LNG journal
The World's Leading LNG publication

36 pages essential LNG news!

November/ December 2017

In this issue:

Australia moves closer to leading global output with annual 88 million tonnes

Government report says everything on track for LNG export income to rise to A$35 billion depending on oil price

The Australian government said the value of Australia's liquefied natural gas exports is forecast to increase from A$22 billion (US$17.12Bln) in 2016-2017 to A$35 billion in 2018-2019, driven by higher export volumes and, to a lesser extent, higher prices.

The completion of the final three Australian LNG projects will underpin strong growth in export volumes and bring total export capacity to 88 million tonnes.

"LNG is forecast to overtake metallurgical coal as Australia's second-largest resource and energy export in 2018-2019," said the Quarterly Resources Report from the Australian Office of the Chief Economist.

Pricing

"LNG contract prices - under which most Australian LNG is sold - are forecast to increase in line with oil prices," was another major point noted by the report.

The Australians said that the outlook for LNG export earnings is not without risks.

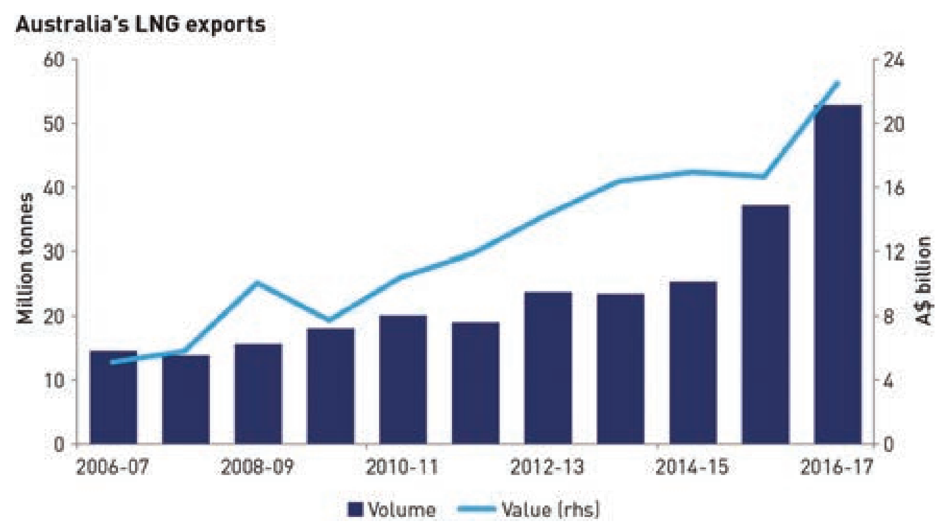
"Australia faces increasing competition in export markets. Oil prices are also a key sensitivity," it said.

Oil price movements will continue to be the main driver of Australian LNG prices.

The report's latest available data showed that the average price of an Australian LNG free-on-board (FOB) cargo declined from an 18-month high of A$9.00 per gigajoule in June to A$8.20 a gigajoule in July - or around US$6.80 per million British thermal units (MMBtu).

"The decline was driven by a fall in oil prices in April 2017, with the majority of Australian LNG sold on long-term contracts linked to the price of Japan Customs-cleared Crude (JCC) oil by a time lag of three months," said the report.

LNG spot prices in Asia have risen in recent months, bringing them more closely in line with long-term oil-linked contract prices.



Volumes and income from nation's rising production

"LNG spot prices (Delivered Ex-Ship) averaged an estimated $8.20 a gigajoule in September (US$6.90 per MMBtu) while an indicative price for LNG on a long-term oil-linked contract (Delivered Ex Ship) was around $9.20 a gigajoule.

"The average price of Australian LNG (FOB) is forecast to increase to average $9.10 a gigajoule in 2018-2019, largely driven by higher prices on oil-linked contracts. The JCC oil price is forecast to average US$55.00 a barrel in 2018-2019, up from an average US$50 a barrel in 2016-2017," the report said.

Asian spot

However, low spot prices will play some role in constraining the average export price realized, particularly if Australian exporters increase their share of sales at spot prices.

Asian LNG spot prices (Delivered Ex Ship) are forecast to fall to an average $6.40 a gigajoule in 2019 (around US$5.20 per MMBtu), as additions to global supply capacity outstrip growth in LNG demand.

"The forecast divergence between oil-linked contract prices and LNG spot prices is expected to encourage buyers to turn to the short-term contract or spot market, reducing purchases on long-term contracts to minimum 'take-or-pay' levels.

"A widening in the difference between spot and contract prices may also encourage buyers to seek changes to their contractual arrangements with sellers.

"In September, it was reported that India's Petronet LNG had negotiated a more favourable oil-linked pricing formula with ExxonMobil for LNG supplies from the Gorgon project," the report noted.

World trade

The Australian overview explained that although growth in global gas demand is forecast to remain modest, it is expected to drive a major expansion in the relatively small LNG market.

World LNG trade is forecast to increase at an average annual rate of 9.3 percent a year, reaching 327 million tonnes in 2019.

"Emerging Asia - led by China - and Europe are expected to drive demand growth. Prospects for growth in the imports of the world's two largest consumers - Japan and South Korea - are more limited.

"While LNG demand is forecast to grow rapidly over the next few years, it is expected to be outpaced by growth in supply capacity. Consequently, the average capacity utilization of LNG plants is expected to fall," it stated.

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The next few years are expected to see a major expansion in global supply capacity. Around half of all new liquefaction capacity will come from the United States.

Global supply

By 2019, all five LNG projects currently under construction in the United States are expected to have started production, bringing nameplate capacity to around 64 million tonnes.

However, US exports are only forecast to rise to around 37MT in 2019, with all of these projects scheduled for completion late in the outlook period.

"With the US expected to be a major source of new supply, it is possible that the cost of delivering US gas to Asia could cap LNG spot prices in the region," the report said.

"The cost of US LNG will be determined by the price for which US LNG exporters can purchase domestic gas for export, plus the cost of liquefaction and transportation," it added.

The report also explained that if current prices persisted, and if tolling fees (fixed charges paid by LNG buyers that cover the capital costs of US LNG plants) are treated as a sunk cost, US LNG could potentially reach Asian markets for around US$5.00 per MMBtu ($6.30 a gigajoule).

US and Qatar

Henry Hub spot prices - the reference price for US domestic gas - remain at about the US$3.00 per MMBtu mark (around $3.80 a gigajoule).

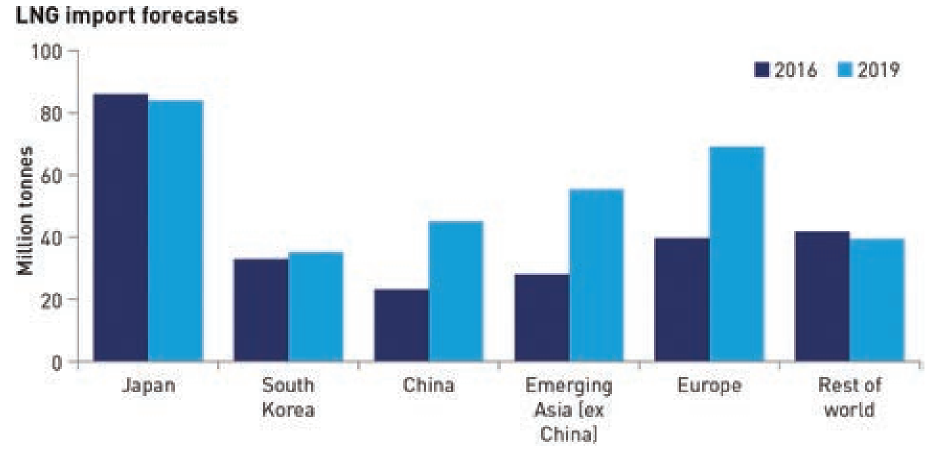
Liquefaction and transportation costs from the US Gulf Coast are thought to be about US$2 per MMBtu ($2.5 a gigajoule) at present, although estimates for transport costs vary.

Qatar's exports are forecast to remain largely unchanged

Qatar is the world's largest LNG exporter. In 2016, Qatar exported 74MT of LNG. Qatar's LNG projects have the lowest short-run marginal production costs in the world, and Qatar's exports are forecast to be broadly stable over the outlook period at 74MT.

"To date, Qatar's LNG exports have been largely unaffected by recent tensions with its Middle Eastern neighbours," the report said.

"Qatar's decision in April to lift the moratorium on new gas development at its North Field, and potentially expand its LNG production capacity, is not expected to affect its LNG exports within the two-year outlook period," it added.



Emerging LNG users help take demand to higher level

Australia

Australia's LNG export volumes are forecast to reach 74MT in 2018-2019, up from 52MT in 2016-2017.

Higher export volumes will be underpinned by higher production at Gorgon, as well as the completion of the two remaining LNG projects under construction. Wheatstone has just started operations and Ichthys near Darwin and the Shell-led Prelude floating venture offshore northwest Australia are nearing completion.

"These three projects will add around 21MT tonnes to Australia's LNG export capacity, bringing total nameplate capacity to around 88 million tonnes," the report stated.

The Wheatstone project has two Trains and the second Train is due online between March and May 2018.

"First LNG at Inpex's Ichthys project is expected in the March quarter 2018, with some reports indicating that Train 2 could commence operations a few months later.

"The Prelude Floating LNG project is likely to be the last of Australia's recent wave of seven LNG projects to be completed, with Shell indicating Prelude will be completed between May and August 2018," stated the report.

Increased exports to Japan, South Korea and China are expected to drive the increase.

While prospects for growth in the imports of Japan and South Korea are limited, Australian producers are expected to capture an increasing share of both country's imports.

Imports

"The imports of the world's largest LNG buyer are set to decline," said the Australian report.

Japan's LNG imports increased by 5.5 percent year-on-year in the first seven months of 2017, with gas demand supported by a hot summer and increased consumption in the industrial sector.

"Despite this, Japan's LNG imports are forecast to increase by only 3.1 percent in 2017 to 88MT (the same as all future Australian annual production). By 2019, Japan's LNG imports are forecast to decline to 84MT," the Australians said.

"Overall energy demand in Japan remains subdued. At the same time, LNG is expected to face increasing competition from other fuel sources in the power sector, which accounts for two-thirds of Japan's gas consumption.

"The recent restart of idle nuclear power generation capacity - which competes with gas-fired power - is expected to weigh on LNG imports from mid-2017.

"Japanese utility Kansai Electric Power reactivated two reactors in the June quarter. Five of Japan's fleet of 42 reactors (combined capacity 4.4 gigawatts) are now operational.

"Further reactor restarts are possible within the outlook period. Four more reactors - with capacity totaling 4.7 gigawatts - have received approval from Japan's Nuclear Regulation Authority to restart. However, the timing and scale of nuclear restarts remains a key uncertainty affecting the outlook," it added.

Renewables

LNG also faces increasing competition in power generation from renewable energy.

The Japanese Government's energy think-tank, the Institute of Energy Economics (IEEJ), expects renewable energy generation to increase at an average annual rate of 7.7 percent between Japanese fiscal years (April to March) 2016-2017 and 2018-2019.

Recent announcements in South Korea could support LNG imports

"South Korea's LNG imports increased by 18 percent year-on-year in the first seven months of 2017. With a number of nuclear reactors offline and nuclear-power generation down, gas-fired generation increased.

"South Korea's LNG imports are forecast to increase by 10 percent in 2017 to 33MT, with the return of nuclear capacity weighing on LNG imports in the second half of 2017," it said.

"In 2018 and 2019, South Korea's LNG imports are forecast to be broadly steady. While gas use in the industrial sector is expected to decline, several announcements by the recently elected South Korean government could lead to a modest increase in the use of LNG in power generation.

"From 2018, operations at six old coal-fired power stations will be suspended between March and June each year to reduce air pollution.

Closures

"There are also plans to close two coal-fired power stations before the end of 2017, with a further eight closures expected before mid-2022.

"South Korea's government will also raise its coal consumption tax by as much as 22 percent from the start of 2018, increasing the cost-competitiveness of gas," the report explained. The Koreans also plan to reduce reliance on nuclear energy, given public concern about the safety of the technology.

The government has paused the construction of two nuclear power stations, pending a review, and intends to close the aged Wolsong 1 nuclear reactor, although a timeline for this has not been specified.

"If gas-fired generation replaces reduced coal-fired and nuclear power capacity, increased LNG imports will be required," the report said.

Generation

The Australians also stated that emerging Asia, led by China, will help to drive growth in LNG demand.

"China's LNG imports increased by 60 percent year-on-year in the first seven months of 2017.

"Natural gas consumption rose strongly, recording a seasonal record in each month of the year. Pipeline imports and domestic production also increased alongside LNG imports.

"A combination of strong economic growth and energy policy targets are expected to support increased consumption.

"The Chinese government is aiming to increase the share of gas in the energy mix from 5.3 percent in 2015 to 10 percent by 2020, with the stated objectives of reducing air pollution and lowering carbon emissions," it added.

LNG is expected to play an important role in servicing rising gas demand. China's LNG imports are forecast to virtually double from 23MT in 2016 to 45MT in 2019.

China has agreed to large contracts for LNG imports, starting over the next few years.

In addition, low LNG prices, especially on the spot market, should assist the cost competitiveness of LNG vis-à-vis domestic production and pipeline gas imports.

"Other emerging Asian economies are expected to make a large contribution to growth in global LNG imports," the report said.

"Growth will be underpinned by low LNG spot and short-term contract prices, and the availability of floating storage and regasification unit (FSRU) technology, which allows small volumes of LNG to be received more cheaply," it added.

Import issues

India, for example, is aiming to increase the share of gas in the energy mix from about 6 per cent to around 15 percent, although a timeline for this remains unclear.

"With no pipeline import infrastructure, a combination of domestic production and LNG imports are expected to be required to meet growing demand," the report noted.

According to the Australian report, Europe's LNG imports are also expected to increase.

"European LNG imports are forecast to increase from 40MT in 2016 to 69MT in 2019," the report said.

"Rising gas consumption, falling domestic production, and a desire to diversify away from Russian pipeline supply are all expected to support LNG imports.

"Europe is not a major destination for Australia's LNG exports. However, if LNG demand in Europe does not grow as strongly as projected, Qatari and US LNG may be displaced, potentially then bringing increased competition to the Asia-Pacific market," it stated. ■

Wheatstone LNG project starts commercial operations behind schedule like most ventures

Pilbara plant contributes to US major's legacy natural gas position in Australia that will be a significant cash generator for decades

Chevron Corp finally shipped the first cargo from the Wheatstone plant in Western Australia to the Japanese buyer, Jera Co Inc, the joint venture company set up by Tokyo Electric Power Co. and Chubu Electric.

The shipment on the "Asia Venture" arrived at Tokyo Bay on November 10.

"The first Wheatstone cargo represents the significant contribution of Wheatstone's partners, contractors and suppliers and the efforts of thousands of people onsite throughout Australia and around the world during the engineering, construction and operations phase," said Chevron.

Facilities

The Wheatstone project includes an onshore facility located at Ashburton North, 12 kilometres west of Onslow in Western Australia's Pilbara region.

The plant has two LNG Trains with a combined capacity of 8.9 million tonnes per annum and a domestic gas plant.

The US major said 80 percent of Wheatstone capacity is fed with natural gas from the Wheatstone and Iago fields, which are operated by Chevron in joint venture with Australian subsidiaries of Kuwait Foreign Petroleum Exploration Co. (Kufpec), Kyushu Electric Power together with PE Wheatstone Ltd. partly owned by Jera.

The remaining 20 percent of feed-gas will be supplied from the Julimar and Brunello fields held by Australian subsidiaries of Woodside Petroleum and the Kuwait company.

Around 85 percent of Chevron's equity LNG from Wheatstone has been committed to premier LNG buyers and the balance will be sold on the spot market.

Wheatstone, which cost over US$30 billion to construct, is the sixth out of eight large-scale projects in a US$200Bln Australian LNG development build-out that will make the nation the world's largest LNG producer ahead of Qatar.

