2017 World LNG Report

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Message from the President of the International Gas Union

Dear colleagues:

Liquefied natural gas (LNG) experienced a dynamic 2016, with global trade reaching a record 258 million tonnes (MT), an increase of 13 MT over 2015. Supply ramped up at projects spanning the globe, from the United States to Australia, and LNG found new markets in a diverse array of countries. At the same time, delays and plant outages kept supply growth subdued. LNG prices remained below the cost of new supply as demand grows to reach balance.

As the advantages of natural gas in the global energy mix become increasingly apparent to governments, businesses and consumers around the world, 2016 saw some encouraging trends in LNG. The much awaited tranche of US LNG production began with Sabine Pass Trains 1&2 entering commercial operation. Ramp-up in Australia continued as well, with Gorgon LNG Trains 1&2 and Australia Pacific LNG starting commercial operation, coupled with new train additions at Gladstone LNG and Queensland Curtis LNG. Keen interest in LNG was also evidenced by more than 879 MTPA of proposed project development, concentrated in North America, East Africa and Asia Pacific.

Supply ramped up at projects spanning the globe, from the United States to Australia, and LNG found new markets in a diverse array of countries.

On the demand side, LNG continued to find new markets as a fuel of choice for existing grids that have limited indigenous production, such as Egypt and Pakistan, with combined growth of 6 MT. New niche markets have also developed that prefer clean, flexible fuel for power generation, such as Jamaica and Malta. China's LNG consumption increased dramatically, by nearly 35%, to around 27 MTPA. At the same time, however, the two largest markets – Japan and South Korea – are showing signs of satiation, as nuclear, coal and renewables find their balance in the power mix. With a rebound in hydro-power reservoir levels, Brazilian demand for LNG was down 80% (4 MT), demonstrating the flexible value of LNG. As LNG prices continue in a competitive range, opportunities for demand growth in 2017 abound globally.

Trends in floating storage regasification units (FRSUs) and LNG bunkering are shaping the LNG industry. FRSU new-builds and conversions are expanding access for emerging LNG markets and will continue to help absorb supply. LNG is increasingly seen as a vital bunkering fuel for maritime transport as well. Last year, for example, the Port of Rotterdam installed its third LNG fueling berth, as the benefits of switching to natural gas become increasingly apparent. Switching to LNG in the port can reduce NOx emissions by up to 90% and SOx and particulate emissions by up to 100%.

These trends must all be seen in a wider context. It is not an exaggeration to say that the increased uptake of natural gas has direct and positive impacts on the environment and on human health around the world. In a post-COP 21 world, gas must become an increasingly vital part of the future energy mix.

IGU continues to advocate vigorously for the benefits of natural gas, and the LNG industry plays a key role in expanding access to gas across the globe. The World LNG Report, a flagship publication of IGU first published in 2010 and now published annually, provides key insights into the LNG industry. It remains a standard desk reference on the LNG industry around the world.

Yours sincerely,

David Carroll
President of the International Gas Union

Tokyo

2. State of the LNG Industry[1]

258 MT
Global trade in 2016

Global Trade:For the third consecutive year, global LNG trade set a new record, reaching 258 million tonnes (MT). This marks an increase of 13.1 MT (+5%) from 2015, when a previous record of 244.8 MT was set over the 2014 trade volume of 241.1 MT. The growth rate in 2016 was a noticeable increase from the average growth of 0.5% over the last four years, when there were not very many new supply additions. The continued addition of supply in the Pacific Basin, primarily in Australia, as well as the start of exports from the United States Gulf of Mexico (US GOM) enabled this increase. Demand growth was most pronounced in Asia; China, India, and Pakistan added a combined 13.0 MT in incremental LNG demand. Inter-basin LNG trade flows have declined, particularly as Pacific Basin supplies continued to catch up with high demand in that region.

72 MT
Non long-term trade, 2016

Short and Medium-term LNG Market: Short and medium-term LNG trade reached 72.3 MT in 2016 (+0.4 MT YOY) and accounted for 28% of total trade. Historically, short and medium-term trade grew in 2011, owing to shocks that include the Fukushima crisis, which called on emergency cargos to help fill the power generation gap; and the growth of shale gas in the United States, which facilitated excess cargos no longer needed in a flush market. Both events added a need for commercial innovation and flexibility. However, the share of LNG traded without a long-term contract as a percentage of the global market has tapered off since 2013. Short and medium-term trade, as a share of total traded LNG, fell by 4%. Several emerging markets like Pakistan and Malaysia, seeking firm supply, began importing LNG under new long-term contracts in 2016. Other markets that typically rely heavily on spot and short-term volumes experienced a significant decline in demand. In the case of Brazil it was due to improved hydro-power availability. Further, the majority of new liquefaction projects that started operations in 2015 and 2016 in the Asia-Pacific region are supported by long-term contracts that are coming into force.

$5.52/MMBtu
Average Northeast Asian spot price, 2016

Global Prices: Asian and spot LNG prices fell steadily in the first half of 2016 as supply overwhelmed demand, settling at $4.05 per million British thermal units (MMBtu) in May. A reversal occurred in the second half of the year, with supply disruptions and cold winter temperatures driving spot prices to $9.95/MMBtu by February 2017. With cold weather and storage constraints at Rough, the United Kingdom National Balancing Point (NBP) also ended the year on an upswing at $5.44/MMBtu. The oil price continued to decline in the first half of the year resulting in low oil-indexed contract prices. As prices fell around the world, the market moved closer to price convergence; the differential between NBP and Northeast Asian spot prices narrowed to an average $0.91/MMBtu in 2016. Notably, the differential was negative for several months for the first time in six years. In May and June 2016, the Asian spot price was ~$0.40/MMBtu lower than NBP.

[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, 1.0 MTPA for regasification, and 60,000 cm for LNG vessels. Domestic movements of LNG are also not included.

340 MTPA
Global nominal liquefaction capacity, January 2017

Liquefaction plants: Global liquefaction capacity grew at a similar rate in 2016 as in 2015, adding 35 MTPA of capacity between end-2015 and January 2017 to reach 339.7 MTPA. This includes new projects such as Gorgon LNG, Australia Pacific LNG and Sabine Pass LNG, as well as additional trains at Gladstone LNG (GLNG), Queensland Curtis LNG (QCLNG), and Malaysia LNG (MLNG). Liquefaction capacity additions are poised to increase over the next few years as 114.6 MTPA of capacity was under-construction as of January 2017. Two projects entered the construction phase of development in 2016: a brownfield expansion of Tangguh LNG (3.8 MTPA) as well as an additional US project, Elba Island LNG (2.5 MTPA).

879 MTPA
Proposed liquefaction capacity, January 2017

New Liquefaction Proposals: Given abundant gas discoveries globally and the shale revolution in the US, proposed liquefaction capacity reached 890 million tonnes per annum (MTPA) by January 2016. This figure fell slightly to 879 MTPA at end-January 2017 in an attempt at rationalization with market demand. More of these projects will not go forward as demand remains far below this ambitious target; particularly as ample pipeline supply - by Russia and Norway to Europe, and the US to Mexico - reduce the need for LNG in those markets. Additionally, Egypt will experience a drastic reduction in LNG demand as the Zohr field comes on-line and preferentially supplies the domestic market. In fact, there is potential for Egypt to again be a significant LNG exporter. The areas with the largest proposed volumes include the US GOM, Canada, East Africa, and Asia-Pacific brownfield expansions.

795 MTPA
Global nominal regasification capacity, January 2017

Regasification Terminals: Global regasification capacity increased to 776.8 MTPA by the end of 2016 and 794.6 MTPA by the end of January 2017, primarily supported by additional capacity coming online in established markets such as China, Japan, France, India, Turkey, and South Korea. This stands in contrast with 2015, when capacity was driven by floating regasification projects in emerging markets: Egypt, Jordan, and Pakistan. The expansion of new markets slowed in 2016, as capacity was only added in Jamaica - both Colombia and Malta received their initial LNG cargoes in 2017. An additional 90.4 MTPA of capacity were under construction as of January 2017. A combined eleven projects are under construction in China and India, countries that displayed the strongest LNG demand growth in 2016. New entrants are also set to complete regasification projects in the coming years, including the Philippines, Bahrain, and Russia (Kaliningrad).

83 MTPA[2]
FSRU capacity, January 2017

Floating Regasification: Two floating storage and regasification units (FSRUs) located in the United Arab Emirates (Abu Dhabi – 3.8 MTPA) and Turkey (5.3 MTPA) reached commercial operations by January 2017, boosting global FSRU capacity to 83.0 MTPA. Floating regasification infrastructure was also added in Colombia (FSRU) and Malta (a floating storage unit) but neither had begun commercial operations by January 2017. This builds on the fast growth in 2015, when 17.5 MTPA of capacity was added across Egypt, Jordan, and Pakistan. Although an FSRU arrived in Ghana during 2016, land-based infrastructure has been the critical path to start-up. Looking forward, several FSRU projects are in advanced stages for Uruguay, Chile, Puerto Rico, and Russia. Turkey's first offshore regasification terminal was able to come online in under one year of construction, demonstrating the speed with which new projects utilizing FSRU technology can be brought online. Although there are eight FSRUs on the order book as of January 2017, very few existing FSRUs were available for charter, leading shipping companies to order new FSRUs or convert existing conventional vessels on a speculative basis.

439 Vessels
LNG fleet, January 2017

Shipping Fleet: The global LNG shipping fleet consisted of 439 vessels as of January 2017, including conventional vessels and ships acting as FSRUs and floating storage units. In 2016, a total of 31 newbuilds (including two FSRUs) were delivered from shipyards, a 7% increase when compared to 2015. Relative to the previous year, this was a much more balanced addition relative to liquefaction capacity (which grew by 35 MTPA). Nevertheless, the accumulation of the tonnage buildout from the previous years is still being worked through, keeping short-term charter rates at historical lows. In 2016, two vessels were retired and sold for scrap.

10% of Supply
Share of LNG in global gas supply in 2015[3]

LNG in the global gas market: Natural gas accounts for roughly a quarter of global energy demand, of which 9.8% is supplied as LNG. Although LNG supply previously grew faster than any other natural gas supply source – averaging 6.2% per annum from 2000 to 2015 – its market share growth has stalled since 2010 as indigenous production and pipeline supply have competed well for growing global gas markets. Despite the lack of market share growth in recent years, the large additions of LNG supply through 2020 mean LNG is poised to resume its expansion.

[2] This 81 MTPA is included in the global regasification capacity total of 793 MTPA quoted above.
[3] Data for pipeline trade and indigenous gas production comes from the BP Statistical Review. Data for 2016 is not yet available.

Chevron LNG Journey to Japan – Courtesy of Chevron

3. LNG Trade

In 2016, global LNG trade reached a new record of 258.0 MT, the third consecutive year of incremental growth. The majority of supply growth was supported by commercial production at multiple new liquefaction plants in East and West Australia, and commissioning production at a new train in Malaysia. The successful and timely completion of the first two trains of the Sabine Pass LNG facility marked the start of US Gulf of Mexico (GOM) exports. Also in the Atlantic Basin, Angola resumed LNG exports, as its sole exporting facility returned to operation. However, global LNG supply growth did not meet expectations. As delay and supply disruptions were coupled with demand uptake in Asia, the expected trade volume of LNG did not result; excess volumes that might have reached Europe did not materialize.

LNG trade was bolstered by large markets such as China, India, and Egypt, as combined demand in Japan and South Korea declined slightly. New importers from 2015 continued to increase volumes, ramping-up at a rate faster than had been standard in the past. Moderate growth was present in a number of other markets globally, however a sharp contraction of LNG demand occurred in Brazil as the country was able to meet its lower power needs via hydro power as well as steady indigenous gas production.

Looking forward, supply is poised to increase again in 2017 as new plants and additional trains come online, largely in the Pacific Basin. Major economies such as China and India, as well as new LNG importers such as Pakistan, Egypt, and Jordan, will continue to support fundamental-driven demand. The looser LNG supply/demand balance will manifest additional deliveries into European markets with ample infrastructure, such as the UK, France, and Spain. Another developing trend will be the continued push by developers to locate small pockets of demand, which although individually small could amount to substantial volumes in aggregate.

3.1. Overview

In 2016, total globally-traded LNG volumes reached 258.0 MT, a 13.1 MT increase over 2015 and new record for global LNG trade (see Figure 3.1). However, this record is poised to be broken repeatedly over the next few years as additional liquefaction plants come online. The annual growth of 13.1 MT marks the highest level since 2011.

258.0 MT
Global LNG trade reached a historic high in 2016

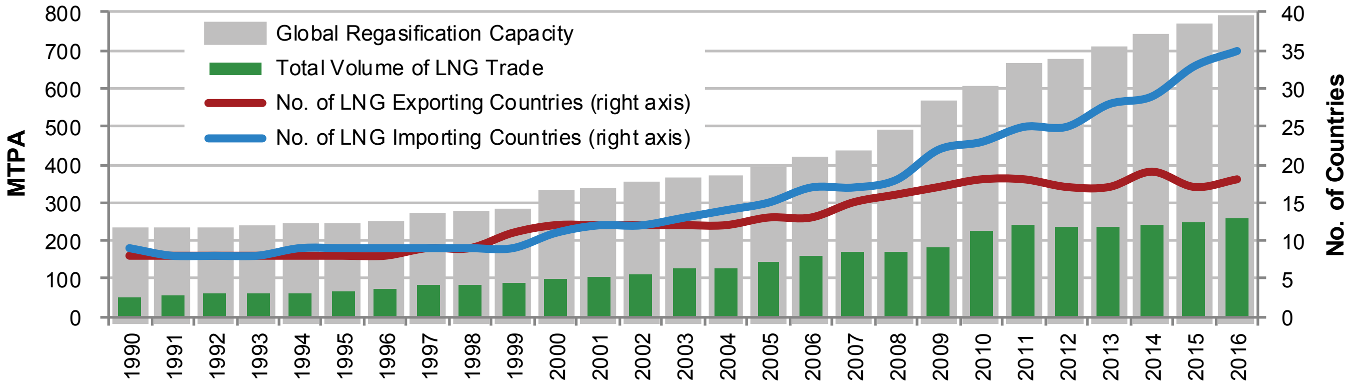
The number of countries exporting LNG in 2016 returned to 18 from 17 in 2015 as Angola and Egypt resumed exports midway through the year. Political instability in Yemen meant LNG imports were unable to restart after shutting down in mid-2015. The start of operations at Sabine Pass LNG marked the start of US GOM LNG exports for the US, although the Kenai LNG plant in Alaska did not send out any cargoes during the year. Total re-export activity stayed relatively stable globally, with 4.4 MT re-exported by 10 countries during the year (10 countries also re-exported LNG in 2015).[1]

Driven by growth in Qatari production, the Middle East was the world's largest LNG exporting region from 2010 to 2015. However, the Asia-Pacific regained this mantle in 2016 due to new production at several new liquefaction plants, coupled with Yemen LNG remaining offline due to continued unrest in the country. Asia-Pacific countries represented 38.6% of total exports, compared to 35.3% for the Middle East in 2016. Qatar continues to remain the world's largest LNG exporting country, accounting for around 30% of global trade by exporting 77.2 MT.

Growth in Asia-Pacific supply was 15.4 MT, primarily from Australian project start-ups, including Gorgon LNG T1-2, GLNG T1-2 and Australia Pacific LNG T1. QCLNG T2 and Donggi-Senoro LNG, both of which started up in Q4 2015, also added to the growth in annual volumes from this region.

The US shifted from its pattern of exporting only minor volumes from Kenai LNG and a handful of re-exported cargoes, to exporting 2.9 MT from the new Sabine Pass project in the US GOM during 2016. Elsewhere in the Atlantic Basin, Trinidad continued to struggle with feedstock limits, as production at Atlantic LNG (ALNG) was down substantially for the second consecutive year, falling 2.0 MT year-on-year

Figure 3.1 LNG Trade Volumes, 1990-2016



Source: IHS Markit, IEA, IGU

[1] The United States is included in both totals, since it exports domestically-produced LNG and re-exports LNG from regasification terminals in the Gulf of Mexico.

(YOY). Nigeria LNG (NLNG) produced 1.8 MT less in 2016, due to domestic unrest in the Niger Delta region, as well as a period of extended maintenance during the first half of the year. Contrasting with difficulties in those countries, the return of Angola and Egypt to exporting status provided a combined boost of 1.3 MT in 2016 to Atlantic Basin production.

Asia-Pacific and Asia markets (the distinction between these regions is illustrated in Section 8.3) continued to represent the most activity in LNG imports, recording a small increase in combined market share from 71.7% in 2015 to 72.4% in 2016. Given a decline in Japanese demand and near-flat South Korean demand, this slight growth was due to strong demand growth from both China and India (+6.9 MT and +4.5 MT YOY, respectively). Continued moderate growth in smaller markets such as Thailand, Pakistan, and Singapore helped these regions retain their important role in global trade.

The addition of Jamaica and Colombia brought the number of importing countries to 35, although the pair registered just 0.1 MT of additional trade.[2] The four new markets from 2015, Egypt, Pakistan, Jordan, and Poland, added 7.7 MT in 2016, including 4.3 MT by Egypt alone. This builds on the 6.0 MT of imports those markets contributed to global trade during 2015. Looking forward, Malta received its first commissioning cargo in January 2017, and will likely be the only new importer of LNG in 2017.

European LNG imports increased YOY for the second consecutive year, although strong Pacific Basin prices during the second half of 2016, and particularly during the last quarter of 2016, kept gains from exceeding 0.6 MT. The Northwest European markets of the UK, Belgium, and the Netherlands declined by a combined 3.4 MT YOY as ample pipeline supplies from both Russia and Norway were readily available. In contrast, the newest markets of Poland and Lithuania contributed a combined 1.4 MT of growth in 2016. Re-export activity from Europe decreased slightly in 2016 (-6.6% YOY), with the largest decrease in re-exports by Spain (-1.2 MT).

Imports in many North American and Latin American markets fell, with the combined regions' imports decreasing by 5.8 MT. Increased pipeline supply availability in Mexico and improved hydroelectric power generation in Brazil were the leading factors behind this drop. The only countries with expansions in LNG imports in the Western Hemisphere were Chile (+0.3 MT), Colombia, and Jamaica (both new, totalling 0.1 MT). The increase in Chilean imports was partially supported by gas sales across the Andes to Argentina to help meet winter demand; this is likely to be repeated again in 2017.

Looking forward, an important factor in 2017 will include the trend of structural demand loss for LNG in foundational importing countries of Japan and South Korea. This is despite continued uncertainty regarding nuclear power generation in both countries. The rapidly-increasing demand for energy in both China and India will also support LNG imports into those markets, as additional Pacific Basin production becomes available.

European LNG imports will be shaped by inter-basin differentials, as we have seen demand is comfortably filled by pipeline imports and domestic production. Ample gas supply via pipeline from both Russia and Norway will continue to compete with LNG in well-integrated European gas networks. Gas-fired power generation in Spain, Greece, and Italy will help gas and LNG demand. Carbon pricing policy in the UK has greatly aided gas's competiveness vis-à-vis coal in that

2015-2016 LNG Trade in Review

Global LNG Trade **+13.1 MTPA** Growth of global LNG trade	LNG Exporters & Importers **+2** Number of new LNG importers in 2016	LNG Re-Exports **FLAT YOY** Re-exported volumes remained flat in 2016	LNG Price Change **-$2.32** Drop in average Northeast Asian spot price from 2015 to 2016, in MMBtu
Global LNG trade reached a record of 258.0 MT in 2016, rising above the previous 244.8 MT set last year. China, India, and Egypt provided 15.7 MT in new import demand. Contractions were largest in Brazil, the UK, and Japan (combined -8.8 MT).	Two new countries began importing LNG in 2016, Colombia and Jamaica, although volumes were less than 0.2 MT. Exports resumed from Angola and Egypt. Yemen recorded no exports for the year, after production was shut in during the first half of 2015.	Brazil, a country which had reload capabilities during 2015, but did not do so internationally, reloaded 0.4 MT in 2016. India re-exported LNG internationally during 2015, but did not during 2016. One notable shift in re-export behaviour was a large drop in reloads from Spain (-1.2 MT) and increase in French re-exports (+0.9 MT).	Spot prices in general continue to face weakness due to supply additions outpacing demand growth. Spot price rebounded in the second half of 2016 in response to unanticipated supply outages and cold winter weather in Asia and Europe.

[2] All counts and totals within this section only include countries that imported LNG on conventionally-sized LNG carriers and above, and exclude countries which buy cargoes exclusively from domestic liquefaction plants, such as Indonesia. Refer to Chapter 8 for a description of the categorization of small-scale versus large-scale LNG.

market, however in other European markets gas will face strong competition from both coal and renewables. Thus, additional flows to Europe will depend on LNG price shifts influenced by global LNG balances.

From a supply perspective, trends in 2017 will be nearly parallel to those of 2016, with new production coming primarily from the Pacific Basin. Gorgon LNG T1 & T2, Australia Pacific LNG T2, MLNG T9 and PFLNG Satu are in position to reach nameplate annual production. Gorgon LNG T3 and Ichthys LNG are set to start-up in 2017. In the Atlantic Basin, two additional trains at Sabine Pass will boost US GOM output and Angola LNG is set for a full year of production.

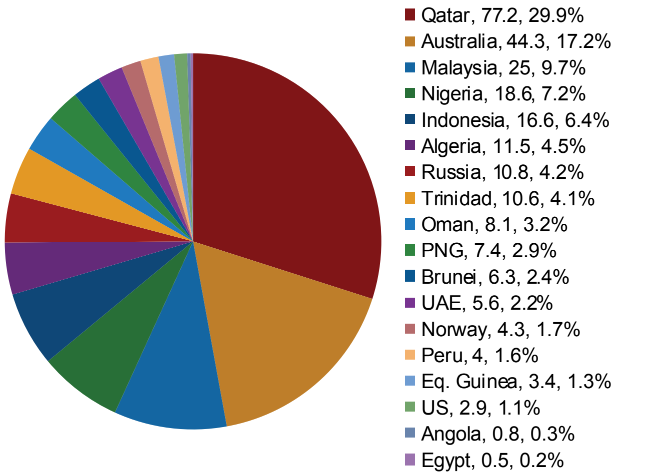
3.2. LNG Exports by Country

The number of exporting countries returned to 18 in 2016 as Angola and Egypt (Egyptian LNG) both returned to producing LNG. The Pacific Basin provided the majority of new supply, as 15.0 MT of additional LNG was exported from Australia alone (see Figure 3.3). Yemen, which exported LNG during the first half of 2015, did not export a single cargo in 2016 due to ongoing instability in the country. The US, although nominally an LNG-exporting country in 2015 via the Kenai LNG plant in Alaska and minor re-exported volumes, began LNG exports from the US GOM Sabine Pass LNG.

With exports of 77.2 MT, Qatar continued to be the largest LNG exporter, a position it has now held for over a decade. Qatar's global market share has dropped to just under 30% as its production remains stable while other countries have grown (see Figure 3.2).

The order of the top five exporters by share (Qatar, Australia, Malaysia, Nigeria, Indonesia; respectively) remained the same between 2015 and 2016. Although Australia remains a distant second to Qatar, it gained significant ground in 2016 and is poised to do so again in 2017. With a full year of production at its first two trains, as well as additional expansion trains, the US will be able to move up the ranks of producers again in 2017. Angola is poised to benefit from a full year of production in 2017.

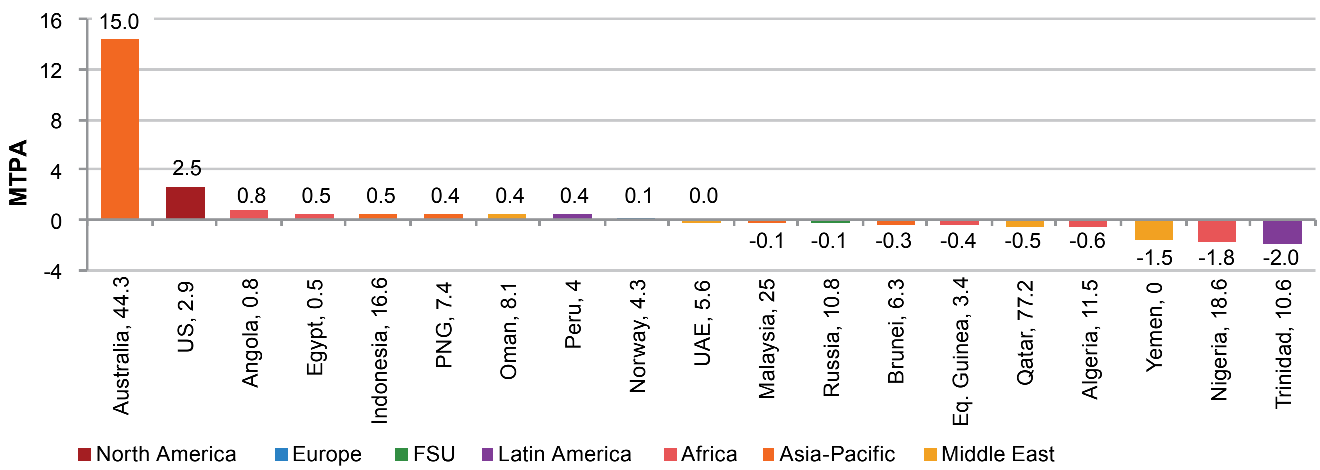
Figure 3.2: LNG Exports and Market Share by Country (in MTPA)



Note: Numbers in the legend represent total 2016 exports in MT, followed by market share. Source: IHS Markit, IGU

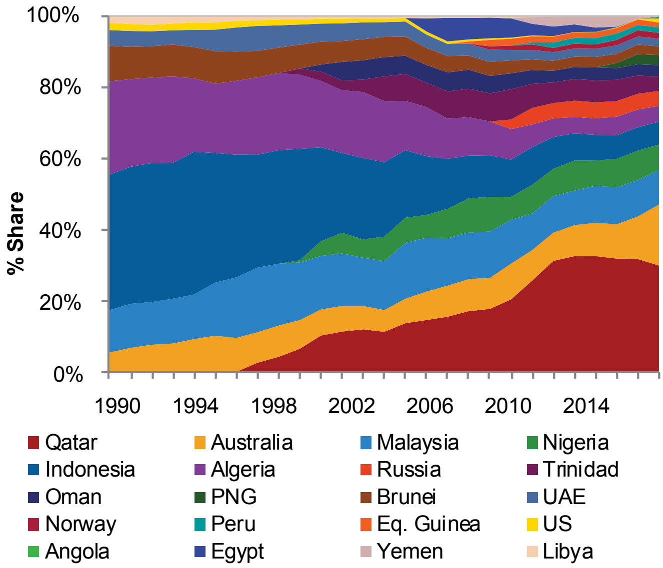
Production from Trinidad decreased for the third consecutive year as feedstock shortages at Atlantic LNG persist. Declines were also evident in Yemen, although this is merely a continuation of the force majeure from last year. Although it had a strong year in 2015, NLNG production dropped by 1.8 MT in 2016, as sabotage in the Niger Delta regions affected midstream operations and the facility underwent extended maintenance during the first half of the year. In North Africa, Egypt's ELNG facility was able to begin exporting LNG again after Shell reached an agreement for limited feedstock from Egyptian Natural Gas Holding Company (EGAS). Algerian LNG production decreased for the second consecutive year, although this was due to a sharp rise in pipeline gas exports to Italy as Algerian domestic production rose. Europe's only LNG-producing country, Norway, produced just slightly more LNG than in 2015, a record 4.3 MT for the country via Snøhvit LNG.

Figure 3.3. 2016 Incremental LNG Exports by Country Relative to 2015 (in MTPA)



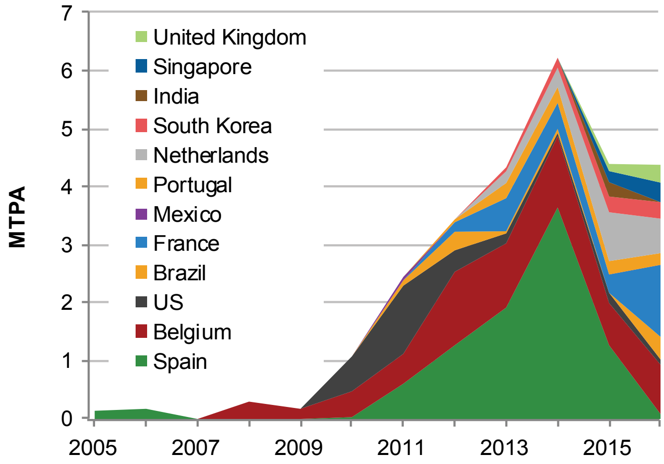
Source: IHS Markit, IGU

Figure 3.4 Share of Global LNG Exports by Country, 1990-2016



Source: IHS Markit, IGU

Figure 3.5: Re-exports by Country, 2005-2016



Note: Re-exports figures exclude volumes that were reloaded and discharged within the same country. Sources: IHS Markit

4.4 MT
Re-exported LNG volumes in 2016

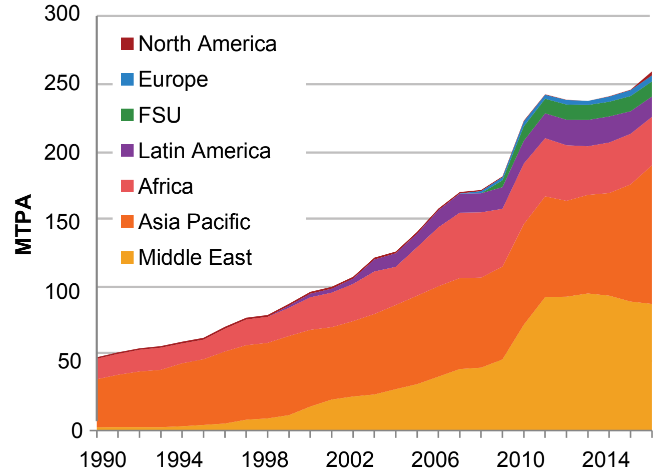
Re-exported volumes remained relatively stable YOY, at 4.4 MT. The number of countries once again remained at 10, however this included no re-exports by India and a restart of re-export activity by Brazil. Brazilian re-exported cargoes were generally sent to points in South America, however a lone re-export was sent to India in December. The US remained the only country to both re-export LNG in addition to exporting domestically-sourced gas. As in the past four years, Mexico again did not utilize its re-export capabilities in 2016.

Europe registered a decrease of 0.2 MT in re-exports (see Figure 3.5). However this obscures the major shift in re-exports from Spain (-1.2 MT) to France (+0.9 MT). Given high resurgent spot prices in the Pacific Basin as well as tenders offered by short-term buyers, 20 cargoes were re-exported from French terminals in 2016. UK and Belgian re-exports inched up (+0.2 MT and +0.1 MT, respectively), while Dutch re-exports dropped (-0.2 MT).

Re-export trade will continue to face pressure as additional LNG supply enters the market globally, reducing the number of cross-basin arbitrage opportunities as buyers are able to source from their respective regions. Additionally, the gap between European and East Asian spot prices is set to diminish as the market shifts into a period of oversupply. How players with large supply portfolios choose to manage those volumes, including portfolio optimization to take advantage of seasonal arbitrage opportunities, will also determine any change in re-export trade moving forward.

Regional trade had been dominated by the Middle East, owing to Qatar's industry-leading 77 MT of nameplate capacity. However, additions in Australia during 2016 (as well as commercial volumes from Indonesia's Donggi-Senoro LNG) helped Asia Pacific take the lead role in LNG production at 99.5 MT (+15.4 MT YOY; see Figure 3.6). Only Asia Pacific and North America saw gains in market share in 2016, with all other regions' market shares decreasing. African exports were down due to decreases in Algeria, Nigeria, and Equatorial Guinea, despite the return of Angola and Egypt (ELNG) as exporting countries. Latin American production (Trinidad and Peru) was down due to feedstock issues at Atlantic LNG, while European and FSU exports held constant in absolute value, resulting in a drop in market share for those regions. North American production began the first of what is likely to be a number of years of increasing output, exporting 1.1% of global LNG in 2016.

Figure 3.6: LNG Exports by Region, 1990-2016



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

3.3. LNG Imports by Country

Although last year's record LNG import levels were aided by an additional 6.0 MT of imports into the four new markets, 2016 marked a year where larger growth was supported by existing buyers. China and India added 11.5 MT compared to 7.7 MT added by the four new entrants from 2015: Egypt, Jordan, Pakistan and Poland. First-year importers Jamaica and Colombia imported just 0.1 MT, all during the second half of 2016.

Asia Pacific remained the largest market by a comfortable margin in 2016, taking in 53.6% of global supply. This marks a decrease from the 57.1% of total imports the region received in 2015 as total imports into the region declined by 1.6 MT. Demand in Asia-Pacific continues to be led by Japan (83.3 MT), with South Korea (33.7 MT) a distant second. Buyers in the region received an increased amount of LNG from sellers within the region, with intra-regional trade rising to 76.5 MT from 68.5 MT in 2015.

After alternating with Europe for second-largest importing region between 2013 and 2015, Asia took a decisive lead in 2016, importing 48.6 MT, compared with 38.1 MT for Europe. Asia was home to the two markets which grew by the largest margins, China (+6.9 MT) and India (+4.5 MT), while Pakistan also showed strong growth (+1.6 MT). Although Europe showed the most expansion in LNG imports in 2015, Asia, driven by China and India, displayed the strongest regional growth in 2016, rising by 13.0 MT. Buyers in the region continued to source primarily from a mix of Middle East and Asia Pacific suppliers.

European imports appeared poised for a year of solid growth, but a resurgence in Asian prices during the second half of the year directed supply into the Pacific Basin. Growth in Europe was most evident in France (+1.0 MT) and Spain (+1.0 MT), as nuclear outages in the former supported regional gas demand during the second half of the year in addition to cooler weather during that time. The newest importers on the continent, Lithuania and Poland, provided a boost of 0.7 MT each YOY. Europe received a higher proportion of its LNG from Africa in 2016 than in 2015, as Middle East exports were redirected to Asia and Asia Pacific.

Table 3.1: LNG Trade between Basins, 2016, MT

Exporting Region / Importing Region	Africa	Asia-Pacific	Europe	Former Soviet Union	Latin America	Middle East	North America	Reexports Received	Reexports Loaded	Total
Africa	1.2	0.3	0.2		0.4	4.4		0.8		**7.3**
Asia	5.5	21.5	0.2	0.3	1.1	18.9	0.5	0.7		**48.6**
Asia-Pacific	4.4	76.5	0.1	10.6	0.3	45.7		1.2	0.6	**138.2**
Europe	18.2		2.8		2.5	17.4	0.3	0.4	3.4	**38.1**
Latin America	1.7	0.1	0.7		5.2	1.0	1.2	0.7	0.4	**10.1**
Middle East	3.2	0.7	0.1		0.8	3.6	0.4	0.7		**9.5**
North America	0.7	0.5	0.1		4.3		0.5	0.1	0.1	**6.1**
Total	**34.8**	**99.5**	**4.3**	**10.8**	**14.6**	**91.0**	**2.9**	**4.5**	**-4.5**	**258.0**

Sources: IHS Markit, EIA, IGU

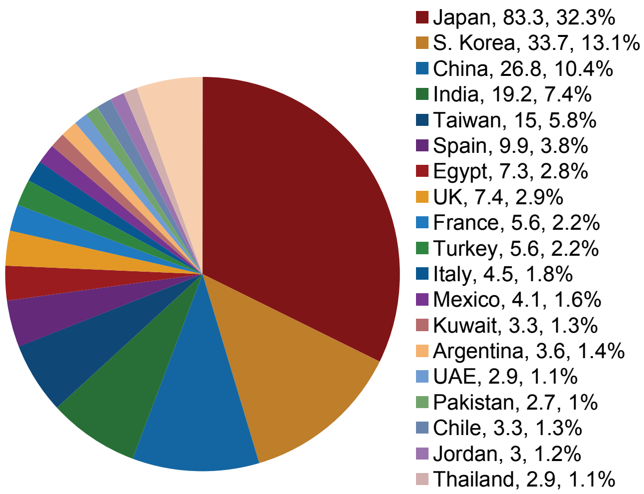
North American and Latin American LNG imports both fell again in 2016 (-1.4 MT and -4.4 MT, respectively). Latin America was particularly hard-hit, as the return of normal rainfall levels and economic contraction in Brazil during 2016 were responsible for the decrease in imports in that country (-4.1 MT). LNG imports into Argentina also fell (-0.6 MT) given steadily increasing domestic gas production. Chile was able to increase LNG imports by 0.3 MT YOY, but some of this was actually destined for the Argentine market, piped over the Andes to meet seasonal demand. Latin America added two new importers, Colombia and Jamaica; however they only provided a combined 0.1 MT of import growth.

Strong pipeline flow from the US to Mexico caused global LNG imports into the latter to continue to decline (-1.0 MT). This continues the trend from 2015, when the country experienced a decrease of 1.7 MT in imports. An additional result of continued strong US domestic gas production was Canadian LNG imports decreasing to their lowest annual total since imports began in 2009.

As in 2015, emerging regions experienced steady demand growth. In the Middle East, Kuwait, the UAE, Israel, and Jordan all posted gains, collectively adding 2.6 MT to global LNG imports. The persistence of low LNG prices throughout the year enabled these countries to import extra LNG to meet growing demand, as did new contracts and a second FSRU commissioned in the UAE. In Africa, Egypt continued to be the lone LNG importer, adding 4.3 MT of additional trade, more than doubling imports to 7.3 MT during its second year of importing LNG. This resulted in a total of 10.3 MT imported in the market's first two years of imports, compared to the previous record of 3.9 MT imported by China in 2006 and 2007. Jordan and Pakistan had 2-year cumulative demand of 5 MT and 4.4 MT, respectively. Some Jordanian imports were actually destined for Egypt via the Arab Gas Pipeline.

