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# Wholesale gas prices survey charts delivery trends in LNG and pipeline

*International Gas Union explains price formation developments during a period of key gas market upheaval*

Gas-on-gas competition has seen an increase in the share in Europe being offset by declines in Asia and the Asia-Pacific region, reflecting fewer pure spot LNG cargoes.

This is according to the International Gas Union Wholesale Gas Price survey, the ninth to be undertaken in a series which began 10 years ago.

## Ninth

The nine surveys have confirmed the significant changes in wholesale price formation mechanisms during a period of key developments and upheaval in the global gas market.

Average wholesale prices at the world level were $3.35 per million British thermal units last year, the lowest level recorded in all the nine surveys.

In 2016, prices were also more converged than in previous years, as "market" prices continued to decline, while "regulated" prices predominantly rose, outside the FSU where the currency weakness reduced the prices in dollar terms.

In Europe, gas-on-gas (GOG) competition has increased from 15 percent in 2005 to 66 percent last year, with Oil Price Escalation (OPE) declining from 78 percent to 30 percent during the same time-frame.

It was also noted that pipeline imports in 2016 accounted for some 18 percent of total world consumption – around 650 billion cubic metres.

## Breakdown

LNG imports are split 76 percent OPE and 24 percent GOG. The regional breakdown is shown in Figure 1.

OPE at some 266 Bcm is mostly in the Asia-Pacific region – Japan, Korea and Taiwan, followed by Asia - China and India - and Europe - mainly Spain,

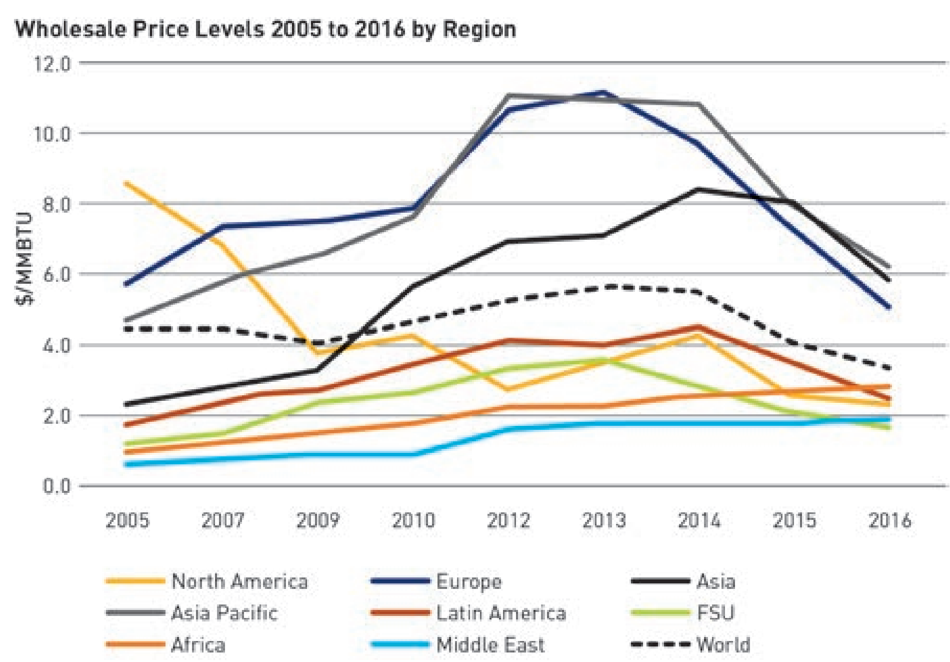


**Figure 1: Wholesale price levels 2005 to 2016 by region**

Turkey, France and Italy. GOG totals some 86 Bcm and can be divided into imports into North America and countries such as the UK, Belgium and Netherlands.

## Mechanism

The domestic market pricing mechanism is GOG, and all other countries which are importing spot and short-term priced LNG cargoes, which is almost every other LNG importing country - Japan and Korea taking the largest shares - but also includes Argentina and Brazil.

Total imports in 2016 accounted for some 28 percent of total world consumption - around 1,000 Bcm.

Total imports are the sum of pipeline and LNG imports and comprise the three categories of OPE (49 percent), GOG (46 percent) and Bilateral Monopoly (BIM) at 5 percent.

The OPE share increased last year, reflecting a small rise in Europe but principally in Asia and the Asia-Pacific region, as the share in LNG imports increased.

This also reflected a rise in domestic production in China, as the full-year effect of the change in city-gate pricing came through.

Cross-border flows of gas account for some 28 percent of total world consumption. Pipeline imports are now over 57 percent GOG, with OPE at 35 percent, while OPE has 76 percent of LNG imports with GOG at 24 percent.

"Gas-on-gas competition had the largest share of total world consumption at 45 percent, predominantly in North America, Europe, the Former Soviet Union and Latin America. The oil price escalation (OPE) share stood at 20 percent, and is predominantly Asia Pacific, Asia and Europe," the IGU said.

"The regulated categories - regulated cost of service (RCS), regulated social and political (RSP) and regulated below cost (RBC) - account in total for some 31 percent.

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"RCS is mainly the Former Soviet Union, Asia and Africa, RSP mainly the Middle East, Former Soviet Union, Latin America and Asia Pacific and RBC the Former Soviet Union, Latin America and Africa," the report added.

## Cross-border

The changes in cross-border trade have been predominantly in pipeline imports with the GOG share rising from 23 percent to 57 percent between 2005 and 2016, all in Europe, at the expense of OPE.

"The shares in LNG imports have been more stable in recent years, although GOG rose from 13 percent in 2005 to 32 percent in 2015, but over half this increase came between 2005 and 2007 as the spot LNG market grew, and then as trading markets such as the UK began importing LNG." The IGU explained.

"The GOG share of LNG imports fell back again in 2016 to 24 percent as the rise in LNG trade was all in contracted volumes, linked to oil prices, and the growth was also outside the traded markets in Europe. The LNG world became more contracted in 2016," it noted.

In the Asia-Pacific area, which is heavily LNG import dependent, there has been little change with OPE, at around 58 percent or so for the whole period, before rising to 64 percent in 2016, reflecting the changing mix in the LNG market.

There was a significant increase in GOG between 2005 and 2007, which was principally due to a rise in spot LNG imports in Asia and the Asia Pacific region and a smaller rise in North American imports.

## Offsetting

Since 2007, there have been offsetting changes with North American LNG imports - which are all GOG - declining, European imports, principally to the UK increasing in 2009 and 2010 and relative stability in Asia and Asia-Pacific spot LNG imports.

In 2012, as Europe's LNG imports declined, these were more than offset in the GOG category by rising spot LNG imports in Asia and the Asia Pacific areas.

"The decline in 2013 reflected the fall in the share of spot LNG imports and a decline in LNG imports into the UK, the US and Canada," the IGU said.

"The further small decline in 2014 was principally due to lower Asian and Asia-Pacific spot LNG cargoes, with correspondingly higher OPE under long-term contracts," it added.The rebound in 2015 was largely due to more spot LNG cargoes in all markets, but especially Japan and the new markets, as the fall in spot LNG prices preceded the decline in oil-linked contract prices.principally principally due to lower Asian and Asia-Pacific spot LNG cargoes, with correspondingly higher OPE under long-term contracts," it added.

The rebound in 2015 was largely due to more spot LNG cargoes in all markets, but especially Japan and the new markets, as the fall in spot LNG prices preceded the decline in oil-linked contract prices.

## Factors

In 2016, the decline in GOG was a consequence of a number of factors:

- The rise in LNG trade was largely built on new projects and contracts linked to oil prices;
- A decline in the volume of pure spot LNG cargoes; and
- The lack of growth in LNG imports in the traded markets in Europe.

Essentially, LNG trade became more contracted in 2016, which benefitted OPE, and the start-up of US LNG exports, effectively Henry Hub priced, only had a small effect.

"There was also little change in Africa, heavily dominated by RBC in the 70 percent to 80 percent range until the change to more RCS and GOG in Egypt and Nigeria, brought the share down to 50 percent and below in 2015 and 2016 respectively," said the IGU.

"The Middle East also has shown relative stability, apart from the major Iranian pricing changes in 2012, away from RBC to RSP, as prices were increased," it added.

In the Former Soviet Union (FSU) there were early changes away from RBC to RCS in Russia, and the move to GOG in 2009 as independents competed with Gazprom in Russia, but apart from these there have been few significant changes.

Latin America has experienced a gradual move to OPE and GOG (Argentina especially), with the regulated categories declining, over the period.

## Peaked

"Wholesale price levels, in most regions, reached their peak in 2013 or 2014. This rise was across all regions apart from North America, where the dramatic increase in shale gas supply has led to sharp falls in prices - with a small rebound in 2013," the report said.

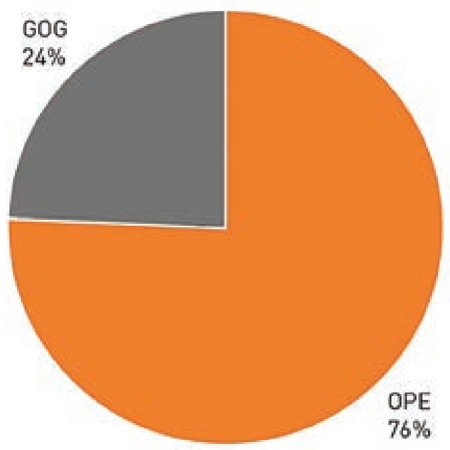



**Figure 2: World price formation 2016 - LNG imports**

The rise in prices in Europe and the Asia-Pacific has been well documented and studied, but prices have also risen in Asia, largely due to increases in prices in China, both as more gas was imported and regulated domestic prices increased, and in India for similar reasons.

Price falls in Europe began to decline in 2014 as the market weakened and in the FSU especially, as the rouble depreciated.

This accelerated in 2015 and 2016, and prices also fell back in North America and Asia Pacific on the back of weak demand, abundant supply and the impact of the sharp fall in oil prices.

"However, some regions did not see the 2014 and 2015 fall in prices. These were Asia, as pricing reforms and inertia increased and kept prices up in China and India, the Middle East, as regulated prices were increased in Bahrain, Oman and Iran, with other prices staying stable - and Africa - where prices have increased in Egypt, Nigeria and more recently in Algeria," stated the IGU.

## Delayed

In 2016 Asian prices also declined as the delayed effects of the oil price decline impacted China prices and also the fall in spot prices affected the India domestic pricing formula.

FSU prices declined further reflecting currency weakness, but Africa and Middle East prices continued to rise.

GOG has the largest share in domestic production at 44 percent, totalling some 1,160 Bcm, with North America accounting for 832 Bcm - almost three quarters of the total.

The next largest share is in the FSU, where the sales of gas in Russia to the large eligible customers by either Gazprom or the independent producers is classified as GOG (see the section on Former, accounting for some 155 Bcm.

The balance is in Europe at 78 Bcm - principally the Netherlands and UK, the Asia Pacific at 28 Bcm - Australia and New Zealand and Asia at 28 Bcm – and all of India and Latin America at 23 Bcm - mainly Argentina and Colombia.

OPE has a relatively small share in domestic production at 9 percent, totalling some 231 Bcm, with 138 Bcm in Asia - China and Pakistan mainly, 59 Bcm in the Asia-Pacific region - mainly Thailand, with some in Australia, the Philippines and Malaysia, 24 Bcm in Latin America - Brazil and Colombia, 5 Bcm in Europe - small amounts in a few countries, and 5 Bcm in Africa, mainly Tunisia.

## Regulated categories

The regulated categories - RCS, RSP and RBC - in total account for 42 percent of domestic production, with RCS principally in the FSU and Asia, RSP principally in the Middle East, the FSU, Asia-Pacific and Latin America and RBC in the FSU Africa, Latin America and the Middle East.

Pipeline imports are split between just three categories - OPE, GOG and Bilateral Monopoly (BIM) prices.

In the regional breakdown, GOG is well over half of all pipeline imports, totalling some 372 Bcm, with Europe at 248 Bcm and North America the rest.

Most of the European gas importing countries, have some element of GOG pipeline imports with the top four countries being Germany, Italy, France and UK.

OPE is around 35 percent of all pipeline imports, totalling some 229 Bcm, mostly in Europe with some 119 Bcm - Turkey, Italy, Spain and Germany being the main contributors.

Asia accounts for some 40 Bcm - China, the FSU for some 22 Bcm - principally Ukraine and Russia, with 22 Bcm in the Asia-Pacific region - Thailand, Singapore and Malaysia and 16 Bcm in Latin America - mainly Brazil and Argentina.

There are also small quantities in other regions, apart from North America, including countries such as Iran and Tunisia.

## Balance

"BIM has the balance of 8 percent, totalling some 52 Bcm. This is mainly in the FSU and the Middle East with just two routes - Russia to Belarus and Qatar to the UAE - comprising most of it," the IGU explained.

The main changes in price formation over the nine surveys have been the general rise in GOG from 35 percent in 2005 to 44 percent in 2016. The share rose marginally in 2016, as the GOG share rose again in Europe, FSU and Latin America.

"The OPE category is not particularly large in terms of domestic production, but rose again in 2016 as the full year effect of China extended its pricing mechanism, linking city-gate prices to competing fuels for all sectors other than residential and fertilizers, came through. This resulted in a move away from RCS," the report said.

Over the period as a whole, GOG has gained share from the three regulated categories which in 2005 totalled some 52 percent compared to 42 percent in 2016.

"A large part of this occurred in 2009 and 2010 when the GOG category increased in Russia at the expense of the regulated categories, as the market began to open up to independents more, and there was more effective competition between the independents and Gazprom for power sector and industrial customers," it added.

This was followed by the changes in India in 2015, as regulated pricing was replaced with a formula linked to international, predominantly hub, prices for key sectors. There has also been an increase in GOG in Latin America as well, principally in 2009.

"Total imports are the sum of pipeline imports and LNG imports and have only comprised three categories - OPE, GOG and BIM - in all nine surveys from 2005 to 2016.

"OPE declined from 63 percent in 2005 to 59 percent in 2007 as GOG rose from just over 21 percent to 28 percent and then in 2009, OPE gained share rising to 66 percent as BIM fell from 14 percent to 6 percent, with GOG rising to 29 percent.

"Since then OPE has lost share by around 16 percentage points and GOG gained a similar share, in large part due to pipeline imports in Europe," the IGU said. ■

# Fluor offers returns from US shale-gas market for LNG export development and gas processing plants

*John Mak, Senior Fellow and Technical Director at Fluor Corp, Aliso Viejo, California*

Shale gas has become an increasingly important source of natural gas in the United States. The US government's Energy Information Administration predicts that by 2035, 46 percent of US natural gas supplies will come from shale.

Shales gas can be found in various formations and in different pockets. The gas reserves are typically small and are short lived.

## Economics

An economically viable solution for the US market is a small to mid-size gas plant to produce pipeline-gas-quality gas and recover the liquid contents as natural gas liquid (NGL) products. Excessive gas can be liquefied for export as liquefied natural gas (LNG).

For the North and South American markets, Fluor has developed a deep dewpointing process that combines high NGL recovery with simplicity of design, yet is flexible enough to accommodate a range of compositions and flow rates.

This design is well suited for standardization of small to mid-sized gas plants where feed gas compositions vary and capacity increases are not well known, as currently experienced in many shale gas sites. A short implementation schedule provides first-to-market economic benefits.

The plant must be highly modularized to minimize installation efforts, and can be implemented in a substantially shorter time frame than traditional projects. Fluor's 3rd Gen Modular Execution[SM] is proven to significantly reduce a plant's footprint compared to traditional modularization practices.

This new approach makes it possible to design a gas processing facility as transportable modules that can reduce installation costs and be relocated to different sites when the gas reserves are depleted.

This paper presents Fluor's solution for the US market. It combines the benefits of high gas liquids recovery with low investment, and is delivered in compact, relocatable modules that allow for flexible field development strategies.

Shale-gas development can be challenging for small to medium-sized fields with uncertain reservoir definition and production profiles. Furthermore, limitations on processing infrastructure, coupled with the low prices for ethane, warrant an economically viable gas plant that can produce pipeline quality gas and recover attractive amounts of truckable C3+ natural gas liquids (NGLs).

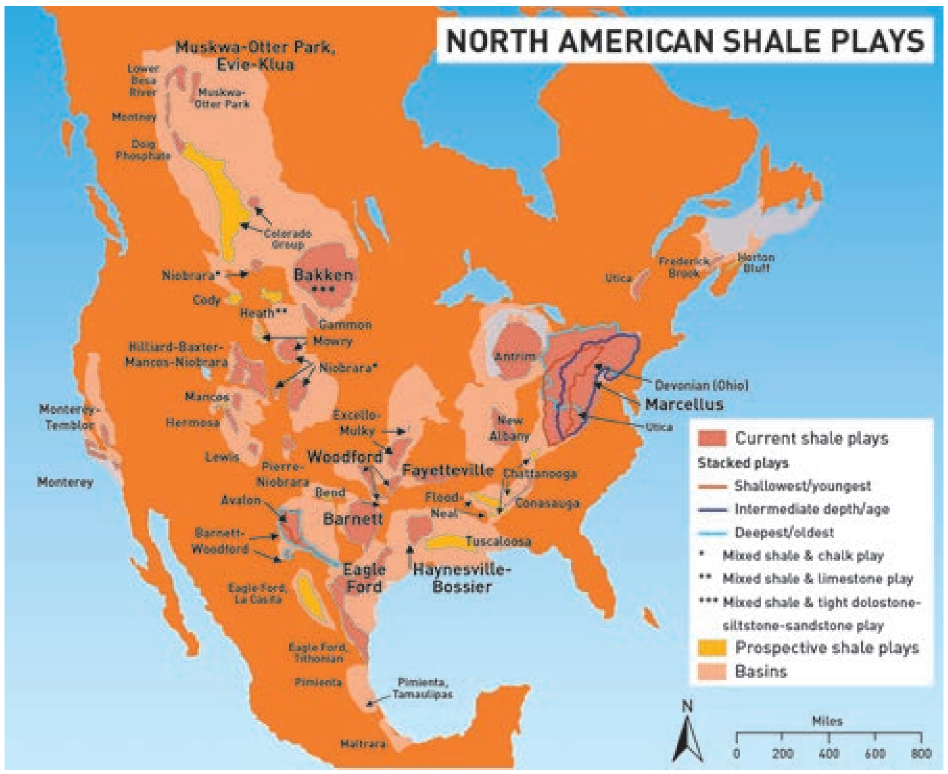
We will present a viable solution for the US market that combines the benefits of high C3+ NGL recovery with low investment, supplied in relocatable modules for shale field development and with opportunity for ethane and LNG production.