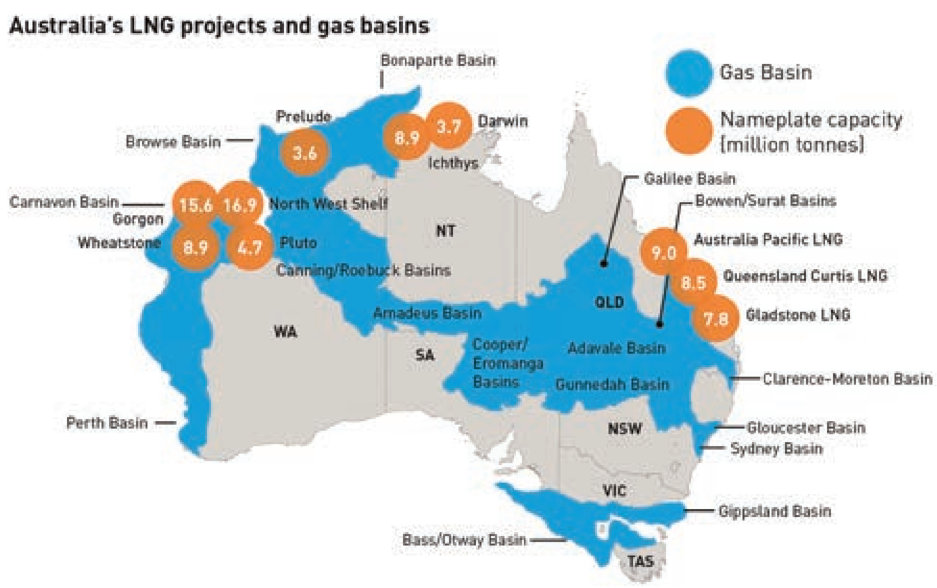
Pipeline

The two remaining projects, the Ichthys venture in the Northern Territory near Darwin, being built by Japan's Inpex and France's Total, and the Royal Dutch Shell-led Prelude floating LNG project, also including Inpex, would take Australia past Qatar's 77 MTPA of total production.

> *In mature markets such as Japan and continental Europe, deregulation, fuel competition and environmental concerns will be important factors in making investment decisions.*

According to the latest Wheatstone production timetable, Train 1 will now be ramped up to full production followed by Train 2 coming on stream in early 2018.

Chevron is also operator of the Gorgon LNG plant on Barrow Island in Western Australia, which was the nation's newest before Wheatstone came on stream.



Australia has LNG and gas developments in areas around the country

While the Gorgon plant experienced several production interruptions after it shipped its first cargo on 21 March 2016, by a year later the second and third Trains were fully operational to meet cargo contracts in the Asia-Pacific region.

Most LNG production plants have output stoppages in the first 18 months or so and are often temporarily shut as part of the medium-term checking process to make sure operations are running smoothly and safely.

Executives

Chevron's Wheatstone was one of the LNG expansion ventures undertaken by the US major during the tenure of Chief Executive John Watson, who witnessed the first shipment from Wheatstone before he formally steps down early next year.

Watson's replacement as Chairman and CEO will be Michael K. Wirth in a succession timed for February 2018.

Based on current projections, the Chevron incoming CEO has said LNG demand will outstrip supply from existing production and currently sanctioned projects in the next decade. Project developers must take a long-term view in making their decisions.

"Supporting these growing economies and improved living standards will require affordable energy that fits into household, business and government budgets.

"Natural gas will be critical to providing the basics, such as transportation to get to work and to seek medical attention, and electricity to cook food and light homes, schools and businesses," Wirth has said.

"In mature markets such as Japan and continental Europe, deregulation, fuel competition and environmental concerns will be important factors in making investment decisions.

Markets

"In emerging markets, natural gas will assume a rising share of the energy mix, encouraging new markets and new buyers for LNG.

"Natural gas is truly becoming a globally traded commodity, and the future is bullish for LNG," according to Wirth.

"With LNG demand projected to grow by roughly two-thirds over the next decade, it's an exciting time to be a part of this industry," he stated.

Wirth added that the next wave of supply has already begun to come from major projects now under construction in the United States.

However, beyond these projects, the energy industry will face key challenges and major investment decisions on how to best meet long-term demand by developing supply and delivering to market reliable, affordable LNG.

"Only the most economically feasible and cost-competitive projects are likely to be sanctioned," says Wirth. Achieving this goal will require strong customer relationships and the development of new partnerships as buyers' needs change and new buyers enter the market.

Governments

"Support of host governments will be essential to source LNG, access markets and enable development. This will require mutually beneficial financial, social and environmental terms and conditions," he added.

"Producers and buyers will play key roles in driving forward any new LNG projects. Producers will need to drive down the costs of their projects, recognizing that buyers have choices," said the incoming CEO.

"And buyers will need to keep in mind that today's low prices won't last if long-term supply does not keep up with demand," he said.

Wirth recognizes that these are not necessarily new challenges; but they can be met, as they have in the past. "It is through communication, collaboration, technology and ingenuity that we'll solve them again," he said.

Chevron-led ventures had combined initial investment of $84 billion for the Gorgon and Wheatstone natural gas projects. Together these represent the largest single investment by a company in Australia's history

Since 2011, around 300 contracts have been awarded to Australian companies as part of the development of Wheatstone.

The project directly employed more than 7,000 workers. Over the life of the project it is expected more than 30,000 direct and indirect jobs will be created in Australia, nearly 1,000 jobs per year.

Wheatstone is forecast to add more than $180 billion to Australia's gross domestic product, nearly $6 billion per year.

At full capacity, the Wheatstone domestic gas plant will be able to generate enough electricity to supply 1.8 million households. ■

For the Record

ARGENTINA plans to auction offshore oil and gas exploration rights in 2018 in the hope of developing fields off its Atlantic coast like those in neighbouring Brazil and to complement its efforts in onshore shale plays for energy production to offset imports such as LNG. Argentina has hired several foreign survey and research data companies to pinpoint the likely blocks to be set aside for auctions. Norway's Spectrum was commissioned to conduct a seismic survey in cooperation with state-run oil and gas company Yacimientos Petroleiferos Fiscales (YPF) and the Ministry of Energy. Spectrum started a survey of 35,000 square kilometres in April 2017 as part of an overall plan to carry out a two-dimensional seismic tour of the deep waters offshore Argentina. This survey will provide Argentina with the first ever detailed seismic grid over the under-explored frontier area, allowing for basin-wide studies and prospect interpretations for the forthcoming licence rounds. Spectrum said that the expansion of the Atlantic Margin seismic coverage would soon allow it to offer a modern 2D library from French Guiana in the north through Brazil to the edge of Argentine offshore waters in the south. "With the potential for a billion-barrel field discovery offshore, Argentina has the opportunity to join the ranks of the recent Atlantic Margins successes in place such as Guyana, Ghana, Brazil and Angola, to name a few," the Norwegian company has said. The Energy Ministry said Australian company Searcher Seismic was also surveying the area. "There is a high probability that the subsalt basin that exists on the coast of Brazil continues south so we see the discovery of any formation of oil and conventional gas in the area as very attractive." said the Ministry. "It could be very profitable for the country," it added. Brazil recently attracted US$1.2 billion in bids for its 14th round of tenders for oil exploration and production rights. Since taking office in late 2015 the Argentine government of President Mauricio Macri has made investment in the energy sector a priority. However, up until now attention has focused on Argentina's Vaca Muerta (Dead Cow) onshore shale fields rather than offshore exploration. The Vaca Muerta formation within the Neuquen Basin has similar geological properties to the US Eagle Ford shale play near the Gulf of Mexico in Texas in terms of its depth, thickness, pressure and mineral composition. Argentina believes it is still on track to cease LNG imports as substantial shale-gas supplies from its estimated 308 trillion cubic feet of technically recoverable gas resources begin to flow from the Vaca Muerta (Dead Cow) shale wells by 2022. Argentina is one of the few countries in the world after the US, Canada, China and to a limited extent Australia to commercially develop shale gas. Argentine LNG imports in 2016 amounted to 3.42 million tonnes, the second-largest in the region after Mexico with 4.10MT. However, even after Brazil discovered huge oil and gas resources offshore it still had to import LNG for power use and to locations near existing gas-fired power plants.

ATLANTIC, Gulf and Pacific Co. of the Philippines, the LNG infrastructure and fabricated modules supply company, said it was making progress in its plans to building up its own LNG project portfolio of small-scale ventures in the Asian and South East Asian regions as it also strengthened its executive team. AG&P's current plans involve India, Bangladesh, Sri Lanka and Indonesia, according to Abhilesh Gupta, the company's recently-appointed, Indian-born Chief Financial Officer and head of the commercial division. "We aim to provide access to LNG for an enormous number of off-grid, energy-hungry end-users that are currently without access to a reliable supply of gas," said Gupta, a former senior executive at India's main LNG company Petronet. "This will lay the foundations for a viable LNG supply network connecting hundreds of smaller end-users through milk-run, shuttle vessels that potentially allow doorstep delivery of gas on regular routes," Gupta explained. Gupta said he had been appointed to help lead the expansion of the company in India and beyond, with a focus on connecting off-grid customers across the country to affordable gas supply. AG&P, which was one of the main providers of fabrication units and modules for LNG export projects in countries such as Australia, is now also a growing player specializing in delivering standardized, LNG solutions that are commercially competitive. It has additionally signed a string of technology agreement with other players to enable the execution of projects. AG&P Chairman Jose. P Leviste Jr. announced the appointment of Gupta in September 2017 to strengthen the LNG expertise at the top of the company. "Abhilesh is one of India's most recognized experts in commercializing LNG projects with over 22 years' experience in leading and managing international finance and commercial portfolios in LNG/natural gas and power in India and Singapore. AG&P's singular objective is to optimize the quantity of LNG through its terminals, underpinned by our scalable designs. Abhilesh will help out global leadership team to drive our LNG vision forward," he added. Prior to joining AG&P, Gupta was General Manager of Finance at Petronet in India and then served as Group CFO for Asia Genco, where he oversaw the commercial, regulatory and treasury functions of their Asian power plant build-out. During his tenure at Petronet, he played a pivotal role in the financing of two of India's existing LNG receiving and regasification terminals at Dahej, north of Mumbai, and at Kochi in the state of Kerala. Gupta said that AG&P's streamlined solution reduces costs and is faster to implement than current business models that require building very large-scale operations with guaranteed large off-takers secured with long-term contracts. AG&P itself signed an accord in January 2017 to supply an import terminal as well as cargoes for power stations in the East Godavari region of the state of Andhra Pradesh on the East Coast of India. The agreement is between AG&P and Hindustan LNG, a Hyderabad-based LNG import terminal development company. In India, AG&P has also signed an agreement with Konaseema Power, a private power plant owner, to develop an integrated LNG supply and gas distribution solution to serve three currently idled power facilities in the East Godavari region. It has additionally embarked on a joint venture with Gas Entec of South Korea to design and make small-scale and mid-scale LNG facilities. AG&P signed a further accord in March 2017 to cooperate with the engineering unit of French industrial gases company Air Liquide to develop its small-scale LNG infrastructure and distribution across Asia. The Filipino company and Air Liquide said they planned to offer fully integrated units for LNG entrants with a focus on liquefaction, transportation and downstream infrastructure to deliver LNG for power, bunkering, ground transport and other industrial applications.

BNP PARIBAS, France's largest stock exchange-listed bank, will stop representing global LNG shipping companies in bonds sales and project financing as well as developers of US LNG export projects under the bank's new environmental investment policies. BNP said it would stop investment in unconventional and Arctic oil and gas resources, including LNG and shale gas, as the French National Assembly upheld a government plan engineered by its radical Environment Minister to ban oil production. "France is on an unstoppable path to scrapping fossil fuels," said Nicolas Hulot, the green activist and agitator named by President Emmanuel Macron as his Environment Minister after the May 2017 election, after the vote to ban oil output. BNP in a move that coincided with the government ban on oil issued a long list of hydrocarbon projects it would not be involved in or would be withdrawing from. The bank, in which the government holds no stake, stated that there would be "no financing of LNG terminals that predominantly liquefy and export gas from shale" and there would be no financing of pipelines that "primarily carry oil and gas from shale" and the bank would have "no business relations" with companies that derive the majority of their revenue from these activities. "The BNP Paribas Group will no longer do business with companies whose principal business activity is the exploration, production, distribution, marketing or trading of oil and gas from shale and/or oil from tar sands," it said. BNP and its investment banking unit are also ceasing the financing of projects that are primarily involved in the transportation or export of oil and gas from shale or oil from tar sands. "These new measures complement the Group's previous decisions to reduce its support for coal mines and coal-fired power generation, to increase its total financing for renewable energy to 15 billion euros ($17.8Bln) by 2020," the bank stated. The French bank has been a regular representative in bond sales by LNG shipping companies for newbuild financing and has been retained by several LNG development projects on the US Gulf Coast of Louisiana and Texas, committed to using shale-gas at their liquefaction plants. BNP said its policy was to bring its financing and investment activities into line with the aim of government and international policies to reduce global warming. “To achieve this goal, the world must reduce its dependence on fossil fuels, starting with oil and gas from shale and oil from tar sands whose extraction and production emits high levels of greenhouse gases and has harmful effects on the environment,” it said. These measures mean that BNP will gradually cease to finance a significant number of players who are not actively part of its view of the transition to a lower carbon economy, of which LNG has always been a part. “We’re a long-standing partner to the energy sector and we’re determined to support the transition to a more sustainable world,” said Jean-Laurent Bonnafe, Chief Executive of BNP. “As an international bank, our role is to help drive the energy transition and contribute to the decarbonisation of the economy. As we have announced, we’re committed to working with and supporting those energy sector partners who have decided to make environmental issues a central part of their business policy,” the CEO said.

BUREAU VERITAS, the French maritime classification society, has issued new rules on Floating Storage and Regasification Units (FSRUs) in response to industry demands to set out technical requirements for the vessels carrying out different operations. “These requirements span demand for units that may operate as a floating terminal for one or more decades to FSRUs that may be required for much shorter periods and whose operators may want the option of trading as an LNG carrier,” said Bureau Veritas in announcing the measures, known as Rule NR645. “Demand for FSRUs is growing. They are a fast, cost effective route to meet growing demand for LNG as a clean and cost competitive energy source,” the class society explained. “The new BV rules enable the classification of all types of floating storage and regasification assets in a comprehensive and pragmatic manner by building on Bureau Veritas's extensive experience in the LNG sector,” it added. The rules set out technical requirements to address the technical and operational issues of FSRUs They address this range of needs while applying a unified approach to safety and design challenges and providing "clarity in terms of classification requirements" by offering two distinct class notations. They are the "Liquefied Gas Carrier - FSRU notation" and the "FSRU notation". For the "Liquefied Gas Carrier" rules, this enables gas trading in addition to floating storage and regasification terminal operations. "The notation provides the possibility for exemptions from the traditional class survey regime, such as five-year, dry-docking survey requirements, when the vessel is in use as an FSRU," Bureau Veritas said. "For units dedicated to pure gas storage and regasification terminal operations and not intending to trade - the FSRU notation - this provides full optimization for site conditions and a class survey regime as applicable to permanent units with continuous operation requirements. No dry-docking would be required and some exemptions from IGC Code requirements compared to typical LNG carriers are allowed. For example, no bottom damage stability requirements would be necessary having addressed specific operational circumstances," it said. Jean-François Segretain, Marine Technical Director of Bureau Veritas said FSRUs are a special market with both "marine" and "offshore" approaches and requirements involved. "So, FSRU projects raise a lot of questions from all stakeholders," Segretain pointed out. "These new rules take into account the specific technical, regulatory, operational and environmental requirements of FSRU stakeholders to provide a much higher level of confidence when making significant commercial decisions," he added. With a growing demand across the gas supply chain, Bureau Veritas specialists are involved in a wide range of LNG projects, including the Yamal Project in Arctic Russia and its 15 Yamal ice-class LNG carriers.

EBARA CORP., the Japanese process industries company whose headquarters are in Tokyo, said its EIC Cryo unit in the US for LNG and turbomachinery equipment has been integrated with Ebara's other US subsidiary, the Elliott Group, in the US state of Pennsylvania. Ebara said the US EIC Cryo and the cryodynamics division will become part of the Elliott Group, based in the town of Jeannette in Pennsylvania. "This integration will further strengthen our position in liquid gas markets," said Ebara. "The integration of the two businesses is a natural fit. In addition to sharing the same corporate parent, we also serve many of the same markets and customers," said Ebara. "These synergies will enable us to support our customers more efficiently with integrated product options. Elliott Group's global service footprint and manufacturing capability will enhance EIC Cryo's capabilities," said the Japanese company from its US base. Ebara said the integration of EIC Cryo, including relocation of manufacturing and test facilities into Elliott Group, will take place over the next 24 months. "EIC Cryo will continue to operate under that name and will be operated as one of four business units within Elliott," it explained. At the same time, Elliott announced new executive appointments to go with the restructuring. Elliott said it had appointed John Rann as Vice President of its newly integrated cryogenic pumps business for EIC Cryo. "John's broad experience in oil and gas processing makes him uniquely qualified to lead EIC Cryo, and his in-depth knowledge of processes related to the production of LNG and other liquefied gases will reinforce this natural expansion of Elliott's technologies and capabilities," said Michael Lordi, Chief Operating Officer of Elliott. Ebara said Rann joined Elliott's UK engineering apprenticeship programme in 1973. "In the four decades since, he has worked for each of Elliott's business units, in every region of the world, in positions ranging from manufacturing and product engineering, to sales and marketing. Most recently, he has held executive roles as Vice President of Industrial Products from 2011 to 2013, and Vice President of Engineered Products from 2013 to October 2017," the company said. Elliott also announced the promotion of Shugo Hosoda to Vice President of Engineered Products in succession to Rann. Hosoda transferred from parent company Ebara in 2016 to serve as Deputy Vice President of Elliott's Engineered Products business. Prior to his transfer to Elliott, he served as Division Executive for Ebara's Corporate Strategy Planning Division in Tokyo. "Shugo brings nearly 25 years of product engineering and executive experience within Ebara and Elliott to his new role," said Lordi. "With his strong credentials in business development, strategic planning, and R&D, he is well equipped to lead our Engineered Products business," he added.