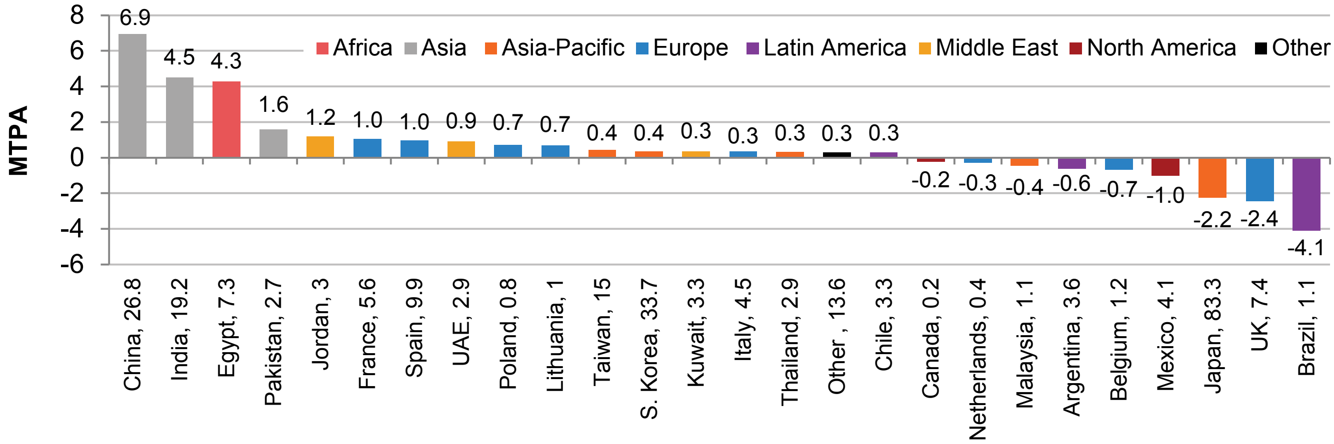
The largest single country increase was experienced in China, particularly as cold weather spurred demand fundamentals

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 imports less than 2.5 MT (by order of size): Singapore, US, Portugal, Puerto Rico Belgium, Malaysia, Brazil, Lithuania, Poland, Dominican Republic, Greece, Netherlands, Israel, Canada, Jamaica, and Colombia. Sources: IHS Markit, IGU

Figure 3.8: Incremental 2016 LNG Imports by Country & Incremental Change Relative to 2015 (in MTPA)



Note: "Other" includes countries with incremental imports of less than ±0.2 MT: Israel, Portugal, Greece, Colombia, Jamaica, Singapore, Puerto Rico, Turkey, the US, and Dominican Republic. Sources: IHS Markit, IGU

during the winter, including a doubling YOY of imports in December 2016 (see Figure 3.8). Growing Pacific Basin drove this increase, as Australian projects (+15.0 MT YOY) supplied a series of Chinese contracts which began during the year. The continued ramp-up in supply in Australia throughout 2017-18 will further enable Chinese and other Asian demand to expand. Also in Asia, Indian LNG imports grew by the second highest amount globally in 2016 (+4.5 MT), spurred by low spot prices meeting price-elastic demand outlets.

Asia-Pacific imports declined by 1.6 MT YOY; however, this translates to only a 1.1% drop in annual imports. Five of the six importers of this region all changed by less than 1 MT YOY, with three increasing imports and two decreasing. The largest absolute change was in Japan (-2.2 MT), where nuclear restarts have continued, albeit at a slow pace, and a rapid renewables build is squeezing thermal generation amidst weak demand. After two years of falling LNG demand, South Korean imports grew slightly in 2016 (+0.4 MT), with the cold winter and hot summer a significant driver. Across the region, even in a year with falling LNG and rising coal prices, coal remained strongly competitive in the power sector.

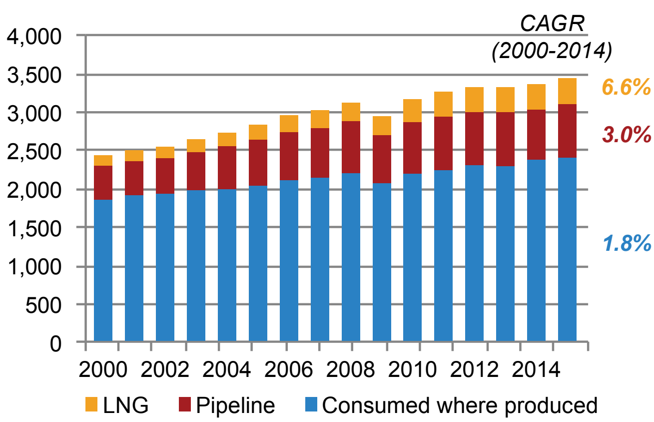
+ 6.2% p.a.
Average yearly growth rate of LNG demand since 2000

Although LNG has posted a higher annual rate of growth over the past 15 years than either global production for indigenous consumption or international pipeline exports, much of the impressive growth was focused in the first decade, with pipeline trade displaying a similar growth rate to LNG over the past few years (see Figure 3.9). Between 2010 and 2015, the average growth rate of LNG trade has slowed to just 2.1%, roughly on par with indigenous production (1.9%) and pipeline trade (0.8%). In 2015, LNG's share of global trade dipped slightly, remaining around 9.8%, while pipeline's share of gas trade increased to 20.3%, aided by historically-high levels of pipeline exports by both Russia and Norway.

Despite a slowing rate of growth in recent years, LNG trade has continued to develop for various reasons by country. In the markets of the Asia Pacific, LNG imports are driven by geographic isolation and gas resource scarcity. Additionally, questions regarding nuclear as a power source continue to support LNG imports. Unlike some other importing regions, these countries either find themselves without prospects for increased domestic gas production, or otherwise insufficient production to meet demand. Cross-border pipeline connections have yet to make a major impact on regional gas dynamics.

In other markets, LNG is used to supplement domestic production, which is either maturing or insufficient to keep pace with domestic demand. Despite the UK being able to record an increase in gas production in 2016, production is in a long-term trend of decline. Additional restraints at the Groningen field in the Netherlands have likewise decreased output from that country. A more common occurrence globally has been the inability of gas production to keep pace with demand growth, including in Kuwait, Thailand, and Argentina.

Figure 3.9: Global Gas Trade, 2000-2015



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

LNG continues to be used as a means to increase gas supply security even in markets with ample pipeline connections. European importers such as France, Italy, and Turkey use LNG to diversify their import mix and to maintain access to gas in the case of inadequate pipeline flows. Concerns over the pricing and security of pipeline imports prompted both Lithuania and Poland to become LNG importers during the past few years.

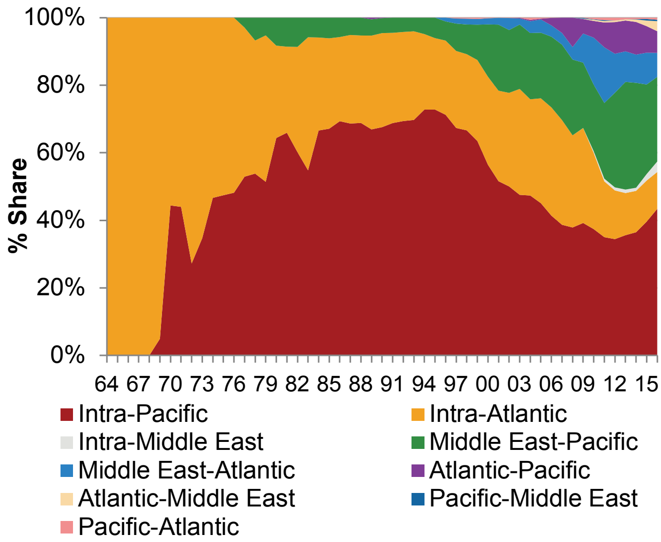
During the past decade, the fortunes of domestic gas production in a number of countries have, and will continue to affect their outlooks as importers. The most pronounced shift was the shale revolution in the US, which allowed the country to begin exporting LNG from the Lower 48 states, instead of becoming a net importer as had previously been projected. US production in turn influenced the LNG import needs of neighbouring Canada and Mexico as well. In other importers, such as China and Argentina, the possibility of expanding shale production could reduce the need for LNG imports in the long term. Egypt is likely to experience a pronounced reduction in LNG imports in the coming years as recent discoveries come on stream.

3.4. LNG Interregional Trade

The largest global trade flow route continues to be Intra-Pacific trade, a trend which is poised to continue as that basin posted the largest gains in both supply and demand by region (see Figure 3.10). Continuing growth in Chinese and Indian demand, as well as Australian production, will cement this trade route's prominence. Trade between the Middle East and Pacific was the second-highest by volume, due to Qatar's role in supplying Japan and South Korea. Given elevated prices in Asian markets during the second half of 2016, much of Qatar's supply went to the Pacific, meaning Middle-East to Atlantic trade declined to just 7% of global trade in 2016. That route was the fastest-declining in 2016, dropping by 4.7 MT YOY.

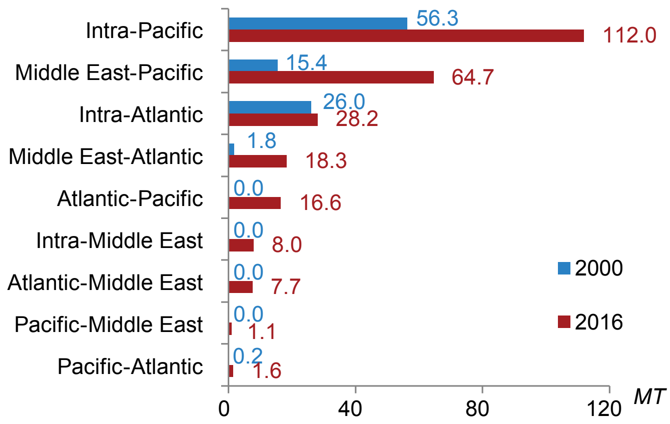
Very few volumes from the Pacific left the basin, with Pacific Basin exports to the Middle East or Atlantic totalling just 2.7 MT in 2016. Fewer cargoes from the Atlantic likewise made the journey to the Pacific in 2016, instead stopping in the Middle East. Combined Atlantic trade to the Pacific and Middle East totalled 23.3 MT in 2015 and 24.2 MT in 2016.

Figure 3.10: Inter-Basin Trade Flows 1964-2016



Sources: IHS Markit, IGU

Figure 3.11: Inter-Basin Trade, 2000 v. 2016



Sources: IHS Markit, IGU

Sabine Pass LNG – Courtesy of Cheniere Energy

Table 3.2: LNG Trade Volumes between Countries, 2016 (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	2015 Net Imports	2014 Net Imports	2013 Net Imports	2012 Net Imports
Egypt	-	-	0.25	-	-	0.06	-	0.07	1.09	0.20	-	-	-	4.42	-	0.41	-	-	-	0.82	-	7.32	3.02	-	-	-
Africa	-	-	0.25	-	-	0.06	-	0.07	1.09	0.20	-	-	-	4.42	-	0.41	-	-	-	0.82	-	7.32	3.02	-	-	-
China	-	-	12.44	0.06	0.06	-	2.84	2.76	0.34	0.17	0.12	2.01	0.26	4.91	0.26	0.12	-	0.20	-	0.22	-	26.78	19.83	19.81	18.60	14.77
India	0.07	0.35	1.17	-	0.06	1.24	-	0.06	2.91	0.06	0.27	-	0.06	11.09	-	0.52	0.57	0.34	-	0.40	-	19.17	14.67	14.48	12.92	13.99
Pakistan	-	-	0.13	-	-	0.33	-	-	0.13	-	-	-	-	1.91	-	0.11	-	-	-	0.07	-	2.68	1.11	-	-	-
Asia	0.07	0.35	13.75	0.06	0.13	1.57	2.84	2.82	3.39	0.24	0.39	2.01	0.32	17.91	0.26	0.74	0.57	0.54	-	0.69	-	48.64	35.61	34.29	31.52	28.76
Japan	0.19	-	22.59	4.24	0.06	0.47	6.78	15.38	1.86	-	2.55	3.96	-	12.06	7.38	0.06	4.88	-	-	0.88	-	83.34	85.58	88.69	87.79	87.26
Malaysia	-	-	0.44	0.26	-	-	0.13	-	-	-	0.06	-	-	0.07	-	0.10	-	-	-	0.07	-	1.13	1.57	1.60	1.62	-
Singapore	-	0.07	1.35	-	0.13	0.13	-	0.06	-	-	-	-	-	0.64	-	-	0.06	-	-	-	(0.34)	2.12	2.10	1.89	0.94	-
South Korea	0.13	0.07	4.79	1.41	-	0.14	4.50	4.02	0.58	0.07	4.04	0.14	0.12	11.93	1.92	-	-	-	-	0.14	(0.28)	33.71	33.36	37.81	40.86	36.78
Taiwan	0.07	-	0.27	0.31	-	0.06	2.01	2.62	0.46	0.06	0.12	1.26	-	6.32	1.29	0.05	0.07	-	-	0.06	-	15.04	14.63	13.59	12.83	12.78
Thailand	-	-	-	-	-	-	-	-	-	-	0.06	-	-	2.84	-	-	-	-	-	-	-	2.90	2.58	1.31	1.42	0.98
Asia-Pacific	0.38	0.14	29.45	6.22	0.19	0.80	13.42	22.08	2.90	0.13	6.84	5.35	0.12	33.86	10.59	0.21	5.01	-	-	1.16	(0.62)	138.24	139.82	144.88	145.46	137.80
Belgium	0.01	-	-	-	-	-	-	-	-	-	-	-	-	2.02	-	-	-	-	-	0.03	(0.85)	1.21	1.89	0.90	1.10	1.91
France	4.49	-	-	-	-	-	-	-	1.39	0.34	-	-	0.12	0.49	-	-	-	-	-	-	(1.24)	5.59	4.54	4.72	5.80	7.48
Greece	0.54	-	-	-	-	-	-	-	0.02	-	-	-	-	-	-	-	-	-	-	-	-	0.56	0.42	0.40	0.51	1.07
Italy	0.17	-	-	-	-	-	-	-	0.06	0.12	-	-	0.06	4.08	-	-	-	0.05	-	-	-	4.54	4.21	3.35	4.25	5.23
Lithuania	-	-	-	-	-	-	-	-	-	1.02	-	-	-	-	-	-	-	-	-	-	-	1.02	0.33	0.11	-	-
Netherlands	-	-	-	-	-	-	-	-	0.07	0.40	-	-	-	0.36	-	0.12	-	-	-	-	(0.59)	0.36	0.63	0.47	0.32	0.61
Poland	-	-	-	-	-	-	-	-	-	0.06	-	-	-	0.73	-	-	-	-	-	-	-	0.79	0.08	-	-	-
Portugal	0.18	-	-	-	-	-	-	-	0.88	0.06	-	-	-	0.30	-	-	-	0.06	-	-	(0.20)	1.28	1.16	0.98	1.32	1.66
Spain	2.19	0.07	-	-	-	-	-	-	3.64	0.58	-	-	1.31	1.60	-	0.52	-	0.06	-	-	(0.08)	9.88	8.91	8.20	9.36	14.22
Turkey	3.12	-	-	-	0.07	-	-	-	1.01	0.06	-	-	-	0.65	-	0.25	-	0.11	-	0.27	-	5.55	5.55	5.32	4.24	5.74
United Kingdom	0.15	-	-	-	-	-	-	-	0.14	0.20	-	-	-	7.14	-	0.06	-	-	-	0.07	(0.38)	7.37	9.79	8.47	6.84	10.45
Europe	10.84	0.07	-	-	0.07	-	-	-	7.20	2.84	-	-	1.50	17.37	-	0.96	-	0.28	-	0.37	(3.35)	38.15	37.51	32.92	33.74	48.37
Argentina	0.16	-	0.06	-	-	-	-	-	0.52	0.26	-	-	-	0.71	-	1.05	-	0.34	-	0.47	-	3.58	4.19	4.68	4.93	3.82
Brazil	-	0.14	-	-	-	0.07	-	-	0.61	0.19	-	-	-	0.22	-	0.09	-	0.18	-	0.03	(0.39)	1.13	5.22	5.71	4.44	2.52
Chile	-	-	-	-	-	0.06	-	-	-	0.10	-	-	-	0.07	-	2.36	-	0.60	-	0.09	-	3.28	3.01	2.78	2.86	3.03
Colombia	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.06	-	-	-	-	-	0.06				
Dominican Republic	-	-	-	-	-	-	-	-	-	0.06	-	-	-	-	-	0.66	-	0.06	-	-	-	0.78	0.95	0.92	1.09	0.96
Jamaica	-	-	-	-	-	-	-	-	0.06	-	-	-	-	-	-	-	-	-	-	-	-	0.06				
Puerto Rico	-	-	-	-	-	0.06	-	-	-	0.06	-	-	-	-	-	1.00	-	-	-	0.12	-	1.24	1.19	1.24	1.20	0.97
Latin America	0.16	0.14	0.06	-	-	0.19	-	-	1.19	0.67	-	-	-	1.00	-	5.21	-	1.18	-	0.70	(0.39)	10.12	14.56	15.33	14.51	11.30
Israel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.28	-	-	-	-	-	0.28	0.13	0.12	1.56	2.11
Jordan	-	-	0.07	-	0.06	0.48	-	-	1.12	-	0.06	-	-	0.43	-	0.32	-	0.19	-	0.26	-	2.99	1.81	-	-	-
Kuwait	-	0.07	0.27	-	-	0.14	0.06	-	0.34	0.07	0.71	-	-	1.32	-	0.13	-	0.14	-	-	-	3.25	2.90	2.73	1.08	1.24
United Arab Emirates	-	-	0.24	-	0.06	0.14	0.07	-	0.78	0.06	0.13	-	-	0.93	-	0.06	-	0.06	-	0.40	-	2.93	2.03	1.39	0.41	-
Middle East	-	0.07	0.57	-	0.12	0.76	0.13	-	2.24	0.13	0.91	-	-	2.68	-	0.79	-	0.40	-	0.66	-	9.45	6.88	4.24	3.06	3.35
Canada	-	-	-	-	-	-	-	-	-	0.06	-	-	-	-	-	0.18	-	-	-	-	-	0.24	0.47	0.42	0.75	1.28
Mexico	0.07	-	0.26	-	-	0.07	0.19	-	0.56	-	-	-	2.10	-	-	0.35	-	0.47	-	0.06	-	4.14	5.13	6.87	5.97	3.55
United States	-	-	-	-	-	-	-	-	-	0.06	-	-	-	-	-	1.71	-	-	-	-	(0.09)	1.68	1.82	1.17	1.83	3.26
North America	0.07	-	0.26	-	-	0.07	0.19	-	0.56	0.12	-	-	2.10	-	-	2.24	-	0.47	-	0.06	(0.09)	6.06	7.43	8.47	8.54	8.09
2016 Exports	11.52	0.78	44.34	6.28	0.51	3.45	16.59	24.97	18.57	4.32	8.14	7.36	4.04	77.24	10.84	10.57	5.58	2.88	-	4.46	(4.46)	257.97				
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

Note: Indonesia, Malaysia, India, and the UAE conducted domestic LNG trade in 2012- 2016. These volumes are not included above as they do not reflect international trade between countries. Sources: IHS Markit, IGU

3.5. Spot, Medium and Long-term Trade[3]

Historically, a large portion of LNG volumes have been traded under long-term, fixed destination contracts. Over the past decade, a growing number of cargoes have been sold under shorter contracts or on the spot market. This "non long-term" LNG trade[4] has been made possible by the proliferation of flexible-destination contracts and an emergence of portfolio players and traders. The growth of non long-term trade accelerated in 2011 owing to shocks like those that resulted from the Fukushima crisis and the growth of shale gas in the United States. However, the share of LNG traded without a long-term contract as a percentage of the global market has tapered off since 2013.

Short-term trade – defined here as all volumes traded under agreements of less than two years – accounts for the vast majority of all volumes traded without a long-term contract. In 2016, short-term trade reached 67.6 MT, or 25.8% of total gross traded LNG (including re-exports). Although this volume equates to a total growth of 1.65 MT relative to 2015, its share of total traded LNG declined by 0.6%. Several emerging markets like Pakistan and Malaysia began importing LNG under new long-term contracts in 2016; while other markets that typically rely very heavily on spot and short-term volumes, like Brazil, measured large drops in LNG imports. Further, the majority of new liquefaction projects that started operations in 2015 and 2016 in the Asia-Pacific region are supported by long-term contracts.

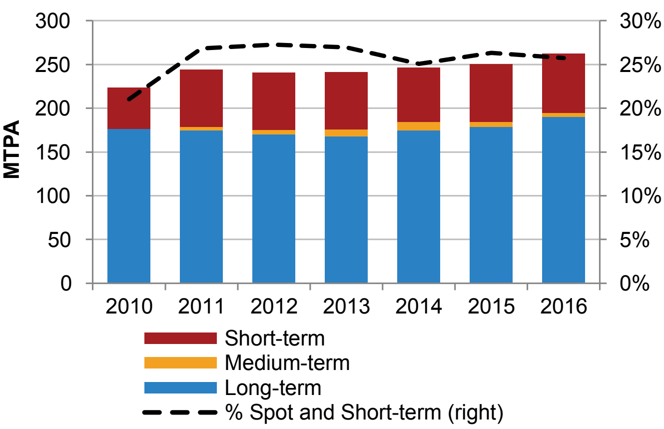
Volumes traded under medium-term contracts (between 2 and <5 years) remain a comparatively small portion of all non long-term trade. Medium-term deliveries declined for the second year in a row in 2016, falling to 4.7 MT from 6.0 MT in 2015, as several contracts were filled increasingly with short-term 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; and have been 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 72.3 MT in 2016 (+0.4 MT YOY) and accounted for 28% of total gross LNG trade—a 4% decline in share from 2015. This volume was 1.0 MT lower than the peak that non long-term trading reached in 2013, when Japan was turning heavily to the spot market to satisfy its post-Fukushima needs. Since then, the start-up of new projects underpinned by long-term contracts has led the non long-term market to decline consistently as a share of total traded LNG. Still, the volume of LNG traded without a long-term contract in 2016 is more than double the amount traded a decade ago. This 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 2016, 29 countries (including re-exporters) exported spot volumes to 35 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.
- 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.

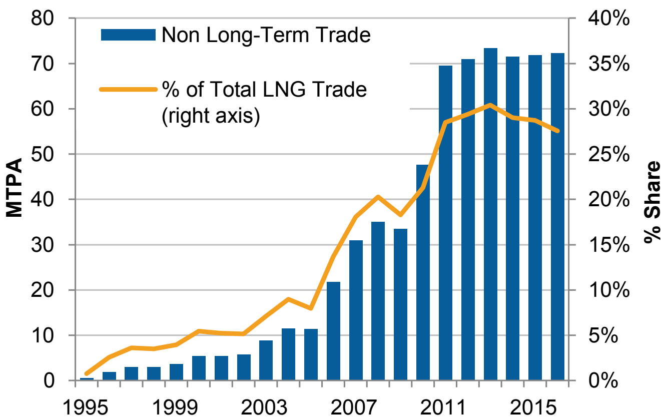
In 2016, trends among suppliers in the non long-term market closely followed those of the global LNG market as a whole. The largest growth in non long-term supply came from Australia. Although the majority of new Australian liquefaction projects are supported by long-term contracts, several of these are destination-flexible, and commissioning cargoes from six new trains also contributed to the country's 5.9 MT of YOY growth. The first two trains of the United States' first US GOM plant – Sabine Pass – are underpinned by destination-flexible contracts with LNG aggregators, and as a result

Figure 3.12: Short, Medium and Long-Term Trade, 2010-2016



Sources: IHS, IGU

Figure 3.13: Non Long-Term Volumes, 1995-2016

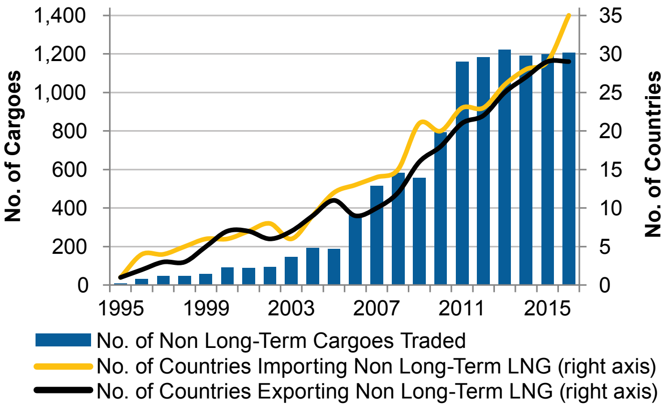


Sources: IHS, IGU

[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).

Figure 3.14: Non Long-Term Cargo Market Development, 1995-2016



Sources: IHS, IGU

68% of volumes delivered in 2016 (1.9 MT) were on the non long-term market. The expiration of older contracts also contributed to the increase in short-term trade, particularly in Malaysia, where deliveries grew by 1.2 MT YOY.

Most of the biggest declines in short- and medium-term trade were primarily the result of supply-side factors at individual exporters. Algeria, Nigeria, and Trinidad all saw non long-term deliveries fall by over 1.5 MT owing to production outages and feedstock shortfalls. Qatar's short-term deliveries fell by 2.2 MT, but this was the result of several new contract start-ups in Pakistan, Japan, and India.

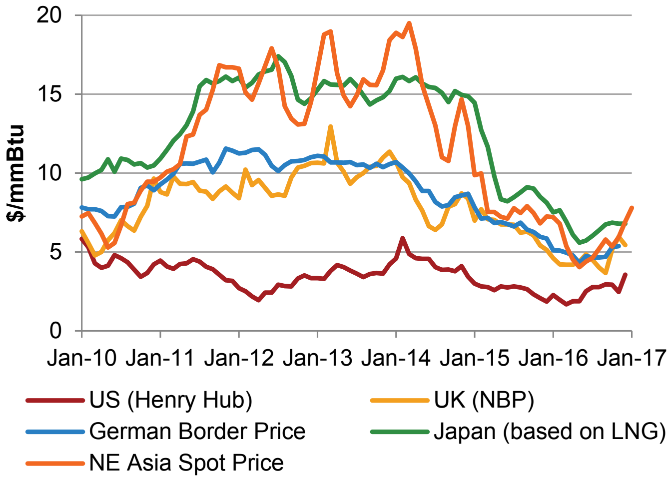
Continuing the trend from 2015, Egypt had the largest growth in non long-term imports. The market relies almost exclusively on one- or two-year tenders for its LNG supply, resulting in a 4.3 MT increase in short-term imports. Although the vast majority of China's total 6.9 MT of YOY import growth was satisfied by new long-term contracts, it still had over 1 MT of new non long-term imports as it turned to the spot market to cover high year-end demand. New medium-term contracts fuelled moderate gains in several countries in the Middle East – Kuwait and Jordan grew by 0.3 and 0.5 MT, respectively.

Because Brazil's LNG imports are sourced entirely from the spot and short-term market, its 4.1 MT demand decline was the largest drop in non long-term imports globally. This was followed by Japan, where the start-up of new long-term contracts, combined with lower total demand, brought a decline of 2.7 MT of non long-term imports. New long-term contracts were also responsible for a decrease in non long-term imports in Taiwan (-1.0 MT), and kept Pakistan's spot and short-term imports flat despite its 1.6 MT demand gain.

3.6. LNG Pricing Overview

LNG-related prices in 2016 had different drivers in each half of the year. With increasing supply and weak demand in the first six months of 2016, Asian and European spot prices and oil-indexed contract prices continued to weaken. By mid-year, supply disruptions and a recovery in oil prices began to influence prices upward. Colder winter weather in Asia and Europe, encouraged a run on spot volumes at the end of the year and hastened the run-up. By February 2017, landed

Figure 3.15: Monthly Average Regional Gas Prices, 2010 - January 2017



Sources: IHS, Cedigaz, US DOE

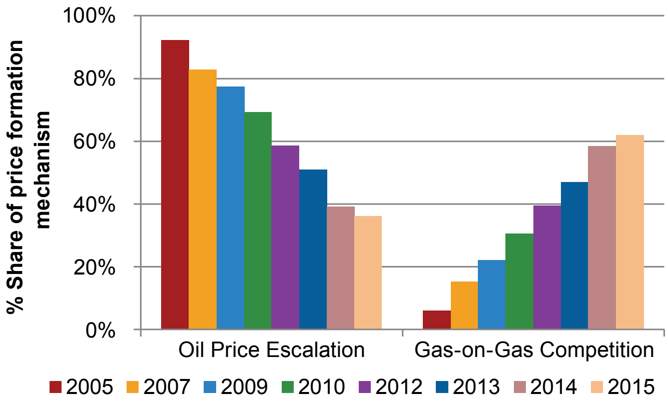
Asian LNG spot prices reached an average $9.55/MMBtu —their highest point since early 2015. While this resurgence is notable, spot prices are likely to once again face downward pressure in the coming years as new liquefaction capacity is added. In November 2016, the Organisation of Petroleum Exporting Countries (OPEC) and Russia reached a deal to limit oil production. If producers adhere to their new quota levels, oil prices could strengthen in 2017, which would consequently lend strength to oil-indexed LNG.

The supply outages and cold weather at end 2016 revealed that some tightness in the global LNG market is still possible, particularly in the winter. Asian spot prices rose, disconnecting from European prices and even rising above oil parity. During this time, price signals were so pronounced that US LNG began flowing to Asia. The delivered costs of US LNG provides an increasingly important reference point for global markets, given the flexibility of its destination-free supply as well as the liquidity and pricing transparency of the US market.

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.

Oil prices are particularly important for the LNG market. As oil prices fell in late 2014 through late 2016, 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 an average of $52/bbl in 2015 and $43/bbl in 2016. 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 oil price became apparent and continued through 2016. The Japanese import price averaged $9.77/MMBtu in 2015 and $6.59/MMBtu in 2016.

Figure 3.16: European Import Price Formation, 2005 to 2015



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 – 2016 Edition

Over the past six 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. 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; prompting Japanese, South Korean, Indian, and Indonesian companies, among others, to sign a number of offtake agreements based on Henry Hub linkage. However, as oil price has declined, buyer contracting activity from the US has also waned. 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.

Northeast Asian spot LNG prices fell steadily in the first half of 2016 as supply overwhelmed demand, but the opposite occurred in the second half when supply shortages and cold winter temperatures drove spot prices back up. Landed Asian spot LNG prices averaged $5.52/MMBtu during the year, although there was considerable volatility during the year. Prices fell to $4.05/MMBtu in May 2016 as supply overwhelmed demand, but climbed to $9.95/MMBtu by February 2017 owing to supply shortages and cold winter temperatures.

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.

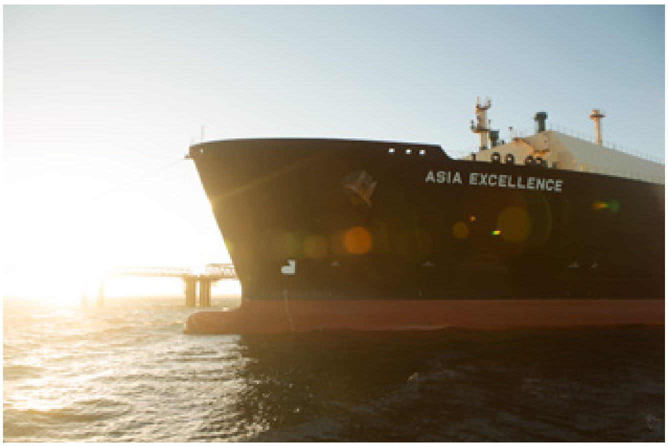
Similar to contracted Japanese LNG prices, the German border gas price – a proxy for contracted European gas import prices – began to reflect the fall in oil prices in 2015, averaging $6.80/MMBtu for the year and falling to $4.89/MMBtu during the first eleven months of 2016. Moreover, increased indexation to hub prices also contributed to lower border prices.

From mid-2014 to early-2016, low oil prices pulled prices at European gas hubs down; decreasing global spot prices for LNG also removed upward pressure on the UK NBP benchmark. Weak demand fundamentals in both power generation and the residential and commercial sectors (owing to warm weather) in the UK failed to provide a typical seasonal price rally. Following a slight lag in oil price recovery, the benchmark price at NBP rose in May and June 2016, but decreased in line with lower summer demand and ample supply; by September 2016, NBP hit a low of $3.67/MMBtu. Moving into winter, NBP prices began to recover, jumping 48% in three months to reach $5.44/MMBtu by December. The Rough storage outage in the UK was a contributor to price appreciation during this period. If LNG imports into the European continent increase substantially in the short run, it will put downward pressure on the UK NBP in the coming years.

As prices fell around the world, the market moved closer to price convergence; the differential between NBP and Northeast Asian spot prices narrowed to an average $0.91/MMBtu in 2016. Notably, the Northeast Asian spot price was at a discount to NBP for several months for the first time in six years. In May and June 2016, average Asian spot prices were ~$0.40/MMBtu lower than NBP.

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 reduced the growth of gas production in 2016, the volumetric impact is minimal relative to the size of US gas production. Further, reduced liquids activity has reduced the costs of rigs, crews, and equipment, which benefited operators. Downward price pressure will come from removing infrastructure constraints in Marcellus and Utica shale. In addition, end-market fuel competition with coal and renewables in the power sector will provide an upside limit. Renewables in particular have been promoted by the Clean Power Plan. On an annual basis, Henry Hub averaged ~$2.50/MMBtu in 2016 – the lowest level since 1999.

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.



Courtesy of Chevron.

Looking Ahead

What does the global LNG supply/demand balance hold? Incremental LNG supply growth in 2017 is likely to be similar to 2016, with additional supply from the US GOM, Australia, and South East Asia coming online. Given steady output from new trains and stabilized production at facilities that experienced production issues during 2016, supply growth is likely to outpace demand in 2017. Much of the new LNG supply will be located in the Pacific Basin during 2017, with the balance of new supply shifting to the Atlantic Basin in 2018. The result of most additional capacity coming online in the Pacific Basin means that the region will be less subject to supply-related price shocks, and further reduce arbitrage opportunities between basins.

To what degree will domestic market factors impact LNG imports? Questions surrounding nuclear power in established markets such as Japan and South Korea could aid LNG imports. The pace of gas industry-related reforms in nearby China will also be critical. Underserved gas markets such as India and Pakistan could benefit from lower prices, but midstream infrastructure may act as a limit to gas market growth. In Europe, the EU Commission's Strategy for LNG and Gas Storage could lead to higher LNG imports in the interest of supply security.

How will new project startups influence short-term trade in 2017? Of the 31.7 MTPA of new liquefaction startups in 2016, 72% were located in the Pacific Basin that held long-term contracts with primarily Asian buyers. In 2017, over 45 MTPA of new liquefaction capacity expects to begin commercial operations, 37% of which is either uncontracted, or contracted to Atlantic Basin aggregators. This increase in flexible-destination and Atlantic supply could support faster growth of spot and short-term trade in 2017. This trend will only accelerate in 2018, when roughly half of new liquefaction capacity expected online will be located in the US.

Courtesy of Chevron.

4. Liquefaction Plants

Global nominal[1] liquefaction capacity has grown to 339.7 MTPA as of January 2017, an increase of approximately 35 MTPA relative to end-2015. Project delays and outages during 2016 limited the effect of the anticipated imbalance in the LNG market. However, the pace of liquefaction investment continued to wane as a result of these expectations and capital spending constraints. Only two projects, totalling 6.3 MTPA, reached a final investment decision (FID) in 2016. Under-construction capacity totalled 114.6 MTPA as of January 2017. Projects are focused primarily in Australia, the continental United States (which began to export LNG in 2016), and on several floating LNG (FLNG) developments, the first of which is expected online in early 2017. With more than 55 MTPA of capacity online and more than 30 MTPA expected online in the next two years, Australia is expected to become the largest liquefaction capacity holder in 2018.

North America accounts for the majority of new liquefaction proposals, where 664 MTPA of capacity has been announced in the US and Canada, excluding 68.1 MTPA of existing and under-construction capacity in the continental United States. The anticipated LNG oversupply and structural shifts in some buyers' demand requirements have continued to slow the long-term contracting activity that is generally required to finance new projects. With numerous projects competing for offtakers, only the most cost-effective proposals are likely to advance during this period. The increasing proliferation of new, generally smaller LNG importing markets offers an array of contracting opportunities for liquefaction project sponsors. In some cases, these end-markets face infrastructure, regulatory, and credit-related hurdles that may limit the underpinning of new liquefaction projects in the near term.

4.1. Overview

339.7 MTPA
Global nominal liquefaction capacity, January 2017

Global nominal liquefaction capacity was 339.7 MTPA as of January 2017, an increase from 304.4 MTPA at end-2015. Four new projects totalling 31.7 MTPA of capacity began commercial operations in 2016: Gorgon LNG T1-2 (10.4 MTPA), GLNG T1-2 (7.8 MTPA), and Australia Pacific LNG T1 (4.5 MTPA) in Australia as well as the first two trains (9 MTPA) at Sabine Pass LNG in the United States. MLNG T9 in Malaysia (3.6 MTPA) began commercial operations in January 2017.

In 2017, project sponsors plan to bring 47.6 MTPA of nominal capacity online – 50% more than in 2016 – in the US, Australia, Cameroon, Malaysia, Indonesia, and Russia. Under-construction capacity was 114.6 MTPA as of January 2017, with two projects totalling 6.3 MTPA reaching FID in 2016[2]: Tangguh LNG T3 (3.8 MTPA) in Indonesia and Elba Island LNG (2.5 MTPA) in the United States. Australia Pacific LNG T2 also sent out commissioning cargoes in 2016; commercial operations are scheduled to begin in 2017.

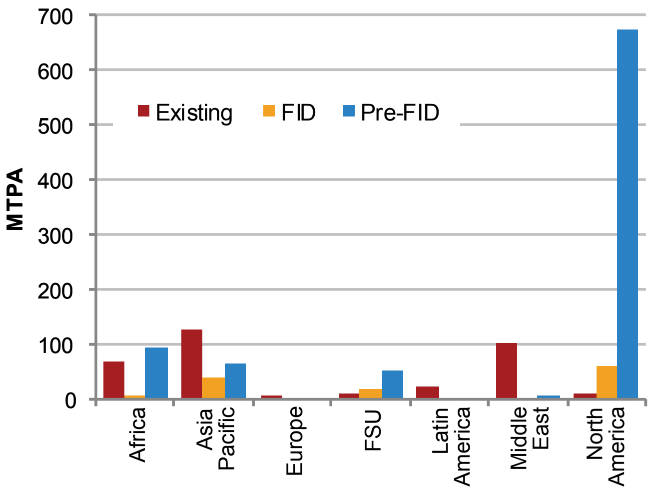
Together, the US and Australia will be the main contributors to new liquefaction capacity. Australia will have the largest liquefaction capacity in the world by 2018, with capacity expected to grow to 85 MTPA, up from 43.7 MTPA in 2016. In the US, 57.6 MTPA is under construction.

114.6 MTPA
Global liquefaction capacity under construction, January 2017

More than three quarters of the 879 MTPA of proposed capacity at end-January 2017 is located in the US and Canada (see Figure 4.1), though relatively few have made substantial commercial progress. Only 42% of proposed capacity in the US and Canada is at or beyond the pre-front end engineering and design (pre-FEED) stage. Australia, East Africa, and Russia also have major proposed liquefaction capacity. Across regions, the anticipated market oversupply, weaker demand growth in key import markets, decreased capital budgets, and project-specific hurdles, have slowed the pace of development.

Feedstock availability and security concerns continued to impact operations at several projects in 2016. In Egypt, Damietta LNG, remained offline due to limited feedgas production. After being offline since end-2014, Egyptian LNG (ELNG) exported several cargoes during 2016. In Yemen, LNG production was halted in early 2015 and remained offline as of January 2017 owing to the ongoing civil war in the country.