## Reservoirs

Traditional gas production is from large gas reservoirs, which can maintain production for many years. Conventional gas is generally a lean gas, with C2+ content ranging from 2 to 4 gallons per thousand standard cubic feet (GPM).

World-scale gas plants are large, with capacity of 500 million standard cubic feet per day (MMscfd) and higher, which can justify large investment.

Shales gas is found in small gas reservoirs, with much shorter life. Shale gas compositions and properties for various shale gas production sites.




Source: U.S. EnergyInformation Administration based on data from various published studies. Canada and Mexico plays from ARI. Updated: May 9, 2011

**Figure 1: US shale-gas plays have transformed global markets**

Shale gas is an ultra-rich gas, containing significantly more C2+ liquid than conventional gas.

For example, the Bakken gas contains 24 mole % C2 with C2+ liquid content over 12 GPM and heating value over 1,500 British thermal units per standard cubic foot (Btu/scf). Shale-gas pressure is also relatively low, 500 to 800 pounds per square inch gauge (psig), which would require gas compression to operate the traditional cryogenic gas plants.

Unlike conventional gas plants, shale-gas plants do not have the economy of scale and could be difficult to justify from gas sales alone. However, the rich liquid contents can add revenue to justify the development.

To meet the gas pipeline specifications, there are three NGL recovery options: a hydrocarbon dewpointing unit with mechanical refrigeration, cryogenic expander plant and the Fluor Deep Dewpointing (DDP) unit. The first two options are well known in the gas processing industry. The Fluor DDP process is a proprietary process from Fluor's Cryo-Gas[sm] Process NGL portfolio.

## Hydrocarbon dewpoint control

The mechanical refrigeration unit (MRU) is a common industry standard unit used for lean gas applications with limited NGL recovery, whose main purpose is meeting the sales gas hydrocarbon dewpoint.

In this process, the feed gas is chilled

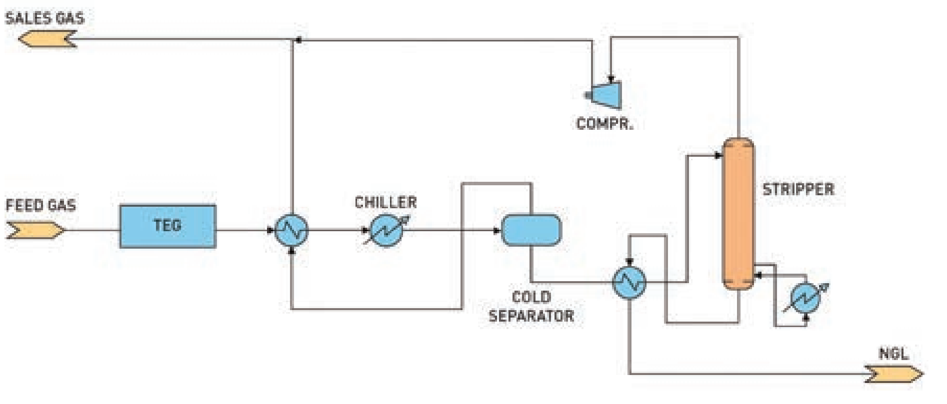



**Figure 2: Mechanical refrigeration unit**

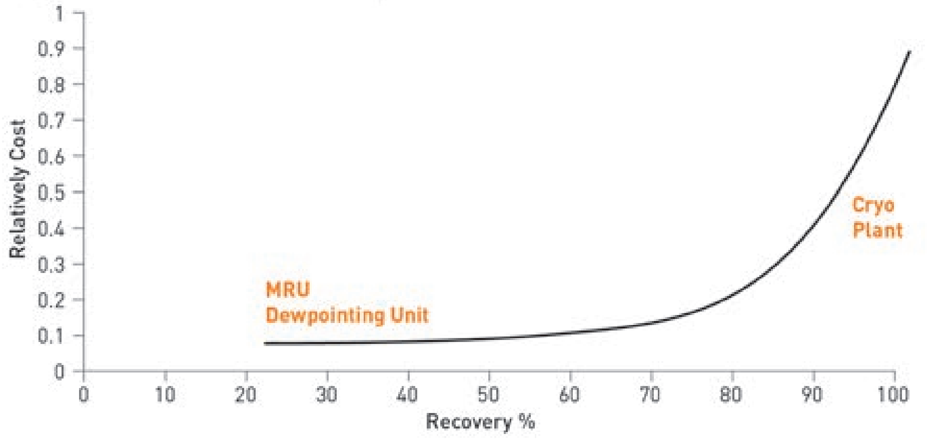



**Figure 3: Relative Cost vs Recovery**

by propane refrigeration, and the liquid is removed and fed to a stripper or stabilizer. NGL is produced from the stripper and the overhead gas is compressed to the sales gas pipeline.

Propane recovery using the MRU is relatively low, limited to 40 to 50 percent. For processing a rich gas, the low recovery may not meet the heating value specification of the pipeline gas.

## Cryogenic plant

To meet the heating value and Wobbe Index of pipeline gas, the common solution is a NGL recovery unit using turbo expander technology. The Gas Subcooled Process (GSP) can be used to recover 70 to 80 percent ethane from the conventional lean gas with low C2 content.

With the high C2 content in shale gas (10 mole% to 24 mole%), there is sufficient ethane in the feed gas, such that high C2 recovery is no longer necessary. Therefore, high recovery design may be superfluous with the shale gas. Lowering the recovery level would reduce the cost of the installation, as shown in Figure 3.

The GSP process uses a turbo expander to generate refrigeration, and the flash gas from the cold separator is used in refluxing the demethanizer, which is a tall column operating at cryogenic temperatures. When processing a rich gas, additional cooling with propane refrigeration is required.

The drawback of an expander plant is its limited turndown, typically 50 percent. The expander plant is also sensitive to changes in feed gas compositions and flow rates, and re-wheeling of the expander may be necessary to accommodate significant changes.

When ethane prices drop below the Btu equivalent of natural gas, the GSP process is required to operate in ethane rejection. The problem of ethane rejection using the GSP process is the propane losses, as some propane is also rejected with the ethane.

The Fluor Deep Dewpointing Process (DDP) was originally developed for propane recovery which has been successfully proven in operation for high recovery. The design has been modified using JT valves for cooling, instead of a

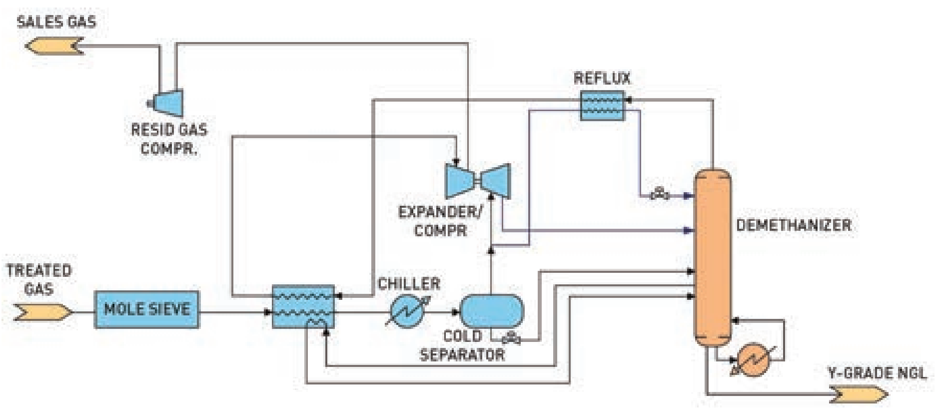



Figure 4: Cryogenic process for gas facilities

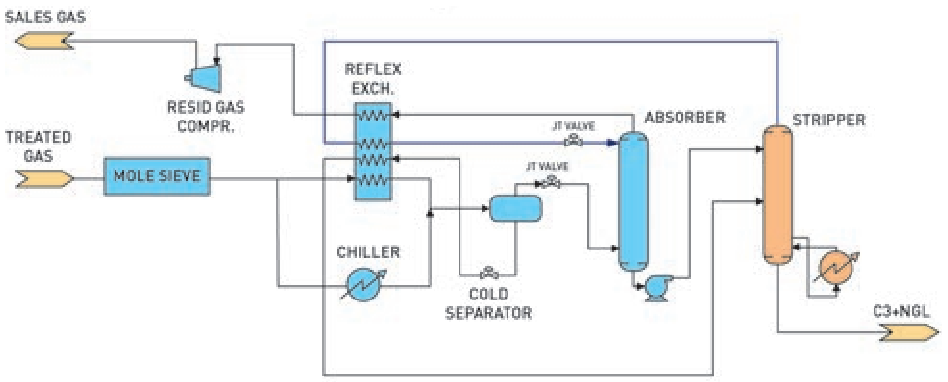



Figure 5: Fluor DDP module-ethane rejection

turbo expander, and has eliminated some of the difficulties in shale gas plants.

The DDP process is not sensitive to changes in feed gas compositions and feed rates, and can be significantly turned down. The process is most suitable in processing the ultra-rich shale gas, especially when the gas characteristics and capacities are not fully known during the project development. (Mak et al, 2015).

## Ethane rejection

A graphic shows the basic process configuration of the DDP process operating to recover propane in ethane rejection mode. The process consists of two short columns, an absorber and a stripper.

The absorber produces an ethane rich bottom which is fed to a non-refluxed stripper. The stripper overhead is used to reflux the absorber.

This process uses the C2 content in the overhead vapor in absorbing the C3+ content in the absorber. Therefore, cryogenic temperatures that are used in the GSP process are not required.

The DDP process can recover over 95 percent propane in full ethane rejection operation.

## Ethane recovery

Figure 6 (a) shows the DDP plant operation in ethane recovery mode. During this operation, a portion of the flash vapor from the cold separator is used as reflux to the absorber. The stripper overhead is re-routed to the bottom of the absorber. To reduce refrigeration consumption, side reboilers can be added to the stripper for pre-chilling the feed gas. With these changes, the process can recover about 60% of the ethane while maintaining 95% propane recovery. No additional equipment is required for this operation.

## LNG and ethane production integration

When ethane or LNG is required, the Fluor Enhanced Recycle Gas Reflux (ERGR) ethane recovery process can be bolted on to the DDP process as shown in Figure 6 (b).

The residue gas from the DDP process consists of C1 and C2 component, which can be easily separated in a demethanizer. Refrigeration can be provided by turbo expander and propane refrigeration. The process can recover at least 95% ethane with 99% purity as the bottom product, and a residue gas containing over 98% methane. Ethane can be pumped to the ethane pipeline, and the residue vapor can be sent to a liquefaction plant to produce LNG. Such integration can significantly reduce the capital and operating costs of the traditional LNG plants.

A case study was performed to compare the three NGL recovery technologies for a typical shale gas composition.

The feed rate is 80 MMSCFD and the pressure is 800 psig. A closed loop propane refrigeration system, hot oil system and air coolers were utilized. The units were designed to meet a sales gas higher heating value (HHV) of 993-1162 Btu/scf.

A lower sales gas HHV can be achieved with higher refrigeration consumption. Table 1 summarizes the performance and the economics of the NGL recovery technologies based on fabrication in the US Gulf Coast. The sales gas, NGL and power prices were assumed to be 5.3 USD/MMBtu, 25 USD/barrel and 0.05 USD/kWh respectively. The net present value is calculated with an 8% discount rate for an operating period of 20 years.

In comparison to the MRU, the Fluor DDP can produce a lower Wobbe Index sales gas and recover significantly more NGLs for a marginal increase in CAPEX and OPEX. As the price of C3+ NGLs liquid is always higher than natural gas, the higher NGL recovery of the Fluor DDP will offset the higher CAPEX and OPEX, as demonstrated by the positive NPV.

The GSP has similar NGL recovery compared to the Fluor DDP, but higher power consumption and greater CAPEX. Plus, the use of a turboexpander would limit the plant's turndown capability.

**Unconventional gas development**: Fluor's solution to the challenges of U.S. gas development is the combination of Fluor DDP and 3rd Gen Modular Execution. With its simplicity, reliability and flexibility, Fluor's solution is ideal for shale gas reservoirs that may not be developed due to associated risks and uncertainties.

This solution offers several advantages that can mitigate these risks to achieve successful gas development while generating revenue from high C3+ NGL recovery. The following are some potential risks that can be mitigated by Fluor's solution.

**Gas reservoir uncertainty:** One of the risks associated with unconventional gas reservoirs is the unexpected production rate and gas compositions. Fluor's solution mitigates this risk using JT valves instead of an expander, allowing units to be turned down.

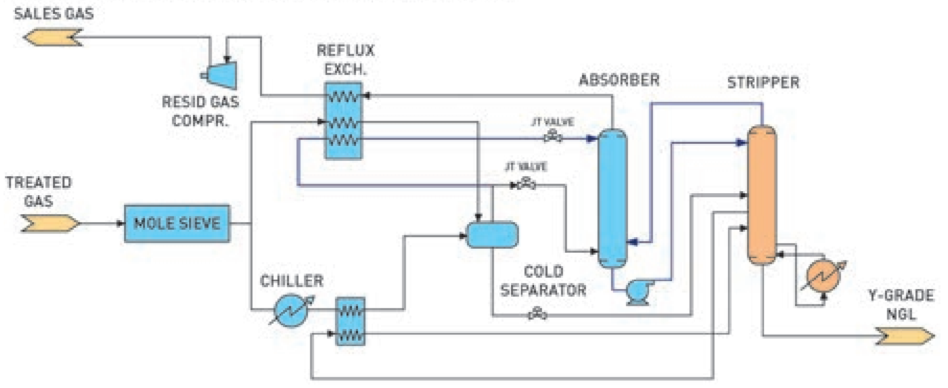



Figure 6 (a) Fluor DDP Module–Ethane Recovery

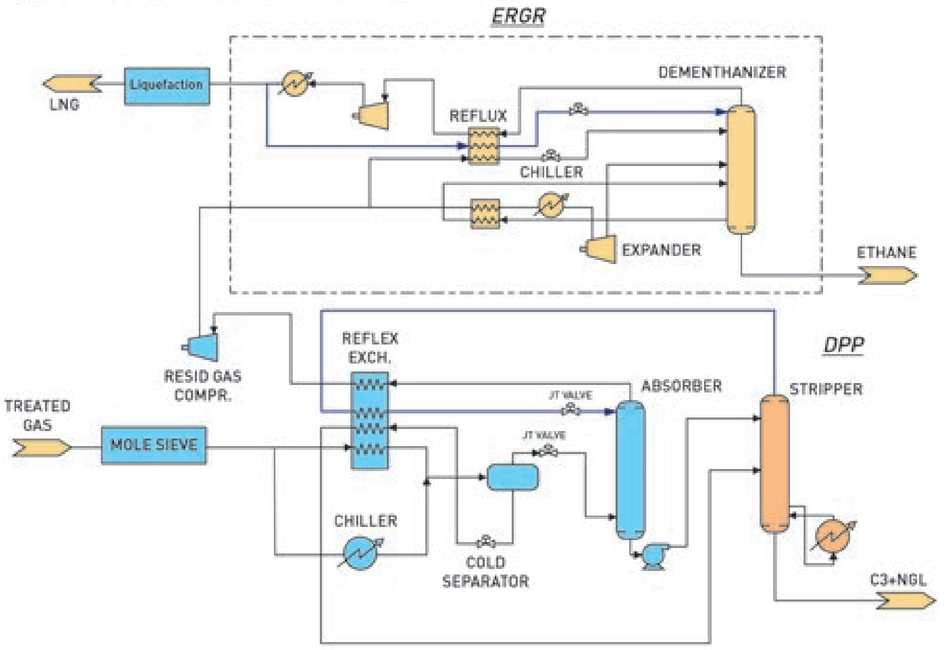



Figure 6 (b) Fluor DDP Module + Fluor ERGR Module

| PERFORMANCE SUMMARY OF LNG TECHNOLOGIES FOR ETHANE REJECTION | | | |
|---|---|---|---|
| **NGL Recovery Technology** | **MRU** | **DDP** | **GSP** |
| Ethane Recovery, % | 2.1 | 4.1 | 3.6 |
| Propane Recovery, % | 43.7 | 95.3 | 96.5 |
| Sales Gas HHV, Btu/scf | 1162 | 1076 | 1076 |
| Sales Gas Wobbe Index, Btu/scf | 1406 | 1355 | 1355 |
| Refrigeration Compressor, kW | 2231 | 1738 | 2182 |
| Overhead Compressor, kW | 382 | not required | not required |
| Residue Gas Compressor, kW | not required | 2014 | 2152 |
| Total Power, kW | 2613 | 3752 | 4334 |
| Reboiling Duty, kW | 1748 | 3629 | 4079 |
| NGL Product, BPD | 4163 | 6844 | 6863 |
| Capital Expenditure (CAPEX) | Base | +6% | +16% |
| Operating Expense (OPEX) | Base | +22% | +37% |
| Net Present Value (NPV) | Base | +28.5 MM USD | +15.7 MM USD |

**Table 1: Performance summary of NGL technologies for ethane rejection**

Another risk is the possibility of encountering a smaller reserve with a short production plateau. This is mitigated by the modular nature of Fluor's solution. Modules can be disconnected and relocated by trucks to the next reservoir.