EXXONMOBIL, the US major with worldwide volumes from liquefied natural gas production plants in areas such as the Middle East and the Asia-Pacific region, said a shipping industry survey it conducted found that the route to compliance with the International Maritime Organization 2020 global sulphur cap of 0.5 percent is unclear for many vessel operators. ExxonMobil, a main partner in the Qatar production of 77 million tonnes per annum of LNG some of which could be directed to LNG-fueled ships to meet the new IMO standards, said the survey results highlight an ongoing sense of confusion and lack of preparedness. According to 70 percent of respondents, the shipping industry was not yet ready for the deadline which would require maritime fuels such as LNG or alternatives with close to zero sulphur. "The make-up of the marine fuel mix in 2020 and beyond is a clear area of concern, with wide-ranging views from the industry on how the landscape will evolve," said ExxonMobil in its analysis of the findings. Many shipping company people who answered the survey are expecting the development of new low-sulphur fuels. A further 45 percent of respondents forecast increased investment in abatement technologies such as scrubbers "Thirty-two percent of those surveyed predict that a combination of heavy fuel oil, marine gas oil and fuels and blends will be used, while 69 percent believe the cap will lead to the development of new low sulphur fuels," said the US major. "At ExxonMobil we expect that new 0.5 percent fuel formulations will emerge, based on low sulphur refinery streams, in addition to novel fuel blends," said Iain White, Global Marine Marketing Manager at ExxonMobil. "As a result, it's likely we will see increased compatibility and stability problems, which will make purchasing fuels from a trusted supplier more important than ever," added White. The cost implications of the cap were also highlighted as a potential challenge, with 53 percent of respondents predicting an increase in fuel spend. "When asked about the uptake of LNG, 31 percent of respondents believe there will be a growth in its adoption as a marine fuel. These findings align with ExxonMobil's '2017 Outlook for Energy: A View to 2040', which predicts that by 2040 global LNG consumption will rise to more than two and a half times the 2015 level," the company stated. ExxonMobil said 45 percent of respondents forecast increased investment in abatement technologies such as scrubbers, marine exhaust gas cleaning systems that remove sulphur oxides from ship's engine as well as other exhaust gases and pollutants. "However, only 11 percent said they were actively looking to install a scrubber before 2020, with 40 percent citing a lack of economic clarity as a reason for forgoing investment," said ExxonMobil. "The results of this survey show that we are heading to a multi-fuel future and that there is not one obvious fuel solution that will apply to all vessels," said White. "To avoid the pitfalls that may lie ahead, it's vital that operators work closely with trusted fuel suppliers to ensure that they select the best route to compliance for their vessel's needs," he stated.

FLEX LNG, the Oslo-listed company whose shareholders include a fund controlled by John Fredriksen, has named Oystein Kalleklev as its new Chief Financial Officer as it plans to take its place in the floating storage and regasification market for import terminals. Shipping tycoon Fredriksen retains a 52 percent stake in Flex, which is awaiting the delivery of six LNG carriers by 2019 and is planning joint ventures with US export and liquefaction plant developer NextDecade Corp. The Fredriksen stake in Flex is held by Geveran Trading, a company indirectly controlled by trusts established by the billionaire for the benefit of his immediate family. Flex said Kalleklev brought extensive experience in the shipping and energy sectors and capital markets experience to the company. Prior to joining Flex, he served as CFO of Knutsen NYK Offshore Tankers AS from 2013 and Chairman of the General Partner of NYSE-listed Knot Offshore Partners. Kalleklev also worked as CFO for industrial investment company, the Umoe Group, from 2006 to 2011. In addition, Kalleklev was a partner at Nordic investment bank Clarksons Platou from 2011 to 2013. He holds an MSc degree in Business Administration from Norwegian School of Economics and a BA in Business and Finance from Heriot-Watt University in Edinburgh. "I am pleased to announce that Oystein has joined Flex LNG," said Jonathan Cook, Flex Chief Executive. "We expect that the breadth of his industry and corporate finance experience will add significant value to the company as we work towards building the business into a leading player in the LNG shipping and floating regasification markets," added

Cook. The six Flex newbuilds will each have a capacity of 174,000 cubic metres when completed at Samsung Heavy Industries and Daewoo Shipbuilding and Marine Engineering in South Korea, with delivery dates in 2018 and 2019. Flex is marketing these vessels for charter and is also actively pursuing FSRU projects with the ships in cooperation with NextDecade, a company developing the Rio Grande LNG export project in Texas and whose CEO is former Shell LNG executive Kathleen Eisbrenner. These joint ventures include one European project proposed with NextDecade for the Irish port of Cork.

GAS NATURAL Fenosa, the Spanish liquefied natural gas market participant, and Norwegian fuel-transfer technology company Connect LNG said they completed a fuel operation in Norway using the small-scale carrier "Coral Energy" and a new system that removes the need for jetty structures. The LNG ship-to-shore transfer took place at the onshore LNG terminal at Heroya in Norway. The patented Universal Transfer System (UTS) is described by Connect as a floating solution for transfers between ship and shore that replaces the need for cost and environmental intensive harbour and jetty structures. "This solution allows for rapid expansion of the value chain and transfer of LNG at locations where it was previously not possible due to environmental and economic constraints," the Spanish and Norwegian companies said after the trial. "Gas Natural Fenosa, in collaboration with Connect LNG is putting in the market a system to enable rapid expansion of the LNG value chain to allow end users to access cheaper and cleaner energy," they added. GNF is Spain's largest LNG market participant. The utility has volumes booked from plants such as Sabine Pass in the US state of Louisiana and will also import cargoes from the new Russian plant on the Yamal Peninsula in Siberia when it comes on stream. The UTS cargo-transfer system is a floating platform which can connect to any LNG carrier. The fuel is then transferred from the platform to the onshore terminal through floating flexible pipes. "We started an innovation journey and here we are with a game-changing solution that is revolutionary for the LNG industry," said GNF. "From now on, we have a market-ready system that opens a world of possibilities in the LNG small-scale business," the Spanish company added. The Norwegian company said its system was ideal for "cost-efficient marine transfer of LNG" as well as other fluids such as liquefied petroleum gas, where safety requirements are similar. "Connect LNG's patent-pending solution comprise a uniquely designed platform, transfer lines, process equipment and mooring systems for safe and efficient connection of transfer lines between a ship and a terminal," the Norwegian company said. "The ship is kept in position during operations, for instance by a conventional multi-buoy mooring system," it added. "The attachment system minimizes interaction forces, protecting manifolds, aerial hoses, the ship hull and effectively absorbs forces from floating transfer lines," Connect stated. The Norwegians said the system is designed for import, export and bunkering of fluids from all types of terminals and does not require any ship modifications.

GASSCO, the Norwegian pipeline and natural gas infrastructure company, has taken over as operator of the gas processing plant at Nyhamna on the West Coast of Norway as part of plans to boost pipeline export capacity in competition to LNG shipments in Europe. The Nyhamna plant was originally built to handle onshore processing and the export of gas from the Ormen Lange field in the Norwegian Sea. Gassco said that after a substantial upgrading, the plant can now also handle gas from Aasta Hansteen in the Norwegian Sea as well as other future fields which may be tied into the Polarled pipeline. "By virtue of its role as the neutral operator responsible for operations and infrastructure in Norway's gas transport systems, Gassco is now running Nyhamna and its further development," the Norwegian company explained. "This plant fits well with our portfolio and, with the Polarled pipeline, increases gas export capacity from the Norwegian Sea," said Gassco Chief Executive Frode Leversund. "The Nyhamna expansion project has helped to boost its processing capacity and permits better utilisation of the surplus capacity established earlier in the Langeled pipeline to the UK," added Leversund. "That provides flexibility and opportunities which in turn create renewed interest in the Norwegian Sea as a gas province. Our goal is to fill the Polarled-Nyhamna-Langeled axis with gas," he stated. Running for 482 kilometres from Aasta Hansteen to Nyhamna, the Polarled pipeline will also allow the processing plant to receive gas from additional fields. Opened in 2007, Nyhamna was dedicated to gas from Ormen Lange. With Aasta Hansteen as its second field, it now has an export capacity of 84 million standard cubic metres per day. "This electrically driven facility allows gas from the axis to be brought to market with very low CO2 emissions per unit of gas delivered," said the Gassco CEO. "That's positive for both customers and the environment," he added. Ownership of the Nyhamna plant was formally transferred on October 1 from the Ormen Lange licence to the new Nyhamna JV partnership. This comprises Statoil, Petoro, Shell, Dong, Wintershall, OMV, ExxonMobil, Total, ConocoPhillips, CapeOmega, Edison and DEA. "We've prepared well for this change," said area vice president of Shell, Odin Estensen. "Gassco is taking over the commitments related to operation and further development. Meanwhile, we'll remain the technical service provider (TSP) for Nyhamna, along the same lines as Statoil at the Karsto and Kollsnes plants," explained Estensen. "Our employees will continue to do the same challenging job at Nyhamna as before, and we will remain operator for the Ormen Lange field itself," he added.

GE OIL and Gas (BHGE), the merged Baker Hughes company, a key supplier of services and equipment to the LNG industry, said its board of directors had elected President and Chief Executive Lorenzo Simonelli as Chairman of the BHGE board. Simonelli will continue in his President and CEO role, which he has held since the closing of the merger between oil and gas services company Baker Hughes Inc. and General Electric's GE Oil and Gas business in July 2017. "Simonelli replaces former GE Chairman and CEO Jeff Immelt, who retired from the BHGE board effective October 2," said BHGE. BHGE is a maker of LNG equipment from gas turbines to pumps and gearing technology, while before the merger GE Oil & Gas was lined up by several large US LNG export projects as a supplier. It also became an initial investor in some of the development companies with sites on the US Gulf Coast. BHGE's global organization now employs around 70,000 people in four product divisions. These are Oilfield Services, Oilfield Equipment, Turbomachinery and Process Solutions and Digital Solutions. "I am honored to take on the added role of chairman and further help BHGE win in the market and deliver for our shareholders," said new Chairman Simonelli. "We have a differentiated fullstream portfolio, a great team and valued customers," said Simonelli. "We are making the right moves to compete in the down cycle and position the company for long-term value creation. I look forward to serving the board, the company and shareholders," he added. BHGE noted that in addition to Immelt's departure, BHGE board member Larry Nichols announced his decision to resign from the board. "Nichols served as a member of the legacy Baker Hughes Inc. board, and for the past 16 years has provided valuable counsel and board leadership," BHGE added. "With these two resignations, BHGE has reduced the size of its board to nine members and has named current GE-designee BHGE board member W. Geoffrey Beattie as the new lead director," the company added. GE owns approximately 62.5 percent of BHGE, and retains five designated seats on the BHGE board. "BHGE is a valued and strategic energy business and an important part of the GE portfolio," said GE Chairman and CEO John Flannery. "With Lorenzo's new chairmanship, the strong GE representation and the experience of the legacy Baker Hughes Incorporated board members, the board leadership is in good hands," added Flannery.

GOLAR LNG, the project and shipping company, said the floating LNG production vessel, the "Hilli Episeyo", has departed Singaporean waters to be deployed for an FLNG joint venture before the end of November 2017 offshore the West African state of Cameroon. The FLNG vessel had been moved out of Keppel Shipyard in Singapore in early October into a deep-water anchorage offshore Singapore for final commissioning before the vessel is handed over for a joint venture in the West African state of Cameroon. "The earlier than anticipated departure reflects an operational decision to complete LNG bunkering in Cameroon rather than in Singapore," said Golar. "The voyage to Cameroon is expected to take between 32 and 40 days," added the Hamilton, Bermuda-based company founded in Norway. The mooring system has already been installed offshore Cameroon and is ready for hook up to the "Hilli Episeyo". The Golar FLNG vessel will be put into operation off the port of Kribi in Cameroon in a venture also involving the state energy company, Société Nationale des Hydrocarbures (SNH) and European oil and gas company Perenco. The shipyard work for the project completed by Keppel involved the world's first FLNG hull conversion. The "Hilli Episeyo" was converted from a 1975-built, Moss-type LNG carrier, the "Hilli", with a storage capacity of 125,000 cubic metres. The topside equipment includes a pre-treatment system, four single mixed-refrigerant liquefaction Trains using PRICO technology from US company Black & Veatch and boil-off gas compression and offloading equipment. The "Hilli Episeyo" is designed for a liquefaction capacity of about 2.4 million tonnes of LNG per annum. Keppel has said it believed that compared to newbuilds, converted FLNGVs are significantly more cost-effective and faster to market "without compromising safety and processing" capabilities. The decision to proceed with the "Hilli Episeyo" came in 2015 when Russia's Gazprom, through its Singapore-based Marketing & Trading unit, won the tender to be the sole off-taker from the Cameroon FLNG venture, clearing the way for the project financing to go ahead. Gazprom signed up for 1.2 million tonnes per annum of LNG for an initial eight years on a free-on-board basis, whereby the Russians supply their own ships. The Cameroon project is based on the initial allocation of feed-gas supplied by Perenco and SNH from the Sanaga Sud and Ebome gas fields. Golar is also involved in the FLNG production project in Equatorial Guinea, also in West Africa.

KBR, the US LNG and energy engineering company, was awarded an engineering and project management services contract for the biggest natural gas joint ventures currently under way in Algeria at In Salah and In Amenas. The contract was awarded by Algerian state energy company Sonatrach, also operator of the nation's two LNG export plants on the Mediterranean coast, and by partners Statoil of Norway and BP of the UK. KBR said the scope of the work included providing design engineering, procurement services as well as construction management at the major ongoing gas developments at In Salah Gas and In Amenas. The gas processing facility at In Amenas was the scene of a terrorist attack in January 2013 during which 40 workers were killed. The In Amenas joint venture is one of the largest wet gas projects in Algeria and involves the development and production of natural gas and gas liquids from fields in the Illizi Basin in south-eastern Algeria. It is called wet gas because it contains ethane, propane, butane and the heavier hydrocarbons. First gas was produced at In Amenas in 2006. Its compression project is the final stage of planned development. The In Salah project is a dry gas venture of mainly methane and involves the development of seven proven gas fields in the southern Sahara, 745 miles south of the capital Algiers. The first phase of development came on stream in July 2004 covering the largest three gas fields. The second phase, the In Salah southern fields project, came on stream in February 2016 and involved the remaining four fields. Other construction phases are still continuing and being planned. "This work, which is expected to be performed over 48 months, will be a KBR collaboration with engineering and the procurement services being performed from the UK and Chennai offices in partnership with the local, in-country, engineering office," said KBR. KBR pointed out that it was proud of its long history in Algeria where it has been present for 45 years. "This project will demonstrate KBR's ability to utilize its global resources to provide the full spectrum of engineering project services on one of the largest projects in the country," said Jay Ibrahim, KBR regional president. "Revenue associated with this project will be booked into backlog of unfilled orders for KBR's Engineering & Construction Business as task orders are confirmed," said the Houston-based company.

OPHIR Energy, the UK exploration and production company with assets in Africa and Asia, said it awarded the upstream contract for the Fortuna floating LNG project offshore Equatorial Guinea to a joint venture comprising a subsidiary of oil and gas services firm Schlumberger and UK-based company Subsea 7. The joint venture is called Subsea Integration Alliance, which is a partnership between Schlumberger's Houston, Texas-based firm OneSubsea and Subsea 7. Ophir said the contract is structured as an engineering, procurement, construction, installation and commissioning (EPCIC) contract for the subsea umbilicals, risers and flowlines and for the subsea production systems scope of work. A final investment decision on Equatorial Guinea Fortuna FLNG is expected before the end of 2017 once project funding is complete. As well as Ophir, the Fortuna partners include shipping and project company Golar LNG, Schlumberger and the Equatorial Guinea government and state energy firm. The project partners have also signed an agreement nominating global commodities company, the Gunvor Group, as the main LNG buyer for the offtake. They have ordered a floating production hull, the former Golar vessel, the 126,000 cubic metres capacity "Gandria", to be converted at Keppel Shipyard in Singapore. Ophir said the scope of the subsea contract just awarded is to deliver 440 million standard cubic feet per day of gas through infrastructure comprising four wells in the Fortuna field and the Viscata field located at an average water depth of 1,790 metres. "The EPCIC schedule is consistent with the planned delivery of first gas in 2020," said Ophir. Nick Cooper, Chief Executive of Ophir, said the FID was now closer with the "full suite" of upstream and midstream construction contracts now awarded. "The government is a key stakeholder in the Fortuna project and I am pleased that the local content requirements in these contracts will help to further develop the state of Equatorial Guinea," added Cooper. The Fortuna FLNG project when completed will produce 2.5 million tonnes per annum of LNG from the converted hull deployed over the gas fields. Equatorial Guinea already has an onshore LNG production plant on Bioko Island, operated by US company Marathon Oil and on stream since 2007. The single-Train Bioko facility has a nameplate capacity of 3.4 MTPA.