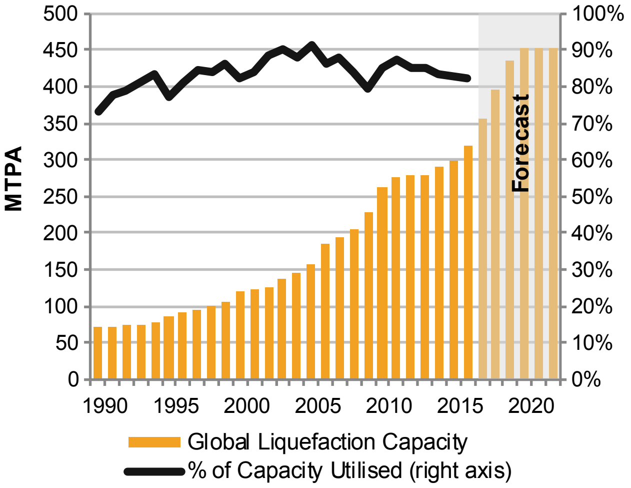
Figure 4.1: Nominal Liquefaction Capacity by Status and Region, as of January 2017



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

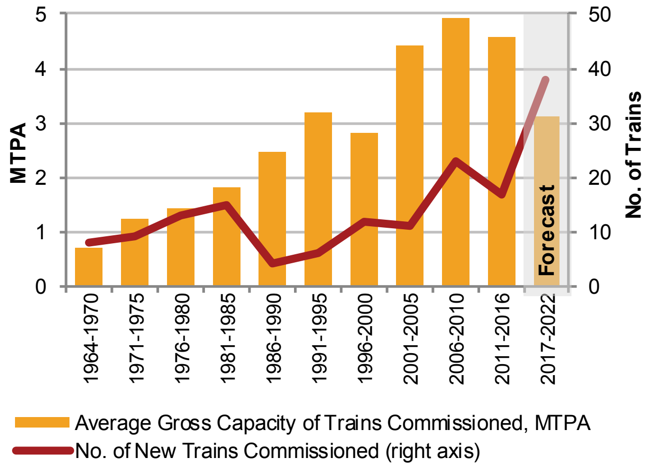
[1] Nominal liquefaction capacity refers to projects' nameplate capacities and is not prorated based on project start dates.
[2] Excludes Woodfibre LNG (2.1 MTPA) in Canada since the project was not under construction as of January 2017. Includes Elba Island LNG as it began onsite construction in 2016, although a formal FID has not been announced.

Figure 4.2: Global Liquefaction Capacity Build-Out, 1990-2022



Sources: IHS, Company Announcements

Figure 4.3: Number of Trains Commissioned vs. Average Train Capacity, 1964-2022



Sources: IHS, Company Announcements

4.2. Global Liquefaction Capacity and Utilisation

While LNG exports have grown, liquefaction capacity utilisation has declined slightly in recent years. Existing projects without declining feedstock availability or other challenges affecting output generally were highly utilised, while idled capacity at some projects removed potential volumes from the market. Utilisation in 2016 was 82%, below the average of 84% since 2010 (see Figure 4.2).

Several projects remained offline in 2016, and others faced production outages or feedstock shortages. As of January 2017, Yemen LNG was offline. Due to increased political violence, the project partners declared force majeure in mid-2015, which resulted in the stoppage of exports. Following extended repairs that caused the project to halt operations in 2014, Angola LNG resumed exports in 2016 but experienced multiple production outages during the year. In Australia, Gorgon LNG T1 also faced outages in 2016. A reduction in utilisation at Nigeria LNG was due in part to force majeure being declared on a feed gas pipeline in mid-2016. Declining domestic production contributed to falling exports from Algeria, Brunei, and Trinidad.

These losses were mostly balanced by strong utilisation at a number of existing projects. Qatar, Malaysia, Norway, Papua New Guinea, Russia, and the UAE all operated at or near full capacity in 2016. The United States saw an uptick in utilisation as Sabine Pass LNG exported its first cargoes in 2016. Utilisation remained flat in Australia despite start-ups at Gorgon LNG, GLNG, and Australia Pacific LNG during the year. Egypt resumed exports from ELNG in 2016, though overall utilization remained low. During the year, one of the ELNG partners concluded an agreement with the Egyptian government to send a small amount of feedstock, initially 125 million cubic feet per day (mmcfd) and reportedly increased to 250 mmcfd, to the plant for export.

4.3. Liquefaction Capacity by Country

Existing

Five countries: Qatar, Australia, Malaysia, Algeria, and Nigeria, account for more than sixty percent of the world's nominal liquefaction capacity. Qatar alone holds nearly one quarter of the total. No new countries have built liquefaction plants since Papua New Guinea in 2014, which brought the total number of countries with liquefaction capacity to nineteen[3] .

+35% by 2022
Expected growth in global liquefaction capacity

Under Construction

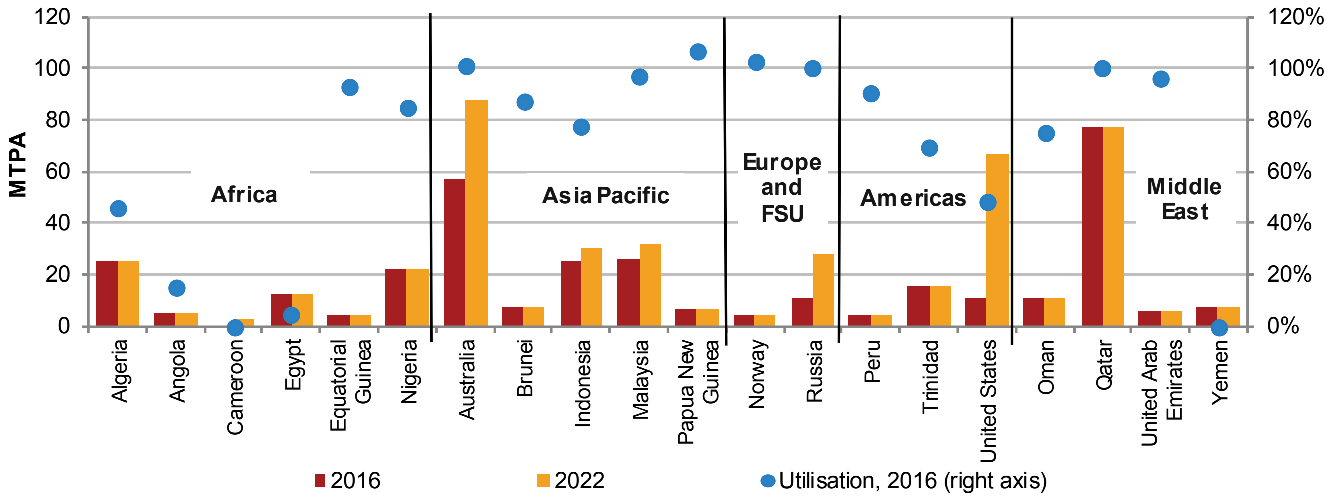
The majority of the 114.6 MTPA of under-construction capacity is located in the US (57.6 MTPA) and Australia (31.1 MTPA). Additional projects are under construction in Russia (16.5 MTPA), Malaysia (2.7 MTPA), Indonesia (4.3 MTPA), and Cameroon (2.4 MTPA)[4]. A second train at Australia Pacific LNG as well as PFLNG Satu are in the commissioning phase and expected to begin commercial operations in early 2017.

In 2016, Australia maintained its position as the second-largest LNG capacity holder, behind only Qatar. Over the next several years, it will be a major source of incremental supply growth. Five projects are under construction in the country and all are expected online by 2018, which will make Australia the world's largest liquefaction capacity holder.

The US will be the primary source of incremental liquefaction capacity over the next five years[5]. Six projects (57.6 MTPA) are under construction on the US GOM and East Coast (see Figure 4.4). The US currently only exports from two trains at Sabine Pass LNG located on the US Gulf Coast. The country previously exported small volumes from the Kenai LNG project in Alaska but did not do so in 2016. Three of the under-construction projects, both expansions and newbuilds, were sanctioned in 2015, and all are expected online by 2019. Elba Island LNG (2.5 MTPA) began onsite construction in 2016, though construction on the modular liquefaction units was reported to have begun offsite several years earlier. Apart from Corpus Christi LNG,

[3] Includes Yemen, which did not export cargoes in 2016. Although the US has exported from Kenai LNG in Alaska, the continental US began exporting in 2016 (not including re-exports). Projects in the continental US are utilising a different resource base.
[4] See Appendix II for a detailed list of under-construction liquefaction projects.
[5] Excludes proposed liquefaction capacity with announced start dates prior to 2022 that has not been sanctioned as of January 2017.

Figure 4.4: Nominal Liquefaction Capacity by Country in 2016 and 2022



Note: Liquefaction capacity only takes into account existing and under construction projects expected online by 2022.
Sources: IHS, IGU, Company Announcements

the under-construction projects are brownfield developments associated with existing regasification terminals.

In Russia, construction at Yamal LNG began in 2013 and continued throughout 2016. The first train is announced to come online in 2017, and all trains are scheduled to be operational by 2019. Once completed, it will bring Russia's total liquefaction capacity to 27.3 MTPA.[6] The project completed financing in 2016, which was previously a considerable obstacle.

Proposed

While the number of liquefaction proposals has increased significantly in recent years, totalling 879 MTPA in January 2017, proposal activity slowed in 2016 mainly due to the anticipated market imbalance, low oil prices, and uncertain long-term demand requirements. Projects will face significant competition given the relative size of the market.

The vast majority of this proposed capacity is in North America, where 59 liquefaction projects or expansion trains have been announced totalling approximately 671 MTPA[7]. Few have made significant commercial progress, however, and the actual capacity buildout is likely to be less than announced.

Most of the approximately 335 MTPA of proposed capacity in the US is located on the Gulf Coast. British Columbia on Canada's West coast accounts for most of the country's proposed 329 MTPA of capacity. While major LNG buyers are equity partners in several projects, their near-term interest in committing to long-term contracts may diminish in a market with many supply options. In contrast to most US projects, a number of these proposals require large upstream and pipeline investments.

In addition to the market risks noted above, the several projects proposed in Eastern Canada and Mexico face

Chevron LNG Journey to Japan – Courtesy of Chevron

[6] Excludes proposed liquefaction capacity with announced start dates prior to 2022 that has not been sanctioned as of January 2017.
[7] Excludes stalled and cancelled projects. 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).

feedstock availability challenges. Projects in Eastern Canada will likely require pipeline reversal and capacity expansion. Increased gas demand in Mexico has resulted in additional US pipeline (and, to a lesser extent, LNG) imports as domestic production declines. Mexico's two proposed liquefaction projects totalling 7 MTPA of capacity are therefore longer-term export opportunities.

The discovery of large gas reserves offshore East Africa has resulted in multiple liquefaction proposals in Mozambique (53.4 MTPA) and Tanzania (20 MTPA). Some East African projects made significant commercial progress during 2016, and an FID at Coral FLNG in Mozambique may be imminent. Based on announced start dates, several projects are planned to begin operations in the first half of the 2020s. In addition to broader LNG market conditions, projects in the region must contend with a lack of infrastructure and the completion of commercial and regulatory frameworks, though recent progress has been made. Several smaller FLNG proposals have quickly emerged in West Africa in addition to the under-construction Cameroon FLNG project. These include Fortuna FLNG in Equatorial Guinea, and most recently, a proposed cross-border development between Mauritania and Senegal.

A challenging operating environment, higher cost estimates, and, in some cases, lengthy estimated construction timelines have impacted some proposed projects in the Arctic and sub-Arctic. In Russia, Novatek is considering a gravity-based development as a means of potential cost reduction for its proposed Arctic LNG-2 (12-18 MTPA) project. The approximately 20 MTPA Alaska LNG project is estimated to cost approximately $45 billion and requires the construction of an 800-mile pipeline. The state of Alaska is evaluating several options to restructure the proposal and improve project economics after other partners withdrew from the project in 2016. A brownfield expansion train at Sakhalin-2 in Russia is announced to come online in the early 2020s, but has not yet reached FID.

Due to a high-cost environment, particularly in Australia, as well as competition with other proposed supply sources, Asia Pacific projects are planned as longer-term opportunities. Proposals in the region are based primarily on offshore reserves and totalled 63.5 MTPA as of January 2017. Project sponsors have not announced start dates for nearly 60% of proposed capacity (36 MTPA). Thirty-four percent (22 MTPA) of proposed capacity is composed of brownfield expansions of existing or under-construction capacity, while more than 35% (23 MTPA) plans to utilise FLNG technology. As feedstock at existing legacy projects in the region declines, projects like North West Shelf and Darwin have discussed backfilling existing trains in lieu of developing additional expansion trains or greenfield projects.

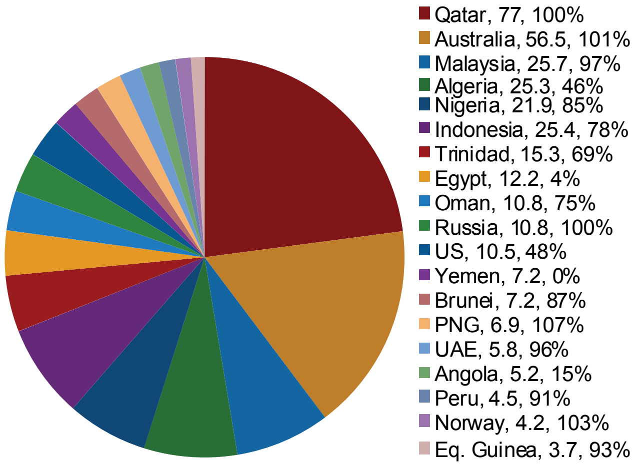
Decommissioned

Few projects are expected to be decommissioned over the next several years, and none were officially decommissioned in 2016. In Indonesia, Arun LNG 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. 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. However, in 2016 it announced plans to upgrade two trains at Arzew LNG.

While Kenai LNG in Alaska received a two-year extension of its export authorization in early 2016 it did not export cargoes during the year. Its export program for 2017 remains uncertain as ConocoPhillips has announced plans to sell the project. Due to declining feedstock, the project was shut down in 2012 but resumed operations in 2014, exporting cargoes during the summer months of 2014 and 2015.

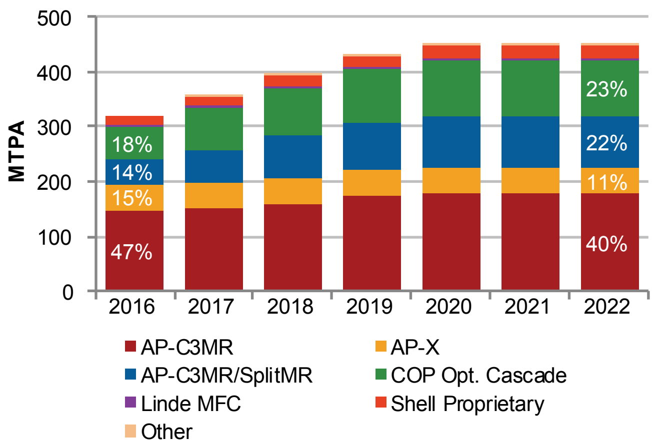
Declining domestic gas production and rising demand in Egypt has caused the country's two export projects, Damietta and ELNG, to be significantly underutilized. The country began importing LNG in 2015. Damietta LNG has been idled since 2012, and ELNG resumed modest exports in 2016 after not exporting in 2015. With the approximately 24 trillion cubic feet (Tcf)[9] Zohr discovery and developments in the West Nile Delta, Egypt plans to resume its status as a net exporter by 2021. This would be facilitated if further exploration success occurs and/or the Leviathan discovery in Israel or the Aphrodite

Figure 4.5: Nominal Liquefaction Capacity and Utilisation by Country, 2016[8]



Sources: IHS, IGU

Figure 4.6: Liquefaction Capacity by Type of Process, 2016-2022



Source: IHS

[8] Utilisation is calculated based on prorated capacity.
[9] Estimated recoverable reserves. Gas in place reserves are estimated at approximately 30 Tcf.

discovery in Cyprus is partly monetized via Egypt's LNG infrastructure through a shared arrangement.

Oman has announced it intends to decommission its export projects by 2025 to fulfil domestic demand. Discussions occurred throughout 2016 regarding a potential 1 billion cubic feet per day (Bcfd) gas agreement with Iran, which may backfill a portion of Oman LNG. The pipeline, with an estimated cost of $1-1.5 billion, needs to be rerouted to bypass the UAE's Exclusive Economic Zone, and negotiations over gas pricing remain a hurdle. The UAE is also considering various options to meet growing demand, including potentially decommissioning some of the ADGAS trains, when the project's long-term contracts expire in 2019.

4.4. Liquefaction Processes

The choice of liquefaction processes has become increasingly diverse in recent years. A number of designs have focused on new concepts, such as smaller and floating liquefaction trains.

Air Products' liquefaction processes accounted for nearly 80% of existing plants in 2016 (see Figure 4.6): the AP-C3MR™ process held the greatest share at 47%, followed by the AP-X® (15%) and AP-C3MR/SplitMR® (14%) processes. Air Products processes account for 68.2 MTPA (59%) of the 114.6 MTPA of capacity under construction as of January 2017. Cameron LNG and Yamal LNG have selected the AP-C3MR™ process, while Cove Point, Freeport LNG, Gorgon LNG, Ichthys LNG, and Tangguh LNG T3 use the AP-C3MR/SplitMR® design. PFLNG Satu uses the AP-N™ process. The large-scale AP-X® process has thus far been used exclusively in Qatari projects.

Air Products is therefore expected to retain its leading position. However, the ConocoPhillips Optimized Cascade® process will see strong growth with eight trains (35.9 MTPA of capacity) under construction as of January 2017. Sixty percent of the 35.3 MTPA of new capacity that came online since January 2016 utilises the Optimized Cascade® process. 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 pipeline-quality dry gas feedstock.

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. The use of these processes may allow developers to begin constructing liquefaction trains offsite, which in turn may help to reduce costs. In North America, multiple projects have been proposed based on small-scale modular liquefaction processes, such as IPSMR® (Chart Industries), OSMR® (LNG Limited), and PRICO® (Black & Veatch). The 2.5 MTPA Elba Island LNG project in the US, which began onsite construction in 2016, will utilise Shell's Movable Modular Liquefaction System (MMLS) process.

4.5. Floating Liquefaction

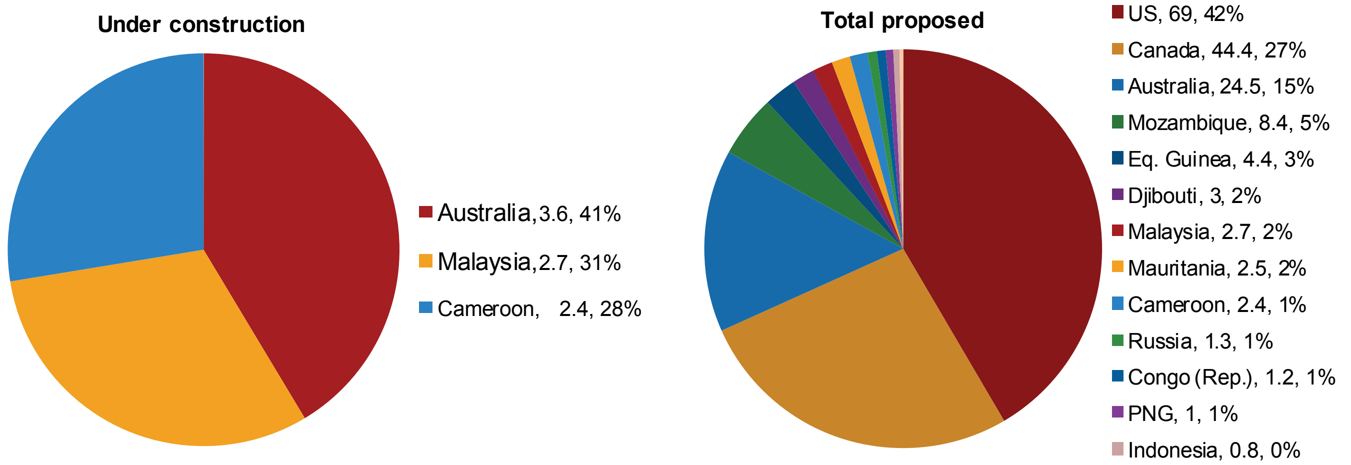
156.9 MTPA
Proposed FLNG capacity as of January 2017[10]

Numerous FLNG projects, particularly small-scale, are under development as the pace of onshore liquefaction proposals has slowed. Four FLNG projects in Australia, Malaysia, and Cameroon totalling 8.7 MTPA were under construction as of January 2017 (see Figure 4.7). The first two projects, PFLNG Satu and Cameroon FLNG, are expected to begin operations in 2017, and all four are scheduled to be online by 2020.

An additional twenty-four FLNG proposals totalling 156.9 MTPA have been announced as of January 2017, principally in the US, Canada, and Australia. Others are proposed to be located in the Republic of the Congo, Djibouti, Equatorial Guinea, Indonesia, Iran, Mauritania and Senegal, Mozambique, Papua New Guinea, and Russia.

FLNG projects can be based on several development concepts – purpose-built, near-shore barge, and conversions. They generally aim 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. In many cases, they are smaller in capacity compared with onshore proposals. In some instances, FLNG projects reportedly have lower cost

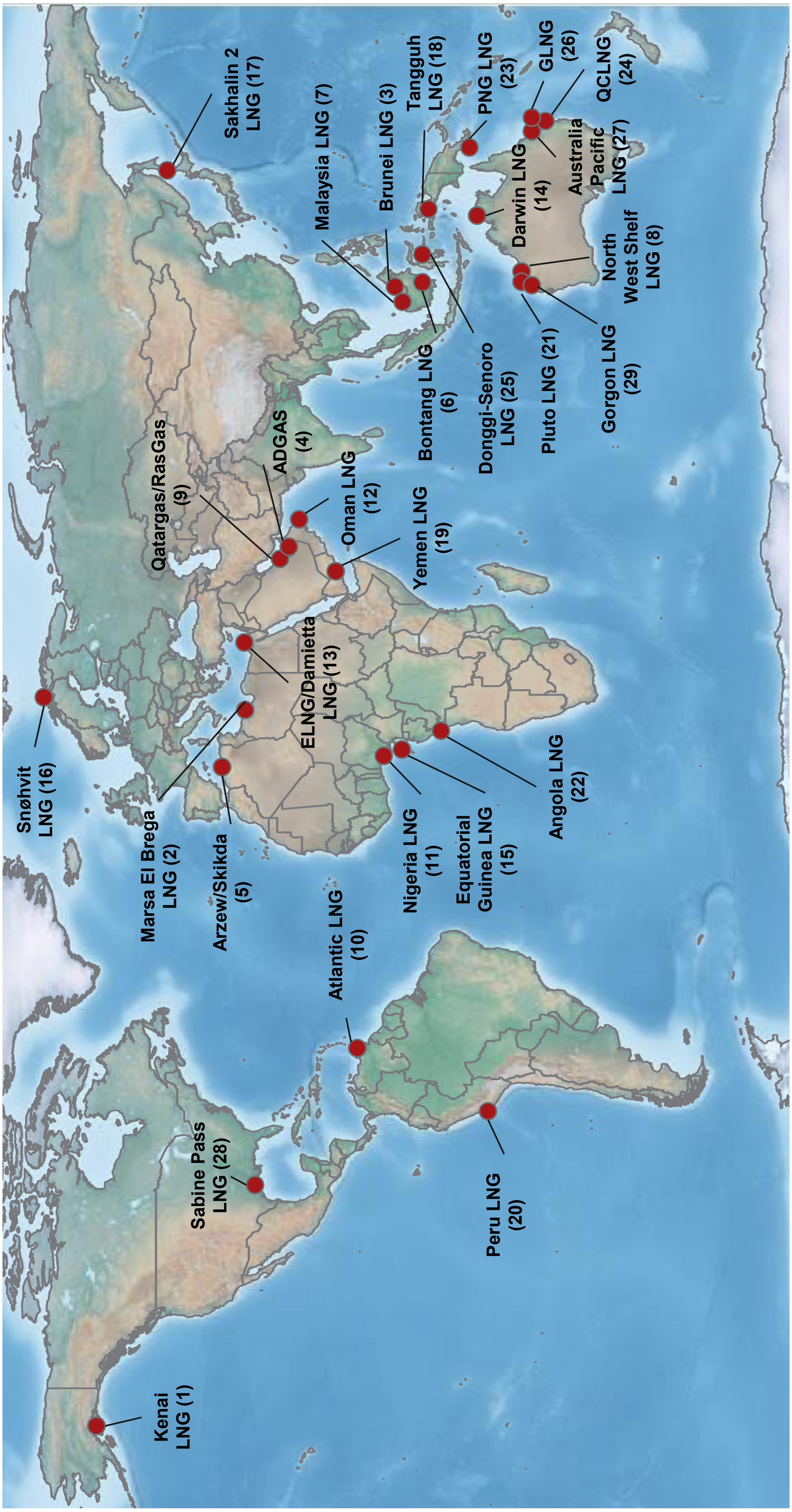
Figure 4.7: Under Construction and Total Proposed FLNG Capacity by Country in MTPA and Share of Total, as of January 2017



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

[10] This number is included in the 879 MTPA of total proposed global liquefaction capacity quoted in Section 4.1. Excludes the 8.7 MTPA of FLNG capacity currently under construction.

Figure 4.8: Global Liquefaction Plants, as of January 2017



Source: IHS

2015–2016 Liquefaction in Review

Capacity Additions **+31.7 MTPA** Year-over-year growth of global liquefaction capacity in 2016	New LNG Exporters **1** Number of new LNG exporters since 2014	US Build-out Begins **9 MTPA** Continental US capacity online in 2016	Floating Liquefaction **8.7 MTPA** FLNG capacity under construction as of January 2017
Global liquefaction capacity increased from 304.4 MTPA in 2015 to 336.1 MTPA in 2016 114.6 MTPA was under construction as of January 2017 879 MTPA of new liquefaction projects have been proposed as of January 2017, 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, 57.6 MTPA of export capacity was under construction in the US as of January 2017 335.2 MTPA of capacity is proposed in the US, excluding under-construction projects, though a number of projects face commercial obstacles	156.9 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 commercialize gas from smaller, stranded offshore fields relatively quickly

estimates, though only once projects begin operations will greater cost certainty be established.

Three of the four under-construction FLNG projects – Prelude (3.6 MTPA), PFLNG Satu (1.2 MTPA), and PFLNG 2 (1.5 MTPA) – are utilising purpose-built vessels. As of January 2017, PFLNG Satu was in commissioning, with its first cargo expected shortly. In early 2016, construction of PFLNG 2 was put on hold. The proposed 3.4 MTPA Coral FLNG project offshore Mozambique would use a similar approach and achieved several milestones in 2016 and early 2017 as an offtake agreement was finalised and several of the partners have sanctioned the project. Eni is seeking FID in 2017 and start-up by 2022.

Cameroon FLNG, a 2.4 MTPA FLNG conversion, was the latest FLNG project to take FID, in 2015. Fortuna FLNG in Equatorial Guinea (2.2 MTPA) is seeking FID in 2017. In 2016, the cross-border Greater Tortue FLNG project was proposed to commercialize the approximately 15 Tcf field that straddles Mauritania and Senegal. The 2-3 MTPA proposal is also considering a vessel conversion and currently expects to begin exports in 2021. The project would be a cross-border development and require alignment between Mauritania and Senegal. There is precedent for cross-border developments with Darwin LNG in Australia, which sources feedstock from the Joint Petroleum Development Area shared between Australia and Timor-Leste.

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. Costs may be relatively lower accordingly, but as with any liquefaction project – particularly those seeking to implement a development scheme for the first time – there is the potential for design changes.

The 0.5 MTPA Caribbean FLNG project offshore Colombia was originally slated to be the first operational floating project. In early 2015 Pacific Rubiales announced delays due to commercial conditions, and the project was cancelled altogether in 2016. Exmar is seeking opportunities to place the vessel elsewhere for liquefaction work. In Canada, the Douglas Channel FLNG partners – Altagas, Idemitsu, EDF Trading, and Exmar – halted development of the project in early 2016.

Only two under-construction FLNG projects, Prelude and Cameroon FLNG, have announced binding offtake agreements. One proposed project, Coral FLNG, has contracted its full capacity. Given the expected weakness in near-term market fundamentals, uncontracted FLNG projects may face marketing challenges similar to onshore projects. That said, with a smaller parcel size than large land-based projects, some FLNG projects may find it easier to secure offtakers and reach FID in the near term.

FLNG project sponsors are increasingly assessing the potential of smaller capacities, which may facilitate the optimization of project costs and attract buyers with smaller volume requirements. For example, the Browse FLNG partners in Australia put the 11 MTPA project on hold in 2016 and are examining smaller-scale options.

4.6. Project Capital Expenditures (CAPEX)[11]

Project costs will be an important determinant of which projects are sanctioned as the market oversupply likely deepens in 2017. 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

[11] 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.

Sabine Pass LNG – Courtesy of Cheniere

removal as well as dehydration. Figures 4.9 and 4.12 include additional information on average liquefaction project costs by construction component and expense category.

Cost escalation has been considerable, with several projects reporting cost overruns in the range of approximately 30% to 50% relative to estimates at FID. Unit costs[12] for liquefaction plants increased from an average of $413/tonne in the 2000-2008 period to $987/tonne from 2009-2016. Over the same periods, greenfield projects increased from $507/tonne to $1,389/tonne, while brownfield projects only increased to $532/tonne, up from $329/tonne (see Figure 4.10). The commencement of operations at the first FLNG projects beginning in 2017 will likely provide additional clarity on FLNG costs.

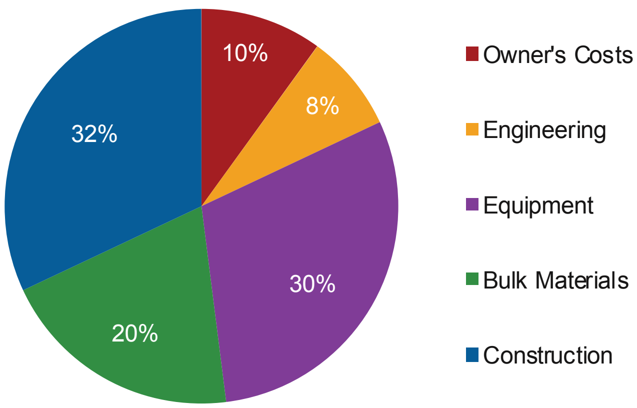
With numerous projects starting construction in close succession, higher input and labour costs became common due to global competition for engineering, procurement and construction (EPC) services. Cost escalation has been pervasive in both the Atlantic and Pacific Basins, though Australia has been particularly affected due in part to exchange rate fluctuations and skilled labour shortages. The challenges associated with complex upstream resources and/or difficult operating environments, such as CBM in Eastern Australia, deepwater fields in Asia Pacific, and Arctic environments in Norway and Russia, have contributed to delays at numerous projects, driving 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, if sustained, may reduce overall capital expenditure requirements. There has also been greater pressure from project sponsors to optimize EPC costs over the past year in order to increase projects' competitiveness in an oversupplied market.

$1,541/tonne
Weighted average expected cost for greenfield projects announced to come online between 2017 and 2022

Middle Eastern projects generally remained low-cost in the 2009-2016 period, averaging $452/tonne, largely due to the lower cost of brownfield expansions in Qatar. Conversely, projects in both the Pacific and Atlantic Basins experienced significantly higher costs during 2009-2016 relative to 2000-2008 (see Figure 4.11). The Pacific Basin had the highest increases, with per unit liquefaction costs nearly quadrupling from $347/tonne to $1,373/tonne between the same periods due in part to cost escalation at some projects. The average unit liquefaction cost for Atlantic Basin LNG projects rose to $1,221/tonne from 2009-2016, compared to $461/tonne from 2000-2008. Although ultimate FLNG costs are not yet clear, several FLNG projects based on vessel conversion schemes have had lower announced cost estimates relative to onshore greenfield and FLNG newbuild proposals.

Figure 4.9: Average Cost Breakdown of Liquefaction Project by Construction Component [13]

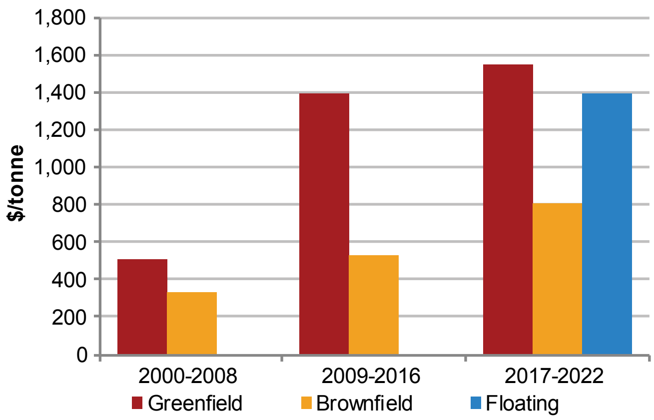


Source: Oxford Institute for Energy Studies

[12] All unit costs are in real 2014 dollars.

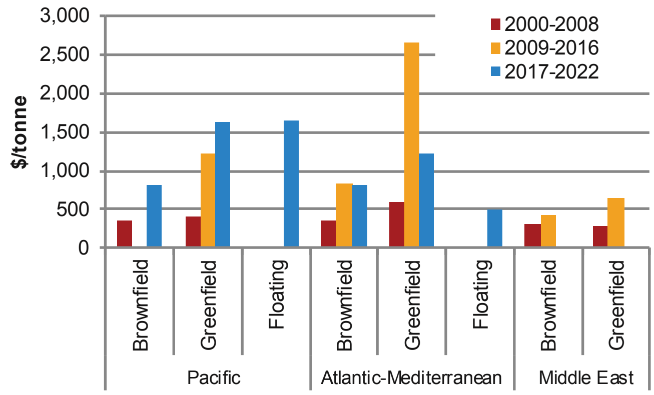
[13] According to the Oxford Institute for Energy Studies paper, "LNG Plant Cost Escalation", equipment costs include the cryogenic heat exchangers, compressors and drivers, power plant, and storage tanks. Bulk materials are assumed to refer to steel and other raw materials. Owner's costs include all technical and commercial components of project management prior to the commencement of operations, including costs associated with contractors/consultants for pre-FEED and FEED, environmental impact studies, and contract preparation prior to FID, as well as working with financiers and government and regulatory authorities.

Figure 4.10: Average Liquefaction Unit Costs in $/tonne (real 2014) by Project Type, 2000-2022



Sources: IHS, Company Announcements

Figure 4.11: Average Liquefaction Unit Costs in $/tonne (real 2014) by Basin and Project Type, 2000-2022



Sources: IHS, Company Announcements

Based on cost announcements and the advantages associated with existing infrastructure, brownfield projects will generally be competitive with greenfield developments in terms of unit costs of liquefaction capacity. Five of the six liquefaction projects under construction in the US are brownfield projects associated with existing regasification terminals. Unit costs for these continental US brownfield projects average $807/tonne, well below the $1,508/tonne associated with under-construction greenfield projects globally.

Dry gas to be sourced by most US projects 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. Contractors therefore run the full risk of project cost over-runs.

For most projects globally to move forward, developers will need to secure long-term contracts to underpin project financing. Lower oil prices and demand growth in major import markets would in many cases weaken project economics and make this task a more difficult undertaking. In some cases, high costs are expected to be a major source of delay for some greenfield projects. Relatively low upstream development costs reported by some project developers could potentially improve economics.

Apart from high liquefaction costs, greenfield projects proposed in Western Canada and Alaska require lengthy (300 miles or more) pipeline infrastructure. Integrated Western Canadian projects have announced cost estimates of up to $40 billion, while in Alaska the estimate was revised downward in 2016 to approximately $45 billion from $45-65 billion previously.

4.7. Risks to Project Development

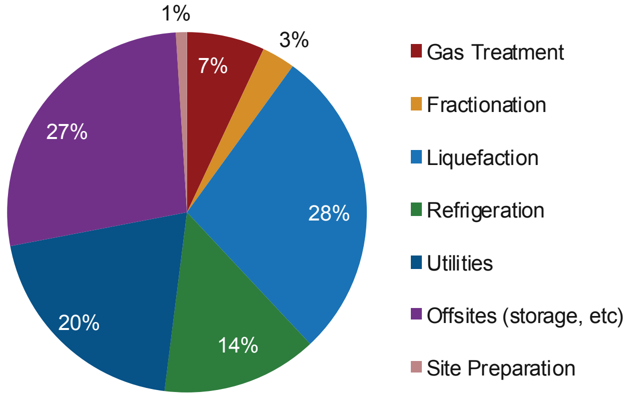
As with other major infrastructure projects, liquefaction plants face a variety of commercial, political, regulatory, and macroeconomic risks that may affect the pace of project development. In the case of liquefaction projects, these include project economics, politics and geopolitics, environmental regulation, partner priorities and partners' ability to execute, business cycles, domestic gas needs and fuel competition, feedstock availability, and marketing and contracting challenges.

Low oil prices and the expectation of challenging market conditions for project sponsors over the next several years have in particular highlighted risks associated with project economics, partner priorities, and marketing. Timelines for a number of projects, particularly those with high cost estimates and either no buyers or those with uncertain demand requirements, have been pushed back by several years. In 2016, several projects facing such risks were delayed or cancelled, and additional delays or cancellations are possible going forward.

Project Economics

With high cost estimates a leading obstacle to project development – particularly as the LNG market becomes increasingly oversupplied and if oil prices remain low – some

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



Source: Oxford Institute for Energy Studies project sponsors have sought to optimize costs and, in some cases, development concepts. Especially in emerging liquefaction regions, challenging or uncertain fiscal and regulatory regimes, are an additional risk.

Politics, Geopolitics, and Environmental Regulation
Political and regulatory risk exists in both developed and developing liquefaction regions, though significant geopolitical risks and instability have tended to be more associated with developing markets.

Several developed supply regions have stringent regulatory and environmental approval processes for liquefaction projects, which can be time consuming and costly. For instance, environmental permitting for US brownfield developments has taken nearly two years or more. Other countries, such as Tanzania, are still developing regulatory and legislative frameworks for LNG in order to provide greater certainty to project sponsors. This process will govern the pace of project development.

Political instability and sanctions can affect projects both prior to FID and while they are operational. It has delayed the development of additional liquefaction capacity in Nigeria and several other countries. Ongoing civil war has halted operations at Yemen LNG since early 2015.

The easing of sanctions against Iran in 2016 has removed some obstacles to foreign investment and participation in Iran's gas sector, and there has been a revived interest in Iranian LNG exports as a result. However, the country's LNG ambitions remain challenged. Sanctions that remain in place prevent Iran from obtaining US-sourced liquefaction technology, which maintains a majority of market share. US companies are still unable to invest in the country's energy sector, and secondary sanctions against non-US entities, such as financial institutions, may complicate financing efforts.

Partner Priorities, Ability to Execute, and Business Cycles
There must be stakeholder alignment before a project can proceed. Projects with multiple partners must, in some cases, contend with divergent priorities. Smaller companies may be unable or unwilling to commit to investments, particularly for large-scale proposals, while larger players are frequently in the position of choosing between several large opportunities in their respective portfolios. Even for projects with one shareholder, they must consider the project in relation to other options in their portfolio, if applicable. These factors can impact project sanctioning.

Moreover, many of the large number of projects proposed in recent years are being developed by new LNG players with no direct experience in liquefaction, particularly in North America. 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 financing and offtakers.

Macroeconomic, market conditions and commodity cycles are also considerations in project sanctioning. Low oil prices have caused many companies to reduce capital spending over the past few years, resulting in numerous project deferments, likely pending a price recovery. The number of new project proposals similarly slowed in 2015 and 2016.

