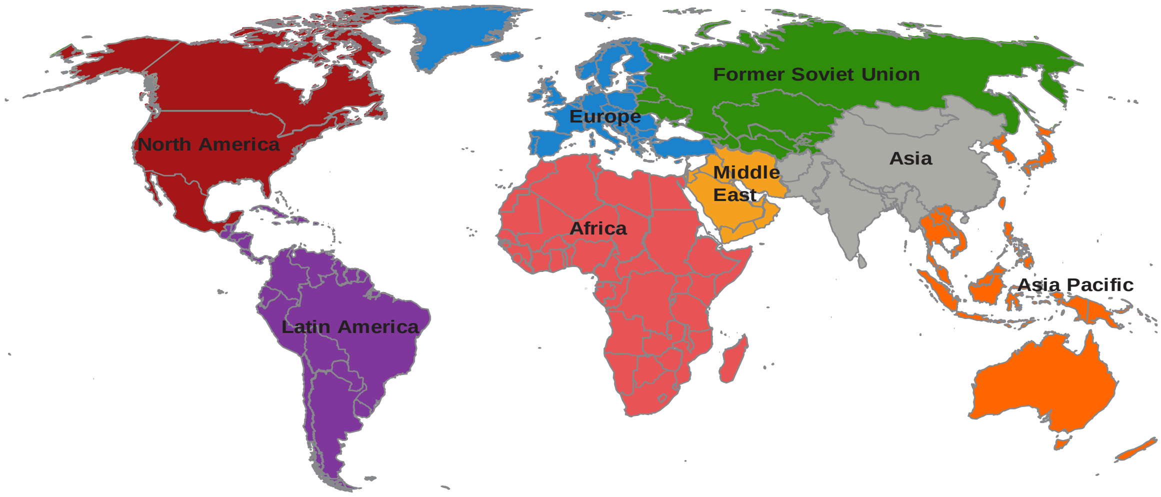
- Short-term trade = volumes traded on a spot basis or under contracts of less than 2 years
- Medium-term trade = volumes traded under a 2 to <5 year contract
- Long-term trade = volumes traded under a 5+ year contract

Traded LNG Volumes: Trade figures are measured according to the volume of LNG imported at the regasification level. Only international trade is taken into account. Domestic LNG trade in Indonesia is thus excluded from the global figures.

8.3. Regions and Basins

The IGU regions referred to throughout the report are defined as per the colour coded areas in the map on the next page. The report also refers to three basins: Atlantic, Pacific and Middle East. The Atlantic Basin encompasses all countries that border the Atlantic Ocean or Mediterranean Sea, while the Pacific Basin refers to all countries bordering the Pacific and Indian Oceans. However, these two categories do not include the following countries, which have been differentiated to compose the Middle East Basin: Bahrain, Iran, Iraq, Israel, Jordan, Kuwait, Oman, Qatar, UAE and Yemen. IGU has also taken into account countries with liquefaction or regasification activities in multiple basins and has adjusted the data accordingly.

8.3 Regions and Basins



8.4. Acronyms

BOG = Boil-Off Gas
BOR = Boil-Off Rate
CBM = Coalbed methane
DFDE = Dual-Fuel Diesel Electric LNG vessel
EPC = Engineering, Procurement and Construction
FEED = Front-End Engineering and Design
FERC = Federal Energy Regulatory Commission
FID = Final Investment Decision
FOB = Free On Board
FTA = Free-Trade Agreement
FLNG = Floating Liquefaction
FSRU = Floating Storage and Regasification Unit
FSU = Former Soviet Union
GHG = Greenhouse gas
ISO = International Standards Organization
LCA = Life Cycle Assessment
LCI = Life Cycle Inventory
ME-GI = M-type, Electronically Controlled, Gas Injection
PCA = Panama Canal Authority
PNG = Papua New Guinea
SPA = Sales and Purchase Agreement
SSD = Slow Speed Diesel
SSLNG = Small-scale LNG
TFDE = Tri-Fuel Diesel Electric LNG vessel
UAE = United Arab Emirates
UK = United Kingdom
US = United States
US DOE = US Department of Energy
US Lower 48 = United States excluding Alaska and Hawaii
YOY = Year-on-Year

8.5. Units

Bcfd = billion cubic feet per day
bcm = billion cubic meters
cm = cubic meters
KTPA = thousand tonnes per annum
mcm = thousand cubic meters
MMBtu = million British thermal units
mmcm = million cubic meters
MT = million tonnes
MTPA = million tonnes per annum
Tcf = trillion cubic feet

8.6. Conversion Factors

← Multiply by →

	Tonnes LNG	cm LNG	cm gas	cf gas	MMBtu	boe
Tonnes LNG		2.222	1,300	45,909	53.38	9.203
cm LNG	0.450		585	20,659	24.02	4.141
cm gas	7.692 x 10-4	0.0017		35.31	0.0411	0.0071
cf gas	2.178 x 10-5	4.8 x 10-5	0.0283		0.0012	2.005 x 10-4
MMBtu	0.0187	0.0416	24.36	860.1		0.1724
boe	0.1087	0.2415	141.3	4,989	5.8	

Appendix 1: Table of Global Liquefaction Plants

Reference Number	Country	Project Name	Start Year	Nameplate Capacity (MTPA)	Owners*	Liquefaction Technology
1	US	Kenai LNG**	1969	1.5	ConocoPhillips	ConocoPhillips Optimized Cascade®
2	Libya	Marsa El Brega***	1970	3.2	LNOC	APC C3MR
3	Brunei	Brunei LNG T1-5	1972	7.2	Government of Brunei, Shell, Mitsubishi	APC C3MR
4	United Arab Emirates	ADGAS LNG T1-2	1977	2.6	ADNOC, Mitsui, BP, TOTAL	APC C3MR
5	Algeria	Arzew - GL1Z (T1-6)	1978	7.9	Sonatrach	APC C3MR
5	Algeria	Arzew - GL2Z (T1-6)	1981	8.2	Sonatrach	APC C3MR
6	Indonesia	Bontang LNG T3-4	1983	5.4	Pertamina	APC C3MR
7	Malaysia	MLNG Satu (T1-3)	1983	8.1	PETRONAS, Mitsubishi, Sarawak State Government	APC C3MR
8	Australia	North West Shelf T1	1989	2.5	BHP Billiton, BP, Chevron, Shell, Woodside, Mitsubishi, Mitsui	APC C3MR
8	Australia	North West Shelf T2	1989	2.5	BHP Billiton, BP, Chevron, Shell, Woodside, Mitsubishi, Mitsui	APC C3MR
6	Indonesia	Bontang LNG T5	1989	2.9	Pertamina	APC C3MR
8	Australia	North West Shelf T3	1992	2.5	BHP Billiton, BP, Chevron, Shell, Woodside, Mitsubishi, Mitsui	APC C3MR
6	Indonesia	Bontang LNG T6	1994	2.9	Pertamina	APC C3MR
4	United Arab Emirates	ADGAS LNG T3	1994	3.2	ADNOC, Mitsui, BP, TOTAL	APC C3MR
7	Malaysia	MLNG Dua (T1-3)	1995	7.8	PETRONAS, Shell, Mitsubishi, Sarawak State Government	APC C3MR
9	Qatar	Qatargas I (T1)	1997	3.2	Qatar Petroleum, ExxonMobil, TOTAL,, Marubeni, Mitsui	APC C3MR
9	Qatar	Qatargas I (T2)	1997	3.2	Qatar Petroleum, ExxonMobil, TOTAL, Marubeni, Mitsui	APC C3MR
6	Indonesia	Bontang LNG T7	1998	2.7	Pertamina	APC C3MR
9	Qatar	Qatargas I (T3)	1998	3.1	Qatar Petroleum, ExxonMobil, TOTAL, Mitsui, Marubeni	APC C3MR
6	Indonesia	Bontang LNG T8	1999	3	Pertamina	APC C3MR
10	Nigeria	NLNG T1	1999	3.3	NNPC, Shell, TOTAL, Eni	APC C3MR
9	Qatar	RasGas I (T1)	1999	3.3	Qatar Petroleum, ExxonMobil, KOGAS, Itochu, LNG Japan	APC C3MR
11	Trinidad	ALNG T1	1999	3.3	BP, BG, Shell, CIC, NGC Trinidad	ConocoPhillips Optimized Cascade®
10	Nigeria	NLNG T2	2000	3.3	NNPC, Shell, TOTAL, Eni	APC C3MR
12	Oman	Oman LNG T1	2000	3.55	Omani Govt, Shell, TOTAL, Korea LNG, Partex, Mitsubishi, Mitsui, Itochu	APC C3MR
12	Oman	Oman LNG T2	2000	3.55	Omani Govt, Shell, TOTAL, Korea LNG, Partex, Mitsubishi, Mitsui, Itochu	APC C3MR

9	Qatar	RasGas I (T2)	2000	3.3	Qatar Petroleum, ExxonMobil, KOGAS, Itochu, LNG Japan	APC C3MR
10	Nigeria	NLNG T3	2002	3	NNPC, Shell, TOTAL, Eni	APC C3MR
11	Trinidad	ALNG T2	2002	3.4	BP, BG, Shell	ConocoPhillips Optimized Cascade®
7	Malaysia	MLNG Tiga (T1-2)	2003	6.8	PETRONAS, Shell, Nippon, Sarawak State Government, Mitsubishi	APC C3MR
11	Trinidad	ALNG T3	2003	3.4	BP, BG, Shell	ConocoPhillips Optimized Cascade®
8	Australia	North West Shelf T4	2004	4.4	BHP Billiton, BP, Chevron, Shell, Woodside, Mitsubishi, Mitsui	APC C3MR
9	Qatar	RasGas II (T1)	2004	4.7	Qatar Petroleum, ExxonMobil	APC C3MR/ Split MR™
13	Egypt	ELNG T1***	2005	3.6	BG, PETRONAS, EGAS, EGPC, ENGIE	ConocoPhillips Optimized Cascade®
13	Egypt	ELNG T2***	2005	3.6	BG, PETRONAS, EGAS, EGPC	ConocoPhillips Optimized Cascade®
13	Egypt	Damietta LNG T1***	2005	5	Gas Natural Fenosa, Eni, EGPC, EGAS	APC C3MR/
						Split MR™
9	Qatar	RasGas II (T2)	2005	4.7	Qatar Petroleum, ExxonMobil	APC C3MR/
						Split MR™
14	Australia	Darwin LNG T1	2006	3.6	ConocoPhillips, Santos, INPEX, Eni, TEPCO, Tokyo Gas	ConocoPhillips Optimized Cascade®
10	Nigeria	NLNG T4	2006	4.1	NNPC, Shell, TOTAL, Eni	APC C3MR
10	Nigeria	NLNG T5	2006	4.1	NNPC, Shell, TOTAL, Eni	APC C3MR
12	Oman	Qalhat LNG	2006	3.7	Omani Govt, Oman LNG, Union Fenosa Gas, Itochu, Mitsubishi, Osaka Gas	APC C3MR
11	Trinidad	ALNG T4	2006	5.2	BP, BG, Shell, NGC Trinidad	ConocoPhillips Optimized Cascade®
15	Equatorial Guinea	EG LNG T1	2007	3.7	Marathon, Sonagas, Mitsui, Marubeni	ConocoPhillips Optimized Cascade®
16	Norway	Snøhvit LNG T1	2007	4.2	Statoil, Petoro, TOTAL, ENGIE, RWE	Linde MFC
9	Qatar	RasGas II (T3)	2007	4.7	Qatar Petroleum, ExxonMobil	APC C3MR/
						Split MR™
8	Australia	North West Shelf T5	2008	4.4	BHP Billiton, BP, Chevron, Shell, Woodside, Mitsubishi, Mitsui	APC C3MR
10	Nigeria	NLNG T6	2008	4.1	NNPC, Shell, TOTAL, Eni	APC C3MR
17	Indonesia	Tangguh LNG T1	2009	3.8	BP, CNOOC, Mitsubishi, INPEX, JOGMEC, JX Nippon Oil & Energy, LNG Japan, Talisman Energy, Kanematsu, Mitsui	APC C3MR/Split MR™

