LNG journal
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February 2019

In this issue:

LNG spot price curve influenced by seasonality and lack of storage

Asia has a marked lack of storage as a moderating factor on the impact of demand spikes on pricing

Spot liquefied natural gas prices in Asia are expected to decline as additions to global supply capacity outstrip growth in demand and as oil prices ease. The Asian LNG futures curve suggests a modest tapering in spot prices over 2019 and 2020.

That's the view of an Australian government report that forecasts prices rising in 2019 before they moderate after 2020 as Australia itself reaches 88 million tonnes per annum of nameplate capacity.

"The futures curve also suggests that seasonality in LNG spot prices will continue. In Asia, gas storage, which moderates the impact of seasonal demand spikes on prices, is still limited," noted the latest Australian government report.

Evolution and growth of Chinese LNG requirements over recent years

Long term

"LNG contract prices, at which most Australian LNG is sold, are forecast to rise before easing and LNG spot prices are expected to decline as global supply capacity outstrip growth in demand and as oil prices ease," stated the report.

This year's winter price spike was due to a rapid increase in Chinese LNG imports, driven by surging gas demand and an unexpected shortfall in China's pipeline gas imports from Central Asia.

"China has subsequently put in place measures to meet winter gas demand, such as boosting gas storage, and may not experience the same shortfall in pipeline gas imports from Central Asia this year," it added.

Europe and emerging Asia, led by China, are expected to drive demand growth in the coming years.

Chinese LNG imports from Australia increased by 34.9 percent in 2018 and Australian projects delivered 34 cargoes to China in December 2018, down from 39 in November.

"From early next decade, the LNG market is expected to begin rebalancing, as demand growth absorbs the available capacity," said the report.

"LNG markets have been expected to enter a period of overcapacity for some time, but stronger than expected demand growth coupled with delays in project completions have delayed its arrival and reduced its anticipated severity," it explained.

Japan is the largest Australian customers with multiple long-term contracts signed by the nation's utilities.

The Japanese imported almost 30MT of Australian LNG in 2018, up 11.8 percent from 2017.

Alternative

Japan has been the world's leading buyer of LNG since the 1970s, though imports are projected to fall from 85 million tonnes in 2017 to 81MT in 2020 with the restart of several nuclear reactors over the past year reducing gas demand, and further restarts possible.

Japan has nine nuclear plants in operation from its current plants numbering 42 that have passes safety tests.

Japan's Institute of Energy Economics expects two more reactors to restart by March 2020, but there could be as many as five.

A total of 18 reactors have applications for restart with the Nuclear Regulation Authority, the administrative body charged with ensuring the safety of nuclear plants.

However, nuclear energy in Japan continues to face public opposition and legal challenges. There remain significant risks of delays and slippages in nuclear restarts.

Oil influence

LNG contract prices in Asia are forecast to decline modestly from current highs, though will remain well above levels seen over the past few years.

The Japan Customs-cleared Crude (JCC) oil price, to which LNG contract prices in Asia are often linked, is forecast to average US$72 a barrel in 2020, down slightly on current levels of US$76 a barrel, but up from an average of US$54 a barrel in 2017.

"Rising oil prices have likely contributed to higher LNG spot prices. Buyers have some flexibility in the volumes of LNG they purchase on long-term oil-linked contracts, and higher oil prices increase the relative attractiveness of spot cargoes, pushing up spot prices," the report explained.

Australia estimates that its LNG exports reached 69.5MT in 2018, up 23 percent from 56.5MT in 2017.

"The start-up of the Ichthys project during 2018 and continued good performance of Wheatstone, which started production from Train 2 during

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Maritime Content Ltd
2 Prospect Road
St Albans AL1 2AX
United Kingdom
www.LNGjournal.com
+44 (0)20 7253 2700

Publisher
Stuart Fryer

Editor
John McKay
editor@lngjournal.com

Advertising
David Jeffries
Only Media Ltd
Tel: +44 (0) 208 150 5293
djeffries@lngjournal.com

Subscriptions Sales Manager
Gabi Weck
Tel: + 44 (0) 7253 2700
gabi@lngjournal.com

Production
Vivian Chee
Tel: +44 (0) 20 8995 5540
chee@btconnect.com

Subscription

Print & online	£655/€810/US$1050
Online only	£595/€795/US$950

See website for more details
www.lngjournal.com
gabi@lngjournal.com
hotline +44 (0)20 7253 2700

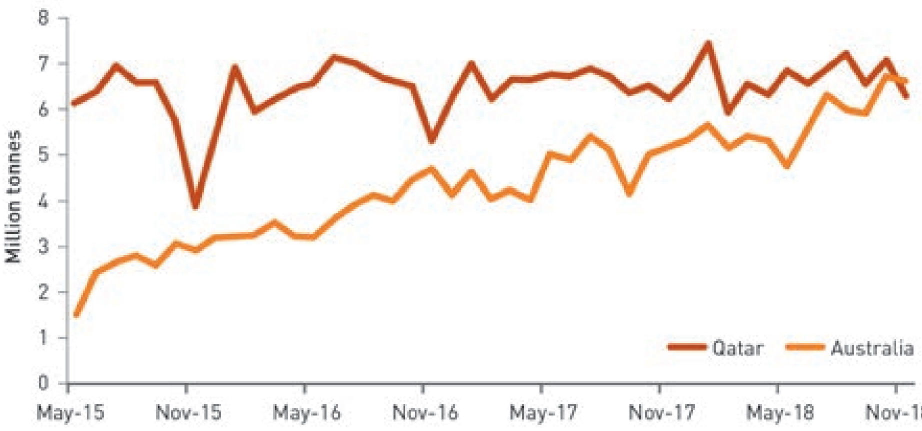
Printed by: Rabarbar s.c.,
Polna 44,
41-710 Ruda Śląska,
Poland

2018, has made a major contribution to the growth in Australian exports and the long-awaited Prelude project began production in late December," said the report.

The East Coast Australian plants in Queensland continue to perform below capacity, due to the increasingly tight gas supply market.

West coast producers, however, continue to outperform, with the North West Shelf plant, operated by Woodside Petroleum, continuing to be the largest producer.

Qatar and Australia's monthly LNG exports



Qatari and Australian LNG export volumes crossed paths at year-end

Shutdown

The Gorgon plant on Barrow Island, operated by Chevron Corp., has stayed in second place having consistently high production rates during 2018, though one Train was closed for technical issues in January 2019.

Exports to Korea again increased significantly and Australia remained Korea's second-largest LNG supplier after Qatar.

In regard to world LNG trade, the report said the expansion in global LNG supply capacity is expected to outpace growth in LNG demand over the next few years.

"From early next decade, the LNG market is expected to begin rebalancing, as demand growth absorbs the available capacity," it said.

By 2020, China's LNG imports are forecast to reach 53MT, the equivalent of 73 billion cubic metres. Chinese gas consumption will have a major impact on LNG markets.

China's target of lifting the share of gas in the energy mix implies gas consumption of 305-365 Bcm. This difference of 50 Bcm of gas is equivalent to around 37MT, as much as LNG as China imported during 2017.

"Other factors affecting China's LNG demand over the outlook period will be the extent of competition from domestic gas production and pipeline gas imports," said the Australians.

Siberia pipeline

"China is expected to begin importing Russian gas via the Power of Siberia pipeline from late 2019. Imports are expected to be about 5 Bcm in the first year of operation, reaching 38 Bcm in the sixth year," the report added.

China is reportedly targeting natural gas production of 200 Bcm in 2020, up from around 150 Bcm in 2017.

However, China faces challenges in lifting domestic output and is expected to fall short of this target because of difficult geology and gas resources being located in densely populated or heavily cultivated areas.

Another of Australia's main customers, South Korea, is expected to see modest growth.

South Korea is the world's third-largest LNG buyer and is aiming to lower LNG costs.

From April 2019, South Korea will lower taxes on LNG imports and again raise taxes on thermal coal imports as part of its anti-pollution policy.

South Korea's long-term plan is to increase the share of gas in the energy mix from 15 percent in 2016 to around 19 per cent by 2030.

"From early next decade, the LNG market is expected to begin rebalancing, as demand growth absorbs the available capacity'"

Other emerging Asian nations are also driving demand and increasing the share of natural gas versus other fuels.

"Economies in emerging Asia are expected to make a large contribution to growth in global LNG imports during the outlook period, including India, Pakistan, Bangladesh, Indonesia, Thailand and Singapore," stated the report.

In India, LNG imports are forecast to increase from 18MT in 2017 to 33MT in 2020, with India's domestic gas production not expected to keep pace with growing demand.

There are several LNG import terminals under construction on India's east coast and the Government is aiming to lift gas's share of the energy mix to 15 percent by 2030 from 5 percent at present.

The report said that in the next few years there will be a major expansion in global supply capacity, driven primarily by the US, though some ramp-up is also expected in Australia and Russia.

Volumes

Around two-thirds of the increase in supply capacity between 2018 and 2020 will come from the US. The nameplate capacity of US LNG projects is on track to triple to around 70MT, with six plants expected to be operational by the end of 2019.

This expansion in LNG infrastructure is expected to make the US the third-largest LNG exporter in the world, behind Australia (where nameplate capacity will soon reach 88MT) and Qatar (where nameplate capacity is expected to remain at 77MT for the next few years).

Russia's exports are expected to increase over the next few years, as the country's second project, Yamal LNG, ramps up production.

The commencement of operations at the third 5.5 MTPA Train at Yamal in the Arctic region will bring the nameplate capacity of the two Russian facilities to 27MT. The other plant is as Sakhalin island in the Russian Far East. ■

US LNG exports rise until 2030 while pipeline shipments to Mexico start to slow down in 2025

Output grows in volume because of the sheer size of the resources extending over 500,000 square miles

US liquefied natural gas exports and pipeline shipments to Mexico are both forecast to increase until 2025, though pipeline export growth to Mexico slows and LNG exports continue rising through 2030.

This is one of the main points from the US Annual Energy Outlook of 2019. It includes a reference case and six side cases designed to examine the robustness of key assumptions.

All systems go

The reference case in the Energy Information Administration report forecasts significant continued development of US shale and tight oil and natural gas resources, as well as the growth in use of renewable resources.

Three LNG export facilities were operational in the Lower 48 states by the end of 2018 and three more are expected to come on stream in 2019.

After all LNG export facilities and expansions currently under construction are completed by 2022, LNG export capacity increases further as a result of growing Asian demand and US natural gas prices remaining competitive.

Over the longer term, dry natural gas production reaches 43.4 trillion cubic feet by 2050.

Growth in drilling in the Southwest region also drives natural gas production from tight oil formations in the reference case.

Production growth is forecast to outpace natural gas consumption in all cases.

Infrastructure

Increasing natural gas exports to Mexico are a result of more pipeline infrastructure to and within Mexico, allowing for a rise in natural gas-fired power generation.

However, by 2030 Mexican domestic natural gas production begins to displace US exports.

The US report added that imports of natural gas from Canada, primarily from its prolific Western Region, continue their decline from historical levels.

"US exports of natural gas to Eastern Canada continue to increase because of Eastern Canada's proximity to US natural gas resources in the Marcellus and Utica plays and additional, recently built pipeline infrastructure," explained the report.

US LNG will remain sensitive to oil and natural gas price movements.

"Henry Hub prices in the reference case remain lower than $5 per million British thermal units throughout the projection period," said the report.

"Growing demand in domestic and export markets leads to increasing natural gas spot prices at the benchmark Henry Hub during the projection period despite continued technological advances that support increased production," it added.

Pressures

According to the Outlook, to satisfy the growing demand for natural gas, production must expand into less prolific and more expensive-to-produce areas, putting upward pressure on production costs.

"Natural gas prices in the reference case remain lower than $4 per MMBtu through 2035 and lower than $5 per MMBtu through 2050 because of an increase in lower-cost resources, primarily in tight oil plays in the Permian Basin, which allows higher production levels at lower prices during the projection period," said the report.

The High Oil and Gas Resource and Technology case, which reflects lower costs and higher resource availability, shows an increase in production and lower prices relative to the reference case.

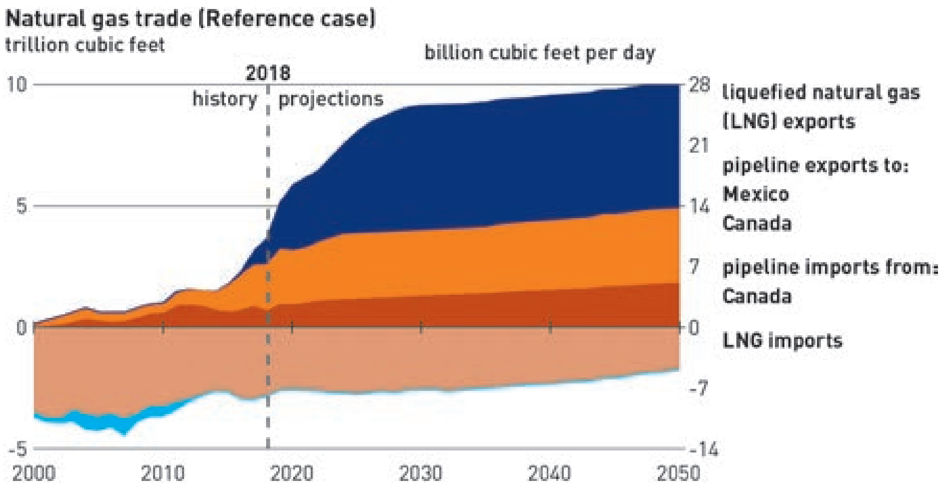
"In the Low Oil and Gas Resource and Technology case, high prices, which result from higher costs and fewer available resources, mean lower domestic consumption and exports," stated the report.

Natural gas production in the reference case grows 7 percent per annum from 2018 to 2020, which is more than the 4 percent per year average growth rate from 2005 to 2015.

However, after 2020, growth slows to less than 1 percent per year as growth in both domestic consumption and demand for US natural gas exports slows.

Intensive

"Across the reference case and all sensitivity cases, recent historical and near-term natural gas production growth in an environment of relatively low and stable prices supports growing demand from large natural gas-intensive and capital-intensive projects currently under construction, including chemical projects and liquefaction export terminals," said the report.



The overall US natural gas trade volumes in the various categories

"After 2020, production grows at a higher rate than consumption in most cases, leading to a corresponding growth in US exports of natural gas to global markets," it added.

"The exception is in the Low Oil and Gas Resource and Technology case, where production, consumption, and net exports all remain relatively flat as a result of higher production costs," noted the report.

"The Low Oil and Gas Resource and Technology case, which has the highest natural gas prices relative to the other cases, is the only case where U.S. natural gas consumption does not increase during the projection period," it said.

Tight and shale resources will account for nearly 90 percent of dry natural gas production in 2050.

Eastern shale output leads growth along with followed by growth in Gulf Coast onshore production.

Shale Basins

"Total US natural gas production across most cases is driven by continued development of the Marcellus and Utica shale plays in the East," said the report.

"Natural gas from the Eagle Ford (co-produced with oil) and the Haynesville plays in the Gulf Coast region also contributes to domestic dry natural gas production," it added. "Associated natural gas production from tight oil production in the Permian Basin in the Southwest region grows strongly in the early part of the projection period but remains relatively flat after 2030," stated the Outlook.

Technological advancements and improvements in industry practices lower production costs in the reference case and increase the volume of oil and natural gas recovery per well.

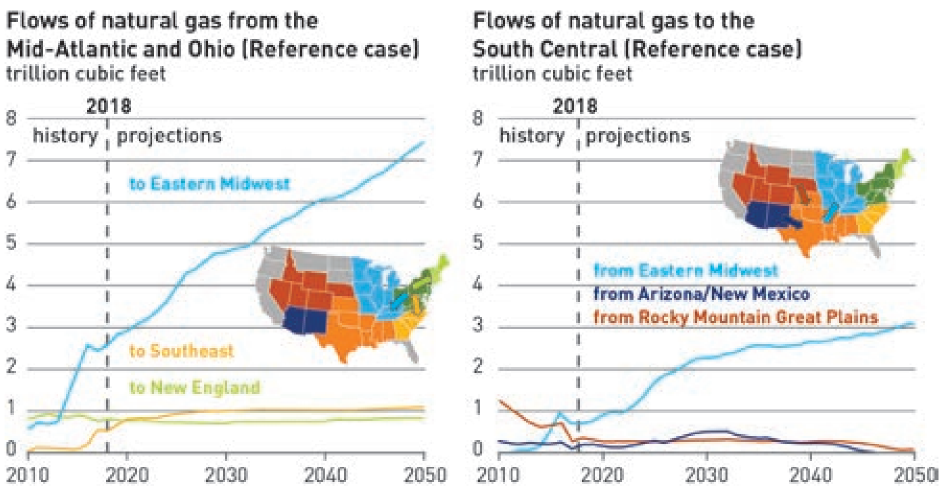
Acreage

It said that this progress would have a significant cumulative effect in plays that extend over wide areas and that have large undeveloped resources such as the Marcellus, Utica, and Haynesville Shale Basins.

Natural gas production from regions with shale and tight resources show higher levels of variability across the resource and technology cases, compared with the reference case because assumptions in those cases target those specific resources.

"Natural gas production from shale gas and tight oil plays as a share of total US natural gas production continues to grow in both share and absolute volume because of the sheer size of the associated resources, which extend over nearly 500,000 square miles, and because of improvements in technology that allow for the development of these resources at lower costs," it stated.

The report also explained that in the High Oil and Gas Resource and Technology case, which has more optimistic assumptions regarding



The flows of natural gas from US production areas to consumers

resource size and recovery rates, cumulative production from shale gas and tight oil is 18 percent higher than in the reference case.

"Conversely, in the Low Oil and Gas Resource and Technology case, cumulative production from those resources is 24 percent lower," it added.

Across all cases, onshore production of natural gas from sources other than tight oil and shale gas, such as coalbed methane, generally continues to decline through 2050 because of unfavourable economic conditions for producing that resource.

Offshore natural gas production in the US remains nearly flat during the projection period in all cases as a result of production from new discoveries that generally offsets declines in legacy fields.

Because drilling activity in oil formations primarily depends on crude oil prices rather than natural gas prices, the increase in natural gas production from oil-directed drilling puts downward pressure on natural gas prices.

Sustained low natural gas prices and declining costs of renewable power enable the shares of electricity generated by natural gas and renewables to increase.

"The natural gas share increases from 34 percent in 2018 to 39 percent in 2050, and the renewables share increases from 18 percent in 2018 to 31 percent in 2050," said the report.

Power sector

Natural gas and renewable energy shares grow in US electric generation. The EIA's reference case highlights the impact of sustained low natural gas prices and declining costs of renewables on the electricity generation fuel mix.

The natural gas share maintains its lead and continues to grow, increasing from 34 percent in 2018 to 39 percent in 2050.

"The renewables share, including hydroelectric generation, also increases from 18 percent in 2018 to 31 percent in 2050, driven largely by growth in wind and solar generation," it said.

"Renewables grow to become a larger share of US electric generation than nuclear and coal in less than a decade," it added.

Increasing energy efficiency across end-use sectors keeps U.S. energy consumption relatively flat, even as the U.S. economy continues to expand. Delivered U.S. energy consumption grows across all major end-use sectors, with electricity and natural gas consumption growing fastest.

It also includes projections of US energy markets through 2050 based on a reference case and six side cases that include different assumptions regarding prices, economic activity, and technology and resource estimates.

In the Reference case, US crude oil production continues to set annual records through the mid-2020s and remains greater than 14.0 million barrels per day (b/d) through 2040.

The continued development of tight oil and shale gas resources, particularly those in the East and Southwest regions, supports growth in NGPL production - which reaches 6.0 million b/d by 2030 - and dry natural gas production," said the EIA. ■

For the Record

ABU DHABI, the LNG producer in the United Arab Emirates with plans to expand its natural gas and oil exploration, has signed two concession agreements with Italian energy company Eni and its joint venture partner from Thailand, PTT Exploration and Production Company. Eni has acquired a 70 percent stake in the Offshore Block 1 and Offshore Block 2 exploration areas in Abu Dhabi waters for a duration of 35 years while PTTEP has a 30 percent share. The two blocks, located in the northwest of the Abu Dhabi emirate, are the first blocks to be awarded among those that were offered for commercial bidding by the Abu Dhabi National Oil Company (Adnoc) in April 2018 as part of Abu Dhabi's first-ever open block licensing strategy. Adnoc has an option to hold a 60 percent stake in the blocs if any commercial discoveries are made. The UAE is the oldest LNG producer in the Middle East from its Das Island plant offshore Abu Dhabi consisting of three Trains with capacity of around 5.5 million tonnes of LNG per annum. The Das Island plant was commissioned in 1977 and mainly supplies the Jera Co Inc. joint venture company formed by Japanese utilities Tokyo Electric Power Co. and Chubu Electric for their shipments. The UAE is also an LNG importer at facilities in Dubai and Ruwais to help meet its own domestic gas needs and has recently revised its oil and gas strategy after making large discoveries. Under the terms of the Eni-PTTEP agreements, Eni will operate the concessions and invest with PTTEP more than 844 million UAE dirhams ($230 million) to explore for oil and gas and appraise the existing discoveries in the two blocks, which cover a combined area of around 8,000 square kilometres.

Eni said the exploration phase of the agreement has a maximum period of nine years and, subject to successful exploration, an overall concession term will extend to 35 years for development and production phases. The concession agreements were signed by Ahmed Al Jaber, the UAE Minister of State and Adnoc's Chief Executive, Claudio Descalzi, CEO of Eni and Phongsthorn Thavisin, President and CEO of PTTEP. For PTTEP, it is among its largest overseas commitments outside its stake in the onshore Mozambique LNG export project underpinned by US energy company Anadarko Petroleum's Area 1 licence in the offshore Rovuma Basin. "These historic agreements on the first blocks to be awarded following a competitive bidding process, represent a major advancement in how Abu Dhabi and Adnoc unlocks and maximizes value from its substantial hydrocarbon resources, in line with the leadership's directives," said Al Jaber. Adnoc recently confirmed new discoveries of gas in place totaling 15 trillion cubic feet and intends to continue LNG production through 2040. It has also renewed LNG supply contracts with Jera. "The awards underline Adnoc's 2030 smart growth strategy and our targeted approach to engage with value-add partners who can contribute the right combination of capital, technology and capabilities to accelerate the development of Abu Dhabi's hydrocarbon resources," added the UAE Minister. "This award builds on Adnoc's and Eni's growing partnerships on various fronts. It broadens Adnoc's strategic partnership base as we add, for the first time, Thailand's PTTEP, and reinforces the confidence the international community places on the UAE's stable and secure investment environment," stated Al Jaber. Eni CEO Descalzi said the award represented a new important step towards Eni's expansion in one of the world leading regions for the oil and gas industry, not only by participating in producing fields, but also by exploring new blocks. "In particular, Offshore Blocks 1 and 2 are extremely important thanks to the virtuous synergies they will have with Ghasha offshore concession," said CEO Descalzi. "This further reinforces the partnership between Eni and Adnoc. Eni will make available its exploration expertise and leading-edge technology to tap additional resources offshore of Abu Dhabi," he added.

AGIG, the Australian Gas Infrastructure Group, one of the nation's largest natural gas network and transmission companies, has successfully commissioned the Pluto Inlet Station, the new facility connecting the Pluto LNG plant in Western Australia to the Dampier-to-Bunbury Natural Gas Pipeline. The Dampier-to-Bunbury pipeline has been in continuous operation in Western Australia since 1984, linking the gas fields in the Carnarvon Basin off the Pilbara coast directly to mining, industrial, commercial and residential customers throughout the State. AGIG said the commissioning of the pipeline allows additional gas supply to reach Western Australian consumers. Woodside Petroleum, operator of the Pluto LNG plant near Karratha, had engaged AGIG's development group to undertake a front-end engineering and design study to convert an existing outlet meter station to an inlet facility, along with the required compression. Woodside is developing LNG distribution and increasing domestic gas supplies to customers as well as prolonging operations from the state's oldest LNG plant, the North West Shelf facility that has been in operation since 1989.

The completed inlet facility now has the capacity to supply up to 25 terajoules per day via the Dampier-to-Bunbury pipeline to domestic customers. Andrew Staniford, the Chief Customer Officer at AGIG, said he was pleased to play a key role in this latest project achievement for Woodside, expanding increased capacity for natural gas. "Delivering the successful commissioning of the Pluto facility for Woodside demonstrates continued project success for AGIG and a greater diversification of gas sources available to the WA market," said Staniford. AGIG was only formed in 2017 through the merger of Australian Gas Networks (AGN), the Dampier-to-Bunbury Pipeline (DBP) and Multinet Gas Networks (MGN). Combing these distribution, transmission and storage assets has made AGIG one of the largest gas infrastructure businesses in Australia. AGIG has around 2 million customers covering every mainland Australian state and the Northern territory, 34,000 kilometres of distribution networks, over 3,500 kilometres of gas transmission pipelines and 42 petajoules, the equivalent of just over 1 billion cubic metres, of gas storage capacity.

ALASKA Governor Michael J. Dunleavy has named four new members to the seven-member board of directors governing the Alaska Gasline Development Corp., the state company aiming to build the Alaska LNG project to supply Asian nations. Governor Dunleavy, a Republican, named two oil and gas industry supporters, Doug Smith and Dan Coffey, both of Anchorage, to replace outgoing board members Hugh Short of Girdwood and Joey Merrick of Eagle River. The two other appointees were Department of Labor Commissioner Tamika Ledbetter and Department of Environmental Conservation Commissioner Jason Brune to serve as State of Alaska department-level members of the AGDC Board. The Alaska LNG developers are expected to spend up to $45 billion to build an 800-mile gas pipeline from the North Slope in northern Alaska to a planned liquefaction plant in Nikiski on the Kenai Peninsula, south of Anchorage. A gas processing plant, needed mainly to remove carbon dioxide from the Prudhoe Bay gas, would also be built on the North Slope. "Alaskans have long focused on the benefits of reduced energy costs, bringing our rich energy resources to market and monetizing our North Slope gas," said Dunleavy "The announcement continues those goals, while putting in place the personnel to make diligent review of the project," he added. "AGDC is tasked with a very complex mission and I look forward to seeing how best the State can assist in moving a project forward," he explained. "Each one of our appointees bring a wealth of knowledge and experience to table, including in areas of resource development, labor and workforce, regulatory issues and oversight, and I look forward to working closely with them in the future," stated Dunleavy.