SCOTLAND has decided to ban shale-gas extraction, meaning the loss of a potential jobs renaissance and the country will now have to continue importing cargoes of ethane from US shale gas. It may also eventually need more conventional LNG cargoes than are currently planned for domestic and industrial use. UK company Ineos, the group which owns Scotland's only crude oil refinery at Grangemouth on the River Forth and produces bulk fuels and products for the petrochemical industry, condemned the recent Scottish devolved government's decision to continue indefinitely a moratorium on hydraulic fracturing in place since 2015. Ineos pointed out that the Scottish decision went against a report commissioned by the Government itself which judged shale-gas extraction through fracking was safe. The company's subsidiary, Ineos Shale, is the operator of two shale-gas exploration licenses in areas between Glasgow and Edinburgh. Ineos, in addition to being one of the largest global chemical companies and the importer of US shale gas in the form of ethane, has been broadening its presence in UK shale-gas exploration to lessen its future reliance on imports. The first shipment of US ethane, derived from shale gas, was unloaded at Grangemouth in September 2016 to be used as chemical plant feed-stock. "The Scottish announcement comes at the end of a two-year process during which Scottish industry has been left in limbo," said Ineos. "With an official ban on shale extraction, Scotland will miss out on the numerous economic and employment benefits that will be enjoyed by the rest of the UK," the company added. "Expert reports have clearly stated that this technology can be applied safely and responsibly - but it will be England that reaps the benefits," it said. In addition to the shale-gas ethane imports, there are already plans to import conventional LNG to the port of Rosyth to meet the natural gas needs of areas that have not had investment in pipeline connections. Tom Pickering, Operations Director of Ineos Shale, said: "It is a sad day for those of us who believe in evidence-led decision making. The Scottish Government has turned its back on a potential manufacturing and jobs renaissance and lessened Scottish academia's place in the world by ignoring its findings," stated Ineos. Over the last 50 years North Sea exploration has been a rare economic and technological success story for the country. "As North Sea oil and gas declines, shale gas could offer Scotland a vital opportunity to revitalise its energy economy," said Ineos. Pickering said the decision was a slight on the dedicated professionalism that Scottish workers have pioneered in the North Sea. "We lead the world in exploration safety, but I fear we will start to see large numbers of Scottish workers leaving the country to find work as the North Sea oil and gas industry continues to decline," added Pickering. He pointed out that shale gas was fully backed by the UK government and the British Geological Survey and offered the UK an opportunity to provide the energy the economy needs with reduced carbon-dioxide emissions. Pickering concluded: "Natural gas will be needed by Scotland for the foreseeable future and production from the North Sea continues to decline. This decision, which beggars belief, means gas becomes a cost for the Scottish economy instead of an ongoing source of income. It speaks volumes about Scottish leadership on the world stage and sends a clear and negative message to any future investors in Scotland."

SDX ENERGY, the UK-listed exploration and production company, said it had made a natural gas discovery in Morocco, the North African kingdom that is a net importer of energy and is preparing to join the ranks of global LNG importers. Morocco does produce some amounts of its own oil and natural gas, though these volumes are not sufficient to cover its needs. SDX said it made its Moroccan discovery at its onshore KSR-14 development well covered by the Sebou permit in which it has a 75 percent interest. The discovery is part of a 135 square kilometres concession located in the Rharb Basin between the coastal cities of Tangier and the capital Rabat "The KSR-14 well was drilled to a total depth of 1,830 meters and encountered 20 meters of net conventional natural gas pay in the Guebbas and Hoot formations over four intervals," said SDX. "The initial results have exceeded pre-drill estimates, and work is currently underway to further evaluate the well's accurate recoverable volume estimate," the company said. SDX said that once the drilling rig has left the location, the company expects that the well will be connected to the existing infrastructure and produced. "The well is anticipated to be on production in approximately 30 days," the company added. Paul Welch, President and Chief Executive of SDX, said the positive result followed the company's recent oil discovery at its West Gharib Concession in Egypt. "This outcome in Morocco is an excellent start to our nine-well programme, where we are targeting an increase in our local gas sales volumes in Morocco by up to 50 percent," said Welch. "I look forward to reporting on the flow rates from the KSR-14 discovery," he added. SDX, whose headquarters are in London, has a working interest in two producing discoveries in Egypt's onshore Eastern Desert region, adjacent to the Gulf of Suez, as well as its Sebou concession in Morocco's Rharb Basin. The Moroccan gas discovery comes as the nation plans to follow the path of Egypt, Jordan, Kuwait and the United Arab Emirates to become the latest Arab-speaking nation to purchase LNG shipments. Morocco's Office National de l'Electricite et de l'Eau Potable (ONEE) first revealed plans in January 2017 to import an initial 5 million tonnes per annum of LNG for a gas-fired power venture. It has appointed consultants to advise on an import terminal project and adjacent to a gas-fired power plant, as well as the construction of a jetty for LNG carriers. ONEE has chosen as its financial advisers the international bank, HSBC Middle East Ltd, while the Paris office of law firm Ashurst LLP will give legal advice on the multiple projects. All current LNG importers among the Arab nations use floating storage and regasification units deployed at the ports of Aqaba in Jordan, Ain Sokhna in Egypt, Dubai in the United Arab Emirates and Mena Al Ahmadi in Kuwait. Morocco currently receives natural gas supplies from the Maghreb-Europe Pipeline which transits the country on its way from Algeria to Spain and Europe. In lieu of charging the pipeline company transit fees, Morocco instead receives payment in the form of gas supplies. Morocco's near neighbour Spain has Europe's largest network of LNG import terminals and is also a re-exporter of cargoes.

SHELL completed the sale of its minority interest in Comgas, Brazil's largest natural gas distributor, for cash and shares amounting to $380 million as it continues to offload assets that are not part of the core business. Brazilian energy conglomerate Cosan SA agreed to pay Shell the sum for its 16.8 percent stake in Comgas by transferring shares equal to 5 percent of Cosan's total equity in Brazilian shares and $168M in cash, including around $70M when the transaction is completed and a further $68M in cash a year later. Shell said its future share position in Cosan will be managed for "value realization" over time. Cosan is currently a 63.4 percent shareholder in Comgas. Comgas had previously been majority-owned by LNG portfolio company BG Group, now part of Shell. However, in November 2012, BG had completed the sale of over 60 percent of Comgas for $1.7 billion to Cosan. Comgas has a distribution network covering more than 170 towns and cities in the state of Sao Paulo. It is the largest piped natural gas distributor in Brazil with more than 14,000 kilometres of pipelines and over 1.7 million customers. Cosan is one of Brazil's largest companies on the nation's stock exchange in Sao Paulo and focuses on investments on strategic industries such as agribusiness, fuel and natural gas distribution and logistics. Shell said it would retain its other diverse operations in Brazil that are not affected by the transaction, including its deepwater portfolio and downstream business. Shell said its Comgas sale agreement was expected to be completed by year-end, subject to customary closing conditions, regulatory approvals and certain consents. "This transaction allows us to focus our efforts in Brazil on areas where we see the most strategic value for Shell longer-term," said Shell's Integrated Gas Director Maarten Wetselaar. "Brazil is an important country to Shell, and our portfolio of high quality assets and development opportunities positions us well for the future," said Wetselaar.

SHELL said that two of its fuel subsidiaries signed a long-term agreement with shipping line Siem Car Carriers to supply LNG to fuel two new car-carrying ships being used to transport Volkswagen vehicles from Europe to North America. The Shell LNG and Shell Western units signed the fuel deals for the vessels, expected to be delivered in 2019. They will be among the first car-carrying ships in the world to be powered by LNG and will be among the first LNG-fuelled vessels to operate trans-Atlantic between Europe and the US. Siem Car Carriers is part of an industrial group also involved in the transport of refrigerated cargoes, oil and gas offshore services, shipyard operations and finance and has its headquarters in the Cayman Islands. Shell plans to refuel the vessels in Northwest Europe and at a second supply point in the US. The Anglo-Dutch company's LNG bunkering operation currently comprises of one small-scale ship and is based in the Dutch port of Rotterdam. Shell is a break-bulk cargo operator at Rotterdam's Gate LNG import terminal where shipments are received under long-term contract from nations such as Qatar. "This agreement is an important development for Shell's growing LNG fuels business," said Lauran Wetemans, Shell's General Manager of Downstream LNG. "We are pleased to be working with SIEM Car Carriers to provide a cleaner burning fuel and look forward to future opportunities for collaboration," added Wetemans. Shell noted that more ship owners and operators were choosing LNG fuel over traditional marine fuels to respond to sulphur and nitrogen oxide emissions regulations, including the International Maritime Organization decision to implement a global 0.5 percent sulphur cap from 2020. Shell has previously signed an agreement to supply LNG maritime fuel to Russian shipping line Sovcomflot for the world's first LNG-powered Aframax crude oil tankers. Those ships will operate in the Baltic Sea and Northern Europe, transporting crude oil and petroleum products. Shell will additionally supply LNG to the world's first LNG-powered cruise ships following an agreement with Carnival Corp. of the US. When completed, the two Carnival vessels will be the world's largest passenger cruise ships and will enter service in northwest Europe and the Mediterranean in 2019.

STATOIL, the Norwegian energy company, has chosen a joint venture comprising French energy company Engie and two Japanese partners to supply LNG marine fuel in the Dutch port of Rotterdam for four crude oil shuttle tankers. The four Statoil dual-fuel vessels with LNG capability are scheduled to enter service in early 2020 and will operate Northwest European waters within an Emission Control area. The LNG fuel agreement is the second major contract secured by Engie for its LNG joint venture also involving Japanese shipping line Nippon Yusen Kabushiki Kaisha (NYK) and the trading house Mitsubishi corp., a company with assets along the LNG value chain. The first customer of the Engie-led bunkering joint venture was United European Car Carriers (UECC) for several LNG-powered vessels it operates. Engie and its partners will use the newbuild LNG bunkering vessel "Engie Zeebrugge", a 5,000 cubic metres-capacity fueling ship, to fulfil current and future contracts in the area of the ports of Rotterdam and Zeebrugge, the home port of the vessel. The "Engie Zeebrugge" carried out its first trial bunkering operation at Zeebrugge in April 2017 and has since bunkered vessels for UECC. Engie, Mitsubishi and NYK have set up a marketing company called Gas4Sea to develop the LNG fuel market in northwest Europe and elsewhere. Statoil has booked fuel from the Gas4Gas venture even as it has supplies of its own from Europe's only baseload LNG production plant at Hammerfest in northern Norway. The Gas4Gas bunkering vessel was built at the Hanjin Heavy Industries and Construction Co. shipyard in the port of Busan in South Korea and delivered in February 2017. The vessel will regularly take on LNG at Zeebrugge where carriers deliver shipments from Qatar and elsewhere and where docking is also provided for small-scale tankers supplying the regional market on a break-bulk basis. More ship owners and operators are choosing LNG over traditional marine fuels to respond to the creation of ECAs with tougher pollution rules in Northwest Europe and elsewhere. Additional sulphur emissions regulations come into force in 2020 when the International Maritime Organization implements a decision for a global 0.5 percent sulphur cap.

STOLT-NIELSEN, the Norwegian-listed shipping and storage company with small-scale LNG project plans on the Italian Island of Sardinia and in Scotland, posted a 19 percent rise in third-quarter net profits as revenues also increased. The company, listed on the Oslo stock exchange and with operational offices in London and elsewhere, reported net profit of $18.5 million versus $15.6M in the year-ago quarter and revenues of $513.8M versus $500.8M in the same three months of 2016. Net profit for the first nine months was $49.2M compared with $90.3M in 2016, while revenues amounted to $1.49 billion versus $1.41Bln in the first nine months of last year. The Stolt-Nielsen gas division is one of the company's smallest units and is currently being developed, while its main business remains tankers, containers and fuel terminals. "SNG continues to focus on the development of small-scale LNG storage and distribution supply chains to serve locations lacking access to LNG pipelines," said the earnings statement. "On September 29, subsequent to the quarter-end, Stolt-Nielsen Gas invested $5.6 million in Higas Srl, increasing SNG's ownership to 66.25 percent," Stolt-Nielsen said. It was referring to the Livorno, Italy-based private company behind the Sardinia LNG project. "Higas was formed to develop shore-based storage, regasification and distribution in the port of Oristana, Sardinia, to supply local industry with LNG," explained Stolt-Nielsen. "Further investments are planned subject to securing additional off-take contracts," the company added.

Additionally, Stolt-Nielsen and Flogas Britain in November 2016 signed an accord to work on a joint project to bring small LNG shipments to the eastern Scottish Port of Rosyth. The shipments are scheduled to start by 2019 in small-scale LNG carriers and will supply off-grid customers with LNG. "While SNL's third-quarter results were up, the improvement was largely driven by unrealised gains related to the bunker-hedging programme at Stolt Tankers," said Niels G. Stolt-Nielsen, Chief Executive of the company. "Excluding the impact of that programme, results at Stolt Tankers were down slightly, as market conditions continued to soften during the quarter. Results at Stolthaven Terminals were once again largely in line with those of the previous quarter, as we continue to implement actions aimed at improving that division's sustained long-term performance," added the CEO. "Stolt Tank Containers continued to show evidence of margin improvement, along with lower empty repositioning costs and improved contributions from joint-venture depots," he added. The company said its overall outlook remained unchanged. "We do not anticipate any substantial improvement in the chemical tanker market until the latter part of 2018, when the current orderbook will have been significantly reduced and the balance between tonnage supply and demand improves," the company said. "For Stolthaven Terminals, we continue to expect a modest but steady improvement in results, driven by actions to enhance operational performance across our network," it added.

TELLURIAN Inc., the developer of the Driftwood LNG project on the Gulf Coast of Louisiana has entered into a six-month time charter for a modern LNG carrier to start gaining market exposure by trading during the coming Northern Hemisphere winter. Tellurian, founded by former Cheniere Energy Chief Executive Charif Souki and by Martin Houston, who ran the operations of the LNG portfolio company, BG of the UK, has already purchased shale-gas assets while its project is going through the regulatory process. The company now has a six-month charter on the "Maran Gas Mystras", a tri-fuel diesel electric (TFDE) propulsion vessel with 160,000 cubic metres of storage capacity. The vessel was delivered in 2015 to owner Maran Gas, the LNG shipping unit of the Angelicoussis Shipping Group, a private company based in Athens, Greece. Tellurian took over the carrier for the short-term charter at the port of Galle in Sri Lanka on October 1. No details of the rates were disclosed, though vessels like the "Maran Gas Mystras" have during 2017 cost between $25,000 and $30,000 per day to hire. "At Tellurian, we are building a global natural gas business and proactively shaping the company to build long term value amid a robust and dynamic market," said Tellurian CEO Meg Gentle, also a former Cheniere executive. "As winter approaches, we will begin buying and delivering LNG on the 'Maran Gas Mystras', one of the most efficient vessels in the Maran Gas fleet," explained Gentle. "Developing our LNG marketing capabilities now prepares us to be one of the most flexible, competitive, and reliable LNG suppliers when Driftwood LNG begins operations in 2022," she added. Analysts said Tellurian was likely to become a regular trader in the Northern Hemisphere winter when LNG demand is highest in Europe and Northeast-Asia and arbitrage windows can open up. Tellurian has previously submitted applications to the Federal Energy Regulatory Commission to construct and operate the Driftwood liquefaction plant on a 1,000-acre site on the west bank of the Calcasieu River near the town of Carlyss in Calcasieu Parish. Souki's project involves constructing a liquefaction and export plant near Lake Charles to match the nearby Sabine Pass venture of Cheniere with 27 million tonnes per annum of output. Tellurian recently agreed to acquire acreage in Haynesville Shale play in the northwest of the state of Louisiana to add potential gas assets to its portfolio for future export. It entered into an agreement with a private seller to acquire natural gas producing assets and undeveloped acreage in northern Louisiana for $85.1 million. The transaction by Nasdaq-listed Tellurian is scheduled to close by the end of November 2017. The seller was described in Tellurian's Securities and Exchange Commission documents as an unrelated third party. Analysts pointed out that Tellurian's new gas assets in addition to providing future feed-gas from shale at competitive prices will also require investment funds for the development of the plays located in Red River, DeSoto and Natchitoches Parishes of Louisiana. The company said the 9,200 net acres have 138 operated Haynesville and Bossier drilling locations. Tellurian added that the Haynesville plays had around 1.3 trillion cubic feet of potential gas resources from 19 producing and operated wells with net current production of 4 million cubic feet per day. The asset purchase also comes with associated natural gas gathering and processing facilities. The Haynesville shale covers areas of northeast Texas as well as northwest Louisiana and is one of the most prolific in the US.