17	Indonesia	Tangguh LNG T2	2009	3.8	BP, CNOOC, Mitsubishi, INPEX, JOGMEC, JX Nippon Oil & Energy, LNG Japan, Talisman Energy, Kanematsu, Mitsui	APC C3MR/Split MR™
9	Qatar	Qatargas II (T1)	2009	7.8	Qatar Petroleum, ExxonMobil	APC AP-X
9	Qatar	Qatargas II (T2)	2009	7.8	Qatar Petroleum, ExxonMobil, TOTAL	APC AP-X
9	Qatar	RasGas III (T1)	2009	7.8	Qatar Petroleum, ExxonMobil	APC AP-X
18	Russia	Sakhalin 2 (T1)	2009	4.8	Gazprom, Shell, Mitsui, Mitsubishi	Shell DMR
18	Russia	Sakhalin 2 (T2)	2009	4.8	Gazprom, Shell, Mitsui, Mitsubishi	Shell DMR
19	Yemen	Yemen LNG T1	2009	3.6	TOTAL, Hunt Oil, Yemen Gas Co., SK Corp, KOGAS, GASSP, Hyundai	APC C3MR/Split MR™
7	Malaysia	MLNG Dua Debottleneck	2010	1.2	PETRONAS, Shell, Mitsubishi, Sarawak State Government	APC C3MR
20	Peru	Peru LNG	2010	4.45	Hunt Oil, Shell, SK Corp, Marubeni	APC C3MR/Split MR™
9	Qatar	Qatargas III	2010	7.8	Qatar Petroleum, ConocoPhillips, Mitsui	APC AP-X
9	Qatar	RasGas III (T2)	2010	7.8	Qatar Petroleum, ExxonMobil	APC AP-X
19	Yemen	Yemen LNG T2	2010	3.6	TOTAL, Hunt Oil, Yemen Gas Co., SK Corp, KOGAS, GASSP, Hyundai	APC C3MR/
9	Qatar	Qatargas IV	2011	7.8	Qatar Petroleum, Shell	APC AP-X
21	Australia	Pluto LNG T1	2012	4.3	Woodside, Kansai Electric, Tokyo Gas	Shell propane pre-cooled mixed refrigerant design
5	Algeria	Skikda - GL1K Rebuild	2013	4.5	Sonatrach	APC C3MR
22	Angola	Angola LNG T1	2013	5.2	Chevron, Sonangol, BP, Eni, TOTAL	ConocoPhillips Optimized Cascade®
23	Papua New Guinea	PNG LNG T1	2014	3.45	ExxonMobil, Oil Search, Govt. of PNG, Santos, Nippon Oil, PNG Landowners (MRDC), Marubeni, Petromin PNG	APC C3MR
23	Papua New Guinea	PNG LNG T2	2014	3.45	ExxonMobil, Oil Search, Govt. of PNG, Santos, JX Nippon Oil & Energy, MRDC, Marubeni, Petromin PNG	APC C3MR
5	Algeria	Arzew - GL3Z (Gassi Touil)	2014	4.7	Sonatrach	APC C3MR/Split MR™
24	Australia	QCLNG T1	2014	4.3	BG, CNOOC	ConocoPhillips Optimized Cascade®
24	Australia	QCLNG T2	2015	4.3	BG, Tokyo Gas	ConocoPhillips Optimized Cascade®
25	Indonesia	Donggi-Senoro LNG	2015	2	Mitsubishi, Pertamina, KOGAS, Medco	APC C3MR

Sources: IHS, Company Announcements
** Companies are listed by size of ownership stake, starting with the largest stake*
*** Kenai LNG was scheduled to be decommissioned in 2016 but has applied for an additional two-year export license.*** Damietta LNG in Egypt has not operated since the end of 2012; operations at ELNG in Egypt were greatly reduced in 2014, and the plant did not export cargoes in 2015. The Marsa El Brega plant in Libya is included for reference although it has not been operational since 2011.*

Appendix 2: Table of Liquefaction Plants Under Construction

Country	Project Name	Start Year	Nameplate Capacity (MTPA)	Owners*	Liquefaction Technology
Australia	APLNG T1	2016	4.5	ConocoPhillips, Origin Energy, Sinopec	ConocoPhillips Optimized Cascade®
Australia	APLNG T2	2016	4.5	ConocoPhillips, Origin Energy, Sinopec	ConocoPhillips Optimized Cascade®
Australia	GLNG T1	2016	3.9	Santos, PETRONAS, TOTAL, KOGAS	ConocoPhillips Optimized Cascade®
Australia	Gorgon LNG T1-2	2016	10.4	Chevron, ExxonMobil, Shell, Osaka Gas, Tokyo Gas, Chubu Electric	APC C3MR/Split MR™
Malaysia	MLNG 9	2016	3.6	PETRONAS	APC Split MR™
Malaysia	PFLNG 1	2016	1.2	PETRONAS	APC AP-N™
Australia	GLNG T2	2016	3.9	Santos, PETRONAS, TOTAL, KOGAS	ConocoPhillips Optimized Cascade®
US	Sabine Pass T1-2	2016	9	Cheniere	ConocoPhillips Optimized Cascade®
Australia	Wheatstone LNG T1	2016	4.45	Chevron, Apache, Pan Pacific Energy, KUFPEC, Shell, Kyushu Electric	ConocoPhillips Optimized Cascade®
Indonesia	Senkang LNG T1	2016	0.5	EWC	Siemens
Australia	Gorgon LNG T3	2017	5.2	Chevron, ExxonMobil, Shell, Osaka Gas, Tokyo Gas, Chubu Electric	APC C3MR/Split MR™
Australia	Ichthys LNG T1	2017	4.45	INPEX, TOTAL, Tokyo Gas, CPC, Osaka Gas, Chubu Electric, Toho Gas	APC Split MR™
Australia	Prelude FLNG	2017	3.6	Shell, INPEX, KOGAS, CPC	Shell Floating LNG
Australia	Wheatstone LNG T2	2017	4.45	Chevron, Apache, Pan Pacific Energy, KUFPEC, Shell, Kyushu Electric	ConocoPhillips Optimized Cascade®
Russia	Yamal LNG T1	2017	5.5	Novatek, TOTAL, CNPC	APC C3MR™
US	Cove Point LNG	2017	5.25	Dominion	APC C3MR/Split MR™
US	Sabine Pass T3-4	2017	9	Cheniere	ConocoPhillips Optimized Cascade®
Cameroon	Cameroon FLNG	2017	2.4	Golar, Keppel	GoFLNG
Australia	Ichthys LNG T2	2018	4.45	INPEX, TOTAL, Tokyo Gas, CPC, Osaka Gas, Chubu Electric, Toho Gas	APC Split MR™
Malaysia	PFLNG 2	2018	1.5	PETRONAS, MISC, Murphy Oil	APC AP-N™
Russia	Yamal LNG T2	2018	5.5	Novatek, TOTAL, CNPC	APC C3MR™
US	Cameron LNG T1-3	2018	12	Sempra, Mitsubishi/NYK JV, Mitsui, ENGIE	APC C3MR™
US	Freeport LNG T1	2018	4.4	Freeport LNG, Osaka Gas, Chubu Electric	APC C3MR/Split MR™
Russia	Yamal LNG T3	2019	5.5	Novatek, TOTAL, CNPC	APC C3MR™
US	Freeport LNG T2	2019	4.4	Freeport LNG, IFM Investors	APC C3MR/Split MR™
US	Sabine Pass T5	2019	4.5	Cheniere	ConocoPhillips Optimized Cascade®
US	Freeport LNG T3	2019	4.4	Freeport LNG	APC C3MR/Split MR™
US	Corpus Christi LNG T1-2	2019	9	Cheniere	ConocoPhillips Optimized Cascade®

Sources: IHS, Company Announcements
** Companies are listed by size of ownership stake, starting with the largest stake. List excludes the stalled Caribbean FLNG project offshore Colombia.*

Appendix 3: Table of LNG Receiving Terminals

Reference Number	Country	Terminal Name	Start Year	Nameplate Receiving Capacity (MTPA)	Owners*	Concept
1	Spain	Barcelona	1969	12.8	ENAGAS 100%	Onshore
2	Japan	Negishi	1969	12	TEPCO 50%; Tokyo Gas 50%	Onshore
3	US	Everett	1971	5.4	GDF SUEZ 100%	Onshore
4	Italy	Panigaglia (La Spezia)	1971	2.5	Eni 100%	Onshore
5	France	Fos Tonkin	1972	4	GDF SUEZ 100%	Onshore
6	Japan	Senboku	1972	15.3	Osaka Gas 100%	Onshore
7	Japan	Sodegaura	1973	29.4	TEPCO 50%; Tokyo Gas 50%	Onshore
8	Japan	Chita LNG Joint/ Chita Kyodo	1977	8	Chubu Electric 50%; Toho Gas 50%	Onshore
9	Japan	Tobata	1977	6.8	Kitakyushu LNG 100%	Onshore
10	US	Cove Point	1978	11	Dominion 100%	Onshore
11	US	Elba Island	1978	12.4	KM LNG Operating Partnership 100%	Onshore
12	Japan	Himeji	1979	13.3	Osaka Gas 100%	Onshore
13	France	Montoir-de-Bretagne	1980	7.3	GDF SUEZ 100%	Onshore
14	US	Lake Charles	1982	17.3	Southern Union 75%; AIG Highstar (Private Equity) 25%	Onshore
15	Japan	Chita	1983	12	Chubu Electric 50%; Toho Gas 50%	Onshore
16	Japan	Higashi-Ohgishima	1984	14.7	TEPCO 100%	Onshore
17	Japan	Nihonkai (Niigata)	1984	8.9	Nihonkai LNG 58.1%; Tohoku Electric 41.9%	Onshore
18	Japan	Futtsu	1985	16	TEPCO 100%	Onshore
19	Korea	Pyeong-Taek	1986	34.5	KOGAS 100%	Onshore
20	Japan	Yokkaichi LNG Works	1987	7.1	Chubu Electric 100%	Onshore
21	Belgium	Zeebrugge	1987	6.6	Publigas 89.97%; Fluxys 10.03%	Onshore
22	Spain	Huelva	1988	8.9	ENAGAS 100%	Onshore
23	Spain	Cartagena	1989	7.6	ENAGAS 100%	Onshore
24	Japan	Oita	1990	5.1	Kyushu Electric 100%	Onshore
25	Japan	Yanai	1990	2.4	Chugoku Electric 100%	Onshore
26	Taiwan	Yong an (Kaohsiung)	1990	10	CPC 100%	Onshore
27	Turkey	Marmara Ereglisi	1994	5.9	Botas 100%	Onshore
28	Korea	Incheon	1996	38	KOGAS 100%	Onshore
29	Japan	Sodeshi/Shimizu LNG	1996	1.6	Shizuoka Gas 65%; TonenGeneral 35%	Onshore
30	Japan	Kawagoe	1997	7.7	Chubu Electric 100%	Onshore
31	Japan	Ohgishima	1998	6.7	Tokyo Gas 100%	Onshore
32	Puerto Rico	Peñuelas (EcoElectrica)	2000	1.2	Gas Natural Fenosa 47.5%; International Power 25%; Mitsui 25%; GE Capital 2.5%	Onshore
33	Greece	Revithoussa	2000	3.3	DEPA 100%	Onshore
34	Japan	Chita Midorihama Works	2001	8.3	Toho Gas 100%	Onshore
35	Korea	Tong-Yeong	2002	17	KOGAS 100%	Onshore

36	Dominican Republic	AES Andrés	2003	1.9	AES 100%	Onshore
37	Spain	Bilbao (BBG)	2003	5.3	ENAGAS 40%; EVE 30%; RREEF Infrastructure 30%	Onshore
38	India	Dahej LNG	2004	10	Petronet LNG 100%	Onshore
39	Portugal	Sines LNG	2004	5.8	REN 100%	Onshore
40	UK	Grain LNG	2005	15	National Grid Transco 100%	Onshore
41	Korea	Gwangyang	2005	1.8	Posco 100%	Onshore
42	India	Hazira LNG	2005	5	Shell 74%; TOTAL 26%	Onshore
43	Japan	Sakai	2005	2	Kansai Electric 70%; Cosmo Oil 12.5%; Iwatani 12.5%; Ube Industries 5%	Onshore
44	Turkey	Aliaga LNG	2006	4.4	Egegaz 100%	Onshore
45	Mexico	Altamira LNG	2006	5.4	Vopak 60%; ENAGAS 40%	Onshore
46	China	Guangdong Dapeng LNG I	2006	6.7	Local companies 37%; CNOOC 33%; BP 30%	Onshore
47	Japan	Mizushima LNG	2006	1.7	Chugoku Electric 50%; JX Nippon Oil & Energy 50%	Onshore
48	Spain	Saggas (Sagunto)	2006	6.7	RREEF Infrastructure 30%; Eni 21.25%; Gas Natural Fenosa 21.25%; Osaka Gas 20%; Oman Oil 7.5%	Onshore
49	Spain	Mugardos LNG (El Ferrol)	2007	2.6	Grupo Tojeiro 36.5%; Gas Natural Fenosa 21%; Comunidad Autonoma de Galicia 17.5%; Other Companies 15%; Sonatrach 10%	Onshore
50	UK	Teesside GasPort	2007	3	Excelerate Energy 100%	Floating
51	Mexico	Costa Azul	2008	7.5	Sempra 100%	Onshore
52	US	Freeport LNG	2008	11.3	Michael S Smith Cos 45%; ZHA FLNG Purchaser 30%; Dow Chemical 15%; Osaka Gas 10%	Onshore
53	China	Fujian (Putian)	2008	5	CNOOC 60%; Fujian Investment and Development Co 40%	Onshore
54	US	Northeast Gateway	2008	3	Excelerate Energy 100%	Floating
55	US	Sabine Pass	2008	30.2	Cheniere Energy 100%	Onshore
56	Argentina	Bahia Blanca GasPort	2008	3.8	YPF 100%	Floating
57	Italy	Adriatic LNG/Rovigo	2009	5.8	ExxonMobil 46.35%; Qatar Petroleum 46.35%; Edison 7.3%	Offshore
58	US	Cameron LNG	2009	11.3	Sempra 50.2%; GDF SUEZ 16.6%; Mitsubishi 16.6%; Mitsui 16.6%	Onshore
59	Canada	Canaport	2009	7.5	Repsol 75%; Irving Oil 25%	Onshore
60	UK	Dragon LNG	2009	4.4	BG Group 50%; PETRONAS 30%; 4Gas 20%	Onshore
61	Kuwait	Mina Al-Ahmadi	2009	5.8	Kuwait Petroleum Corporation 100%	Floating
62	Brazil	Pecém	2009	1.9	Petrobras 100%	Floating
63	Chile	Quintero LNG	2009	2.7	ENAGAS 20.4%; ENAP 20%; ENDESA 20%; Metrogas 20%; Oman Oil 19.6%	Onshore