AGDC is governed by a seven-member board of directors, five public members and two principal department heads of the State of Alaska. Board members are appointed by the governor and subject to confirmation by the legislature. The four new members will join existing AGDC board members Dave Cruz of Palmer, Alaska, David Wright of Anchorage, and Warren Christian from the town of North Pole. The board changes come as AGDC is expected to sign a final joint development agreement with Chinese investors by the end of the first quarter of 2019. These include companies such as China Petroleum & Chemical Corp., known as Sinopec, and Chinese banks. Dunleavy was sworn in as Alaska's governor on December 3. The former incumbent, Bill Walker, was an independent and dropped his re-election bid in October. Dunleavy, a former state senator, won office by defeating Democratic former US Senator Mark Begich in November's election. The first agreement with Sinopec, a potential main customer for the project, was signed by AGDC in November 2017 to purchase up to 75 percent of the venture's expected 20 million tonnes per annum of output. The initial accord was signed during President Trump's state visit to China in the presence of Trump and Chinese President Xi Jinping.

BP of the UK and Italian energy company Eni signed a heads of agreement with the Ministry of Oil and Gas of the Sultanate of Oman to work jointly towards a significant new exploration opportunity in the Arabian Peninsula nation where BP's onshore Khazzan natural gas discovery revitalized LNG production. BP said that under the accord, the two companies would work with Oman towards the award of a new exploration and production sharing agreement (EPSA) for Block 77 in central Oman. BP and Eni will now enter discussions with the Ministry to finalise details. "This would represent a further deepening of BP's important position in Oman, building on our successful delivery of the major Khazzan project in 2017 and its second phase of development that is currently under construction," said Bernard Looney, BP chief executive of the upstream division in reference to additional output achieved by Oman LNG from having sufficient domestic gas supplies. "We look forward to continuing to explore and efficiently develop the country's resources, working in close partnership with Eni and Oman to underpin our commitment to delivering long-term gas production for Oman," he added. The country's three existing liquefaction Trains at the facilities near the town of Sur have been at full capacity since 2017 after previously suffering from a lack of feed-gas as supplies were diverted to fill domestic gas shortages.

The Omani government allocates Oman LNG supplies from various gas fields and the Khazzan field production has ended all feed-gas concerns for the near future. The three Omani LNG processing Trains currently produce around 10.4 million tonnes per annum and supply nations such as Japan, South Korea, India and Kuwait. Block 77, with a total area of almost 3,100 square kilometre, is located in central Oman, 30km east of the BP-operated Block 61, which contains the already-producing Khazzan gas project as well as the Ghazeer project currently under development. The Khazzan natural gas field began production in 2017, under budget and ahead of schedule. Khazzan now produces around 1 billion cubic feet of gas a day. The Ghazeer field is expected to add a further 0.5 bcf/d of production and is expected to come on stream in 2021. BP has had an upstream presence in Oman since 2007 when it signed an exploration and production sharing agreement for Block 61. Gas sales agreements and approval for the development of the Khazzan project on Block 61 were signed in 2013. In 2016, the EPSA for Block 61 was amended, adding a further 1,000 square kilometres and allowing a second phase of development.

BP ENERGY Partners (BPEP), the Texas-based private equity firm, has purchased a controlling interest in Cryopeak LNG Solutions Corp., a small-scale Canadian provider of liquefied natural gas to users in remote locations. BPEP said it would commit fresh capital to Cryopeak, whose headquarters are in Vancouver, to support its continued growth throughout North America. The terms of the transaction were not disclosed Cryopeak is focused on providing industrial customers and utilities with access to natural gas through using LNG in locations where pipeline services are unavailable, limited or unreliable. "The company provides safe and reliable LNG virtual pipeline services including procurement, transportation and onsite equipment and support," said BPEP. Cryopeak delivers LNG by tanker trucks to locations such as mining sites where LNG is used instead of diesel to supply power and to towns in isolated regions of British Columbia and other provinces. It sources its LNG from the small-scale Tilbury Island liquefaction plant in BC, owned by the utility FortisBC. Calum McClure, Chief Executive of Cryopeak, said he was pleased with the deal and to have BPEP as a major investor.

McClure was previously an executive with shipping company Teekay Corp. before founding Cryopeak in 2012. "BP Energy Partners' investment provides Cryopeak with the capital to grow the business providing our customers with a cleaner, lower cost fuel.," said McClure. "The team at BP Energy Partners has great experience in energy investments and we look forward to Cryopeak continuing to grow as a leader in the small-scale LNG industry," he stated. Michael Watzky, Managing Partner of BPEP whose HQ is in Dallas, said the Cryopeak transaction was an exciting addition to the BPEP platform. "Calum and his team have demonstrated an excellent ability to provide LNG services and equipment and we look forward to partnering with them to grow the business," added Watzky.

ELENGY, the main French LNG terminal operator, said it was preparing the launch in February of a sale of 10-year access capacities for the Fos Tonkin import facility near the Mediterranean port of Marseille. The capacity sale will cover terminal access for a period of 10 years from 2021 to 2030. "Within the sale process, Elengy will offer its potential customers several types of services, including the conventional unloading of Medmax-type (75,000 cubic metres capacity) LNG tankers, the reloading of small-scale tankers for LNG bunkering needs, as well as LNG truck-loadings," said Elengy. "Detailed information concerning the services offered will be provided in the information memorandum at the opening of the sale," added the company. Elengy owns the Fos Tonkin terminal and is a 72.5 percent shareholder in Fosmax LNG, owner of the Fos Cavaou terminal, also near Marseille.

The other shareholder in the Fos Cavaou terminal is French energy major Total. The Elengy company is itself a subsidiary of French natural gas network owner GRTgaz within the large French utility group Engie. France has a total of four LNG import terminals, with the other two located at Montoir-de-Bretagne on the Atlantic Coast and at the Channel port of Dunkirk. The port of Marseille-Fos, which is France's largest trading port, is also developing plans for the construction of LNG bunkering infrastructure in cooperation with the managers of the Fos Tonkin and Fos Cavaou terminals. The bunkering stations will be the centre of the regional availability of LNG as a maritime fuel as the shipping industry aims to reduce the impact of emissions.

GASLOG LTD, the Monaco-based LNG fleet owner with 25 ships operating and nine others on order, has given more details of its terms for the latest time charters for vessels to US LNG producer Cheniere Energy, owner of the Sabine Pass plant in Louisiana and the Corpus Christi facility in Texas. GasLog also outlined its preference for the most modern technology in its LNG fleet and its attractive earnings prospects. Cheniere has signed charter party agreements, each for a firm period of seven years, for two vessels ordered from Samsung Heavy Industries in South Korea. The two carriers each have 180,000 cubic metres of storage capacity with low-pressure, two-stroke propulsion and Mark III Flex-Plus cargo containment systems from French technology company GTT. The ships are schedule to be delivered from the Samsung yard in mid-2021. GasLog's existing relationship with Cheniere now totals four newbuilds on order and the GasLog Partners-owned "GasLog Sydney". This ship is currently on a multi-year time charter. "The rate of hire for the Charters is broadly in line with mid-cycle rates and delivers returns in line with GasLog's financial strategy," said GasLog. GasLog Partners, the shipping line's affiliate listed on the New York Stock Exchange, has the right to acquire the vessels delivered into the charters with Cheniere.

As a result, GasLog said that the potential fleet of GasLog Partners could increase to 12 LNG carriers with charter lengths of five years or longer and the partnership could announce a further dropdown acquisition within the first quarter of 2019. "I am delighted to build further on our existing relationship with Cheniere," said Paul Wogan, Chief Executive of GasLog. "The four newbuilds that we now have on order for them will provide further support for their leading position in US LNG exports," added Wogan. Gaslog noted that during 2018 it had placed seven newbuild orders, all equipped with the latest advancements in propulsion and boil-off technology. "Six of these newbuilds have long-term charters attached, cementing our status as a leading owner and operator of LNG carriers," said the company. "Attractive LNG shipping market fundamentals, the strong liquidity position of the GasLog group and increasing debt capacity due to scheduled amortization underpin the funding strategy for our newbuild program," it added. "As a result of our activities in 2018, we have made substantial progress towards meeting our target of more than doubling consolidated EBITDA (gross earnings) over the 2017-2022 period," stated GasLog.

GASSCO, the Norwegian natural gas pipeline operator and one of the main competitors to LNG, transported 114.2 billion cubic metres of gas during 2018 from the Norwegian Continental Shelf to mainland Europe and the UK. The pipeline deliveries from Norway were down 2.6 percent compared with the previous year's record 117.4 Bcm of supply. "Norway's gas deliveries to Europe are stably high, and exports in 2018 were the second-highest ever," said Gassco Chief Executive Frode Leversund. "This shows that Norwegian gas is regarded as an attractive and reliable energy source for European consumers," added Leversund. The pipeline gas supply sent from Norway to Europe last year was the equivalent of 84.5 million tonnes of LNG, which is almost equal to the amount of LNG imported by Japan each year. Although the deliveries were short of the 2017 record volumes, a new record for summer deliveries to Europe was set with 36.8 Bcm of gas exported between May and August 2018. The Norwegian deliveries compare favourably in terms of energy security with pipeline volumes shipped to the European Union by Russia's Gazprom. Gazprom pipeline gas exports to the EU rose 8 percent in 2018 to a record 193.9 Bcm.

However, Gazprom has lowered its prices in the last few years while it has faced new competition, on a small scale, from LNG in EU nations in the east such as Poland and Lithuania, who have become LNG importers. Norway is also an LNG exporter to Europe from a small single-Train plant at Hammerfest, operated by Equinor. Gassco has emphasized the reliability of its pipeline system, given the huge volumes it handles. "Availability for delivering gas in the transport system was over 99 percent in 2018," explained Gassco's Leversund. "This is a strong figure, and we're very proud of it," he said. "Norwegian gas has many competitive advantages, but the fact that the integrated transport system, with process plants and terminals, runs steadily with the lowest possible climate impact is something we work had to achieve every single day," stated the CEO. Deliveries of natural gas liquids (NGLs) and condensate from the process plants at Karsto, Kollsnes (via Vestprosess) and Nyhamna totalled 10.3 million tonnes in 2018.

GASTRADE, the Greek company developing a liquefied natural gas hub and terminal project for the port of Alexandroupolis to serve the Balkans, has revised its invitation for expressions of interest as the delivery of the floating storage and regasification unit will take six months longer than originally scheduled. The first phase of a market test conducted in late 2018 was completed with great success after 20 companies expressed interest in the project. Gastrade now says there is a revised and extended deadline for expressions of interest for the Alexandroupolis Independent Natural Gas System Project set for February 15. The project comprises the FSRU for the reception, storage and regasification of LNG, a mooring and a system of a subsea and onshore gas transmission pipelines, through which natural gas will be delivered to the Greek National Natural Gas Transmission System (NNGTS) and onwards to the final consumers. The FSRU will be stationed in the sea off Thrace in northeast Greece, 17.6 kilometres southwest of the town of Alexandroupolis. The pipeline will be connecting the FSRU to the NNGTS near the village of Amphitriti, 5.5km northeast of Alexandroupolis. The FSRU venture and gas hub have been listed by the European Union as a project of European Common Interest, thus attracting EU grants. The Alexandroupolis FSRU project will double Greece's current LNG import capacity.

It is expected to secure new natural gas quantities for the supply to the Greek and the regional Southeast European markets, offer new sources and routes of natural gas supply, promote competition and enhance the security of supply in Greece and the Balkan markets. The pipeline will deliver natural gas to the Greek NNGTS network and onwards to customers in Greece, Bulgaria, Serbia, the former Yugoslav state of Macedonia, Turkey and Romania, as well as Hungary and Ukraine. The FSRU will have a nominal regasification and send-out capacity of 530 million standard cubic feet per day. Gastrade said there was also potential for a future tie-in to the Trans-Adriatic Pipeline gas transmission system. The company said companies wishing to express their interest are requested to send all required information electronically to info@gastrade.gr for the attention of Andreas Diamandopoulos.

GASUM, the natural gas network owner in Finland and an LNG distributor and regasification terminal operator through its subsidiary Skangas, has sold its technical unit to the Finnish Viafin Service Group. "This arrangement is part of Gasum's strategy of focusing on the development of the gas market and energy infrastructure in the Nordic countries," said Gasum. Gasum has sold the technical subsidiary for an undisclosed sum as Finland prepares for the opening up of the natural gas wholesale and retail markets, scheduled for the beginning of 2020. "It's great to carry out this transaction with Viafin Service, an experienced maintenance service specialist with a focus on expanding maintenance and related services at the core of its strategy," said Gasum Chief Executive Johanna Lamminen. "This transaction enables us to ensure service quality, and we'll continue to buy services from the company in the future, too," she explained. "We both share the aim of maintaining and developing technical competencies, high work quality and cost-effective operations in the gas sector," added the CEO. The transaction is expected to be closed by the end of February 2019.

Viafin has four different business activities in Finland, specializing in providing pulp towers, pressure vessels and piping assemblies as well as installation and maintenance services. Additionally, the Gasum LNG unit Skangas is expected to change its name to Gasum after the parent company increased its shareholding in Skangas from 70 percent to 100 percent in October 2018 by purchasing the balance of the shares from the Norwegian Lyse Group. Among its activities, Skangas imports LNG to Finland and is a leading Nordic supplier as well as having regasification and bunkering assets to cater for various markets from shipping to the industrial sectors in Finland, Sweden and Norway. Skangas owns the Finnish LNG import terminal at the port of Pori. A second Finnish import terminal, the Tornio Manga facility, has been completed as a joint venture at the northern Port of Tornio and Skangas is a partner. Gasum's subsidiary also owns and operates a small-scale liquefaction plant in Risavika in Norway and two other regasification terminals at Ora in Norway and in Lysekil in Sweden. Skangas is additionally involved in the LNG fuel and shipping market. It has the 5,800 cubic metres capacity LNG bunkering vessel "Coralius" and operates the small-scale chartered LNG carrier, the "Coral Energy".

GIBRALTAR said its new gas-fired power station project had handled its first operation with a small-scale LNG carrier delivery as part of safety trials in the run-up to the start of full operations. A partial cargo was delivered on the 7,550 cubic metres capacity carrier "Coral Methane", owned by Dutch shipping line Anthony Veder and chartered to Royal Dutch Shell. The UK overseas territory, located on a peninsula at the southern tip of Europe adjacent to Spain, had reached agreement with Shell in 2016, through its subsidiary Gasnor, for the organization of the LNG systems for the power station. Shell will help organize the LNG deliveries to Gibraltar on small-scale LNG carriers and a maximum of two per month are likely to be needed. There is also potential for LNG bunkering operations in the future. The fuel is being stored in several 1,000 cubic metres capacity double-walled LNG storage tanks from where it is transferred to vaporisers and regasified to produce electricity at the power station. The Gibraltar authorities said the "Coral Methane" rehearsed docking procedures at the regasification equipment. A statement said the operation provided an opportunity for staff to test the terminal's loading arm and its safety systems as the vessel unloaded a small volume of LNG cargo.

"This has been another exciting step on the way to producing our energy in a much cleaner and more efficient way," said John Cortes, Gibraltar's Minister for the Environment, Energy and for Climate Change. "It gave us the chance to take on some gas, thus testing our unloading systems and procedures in the most realistic manner possible and I am delighted to say that everything went extremely smoothly," added Cortes. "Over the weeks ahead, we will continue to test and evaluate all the systems in both the terminal and the power station," he stated. While Gibraltar is known as a bunkering port, the use of LNG for refueling ships is being viewed separately as an industry for the future. After the Gibraltar operations, the "Coral Methane" headed for Tenerife in the Spanish Canary Islands to deliver the remainder of its cargo, which can be used for bunkering at the Santa Cruz de Tenerife terminal.

GNL QUEBEC Inc. is still planning an export project in the French-speaking Canadian province, comprising a liquefaction and export plant near Port Saguenay at the junction of the Saguenay River and the St. Lawrence River. The company said its LNG proposals were still on track as it filed with the Canadian National Energy Board on January 8 as an interested party in the North Bay Junction fixed-price natural gas delivery service of TransCanada Corp. The GNL Quebec LNG project is known as Energie Saguenay and is backed by two equity firms based on the West Coast of the US. They are Breyer Capital of Menlo Park, California, and Freestone International from San Francisco. "GNL Quebec wishes to participate in the North Bay Junction proceedings as the issues to be addressed are material to its Energie Saguenay LNG export project, which is planned to be in service by 2025," it told the Board. The Quebec liquefaction facility proposes to export up to 11 million tonnes per annum of LNG to Europe, Asia and South America. "An integral part of the project is procuring gas supply with terms of up to 20 years from Western Canadian producers and finalizing long-term transportation arrangements on the TransCanada Canadian Mainline to supply the project facility in Quebec," GNL Quebec told the Board. "GNLQ plans to receive firm service transportation in 2025 from Empress to Ramore, which is a proposed delivery point located near North Bay Junction," the Board was told. "Substantial capacity will be requested of up to 1.6 billion cubic feet per day, and commercial discussions have been initiated with TransCanada for this service," it explained. "At Ramore, the proposed Gazoduc Pipeline will interconnect with the Mainline and transport gas on its 42-inch pipeline," it added.

"Gazoduc will extend 750km across northern Ontario and Quebec to Chicoutimi, Quebec where the LNG project will be located," said GNL Quebec. The developers of the Gazoduc pipeline filed their pre-application project description with the NEB on November 20, 2018, and their project notice with Quebec's Ministry of Environment and the Fight Against Climate Change (MELCC). GNL Quebec said it expected its project economics and the gas transportation service will be substantially impacted by the issues that are considered and decided in the North Bay Junction proceedings, including the terms of service, tolls, tolling structure and the availability of Mainline capacity. "For example, the availability of capacity across the Prairies and the Northern Ontario Line in the 2025 timeframe when the project commences service may well be impacted by the proposed new service," explained Quebec GNL. "The Board may wish to consider whether the terms and conditions approved will contribute to efficient system expansion and non-discriminatory treatment of new shippers willing to subscribe for firm service in the same timeframe and over the same path as the new service," it added.

JERA TRADING (Jerat), the joint trading venture between Japanese LNG and fuel procurement and utility company Jera Co. Inc. and French firm EDF Trading established in April 2017 following the acquisition of EDFT's coal business, is continuing its countdown to becoming Jera Global Markets. Jerat is strengthening its team by hiring a senior trader from global commodities firm Vitol. Jerat said Alex Baileff would join the company in April as Senior Vice President for Coal. "We are looking forward to welcoming Alex to Jera Trading. He brings with him a wealth of knowledge and trading experience which will be an asset to our coal and freight activities as we develop Jerat's global footprint," said Sunao Nakamura, Chairman of the Board of Jera Trading. Jera and EDF Trading signed an agreement last year to form an LNG optimization and trading joint venture whereby Jera's and EDFT's LNG trading activities would be merged into Jerat, which will be renamed Jera Global Markets. This agreement is expected to be completed in early 2019. Baileff will join Jerat's senior team comprising Kazunori Kasai, Chief Executive; Robert Quick, Director of Corporate Affairs; Hisaki Endo, Director of Group Coordination; Ronan Lory, Chief Operating Officer; and Sarah Behbehani, senior Vice President of LNG. Jera Co. Inc is the main company in all the operations.

It was set up by Tokyo Electric Power Co and Chubu Electric to combine their LNG and other trading activities and ultimately to run their power businesses as the industry in Japan reformed and was deregulated. On the trading front, the new Jera Global Markets will have more than 300 people and offices in Japan, Singapore, the UK, the US and the Netherlands, Jerat will become one of the largest utility-owned seaborne energy optimizers, spanning Asia, the Pacific and the Atlantic Basins. The two firms noted that as the demand for LNG in Japan becoming increasingly variable and difficult to predict and with the ramp-up in US liquefaction and exports, Europe has become a key balancing market for excess global LNG. Jera and EDFT have said there is significant room for optimizing LNG on a global basis, establishing a more liquid market, and over time developing a clear pricing signal for LNG in Asia. Jera Co. Inc. holds 66.67 percent of the equity in Jerat through its wholly-owned subsidiary Jera Trading International while the French firm holds 33.33 percent of the Jerat shares.

KINDER MORGAN said it expected to provide about 40 percent of the volumes for current and future LNG and pipeline exports as it remained on schedule to brings its own small-scale liquefaction facility on stream in the first quarter at Elba Island in Georgia and eventually a second plant in Mississippi. Elba Island is an existing import terminal being transformed into an export plant to produce an initial 2.5 million tonnes per annum of LNG. Kinder Morgan, based in Houston, had earlier given a start-up date for Elba Island as the fourth quarter of 2018. The Elba Liquefaction Project is being built at a cost of just $2 billion and will have feed-gas needs equivalent to around 350 million cubic feet per day. "The project is supported by a 20-year contract with Shell," said Kinder in a presentation to investors following its fourth-quarter results. "The first of 10 units is expected to be placed in service at the end of the first quarter of 2019, with the remaining nine units to come online throughout 2019," it added. Kinder's partner in the joint venture, called Elba Liquefaction, is the US equity fund EIG Global Energy Partners, which holds 49 percent. Elba Liquefaction will own the liquefaction units and other ancillary equipment. "Certain other facilities associated with the project are 100 percent owned by Kinder Morgan," said the company. "The newly constructed Elba Express Modification Project is now in service, adding upstream compression facilities on the Elba Express pipeline to provide feed gas for liquefaction," explained Kinder. The company stated that natural gas is critical to the American economy and to meeting the world's evolving energy needs. "Objective analysts project US natural gas demand, including net exports of LNG and exports to Mexico, will increase from 2018 levels by 32 percent to nearly 119 Bcf/d by 2030," it said. "Of the natural gas consumed in the US, about 40 percent moves on Kinder Morgan pipelines, and roughly the same percentage holds true for US natural gas exports," added Kinder. "Kinder expects future natural gas infrastructure opportunities through 2030 will be driven by greater demand for gas-fired power generation across the country (forecast to increase by 15 percent), net LNG exports (forecast to increase almost five-fold), exports to Mexico (forecast to rise by 39 percent), and continued industrial development, particularly in the petrochemical industry," it said.

The existing LNG terminal on Elba Island is about eight miles upstream from the mouth of the Savannah River. It was first authorized by the Federal Energy Regulatory Commission in 1972 as an import facility. The transformation project to turn the terminal into a liquefaction plant began in November 2016. Kinder and two equity funds are also making progress on receiving FERC permits to transform the existing Gulf LNG import terminal in Pascagoula in Mississippi into an export plant. The proposed Gulf LNG export facility would consist of two Trains, each with capacity of about 5 MTPA. "The Gulf Liquefaction Company, Gulf LNG Energy and Gulf LNG Pipeline units are scheduled to have their final Environmental Impact Statement in April 2019, and the final decision for issuance of the FERC certificate is expected in July 2019," said Kinder. Natural gas transport volumes on Kinder's pipeline system for the fourth quarter were up 4.5 Bcf/d compared with the same three months in the previous year. "The group's success mirrors the record-breaking year enjoyed by the natural gas sector as a whole. US natural gas demand rose to 90 Bcf/d from 81 Bcf/d in 2017, an 11 percent increase," it said. "This increase was driven by higher throughput on El Paso Natural Gas due to additional Permian capacity sales, on Colorado Interstate Gas due to growing Denver-Julesburg Basin production, and on Tennessee Gas Pipeline due to power demand and projects placed in service," said the company. Kinder said its Texas intrastate networks also contributed to a rise in transport volumes due to higher demand from shippers serving Mexico and the Texas Gulf Coast industrial markets, and on Natural Gas Pipeline Company of America due to cold weather early in the quarter, increased Permian Basin receipts and power demand.

LNG CANADA, the export project led by Royal Dutch Shell and four Asian partners in the West Coast province of British Columbia, said it had approved more than US$770 million in contracts and subcontracts and expected to employ around 10,000 Canadian workers as activities develop. Shell and its four partners, Mitsubishi Corp. of Japan, Malaysian energy company Petronas, Chinese major PetroChina and Korea Gas Corp., had agreed in October 2018 to proceed with the joint venture and with construction at a cost of up to US$31 billion of the plant and its associated facilities. The liquefaction plant is to be constructed at a brownfield site near Kitimat that had been an energy products terminal before being acquired by Shell in 2011. The plant itself is expected to cost around US$11Bln using modular construction methods and will have two large liquefaction Trains initially, with each producing 7 million tonnes per annum of LNG by 2025. The plant would then be expanded. Additional costs of up to US$20Bln will include feed-gas supplies for TransCanada's Coastal GasLink pipeline and other facilities. "By the end of construction phase, LNG Canada and the Coastal GasLink pipeline project that is needed to transport natural gas from northeast BC to the LNG export facility near Kitimat, expect to employ approximately 10,000 Canadian workers," said the company.

"As the project progresses, more contracts will be awarded to benefit Canadian communities," it added. LNG Canada said its contracts include one for US$132M to local First Nations businesses and, with the addition of contracts awarded to local firms in Kitimat, that total increases to US$248M and US$398M with the addition of BC businesses outside the local area. "What these contracts and subcontracts represent, is tremendous opportunity for individuals to find employment on the LNG Canada project through our contractors and subcontractors," said Susannah Pierce, LNG Canada's Director of External Relations. "For First Nations communities, it is delivering on the opportunities we have committed to that will assist the Nations address issues of poverty, unemployment and skills development," added Pierce. "For local communities, it is the opportunity for young people to find employment that allows them to remain living in the North," she stated. During the first month of the construction phase of operations in October 2018, there were 249 workers from the local area, including First Nations, employed by LNG Canada or one of its contractors.