Table 4.1: Liquefaction Project Development Risks

Risk Factors	Impact on LNG Project Development
Project Economics	Long-term sales contracts that allow for a sufficient return typically underpin the financing of LNG projects. High project costs or changing market prices can have a large impact on when or if a project is sanctioned, and cost overruns post-FID can impact project returns.
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 pipeline gas or 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. In some cases, it may also limit the life of existing projects.
Marketing/Contracting	Project developers generally need to secure long-term 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

Chevron LNG Journey to Gorgon.– Courtesy of Chevron

Shifts in country-specific demand fundamentals (e.g., economic downturn in China or deregulation in the Japanese power and gas sectors) have increased the uncertainty of several countries' LNG import requirements. With strong supply additions and unpredictable demand in key markets, buyers remain hesitant of new long-term obligations.

Feedstock Availability, Domestic Gas Needs, and Fuel Competition

Countries with declining production and growing demand have tended to prioritize gas for domestic consumption over LNG exports. Feedstock originally allocated to Egypt's export plants has been mostly diverted to the domestic market, resulting in the closure of Damietta LNG in late 2012 and the cessation of exports at ELNG in 2014 – though ELNG did resume small exports in 2016. While production from fields associated with these projects is set to continue to decline over time, the West Nile Delta and Zohr developments could potentially revive domestic production growth in the longer term. Both are expected to commence production in 2017. Additional successful exploration efforts in surrounding areas and/or the Leviathan and Aphrodite discoveries could alleviate feedstock constraints if monetized partially via Egypt.

Growing domestic demand and declining domestic production has also impacted Indonesia, UAE, Malaysia, Oman, and Trinidad, which may eventually result in lower LNG exports or, in some cases, exports being halted. New or brownfield export proposals, including those in Malaysia, Mexico, and Algeria may also be impacted. Additionally, feedstock challenges in Eastern Australia may impact utilisation of the three CBM-to-LNG projects in Gladstone and have led to LNG imports being proposed. Certain drilling restrictions and capital spending reductions have hindered domestic production growth while significant volumes have been contracted for export as LNG.

Additionally, the competitiveness of LNG relative to pipeline gas (if applicable) and alternate fuels – both in terms of project returns and downstream economics – remains a major factor that can affect liquefaction project investment decisions.

Marketing and Contracting

With liquefaction capacity set to expand to more than 450 MTPA by 2020, mainly due to growth from under-construction projects in Australia and the US, there will be greater competition amongst proposed projects to secure long-term buyers. Some under-construction projects have also not yet signed offtake contracts for their full capacities.

Shorter-term contracts have become increasingly common over the last several years as a number of new buyers have entered the market. In some cases, the anticipated LNG surplus has reduced buyers' interest in long-term contracting, at least for the time being. In many cases, however, longer-term agreements will be necessary for projects to secure financing. Some buyers desire greater diversity in pricing structures, and a growing number of contracts, which have traditionally been linked to oil, show multiple oil, gas, and other benchmarks.

Companies that have traditionally served as foundational buyers, such as aggregators, may have portfolios that may require or benefit from full destination flexibility in their contracts. The amount of flexible-destination LNG on the market is expected to increase significantly, in part driven by US offtake agreements that are free of destination restrictions. Additionally, Japan in 2016 began an investigation of destination restrictions in its contracts and may seek to remove them; it is also likely to pursue only destination-flexible contracts moving forward. Fixed-destination contracts actually became prominent again in 2016 as a number of new contracts and tenders were awarded by buyers seeking volumes for their own markets. In a number of cases, these were buyers in emerging markets. As the pace of FIDs increases again, the split between fixed- and flexible-destination contracts may evolve further.

The emergence of the US as a major LNG supply source will increase the prominence of the tolling model, in which the market risk is shifted to the tolling customer. Most US projects are being developed as pure or hybrid tolling facilities. 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. In a hybrid model, the project owner additionally procures feedstock on behalf of the offtaker and charges a marketing and transportation margin above a benchmark price, such as Henry Hub. While the take-or-pay model offers developers and lenders greater revenue certainty, tolling customers face financial exposure if price fluctuations or changing demand fundamentals incentivize them to turn away cargoes.

4.8. Update on New Liquefaction Plays

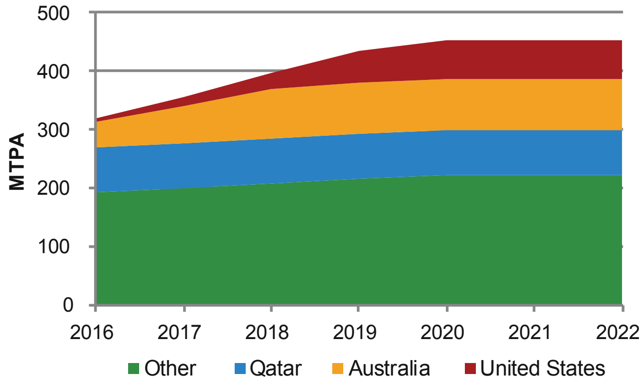
Despite market headwinds, there was significant commercial and regulatory progress made in several emerging liquefaction regions during 2016. However, the potential for sustained low oil prices and continued expectations of an LNG oversupply are testing projects' competitiveness globally, and the number of new project proposals similarly slowed in 2015 and 2016. Although regulatory certainty generally improved in 2016, remaining political risks also have the potential to lengthen development timelines in several regions.

United States

In 2016, the continental US began exporting LNG for the first time.[14] Two trains totalling 9.5 MTPA at Sabine Pass LNG were operational as of January 2017, and six projects totalling 57.6 MTPA of capacity were under construction as of January 2017.

The US has been widely perceived as among the lowest-cost sources of LNG on a long-term basis due to the brownfield nature of many developments[15] and relatively inexpensive feedstock. In the near term, however, the competitiveness of Henry Hub-linked LNG is a major development risk for US projects that have not reached FID. Over the past two years, the price differential between oil-linked and Henry Hub-linked contracts has narrowed, though price differentials will widen should oil prices continue to recover. Low oil prices have also caused many companies to reduce capital spending, resulting in numerous project deferments.

Figure 4.13: Post-FID Liquefaction Capacity Build-Out, 2016-2022

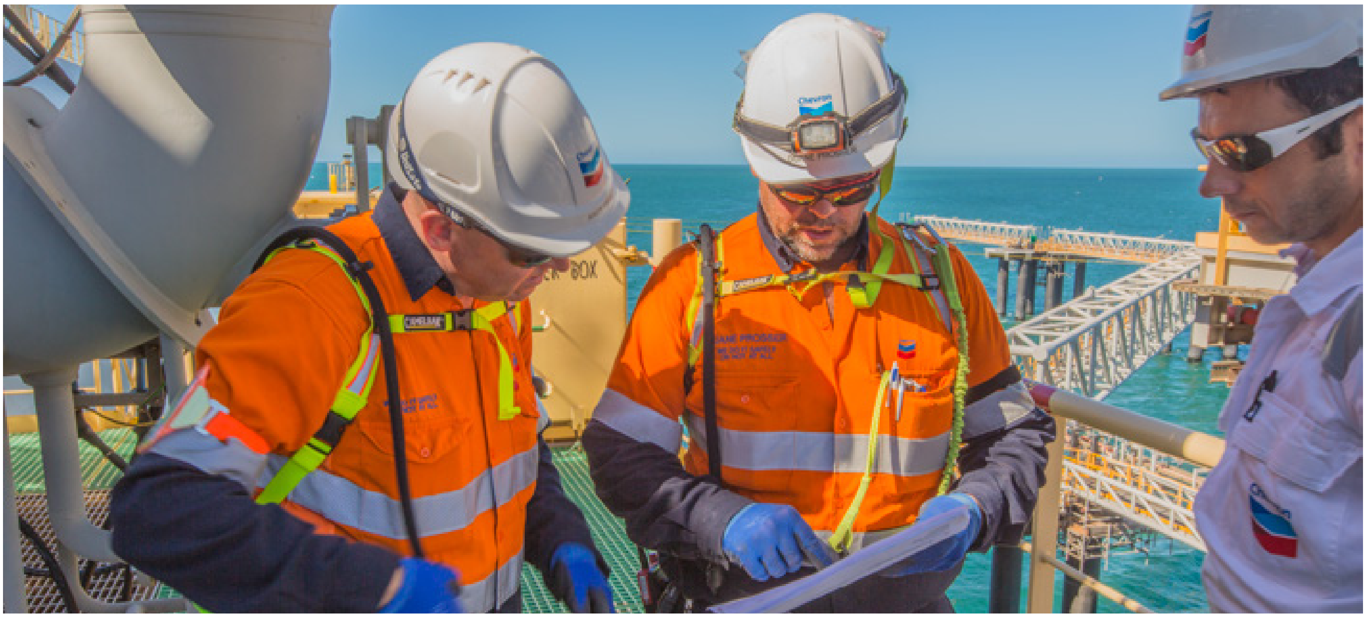


Note: This build-out only takes into account existing and under construction projects. Sources: IHS, Company Announcements

Only 10 MTPA of binding and non-binding offtake agreements were signed in 2016 through January 2017, out of approximately 102 MTPA[16] in total from US projects so far. Given market conditions, it may be difficult for projects to proceed in the near term. Lake Charles LNG delayed FID in 2016, though its capacity is fully subscribed by one aggregator. No new FID date has been specified. Several other uncontracted or partially contracted projects were delayed or cancelled during 2016 due in part to marketing challenges.

In light of these challenges, some US project sponsors have demonstrated considerable commercial flexibility. Some have considered low tolling fees and alternative pricing structures; others have made or are considering making downstream investments in order to provide a market for their LNG. Tellurian, sponsor of the 26 MTPA Driftwood LNG project, secured multiple equity investments in 2016, including from TOTAL.

Regulatory certainty has increased but remains time-consuming and costly, though some expansion trains at



Chevron LNG Hook-up – Courtesy of Chevron

[14] Excluding previous re-exports of imported LNG.
[15] Five of the six projects under construction are brownfield projects associated with existing regasification terminals, while the sixth is a former regasification proposal.
[16] Excludes contracts deemed to have been cancelled or lapsed, those with unknown counterparties, as well as Cheniere Marketing's options to take volumes not required by other customers at Sabine Pass and Corpus Christi LNG.

projects already under construction may be able to complete the regulatory process more quickly. 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 Department of Energy (DOE).[17]

Eleven[18] projects have now moved through the FERC environmental review process, including four in 2016: Cameron LNG T4-5, Elba Island, Golden Pass, and Magnolia LNG. While there is greater clarity regarding expected timelines and costs, FERC also denied approval of an LNG export project for the first time in 2016. FERC did not approve the 6 MTPA Jordan Cove LNG project and its associated pipeline, citing concerns that the pipeline had not demonstrated sufficient commercial need to outweigh landowner concerns. After an unsuccessful appeal, the sponsor plans to submit a new application. Most other projects in the continental US do not require significant new pipeline infrastructure and so may be less likely to face the same obstacles.

Canada

In contrast to most US projects, nearly all projects proposed in Canada, with the exception of Canaport LNG, are greenfield developments. A number of them require lengthy pipeline infrastructure and plan to utilise an integrated structure, in which partners' upstream resources are dedicated as feedstock for the project. In some cases, these factors have contributed to higher cost estimates at Canadian projects relative to proposals elsewhere.

The inability to secure buyers has been a major impediment to the development of many LNG projects in Western Canada. To date, few binding offtake contracts elsewhere have been signed, though several projects have offtakers as equity partners. Decisions to reduce capital spending, combined with the availability of potentially more cost-effective sources of supply and weakened demand growth in some buyers' home markets, has reduced momentum and contributed to delays and cancellations at several projects.

In 2016, LNG Canada postponed FID to an undetermined date, citing capital spending considerations. After receiving a long-delayed environmental approval in 2016, Pacific Northwest LNG is currently undertaking a full review of the project before determining whether to proceed. It previously reached a conditional FID in 2015. Partners at both projects plan to offtake volumes in proportion to their equity stakes.

Douglas Channel FLNG halted development in early 2016, and the nascent Triton FLNG proposal was stalled several months later. An internationally-focused expansion to 3 MTPA of the Tilbury LNG facility, an existing micro-scale plant serving local and regional markets, was scrapped after its contract to supply Hawaii Electric lapsed. In Q4 2016, Woodfibre LNG (2.1 MTPA) announced that its parent company had authorized funding. This is unusual in that the project is still in the FEED phase and has not fully completed the regulatory process or concluded binding offtake agreements.

Canada's environmental approval process is fairly well established but is nonetheless rigorous. Approval must be obtained from each First Nations groups impacted by the projects, including those along associated pipeline routes. In some instances, First Nations and other local opposition has emerged as a significant hurdle.

In Canada, projects must receive environmental and export approval from the Canadian Environmental Assessment Agency (CEAA) and the National Energy Board (NEB), respectively. In some cases, a provincial environmental assessment can be a substitute for a federal environmental assessment. Reviews generally take nearly two years to complete, though the review of Pacific Northwest LNG, had faced significant delays prior to receiving environmental approval in September 2016. Kitimat LNG also has all environmental approvals and is working toward further development, with no announced FID date.

Only a few projects have been approved, with most proposals yet to begin the process. In 2016, the Canadian federal government announced its intention to incorporate direct and upstream greenhouse gas emissions into its environmental review process. In some cases, a provincial environmental assessment can substitute the federal environmental assessment process.

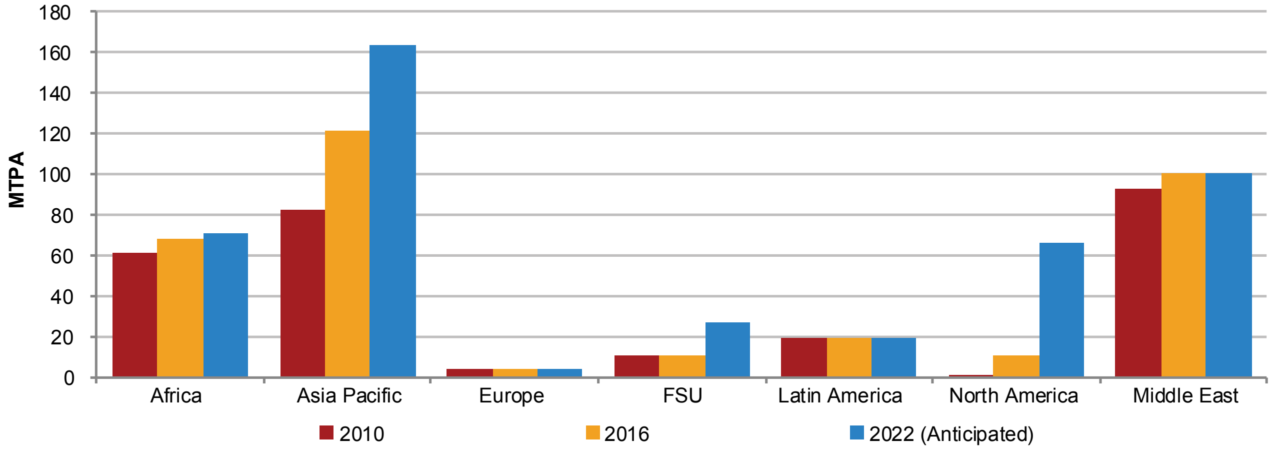
Table 4.2: Nominal Liquefaction Capacity by Region in 2010, 2016, and 2022

Region	2010	2016	2022 (Anticipated)	% Growth 2010-2016 (Actual)	% Growth 2017-2022 (Anticipated)
Africa	61.2	68.3	70.7	12%	4%
Asia Pacific	82.8	121.7	163.4	47%	34%
Europe	4.2	4.2	4.2	0%	0%
FSU	10.8	10.8	27.3	0%	153%
Latin America	19.8	19.8	19.8	0%	0%
North America	1.5	10.5	66.6	600%	534%
Middle East	93.0	100.8	100.8	8%	0%
Total Capacity	**273.2**	**336.1**	**452.7**	**23%**	**35%**

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

[17] DOE approval has two phases. Approval to export to countries with which the US holds a free trade agreement (FTA) is issued essentially automatically. For non-FTA approved countries, a permit will be issued only after the project receives full FERC approval.
[18] Sabine Pass LNG T5-6 and Cameron T4-5 are counted separately from their initial phases.

Figure 4.14: Liquefaction Capacity by Region in 2010, 2016, and 2022



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

The British Columbia government provided clarity on taxation in 2014 and 2015 via a new LNG export-specific tax and royalty regime. Previously a major uncertainty, these steps are unlikely to have a major impact on the overall pace of project development, as evidenced by the reduced commercial momentum in 2016.

Projects totalling 47.5 MTPA of capacity[19] have also been proposed in Eastern Canada. Given long shipping distances to Asia, most projects appear to be targeting European importers. However, only Goldboro LNG has secured a binding offtake agreement with Uniper. Most of the East Coast projects also depend on pipeline reversal and capacity expansion, subject to regulatory approval from both Canada and the US.

East Africa

Since 2010, large offshore dry gas discoveries have underpinned several floating and onshore proposals in Mozambique and Tanzania totalling more than 73 MTPA of capacity. The region has significant potential to become a major LNG supplier. However, higher midstream costs and dry gas reserves may translate to higher breakeven costs, which could slow the pace of development during a period of LNG surplus.

That said, projects in Mozambique gained momentum in 2016. Area 4's Coral FLNG project – owned by Eni, KOGAS, CNPC, Galp Energia, and Empresa Nacional de Hidrocarbonetos (ENH) – has its entire capacity contracted to BP and FID may be imminent as several of the partners have already sanctioned the project. Toward the end of 2016, Area 1 partners – Anadarko, Mitsui, ONGC Videsh, Oil India, Bharat Petroleum, PTT, and ENH – formally submitted their Development Plan to the Government of Mozambique for a two-train 12 MTPA onshore liquefaction project.

While both governments support the development of liquefaction projects and have actively worked to establish gas-specific legislation, projects in Mozambique and Tanzania face some political risks. The Mozambique government in 2014 set out constructive taxation terms and required companies developing LNG proposals to submit plans for unitisation, which occurred in late 2015. Contractual amendments in Q4 2016 and an approved resettlement plan build on the progress made in previous years and may facilitate the financing of two projects based on standalone reserves. The government also recently agreed to allow the marketing and sale of LNG volumes collectively by the Area 1 project consortium, which will facilitate offtake agreements. The country's ongoing debt crisis is a potential obstacle, though in Q4 2016 an agreement was reached to fund the equity share of ENH, the Mozambique national oil company (NOC), for the two most advanced projects. Repayments will be made with profits from future LNG sales.

Regulatory challenges, in conjunction with potentially divergent partner priorities, may slow progress in Tanzania. In 2015, the government enacted the first of a series of oil and gas policy and regulatory reforms, 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. A new gas policy has also been approved, but a formal law regarding the country's Gas Master Plan must still be passed.

West Africa

Over the last few years, West Africa has emerged as an important region for the deployment of small-scale floating liquefaction. While small in terms of capacity, commercial momentum achieved during the last two years indicates the ability of some projects to potentially move forward in an oversupplied market.

The last project to reach FID in sub-Saharan Africa was Cameroon FLNG (2.4 MTPA) in 2015. In Equatorial Guinea, the 2.2 MTPA Fortuna FLNG project, also based on a vessel conversion, announced significant cost reductions and advanced offtake discussions during 2016.

Proposed in 2016, the 2-3 MTPA Greater Tortue FLNG project on the maritime border between Mauritania and Senegal has made notable progress in a short time. The project aims to rapidly commercialize a portion of 15 Tcf of gas resources. The developer has indicated additional FLNG vessels or potentially a larger, onshore component could be utilised to monetize potential future discoveries. Government and project stakeholders currently appear to be aligned, with unitisation negotiations having occurred. The sponsor has also been negotiating the use of a vessel conversion and has attracted a

[19] See Appendix 3 on page 69

major equity investment from BP. Greater Tortue FLNG would be the first cross-border liquefaction project ever developed, and so it is possible the project could face additional complexities.

In Nigeria, a revised development concept was announced in 2016 for a proposed two-train expansion at NLNG. The project is now evaluating smaller 4.3 MMtpa trains instead of the 8.4 MMtpa megatrains previously planned. The 10 MTPA Brass LNG project is undergoing a planning review by partners Nigerian National Petroleum Corporation (NNPC), TOTAL, and Eni.

Russia

Located in a challenging geographical region, the Yamal LNG (16.5 MTPA) project remains under construction in Russia. Due to the imposition of US and EU sanctions on Russia, the project had previously faced financing challenges but resolved these and completed financing in 2016. 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. A third train at Sakhalin-2 LNG in Russia's Far East, for instance, has been delayed in part by sanctions imposed against the development of the Yuzhno-Kirinskoye field, a key source of feedstock for the expansion. Yamal LNG operator Novatek is in the early stages of evaluating an Arctic LNG-2 project, and so the specific impact of sanctions, if any, remains to be seen.

Australia

Beyond the ongoing capacity buildout, additional greenfield projects and brownfield expansion trains have been proposed on Australia's East and West coasts, based on CBM and conventional off-shore resources, respectively. With costs likely to remain high, the challenges associated with CBM-to-LNG production, and an anticipated market oversupply, many proposals face challenges and are unlikely to advance in the near term; several have been delayed or cancelled. There is also growing concern that exports from the CBM-to-LNG projects are causing gas shortages in the Australian market that have at times led to domestic price surges.

There have been proposals to backfill existing trains that have declining feedstock supply. Doing so may offer more attractive economics relative to using those resources to develop additional trains or greenfield projects. Apart from the under-construction Prelude FLNG, most floating proposals in Australia are considered longer-term options. In Q1 2016, the Browse FLNG partners decided not to pursue an 11 MMtpa concept and are evaluating a smaller-scale development concept.

Eastern Mediterranean

Depending on the monetization method, the Leviathan and Aphrodite developments, as well as any major future discoveries in the Eastern Mediterranean, may facilitate the region regaining its potential as a major new source of LNG supply. The Zohr and West Nile Delta developments in Egypt are likely to be used to meet domestic consumption and may help alleviate the constraints that domestic demand has placed on LNG exports from Egypt. Momentum in the region had slowed owing to a greater focus on pipeline exports, significant regulatory uncertainty over upstream licenses, and the prioritization of gas for domestic uses.

Political hurdles also remain, especially regarding development schemes that may require significant cross-border cooperation and infrastructure. The Leviathan development in Israel advanced in 2016, signing several gas sales agreements; an FID is planned for 2017. Various commercialization options have been proposed for additional Leviathan production, including LNG exports via Egypt. Developments elsewhere in the Eastern Mediterranean, such as Aphrodite in Cyprus, or future discoveries could also transform the region into a major liquefaction play or potentially provide feedstock for LNG exports from Egypt; however, progress is still at an early stage, and there are numerous political and commercial challenges.

Looking Ahead

To what extent will the expected liquefaction capacity surplus be realized in 2017? Delays and production outages at several projects dampened the effect of the anticipated oversupply in 2016. With approximately 48 MTPA of capacity expected online in 2017 across a diverse range of suppliers, it is likely that only major construction delays or a significant production outage could cause a market imbalance.

Will project sponsors commit to new liquefaction investment in the near term? Project developers postponed or cancelled a number of projects in 2016 due to spending constraints and marketing difficulties. While project sanctioning activity is expected to continue to remain low in 2017, it is likely that some projects will reach FID in what is anticipated to be a low- LNG price environment. FIDs may occur for a variety of reasons based on the considerations of individual companies' portfolios. The recent agreement between OPEC and Russia to cut production provided oil price support, and by extension, to energy markets. As a result, more LNG investment is likely after two years of tight fiscal restraint. Some larger players may have long time horizons and be able to position counter-cyclically. Although many traditional buyers' general hesitancy to commit to long-term offtake is likely to continue in 2017, some smaller-scale or lower-cost projects may find it easier to contract their capacities and potentially move forward.

Will floating LNG gain additional traction in an anticipated low-price environment? The proposed benefits of FLNG, including lower cost structures and the potential ability to be diverted to other markets, will begin to be tested in 2017. With the first FLNG unit, PFLNG Satu, expected to export its first cargo in 2017, the performance and ultimate cost of the first FLNG projects, mostly larger-scale and purpose-built, will in part determine the scale at which FLNG is adopted. The market will similarly look to the performance of the first FLNG projects based on vessel conversions and barges once they begin operations. It is not yet clear the extent to which delays at several FLNG projects may impact costs.

Chevron LNG Gorgon Pilot Boat Trip – Courtesy of Chevron

5. LNG Carriers

LNG shipping has evolved in response to significant changes in the LNG market over the past decade. Spot charter rates hit historic highs in 2012 following the Fukushima disaster, but have since fallen drastically to where the market currently stands facing historic lows. The LNG shipping sector, like most shipping markets, is cyclical in nature and 2016 continued the trend from the previous year, marking historic lows in spot charter rates as new tonnage enters an already over supplied market.

Average estimated spot charter rates for steam vessels fell below \$20,000/day for a period of time during the year, with rates ultimately averaging ~\$20,500/day. Average dual-fuel diesel electric (DFDE)/ tri-fuel diesel electric (TFDE) day rates dipped to ~\$33,500/day as demand for Atlantic volumes in the Pacific Basin continued to decrease, resulting in a more regionalized LNG trade. The continuous wave of newbuilds hitting the market in 2017 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. However, we will see a more substantial increase in new liquefaction capacity come online during 2017, which could potentially absorb some of the excess capacity.

5.1. Overview

At the end of 2016, there were a total of 439 LNG tankers in the global LNG fleet, either actively trading or sitting idle available for work.[1] Of these vessels, 23 are currently chartered as FSRUs and three are chartered as floating storage units. Throughout the year, a total of 31 newbuilds (including two FSRUs) were delivered from shipyards, a 7% increase when compared to 2015 (see Figure 5.1). The newbuilds entering the market during 2016 were much more aligned with liquefaction growth than the previous year, when 29 newbuilds were delivered to a meagre 4.7 MTPA of new liquefaction capacity. Throughout 2016 a total of 26.5 MTPA of new liquefaction capacity was brought online, however, the accumulation of the tonnage buildout from previous years continued to overwhelm the market, keeping rates at historic lows.

The growth in shipping tonnage entering the market, which began back in early 2013, has continued through 2016. This buildout of new tonnage has consistently outpaced the incremental growth in globally traded LNG during this period, which has been reflected in the strong decline in charter rates. Unlike newbuild construction cycles of the past, this current cycle includes a significant number of tankers that were ordered on a speculative basis, not tied to any specific project.

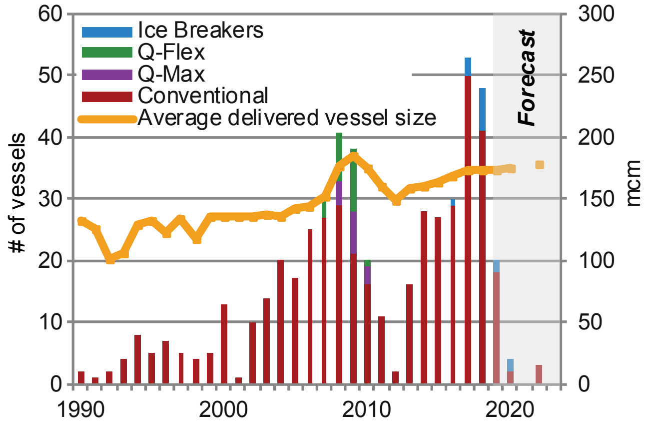
439 vessels
Number of active LNG vessels (including chartered FSRUs) at end-2016

Tanker storage capacity continues to grow as charterers prefer larger tankers that reduce the unit cost of transported LNG. The average LNG storage capacity for a newbuild delivered during 2016 was around 168,000 cubic meter (cm), compared to 153,000 cm for the global LNG fleet in 2015 (144,000 cm if we exclude Q-Flex & Q-Max tankers).

Dynagas Clean Vision - Courtesy of Dynagas

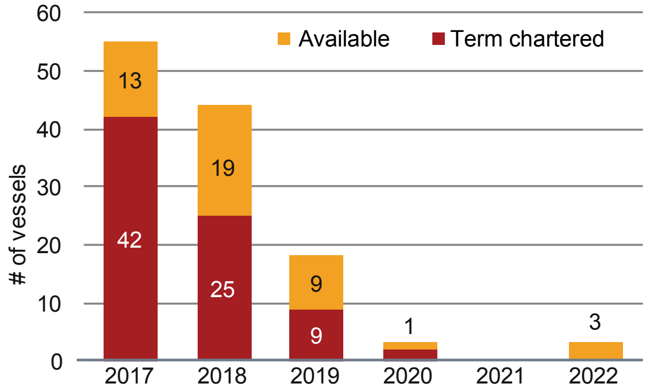
[1] For the purposes of this report, only LNG vessels with a capacity greater than 60,000 cm are considered part of the global fleet and included in this analysis. All vessels below 60,000 cm are considered small-scale.

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



Source: IHS Markit Markit

Figure 5.2: Estimated Future Conventional Vessel Deliveries, 2017-2022



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

As of end-2016, the order book included 121 tankers expected to be delivered through 2022, of which 6 were ordered during 2016; a significant decrease from the 28 tankers ordered in the prior year.[2] The slowdown in newbuild orders coincides with the slowdown in liquefaction project FIDs being reached. Only 66% of the tankers currently on the order book are tied to a specific charterer, leaving many options for potential project offtakers (see Figure 5.2).

In 2017, an additional 55 tankers (including 4 FSRUs, 1 FLNG unit, and 1 converted FLNG unit) will be delivered from shipyards, while an additional 36.8 MTPA of new liquefaction capacity is expected to come online. Despite the increase in liquefaction capacity start-ups, the concurrent rise in vessel deliveries will maintain the ongoing mismatch in tonnage availability to liquefaction capacity, keeping charter rates at their historic lows.

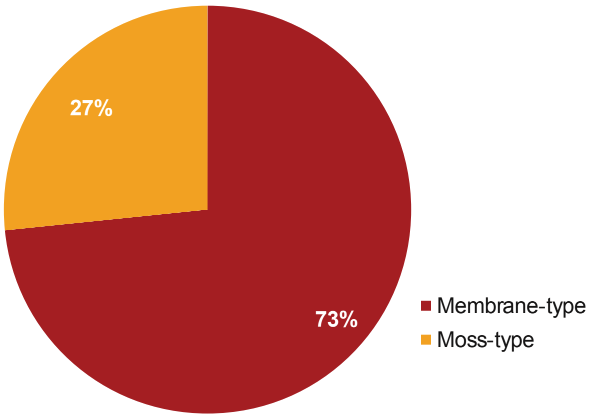
With the Panama Canal expansion finally completed, 91% of the global LNG fleet can now pass through the canal. However, the long awaited expansion has not become the gateway to Asia as many thought it would. Following the expansion of the Panama Canal in mid-2016, most volumes passing through have been delivered into the Latin American markets; Chile's Quintero and Mejillones LNG terminal as well as Mexico's west coast terminal of Manzanillo. However, there was an uptick in volumes transiting the canal towards Asia in December. This was a result of the arbitrage between the Atlantic Basin and the Far East opening up, prompting traders to move volumes west through the canal. When the winter demand season comes to an end and the arbitrage closes, we could see cargo flows return to previous regionalized trading patterns, which will ultimately exacerbate the saturated tanker market.

The one bright spot in the LNG shipping sector are FSRUs, which are in high demand at the moment. Project developers are starting to look towards emerging markets as the answer to the LNG supply glut. FSRUs are ideal for markets that have stagnant or dwindling domestic gas production, or are looking to switch from expensive liquid fuels to gas in a relatively short period of time with limited capital expenditures. Some ship-owners have even started the process of ordering long-lead items for the potential conversion of an existing tanker. Once these long-lead items are delivered, a shipyard can complete a conversion in 6 to 8 months. In the two months of 2017, there have already been three confirmed FSRU orders placed. Two of the FSRUs were ordered by Hoegh LNG in January – one earmarked for Ghana's Tema LNG project and the other

Cardiff TMS "Kita LNG" LNG Carrier – Courtesy of Cardiff TMS

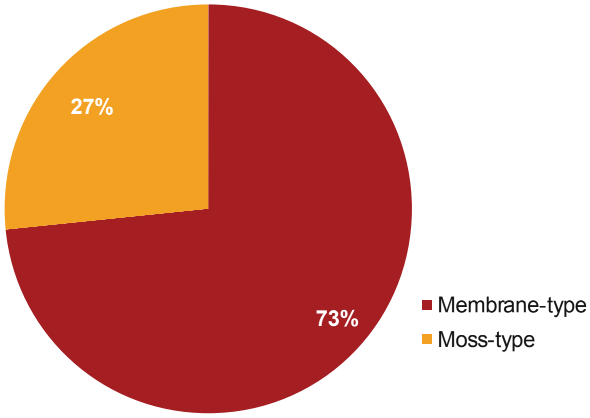
[2] As with existing vessels, only LNG vessels with a capacity greater than 60,000 cm are included in the analysis of the order book. All vessels below 60,000 cm are considered small-scale.

Figure 5.3: Existing Fleet by Containment Type, end-2016



Source: IHS Markit Markit

Figure 5.4: Existing and On Order LNG Fleet by Propulsion Type, end-2016



Source: IHS Markit

ordered on spec – while the other was placed for a firm unit (plus an option for a second) by Kolin Construction, a company new to the FSRU business.

Older tonnage is also being earmarked for projects where vessels will be used as floating storage units. In 2016, the Golar Arctic was positioned off the coast of Jamaica, where it is being utilised for breakbulk operations; the much smaller Coral Anthelia loads volumes off the Golar Arctic via a ship-to-ship transfer and then sails to Montego Bay to discharge at the regasification plant. Malta's first regasification project is also using a floating storage unit; the Armada LNG Mediterrana (formerly the Wakaba Maru) is moored in the Marsaxlokk port, where it sends volumes onshore to the regasification plant.

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]. The GTT Mark V membrane system, their newest design with a very low boil-off rate of around 0.08%, saw its first order in Q4 2016 by Gaslog. The 180,000 cm tanker will be built at the Samsung Heavy Industry ship yard and delivered in 2019. A new version of the membrane containment design, KC-1, has been developed by Kogas; it will be installed on two vessels ordered by SK Shipping. At the end of 2016, 74% of the active fleet had a Membrane-type containment system (see Figure 5.3), which also continues to lead the orderbook as the preferred containment option for 93% of vessels on order.

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 not optimal. 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 2000s, 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 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 loses market share and fewer seamen pursue this qualification.

[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.

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 LNG carriers to be powered by DFDE propulsion 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 liquid spark. 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 needed for the engines.

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 consists of over 28% of vessels planned with TFDE systems (see Figure 5.4).

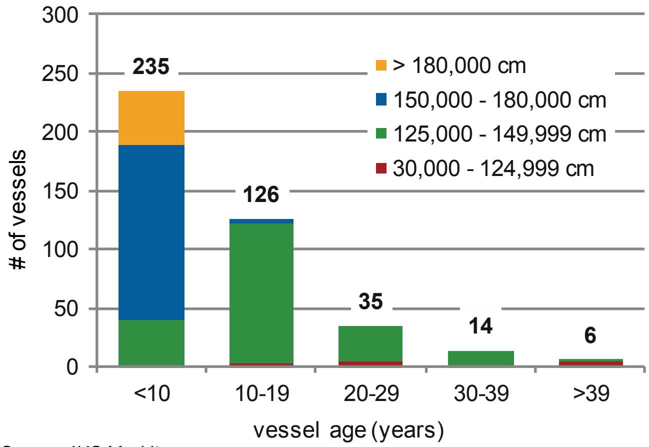
Slow-Speed Diesel (SSD) with a BOG Re-liquefaction Plant. Another propulsion system was introduced to the LNG shipping industry in the mid-2000s, primarily developed in tandem with the Qatari megatrain projects. Instead of using BOG to generate propulsion and/or electric energy, vessels are propelled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

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



Source: IHS Markit

A 170,000 cm, ME-GI LNG carrier – operating at design speed and fully laden in gas mode – will consume around 15-20% less fuel than the same vessel with a TFDE propulsion system. The ME-GI propulsion system now accounts for almost as many vessels in the order book as TFDE/DFDE tankers. The more fuel efficient propulsion system seems to be gaining traction amongst ship owners as the bulk of the most recent newbuild orders have been placed for vessels with the ME-GI propulsion system. Currently in the global LNG fleet there are nine tankers utilizing this propulsion system, with another 20 expected to be delivered in 2017.

Wärtsilä Low-Pressure Two-Stroke Engine. Wärtsilä introduced its low-speed two-stroke dual-fuel engine in 2014. This alternative to DFDE propulsion systems is estimated to offer capital expenditure reductions of 15-20% via a simpler and lower cost LNG and gas handling system. Significant gains are reportedly achieved by eliminating the high pressure gas compression system. In addition, the nitrogen oxides (NOX) abatement systems may not be required.

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.

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 Markit

2015-2016 LNG Trade in Review

Global LNG Fleet **+29** Conventional carriers added to the global fleet in 2016	Propulsion systems **~30%** Active vessels with DFDE/TFDE propulsion systems	Charter Market **$20,500** TFDE /DFDE $33,500 Spot charter rate per day in 2016	Orderbook Growth **+6** Conventional carriers ordered in 20156
The active fleet expanded to 439 carriers in 2016 The average ship capacity of newbuilds in 2016 increased by 4.5% to 170,660 cm compared to the average in 2015 Two vessels – both over 35 years of age – were scrapped in 2016	In 2015, over 72% of the fleet was steam-based; by 2016, DFDE/TFDE ships accounted for over 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 Between 2014-16, +90 vessels entered the market during a period of minimal incremental growth in LNG supply, pushing charter rates almost to operating costs	26 newbuild orders were placed during 2015 as buyers continued to secure shipping tonnage for the upcoming growth in LNG supply, primarily from the US; down from the 68 orders in 2014. There were only 6 vessels ordered throughout 2016 as liquefaction project FIDs have been pushed back

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-2016, 49% of active LNG carriers had a capacity within this range, making it the most common vessel size in the existing fleet (see Figure 5.5), but this share is steadily decreasing. Tanker newbuilds delivered during 2016 had an average size of 173,600 cm.

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 (45 vessels in total) accounted for 11% of the active fleet and 18% of total LNG transportation capacity at the end of 2016.

The growing size of LNG vessels 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[4]. By the end of 2016, 36% of the active global fleet was in the 150,000 to 180,000 cm range. This share will grow rapidly in the years ahead with the average capacity in the orderbook standing at approximately 172,000 cm at the end of 2016.

Vessel Age. At the end of 2016, 56% 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 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 6% of active LNG carriers were over 30 years of age in 2016; 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 2016, 18 vessels (primarily Moss-type steam tankers with a

ENGIE/NYK/MC Engie Zeebrugge – Courtesy of ENGIE, Mitsubishi Corporation and NYK.

[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 180,000m³, but there is no specific limitation on capacity.

capacity of under 150,000 cm) were laid-up. Over 77% 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 2016, we saw 2 vessels retired from the fleet by selling the tanker for scrap. Unlike 2015, where four vessels were flagged for conversion to either become an FLNG or floating storage unit, 2016 did not see any tankers nominated for any conversions. Ship owner Gaslog had started to order long-lead items necessary for conversion in late 2016; however, no specific tanker had been selected for the conversion job.