The relocatable unit can also be utilized as an early production system to prove the viability of larger reservoirs with lower reservoir certainty.

**Market conditions and flexibility:** Market conditions may change in the future and adversely affect the profitability of a gas plant. Fluor's solution mitigates this risk with its flexibility to change its mode of operation. If C3+ NGL prices decline with respect to the sales gas, the unit can switch to operate as a dewpointing unit similar to an MRU. If C2+ NGL prices become attractive, the unit can switch to ethane recovery mode to recover ethane.

If ethane and LNG products are desired, a Fluor ERGR module can be added downstream of the DDP module to produce ethane and methane to feed an LNG plant.

**Operability:** Turboexpander in cryogenic gas plant is critical for plant performance and must be closely monitored and controlled. The DDP process uses JT valves which has eliminated this criticality. Consequently, the process is more robust, and plant performance is not affected by changing gas compositions and flow rates. The module can be operated in an unmanned mode.

**Budget and schedule:** One of the primary concerns of gas development in remote areas is budget. Due to the remote location, labor costs and camp maintenance costs are extremely high and difficult to control. Fluor's solution mitigates this risk by shifting a large proportion of the construction hours to the module yard, leaving a much simpler installation at site.

Schedule delays are also a concern for gas development projects. The remote nature of the site can cause schedule delays due to late equipment arrival, adverse weather conditions and travel time to and from site. Fluor's solution improves productivity by way of simpler module installation at site, thus de-risking elements of the construction schedule.

**3rd Gen Modular Execution:** Fluor's 3rd Gen Modular Execution technology for the DDP module was developed in many stages, and is now an optimized solution that has been proven in many industrial installations.

3rd Gen Modular Execution gives execution certainty by reducing interconnections, materials, equipment and labor, resulting in significant cost savings. Material and labor contingency, labor force, camp size, field indirect and infrastructure costs are also reduced. Schedule savings are achieved due to increased productivity and simpler installation at site and due to elements of the site construction schedule being de-risked.

The 3rd Gen Modular Execution leads to improved safety. This is due to the reduction of safety risks associated with material movements, particularly elevated work and the removal of construction hours from site to the controlled module yards.

Quality is also improved due to modules being fabricated in the yards under a controlled quality production environment.

## Conclusion

The US has many unconventional gas reservoirs in remote locations. The remote nature and limitations on existing infrastructure impose several risks that can deter the development of these reservoirs. Fluor's solution to these challenges is the combination of Fluor's NGL process and 3rd Gen Modular Execution.

This solution mitigates these risks by offering a simple, reliable and flexible NGL recovery unit that recovers high levels of C3+ NGLs. The unit can accommodate a wide range of gas compositions and production rates.

Construction in a controlled module yard, as opposed to the site, offers project cost and schedule savings as well as improvements in safety and quality.

The flexibility of the design allows the unit to operate in ethane rejection or ethane recovery modes in response to market conditions. The unit can also be relocated by trucks from one gas field to another, allowing for extremely flexible field development strategies.

Fluor's solution for the shale gas development is applicable for pipeline gas production and also provides an integration opportunity for ethane and LNG production. ■

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# For the Record

**ABS**, the American Bureau of Shipping, the US classification society, has granted an approval in principle (AIP) for a new Moss-type LNG tank design concept developed by Japan's Kawasaki Heavy Industries to boost shipment capacity through the Panama Canal. "We are pleased to issue this AIP that further demonstrates our commitment to technology advancements and safety," said ABS Vice President for Global Gas Solutions Patrick Janssens. "KHI's concept applies the latest technologies, introducing new efficiencies and innovations that promote a safer and more sustainable shipping industry," added Janssens. According to KHI, the non-spherical design concept allows Panamax-size LNG carriers to expand their total carrying capacity to 180,000 cubic metres, a 25,000 cubic metres volume increase when compared to using traditional Moss spherical tanks. The larger-sized Kawasaki carriers are at the optimum limit for the economics of shipping US cargoes to Asia from the US Gulf Coast via the expanded Panama Canal. In issuing its AIP, ABS said it reviewed the strength and fatigue analysis to support KHI in demonstrating the feasibility of the new concept. Designated as an IMO Type B independent tank, it takes a new approach by applying a non-spherical tank design to increase the use of space on board an LNG carrier. "As the Panama Canal expands and LNG demand increases, owners and operators are looking to gain efficiencies without compromising safety," said Hideaki Naoi, a general manager for KHI's Ship & Offshore division. "This new concept adds 15 percent more carrying capacity while maintaining the size of the new Panamax tankers. By working with a proven technology leader like ABS, we were able to prove the feasibility of this innovative design," added Naoi. Japanese shipping companies Mitsui OSK Lines (MOL) and Nippon Yusen Kabushiki Kaisha (NYK Line) have each ordered two of the larger LNG carriers. At least two of them will ship US LNG from the Freeport LNG export plant at Quintana Island in Texas from 2018.

**ADD ENERGY,** the Norwegian-based consultancy and services company was awarded a contract as part of the development of the Angelin natural gas field by BP in Trinidad to supply more feed-gas for the Atlantic LNG liquefaction and export plant at Point Fortin. The Angelin gas field is located 60 kilometres offshore the east coast of the Caribbean nation. Add Energy said its contract, valued at around $645,000, is to carry out the development of a full asset maintenance build and will include the delivery of an asset register. The Angelin project is a dry gas development in the northern Columbus Basin of the Caribbean in over 210 feet (65 metres) of water. With a design throughput of 600 million standard cubic feet of gas per day, production will be sent to the Cassia platform for processing. The feed-gas from the venture will be transported by pipeline to the Atlantic LNG plant at Point Fortin and the liquids produced will go to Galeota terminal via a new 13-mile pipeline. BP is also currently completing the construction of the Juniper project to supply more feed-gas to the LNG plant from 50 miles off the southeast coast of Trinidad. The four processing Trains at Atlantic LNG are running below capacity. Last year they produced 10.46 million tonnes of LNG compared with 11.81MT the previous year The Add Energy contract involves the development of maintenance strategies for critical and non-critical equipment, job plans and procedures for the gas field work. It is expected to last eight months and will be led by Add Energy's Technical Manager, Julio Monsalve and will cover 6,500 equipment tags. Add Energy is headquartered in Stavanger, Norway, and has offices in seven other countries, including the US. As part of this win, Add Energy said it had recruited four new personnel in Houston, Texas, to support the project delivery. "As we continue to work closely with BP and expand our presence in delivering projects in the Trinidad and Tobago region, we are delighted to have been selected for this project," said Peter Adam, Executive Vice President of Add Energy. "We believe that Add Energy's customer-focused approach, in combination with project execution expertise and lessons learnt from previous maintenance builds, will enhance this project and support the operator in getting best value for money," added Adam.

**BAKER HUGHES,** the US energy services company, and GE's oil and gas business, which provides LNG equipment from gas turbines to pumps and gearing technology, have completed their transaction to form a new company called BHGE to offer services across the full value chain of the oil and gas sector. "No other company brings together capabilities across the full value chain of oil and gas activities, from upstream to midstream to downstream," said BHGE. BHGE's global organization will employee 70,000 people in four product companies. These are Oilfield Services, Oilfield Equipment, Turbomachinery and Process Solutions and Digital Solutions. The combination will have dual headquarters in Houston and London and the merged company is listed on the New York Stock Exchange under the BHGE ticker. GE Chairman and Chief Executive Jeffrey Immelt is serving as Chairman of Baker Hughes and Martin Craighead, former Chairman and CEO at Baker Hughes, is Vice Chairman of the BHGE board. "This portfolio positions BHGE to create new sources of value, improving productivity and project economics through integrated equipment and service offerings," the combined company said. "BHGE will use cloud-based software, advanced manufacturing and brilliant factory solutions to help its customers capture some of this opportunity - reducing risk and improving productivity in their operations as well as its own," added BHGE. Lorenzo Simonelli, President and Chief Executive of Baker Hughes, said his focus was on integrating the businesses "quickly and seamlessly" to drive long-term value for stakeholders. "We created BHGE because oil and gas customers need to withstand volatility, work smarter and bring energy to more people," said Simonelli. Chairman Immelt said BHGE can help the company's customers be more productive in any business cycle. "It's a smart deal for our combined customers, shareholders and employees. Lorenzo and his team are world-class leaders and will focus on accelerating the company's capability to extend the digital framework in ways oil and gas customers have never seen before," said Immelt. "The completion of the transaction marks a new era in the industry, and I am extremely proud of our team's focus, dedication and diligence, which resulted in the completion of this combination in just eight months," stated Immelt.

**BANGLADESH** has signed its first initial LNG supply agreement with Qatar after recent progress on establishing the Asian nation's first import facility at an island in the Bay of Bengal. Qatar and Bangladesh's state-owned energy company PetroBangla signed the preliminary accord prior to a sale and purchase agreement

(SPA) to import 2.5 million tonnes per annum. for a 15-year period. A delegation from Qatar has just negotiated the agreement in the Bangladeshi capital Dhaka, including the pricing of the shipments, which will be linked to crude oil. Excelerate Energy, the US LNG terminal project company, and the World Bank in July 2017 arranged the debt financing for the first Bangladesh facility. The World Bank's International Financing Corp., which offers advice and investment to the private sector in developing countries, and Excelerate will bring LNG infrastructure to the Asian nation for an initial investment of $179.5 million. The floating storage and regasification unit (FSRU) and shore-based infrastructure will be put in place at Moheshkhali Island. The construction of the terminal will commence in the fourth quarter of 2017 and is expected to be in service by mid-2018. The Moheshkhali terminal will include an FSRU with 138,000 cubic metres of LNG storage capacity supplied by Excelerate, the installation of a subsea buoy system anchored offshore and the employment of port service vessels during operations. The equity for the project had been tied up earlier with the IFC coming in with a contribution of $10.8M and Excelerate's equity amounting to $43.1M. As lead arranger for the project, the IFC said it helped arrange the debt financing package of $125.7M for the venture. Bangladesh's first LNG import terminal will enable state energy company PetroBangla to increase natural gas supply in the country by up to 20 percent, sufficient to support up to 3,000 megawatts of gas-fired power generation capacity. Excelerate said the terminal was the first fully integrated turnkey floating terminal solution whereby all services will be provided under a single contract. "The concession agreements for the project can serve as a template for other LNG projects in the country," it added.

**CB&I,** the US energy engineering company, was awarded a contract valued at nearly $200 million by Venture Global LNG, a US-based project developer based in Washington DC, to construct two LNG storage tanks for the company's proposed Calcasieu Pass export facility in southwest Louisiana. Venture Global's Calcasieu Pass is expected to produce 10 million tonnes per annum of LNG when the plant is completed. The facility's design will use a liquefaction system with 18 mid-scale modular Trains driven by electric motors to achieve optimum efficiency and reliability. CB&I will provide, on a turn-key basis, two single-containment LNG storage tanks. Construction of the tanks is expected to begin in 2018. "CB&I has an established track record of successfully executing LNG storage projects both in the US Gulf Coast region and around the world," said Luke V. Scorsone, Executive Vice President of CB&I's Fabrication Services operating group. "Our ability to deliver certainty of outcome provides Venture Global with a cost-effective, low-risk solution for the Calcasieu Pass facility," added Scorsone. Venture Global is developing two LNG export plants in Louisiana, with the second called Plaquemines LNG and located on 630 acres near river mile-marker 55 on the west side of the Mississippi, 30 miles south of New Orleans. The Mississippi river project will produce 20 MTPA and will include small-scale liquefaction Trains, four LNG storage tanks and three marine loading berths. The company was founded by Michael Sabel, an equity fund manager and venture capitalist, and Robert Pender, a former partner at Hogan Lovells, a global law firm. They recently signed an agreement with the oil and gas unit of General Electric to supply compressor power for liquefaction and to generally cooperate on the projects. "We are pleased to have an agreement with the premiere LNG tank contractor in the world," said Venture Global. "We collaborated to develop a detailed scope and agreement that gives us confidence in the CB&I solution," the company added.

**CB&I** said that Patrick K. Mullen had formally assumed his roles as President and Chief Executive. The company announced in May that Philip K. Asherman would be retiring, aged 66, from his positions after 12 years in the posts of President and CEO to be replaced by Mullen. Mullen, aged 52, had been named Chief Operating Officer in 2016 after previously serving as Executive Vice President and President of CB&I's Engineering and Construction unit where he was responsible for worldwide operations. "It is an honor to have been chosen to lead CB&I," said Mullen after taking over the helm. "While I recognize this is a challenging cycle for our industry, I have a great deal of confidence in CB&I's employees and capabilities and in our ability to create long-term value for all of our stakeholders," he added. "To best position CB&I going forward as we maintain our relentless focus on safety and sound execution of our backlog, we will be taking decisive action in several areas," he explained. Mullen pledged to take action for the "strengthening of our balance sheet" while "streamlining the company's cost profile and further enhancing the company's risk management and execution standards. Actions in these areas will build on CB&I's many existing strengths. We look forward to sharing more detail on these actions and CB&I's strategic direction in the coming months," said the new CEO. CB&I posted first-quarter net income of $25 million compared with $107M in the same three months of 2016 amid a full US book of LNG contracts. Revenue for the quarter was $2.4 billion compared with $2.7Bln in the year-ago period. New awards amounted to $3.3Bln versus $1.2Bln for the first quarter of 2016. CB&I's backlog at the end of the first quarter of 2017 was $19.3Bln. The Houston-based company is currently working on two large-scale LNG export projects on the Gulf Coast to be completed by 2018. These are the Freeport LNG plant on Quintana Island in Texas, led by energy entrepreneur Michael Smith, and the Cameron liquefaction project in Louisiana being developed by California-based Sempra Energy and European and Japanese utilities. CB&I and its joint venture partner, Chiyoda Corp. of Japan, were awarded the contract valued at $6 billion by Cameron LNG to transform an existing import facility at Hackberry in Louisiana into an export plant. The Cameron project will consist of three liquefaction trains with a nameplate capacity of around 13.5 million tonnes per annum of LNG. Together with its joint venture partners, Zachry and Chiyoda, CB&I is also constructing liquefaction infrastructure at the existing Freeport LNG terminal to provide export capacity of almost 14 MTPA. However, CB&I has not mentioned any new LNG contract wins so far in 2017. Its last LNG contract award was in November 2016 and worth more than $200M. This was from Puget Sound Energy for the engineering, procurement and construction of an LNG storage and fuel terminal in Tacoma port in Washington state.

**CEDIGAZ,** the Paris-based energy consultants, said natural gas growth in absolute terms would outstrip that of all other energy sources and the strong expansion of LNG supply and the abundance of both conventional and unconventional resources would help gas to expand its role in the energy mix to the detriment of coal and oil. Cedigaz also said in its "Medium and Long Term Natural Gas Outlook 2017" that demand would pursue its short and medium-term growth trajectory to 2035, rising at a gradual pace of 1.6 percent per annum under the impulsion of China and the Middle East. "Natural gas will increase its relative share in the world primary energy supply from 21.2 percent in 2014 to 23.9 percent in 2035," said Cedigaz. "Gas is viewed as a bridging resource in the transition towards an increasingly renewable-based and decarbonised energy system," it added. "China and the Middle East lead the way in gas demand growth, accounting for respectively 28 percent and 24 percent of the incremental volume over the projection period," the report stated. "At the national level, the largest growths in gas demand are recorded in China, India, Iran, the US and Saudi Arabia," it said. Cedigaz explained that net Inter-regional (long distance) trade is forecast to grow by 3.1 percent a year from 392 billion cubic metres in 2015 to 729 Bcm in 2035. It thus increases much faster than demand, as import dependence grows both in Europe and Asia. In these markets, the diversity of both pipeline and LNG sources tends to improve the security of supply. "The largest growths in inter-regional flows come from CIS exports to China and US LNG exports to Asian emerging countries," the report said. Inter-regional pipeline flows grow by around 2 percent per annum and Europe will remain 30 percent dependent on Russian gas, which will maintain its competitiveness. "LNG increases more rapidly than pipeline gas. The share of LNG in inter-regional flows will grow from 44 percent in 2015 to 55 percent in 2035," according to Cedigaz estimates. "International LNG trade will grow by 3.7 percent a year to 669 Bcm in 2035. Asian emerging markets will explain more than 70 percent of the incremental imports. Additional LNG export capacity is required post 2023 to meet rising natural gas demand," the report stated.

**CHART INDUSTRIES,** the US LNG equipment maker, said it delivered its first re-fueling vehicle for LNG and diesel designed and built under a joint venture for a rock quarry customer in Florida. The customer is using the vehicle as a fueling solution for its recently converted fleet of haulage trucks retro-fitted with LNG fuel conversions. Chart said it teamed up with US company Ground Force Worldwide to deliver its first LNG-diesel re-fueling truck. GFW is a maker of vehicles and equipment for the mining industry and has its headquarters at Post Falls in the northwest state of Idaho. The re-fueling truck is a Kenworth T800 vehicle with the addition of Chart's Orca MicroBulk Delivery System for LNG with its safety pumps and technology. Originally developed more than 20 years ago as an efficient way of delivering packaged atmospheric gases, Chart said the latest version of the Orca System has brought the technology forward. "The two companies hadn't worked together previously and this was GFW's first excursion into LNG and cryogenics but both companies pronounced the collaborative effort a resounding success," said Chart. The company said that with the mining sector showing increased interest in LNG and the major truck makers developing LNG and LNG-diesel hybrid haulers, there was scope for the partnership to flourish. "Importantly, the partners have been able to gather information from the field with the quarry reportedly impressed with the unit's build quality and an ability to fuel 50 percent faster than with its previous system," added Chart.