MITSUBISHI Shipbuilding of Japan said it held a naming ceremony for the fourth vessel in a series of five being constructed to ship LNG cargoes from the US Gulf Coast to the main Japanese import terminals. The 180,000 cubic metres capacity carrier "Noshu Maru" with covered Moss-type storage tanks will be put into regular service transporting LNG from the Freeport LNG plant in Texas for Jera Co. Inc. the LNG supply arm of Tokyo Electric Power Co. and Chubu Electric. The joint owner of the "Noshu Maru" with Jera is Japanese shipping line Mitsui OSK Lines, which will operate the ship. "The latest model 'Sayaringo' type ship features significant improvements in both LNG carrying capacity and fuel performance due to the adoption of a more efficient hull structure and an innovative hybrid propulsion system" said Mitsubishi. The christening ceremony was held at Mitsubishi's Nagasaki Shipyard and was attended by representatives of the ship owners and their guests. Mitsubishi said that Chubu Electric Power President, Satoru Katsuno, announced the name of the ship while his wife performed the ceremonial rope cutting. The "Noshu Maru" is 297.5 metres in length and is 48.94m in width. It has a depth of 27.0m, with a draft of 11.1m. Deadweight tonnage is approximately 80,300 tons.

Ship joint-owner Jera was established in 2015 as an equal-share joint venture between Tepco and Chubu. Its business operations include the construction and refurbishment of thermal power plants in Japan, as well as energy infrastructure projects and power generation overseas. Mitsubishi explained that the "Sayaringo STaGE" is a successor to the "Sayaendo" type, a vessel acclaimed for its reliability and innovatively refined Moss-type spherical tanks. "The use of apple-shaped tanks allows for greater LNG carrying

capacity without increases to the ship's width, while the hybrid propulsion system further improves fuel efficiency over the previous model," said Mitsubishi. The company said that STaGE was an acronym derived from "Steam Turbine and Gas Engines," describing the hybrid propulsion system combining steam-turbine and gas-fired engines. "Going forward, Mitsubishi Shipbuilding and MHI Marine Structure will continue the development of next-generation LNG carriers with exceptional fuel efficiency and sustainable performance," stated the company.

NATIONAL GRID of the UK said its Isle of Grain import terminal on the Medway River southeast of London sent out more regasified LNG in December 2018 than any other facility in Northwest Europe. The Grain LNG terminal operator said that market conditions and a robust UK benchmark National Balancing Point natural gas price led to a record performance. "This is a stark contrast to December 2017, when the terminal only delivered gas above minimum send out on two occasions," said Grain LNG. "This winter, the UK has proved to be a strong market for LNG sellers looking to home excess LNG resulting from various supply projects coming on line," said the company. Grain LNG is currently the only UK terminal capable of accepting the full range of global LNG due to its extensive nitrogen processing plant. "The UK has a more stringent Wobbe limit than most of Europe but plans are underway to relax this, which should lead to a significant reduction in costs as well as ensuring LNG is able to enter any of the UK terminals," said the UK operator.

Other UK terminals have also seen increased activity, with both terminals in Milford Haven in Wales, the South Hook facility and the Dragon terminal, accepting many cargoes. "We are delighted to see such high utilisation at our terminal and proud of our consistent performance and ability to deliver our customer nominations after a long period of low activity," said Simon Culkin, the Grain LNG terminal manager. The UK terminal noted that during 2018 a total of 26 million tonnes of additional LNG production hit the market and shipping charter rates reached a record high. "These two factors resulted in traders delivering more LNG than expected to Europe as the differential available between European and Asian prices did not justify the additional shipping costs," explained Grain LNG. "The gas price in the UK remained steadfast and as utilisation at the Grain terminal rose it is expected that variable costs on a per unit basis would have decreased significantly as the terminal typically operates more efficiently at higher send-out as per the design basis," it added.

NEXTDECADE Corp., the developer of the Rio Grande liquefied natural gas export project in Texas, has held two public events to gather support for its second Texan export venture called Galveston Bay LNG. The Houston-based company has just held two open house events, one at Rosenberg in Texas attended by landowners who inquired about the pipeline route, and a second at Texas City. Galveston Bay LNG will include a 97-mile affiliated pipeline to move 3 billion cubic feet of natural gas per day from the Katy Hub in Waller County, while the liquefaction plant is proposed for a 550-acre site along the Texas City Ship Channel. The Galveston Bay liquefaction plant would produce an initial 5.5 million tonnes per annum of LNG. "The Galveston Bay project open houses represent the first of several opportunities throughout the regulatory and permitting process, led by FERC, for area residents to learn more about the proposed project and to ask questions," said NextDecade. The company is also near the end of the regulatory process for the Rio Bravo Pipeline in South Texas and the Rio Grande export plant at the Port of Brownsville to produce around 27 MTPA of LNG.

The Texas Commission on Environmental Quality granted the Rio Grande project and its Rio Bravo Pipeline a state permit in December 2018, though federal regulators were not expected to make a decision about the projects until July 2019. The Rio Bravo Pipeline is expected to transport 4.5 billion cubic feet per day from the Agua Dulce area to the Rio Grande liquefaction plant in Brownsville. NextDecade's Rio Grande project remains subject to final review by the Federal Energy Regulatory Commission. The FERC issued a draft environmental impact statement for the Rio Grande venture and its associated pipeline in October 2018. A final EIS will be issued on April 26 for the Rio Grande developments and the FERC has established a 90-day decision deadline of July 25, 2019. NextDecade, whose shares are listed on the Nasdaq stock exchange, anticipates a final investment decision on the Rio Grande LNG venture in the third quarter of 2019.

OPHIR Energy, the UK company that lost its Equatorial Guinea licence in West Africa and the potential Fortuna floating liquefied natural gas project, is still holding out hope of securing revenue from its stake in an onshore LNG export project in the East African nation of Tanzania. Ophir was informed by the Equatorial Guinea Ministry of Mines and Hydrocarbons that the Block R Licence, which contains the Fortuna gas discovery, had expired on 31 December 2018. The UK company had been unable to meet its schedule for a final investment decision on the Fortuna floating LNG project. Ophir and OneLNG, a joint venture between Bermuda-based Golar LNG and global energy services company Schlumberger, had established a joint operating company to develop the Fortuna FLNG venture using Golar's floating hull technology. "As we announced on 5 January, the Block R licence in Equatorial Guinea has not been extended," said interim Chief Executive Alan Booth. "We are in negotiations to rationalise parts of our frontier exploration portfolio with the potential to not only bring in cash, but also importantly reduce our future exploration capital commitments and further improve our liquidity position," he explained. "We remain mindful of the potential value of our gas assets in Tanzania, notwithstanding the uncertainty over timing for their development," stated Booth. Ophir's exploration offshore Tanzania and that of other companies has led to discoveries of 15 trillion cubic feet of gross contingent natural gas resources. The assets have entered the pre-development phase for the Tanzania LNG project. The UK company and its partners have drilled 16 wells since 2010, including the large Mzia and Jodari discoveries in Block 1.

Of the wells drilled, 11 have been successful exploration wells and five have been appraisals. Production flow tests have also been completed on Jodari, Mzia, Pweza and Taachui discoveries. Ophir retains a 20 percent interest in Blocks 1 and 4 and sold 60 percent to BG Group in 2010, now owned by Royal Dutch Shell, and sold a further 20 percent to Pavilion Energy of Singapore in 2014 for US$1.3 billion. In 2014 the joint venture partners in Blocks 1 and 4 and the partners in Block 2, Equinor of Norway and ExxonMobil, signed an agreement to co-operate on a combined onshore LNG plant. The Block 1 and 4 partners, as well as the Block 2 partners and the Government also signed an accord for the project, including the site of the LNG plant and the process for acquiring the land and for how any resettlement will be managed. "The project is currently in the pre-FEED stage and is expected to enter into FEED following the completion of the LNG site acquisition, the geotechnical investigations and engineering studies," said Ophir. "In parallel, the concept selection is in progress for the upstream part of the project which will determine the configuration and production rates from each of the fields," it added.

PHILIPPINES LNG has been in developing, though a second large-scale LNG import project has now been proposed with the Chinese major, China National Offshore Oil Corp., named as one of the partners in the facility to be located south of the capital Manila. The CNOOC-backed terminal is being developed in partnership with Filipino fuel retail company Phoenix Petroleum. Phoenix said it had set up a subsidiary called Tanglawan Philippine LNG Inc to undertake the project with initial capacity of 2.2 million tonnes per annum and a start-up date of 2023. The CNOOC-Phoenix joint venture follows another revealed in December 2018 led by Japanese utility Tokyo Gas and involving Philippines power company First Gen Corp. That terminal will be developed in Batangas province, though the partners disclosed no details on capacity or on the exact location. The only other regasification facility in the Philippines is at Pagbilao in Quezon province where Australia-listed Energy World Corp. has a small-scale facility linked to a power project that has not yet begun imports.

The Tokyo Gas-First Gen venture is expected to be a large scale as First Gen operates four of the country's five gas-fired power plants with total capacity of about 2,000 megawatts, all of them in Batangas province. The Philippines is preparing to start importing LNG to feed its gas-fired power plants as domestic gas supply from its Malampaya field is set to run out in 2024. State-run Philippine National Oil Co. had been seeking a joint venture partner to build and run an LNG hub in Batangas Bay. The Tokyo Gas venture with First Gen is its first energy infrastructure activity in the Philippines. The Japanese company has a 20 percent stake in the project and First Gen, a subsidiary of the Filipino conglomerate, the Lopez Group, holds 80 percent.

SANTOS, the Australian energy company, a stakeholder in three Asia-Pacific LNG plants, said it signed extension agreements with two operators for gas processing and related gas purchases at its Moomba gas facilities in the state of South Australia. Santos said the agreements, though relatively small, will result in the production of natural gas for domestic consumption in cities such as Sydney and Adelaide. Beach Energy and Senex Energy are the two local companies that have extended their deals with Santos for Moomba gas processing of production from the Cooper Basin. "These processing agreements demonstrate the benefits of the Santos strategy to leverage our existing infrastructure to facilitate more gas supply and more competition in the East Coast domestic gas market as well as continuing to build our Queensland production for both domestic customers and our LNG exports from Gladstone," said Naomi James, Santos Executive Vice President of Midstream Infrastructure. Santos is also operator of the Gladstone LNG plant and a stakeholder in liquefaction facilities in Darwin in the Australian Northern Territory and in Papua New Guinea. The gas processing agreement extensions are expected to result in the production of up to 20 petajoules of gas, the equivalent of 0.837 billion cubic metres of gas, over the three-year term. "These gas processing agreement extensions reaffirm the strategic importance of the Santos-operated Moomba gas plant in facilitating access to the East Coast domestic gas market for other producers in the Cooper Basin to increase gas supply and competition, which is the best way to put downward pressure on gas prices for customers," Santos explained. The Australian government had expressed concern about natural gas supplies for domestic use and high prices because of feed-gas requirements for LNG exports in states such as Queensland.

Other factors also led to the supply concerns, however, including state governments embracing renewable energy projects at the expense of natural gas exploration and production ventures so that fossil fuel supplies meet growing demand. Plans are already underway for LNG to be shipped to major cities on the East Coast with regasification facilities being planned near Sydney and Melbourne. The Moomba facility operated by Santos accepts production from surrounding Cooper Basin oil and gas fields through 5,600 kilometres of pipelines and flowlines. The plant also incorporates substantial underground storage for processed sales gas and ethane. Natural gas liquids are recovered via a refrigeration process in the Moomba plant and sent together with stabilized crude oil and condensate through a 659-kilometre pipeline to Port Bonython near Whyalla in South Australia. Gas is then sent from Moomba to Adelaide via a 790-kilometre pipeline and to Sydney via a 1160-kilometre pipeline. The agreement extensions will allow raw gas from Beach's western flank of the Cooper Basin and gas from Senex's Vanessa project to be processed to sales gas quality. "The Santos-operated Moomba gas facilities in South Australia's Cooper Basin are a critical hub in eastern Australia's gas processing and transportation network, connecting supply from multiple producers in Queensland and South Australia to southern domestic gas markets," said Adelaide-based Santos.

SEA-LNG, a global coalition of energy and shipping companies backing the increased use of liquefied natural gas as a maritime fuel, said it had appointed representatives of French bank and project financier Societe Generale and the Maritime and Port Authority of Singapore to replenish its 12-strong board. Sea-LNG named Paul Taylor from Societe Generale and Captain M. Segar for the Port Authority of Singapore as the directors. The group, founded in 2016 to help provide strategic development of the emerging LNG marine fuel market, said two other new board members were elected in December 2018, Tahir Faruqui of Royal Dutch Shell, and Xavier Pfeuty of Total Marine Fuels. Peter Keller, the Sea-LNG Chairman and who is also Executive Vice President of US shipping line TOTE Maritime Inc., said that in the past year the organization had grown to 36 member companies and port authorities. "I am delighted to welcome Paul and Capt. Segar as representatives from these organisations, as well as Xavier and Tahir to the Sea-LNG Board for 2019," said Keller. "I would like to express my sincerest gratitude to our outgoing founding board members Yvonne van der Laan (Port of Rotterdam), Michael Chia (Keppel Offshore & Marine) and Lauran Wetemans (Shell) for their valuable participation as founding board members of Sea-LNG," added Keller. "We have benefitted significantly from their leadership, dedication and guidance, and wish them all the best for the future," stated Keller.

"I would also like to appreciate the ongoing commitment of our other board members, all of whom possess a broad range of highly relevant skills and experience and a singular desire to drive forward our vision of a competitive global LNG value chain for cleaner maritime shipping towards 2020 and beyond," said the Sea-LNG Chairman. Keller explained that throughout 2019, Sea-LNG would continue to unite key industry players from major LNG suppliers, downstream companies, shipping companies, infrastructure providers, and shipyards and others to transform the use of LNG as a marine fuel. The 2019 Sea-LNG Board members are: Peter Keller, Chairman, (representing Tote Maritime, USA); Stefan Eefting (MAN PrimeServ, Augsburg, Germany); Tahir Faruqui (Shell); Timo Koponen (Wartsila, Finland); Masamichi Morooka (Yokohama-Kawasaki, Japan); Xavier Pfeuty (Total Marine Fuels); Hiroyasu Sakaguchi (Mitsubishi Corp. of Japan); Torsten Schramm (DNV GL, Oslo, Hamburg); Capt M Segar (MPA, Singapore); Svein Steimler (NYK Group, Japan); Tom Strang (Carnival Corp.); and Paul Taylor (Societe Generale).

SEMPRA ENERGY, the California-based utility, is making good progress on the commissioning process for the first liquefaction Train and other facilities at the Cameron LNG export plant in Hackberry in Louisiana, with almost 8,700 workers currently on site at year-end as activities increased. "Construction continued in all areas with focus on aboveground piping installation, pressure testing, structural steel, electrical work, insulation, and fire proofing," said a report from the Federal Energy Regulatory Commission after an inspection visit. The Cameron plant is a former import terminal that is being transformed by the addition of liquefaction Trains. The project's first phase includes building three Trains at a cost of $10 billion with export capability of almost 15 million tonnes per annum of LNG. "On Train 1, CLNG is preparing for the commissioning of the Hot Oil System and the solo run for the Mixed Refrigerant (MR) Gas Turbine. Installation of the Train 2 Main Cryogenic Heat Exchanger insulation, structural steel and above ground piping continues," said the FERC report. "On Train 3, installation of underground and above-ground piping continues" it added. Cameron LNG is jointly owned by Sempra, French major Total, Japanese trading house Mitsui & Co and Japan LNG Investment, a venture owned by Japan's Mitsubishi Corp. and the shipping company Nippon Yusen Kabushiki Kaisha, known as NYK Line.

At least two of the three Trains are expected to be producing LNG by the end of 2019. "On average there are 8,680 workers on the site daily, between 650 and 750 of which work the nightshift. The construction workforce will decrease as commissioning activities progress," said the FERC report. The FERC noted that the objective of the project was to export approximately 14.95 MTPA of LNG with a maximum operating capacity equivalent to pipeline receipts of up to 2.33 billion cubic feet per day of feed-gas. Each of the liquefaction Trains will have maximum capacity of 4.98 MTPA and an additional 160,000 cubic metres capacity LNG storage tank is being built to give a total of 640,000 of LNG storage from four tanks. The FERC said that the Train 1 hot oil system will be commissioned in several weeks and the flare pilot will also be started. "The boil-off gas compressors have been installed and construction activities are complete," said the report. "Construction within the project site and observed during the inspection complied with the designs and plans filed with and approved by the FERC," the report concluded.

SOUTH KOREAN LNG imports rose to a record 44 million tonnes as shipments increased from traditional Middle East supplier Qatar and from new projects in Australia and the US. According to Korean customs data, imports of LNG were up by 17.3 percent compared with the 2017 total when volumes had amounted to 37.6MT. Imports from Qatar totaled 14.25MT in 2018, a rise of 21 percent compared with the 11.78MT of cargoes received in 2017. Australia was the second-largest LNG supplier to Korea in 2018 with 7.87MT versus 7.01MT the previous year, followed by the US with 4.66MT compared with 1.91MT in 2017 and Oman with 4.29MT, slightly up on the previous year's 4.19MT. The Koreans also received shipments from Asian nations like Indonesia and Malaysia as well as cargoes from the

Atlantic Basin exporters, Nigeria and Trinidad. In addition, there were re-exports logged from European countries like the Netherlands, Spain and the UK. Korea Gas Corp, a shareholder in the Gladstone LNG plant in Queensland, is the dominant LNG importer, though other companies also received shipments at two of the nation's six import terminals.

South Korea's previous annual record of LNG shipments was set in 2013 when it faced a series of nuclear reactor shutdowns due to a safety scandal over faulty parts, leading to an increase in gas-fired power generation. Four of Korea's import terminals at Incheon, Pyeong-Taek, Samcheok and Tong-Yeong are operated by state-controlled Kogas and have huge storage tank capacity. The two other terminals are owned by a utility and an industrial company. The Boryyeong terminal is operated by GS Energy and the Kwangyang facility by the steelmaker POSCO, whose shipments are organized by trading unit POSCO Daewoo.

TELLURIAN Inc., developer of the Driftwood LNG export project in Louisiana, said it expected to start construction near the Lake Charles site in the first half of 2019 after regulators issued a final environmental impact statement. The final EIS was issued by the Federal Energy Regulatory Commission to develop the liquefaction plant to produce around 27.6 million tonnes per annum of LNG and its associated 96-mile pipeline. "Tellurian thanks the FERC for a thorough review and for remaining on schedule," said Tellurian President and Chief Executive Meg Gentle. "We look forward to receiving the agency's order granting authorization to site, construct and operate our Driftwood project," added Gentle. "Tellurian will then stand ready to make a final investment decision and begin construction in the first half of 2019, with the first LNG expected in 2023," stated the CEO. Tellurian, founded by former Cheniere Chief Executive Charif Souki, continues to sign up customers and investors for its export joint venture. The most recent was in December 2018 when it signed a preliminary accord with Swiss-based international commodities firm Vitol to supply 1.5 MTPA of LNG cargoes for 15 years. The Tellurian-Vitol is based on the Japan Korea Marker (JKM) price and cargoes on a free-on-board (FOB) basis whereby Vitol provides its own shipping.

Under the MOU, Tellurian and Vitol have agreed to negotiate a future LNG sale and purchase agreement subject to Tellurian's receipt of approvals from the FERC. In addition to signing the accord on cargoes, Vitol said it was also evaluating a potential equity investment in the Driftwood Holdings partnership. Tellurian has said it had advanced the sale of LNG and Driftwood partnership interests with around 35 customers and potential partners conducting due diligence and would be announcing an investor and buyer list. The Houston-based company, listed on the Nasdaq, disclosed the number as it reported a third-quarter net loss of $33.2 million compared with a loss of $22.9M in the same three months of 2017. Tellurian also plans to develop its own pipeline network, including the Driftwood Pipeline and two additional pipelines to expand supply alternatives for liquefaction and domestic distribution in Louisiana. The three pipelines are anticipated to be in-service between mid-2021 and the end of 2022, subject to commercial agreements. Tellurian agreed in 2017 to purchase natural gas producing assets and undeveloped acreage in the Haynesville Shale of northern Louisiana from Rockcliff Energy.

Diary of events

February
3rd Annual LNG USA Summit
26-27 February, 2019
Houston, Texas
www.lng-usa.com

April
19th International Conference & Exhibition on LNG
1-5 April, 2019
Shanghai, China
www.LNG19.com

May
Canada Gas & LNG Exhibition and Conference
21-23 May, 2019
Vancouver, Canada
www.canadagaslng.com

TOKYO GAS, the utility and importer of around 12 million tonnes per annum of LNG to Japan, has helped start the first non-state natural gas distribution business in Thailand in a joint venture with Japanese trading house Mitsui and three Thai companies. Thailand's largest private power generation companies are the main partners of Tokyo Gas and Mitsui. The holding company for the new business has three Thai firms and the Tokyo Gas-Mitsui joint venture, known as MITG (Thailand) Ltd, as shareholders. The Thais own 70 percent of the business and the Japanese 30 percent. The Thai companies involved include Gulf Energy Development Public Company, headed by Chief Executive Sarath Ratanavadi. WHA Utilities and Power Public Company, whose CEO is Wisate Chungwatana, has also joined the gas distribution business along with Whaup, a private utility supplier for industrial estates in Thailand. Tokyo Gas said that through these gas distribution subsidiaries, the Thai-Japanese venture will supply natural gas to industrial users, creating Thailand's first fully private gas distributor. "The industrial users are in the Eastern Economic Corridor, a special economic zone specified by the Thai government for the purpose of promoting investment," explained Tokyo Gas. "Various companies, including non-Japanese as well as Japanese companies, are eager to enter this industrial area," it added.

"Tokyo Gas will seek to expand the gas distribution business in the industrial area, leveraging know-how on gas distribution backed by years of experience and successful operations in Japan, together with its knowledge of the LNG value chain," stated the utility. Analysts said that Tokyo Gas and Mitsui could develop the business in the future with infrastructure and the ability to import LNG for gas-fired power. Tokyo Gas is one of the world's most experienced LNG and city-gas distribution companies and has long-term contracts with 11 projects in six countries, Australia, Malaysia, Indonesia, Brunei Russia and Qatar. The Tokyo Gas network includes three large LNG import terminals to serve the Tokyo metropolitan area as well as storage and gas-fired power plants. The utility's city-gas business has a pipeline network totaling 59,575 kilometres and it has also broadened its activities to include electricity supply after the deregulation of Japan's energy industry. Tokyo Gas noted in its Thailand statement that it received Japan's first ever LNG cargo (from Alaska) on November 4, 1969, and this year it is marking the 50th anniversary with various events.

TOTAL, the French energy major, said it expected to approve plans for increased oil and gas activities in Nigeria in the coming months and is also hoping to help increase Nigeria's liquefied natural gas production with the long-awaited Train 7 expansion. "There is a huge potential in Nigeria, it is probably the most prolific country in West Africa in terms of oil and gas and it is time to launch new projects and we are working on many of them," said Total Chief Executive Patrick Pouyanne at a French-Nigerian business forum in Paris. The West African nation has produced LNG since 1999 and the main shareholders in the six Trains are Total, Royal Dutch Shell and Eni of Italy, as well as Nigeria National Petroleum Corp., which owns 49 percent of the venture. Nigeria LNG is the operating company at the Bonny Island liquefaction plant in the Niger Delta and it took the first steps in July 2018 towards constructing the seventh Train after years of delay. Front-end engineering and design contracts for Train 7 have been awarded on a contest basis to two consortiums. The Total CEO said he was expecting to join in the expansion of the Nigerian LNG plant. "The market is very good today to do that, it would be a very profitable project and the partners are in line to start developments in 2019," added Pouyanne. The FEED contracts for the Train 7 construction were awarded to two separate groups. One comprises Italy's Saipem, Chiyoda Corp. of Japan and Daewoo Engineering of South Korea and the second includes KBR of the US with the Franco-US firm TechnipFMC and JGC Corp. of Japan. Nigeria LNG also uses associated gas from oil fields to produce LNG. The company has converted over five trillion cubic feet of associated gas from oil production, which otherwise would have been flared as greenhouse gas.

Total is additionally a stakeholder in the Egina oil field 150 kilometres offshore Nigeria that has just started production. Egina is the third deep offshore development of Total in Nigeria. The Egina field will be ramped up to produce about 200,000 barrels of oil per day, about 10 percent of Nigeria's total output. "In the same area as Egina, we have Preowei, which could be connected to Egina. We are working on that," said Pouyanne. An investment decision on the Preowei field is scheduled for later in 2019. Pouyanne also called on Nigeria to issue new exploration licences, saying the country's oil and gas sector had been largely dormant in recent years in terms of exploration and new projects, citing continuing uncertainties and the ongoing discussions about the improved regulation of Nigeria's energy industry. The last round of exploration licenses tenders in Nigeria was in 2011. "I hope that the new government that will come after the election will launch new tenders for awarding exploration licenses," said the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Total CEO. NLNG runs an integrated plant on Bonny Island where its current six LNG Trains produced more than 20 million tonnes per annum of LNG, making the nation the world's fifth-largest producer behind, Qatar, Australia, the US and Malaysia. The Nigerian plant shares common facilities including storage tanks, shipping capacity and loading jetties with a gas intake of 3.5 billion standard cubic feet of natural gas per day.