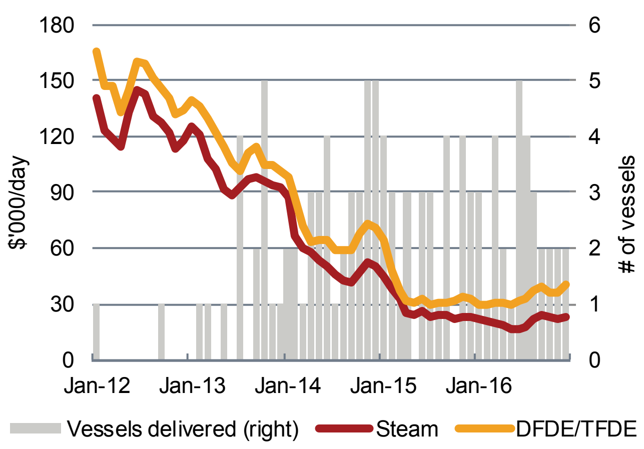
5.3. Charter Market

Charter rates throughout 2016 remained quite low as new tonnage continued to enter the market and trading patterns became more regionalized. Even with the number of spot fixtures at an all-time high, the saturated shipping market has kept a lid on any substantial increase in rates. The delta between charter rates for older steam turbine tankers and newer DFDE/TFDE tankers has increased as charterers overwhelmingly prefer the larger and more fuel efficient tankers.

A total of 31 tankers were delivered from shipyards during 2016, of which two were FSRUs, and one was a floating storage unit conversion. Of the 31 tankers, only three were delivered without a charterer lined up, which coincides with the start-up of multiple liquefaction projects globally and replacement tankers for existing projects. Six liquefaction project trains were brought online during 2016 with a total liquefaction capacity of 26.5 MTPA. This lines up with the industry rule of thumb that one tanker is needed for each 1 MTPA of liquefaction capacity; however, many of the project tankers were delivered well ahead of time during 2015 alongside speculatively ordered tankers, adding length to the market.

- The 2015 addition of 29 newbuilds into the global fleet plus another 31 during 2016 was far more than the market required for the 24.4 MTPA of incremental liquefaction capacity growth in the same timeframe.
- The production shut-ins and outages at Yemen, Angola, and Egypt all added shipping length to the market. Also contributing to the growth in excess shipping tonnage has been the decrease in LNG exports out of Trinidad.
- With spot LNG prices in the Pacific and Atlantic Basin almost at parity throughout 2016, arbitrage opportunities were limited, resulting in a more regionalized trade and fewer nautical miles travelled per voyage. Atlantic Basin volumes sailing to the Far East fell by 50% on a YOY basis.

Figure 5.6: Average LNG Spot Charter Rates versus Vessel Deliveries, 2012 – December 2016



Source: IHS Markit

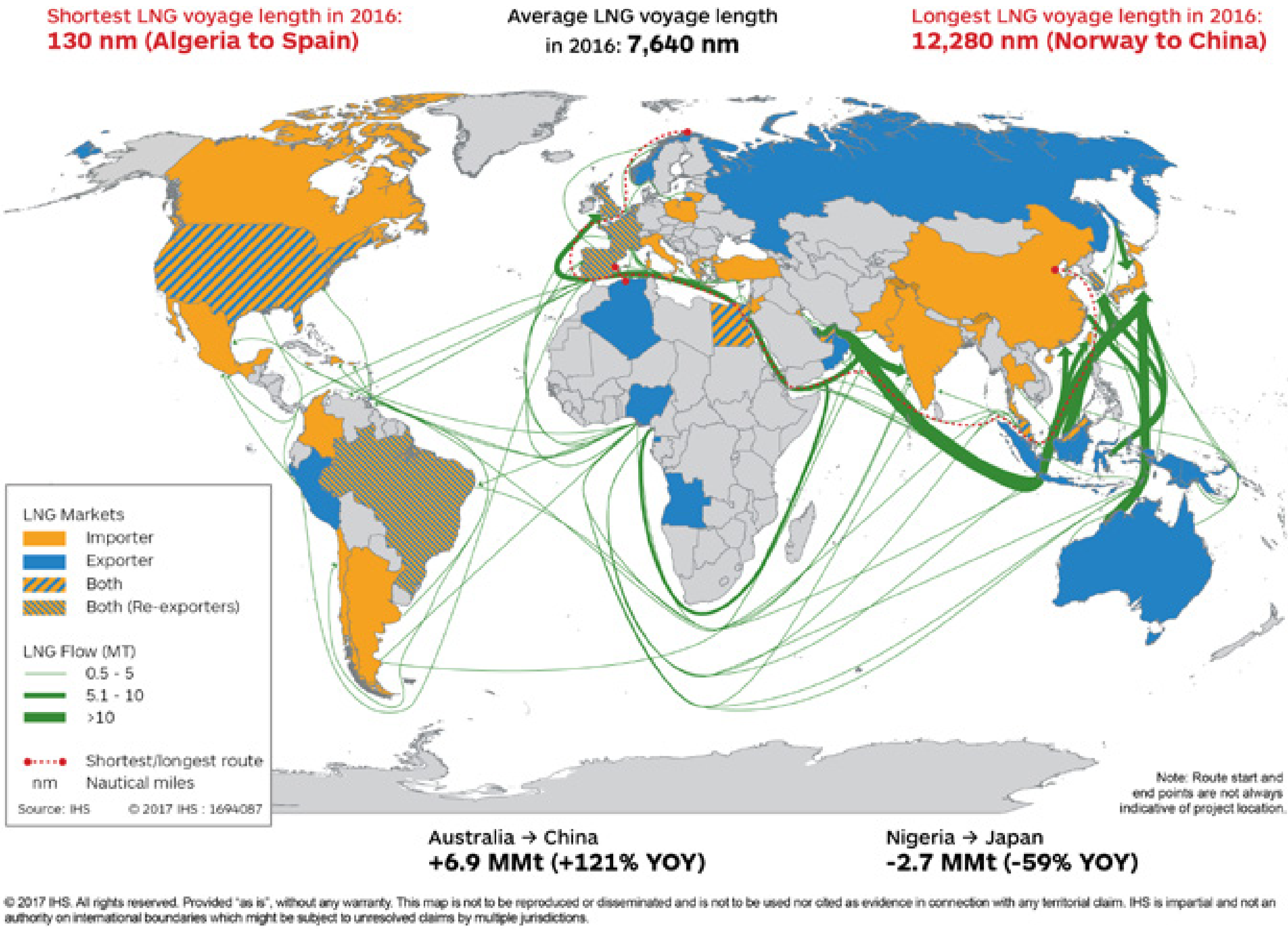
Spot charter rates for much of 2016 remained low and relatively flat throughout the year (see Figure 5.6). Rates for a TFDE/DFDE tanker averaged ~$34,000/day during 2016, compared to ~$36,000/day during 2015 – a 6% YOY decrease. In regards to conventional steam tankers, there was a more dramatic YOY decrease of 25%; rates averaged ~$20,000/day during 2016, compared to the 2015 average of ~$27,000/day. This is further evidence of the market's preference for the newer, larger, and more fuel efficient TFDE/DFDE tankers. TFDE/DFDE tankers were nominated for most of the spot trade, leaving older steam tankers to sit idle with longer periods of time between cargoes, resulting in storage tanks and the associated cryogenic equipment becoming warm; this requires the vessel to take in cool-down volumes to return to service, resulting in additional time and expenses.

Pure LNG traders have played a critical role in helping soaking up excess tonnage. With the relatively recent trend of securing volumes via short-term tenders – as has occurred in markets like Argentina, Egypt, and Pakistan – traders are participating in global LNG trade without having to commit to long-term supply purchase agreements or long-term charters. With an over supplied product and shipping market, traders are taking on short positions in the market and covering them with spot LNG volumes transported on tankers fixed on a short-term basis. As the market becomes more liquid, short-term fixtures will be more prevalent. Total spot fixtures (a charter of six months or less) during 2016 reached an estimated 280 fixtures compared to 175 fixtures in 2015, with traders making up a third of all spot fixtures.

For the most part, spot charter rates for the 2016 remained flat, however, we did witness an increase in Atlantic Basin spot charter rates at the end of Q4 2016. A jump in Northeast Asian spot LNG prices in December resulted in an increase in cross-basin trade; the increase in voyage days associated with the cross-basin trade left the Atlantic Basin short on shipping capacity. With the bulk of the liquefaction capacity located in the Pacific Basin, as well as all newbuilds being delivered from Japanese, Korean, or Chinese shipyards, there are a disproportional number of available tankers in the Pacific Basin. Ship owners are hesitant to reposition their tankers from the Pacific to the Atlantic and incur repositioning fuel costs, on hopes that the vessels might later be fixed at a higher rate.

Looking forward to 2017, if all 53 LNG tankers are delivered on schedule, charter rates are likely to continue to face downward pressure. Global LNG trade is set to continue its regionalization, as new liquefaction capacity comes online in both the Atlantic and Pacific Basin. These new volumes will keep prices in both basins at parity, reducing the need for cross-basin trade. Ship owners may potentially start looking with more interest at converting some of their existing tankers into FSRUs. The retirement or conversion of older tonnage could provide some relief to this oversupplied market; however,

Figure 5.7: Major LNG Shipping Routes, 2016



Source: IHS Markit.

it will take multiple years to work through excess tonnage in a meaningful way.

5.4. Fleet Voyages and Vessel Utilisation

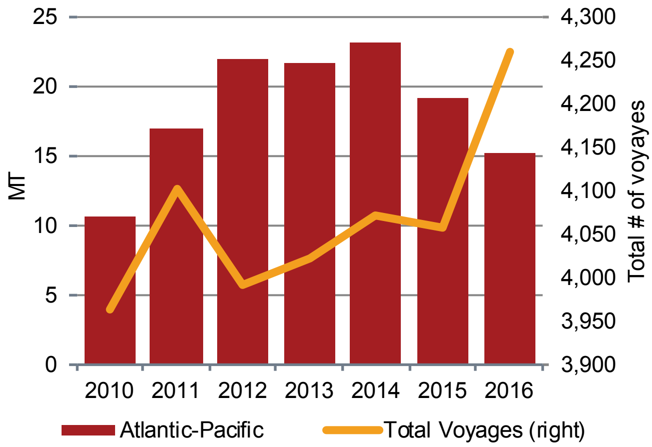
The total number of voyages completed in 2016 increased as new liquefaction capacity came online, and the Africa and Middle East regions emerged as significant LNG importers. A total of 4,246 voyages were completed during 2016, a 5% increase when compared to 2015 (see Figure 5.8). Trade was traditionally 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, the growing trend of inter-basin trade was quite muted throughout 2016 due to the increase in new liquefaction capacity in both the Atlantic and Pacific Basins. With limited arbitrage opportunities available for traders, inter-basin trade shrank by 47% when compared to 2015.

4,246 Voyages
Number of voyages of LNG trade voyages in 2016

Given the increased regionalisation of trade throughout 2016, the average nautical miles travelled per voyage has decreased. Also, with the Panama Canal expansion finally completed, the voyage distance from the US Gulf Coast to Japan has now been reduced to 9,500 nautical miles (nm), compared to the 14,400 nm when the Suez Canal is used. However, the Panama Canal expansion has not been utilised to the extent as anticipated. Price parity between the Atlantic and Pacific has limited Atlantic basin volumes from flowing through the canal to access the Asian markets, except for during the recent cold winter in Asia which coincided with unexpected production outages.

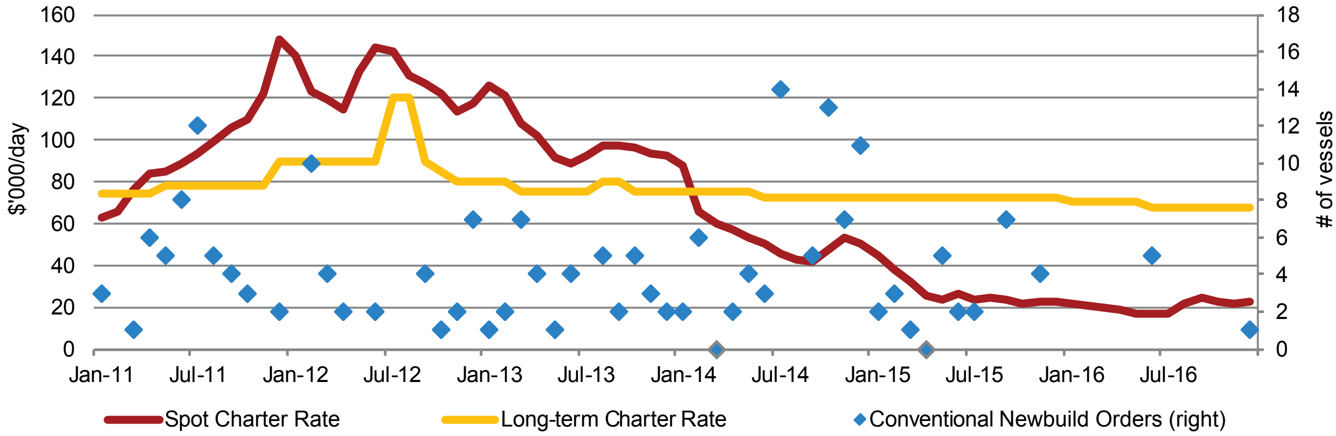
In 2016, the longest voyage – from Trinidad to China around the Cape of Good Hope – was taken by only one vessel.

Figure 5.8: Atlantic-Pacific Trade versus Total Number of Voyages per year, 2010-2016



Source: IHS Markit

Figure 5.9: Estimated Long-term and Spot Charter Rates versus Newbuild Orders, 2011-2016[5]



Source: IHS Markit

However, two other Atlantic LNG cargoes were sent to the Far East using a similar route via the Cape of Good Hope. Conversely, the shortest voyage – a more traditional route from Algeria to the Cartagena terminal in Spain – occurred only once. However, voyages from Algeria to Spain's four southern terminals occurred 59 times in 2016. The most common voyage in 2016 was from Australia to Japan, with 386 voyages completed during the year, a 29% YOY increase.

In 2016, the amount of LNG delivered on a per tanker basis, including idle tankers, reached 0.62 MT compared to the 0.73 MT in 2011, before the tanker buildout cycle began. The buildout in tonnage continues to outpace new liquefaction capacity, resulting in an increase in tanker availability. 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. Strong Atlantic to Pacific trade continued in the following three years as traders capitalised on the arbitrage opportunity between basins. The extended voyage distance between the Atlantic and Pacific put a strain on the global LNG fleet, which caused charter rates to skyrocket and led ship owners to go to shipyards to put in orders on a speculative basis.

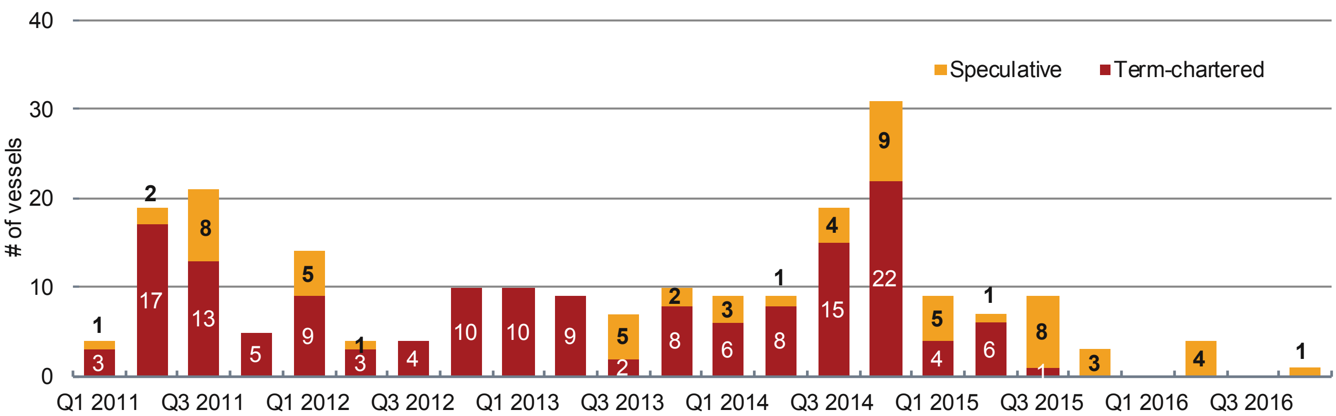
Tanker availability has remained high since 2014, as the build-up in LNG liquefaction capacity lags behind the influx of newbuilds to the market. However, a portion of the available tankers had higher utilisation rates than the rest, because their owners offered the tankers at below market price early on to maintain cold tanks, and build up an operational history for the tanker at multiple ports. As a result, many of the same tankers were used for single voyages or backhauls while the rest sat idle. Also helping keep tanker utilization from falling any further has been the emergence of traders such as Trafigura and Vitol. These traders do not have any long-term dedicated tankers; instead they use the spot charter market to cover their shipping needs.

5.5. Fleet and Newbuild Orders

At the end of 2016, 121 vessels were on order. Around 67% of vessels in the orderbook were associated with charters that extend beyond a year, while 44 vessels were ordered on a speculative basis.

In 2016, newbuild vessel orders decreased by 77% YOY to just six (see Figure 5.10), one of which was for an FSRU. With a looming supply glut, many liquefaction projects have postponed taking FID, delaying any decision on potential newbuilds. Also, with an order book heavy with speculatively ordered tonnage, many potential project offtakers could easily cover their shipping requirements with these tankers. Orders in 2015 were also tied to the upcoming US LNG build-out,

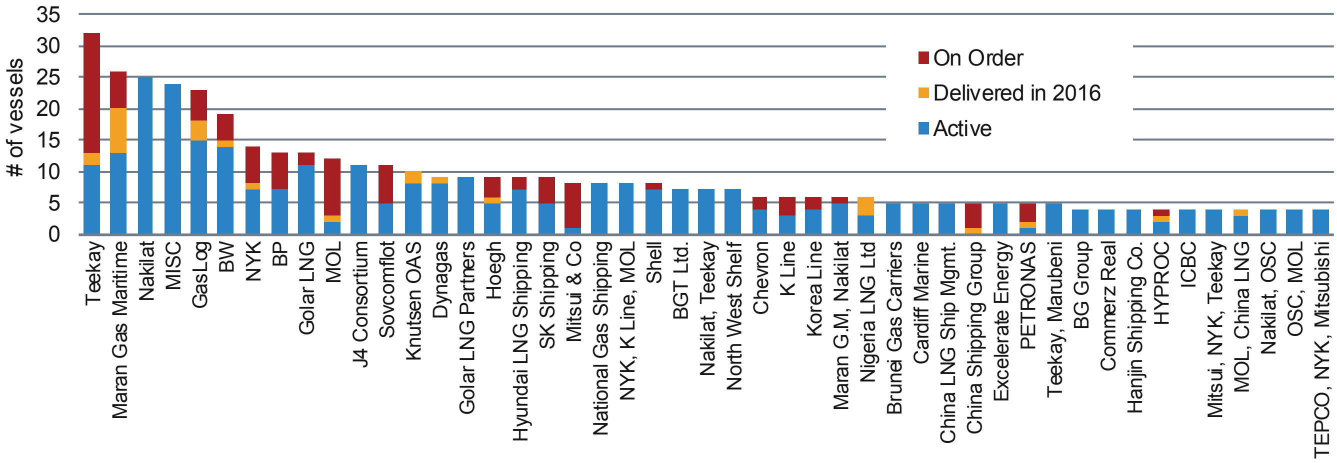
Figure 5.10: Firm Conventional Newbuild Orders by Quarter, 2011-2016



Sources: IHS Markit, Shipyard Reports

[5] Long-term charter rates refer to anything chartered under a contract of five years or above. Sport charter rates refer to anything chartered under a contract of six months or less.

Figure 5.11: LNG Fleet by Respective Company Interests, end - 2016



Source: IHS Markit

particularly with Asian buyers. The majority of orders in 2016 are slated for delivery by late 2019. All vessels ordered in 2016 will have a capacity greater than or equal to 170,000 cm. As these larger, more 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.

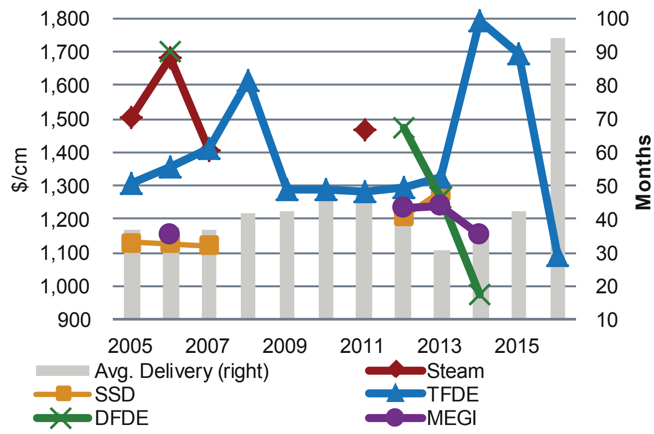
Out of the 77 vessels on charter in the order book, 20% are tied to companies that are considered an LNG producer (e.g., Sonatrach, Yamal LNG, etc.; see Figure 5.11). LNG buyers make up 38% of the new-build orders as the companies gear up for their Australian and US offtake. The remaining charters comprise companies with multiple market strategies.

5.6. Vessel Costs and Delivery Schedule

Throughout the 2000s, average LNG carrier costs per cubic meter remained within a narrow range. The rapid growth in demand for innovative vessels starting in 2014, particularly vessels with TFDE propulsion, pushed average vessel costs to rise from $1,300/cm in 2005 to $1,770/cm in 2014 (see Figure 5.12). This was mainly driven by the Yamal LNG icebreaker vessels, which are more expensive than a typical carrier. However, in 2016, the costs for TFDE vessels dropped back to $1,092/cm. Korean shipyards, which have been suffering from the overall downturn in shipping, have been quite aggressive with their pricing, in turn forcing Japanese and Chinese shipyards to also offer competitive bids for newbuilds.

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 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. DFDE tankers delivered in 2006 saw an average time of 60 months between order and delivery.

Figure 5.12: Average Delivery and Cost per Cubic Meter in Ordered Year by LNG Carrier Type, 2006-2016



Source: IHS Markit

YAMAL LNG Carrier "Christophe de Margerie" – Courtesy of SCF-GROUP

Yamal's three liquefaction trains are under construction, and upon completion, the project will require up to 17 ice-breaker LNG carriers; 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. As of February 2017, the first of these vessels was sailing to the Arctic to begin ice trials.

5.7. Near-Term Shipping Developments

Newbuilds and Conversions

With the looming LNG supply glut, many emerging markets have shown interest in LNG as a replacement fuel for expensive oil-based fuels. Currently, the quickest and cheapest option is an FSRU. Many of the current LNG ship owners are working with independent power producers (IPPs) and NOCs in these markets, trying to secure long-term contracts to supply them with an FSRU.

Currently all but one of the existing FRSUs have been chartered to specific projects or are earmarked to begin a project in the near future. Petrobras is redelivering one of the Golar FSRUs in mid-2017, after terminating its contract a year early. As of end-2016, there are eight FSRUs on the order book, five of which are dedicated to projects. The list of potential FSRU projects continues to grow, while the order book remains relatively subdued. The construction time for a newbuild FSRU ranges between 30 and 40 months, depending on space availability at the shipyard and whether it is a repeat order, which would require less engineering work.

Regarding conversions, if the long-lead items are ordered ahead of their planned conversion, they can cut the conversion process timeline from 18-20 months to 6-8 months. There are quite a few potential conversion candidates currently in the market. Ship owners such as Golar, Dynagas, and TMS Cardiff Gas, which have taken delivery of speculatively ordered tonnage, are well positioned for an FSRU conversion.

Emerging markets utilizing vessels for creative import solutions

Jamaica imported its first LNG cargoes in 2016 through new LNG regasification infrastructure delivering to the converted Bogue power plant. The process involves a series of ship-to-ship transfers from conventional LNG carriers to a floating storage unit stationed offshore, then to a lightering vessel set to deliver smaller volumes to an onshore regasification receiving centre. This process is similar to the one first established at Chile's Mejillones terminal, which used a floating storage unit in combination with onshore regasification capacity to allow imports to begin before terminal's onshore storage tank was completed. Jamaica's path to LNG imports highlights a potential trend in the LNG industry – that of smaller, immature markets joining the global LNG space by utilising idle existing infrastructure to develop small-scale projects relatively quickly. Similarly, Malta became an LNG importer in January 2017 by also utilising an older tanker as a floating storage unit and then sending volumes onshore to a small-scale regasification terminal.

With the LNG product market expected to remain over supplied, low prices could motivate more small-scale LNG-to-power projects. Power producers will get access to a potentially cheaper and cleaner fuel, while LNG suppliers will have new downstream markets to supply.

Looking Ahead

Will there be more trade route optimization in 2017?

With new liquefaction capacity coming online, charter rates could start to recover as spot and term fixtures increase. Throughout most of 2016, cross-basin trading decreased as prices in the Atlantic and Pacific were almost at parity. With limited arbitrage opportunities for traders to act on, the number of long-distance voyages from west to east was limited, resulting in an increase in shipping availability. While the start-up of several new liquefaction trains including Gorgon LNG T1-2, GLNG T1-2, Australia Pacific LNG T1, and Sabine Pass T1-2 has increased shipping demand to help absorb some of this excess tonnage, much of the trade from these projects will stay in-basin, limiting ship ton-miles.

Going into 2017, the global trade will continue to become more regionalized as prices between regions converge. However, there may be moments where there could be a brief uptick in cross-basin trading activity, similar to what occurred at the end of 2016. Production issues at Gorgon LNG and cold weather in Asia sent spot LNG prices upwards, signalling to Atlantic Basin producers to divert cargoes towards the Far East. This is a good example of how the market can react to price signals and that it is flexible enough to divert at a moment's notice. However, to facilitate this flexibility, the market needs access to spot tonnage.

Can older steam tankers compete in an over supplied tanker market? Another theme that will carry into 2017 will be the market's overwhelming preference for DFDE/TFDE tankers over the conventional steam tanker. With slim trading margins due to low commodity prices, traders are looking to save on whatever components of the trade they can control, and shipping is a prime prospect for rationalization. The gap between charter rates for the more fuel efficient DFDE/TFDE tankers and steam tankers will continue to grow in 2017. The preference for the newer DFDE/TFDE tankers has left many older steam tankers sitting idle for quite some time, resulting in expired Ship Inspection Report Programme (SIRE) documents and warm tanks; this makes them less marketable for spot trades and widens the gap between the two tanker types. The resulting increase in steam tonnage availability has many ship owners looking for alternative uses for their tankers, such as floating storage unit, FSRU, and FLNG conversions.

6. LNG Receiving Terminals

Tracking the growth of LNG demand, global LNG regasification capacity also increased, reaching 777 MTPA by end-2016 and 795 MTPA as of January 2017. In contrast to 2015, growth in receiving terminal capacity was primarily centred in established LNG markets, including: China, Japan, France, India, and South Korea. Poland and Colombia joined the global LNG market as new importers. The Emirate of Abu Dhabi also began imports via an FSRU; although as a country, UAE was already an importer. Furthermore, Jamaica completed its first LNG terminal in late 2016 and began importing LNG via floating storage and a break-bulk delivery vessel.[1] Over the last few years, given relatively low LNG price, new markets have been able to complete regasification projects fairly quickly using FSRUs. However, the majority of new regasification capacity came from expansions to existing terminals and the inauguration of new, larger onshore terminals. The Dunkirk terminal in France (9.5 MTPA) is the largest terminal to come online in five years.

The incentives for developing new receiving terminal projects and expansions is increasing given that a significant amount of new liquefaction capacity will continue to be added to the market through 2020. Lower prices could unlock previously unattainable pockets of demand, both within existing LNG markets and countries new to the LNG space. Regasification capacity growth in the next two years is concentrated in existing Asian markets, particularly China and India. Japan, Pakistan, Thailand, Singapore, and Malaysia are among the other Asian importers set to expand capacity by end-2018. However, new LNG markets are still expected to materialize around the world. Beyond Colombia, which is expected to reach commercial operations at its first terminal in 2017, the Philippines, Russia (through an FSRU in Kaliningrad), and Bahrain are expected to complete their first regasification projects in the near-term. Further out, Ghana, Bangladesh, Uruguay, Croatia, Myanmar, Ivory Coast, Morocco, South Africa, and Sudan all have project proposals announced to come online by end-2020. LNG demand in emerging markets is still expanding. These new markets provide additional outlets for LNG producers, particularly important in a market with growing supply.

6.1. Overview

The majority of new regasification capacity in 2016 came from established LNG countries, including Japan, China, India, and France. First-time importer Poland began commercial operations in mid-2016, the Emirate of Abu Dhabi in the UAE developed its first regasification terminal via FSRU; and Colombia, another new entrant to the LNG market, received its first commissioning cargo in November 2016. Overall, total global regasification capacity grew by 22.4 MTPA in 2016, bringing total capacity worldwide to 776.8 MTPA in 34 countries (see Figure 6.1). A further 17.8 MTPA was added by the end of January 2017, with terminals reaching commercial operations in France, South Korea, and Turkey.

795 MTPA
Global LNG receiving capacity, January 2017

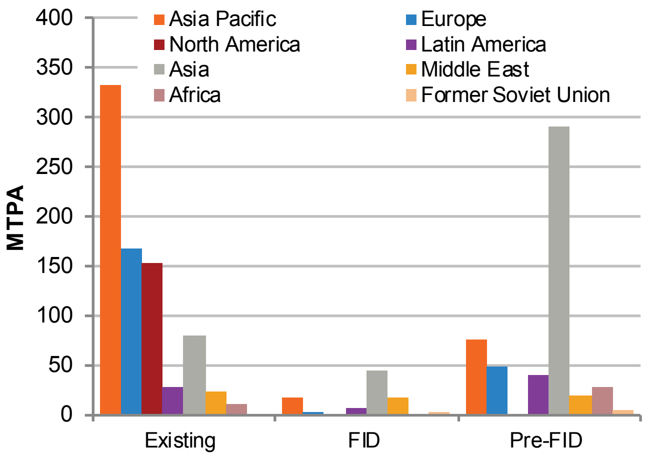
The highest concentration of regasification capacity continues to be in the Asia and Asia Pacific region, with growth expected to continue both in established and growth LNG markets. Beyond small-scale developments in the Caribbean, North America is the only region where regasification capacity has not grown recently. The introduction of FSRUs granted a number of new countries access to the global LNG market over the last several years, especially in the Middle East, Asia, and Latin America. FSRUs are expected to continue playing an important role in 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 desired and time is available.

6.2. Receiving Terminal Capacity and Utilisation Globally

Over the last 15 years, the number of countries with LNG regasification capacity has tripled. LNG trade has expanded due to growing flexibility of supply and quicker access to new and existing markets via FSRUs. Lower LNG prices have been a driver for demand growth in India, while China approaches contract levels. 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.

Four new regasification terminals reached commercial operations in 2016 (see Figure 6.3), two of which were onshore terminals located in existing markets in the Asia Pacific region: China (Guangxi Beihai) and Japan (Hitachi). Poland joined

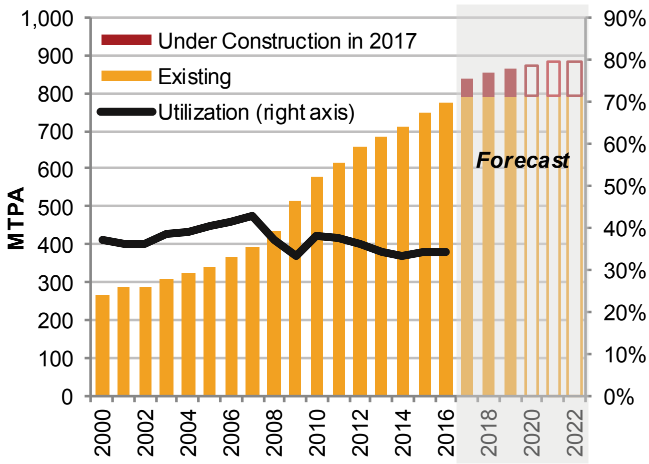
Figure 6.1: LNG Receiving Capacity by Status and Region, as of January 2017.



Sources: IHS Markit, Company Announcements

[1] All counts and totals within this section only include countries with large-scale LNG regasification capacity (1 MTPA and above). This includes countries that only regasify 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, 2000–2022



Note: The above forecast only includes projects sanctioned as of January 2017. 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 outlined 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 Markit, IGU, Company Announcements

the global LNG market with an onshore terminal, which began commercial operations in mid-2016. Abu Dhabi completed its first terminal with the installation of an FSRU. In addition, a number of terminals were expected online in early 2017. France's Dunkirk terminal commenced with commercial operations in January 2017, and Turkey's Etki FSRU received its first LNG cargo in December 2016. South Korea added an additional terminal in early 2017, further expanding the number of new regasification terminals to 7 by the end of January 2017. In total, 22 MTPA was added in 2016 and a further 18 MTPA in the first month of 2017.

7 terminals
Number of new receiving terminals brought online in 2016 and January 2017

Terminal capacity expansions were also prevalent throughout 2016 as three existing terminals completed expansion projects. The Jiangsu Rudong and Liaoning Dalian terminals in China each added 3 MTPA of capacity, and the Dahej LNG terminal in India completed a 5 MTPA expansion.

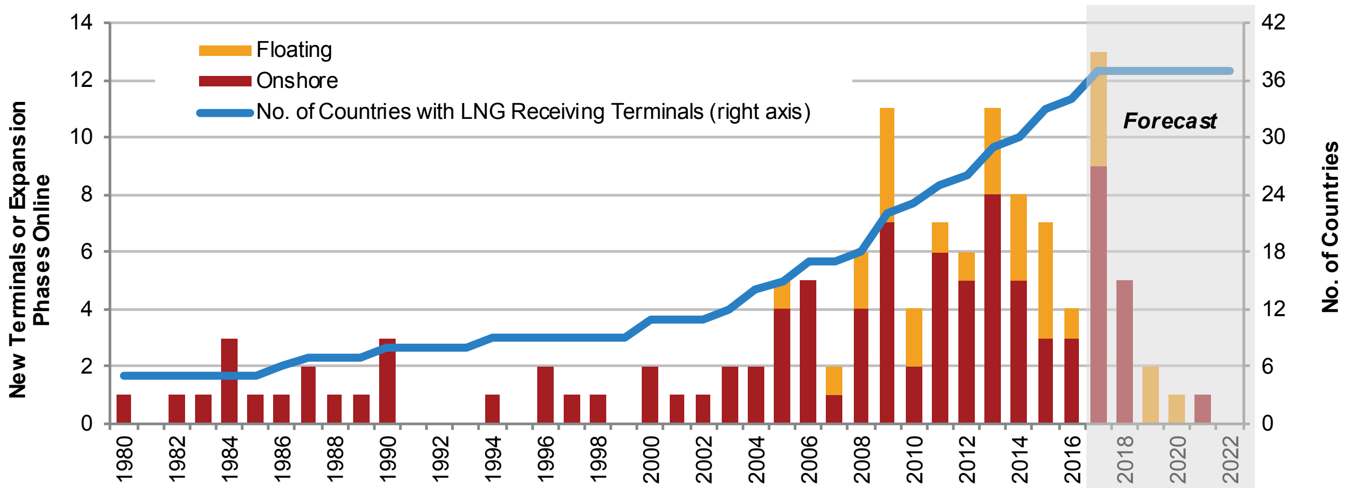
As of January 2017, 90.4 MTPA of new regasification capacity was considered to be under construction, including thirteen new onshore terminals, six FSRUs, and four expansion projects to existing receiving terminals. Although 85% of this total capacity was located in existing import markets, four under-construction projects are anticipated to add capacity for the first LNG imports in Colombia, Bahrain, Russia, and the Philippines. China has eight under-construction projects, followed by India's three. Additional projects are underway in Thailand, Greece, Pakistan, Singapore, Japan, Malaysia, Brazil, and Kuwait.

Beyond under-construction projects, seven FSRU projects were considered to be in advanced stages.[2] The projects are located in India, Ghana, Uruguay, Puerto Rico, Pakistan, and Chile, with a total combined capacity of 28.7 MTPA. Only 60% of this figure stems from countries with established regasification capacity.

90.4 MTPA
New receiving capacity under-construction, Q1 2017

Global LNG regasification utilisation rates averaged 34% in 2016, roughly equal to 2015 levels. If mothballed terminals[3] are excluded, this number would reach 37% in 2016. Due to the requirement to meet peak seasonal demand and ensure security of supply, regasification terminal capacity far exceeds liquefaction capacity. Global utilisation levels have stayed flat, despite adding 22.4 MTPA of new

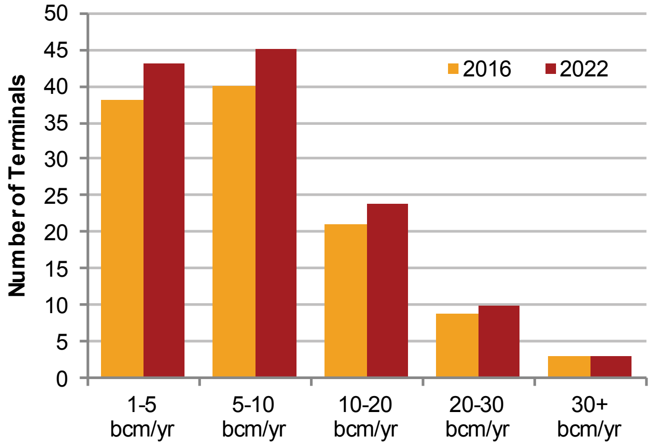
Figure 6.3: Start-Ups of LNG Receiving Terminals, 1980–2022.



Sources: IHS Markit, Company Announcements

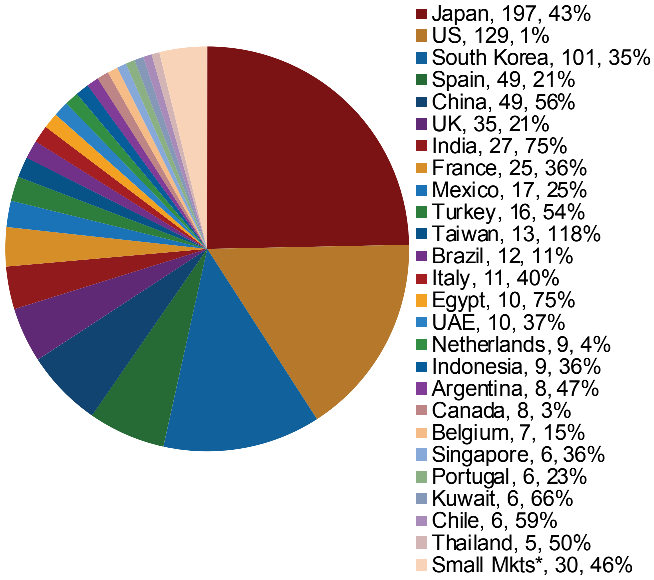
[2] Although these projects technically have binding agreements in place with FSRU providers, they are still considered as "Pre-FID" until on-site construction is confirmed.
[3] Including El Musel, Cameron, Golden Pass, Gulf LNG, and Lake Charles.