64	China	Shanghai (Yangshan)	2009	3	Shenergy Group 55%; CNOOC 45%	Onshore
65	UK	South Hook	2009	15.6	Qatar Petroleum 67.5%; ExxonMobil 24.15%; TOTAL 8.35%	Onshore
66	Taiwan	Taichung LNG	2009	3	CPC 100%	Onshore
67	UAE	Dubai	2010	3	Dubai Supply Authority (Dusup) 100%	Floating
68	France	FosMax LNG (Fos Cavaou)	2010	6	GDF SUEZ 71.97%; TOTAL 28.03%	Onshore
69	Chile	Mejillones LNG	2010	1.5	GDF SUEZ 63%; Codelco 37%	Onshore
70	China	Dalian	2011	3	CNPC 75%; Dalian Port 20%; Dalian Construction Investment Corp 5%	Onshore
71	Netherlands	GATE LNG	2011	8.8	Gasunie 40%; Vopak 40%; Dong 5%; EconGas OMV 5%; EON 5%; RWE 5%	Onshore
72	US	Golden Pass	2011	15.6	Qatar Petroleum 70%; ExxonMobil 17.6%; ConocoPhillips 12.4%	Onshore
73	US	Gulf LNG (formerly Clean Energy Terminal)	2011	11.3	KM LNG Operating Partnership 50%; GE Energy Financial Services 30%; Sonangol 20%	Onshore
74	Argentina	Puerto Escobar	2011	3.8	Enarsa 100%	Floating
75	Thailand	Map Ta Phut LNG	2011	5	PTT 100%	Onshore
76	China	Rudong Jiangsu LNG	2011	3.5	PetroChina 55%; Pacific Oil and Gas 35%; Jiangsu Guoxin 10%	Onshore
77	Brazil	Guanabara LNG/Rio de Janeiro	2012	6	Petrobras 100%	Floating
78	Indonesia	Nusantara	2012	3.8	Pertamina 60%; PGN 40%	Floating
79	Japan	Ishikari LNG	2012	1.4	Hokkaido Gas 100%	Onshore
80	Japan	Joetsu	2012	2.3	Chubu Electric 100%	Onshore
81	Mexico	Manzanillo	2012	3.8	Mitsui 37.5%; Samsung 37.5%; KOGAS 25%	Onshore
82	China	Dongguan	2012	1	Jovo Group 100%	Onshore
83	Israel	Hadera Gateway	2013	3	Israel Natural Gas Lines 100%	Floating
84	India	Dabhol	2013	2	GAIL 31.52%; NTPC 31.52%; Indian financial institutions 20.28%; MSEB Holding Co. 16.68%	Onshore
85	Spain	El Musel	2013	5.4	ENAGAS 100%	Onshore
86	Singapore	Singapore LNG	2013	6	Singapore Energy Market Authority 100%	Onshore
87	Malaysia	Lekas LNG (Malacca)	2013	3.8	PETRONAS 100%	Onshore
88	China	Ningbo, Zhejiang	2013	3	CNOOC 51%; Zhejiang Energy Group Co Ltd 29%; Ningbo Power Development Co Ltd 20%	Onshore
89	China	Zhuhai (CNOOC)	2013	3.5	CNOOC 30%; Guangdong Gas 25%; Guangdong Yuedian 25%; Local companies 20%	Onshore

90	Italy	Livorno/LNG Toscana	2013	2.7	EON 46.79%; IREN 46.79%; OLT Energy 3.73%; Golar 2.69%	Floating
91	China	Tangshan Caofeidian LNG	2013	3.5	PetroChina 100%	Onshore
92	China	Tianjin	2013	2.2	CNOOC 100%	Floating
93	Japan	Naoetsu (Joetsu)	2013	2	INPEX 100%	Onshore
94	India	Kochi LNG	2013	5	Petronet LNG 100%	Onshore
95	Brazil	Bahia/TRBA	2014	3.8	Petrobras 100%	Floating
96	Indonesia	Lampung LNG	2014	1.8	PGN 100%	Floating
97	Korea	Samcheok	2014	6.8	KOGAS 100%	Onshore
98	China	Hainan LNG	2014	2	CNOOC 65%; Hainan Development Holding Co 35%	Onshore
99	Japan	Hibiki LNG	2014	3.5	Saibu Gas 90%; Kyushu Electric 10%	Onshore
100	China	Shandong LNG	2014	3	Sinopec 99%; Qingdao Port Group 1%	Onshore
101	Lithuania	Klaipeda LNG	2014	3	Klaipedos Nafta 100%	Floating
102	Indonesia	Arun LNG	2015	3	Pertamina 70%; Aceh Regional Government 30%	Onshore
103	Japan	Hachinohe LNG	2015	1.5	JX Nippon Oil & Energy 100%	Onshore
104	Egypt	Ain Sokhna Hoegh	2015	4.1	EGAS 100%	Floating
105	Pakistan	Engro LNG	2015	3.8	Engro Corp. 100%	Floating
106	Jordan	Aqaba LNG	2015	3.8	Jordan Ministry of Energy and Mineral Resources (MEMR) 100%	Floating
107	Egypt	Ain Sokhna BW	2015	5.7	EGAS 100%	Floating
108	Japan	Shin-Sendai	2015	1.5	Tohoku Electric 100%	Onshore

Sources: IHS, Company Announcements

Appendix 4: Table of LNG Receiving Terminals Under Construction

Reference Number	Country	Terminal or Phase Name	Start Year	Nameplate Receiving Capacity (MTPA)	Owners*	Concept
109	China	Rudong Jiangsu LNG Phase 2	2016	3	CNPC 55%; Pacific Oil and Gas 35%; Jiangsu Guoxin 10%	Onshore
110	China	Yuedong LNG (Jieyang)	2016	2	Shenergy Group 55%; CNOOC 45%	Onshore
111	China	Beihai, Guangxi LNG	2016	3	Sinopec 100%	Onshore
112	Philippines	Pagbilao LNG Hub	2016	3	Energy World Corporation 100%	Onshore
113	France	Dunkirk LNG	2016	10	EDF 65%; Fluxys 25%; TOTAL 10%	Onshore
114	Poland	Swinoujscie	2016	3.6	GAZ-SYSTEM SA 100%	Onshore
115	China	Dalian Phase 2	2016	3	CNPC 75%; Dalian Port 20%; Dalian Construction Investment Corp 5%	Onshore
116	China	Tianjin (onshore)	2016	3.5	CNOOC 100%	Onshore
117	China	Yantai, Shandong Phase 1	2016	1.5	CNOOC 100%	Onshore
118	Greece	Revithoussa (Expansion Phase 2)	2016	1.9	DEPA 100%	Onshore

119	India	Dahej LNG (Phase 3-A1)	2016	5	Petronet LNG 100%	Onshore
120	China	Tianjin (Sinopec) Phase 1	2016	2.9	Sinopec 100%	Onshore
121	Thailand	Map Ta Phut Phase 2	2017	5	PTT 100%	Onshore
122	India	Mundra	2017	5	Adani Group 50%; GSPC 50%	Onshore
123	Korea	Boryeong	2017	3	GS Energy 50%; SK Energy 50%	Onshore
124	China	Shenzhen (Diefu)	2017	4	CNOOC 70%; Shenzhen Energy Group 30%	Onshore
125	China	Fujian (Zhangzhou)	2018	3	CNOOC 60%; Fujian Investment and Development Co. 40%	Onshore
126	Japan	Soma LNG	2018	1.5	Japex 100%	Onshore
127	China	Zhoushan	2018	3	ENN Energy 100%	Onshore
128	India	Ennore LNG	2019	5	Indian Oil Corporation 95%; Tamil Nadu Industrial Development Corporation 5%	Onshore

Sources: IHS, Company Announcements

Appendix 5: Table of Active LNG Fleet

Ship Name	Shipowner	Shipbuilder	Type	Delivery Year	Capacity (cm)	Propulsion Type	IMO #
AAMIRA	Nakilat	Samsung	Q-Max	2010	260,912	SSD	9443401
ABADI	Brunei Gas Carriers	Mitsubishi	Conventional	2002	135,269	Steam	9210828
ADAM LNG	Oman Shipping Co (OSC)	Hyundai	Conventional	2014	162,000	TFDE	9501186
AL AAMRIYA	NYK, K Line, MOL, Iino, Mitsui, Nakilat	Daewoo	Q-Flex	2008	206,958	SSD	9338266
AL AREESH	Nakilat, Teekay	Daewoo	Conventional	2007	148,786	Steam	9325697
AL BAHIYA	Nakilat	Daewoo	Q-Flex	2010	205,981	SSD	9431147
AL BIDDA	J4 Consortium	Kawaski	Conventional	1999	135,466	Steam	9132741
AL DAAYEN	Nakilat, Teekay	Daewoo	Conventional	2007	148,853	Steam	9325702
AL DAFNA	Nakilat	Samsung	Q-Max	2009	261,988	SSD	9443683
AL DEEBEL	MOL, NYK, K Line	Samsung	Conventional	2005	142,795	Steam	9307176
AL GATTARA	Nakilat, OSC	Hyundai	Q-Flex	2007	216,200	SSD	9337705
AL GHARIYA	Commerz Real, Nakilat, PRONAV	Daewoo	Q-Flex	2008	205,941	SSD	9337987
AL GHARRAFA	Nakilat, OSC	Hyundai	Q-Flex	2008	216,200	SSD	9337717
AL GHASHAMIYA	Nakilat	Samsung	Q-Flex	2009	211,885	SSD	9397286
AL GHUWAIRIYA	Nakilat	Daewoo	Q-Max	2008	257,984	SSD	9372743
AL HAMLA	Nakilat, OSC	Samsung	Q-Flex	2008	211,862	SSD	9337743
AL HAMRA	National Gas Shipping Co	Kvaerner Masa	Conventional	1997	137,000	Steam	9074640
AL HUWAILA	Nakilat, Teekay	Samsung	Q-Flex	2008	214,176	SSD	9360879
AL JASRA	J4 Consortium	Mitsubishi	Conventional	2000	135,855	Steam	9132791
AL JASSASIYA	Maran G.M, Nakilat	Daewoo	Conventional	2007	142,988	Steam	9324435
AL KARAANA	Nakilat	Daewoo	Q-Flex	2009	205,988	SSD	9431123
AL KHARAITIYAT	Nakilat	Hyundai	Q-Flex	2009	211,986	SSD	9397327
AL KHARSAAH	Nakilat, Teekay	Samsung	Q-Flex	2008	211,885	SSD	9360881
AL KHATTIYA	Nakilat	Daewoo	Q-Flex	2009	205,993	SSD	9431111

AL KHAZNAH	National Gas Shipping Co	Mitsui	Conventional	1994	137,540	Steam	9038440
AL KHOR	J4 Consortium	Mitsubishi	Conventional	1996	135,295	Steam	9085613
AL KHUWAIR	Nakilat, Teekay	Samsung	Q-Flex	2008	211,885	SSD	9360908
AL MAFYAR	Nakilat	Samsung	Q-Max	2009	261,043	SSD	9397315
AL MARROUNA	Nakilat, Teekay	Daewoo	Conventional	2006	149,539	Steam	9325685
AL MAYEDA	Nakilat	Samsung	Q-Max	2009	261,157	SSD	9397298
AL NUAMAN	Nakilat	Daewoo	Q-Flex	2009	205,981	SSD	9431135
AL ORAIQ	NYK, K Line, MOL, Iino, Mitsui, Nakilat	Daewoo	Q-Flex	2008	205,994	SSD	9360790
AL RAYYAN	J4 Consortium	Kawaski	Conventional	1997	134,671	Steam	9086734
AL REKAYYAT	Nakilat	Hyundai	Q-Flex	2009	211,986	SSD	9397339
AL RUWAIS	Commerz Real, Nakilat, PRONAV	Daewoo	Q-Flex	2007	205,941	SSD	9337951
AL SADD	Nakilat	Daewoo	Q-Flex	2009	205,963	SSD	9397341
AL SAFLIYA	Commerz Real, Nakilat, PRONAV	Daewoo	Q-Flex	2007	210,100	SSD	9337963
AL SAHLA	NYK, K Line, MOL, Iino, Mitsui, Nakilat	Hyundai	Q-Flex	2008	211,842	SSD	9360855
AL SAMRIYA	Nakilat	Daewoo	Q-Max	2009	258,054	SSD	9388821
AL SHAMAL	Nakilat, Teekay	Samsung	Q-Flex	2008	213,536	SSD	9360893
AL SHEEHANIYA	Nakilat	Daewoo	Q-Flex	2009	205,963	SSD	9360831
AL THAKHIRA	K Line, Qatar Shpg.	Samsung	Conventional	2005	143,517	Steam	9298399
AL THUMAMA	NYK, K Line, MOL, Iino, Mitsui, Nakilat	Hyundai	Q-Flex	2008	216,235	SSD	9360843
AL UTOURIYA	NYK, K Line, MOL, Iino, Mitsui, Nakilat	Hyundai	Q-Flex	2008	211,879	SSD	9360867
AL WAJBAH	J4 Consortium	Mitsubishi	Conventional	1997	134,562	Steam	9085625
AL WAKRAH	J4 Consortium	Kawaski	Conventional	1998	134,624	Steam	9086746
AL ZUBARAH	J4 Consortium	Mitsui	Conventional	1996	135,510	Steam	9085649
ALTO ACRUX	TEPCO, NYK, Mitsubishi	Mitsubishi	Conventional	2008	147,798	Steam	9343106
AMADI	Brunei Gas Carriers	Hyundai	Conventional	2015	155,000	Steam Reheat	9682552
AMALI	Brunei Gas Carriers	Daewoo	Conventional	2011	147,228	TFDE	9496317
AMANI	Brunei Gas Carriers	Hyundai	Conventional	2014	155,000	TFDE	9661869
AMUR RIVER	Dynagas	Hyundai	Conventional	2008	146,748	Steam	9317999
ARCTIC AURORA	Dynagas	Hyundai	Conventional	2013	154,880	TFDE	9645970
ARCTIC DISCOVERER	K Line, Statoil, Mitsui, Iino	Mitsui	Conventional	2006	139,759	Steam	9276389
ARCTIC LADY	Hoegh	Mitsubishi	Conventional	2006	147,835	Steam	9284192
ARCTIC PRINCESS	Hoegh, MOL, Statoil	Mitsubishi	Conventional	2006	147,835	Steam	9271248
ARCTIC SPIRIT	Teekay	I.H.I.	Conventional	1993	87,305	Steam	9001784
ARCTIC VOYAGER	K Line, Statoil, Mitsui, Iino	Kawaski	Conventional	2006	140,071	Steam	9275335
ARKAT	Brunei Gas Carriers	Daewoo	Conventional	2011	147,228	TFDE	9496305
ARWA SPIRIT	Teekay, Marubeni	Samsung	Conventional	2008	163,285	DFDE	9339260