US pipeline operator Kinder Morgan and two other companies have signed an accord to develop the Gulf Coast Express Pipeline Project as an outlet for increased natural gas production from the Permian Basin for LNG export plant developers in Texas and for the Mexican pipeline market. Kinder Morgan Texas Pipeline (KMTP), a Kinder subsidiary, will work on the Gulf Coast Express (GCX Project) with DCP Midstream and Targa Resources. "The participation of the three parties involved with the GCX Project is subject to negotiation and execution of definitive agreements among KMTP, DCP Midstream and Targa," they said. The Permian oil and gas fields stretch over 75,000 square miles from West Texas into southeast New Mexico. They are split into two zones, the Delaware Basin in the west and the Midland Basin to the east, both with huge oil and natural gas resources in place. "As part of the definitive agreements, Targa and DCP Midstream would commit significant volumes to the proposed project, including certain volumes provided by Pioneer Natural Resources Company, a joint owner in Targa's WestTX Permian Basin system and one of the largest producers in the Permian," the companies explained. The capacity of the GCX Project is expected to be approximately 1.92 billion cubic feet per day (Bcf/d) and would include a lateral into the Midland Basin, consisting of approximately 50 miles of 36-inch pipeline and associated compression to serve gas processing facilities owned by Targa, as well as facilities owned jointly by Targa and Pioneer. Kinder currently operates 84,000 miles of pipelines and 155 terminals in North America. Denver-Colorado-based DCP owns and operates more than 60 plants and 64,000 miles of natural gas pipelines. The expected in-service date of the Gulf Coast Express continues to be scheduled for the second half of 2019, pending the completion of definitive agreements with shippers and a final investment decision. Kinder would build, operate and own a 50 percent interest in the project and DCP and Targa would each hold a 25 percent equity interest. "We are thrilled to have Targa join DCP Midstream and Kinder Morgan in developing the project and to add both Targa and Pioneer as major customers on the proposed system," said Kinder Morgan Natural Gas Midstream President Duane Kokinda. "With DCP Midstream and Targa, we now have two of the premier gathering and processing supply aggregators in the Permian Basin on board, as well as one of the Basin's largest producers with Pioneer," he added. "The commitments of these parties confirm our premise that combining supply source optionality in the Basin with unparalleled market access on the Agua Dulce end provides an attractive takeaway solution for the parties developing natural resources in the Permian Basin," explained Kokinda. Wouter van Kempen, Chairman, President and CEO DCP, said he was excited to have the opportunity to expand the company's portfolio in the Permian. "This is a strong collaboration of players that draws upon our combined capabilities to provide a competitive and capital efficient solution to the industry," said Van Kempen Joe Bob Perkins, CEO of Targa, commented: "We are excited to be joining KMI and DCP Midstream in the development of the GCX Project. "Given our significant Permian Basin footprint, continuing to provide our customers with flexibility and access to premier markets is always our focus, and we believe that the GCX project would further enhance those capabilities." The three companies said they anticipated that natural gas supply would be sourced into the project from multiple locations. These include existing receipt points along Kinder's KMTP and El Paso Natural Gas pipeline systems in the Permian, a proposed interconnection with the Trans-Pecos Pipeline and additional interconnections to the Waha Hub in north Pecos County in Texas. "Deliveries of natural gas into the Agua Dulce area would include points into KMTP's existing Gulf Coast network, KMI-owned intrastate affiliates (KM Tejas and KM Border pipelines), the Valley Crossing pipeline, the NET Mexico header and multiple other intrastate and interstate natural gas pipelines," they said.

VOLVO, the Sweden-based auto manufacturer, said it was introducing new heavy-duty trucks to run on liquefied natural gas and compliant with new European Union emission restrictions.

The Swedish firm said its new Volvo FH LNG and Volvo FM LNG trucks have the same performance, drivability and fuel consumption as Volvo's diesel-powered models. However, it said the carbon-dioxide emissions are 20 percent to 100 percent lower compared with diesel, depending on choice of fuel. The new Volvo FH LNG and Volvo FM LNG trucks are available with 420 horsepower or 460 horse-power for heavy regional and long-haul operations. Volvo said its LNG trucks were Euro 6-compliant, meaning they qualify for the latest EU directive to reduce harmful pollutants from vehicle exhausts. The Euro 6 standard was introduced in September 2015 and all mass-produced vehicles sold in the EU from that date need to meet these emissions requirements to reduce pollution. In its announcement, Volvo said it would start selling the vehicles during the second quarter of 2018 in the European market. "With our new trucks running on liquefied natural gas or biogas, we can offer an alternative with low climate impact that also meets high demands on performance, fuel efficiency and operating range," said Lars Martensson, director of environment and innovation at Volvo Trucks. "This is a combination that our customers in regional and long haulage require," added Martensson. Volvo said that instead of an Otto cycle engine, which is the conventional solution for gas-powered vehicles, the Volvo FH LNG and Volvo FM LNG are powered by gas engines using diesel cycle technology. The company said its 460 hp gas engine delivered maximum torque of 2300 Newton metres while the 420 hp version produces 2100 Nm, the same as Volvo's corresponding diesel engines. "What is more, fuel consumption is on par with Volvo's diesel engines, but 15 percent to 25 percent lower than for conventional gas engines," added Volvo. The fuel used is natural gas in the form of LNG or biogas, known as bio-LNG. Both fuels consist of methane. "If biogas is used, the climate footprint can shrink by as much as 100 percent, and if natural gas is used, the reduction is 20 percent," said Volvo. This relates to emissions from the vehicle during usage, known as tank-to-wheel.

WARTSILA, the Finnish power project company, which also makes propulsion and gas equipment for ships, said it was awarded the contract to give Finland its third small-scale import and regasification facility at the port of Hamina. The Hamina terminal will be the first of the three facilities in Finland to be connected to the national gas grid, offering security of supply to gas customers. Wartsila recently completed the second Finnish onshore terminal at Tornio, which enters commercial operations in early 2018. The company said it was awarded a turn-key contract by Hamina LNG for the terminal at a site in southern Finland about 145 kilometres east of the capital Helsinki. The Hamina project is a joint venture between Hamina Energia, a regional energy distribution company, and the Estonian Alexela Group, a terminal operator in the Baltic region Alexela is also involved in developing the Paldiski LNG import project in Estonia. Finland's first LNG import terminal at the port of Pori is owned by Nordic LNG player Skangas and its Finnish parent company Gasum, a natural gas operator. Skangas and Gasum are also shareholders in the Tornio terminal, along with the Finnish industrial group Outokumpu, the Swedish-Finnish company Svenskt Stal AB and EPV Energy. The Tornio terminal will primarily provide natural gas to Outokumpu's Tornio steel mill. Wartsila said the contract scope for the Hamina terminal includes civil works, infrastructure, a full containment storage tank with 30 000 cubic metres capacity as well as regasification, metering and boil-off gas handling systems. The Hamina terminal, expected to be operational by August 2020 will additionally offer truck-loading and will act as a regional ship bunkering station for LNG fuel. "We wanted to create a terminal infrastructure which would provide bunkering for vessels as well as diversify the country's sources of gas supply," said Peter van Buuren, Chief Executive of the Hamina LNG development company. "Wartsila's technology fits our need and they have the best local knowledge and experience as an EPC provider in harsh weather conditions. Wartsila offered us full engineering, procurement and construction capabilities as well as a unique know-how in gas processing," added the CEO. Timo Mahlanen, Senior Business Development Manager of Wartsila Energy Solutions, said the Hamina project was part of Finland's plans to create a network of medium-scale LNG terminals with the aim of offering gas supply to the local industry and LNG as fuel. "The project will bring a significant reduction in CO2 emissions by providing cleaner fuel for transport and industry," said Mahlanen. "At the same time, the LNG infrastructure will increase the security of supply in Finland with gas grid connection," he added. The newly-completed Tornio terminal at the port of Roytta is larger than the existing Pori facility which has been in operation since 2016. Tornio is set to become the biggest receiving terminal in the Nordic region when it begins commercial operations in 2018 with its storage capacity of 50,000 cubic metres. The first cargo for commissioning of the Tornio terminal is expected to be delivered in November.

WORLEYPARSONS, the Australian LNG and energy engineering company has put behind it several years of restructuring to pay 182 million pounds (US$240) to expand into the UK North Sea petroleum market with an agreed takeover. WorleyParsons is acquiring AFW UK Oil & Gas, a provider of engineering and construction services on the UK Continental Shelf after itself being the subject of takeover speculation for several years. WorleyParsons, whose past projects have included liquefaction plants in Western Australia such as Wheatstone LNG, earlier in 2017 also signed a long-term, multi-regional agreement with Chevron for engineering and procurement services. The Australians are funding the UK acquisition with a A$322M (US$250M) issue of new shares on the Australian Securities Exchange through a one-for-10 entitlement offer and with existing debt facilities. Around 24.8 million new WorleyParsons shares will be issued at A$13 per share, an 8.5 per cent discount to its last closing price. "We are excited to enter the UK North Sea market as a leading player based in Aberdeen," said WorleyParsons Chief Executive Andrew Wood. WorleyParsons has been a leading designer and builder of Asia-Pacific facilities and in addition to Wheatstone has worked on ventures such as the Northwest Shelf and Pluto LNG production plants in Western Australia in addition to the Singapore LNG import terminal. The Australian engineering group said the deal to buy AFW UK would accelerate its strategy to build "a world class global maintenance, modifications and operations (MMO) capability". AFW has five offices in the UK and two in the Middle East. WorleyParsons expects that the AFW transaction will be complete by the end of October and that its new acquisition would contribute to positive earnings per share in the first year. The AFW assets are being offloaded by the UK-listed engineering company Amec Foster Wheeler to address "competition concerns" in the UK market. Amec FW has recently been taken over itself by UK-based multinational energy company, the Wood Group, and the selling of AFW was to satisfy regulators. "AFW UK has world-class Maintenance, Modifications & Operations capabilities and is a leader in the Engineering & Construction, Operations and Maintenance and Hook-up services markets on the UK Continental Shelf," said WorleyParsons in a presentation to investors. "AFW has a strong track record of global expansion leveraging deep customer relationships, a strong track record and a highly capable management team. "The business represents the majority of Amec FW's former UK upstream Oil and Gas operations, divested as a remedy to competition concerns," it explained. "The compelling transaction provides a range of strong strategic benefits, including robust entry into the UK North Sea as a profitable market leader and to the attractive and growing global MMO market. The transaction combines AFW UK's capabilities and strong track record of global expansion with WorleyParsons' global network to create a genuine global MMO business," it stated. ■

Diary of events

2018

May
Flame Gas and LNG conference
14-17 May 2018
Hotel Okura, Amsterdam
The Netherlands
https://energy.knect365.com/flame

June
27th World Gas Conference
25-29 June 2018
Washington Convention Center
801 Mount Vernon Place Northwest
Washington, DC 20001, USA
http://wgc2018.com

September
Gastech
17-20 September, 2018
Fira Gran Via Conference Centre
Barcelona, Spain
www.gastechevent.com

Saipem XSIGHT proposes compact low-cost solutions for maximizing LNG regasification terminal efficiency

Julien Bellande, Sophie Caron of the Saipem XSIGHT division, with the collaboration of Bertrand Duparc and Omar Belaid of Saipem

In the global effort toward greenhouse gases emission reduction, natural gas is often presented as one of the environmentally acceptable energy sources for the next decades.

In its liquid form as LNG, natural gas is an easily transportable fuel with lower impacts on global warming and local emissions than coal or oil and as such this should occupy an increasing part of the world energy mix.

Downstream of the LNG chain, this implies that new infrastructures will be required to allow importing LNG in higher quantity.

Investment

If high investment costs have historically been an obstacle to the construction of new LNG import terminals, the development of low-CAPEX LNG import and regasification solutions over the last decade has contributed to promoting LNG as an energy source.

Indeed, a significant portion of the LNG import facilities built in the last 10 years are no longer onshore LNG terminals but Floating Storage and Regasification Facilities (FSRUs) or Floating Storage Units (FSUs) combined with modularized regasification facilities.

These facilities lower the cost of LNG import by replacing tailor-made onshore regasification terminals by standardized floating plants or converted LNG carriers built in high efficiency shipyards.

FSRUs and FSUs are often proposed as leased units by fleet operators, which allows energy companies benefiting from a quick and flexible LNG import solution with limited initial investment (but at the expense of additional leasing costs with respect to an owned unit).

Although LNG cost is currently low due to increasing global supply, natural gas and LNG still suffer from the competition of coal.

Even in countries that put in place carbon emission taxation or trading, emission costs are often too low to give a long-term economic advantage to LNG with respect to coal.

Therefore, in order to improve the attractiveness of LNG, it is of prime importance to maximize the “LNG to electricity” efficiency whilst limiting the cost of LNG infrastructures. This efficiency increase is of course also required to minimize the carbon footprint of the LNG chain itself.

We focus in this article on low CAPEX technical solutions to enhance the energy efficiency of LNG regasification terminals. We concentrate in particular on compact solutions with low equipment count that can easily be implemented on FSRUs or in modular regasification units.

Efficient vaporization

On most existing LNG regasification plants, heat input for LNG vaporization originates either from the combustion of natural gas, and/or from using heat from an ambient heat sink (seawater or air). A more limited number of onshore LNG terminals include advanced LNG regasification solutions such as:

- Integration with other industries that utilize the LNG vaporization duty for refrigeration
- Integration with a power plant where warm cooling water from the power plant is used as a heat source for LNG vaporization. In this case the “cold” duty of LNG vaporization can also be used for chilling air at the intake of power plant gas turbines so as to boost their throughput
- Generation of free “cold” electrical power by use of a thermodynamic cycle, that ensures LNG vaporization whilst utilizing the temperature differential between the environment and LNG for generating electrical power. A number of processes have been developed for “cold” electrical power generation including several advanced proprietary schemes by Saipem, which are out of the scope of the present article.

The single stage Organic Rankine Cycle illustrated in Figure 2 is a solution that has been running for several decades on multiple sites.

When the organic fluid is a pure fluid this cycle typically allows generating 2MW to 2.5MW electrical power per million tons per annum (MTPA) LNG throughput. More advanced configurations allow increasing significantly the power output at the expense of increased equipment count and complexity.

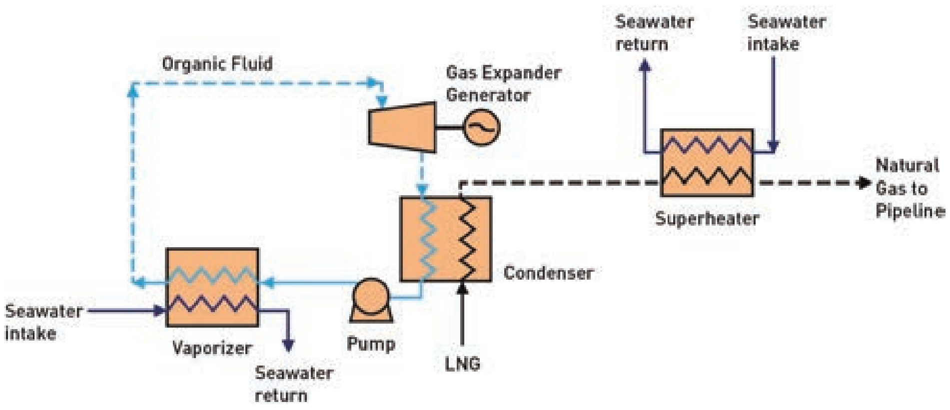


Figure 2: Single Stage Organic Rankine Cycle principle

Advanced LNG vaporization schemes that use site-specific synergies with surrounding industrial facilities or power plants are by definition difficult to implement on standardized low-cost regasification units located nearshore.

Challenging

On this type of regasification facility implementing complex “cold” electrical power generation schemes in a congested environment is also challenging. The use of natural gas combustion or heat from the environment are therefore obvious options for providing heat for LNG vaporization on FSRUs or modular regasification units.

When natural gas combustion is the only source of heat for LNG vaporization, it is required to burn approximately 1.5 percent of the plant throughput as fuel to provide heat for LNG vaporization, which corresponds to a significant loss of valuable natural gas.

For this reason, using “free” heat from the environment for vaporizing LNG is clearly more attractive that burning natural gas from an economic and environmental perspective.

On FSRUs and nearshore modular regasification facilities, seawater is readily available at low-cost and constitutes an obvious heat source for LNG regasification providing the seawater temperature is high enough to ensure the required duty.