Figure 6.4: Annual Send-out Capacity of LNG Terminals in 2016 and 2022.



Sources: IHS Markit, Company Announcements

Figure 6.5: LNG Regasification Capacity by Country (MTPA) and Utilisation, January 2017.



Note: "Smaller Markets" includes Malaysia, Jordan, Pakistan, Poland, Greece, Lithuania, Israel, Dominican Republic, and Puerto Rico. Each of these markets had 4 MTPA or less of nominal capacity as of January 2017. Utilisation figures are based on 2016 trade data. Sources: IHS Markit, IGU

receiving capacity in 2016. However, if the US is removed, global utilisation reached 41% in 2016. The US imported just 1% of the country's 129 MTPA capacity, as gas production from shale has expanded.

Average peak send-out capacity has followed a trajectory of decline over the last few years, largely as 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. Average regasification capacity for existing onshore terminals stood at 7.6 MTPA as of January 2017, compared to 4.0 MTPA for floating terminals. Global average peak send-out capacity has fallen from 12.2 billion cubic meters per year (bcm/yr; equivalent to 8.9 MTPA) in 2011 to 11.0 bcm/yr (8.0 MTPA) in 2016 (see Figure 6.4).

6.3. Receiving Terminal Capacity and Utilisation by Country

Japan remains the world's largest LNG importer and contains the most regasification capacity (see Figure 6.5). Japan added the 1 MTPA Hitachi terminal in March 2016, bringing total regasification capacity in Japan to 197 MTPA by end-2016, or 25% of the world's total regasification capacity. As of January 2017, one terminal in Japan was under construction, Soma LNG, which is expected to come online in 2018.

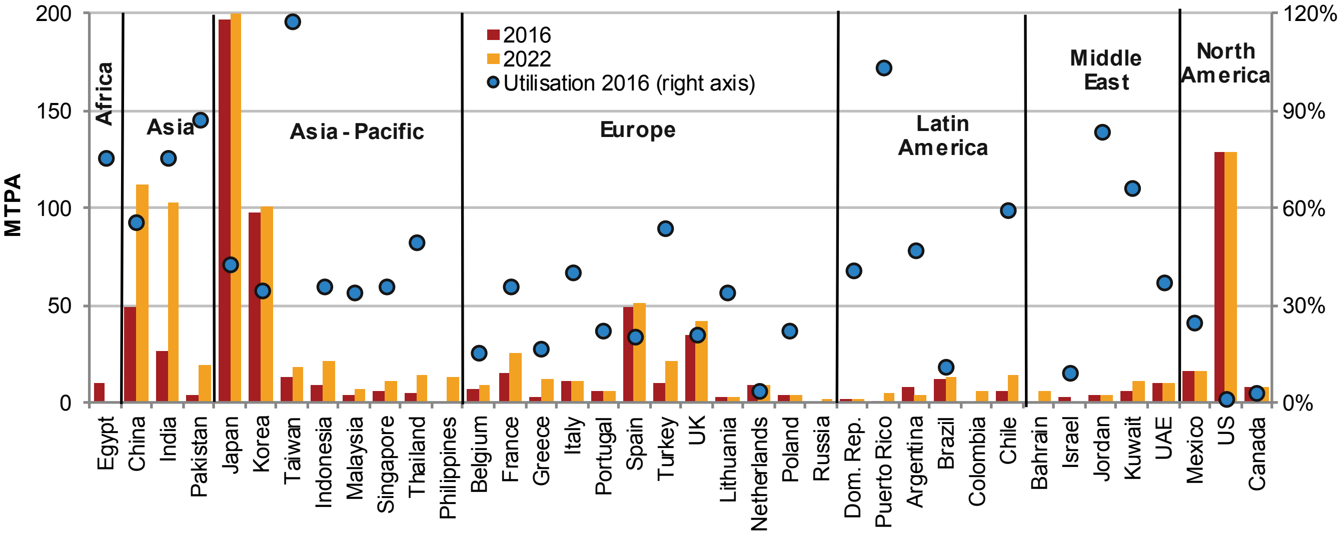
Capacity utilisation stood at 43% in 2016, a minor decrease from 44% in 2015.

South Korea, the world's second largest LNG importer in 2016, has 101 MTPA of regasification capacity, behind only Japan and the US. The country added 3 MTPA of capacity after completing the Boryeong terminal in January 2017, but did not have any additional capacity under construction as of early 2017. Although South Korea experienced a utilisation rate of 35% in 2016 (+1% YOY), LNG demand has fallen from a peak in 2013 at the expense of nuclear and coal-fired power.

Taiwan remains one of the largest LNG importers, generally importing above its 13 MTPA of nameplate regasification capacity. Although no new terminals have been completed since 2009, Taiwan has announced a number of proposals to expand regasification capacity, including a 2 MTPA expansion

Huelva LNG Terminal — Courtesy of Enagas

Figure 6.6: Receiving Terminal Import Capacity and Utilisation Rate by Country in 2016 and 2022.



Sources: IHS Markit, IGU, Company Announcements

project at the existing Taichung LNG terminal. Taiwan's LNG demand has increased incrementally over the last few years as gas utilisation in the power sector rose.

Over the past five years, the fastest growing LNG market in terms of regasification capacity was China, increasing to 6.3% of the market as of end-2016, compared to 3.5% in 2011. China completed one terminal and two expansion projects in 2016, adding 9 MTPA of new capacity. China also has 18.4 MTPA of under-construction regasification capacity announced to come online in 2017 (and 6 MTPA under construction for 2018). China is the world's fifth largest regasification market by capacity as of January 2017, at 49 MTPA. Notably, this is up from only 6 MTPA in 2008. Although it remains the third largest importer by volume, LNG demand growth in 2016 remained below contract expectations. China's average terminal utilisation increased to 56% in 2016, rising from 50% in 2015 (see Figure 6.6). 34.4 MTPA of new regasification capacity is announced to come online in 2017-2018.

India, forecasted to be a significant growth market for LNG imports, had 27 MTPA of regasification capacity as of January 2017, after completing a 5 MTPA expansion of Dahej LNG terminal in September 2016. The country has 15 MTPA of projects under construction that are targeted to be completed by 2019. Indeed, India's total regasification capacity could reach as high as 103 MTPA by 2020 based on the number of announced project proposals. Eastern India requires additional supply since domestic upstream projects have either under-performed or been delayed. Other parts of India that have not used much gas are more actively developing terminal plans such as northeastern and southwestern India. Despite

2015–2016 Receiving Terminals in Review

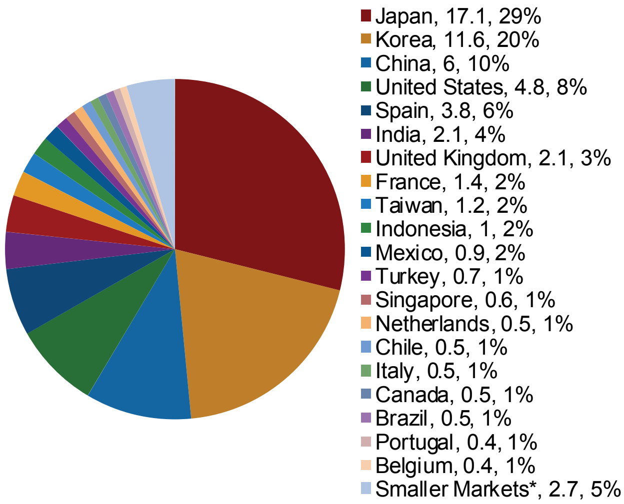
Receiving Capacity	New LNG import terminals	Number of regasification markets	Offshore Terminals
+22 MTPA Growth of global LNG receiving capacity	**+4** Number of new regasification terminals	**+1** Markets that added regasification capacity	**+1** Number of new offshore LNG terminals
Regasification capacity grew by 22.4 MTPA (+3%), from 754 MTPA in 2015 to 777 MTPA in 2016. An additional 18 MTPA reached commercial operations by end-January 2017, including France's 9.5 MTPA Dunkirk terminal. Growth capacity was led by the Asia and Asia Pacific regions in 2016.	New terminals in China, the UAE, and Japan (existing markets), and Poland (new importer) brought the total number of active regasification terminals from 110 to 114 by end-2016. By end-January 2017, that number grew to 117 with new terminals in France, Turkey and South Korea (all existing markets).	The number of countries with regasification capacity increased from 33 to 34 as Poland began commercial operations at its new terminal. Colombia began received a commissioning cargo at its first terminal in late 2016. Russia (Kaliningrad), the Philippines, and Bahrain all have their first regasification projects under construction in 2017, set to come online over the next two years.	One FSRU began commercial operations in 2016, in the UAE, as Abu Dhabi received its first LNG terminal. Turkey's Etki FSRU reached commercial operations in early 2017 and Colombia's Cartagena LNG FSRU received a commissioning cargo in late 2016. Teesside GasPort (UK) was decommissioned in 2015 after the facility came to the end of its commercially viable life.

this strong activity for new regasification developments, new pipeline connections will be needed to maximize gas penetration throughout the country. The lack of connectivity near the Kochi terminal in particular has limited throughput thus far and current expectations by the operator are that the pipeline will be completed by 2019 at the earliest.

Utilisation rates have been low across Europe, reaching an average of 25% in 2016 (steady with 2015), ranging between 4% and 54% by country. Despite holding 20% of global LNG import capacity, imports have been down in recent years due to competition from pipeline gas and weak continental demand, particularly in the power sector. Record Norwegian pipeline imports in 2015 as well as record Russian pipeline imports in 2016 further squeezed LNG in many markets. The expected growth of LNG into Europe did not materialize in 2016.

Given 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. France, Poland, and Turkey are the only European markets to complete new regasification terminals in Europe since Lithuania did so in 2014. Poland's 3.6 MTPA Swinoujscie terminal is the country's first LNG infrastructure, designed to diversify the country's gas supply away from Russia. France's 9.5 MTPA Dunkirk LNG terminal, which reached commercial operations in January 2017, is one of the largest import terminals in the world to come online in recent years, located in France's northeast in proximity to the GATE, Zeebrugge, and Isle of Grain terminals. In addition, Turkey's Etki LNG FSRU began commercial operations in early 2017, with two more Turkish FSRU proposals navigating the regulatory stages of development. In the medium term, Croatia could potentially become an LNG importer if progress is made on its Krk LNG terminal. Also on the Mediterranean Sea, Greece and Bulgaria are pushing to install an FSRU at Alexandroupolis, which has been aided by the progress on both the Trans-Adriatic Pipeline (TAP) and Interconnector Greece Bulgaria (IGB).

Figure 6.7: LNG Storage Tank Capacity by Country (mmcm) and % of Total, as of Q1 2017



Note: "Smaller Markets" includes Egypt, Thailand, United Arab Emirates, Argentina, Malaysia, Kuwait, Lithuania, Jordan, Dominican Republic, Puerto Rico, Pakistan, Israel, and Greece. Each of these markets had less than 0.4 mmcm of capacity as of January 2017. Sources: IHS Markit, Company Announcements

Behind Japan, the US still holds the second most regasification capacity in the world. However, the country's terminals remain minimally utilized, if at all; the country averaged 1% utilisation in 2016. In fact, only three regasification terminals in the US received cargoes in 2016. 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 also had one of the lowest utilisation levels in 2016 (3%), also due to the availability of domestic production. Taiwan (118%) and Puerto Rico (103%) registered the highest regasification terminal utilisation in 2016. Taiwan has typically received higher volumes than its announced regasification capacity, often leading to utilisation levels over 100%.

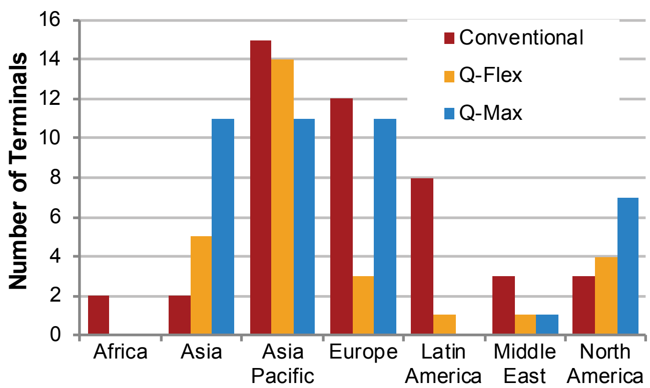
6.4. Receiving Terminal LNG Storage Capacity

The seven new terminals added through January 2017 increased announced global LNG storage capacity to 59 million cubic meters (mmcm), averaging at 524 mcm for existing terminals in the global market (see Figure 6.7). As oversupply looms in the LNG market, the strategic importance of gas storage will increase, particularly in Europe and Asia as US volumes come online.

Of the world's total existing storage capacity, 42% is located in the 20 largest LNG storage terminals, which range from 0.5 to 3.3 mmcm in size. 13 of these 20 terminals are located in Asia, as terminal operators in the region placed a premium on large storage capacity in order to secure supply and enhance flexibility, particularly given Asia's seasonal demand cycles. Importers like China, Japan, India and South Korea also often have little gas storage available outside of LNG terminals.

While South Korea's Pyeong-Taek terminal maintains the largest storage capacity at 3.36 mmcm, the Samcheok LNG terminal added 1.0 mmcm of storage capacity in mid-2016, bringing its total to 1.8 mmcm. An additional 0.81 mmcm is expected online by mid-2017, set to be completed through three tanks of 270,000 cm each – the world's largest capacity for a single storage tank. Outside of Asia, France's Dunkirk, completed in January 2017, contains 0.57 mmcm of storage.

Figure 6.8: Maximum Berthing Capacity of LNG Receiving Terminals by Region, 2016.[4]



Sources: IHS Markit, 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.

Storage capacity is following two trends: growth in average storage capacity per terminal in existing markets, particularly onshore terminals in Asia, and decline in average storage capacity in new markets deploying FSRUs, which typically contain far less storage capacity than onshore systems. Onshore terminals generally contain between 200 and 600 mcm of storage capacity, whereas floating terminals typically utilize storage tanks between 125 and 170 mcm in size. However, with a storage capacity of 263 mcm, Uruguay's GNL del Plata FRSU – reported to come online in 2018 – will become the world's largest FSRU to enter operations.

6.5. Receiving Terminal Berthing Capacity

LNG receiving facilities vary widely in their ship berthing capabilities. In similar fashion to recent observations in storage capacity, the maximum size of ships able to berth at onshore facilities in existing markets has generally been increasing. In comparison, newer markets often utilise FSRUs or small-scale facilities, which encompass much smaller ship berthing capacities. These smaller terminals generally can only receive conventional ships (under 200,000 cm capacity). Q-Class carrier (over 217,000 cm) utilization has generally increased as higher-demand and established markets moved to expand their ship berthing capacities in recent years.

Q-Max vessels, the largest of LNG carriers, have capacities of 261,700-266,000 cm. Sixteen different import markets (41 out of 114 existing regasification terminals) were known to be capable of receiving Q-Max ships as of January 2017 (see Figure 6.8). Twenty-two of these terminals were located in Asia and Asia Pacific, and none in Latin America or Africa. An additional twenty-eight existing regasification terminals are capable of receiving Q-Flex vessels (217,000-261,700 cm), as well as conventional carriers. In total, twenty-one out of thirty-four 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 2016, is only able to receive conventional vessels. Of the 45 terminals that are reported to be limited to receive conventional vessels, 20 are FSRUs. Some terminals are capable of receiving even smaller LNG ships as small-scale LNG facilities continue to develop worldwide; one example is the new Montego Bay terminal in Jamaica, which utilizes a small lightering vessel to make ship-to-ship transfers from an FSU and then shuttle to an onshore regasification system. Many European terminals have also made adjustments to accommodate small-scale vessels and add LNG bunkering capabilities to comply with emissions targets and capture new commercial opportunities.

6.6. Receiving Terminals with Reloading and Transshipment Capabilities

The growth of LNG re-exports largely stemmed from markets with ample pipeline access that utilize LNG to capture arbitrage opportunities between basins. Re-exports have also been a result of logistical motives within the market. France generated the most re-export cargoes in 2016, reaching

Table 6.1: Regasification Terminals with Reloading Capabilities as of January 2017.

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
France	**Dunkirk**	**4.0 mcm/h**	**570**	**1**	**N/A**
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	564	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	600	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 Markit, IGU*

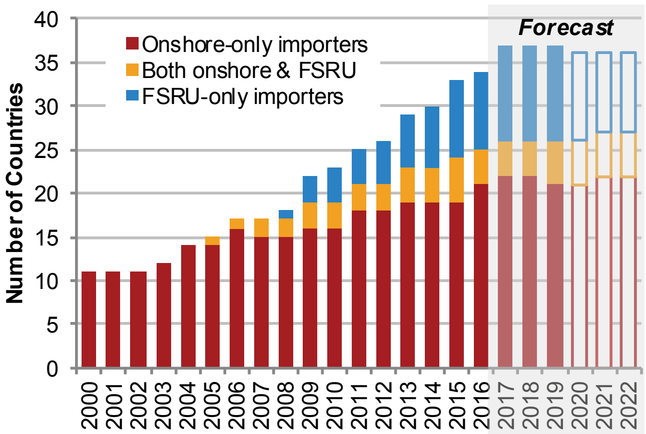
1.2 MTPA, coming from both Montoir and FosMax LNG. Although Spain has traditionally been the world's largest re-exporter, the country only re-exported two cargoes in 2016. Of 25 regasification terminals in Europe, 14 have re-export capabilities.

The only new re-exporting terminal in 2016 was in Lithuania, although this is considered to be small-scale. However, in 2015 three terminals re-exported cargoes for the first time, 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 brought the total number of terminals able to reload cargoes to 23 in 13 different countries. Furthermore, the Andres terminal in the Dominican Republic and the Sodeshi terminal in Japan are expected to be re-export-ready in early 2017. Other facilities, such as Cove Point in the US, have been authorized to re-export, but decided not to pursue this option as they have instead focused on adding liquefaction capacity. France's Dunkirk regasification terminal, which began commercial operations in January 2017, also has reloading capabilities, although it had not generated a re-export cargo as of January 2017.

Although non-European reloads grew in 2016, reaching 21 compared to only a few cargoes in previous years, European countries continued to provide the majority of re-exports, with France, Belgium, and the Netherlands leading the way. Outside of Europe, Singapore and Brazil reloaded 6 and 8 cargoes, respectively, generating a large portion of non-European reloading growth in 2016. South Korea, the US, and India also re-exported cargoes throughout the year.

Receiving terminals with two jetties are capable of providing bunkering services and completing transshipments, such as the Montoir-de-Bretagne (France) terminal. 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).

Figure 6.9: Rise of FSRUs among Import Markets, 2000–2022



Note: The above graph only includes importing countries that had existing or under construction LNG import capacity as of end-2016. 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 outlined bars. The decline in number of countries at the end of the forecast period is the result of short FSRU contract expirations. Sources: IHS Markit, Company Announcements

A number of regasification terminals, including the Isle of Grain terminal in the UK, have established truck loading capabilities. The transportation sector continues to be a growing consumer for LNG. In addition small-scale consumption has increased, reaching isolated demand pockets outside of the primary pipeline infrastructure. For more information on this topic, see the 2015 edition of the IGU World LNG Report.

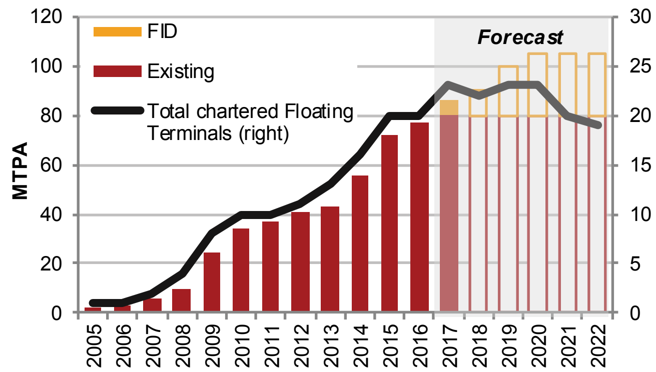
6.7. Comparison of Floating and Onshore Regasification

As of January 2017, 82% of existing receiving terminals were located onshore. Three out of the four terminals completed in 2016 were onshore developments, as well as two of the three terminals that began operations in January 2017. In 2015, however, of the seven new terminals, four were FSRUs, and six of the 19 currently under-construction projects are floating concepts, indicating that the ratio of onshore to offshore terminals will continue to shift.

FSRUs have been the most common pathway for new markets to enter the LNG market over the past several years (see Figure 6.9). Colombia is set to join the ranks of countries with LNG import capacity in 2017 via the commissioning of an FSRU, following Egypt, Jordan, and Pakistan in 2015. Abu Dhabi in the UAE also began imports with an FSRU in 2016 under an accelerated development schedule. Thirteen out of thirty-four current import markets had floating capacity by end-2016. Four of these thirteen had onshore capacity as well. Five FSRU projects were under construction or had already selected an FSRU contractor and have announced plans to come online by end-2017, totaling 19.3 MTPA (in Colombia, Russia, and Ghana—all new LNG markets—and India and Pakistan). Furthermore, multiple FSRUs have been announced for 2018, particularly in Uruguay, the Philippines, Bangladesh, and Ivory Coast, all of which would be new import markets. Nevertheless, there are still several new importers, such as Morocco and Sudan, which announced plans to enter the LNG market using onshore proposals to establish a more permanent solution for gas imports.

A new FSRU began operations in Abu Dhabi (UAE) in September 2016. Turkey's Etki FSRU began commercial operations in early 2017 after receiving its first cargo in late

Figure 6.10: Floating Regasification Capacity by Status and Number of Terminals, 2005–2022



Note: The above forecast only includes floating capacity sanctioned as of end-2016. 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 outlined 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 Markit, Company Announcements

Table 6.2: Benefits of 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

2016. At the end of January 2017, total active floating import capacity stood at 83 MTPA at 21 terminals (see Figure 6.10).

Both onshore terminals and FSRUs have their own merits and challenges for implementation and their utilization depends greatly on the specific needs and requirements of the target market. Recent trends have indicated that new markets have favoured utilising floating terminals, as evidenced by Egypt, Jordan, Pakistan, and Abu Dhabi, all joining the LNG market via FSRU in recent years. Overall, FSRUs allow for more rapid fuel switching, as projects can often be brought online faster than an onshore option, which can prove advantageous for new markets targeting near-term demand requirements. FSRUs can include faster permitting processes, and they are generally less expensive than onshore projects, particularly given that vessels are typically chartered from a third party (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. Additionally, floating receiving terminals are often linked to an offshore buoy that connects into a subsea gas pipeline system and can therefore operate further offshore than conventional terminals.

Onshore terminals provide a number of benefits in comparison to FSRUs, which become evident depending on target market requirements. While the majority of recent newcomers to the LNG market utilised FSRUs for their first LNG imports, Poland joined the LNG market through an onshore scheme in 2016. In general, onshore terminals can contain larger storage and send-out capacities, which could be strategically important given the current market environment. This can also alleviate concerns around impediments and limitations for onloading capacities, sometimes experienced with FSRUs. FSRUs face potential risks related to the terminal's operability, including vessel performance, heavy seas or meteorological conditions, and a longer LNG deliverability downtime. Furthermore, onshore terminals allow for the possibility of future expansions, both in terms of storage and regasification capacity.

Engine capabilities within floating terminals create two separate classifications of FSRUs. 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 that can be contracted for short periods. These FSRUs can function as

Hitachi LNG Terminal – Courtesy of Tokyo Gas 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.

Eight FSRUs (with capacities over 60,000 cubic meters) were announced to be on the order book as of January 2017. However, there are limited FSRUs available in the near term, with the *Golar Spirit* as one of the only un-chartered vessels. The *Excelsior* will come off hire in October, but it is earmarked for a project in Bangladesh. In the very near-term, there are limited opportunities to develop regasification capacity via floating terminals beyond what is already delivered and on order, given the lack of idle FSRUs. Therefore, 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 LNG markets.

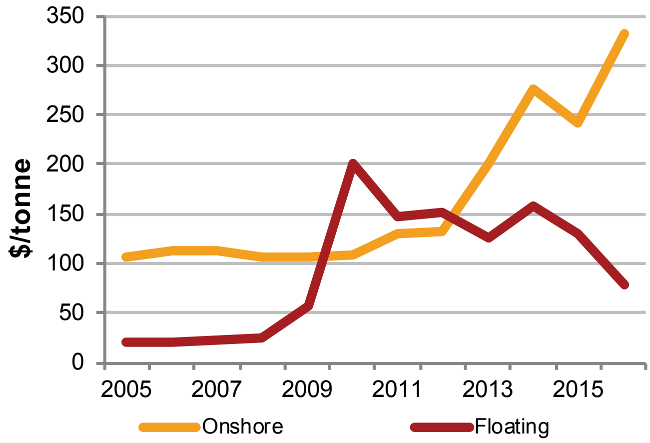
6.8. Project CAPEX

CAPEX costs for new receiving terminals have risen significantly over the last few years, specifically onshore terminals, after experiencing a period of relative steadiness between 2006 and 2012. FSRU CAPEX has remained fairly steady with a slight decline in recent years. FSRUs had experienced a large jump in 2009 and 2010 as the active number of floating terminals increased from four to ten; some of which were capital intensive projects. Regasification CAPEX figures are typically composed of costs associated with vessel berthing, storage tanks, regasification equipment, send-out pipelines, and metering of new facilities.

$334/tonne
Average costs of new onshore LNG import capacity in 2016

In 2016, the weighted average unit cost of onshore regasification capacity that came online during the year was $334/tonne (based on a three-year moving average), which is significantly higher than the 2015 average ($242/tonne), as the Hitachi (Japan) and Swinoujscie (Poland) projects both began operations in 2016 (see Figure 6.11). 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 2017 and 2018, bringing down overall costs. CAPEX for onshore capacity under construction are set to fall to $212/tonne in 2017 and $285/tonne in 2018, if all developing projects come online on time. However, a number of proposed projects that may soon reach construction milestones have higher CAPEX, which could ultimately bring these averages higher. Nonetheless, these figures vary significantly on a case-by-case basis, often depending on country-specific factors, including associated infrastructure development requirements.

Figure 6.11: Regasification Costs based on Project Start Dates, 2005–2016



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

Given that floating terminals require relatively limited infrastructure development in order to reach operations, CAPEX for FSRUs has been generally lower than onshore proposals. However, typically OPEX is higher for floating receiving terminals given that vessel charters are considered an OPEX cost.

New floating terminals' CAPEX have remained roughly steady over the past three years, declining from a high of $158/tonne in 2014.[5] In 2016, the weighted average unit cost of floating regasification based on a three-year moving average was $78/tonne. A rise in FSRU conversions, which can be brought into operations at a lower cost than new-build vessels, will be a factor in reducing average floating terminal CAPEX. However, this figure is slightly skewed due to limited reporting of CAPEX figures for recently completed floating terminals. As of January 2017, there were six FSRUs considered to be under construction and seven forthcoming FSRU projects that have selected an FSRU provider. Four of these projects have notably high CAPEX, particularly the Uruguay, Bahrain, Brazil, and Chile proposals, indicating that average FSRU costs could be rising moving forward. As with onshore terminals, larger vessels – and thus greater storage and send-out capacity – have accompanied higher CAPEX. Still, there is generally less variation in overall CAPEX for floating terminals than for onshore facilities, which is partly a reflection of fewer differences in capacity and storage size for vessel-based terminal solutions.

6.9. Risks to Project Development

While they are perhaps not as cumbersome as the risks facing liquefaction plants, regasification project developers still face a number of challenges when trying to bring proposed terminals online. Given the physical disparities between FSRUs and onshore terminals, project developers could utilize different approaches in order to mitigate the risks to develop each type of projects. Nonetheless, receiving terminals, both onshore and floating, must navigate similar risks to achieve commercial operations. These include:

- Project and equity financing, which are required for terminal plans to advance. Bangladesh's Moheshkhali LNG (Petrobangla) FSRU project has faced multiple delays, largely due to financing challenges. The latest announcement indicated a 2018 target start date for commercial operations.

[5] Figures in this section have been revised from the 2016 edition of the IGU World LNG Report

- 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 Aguirre GasPort FSRU project in Puerto Rico has faced an extended timeline due to regulation and permitting processes since beginning the initial filing process in 2012. The terminal is now announced to come online in 2018.
- 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 that indicated that intricate oceanographic conditions in Mossel Bay would prevent the project from moving forward.
- Reliability and liquidity of contractors and engineering firms during the construction process. Financial and regulatory issues with contractors or construction companies can lead to project delays or even equity partners pulling out of the project all together.
- 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 2017, Uruguay's FSRU project, the first for the country, is facing growing uncertainty given that a supply deal between Uruguay and Argentina had not been reached. 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. Ghana's West African Gas Limited (WAGL) Tema LNG project requires significant downstream infrastructure development in order to move forward. The *Golar Tundra* was delivered in May 2016, but remains idle offshore until the issues are sorted out The Kochi terminal in India continues to limit receiving capabilities due to the lack of completed pipeline connections to downstream users.

Barcelona LNG Terminal – Courtesy of Enagas

Dunkirk LNG Terminal First Delivery – Courtesy TOTAL

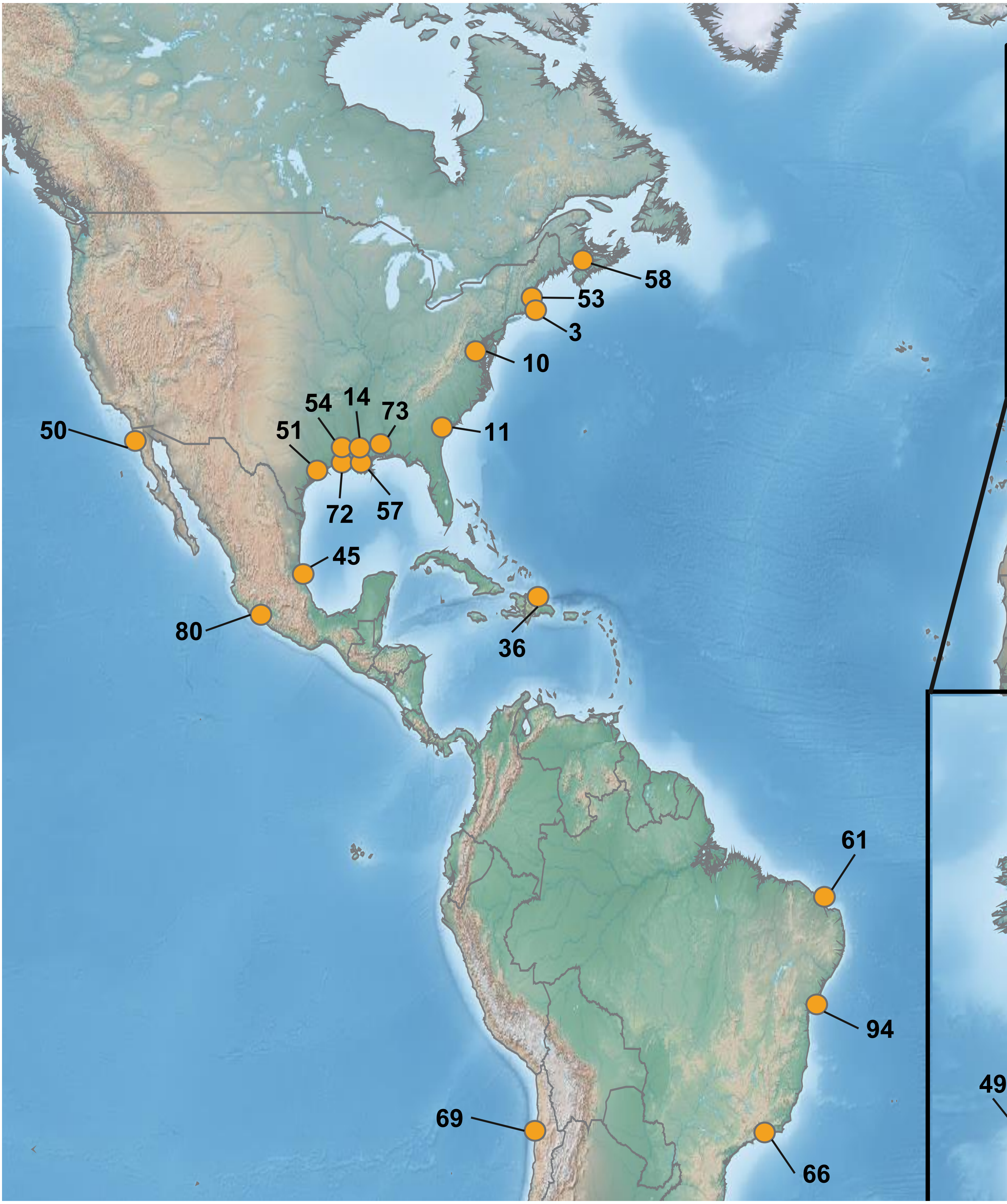
Looking Ahead

Will regasification capacity growth continue to be driven by existing LNG markets in the near term? Although Poland's first terminal began commercial operations in mid-2016, 84% of newly constructed regasification capacity in 2016 was completed in existing LNG markets, compared to only 30% in 2015. Supporting the trend are expansion projects at existing onshore terminals and France's new Dunkirk terminal. Colombia, Russia (Kaliningrad) and the Philippines are planning to add capacity by end-2017 as new importers. However, the majority of regasification capacity likely to be completed over the year will come from existing importers, particularly in China and India.

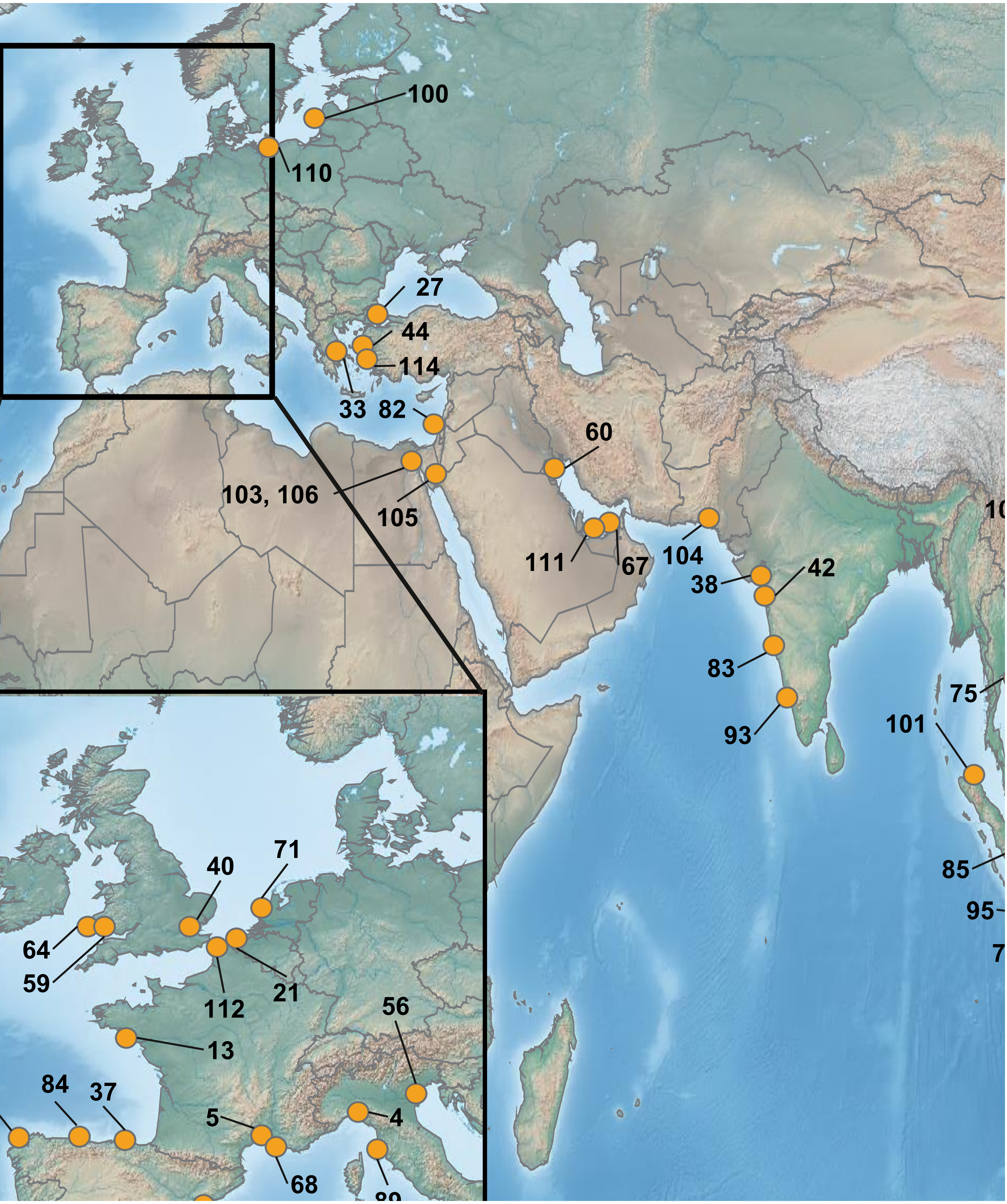
Can emerging markets readily respond to lower prices by completing regasification terminal projects in a timely manner? With Colombia's floating regasification terminal set to reach commercial operations in 2017, it will become the first emerging market to become an LNG buyer since mid-2015. Lower prices help unlock new pockets of demand and provide incentive for emerging markets to fast-track their first receiving terminals, as was observed in 2015 in Egypt, Jordan, and Pakistan. However, emerging markets still face a number of hurdles before projects can prove viable, including regulatory, infrastructure, and financing challenges, particularly in higher credit risk markets.

Will floating regasification capacity regain momentum in 2017? Although seven FSRUs were initially planned for completion in 2016, Abu Dhabi's FSRU was the only floating project to reach commercial operations during the year. In comparison, four FSRUs were completed in 2015. However, the utilization of FSRUs is expected to rebound throughout 2017 and into 2018, particularly in nascent LNG markets. Turkey's FSRU began commercial operations in early 2017 after taking a first cargo in late 2016. Colombia, India, Pakistan, and Russia (Kaliningrad) all have under-construction FSRUs anticipated online by the end of the year. Furthermore, a wide range of announced floating proposals for starts by end-2018 are in various stages of planning, indicating that the use of FSRUs is set to expand significantly in the near term.

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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Cartagena LNG Terminal – Courtesy of Enagas

7. The LNG Industry in Years Ahead

Will the high Asian spot prices of winter 2016-2017 be sustained?

A range of factors have enabled a strong run-up in Asian spot prices in the second half of 2016. In the final two months of the year, a significant premium opened up between Asian and European assessed LNG spot prices – typically a sign of a tighter market. Much of the impetus for higher prices has been unexpected supply shortfalls from existing projects and new projects that have struggled to start producing consistently. Moreover, very cold temperatures in Northeast Asia and Europe created additional demand needs. Nevertheless, the current relatively high spot price levels will be met with additional supply in 2017.