**CHART** is celebrating 25 years since its pioneering of the ISO shipping containers that now carry LNG to small-scale users in the Caribbean, Europe and Asia. "Some of those earliest items are still in service today and it is their reliability, durability and our continued technical innovation that ensures Chart products remain the industry benchmark," said Chart. "Originally developed for the safe, economical and convenient transport by road, rail and water, of atmospheric and technical gases for industry and leisure; the standard 20-feet and 40ft containers are also now widely used for LNG and are key components in Chart's small-scale LNG solutions, facilitating the use of natural gas as a clean-burning, economical fuel alternative to diesel and other distillates," the company explained. Chart said ISO containers were integral to its skid-mounted Natural Gas Vehicle fueling stations, onboard ship-fueling systems, satellite stations and even feature as tender cars for natural gas-powered locomotives. The US company noted that in 2016 Chart delivered an LNG solution enabling the power station on the Portuguese island of Madeira to burn natural gas, despite not being connected to the pipeline grid. Chart is currently consolidating its core business of LNG and recently entered into an agreement to acquire its smaller US sector rival Hudson Products Corp. for $410 million in cash. Hudson, based in Beasley, Texas, makes a range of heat-transfer equipment for the refining, petrochemical, natural gas and other industrial markets. Hudson is a North American leader in air-cooled heat exchangers (ACHXs) and a global leader in axial flow cooling fans. The Texas company was majority-owned by equity funds managed by Riverstone Holdings. The air-cooled heat exchangers will widen the product range for Chart and improve its offerings as it makes a place for itself in the small-scale and medium-sized LNG plant sector. The acquisition comes as Chart continues with the moving of its corporate headquarters from Garfield Heights in Ohio to the town of Canton in the state of Georgia, expected to be completed by the end of 2017. Chart has also restructured to concentrate on its energy and LNG businesses as it has sold non-core assets and cut costs across the group. The restructuring was initiated under the previous leadership of Sam Thomas who has now handed over to new President and Chief Executive Bill Johnson.

**COMMONWEALTH LNG**, a US export project in Louisiana, has initiated its pre-filing environmental review process with the Federal Energy Regulatory Commission for a liquefaction plant in Louisiana with 9 million tonnes per annum of capacity. The facility would be located along the South Prong of Grand Bayou in Cameron Parish, where several other projects are being built. Commonwealth said it intended to file a formal application for the project with the FERC no later than August 2018. Its industry partners for equipment include, compressors and drives maker, Siemens of Germany, and US-based consultants CH-IV, a subsidiary of Australian engineering group Clough Ltd. The project company said it planned to construct eight single mixed-refrigerant LNG liquefaction Trains, one marine loading berth with three loading arms, six 400,000 cubic metres capacity LNG storage tanks and four miles of pipeline to connect to inter-state feed-gas supplies. "By employing innovative yet proven methods, our team has reimagined the engineering and construction process to advance schedule and reduce risk for investors, customers and EPC partners," said Commonwealth's President and Chief Executive Paul Varello said. "This creative process also improves safety and decreases overall capital costs," added Varello. Commonwealth's Chie Operating Officer Scott Johnson said the companies initiation of the FERC process was the culmination of over two and a half years of work by the management team and its LNG consultants, advisors and vendors. "We are eager to meet with community leaders, policy makers and all other stakeholders to introduce our project and to discuss the many benefits it will bring to Cameron Parish," stated Johnson. Pending a successful environmental review process and receipt of a FERC permit, Commonwealth said it expected to begin construction in 2019 and commercial operations in 2022. "When Commonwealth files its application with the Commission, we will evaluate the progress made during the pre-filing process, based in part on your success in resolving the issues raised during scoping," the FERC told the company. "Once we determine that your application is ready for processing, we will establish a schedule for completion of the environmental document and for the issuance of all other federal authorizations," it added. The FERC said it had also reviewed the proposals submitted for the selection of a third-party contractor to assist the Commission in preparing the National Environmental Policy Act (NEPA) documentation. The was named as Cardno Inc. "Cardno as the third-party contractor will work solely under the direction of the Commission staff. Factors considered in this selection included technical approach, personnel qualifications, past work history, and clearance of any organizational conflict of interest," it added. "I request that you proceed with executing a contract with Cardno and prepare a Memorandum of Understanding between the Federal Energy Regulatory Commission, Commonwealth and Cardno," it told Commonwealth.

**CONOCOPHILLIPS** intends to fully shut down its small-scale liquefaction and export plant located in Nikiski on the Kenai Peninsula because of low global LNG prices and the US major's lack of progress in finding a suitable buyer for the plant. ConocoPhillips said it was preparing to put the plant into long-term shutdown mode in the autumn. "The reduced operations will focus on continued preservation of the facilities for future LNG exports," the company said. "How long the plant is mothballed will depend on market conditions and right now there are about 30 people working at the LNG plant, 18 of whom are ConocoPhillips employees," it added. The location had always been favoured by the new and larger Alaska LNG project and the purchase of the plant would give the venture a brownfield site to build on. ConocoPhillips said in November 2016 it planned to sell the Kenai facility, which was the first US liquefaction and export plant to come on stream in 1969 and went on to export cargoes to Japan for 46 years. Kenai LNG had been given a short reprieve after shutting down in 2013 and during 2014 and 2015 exported about 10 cargoes to Japan, mostly on a spot basis to Japanese utilities. LNG from Kenai had previously been shipped under long-term contract to Tokyo Electric Power Co. and Tokyo Gas, though operations were gradually cut back at the ageing plant where the capacity is less than 900,000 tonnes per annum. The volumes delivered from the two-Train Kenai plant were small compared with the eventual 27 million tonnes per annum for the first US Gulf Coast LNG export plant to come on stream, Sabine Pass in Louisiana. The AGDC-led Alaska LNG project itself is planning to produce an initial 20 MTPA of LNG from its four planned processing Trains. The original investors in the Kenai plant were Marathon Oil and the predecessor company of ConocoPhillips. Its start-up in 1969 came four years after the first full-scale LNG export plant began commercial operations at Arzew in Algeria.

**DUTCH GATE LNG** terminal owners, the utility Gasunie and global storage company Vopak, plan to develop Germany's first LNG import terminal at Brunsbüttel on the Elbe River near the port city of Hamburg. Vopak and Gasunie said they were teaming up with German company Oiltanking GmbH for the LNG project and had already gained the European Commission's approval under merger regulations to establish a joint venture. The three companies are jointly investigating the possibilities for constructing and operating a multi-service LNG terminal, including imports and additional services such as truck-loading and bunkering. However, it is likely to be mainly a break-bulk terminal concentrating on LNG distribution for the fuel markets rather than being in competition to the huge volumes of Russian pipeline gas that flow into Germany from Gazprom. "This positive decision of the European Commission is an important milestone in developing an LNG facility in Northern Germany," the three companies said. "The feasibility study consists of economic, technical, nautical and regulatory assessments as well as the permits procedures. Now that the EC approval is in place, the parties are ready to jointly work towards the next development phases. No financial investment decisions have been taken yet," they added. Germany is the only major European Union nation without LNG import facilities, though it is advancing some LNG fuel and bunkering services in Baltic ports such as Rostock and on the European river networks for barge traffic. Germany's transition to the cleaner fuel era has not so far depended on LNG, but on Russian pipeline natural gas. German gas imports from Gazprom soared by almost 16 percent in the first five months of 2017 compared with last year. Gazprom said it supplied 22.3 billion cubic metres of gas to the German market from January until the end of May, which is 3 Bcm more than in the same period last year. The volumes of German gas received from Russia amounted to almost 50 Bcm in 2016. This is the equivalent of 37 million tonnes of LNG while the Brunsbüttel import terminal would have initial capacity of around 5 million tonnes a year. The Russians are also currently expanding the Baltic Sea pipeline route for pipeline gas called Nord Stream II to pump more gas into Germany and Western Europe. Up until now Europe's largest economy has been forging closer pipeline ties with Gazprom as the Russian natural gas giant also acquires more German gas assets. More than 900 natural gas filling stations for fuel are now available to customers across Germany, though mostly compressed natural gas rather than LNG.

**EAGLE LNG** Partners has filed an application to export liquefied natural gas from a second production and storage facility currently under construction at a site in West Jacksonville in Florida. The company's subsidiary Eagle Maxville is seeking the permit from the Department of Energy for small-scale volumes up to a total of 60,000 tonnes per annum of LNG for a period of 20 years to nations with or without a Free Trade Agreement with the US. Eagle LNG is in the process of completing its principal facility at Jacksonville to supply fuel to US shipping company Crowley Maritime Corp. and its LNG-powered cargo ships sailing between Florida and Puerto Rico. The Eagle Maxville unit is at a separate site and would involve new and some remaining supplies for export and domestic use. The company said volumes for the overseas market would be shipped in ISO containers to serve industrial customers in the Caribbean Basin. "The Maxville facility is separate and distinct from the LNG production and export terminal which Eagle Maxville's affiliate, Eagle LNG, is developing at a site on the St. Johns River in Jacksonville," the company explained. Eagle Maxville expects that the Maxville facility would be placed into commercial operation and begin producing LNG in September 2017. At the Maxville facility, Eagle would receive domestically produced natural gas via a local utility, process this gas into LNG and temporarily store it. It would then be periodically loaded into cryogenic transport trailers or ISO containers for transportation by truck to ports for transfer into vessels for use as marine fuel for their trading between Florida and the US territory of Puerto Rico. It would also be supplied to customers in the Florida domestic market. "LNG in excess of quantities required from time to time to satisfy marine fuel demand may be delivered to vehicle fueling facilities in the region for use in vehicular fuel applications, or may be transferred to port facilities for loading onto ocean-going container ships for domestic use or for export," the company added in its application. "The Maxville Facility will be modest in scale, but it will address significant demands for LNG for use as marine fuel and as transportation fuel for domestic purposes and for export to markets in the Caribbean Basin and elsewhere in the region," it said. Eagle LNG Partners is a subsidiary of Ferus Natural Gas Fuels, which is a partnership registered in the state of Delaware. Eagle Maxville has been developing the Maxville facility since mid-2015 and commenced construction in May 2016.

**EXCELERATE** Energy, the US floating liquefied natural gas LNG terminal project company, and the World Bank have arranged the debt financing for the first floating LNG facility for Bangladesh. The World Bank's International Financing Corp., which offers advice and investment to the private sector in developing countries, and Excelerate will bring LNG to the Asian nation for an initial investment of $179.5 million. The floating storage and regasification unit (FSRU) and shore-based infrastructure will be put in place at Moheshkhali Island in the Bay of Bengal. The construction of the terminal will commence in the fourth quarter of 2017 and is expected to be in service by mid-2018. The Moheshkhali terminal will include an FSRU with 138,000 cubic metres of LNG storage capacity supplied by Excelerate, the installation of a subsea buoy system anchored offshore and the employment of port service vessels during operations. The equity for the project had been tied up earlier with the IFC coming in with a contribution of $10.8M and Excelerate's equity amounting to $43.1M. As lead arranger for the project, the IFC said it helped arrange the debt financing package of $125.7M for venture. "The funding will support the timely construction and installation of the fixed infrastructure required for the project," the IFC said. Bangladesh's first LNG import terminal will enable state energy company PetroBangla to increase natural gas supply in the country by up to 20 percent, sufficient to support up to 3,000 megawatts of gas-fired power generation capacity. A ceremony for the signing of the financing documents for the LNG facility was held in a hotel in the capital Dhaka. The event was attended by Excelerate and IFC executives as well as the Bangladesh government's main energy adviser Tawiq-E-Elahi Chowdhury, the country's Minister for Power, Energy and Mineral Resources Nasrul Hamid and PetroBangla Chairman Abul Mansur Mohammed Faizullah. "Our partnership with the IFC has been essential to the development of this project," stated Excelerate's Chief Financial Officer Nick Bedford. "The IFC has demonstrated its commitment to bringing new energy to Bangladesh with the execution of these agreements. Excelerate takes great pride in helping bring sustainable energy solutions to countries with high energy demand, and we expect this project to have a great impact on the wider Bangladeshi economy," stated Bedford. "The terminal is the first fully integrated turnkey floating terminal solution whereby all services will be provided under a single contract by a single provider – Excelerate," the US company noted. "The concession agreements for the project can serve as a template for other LNG projects in the country," it added. The IFC's regional representative, Hyun-Chan Cho, said the World Bank institution was committed to partnering with Bangladesh in bringing reliable and affordable clean energy to all. "Addressing the issue of depleting gas supplies is critical for the country," he added. "We hope this first LNG import facility in Bangladesh will pave the way to expand support to the power sector and industry, promote growth and mitigate climate change impacts," the IFC executive said.

**INDIAN** Petroleum and Natural Gas Minister Dharmendra Pradhan has led a ceremony marking the start of construction of the first liquefied natural gas import terminal on the East Coast of India. The main developer of the Dhamra LNG project is the Adani Group's petroleum subsidiary, Adani Petroleum, headquartered in Ahmedabad in the state of Gujarat in northwest India. Adani has a 49 percent shareholding in the first East Coast terminal, while Indian Oil Corp. and Gas Authority of India have a combined 49 percent stake in the development. The 2 percent balance of shares will be held by banks and financial institutions. The project launch included a ground-breaking ceremony and the installation of a plaque for the development of the facility at Dhamra Port in the eastern Indian state of Odisha (formerly Orissa), located on the Bay of Bengal. "In eastern India, Dhamra will have the distinction of hosting the first LNG terminal, which will import gas from countries like the US and Qatar," said Pradhan. "This LNG terminal with 5 million tonnes per annum capacity is expected to be commissioned by 2020-2021 at an estimated cost of 6,000 crore rupees ($930 million). It will be a source of huge employment and investment opportunities for Odisha and eastern India along with access to clean fuel," added the minister. The Dhamra project is one of up to half-a-dozen planned for the East Coast where there are no import terminals currently operating. GAIL has regasification capacity at three of India's four operating import terminals on the west coast of India, at Dahej and Dabhol near Mumbai and at the Kochi facility in the southwest state of Kerala. "Besides, an investment of 4,500 crore rupees ($695M) would be made for the laying of pipelines and the establishment of city-gas distribution," said Minister Pradhan. "Dhamra will be a vital link in connecting eastern India to the gas infrastructure of the country and will also benefit neighbouring countries. Natural gas from this LNG terminal will also be an important gas supply source to the Urja Ganga Project," the minister stated. This is a reference to the fast-tracked project being pushed forward by Prime Minister Narendra Modi to boost city-gas pipeline connections in eastern India. The pipeline expansion venture is led by GAIL and involves laying 2,540 kilometres of pipelines in five eastern states to provide gas for 40 districts and 2,600 towns and villages. City-gas deliveries are then planned for seven cities named as Varanasi, Patna, Jamshedpur, Kolkata, Ranchi, Bhubaneshwar and Cuttack, all on the new

Urja Ganga pipeline route. "The terminal will also meet the gas requirements of the Indian Oil Corp.'s refineries at Barauni in Bihar, Haldia in West Bengal and Paradip in Odisha," said the minister in launching the LNG project. "The Dhamra LNG terminal is a step closer towards realising the dream of the Prime Minister of development of eastern India for the overall growth of our nation. I have requested all possible help for the State Government to ensure a smooth execution of the terminal infrastructure for the benefit of the people of Odisha," added Pradhan.

**INTERCONTINENTAL** Exchange (ICE), the operator of global pricing and clearing for energy and commodities, has made the ICE Endex European pricing and trading platform a fully-owned subsidiary after acquiring the remaining shares held by Dutch natural gas transmission company Gasunie. ICE bought a 20 percent shareholding for an undisclosed sum from the Dutch network operator and joint owner of the Gate LNG terminal in Rotterdam. "In addition, ICE and Gasunie have signed a memorandum of understanding which sets out the basis for further cooperation between the two parties in relation to the operation of the Dutch gas and power markets following ICE's acquisition of the Gasunie shares," a statement said. ICE's full ownership of ICE Endex comes at a time when the Dutch Transfer Title Facility (TTF) price is growing in importance as a continental European rival to the UK National Balancing Point (NBP), previously the dominant benchmark price. The Dutch TTF is a virtual trading point for natural gas in the Netherlands, set up by Gasunie in 2003. Since then the Dutch TTF has become the leading continental European benchmark and trading hub for spot, forward and futures gas trades. It will grow in importance as the UK leaves the European Union. As the leading energy exchange in continental Europe, ICE Endex provides widely accessible continental European markets for trading natural gas and power derivatives, gas balancing markets and gas storage services. "Gasunie have been terrific partners in building ICE Endex and in growing the Dutch TTF gas futures and options complex to help customers manage their price risk," said

ICE, based in the US city of Atlanta and which also owns the New York Stock Exchange. "Our acquisition of the remaining shares in ICE Endex along with further cooperation with Gasunie will allow us to further develop these markets and to serve the needs of our European gas and power customers," said David Peniket, President and Chief Operating Officer of ICE Futures Europe. "We look forward to continuing to work with Gasunie as we collaborate in support of the growth of both the European and global natural gas markets," added Peniket. Ulco Vermeulen, a member of the Gasunie board and a Business Development executive, pointed out that it was only three years ago that Gasunie decided to join forces with ICE for a period of time to develop a secure and efficient continental European platform for trading gas and power. "By bringing the expertise of both companies together we have been able to deliver this initiative. Trade is now flourishing and the 100 percent ownership by ICE is the most logical step for the ICE Endex business," added Vermeulen.