ASEEM	MOL, NYK, K Line, SCI, Nakilat, Petronet	Samsung	Conventional	2009	154,948	TFDE	9377547
ASIA ENDEAVOUR	Chevron	Samsung	Conventional	2015	154,948	TFDE	9610779
ASIA ENERGY	Chevron	Samsung	Conventional	2014	154,948	TFDE	9606950
ASIA EXCELLENCE	Chevron	Samsung	Conventional	2015	154,948	TFDE	9610767
ASIA VISION	Chevron	Samsung	Conventional	2014	154,948	TFDE	9606948
ATLANTIC ENERGY	Sinokor Merchant Marine	Kockums	Conventional	1984	132,588	Steam	7702401
BACHIR CHIHANI	Sonatrach	CNIM	Conventional	1979	129,767	Steam	7400675
BARCELONA KNUTSEN	Knutsen OAS	Daewoo	Conventional	2009	173,400	TFDE	9401295
BEBATIK	Shell	Chantiers de l'Atlantique	Conventional	1972	75,056	Steam	7121633
BEIDOU STAR	MOL, China LNG	Hudong-Zhonghua	Conventional	2015	172,000	MEGI	9613159
BELANAK	Shell	Ch.De La Ciotat	Conventional	1975	75,000	Steam	7347768
BERGE ARZEW	BW	Daewoo	Conventional	2004	138,089	Steam	9256597
BILBAO KNUTSEN	Knutsen OAS	IZAR	Conventional	2004	135,049	Steam	9236432
BRITISH DIAMOND	BP	Hyundai	Conventional	2008	151,883	DFDE	9333620
BRITISH EMERALD	BP	Hyundai	Conventional	2007	154,983	DFDE	9333591
BRITISH INNOVATOR	BP	Samsung	Conventional	2003	136,135	Steam	9238040
BRITISH MERCHANT	BP	Samsung	Conventional	2003	138,517	Steam	9250191
BRITISH RUBY	BP	Hyundai	Conventional	2008	155,000	DFDE	9333606
BRITISH SAPPHIRE	BP	Hyundai	Conventional	2008	155,000	DFDE	9333618
BRITISH TRADER	BP	Samsung	Conventional	2002	138,248	Steam	9238038
BROOG	J4 Consortium	Mitsui	Conventional	1998	136,359	Steam	9085651
BU SAMRA	Nakilat	Samsung	Q-Max	2008	260,928	SSD	9388833
BW GDF SUEZ BOSTON	BW, ENGIE	Daewoo	Conventional	2003	138,059	Steam	9230062
BW GDF SUEZ BRUSSELS	BW	Daewoo	Conventional	2009	162,514	TFDE	9368314
BW GDF SUEZ EVERETT	BW	Daewoo	Conventional	2003	138,028	Steam	9243148
BW GDF SUEZ PARIS	BW	Daewoo	Conventional	2009	162,524	TFDE	9368302
BW PAVILION LEEARA	BW	Hyundai	Conventional	2015	161,880	TFDE	9640645
BW PAVILION VANDA	BW Pavilion LNG	Hyundai	Conventional	2015	161,880	TFDE	9640437
BW SINGAPORE	BW	Samsung	FSRU	2015	170,000	TFDE	9684495
CADIZ KNUTSEN	Knutsen OAS	IZAR	Conventional	2004	135,240	Steam	9246578
CASTILLO DE SANTISTEBAN	Anthony Veder	STX	Conventional	2010	173,673	TFDE	9433717
CASTILLO DE VILLALBA	Anthony Veder	IZAR	Conventional	2003	135,420	Steam	9236418
CATALUNYA SPIRIT	Teekay	IZAR	Conventional	2003	135,423	Steam	9236420
CELESTINE RIVER	K Line	Kawaski	Conventional	2007	145,394	Steam	9330745
CHEIKH BOUAMAMA	HYPROC, Sonatrach, Itochu, MOL	Universal	Conventional	2008	74,245	Steam	9324344

CHEIKH EL MOKRANI	HYPROC, Sonatrach, Itochu, MOL	Universal	Conventional	2007	73,990	Steam	9324332
CLEAN ENERGY	Dynagas	Hyundai	Conventional	2007	146,794	Steam	9323687
CLEAN HORIZON	Avoca Maritime Corp Ltd	Hyundai	Conventional	2015	162,000	TFDE	9655444
CLEAN OCEAN	Dynagas	Hyundai	Conventional	2014	162,000	TFDE	9637492
CLEAN PLANET	Dynagas	Hyundai	Conventional	2014	162,000	TFDE	9637507
COOL EXPLORER	Thenamaris	Samsung	Conventional	2015	160,000	TFDE	9640023
COOL RUNNER	Thenamaris	Samsung	Conventional	2014	160,000	TFDE	9636797
COOL VOYAGER	Thenamaris	Samsung	Conventional	2013	160,000	TFDE	9636785
CORCOVADO LNG	Cardiff Marine	Daewoo	Conventional	2014	159,800	TFDE	9636711
CUBAL	Mitsui, NYK, Teekay	Samsung	Conventional	2012	154,948	TFDE	9491812
CYGNUS PASSAGE	TEPCO, NYK, Mitsubishi	Mitsubishi	Conventional	2009	145,400	Steam	9376294
DAPENG MOON	China LNG Ship Mgmt.	Hudong-Zhonghua	Conventional	2008	147,200	Steam	9308481
DAPENG STAR	China LNG Ship Mgmt.	Hudong-Zhonghua	Conventional	2009	147,200	Steam	9369473
DAPENG SUN	China LNG Ship Mgmt.	Hudong-Zhonghua	Conventional	2008	147,200	Steam	9308479
DISHA	MOL, NYK, K Line, SCI, Nakilat	Daewoo	Conventional	2004	136,026	Steam	9250713
DOHA	J4 Consortium	Mitsubishi	Conventional	1999	135,203	Steam	9085637
DUHAIL	Commerz Real, Nakilat, PRONAV	Daewoo	Q-Flex	2008	210,100	SSD	9337975
DUKHAN	J4 Consortium	Mitsui	Conventional	2004	137,672	Steam	9265500
DWIPUTRA	P.T. Humpuss Trans	Mitsubishi	Conventional	1994	127,386	Steam	9043677
EAST ENERGY	Sinokor Merchant Marine	Chantiers de l'Atlantique	Conventional	1977	122,255	Steam	7360136
ECHIGO MARU	NYK	Mitsubishi	Conventional	1983	125,568	Steam	8110203
EJNAN	K Line, MOL, NYK, Mitsui, Nakilat	Samsung	Conventional	2007	143,815	Steam	9334076
EKAPUTRA 1	P.T. Humpuss Trans	Mitsubishi	Conventional	1990	136,400	Steam	8706155
ENERGY ADVANCE	Tokyo Gas	Kawaski	Conventional	2005	144,590	Steam	9269180
ENERGY ATLANTIC	Alpha Tankers	STX	Conventional	2015	157,521	TFDE	9649328
ENERGY CONFIDENCE	Tokyo Gas, NYK	Kawaski	Conventional	2009	152,880	Steam	9405588
ENERGY FRONTIER	Tokyo Gas	Kawaski	Conventional	2003	144,596	Steam	9245720
ENERGY HORIZON	NYK, TLTC	Kawaski	Conventional	2011	177,441	Steam	9483877
ENERGY NAVIGATOR	Tokyo Gas, MOL	Kawaski	Conventional	2008	147,558	Steam	9355264
ENERGY PROGRESS	MOL	Kawaski	Conventional	2006	144,596	Steam	9274226
ESSHU MARU	Mitsubishi, MOL, Chubu Electric	Mitsubishi	Conventional	2014	155,300	Steam	9666560
EXCALIBUR	Excelerate, Teekay	Daewoo	Conventional	2002	138,000	Steam	9230050
EXCEL	Exmar, MOL	Daewoo	Conventional	2003	135,344	Steam	9246621
EXCELERATE	Exmar, Excelerate	Daewoo	FSRU	2006	135,313	Steam	9322255
EXCELLENCE	Excelerate Energy	Daewoo	FSRU	2005	138,124	Steam	9252539
EXCELSIOR	Exmar	Daewoo	FSRU	2005	138,000	Steam	9239616

EXEMPLAR	Excelerate Energy	Daewoo	FSRU	2010	151,072	Steam	9444649
EXPEDIENT	Excelerate Energy	Daewoo	FSRU	2010	147,994	Steam	9389643
EXPERIENCE	Excelerate Energy	Daewoo	FSRU	2014	173,660	TFDE	9638525
EXPLORER	Exmar, Excelerate	Daewoo	FSRU	2008	150,900	Steam	9361079
EXPRESS	Exmar, Excelerate	Daewoo	FSRU	2009	150,900	Steam	9361445
EXQUISITE	Excelerate Energy	Daewoo	FSRU	2009	151,035	Steam	9381134
FORTUNE FSU	Compass Energy	Dunkerque Normandie	Conventional	1981	130,000	Steam	7428471
FRAIHA	NYK, K Line, MOL, Iino, Mitsui, Nakilat	Daewoo	Q-Flex	2008	205,950	SSD	9360817
FSRU TOSCANA	OLT Offshore LNG Toscana	Hyundai	Converted FSRU	2004	137,500	Steam	9253284
FUJI LNG	Cardiff Marine	Kawaski	Conventional	2004	144,596	Steam	9275359
FUWAIRIT	K Line, MOL, NYK, Nakilat	Samsung	Conventional	2004	138,262	Steam	9256200
GALEA	Shell	Mitsubishi	Conventional	2002	135,269	Steam	9236614
GALICIA SPIRIT	Teekay	Daewoo	Conventional	2004	137,814	Steam	9247364
GALLINA	Shell	Mitsubishi	Conventional	2002	135,269	Steam	9236626
GANDRIA	Golar LNG	HDW	Conventional	1977	123,512	Steam	7361934
GASELYS	GDF SUEZ, NYK	Chantiers de l’Atlantique	Conventional	2007	151,383	DFDE	9320075
GASLOG CHELSEA	GasLog	Hanjin H.I.	Conventional	2010	153,000	DFDE	9390185
GASLOG SALEM	GasLog	Samsung	Conventional	2015	155,000	TFDE	9638915
GASLOG SANTIAGO	GasLog	Samsung	Conventional	2013	154,948	TFDE	9600530
GASLOG SARATOGA	GasLog	Samsung	Conventional	2014	155,000	TFDE	9638903
GASLOG SAVANNAH	GasLog	Samsung	Conventional	2010	154,948	TFDE	9352860
GASLOG SEATTLE	GasLog	Samsung	Conventional	2013	154,948	TFDE	9634086
GASLOG SHANGHAI	GasLog	Samsung	Conventional	2013	154,948	TFDE	9600528
GASLOG SINGAPORE	GasLog	Samsung	Conventional	2010	154,948	TFDE	9355604
GASLOG SKAGEN	GasLog	Samsung	Conventional	2013	154,948	TFDE	9626285
GASLOG SYDNEY	GasLog	Samsung	Conventional	2013	154,948	TFDE	9626273
GDF SUEZ CAPE ANN	Hoegh, MOL, TLTC	Samsung	FSRU	2010	145,130	DFDE	9390680
GDF SUEZ GLOBAL ENERGY	GDF SUEZ	Chantiers de l’Atlantique	Conventional	2004	74,130	Steam	9269207
GDF SUEZ NEPTUNE	Hoegh, MOL, TLTC	Samsung	FSRU	2009	145,130	Steam	9385673
GDF SUEZ POINT FORTIN	MOL, Sumitomo, LNG JAPAN	Imabari	Conventional	2010	154,982	Steam	9375721
GEMMATA	Shell	Mitsubishi	Conventional	2004	135,269	Steam	9253222
GHASHA	National Gas Shipping Co	Mitsui	Conventional	1995	137,100	Steam	9038452
GIGIRA LAITEBO	MOL, Itochu	Hyundai	Conventional	2010	173,870	TFDE	9360922
GIMI	Golar LNG	Rosenberg Verft	Conventional	1976	122,388	Steam	7382732
GOLAR ARCTIC	Golar LNG	Daewoo	Conventional	2003	137,814	Steam	9253105
GOLAR BEAR	Golar LNG	Samsung	Conventional	2014	160,000	TFDE	9626039
GOLAR CELSIUS	Golar LNG	Samsung	Conventional	2013	160,000	TFDE	9626027
GOLAR CRYSTAL	Golar LNG	Samsung	Conventional	2014	160,000	TFDE	9624926