WESTPORT Fuel Systems Inc., the Canadian-based supplier of LNG and compressed natural gas vehicle engine and storage technology and components, has named David M. Johnson as its new Chief Executive. Westport's vehicle engines and fuel storage systems can be liquefied natural gas or compressed natural gas and its brands include Cummins Westport that specializes in the trucking sector. The company said that CEO Johnson replaces Nancy S. Gougarty who has decided to retire. Gougarty is stepping down after successfully leading the integration after the 2016 merger of Toronto Stock Exchange-listed Westport Innovations Inc. and New York-based Fuel Systems Solutions into the combined Westport Fuel Systems Inc. With its headquarters in Vancouver in the province of British Columbia, the merged Westport company has global operations and customers and is expanding into China. The company offers automotive brands power packages and components for LNG, CNG and also liquefied petroleum gas engines. Westport said Johnson was joining the company having served for 10 years as President and Chief Executive of California-based US engines developer Achates Power. "Prior to his most recent role, Johnson served in a variety of roles with some of the world's leading automotive companies, including senior roles at Navistar, Ford and General Motors," said Westport. "Johnson combines deep technical expertise with a decades-long career in international markets, during which time he successfully led and managed several global vehicle and engine development and commercialization programs," added the company.

Brenda Eprile, Chair of the Westport Board, said the company was pleased to appoint "an entrepreneurial leader" with specific experience and insights in the global original equipment manufacturers (OEMs) market where Westport has more than 100 customers. Westport is expected to post consolidated revenue from continuing operations in the range of US$260 million to US$275M for the full year 2018. "David is well positioned to build on Westport Fuel Systems' global success as we continue to execute our long-term strategy," said Eprile. Johnson said he was honoured to lead the company and to build on a strong record of success and growth. "I would like to thank the Board of Directors for their confidence. I am excited to get to work with our excellent team and look forward to meeting and engaging with our stakeholders in the coming days and weeks," stated the new CEO.

WOODSIDE Petroleum, the operator of the North West Shelf and Pluto liquefied natural gas plants in Western Australia and a stakeholder in the state's newest Wheatstone facility, posted a more than 40 percent jump in LNG sales revenue in 2018 to US$3.76 billion on increased demand from Asian customers and higher prices. Woodside said in its fourth-quarter report to the end of December that the 2018 total compared well with the US$2.67Bln of LNG sales revenue received in 2017. Woodside said its quarterly revenue from LNG sales amounted to US$1.17Bln compared with US$881 million in the previous three months to September and US$717M in the fourth quarter of 2017. Woodside said demand was higher from the North West Shelf, Pluto and Wheatstone plants in Western Australia because of a combination of factors including customer demand, ongoing plant optimization and in the case of Wheatstone, higher output after the commissioning of the second liquefaction Train. Woodside said its overall quarterly sales revenue, including oil and condensates, came in at US$1.42 billion, an increase of 43 percent compared with the fourth quarter of 2017. The company's average LNG price during the quarter was US$10.40 million British thermal units, with US$9.20 per MMBtu for North West Shelf, US$10.80 per MMBtu for Pluto and US$11.20 per MMBtu for Wheatstone volumes. Woodside's total sales revenue for 2018, including oil, condensate and other products was US$4.82 billion versus US$3.68Bln in 2017. Woodside's one-sixth share of LNG sales from the North West Shelf plant amounted to 667,682 tonnes, an increase from 593,338 tonnes posted in the previous quarter, though down on the 728,453 tonnes logged in the same three months of 2017. Its Pluto LNG quarterly sales volumes rose to 1.21 million tonnes versus 1.02MT in the previous quarter and 1.07MT in the 2017 quarter. Woodside's volumes from the Chevron Corp.-operated Wheatstone LNG plant were also ramped up to 308,547 tonnes from 191,869 tonnes in the previous quarter and 19,291 in the same three months a year before.

Chief Executive Peter Coleman said the base business turned in another strong performance in the fourth quarter, with Wheatstone's production continuing to exceed expectations and Pluto achieving almost full reliability. "Production rose 10 percent compared to the fourth quarter of 2017, while sales revenue climbed 43 percent to US$1,419 million on the back of higher prices," said Coleman. "A highlight of the quarter was the start-up of the Greater Western Flank Phase 2 project in October, six months ahead of schedule and $630M under total budget," added the CEO. "In addition to the outstanding result in delivering Greater Western Flank Phase 2, we achieved significant milestones in the development of our next wave of projects, which will underpin Woodside's future growth," he said. In the company's West African operations offshore Senegal, it commenced front-end engineering design activities for its SNE Field Development Phase 1. "Subsequent to the end of the quarter, the Senegalese Government approved the development's Environmental and Social Impact Assessment," said Coleman. He added that key steps were also taken during the quarter towards the realisation of the company's vision for the Burrup Hub development, involving the proposed Pluto-North West Shelf Interconnector gas pipeline for the expanded Pluto LNG facilities. "Bechtel has been awarded the front-end engineering and design contract for the proposed Pluto Train 2," said Coleman. "We are converting the preliminary agreement signed in the fourth quarter of 2018 to a fully-termed, binding agreement for the processing of Browse gas through the North West Shelf's Karratha Gas Plant," he added. "We continue to demonstrate our commitment to supplying the Western Australian domestic gas market, signing sale and purchase agreements. We also delivered our first supplies from Pluto into the Dampier to Bunbury Natural Gas Pipeline," stated Coleman.

WOODSIDE has awarded four contracts for front-end engineering and design activities for the proposed Scarborough natural gas project to underpin expansion at the Pluto facility on the Burrup Peninsula. Woodside said the contracts were for engineering activities related to the upstream development's floating production unit, the export trunkline and the subsea umbilical risers. Woodside's preferred concept for development of the Scarborough gas resources of 7.3 trillion cubic feet is through new offshore facilities connected by 430 kilometres of pipeline to the Burrup Peninsula, with onshore processing at the expanded Pluto liquefaction facility. "Each contract includes an option to progress to execute phase activities, which is subject to, among other conditions, a positive final investment decision being taken on the project by the Scarborough joint venture," said Woodside, operator of the gas field and whose licence partner is commodities firm BHP Billiton. Woodside said US energy engineering company McDermott had been awarded a contract to undertake engineering studies for the floating production unit, which includes the option to progress to an engineering, procurement and construction contract.

A consortium called, Subsea Integration Alliance, including OneSubsea and Subsea 7, has been awarded a contract to undertake engineering studies for the umbilical risers and flowlines, with the option to progress to an engineering, procurement, construction and installation contract. The Australian subsidiary of Italian energy engineer Saipem was awarded the contract to provide export trunkline engineering support services with an option to execute pipeline coating and installation activities. The fourth contract went to Intecsea, a subsidiary of Australian company WorleyParsons, for export trunkline engineering. "Each contract was awarded by Woodside in its corporate capacity as a Scarborough titleholder and will be funded initially by Woodside on a 100 percent basis," said Woodside. Woodside Chief Executive Peter Coleman said the award of these contracts would support the project schedule and Woodside's FID scheduled for 2020. "We have made good progress since announcing last year that we had increased our stake in Scarborough. The award of these contracts brings us closer to unlocking the Scarborough resource," said Coleman. "We want to continue to maintain the momentum that has been generated during 2018," the CEO added. ■

Competition between Russian gas and US LNG should be fought out more in Asian than in European markets

US liquefaction projects not already under construction will find marketing conditions tougher

Even if the massive arrival of US LNG on the markets over the next few years will fundamentally change the configuration of world gas supply, a distinction must nonetheless be made between the short term and the long term, and between the European and Asian markets.

On the European markets, only the US LNG produced by existing installations can currently be valued at a cost similar to that of Russian gas (between $5-$6 per million British thermal units) imported by pipeline.

However, it will prove difficult for LNG from installations that have not yet been built (US$8 per MBTU) to compete with Russian gas.

Oil theory

In theory, if oil prices increase to around $70 a barrel, gas prices will automatically increase, making American LNG competitive. In view of the production costs, however, the Russians can easily grant their European clients discounts relative to the indexed contract prices.

This spot market strategy already applies to two-thirds of the volumes produced. In economic terms, the Russians therefore have major levers, both short-term, by imposing prices lower than the indexed prices, and longer-term, by deterring investment decisions on future LNG trains.

As proof, US exports of LNG to Europe in 2016 and 2017 accounted for less than 10 percent of total US LNG exports.

Nevertheless, behind the scenes of this price war, the Europeans do not want to jeopardize their energy security by over-reliance on the Russian gas supply.

The difficulties in launching the Nord Stream 2 project show that in spite of proven competitiveness and significant levers on margins, geopolitical problems make the Russian gas strategy vulnerable.

The situation is very different on the Asian markets, as onshore pipeline infrastructures are non-existent.

Investments

The projects for creating the West entry (Altai gas pipeline) and the East entry (development of the Chayanda and Kovykta fields, Power of Siberia pipeline) to the Chinese network, are requiring heavy investments, generating a gas price of $9 per MMBtu, almost equivalent to that of US LNG which, thanks to the expansion of the Panama Canal, now has access to the Asian markets.

The competition between Russian gas and US LNG should therefore be fought out on the Asian markets and not on the European markets.

Finally, the competition between the Russians and the Americans will make it incredibly difficult to develop unconventional resources in Europe and in China.

In view of the geological and climatic difficulties (in China) and the socio-political concerns (in Europe), developing these indigenous resources would cost between $12-$15 per MMBtu. Unless the developments are partly subsidized by the states for political reasons, shale gas has no real economic future in the medium term in China and in Europe.

The US shale gas revolution is a play in three acts.

The US is the world's leading consumer and historically, also the main gas producer. US remained gas independent until the end of the 1980s.

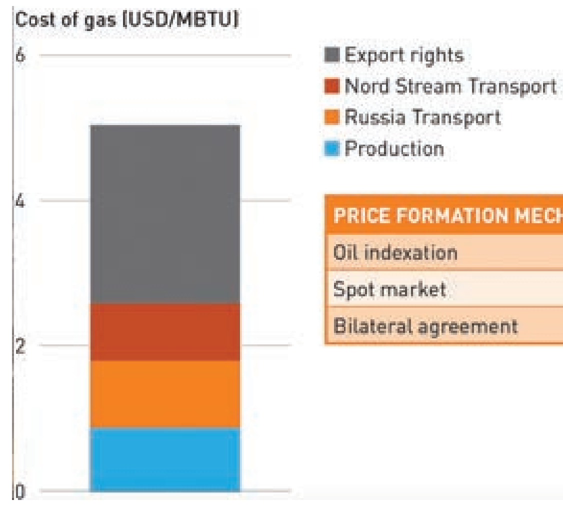
In the early 1990s, however, after a steady increase in consumption and the stagnation of its domestic production, the US began to import gas and in less than 10 years, its gas dependence rose to 15 percent.

Transition

At the beginning of the 2000s, all the observers agreed that US dependence would continue to grow over the following decade, spelling massive imports of liquefied natural Gas. So, in the early 2000s, the US authorities decided to build regasification terminals in the Gulf of Mexico and along the Atlantic coast.

With the steep drop in production and the forecast of massive LNG imports, gas prices across the Atlantic rocketed, practically doubling between 2000 and 2007. This growth inevitably made coal more competitive and had negative consequences on US greenhouse-gas emissions. But this first act is in fact pure fiction.

The second act began in the early 1980s in northern Texas. In total anonymity, an unknown independent company called Mitchell Energy was exploring the gas contained in the Barnett formation.



PRICE FORMATION MECHANISM	LNG	GAS PIPELINE
Oil indexation	60%	32%
Spot market	40%	64%
Bilateral agreement	0%	4%

Average cost of Russian gas for Europe with price mechanisms

The geological formation was not a conventional reservoir but a source (shale) rock.

Although the Barnett formation contains huge amount of gas, it could not be produced cost-effectively using conventional extraction methods owing to the shale rock's very low permeability - hence the term "shale gas".

Top producer

Thanks to the shale-gas revolution, the Americans regained not only their gas independence, but also their place as leading gas producer ahead of the Russians in just under a decade.

The growth in production was remarkable. Inexistent in 2006, it reached 12 Bcf/day in 2010 and 49 Bcf/day by the end of 2017.

And despite a new drop in prices in 2012 and 2017, and a marked decrease in production continued to rise. This amazing resilience can be explained by the massive well portfolio, the spectacular improvement in operational performance, the tremendous progress made in well completion and in the identification of sweet spots.

At the end of 2017, shale-gas production therefore represented 66 percent of US gas output.

Where the US was set to become a major LNG importer, it was actually the opposite scenario that occurred. After a heated debate between producers in favor of exporting gas surplus (from 2 Bcf/day in 2020 to 12 Bcf/day in 2035) and consumers in fear of a price increase that would jeopardize the newfound competitiveness, the US authorities finally decided in favor of the producers.

They authorized the conversion of the newly-built regasification terminals into liquefaction units.

In the context of an LNG market that foresees world production of around 500 million tons by 2030 (compared with 256 million tons in 20165), the US liquefaction capacity should exceed 60 million tons by 2025, and reach 80 million tons at the beginning of the following decade.

The first LNG shipment from the Sabine Pass liquefaction unit (operated by Cheniere) was exported to Brazil in March 2016, whereas the first European delivery was offloaded in Portugal at the end of April 2016.

Asia route

The export of US LNG, produced essentially on the Atlantic Coast and in the Gulf of Mexico, to the Asian markets was to be made much easier by the early opening (2016) of the Panama Canal to large LNG carriers.

What is the economic efficiency of US LNG in the short and medium term?

Does US LNG actually have the potential to create a world gas market and merge regional market prices, as some opinion-makers might suggest?

Even if the LNG market is rocketing, the volumes exported in 2016 represented less than 10 percent of global consumption, whereas the regional exchanges via gas pipelines represented 20 percent, and indigenous consumption 70 percent.

Inherently a commodity that is preferably consumed in a perimeter relatively close to its extraction site, gas is still a long way away from a single world market.

Just like its peers, under no circumstances can US LNG bank on a spot market. US LNG export projects have very attractive advantages compared to their competitors (much lower CAPEX, price indexed on the Henry Hub and not on oil prices, tolling contracts, no destination clause. However, they cannot escape the rules of regional European and Asian markets, built on long-term oil-indexed contracts.

Differentiation

Although the potential export capacity approved by the FERC is just over 100 million tons per year, it is crucial to differentiate between the degree of cost-effectiveness of operational units that already have the required infrastructures, and for which investments have been all but amortized (20 million tons per year), units under construction (40 other million tons per year), for which sales contracts have already been negotiated, and long-term projects, for which investments have not yet been decided on (another 40 million tons per year).

Since the fall of 2014, the drop in oil prices has had an automatic knock-on effect on the price of gas on both the European and Asian markets.

Between 2014 and 2016, the price of gas in Europe dropped on average from $11 per MMBtu to $6 per MMBtu, whereas in Asia, LNG that was negotiated at over $15 per MMBtu in 2014, plummeted to under $7 per MMBtu in 2016. This new configuration fundamentally modified the degree of cost-effectiveness of future US LNG export projects.

For operational projects, or those under construction, for which most investments have already been made, the extent of cost-effectiveness depends on the marginal costs alone (gas price + OPEX covering transportation and regasification; these are, on average, around $5 per MMBtu in Europe and $6.7 per MMBtu in Asia.

US LNG therefore generates profit margins for an oil price of around $45 a barrel. For new projects, however, whose economic efficiency must be evaluated in view of the total costs (gas price + OPEX + CAPEX), the price of the barrel would have to exceed $70 for LNG suppliers to generate profit margins.

In other words, given the current crude oil prices, the cost of new US LNG projects is currently higher than the European and Asian gas prices, which explains why the start-up of new projects has been deferred. In the medium term, the potential production capacity should therefore be limited to projects that are already under way, i.e. 60 million tons per year.

In 2016, Russia produced 55.9 Bcf/day, and exported by gas pipeline one third of it, i.e. 18,2 Bcf/day, to three main clients: the European Union (75 percent), the former Soviet Republics (the Ukraine and Belarus – 13 percent) and Turkey (12 percent).

The Russians' main competitors on the European market are Norway, Algeria and, to a lesser extent, Nigeria and Libya.

Russia, however, is still a second order LNG producer with just 10 MTPA, exported to Japan from the Sakhalin Island and with the Yamal plant now onstream.

Due to high prices indexed on those of oil, a marked drop in electricity demand and a low economic growth, European gas consumption has decreased by over 15 percent in six years, from 47.6 Bcf/day in 2010 to 41 Bcf/day in 2016.

However, due to a continuous drop of its domestic production (North Sea and Netherlands) gas importation have strongly increased. But this increase was from pipeline and from Russia, whereas LNG has remained mostly marginal since representing 8 percent of the European global consumption in 2016.

Competitors

Compared with most of its competitors, Russian gas enjoys undeniable competitive advantages: very low production costs of less than $1 per MMBtu, heavy devaluation of the Ruble and marginal transportation costs owing to the existing gas pipeline network.

When transit rights are added to that, the average long-term cost is around $5 per MMBtu which makes Russian gas competitive with oil at around $43 a barrel.

In other words, only US LNG from existing liquefaction plants (breakeven point at $5.5 per MMBtu and $45/bbl) can compete with the Russian gas delivered to Europe.

However, the analysis confirms that US LNG from liquefaction plants in the project phase can be competitive on the European market only if there is a significant uplift in the price of oil, to take it above USD 70/bbl.

Moreover, even if Gazprom, whose model is intrinsically based on long-term contracts, does not look favorably on the liberalization of European markets, the Russian group has economic margins that are significant enough to protect its European markets. In particular, it can break with certain restrictive clauses by granting reductions to its European clients compared with the contractual prices indexed on barrel prices.

This strategy is already extensively applied on a considerable share of the volumes delivered by gas pipeline, two thirds of which are currently related to a spot market removed from oil prices.

Conversely, the European LNG market is still dominated by the OPE (Oil Price Escalation) mechanism indexed on oil prices.

Economics

Economically speaking, the Russians therefore have major levers to impose a price war on US LNG and counteract its entry into the European markets, both in the short term, by imposing prices lower than the indexed prices, and in the longer term, by deterring investment decisions.

In the wings of this latent price competition however, the Europeans do not want to jeopardize their energy security by amplifying their gas dependence on Russia.

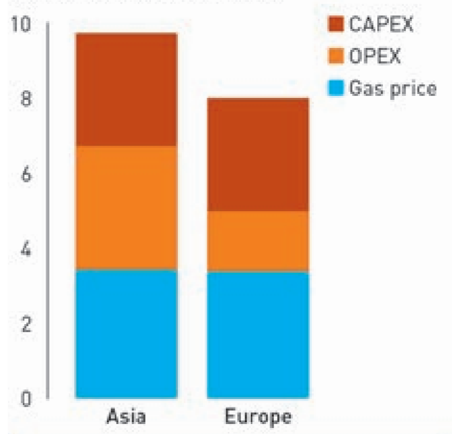
The idea of doubling the Nord Stream pipeline is therefore far from being widely endorsed by the European Counties. While the Russian and German authorities enthusiastically support the project, the Ukrainians, Slovaks, Czechs, Polish as well as the Baltic countries are opposed to it, as they consider it will automatically reinforce the EU's energy dependence on Russia.

According to its critics, it would be in contradiction with the EU's energy security policy based, among other things, on the diversification of supplies.

In spite of the agreement signed in April 2017 between Gazprom (50 percent) and five European companies (French Engie, British/Dutch Shell, Germans Uniper and Wintershall and Austrian OMV each 10 percent), the Nord Stream 2 project has yet to be fully approved.

This example shows that, in spite of proven competitiveness and significant levers on margins, geopolitical problems make the Russian gas strategy vulnerable against the potential US LNG market, and also against new Middle East resources from Iran, Israel and Egypt following the discovery of giant fields in the east Mediterranean.

Comparison of the average cost of "long-term"[14] US LNG delivered in Europe and in Asia at regional gas prices



OIL	EUROPE GAS	ASIA GAS
USD/bbl	USD/MBTU	USD/MBTU
110	11,2	15,3
50	5,6	7,5
30	3,8	4,9

The average cost of 'long-term' US LNG delivered in Europe and Asia

Build-up

Competition on the Asian markets Russian gas exports to Asia tentatively began in 2009 with the opening of the Sakhalin liquefaction plant and the shipment of LNG to Japan.

Moreover, they remain marginal in an LNG market (even after Yamal LNG) dominated by Qatar, Indonesia, Malaysia and even Australia, whose liquefaction capacities have increased significantly.

However, the competitiveness of Russian gas in Southeast Asia, China in particular, will depend essentially on the development of gas fields located in East Siberia (Chayanda and Kovytkta - 6 Bcf/day) and on the construction of two gas pipeline network in order to supply China.

Russia is building two pipelines. One from the East (the "Power of Siberia" project) will link Chayanda and Kovykta to the Sakhalin network and the Vladivostok terminal.

From the West the "Altai" pipeline project will connect the Chinese network to the fields located in western Siberia (Yamal peninsula and Urengoy).

The Russia-China gas contracts amount to $400 billion over 30 years and Russia should deliver to China more than 3 trillion cubic feet per annum of natural gas.

It should heavily displace coal in China, the consumer of half of the world's coal resources while emitting 30 percent of global greenhouse gases to fire Chinese power generation. ■

This article is based on extracts from a conference presentation entitled: "Competitiveness in the energy market: Will US Liquefied Natural Gas be able to compete with the Russian gas markets in the long term?". The Author of the paper is Philippe A. Charlez, Senior Technical Advisor, Total Exploration & Production

Golden Pass go-ahead will shape the future LNG strategies for Qatar Petroleum and ExxonMobil

Ceremony held in Washington DC was of special significance for the Arab Gulf and the US Gulf Coast

CEOs of ExxonMobil and Qatar Petroleum sign up to proceed with Texas liquefaction project

Qatar Petroleum and ExxonMobil finally made their investment decision to proceed with development of the Golden Pass LNG export project in Texas and awarded construction contracts to a US-Japanese consortium for work to begin within weeks and for the facility to be operational in 2024.

The decision to proceed was announced during a special ceremony held in Washington DC on February 5, attended by Rick Perry, the US Secretary of Energy, and Saad Sherida Al-Kaabi, the Minister of State for Energy Affairs in Qatar and who is also President and Chief Executive of Qatar Petroleum.

High value

Also in attendance were the ExxonMobil CEO Darren Woods and other senior executives from Qatar Petroleum, ExxonMobil and the Golden Pass LNG project.

It is estimated that the project will generate more than $35 billion of economic benefits in the US including federal, state and local tax revenues over the life of the project.

Speaking at the Washington ceremony, Al-Kaabi thanked Secretary Perry for being part of such an important event for the Arab Gulf nation.

"Your presence is a testament to the depth and strength of the strategic bilateral relations between the United States and the State of Qatar, and to the commitment of both sides for expanding and reinforcing bilateral cooperation in the field of energy," said Al-Kaabi.

An engineering consortium comprising McDermott and Zachry Group of the US and Japan's Chiyoda Corp. have been awarded the contract to build the plant.

"The extensive experience of ExxonMobil and Qatar Petroleum provides the expertise, resources and financial strength needed to construct and operate an integrated liquefaction and export facility in the US," added Woods.

Sabine-Neches

The Golden Pass project is located on the Sabine-Neches Waterway in Texas. It is 70 percent-owned by Qatar Petroleum while ExxonMobil holds the remaining 30 percent stake, having acquired 15 percent from former shareholder ConocoPhillips.

Originally designed as an import facility before the shale-gas revolution, Golden Pass will be reconfigured at a cost of more than $10 billion to export up to 15.6 million tonnes per annum of LNG.

"Golden Pass will provide an increased, reliable, long-term supply of liquefied natural gas to global gas markets, stimulate local growth and create thousands of jobs," said ExxonMobil CEO Woods.

Vertically-integrated

"It is expected to create about 9,000 jobs over the five-year construction period and more than 200 permanent jobs during operations," added Woods.

The Golden Pass regasification terminal, with its five storage tanks, two ship-loading berths and header pipeline, already includes much of the infrastructure needed for an export project, apart from the liquefaction Trains.

McDermott, Chiyoda and Zachry will perform engineering, procurement, construction and commissioning of three Trains, each with capacity to produce 5.2 MTPA.

"McDermott has extensive experience in executing major projects along the US Gulf Coast," said Richard Heo, McDermott's regional Senior Vice President.

"We will apply not only our vertically-integrated capabilities but also some of the best practices and lessons learned for major construction projects in the region," he explained.

"We will also leverage the existing relationships we have with our partners and our customers to ensure that the Golden Pass project is a success," stated the McDermott executive.

Golden Pass is part of ExxonMobil's plans to invest more than $50 billion over the next five years to build and expand manufacturing facilities in the US.

"This project builds upon the successful international relationship between ExxonMobil and Qatar Petroleum, with Qatar Petroleum joining ExxonMobil in exploration and development activities in Argentina, Brazil and Mozambique," said the US major.

The US Federal Energy Regulatory Commission has already approved the Golden Pass project, concluding that it "would result in some adverse environmental impact, though impacts would not be significant with implementation of proposed mitigation" by the developers and the regulators.

Analysts said that from a cost standpoint the timing of the FID and its Washington announcement was a prudent move.

Locked in costs

Proceeding with construction now will enable the project to lock in costs and minimise exposure to inflationary pressures before the next cycle of global LNG investment heats up.

By moving ahead now, the Qatar and ExxonMobil also ensure that Golden Pass will be at the forefront of the second wave of US LNG exports.

For the Qataris, Golden Pass offers Qatar Petroleum the opportunity to optimise shipping costs, particularly into Europe and Latin America.

The project further strengthens ExxonMobil's relationship with Qatar, the most valuable country in its global portfolio.

It additionally helps Qatar protect its market share as it seeks to leverage all its LNG assets in response to a changing market structure.

The Arab Gulf state can also proceed with confidence in developing its own LNG expansion at Ras Laffan by adding more than 30 MTPA to its current production of around 77 MTPA. The feed-gas will come from the prolific North Field gas resources and its adjoining

Basin whose other part owner is Gulf neighbour Iran.

There are key advantages for ExxonMobil as well. The company is the second-largest producer of natural gas in the Lower 48 and Golden Pass supports additional upstream supply development.