**JAPANESE** liquefied natural gas imports rebounded in July as a fall in shipments from other Asian countries was offset by more Middle East cargoes as well as Russian and US deliveries. LNG shipments in July amounted to 6.81 million tonnes compared with 6.57MT in July 2016, a rise of 3.6 percent. The latest imports cost a total of 316.19 billion yen ($2.89Bln), 42 percent more in dollar terms than in the same month in 2016, when the monthly LNG bill was 224.90Bln yen ($2.05Bln), according to the trade figures from the Japanese Finance Ministry. July thermal coal imports surged 13.6 percent to 10.59 million tonnes. The nation's LNG shipments in June had fallen by 1.2 percent to 6.18MT compared with 6.26MT in the year-ago period. The Ministry data on LNG imports showed that Asian shipments in June from nations such as Malaysia and Indonesia, Papua New Guinea and Brunei dropped 16.8 percent from a year ago to 2.00MT. Imports from the Middle East region rose just over 15 percent compared with July 2016. The shipments from countries like Qatar, the United Arab Emirates and Oman totalled 1.46MT. Monthly Russian shipments, mostly from the Sakhalin Island plant in the Far East, jumped 71.3 percent to 582,000 tonnes. Two cargoes from the US export plant at Sabine Pass in Louisiana were unloaded in Japan during the month and amounted to 140,000 tonnes compared with one a year ago. While there were no shipments from the US in June, the Japanese logged 143,000 tonnes of US LNG in May and more is expected in the future as Sabine Pass ramps up its capacity and a new export plant comes on stream at Cove Point in Maryland. The balance of July imports from other nations in the preliminary figures edged lower to 2.63MT versus 2.66MT in June 2017, covering shipments from countries such as Australia and Nigeria, as well as from the spot market. Japanese LNG imports for all of 2016 amounted to 83.34MT, a decline of 2 percent on the previous year. Those shipments cost the equivalent of $28.94Bln, a drop of 40.4 percent compared with 2015. Government figures released on August 9 showed that spot cargo prices in July had fallen. The average delivered price of spot LNG arriving in Japan in July was $5.60 per million British thermal units, a fall of $0.40 per MMBtu on the $6.00 per MMBtu registered in July 2016. Spot cargo numbers come from the commerce division of the Japanese Ministry of Economy, Trade and Industry and are only issued if a minimum number of two trades are recorded. The preliminary average contracted price for July 2017 fell by $0.20 per MMBtu to $5.60 per MMBtu versus $5.80 per MMBtu in July 2016. The ministry emphasizes that "spot LNG" refers to fuel traded on a cargo-to-cargo basis and does not mean shipments under contracts on a short-term, medium-term or long-term basis. The statistical accounting of the spot prices started in March 2014.

**JGC CORP.** of Japan and Kiewit Energy Group of the US were chosen by Veresen Inc. of Canada as preferred for the Jordan Cove LNG export plant planned for Coos Bay in the northwest US state of Oregon. Another US company, Black & Veatch of Kansas, is the choice to provide the liquefaction technology and other aspects of the project as part of the engineering and construction contract awarded to the KBJ joint venture. The Jordan Cove facility is expected to produce up to 7.8 million tonnes per annum of LNG and have around 320,000 cubic metres of LNG storage capacity as well as deepwater marine facilities. JGC is one of the world's most experienced LNG liquefaction plant builders while Kiewit Energy, based in Houston, is currently building the Cove Point LNG export facility at Chesapeake Bay in the state of Maryland. JGC, based in Yokohama, Japan, said it would work closely with Black & Veatch to perform the engineering, procurement and module fabrication for the Jordan Cove venture. Kiewit, a direct hire union construction contractor with significant experience throughout North America, will manage the construction of the facility. "The selection of the EPC contractor is a major milestone in the development of Jordan Cove and is the culmination of two years of extensive engineering work," said Don Althoff, Chief Executive of Veresen, which is currently in the midst of an agreed and friendly US$4.3 billion merger with Canadian peer Pembina Pipeline Corp. "Kiewit and Black & Veatch have been valued service providers to the project since its inception and we are pleased to involve JGC, a world class engineering firm with significant LNG experience," added the Veresen CEO. Veresen and Pembina, both based in the city of Calgary in the Canadian province of Alberta, said their transaction was expected to bolster the delivery of their existing strategy and portfolio of projects, including Jordan Cove. The Oregon venture is currently proceeding in the US Federal Energy Regulatory Commission permit process. The FERC has issued a notice of its intent to prepare an environmental impact statement, also involving the affiliated Pacific Connector Pipeline, and comments on the scope of the EIS were due by July 10, 2017. Veresen's development budget for 2017 is US$30M, with the expectation that Jordan Cove will finalize agreements with existing buyers and secure additional off-takers. "This would position the project for a potential final investment decision in 2019 and an in-service date in 2024 at an estimated total project cost of approximately US$10Bln," stated Veresen in its most recent earnings statement. Jordan Cove will be built on an undeveloped, 400-acre industrial site on the North Spit of lower Coos Bay. It represents the first and most advanced LNG export terminal development on the west coast of North America. "The Jordan Cove LNG project reflects extensive, detailed engineering design, planning, innovation and community collaboration," said Tom Shelby, executive representative for the KBJ consortium. "We commend the Jordan Cove team on their steadfast commitment to this project and are honored to serve as the engineering, procurement and construction contractor," added Shelby. The contractors and Veresen said Jordan Cove would be the largest single, private investment in the history of southern Oregon, benefitting the region and its residents through hundreds of millions of dollars in payments and tax revenue. "The complete construction of the project is anticipated to span 53 months and will require nearly 2,000 construction workers at peak," they added.

**KBR**, the US energy engineering company, said it was awarded pre-front end engineering and design and project support services contracts by BP of the UK for the development of the Tortue-Ahmeyim gas fields offshore Mauritania and Senegal that will form the basis of two floating LNG projects. The Houston-based company said that was awarded the work under its existing global services agreement with BP. The pre-FEED and project support work involves design of the subsea, pre-treatment floating production storage and offloading (FPSO) facility, the inshore hub-terminal and aspects of the FLNG development. This new work will build on the earlier concept phase work for the development of the field already completed by KBR's subsidiary Granherne for BP's partner, Kosmos. BP only entered the Mauritania and Senegal LNG project area of Kosmos with an agreement finalized in December 2016. BP bought a stake in the licences offshore West Africa and will provide more experience for Dallas-based Kosmos to achieve the construction of an LNG production system in the basin. First gas from Kosmos-BP FLNG Train 1 is scheduled for 2021 and the start of FLNG Train 2 is set for 2023. The UK and US companies have begun stem testing the Tortue discovery and will drill three additional exploration wells over the next 12 months offshore Senegal and Mauritania. The Tortue field is estimated to contain more than 15 trillion cubic feet of discovered gas resources. "KBR is pleased to offer our world-class engineering design expertise to continue to support this significant project from its early stages and to help BP and its partners develop an LNG hub for Mauritania and Senegal," said Jay Ibrahim, KBR President for Europe, the Middle East and Africa. "This award confirms KBR's strategic commitment to and builds upon our ongoing relationship with BP for engineering services around the globe," added Ibrahim. KBR's pre-FEED work is expected to be performed over the next six months, with KBR supporting BP in the optimize stage of the Tortue field development. "The work will be executed from KBR's London office which has played a key role in multiple recent BP projects including the Glen Lyon FPSO and Shah Deniz Phase II projects," KBR explained. In April 2017, the UK company agreed to deepen its investment in Senegal by acquiring the full 30 percent minority participating interests that Timis Corp. held in the Saint-Louis Profond and Cayar Profond blocks offshore. Participating interests in the Senegal blocks are similar to the aligned partnership in Mauritania, with BP holding participating and effective working interests of close to 60 percent, Kosmos close to 30 percent and Societe des Petroles du Senegal (Petrosen) 10 percent.

**LEBANON** plans to award exploration and production licences in five offshore blocks in the East Mediterranean by November 15 this year in the Middle East country's first attempt at establishing a domestic oil and gas industry to secure resource revenue and future infrastructure for LNG and gas-fired power. Lebanese Minister of Energy Cesar Abi Khalil has explained the licensing tender process in a roadshow for investors in the US hosted by law firm Mayer Brown in America's energy capital, Houston. Lebanon has been so far absent from the East Med energy rush as huge natural gas discoveries such as the Leviathan and Tamar fields have been made offshore Israel and Greek-speaking Cyprus has celebrated its Aphrodite gas find in Mediterranean waters. Lebanon, bordered by Syria to the north and Israel to the south, is attempting to reassure oil and gas exploration companies whose impressions of Lebanon and the region are of chaos and high risk. The US roadshow to publicise the licensing round is being backed up by Lebanese officials also attending international energy events. "We want to make this sector a success story for the Lebanese," said Minister Khalil during the small conference in Houston. "This is our natural and sovereign right," he added. Lebanon is showcasing five offshore blocks, three of which are located along Lebanon's southern border with Israel. It is offering exploration and production agreements to investors and Kalil said Lebanon has benefited from the experience of others in developing what he called an attractive legal framework. Lebanese energy officials

hope its low domestic gas demand and proximity to European markets will provide export options. The country is also pointing to its options in the existing Arab Gas Pipeline, the 1,200 kilometres line built to allow the export of Egyptian natural gas to Jordan, Syria and Lebanon. The Arab Pipeline was built at a cost of around $1.2 billion and represented a unique model for strategic Arab co-operation. However, since March 2012 the pipeline has been out of order because of attacks on a feeder pipeline to el-Arish and links to Israel and Jordan. More than 10 terrorist attacks have targeted the Arab Pipeline in the past six years. Egypt has also undergone economic changes and no longer exports natural gas by the Arab pipeline route nor as LNG from its mothballed liquefaction plants at Idku and Damietta on the Mediterranean coast. It has instead become an LNG importer at two facilities deployed at the Gulf of Suez port of Ain Sokhna to meet its rising domestic demand. The major stakeholders of the Arab Pipeline include the Egyptian Natural Gas Holding Company (EGAS), the organiser of LNG imports to Egypt, the Egyptian Natural Gas Company (GASCO) and the Syrian Petroleum Company (SPC). Minority stakeholders include subsidiaries and companies based in the US, the UK, Germany, Canada and Russia.

**RIO GRANDE LNG**, a project development company in Texas run by former Royal Dutch Shell senior executive Kathleen Eisbrenner called NextDecade, has been listed on the US-based Nasdaq global stock exchange. The export venture is currently advancing through the Federal Energy Regulatory Commission permitting process aimed at building a plant to produce 27 million tonnes per annum of LNG. The Tellurian Inc. development company of former Cheniere Energy Chief Executive Charif Souki recently completed a reverse takeover of a small oil and gas exploration outfit to give Tellurian a listing on the Nasdaq global exchange to help funding for its Driftwood LNG project in Louisiana. “NextDecade’s first proposed LNG export facility, the RGLNG project located in Brownsville, Texas, is optimally located,” said NextDecade. “RGLNG and its associated Rio Bravo Pipeline, originating in the Agua Dulce market area, are well-positioned among the second wave of US LNG projects,” the Eisbrenner company added. NextDecade, based in The Woodlands, near Houston, was founded in 2010, with an experienced team, including Eisbrenner, with extensive experience in signing major LNG off-take deals and developing and managing LNG and floating storage and regasification unit projects. Eisbrenner's role at Shell before founding NextDecade was as Executive Vice President for Global LNG Development. She also worked in senior management in the US with El Paso Energy Corp. and was one of the founders of Excelerate Energy, the US floating LNG project developer.

**SINGAPORE** shipyard Keppel Offshore and Marine said it would soon deliver the world's first converted Floating Liquefaction Vessel (FLNGV) owned by Norwegian project company Golar LNG and set to be deployed offshore the West African nation of Cameroon. The vessel has just been named “Hilli Episeyo” at a ceremony held at the Keppel shipyard. The Golar FLNG vessel will be put into operation offshore the port of Kribi in Cameroon in a joint venture also involving the state energy company, Société Nationale des Hydrocarbures and European oil and gas company Perenco. “We are proud to be able to deliver the world's first FLNGV conversion in partnership with Golar LNG within three years and with a commendable safety record,” said Mr Chris Ong, Chief Executive of Keppel Offshore. “By combining our expertise from a variety of complex offshore conversion projects and our capabilities in executing LNG-related engineering, procurement and construction projects, we are able to offer innovative and reliable floating liquefaction solutions to meet the growing midstream needs of the LNG industry,” stated Ong. “Compared to newbuilds, converted FLNGVs are significantly more cost-effective and faster to market, without compromising safety and processing capabilities. With the experience gained from this first FLNGV conversion project, we are in a unique position to provide customers with reliable end-to-end solutions for the EPC and commissioning of FLNGV as well as FSRU (floating storage and regasification unit) conversions,” added the Singaporean shipyard CEO. The “Hilli Episeyo” was converted from a 1975-built, Moss-type LNG carrier with a storage capacity of 125,000 cubic metres. The topside equipment includes a pre-treatment systems, 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. “Being on its final leg towards completion, the ‘Hilli Episeyo’ represents a game-changer in the LNG industry with its fast-track, low-cost project execution,” said Mr Oscar Spieler, CEO of Golar LNG. “The development of this FLNGV positions us as front-runners in providing offshore liquefaction solutions to meet the growing demand for LNG,” added Spieler. “We are uniquely positioned to take on projects also in a low commodity price environment and determined to enable the unlocking of reserves from remote, marginal and stranded gas fields,” he said.

**SINGAPORE’s** port authority said three other ports in Asia, Europe and North America had joined it and seven other organisations in the international LNG bunkering port group formed to underpin the drive for the uptake of LNG as a marine fuel. The new members of the LNG bunker-ready ports are China’s Ningbo-Zhoushan Port, the French Port of Marseille Fos and the Canadian Pacific port of Vancouver. The group was first formed in 2014 by the Maritime and Port Authority of Singapore (MPA), the two Belgian ports of Antwerp and Zeebrugge and the Dutch Port of Rotterdam. The founding members were later joined by the US Port of Jacksonville, the Norwegian Maritime Authority, the Ministry of Land, Infrastructure and Transport in Japan and the Ulsan Port Authority in South Korea. “All members of the group are committed to working together to deepen cooperation and information sharing in relation to LNG bunkering, to develop a network of LNG bunker-ready ports across the East and West and Trans-Pacific trade,” said Singapore’s MPA. The first group meeting was held on 20 April 2015 in Singapore followed by an April 2017 gathering in Yokohama, Japan, where the group agreed to focus on more collaborative efforts. The inclusion of Ningbo-Zhoushan, Marseille Fos and Vancouver came at the 3rd Port Authorities Roundtable held from July 8-11 in China by the Ningbo Municipal Port Administration Bureau. “The Port Authorities Roundtable, initiated by Singapore, is a useful high-level platform to forge closer collaboration between ports based on like-minded interests,” said Andrew Tan, Chief Executive of Singapore’s MPA. We are pleased that at this meeting, three more ports, including the first Chinese port, will be joining the LNG Bunkering Port Focus Group. “We are confident that the inclusion of Port of Ningbo-Zhoushan will add further impetus to enable the uptake of LNG bunkering for the Far East-Europe and Intra-Asia trade routes,” added Tan. “With this expansion, the network will comprise a total of 11 ports and maritime administrations across Asia, Europe and North America,” the Singaporeans noted. “Topics of discussion also included cooperation among ports to enhance cybersecurity responses, building sustainable ports for the future as well as integration of port resources to improve efficiency,” Singapore's statement said. Other future members could be Japan's Kobe City, the Japanese Port and Harbour Bureau of Yokohama, the Port of Le Havre in France and China’s Dalian Port Authority who participated in a roundtable event for the first time.

**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 second-quarter drop in net profit of around 60 percent to $15.6 million compared with $38.0M in the year-ago quarter. The company listed on the Oslo stock exchange reported higher revenue for the three months of $500.8 million versus $478.9M in the same quarter of 2016. Stolt-Neilsen revealed in May 2017 that it had ordered two 7,500 cubic metres capacity LNG carriers with options for three similar ships as it builds a small-scale portfolio to serve ventures without supplies from the pipeline grid. The contract for the initial two ships is valued at around $80M, including site-team costs and capitalised interest during construction. The ships are to be built at Keppel Singmarine's shipyard in Nantong, China, with deliveries scheduled in the second and third quarters of 2019. They will be able to run on either diesel fuel or LNG, with a class notation and technical capability for ship-to-ship bunkering to enhance their versatility. The Stolt-Nielsen Gas (SNG) unit has established a wholly owned subsidiary called Avenir LNG to focus mainly on the development of small-scale LNG supply chains. SNG's current projects include plans to build and operate an LNG terminal and distribution facility in the port of Oristano in Sardinia and a venture to provide LNG to areas of Scotland not served by the existing natural gas grid. Stolt-Nielsen and Flogas Britain said in November 2016 they had 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. “SNG continues to focus on the development of small-scale LNG storage and distribution supply chains to serve locations lacking access to LNG pipelines,” the company said in its earnings statement. Stolt-Nielsen attributed its profit falls to continued challenges in its various divisions. The Stolt Tankers unit posted an operating profit of $27.6M compared with $28.5M in the previous three months “reflecting continued softness in the chemical tanker market, as rates overall edged lower and bunker prices continued to rise.” Stolthaven Terminals reported an operating profit of $16.1M, down from $16.7M, primarily reflecting lower utilisation at the Singapore terminal. The Stolt Tank Containers division had an operating profit of $13.7M, up from $9.0M as markets firmed after the seasonally weak first quarter. “Stolt-Nielsen Ltd’s second- quarter results were disappointing overall, but in line with both our expectations and our results in the first quarter, as the fundamentals of our markets remained largely unchanged,” said Niels G. Stolt-Nielsen, Chief Executive. “Our outlook remains cautious. We do not expect a significant improvement in the chemical tanker market until most of the current orderbook has been delivered, which, barring any new orders, is expected to be in the second half of 2018,” the company added.