GOLAR ESKIMO	Golar LNG	Samsung	FSRU	2014	160,000	TFDE	9624940
GOLAR FREEZE	Golar LNG Partners	HDW	Converted FSRU	1977	126,000	Steam	7361922
GOLAR FROST	Golar LNG	Samsung	Conventional	2014	160,000	TFDE	9655042
GOLAR GLACIER	ICBC	Hyundai	Conventional	2014	162,500	TFDE	9654696
GOLAR GRAND	Golar LNG Partners	Daewoo	Conventional	2005	145,700	Steam	9303560
GOLAR ICE	ICBC	Samsung	Conventional	2015	160,000	TFDE	9637325
GOLAR IGLOO	Golar LNG Partners	Samsung	FSRU	2014	170,000	TFDE	9633991
GOLAR KELVIN	ICBC	Hyundai	Conventional	2015	162,000	TFDE	9654701
GOLAR MARIA	Golar LNG Partners	Daewoo	Conventional	2006	145,700	Steam	9320374
GOLAR MAZO	Golar LNG Partners	Mitsubishi	Conventional	2000	135,000	Steam	9165011
GOLAR PENGUIN	Golar LNG	Samsung	Conventional	2014	160,000	TFDE	9624938
GOLAR SEAL	Golar LNG	Samsung	Conventional	2013	160,000	TFDE	9624914
GOLAR SNOW	ICBC	Samsung	Conventional	2015	160,000	TFDE	9635315
GOLAR SPIRIT	Golar LNG Partners	Kawasaki Sakaide	Converted FSRU	1981	129,000	Steam	7373327
GOLAR TUNDRA	Golar LNG	Samsung	FSRU	2015	170,000	TFDE	9655808
GOLAR VIKING	PT Equinox	Hyundai	Conventional	2005	140,000	Steam	9256767
GOLAR WINTER	Golar LNG Partners	Daewoo	Converted FSRU	2004	138,000	Steam	9256614
GRACE ACACIA	NYK	Hyundai	Conventional	2007	146,791	Steam	9315707
GRACE BARLERIA	NYK	Hyundai	Conventional	2007	146,770	Steam	9315719
GRACE COSMOS	MOL, NYK	Hyundai	Conventional	2008	146,794	Steam	9323675
GRACE DAHLIA	NYK	Kawaski	Conventional	2013	177,425	Steam	9540716
GRAND ANIVA	NYK, Sovcomflot	Mitsubishi	Conventional	2008	145,000	Steam	9338955
GRAND ELENA	NYK, Sovcomflot	Mitsubishi	Conventional	2007	147,968	Steam	9332054
GRAND MEREYA	MOL, K Line, Primorsk	Mitsui	Conventional	2008	145,964	Steam	9338929
HANJIN MUSCAT	Hanjin Shipping Co.	Hanjin H.I.	Conventional	1999	138,366	Steam	9155078
HANJIN PYEONG TAEK	Hanjin Shipping Co.	Hanjin H.I.	Conventional	1995	130,366	Steam	9061928
HANJIN RAS LAFFAN	Hanjin Shipping Co.	Hanjin H.I.	Conventional	2000	138,214	Steam	9176008
HANJIN SUR	Hanjin Shipping Co.	Hanjin H.I.	Conventional	2000	138,333	Steam	9176010
HISPANIA SPIRIT	Teekay	Daewoo	Conventional	2002	137,814	Steam	9230048
HOEGH GALLANT	Hoegh	Hyundai	FSRU	2014	170,000	TFDE	9653678
HYUNDAI AQUAPIA	Hyundai LNG Shipping	Hyundai	Conventional	2000	134,400	Steam	9179581
HYUNDAI COSMOPIA	Hyundai LNG Shipping	Hyundai	Conventional	2000	134,308	Steam	9155157
HYUNDAI ECOPIA	Hyundai LNG Shipping	Hyundai	Conventional	2008	146,790	Steam	9372999
HYUNDAI GREENPIA	Hyundai LNG Shipping	Hyundai	Conventional	1996	125,000	Steam	9075333
HYUNDAI OCEANPIA	Hyundai LNG Shipping	Hyundai	Conventional	2000	134,300	Steam	9183269
HYUNDAI TECHNOPIA	Hyundai LNG Shipping	Hyundai	Conventional	1999	134,524	Steam	9155145

HYUNDAI UTOPIA	Hyundai LNG Shipping	Hyundai	Conventional	1994	125,182	Steam	9018555
IBERICA KNUTSEN	Knutsen OAS	Daewoo	Conventional	2006	135,230	Steam	9326603
IBRA LNG	OSC, MOL	Samsung	Conventional	2006	145,951	Steam	9326689
IBRI LNG	OSC, MOL, Mitsubishi	Mitsubishi	Conventional	2006	145,173	Steam	9317315
INDEPENDENCE	Hoegh	Hyundai	FSRU	2014	170,132	TFDE	9629536
ISH	National Gas Shipping Co	Mitsubishi	Conventional	1995	137,512	Steam	9035864
K. ACACIA	Korea Line	Daewoo	Conventional	2000	138,017	Steam	9157636
K. FREESIA	Korea Line	Daewoo	Conventional	2000	138,015	Steam	9186584
K. JASMINE	Korea Line	Daewoo	Conventional	2008	142,961	Steam	9373008
K. MUGUNGWHA	Korea Line	Daewoo	Conventional	2008	148,776	Steam	9373010
KITA LNG	Cardiff Marine	Daewoo	Conventional	2014	159,800	TFDE	9636723
LALLA FATMA N'SOUMER	HYPROC	Kawaski	Conventional	2004	144,888	Steam	9275347
LARBI BEN M'HIDI	HYPROC	CNIM	Conventional	1977	129,500	Steam	7400663
LENA RIVER	Dynagas	Hyundai	Conventional	2013	154,880	TFDE	9629598
LIJMILIYA	Nakilat	Daewoo	Q-Max	2009	258,019	SSD	9388819
LNG ADAMAWA	BGT Ltd.	Hyundai	Conventional	2005	142,656	Steam	9262211
LNG AKWA IBOM	BGT Ltd.	Hyundai	Conventional	2004	142,656	Steam	9262209
LNG AQUARIUS	Hanochem	General Dynamics	Conventional	1977	126,750	Steam	7390181
LNG BARKA	OSC, OG, NYK, K Line	Kawaski	Conventional	2008	152,880	Steam	9341299
LNG BAYELSA	BGT Ltd.	Hyundai	Conventional	2003	137,500	Steam	9241267
LNG BENUE	BW	Daewoo	Conventional	2006	142,988	Steam	9267015
LNG BONNY II	Nigeria LNG Ltd	Hyundai	Conventional	2015	177,000	DFDE	9692002
LNG BORNO	NYK	Samsung	Conventional	2007	149,600	Steam	9322803
LNG CROSS RIVER	BGT Ltd.	Hyundai	Conventional	2005	142,656	Steam	9262223
LNG DREAM	NYK	Kawaski	Conventional	2006	147,326	Steam	9277620
LNG EBISU	MOL, KEPCO	Kawaski	Conventional	2008	147,546	Steam	9329291
LNG ENUGU	BW	Daewoo	Conventional	2005	142,988	Steam	9266994
LNG FINIMA II	Nigeria LNG Ltd	Samsung	Conventional	2015	170,000	DFDE	9690145
LNG FLORA	NYK, Osaka Gas	Kawaski	Conventional	1993	125,637	Steam	9006681
LNG IMO	BW	Daewoo	Conventional	2008	148,452	Steam	9311581
LNG JAMAL	NYK, Osaka Gas	Mitsubishi	Conventional	2000	136,977	Steam	9200316
LNG JUPITER	Osaka Gas, NYK	Kawaski	Conventional	2009	152,880	Steam	9341689
LNG JUROJIN	MOL, KEPCO	Mitsubishi	Conventional	2015	155,300	Steam Reheat	9666998
LNG KANO	BW	Daewoo	Conventional	2007	148,565	Steam	9311567
LNG KOLT	STX Pan Ocean	Hanjin H.I.	Conventional	2008	153,595	Steam	9372963
LNG LERICI	ENI	Sestri	Conventional	1998	63,993	Steam	9064085
LNG LIBRA	Hoegh	General Dynamics	Conventional	1979	126,000	Steam	7413232
LNG LOKOJA	BW	Daewoo	Conventional	2006	148,471	Steam	9269960
LNG MALEO	MOL, NYK, K Line	Mitsui	Conventional	1989	127,544	Steam	8701791
LNG OGUN	NYK	Samsung	Conventional	2007	149,600	Steam	9322815
LNG ONDO	BW	Daewoo	Conventional	2007	148,478	Steam	9311579
LNG OYO	BW	Daewoo	Conventional	2005	142,988	Steam	9267003
LNG PIONEER	MOL	Daewoo	Conventional	2005	138,000	Steam	9256602

LNG PORT-HARCOURT II	Nigeria LNG Ltd	Samsung	Conventional	2015	170,000	MEGI	9690157
LNG PORTOVENERE	ENI	Sestri	Conventional	1996	65,262	Steam	9064073
LNG RIVER NIGER	BGT Ltd.	Hyundai	Conventional	2006	142,656	Steam	9262235
LNG RIVER ORASHI	BW	Daewoo	Conventional	2004	142,988	Steam	9266982
LNG RIVERS	BGT Ltd.	Hyundai	Conventional	2002	137,500	Steam	9216298
LNG SOKOTO	BGT Ltd.	Hyundai	Conventional	2002	137,500	Steam	9216303
LNG VENUS	Osaka Gas, MOL	Mitsubishi	Conventional	2014	155,300	Steam	9645736
LOBITO	Mitsui, NYK, Teekay	Samsung	Conventional	2011	154,948	TFDE	9490961
LUCKY FSU	Compass Energy	Dunkerque Normandie	Conventional	1981	127,400	Steam	7428469
LUSAIL	K Line, MOL, NYK, Nakilat	Samsung	Conventional	2005	142,808	Steam	9285952
MADRID SPIRIT	Teekay	IZAR	Conventional	2004	135,423	Steam	9259276
MAGELLAN SPIRIT	Teekay, Marubeni	Samsung	Conventional	2009	163,194	DFDE	9342487
MALANJE	Mitsui, NYK, Teekay	Samsung	Conventional	2011	154,948	TFDE	9490959
MARAN GAS ACHILLES	Maran Gas Maritime	Hyundai	Conventional	2015	174,000	MEGI	9682588
MARAN GAS ALEXANDRIA	Maran Gas Maritime	Hyundai	Conventional	2015	164,000	TFDE	9650054
MARAN GAS APOLLONIA	Maran Gas Maritime	Hyundai	Conventional	2014	164,000	TFDE	9633422
MARAN GAS ASCLEPIUS	Maran G.M, Nakilat	Daewoo	Conventional	2005	142,906	Steam	9302499
MARAN GAS CORONIS	Maran G.M, Nakilat	Daewoo	Conventional	2007	142,889	Steam	9331048
MARAN GAS DELPHI	Maran Gas Maritime	Daewoo	Conventional	2014	159,800	TFDE	9633173
MARAN GAS EFESSOS	Maran Gas Maritime	Daewoo	Conventional	2014	159,800	TFDE	9627497
MARAN GAS LINDOS	Maran Gas Maritime	Daewoo	Conventional	2015	159,800	TFDE	9627502
MARAN GAS MYSTRAS	Maran Gas Maritime	Daewoo	Conventional	2015	159,800	TFDE	9658238
MARAN GAS POSIDONIA	Maran Gas Maritime	Hyundai	Conventional	2014	164,000	TFDE	9633434
MARAN GAS SPARTA	Maran Gas Maritime	Hyundai	Conventional	2015	162,000	TFDE	9650042
MARAN GAS TROY	Maran Gas Maritime	Daewoo	Conventional	2015	159,800	TFDE	9658240
MARIB SPIRIT	Teekay	Samsung	Conventional	2008	163,280	DFDE	9336749
MATTHEW	GDF SUEZ	Newport News	Conventional	1979	126,540	Steam	7391214
MEKAINES	Nakilat	Samsung	Q-Max	2009	261,137	SSD	9397303
MERIDIAN SPIRIT	Teekay, Marubeni	Samsung	Conventional	2010	163,285	TFDE	9369904
MESAIMEER	Nakilat	Hyundai	Q-Flex	2009	211,986	SSD	9337729
METHANE ALISON VICTORIA	BG Group	Samsung	Conventional	2007	145,000	Steam	9321768
METHANE BECKI ANNE	GasLog	Samsung	Conventional	2010	167,416	TFDE	9516129
METHANE HEATHER SALLY	BG Group	Samsung	Conventional	2007	142,702	Steam	9321744