For 2017, we expect several new trains and ramp-ups, particularly in Australia and the United States. Supply should outpace demand growth and further cushion the Asian market, and thereby put considerable pressure on the supply/demand balance once the winter season ends in Asia and Europe. Many Asian importers are gearing up for higher contracted supply from new Australian projects that will dampen their spot and short-term purchasing needs. During the year, global supply additions should also be sufficient to cover emerging demand in new markets like Egypt and Pakistan. These countries have been actively tendering for short-term cargoes, with Pakistan recently awarding a new five-year contract.

While the balance is expected to be comfortable, volatility cannot be under-estimated. European prices are in a period of transition. NBP rose in second half 2016, driven by the rapid climb in global steam coal prices, which are linked by power generation in Europe. However, Pacific Basin LNG supply is ramping up faster than demand in 2017 and could lead to a significant increase in LNG arriving in Europe. With more LNG flowing into Europe in 2017 especially from the US GOM, the European market would be well-supplied allowing for the potential of cross-basin LNG trade to return. The Asian LNG premium is expected to again re-align with an inter-connected global LNG market, with European gas fundamentals returning to the forefront. However, delays in starting up new projects are a key risk to this rebalancing timeframe.

In addition, coal prices remain highly volatile. Much of this uptick in coal prices was driven by policy changes in China designed to curb oversupply – an indication of how quickly markets can cycle, with far-reaching impacts. Chinese government intervention in the domestic coal market is likely to continue, creating uncertainty for global coal prices. In the current environment, where European gas markets are highly influenced by coal, volatility in LNG markets can be expected until further supply comes on-stream.

Will there be more liquefaction FIDs despite loose market conditions?

With relatively low LNG prices, developers will naturally be cautious about new investment. Nevertheless, companies make independent decisions as they seek to monetize gas resource according to their own outlooks. Given demand uncertainty and changing buyer preferences, smaller-scale projects have been gaining the most momentum and commercial interest. Many of these also happen to be floating projects. These projects can help minimize risk and capital exposure in this price environment.

Coral FLNG in Mozambique may take FID imminently as multiple project partners have achieved internal board approvals. Fortuna FLNG could also reach FID soon as partner alignment has progressed and upstream costs are reported to have been reduced. Woodfibre LNG benefits from strong sponsor commitment and preliminary contracts. These three projects are strong contenders to reach FID in 2017. In addition, Exmar's Caribbean FLNG (0.5 MTPA), which had been slated for Colombia, has become a speculative asset that could quickly add capacity.

Photo courtesy of Chevron.

What trends could emerge for new LNG contracts?

With few new projects expected to reach FID in the coming year, contracting activity will continue to be dominated by secondary and tertiary deals – i.e., aggregators (particularly with US LNG volumes) re-contracting flexible-destination supply. In addition, the trend of shorter duration contracts will provide buyers with fewer long-term commitments, enhancing optionality, but adding long-term market exposure.

In addition to seeking out shorter lengths, buyers are also pursuing smaller contracts. Small contracts (less than 1.0 MMtpa) made up only 15% of all contracts signed in 2013, but rose to account for 46% of all contracts signed in 2016. Although traditional buyers in Japan, South Korea, and Taiwan drove small-volume activity in the early 2010s, continued growth has been supported primarily by new buyers. This includes buyers in emerging markets in the Middle East, Africa, Asia and Asia Pacific, as well as new companies in more established markets like China. These buyers often have smaller or more unpredictable demand profiles that make them unable to accommodate a large contract in the first few years of imports.

During the height of contracting activity at US projects, contracts with full destination flexibility made up the vast majority of new contracts signed – 81% of total contracts in 2013 – but since then, fixed destination contracts have accounted for a higher portion. This trend toward fixed destination contracts is primarily the result of two factors: the slowdown in global liquefaction FIDs and the emergence of new markets. Many emerging markets like Egypt and Pakistan have contracted volumes fixed to their own terminals. However, more established buyers in markets like Japan are increasingly pursuing more destination flexibility in their future contracts.

In order to avoid a supply shortage, long-term agreements will be necessary for underpinning new, large-scale LNG projects. While buyers are navigating the current market, and at times demanding terms to enhance their supply optionality, long-term contracts will be of particular importance to buyers who face a portfolio of expiring contracted supply.

How will existing LNG contracts come under pressure in 2017?

Customers of existing long-term contracts that are reacting to oversupply conditions largely fall into two groups: those that are seeking to re-negotiate pricing and those that do not have enough demand to meet their contractual commitments. Petronet LNG's price renegotiation with RasGas at the end of 2015 was an important catalyst for other bilateral relationships in 2016.The government of Peru pushed to review terms of its arrangement with Shell. India's GAIL sought to revise terms with Gazprom and Cheniere. Thailand's PTT reportedly looked to reduce the price agreed to in heads of agreement (HOAs) with Shell and BP.

Gas demand has slowed quicker than anticipated in some importing markets – particularly in Asia Pacific. As a result, buyers in those countries have to be creative to manage over-commitments. China has been over-contracted since 2015 and this may continue in 2017 given the large additions of Australian capacity and associated contracts with the Chinese NOCs. Beyond the NOC's, smaller LNG players in China – e.g., ENN Energy, Beijing Gas, Jovo Group – are becoming more active players. In the same way, other Asian LNG buyers in Japan and South Korea are potentially overcommitted in the near term and many have formed trading businesses to manage their portfolios.

Will there be more LNG-related asset ownership changes?

Since the second half of 2016, a series of asset acquisitions associated with major gas and LNG projects have been announced – e.g., ExxonMobil's acquisition of InterOil, BP's entry into Mauritania and Senegal, and TOTAL's investment in Tellurian Investments – developer of Driftwood LNG, located in U.S. Notably, the acquiring companies in these deals have primarily been large international oil companies (IOCs), and gas and LNG-related assets have disproportionately been the focus of their investment appetites. As the oil market begins to potentially turn around, several long-term strategic drivers could re-surface and motivate IOCs and other companies to further invest in the gas space.

The scope and financial exposure of the deals vary, as do the drivers behind them. The IOCs that have made investments thus far have a long-term time horizon, which allows them to make commitments despite the shorter-term prospect of weak market conditions. The notable focus by some companies in gas assets could be a result of their worldview that gas will play a critical role in a carbon-constrained future.

Can LNG in shipping bunkers be transformative for LNG demand?

The use of LNG has generated much interest in the shipping community, with two main drivers. First, LNG emits virtually no sulfur oxides (SOX), much less NOX and particulate matter, and significantly less carbon dioxide (CO2) per unit of energy released than oil-derived liquid fuels. This can reduce the compliance cost imposed by the use of traditional liquid fuels. Second, interest in LNG is also driven by lower prices and by the need of gas marketers to create new markets for now abundant gas supplies. The lower retail price of natural gas – everywhere in the world – is a strong driver for LNG penetration in commercial transport.

While natural gas retains a commodity price advantage even at low oil prices, the higher fixed costs of producing and delivering LNG erode and can even reverse that advantage. Thus environmental specifications will ultimately influence the potential use of LNG in bunkering.

The International Maritime Organization (IMO) provided clarity in October 2016 when it confirmed the originally-proposed timetable of 2020 for reducing the permitted sulfur content of marine fuel from 3.5% currently, to 0.5%. LNG can meet the technical specifications of the IMO standards, but the amount of switching that occurs will depend upon the economics compared with the alternative of using marine diesel and installation of scrubbers. The pace of infrastructure development to support this new market is also a major question.

How will individual country (regional) dynamics impact the LNG balance?

As always, individual country (or regional) dynamics will have important consequences on the LNG market. In particular, the following countries and regions will be influential for the LNG market balance.

Japan: How will the market deal with continued uncertainty from nuclear restarts and market deregulation? The opening of Japan's entire retail power sector to competition in April 2016 led to relatively fast customer switching, with a direct impact on incumbents' fuel procurement needs. This builds upon the further uncertainty the incumbent electricity utilities face regarding the timing of nuclear restarts. The Osaka High Court is expected to rule in early 2017 on whether Units 3 and 4 of Kansai Electric's Takahama reactors can restart following the provisional injunction issued by Otsu local District Court. The court injunction brought on by residents has halted the operations of once-restarted reactors despite the regulator's approvals. Many other reactors face similar ongoing judicial risks regarding when they can come back online – any further delays will lead to a greater need for short-term LNG imports. By contrast, the April 2017 opening of the gas market to full competition could have uncertain impacts on the industry, given the challenges facing new entrants in accessing infrastructure. Some areas will have intense retail gas competition between the city gas and electric power companies. To prepare for such uncertain future, traditional regional utilities have been setting-up trading businesses to hedge their relative broadening contract portfolios which increasingly include US LNG.

China: How will LNG imports respond to commercial and political changes? China's ability to absorb growing amounts of contracted LNG continues to be an important signpost for the global market. The country has been over-contracted since 2015. However, there was a dramatic increase in LNG deliveries in the last two months of 2016; November and December 2016 imports were the highest levels ever in those months, with December imports reaching 4.1 MMt. Some of this huge increase could be attributed to CNPC's Qatari contract being weighted towards winter delivery.

Nevertheless, there are other factors that could position China to catch up with contracts. The policy push to improve air quality standards in China's coastal provinces is a major driver of using more gas in the power and heating sectors. While there are means to import coal and renewable power from inland provinces to the coast, gas could be pushed more heavily in the country's energy mix. Indeed, China could be the second largest regasification capacity holder in Asia by 2022. While the NOCs are dealing with over-contracted conditions, many private generators and other non-NOCs have achieved some success in securing regasification terminal rights and offtake contracts with international suppliers.

South Korea: Will South Korea continue to see LNG import declines? Despite the short-term boost to demand driven by the temporary shutdown of nuclear power plants and cold winter weather in 2016, the structural drivers leading to lower LNG demand persist. Significant coal and nuclear capacity additions and expected weak power growth may continue to squeeze South Korea's LNG consumption. If any of these new plants take longer than anticipated to start-up, additional LNG might be needed. Another area to watch is an apparent shift in the government's stance toward coal. In 2016, new policies were proposed that could potentially reign in the growth of coal consumption. These include the increased import tax for coal used in power generation and the proposals to close older coal plants and change the dispatch order in power generation based on factors linked to pollution and not just short-run costs. On the political front, increased U.S. LNG imports have been discussed as a way to help balance the U.S. - South Korea trade deficit. In addition, the upcoming Presidential election in 2017 may result in energy policy changes.

India: Will price relationship shifts slow India's spot import momentum? For the last two years, India has provided an important destination for spot cargoes and we expect this to continue into 2017. The country will benefit from additional regasification capacity during the year. A key factor in India's 2017 procurement will be the oil price and arbitrage potential between oil-indexed LNG contracts and spot volumes. If spot prices increase relative to oil, this could yield a much milder appetite for spot LNG. Another important signpost for demand will be the impact of the reduction in the customs duty on LNG imports from 5% to 2.5% for the upcoming fiscal year.

Egypt: Could LNG growth backtrack as new production starts? New indigenous production starting during 2017 could put pressure on imports in 2017 despite strong levels in previous years. Consequently, Egypt has substantially reduced its LNG tender for 2017 below original expectations and has canceled its tender for a third FSRU in the country. The BP-operated West Nile Delta and Eni-operated Zohr field are expected to start during the year. The exact start of these fields will be closely watched to determine if more LNG will be needed to meet demand in the power sector.

Other Middle East and Asia: Will demand grow in gas-short countries? Many Middle Eastern (i.e., Kuwait, UAE, Jordan, and Bahrain) and Asian (i.e., Pakistan and Bangladesh) markets are witnessing a rapid expansion in gas demand for power and industrial projects. At the same time, domestic production in many of these countries is limited, increasing the potential call on LNG imports. Given political hurdles for international pipelines in these regions, LNG will continue to have an important role.

Europe: What factors will impact the continent's ability to balance the LNG market? LNG imports are expected to increase to Europe over the next two years as U.S. supply increases. This influx will be a consequence of global demand not growing as fast as incremental supply additions, not necessarily due to market-specific needs of the European market. The continent can serve as a backstop market for any excess cargoes that cannot find a dedicated international buyer. The additional LNG volumes combined with sufficient pipeline imports, should keep Europe well-supplied. As a result, the gas-fired power sector may see increased utilization, particularly if coal prices stay at current levels or continue to trend upwards, including via the broader adoption of a carbon price.

8. References Used in the 2017 Edition

8.1. Data Collection

Data in the 2017 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 2015 and 2016 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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8.2. Definitions

Brownfield Liquefaction Project: A land-based LNG project at a site with existing LNG infrastructure, such as: jetties, storage tanks, liquefaction facilities or 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 company 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 60,000 cm are considered part of the global fleet discussed in the "LNG Carriers" chapter (Chapter 5). Vessels with a capacity of under 60,000 cm are considered small-scale LNG carriers.

Long-term and Spot Charter Rates: Long-term charter rates refer to anything chartered under a contract of five years or above. Sport charter rates refer to anything chartered under a contract of six months or less.

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:

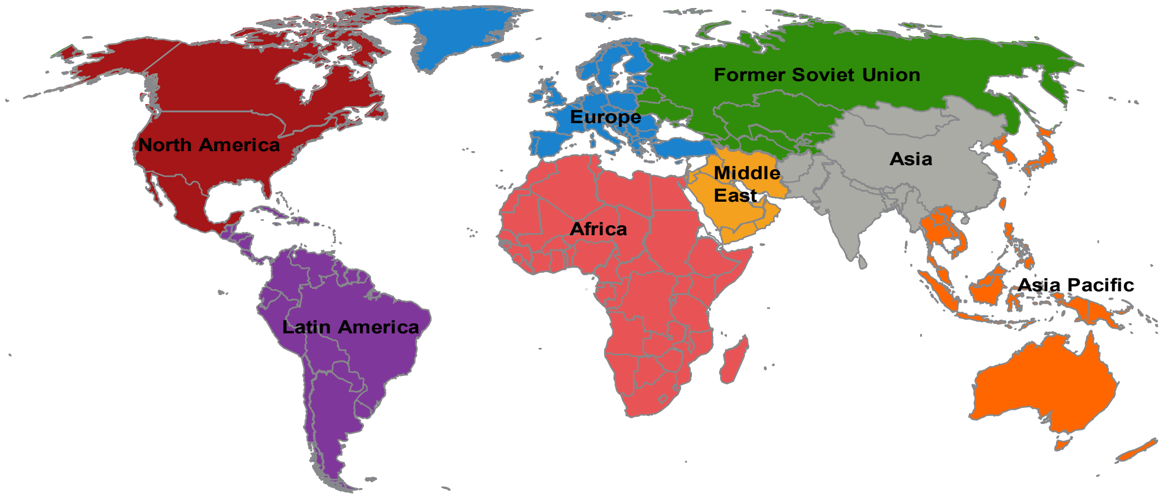
- Short-term trade = volumes traded on a spot basis or under contracts of less than 2 years
- Medium-term trade = volumes traded under a 2 to <5 year contract
- Long-term trade = volumes traded under a 5+ year contract

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 above. 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.

El Musel LNG Terminal.



8.4. Acronyms

BOG = Boil-Off Gas
CAPEX = Capital Expenditures
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
FLNG = Floating Liquefaction
FSRU = Floating Storage and Regasification Unit
FSU = Former Soviet Union
HFO = Heavy Fuel Oil
HOA = Heads of Agreement
IOC = International Oil Company
IPP = Independent Power Producers
ME-GI = M-type, Electronically Controlled, Gas Injection
MDO = Marine Diesel Oil
NBP = National Balancing Point
NOC = National Oil Company
NOX = Nitrogen Oxides
NSR = North Sea Route
OPEC = Organisation of Petroleum Exporting Countries
OPEX = Operating Expenditures
SOX = Sulphur Oxides
SPA = Sales and Purchase Agreement
SSD = Slow Speed Diese
TFDE = Tri-Fuel Diesel Electric LNG vessel
UAE = United Arab Emirates
UK = United Kingdom
US = United States
US DOE = US Department of Energy
US GOM = US Gulf of Mexico
US Lower 48 = US 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
mmcfd = million cubic feet per day
mmcm = million cubic meters
MMBtu = million British thermal units
MT = million tonnes
MTPA = million tonnes per annum
nm = nautical miles
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	7.692×10^{-4}	0.0017		35.31	0.0411	0.0071
cf gas	2.178×10^{-5}	4.8×10^{-5}	0.0283		0.0012	2.005×10^{-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	United States	Kenai LNG**	1969	1.5	ConocoPhillips	ConocoPhillips Optimized Cascade®
2	Libya	Marsa El Brega***	1970	3.2	LNOC	APC C_3MR
3	Brunei	Brunei LNG T1-4	1973	5.76	Government of Brunei, Shell, Mitsubishi	APC C_3MR
3	Brunei	Brunei LNG T5	1974	1.44	Government of Brunei, Shell, Mitsubishi	APC C_3MR
4	United Arab Emirates	ADGAS LNG T1-2	1977	2.6	ADNOC, Mitsui, BP, TOTAL	APC C_3MR
5	Algeria	Arzew - GL1Z (T1-6)	1978	7.9	Sonatrach	APC C_3MR
5	Algeria	Arzew - GL2Z (T1-6)	1981	8.2	Sonatrach	APC C_3MR
6	Indonesia	Bontang LNG T3-4	1983	5.4	Pertamina	APC C_3MR
7	Malaysia	MLNG Satu (T1-3)	1983	8.4	PETRONAS, Mitsubishi, Sarawak State Government	APC C_3MR
8	Australia	North West Shelf T1	1989	2.5	BHP Billiton, BP, Chevron, Shell, Woodside, Mitsubishi, Mitsui	APC C_3MR
8	Australia	North West Shelf T2	1989	2.5	BHP Billiton, BP, Chevron, Shell, Woodside, Mitsubishi, Mitsui	APC C_3MR
6	Indonesia	Bontang LNG T5	1990	2.9	Pertamina	APC C_3MR
8	Australia	North West Shelf T3	1992	2.5	BHP Billiton, BP, Chevron, Shell, Woodside, Mitsubishi, Mitsui	APC C_3MR
4	United Arab Emirates	ADGAS LNG T3	1994	3.2	ADNOC, Mitsui, BP, TOTAL	APC C_3MR
6	Indonesia	Bontang LNG T6	1995	2.9	Pertamina	APC C_3MR
7	Malaysia	MLNG Dua (T1-3)	1995	9.6	PETRONAS, Shell, Mitsubishi, Sarawak State Government	APC C_3MR
9	Qatar	Qatargas I (T1)	1997	3.4	Qatar Petroleum, ExxonMobil, TOTAL, Marubeni, Mitsui	APC C_3MR
9	Qatar	Qatargas I (T2)	1997	3.4	Qatar Petroleum, ExxonMobil, TOTAL, Marubeni, Mitsui	APC C_3MR
6	Indonesia	Bontang LNG T7	1998	2.7	Pertamina	APC C_3MR
9	Qatar	Qatargas I (T3)	1998	3.2	Qatar Petroleum, ExxonMobil, TOTAL, Marubeni, Mitsui	APC C_3MR
9	Qatar	RasGas I (T1)	1999	3.3	Qatar Petroleum, ExxonMobil, KOGAS, Itochu, LNG Japan	APC C_3MR
10	Trinidad	ALNG T1	1999	3.3	Shell, BP, CIC, NGC Trinidad	ConocoPhillips Optimized Cascade®
11	Nigeria	NLNG T1	2000	3.3	NNPC, Shell, TOTAL, Eni	APC C_3MR
12	Oman	Oman LNG T1	2000	3.55	Government of Oman, Shell, TOTAL, Korea LNG, Mitsubishi, Mitsui, Partex, Itochu	APC C_3MR
6	Indonesia	Bontang LNG T8	2000	3	Pertamina	APC C_3MR
12	Oman	Oman LNG T2	2000	3.55	Government of Oman, Shell, TOTAL, Korea LNG, Mitsubishi, Mitsui, Partex, Itochu	APC C_3MR
9	Qatar	RasGas I (T2)	2000	3.3	Qatar Petroleum, ExxonMobil, KOGAS, Itochu, LNG Japan	APC C_3MR
11	Nigeria	NLNG T2	2000	3.3	NNPC, Shell, TOTAL, Eni	APC C_3MR
10	Trinidad	ALNG T2	2002	3.4	Shell, BP	ConocoPhillips Optimized Cascade®
11	Nigeria	NLNG T3	2003	3	NNPC, Shell, TOTAL, Eni	APC C_3MR
10	Trinidad	ALNG T3	2003	3.4	Shell, BP	ConocoPhillips Optimized Cascade®
7	Malaysia	MLNG Tiga (T1-2)	2003	7.7	PETRONAS, Shell, JX Nippon Oil & Energy, Sarawak State Government, Mitsubishi, JAPEX	APC C_3MR

Appendix 1: Table of Global Liquefaction Plants (continued)

Reference Number	Country	Project Name	Start Year	Nameplate Capacity (MTPA)	Owners*	Liquefaction Technology
9	Qatar	RasGas II (T1)	2004	4.7	Qatar Petroleum, ExxonMobil	APC C_3MR/ Split MR™
8	Australia	North West Shelf T4	2004	4.6	BHP Billiton, BP, Chevron, Shell, Woodside, Mitsubishi, Mitsui	APC C_3MR
13	Egypt	Damietta LNG T1***	2005	5	Gas Natural Fenosa, Eni, EGPC, EGAS	APC C_3MR/ Split MR™
13	Egypt	ELNG T1***	2005	3.6	Shell, PETRONAS, EGAS, EGPC, ENGIE	ConocoPhillips Optimized Cascade®
9	Qatar	RasGas II (T2)	2005	4.7	Qatar Petroleum, ExxonMobil	APC C_3MR/ Split MR™
13	Egypt	ELNG T2***	2005	3.6	Shell, PETRONAS, EGAS, EGPC	ConocoPhillips Optimized Cascade®
12	Oman	Qalhat LNG	2006	3.7	Government of Oman, Oman LNG, Gas Natural Fenosa, Eni, Itochu, Mitsubishi, Osaka Gas	APC C_3MR
10	Trinidad	ALNG T4	2006	5.2	Shell, BP, NGC Trinidad	ConocoPhillips Optimized Cascade®
11	Nigeria	NLNG T4	2006	4.1	NNPC, Shell, TOTAL, Eni	APC C_3MR
11	Nigeria	NLNG T5	2006	4.1	NNPC, Shell, TOTAL, Eni	APC C_3MR
14	Australia	Darwin LNG T1	2006	3.7	ConocoPhillips, Santos, INPEX, Eni, JERA, Tokyo Gas	ConocoPhillips Optimized Cascade®
9	Qatar	RasGas II (T3)	2007	4.7	Qatar Petroleum, ExxonMobil	APC C_3MR/ Split MR™
15	Equatorial Guinea	EG LNG T1	2007	3.7	Marathon, Sonagas, Mitsui, Marubeni	ConocoPhillips Optimized Cascade®
16	Norway	Snøhvit LNG T1	2008	4.2	Statoil, Petoro, TOTAL, ENGIE, LetterOne	Linde MFC
11	Nigeria	NLNG T6	2008	4.1	NNPC, Shell, TOTAL, Eni	APC C_3MR
8	Australia	North West Shelf T5	2008	4.6	BHP Billiton, BP, Chevron, Shell, Woodside, Mitsubishi, Mitsui	APC C_3MR
9	Qatar	Qatargas II (T1)	2009	7.8	Qatar Petroleum, ExxonMobil	APC AP-X
17	Russia	Sakhalin 2 (T1)	2009	5.4	Gazprom, Shell, Mitsui, Mitsubishi	Shell DMR
17	Russia	Sakhalin 2 (T2)	2009	5.4	Gazprom, Shell, Mitsui, Mitsubishi	Shell DMR
9	Qatar	RasGas III (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
18	Indonesia	Tangguh LNG T1	2009	3.8	BP, CNOOC, JX Nippon Oil & Energy, Mitsubishi, INPEX, KG Berau, Sojitz, Sumitomo, Mitsui	APC C_3MR/ Split MR™
19	Yemen	Yemen LNG T1	2009	3.6	TOTAL, Hunt Oil, Yemen Gas Co., SK Group, KOGAS, Hyundai, GASSP	APC C_3MR/ Split MR™
18	Indonesia	Tangguh LNG T2	2010	3.8	BP, CNOOC, JX Nippon Oil & Energy, Mitsubishi, INPEX, KG Berau, Sojitz, Sumitomo, Mitsui	APC C_3MR/ Split MR™
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 Group, KOGAS, Hyundai, GASSP	APC C3MR/ Split MR™
20	Peru	Peru LNG T1	2010	4.45	Hunt Oil, Shell, SK Group, Marubeni	APC C3MR/ Split MR™
9	Qatar	Qatargas III	2010	7.8	Qatar Petroleum, ConocoPhillips, Mitsui	APC AP-X

Appendix 1: Table of Global Liquefaction Plants (continued)

Reference Number	Country	Project Name	Start Year	Nameplate Capacity (MTPA)	Owners*	Liquefaction Technology
9	Qatar	Qatargas IV	2011	7.8	Qatar Petroleum, Shell	APC AP-X
21	Australia	Pluto LNG T1	2012	4.43	Woodside, Kansai Electric, Tokyo Gas	Shell propane pre-cooled mixed refrigerant design
5	Algeria	Skikda - GL1K Rebuild	2013	4.5	Sonatrach	APC C_3MR
22	Angola	Angola LNG T1	2014	5.2	Chevron, Sonangol, BP, Eni, TOTAL	ConocoPhillips Optimized Cascade®
23	Papua New Guinea	PNG LNG T1	2014	3.45	ExxonMobil, Oil Search, PNG Government, Santos, JX Nippon Oil & Energy, MRDC, Marubeni, Petromin PNG	APC C_3MR
23	Papua New Guinea	PNG LNG T2	2014	3.45	ExxonMobil, Oil Search, PNG Government, Santos, JX Nippon Oil & Energy, MRDC, Marubeni, Petromin PNG	APC C_3MR
5	Algeria	Arzew - GL3Z (Gassi Touil)	2014	4.7	Sonatrach	APC C_3MR/ Split MR™
24	Australia	QCLNG T1	2015	4.25	Shell, CNOOC	ConocoPhillips Optimized Cascade®
24	Australia	QCLNG T2	2015	4.25	Shell, Tokyo Gas	ConocoPhillips Optimized Cascade®
25	Indonesia	Donggi-Senoro LNG	2015	2	Mitsubishi, Pertamina, KOGAS, Medco	APC C_3MR
26	Australia	GLNG T1	2016	3.9	Santos, PETRONAS, TOTAL, KOGAS	ConocoPhillips Optimized Cascade®
27	Australia	Australia Pacific LNG T1	2016	4.5	ConocoPhillips, Origin Energy, Sinopec	ConocoPhillips Optimized Cascade®
28	United States	Sabine Pass T1	2016	4.5	Cheniere Energy, Blackstone	ConocoPhillips Optimized Cascade®
26	Australia	GLNG T2	2016	3.9	Santos, PETRONAS, TOTAL, KOGAS	ConocoPhillips Optimized Cascade®
28	United States	Sabine Pass T2	2016	4.5	Cheniere Energy, Blackstone	ConocoPhillips Optimized Cascade®
29	Australia	Gorgon LNG T1	2016	5.2	Chevron, ExxonMobil, Shell, Osaka Gas, Tokyo Gas, JERA	APC C_3MR/ Split MR™
29	Australia	Gorgon LNG T2	2016	5.2	Chevron, ExxonMobil, Shell, Osaka Gas, Tokyo Gas, JERA	APC C_3MR/ Split MR™
7	Malaysia	MLNG T9	2017	3.6	PETRONAS, JX Nippon Oil & Energy, Sabah State	APC C_3MR/ Split MR™

Sources: IHS, Company Announcements
** Companies are listed by size of ownership stake, starting with the largest stake*
*** Kenai LNG's export license is valid until February 2018, though the plant's future exports are uncertain. It did not export cargoes in 2016.*
**** Damietta LNG in Egypt has not operated since the end of 2012; operations at ELNG in Egypt returned in 2016 after 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*
Australia	Australia Pacific LNG T2	2017	4.5	ConocoPhillips, Origin Energy, Sinopec
Malaysia	PFLNG Satu	2017	1.2	PETRONAS
Indonesia	Senkang LNG T1	2017	0.5	EWC
United States	Sabine Pass LNG T3-4	2017	9	Cheniere Energy, Blackstone
Australia	Ichthys LNG T1	2017	4.45	INPEX, TOTAL, CPC, Tokyo Gas, Kansai Electric, Osaka Gas, JERA, Toho Gas
Cameroon	Cameroon FLNG	2017	2.4	Golar, Keppel
Australia	Gorgon LNG T3	2017	5.2	Chevron, ExxonMobil, Shell, Osaka Gas, Tokyo Gas, JERA
Australia	Wheatstone LNG T1	2017	4.45	Chevron, KUFPEC, Woodside, JOGMEC, Mitsubishi, Kyushu Electric, NYK, JERA
Russia	Yamal LNG T1	2017	5.5	Novatek, TOTAL, CNPC, Silk Road Fund
United States	Cove Point LNG	2017	5.25	Dominion
Australia	Ichthys LNG T2	2018	4.45	INPEX, TOTAL, CPC, Tokyo Gas, Kansai Electric, Osaka Gas, JERA, Toho Gas
Australia	Wheatstone LNG T2	2018	4.45	Chevron, KUFPEC, Woodside, JOGMEC, Mitsubishi, Kyushu Electric, NYK, JERA
United States	Elba Island LNG T1-6	2018	1.5	Kinder Morgan
Australia	Prelude FLNG	2018	3.6	Shell, INPEX, KOGAS, CPC
United States	Cameron LNG T1	2018	4	Sempra, Mitsubishi/NYK JV, Mitsui, ENGIE
Russia	Yamal LNG T2	2018	5.5	Novatek, TOTAL, CNPC, Silk Road Fund
United States	Cameron LNG T2	2018	4	Sempra, Mitsubishi/NYK JV, Mitsui, ENGIE
United States	Freeport LNG T1	2018	5.1	Freeport LNG, JERA, Osaka Gas
United States	Corpus Christi LNG T1	2019	4.5	Cheniere Energy
United States	Elba Island LNG T7-10	2019	1	Kinder Morgan
United States	Freeport LNG T2	2019	5.1	Freeport LNG, IFM Investors
United States	Corpus Christi LNG T2	2019	4.5	Cheniere Energy
United States	Cameron LNG T3	2019	4	Sempra, Mitsubishi/NYK JV, Mitsui, ENGIE
United States	Sabine Pass LNG T5	2019	4.5	Cheniere Energy, Blackstone
Russia	Yamal LNG T3	2019	5.5	Novatek, TOTAL, CNPC, Silk Road Fund
United States	Freeport LNG T3	2019	5.1	Freeport LNG
Indonesia	Tangguh LNG T3	2020	3.8	BP, CNOOC, JX Nippon Oil & Energy, Mitsubishi, INPEX, KG Berau, Sojitz, Sumitomo, Mitsui
Malaysia	PFLNG 2	2020	1.5	PETRONAS
Malaysia	PFLNG 2	2020	1.5	PETRONAS

Sources: IHS, Company Announcements
** Companies are listed by size of ownership stake, starting with the largest stake.*

Appendix 3: Proposed Liquefaction Plants by Region

Project		Capacity	Status	Latest Company Announced Start Date	DOE/FERC Approval	FTA/non-FTA Approval	Operator
United States Lower 48							
Sabine Pass LNG	T3-4	9	UC**	2017	DOE/FERC	FTA/ non-FTA	Cheniere Energy
	T5	4.5	UC**	2019	DOE/FERC	FTA/ non-FTA	
	T6	4.5	Pre-FID	N/A	DOE/FERC	FTA/ non-FTA	
Cove Point LNG		5.25	UC**	2017	DOE/FERC	FTA/ non-FTA	Dominion Resources
Elba Island LNG		2.5	UC**	2018	DOE/FERC	FTA/ non-FTA	Kinder Morgan
Cameron LNG	T1-3	12	UC**	2018	DOE/FERC	FTA/ non-FTA	Sempra Energy
	T4-5	8	Pre-FID	2021	DOE/FERC	FTA/ non-FTA	
Freeport LNG	T1-2	10.2	UC**	2018-19	DOE/FERC	FTA/ non-FTA	Freeport LNG Liquefaction
	T3	5.1	UC**	2019	DOE/FERC	FTA/ non-FTA	
	T4	5.1	Pre-FID	2021	N/A	N/A	
Corpus Christi LNG	T1-2	9	UC**	2019	DOE/FERC	FTA/ non-FTA	Cheniere Energy
	T3	4.5	Pre-FID	N/A	DOE/FERC	FTA/ non-FTA	
	T4-5	9	Pre-FID	N/A	DOE	FTA	
American LNG - Titusville		0.6	Pre-FID	2017	DOE	FTA	Fortress Investment Group
Eagle LNG		0.99	Pre-FID	2018-2020	DOE	FTA	Ferus Natural Gas Fuels
Calcasieu Pass LNG		10	Pre-FID	2020	DOE	FTA	Venture Global Partners
CE FLNG		7.5	Pre-FID	2020	DOE	FTA	Cambridge Energy Holdings
Delfin FLNG		12	Pre-FID	2020	DOE	FTA	Fairwood LNG
Main Pass Energy Hub FLNG		24	Pre-FID	2020	DOE	FTA	Freeport-McMoran Energy
Plaquemines LNG		20	Pre-FID	2020	DOE	FTA	Venture Global LNG
Rio Grande LNG		27	Pre-FID	2020-22	DOE	FTA	NextDecade
Barca FLNG		12	Pre-FID	2021	DOE	FTA	Barca LNG
Eos FLNG		12	Pre-FID	2021	DOE	FTA	Eos LNG
Gulf Coast LNG		21	Pre-FID	2021	DOE	FTA	Gulf Coast LNG
Texas LNG		4	Pre-FID	2021	DOE	FTA	Texas LNG
Annova LNG		6	Pre-FID	2021-22	DOE	FTA	Exelon
Golden Pass LNG		15.6	Pre-FID	2021-22	DOE/FERC	FTA	Golden Pass Products
Gulf LNG		10	Pre-FID	2021-22	DOE	FTA	Kinder Morgan
G2 LNG		13.4	Pre-FID	2022	DOE	FTA	G2 LNG
General American LNG		4	Pre-FID	2022	N/A	N/A	General American LNG
Magnolia LNG		8	Pre-FID	2022	DOE/FERC	FTA/ non-FTA	LNG Limited
Point Comfort FLNG		9	Pre-FID	2022	N/A	N/A	Lloyds Energy Group
Driftwood LNG		26	Pre-FID	2022-25	N/A	N/A	Tellurian Investments
Port Arthur LNG		10	Pre-FID	2023	DOE	FTA	Sempra Energy
Monkey Island LNG		12	Pre-FID	2023-24	DOE	FTA	SCT&E
Jordan Cove LNG		6	Pre-FID	2024	DOE	FTA/ non-FTA	Veresen
Lake Charles LNG		15	Pre-FID	N/A	DOE/FERC	FTA/ non-FTA	Shell
Alturas LNG		1.5	Pre-FID	N/A	N/A	N/A	WesPac
Commonwealth LNG		1.25	Pre-FID	N/A	DOE	FTA	Commonwealth Projects
Avocet FLNG		N/A	Pre-FID	N/A	N/A	N/A	Fairwood LNG
Energy World Gulf Coast LNG		2	Pre-FID	N/A	N/A	N/A	EWC
Penn America Energy LNG		N/A	Pre-FID	N/A	N/A	N/A	Penn America Energy Holdings
Shoal Point LNG		N/A	Pre-FID	N/A	N/A	N/A	NextDecade

Appendix 3 (continued)

Project	Capacity	Status	Latest Company Announced Start Date	DOE/FERC Approval	FTA/non-FTA Approval	Operator
Alaska						
Alaska-Japan LNG	1	Pre-FID	2021	N/A	N/A	Resources Energy Inc.
Alaska LNG T1-3	20	Pre-FID	2025-26	DOE	FTA/ non-FTA	State of Alaska

*** UC denotes "Under Construction"*

Project		Capacity	Status	Latest Company Announced Start Date	NEB Application Status	Operator
Western Canada						
Kitsault FLNG		8	Pre-FID	2018-19	Approved	Kitsault Energy
Stewart Energy LNG	FLNG 1	5	Pre-FID	2018-19	Approved	Stewart Energy Group
	T2-6	25	Pre-FID	2020-25	Approved	
Orca FLNG	1	4	Pre-FID	2019	Approved	Orca LNG
	2-6	20	Pre-FID	N/A	Approved	
NewTimes Energy LNG		12	Pre-FID	2019-21	Approved	NewTimes Energy LNG
Cedar FLNG		6.4	Pre-FID	2020	Approved	Haisla First Nation
Woodfibre LNG		2.1	Pre-FID	2020	Approved	Pacific Oil and Gas
Pacific Northwest LNG	T1-2	12	Pre-FID	2021-22	Approved	PETRONAS
	T3	6	Pre-FID	N/A	Approved	
Grassy Point LNG		20	Pre-FID	2021	Approved	Woodside
Discovery LNG		20	Pre-FID	2021-24	Approved	Quicksilver Resources
WCC LNG	T1-3	15	Pre-FID	2025	Approved	ExxonMobil
	T4-6	15	Pre-FID	N/A	Approved	
Aurora LNG	T1-2	12	Pre-FID	2026	Approved	Nexen (CNOOC)
	T3-4	12	Pre-FID	2028	Approved	
Kitimat LNG	T1	5	Pre-FID	N/A	Approved	Chevron
	T2	5	Pre-FID	N/A		
LNG Canada	T1-2	13	Pre-FID	N/A	Approved	Shell
	T3-4	13	Pre-FID	N/A	Approved	
Malahat FLNG		6	Pre-FID	N/A	Approved	Steelhead Group
Prince Rupert LNG	T1-2	14	Pre-FID	N/A	Approved	Shell
	T3	7	Pre-FID	N/A	Approved	
Sarita LNG		24	Pre-FID	N/A	Approved	Steelhead Group
SK Group Canada 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.