**SWEDEGAS**, Sweden’s natural gas transmission company, said it was investing in liquefied natural gas bunkering facilities at the quayside of the Port of Gothenburg, where vessels will be able to refuel with LNG while loading or unloading their cargoes. The Gothenburg LNG fuel facility will comprise a discharge station, a cryogenic pipeline and bunkering equipment. The LNG will be brought to the station using trailers or containers. LNG will then be distributed via a 450-metre vacuum-insulated pipeline to the quays in the Skarvik area at Gothenburg. “This is the first LNG facility in Gothenburg, the largest port in Scandinavia, making it possible for vessels to bunker LNG at the quaysides. It is expected to be fully operational in 2018,” stated Swedegas. Swedegas is the national infrastructure company whose gas transmission grid extends from Dragor in Denmark to the city of Stenungsund in Sweden. The Swedegas pipelines directly connect customers in 33 municipal areas as well as supplying industrial enterprises, power plants and vehicle filling stations. “The need in the shipping industry for a viable alternative to heavy oil and diesel is being driven by increasingly stringent emission controls,” said Swedegas. “LNG

is the cleanest marine fuel available and is the foremost alternative for large-scale shipping," it added. Emissions of sulphur dioxide and nitrogen oxides are a major problem, affecting both the air and environment. The use of LNG as a fuel reduces emissions of sulphur, particles and heavy metals to a minimum. "This investment marks the starting point for the gradual expansion of the facility, eventually supplying the transport sector and Swedish industry with LNG," said Johan Zettergren, Swedegas Chief Executive. "Regardless of the sector, it ultimately comes down to making the transition from oil-based products," added Zettergren.

**TIMOR ESTE,** the former Portuguese colony located north of Australia, has raised hopes of LNG and natural gas projects in the future as the Greater Sunshine project remains deadlocked. This is because of new exploration data that is being examined by geologists. "Preliminary evaluation of the 3D seismic survey off the southeast tip of Timor Leste indicates the presence of more than 30 individual closed seismic structures at three geological levels, which are frequently stacked vertically and seen in 17 geographically distinct locations," said the report. The survey covered 2,780 square kilometres and was carried out by the "BGP Prospector" geophysical vessel over the PSC TL-SO-15-01 block some 50 km southeast of the eastern tip of Timor Este. The block is midway between Timor and the Greater Sunrise gas and condensate fields and lies exclusively within Timor Este's maritime boundaries. Timor Este and the Australian Government in January 2017 announced they would abandon a 10-year-old treaty on maritime borders. The Australia-Timor treaty was an agreement that a freeze of 50 years be put on negotiations for a permanent maritime border in the Timor Sea. Within the area is the large Greater Sunrise gas field, which straddles Australian and East Timor waters in a proportion of 80 percent to 20 percent. Timor Este wants the field developed by bringing the gas to an onshore LNG liquefaction plant. However, potential partner Woodside Petroleum views that venture as uneconomic. Its aim is to boost economic development and create new downstream resources to boost income for the nation ruled by Indonesia until 2002 and previously by Portugal. "Initial results reveal a clear geological picture in the zone beneath the northern slope of the Timor trough," the report said. A full analysis is not yet complete, but the size of the structures suggests potential for hydrocarbon accumulations relatively close to the Timor Este shoreline.

**TOTAL**, the French energy major, has signed an agreement with Brittany Ferries to supply LNG bunkering fuel to the port of Ouistreham in northwest France and for the first LNG-powered French cruise ferry that will provide regular services to Portsmouth in England from 2019. The LNG will be supplied to the newbuild, the "Honfleur", to start its France-UK service in two years' time by Total's bunkering affiliate responsible for marketing marine fuels worldwide. Total has partnered with the Dunkirk LNG import terminal, which began commercial operations in January 2017 and in which Total is a shareholder, to start supplying LNG for bunkering using ISO containers. The other partner is Groupe Charles André, a French trucking and tanker firm in the petroleum products and furl sector.
"Transported by truck from the LNG terminal of Dunkirk to the port of Ouistreham, the containers will be lifted aboard the cruise ferry using onboard cranes to supply a fixed LNG storage tank at the rear of the superstructure," Total explained. "Once empty, the containers will be offloaded from the ferry at the next call at Ouistreham and replaced by full containers," it added. "The agreement with Brittany Ferries is a landmark one - our first contract to supply LNG bunker," said Olivier Jouny, Managing Director of the Total fuel unit. "In addition, the work carried out with Dunkirk LNG and Groupe Charles André has made it possible to supply the LNG by developing a safe, innovative logistics solution. We are proud of these agreements, which mark a milestone in the growth of LNG in France," added Jouny. LNG's environmental performance is set to make it a particularly attractive solution for shipping, allowing operators to meet the International Maritime Organization's new sulfur regulations, applicable in Emission Control Areas since 2015 and worldwide from 2020. LNG also reduces emissions from ship propulsion of nitrogen oxide and carbon dioxide, supporting its growth as a new marine fuel. "Brittany Ferries, a leader in passenger transportation in the Arc Atlantique Corridor, is embarking on an innovative partnership with Total and is committed to improving our environmental footprint," said Frederic Pouget, Group Maritime port and operations director of Brittany Ferries. "The shipping industry needs access to LNG. This partnership demonstrates that unique, local solutions can be developed to supply LNG to ships. In the first step of the upcoming energy transformation, Brittany Ferries intends to make LNG the preferred fuel for its future owned newbuilds," stated Pouget.

**TOTAL** becomes the first western energy company to return to Iran with the signing of a $4.8 billion contract on July 3 with China National Petroleum Corp. and Iranian partners to develop the South Pars field that borders the feed-gas block in the Persian Gulf adjoining the territorial waters of Qatar, the largest LNG producer. The preliminary agreement on the South Pars gas development was signed in November 2016 in Tehran. The full international accord for the development of South Pars was being signed in the presence of the Iranian Minister of Petroleum and senior executives of Total, China's CNPC and the Iranian company Petropars. Total thus becomes the first western energy company in the sector - the third-biggest French company after car producers Peugeot (PSA) and Renault - to return to Iran after sanctions imposed because of its nuclear policies. "We are proud and honoured to be the first international company to sign an Iranian petroleum contract following the conclusion of the international nuclear agreement in 2015," said Total. "This major agreement will contribute to the development of relations between Europe and Iran. Of course, Total will implement the project in the strictest respect of national and international legislation. The first phase of the project represents a $1Bln financial exposure financed in equity," said the French company. Total will hold 50.1 percent of the shares of the South Pars consortium that will operate the gas field, followed by the CNPC with 30 percent and the Iran's Petropars with 19.9 percent, according to the Iranian National Oil Company, the group affiliate of Petropars. South Pars is part of the largest developed field in the world. The other part is known as the North Field and is owned by Qatar and used for its LNG plant at Ras Laffan as well as pipeline supplies. Total had previously initiated development of South Pars but all work in Iran was later suspended for various reasons. Analysts said that although there is no LNG element for the post-sanctions project, the development of the field will produce a bonanza of subsea and related contracts for global players to bid for in tenders. The South Pars project will be developed in two phases. The first phase, costing $2Bln, will consist of 30 wells and two well-head platforms connected to existing onshore treatment facilities by two subsea pipelines. The second phase will cost about $2.8Bln. The South Pars project will have a production capacity of 1.8 billion cubic feet per day, or 370,000 barrels of oil equivalent per day. Iran has no liquefaction plants to make its own LNG, though it previously had three ventures under development called Pars LNG, Persian LNG and Iran LNG. However, these ventures were abandoned. Firstly because of the interference in the projects by the extremist Iranian Revolutionary Guards and later because of Western sanctions that prohibited investments in Iran because of the nuclear issue, now resolved. The French contract signing comes despite Washington's hostile position and the recent US Senate vote on new sanctions against Iran. The conclusion in July 2015 of the nuclear agreement with the US, Russia, China, France, the UK and Germany resulted in the lifting in January 2016 of part of the international sanctions against Tehran. However, the changed US policies under the US Administration of President Donald Trump have made it difficult to normalize Iran's economic relations with the rest of the world, especially because of the reluctance of the big international banks to work with Tehran amid concern about renewed sanctions or punitive measures from Washington. That said, Total is also part of the Yamal LNG project in Arctic Russia and during financial sanctions imposed by the West over Ukraine the Yamal developer, Russian natural gas company Novatek, came up with Chinese financing for the venture. ■

## Diary of events

### October

**3rd International LNG Congress**
October 17-17
Barcelona,
Spain
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# How LNG buyers and sellers can inter-act in Africa's emerging cargo import market

*The second part of a report from Anne-Sophie Corbeau on African LNG covering infrastructure and contracts*

Most of the countries currently importing LNG are relatively mature Organization for Economic Cooperation and Development (OECD) markets, or large developing gas markets like China, India and Brazil.

LNG has so far rarely penetrated small developing countries with no or very limited gas consumption, or poor economies with low credit ratings where oil-fired technology is often the default solution.

Exceptions are Puerto Rico and the Dominican Republic, while Uruguay is trying to replicate their experience.

Among recently emerging LNG importers, Egypt and Pakistan already had developed gas markets with consumption of more than 40 billion cubic metres a year (bcm/y).

Jordan had pipeline infrastructure and gas-fired plants in place and demand has exceeded 3 bcm/y.

By contrast, among all the countries considered, only South Africa, Tunisia, Ghana and Côte d'Ivoire consume more than 2 bcm/y.

## Sellers

Sellers' interest has started to shift in favor of new markets. Major LNG producers are considering investing in ship-fueling operations, FSRUs and power plants to open new markets and absorb the current global LNG surplus.

They are also now beginning to consider supplying local African markets, either with piped gas or with LNG (Smedley 2016). Total's Chie Executive Patrick Pouyanné was reported as saying: "We are not a fan of investing in an IPP, but if we need to create demand, why not?" (Sonali 2016).

In addition, such markets might be a good short-term option for aggregators with a lot of uncontracted LNG.

However, how committed would such sellers be after the initial lease if and when less risky and higher priced markets returned to solid growth? The answer would very much depend on the respective netbacks achieved by the sellers and whether African LNG can provide a cost-effective regional source of gas over time.

LNG supply is more diversified than it used to be, while the US is emerging as a new LNG supply source which is also at a reasonable distance from most African markets.

African importers could also source LNG from their neighbors. African LNG exports reached 35 million tonnes per annum in 2015 and half of this was exported as spot and short-term volumes.

## Soyo plant

Angola LNG at the port of Soyo restarted in the second half of 2016 and the Cameroon floating liquefaction project is expected to be operational in 2018.

The proximity of Nigeria, Equatorial Guinea and Angola to Namibia and South Africa makes them attractive as future LNG suppliers.

Moreover, the spot and short-term LNG market is expected to increase significantly over the coming years.

There is also more diversity in terms of sellers, with trading firms such as Trafigura, Gunvor, Glencore and Vitol engaged in LNG supply, often as intermediaries, backed by primary LNG suppliers.

These companies have been quite active in the tenders organized by new LNG importers Egypt, Pakistan and Jordan.

The emergence of floating storage and regasification unit (FSRU) facilitates has seen the rise of new types of importers.

FSRUs are planned by eight of the ten countries looking at LNG imports. Morocco is the exception, while Sudan has not disclosed what type of terminal it is considering. The attractiveness of the FSRU comes from its low cost and faster implementation.

A newbuild 170,000 cubic metres capacity FSRU would typically cost in excess of $250 million, while the vessel plus the land-side infrastructure could add up to around $400 million. By contrast, the cost of an onshore terminal of comparable size is around $1 billion (White 2015).

In practice, importing countries will have to decide whether they want to lease the FSRU or to buy it. So far, most FSRUs have been leased.

**Angola LNG at the port of Soyo restarted in the second half of 2016**

This is because FSRU developers such as Excelerate, Golar, Hoëgh and BW Group can secure lower costs at shipyards by developing multiple FSRUs (King & Spalding 2015). They can also achieve lower capital costs by converting old vessels - around $100 million for a second-hand converted LNG carrier.

Also, the lack of operational experience is a deterrent for developers wishing to purchase FSRUs directly. When FSRUs are chartered, they are generally financed separately from the other infrastructure.

## Expenditure

Capital expenditure costs would also lie with the FSRU owner and not the charterer, which is an advantage for countries with limited payment possibilities for upfront costs.

Nevertheless, the charterer has still to pay a day rate: leasing an FSRU can be quite expensive as daily rates vary between $113,000 and $155,000, according to the type of vessel and the duration of the lease (Toungara 2016).

FSRUs may not be the ideal solution if additional breakwaters and jetties are needed (Smedley 2016). The choice of the technology and the size of the ship may also depend on the site - protected and calm, or a hostile weather site for which a larger vessel would be preferable.

## Speed

The facilities are said to be faster to bring onstream. Some have been deployed rapidly, as in Egypt. The newbuild FSRU deployed by BW in the port of Ain Sokhna took five months from project inception to first gas.

The conversion of a conventional LNG vessel would take around six months, assuming a vessel and a shipyard slot are available, while a newbuild FSRU can be delivered within around 28-32 months (White 2015).

However, licenses and permits including environmental impact, marine operation, gas processing and trading are needed before deploying a FSRU on-site.

FSRUs offer additional advantages. Regasification capacity is usually between 2 and 8 bcm/y, based on data on existing facilities, with most being around 5 bcm/y (or 3.5 MTPA).

Such a facility may be large for a developing market, but 2 bcm/y used at 60 percent and fueling an open-cycle plant with a 40 percent efficiency would feed a capacity of 1.1 gigawatts for 5,000 hours.

The vessels thus prove a good match for small to medium-scale developments. Additionally, they can be upgraded to increase send-out capacity as demand builds up. This kind of operational flexibility and potential to increase capacity incrementally in line with demand growth is a fundamental prerequisite for an investment like this.

## Previous success

For example, in Dubai, the emirate's Dubai Supply Authority (DUSUP) entered into a long-term time charter party agreement (TCPA) with Excelerate in 2014 for a larger and more efficient FSRU to replace its existing unit.

Excelerate upgraded the "Explorer" and customized the FSRU to meet DUSUP's supply requirements.

The size of FSRUs on order has also increased, with the largest under construction, for Uruguay, having a storage capacity of 263,000 cubic metres capacity, compared to the typical 170,000 cubic metres capacity.

The advantage of these units is that they offer flexibility, not only in terms of seasonal LNG supply in countries such as Kuwait and Dubai, but also in the chartering arrangements, as contracts as short as five years can be negotiated.

FSRUs can provide mid-term solutions while a longer term solution involving a pipeline or domestic production is developed. They also represent a lower risk/cost means of testing and developing markets until they reach the critical mass required to support larger scale, longer term supply solutions.

A possible next stage in the longer term could be to replicate the small-scale LNG project envisaged in Indonesia, should it be successful.

## Indonesia example

Due to the size of the Indonesian archipelago, with numerous small island markets, any normal FSRU would be too large. Instead investors are considering small-scale LNG transportation and receiving terminals, with plans for a range of smaller scale FSRUs down to 3,000 cubic metres capacity.

However, the economic viability of the whole project may be imperilled by its limited size.

Further analysis of the economies of scale in the small-scale FSRU market is necessary to understand whether such developments can be economically viable in the future.

The cost of a 20,000-to-50,000 cubic metres capacity FSRU would be in the region of $50M to $70M (King & Spalding 2015).

Considering demand for African LNG import projects, the crucial issue would be building demand, but here technology can help to mitigate the risk.

In some countries, there are power plants that can run on natural gas. By contrast, most CCGT plants are capable of being configured to operate on liquid fuel as a backup when gas is unavailable, even though this decreases efficiency and increases both operational and maintenance costs.

However, fuel flexibility offers the IPP the ability to mitigate its exposure to delays in completion of the regasification infrastructure and to short-term LNG unavailability, which is likely to be a function of the price.

Another issue would be the potential use of gas by third parties.

While LNG prices were quite high over 2011-14, notably in Asia, they have now reduced significantly due to the combined fall in oil prices and the global LNG glut.

This has prompted interest in LNG imports among developing countries. But even though LNG prices fell to around $4-6/MMBtu, it has still not become a cheap fuel source.

Prices may drop even further due to an increasing oversupply situation as more LNG comes to the markets by 2017-18, but they could reasonably be expected to rise again to a level enabling new LNG projects to proceed with their financial investment decision (FID).

However, not all the LNG that is sold is indexed to oil prices, though the greater part of it is at present.

The rise of US LNG will allow buyers to buy LNG on a Henry Hub plus basis. Given the proximity to Europe, it is also quite possible that buyers could get a price indexed to the UK National Balancing Point (NBP) price.

That type of spot indexation better reflects supply/demand balances, though not those of the African market.

## Affordability

This creates some uncertainty over the future evolution of the price of LNG. The pricing mechanism that is agreed by African buyers will be critical to determining the long-term viability of their LNG project. Affordability and predictability will be key.

African buyers may have difficulties managing pricing risks they are not familiar with, especially where gas is largely used to produce electricity, which is sold to relatively low income residential consumers.

Additionally, some countries or project sponsors - in Ghana and Namibia - plan to use the current market oversupply to source their gas on the spot market, by organizing tenders.

This is what Egypt has been doing since its two LNG imports terminals started up. It works relatively well in a situation of global LNG oversupply, but the product may become more expensive if the market tightens, highlighting the need to carefully assess pricing mechanisms and their possible long-term implications.

For example, it would be a mistake to agree on a pricing formulae based on today's forward curves, as such price curves are often poor indicators of future price levels.

## Review of some projects

As of late-2016, 10 countries are either importing LNG (Egypt) or considering LNG imports over the medium term: Benin, Côte d'Ivoire, Ghana, Kenya, Morocco, Namibia, Senegal, Sudan and South Africa.