METHANE JANE ELIZABETH	GasLog	Samsung	Conventional	2006	145,000	Steam	9307190
METHANE JULIA LOUISE	GasLog	Samsung	Conventional	2010	167,416	TFDE	9412880
METHANE LYDON VOLNEY	BG Group	Samsung	Conventional	2006	145,000	Steam	9307205
METHANE MICKIE HARPER	BG Group	Samsung	Conventional	2010	167,400	TFDE	9520376
METHANE NILE EAGLE	BG, GasLog	Samsung	Conventional	2007	145,000	Steam	9321770
METHANE PATRICIA CAMILA	BG Group	Samsung	Conventional	2010	167,416	TFDE	9425277
METHANE PRINCESS	Golar LNG Partners	Daewoo	Conventional	2003	136,086	Steam	9253715
METHANE RITA ANDREA	GasLog	Samsung	Conventional	2006	145,000	Steam	9307188
METHANE SHIRLEY ELISABETH	BG Group	Samsung	Conventional	2007	142,800	Steam	9321756
METHANE SPIRIT	Teekay, Marubeni	Samsung	Conventional	2008	163,195	TFDE	9336737
METHANIA	Distrigas	Boelwerf	Conventional	1978	131,235	Steam	7357452
MILAHA QATAR	Nakilat, Qatar Shpg., SocGen	Samsung	Conventional	2006	145,140	Steam	9321732
MILAHA RAS LAFFAN	Nakilat, Qatar Shpg., SocGen	Samsung	Conventional	2004	136,199	Steam	9255854
MIN LU	China LNG Ship Mgmt.	Hudong-Zhonghua	Conventional	2009	145,000	Steam	9305128
MIN RONG	China LNG Ship Mgmt.	Hudong-Zhonghua	Conventional	2009	145,000	Steam	9305116
MOSTEFA BEN BOULAID	Sonatrach	Ch.De La Ciotat	Conventional	1976	125,260	Steam	7359955
MOURAD DIDOUCHE	Sonatrach	Chantiers de l'Atlantique	Conventional	1980	126,190	Steam	7400704
MOZAH	Nakilat	Samsung	Q-Max	2008	261,988	SSD	9337755
MRAWEH	National Gas Shipping Co	Kvaerner Masa	Conventional	1996	135,000	Steam	9074638
MUBARAZ	National Gas Shipping Co	Kvaerner Masa	Conventional	1996	135,000	Steam	9074626
MURWAB	NYK, K Line, MOL, Iino, Mitsui, Nakilat	Daewoo	Q-Flex	2008	205,971	SSD	9360805
NEO ENERGY	Tsakos	Hyundai	Conventional	2007	146,838	Steam	9324277
NIZWA LNG	OSC, MOL	Kawaski	Conventional	2005	145,469	Steam	9294264
NKOSSA II	AP Moller	Mitsubishi	Conventional	1992	78,488	Steam	9003859
NORTHWEST SANDERLING	North West Shelf Venture	Mitsubishi	Conventional	1989	125,452	Steam	8608872
NORTHWEST SANDPIPER	North West Shelf Venture	Mitsui	Conventional	1993	125,042	Steam	8913150
NORTHWEST SEAEAGLE	North West Shelf Venture	Mitsubishi	Conventional	1992	125,541	Steam	8913174
NORTHWEST SHEARWATER	North West Shelf Venture	Kawaski	Conventional	1991	125,660	Steam	8608705
NORTHWEST SNIPE	North West Shelf Venture	Mitsui	Conventional	1990	127,747	Steam	8608884
NORTHWEST STORMPETREL	North West Shelf Venture	Mitsubishi	Conventional	1994	125,525	Steam	9045132

NORTHWEST SWAN	North West Shelf Venture	Daewoo	Conventional	2004	140,500	Steam	9250725
NUSANTARA REGAS SATU	Golar LNG Partners	Rosenberg Verft	Converted FSRU	1977	125,003	Steam	7382744
OB RIVER	Dynagas	Hyundai	Conventional	2007	146,791	Steam	9315692
ONAIZA	Nakilat	Daewoo	Q-Flex	2009	205,963	SSD	9397353
PACIFIC ARCADIA	NYK	Mitsubishi	Conventional	2014	145,400	Steam	9621077
PACIFIC ENLIGHTEN	Kyushu Electric, TEPCO, Mitsubishi, Mitsui, NYK, MOL	Mitsubishi	Conventional	2009	147,800	Steam	9351971
PACIFIC EURUS	TEPCO, NYK, Mitsubishi	Mitsubishi	Conventional	2006	135,000	Steam	9264910
PACIFIC NOTUS	TEPCO, NYK, Mitsubishi	Mitsubishi	Conventional	2003	137,006	Steam	9247962
PALU LNG	Cardiff Marine	Daewoo	Conventional	2014	159,800	TFDE	9636735
PAPUA	MOL, China LNG	Hudong-Zhonghua	Conventional	2015	172,000	TFDE	9613135
PGN FSRU LAMPUNG	Hoegh	Hyundai	FSRU	2014	170,000	TFDE	9629524
POLAR SPIRIT	Teekay	I.H.I.	Conventional	1993	88,100	Steam	9001772
PROVALYS	GDF SUEZ	Chantiers de l'Atlantique	Conventional	2006	151,383	DFDE	9306495
PSKOV	Sovcomflot	STX	Conventional	2014	170,200	TFDE	9630028
PUTERI DELIMA	MISC	Chantiers de l'Atlantique	Conventional	1995	127,797	Steam	9030814
PUTERI DELIMA SATU	MISC	Mitsui	Conventional	2002	134,849	Steam	9211872
PUTERI FIRUS	MISC	Chantiers de l'Atlantique	Conventional	1997	127,689	Steam	9030840
PUTERI FIRUS SATU	MISC	Mitsubishi	Conventional	2004	134,865	Steam	9248502
PUTERI INTAN	MISC	Chantiers de l'Atlantique	Conventional	1994	127,694	Steam	9030802
PUTERI INTAN SATU	MISC	Mitsubishi	Conventional	2002	134,770	Steam	9213416
PUTERI MUTIARA SATU	MISC	Mitsui	Conventional	2005	134,861	Steam	9261205
PUTERI NILAM	MISC	Chantiers de l'Atlantique	Conventional	1995	127,756	Steam	9030826
PUTERI NILAM SATU	MISC	Mitsubishi	Conventional	2003	134,833	Steam	9229647
PUTERI ZAMRUD	MISC	Chantiers de l'Atlantique	Conventional	1996	127,751	Steam	9030838
PUTERI ZAMRUD SATU	MISC	Mitsui	Conventional	2004	134,870	Steam	9245031
RAAHI	MOL, NYK, K Line, SCI, Nakilat	Daewoo	Conventional	2004	138,077	Steam	9253703
RAMDANE ABANE	Sonatrach	Chantiers de l'Atlantique	Conventional	1981	126,190	Steam	7411961
RASHEEDA	Nakilat	Samsung	Q-Max	2010	260,912	MEGI	9443413
RIBERA DEL DUERO KNUTSEN	Knutsen OAS	Daewoo	Conventional	2010	173,400	TFDE	9477593
SALALAH LNG	OSC, MOL	Samsung	Conventional	2005	148,174	Steam	9300817
SCF MELAMPUS	Sovcomflot	STX	Conventional	2015	170,200	TFDE	9654878

SCF MITRE	Sovcomflot	STX	Conventional	2015	170,200	TFDE	9654880
SEISHU MARU	Mitsubishi, NYK, Chubu Electric	Mitsubishi	Conventional	2014	155,300	Steam	9666558
SENSHU MARU	MOL, NYK, K Line	Mitsui	Conventional	1984	125,835	Steam	8014473
SERI ALAM	MISC	Samsung	Conventional	2005	145,572	Steam	9293832
SERI AMANAH	MISC	Samsung	Conventional	2006	142,795	Steam	9293844
SERI ANGGUN	MISC	Samsung	Conventional	2006	145,100	Steam	9321653
SERI ANGKASA	MISC	Samsung	Conventional	2006	142,786	Steam	9321665
SERI AYU	MISC	Samsung	Conventional	2007	143,474	Steam	9329679
SERI BAKTI	MISC	Mitsubishi	Conventional	2007	149,886	Steam	9331634
SERI BALHAF	MISC	Mitsubishi	Conventional	2009	154,567	TFDE	9331660
SERI BALQIS	MISC	Mitsubishi	Conventional	2009	154,747	TFDE	9331672
SERI BEGAWAN	MISC	Mitsubishi	Conventional	2007	149,964	Steam	9331646
SERI BIJAKSANA	MISC	Mitsubishi	Conventional	2008	149,822	Steam	9331658
SESTAO KNUTSEN	Knutsen OAS	IZAR	Conventional	2007	135,357	Steam	9338797
SEVILLA KNUTSEN	Knutsen OAS	Daewoo	Conventional	2010	173,400	TFDE	9414632
SHAGRA	Nakilat	Samsung	Q-Max	2009	261,988	SSD	9418365
SHAHAMAH	National Gas Shipping Co	Kawaski	Conventional	1994	137,756	Steam	9035852
SHEN HAI	China LNG, CNOOC, Shanghai LNG	Hudong-Zhonghua	Conventional	2012	142,741	Steam	9583677
SIMAISMA	Maran G.M, Nakilat	Daewoo	Conventional	2006	142,971	Steam	9320386
SK SPLENDOR	SK Shipping	Samsung	Conventional	2000	135,540	Steam	9180231
SK STELLAR	SK Shipping	Samsung	Conventional	2000	135,540	Steam	9180243
SK SUMMIT	SK Shipping	Daewoo	Conventional	1999	135,933	Steam	9157624
SK SUNRISE	Iino Kaiun Kaisha	Samsung	Conventional	2003	135,505	Steam	9247194
SK SUPREME	SK Shipping	Samsung	Conventional	2000	136,320	Steam	9157739
SOHAR LNG	OSC, MOL	Mitsubishi	Conventional	2001	135,850	Steam	9210816
SOLARIS	GasLog	Samsung	Conventional	2014	154,948	TFDE	9634098
SONANGOL BENGUELA	Mitsui, Sonangol, Sojitz	Daewoo	Conventional	2011	160,500	Steam	9482304
SONANGOL ETOSHA	Mitsui, Sonangol, Sojitz	Daewoo	Conventional	2011	160,500	Steam	9482299
SONANGOL SAMBIZANGA	Mitsui, Sonangol, Sojitz	Daewoo	Conventional	2011	160,500	Steam	9475600
SOUTHERN CROSS	MOL, China LNG	Hudong-Zhonghua	Conventional	2015	169,295	Steam Reheat	9613147
SOYO	Mitsui, NYK, Teekay	Samsung	Conventional	2011	154,948	TFDE	9475208
SPIRIT OF HELA	MOL, Itochu	Hyundai	Conventional	2009	173,800	TFDE	9361639
STENA BLUE SKY	Stena Bulk	Daewoo	Conventional	2006	142,988	Steam	9315393
STENA CLEAR SKY	Stena Bulk	Daewoo	Conventional	2011	173,593	TFDE	9413327
STENA CRYSTAL SKY	Stena Bulk	Daewoo	Conventional	2011	173,611	TFDE	9383900
SUNRISE	Shell	Dunkerque Ateliers	Conventional	1977	126,813	Steam	7359670
TAITAR NO. 1	CPC, Mitsui, NYK	Mitsubishi	Conventional	2009	144,627	Steam	9403669
TAITAR NO. 2	MOL, NYK	Kawaski	Conventional	2009	144,627	Steam	9403645
TAITAR NO. 3	MOL, NYK	Mitsubishi	Conventional	2010	144,627	Steam	9403671
TAITAR NO. 4	CPC, Mitsui, NYK	Kawaski	Conventional	2010	144,596	Steam	9403657