Expansion

ExxonMobil has extensive assets in the US Gulf Coast area and is the biggest leaseholder in the Permian Basin, owning properties as well as pipelines and petrochemical infrastructure and plants that extend from South Texas into Louisiana.

The FERC has also approved permits for the associated Golden Pass Pipeline linking the plant to the major pipelines bringing in shale-gas resources.

ExxonMobil's growing Gulf expansion programme consists of 11 major chemical, refining, lubricant and energy projects at proposed new and existing facilities along the Texas and Louisiana coasts.

In his speech at the Washington signing event, Al-Kaabi said that that the Golden Pass project was not Qatar's first investment in the US and it certainly would not be the last.

"It represents a significant part of the plans that Qatar Petroleum had announced to invest $20 billion in the US energy sector, which we believe would bring great benefits for both the United States and the State of Qatar," explained Al-Kaabi.

"This investment of over $10 billion is of particular importance as it is one of the largest single investment decisions in US LNG history," stated the QP CEO.

In his remark, Al-Kaabi also took the time to thank the US and ExxonMobil, which was the most important partner in helping Qatar become a prominent LNG exporting nation with all its economic benefits.

"I would like to take this opportunity to thank Darren Woods and the whole ExxonMobil organization for our successful long-term partnership," stated Al-Kaabi.

Execution

"I would also like to thank the management and staff of Golden Pass LNG, Chiyoda, McDermott and Zachry for all their efforts to get us to this important milestone. We will all continue working together towards the successful execution of this project, which will benefit the US economy and the neighboring local communities in the US Gulf Coast," he said.

" I would also like to thank the various state and federal agencies involved in the permitting and regulatory processes for their support," he added.

"The development of the Golden Pass LNG export facility enhances the depth and flexibility of our global LNG supply portfolio, and reinforces the position of the US as a key contributor to meeting the world's growing demand for LNG," he said.

In his concluding remarks, Al-Kaabi expressed his thanks to His Highness Sheikh Tamim Bin Hamad Al-Thani, The Emir of the State of Qatar, for his guidance and unwavering support for Qatar Petroleum.

"I would also like to thank the executive management team and employees of Qatar Petroleum for their hard work and dedication," stated Al-Kaabi.

US Energy Secretary Perry said the agreement to proceed with Golden Pass was the latest example of the vital partnership between the US and Qatar.

"This includes American universities putting campuses in Qatar, to our strategic military relationship, and of course, our collaboration in the energy sector," said Perry.

"The Golden Pass project is proof that two of the world's top energy producers can work together as allies to increase energy diversity, advance energy security, and support rather than subvert an open energy marketplace," added Perry.

ExxonMobil CEO Woods concluded that Qatar Petroleum and the US major had for decades successfully demonstrated their capabilities in the LNG and energy sectors.

"We look forward to bringing our shared expertise to bear at Golden Pass, which will help to provide low-cost, cleaner-burning natural gas to meet growing global energy demand and improve living standards," stated Woods. ■

Canadian authorities will seek high-level cuts in methane emissions at LNG plants and other energy installations

The Canadian Energy Research Institute has developed a modelling tool to assess reduction opportunities in the natural gas supply chain

The Canadian government, along with some provincial administrations, has set policies to cut methane emissions from between 40-45 percent of baseline value by the year 2025 and these regulations will affect pipelines and energy installations, including LNG liquefaction plants.

Canada has only three projects moving forward, all in the province of British Columbia. They comprise two small-scale ventures, Woodfibre LNG in the district of Squamish and Kwispaa LNG on Vancouver Island at Sarita Bay in the Alberni Inlet.

Scale

The third project is LNG Canada being developed by Royal Dutch Shell and its four partners, Mitsubishi Corp. of Japan, Malaysian energy company Petronas, Chinese major PetroChina and Korea Gas Corp.

The five companies had agreed in October 2018 to proceed with the joint venture and with construction of the export plant and its associated facilities at a cost of up to US$31 billion.

The liquefaction plant is to be constructed at a brownfield site near Kitimat that had been an energy products terminal before being acquired by Shell in 2011.

The plant itself is expected to cost around US$11Bln using modular construction methods and will have two large liquefaction Trains initially, with each producing 7 million tonnes per annum of LNG by 2025.

The plant would then be expanded.

> *The plant is expected to cost around US$11Bln using modular construction methods*

Additional costs of up to US$20Bln will include feed-gas supplies for TransCanada's Coastal GasLink pipeline and other facilities.

The Canadian Energy Research Institute, based in Calgary, Alberta, published an 86-page study in January 2019 on "Economic and Environmental Impacts of Methane Emissions Reduction in the Natural Gas Supply Chain".

Here are extracts of an overview of the Institute's findings:

Targeted

Baselines might differ between governments, but the overall targeted reductions by Canada are about 25 Mt CO_2e of methane emissions by 2025.

The gas supply chain can be broadly divided into upstream, midstream and downstream sectors where sources of methane emissions are identified, and mitigation technologies are assessed from wellhead to burner-tip.

Methane emissions from the sectors can be further grouped into source categories such as fugitives, flared, vented, line heating and burner-tip.

Liquefied natural gas production is considered in the Midstream section.

A significant percentage of the world's natural gas reserves are geographically isolated from energy markets. Transportation by pipeline is efficient for high volumes of consistent demand and shorter distances but lacks flexibility in demand and location. Instead, natural gas can be compressed and shipped.

To make shipping economically feasible, it is liquefied so that the energy density is much higher. Large quantities of natural gas are found in Australia, Algeria, Qatar, Iran, Malaysia, Brazil, Trinidad and Tobago, and Indonesia.

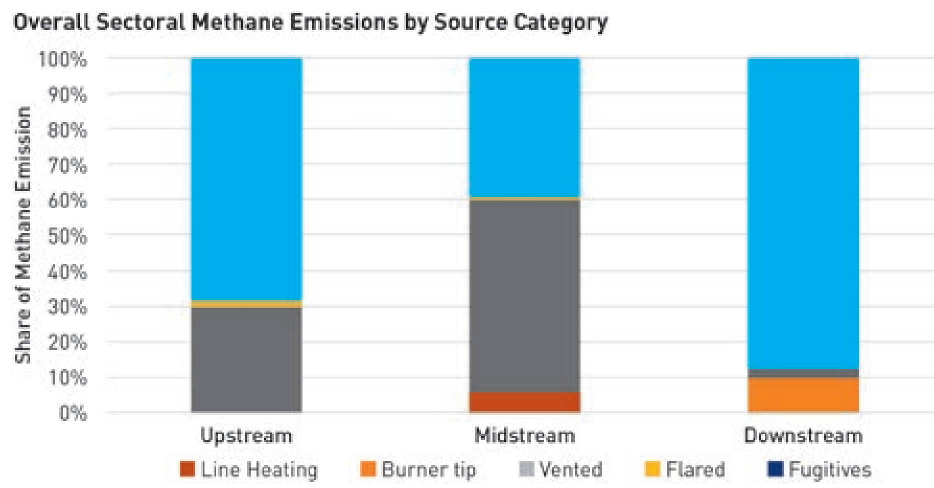
Process

Without LNG, all these gas fields would be stranded from markets by either politically bureaucratic or regulatory difficulties with transnational transmission or extremely large distances.

The liquefaction process involves cooling the gas to a temperature of approximately -160 C and then maintaining that temperature by storing the liquefied gas in cryogenic containers.

Prior to cooling, the gas must be processed to remove any impurities that will freeze, such as water, CO_2, H_2S, N_2 and heavy hydrocarbons. LNG is typically in the range of 95 to 100 percent methane; small quantities of impurities such as N_2, ethane and butane will not cause problems to the liquefaction process.

The Midstream section also includes transmission and storage.



Emissions from natural gas value chain are grouped into sources

Networks

Once processed, the gas is sent through long-distance pipeline networks, either nationally or transnationally. Gas may travel distances of hundreds or thousands of kilometres.

Therefore regular compression stations are required throughout the network to drive the gas and overcome pipeline friction. Transmission lines operate at up to approximately 1,450 psig (Tobin 2007).

In the storage overview it was noted that the demand for gas varies throughout the year, with winter in the northern hemisphere causing a surge in demand. As supply rates tend to be relatively inelastic, most countries have underground storage reservoirs that can be called upon to meet spikes in demand.

According to the Energy Information Agency (EIA 2015), the 2013 US storage capacity comprised 77 percent depleted gas reservoirs, 16 percent depleted aquifers and 7 percent salt caverns. A small percentage of the gas that is injected underground for storage cannot be recovered again later and is known as base gas.

Stored gas often picks up water during underground storage and therefore requires dehydration prior to being released back into the distribution network. It is therefore common for storage facilities to have both dehydration and compression facilities.

In line with the ongoing debate on the economic and environmental impacts of methane emissions from natural gas supply chains, the Canadian Energy Research Institute (CERI) developed a modelling tool, the Integrated CH_4 Emission Reduction Model (ICERM), with the objective to quantify methane emissions and assess reduction opportunities covering end-to-end of the Canadian natural gas supply chain.

ICERM has three modules for emission quantification, abatement cost analysis and optimized selection of mitigation technologies to meet emission reduction targets cost-effectively.

CERI used ICERM to quantify methane emissions from the Canadian natural gas supply chain in 2017 to be 47.5 million tonnes (Mt) CO_2e.

Western issues

Western provinces with more upstream oil and gas activities generate more emissions than eastern provinces where natural gas demand may be high but supplied from other provinces.

Alberta contributes more emissions than other provinces with an estimated total in 2017 of about 25.4 Mt CO_2e, of which the upstream sector is responsible for up to 96 percent of this number. These emissions are mainly from oil and gas wells and gathering facilities.

Similar to Alberta, the other western provinces (British Columbia, Saskatchewan and Manitoba) have higher upstream emission footprints with total estimated values of 3.6, 16.2, and 1.3 Mt CO2e respectively. Both upstream and midstream emissions from producing provinces are primarily of the fugitive and venting categories.

The downstream emissions are mostly from the fugitive and burner-tip source categories, both representing about 95 percent of downstream releases in most cases.

The eastern provinces do not have as much upstream oil and gas activities, so their emissions come from midstream and downstream segments of the gas supply chain where either imported gas or Canadian gas from other provinces is transported for distribution to various end-users.

As such, gas transmission and distribution emissions are the major sources. In these areas, midstream sector emissions are from fugitive releases and venting activities.

In Ontario, fugitive and vented emissions account for over 90 percent of total midstream emissions. Fugitive and burner- tip emissions due to undestroyed hydrocarbons at end-use dominate downstream sector emissions.

Fugitive

The fugitive emissions are often from distribution pipeline and customer metering losses. These account for about 95 percent of total downstream emissions.

The optimization module in ICERM combines emission quantification and abatement cost data to evaluate emission reduction and economic impacts of various policy scenarios. This study evaluated three different hypothetical policy scenarios to achieve emission reductions by adopting various combinations of mitigation technologies.

These scenarios are:

- Maximum reduction, which evaluated the economic cost and the maximum amount of emission reduction that can be achieved using the mitigation technologies assessed in this study.
- Uniform reduction, which evaluated the economic cost and emission reduction achieved if a 45 percent reduction target is assigned to each emitting device in the supply chain (except burner-tip emissions).
- Optimal reduction, which identifies a cost-effective mitigation pathway to reduce emissions to 45 percent of 2012 levels as reported by Canada in the National Inventory Report (this scenario is created to mimic federal methane regulation).

These scenarios are applied to the entire Canadian natural gas supply chain. This contrasts with the existing federal and provincial regulations which place methane emission reduction targets mainly in the upstream sector.

Omissions

In order to realize the most economic reductions in the optimal scenario, some of the emission source categories are omitted when choosing where mitigation should be deployed. These include emissions from midstream venting, upstream fugitives, compressors and surface casing vent flow.

Optimal emission reduction is calculated from the average of the results obtained using the lower and upper ranges of the abatement costs.

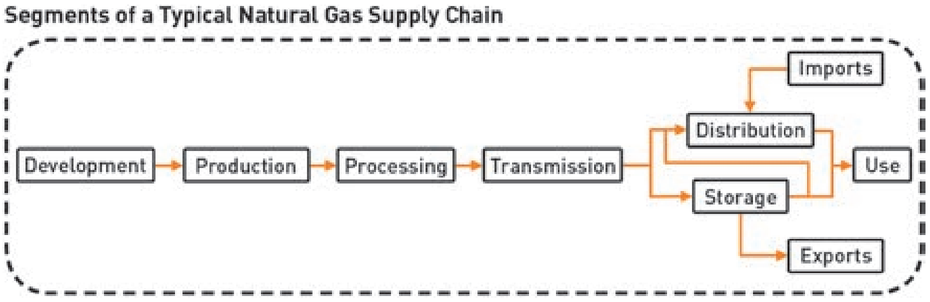
This scenario does not arbitrarily specify what emission sources should be controlled but uses linear programming to determine the cost-effective mitigation to meet expected reduction at both federal and provincial levels.

The reductions in the maximum and uniform scenarios are predominantly from upstream venting, fugitives and pneumatic pumps. In the optimal scenario, reductions are mainly from upstream venting and pneumatic devices including pumps, controllers and generic instrumentation.

At the provincial level, optimal (45 percent) reduction of emissions is based on contributions to total Canadian methane emissions during 2012.

Mitigation of emissions from surface casing vent flow (SCVF) and compressors are not done in the optimal adoption scenario due to their higher abatement costs.

Segments of a Typical Natural Gas Supply Chain



Segments of the natural gas supply chain that can be considered

Opportunities

Most emission reduction opportunities are identified from pneumatic, venting and fugitive sources under each mitigation scenario. Also, in line with the distribution of overall emissions across supply chain sectors, the upstream sector is the major source of the emissions where significant mitigation efforts are to be channelled to achieve deeper cuts in emission reductions.

The results summary showing total emission reductions and cost of achieving those reductions under the various abatement analysis scenarios for the entire Canadian natural gas supply chain.

For the three abatement scenarios, total cost of emissions reduction in the maximum reduction scenario is in the range of \$2.5 to \$5.3 billion, for a total methane emission reduction of about 38 Mt CO2e.

For the uniform scenario, the cost is in the range of \$1.4 to \$2.8 billion and total reduction of 21 Mt CO2e, whereas the optimal reduction scenario achieves about a 25 Mt CO2e emissions cut for a total cost range of \$0.4 to \$1.5 billion.

We note that these do not include costs of administration, measurement and reporting which are required by existing methane regulations in Canada.

The reductions in the maximum and uniform scenarios are predominantly from upstream venting, fugitives and pneumatic pumps. In the optimal scenario, reductions are mainly from upstream venting and pneumatic devices including pumps, controllers and generic instrumentation.

Provincial

At the provincial level, optimal (45 percent) reduction of emissions is based on contributions to total Canadian methane emissions during 2012.

Mitigation of emissions from surface casing vent flow (SCVF) and compressors are not done in the optimal adoption scenario due to their higher abatement costs.

Most emission reduction opportunities are identified from pneumatic, venting and fugitive sources under each mitigation scenario.

Also, in line with the distribution of overall emissions across supply chain sectors, the upstream sector is the major source of the emissions where significant mitigation efforts are to be channelled to achieve deeper cuts in emission reductions.

The provincial breakdown gives estimated methane emissions, required emission reductions and total abatement cost for an optimal implementation of emission reduction targets at the 45 percent reduction below 2012 levels.

The estimated total abatement cost for Alberta is C\$450 million (2017 dollars), for an emission reduction program focusing on upstream oil and gas emissions in line with current regulation, while this cost for British Columbia and Saskatchewan are about C\$70 and C\$205 million, respectively.

Options

In 2017, British Columbia produced 4.98 Bcf per day of natural gas, whereas Saskatchewan produced 0.51 Bcf per day. Saskatchewan generated more emissions than British Columbia over the same year due to higher oil production activities where associated gas is often emitted from upstream facilities.

In the case of Ontario, optimization of mitigation options is not performed because of the small number of source categories available in midstream and downstream supply chain sectors where most of the emissions in the province emanate from.

The 45 percent reduction in the optimized mitigation strategy applies to the provincial contribution to overall Canadian methane emissions in the baseline year.

Given the fewer source categories for Ontario's emissions, the emission sources to be mitigated in both the uniform and optimized reduction scenarios are essentially the same.

Hence, the abatement costs are also the same. Therefore, the total abatement cost of the uniform (45 percent) emission reduction scenario of C\$55 million is applied to Ontario. Moreover, upstream impacts of US gas imports into Ontario in 2017 of about 2.35 Bcf per day is not accounted for in the current model.

The Institute acknowledges that more accurate data for modelling will become available over time as new field measurements are reported. Hence, future versions of ICERM will incorporate updated information in order to improve the accuracy of results. ■

World LNG Carrier Fleet

LNG carrier	Capacity m³	Owned or Ordered by	Builder	Delivery Date	Flag	Power Plant	Cargo System	No. of tanks	Ship built for Export plant
Aamira	266,000	QGTC	Samsung	Dec-10	Liberia	DRL	TZ Mk. III	5	Qatargas IV
Abadi	135,000	Brunei Gas Carriers	Mitsubishi Nagasaki	Jun-02	Brunei	S	Moss	5	Brunei LNG
Abalamabie	174,900	Bonny Gas	Samsung	June-16	Bermuda	DFDE	TZ Mk III	4	Nigeria LNG
Adam LNG	162,000	Oman LNG	Hyundai	Dec-14	Marshall Is.	DFDE	TZ Mk. III	4	Oman LNG
Al Aamriya	210,100	J5 Consortium	Daewoo	Feb-08	Marshall Is.	DRL	GT NO 96	4	Qatargas
Al Areesh	151,700	Teekay LNG	Daewoo	Jan-07	Qatar	S	GT NO 96	4	Ras Gas II
Al Bahiya	210,185	QGTC	Samsung	Oct-09	Liberia	DRL	TZ Mk. III	5	Qatar-Atlantic
Al Biddah	135,275	J4 Consortium	Kawasaki Sakaide	Nov-99	Japan	S	Moss	5	Qatargas
Al Daayen	151,700	Teekay LNG	Daewoo	Apr-07	Qatar	S	GT NO 96	4	RasGas II
Al Dafna	266,000	QGTC	Samsung	Oct-09	Marshall Is.	LR DRL	GT NO 96	4	Qatar-Atlantic
Al Deebel	145,000	Peninsular LNG	Samsung	Dec-05	Bahamas	S	TZ Mk. III	4	Qatargas
Al Gattara	216,200	OSG/Nakilat	Hyundai	Oct-07	Marshall Is.	DRL	TZ Mk. III	4	Qatargas II
Al Ghariya	210,100	ProNav	Daewoo	Feb-08	Bahamas	DRL	GT No. 96	4	Qatargas
Al Gharaffa	216,200	OSG/Nakilat	Hyundai	Jan-08	Marshall Is.	DRL	TZ Mk. III	4	Various
Al Ghashamiya	216,000	QGTC	Samsung	Mar-09	Liberia	DRL	TZ Mk. III	4	Qatar-Atlantic Basin
Al Ghuwairiya	261,700	QGTC	Daewoo	Aug-08	Marshall Is.	DRL	GT NO. 96	5	Qatar-Atl'c Basin
Al Hamla	216,000	OSG	Samsung	Feb-08	Marshall Is.	DRL	TZ Mk. III	4	QatarGas
Al Hamra	137,000	National Gas Shipping	Kvaerner-Masa	Jan-97	Liberia	S	Moss	4	ADGAS
Al Huwaila	217,000	Teekay	Samsung	May-08	Bahamas	DRL	TZ Mk. III	4	RasGas III
Al Jasra	137,100	J4 Consortium	Mitsubishi Nagasaki	Jul-00	Japan	S	Moss	5	Qatargas
Al Jassasiya	145,700	Maran-Nakilat	Daewoo	May-07	Greece	S	GT No 96	4	RasGas
Al Kharaitiyat	216,200	QGTC	Hyundai	May-09	Liberia	DRL	TZ Mk. III	4	Qatargas III
Al Kharaana	210,000	QGTC	Daewoo	Oct-09	Marshall Is.	DRL	GT NO 96	4	Qatargas IV
Al Kharsaah	217,000	Teekay	Samsung	May-08	Bahamas	DRL	TZ Mk. III	4	RasGas III
Al Khattiya	210,000	QGTC	DSME	Oct-09	Marshall Is.	DRL	GT No. 96	4	Qatargas IV
Al Khaznah	135,500	National Gas Shipping	Mitsui Chiba	Jun-94	Liberia	S	Moss	5	ADGAS
Al Khor	137,350	J4 Consortium	Mitsubishi Nagasaki	Dec-96	Japan	S	Moss	5	Qatargas
Al Khuwair	217,000	Teekay LNG	Samsung	Jul-08	Korea	DRL	TZ Mk. III	4	RasGas
Al Mafyar	266,000	OSG/Nakilat	Hyundai	Oct-07	Marshall Is.	DRL	TZ Mk. III	4	Qatargas II
Al Marrouna	151,700	Teekay	Daewoo	Nov-07	Bahamas	S	GT NO 96		Ras Gas I
Al Mayeda	266,000	QGTC	Samsung	Jan-09	Liberia	DRL	TZ Mk. III	5	Qatar-US/Var.
Al Nuaman	210,000	QGTC	DSME	Dec-09	Marshall Is.	DRL	GT No. 96	4	Qatargas IV
Al Oraiq	210,000	J5 Consortium	Daewoo	Apr-08	Marshall Is.	DRL	GT No. 96	4	Various
Al Rayyan	135,360	J4 Consortium	Kawasaki Sakaide	Mar-97	Japan	S	Moss	5	Qatargas
Al Rekayyat	216,200	QGTC	Hyundai	Jun-09	Bahamas	DRL	TZ Mk.III	4	Qatar-Atlantic
Al Ruwais	210,100	ProNav	Daewoo	Nov-07	Germany	DRL	GT NO 96	4	Qatargas II
Al Sadd	210,100	QGTC	Daewoo	Mar-09	Liberia	DRL	GT NO 96	4	Qatar-Atlantic Basin
Al Safliya	210,100	ProNav	Daewoo	Dec-07	Bahamas	DRL	GT NO 96	4	Qatargas II
Al Sahla	216,200	J5	Hyundai	Jun-08	Japan	DRL	TZ Mk. III	4	Ras Gas III
Al Samriya	261,700	QGTC	Daewoo	Sep-08	Marshall Is.	DRL	GT NO. 96	5	Qatargas II
Al Sheehaniya	210,100	QGTC	Daewoo	Feb-09	Liberia	DRL	GT NO 96	4	Qatar-Atlantic Basin
Al Shamal	217,000	Teekay LNG	Samsung	Jun-08	Qatar	DRL	TZ Mk. III	4	RasGas
Al Thakhira	145,000	Peninsular LNG	Samsung	Sep-05	Bahamas	S	TZ Mk. III	4	Qatargas
Al Thumama	216,000	J5 Consortium	Hyundai	Apr-08	Japan	DRL	TZ Mk. III	4	Rasgas
Al Utouriya	215,000	J5	Hyundai	Sep-08	Panama	DRL	TZ Mk. III	4	RasGas
Al Utourma	215,000	J5	Hyundai	Sep-08	Panama	DRL	TZ Mk. III	4	Ras Gas III
Al Wajbah	137,350	J4 Consortium	Mitsubishi Nagasaki	Jun-97	Japan	S	Moss	5	Qatargas
Al Wakrah	135,360	J4 Consortium	Kawasaki Sakaide	Dec-98	Japan	S	Moss	5	Qatargas
Al Zhubarah	137,570	J4 Consortium	Mitsui Chiba	Dec-96	Japan	S	Moss	5	Qatargas
Alto Acrux	147,000	LNG Marine Transport	Mitsubishi	Mar-08	Bahamas	S	Moss	4	Various
Amali	148,000	Brunei-Shell	DSME	Jul-11	Brunei	DFDE	GT No. 96	4	Brunei LNG
Amanl	154,800	Brunei-Shell	Hyundai	Nov-14	Brunei	DFDE	TZ Mk. III	4	Brunei LNG
Aman Bintulu	18,928	Perbadanan / NYK Line	NKK Tsu	Oct-93	Malaysia	S	TZ Mk. III	3	Petronas
Aman Hakata	18,800	Perbadanan / NYK Line	NKK Tsu	Nov-98	Malaysia	S	TZ Mk. III	3	Petronas
Aman Sendai	18,928	Perbadanan / NYK Line	NKK Tsu	May-97	Malaysia	S	TZ Mk. III	3	Petronas
Arctic Aurora	160,000	Dynagas	Hyundai	Jul-13	Marshall Is.	DFDE	TZ Mk. III	4	Various
Arctic Discoverer	140,000	K Line	Mitsui Chiba	Jan-06	Bahamas	S	Moss	4	Various
Arctic Lady	147,200	MOL/Hoegh LNG	Mitsubishi Nagasaki	Apr-86	Norway	S	Moss	4	Various
Arctic Princess	147,200	MOL/Hoegh LNG	Mitsubishi Nagasaki	Jan-06	Norway	S	Moss	4	Various
Arctic Sun	89,880	Arctic LNG Shipping	IHI Chita	Dec-93	Liberia	S	IHI SPB	4	ConocoPhillips/Marathon
Arctic Voyager	140,000	K Line	Kawasaki	Jul-06	Bahamas	S	Moss	4	Statoil
Arkat	148,000	Brunei-Shell	DSME	Feb-11	Brunei	DFDE	GT. No. 96	4	Brunei LNG
Arwa Spirit	165,000	Teekay LNG	Samsung	Sep-08	Marshall Is.	DFDE	TZ Mk. III	4	Various
Aseem	154,850	K Line-Petronet	Samsung	Nov-09	Malta	S	GT No 96	4	Qatar-India
Asia Endeavour	160,000	Chevron	Samsung	Dec-14	Bahamas	DFDE	TZ Mk. III	4	Various
Asia Energy	160,000	Chevron	Samsung	Sept-14	Bahamas	DFDE	TZ Mk. III	4	Various
Asia Excellence	160,000	Chevron	Samsung	Sept-13	Bahamas	DFDE	TZ Mk. III	4	Various
Asia Venture	160,000	Chevron	Samsung	Sept-17	Bahamas	DFDE	TZ Mk. III	4	Various
Asia Vision	160,000	Chevron	Samsung	June-14	Bahamas	DFDE	TZ Mk. III	4	Various
Barcelona Knutsen	173,400	Knutsen	Daewoo	May-10	N.I.S.	DFDE	GT NO 96	4	Various
Bebatic	75,060	Brunei Shell Tankers	Atlantique	Oct-72	Brunei	S	TZ Mk. I	6	Brunei LNG
Beidou Star	172,000	MOL	Hudong	Oct-15	Hong Kong	DRL	GT NO. 96	4	Various
Berge Arzew	138,088	BW Gas	Daewoo	Jul-04	Norway	S	GT NO 96	4	Sonatrach
Boris Vilkitsky	172,000	Dynagas	Daewoo	Oct-17	Cyprus	DFDE	GT No. 96	4	Various
BW GDF-Suez Boston	138,059	BW Gas	Daewoo	Jan-03	Norway	S	GT NO 96	4	Suez LN