The minimum acceptable seawater temperature for vaporizing LNG is typically 5°C. In areas where the seawater temperature is too low, the

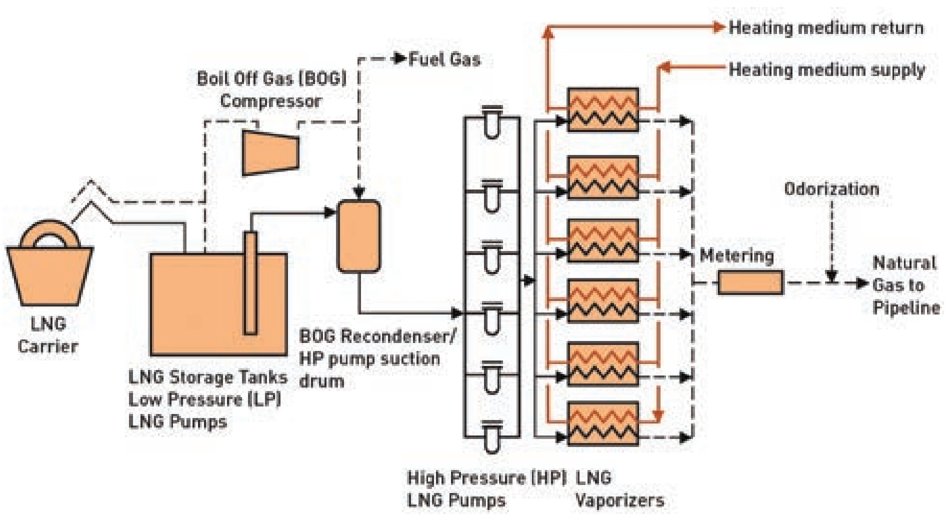


Figure 1: Typical LNG regasification terminal configuration

ambient heat source can be supplemented by an alternate heat source.

Secondary heat

This secondary heat source can simply be natural gas combustion, in which case fuel gas is consumed to make-up the heat which cannot be drawn from seawater. As an alternate the use of waste heat from power generation –when available– can prove advantageous.

For instance on Offshore Livorno Toscana FSRU, designed and built by Saipem, electrical power generation is ensured by condensation steam turbine generators equipped with a seawater-cooled vacuum steam condenser. Pre-heated seawater from the vacuum steam condenser is utilized for vaporizing LNG.

Such a system can be used for vaporizing LNG with cold seawater. On the other hand if seawater temperature is sufficient to allow LNG vaporization this type of arrangement may be used to reduce the seawater circulation rate thereby reducing the cost of piping, equipment and electrical power usage.

In the case of Offshore Livorno Toscana FSRU, integrating LNG vaporization and power generation allowed reducing the seawater flowrate of 25 percent to 30 percent with respect to a standard scheme. This simple energy recovery system is fully compatible with a minimum CAPEX approach and can be installed on an FSRU.

On recent FSRUs electricity is often produced by four-stroke, dual-fuel engine electrical generators. This type of generator provides a high thermal efficiency alternative to other electrical generators such as steam or gas turbines.

Dual-fuel engines produce low temperature exhaust fumes that are not well adapted for generating electricity by cogeneration but can be used for LNG vaporization if a waste heat recovery unit is provided. The engines also use a fairly high cooling water flowrate that can be utilized for LNG vaporization.

Boil-off gas recovery

Despite the thermal insulation measures foreseen to limit heat ingress on regasification plants, LNG boil-off gas (BOG) is permanently generated in LNG tanks. During LNG loading operations the BOG amount increases significantly due to LNG flashing in the storage tanks and LNG tank vapor space displacement.

BOG flaring or venting is of course not an acceptable gas disposal option from an environmental and economical perspective and some alternative ways shall be implemented to handle this low-pressure boil-off gas.

The first option is to use BOG as fuel gas. In holding mode (i.e. no LNG unloading from LNG carrier), the BOG flowrate is usually lower than the fuel gas demand , which allows utilizing all the BOG as fuel.

However, in unloading mode, the BOG flowrate generally exceeds the FSRU fuel gas requirements. On some FSRUs, dumping is used to handle extra BOG: for instance fuel gas excess is burnt in steam boilers and excess steam is condensed by use of seawater. This avoids flaring or venting the BOG excess but in this case the BOG is wasted since it is only used to produce heat that is dissipated to the environment.

Another option is to compress the excess BOG to the gas export line but this requires providing a dedicated high pressure compressor. An efficient alternative is to compress the BOG up to the HP pumps suction pressure and to route it to a BOG recondenser vessel as very commonly done on onshore terminals (see Figure 1 for details).

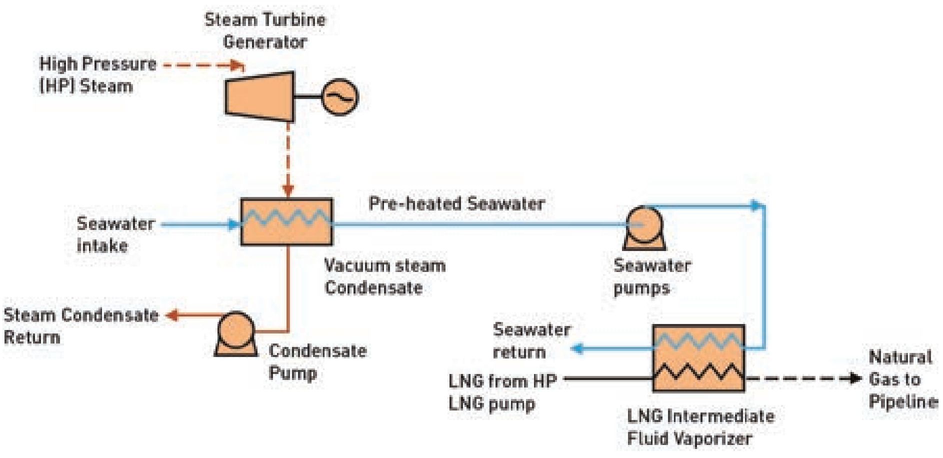


Figure 3: Offshore Livorno Toscana FSRU waste heat recovery scheme

Recondenser

Offshore environment is not a showstopper for implementing a recondenser. For instance, Livorno Toscana FSRU includes a recondenser in an open sea environment.

Finally, a last option for better BOG management on FSRU & FSU is to limit the BOG generation during unloading phases by increasing the LNG tanks operating pressure: the higher is the tank operating pressure, the lower is the LNG flashing in the tanks.

On LNG carriers equipped with Moss spheres, the tanks are mechanically capable of sustaining a pressure in excess of the normal 0.25barg relief valve set pressure defined by the International Maritime Organization.

Increasing the LNG tanks maximum operating pressure beyond 0.25barg when permitted by the LNG tank design and relevant Authority is a low CAPEX option for facilitating BOG handling during unloading.

For example, rising the operating pressure of the receiving LNG tank 70mbar above the unloaded LNG carrier tank pressure typically avoids the LNG vaporization induced by heat ingress in the unloading system.

Lower power use

Electrical power consumption contributes significantly to LNG regasification terminals operating costs and is therefore a key economical optimization parameter.

LNG terminals electrical consumption varies depending on a number of factors including terminal scale, selected vaporization technology and send-out pressure and is generally comprised between 2MW and 3MW per MTPA LNG throughput in normal operation.

Variable frequency drive motors

Many existing LNG terminals have implemented Variable Frequency Drive (VFD) electrical motors in order to optimize their electrical consumption. The installation of VFDs nevertheless has a non-negligible CAPEX impact, induces additional electrical losses and requires

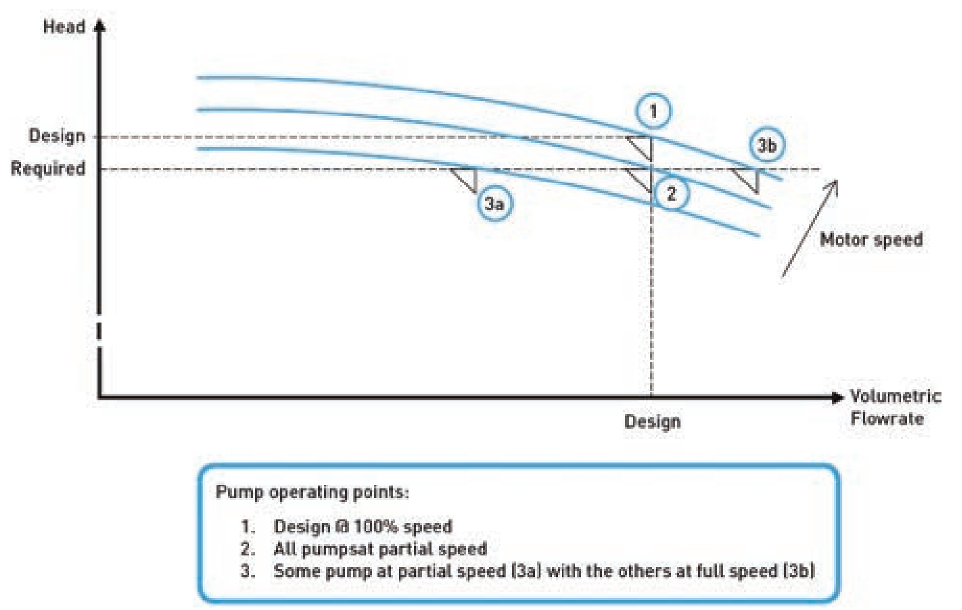


Figure 4: VFD HP LNG pump curves and operating points

additional electrical cabinets equipped with adequate cooling facilities.

In order to maximize the return on investment it therefore makes sense to limit the use of VFDs to the largest electrical users and to consumers for which the energy saving potential outweighs the electrical losses induced by the VFD.

High Pressure (HP) LNG pumps are typically the largest electrical power consumer and can account for up to 50% of the total electrical consumption in an LNG terminal. These are normally designed to pressurize LNG up to the maximum pressure in the export natural gas pipeline considering a wide range of LNG specifications.

As a result of this conservative design the HP pumps discharge pressure is often significantly higher than the pipeline pressure in normal operation, in particular on generic FSRUs designed to be capable of operating at multiple locations. Being a large electrical users with significant overdesign, the HP LNG pumps are therefore the most obvious choice for implementing VFD motors on an LNG regasification terminal. Installing VFDs on HP pumps typically allows performing power savings of approximately 0.05 to 0.1MW per MTPA.

Two strategies can be envisaged for implementing VFDs on HP LNG pumps:

- Providing VFD motors on all HP pumps. In this case all the pumps are operating at the same point (point 2 on figure 4).
- Providing VFD motors on a limited number of HP pumps only

In this case the pumps equipped with a VFD are operating at low flowrate (point 3a on figure 4) whilst the other pumps are operating at the end of their curve at higher flowrate (point 3b on figure 4).

Implementing VFD on one or two HP pumps only can allow reaching up to 90% of the power savings achievable by implementing VFD on all HP pumps and is often a better economic option when HP pumps are moderately overdesigned.

Direct expander cycles

Another strategy for reducing the terminal electrical power consumption is to generate free “cold” electrical power. The direct expander cycle is a very simple and well referenced “cold” electrical power cycle.

Unlike the previously mentioned Organic Rankine Cycle this involves a very limited equipment count and does not require using a dedicated organic fluid. The direct expander cycle consists in expanding part or all of the natural send-out from the vaporization pressure to a lower export pressure.

This type of cycle is particularly attractive when the LNG terminal regasifies LNG at pipeline pressure (typically 60barg to 100barg) and routes part or all of the send-out to a power plant that typically requires a significantly lower fuel gas pressure (typically 30barg to 50barg). In case gas at 5°C is letdown from a typical pipeline pressure of 80barg to 40barg the net power output (deducting the power required for increasing the LNG pressure from 40barg to 80barg) is approximately 1.2MW per MTPA.

Increasing the HP pump discharge pressure allows increasing the direct expander cycle net power output. In case the gas can be pre-heated to 25°C upstream of the gas expander by use of “free” waste heat (from instance warm water from power generation) the generated net electrical power increases to 1.4MW per MTPA.

Since gas expanders are compact and low cost equipment the above scheme is an attractive option for reducing significantly the power consumption of FSRUs and modular regasification units in particular when these facilities feed a power plant.

Semi-open expander cycle

Another simple and low cost strategy for generating “free” cold electrical power is to use a semi-open cycle. This type of cycle is similar in principle to the Organic Rankine Cycle shown in Figure 2 however in this case:

- The “organic fluid” is the natural gas itself
- The cycle pump is a spare LNG HP pump
- The cycle vaporizer is a spare LNG vaporizer
- The cycle condenser is the BOG recondenser

All this equipment is present in a standard LNG terminal and the only additional equipment that is required to run the cycle is a gas expander generator. This cycle utilizes the terminal installed spare regasification capacity for generating electrical power. This electrical power is “free” provided that the heat source used for vaporizing LNG is free.

The maximum electrical power generation capacity is set by the recondenser spare gas absorption capacity, which is typically high in most operating configurations (i.e. outside of periods when the terminal is operating at minimum send-out with LNG carrier unloading).

Based on the typical LNG terminal operating conditions mentioned in the previous paragraph it has been calculated that the net electrical power output (deducting the power required for pumping LNG and additional seawater for vaporizing recirculated LNG) is approximately 0.5 MW per MTPA when no LNG carrier unloading is taking place.

As an optional improvement the gas can be superheated upstream of the expander by use of a waste heat source and pre-cooled against high pressure LNG prior to routing to the recondenser; these two additional operations allow increasing the power generation capacity.

In case an economizer is installed and the gas is pre-heated to 25°C upstream of the gas expander the net electrical power output of the cycle increases to 0.9MW per MTPA considering a recirculation flowrate consistent with the typical capacity of a single LNG vaporizer.

Like the direct expander cycle the semi-open cycle is simple, compact, low cost and suitable for an FSRU or modular regasification unit.

This could also be installed on existing onshore LNG terminals as part of a re-vamp. By combining a direct expander cycle with a semi-open expander cycle it is possible to reduce significantly the electrical consumption of an LNG terminal with very limited equipment count.

Conclusion

To promote transition from carbon intensive energy sources to LNG, the industry will have to be capable of delivering energy efficient LNG import infrastructures at low cost.

Whilst there is always a trade-off to be made between CAPEX and efficiency, several sound engineering solutions can improve significantly the LNG regasification energy efficiency with very moderate CAPEX impact such as :

- Using waste-heat from power generation for LNG vaporisation or natural gas superheating
- Ensuring that LNG Boil Off Gas is fully monetized (for instance by use of a BOG recondenser)
- Providing Variable Frequency Drive motors on key electrical users
- Providing a gas expander generator on natural gas send-out
- Recirculating natural gas to the BOG recondenser via a gas expander generator

All these solutions present the advantage of being compact and suitable for all kinds of LNG regasification facilities including FSRUs and modular regasification units.

If energy price and carbon emission costs rise in the future, more advanced solutions such as Saipem proprietary “cold” power generation schemes are expected to become increasingly attractive from an economical point of view in particular on onshore LNG regasification plants.

This article has been prepared by members of the Saipem XSIGHT division, dedicated to adding value at the early project development phase. It delivers consultancy and engineering services (conceptual studies, master plans, pre-FEEDs, FEEDs, de-bottlenecking studies, commissioning plans, etc.) as well as project services. ■

Japanese policy on LNG is linked to emergence of American export capacity on the Gulf Coast

US-Japan joint study of future of Asian LNG markets underpins new direction for many aspects of the sector

Participants in the Tokyo LNG Producer-Consumer conference attended by ministers and executives

The LNG market in Asia is undergoing a transformation amid additional volumes coming onto the market and diverging natural gas and crude oil prices.

These factors along with shifts in demand patterns from traditional Northeast Asian buyers, Japan, South Korea and Taiwan, and relatively recent market participants such as China.

Competition

"The LNG market is already experiencing rising competition from the US and Australia in a market traditionally reliant upon suppliers from Asia and Middle East," said the study.

"While new competitive forces bring challenges to producers, the development of a broad-based liquid and flexible LNG market can deliver substantial economic, environmental and energy security benefits throughout the region," it added,

The report noted that challenge ahead for policy makers is in securing the widespread benefits of rising supplies of LNG to transform potential demand in Asia into real demand.

"Whether the US can play an integral role in Asian LNG market is dependent not only on the pace and magnitude of LNG demand growth in Asia, but also on sustaining a cost competitive position for US exports," the study explained.

"US policymakers, recognizing the vast indigenous natural gas reserves and advances in extraction technologies, are pursuing a supportive strategy to ensure that production growth and LNG exports are both predictable and sustainable.

The study by the Institute of Energy Economics Japan (IEEJ) and the Energy Policy Research Foundation, Inc. (EPRINC) undertook an assessment of future LNG demand growth in Asia and strategies to improve the competitiveness of US LNG exports in the region.

Experts

The two organizations reached out to nearly 100 experts, government officials and market participants through a series of workshops in Washington DC, Tokyo, and Bangkok.

The research teams received support from Economic Research Institute for ASEAN and East Asia (ERIA), as well as the US and Japanese governments.

All the suggestions and market forecast were considered at the LNG Producer-Consumer Conference held in Tokyo on October 18 and attended by more than 1,200 participants from 32 countries and regions, including 12 cabinet ministers.