TANGGUH BATUR	Sovcomflot, NYK	Daewoo	Conventional	2008	142,988	Steam	9334284
TANGGUH FOJA	K Line, PT Meratus	Samsung	Conventional	2008	154,948	TFDE	9349007
TANGGUH HIRI	Teekay	Hyundai	Conventional	2008	151,885	TFDE	9333632
TANGGUH JAYA	K Line, PT Meratus	Samsung	Conventional	2008	154,948	TFDE	9349019
TANGGUH PALUNG	K Line, PT Meratus	Samsung	Conventional	2009	154,948	TFDE	9355379
TANGGUH SAGO	Teekay	Hyundai	Conventional	2009	151,872	TFDE	9361990
TANGGUH TOWUTI	NYK, PT Samudera, Sovcomflot	Daewoo	Conventional	2008	142,988	Steam	9325893
TEMBEK	Nakilat, OSC	Samsung	Q-Flex	2007	211,885	SSD	9337731
TENAGA LIMA	MISC	CNIM	Conventional	1981	127,409	Steam	7428445
TRINITY ARROW	K Line	Imabari	Conventional	2008	152,655	Steam	9319404
TRINITY GLORY	K Line	Imabari	Conventional	2009	152,675	Steam	9350927
UMM AL AMAD	NYK, K Line, MOL, Iino, Mitsui, Nakilat	Daewoo	Q-Flex	2008	206,958	SSD	9360829
UMM AL ASHTAN	National Gas Shipping Co	Kvaerner Masa	Conventional	1997	137,000	Steam	9074652
UMM BAB	Maran G.M, Nakilat	Daewoo	Conventional	2005	143,708	Steam	9308431
UMM SLAL	Nakilat	Samsung	Q-Max	2008	260,928	SSD	9372731
VALENCIA KNUTSEN	Knutsen OAS	Daewoo	Conventional	2010	173,400	TFDE	9434266
VELIKIY NOVGOROD	Sovcomflot	STX	Conventional	2014	170,471	TFDE	9630004
WEST ENERGY	Sinokor Merchant Marine	Chantiers de l'Atlantique	Conventional	1976	122,255	Steam	7360124
WILENERGY	Awilco	Mitsubishi	Conventional	1983	125,788	Steam	8014409
WILFORCE	Teekay	Daewoo	Conventional	2013	155,900	TFDE	9627954
WILGAS	Awilco	Mitsubishi	Conventional	1984	126,975	Steam	8125832
WILPRIDE	Teekay	Daewoo	Conventional	2013	156,007	TFDE	9627966
WOODSIDE DONALDSON	Teekay, Marubeni	Samsung	Conventional	2009	162,620	TFDE	9369899
WOODSIDE GOODE	Maran Gas Maritime	Daewoo	Conventional	2013	159,800	TFDE	9633161
WOODSIDE ROGERS	Maran Gas Maritime	Daewoo	Conventional	2013	159,800	TFDE	9627485
YARI LNG	Cardiff Marine	Daewoo	Conventional	2014	159,800	TFDE	9636747
YENISEI RIVER	Dynagas	Hyundai	Conventional	2013	154,880	TFDE	9629586
YK SOVEREIGN	SK Shipping	Hyundai	Conventional	1994	124,582	Steam	9038816

Note: All FSRUs that were in use at the end of 2015 are not included in this fleet. Additionally, Laid-up vessels are not included.
Sources: IHS, Company Announcements

Appendix 6: Table of LNG Vessel Orderbook

Ship Name	Shipowner	Shipbuilder	Type	Delivery Year	Capacity (cm)	Propulsion Type	IMO #
ASIA INTEGRITY	Chevron	Samsung	Conventional	2016	154,948	TFDE	9680188
ASIA VENTURE	Chevron	Samsung	Conventional	2016	154,948	TFDE	9680190
BISHU MARU	Trans Pacific Shipping	Kawasaki Sakaide	Conventional	2016	164,700	Steam Reheat	9691137
CASTILLO DE CALDELAS	Elcano	Imabari	Conventional	2017	178,000	MEGI	9742819
CASTILLO DE MERIDA	Elcano	Imabari	Conventional	2017	178,000	MEGI	9742807
CESI GLADSTONE	China Shipping Group	Hudong-Zhonghua	Conventional	2016	174,000	TFDE	9672820
CLEAN VISION	Dynagas	Hyundai	Conventional	2016	162,000	TFDE	9655456
CREOLE SPIRIT	Teekay	Daewoo	Conventional	2016	173,400	MEGI	9681687
DAEWOO 2411	Teekay	Daewoo	Conventional	2016	173,400	MEGI	9721401
DAEWOO 2415	Maran Gas Maritime	Daewoo	Conventional	2016	173,400	TFDE	9732371
DAEWOO 2416	Teekay	Daewoo	Conventional	2017	173,400	MEGI	9705641
DAEWOO 2417	Teekay	Daewoo	Conventional	2017	173,400	MEGI	9705653
DAEWOO 2421	Dynagas	Daewoo	Conventional	2017	172,000	TFDE	9768368
DAEWOO 2422	Dynagas	Daewoo	Conventional	2017	172,000	TFDE	9768370
DAEWOO 2423	Teekay	Daewoo	Conventional	2017	172,000	TFDE	9750696
DAEWOO 2424	Teekay	Daewoo	Conventional	2018	172,000	TFDE	9750701
DAEWOO 2425	Teekay	Daewoo	Conventional	2018	172,000	TFDE	9750713
DAEWOO 2426	MOL	Daewoo	Conventional	2018	172,000	TFDE	9750658
DAEWOO 2427	Dynagas	Daewoo	Conventional	2018	172,000	TFDE	9768382
DAEWOO 2428	Dynagas	Daewoo	Conventional	2018	172,000	TFDE	9768394
DAEWOO 2429	Dynagas	Daewoo	Conventional	2018	172,000	TFDE	9768526
DAEWOO 2430	Teekay	Daewoo	Conventional	2019	172,000	TFDE	9750725
DAEWOO 2431	Teekay	Daewoo	Conventional	2019	172,000	TFDE	9750737
DAEWOO 2432	MOL	Daewoo	Conventional	2018	172,000	TFDE	9750660
DAEWOO 2433	Teekay	Daewoo	Conventional	2020	172,000	TFDE	9750749
DAEWOO 2434	MOL	Daewoo	Conventional	2019	172,000	TFDE	9750672
DAEWOO 2435	BW	Daewoo	Conventional	2017	174,300	MEGI	9758064
DAEWOO 2436	BW	Daewoo	Conventional	2018	174,300	MEGI	9758076
DAEWOO 2441	BP	Daewoo	Conventional	2018	174,000	MEGI	9766530
DAEWOO 2442	BP	Daewoo	Conventional	2018	174,000	MEGI	9766542
DAEWOO 2443	BP	Daewoo	Conventional	2018	174,000	MEGI	9766554
DAEWOO 2444	BP	Daewoo	Conventional	2018	174,000	MEGI	9766566
DAEWOO 2445	BP	Daewoo	Conventional	2019	174,000	MEGI	9766578
DAEWOO 2446	BP	Daewoo	Conventional	2019	174,000	MEGI	9766580
DAEWOO 2447	Frontline Management	Daewoo	Conventional	2017	173,400	MEGI	9762261
DAEWOO 2448	Frontline Management	Daewoo	Conventional	2017	174,000	MEGI	9762273
DAEWOO 2449	Korea Line	Daewoo	Conventional	2017	174,000	MEGI	9761827
DAEWOO 2450	Korea Line	Daewoo	Conventional	2017	174,000	MEGI	9761839
DAEWOO 2451	Hyundai LNG Shipping	Daewoo	Conventional	2017	174,000	MEGI	9761841

DAEWOO 2452	Hyundai LNG Shipping	Daewoo	Conventional	2016	174,000	MEGI	9761853
DAEWOO 2453	Teekay	Daewoo	Conventional	2017	173,400	MEGI	9770921
DAEWOO 2454	Teekay	Daewoo	Conventional	2018	173,400	MEGI	9770933
DAEWOO 2455	Teekay	Daewoo	Conventional	2018	173,400	MEGI	9770945
DAEWOO 2456	Maran Gas Maritime	Daewoo	Conventional	2016	173,400	MEGI	9753014
DAEWOO 2457	Maran Gas Maritime	Daewoo	Conventional	2019	174,000	MEGI	9753026
DAEWOO 2458	Maran G.M, Nakilat	Daewoo	Conventional	2018	173,400	MEGI	9767950
DAEWOO 2459	Maran Gas Maritime	Daewoo	Conventional	2018	173,400	MEGI	9767962
DAEWOO 2460	Chandris Group	Daewoo	Conventional	2018	174,000	MEGI	9766889
DAEWOO 2461	Teekay	Daewoo	Conventional	2018	173,400	MEGI	9771080
DAEWOO 2462	Mitsui & Co	Daewoo	Conventional	2018	180,000	XDF	9771913
DAEWOO 2464	Chandris Group	Daewoo	Conventional	2018	173,400	MEGI	9785158
DAEWOO 2488	BW	Daewoo	Conventional	2018	173,400	MEGI	9792591
DAEWOO 2489	BW	Daewoo	Conventional	2019	173,400	MEGI	9792606
GASLOG GREECE	GasLog	Samsung	Conventional	2016	174,000	TFDE	9687019
GNL DEL PLATA	MOL	Daewoo	FSRU	2017	263,000	TFDE	9713105
HOEGH GRACE	Hoegh	Hyundai	FSRU	2016	170,000	DFDE	9674907
HUDONG-ZHONGHUA H1663A	Teekay	Hudong-Zhonghua	Conventional	2017	174,000	DFDE	9750220
HUDONG-ZHONGHUA H1664A	Teekay	Hudong-Zhonghua	Conventional	2018	174,000	DFDE	9750232
HUDONG-ZHONGHUA H1665A	Teekay	Hudong-Zhonghua	Conventional	2018	174,000	DFDE	9750244
HUDONG-ZHONGHUA H1666A	Teekay	Hudong-Zhonghua	Conventional	2019	174,000	DFDE	9750256
HUDONG-ZHONGHUA H1716A	China Shipping Group	Hudong-Zhonghua	Conventional	2016	174,000	TFDE	9672832
HUDONG-ZHONGHUA H1717A	China Shipping Group	Hudong-Zhonghua	Conventional	2016	174,000	TFDE	9672844
HUDONG-ZHONGHUA H1718A	China Shipping Group	Hudong-Zhonghua	Conventional	2017	174,000	TFDE	9694749
HUDONG-ZHONGHUA H1719A	China Shipping Group	Hudong-Zhonghua	Conventional	2017	174,000	TFDE	9694751
HUDONG-ZHONGHUA H1720A	China Shipping Group	Hudong-Zhonghua	Conventional	2017	174,000	TFDE	9672818
HYUNDAI SAMHO S691	Maran Gas Maritime	Hyundai	Conventional	2016	174,000	DFDE	9682605
HYUNDAI SAMHO S734	Maran Gas Maritime	Hyundai	Conventional	2016	174,000	DFDE	9709489
HYUNDAI SAMHO S735	Maran Gas Maritime	Hyundai	Conventional	2016	174,000	DFDE	9709491

HYUNDAI SAMHO S856	Teekay	Hyundai	Conventional	2019	174,000	MEGI	9781918
HYUNDAI SAMHO S857	Teekay	Hyundai	Conventional	2019	174,000	MEGI	9781920
HYUNDAI ULSAN	Hoegh	Hyundai	FSRU	2017	170,000	TFDE	9762962
HYUNDAI ULSAN 2800	GasLog	Hyundai	Conventional	2017	174,000	XDF	9748899
HYUNDAI ULSAN 2801	GasLog	Hyundai	Conventional	2017	174,000	XDF	9748904
Hyundai Ulsan 2865	Hoegh	Hyundai	FSRU	2019	170,000	-	9780354
IMABARI SAIJO 8200	K Line	Imabari	Conventional	2020	178,000	Steam	9778923
IMABARI SAIJO 8215		Imabari	Conventional	2022	178,000	Steam	9789037
IMABARI SAIJO 8216		Imabari	Conventional	2022	178,000	Steam	9789049
IMABARI SAIJO 8217		Imabari	Conventional	2022	178,000	Steam	9789051
JAPAN MARINE UNITED TSU 5074	MOL	Japan Marine	Conventional	2018	165,000	Steam	9758856
JMU TSU 5070	MOL	Japan Marine	Conventional	2017	165,000	TFDE	9736092
JMU TSU 5071	NYK	Japan Marine	Conventional	2017	165,000	TFDE	9752565
JMU TSU 5072	MOL	Japan Marine	Conventional	2017	165,000	Steam	9758832
JMU TSU 5073	MOL	Japan Marine	Conventional	2018	165,000	Steam	9758844
KALININGRAD	Gazprom JSC	Hyundai	FSRU	2017	174,000	TFDE	9778313
KAWASAKI SAKAIDE 1718	K Line	Kawaski	Conventional	2016	182,000	TFDE	9698123
KAWASAKI SAKAIDE 1720	Kawasaki	Kawaski	Conventional	2016	164,700	Steam Reheat	9749609
KAWASAKI SAKAIDE 1728	Mitsui & Co	Kawasaki Sakaide	Conventional	2017	155,000	TFDE	9759240
KAWASAKI SAKAIDE 1729	Mitsui & Co	Kawasaki Sakaide	Conventional	2017	155,000	TFDE	9759252
KAWASAKI SAKAIDE 1731		Kawasaki Sakaide	Conventional	2017	177,000	TFDE	9774135
KAWASAKI SAKAIDE 1734		Kawasaki Sakaide	Conventional	2018	177,000	DFDE	9791200
KAWASAKI SAKAIDE 1735		Kawasaki Sakaide	Conventional	2018	177,000	DFDE	9791212
KAWASAKI SAKAIDE 3	K Line	Kawasaki Sakaide	Conventional	2016	164,700	Steam Reheat	9766023
KUMUL	MOL, China LNG	Hudong-Zhonghua	Conventional	2016	172,000	SSD	9613161
LA MANCHA KNUTSEN	Knutsen OAS	Hyundai	Conventional	2016	176,300	MEGI	9721724
LNG ABALAMABIE	Nigeria LNG Ltd	Samsung	Conventional	2016	170,000	TFDE	9690171
LNG ABUJA II	Nigeria LNG Ltd	Samsung	Conventional	2016	170,000	DFDE	9690169
LNG FUKUROKUJU	MOL, KEPCO	Kawasaki Sakaide	Conventional	2016	164,700	Steam Reheat	9666986
LNG LAGOS	Nigeria LNG Ltd	Hyundai	Conventional	2016	177,000	DFDE	9692014
LNG MARS	Osaka Gas, MOL	Mitsubishi	Conventional	2016	153,000	Steam Reheat	9645748
LNG SATURN	MOL	Mitsubishi	Conventional	2016	153,000	Steam Reheat	9696149