BW GDF Suez Everett	138,028	BW Gas	Daewoo	Jun-03	Norway	S	GT NO 96	4	Suez LNG
BW Integrity	170,000	BW Gas	Samsung	May-17	Singapore	DFDE	TZ Mk. III	4	FSRU
BW Pavilion Leeara	161,880	BW Gas	Hyundai	Feb-15	Singapore	DFDE	TZ Mk. III	4	Various
BW Pavilion Vanda	161,880	BW Gas	Hyundai	Feb-15	Singapore	DFDE	TZ Mk. III	4	Various
BW Singapore	170,000	BW Gas	Samsung	May-15	Singapore	DFDE	TZ Mk. III	4	FSRU
BW Suez Paris	162,400	BW Gas	Daewoo	May-09	N.I.S.	DFDE	GT NO 96	4	Yemen-Atlantic
Bilbao Knutsen	138,000	Knutsen / Marpetrol	IZAR Sestao	Jan-04	Spain	S	GT NO 96	4	Atlantic LNG
Bilis	77,730	Brunei Shell Tankers	La Seyne	Mar-75	Brunei	S	GT NO 82	5	Brunei LNG
Bishu Maru	162,000	K Line-Transpacific	Kawasaki Sakaide	Dec-15	Panama	S	Moss	4	Australia-Japan
British Diamond	155,000	BP Shipping	Hyundai	Sep-08	IOM	DFDE	TZ Mk. II	4	Indonesia-Various
British Emerald	155,000	BP Shipping	Hyundai	Jun-07	UK	DFDE	TZ Mk. III	4	Tangguh LNG
British Innovator	138,200	BP Shipping	Samsung	Jul-03	Isle of Man	S	TZ Mk. III	4	Various
British Merchant	138,000	BP Shipping	Samsung	Apr-03	Isle of Man	S	TZ Mk. III	4	Various
British Ruby	155,000	BP Shipping	Hyundai	Jan-08	U.K.	DFDE	TZ Mk. III	4	Various
British Sapphire	155,000	BP Shipping	Hyundai	Sep-08	IOM	DFDE	TZ Mk. III	4	Tangguh
British Trader	138,000	BP Shipping	Samsung	Dec-02	Isle of Man	S	TZ Mk. III	4	Engas
Broog	135,466	J4 Consortium	Mitsui Chiba	May-98	Japan	S	Moss	5	Qatargas
Bu Samara	266,000	QGTC	Samsung	Dec-08	Qatar	DRL	TZ Mk. III	5	Qatargas
BW Suez Paris	162,400	BW Gas	Daewoo	May-09	N.I.S.	DFDE	GT NO 96	4	Yemen-Atlantic
BW Suez Brussels	162,400	BW Gas	Daewoo	May-09	N.I.S.	DFDE	GT NO 96	4	Yemen-Atlantic
Cadiz Knutsen	138,826	Knutsen / Marpetrol	IZAR Puerto Real	Jun-04	Spain	S	GT NO 96	4	Engas
Cape Ann	145,000	Hoegh LNG/MOL	Samsung	May-10	Liberia	DFDE	TZ Mk. III	4	Various
Castillo de Santisteban	173,600	Elcano	STX	Aug-10	Malta	S	GT NO. 96		Various
Castillo de Villalba	138,000	Elcano	IZAR	Nov-03	Spain	S	GT NO 96	4	Sonatrach
Catalunya Spirit	138,000	Teekay LNG Partners	IZAR Sestao	Mar-03	Liberia	S	GT NO 96	4	Atlantic LNG
Celestine River	145,000	KLNG	Kawasaki	Dec-07	Bahamas	S	Moss		Various
Cesi Beihai	174,100	MOL-China LNG	Hudong	June-17	Hong Kong	S	GT No 96	4	Australia-China
Cesi Gladstone	174,100	MOL-China LNG	Hudong	Oct-16	Hong Kong	S	GT No 96	4	Australia-China
Cesi Lianyungang	174,100	MOL-China LNG	Hudong	June-18	Hong Kong	S	GT No 96	4	Australia-China
Cesi Qingdao	174,100	MOL-China LNG	Hudong	Nov-16	Hong Kong	S	GT No 96	4	Australia-China
Cesi Tianjin	174,100	MOL-China LNG	Hudong	Sept-17	Hong Kong	S	GT No 96	4	Australia-China
Challenger FSRU	263,000	MOL LNG	Daewoo	Oct-17	St Kitts	DFDE	GT No. 96	4	Various
Cheikh Bouamama	75,500	Skikda LNG Transport	USC	Jul-08	Bahamas	S	TZ Mk. III	4	Sonatrach
Cheikh El Mokrani	75,500	Med LNG Corp	USC	Jun-07	Bahamas	S	TZ Mk. III	4	Sonatrach
Christophe de Margerie	172,600	SCF	Daewoo	Nov-16	Cyprus	DFDE	GT NO 96	4	Various
Clean Energy	150,000	Dynagas	Hyundai	Mar-07	Marshall Is.	S	TZ Mk. III	4	Various
Clean Force	150,000	Dynagas	Hyundai	Jan-08	Marshall Is.	S	TZ Mk. III	4	Various
Clean Ocean	155,900	Dynagas	Hyundai	Mar-14	Marshall Is.	DFDE	TZ Mk. III	4	Various
Clean Planet	155,900	Dynagas	Hyundai	Mar-14	Marshall Is.	DFDE	TZ Mk. III	4	Various
Clean Vision	160,000	Dynagas	Hyundai	Jun-15	Marshall Is.	DFDE	TZ Mk. III	4	Various
Cool Explorer	160,000	Thenamaris	Samsung	Oct-13	Bermuda	DFDE	TZ Mk. III	4	Various
Cool Runner	160,000	Thenamaris	Samsung	May-14	Bermuda	DFDE	TZ Mk. III	4	Various
Cool Voyager	160,000	Thenamaris	Samsung	Oct-13	Bermuda	DFDE	TZ Mk. III	4	Various
Corcovado LNG	160,106	TMSC Gas	Daewoo	Jun-14	Malta	TFDE	GT No 96	4	Various
Creole Spirit	174,000	Teekay	Daewoo	Jan-16	Bahamas	MEGI-DF	NO. 96 GW	4	Cheniere
Cubal	160,400	Mitsui/NYK/Teekay	Samsung	Jan-12	Bahamas	DFDE	TZ Mk. III	4	Various
Cygnus Passage	145,400	Cygnus LNG	Mitsubishi	Feb-09	Panama	S	Moss	4	Various
Dapeng Moon	147,000	China Ships	Hudong	Jul-09	China	S	GT NO 96	4	Various
Dapeng Star	147,000	China Ships	Hudong	Nov-09	China	S	GT NO 96	4	Various
Dapeng Sun	147,000	China Ships	Hudong	Jul-07	China	S	GT NO 96	4	Woodside Energy
Diamond Gas Orchid	165,000	MOL-Jera	MHI-Nagasaki	Aug-18	Japan	S-gas	Moss	4	US-Japan
Diamond Gas Rose	165,000	MOL-Jera	MHI-Nagasaki	Aug-18	Japan	S-gas	Moss	4	US-Japan
Disha	136,000	Petronet LNG Ltd.	Daewoo	Jan-04	Malta	S	GT NO 96	4	Qatargas
Doha	137,350	J4 Consortium	Mitsubishi Nagasaki	Jun-99	Japan	S	Moss	5	Qatargas
Duhail	210,100	ProNav	Daewoo	Jan-08	Germany	DRL	GT NO 96	4	Various
Dukhan	135,000	J4 Consortium	Mitsui Chiba	Oct-04	Japan	S	Moss	4	Qatargas
Dwiputra	127,385	Humpuss Consortium	Mitsubishi Nagasaki	Mar-94	Bahamas	S	Moss	4	Pertamina
Ebisu	147,547	Golar LNG	Kawasaki	Sep-08	Bahamas	S	Moss	4	Various
Eduard Toll	172,000	Teekay-CLNG	Daewoo	Dec-17	Bahamas	MEGI-DF	GT No. 96	4	Various
Ejnan	145,000	4J	Samsung	Jan-07	Bahamas	S	TZ Mk. III		RasGas
Ekaputra	136,400	Humpuss Consortium	Mitsubishi Nagasaki	Jan-90	Liberia	S	Moss	5	Pertamina
Energy Advance	145,000	Tokyo LNG Tankers	Kawasaki Sakaide	Mar-05	Japan	S	Moss	4	Darwin
Energy Atlantic	159,924	Alpha	STX Jinhae	Sep-15	Malta	DFDE	No. 96	4	Various
Energy Confidence	155,000	Tokyo LNG Tankers	Kawasaki	Apr-09	Panama	S	Moss	4	Various
Energy Frontier	147,600	Tokyo LNG Tankers	Kawasaki Sakaide	Sep-03	Japan	S	Moss	4	Darwin
Energy Glory	165,000	Tokyo LNG Tankers	JMU	Sept-18	Japan	S	Moss	4	Various
Energy Horizon	177,000	Tokyo LNG Tankers	Kawasaki	Jul-11	Japan	S	Moss	4	Pluto LNG
Energy Navigator	147,000	Tokyo LNG Tankers	Kawasaki Sakaide	May-08	Japan	S	Moss	4	Various
Energy Progress	145,000	MOL	Kawasaki	Nov-06	Japan	S	Moss	4	Bayu Undan LNG
Esshu Maru	162,000	K Line-Transpacific	Kawasaki Sakaide	Dec-14	Panama	S	Moss	4	Australia-Japan
Excalibur	138,200	Exmar/ Excelerate	Daewoo	Oct-02	Belgium	S	GT NO 96	4	Various
Excel	138,106	Exmar/ MOL	Daewoo	Sep-03	Belgium	S	GT NO 96	4	Various
Excelerate	138,000	Exmar/Excelerate	Daewoo	Oct-06	Belgium	S	GT NO 96	4	Various
Excellence	138,000	GKFF Ltd.	Daewoo	May-05	Belgium	S	GT NO 96	4	Excelerate Energy
Excelsior	138,000	Exmar	Daewoo	Jan-05	Belgium	S	GT NO 96	4	Various
Exemplar	150,900	Excelerate	Daewoo	Jun-10	Belgium	S	GT NO 96	4	Various
Expedient	151,000	Excelerate	Daewoo	Nov-09	Belgium	S	GT NO 96	4	Various
Experience RV	174,000	Exmar/Excelerate	Daewoo	Jul-14	Marshall Is.	DFDE	GT NO 96		Various
Explorer	150,900	Exmar/Excelerate	Daewoo	Mar-08	Belgium	S	GT NO 96	4	Excelerate
Express	151,000	Exmar/Excelerate	Daewoo	May-09	Belgium	S	GT NO 96	4	Various
Exquisite	150,900	Excelerate	Daewoo	Sep-09	Belgium	S	GT NO 96	4	Various
Fedor Litke	172,636	Dynagas	Daewoo	Nov-17	Cyprus	DFDE	GT No. 96	4	Various

Flex Endeavour	173,400	Flex LNG	Daewoo	Jan-18	Marshall Is.	MEGI-DF	NO. 96 GW	4	Various
Flex Enterprise	173,400	Flex LNG	Daewoo	Jan-18	Marshall Is.	MEGI-DF	NO. 96 GW	4	Various
Flex Rainbow	174,000	Flex LNG	Samsung	July-18	Marshall Is.	MEGI-DF	NO. 96 GW	4	Various
Fraiha	210,100	J5 Consortium	Daewoo	Sep-08	Marshall Is.	DRL	GT NO 96	4	Qatargas
FSRU Independence	170,000	Hoegh	Hyundai	Feb-14	NIS	DFDE	TZ Mk. III	4	Various
FSRU Lampung	170,000	Hoegh	Hyundai	May-14	Indonesia	DFDE	TZ Mk. III	4	Various
Fuji LNG	147,895	TMSC Gas	Kawasaki	Jun-04	Malta	S	Moss	4	Various
Fuwairit	138,000	Peninsular LNG	Samsung	Jan-04	Bahamas	S	TZ Mk. III	4	RasGas II
Galea	134,425	Shell Shipping	Mitsubishi Nagasaki	Oct-02	Singapore	S	Moss	5	Shell
Galicia Spirit	140,620	Teekay LNG Partners	Daewoo	Jul-04	Liberia	S	GT NO 96	4	Engas
Gaselys	153,500	GdF/NYK	Atlantique	Mar-07	France	DFDE	CS 1	4	Engas
Gallina	134,425	Shell Shipping	Mitsubishi Nagasaki	Oct-02	Singapore	S	Moss	5	Shell
GasLog Chelsea	153,000	GasLog	Hanjin Korea	Dec-09	Panama	TFDE	TZ Mk. III	4	Various
Gaslog Geneva	174,000	GasLog	Samsung	Sept-16	Bermuda	TFDE	TZ Mk. III	4	Shell charter
Gaslog Gibraltar	174,000	GasLog	Samsung	Oct-16	Bermuda	TFDE	TZ Mk. III	4	Shell charter
Gaslog Glasgow	174,000	GasLog	Samsung	Jun-16	Bermuda	TFDE	TZ Mk. III	4	Shell charter
Gaslog Greece	174,000	GasLog	Samsung	Mar-16	Bermuda	TFDE	TZ Mk. III	4	Shell charter
GasLog Salem	165,000	GasLog	Samsung	Apr-15	Liberia	TFDE	TZ Mk. III	4	Various
GasLog Santiago	155,000	GasLog	Samsung	Mar-13	Liberia	TFDE	TZ Mk. III	4	Various
GasLog Saratoga	155,000	GasLog	Samsung	Dec-14	Bermuda	TFDE	TZ Mk. III	4	Various
Gaslog Savannah	155,000	GasLog	Samsung	May-10	Bermuda	DFDE	TZ Mk. III	4	Various
GasLog Seattle	155,000	GasLog	Samsung	Oct-13	Bermuda	TFDE	TZ Mk. III	4	Various
GasLog Shanghai	155,000	GasLog	Samsung	Jan-13	Liberia	TFDE	TZ Mk. III	4	Various
Gaslog Singapore	155,000	GasLog	Samsung	Jul-10	Bermuda	DFDE	TZ Mk. III	4	Various
Gaslog Skagen	155,000	GasLog	Samsung	Oct-13	Bermuda	DFDE	TZ Mk. III	4	Various
Gaslog Sydney	155,000	GasLog	Samsung	May-13	Bermuda	DFDE	TZ Mk. III	4	Various
GDF-Suez Global Energy	74,000	Gaz de France	Chantiers	Dec-06	France	DFDE	CS1	4	Sonatrach
GDF-Suez Point Fortin	154,200	LNG Japan	Imabari/Koyo	Feb-10	Panama	DFDE	TZ Mk. III	4	Various
Gemmata	138,100	Shell Shipping	Mitsubishi Nagasaki	Mar-04	Singapore	S	Moss	5	Shell
Ghasha	137,510	National Gas Shipping	Mitsui	Jun-95	Liberia	S	Moss	5	ADGAS
Gigira Laitebo	177,000	MOL-Itochu	Hyundai	Feb-09	Panama	DFDE	TZ Mk. III	4	Various
Golar Arctic	140,645	Golar LNG	Daewoo	Dec-03	Marshall Is.	S	GT NO 96	4	Shell Spot
Golar Bear	160,000	Golar	Samsung	Mar-14	Bermuda	DFDE	TZ Mk. III	4	Various
Golar Celsius	160,000	Golar LNG	Samsung	Sep-13	Bermuda	DFDE	TZ Mk. III	4	Various
Golar Crystal	160,000	Golar LNG	Samsung	Oct-13	Bermuda	DFDE	TZ Mk. III	4	Various
Golar Eskimo (FSRU)	160,000	Golar LNG	Samsung	Jan-15	Bermuda	DFDE	TZ Mk. III	4	Various
Golar Freeze	125,850	Golar LNG	HDW	Feb-77	UK	S	Moss	5	Various
Golar Glacier	162,000	Golar LNG	Hyundai	Sep-14	Marshall Is.	DFDE	TZ Mk. III	4	Various
Golar Grand	145,880	Golar LNG	Daewoo	2006	IoM		GT NO 96	4	Various
Golar Ice	160,000	Golar LNG	Samsung	Feb-15	Bermuda	DFDE	TZ Mk. III	4	Various
Golar Igloo (FSRU)	160,000	Golar LNG	Samsung	Oct-13	Bermuda	DFDE	TZ Mk. III	4	Various
Golar Kelvin	160,000	Golar LNG	Samsung	Jan-15	Bermuda	DFDE	TZ Mk. III	4	Various
Golar Maria	145,950	Golar LNG	Daewoo	2006	Marshall Is.		GT NO 96	4	Various
Golar Mazo	135,225	Golar LNG/CPP	Mitsubishi	Jan-00	Liberia	S	Moss	5	Pertamina
Golar Penguin	160,000	Golar LNG	Samsung	Mar-14	Marshall Is.	DFDE	TZ Mk. III	4	Various
Golar Seal	160,000	Golar LNG	Samsung	Aug-13	Bermuda	DFDE	TZ Mk. III	4	Various
Golar Singapore (FSRU)	160,000	Golar LNG	Samsung	June-15	Bermuda	DFDE	TZ Mk. III	4	Various
Golar Snow	160,000	Golar LNG	Samsung	Jan-15	Bermuda	DFDE	TZ Mk. III	4	Various
Golar Tundra (FSRU)	160,000	Golar LNG	Samsung	Dec-15	Bermuda	DFDE	TZ Mk. III	4	Various
Golar Viking	140,000	Golar LNG	Hyundai	Jan-05	Marshall Is.	S	Moss	4	Various
Golar Winter	138,250	Golar LNG	Daewoo	Apr-04	Marshall Is.	S	GT NO 96	4	Petrobras
Grace Acacia	150,000	Algaet Shipping	Hyundai	Jan-07	Japan	S	TK MK III	4	Various
Grace Barleria	150,000	Swallowtail Ship	Hyundai	Oct-07	Japan	S	TZ Mk. III	4	Various
Grace Cosmos	150,000	AGH Shipping	Hyundai	Mar-08	Japan	S	TZ Mk. III	4	Various
Grace Dahlia	177,000	Tokyo Gas	Kawasaki	Oct-13	Japan	S	Moss	4	Various
Gracilis	138,830	Golar LNG	Hyundai	Jan-05	Marshall Is.	S	TZ Mk III	4	Shell BG
Granatina	140,645	Shell Shipping	Daewoo	Dec-03	Singapore	S	GT NO 96	4	Shell
Grand Aniva	147,200	Sovcomflot/NYK	Mitsubishi	Jan-08	Japan	S	Moss	4	Various
Grand Elena	147,200	Sovcomflot/NYK	Mitsubishi	Oct-07	Japan	S	Moss	4	Various
Grand Mereya	147,200	Primorsk/MOL/K Line	Chiba	May-08	Japan	S	Moss	4	Sakhalin II
Hanjin Muscat	138,200	Hanjin Shipping	Hanjin	Jul-99	Panama	S	GT NO 96	4	Oman Gas
Hanjin Pyeong Taek	130,600	Hanjin Shipping	Hanjin	Sep-95	Panama	S	GT NO 96	4	Pertamina
Hanjin Ras Laffan	138,214	Hanjin Shipping	Hanjin	Jul-00	Panama	S	GT NO 96	4	QatarGas
Hanjin Sur	138,333	Hanjin Shipping	Hanjin	Jan-00	Panama	S	GT NO 96	4	Oman Gas
Hispania Spirit	140,500	Teekay LNG Partners	Daewoo	Sep-02	Spain	S	GT NO 96	4	Atlantic LNG
Hoegh Esperanza FSRU	170,000	Hoegh	Hyundai	April-18	Norway	DFDE	GTT MIII	4	Various
Hoegh Gallant FSRU	170,050	Hoegh LNG	Hyundai	May-14	Marshall Is.	DFDE	TZ Mk. III	4	chartered
Hoegh Giant FSRU	170,050	Hoegh LNG	Hyundai	Jan-18	Marshall Is.	DFDE	TZ Mk. III	4	various
Hoegh Grace FSRU	170,050	Hoegh LNG	Hyundai	May-15	Marshall Is.	DFDE	TZ Mk. III	4	various
Hyundai Aquapia	135,000	Hyundai MM	Hyundai	Mar-00	Panama	S	Moss	4	Oman Gas
Hyundai	135,000	Hyundai MM	Hyundai	Jan-00	Panama	S	Moss	4	RasGas
Hyundai Ecopia	145,000	Hyundai	Hyundai	Nov-08	Panama	S	TZ Mk. III	4	Various
Hyundai Greenpia	125,000	Hyundai MM	Hyundai	Nov-96	Panama	S	Moss	4	Pertamina
Hyundai Oceanpia	135,000	Hyundai MM	Hyundai	Jul-00	Panama	S	Moss	4	Oman Gas
Hyundai Technopia	135,000	Hyundai MM	Hyundai	Jul-00	Panama	S	Moss	4	RasGas
Hyundai Utopia	125,182	Hyundai MM	Hyundai	Jun-94	Panama	S	Moss	4	Pertamina
Iberica Knutsen	138,000	Knutsen OAS	Daewoo	Aug-06	Norway	S	GT 96	4	Gas Natural
Ibra LNG	147,100	Oman Gas	Samsung	Jun-06	Panama	S	TK Mk. III	4	Oman LNG
Ibri LNG	145,000	Oman Gas	Mitsubishi	Jul-06	Panama	S	TK Mk. III	4	Oman LNG
Ish	137,540	National Gas Shipping	Mitsubishi Nagasaki	Nov-95	Liberia	S	Moss	5	ADGAS
K Acacia	138,017	Korea Line	Daewoo	Jan-00	Panama	S	GT NO 96	4	Oman Gas
K Freesia	135,256	Korea Line	Daewoo	Jun-00	Panama	S	GT NO 96	4	RasGas