The reasons for turning to LNG vary, depending on the countries: In most cases, countries want to expand their power generation capacity and include natural gas in the mix.

Egypt's power mix is already highly dependent on gas but, due to gas shortages, the country had to turn to LNG imports.

Morocco has been importing gas through neighbor Algeria, but as the contract expires in 2021 it has been looking for alternatives.

It is uncertain whether Tunisia could face the same issues.

Some West African projects will also feed into the West African Gas Pipeline (WAGP), which transports gas from Nigeria to customers in Ghana, Togo and Benin.

Many LNG projects are driven by the absence of gas resources or a development only planned in the medium to long term.

These include Egypt, Ghana, Senegal, Namibia, Sudan and South Africa. Eight countries have opted for FSRUs and most of these projects are led by small independent companies.

## Alternatives

Exceptions include Morocco, where its tender attracted some of the large gas players, Ghana, where GE is behind one project, and Côte d'Ivoire where Total has recently joined the LNG project.

The recent interest shown by the international oil majors has not yet significantly led to concrete projects, but they could take part in some of the existing projects or develop alternative ones in other countries.

As of late 2016, the projects the most advanced besides those in Egypt are in Ghana, Morocco and South Africa.

**ELECTRICITY CONSUMPTION PER CAPITA IN SELECTED COUNTRIES**

| | Electricity per capita (kWh/capita) |
|---|---|
| Benin | 94 |
| Congo | 189 |
| Côte d'Ivoire | 235 |
| Democratic Republic of the Congo | 106 |
| Djibouti | 354 |
| Egypt | 1565 |
| Eritrea | 59 |
| Gabon | 1118 |
| Gambia | 133 |
| Ghana | 380 |
| Guinea | 42 |
| Guinea-Bissau | 20 |
| Kenya | 167 |
| Liberia | 60 |
| Mauritania | 225 |
| Morocco | 855 |
| Namibia | 1611 |
| Senegal | 217 |
| Sierra Leone | 11 |
| Somalia | 31 |
| South Africa | 3962 |
| Sudan | 266 |
| Togo | 146 |
| Tunisia | 1368 |

**African LNG needs will rise with gas-fired power developments**

**Egypt** - importing LNG since 2015 Egypt started importing LNG in 2015 and, as of November 2016, already has two FSRUs in place.

The country imported 2.6 MTPA in 2015 to meet gas shortfalls which had led to rationing for energy-intensive industries such as steel mills and fertilizer plants.

Egypt's natural gas demand has increased rapidly from 20 Bcm in 2000 to peak at 52 Bcm in 2012, driven by power generation needs as well as gas use in industry, cooking and transport, supported by relatively low domestic gas prices.

## Discoveries

However, domestic production flattened from 2009 onward, resulting in demand dropping to 48 Bcm in 2015. The Arab Spring halted reform attempts to increase prices. But prices were increased again in 2014 when President Al Sissi came to power.

Egypt organized a third tender in mid-2016 for an FSRU (7.5 bcm/y) that is expected to begin operations later in 2017.

While the evolution of LNG imports is very uncertain, with calls for the use of FSRUs with five-year charter times, expectations of the future growth of domestic production seem well founded.

Oil Minister Tarek El Molla announced in May 2016 that gas production would increase to around 55-60 Bcm by 2019 because of discoveries.

The Zohr field discovered by Eni in 2015 is expected to ramp up to full capacity (28 Bcm/y) by 2020. Even if delays occur, the development of that field is a priority for both the licence operator, Italy's Eni, and the government.

Meanwhile, other upstream players are investing in new fields, some of which are intended to replace declining production from existing fields. Depending on the pace of these production increases, imports could stop after 2020. Egypt's gas demand, which has been constrained due to the lack of available supply, is also uncertain.

Should spot prices remain low for an extended period of time, some industries - notably the steel industry and fertilizer producers, which have been particularly affected by gas shortages - may decide that gas is still affordable and more competitive than oil products.

Many expect LNG imports to stop by 2020, as the lease signed with Hoëgh for the FSRU runs for five years, though the tender for a third FSRU starting by 2017 questions that assumption.

**Morocco** - an onshore LNG project Morocco has limited domestic gas production and currently imports its gas from Algeria by pipeline. Most of this gas is consumed in the power generation sector. Its two gas-fired plants (Tahaddart and Ain Beni Mathar) were supplied through the payment of gas transit to Europe in kind until 2011. Then a new contract was signed for 10 years. Unlike other countries where LNG supplements domestic production, LNG imports are likely to replace Algerian pipeline supplies after 2021, when the contract expires.

Morocco's proposed LNG terminal will be at the port of Jorf Lasfar, 100 kilometres south of Casablanca, and will be connected to the existing pipeline system.

**Benin, Togo and Ghana** – a three-country project Gasol has been planning to build an FSRU in Benin since at least 2013. Its project is aimed at displacing the use of liquid fuels in the power and industrial sectors in Benin, Togo and Ghana, and thus reducing costs.

Gasol has negotiated two offtake agreements, with the state utilities of Benin, Togo and Ghana and with the Benin Electricity Community and the Volta River Authority (signed in 2014).

The company plans a 1.2 MTPA FSU/FSRU which would not only supply power users directly but also feed the WAGP via a subsea pipeline.

The plant could be later expanded to 2 MTPA. Gasol has applied to the West African Gas Pipeline Company (WAPCo) under its new open access policy to become a shipper on the WAGP.

Gasol and WAPCo have been discussing commercial and technical issues such as the project's connection to the pipeline and the capacity in the WAGP that will be reserved for the Gasol project's use.

**Kenya:** It had planned to build an LNG terminal in Mombasa to meet rising power demand and to provide a solution to the chronic power blackouts and high electricity bills which had been fueling discontent among the population.

A tender for the project was initially expected by early 2012, but was postponed. In 2014, it was reported that only two companies had returned bids, and did not meet the timelines: they proposed to build the plant over two years, instead of 18 months.

In 2015, Kenya postponed signing an agreement with Qatar following the discovery of 1.8 trillion cubic feet of domestic gas by Africa Oil and Marathon Oil Corporation.

LNG imports were to have supplied the 700 MW Dongo Kundu plant, but it was cancelled in mid-2016 after the domestic discoveries. That facility would have also supported KenGen's Kipevu I and Kipevu III thermal power plants in Mombasa, which currently use heavy fuel oil, though this would require construction of a pipeline.

LNG could also have supplied the 90 MW Rabai power plant near Mombasa, which also uses heavy fuel oil.

A feasibility study financed partly by the World Bank showed the economic viability of an LNG import facility.

The project's main competitor is domestic gas, while a pipeline from Tanzania to Mombasa, through Tanga, for power generation and other industrial applications had also been considered in the past.

**Senegal:** The West African nation consumes limited amounts of natural gas - it is estimated 0.1 Bcm in 2014 - which is produced by US company Fortesa and consumed almost 50 percent by Senelec and 50 percent by cement producer Sococim.

LNG imports have been considered for quite some time with a view to substituting expensive oil products with natural gas. In 2014, a World Bank Study concluded that Senegal could replace fuel oil and diesel with LNG, resulting in an LNG import requirement of 0.6 MTPA.

This volume would be too small to make the project economical and it would need to be boosted by other demand, from industry, or by power exports to Gambia or Mali.

In 2015, an agreement was nevertheless signed between the power company Senelec and Qatar's Nebras Power and Mitsui of Japan to build an FSRU and related infrastructure and a 400 MW power plant.

Some recent gas discoveries have been made, which could change the outlook quite significantly.

In early 2016, an ultra-deep gas discovery was made with the Geumbeul-1 well, on the greater Tortue field, which is a trans-border offshore discovery between Mauritania and Senegal. Estimates for the greater Tortue complex are therefore estimated at 17 Tcf.

Paradoxically, such a discovery could be sufficient to export gas by pipeline or as LNG, though the fact that the field extends into two countries could complicate decisions.

Consequently, LNG imports into Senegal could be a bridging solution until domestic gas resources are developed.

**South Africa:** Its power mix depends heavily on coal and the country is suffering from chronic power shortages. As much as 85 percent of the country's electricity comes from coal-fired power plants (Baker & Mckenzie 2015).

The Department of Energy (DOE) has been planning to expand total generating capacity by 40 GW by 2025, including hydro, renewable energies, coal and gas sources.

It has set up a gas-to-power program with the aim of building and supplying 3.126 GW of gas-fired plants, to be run baseload and/or mid-merit.

The gas required for these power plants will come from both imported and domestic gas resources; however, in the medium term, imports seem the only solution.

Eskom is expected to be the sole buyer of electrical capacity and energy generated under the program.

In May 2016 the DOE invited expressions of interest for the construction of a new 600 MW gas power plant at either the port at Saldanha, or at Richards Bay.

Letters of interest had to be submitted by June 20 (DOE 2016). In October 2016, the DOE announced that there will be two LNG-to-power projects, located in Coega (1,000 MW), near Port Elizabeth, and at Richards Bay (2,000 MW).

Both have deep water ports. Another site under consideration as a longer term perspective is Saldanha Bay. All three ports have industrial development zones.

Given its location, South Africa could easily source LNG from Angola and later from Eastern Africa. Using small-scale LNG could also be envisaged.

## Conclusion

LNG projects in Africa have attracted renewed interest because of the current LNG market oversupply and sellers looking for new markets. Taking these two factors together, they could result in an African market that is more than "niche" - which could represent a new demand centre in global LNG markets.

But there are many obstacles to African LNG imports, including significant capital investments requirements, the need for anchor customers, non-existent demand in most cases, along with the lack of established gas consumers and existing infrastructure.

Many projects are LNG-to-power projects, supported by FSRUs. Some seek to spur the development of national gas markets before domestic production or regional pipeline imports can take over, while others are proposed for the longer term.

Compared with some of the large, mature gas markets, African imports do not grab the headlines, but many markets in this long-term business started small.

Consequently, LNG producers know that it takes decades to build large supply relationships.

While the need to electrify Africa is real, developing power generation faces substantial challenges, notably ensuring that electricity is affordable and that costs can be recovered.

Though electricity tariffs in Africa are not the lowest in the world, many countries nevertheless face non-payment issues. Improving the creditworthiness of electricity utilities and enforcing payment discipline are therefore crucial.

However, it can be argued that the development of reliable and affordable electricity supply could boost economic growth and increase populations' standard of living and consequently their ability to pay.

Finally, while renewable energies are currently a favored option, LNG could also offer a solution. However, affordability and predictability will be key.

The pricing mechanism agreed by African buyers - should they opt for multiyear contracts - will be critical to ensuring the long-term viability of the LNG project in question, especially where gas is earmarked to produce electricity sold to relatively low income consumers. ■

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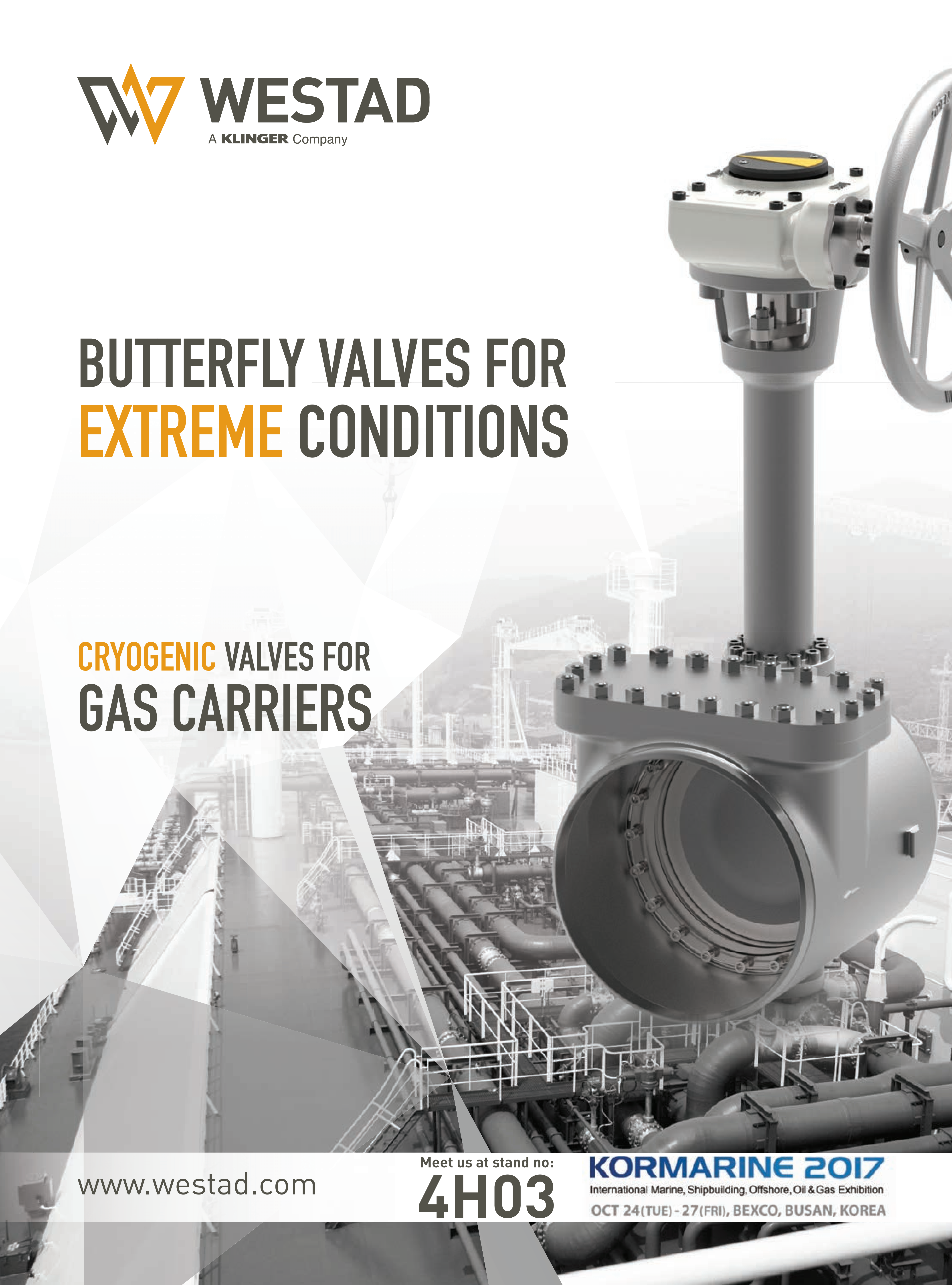
*This article is based on extracts from a 36-page report on African LNG. The author of the original paper, Anne-Sophie Corbeau, is an associate of the King Abdullah Petroleum Studies and Research Center, located in Riyadh, Saudi Arabia. This is a non-profit global institution dedicated to independent research into energy economics, policy, technology and the environment across all types of energy.*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# KBR shows importance of the coupling of a floating liquefaction facility with subsea systems

*Andy Loose, Technical Director FLNG and LNG and Stewart Taylor, Process Controls Chief Engineer, KBR, Houston, US*

Most onshore LNG plants and at shore floating LNG barge units are fed from extensive pipeline networks which create a large gas inventory buffer such that any interruption event at either the LNG plant or the gas source is easily managed by the control systems.

In contrast, a unique feature of most offshore FLNG facilities is the very limited gas inventory in the short flowlines and risers between the subsea wellheads and the inlet of the gas pre-treatment unit.

## Interactions

This close coupling and small inventory can give rise to some significant dynamic interactions between the FLNG liquefaction plant and the subsea wells, particularly for wells with a high design pressure. As such the design and control of the subsea system and FLNG topside process must be considered together as an integrated system and not in isolation.

It is recognised that the liquefaction capacity of an FLNG unit relates to the gas turbine (GT) power available to the compressors. GT available power varies with ambient temperature and hence LNG production follows both the diurnal temperature swing and the seasonal ambient temperature variations as the control system functions to maximise the LNG production at any time.

As the LNG production fluctuates with ambient temperature so too does the feed gas supply.

Without any active control of the subsea chokes the amplitude of the oscillations can be quite significant, especially in early morning and evening when the ambient changes most rapidly, causing packing and unpacking of the flowlines and risers as the topside pressure reduction valves operate to maintain a steady feed gas supply pressure to the inlet facilities.

This paper discusses the interactions between the subsea system and the liquefaction unit and presents the results from an integrated dynamic model that demonstrates how stable operating conditions can be achieved under all scenarios.

In common with other LNG plants, the overall control of an FLNG facility is required to fulfil the following objectives:

- Maintain the system within a safe design envelope;
- Maintain stable control of the system to avoid upset and flaring;
- Maintain the maximum LNG production rate through the diurnal and seasonal ambient temperature variations.

Most onshore LNG plants and at-shore floating LNG barge units are fed from extensive pipeline networks which create a large gas inventory buffer such that any interruption events at either the LNG plant or the gas source are easily managed by the control systems, and the pipeline and topside process systems may almost be regarded as de-coupled.

In contrast, a unique feature of most offshore FLNG facilities is the very limited gas inventory in the short flowlines and risers between the subsea wellheads and the inlet of the gas pre-treatment unit.

This close coupling and small inventory can give rise to some significant dynamic interactions between the FLNG liquefaction plant and the subsea wells, particularly for wells with a high design pressure and for those in deep water.

As such, the design and control of the subsea system and FLNG topside process must be considered together as an integrated system and not in isolation.

## Diurnal swing

Similar to any onshore LNG facility it is recognised that the liquefaction capacity of an FLNG unit relates to the gas turbine (GT) power available to the refrigerant compressors.

All gas turbines have a standard ISO power rating which is adjusted for site specific conditions such as ambient temperature, humidity, etc. Whilst the design case for a plant will be based on specific ambient conditions, the plant must operate through the full range of annual temperatures.