The Conference was hosted by the Japanese Ministry of Economy, Trade and Industry (METI) and the Asia Pacific Energy Research Centre (APERC).

The Japanese strategy for Asia has taken heed of the "Joint Study on The Future of Asian LNG".

The key findings were as follows:

- The US natural gas resource base is big and getting bigger. Advances in extraction technologies show continued improvements indicating that US natural gas output could rise by substantial additional volumes at costs below $4 per 1,000 feet of gas (mcf)
- The US regulatory framework for natural gas production, distribution and construction of processing facilities, including LNG export plants has been largely efficient, but persistent and important challenges remain and these challenges pose risks to the rapid expansion of LNG export facilities.
- Natural gas market in Asia has significant potential and could grow 2.5 times between now and 2030. Meeting this demand growth will require about $80 billion in LNG infrastructure investment in ASEAN and India combined.
- While historic Asian LNG demand centers, Japan, Korea, and Taiwan are likely to experience modest or declining demand growth, emerging Asian LNG importers such as China, India, and other new emerging Asian countries will see rising demand for LNG. The base case assumption of the region's LNG demand will reach 350 million metric tons in 2030.

The Major Policy Recommendations are:

- Developing more liquid and flexible LNG market: Removal of LNG destination restrictions in LNG contracts among all market participants to stimulate spot markets and price discovery.
- Sustaining competitive US LNG export platform: Streamlining the regulatory process, including LNG export approval process and environmental reviews to foster predictable and efficient buildout of US LNG export capacity.
- Cost effective and Long-Term Access to the Panama Canal, engaging the Panama Canal Authority to support long-term and cost-effective movement of LNG vessels to and from Asia and North America.
- Providing financial supports by engaging their export credit agencies, including Japan Bank for International Cooperation (JBIC), Nippon Export and Investment Insurance (NEXT), US Export-Import Bank (Ex-Im), Overseas Private Investment Cooperation (OPIC), development agencies, and multilateral development banks, to increase supports for LNG projects.

- Import capacity building in Asia should be accompanied by technical standards, safety guidelines and environmental regulations for government and industries in emerging LNG importing countries.
- Assisting policy developments in Asia so that countries could take full advantage of natural gas.

Conference

At the Producer-Consumer conference, participants observed the current changes in the LNG market and the importance of appropriate future development of the market, and based on these assessments, they held discussions concerning a variety of issues.

Mr. Hiroshige Seko, Minister of Economy, Trade and Industry, delivered a speech stating that Japan will contribute to expanding the LNG market in Asia, focusing on two points, or "Two Contributions": [1] preparing a 10 billion dollar-level financing initiative from the public and private sectors in Japan aiming at boosting demand for LNG in Asia, and [2] providing opportunities for developing 500 skilled human resources over the coming five years.

Moreover, Minister Seko held individual, bilateral meetings with 11 ministers and exchanged views at each meeting concerning cooperation toward the development of global LNG markets, and issues involving the energy fields in the respective countries.

Japan is also promoting third-party access to LNG receiving terminals and pointed out that destination restrictions may violate its Anti-Monopoly Act in a report from the Japan Fair Trade Commission.

Furthermore, Japan is strengthening cooperation with Europe, India and other countries on LNG trading and is encouraging more Japanese public and private investment in the industry.

Two other interesting points that emerged were that Japan has decided on a roadmap towards the introduction of LNG bunkering, according to which the Yokohama Port would start ship-to-ship LNG bunkering around 2020.

Japan and other Asian countries also pointed to the potential benefits of a US export plant on the West Coast project which is "free from restrictions of Panama Canal" navigation into the Pacific Ocean.

US role

Japan welcomed the US contribution to the discussions given be Dan Brouillette, Deputy Secretary at the US Department of Energy.

The US is currently the world's largest oil, gas producing country, and will become a gas net exporter in 2017," said Brouillette.

"Not only do we have resources but we have also established a transparent market realized by pipeline networks and brisk spot trading. "The US will be able to export gas up to 10 billion cubic feet a day by 2020. As LNG exports are economically beneficial to the US as well, we have already approved export of 21 billion cubic feet a day, including quantities for 2020 and thereafter," he added.

"With regard to the risk of revocation which some importers are concerned about, the US government stresses that it will respect contracts between businesses and will not cancel them unilaterally.

"As well, we have released a handbook for those involved in LNG export/import and would like to use it for human resources development in Asia," said Brouillette. ■

Part II: Improved monitoring onboard FSRUs is required to Enhance operating performance and reduce cargo losses

Maksym Kulitsa, FSRU consultant and David A. Wood, DWA Energy Limited, Lincoln, UK

Cargo performance monitoring of FSRUs requires careful checking of boil-off gas (BOG) consumption in the gas combustion unit (GCU), steam dump (SD) or similar safety equipment.

Such consumption is grouped into two categories: 1) unavoidable for justified safety reasons, and 2) avoidable "loss" that is all other consumption, generally resulting from poor practices.

The cases described here depict the most typical situations that clearly identify to which category BOG consumption should be assigned.

Safety

By definition GCU and SD are safety equipment that should be used only when safety is likely to be compromised without its use, for example, when tank pressure increases above the safe upper operating tank pressure limit as stated by tank manufacturer.

Case 1. Following a rollover, the FSRU cargo officer activated the GCU for the purpose of lowering tank pressure (or lowering pressure before next rollover), but at the end of the rollover the tank pressure remained within safety limits and had only reached 70 percent of its MARVS-pressure rating. GCU was run for day or more causing a significant loss of cargo.

There was no justifiable safety reason for doing this, as the tank pressure was stable and not trending upwards at the time. It was done either due to a lack of understanding of tank pressure behaviour associated with rollovers (Kulitsa & Wood, 2017), or to satisfy the operator's preference (i.e., extra safety headroom) to maintain tank pressure significantly below their upper-operating-pressure limits.

The gas consumed should be considered as category (2) (gas lost), as even on a FSRU without a recondenser the cargo in that "rollovered" tank would have cooled down without recourse to the GCU or steam dump equipment. On a FSRU equipped with a recondenser or LHCS there surely was no justification for activating the GCU/ steam dump equipment in such a situation.

Case 2. The rollover resulted in tank pressure rising to 88 percent of its MARVS-pressure rating, then the GCU was justifiably run for safety reason until the tank pressure decreased to just below the upper-operating-tank-pressure limit i.e., for FSRU 250 mbarg MARVS, that point is at 190 mbarg or76 percent of the tank's MARVS-pressure rating, as stated in the tank specifications of each ship.

From that pressure level the recondenser and BOG consumption by the engine room are safely able to continue cooling the cargo without further recourse to the GCU equipment. Gas consumed is therefore allocated to category (1) (for safety reasons).

However, if the GCU was not stopped at the upper-operating-tank-pressure limit and continued to run, then its gas consumptions from that pressure limit to a lower tank pressure should be considered as category (2) (unnecessary loss of cargo in GCU).

Case 3. During a ship-to-ship (STS) transfer the tank pressures were controlled by running the GCU at close to the upper operating pressure limit of the tank. However, after the STS transfer was completed the cargo mate elected to run the GCU for another full day in order to continue lowering the tank pressure.

Consumption

In that case GCU consumption during the STS transfer should be allocated to category (1) (for safety reasons), but all consumption in GCU after the STS transfer was completed should be allocated to category (2) (cargo lost), as there was considerable time to use the recondenser and engine room BOG consumption by the engine room to cool the cargo prior to the next scheduled STS transfer.

There was no need to force more rapid cargo cooling by continued use of the GCU/steam dump equipment, as the cargo could remain "warm" without compromising safety, because tank pressure remained within the tank pressure operating range, and a warm cargo is not an issue for a FSRU.

Case 4. Often FSRUs run their GCUs for the whole duration of STS transfers (i.e., overuse). In this case, tank pressure in the FSRU reached only a maximum of 140 mbarg (i.e., 57 percent of MARVS 250

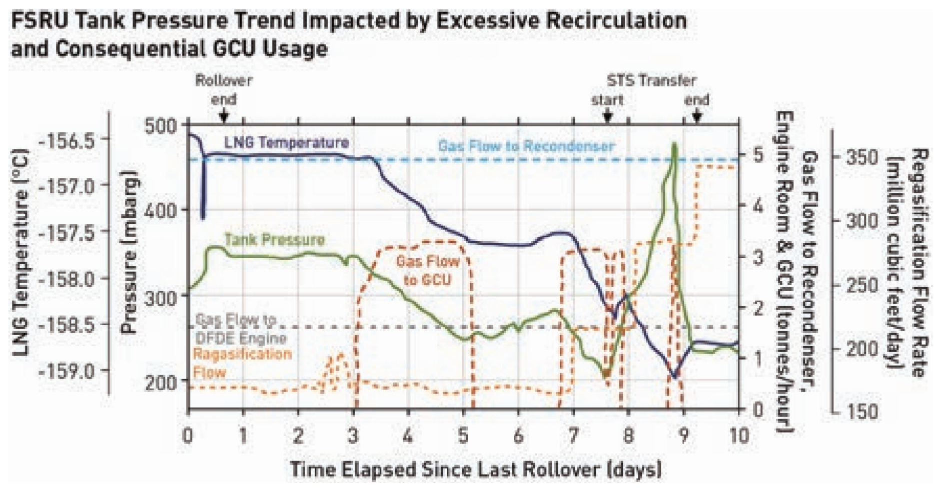


Figure 3: Case 5 showing the impacts of excessive re-circulation of the regas feed pumps leading to unnecessary use of the gas combustion for several days prior to the next STS transfer in order to reduce tank pressure.

mbarg) and remained steady at approximately that pressure for the whole duration of the STS transfer.

As a consequence, total consumption in the GCU is not so easily allocated between the two categories of gas consumption. It is apparent that the GCU was over-employed in this case suggesting not all of its gas consumption could be realistically allocated to category (1) (for safety reasons) as such reasons never materialized. Use of the GCU in this way undoubtedly caused significant loss of cargo.

However, the challenge is to quantify with accuracy what portion of GCU consumption for this period should be considered as loss of cargo. Typically, it is only possible to estimate this.

The most efficient operating procedure would have been in this case to allow tank pressure to creep up until 190 mbarg (i.e., 76 percent of MARVS tank pressure rating and the upper operating pressure limit for FSRU 250), and to start running GCU only at this point and to run it so that tank pressure is held at this level (i.e., not lower or higher).

Pressure

In this case at tank pressure of 190 mbarg (i.e., the upper-operating-pressure limit stated by tank manufacturer) it is an appropriate safety reason to start to control tank pressure with aid of the safety equipment (GCU /SD) and any consumption in the GCU is justifiably allocated to category (1) (for safety reasons).

The consumption difference (avoidable loss) between this case and the most efficient way is estimated at between one-half and one-third of total gas consumption.

Consequently, it is reasonable to conclude that the action taken (i.e., overuse of GCU without justifiable safety reason for doing so) in this case resulted in "loss" of between one-half and one-third of the total consumption in the GCU for the duration of the STS transfer, because the GCU was apparently run for at least part of the time without a clear safety reason for doing so.

Additionally, it is not certain that without using the GCU the tank pressure would always reach the upper-operating-pressure limit. During STS transfers FSRU tank pressure sometimes doesn't reach the upper operating tank pressure limit, and running the GCU would be unnecessary. Alternatively, it may only reach the pressure limit close to the end of the STS transfer, requiring the GCU to be run for a short time only.

Case 5. This involves poor practice related to allowing excessive re-circulation of regasification feed pumps. The last rollover occurred 7 days before the next STS transfer was scheduled.

Best practice advocates that the FSRU tank pressures should be as low as possible before the next STS transfer starts.

The recondenser was run at 5.0 t/h and the DFDE engine consumed 1.8 t/h of BOG, while regasification at 175 mmcf/d continued for gas send-out purposes (350 m3/h LNG is fed to the regasification plant from all tanks in use). The tank pressure did not fall after rollover, even after many hours had elapsed.

Running

Then GCU was started at about 3 t/h and run for about 2 days. Due to the running of the GCU, the tank pressure only gradually decreased, and when the GCU was stopped tank pressure again remained steady, and then started to rise slowly.

GCU was started after two further days elapsed and run for another one and half days with the intention of lowering pressure prior to a pending STS transfer.

The following STS transfer was started at relatively high FSRU tank pressures that was twice the usual low-limit aimed for, as lengthy running of the GCU did not cause tank pressure to reduce sufficiently.

The STS transfer was conducted without running the GCU. Finally, the GCU was run for safety reasons for about 1.5 hours approaching the end of the STS transfer that resulted in only 3.5 tons of BOG consumption in the GCU during the whole STS transfer.

The consumption and allocation of gas consumed in case 5 during the STS transfer (only 3.5 tons in the GCU), and for almost all previous days the total BOG did not exceed the NBOR value of this vessel.

However, looking from another prospective, 237 tons of BOG was burned in the GCU prior to the STS should be considered as category (2) (lost gas) as it could have been easily avoided.

Specified

The NBOR specified for the vessel was 0.15%/day, thus to maintain cargo tank pressure steady it was necessary to evacuate from the tank about 4.2 t/h of BOG (100 percent NBOR). During this period, the recondenser (5.0 t/h) and engine room (1.8 t/h) throughput amounted to consumption of BOG evacuated from tanks of 6.8 t/h, which represented 160 percent of NBOR.

However, even with this removal of vapor, tank pressure remained steady and did not start to decrease, as it should have done.

The NBOR specification is given for a vessel with reference to a full cargo on-board, but in Case 5 the FSRU contained LNG that amounted to close to 50 percent of its cargo capacity when the GCU was started and the problem persisted and deteriorated further when only about 20 percent of its cargo remained on board (i.e., prior to the pending STS transfer).

In such circumstances, the BOG required to maintain tank pressure steady should have been significantly below the NBOR value, especially with only a 20 percent cargo on board (0.15 vol% /day referenced to a full LNG cargo on board).

In addition, ongoing regasification continued to remove some 350 m3/h of LNG from the tank, which was replaced by evaporated vapor in the tank's vapor space to fill the additional vapor-space volume resulting from the reduction in volume of LNG liquid in the tank.

Only additional use of the GCU at 3 t/h lowered tank pressure. With the GCU running, the total BOG handled was about 9.8 t/h, representing 233 percent of NBOR for this ship; bearing in mind that NBOR is referenced to a full cargo and in this case the cargo was less than 50 percent full capacity.

Impact

The only explanations as to why tank pressure did not decrease at 6.7 t/h of gas (160 percent NBOR) handled, was the poor cargo operating practice that resulted in significant heat ingress into the LNG tanks (or heat generation within the tanks).

The impact of that heat was so high, that gas extraction from the tank had to exceed more than twice the specified NBOR in order to cool the cargo of less than one-half ship's capacity, to an extent that eventually lowered the tank pressure.

The poor cargo management practice in this case is associated with running of regasification feed pumps in such a way as to cause excessive recirculation during the period prior to the STS transfer.

Two extra feed pumps were run compared to the minimum required number of feed pumps (i.e., one pump required, but three were running) for regasification rate of 175 mmcf/d. Each regasification feed pump is designed to supply about 450 m3/h of LNG to the regasification plant.

Throughput

LNG throughput in the regasification plant was just 350 m3/h (175 mmcf/d), then running three regasification feed pump generated considerable excess flow (i.e., 3*450 - 350 = 1000 m3/h of LNG), which ultimately was recirculated back to the LNG tanks.

LNG recirculated to the LNG tanks in this case amounted to 285 % of the actual regasification flow rate.

Thus, with three regasification pumps running, the excessive recirculation can be expressed as about 335 m3/h/pump, without any justifiable reason for doing so (as tank levels were high enough at all times, and no pumps were experiencing suction problems during the period leading up to the STS transfer, the convenience of simultaneous discharge of LNG from all tanks cannot be justified as it indirectly caused a loss of cargo).

This excessive recirculation of LNG generated extra heat in the cargo tanks, so much so that 160 percent NBOG was only able to hold the tank pressure steady when the tanks were less than half full of LNG (i.e., BOG caused by natural heat ingress for half cargo would have resulted in significantly less than 100 percent NBOR in this case; and heat generated by excessive recirculation caused this to be 160 percent of NBOR for that tank).

Not running these extra pumps would cause the tank pressure to gradually decrease with the prevailing recondenser and engine room gas consumption alone (i.e.,160 percent NBOR).

It would not then have been necessary to run the GCU at all. The most efficient course of action would have been to run just one regasification feed pump (as required by this FSRU design) at 450 m3/h in order to supply the regasification requirement for send-out gas of 350 m3/h.

Recirculated

That action would have resulted in only 100 m3/h (i.e., 29 percent of the regasification rate) being recirculated, which is not excessive and would be considered as a normal recirculation rate for this FSRU design.

The gas consumption by the GCU in Case 5 should therefore be allocated to category (2) (cargo lost). In fact, the amount of cargo lost in this case is higher than that consumed in the GCU due to the additional power consumed in running the two extra regasification pumps.