K Jasmine	145,700	Korea Line	Daewoo	Mar-08	Panama	S	GT NO 96	4	Kogas offtake
K Mugungwha	152,000	K Line	Daewoo	Nov-08	Panama	S	GT NO 96	4	Various
Kita LNG	160,106	TMSC Gas	Daewoo	Jun-14	Malta	TFDE	GT No 96	4	Various
Kotawaka Maru	125,200	J3 Consortium	Kawasaki Sakaide	Jan-84	Japan	S	Moss	5	Darwin
Kumul	172,000	MOL	Hudong	May-16	Hong Kong	DRL	GT NO. 96	4	PNG-Asia
Lalla Fatma N'Soumer	145,000	Algeria Nippon Gas	Kawasaki Sakaide	Dec-04	Bahamas	S	Moss	4	Various
Lijmilya	261,700	QGTC	Daewoo	Sep-08	Marshall Is.	DRL	GT NO. 96	5	Various
LNG Abalamabie	174,900	Bonny Gas	Samsung	Nov-16	Bermuda	DFDE	TZ Mk III	4	Nigeria LNG
LNG Abuja	126,530	Bonny Gas Transport	GD Quincy	Sep-80	Bahamas	S	Moss	5	Nigeria LNG
LNG Abuja II	174,900	Bonny Gas	Samsung	Oct 16	Bermuda	DFDE	TZ Mk III	4	Nigeria LNG
LNG Adamawa	141,000	Bonny Gas Transport	Hyundai	Jun-05	Bermuda	S	Moss	4	Various
LNG Akwa Ibom	141,000	Bonny Gas Transport	Hyundai	Nov-04	Bermuda	S	Moss	4	Various
LNG Aquarius	126,300	MOL/LNG Japan	GD Quincy	Jun-77	Marshall Is.	S	Moss	5	Various
LNG Barka	153,000	NYK	Kawasaki	Jan-09	Bahamas	S	Moss	4	Various
LNG Bayelsa	137,500	Bonny Gas Transport	Hyundai	Feb-03	Bermuda	S	Moss	4	Nigeria LNG
LNG Benue	145,700	BW Gas	Daewoo	Mar-06	Bermuda	S	GT NO 96	4	Nigeria LNG
LNG Bonny	177,000	Bonny Gas Transport	Hyundai	Oct-15	Bermuda	DFDE	TZ Mk III	4	Nigeria LNG
LNG Borno	149,600	NYK Line	Samsung	Aug-07	Japan	S	TZ Mk. III	4	Nigeria LNG
LNG Capricorn	126,300	MOL/LNG Japan	GD Quincy	Jun-78	Marshall Is.	S	Moss	5	Pertamina
LNG Cross River	141,000	Bonny Gas Transport	Hyundai	Sep-05	Bermuda	S	Moss	4	Various
LNG Dream	145,000	Osaka Gas	Kawasaki	Sep-06	Japan	S	Moss	4	Woodside Energy
LNG Ebisu	147,500	MOL	Kawasaki	Sep-08	Bahamas	S	Moss	4	Various
LNG Edo	126,530	Bonny Gas Transport	GD Quincy	May-80	Bahamas	S	Moss	5	Nigeria LNG
LNG Enugu	145,000	BW Gas	Daewoo	Oct-05	Bermuda	S	GT NO 96	4	Nigeria LNG
LNG Fimina	175,000	Bonny Gas Transport	Samsung	Oct-15	Bermuda	DFDE	TZ Mk III	4	Nigeria LNG
LNG Flora	127,700	J3 Consortium	Kawasaki Sakaide	Mar-93	Japan	S	Moss	4	Pertamina
LNG Fukurokuju	165,000	MOL	Kawasaki	June-15	Japan	S	Moss	4	Various
LNG Gemini	126,300	MOL/LNG Japan	GD Quincy	Sep-78	Marshall Is.	S	Moss	5	Pertamina
LNG Imo	148,300	BW Gas	Daewoo	Jun-08	Bermuda	S	GT NO 96	4	Nigeria LNG
LNG Jamal	135,330	Osaka Gas/J3 Consortium	Mitsubishi Nagasaki	Oct-00	Japan	S	Moss	5	Oman Gas
LNG Juno	177,300	MOL-Osaka	Mitsubishi	Oct-18	Marshall Is.	DFDE	Moss	4	Freeport LNG/Various
LNG Jupiter	145,000	NYK Line	Kawasaki	Jul-09	Bahamas	S	Moss	4	Various
LNG Jurojin	155,300	MOL	MHI Nagasaki	Nov-15	Japan	S	KM	4	Various
LNG Kano	148,471	BW Gas	Daewoo	Jan-07	Bermuda	S	GT No. 96	4	NLNG
LNG Lagos	177,000	Bonny Gas	Hyundai	Oct-15	Bermuda	DFDE	TZ Mk III	4	Nigeria LNG
LNG Leo	126,400	MOL/LNG Japan	GD Quincy	Dec-78	Marshall Is.	S	Moss	5	Pertamina
LNG Lerici	65,000	Exmar	Italcantieri Sestri	Mar-98	Italy	S	GT NO 96	4	Sonatrach
LNG Libra	126,400	Hoegh LNG	GD Quincy	Apr-79	Marshall Is.	S	Moss	5	Various
LNG Lokoja	148,300	BW Gas	Daewoo	Dec-06	Bermuda	S	GT No. 96	4	Nigeria LNG
LNG Mars	155,000	MOL/Osaka Gas	Mitsubishi	Oct-16	Marshall Is.	S	Moss	5	Various
LNG Ogun	148,300	NYK Line	Samsung	Aug-07	Japan	S	TZ Mk. III	4	Nigeria LNG
LNG Ondo	148,300	BW Gas	Daewoo	Sep-07	Bermuda	S	GT NO 96	4	Nigeria LNG
LNG Oyo	140,500	BW Gas	Daewoo	Dec-05	Bermuda	S	GT NO 96	4	Nigeria LNG
LNG Pioneer	138,000	MOL	Daewoo	Jul-05	Bahamas	S	GT No 96	4	Idku
LNG Port Harcourt	175,000	Bonny Gas	Samsung	Oct-15	Bermuda	DFDE	TZ Mk III	4	Nigeria LNG
LNG Portovenere	65,000	Exmar	Italcantieri Sestri	Jun-96	Italy	S	GT No 96	4	Sonatrach
LNG River Niger	141,000	Bonny Gas Transport	Hyundai	May-06	Bermuda	S	Moss	4	Various
LNG River Orashi	145,910	BW Gas	Daewoo	Nov-04	Bermuda	S	GT No 96	4	Nigeria LNG
LNG Rivers	137,231	Bonny Gas Transport	Hyundai	Jun-02	Bermuda	S	Moss	4	Nigeria LNG
LNG Saturn	153,000	MOL	MHI	Nov-15	Japan	S	Moss	4	Various
LNG Sokoto	137,231	Bonny Gas Transport	Hyundai	Aug-02	Bermuda	S	Moss	4	Nigeria LNG
LNG Taurus	126,300	MOL/LNG Japan	GD Quincy	Aug-79	Marshall Is.	S	Moss	5	Various
LNG Venus	155,000	Osaka/MOL	MHI	Oct-14	Japan	S	Moss	4	Various
LNG Vesta	127,547	Tokyo Gas Consortium	Mitsubishi Nagasaki	Jun-94	Japan	S	Moss	4	Pertamina
LNG Virgo	126,400	MOL/LNG Japan	GD Quincy	Dec-79	Marshall Is.	S	Moss	5	Pertamina
Lobito	160,400	Mitsui/NYK/Teekay	Samsung	Oct-11	Bahamas	DFDE	TZ Mk. III	4	Various
Lusail	138,000	Peninsular LNG	Samsung	May-05	Bahamas	S	TZ Mk. III	4	Qatar
Macoma	173,400	Teekay	Daewoo	Oct-17	Bahamas	DFDE	GT No. 96	4	Various
Madrid Spirit	138,000	Teekay LNG Partners	IZAR Puerto Real	Jan-05	Spain	S	GT No 96	4	Engas
Magdala	173,400	Teekay	Daewoo	Feb-18	Bahamas	DFDE	GT No 96	4	Various
Magellan Spirit	165,500	Teekay LNG Partners	Samsung	Sep-08	Denmark	DFDE	TZ Mk. III	4	Various
Malanje	160,400	Mitsui/NYK/Teekay	Samsung	Jul-11	Bahamas	DFDE	TZ Mk. III	4	Various
Maran Gas Achilles	174,000	Maran	Hyundai Samho	Feb-16	Greece	DFDE	GT No 96	4	Various
Maran Gas Agamemnon	174,000	Maran	Hyundai Samho	May-16	Greece	DFDE	GT No 96	4	Various
Maran Gas Alexandria	161,870	Maran	Hyundai Samho	Sep-15	Greece	DFDE	TZ Mk. III	4	Various
Maran Gas Amphipolis	173,400	Maran	Daewoo	Aug-16	Greece	DFDE	GT No 96	4	Various
Maran Gas Apollonia	161,870	Maran	Daewoo	Jan-14	Greece	DFDE	GT No 96	4	Various
Maran Gas Asclepius	145,000	Kristen Navigation	Daewoo	Jul-05	Bermuda	S	GT No 96	4	Qatar
Maran Gas Coronis	145,700	Maran	Daewoo	Sep-07	Greece	S	GT No 96	4	Rasgas II
Maran Gas Delphi	159,800	Maran	Daewoo	Feb-14	Greece	DFDE	GT No 96	4	Various
Maran Gas Efessos	159,800	Maran	Daewoo	Jun-14	Greece	DFDE	GT No 96	4	Various
Maran Gas Hector	174,000	Maran	Hyundai Samho	Nov-16	Greece	DFDE	GT No 96	4	Various
Maran Gas Lindos	159,800	Maran	Daewoo	Jun-15	Greece	DFDE	GT No. 96	4	Various
Maran Gas Mystras	155,900	Maran Gas	Daewoo	May-15	Greece	DFDE	GT No 96	4	Various
Maran Gas Olympias	174,500	Maran	DSME	Feb-17	Greece	DFDE	GT No 96	4	Various
Maran Gas Pericles	174,000	Maran	Hyundai Samho	June-16	Greece	DFDE	GT No 96	4	Various
Maran Gas Posidonia	161,870	Maran	Daewoo	May-14	Greece	DFDE	GT No 96	4	Various
Maran Gas Roxana	173,400	Maran	Daewoo	Jan-17	Greece	DFDE	GT No 96	4	Various
Maran Gas Sparta	161,870	Maran	Hyundai Samho	April-15	Greece	DFDE	G TZ Mk. III	4	Various
Maran Gas Spetses	174,000	Maran	Daewoo	Feb-18	Greece	DFDE	GT No 96	4	Various
Maran Gas Troy	155,900	Maran Gas	Daewoo	May-15	Greece	DFDE	GT No 96	4	various
Maran Gas Ulysses	174,000	Maran	Hyundai Samho	Jan-17	Greece	DFDE	GT No 96	4	Various

Maria Energy	174,000	Tsakos	Hyundai	Mar-15	Marshall Is.	TFDE	GTT Mk II	4	Various
Marib Spirit	165,000	Teekay LNG	Samsung	May-08	Marshall Is.	DFDE	TZ Mk. III	4	Various
Marvel Eagle	155,000	MOL-Osaka	Kawasaki	Sept-18	Marshall Is.	S	Moss	4	Cameron LNG/Various
Matthew	126,540	Suez LNG Shiping	Newport News	Jun-79	Bahamas	S	TZ Mk. I	6	Atlantic LNG
Mekaines	266,000	Naklilat	Samsung	Mar-09	Liberia	DRL	GT No 96	4	Qatar-Atlantic Basin
Meridian Spirit	165,500	Teekay LNG	Samsung	Jan-10	Denmark	DFDE	TZ Mk. III	4	Various
Mesaimeer	210,100	Naklilat	Hyundai	Mar-09	Liberia	DRL	GT No 96	4	Qatar-Atlantic Basin
Methane Alison Victoria	145,000	GasLog	Samsung	Aug-07	Bermuda	S	TZ III	4	Eq.Guinea LNG
Methane Becki Anne	170,000	GasLog	Samsung	Sep-10	Bermuda	TFDE	TZ Mk. III	4	Various
Methane Heather Sally	145,000	GasLog	Samsung	Jul-07	Bermuda	S	Tz Mk. III	4	Eq.Guinea LNG
Methane Jane Elizabeth	145,000	GasLog	Samsung	Jun-06	Bermuda	TFDE	TZ Mk. III	4	Engas
Methane Julia Louise	170,000	GasLog	Samsung	Dec-09	Bermuda	TFDE	TZ Mk. III	4	Various
Methane Kari Elin	138,200	Shell	Samsung	Jun-04	Bermuda	S	TZ Mk. III	4	Various
Methane Lake Charles	145,000	Shell	Samsung	Feb-07	Bermuda	S	TZ Mk. III	4	Marathon Oil
Methane Lydon Volney	145,000	Shell	Samsung	Aug-06	Bermuda	S	TZ Mk. III	4	Engas
Methane Mickie Harper	170,000	Shell-GasLog	Samsung	Nov-10	Bermuda	TFDE	TZ Mk. III	4	Various
Methane Nile Eagle	145,000	Shell-GasLog	Samsung	Dec-07	Bermuda	S	TZ Mk. III	4	Engas
Methane Patricia Camila	170,000	Shell-GasLog	Samsung	Oct-10	Bermuda	TFDE	TZ Mk. III	4	Various
Methane Princess	138,159	Golar LNG	Daewoo	2003	UK	S	GT No 96	4	Spot BG
Methane Rita Andre	145,000	GasLog	Samsung	Mar-06	Bermuda	S	TZ Mk. III	4	Engas
Methane Shirley Elizabeth	145,000	GasLog	Samsung	Apr-07	Bermuda	S	TZ Mk. III	4	Marathon Oil
Methane Sprit	165,000	Teekay LNG	Samsung	Mar-08	Singapore	DFDE	TZ Mk. III	4	Various
Milaha Qatar	145,000	Milaha	Samsung	Apr-06	Denmark	S	TZ Mk. III	4	Qatar
Milaha Ras Laffan	138,270	Milaha	Samsung	Mar-04	Denmark	S	TZ Mk. III	4	RasGas II
Min Lu	147,000	China Ships	Hudong	Aug-09	China	S	GT No 96	4	Various
Min Rong	147,000	China LNG Ships	Hudong	Feb-09	Hong Kong	S	GT No 96	4	Australia-China
Mourad Didouche	126,130	Hyproc Shipping	Atlantique	Jul-80	Algeria	S	GT No 85	5	Sonatrach
Mozah	266,000	QGTC	Samsung	Aug-08	Qatar	DRL	TZ Mk III	5	Qatargas II
Mraweh	137,000	National Gas Shipping	Kvaerner-Masa	Jun-96	Liberia	S	Moss	4	ADGAS
Mubaraz	137,000	National Gas Shipping	Kvaerner-Masa	Jan-96	Liberia	S	Moss	4	Various
Muraq	210,100	J5-K Line	Daewoo	May-08	Marshall Is.	DRL	GT No 96	4	Qatar-Atlantic Basin
Murex	173,400	Teekay	Daewoo	Oct-17	Bahamas	DFDE	GT No 96	4	Various
Murwab	210,100	J5 Consortium	Daewoo	May-08	Marshall Is.	DRL	GT No. 96	4	Qatargas
Muscat LNG	149,170	Oman Gas/MOL	Kawasaki Sakaide	Mar-04	Japan	S	Moss	4	Oman Gas
Neo Energy	149,700	Tsakos	Hyundai	Feb-07	Liberia	S	GTT Mk II	4	Various
Neptune	145,000	Hoegh LNG/MOL	Samsung	Dec-09	Liberia	DFDE	TZ Mk. III	4	Various
Nizwah LNG	145,000	Oryx LNG Carriers	Kawasaki Sakaide	Dec-05	Japan	S	Moss	4	Oman Gas
Northwest Sanderling	127,525	Australia LNG	Mitsubishi Nagasaki	Jun-89	Australia	S	Moss	4	NWS
Northwest Sandpiper	127,500	Australia LNG	Mitsui Chiba	Feb-93	Australia	S	Moss	4	NWS
Northwest Seaeagle	127,450	Australia LNG	Mitsubishi Nagasaki	Nov-92	Bermuda	S	Moss	4	NWS
Northwest Shearwater	127,500	Australia LNG	Kawasaki Sakaide	Sep-91	Bermuda	S	Moss	4	NWS
Northwest Snipe	127,747	Australia LNG	Mitsui Chiba	Sep-90	Australia	S	Moss	4	NWS
Northwest Stormpetrel	127,600	Australia LNG	Mitsubishi Nagasaki	Dec-94	Australia	S	Moss	4	NWS
Northwest Swallow	127,708	J3 Consortium	Mitsui Chiba	Nov-89	Japan	S	Moss	4	NWS
Northwest Swan	138,000	Australia LNG	Daewoo	Mar-04	Australia	S	GT NO 96	4	NWS
Northwest Swift	127,590	J3 Consortium	Mitsubishi Nagasaki	Sep-89	Japan	S	Moss	4	NWS
Noshu Maru	180,000	MOL-Jera	MHI-Nagasaki	Feb-19	Japan	S-gas	Moss	4	US-Japan
Oak Spirit	173,400	Teekay	Daewoo	Jan-16	Bahamas	MEGI-DF	NO. 96 GW	4	Cheniere
Ob River	150,000	Lance Shipping	Hyundai	Oct-07	Marshall Is.	S	TZ Mk. III	4	Various
Onaiza	210,100	Nakilat	Daewoo	Apr-09	Liberia	DRL	GT NO 96	4	Qatar-Atlantic Basin
Ougarta	171,866	Hyproc Shipping	Hyundai	Mar-17	Algeria	DFDE	GTT Mk III	4	Sonatrach
Pacific Arcadia	147,200	NYK Line	MHI	Oct-14	Bahamas	S	KM	4	Various
Pacific Breeze	182,000	K Line	Kawasaki	Mar-18	Marshall Is.	DFDE	Moss	4	Ichthys LNG
Pacific Enlighten	145,000	LNG MT	Mitsubishi	Mar-09	Japan	S	Moss	4	Various
Pacific Eurus	137,000	LNG Marine Transport	Mitsubishi Nagasaki	Mar-06	Bahamas	S	Moss	4	Darwin
Pacific Mimosa	155,300	NYK Line	MHI	Nov-17	Bahamas	S	Moss	4	Australia-Japan
Pacific Notus	137,006	Pacific LNG Shipping	Mitsubishi Nagasaki	Sep-03	Bahamas	S	Moss	5	Darwin
Palu LNG	160,106	TMSC Gas	Daewoo	Jun-14	Malta	TFDE	GT No 96	4	Various
Pan Americas	174,000	Teekay	Hudong	Mar-18	Hong Kong	TFDE	No. 96 GW	4	US-Asia
Pan Asia	174,000	Teekay	Hudong-Zhonghua	July-17	Bahamas	TFDE	NO. 96 GW	4	Cheniere
Pan Europe	174,000	Teekay	Hudong	Sept-18	Hong Kong	TFDE	No. 96 GW	4	US-global
Papua	171,800	MOL-China	Hudong	Jan-15	Hong Kong	DFDE	SSD	4	PNG LNG
Polar Eagle	89,880	Polar LNG	IHI Chita	Jun-93	Liberia	S	IHI SPB	4	ConocoPhillips/Marathon
Prachi	173,000	NYK-SCI	Hyundai	Nov-16	Singapore	TFDE	GT No 96	4	Petronet
Provalys	153,500	Gaz de France	Chantiers	Nov-06	France	DFDE	CS1	4	ELNG
Pskov	170,200	SovComFlot	STX	Mar-14	Liberia	DFDE	GT No. 96	4	Various
Puteri Delima	130,400	MISC	Atlantique	Jan-95	Malaysia	S	GT NO 96	4	Petronas
Puteri Delima Satu	137,100	MISC	Mitsui Chiba	Apr-02	Malaysia	S	GT NO 96	4	Petronas
Puteri Firuz	130,400	MISC	Atlantique	May-97	Malaysia	S	GT NO 96	4	Petronas
Puteri Firuz Satu	137,100	MISC	Mitsubishi Nagasaki	Sep-04	Malaysia	S	GT NO 96	4	Petronas
Puteri Intan	130,400	MISC	Atlantique	Aug-94	Malaysia	S	GT NO 96	4	Petronas
Puteri Intan Satu	137,100	MISC	Mitsubishi Nagasaki	Dec-01	Malaysia	S	GT NO 96	4	Petronas
Puteri Mutiera Satu	137,100	MISC	Mitsui Chiba	Apr-05	Malaysia	S	GT NO 96	4	Petronas
Puteri Nilam	130,400	MISC	Atlantique	Jun-95	Malaysia	S	GT NO 96	4	Petronas
Puteri Nilam Satu	137,100	MISC	Mitsubishi Nagasaki	Sep-03	Malaysia	S	GT NO 96	4	Petronas
Puteri Zamrud	130,400	MISC	Atlantique	May-96	Malaysia	S	GT NO 96	4	Petronas
Puteri Zamrud Satu	137,100	MISC	Mitsui Chiba	Apr-87	Malaysia	S	GT NO 96	4	Atlantic LNG
Raahi	136,000	Petronet LNG Ltd	Daewoo	Dec-04	Malta	S	GT NO 96	4	Qatargas
Ramdane Abane	126,130	Hyproc Shipping	Atlantique	Jul-81	Algeria	S	GT NO 85	5	Sonatrach
Rasheeda	266,000	QGTC	Samsung	Jun-10	Liberia	DRL	TZ Mk. III		Various
Ribera del Duero Knutsen	173,400	Knutsen	Daewoo	Nov-10	Nor-NIS	DFDE	GT NO. 96	4	Various
Rioja Knutsen	176,300	Knutsen	Daewoo	Dec-16	Nor-NIS	DFDE	TZ Mk III	4	Various

Salalah LNG	147,000	Oman Gas/MOL	Samsung	Dec-05	Japan	S	TZ Mk. III	4	Oman
SCF Polar	71,500	Sovcomflot	Kockums	Aug-69	Liberia	S	GT NO 82	6	Sonatrach
Seishu Maru	162,000	K Line-Transpacific	Kawasaki Sakaide	Jan-15	Panama	S	Moss	4	Australia-Japan
Seri Alam	138,000	MISC	Samsung	Oct-05	Malaysia	S	TZ Mk. III	4	Yemen LNG
Seri Amanah	145,000	MISC	Samsung	Mar-06	Malaysia	S	TZ Mk. III	4	Yemen LNG
Seri Anggun	145,000	MISC	Samsung	Nov-06	Malaysia	S	TZ Mk. III	4	Yemen LNG
Seri Angkasa	145,000	MISC	Samsung	Feb-07	Malaysia	S	TZ Mk. III	4	Petronas
Seri Ayu	145,000	MISC	Samsung	Oct-07	Malaysia	S	TZ Mk. III	4	Various
Seri Bakti	152,300	MISC	Mitsubishi	Mar-07	Malaysia	S	GT NO 96	4	Petronas
Seri Balhaf	152,000	MISC	Mitsubishi	Sep-08	Malaysia	S	GT NO 96	4	Various
Seri Balquis	152,000	MISC	Mitsubishi	Dec-08	Malaysia	S	GT NO 96	4	Various
Seri Begawan	152,300	MISC	Mitsubishi	Dec-07	Malaysia	S	GT NO 96	4	Various
Seri Bijaksana	152,300	MISC	Mitsubishi	Feb-08	Malaysia	S	GT NO 96	4	Petronas
Seri Camar	150,200	MISC	Hyundai	Feb-18	Malaysia	S	Moss	4	Petronas
Seri Camellia	150,000	MISC	Hyundai	Nov-16	Malaysia	S	Moss	4	Petronas
Seri Cemara	150,200	MISC	Hyundai	Apr-18	Malaysia	S	Moss	4	Petronas
Seri Cempak	150,200	MISC	Hyundai	Feb-18	Malaysia	S	Moss	4	Petronas
Seri Cenderawasih	150,000	MISC	Hyundai	Jan-17	Malaysia	S	Moss	4	Petronas
Sestao Knutsen	138,000	Knutsen	IZAR Sestao	Jan-07	Spain	S	GT NO 96	4	Atlantic LNG
Sevilla Knutsen	173,400	Knutsen	Daewoo	Jun-10	N.I.S.	DFDE	GT NO 96	4	Various
Shahamah	135,500	National Gas Shipping	Kawasaki Sakaide	Oct-94	Liberia	S	Moss	5	ADGAS
Shangra	266,000	QGTC	Samsung	Nov-09	Liberia	DRL	TZ Mk. III	5	Qatargas IV
Shen Hai	147,100	China LNG	Hudong Zhonghua	Sep-12	China	AB/CC Steam	GT NO 96	4	Various
Simaisma	147,700	Maran Gas Maritime	Daewoo	Jul-06	Greece	S	GT No 96	4	Qatar
SK Audace	180,000	SK-Marubeni	Samsung	Jul-17	Panama	DFDE	TZ Mk. III	4	Various
SK Splendor	138,375	SK Shipping	Samsung	Mar-00	Panama	S	TZ Mk. III	4	Oman Gas
SK Stellar	138,375	SK Shipping	Samsung	Dec-00	Panama	S	TZ Mk. III	4	RasGas
SK Summit	138,000	SK Shipping	Daewoo	Aug-99	Panama	S	GT NO 96	4	RasGas
SK Sunrise	138,306	I. S. Carriers	Samsung	Sep-03	Panama	S	TZ Mk. III	4	RasGas
SK Supreme	138,200	SK Shipping	Samsung	Jan-00	Panama	S	TZ Mk. III	4	RasGas
Sohar LNG	137,250	Oman Gas/ MOL	Mitsubishi Nagasaki	Oct-01	Malta	S	Moss	5	Oman Gas
Solaris	155,000	GasLog	Samsung	Jul-14	Bermuda	TFDE	TZ Mk. III	4	Various
Sonangol Benguela	160,500	Sonangol	Daewoo	Sep-11	Bahamas	S	GT No. 96	4	Angola LNG
Sonangol Etosha	160,500	Sonangol	Daewoo	Sep-11	Bahamas	S	GT No. 96	4	Angola LNG
Sonangol Sambizanga	160,500	Sonangol	Daewoo	Sep-11	Bahamas	S	GT No. 96	4	Angola LNG
Southern Cross	172,000	MOL	Hudong	May-15	Hong Kong	DRL	GT NO. 96	4	Various
Soyo	160,400	Mitsui/NYK/Teekay	Samsung	May-11	Bahamas	DFDE	TZ Mk. III	4	Various
Spirit of Hela	177,000	MOL	Hyundai	Oct-09	Panama	DFDE	TZ Mk. III	4	Various
Stena Blue Sky	145,700	Stena	Daewoo	Jan-06	Panama	S	GT No 96	4	Various
Stena Clear Sky	171,800	Stena	Daewoo	Sep-10	Panama	DFDE	GT NO 96	4	Various
Stena Crystal Sky	171,800	Stena	Daewoo	Jul-10	Panama	DFDE	GT NO 96	4	Various
STX Kolt	145,700	STX Panocean	Korea Hanjin	Nov-08	Panama	DFDE	TZ Mk. III	4	Various
Suez Point Fortin	154,200	Trinity LNG	Koyo Japan	Nov-09	Panama	S	TZ Mk. III	4	Yemen LNG
Taitar No. 1	145,000	NYK Line	Mitsubishi	Oct-09	Liberia	S	Moss	4	Various
Taitar No. 3	145,000	NYK Line	Mitsubishi	Jan-10	Liberia	S	Moss	4	Various
Taitar No. 4	145,000	NYK	Mitsubishi	Jan-10	Liberia	S	Moss	4	Various
Tangguh Batur	145,700	Sovcomflot/NYK	Daewoo	Dec-08	Cyprus	S	GT NO 96		Tangguh
Tangguh Foja	155,000	K Line	Samsung	Jul-08	Panama	DFDE	TZ Mk. III	4	Tangguh LNG
Tangguh Hiri	155,000	Teekay LNG	Hyundai	Nov-08	IOM	DFDE	TZ Mk. III	4	Tangguh
Tangguh Jaya	145,700	K Line	Samsung	Nov-08	Panama	DFDE	TZ Mk. III	4	Tangguh
Tangguh Palung	155,000	K Line	Samsung	Mar-09	Panama	DFDE	TZ Mk. III	4	Tangguh
Tangguh Sago	155,000	Teekay LNG	Hyundai	Mar-09	IOM	DFDE	TZ Mk. III	4	Tangguh LNG
Tangguh Towuti	145,700	Sovcomflot/NYK	Daewoo	Oct-08	Cyprus	S	GT NO 96	4	Tangguh
Tembek	216,200	OSG/Nakilat	Samsung	Sep-07	Marshall Is.	DRL	TZ Mk. III	4	Qatargas II
Tenaga Satu	130,000	MISC	Dunkerque	Sep-82	Malaysia	S	GT NO 88	5	Petronas
Tessala	171,866	Hyproc Shipping	Hyundai	Dec-16	Algeria	DFDE	GTT Mk III	4	Sonatrach
Torben Spirit	173,000	Teekay	Daewoo	Feb-17	Bahama	MEGI-DF	No 96 GW	4	Various
Trinity Arrow	154,900	K Line	Imabari Shipbuilding	Mar-08	Panama	S	TZ Mk. III	4	Various
Umm Al Amad	210,100	J5	Daewoo	Aug-08	Marshall Is.	DRL	GT NO 96	4	Ras Gas III
Umm Al Ashtan	137,000	National Gas Shipping	Kvaerner- Masa	May-97	Liberia	S	Moss	4	ADGAS
Umm Bab	145,000	Kristen Navigation	Daewoo	Nov-05	Bermuda	S	GT NO 96	4	Qatargas
Umm Slaal	266,000	QGTC	Samsung	Nov-08	Qatar	DRL	TZ Mk. III	5	Qatargas
Valencia Knutsen	173,400	Knutsen	Daewoo	Sep-10	Nor-NIS	DFDE	GT NO. 96	4	Various
Velikiy Novgorod	170,200	SovComFlot	STX	Feb-14	Liberia	DFDE	GT No. 96	4	Various
Vladimir Rusanov	172,000	MOL-China Shipping	Daewoo	Mar-18	Hong Kong	DFDE	GT No 96	4	Yamal
Vladimir Viz	172,000	MOL-China Shipping	Daewoo	Sept-18	Hong Kong	DFDE	GT No 96	4	Yamal
Wakaba Maru	125,000	J3 Consortium	Mitsui Chiba	Apr-85	Japan	S	Moss	5	Pertamina
WilEnergy	125,500	Awilco LNG	Mitsubishi	Oct-83	NIS	S	Moss	5	Various
WilForce	156,000	Teekay LNG	Daewoo	Aug-13	NIS	DFDE	GT NO 96	4	Various
WilGas	125,500	Awilco LNG	Mitsubishi	Jul-84	NIS	S	Moss	5	Various
WilPower	125,500	Awilco LNG	Mitsubishi	Jul-84	NIS	S	Moss	5	Various
Woodside Cheney	174,000	Maran	Hyundai Samho	Mar-16	Greece	DFDE	GT No 96	4	Various
Woodside Donaldson	165,500	Teekay LNG	Samsung	Dec-09	Singapore	DFDE	TZ Mk. III	4	Various
Woodside Goode	159,800	Maran	Daewoo	Jul-14	Greece	DFDE	GT No. 96	4	Various
Woodside Reeswithers	173,400	Maran	Daewoo	Nov-16	Greece	DFDE	GT No 96	4	Various
Woodside Rogers	155,900	Maran Gas	DSME	Jul-13	Greece	DFDE	GT NO 96	4	Various
Yari LNG	159,983	TMSC Gas	Daewoo	Jun-14	Malta	TFDE	GT No 96	4	Various
Yenisei River	155,000	Dynagas	Hyundai	Jul-13	Marshall Is.	DFDE	TZ Mk. III	4	Various
YK Sovereign	127,125	SK Shipping	Hyundai	Dec-94	Panama	S	Moss	4	Pertamina
Zarga	266,000	QGTC	Samsung	Dec-09	Liberia	DRL	TZ Mk. III	5	Qatar-Atlantic
Zekreet	135,420	J4 Consortium	Mitsui Chiba	Dec-98	Japan	S	Moss	5	Qatargas