Appendix 3 (continued)

Project	Capacity	Status	Latest Company Announced Start Date	NEB Application Status	Operator
Eastern Canada					
North Shore LNG	1	Pre-FID	2018	Approved	SLNGaz
AC LNG	15.5	Pre-FID	2020	Approved	H-Energy
Saguenay LNG	11	Pre-FID	2020	Approved	GNL Quebec
Goldboro LNG	10	Pre-FID	2021	Approved	Pierdae Energy
Bear Head LNG	12	Pre-FID	2023	Approved	LNG Limited
Canaport LNG	5	Pre-FID	Stalled	Approved	Repsol

Sources: IHS, Company Announcements

Project	Capacity	Status	Latest Company Announced Start Date	Operator
Mexico				
PEMEX LNG	5	Pre-FID	2021	PEMEX
Costa Azul LNG	2	Pre-FID	2024-2025	Sempra Energy

Sources: IHS, Company Announcements

Project		Capacity	Status	Latest Company Announced Start Date	Operator
Eastern Australia (CBM)					
Australia Pacific LNG T2		9	UC**	2017	ConocoPhillips
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	T2-3	10.4	UC**	2017	Chevron
	T4	5.2	Pre-FID	N/A	
Wheatstone LNG	T1-2	8.9	UC**	2017-18	Chevron
	T3-5	13.35	Pre-FID	N/A	
Ichthys LNG		8.9	UC**	2017-18	INPEX
Prelude FLNG		3.6	UC**	2018	Shell
Scarborough FLNG		6.5	Pre-FID	2021	ExxonMobil
Bonaparte FLNG		2	Pre-FID	N/A	ENGIE
Browse FLNG 1-3		4.5	Pre-FID	N/A	Woodside
Cash Maple FLNG		2	Pre-FID	N/A	PTTEP
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 LNG		3	Pre-FID	N/A	MEO

*** UC denotes "Under Construction"*

Appendix 3 (continued)

Country	Project		Capacity	Latest Company Announced Start Date	Operator
Iran	Iran FLNG		0.5	2017	Unknown
Russia	Gorskaya FLNG	1-3	1.26	2017-2021	Unknown
Russia	Pechora LNG		4	2018	Altech Group
Russia	Portovaya LNG		1.5	2019	Gazprom
Djibouti	Djibouti FLNG		3	2020	Poly-GCL
Equatorial Guinea	Fortuna FLNG	1-2	4.4	2020-2025	Golar
Mozambique	Mamba LNG		10	2020-2021	Eni
Congo (Republic)	Congo-Brazzaville FLNG		1.2	2020	NewAge
Mauritania	Greater Tortue FLNG		2.5	2021	Kosmos Energy
Russia	Baltic LNG	T1-2	10	2021	Gazprom
Russia	Sakhalin-2	T3	5.4	2021	Sakhalin Energy Investment Company
Mozambique	Coral FLNG (Area 4)		3.4	2022	Eni
Papua New Guinea	PNG LNG	T3	3.45	2022	ExxonMobil
Mozambique	Mozambique LNG (Area 1)	T1-2	12	2023-2024	Anadarko
Papua New Guinea	Papua LNG	T1-2	8	2023	TOTAL
Indonesia	Abadi LNG	T1-2	9.5	2025-2026	INPEX
Russia	Arctic LNG-2	T1	6	2025	Novatek
		T2-3	12	N/A	
Tanzania	Tanzania LNG	T1-3	15	2026-2027	Statoil
		T4	5	N/A	Shell
Indonesia	East Dara FLNG		0.83	N/A	Black Platinum Energy
Nigeria	NLNG	T7-8	8.6	N/A	Nigeria LNG
Papua New Guinea	Pandora FLNG		1	N/A	Cott Oil & Gas
Russia	Sakhalin 1 LNG (Far East LNG)		5	N/A	ExxonMobil
Indonesia	Sengkang LNG	T2-4	1.5	N/A	EWC
Papua New Guinea	Western LNG T1		1.5	N/A	Repsol
Russia	Yamal LNG T4		5.5	N/A	Novatek

Appendix 4: Table of Regasification Terminals

Reference Number	Country	Terminal Name	Start Year	Nameplate Capacity (MTPA)	Owners*	Concept
1	Spain	Barcelona	1969	12.8	ENAGAS 100%	Onshore
2	Japan	Negishi	1969	12.0	TEPCO 50%; Tokyo Gas 50%	Onshore
3	US	Everett	1971	5.4	ENGIE 100%	Onshore
4	Italy	Panigaglia (La Spezia)	1971	2.5	GNL Italia 100%	Onshore
5	France	Fos Tonkin	1972	2.2	ENGIE 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	8.0	Chubu Electric 50%; Toho Gas 50%	Onshore
9	Japan	Tobata	1977	6.8	Kitakyushu LNG 100%	Onshore
10	US	Cove Point	1978	11.0	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	ENGIE 100%	Onshore
14	US	Lake Charles	1982	17.3	Energy Transfer Equity 100%	Onshore
15	Japan	Chita	1983	12.0	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	16.0	TEPCO 100%	Onshore
19	Korea	Pyeong-Taek	1986	33.9	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	10.0	CPC 100%	Onshore
27	Turkey	Marmara Ereglisi	1994	5.9	Botas 100%	Onshore
28	Korea	Incheon	1996	38.0	KOGAS 100%	Onshore
29	Japan	Sodeshi	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%; ENGIE 35%; Mitsui 15%; 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	17.0	KOGAS 100%	Onshore

Appendix 4: Table of Regasification Terminals (continued)

Reference Number	Country	Terminal Name	Start Year	Nameplate Capacity (MTPA)	Owners*	Concept
36	Dominican Republic	AES Andrés	2003	1.9	AES 92%; Estrella-Linda 8%	Onshore
37	Spain	Bilbao (BBG)	2003	5.1	ENAGAS 70%; EVE 30%	Onshore
38	India	Dahej LNG	2004	15.0	Petronet LNG 100%	Onshore
39	Portugal	Sines LNG	2004	5.8	REN 100%	Onshore
40	UK	Grain LNG	2005	15.0	National Grid Transco 100%	Onshore
41	Korea	Gwangyang	2005	1.8	Posco 100%	Onshore
42	India	Hazira LNG	2005	5.0	Shell 74%; TOTAL 26%	Onshore
43	Japan	Sakai	2005	6.4	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	6.8	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	ENAGAS 72.5%; Osaka Gas 20%; Oman Oil 7.5%	Onshore
49	Spain	Mugardos LNG (El Ferrol)	2007	2.6	Grupo Tojeiro 50.36%; Gobierno de Galicia 24.64%; First State Regasificadora 15%; Sonatrach 10%	Onshore
50	Mexico	Costa Azul	2008	7.5	Sempra 100%	Onshore
51	US	Freeport LNG	2008	11.3	Michael S Smith Cos 57.5%; Global Infrastructure Partners 25%; Osaka Gas 10%; Dow Chemical 7.5%	Onshore
52	China	Fujian Putian	2008	5.0	CNOOC 60%; Fujian Investment and Development Co 40%	Onshore
53	US	Northeast Gateway	2008	3.0	Excelerate Energy 100%	Floating
54	US	Sabine Pass	2008	30.2	Cheniere Energy 100%	Onshore
55	Argentina	Bahia Blanca GasPort	2008	3.8	YPF 50%; Stream JV 50%	Floating
56	Italy	Adriatic LNG/ Rovigo	2009	5.8	ExxonMobil 46.35%; Qatar Petroleum 46.35%; Edison 7.3%	Offshore
57	US	Cameron LNG	2009	11.3	Sempra 50.2%; ENGIE 16.6%; Mitsubishi 16.6%; Mitsui 16.6%	Onshore
58	Canada	Canaport	2009	7.5	Repsol 75%; Irving Oil 25%	Onshore
59	UK	Dragon LNG	2009	4.4	Shell 50%; PETRONAS 30%; 4Gas 20%	Onshore
60	Kuwait	Mina Al-Ahmadi	2009	5.8	Kuwait Petroleum Corporation 100%	Floating
61	Brazil	Pecém	2009	6.0	Petrobras 100%	Floating
62	Chile	Quintero LNG	2009	4.0	ENAGAS 60.4%; ENAP 20%; Oman Oil 19.6%	Onshore
63	China	Shanghai Yangshan	2009	3.0	Shenergy Group 55%; CNOOC 45%	Onshore

Appendix 4: Table of Regasification Terminals (continued)

Reference Number	Country	Terminal Name	Start Year	Nameplate Capacity (MTPA)	Owners*	Concept
64	UK	South Hook	2009	15.6	Qatar Petroleum 67.5%; ExxonMobil 24.15%; TOTAL 8.35%	Onshore
65	Taiwan	Taichung LNG	2009	3.0	CPC 100%	Onshore
66	Brazil	Guanabara LNG	2009	1.9	Petrobras 100%	Floating
67	UAE	Dubai	2010	6.0	Dubai Supply Authority (Dusup) 100%	Floating
68	France	FosMax LNG (Fos Cavaou)	2010	6.0	ENGIE 71.5%; TOTAL 28.5%	Onshore
69	Chile	Mejillones LNG	2010	1.5	ENGIE 63%; Codelco 37%	Onshore
70	China	Liaoning Dalian	2011	6.0	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	2011	11.3	KM LNG Operating Partnership 50%; General Electric 40%; AES 10%	Onshore
74	Argentina	Puerto Escobar	2011	3.8	Enarsa 50%; YPF 50%	Floating
75	Thailand	Map Ta Phut LNG	2011	5.0	PTT 100%	Onshore
76	China	Jiangsu Rudong LNG	2011	6.5	PetroChina 55%; Pacific Oil and Gas 35%; Jiangsu Guoxin 10%	Onshore
77	Indonesia	Nusantara	2012	3.8	Pertamina 60%; PGN 40%	Floating
78	Japan	Ishikari LNG	2012	1.4	Hokkaido Gas 100%	Onshore
79	Japan	Joetsu	2012	2.3	Chubu Electric 100%	Onshore
80	Mexico	Manzanillo	2012	3.8	Mitsui 37.5%; Samsung 37.5%; KOGAS 25%	Onshore
81	China	Guangzhou Dongguan LNG	2012	1.5	Jovo Group 100%	Onshore
82	Israel	Hadera Gateway	2013	3.0	Israel Natural Gas Lines 100%	Floating
83	India	Dabhol	2013	2.0	GAIL 31.52%; NTPC 31.52%; Indian financial institutions 20.28%; MSEB Holding Co. 16.68%	Onshore
84	Spain	El Musel	2013	5.4	ENAGAS 100%	Onshore
85	Singapore	Singapore LNG	2013	6.0	Singapore Energy Market Authority 100%	Onshore
86	Malaysia	Lekas LNG (Malacca)	2013	3.8	PETRONAS 100%	Onshore
87	China	Zhejiang Ningbo	2013	3.0	CNOOC 51%; Zhejiang Energy Group Co Ltd 29%; Ningbo Power Development Co Ltd 20%	Onshore
88	China	Guangdong Zhuhai LNG (CNOOC)	2013	3.5	CNOOC 30%; Guangdong Gas 25%; Guangdong Yuedian 25%; Local companies 20%	Onshore

Appendix 4: Table of Regasification Terminals (continued)

Reference Number	Country	Terminal Name	Start Year	Nameplate Capacity (MTPA)	Owners*	Concept
89	Italy	Livorno/LNG Toscana	2013	2.7	EON 46.79%; IREN 46.79%; OLT Energy 3.73%; Golar 2.69%	Floating
90	China	Hebei Tangshan Caofeidian LNG	2013	3.5	CNPC 51%; Beijing Enterprises Group 29%; Hebei Natural Gas 20%	Onshore
91	China	Tianjin	2013	2.2	CNOOC 100%	Floating
92	Japan	Naoetsu (Joetsu)	2013	2.0	INPEX 100%	Onshore
93	India	Kochi LNG	2013	5.0	Petronet LNG 100%	Onshore
94	Brazil	Bahia/TRBA	2014	3.8	Petrobras 100%	Floating
95	Indonesia	Lampung LNG	2014	1.8	PGN 100%	Floating
96	Korea	Samcheok	2014	6.8	KOGAS 100%	Onshore
97	China	Hainan Yangpu LNG	2014	2.0	CNOOC 65%; Hainan Development Holding Co 35%	Onshore
98	Japan	Hibiki LNG	2014	3.5	Saibu Gas 90%; Kyushu Electric 10%	Onshore
99	China	Shandong Qingdao LNG	2014	3.0	Sinopec 99%; Qingdao Port Group 1%	Onshore
100	Lithuania	Klaipeda LNG	2014	3.0	Klaipedos Nafta 100%	Floating
101	Indonesia	Arun LNG	2015	3.0	Pertamina 70%; Aceh Regional Government 30%	Onshore
102	Japan	Hachinohe LNG	2015	1.5	JX Nippon Oil & Energy 100%	Onshore
103	Egypt	Ain Sokhna Hoegh	2015	4.2	EGAS 100%	Floating
104	Pakistan	Engro LNG	2015	3.8	Engro Corp. 100%	Floating
105	Jordan	Aqaba LNG	2015	3.8	Jordan Ministry of Energy and Mineral Resources (MEMR) 100%	Floating
106	Egypt	Ain Sokhna BW	2015	5.7	EGAS 100%	Floating
107	Japan	Shin-Sendai	2015	1.5	Tohoku Electric 100%	Onshore
108	Japan	Hitachi	2016	1.0	Tokyo Gas 100%	Onshore
109	China	Guangxi Beihai LNG	2016	3.0	Sinopec 100%	Onshore
110	Poland	Swinoujscie	2016	3.6	GAZ-SYSTEM SA 100%	Onshore
111	UAE	Abu Dhabi LNG	2016	3.8	ADNOC 100%	Floating
112	France	Dunkirk LNG	2017	9.5	EDF 65%; Fluxys 25%; TOTAL 10%	Onshore
113	Korea	Boryeong	2017	3.0	GS Group 50%; SK Group 50%	Onshore
114	Turkey	Etki LNG	2017	5.3	Etki Liman Isletmeleri Dolgalgaz Ithalat ve Ticaret 100%	Floating

Appendix 5: Table of Regasification Terminals Under Construction

Reference Number	Country	Terminal Name	Start Year	Nameplate Capacity (MTPA)	Owners*	Concept
115	China	Guangdong Shenzhen (Diefu) (CNOOC)	2017	4.0	CNOOC 70%; Shenzhen Energy Group 30%	Onshore
116	China	Tianjin (Onshore) Phase 1	2017	3.5	CNOOC 100%	Onshore
117	China	Tianjin (Sinopec) Phase 1	2017	2.9	Sinopec 100%	Onshore
118	India	Mundra	2017	5.0	GSPC 50%; Adani Group 50%	Onshore
119	China	Guangdong Yuedong LNG	2017	2.0	Shenergy 55%; CNOOC 45%	Onshore
120	Colombia	Cartagena LNG	2017	3.0	Grupo Tojeiro 100%	Floating
121	Philippines	Pagbilao LNG Hub	2017	3.0	Energy World Corporation 100%	Onshore
122	China	Guangdong Shenzhen (CNPC)	2017	3.0	CNPC 51%; CLP 24.5%; Shenzhen Gas 24.5%	Onshore
123	Pakistan	PGPC Port Qasim	2017	5.7	Pakistan LNG Terminals Limited 100%	Floating
124	Russia	Kaliningrad LNG	2017	1.5	Gazprom 100%	Floating
125	China	Fujian Zhangzhou	2018	3.0	CNOOC 60%; Fujian Investment and Development Co 40%	Onshore
126	Japan	Soma LNG	2018	1.5	Japex 100%	Onshore
127	Malaysia	RGT-2 (Pengerang LNG)	2018	3.5	PETRONAS 65%; Dialog Group 25%; Johor Government 10%	Onshore
128	China	Zhejiang Zhoushan (ENN)	2018	3.0	ENN Energy 100%	Onshore
129	India	Ennore LNG	2018	5.0	Indian Oil Corporation 95%; Tamil Nadu Industrial Development Corporation 5%	Onshore
130	Bahrain	Bahrain LNG	2019	6.0	NOGA 30%; Teekay Corp 30%; Samsung 20%; Gulf Investment Corporation 20%	Floating
131	India	Jafrabad LNG Port	2019	5.0	Exmar 50%; Swan Energy 26%; Gujarat Government 26%; Tata Group 10%	Floating
132	Brazil	Sergipe (CELSE)	2020	3.6	Golar 50%; GenPower 50%	Floating
133	Kuwait	Al Zour	2021	11.3	Kuwait Petroleum Corporation 100%	Onshore

Note: Under construction expansion projects at existing terminals are not included in these totals.

Appendix 6: 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

Appendix 6: Table of Active LNG Fleet (continued)

Ship Name	Shipowner	Shipbuilder	Type	Delivery Year	Capacity (cm)	Propulsion Type	IMO #
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

Appendix 6: Table of Active LNG Fleet (continued)

Ship Name	Shipowner	Shipbuilder	Type	Delivery Year	Capacity (cm)	Propulsion Type	IMO #
BW GDF SUEZ BOSTON	BW, ENGIE	Daewoo	Conventional	2003	138,059	Steam	9230062
BW GDF SUEZ BRUSSELS	BW	Daewoo	Conventional	2009	162,514	DFDE	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
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
CESI GLADSTONE	Chuo Kaiun/Shinwa Chem.	Hudong-Zhonghua	Conventional	2016	174,000	TFDE	9672820
CESI QINGDAO	China Shipping Group	Hudong-Zhonghua	Conventional	2016	174,000	TFDE	9672832
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
CLEAN VISION	Dynagas	Hyundai	Conventional	2016	162,000	TFDE	9655456
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
CREOLE SPIRIT	Teekay	Daewoo	Conventional	2016	173,400	MEGI	9681687
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

Appendix 6: Table of Active LNG Fleet (continued)

Ship Name	Shipowner	Shipbuilder	Type	Delivery Year	Capacity (cm)	Propulsion Type	IMO #
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
EXCELSIOR	Exmar	Daewoo	FSRU	2005	138,000	Steam	9239616
EXPRESS	Exmar, Excelerate	Daewoo	FSRU	2009	150,900	Steam	9361445
FRAIHA	NYK, K Line, MOL, Iino, Mitsui, Nakilat	Daewoo	Q-Flex	2008	205,950	SSD	9360817
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	153,600	DFDE	9390185
GASLOG GENEVA	Anthony Veder	Samsung	Conventional	2016	174,000	TFDE	9707508
GASLOG GIBRALTAR	GasLog	Samsung	Conventional	2016	174,000	TFDE	9707510
GASLOG GLASGOW	GasLog	Samsung	Conventional	2016	174,000	TFDE	9687021
GASLOG GREECE	GasLog	Samsung	Conventional	2016	170,520	TFDE	9687019
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 GLOBAL ENERGY	GDF SUEZ	Chantiers de l'Atlantique	Conventional	2004	74,130	Steam	9269207
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

Appendix 6: Table of Active LNG Fleet (continued)

Ship Name	Shipowner	Shipbuilder	Type	Delivery Year	Capacity (cm)	Propulsion Type	IMO #
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 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 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
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
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
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

Appendix 6: Table of Active LNG Fleet (continued)

Ship Name	Shipowner	Shipbuilder	Type	Delivery Year	Capacity (cm)	Propulsion Type	IMO #
KITA LNG	Cardiff Marine	Daewoo	Conventional	2014	159,800	TFDE	9636723
KUMUL	MOL, China LNG	Hudong-Zhonghua	Conventional	2016	169,147	SSD	9613161
LA MANCHA KNUTSEN	Knutsen OAS	Hyundai	Conventional	2016	176,300	MEGI	9721724
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 ABALAMABIE	Nigeria LNG Ltd	Samsung	Conventional	2016	170,000	MEGI	9690171
LNG ABUJA II	Nigeria LNG Ltd	Samsung	Conventional	2016	175,180	DFDE	9690169
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 FUKUROKUJU	MOL, KEPCO	Kawasaki Sakaide	Conventional	2016	164,700	Steam Reheat	9666986
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 LAGOS II	Nigeria LNG Ltd	Hyundai	Conventional	2016	177,000	DFDE	9692014
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 MARS	Osaka Gas, MOL	Mitsubishi	Conventional	2016	153,000	Steam Reheat	9645748
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

Appendix 6: Table of Active LNG Fleet (continued)

Ship Name	Shipowner	Shipbuilder	Type	Delivery Year	Capacity (cm)	Propulsion Type	IMO #
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 SATURN	MOL	Mitsubishi	Conventional	2016	153,000	Steam Reheat	9696149
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
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 AGAMEMNON	Maran Gas Maritime	Hyundai	Conventional	2016	174,000	MEGI	9682590
MARAN GAS ALEXANDRIA	Maran Gas Maritime	Hyundai	Conventional	2015	164,000	TFDE	9650054
MARAN GAS AMPHIPOLIS	Maran Gas Maritime	Daewoo	Conventional	2016	173,400	DFDE	9701217
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 HECTOR	Maran Gas Maritime	Hyundai	Conventional	2016	174,000	TFDE	9682605
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 OLYMPIAS	Maran Gas Maritime	Daewoo	Conventional	2016	173,400	TFDE	9732371
MARAN GAS PERICLES	Maran Gas Maritime	Hyundai	Conventional	2016	174,000	DFDE	9709489
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
MARIA ENERGY	Tsakos	Hyundai	Conventional	2016	174,000	TFDE	9659725
MARIB SPIRIT	Teekay	Samsung	Conventional	2008	163,280	DFDE	9336749
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	145,000	Steam	9321744

Appendix 6: Table of Active LNG Fleet (continued)

Ship Name	Shipowner	Shipbuilder	Type	Delivery Year	Capacity (cm)	Propulsion Type	IMO #
METHANE JANE ELIZABETH	GasLog	Samsung	Conventional	2006	145,000	Steam	9307190
METHANE JULIA LOUISE	Mitsui & Co	Samsung	Conventional	2010	167,416	TFDE	9412880
METHANE LYDON VOLNEY	Shell	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	GasLog	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
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
OAK SPIRIT	Teekay	Daewoo	Conventional	2016	173,400	MEGI	9681699
OB RIVER	Dynagas	Hyundai	Conventional	2007	146,791	Steam	9315692

Appendix 6: Table of Active LNG Fleet (continued)

Ship Name	Shipowner	Shipbuilder	Type	Delivery Year	Capacity (cm)	Propulsion Type	IMO #
OCEAN QUEST	GDF SUEZ	Newport News	Conventional	1979	126,540	Steam	7391214
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
POLAR SPIRIT	Teekay	I.H.I.	Conventional	1993	88,100	Steam	9001772
PRACHI	NYK	Hyundai	Conventional	2016	173,000	TFDE	9723801
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
RIOJA KNUTSEN	Knutsen OAS	Hyundai	Conventional	2016	176,300	MEGI	9721736
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

Appendix 6: Table of Active LNG Fleet (continued)

Ship Name	Shipowner	Shipbuilder	Type	Delivery Year	Capacity (cm)	Propulsion Type	IMO #
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
SERI CAMELLIA	PETRONAS	Hyundai	Conventional	2016	150,200	Steam Reheat	9714276
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	155,000	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

Appendix 6: Table of Active LNG Fleet (continued)

Ship Name	Shipowner	Shipbuilder	Type	Delivery Year	Capacity (cm)	Propulsion Type	IMO #
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
TESSALA	HYPROC	Hyundai	Conventional	2016	171,800	TFDE	9761243
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
WILFORCE	Teekay	Daewoo	Conventional	2013	155,900	TFDE	9627954
WILPRIDE	Teekay	Daewoo	Conventional	2013	156,007	TFDE	9627966
WOODSIDE CHANEY	Maran Gas Maritime	Hyundai	Conventional	2016	174,000	SSD	9682576
WOODSIDE DONALDSON	Teekay, Marubeni	Samsung	Conventional	2009	162,620	TFDE	9369899
WOODSIDE GOODE	Maran Gas Maritime	Daewoo	Conventional	2013	159,800	TFDE	9633161
WOODSIDE REES WITHERS	Maran Gas Maritime	Daewoo	Conventional	2016	173,400	DFDE	9732369
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
ZARGA	Nakilat	Samsung	Q-Max	2010	261,104	SSD	9431214
ZEKREET	J4 Consortium	Mitsui	Conventional	1998	134,733	Steam	9132818

Appendix 7: Table of LNG Vessel Orderbook

Ship Name	Shipowner	Shipbuilder	Type	Delivery Year	Capacity (cm)	Propulsion Type	IMO #
ASIA INTEGRITY	Chevron	Samsung	Conventional	2017	154,948	TFDE	9680188
ASIA VENTURE	Chevron	Samsung	Conventional	2017	154,948	TFDE	9680190
BISHU MARU	Trans Pacific Shipping	Kawasaki Sakaide	Conventional	2017	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 BEIHAI	China Shipping Group	Hudong-Zhonghua	Conventional	2017	174,000	TFDE	9672844
CHRISTOPHE DE MARGERIE	Sovcomflot	Daewoo	Conventional	2017	170,000	TFDE	9737187
DAEWOO 2416	Teekay	Daewoo	Conventional	2017	173,400	MEGI	9705641
DAEWOO 2417	Teekay	Daewoo	Conventional	2017	173,400	MEGI	9705653
DAEWOO 2421	Sovcomflot	Daewoo	Conventional	2017	172,000	TFDE	9768368
DAEWOO 2422	Sovcomflot	Daewoo	Conventional	2017	172,000	TFDE	9768370
DAEWOO 2423	Teekay	Daewoo	Conventional	2017	172,000	TFDE	9750696
DAEWOO 2424	Dynagas	Daewoo	Conventional	2018	172,000	TFDE	9750701
DAEWOO 2425	Dynagas	Daewoo	Conventional	2018	172,000	TFDE	9750713
DAEWOO 2426	MOL	Daewoo	Conventional	2018	172,000	TFDE	9750658
DAEWOO 2427	Sovcomflot	Daewoo	Conventional	2018	172,000	TFDE	9768382
DAEWOO 2428	Sovcomflot	Daewoo	Conventional	2018	172,000	TFDE	9768394
DAEWOO 2429	Sovcomflot	Daewoo	Conventional	2018	172,000	TFDE	9768526
DAEWOO 2430	Dynagas	Daewoo	Conventional	2019	172,000	TFDE	9750725
DAEWOO 2431	Dynagas	Daewoo	Conventional	2019	172,000	TFDE	9750737
DAEWOO 2432	Dynagas	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 2438		Daewoo	Conventional	2017	170,000	MEGI	9762649
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 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

Appendix 7: Table of LNG Vessel Orderbook (continued)

Ship Name	Shipowner	Shipbuilder	Type	Delivery Year	Capacity (cm)	Propulsion Type	IMO #
DAEWOO 2456	Maran Gas Maritime	Daewoo	Conventional	2019	173,400	MEGI	9753014
DAEWOO 2457	Maran Gas Maritime	Daewoo	Conventional	2019	174,000	DFDE	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		9771913
DAEWOO 2464	Chandris Group	Daewoo	Conventional	2018	173,400	MEGI	9785158
DAEWOO 2466	Maritima Del Norte	Daewoo	Conventional	2019	170,000		9810367
DAEWOO 2467	Maran Gas Maritime	Daewoo	Conventional	2019	170,000		9810379
DAEWOO 2468	Maran Gas Maritime	Daewoo	FSRU	2020	173,400	XDF	9820843
DAEWOO 2488	BW	Daewoo	Conventional	2018	173,400	MEGI	9792591
DAEWOO 2489	BW	Daewoo	Conventional	2019	173,400	MEGI	9792606
DAEWOO 3		Daewoo	Conventional	2017	170,000	MEGI	9762637
FSRU ESPERANZA	Hoegh	Hyundai	FSRU	2018	170,000		9780354
GNL DEL PLATA	MOL	Daewoo	FSRU	2017	263,000	TFDE	9713105
HOEGH GIANT	Hoegh	Hyundai	FSRU	2017	170,000	TFDE	9762962
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 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	MEGI	9672818
HYUNDAI PEACEPIA	Hyundai LNG Shipping	Daewoo	Conventional	2017	174,000	MEGI	9761853
HYUNDAI SAMHO S856	Teekay	Hyundai	Conventional	2019	174,000	MEGI	9781918
HYUNDAI SAMHO S857	Teekay	Hyundai	Conventional	2019	174,000	MEGI	9781920
HYUNDAI ULSAN 2800	GasLog	Hyundai	Conventional	2017	174,000	TFDE	9748899
HYUNDAI ULSAN 2801	GasLog	Hyundai	Conventional	2018	174,000	MEGI	9748904
HYUNDAI ULSAN 2909	Hoegh	Hyundai	FSRU	2018	166,630	DFDE	9822451

Appendix 7: Table of LNG Vessel Orderbook (continued)

Ship Name	Shipowner	Shipbuilder	Type	Delivery Year	Capacity (cm)	Propulsion Type	IMO #
HYUNDAI ULSAN 2937	SK Shipping	Hyundai	Conventional	2019	180,000	DFDE	9810549
HYUNDAI ULSAN 2938	SK Shipping	Hyundai	Conventional	2019	180,000	DFDE	9810551
IMABARI SAIJO 8200	K Line	Imabari	Conventional	2020	178,000	MEGI	9778923
IMABARI SAIJO 8215		Imabari	Conventional	2022	178,000	MEGI	9789037
IMABARI SAIJO 8216		Imabari	Conventional	2022	178,000	XDF	9789049
IMABARI SAIJO 8217		Imabari	Conventional	2022	178,000	XDF	9789051
JMU TSU 5070	MOL	Japan Marine	Conventional	2017	165,000	TFDE	9736092
JMU TSU 5071	NYK	Japan Marine	Conventional	2017	165,000	Steam	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	Steam	9778313
KAWASAKI SAKAIDE 1718	K Line	Kawaski	Conventional	2017	182,000	Steam	9698123
KAWASAKI SAKAIDE 1720	K Line	Kawaski	Conventional	2017	164,700	Steam Reheat	9749609
KAWASAKI SAKAIDE 1728	Mitsui & Co	Kawasaki Sakaide	Conventional	2018	155,000	TFDE	9759240
KAWASAKI SAKAIDE 1729	Mitsui & Co	Kawasaki Sakaide	Conventional	2017	155,000	Steam	9759252
KAWASAKI SAKAIDE 1731		Kawasaki Sakaide	Conventional	2017	177,000	Steam	9774135
KAWASAKI SAKAIDE 1734		Kawasaki Sakaide	Conventional	2018	177,000		9791200
KAWASAKI SAKAIDE 1735		Kawasaki Sakaide	Conventional	2018	177,000		9791212
MARAN GAS ROXANA	Maran Gas Maritime	Daewoo	Conventional	2017	173,400	TFDE	9701229
MARAN GAS ULYSSES	Maran Gas Maritime	Hyundai	Conventional	2017	174,000	SSD	9709491
MITSUBISHI NAGASAKI 2310	K-Line, Inpex	Mitsubishi	Conventional	2017	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	DFDE	9770438
MITSUBISHI NAGASAKI 2322	Mitsui & Co	Mitsubishi	Conventional	2018	177,000	DFDE	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

Appendix 7: Table of LNG Vessel Orderbook (continued)

Ship Name	Shipowner	Shipbuilder	Type	Delivery Year	Capacity (cm)	Propulsion Type	IMO #
MITSUBISHI NAGASAKI 2332		Mitsubishi	Conventional	2019	165,000		9810020
OUGARTA	HYPROC	Hyundai	Conventional	2017	171,800	TFDE	9761267
PAN ASIA	Teekay	Hudong-Zhonghua	Conventional	2017	174,000	DFDE	9750220
SAMSUNG 2081	SK Shipping, Marubeni	Samsung	Conventional	2017	180,000	TFDE	9693173
SAMSUNG 2107	Flex LNG	Samsung	Conventional	2018	174,000	MEGI	9709025
SAMSUNG 2108	Flex LNG	Samsung	Conventional	2018	174,000	MEGI	9709037
SAMSUNG 2130	GasLog	Samsung	Conventional	2018	174,000	MEGI	9744013
SAMSUNG 2131	GasLog	Samsung	Conventional	2019	174,000	MEGI	9744025
SAMSUNG 2148	Mitsui & Co	Samsung	Conventional	2018	174,000	MEGI	9760768
SAMSUNG 2149	Mitsui & Co	Samsung	Conventional	2018	174,000	MEGI	9760770
SAMSUNG 2150	Mitsui & Co	Samsung	Conventional	2018	174,000	MEGI	9760782
SAMSUNG 2189	Golar LNG	Samsung	FSRU	2017	170,000	DFDE	9785500
SAMSUNG 2212	GasLog	Samsung	Conventional	2019	180,000		9816763
CHRISTOPHE DE MARGERIE	Sovcomflot	Daewoo	Conventional	2017	170,000	TFDE	9737187
SERI CAMAR	PETRONAS	Hyundai	Conventional	2017	150,200	Steam Reheat	9714305
MITSUBISHI NAGASAKI 2326	MOL	Mitsubishi	Conventional	2018	180,000	TFDE	9796781
SERI CEMARA	PETRONAS	Hyundai	Conventional	2017	150,200	Steam Reheat	9756389
SERI CEMPAKA	PETRONAS	Hyundai	Conventional	2017	150,200	MEGI	9714290
SERI CENDERAWASIH	PETRONAS	Hyundai	Conventional	2017	150,200	Steam Reheat	9714288
SK AUDACE	SK Shipping, Marubeni	Samsung	Conventional	2017	180,000	DFDE	9693161
SK SERENITY	SK Shipping	Samsung	Conventional	2017	174,000	DFDE	9761803
SK SPICA	SK Shipping	Samsung	Conventional	2017	174,000	MEGI	9761815
TORBEN SPIRIT	Teekay	Daewoo	Conventional	2017	173,400	XDF	9721401

Appendix 8: Table of FSRU, Laid-Up, Converted FSU & FLNG

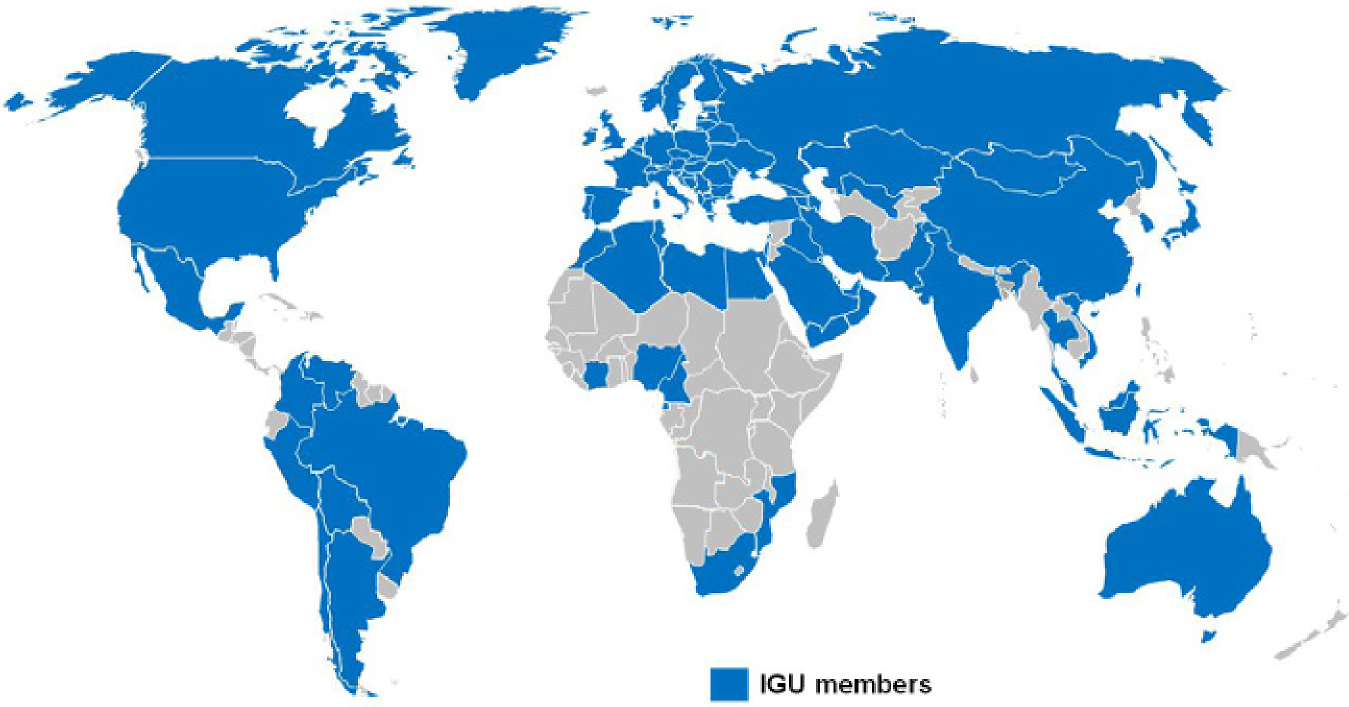
Ship Name	Shipowner	Shipbuilder	Type	Delivery Year	Capacity (cm)	Propulsion Type	IMO #	Status at end-2015
FSRU TOSCANA	OLT Offshore LNG Toscana	Hyundai	Converted FSRU	2004	137,500	Steam	9253284	Chartered as FSRU
GOLAR FREEZE	Golar LNG Partners	HDW	Converted FSRU	1977	126,000	Steam	7361922	Chartered as 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
NUSANTARA REGAS SATU	Golar LNG Partners	Rosenberg Verft	Converted FSRU	1977	125,003	Steam	7382744	Chartered as FSRU
BW INTEGRITY	BW	Samsung	FSRU	2016	170,000	TFDE	9724946	Chartered as FSRU
BW SINGAPORE	BW	Samsung	FSRU	2015	170,000	TFDE	9684495	Chartered as FSRU
EXCELERATE	Exmar, Excelerate	Daewoo	FSRU	2006	135,313	Steam	9322255	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
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 IGLOO	Golar LNG Partners	Samsung	FSRU	2014	170,000	TFDE	9633991	Chartered as FSRU
GOLAR TUNDRA	Golar LNG	Samsung	FSRU	2015	170,000	TFDE	9655808	Chartered as FSRU
HOEGH GALLANT	Hoegh	Hyundai	FSRU	2014	170,000	TFDE	9653678	Chartered as FSRU
HOEGH GRACE	Hoegh	Hyundai	FSRU	2016	170,000	DFDE	9674907	Chartered as FSRU
INDEPENDENCE	Hoegh	Hyundai	FSRU	2014	170,132	TFDE	9629536	Chartered as FSRU
NEPTUNE	Hoegh, MOL, TLTC	Samsung	FSRU	2009	145,130	Steam	9385673	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
ECHIGO MARU	NYK	Mitsubishi	Conventional	1983	125,568	Steam	8110203	Laid-up

Appendix 8: Table of FSRU, Laid-Up, Converted FSU & Converted FLNG (continued)

Ship Name	Shipowner	Shipbuilder	Type	Delivery Year	Capacity (cm)	Propulsion Type	IMO #	Status at end-2015
FORTUNE FSU	Dalian Inteh	Dunkerque Normandie	Conventional	1981	130,000	Steam	7428471	Laid-up
GAEA	Golar LNG	General Dynamics	Conventional	1980	126,530	Steam	7619575	Laid-up
GOLAR VIKING	Golar LNG	Hyundai	Conventional	2005	140,000	Steam	9256767	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	Nova Shipping & Logistics	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
LUCKY FSU	Dalian Inteh	Dunkerque Normandie	Conventional	1981	127,400	Steam	7428469	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
WILENERGY	Awilco	Mitsubishi	Conventional	1983	125,788	Steam	8014409	Laid-up
WILGAS	Awilco	Mitsubishi	Conventional	1984	126,975	Steam	8125832	Laid-up
TENAGA EMPAT	MISC	CNIM	FSU	1981	130,000	Steam	7428433	FSU
TENAGA SATU	MISC	Dunkerque Chantiers	FSU	1982	130,000	Steam	7428457	FSU
ARMADA LNG MEDITERRANA	Bumi Armada Berhad	Mitsui	FSU	2016	127,209	Steam	8125868	FSU
HILLI	Golar LNG	Rosenberg Verft	Converted FLNG	2017	124,890	Steam	7382720	Under conversion
PRELUDE	Shell	Samsung	FLNG	2017	437,000		9648714	Under construction

Notes

Notes



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