In case 5, by not running the GCU, some 237 tons of BOG could have been saved and used subsequently for regasification and send-out gas or for onboard power production.

The estimated value of the associated cargo loss (from the vessel charterer's perspective) during the 5-days preceding

BOIL-OFF GAS (BOG) CONSUMPTION BREAKDOWN AND COMPARISONS WITH NORMAL BOIL-OFF RATE (NBOR) AND REGASIFICATION RATE FOR A SPECIFIC FSRU OVER A 9-DAY OPERATING PERIOD (SUB-OPTIMAL PERFORMANCE EXAMPLE)												
Gas Combustion Unit (GCU) Run Excessively		Day 1	Day 2	Day 3	Day 4	Day 5	Day 6	Day 7	Day 8	Day 9	Total or Average	
		Rollover just Completed	Post-rollover Period: Tank Pressures High but Safe at 50% to 60% MARVS						STS Transfer Conducted	Post-STS Period	For full 9 days	
Actual Boil-off Gas Consumption Measured												
Engine Room (ER) Gas Burning for Power Generation	tonnes/day (t/d)	40.48	41.58	41.79	40.88	39.62	41.69	43.36	47.64	51.37	388.4	tonnes
Gas Combustion Unit (GCU) Gas Consumption	t/d	0	56.41	74.09	26.65	0	47.02	32.64	3.28	0	240.1	tonnes
Total BOG Consumption	**t/d**	**40.48**	**97.99**	**115.88**	**67.53**	**39.62**	**88.71**	**76.00**	**50.92**	**51.37**	**628.5**	**tonnes**
Total BOG Consumption	tonnes/hour (t/h)	1.69	4.08	4.83	2.81	1.65	3.70	3.17	2.12	2.14	**2.91**	t/h (avg)
Monitor Actual Boil-off Gas Comsumption Versus Reference NBOR for FSRU/Location												
Actual BOGR	% /Day of full Cargo	0.060	0.146	0.172	0.100	0.059	0.132	0.113	0.076	0.076	**0.104**	average
Designed NBOR	% /Day of full Cargo	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	**0.15**	average
Difference (BOGR-NBOR)	(-ve = good)	-0.090	-0.004	0.022	-0.050	-0.091	-0.018	-0.037	-0.074	-0.074	**-0.046**	average
BOGR/NBOR	%	**40.2%**	**97.2%**	**115.0%**	**67.0%**	**39.3%**	**88.0%**	**75.4%**	**50.5%**	**51.0%**	**69.3%**	average
Monitor Actual Boil-off Gas Consumption Versus LNG Cargo Regasified ("Regasification Fuel Consumed")												
Regasification Rate	million cubic feet/day (mmcfd)	175	175	175	175	175	175	220	280	330	**1880**	mmcf
LNG Cargo Mass Regasified	t/d	8400	8400	8400	8400	8400	8400	10560	13440	15840	**90240**	tonnes
Actual BOG consumed as % of LNG Cargo Regasified	%	**0.48%**	**1.17%**	**1.38%**	**0.80%**	**0.47%**	**1.06%**	**0.72%**	**0.38%**	**0.32%**	**0.70%**	average

Figure 4: Boil-off gas consumption for recorded inefficient cases and a more efficient operating scenario applied to Case 5 (eliminating use of the GCU) monitored against NBOR (0.15 vol%/day) and regasification fuel (0.6 mass%/day)

the STS transfer for the vessel charterers is about US$87,430 calculated as follows:

*237 t*1000*0.0527 MMBtu/kg = 12 490 MMBtu of cargo loss in energy terms*

LNG selling price US$7 /MMBtu

*Cargo loss * unit price = US$87,430*

If the FSRU receives 60 cargoes/year and the inefficiency associated with Case 5 is repeated in just 50 percent of the STS transfers the accumulated annual cargo lost would be 7110 tonnes of LNG, valued at US$7/MMBtu, such loss would amount to some US$2,622,900. If the inefficiency is repeated in just 10 percent of the annual STS transfers (i.e., only 6 of 60) the accumulated annual cargo lost would be 2370 tonnes of LNG, valued at US$7/MMBtu, such loss would amount to some US$ 524,580.

Avoidable

Even if the GCU/SD consumption remained within the total BOG contracted values, this 237 tons is a loss that could be easily have been avoided.

Perhaps of more concern regarding Case 5, is that daily operating records of cargo consumed versus NBOR, on a similar basis to typical LNGC recording practices conceal the underlying inefficiency and US$87,430 loss of value.

Our data recorded on that basis for the period of 9 days over which Case 5 refers, suggests good contractual performance (i.e., gas consumed each day is within NBOR, except for day 2). The slight excess consumption in day 2 is unlikely to cause concern from a contractual compliance perspective, as NBOG was only exceeded by 15 percent.

Despite there being negligible contractual violation of gas consumption limits, as already explained, efficient operations would have resulted in considerably less gas being consumed without compromising any safety limits and optimizing performance of this FSRU design.

Our data shows how the Case 5 operation would have evolved in terms of gas consumption relative to NBOR on a daily basis if a more efficient operating strategy had been adopted (i.e., no excessive recirculation due to extra regasification pumps and no GCU gas consumption prior to the STS transfer). The BOGR as a percentage of NBOR is generally around the 40 percent level.

Another performance-monitoring measure for FSRUs is the comparison of the total gas consumption as BOG in all BOG handling systems of the ship (termed "regasification fuel") versus the LNG mass regasified, expressed in percentage terms on a daily basis.

Indicative

When this percentage rises above a percentage value agreed/contracted for each specific FSRU, then it is indicative of higher than normal shipboard gas consumption. Typically, a DFDE FSRU equipped with a recondenser has a contracted "regasification fuel" value of about 0.6 mass % (which may vary as agreed by the parties).

For case 5 it is not possible to explain such high shipboard gas consumption in terms of "post-rollover consequences", as a rollover's influence on tank pressure ceases immediately a rollover is completed.

Case 6. During a STS transfer the tank pressure of a 700mbarg MARVS FSRU reached a voluntary set "safety limit" of 500 mbarg (while the upper-tank-operating pressure limit permitted by the tank designer was 630 mbarg).

BOG was disposed through connections to shore-based flaring (similar to GCU) that was operated at a high throughput rate (i.e., 10 to 15 t/h) to dispose of the BOG (rather than the GCU which has an upper limit of about 5 t/h).

Consequently, tank pressure rapidly decreased from 500 to 300 mbarg (i.e., from 72 percent to 43 percent MARVS within 5 hours).

From that point, the tank pressure trend changed behaviour and pressure declined much more slowly (decreasing 60 mbar in 18 hours), conditions that persisted until the STS transfer was completed, at which point tank pressure was 250 mbarg (i.e., 36 percent MARVS) and 245 tonnes of LNG had been flared.

In this case, even if 500 mbarg (set as a pressure limit for this ship by the operator's preferences instead of 630 mbarg allowed by tank design) was perceived as a valid safety reason to start running the FSRU's safety equipment (GCU, steam dump or flaring), then it would have been appropriate to run the safety equipment sparingly, i.e., at a rate sufficient to maintain tank pressure at 500 mbarg.

If the safety equipment had been operated in that way for justifiable safety reasons it is estimated that only 80 to 100 tonnes of BOG would have unavoidably been consumed. In this case, the over use of the safety equipment (i.e., beyond safety requirements) resulted in 245-100 = 145 tonnes of BOG (145 percent above that required for justifiable safety reasons).

That quantity is equivalent to US$53,500 if this cargo were sold at US$7/MMBtu, rather than lost during the 30-hour duration of the STS transfer.

Conclusions

In order to make FSRU's shipboard gas consumption more transparent and accountable, it makes sense to routinely record BOG consumption in the GCU/steam dump or similar safety equipment and document every episode in which that equipment is run.

In simple terms, it is necessary to establish whether the GCU/steam dump equipment were run for justifiable safety reasons or not or was overused beyond justifiable safety reasons. If not, the gas consumed in such use should be considered as an unnecessary loss.

In general, the GCU/SD consumption

must be viewed together with the prevailing tank pressure records. Use of GCU, steam dump or similar equipment for safety reasons can be readily justified for two situations:

1) if the GCU, steam dump or similar equipment is used only at tank pressures very close to upper-operating-pressure limits for a tank, and is used at a rate just sufficient to prevent tank pressure from rising above that limit.

2) Small consumption in the related equipment taken as reactive rollover mitigation measures by FSRU with tanks rated less than 400 mbarg MARVS (i.e., run for not more than 1 to 2 hours just before and during peak rollover conditions).

Following a STS transfer or rollover, it is not prudent to lower tank pressure in anticipation of subsequent rollovers, thus to do so is not a justified safety reason.

Creating lower tank pressure prior to a STS transfer should not be considered as a justifiable reason for use of GCU/steam dump as it typically leads to greater overall fuel consumption for the combined periods of before and during a STS transfer.

All other reasons for running the GCU/SD equipment should be regarded as "not for safety reasons" (i.e., poor cargo management practice leading to unnecessary loss of cargo) unless very special and explainable circumstances are responsible for that action in particular cases.

Such monitoring can serve as an indication of cargo handling efficiency and distinguish poor from good operational practices even if GCU, steam dump or similar equipment consumption is involved. ■

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About the Authors

Maksym Kulitsa is an FSRU onboard operator with more than eight years of experience on different regasification systems and at various terminals. FSRUs are a relatively recent addition to the LNG industry and he has some expertise in optimizing or fine-tuning FSRU-related operations with regard to particular ship designs and operating conditions.

David A. Wood is the Principal Consultant of DWA Energy of the UK, specializing in the integration of technical, economic, fiscal, risk and strategic information to aid project planning decisions. He has more than 35 years of international oil and gas experience, with companies including Phillips Petroleum and Amoco, spanning project operations, technical evaluations and senior management.

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World LNG Carrier Fleet

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	266,000	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
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
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 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
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
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
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 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
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 Cape Ann	145,000	Hoegh LNG/MOL	Samsung	May-10	Liberia	DFDE	TZ Mk. III	4	Various
GDF-Suez Neptune	145,000	Hoegh LNG/MOL	Samsung	Dec-09	Liberia	DFDE	TZ Mk. III	4	Various
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 Gallant FSRU	170,050	Hoegh LNG	Hoegh Hyundai	May-14	Marshall Is.	DFDE	TZ Mk. III	4	chartered
Hoegh Grace FSRU	170,050	Hoegh LNG	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
Lala Fatma N'Soumer	145,000	Algeria Nippon Gas	Kawasaki Sakaide	Dec-04	Japan	S	Moss	4	Sonatrach
Larbi Ben M'Hidi	129,750	SNTM-Hyproc	La Seyne	Jun-77	Algeria	S	GT NO 85	5	Sonatrach
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 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
Madrid Spirit	138,000	Teekay LNG Partners	IZAR Puerto Real	Jan-05	Spain	S	GT No 96	4	Engas
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 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 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
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	SNTM-Hyproc	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-Atl'c Basin
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
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
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
Pacific Arcadia	147,200	NYK Line	MHI	Oct-14	Bahamas	S	KM		Various
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 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 Asia	174,000	Teekay	Hudong-Zhonghua	July-17	Bahamas	TFDE	NO. 96 GW	4	Cheniere
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
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	SNTM-Hyproc	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 Camellia	150,000	MISC	Hyundai	Nov-16	Malaysia	S	Moss	5	Petronas
Seri Cenderawasih	150,000	MISC	Hyundai	Jan-17	Malaysia	S	Moss	5	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 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
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
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	March-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 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

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
	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
	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
	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
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
Greece	Revithoussa	DEPA	2000	2	130,000
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
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
	Sakaide	Shikoku Electric, Cosmo Oil	2011	1	180,000
	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
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
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
Poland	Swinoujscie	Baltic Gaz System	2015	2	320,000

LNG Import Terminals (continued)

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	3	480,000
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

China	Zhoushan Zhejiang	Enn Group	2018	2	320,000
Finland	Tornio	Gasum Skanga	2018	1	30,000
Gibraltar	Gasnor	Shell	2017	1	5,000
India	Ennore	Indian Oil Corp	2018	2	320,000
	Mundra	Gujarat State Petroleum, Adani Group	2018	2	320,000
	FSRU Andhra Pradesh	Engie, Andhra Pradesh Gas	2018	1	135,000
	Pipovav LNG (FSRU), Gujarat	Swan Energy	2018	2	320,000
	Andhra Pradesh	Hindustan LNG, Andhra Pradesh	studies	1	135,000
Indonesia	Labuhan Maringgai	Perusahaan Gas Negara	2018	1	135,000
Japan	Soma, Fukushima	Japan Petroleum	2018	1	230,000
Malaysia	Lahad Datu LNG, Sabah	Petronas	2018	studies	
	Pengerang Johor	Petronas	2019	2	320,000
Panama	Costa Norte	AES	2018	1	130,000
Philippines	Pagbilao LNG	Energy World Corp.	2017	1	130,000
UK	Port Meridian, Barrow-in-Furness	Port Meridian Energy Ltd.	2018	1	150,000
Uruguay FSRU	Montevideo	Gas Sayago, Mitsui Osk Lines	2018	1	230,000

LNG FSRU Import Facilities

Argentina	Bahia Blanca GasPort	Excelerate/YPF Repsol	2008
	Escobar GasPort	Excelerate/Enarsa	2011
Brazil	Pecem, FSRU	Petrobras	2009
	Guanabara Bay FSRU	Petrobras	2009
	Salvador, Bahia FSRU	Petrobras	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
UAE	Ruwais, Abu Dhabi	Gasco (UAE)	2016
	Jebel Ali Port, Dubai	DSA (UAE)	2010
UK	Teesside GasPort	Excelerate	2007

LNG Export Projects

AUSTRALIA	Browse LNG	Woodside, BHP, BP Chevron, Shell, Mitsubishi, Mitsui	2021+	2	10.0
	Ichthys LNG	INPEX, Total	2017	2	8.4
	Prelude FLNG	Shell, Inpex, Kogas CPC	2018	1	3.5
CANADA	Bear Head LNG, Nova Scotia	LNG Ltd.	2024	4	8.0
	GNL Quebec, Saquenay	Freestone Capital and Breyer Capital	2024	4	10.0
	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	2024	2	12.0
	Melford LNG project, Nova Scotia	H-Energy Hiranandani Group	Studies		
	Steelhead LNG, Bamfield	Steelhead LNG Corp	2021	2	12.00
	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, Schlumberger, GEPetrol	2019	1	2.0
INDONESIA	Sengkang LNG	Energy World Corp.	2017	4	2.0
MALAYSIA	Rotan FLNG (Sabah)	Petronas, Murphy Oil	2019	1	1.5
MOZAMBIQUE	Area 1 Onshore	Anadarko Petroleum and partners	2021	2	10
	Area 4 Onshore	Eni and partners	2021	2	10
	Area 4 FLNG	Eni and partners	2019	1	2.5
NIGERIA	NLNG Train 7	NNPC, Shell, BP, Total	2020+	1	8.4
PAPUA NEW GUINEA	Elk-Antelope LNG	Total, ExxonMobil Oil Search, Petromin	Studies		
RUSSIA	Yamal LNG Siberia	Novatek, Gazprom, Total	2018	3	16.5
	Sakhalin II expansion	Gazprom, Shell, Mitsui, Mitsubishi	2021	studies	
	Vladisvostok LNG	Gazprom, Itochu, various	2021	2	10.0
USA	Alaska LNG Nikiski	Alaska Gasline Development Corp.	2022	3	20.0
	Annova LNG, Brownsville	Exelon Corp.	2021	6	6.0
	Cameron LNG, Louisiana	Sempra	2018	5	24.92
	Corpus Christi Liquefaction, Texas	Cheniere	2019	5	22.5
	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	2018	10	2.5
	Freeport LNG, Texas	Freeport LNG	2018	4	20.4
	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.	2021	4	8.0
	Port Arthur LNG	Sempra	2021	2	10.0
	Rio Grande LNG	NextDecade	2021	6	27.0
	Sabine Pass LNG, Louisiana	Cheniere	2018-19	2	9.0
	Texas LNG Brownsville	Chandra, Meyer, Samsung, others	2021	2	4.0
	VG LNG (Cameron Parish)	Venture Global	2021	5	10.0
	VG LNG (Plaquemines)	Venture Global	2021	10	20.0

LNG Exporters

ABU DHABI (UAE)	Das Island (Adgas)	ADNOC, Mitsui, BP, Total	1977	2	3.2	3	240,000
			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
BRUNEI	Lumut	Brunei/Shell/Mitsubishi/Total	1972-74	5	7.2	3	176,000
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 Island	Statoil, Total, GDF-Suez, 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
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	4	18.0	5	800,000
	Cove Point LNG	Dominion Energy	2017	1	5.3	7	695,000
YEMEN	Bal-Haf	Yemen LNG, Total, Yemen Gas, Hunt Oil, SK Group, Hyundai	2009	2	6.7	2	320,000

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