Any observations, additions or suggested revisions to the LNG journal World LNG Carrier Fleet list should be sent to editor@lngjournal.com

LNG JAPAN CORPORATION

LNG Import Terminals

Explanatory Notes

- The tables do not include the following types of LNG facilities :
  - Small marine satellite terminals receiving LNG from liquefaction plants in their own country (such as exist in Norway) or which receive LNG transhipped from nearby reception terminals in their own country (such as in Japan)
  - Satellite LNG storage facilities that receive LNG transported only by road or rail
- Expansions of LNG reception terminals are only shown if they involve new storage tanks
- Where there is a blank in the table the information is uncertain or unknown.

Any comments on the tables, and corrections / additional information from terminal shareholders and project developers would be most welcome, and should be sent to John McKay e-mail editor@lngjournal.com

Country	Location (Project)	Owners	Start up	Storage Tanks	Storage Capacity
Belgium	Zeebrugge	Fluxys	1987	4	380,000
Canada	Canaport Saint John	Irving Oil, Repsol	2009	3	480,000
Chile	Quintero	ENAP, Metrogas, Enagas	2009	3	334,000
	Mejillones	Engie, Codelco	2010	1	175,000
China	Beihai LNG, Guangxi	Sinopec	2015	4	640,000
	Dalian	PetroChina	2011	3	480,000
	Dapeng ND Guangdong	CNOOC	2018	4	640,000
	Dongguan, Guangdong	Jovo Group	2013	2	160 000
	Fujian LNG (Xiuyu)	CNOOC, Fujian I&D Corp.	2008	2	640,000
	Guangdong	CNOOC,BP	2006	3	480,000
	Haikou, Hainan LNG	CNOOC	2014	3	480,000
	Ningbo, Zheijang	CNOOC, Zhejiang Energy	2012	3	480,000
	Qidong, Jiangsu	Guanghui Energy	2018	1	60,000
	Qingdao, Shandong	Sinopec	2014	3	480,000
	Rudong	PetroChina	2011	3	530,000
	Shanghai	CNOOC, Shenergy Group	2009	3	495,000
	Shanghai, Mengtougou	Shanghai Gas	2008	3	120 000
	Shenzen, Diefu	CNOOC	2016	2	320,000
	Tangshan, Hebei	PetroChina	2013	3	480,000
	Tianjin North	Sinopec	2017	2	320,000
	Yuedong, Guangdong	CNOOC	2016	2	320,000
	Zhoushan Zhejiang	Enn Group	2018	2	320,000
	Zhuhai, Gaolan	CNOOC	2013	3	480,000
Dominican Republic	Punta Caucedo	AES Andres	2003	1	160 000
Finland	Pori	Gasum Skangas	2016	1	30,000
	Tornio	Gasum Skangas	2018	1	30,000
France	Fos Tonkin	Elengy	1972	3	150,000
	Montoir-de-Bretagne	Elengy	1980	3	360,000
	Fos Cavaou	Engie, Total	2010	3	330,000
	Dunkirk LNG	EDF, Fluxys, Total	2016	3	570,000
Gibraltar	Gasnor	Shell	2018	1	5,000
Greece	Revithoussa	DEPA	2000	3	225,000
India	Dabhol	GAIL, NTPC (Ratnagiri Gas & Power)	2009	3	480,000
	Dahej	Petronet LNG	2004	4	592,000
	Hazira	Shell India, Total	2005	2	320,000
	Kochi, Kerala	Petronet LNG	2013	2	320,000
	Mundra	Gujarat State Petroleum, Adani Group	2018	2	320,000
Indonesia	Arun	Pertamina	2015	5	507,000
Italy	Panigaglia	Snam	1969	2	100,000
	Porto Levante (offshore GBS)	ExxonMobil, Qatar Petroleum, Edison Gas	2009	2	250,000
Japan	Negishi	Tokyo Gas	1969	14	1,180,000
	Sodegaura	Tokyo Gas	1973	35	2,660,000
	Ohgishima	Tokyo Gas	1998	4	850,000
	Higashi-Ohgishima	Tokyo Electric	1984	9	540,000
	Futtsu	Tokyo Electric	1985	10	1,110,000
	Yokkaichi LNG	Chubu Electric	1988	4	320,000
	Kawagoe	Chubu Electric	1997	6	840,000
	Yokkaichi Works	Toho Gas	1991	2	160,000
	Chita LNG Joint	Toho Gas, Chubu Electric	1978	4	300,000
	Chita LNG	Toho Gas, Chubu Electric	1983	7	640,000
	Chita - Midorihama	Toho Gas	2001	3	600,000
	Senboku I	Osaka Gas	1972	4	180,000
	Senboku II	Osaka Gas	1977	18	1,585,000
	Himeji	Osaka Gas	1984	8	740,000
	Himeji LNG	Kansai Electric	1979	7	520,000
	Yanai	Chugoku Electric	1990	6	480,000
	Niigata	Nihonkai LNG, Tohoku Electric	1984	8	720,000
	Oita	Oita Gas, Kyushu Electric	1990	5	460,000
	Tobata	Kitakyushu LNG	1977	8	480,000
	Fukuoka	Saibu Gas	1993	2	70,000
	Sodeshi	Shizuoka Gas	1996	3	337,200
	Hatsukaichi	Hiroshima Gas	1996	2	170,000
	Kagoshima	Nippon Gas	1996	2	136,000
	Shin-Minato	Sendai City Gas	1997	1	80,000
	Nagasaki	Saibu Gas	2003	1	36,000
	Sakai	Kansai Electric, Cosmo OIl	2006	3	420,000
	Mizushima	Nippon Oil, Chugoku Electric	2006	2	320,000

LNG Import Terminals (continued)

Country	Location (Project)	Owners	Start up	Storage Tanks	Capacity
	Sakaide	Shikoku Electric, Cosmo Oil	2011	1	180,000
Japan (continued)	Ishikari LNG	Hokkaido Gas, Hokkaido Electric	2012	2	380,000
	Okinawa	Okinawa Electric Power	2012	2	280,000
	Naoetsu	Inpex	2013	2	360,000
	Joetsu	Chubu	2011	3	540,000
	Hachinohe LNG	Nippon Oil	2015	2	280,000
	Hitachi LNG	Tokyo Gas	2015	1	230,000
	Soma Fukushima	Japan Petroleum Exploration	2017	1	225,000
Korea	Boryyeong	GS Energy, SK E&S	2017	3	200,000
	Incheon	Kogas	1996	20	2,880,000
	Kwangyang	POSCO	2005	4	530,000
	Pyeong-Taek	Kogas	1986	23	3,360,000
	Samcheok	Kogas	2014	3	600,000
	Tong-Yeong	Kogas	2002	17	2,620,000
Malaysia	Pengerang Johor	Petronas Gas	2017	2	400,000
Mexico	Altamira	Vopak, Enagas	2006	2	300,000
	Energia Costa Azul	Sempra LNG	2008	2	320,000
	Manzanillo	Samsung, Kogas, Mitsui	2012	2	300,000
Netherlands	Gate LNG	Gasunie, Royal Vopak	2011	3	540,000
Panama	Costa Norte	AES	2018	1	130,000
Phillipines	Pagbilao LNG	Energy World Corp.	2017	1	130,000
Poland	Swinoujscie	Baltic Gaz System	2015	2	320,000
Portugal	Sines	REN Atlantico	2004	3	390,000
Puerto Rico	Penuelas	EcoElectrica	2000	1	160,000
Singapore	Singapore	Singapore Energy Authority	2013	3	540,000
Spain	Barcelona	Enagas	1969	8	840,000
	Huelva	Enagas	1988	5	610,000
	Cartagena	Enagas	1989	5	587,000
	Bilbao	Enagas, EVE	2003	3	450,000
	Sagunto	GNF, Osaka Gas, Oman Oil	2006	4	600,000
	Reganosa, Ferrol	Galicia, Sonatrach, Tojeiro	2006	2	300,000
	El Musel, Gijón,	Enagas	2013	2	300,000
Taiwan	Yung-An	CPC	1990	6	690,000
	Tai-Chung	CPC	2009	5	800,000
Thailand	Map Ta Phut	PTT LNG	2011	2	320,000
Turkey	Marmara Ereglisi	Botas	1994	3	255,000
	Izmir	EgeGaz	2006	2	280,000
USA	Everett	Suez LNG NA	1971	2	155,000
	Lake Charles	Shell, ETE	1982	4	425,000
	Elba Island	Kinder	2001	5	535,000
	Cove Point	Dominion	2003	5	530,000
	Freeport	Freeport LNG Development	2008	2	320,000
	Cameron	Sempra LNG	2009	3	480,000
	Golden Pass, TX	Qatar Petroleum, ExxonMobil	2010	5	775,000
	Pascagoula, MS	Gulf LNG, Kinder	2012	2	320,000
UK	Isle of Grain	National Grid	2005	8	1,000,000
	South Hook	ExxonMobil, Qatar Petroleum,Total	2009	5	775,000
	Dragon LNG, Milford Haven	Shell, Petronas	2009	2	310,000

LNG Import Terminal Projects

Country	Location/Project	Owners/Project Developers	Start up	Storage Tanks	Capacity
China	Shenzhen	CNPC Yudean Power	2021	2	120,000
	Yangjiang	CNPC Yudean Power	2023	2	120,000
	Zhangzhou Fujian	CNOOC	2022	2	160,000
India	Ennore	Indian Oil Corp	2019	2	320,000
	FSRU Andhra Pradesh	Andhra Pradesh Gas	2019	1	135,000
	Pipovav LNG (FSRU), Gujarat	Swan Energy	2019	2	320,000
	Andhra Pradesh	Hindustan LNG, Andhra Pradesh	studies	1	135,000
UK	Port Meridian, Barrow-in-Furness	Port Meridian Energy Ltd.	2020	1	150,000

LNG FSRU Import Facilities

Country	Location (Project)	Owners	Start up
Argentina	Bahia Blanca GasPort	Excelerate/YPF Repsol	2008
	Escobar GasPort	Excelerate/Enarsa	2011
Bangladesh	Moheshkhali	Excelerate, PetroBangla	2018
Brazil	Pecem, FSRU	Petrobras	2009
	Guanabara Bay FSRU	Petrobras	2009
	Salvador, Bahia FSRU	Petrobras	2013
China	Tianjin FSRU	CNOOC, Hoegh, various	2013
Colombia	Cartagena FSRU	Promigas, Sociedad Portuaria El Cayao	2016
Egypt	Ain Sokhna, Suez	EGAS, Hoegh	2015
	Ain Sokhna, Suez	EGAS, BW Gas	2015
Indonesia	Lampung	Hoegh LNG, PGN LNG	2014
	Nusantara (Jakarta Bay)	Golar LNG, Pertimana	2012
Italy	Livorno	OLT Offshore LNG Toscana	2013
Jordan	Aqaba, Jordan	Golar LNG	2015
Kuwait	Mina Al-Ahmadi	KPC	2009
Lithuania	Klaipeda	Klaipedos Nafta Hoegh LNG	2014
Malaysia	Malacca FSRU	Petronas	2012
Malta	FSU Armada Mediterrana	ElectroGas	2016
Pakistan	Port Qasim	Excelerate, Engro Corp	2015
	Port Qasim	BW-Mitsui, PGP Consortium	2017
Turkey	Aliaga FSRU, Neptune	Etki LNG	2016
	Dortyol FSRU Challenger	Botas	2018
UAE	Ruwais, Abu Dhabi	Gasco (UAE)	2016
	Jebel Ali Port, Dubai	DSA (UAE)	2010
UK	Teesside GasPort	Excelerate	2007

LNG Export Projects

Country	Location/Project	Project Developers	Planned Start Up	Number of Trains	Capacity In MTPA
AUSTRALIA	Pluto LNG expansion	Woodside	2021+	2	10.0
CANADA	Bear Head LNG, Nova Scotia	LNG Ltd.	2024	4	8.0
	Goldboro LNG, Nova Scotia	Pieridae Energy	2024	2	10.0
	Kitimat LNG, BC	Woodside, Chevron	2024	2	10.0
	LNG Canada, BC	Shell, Mitsubishi, Kogas, PetroChina, Petronas	2024	2	12.0
	Melford LNG project, Nova Scotia	H-Energy Hiranandani Group	Studies		
	Kwispaa FLNG, Vancouver	Steelhead LNG	2024	4	12.0
	Vancouver Tilbury	WesPac Midstream	2021	1	3.25
	Woodfibre LNG, Squamish	Pacific Oil & Gas Co	2020	2	2.1
EQ.GUINEA	Equatorial Guinea Fortuna FLNG	Ophir, Golar LNG, GEPetrol	2020+	1	2.0
INDONESIA	Sengkang LNG	Energy World Corp.	2019	4	2.0
MALAYSIA	Rotan FLNG (Sabah)	Petronas, Murphy Oil	2021	1	1.5
MOZAMBIQUE	Area 1 Onshore	Anadarko Petroleum and partners	2023+	2	10.0
	Area 4 Onshore	Eni and partners	2023+	2	10.0
	Area 4 FLNG	Eni and partners	2020	1	2.5
NIGERIA	NLNG Train 7	NNPC, Shell, Eni, Total	2022+	1	7.0
PAPUA NEW GUINEA	Elk-Antelope LNG	Total, ExxonMobil Oil Search, Petromin	Studies		
RUSSIA	Sakhalin II expansion	Gazprom, Shell, Mitsui, Mitsubishi	2021	studies	
	Vladisvostok LNG	Gazprom, Itochu, various	2023+	2	10.0
USA	Alaska LNG Nikiski	Alaska Gasline Development Corp.	2023+	3	20.0
	Annova LNG, Brownsville	Exelon Corp.	2023+	6	6.0
	Cameron LNG, Louisiana	Sempra, Total, Mitsui, Mitsubishi	2019	3	14.95
	Commonwealth LNG, Louisiana	Commonwealth LNG LLP	2022	8	9.0
	Corpus Christi Liquefaction, Texas	Cheniere	2019	2	9.0
	Delfin LNG, Louisiana	Delfin, Hoegh	2021	3	9.0
	Driftwood LNG, Louisiana	Tellurian Investments	2022	6	26.0
	Elba Island, Georgia	Kinder Morgan, EIG Energy	2019	10	2.5
	Freeport LNG, Texas	Freeport LNG	2019	4	20.4
	Galveston Bay LNG	NextDecade	2023+	6	27.0
	Golden Pass, Texas	Qatar Petroleum, ExxonMobil	2021	3	15.6
	Jordan Cove, Coos Bay	Pembina Corp.	2024	2	7.8
	Lake Charles, Louisiana	Shell, ETE	2024	3	15.0
	Magnolia LNG	Louisiana LNG Ltd.	2023+	4	8.0
	Port Arthur LNG	Sempra	2023+	2	10.0
	Rio Grande LNG	NextDecade	2023+	6	27.0
	Sabine Pass LNG, Louisiana	Cheniere	2018-19	2	9.0
	Texas LNG Brownsville	Chandra, Meyer, Samsung, others	2023+	2	4.0
	VG LNG (Cameron Parish)	Venture Global	2021	5	10.0
	VG LNG (Plaquemines)	Venture Global	2021	10	20.0

LNG Exporters

Country	Location/Project	Shareholders	Start up	Liquefaction		Storage	
				Trains	capacity (nominal) mtpa	No. of tanks	Total capacity m^3
ABU DHABI	Das Island (Adgas)	ADNOC, Mitsui, BP, Total	1977	2	3.2	3	240,000
(UAE)			1994	1	2.5		
ALGERIA	Arzew	Sonatrach GL4Z	1964	3	1.1	3	35,000
	Arzew	Sonatrach GL1Z	1978	6	7.8	3	300,000
	Arzew	Sonatrach GL2Z	1980	6	8.0	3	300,000
	Arzew	Sonatrach	2014	1	4.7		
	Skikda	Sonatrach GL1K II	1980	3	3.0	5	308,000
	Skikda	Sonatrach (rebuild)	2013	1	4.5		
ANGOLA	Soyo	Sonangol, Chevron, BP, ENI, Total	2012	1	5.2	2	370,000
AUSTRALIA	Karratha	NWS Woodside, Shell, BHP	1989	2	5.0	4	260,000
		(BP, Chevron	1992	1	2.5	1	130,000
		(Mistubishi/Mitsui)	2004	1	4.4	1	130,000
		NWS partners	2008	1	4.4	1	130,000
	Darwin	Darwin (Bayu Undan) ConocoPhillips, Santos, Eni, Inpex, TEPCO, Tokyo Gas	2006	1	3.5	1	188,000
	Australia Pacific LNG	ConocoPhillips, Origin Energy, Sinopec	2016	2	7.5	2	320,000
	Gladstone LNG	Santos, Petronas, Total, Kogas	2015	2	7.8	2	280,000
	Gorgon LNG	Chevron, Shell, ExxonMobil	2016	3	15.6	2	360,000
	Pluto LNG	Woodside, Tokyo Gas, Kansei	2012	1	4.8	2	240,000
	QCLNG	Shell, CNOOC	2014	2	8.0	2	280,000
	Wheatstone LNG	Chevron, Woodside, Kuwait (KUFPEC), Jera, Kyushu	2017	2	8.9	2	300,000
	Ichthys LNG	Inpex Corp., Total	2018	2	8.9	2	330,000
	Prelude FLNG	Shell, Inpex, Kogas CPC	2019	1	3.5		
BRUNEI	Lumut	Brunei/Shell/Mitsubishi/Total	1972-74	5	7.2	3	176,000
CAMEROON	Hilli Episeyo FLNG	Kribi Perenco	2018	1	1.2	1	125,000
EGYPT	Damietta	Union Fenosa, EGPC, EGAS	2004	1	5.0	2	300,000
	Idku	EGPC, EGAS, Shell, Total, Petronas	2005	2	7.2	2	280,000
EQ.GUINEA	Bioko Island	Marathon, Sonagas, Mitsui, Marubeni	2007	1	3.4	2	272,000
INDONESIA	Bontang I	Pertamina, VICO, JILCO, Total	1977	2	5.2	5	635,000
	Bontang II		1983	2	5.2		
	Bontang III		1989	1	2.8		
	Bontang IV		1993	1	2.8		
	Bontang V		1997	1	2.8		
	Bontang VI		1999	1	3.0		
	Sulawesi LNG	Medco Energi, Pertamina, Mitsubishi	2015	1	2.0	1	170,000
	Tangguh	BP, MI Berau, CNOOC, Nippon, LNG Japan	2008	2	7.6	2	340,000
MALAYSIA	Bintulu (MLNG Satu)	Petronas, Sarawak, Mitsubishi	1983	3	8.1	4	260,000
	Bintulu (MLNG Dua)	Petronas, Shell, Sarawak, Mitsubishi	1995	3	7.8	1	65,000
	Bintulu (MLNG Tiga)	Petronas, Shell, Sarawak, Mitsubishi, Nippon Oil	2003	2	6.8	1	120,000
	Bintulu Train 9	Petronas	2016	1	3.6		
	Kanowit FLNG	Petronas	2016	1	1.2		
NIGERIA	Bonny Island	NNPC, Shell, Total, Eni	1999	2	6.4	2	168,400
		Nigeria LNG (formed by above)	2002	1	3.2	1	84,200
		Nigeria LNG	2006	2	8.2		
		Nigeria LNG	2008	1	4.1	1	84,200
NORWAY	Snøhvit/Melkoya	Equinor, Total, Petoro	2007	1	4.2	2	280,000
OMAN	Oman LNG	Oman Govt., Shell, Total, Korea LNG Mitsubishi, Mitsui, Partex and Itochu	2000	2	7.1	2	240,000
		Oman Govt.,Oman LNG Union Fenosa, Osaka Gas, & Itochu	2006	1	3.7	2	240,000
PAPUA NEW GUINEA	PNG LNG	ExxonMobil, Oil Search, Santos, JX Nippon Oil	2014	2	6.9	2	320,000
PERU	Peru LNG	Hunt Oil, Shell, Marubeni, SK Group	2010	1	4.4	2	260,000
QATAR	Qatargas 1-T1&2	QP, ExxonMobil, Total, Marubeni, Mitsui	1997	2	6.4	4	340,000
	Qatargas 1-T3	QP, ExxonMobil, Total, Marubeni, Mitsui	1999	1	3.1		
	Qatargas II-T1	QP, ExxonMobil	2009	1	7.8		
	Qatargas II-T2	QP, ExxonMobil, Total	2009	1	7.8	8	1,160,000
	Qatargas III-T1	QP, ConocoPhillips, Mitsui	2010	1	7.8		
	Qatargas IV-TI	QP, Shell	2010	1	7.8		
	RasGas I- T1&2	QP, ExxonMobil, Kogas, Itochu, LNG Japan	1999	2	6.6		
	RasGas II- T3	QP, ExxonMobil	2004	1	4.7		
	RasGas II- T4	QP, ExxonMobil	2005	1	4.7	6	840,000
	RasGas II- T5	QP, ExxonMobil	2007	1	4.7		
	Rasgas III – T6	QP, ExxonMobil	2009	1	7.8		
	Rasgas III – T7	QP, ExxonMobil	2010	1	7.8		
RUSSIA	Sakhalin Island	(Sakhalin Energy) Gazprom, Shell, Mitsui, Mitsubishi	2009	2	9.6	2	200,000
	Yamal LNG Siberia	Novatek, Total, CNPC, Silk Fund	2017	3	16.5	4	640,000
TRINIDAD & TOBAGO	Point Fortin Train 1	BP, Shell, CIC, NGC	1999	1	3.0	2	204,000
	Train 2	BP, Shell	2002	1	3.3	1	160,000
	Train 3	BP, Shell	2003	1	3.3	1	160,000
	Train 4	BP, Shell, NGC	2005	1	5.2	1	160,000
USA	Cheniere Sabine Pass	Cheniere Energy	2016	5	22.5	5	800,000
	Cove Point LNG	Dominion Energy	2017	1	5.3	7	695,000
	Cheniere Corpus Christi	Texas Cheniere	2018	1	4.5	3	480,000
YEMEN	Bal-Haf	Yemen LNG, Total, Yemen Gas, Hunt Oil, SK Group, Hyundai	2009	2	6.7	2	320,000

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