MARAN GAS AGAMEMNON	Maran Gas Maritime	Hyundai	Conventional	2016	174,000	TFDE	9682590
MARAN GAS AMPHIPOLIS	Maran Gas Maritime	Daewoo	Conventional	2016	173,400	DFDE	9701217
MARAN GAS ROXANA	Maran Gas Maritime	Daewoo	Conventional	2016	173,400	TFDE	9701229
MARAN GAS VERGINA	Maran Gas Maritime	Daewoo	Conventional	2016	173,400	DFDE	9732369
MARIA ENERGY	Tsakos	Hyundai	Conventional	2016	174,000	TFDE	9659725
MITSUBISHI NAGASAKI 2310	K-Line, Inpex	Mitsubishi	Conventional	2016	153,000	Steam Reheat	9698111
MITSUBISHI NAGASAKI 2316	NYK	Mitsubishi	Conventional	2017	155,300	Steam Reheat	9743875
MITSUBISHI NAGASAKI 2321	NYK	Mitsubishi	Conventional	2018	177,000	TFDE	9770438
MITSUBISHI NAGASAKI 2322	Mitsui & Co	Mitsubishi	Conventional	2018	177,000	TFDE	9770440
MITSUBISHI NAGASAKI 2323	MOL	Mitsubishi	Conventional	2018	180,000	TFDE	9774628
MITSUBISHI NAGASAKI 2324	NYK	Mitsubishi	Conventional	2018	165,000	TFDE	9779226
MITSUBISHI NAGASAKI 2325	NYK	Mitsubishi	Conventional	2018	165,000	TFDE	9779238
MITSUBISHI NAGASAKI 2326	MOL	Mitsubishi	Conventional	2018	180,000	TFDE	9796781
MITSUBISHI NAGASAKI 2327	NYK	Mitsubishi	Conventional	2018	180,000	TFDE	9796793
OAK SPIRIT	Teekay	Daewoo	Conventional	2016	173,400	MEGI	9681699
OUGARTA	HYPROC	Hyundai	Conventional	2017	171,800	TFDE	9761267
PRACHI	NYK	Hyundai	Conventional	2016	173,000	TFDE	9723801
RIOJA KNUTSEN	Knutsen OAS	Hyundai	Conventional	2016	176,300	MEGI	9721736
SAMSUNG 2073	GasLog	Samsung	Conventional	2016	174,000	TFDE	9687021
SAMSUNG 2080	SK Shipping, Marubeni	Samsung	Conventional	2017	180,000	XDF	9693161
SAMSUNG 2081	SK Shipping, Marubeni	Samsung	Conventional	2017	180,000	XDF	9693173
SAMSUNG 2102	GasLog	Samsung	Conventional	2016	174,000	TFDE	9707508
SAMSUNG 2103	GasLog	Samsung	Conventional	2016	174,000	TFDE	9707510
SAMSUNG 2107	Flex LNG	Samsung	Conventional	2018	174,000	MEGI	9709025
SAMSUNG 2108	Flex LNG	Samsung	Conventional	2018	174,000	MEGI	9709037
SAMSUNG 2118	BW	Samsung	FSRU	2016	170,000	TFDE	9724946
SAMSUNG 2130	GasLog	Samsung	Conventional	2017	174,000	XDF	9744013
SAMSUNG 2131	GasLog	Samsung	Conventional	2017	174,000	XDF	9744025
SAMSUNG 2148	Mitsui & Co	Samsung	Conventional	2018	174,000	XDF	9760768
SAMSUNG 2149	Mitsui & Co	Samsung	Conventional	2018	174,000	XDF	9760770
SAMSUNG 2150	Mitsui & Co	Samsung	Conventional	2018	174,000	XDF	9760782
SAMSUNG 2153	SK Shipping	Samsung	Conventional	2016	174,000	MEGI	9761803
SAMSUNG 2154	SK Shipping	Samsung	Conventional	2016	174,000	MEGI	9761815
SAMSUNG 2189	Golar LNG	Samsung	FSRU	2017	170,000	DFDE	9785500
SCF YAMAL	Sovcomflot	Daewoo	Conventional	2016	170,000	TFDE	9737187
SERI CAMAR	PETRONAS	Hyundai	Conventional	2017	150,200	Steam Reheat	9714305

SERI CAMELLIA	PETRONAS	Hyundai	Conventional	2016	150,200	Steam Reheat	9714276
SERI CEMARA	PETRONAS	Hyundai	Conventional	2017	150,200	Steam Reheat	9756389
SERI CEMPAKA	PETRONAS	Hyundai	Conventional	2017	150,200	Steam Reheat	9714290
SERI CENDERAWASIH	PETRONAS	Hyundai	Conventional	2016	150,200	Steam Reheat	9714288
TESSALA	HYPROC	Hyundai	Conventional	2016	171,800	TFDE	9761243
WOODSIDE CHANEY	Maran Gas Maritime	Hyundai	Conventional	2016	174,000	TFDE	9682576
XIAMEN	Landmark Capital Ltd	Xiamen Shipbuilding Industry	Conventional	2017	45,000		9769855

Note: All Converted FLNG and FSU vessels are not included in this fleet. However, FSRU - not converted FSRUs - are included as the tankers could act as conventional carriers if necessary. Sources: IHS, Company Announcements.

Appendix 7: Table of FSRU and Laid-up Vessels

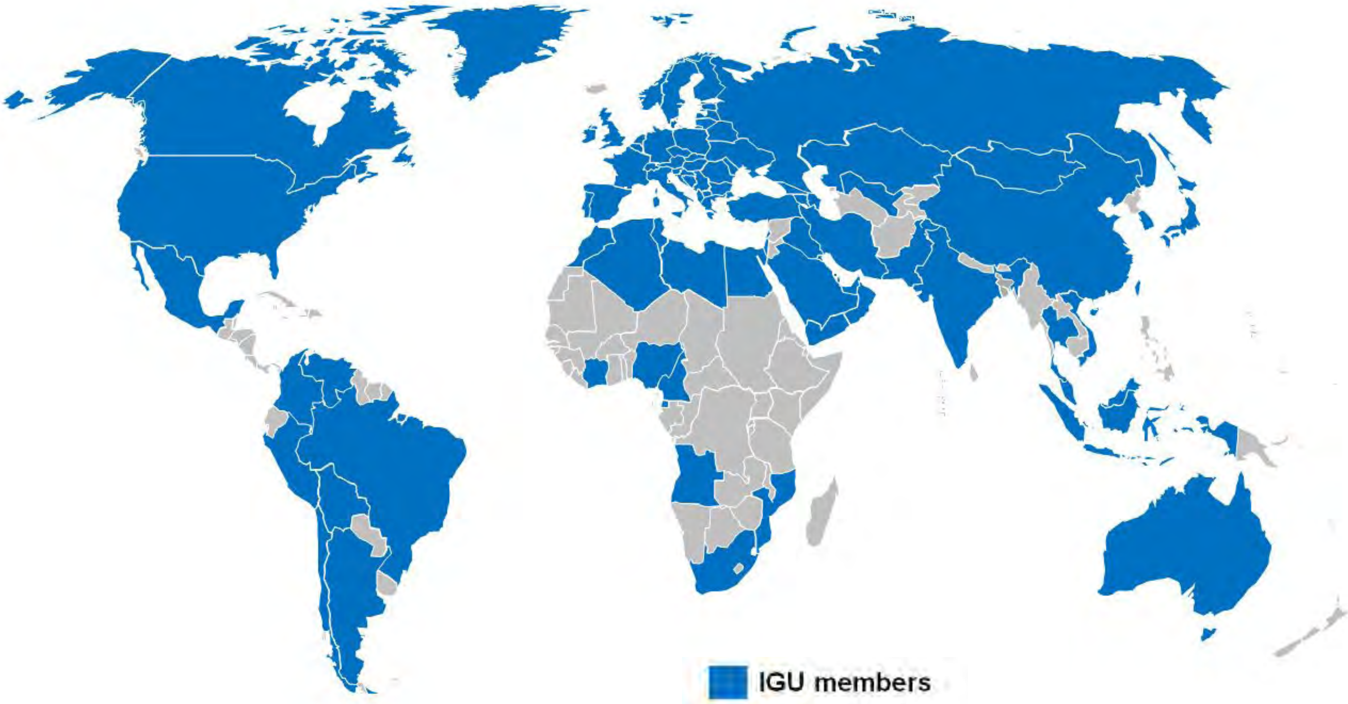
Ship Name	Shipowner	Shipbuilder	Type	Delivery Year	Capacity (cm)	Propulsion Type	IMO #	Status at end-2015
BW SINGAPORE	BW	Samsung	FSRU	2015	170,000	TFDE	9684495	Chartered as FSRU
EXCELLENCE	Excelerate Energy	Daewoo	FSRU	2005	138,124	Steam	9252539	Chartered as FSRU
EXEMPLAR	Excelerate Energy	Daewoo	FSRU	2010	151,072	Steam	9444649	Chartered as FSRU
EXPEDIENT	Excelerate Energy	Daewoo	FSRU	2010	147,994	Steam	9389643	Chartered as FSRU
EXPERIENCE	Excelerate Energy	Daewoo	FSRU	2014	173,660	TFDE	9638525	Chartered as FSRU
EXPLORER	Exmar, Excelerate	Daewoo	FSRU	2008	150,900	Steam	9361079	Chartered as FSRU
EXQUISITE	Excelerate Energy	Daewoo	FSRU	2009	151,035	Steam	9381134	Chartered as FSRU
FSRU TOSCANA	OLT Offshore LNG Toscana	Hyundai	Converted FSRU	2004	137,500	Steam	9253284	Chartered as FSRU
GDF SUEZ CAPE ANN	Hoegh, MOL, TLTC	Samsung	FSRU	2010	145,130	DFDE	9390680	Chartered as FSRU
GOLAR ESKIMO	Golar LNG	Samsung	FSRU	2014	160,000	TFDE	9624940	Chartered as FSRU
GOLAR FREEZE	Golar LNG Partners	HDW	Converted FSRU	1977	126,000	Steam	7361922	Chartered as FSRU
GOLAR IGLOO	Golar LNG Partners	Samsung	FSRU	2014	170,000	TFDE	9633991	Chartered as FSRU
GOLAR SPIRIT	Golar LNG Partners	Kawasaki Sakaide	Converted FSRU	1981	129,000	Steam	7373327	Chartered as FSRU
GOLAR WINTER	Golar LNG Partners	Daewoo	Converted FSRU	2004	138,000	Steam	9256614	Chartered as FSRU
HOEGH GALLANT	Hoegh	Hyundai	FSRU	2014	170,000	TFDE	9653678	Chartered as FSRU
INDEPENDENCE	Hoegh	Hyundai	FSRU	2014	170,132	TFDE	9629536	Chartered as FSRU
NUSANTARA REGAS SATU	Golar LNG Partners	Rosenberg Verft	Converted FSRU	1977	125,003	Steam	7382744	Chartered as FSRU

PGN FSRU LAMPUNG	Hoegh	Hyundai	FSRU	2014	170,000	TFDE	9629524	Chartered as FSRU
BALTIC ENERGY	Sinokor Merchant Marine	Kawaski	Conventional	1983	125,929	Steam	8013950	Laid-up
GAEA	Golar LNG	General Dynamics	Conventional	1980	126,530	Steam	7619575	Laid-up
GRACE ENERGY	Sinokor Merchant Marine	Mitsubishi	Conventional	1989	127,580	Steam	8702941	Laid-up
LNG CAPRICORN	Nova Shipping & Logistics	General Dynamics	Conventional	1978	126,750	Steam	7390208	Laid-up
LNG GEMINI	General Dynamics	General Dynamics	Conventional	1978	126,750	Steam	7390143	Laid-up
LNG LEO	General Dynamics	General Dynamics	Conventional	1978	126,750	Steam	7390155	Laid-up
LNG TAURUS	BGT Ltd.	General Dynamics	Conventional	1979	126,750	Steam	7390167	Laid-up
LNG VESTA	Tokyo Gas, MOL, Iino	Mitsubishi	Conventional	1994	127,547	Steam	9020766	Laid-up
LNG VIRGO	General Dynamics	General Dynamics	Conventional	1979	126,750	Steam	7390179	Laid-up
METHANE KARI ELIN	BG Group	Samsung	Conventional	2004	136,167	Steam	9256793	Laid-up
PACIFIC ENERGY	Sinokor Merchant Marine	Kockums	Conventional	1981	132,588	Steam	7708948	Laid-up
SOUTH ENERGY	Sinokor Merchant Marine	General Dynamics	Conventional	1980	126,750	Steam	7619587	Laid-up
HILLI	Golar LNG	Rosenberg Verft	Converted FLNG	2017	124,890	Steam	7382720	Under conversion
WAKABA MARU	Bumi Armada Berhad	Mitsui	FSU	2016	127,209	Steam	8125868	Under conversion
TENAGA EMPAT	MISC	CNIM	FSU	1981	130,000	Steam	7428433	Converted FSU
TENAGA SATU	MISC	Dunkerque Chantiers	FSU	1982	130,000	Steam	7428457	Converted FSU

Note: All vessels that are not participating in the Active Fleet and Orderbook are included here. These vessels are not included in the total available or eventually available shipping tonnage. Sources: IHS, Company Announcements

Notes

Notes



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