For simplicity, the power available from any gas turbine varies approximately 1 percent for every 1°C in temperature (see Figure 1) and hence LNG production follows both the diurnal temperature swing and the seasonal ambient temperature variations.

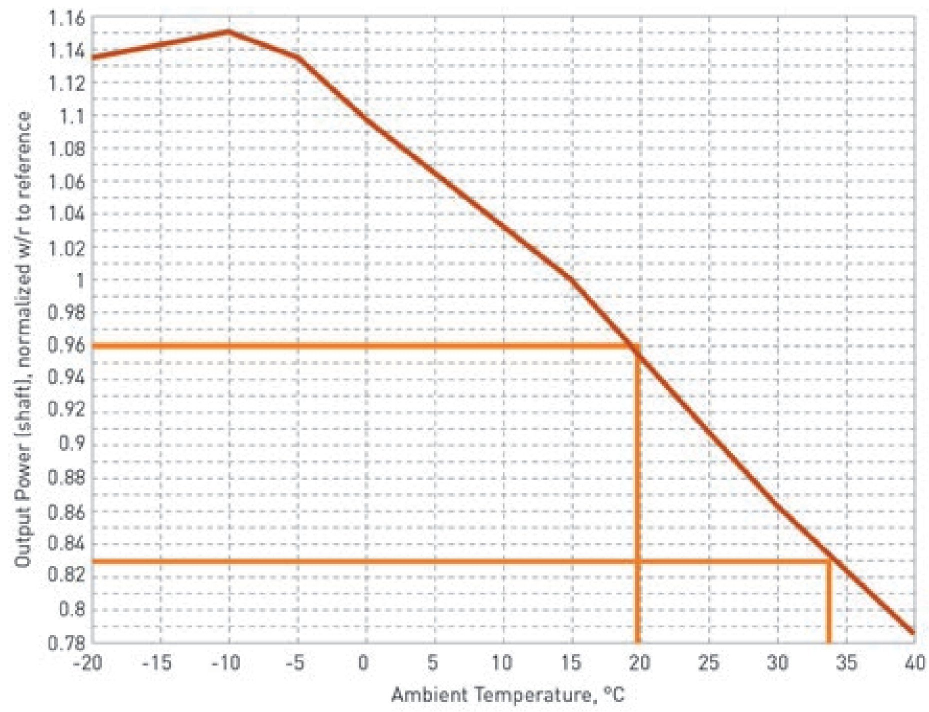


**Figure 1: GT Power Variation with Ambient Temperature**

LNG plant operators want to maximise their production, and hence revenue, so the control system functions to maximise the LNG production at any given time by utilising all the available GT power.

In many locations, the ambient temperature changes most rapidly in the morning as the sun rises and then falls rapidly in the evening as the sun sets. It is these periods that have the most pronounced affect.

A typical daily ambient temperature profile for a hot environment location is shown in Figure 2 and shows daily swings of up to 10°C. This profile was used for the purposes of the study. Each subsea well is fitted with a choke valve.

For feed gas supplies to platforms, FPSOs or direct to onshore LNG plants, the subsea choke valves at the wells normally operate in a fixed position with no active control as the operators prefer to minimise the use of the hydraulic chokes.

In initial years of operation, the choke valves operate with high pressure drop in choked flow, and hence the flow is unaffected by flowline backpressure. In these initial years, well pressures of 300-400 bara are quite common for many gas fields.

As the LNG production fluctuates with ambient temperature so too does the feed gas supply to the inlet facilities. The flowline backpressure will vary with the throughput, as the lines are packed at low LNG production and unpacked at high LNG production.

## Oscillations

Without any active control of the subsea chokes, the amplitude of these oscillations can be significant, especially in early

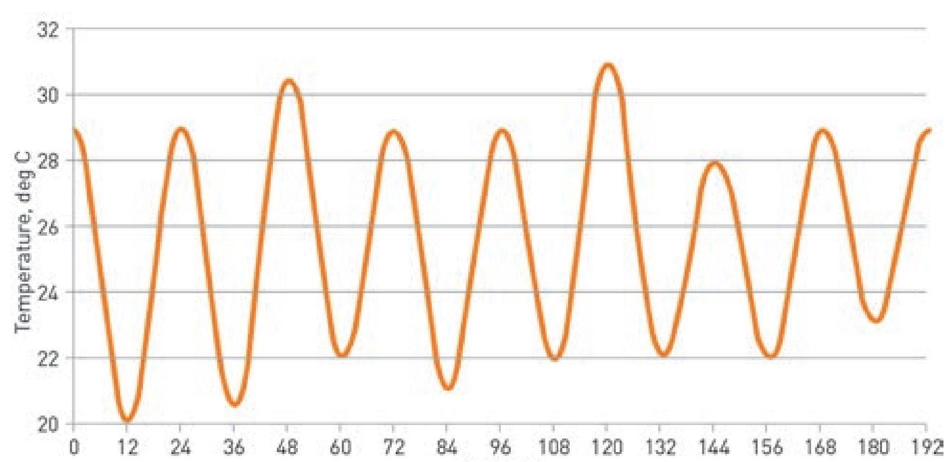


**Figure 2: Ambient Temperature Variation**

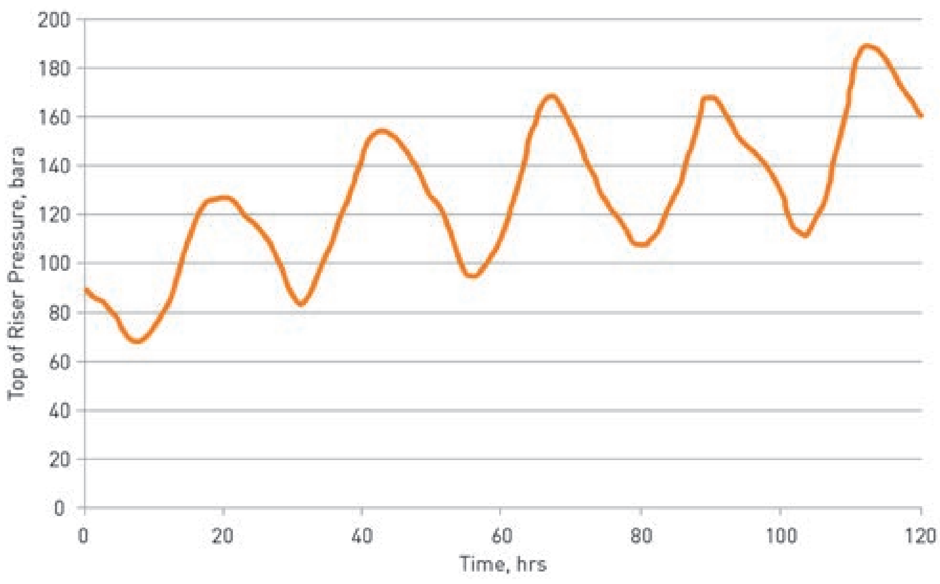


**Figure 3: Pressure fluctuation at the top of riser without active control**

morning and evening when the ambient temperature changes most rapidly, causing packing and unpacking of the flowlines and risers as the topside pressure reduction valves operate to maintain a steady feed gas supply pressure to the inlet facilities.

To determine the magnitude of the pressure variation for the gas supply at the top of the riser for typical operational conditions without active control of the sub-sea chokes, a model of the wells, flowlines and riser system was built using OLGA software.

The results indicated that the arrival pressure would vary significantly, from an initial value of 100 bara down to 80 bara and to more than 140 bara for a typical case as the ambient temperature average rises, thereby reducing the average production rate.

This fluctuating arrival pressure caused by the diurnal swing is highlighted in Figure 3.

Once the top of riser pressure exceeds 50 percent of the well pressure then the subsea choke is no longer in choked flow regime and the backpressure restricts flow through the subsea choke.

The degree of pressure swing depends on the flow variation, length of the flowline (longer lines with more inventory tend to dampen swings) and the flowline throughput (higher flows increase sensitivity).

## Arrival conditions

The feed gas supply pressure in the inlet facilities for an LNG plant is typically controlled to maintain a pressure of 65-70 bara for the pre-treatment. Within the turret, topside chokes are used to control the feed gas pressure into the slug catchers, and then the pressure reducing station (PRS) will further drop the pressure for input to the LNG pre-treatment unit.

The arrival temperature of the gas at the top of riser will depend upon the temperature of the gas in the well, the seabed depth, the length of the flowline, type of flowline heating or insulation used, if any, operating pressure and flowrate.

The gas temperature in the flowlines will approach the seabed temperatures and then be further cooled by the Joule-Thomson (JT) effect in the riser.

The main constraint for higher topside arrival pressures is therefore consequential lower temperatures after the topside choke due to JT expansion.

The gas temperature is further reduced by the pressure drop across the topside chokes. In deep-water applications the risk is that temperatures downstream of the topside choke valve become so low as to result in hydrate and/or ice formation.

## Deep-water

In many deep-water applications it is becoming common to inject MEG continuously at the well to mitigate the risks of hydrate formation; however there is a limit to which MEG can be used for this purpose. The freezing point of MEG as a function of concentration in water is shown in Figure 4 below.

Considering a 90 percent MEG concentration and allowing for some margin, a minimum practical operating temperature of about minus 20°C is considered to apply in order to prevent freezing of MEG and tow prevent ice/hydrate formation downstream of the topside chokes.

Depending on the required topside choking and resulting fluid temperatures careful selection of lean MEG concentration will be required to eliminate lean MEG freezing. Attention must also be given to the minimum design temperature of swivel components and in particular its seals.

The arrival temperatures for a range of flows and pressures in different, uninsulated, flowline lengths were estimated using the model. From the results, allowing for a minimum arrival temperature of about minus 10°C, the topside arrival pressure needs to be restricted to 100 bara to prevent temperatures after the topside choke dropping too low.

This means that the operating range for similar cold, deepwater scenarios is quite restricted, from 70 to 100 bara. Even very small diurnal variations will cause the pressure to go above this range, particularly after a few days operation when the average temperature has drifted from the initial value.

Based on this analysis for the specific conditions, it was concluded that operating the system without active control of the subsea chokes is not feasible unless the gas is heated upstream of the topside chokes.

The studies determined that active control of the subsea chokes should be developed as a solution in preference to heating the gas or other considered options. Active control of the subsea

chokes, in order to control the topside arrival pressure in the acceptable range, would require partial stroking of the subsea chokes on a daily basis. It was considered that this would constitute infrequent operation and the level of control would be coarse with fine control achieved using the topside chokes.

## Transient effects

In addition to diurnal swings, more dramatic transient effects also need to be considered for the operation of the system. A trip of one liquefaction compression string would result in a near instantaneous reduction of total flow by about 50 percent and a rapid corresponding rise in arrival pressure.

This scenario could be considered as the most severe transient to be accommodated.

The overall control arrangement for a typical FLNG facility to manage gas production rate is summarized in Figure 5.

This sketch indicates the main gas production control loops and is not intended to depict all details. The production rate is set by the temperature controller (TC) at the outlet of the liquefaction unit.

Other controllers provide feedback control to various segments of the system, to maintain pressures (and levels) in the required range, reacting as required to the rate set by the

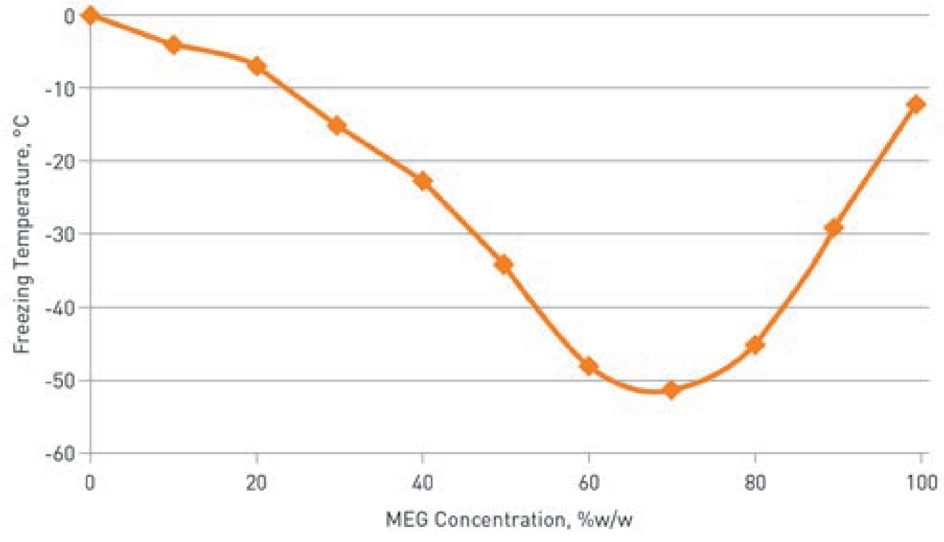


**Figure 4: MEG Freezing Temperature**

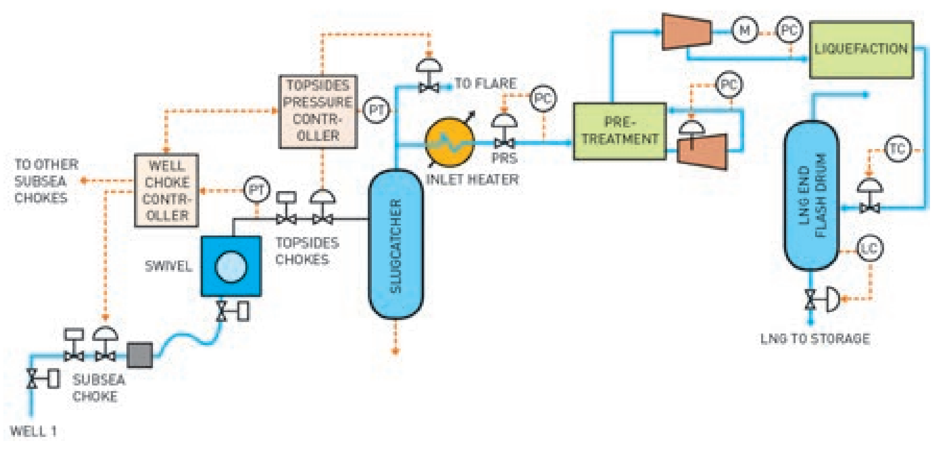


**Figure 5: Overall Control Scheme**

liquefaction temperature controller. Gas pre-treatment ($CO_2$ removal, dehydration, mercury removal, etc.) operates at a fixed inlet pressure, as set by the pre-treatment unit to the LNG plant. It is important that this pressure is kept stable, to avoid upsets and mal-operation in pre-treatment. Pressure let-down to the demethaniser is controlled using inlet guide vanes on the turbo-expander.

## Compressor

Following removal of heavy hydrocarbons, an electrically driven compressor boosts the pressure under speed control prior to entering the liquefaction unit. After cooling and liquefying the feed gas, the pressure is let down into a flash drum. LNG from this drum is rundown to storage, and flashed gas is compressed for use as fuel.

Control of the liquefaction throughput is refrigeration-led when operating the plant. As discussed earlier, refrigeration circulation is dependent on the power available from the gas turbine drivers which, in turn, is dependent on ambient air temperature, with less power available at higher temperatures.

Therefore, LNG production is directly related to the available GT power.

The overall production rate is controlled by the temperature controller (TC) on the LNG outlet stream from liquefaction. This controller keeps the LNG temperature at the required setting by adjusting the feed gas flowrate in line with the available refrigerant cooling. In normal LNG plant control this TC cascades to a flow controller (FC). When there is insufficient refrigeration capacity the product temperature starts to rise and the TC cuts back on the rundown flow.

Depending on the overall rate set by this TC, the other controllers act to keep operating pressures at the required settings. The pressure in the demethaniser is set by the expander inlet guide vane settings (and JT bypass valve), while the pressure to liquefaction is set by the speed of the booster compressor.

## Controller

The main function of the subsea choke controller is to maintain the top of riser arrival pressures within a set control band whist allowing some margin for operational upsets. In order to stay within this range, close inventory control is required, i.e. the gas flow into the system must match the gas flowing out of the system. Even a difference in flows of 1 or 2 percent over several hours will result in the pressure going outside the set range.

The main function of the topside choke controller is to maintain the required set pressure in the slug catcher. In most applications there will be multiple topside chokes (one per flowline) and these are adjusted simultaneously with the aim to keep the pressure at the top of all the risers close to the same value in normal operation.

This simultaneous movement of topside chokes has the objective of using the full subsea system volume to absorb flow imbalances, in order to minimise subsea choke movements.

The main function of the pressure reduction station (PRS) is to maintain a constant, steady pressure to the LNG pre-treatment units. This control loop should be relatively fast, as required by the smaller volumes between the slug catcher and PRS, with tight control of the slug catcher pressure via the topside chokes and coarser control by the subsea chokes. In order to ensure constant pressure to gas pre-treatment during upset conditions, the action of alternative controllers may at times be necessary.

## Dynamic model set-up

If the pressure increases too far above the normal set-point, a spill-off controller to open a valve to flare can be used to manage temporary upset conditions. If the pressure falls due to insufficient gas supply from the wells, the LNG production rate set by the liquefaction TC can be over-ridden to reduce the production rate.

To provide proof of concept and demonstrate the robustness of the proposed control strategy a dynamic model of the system from wellhead to LNG run-down was created using UniSim software.

The model included all the wells, flowlines, risers, turret and main topside process units and associated control loops. To validate the accuracy of the subsea portion of the UniSim dynamic model, hydraulic simulations of the multiphase subsea system were completed using OLGA software, commonly used for flow assurance activities.

The wells are represented by constant pressure sources and are treated as delivering the same simplified composition at the same temperature. Differing well pressures and flowline volumes mean that the rates of pressure change vary between risers. As the flowlines are taken as uninsulated; the gas cools to close to the sea-bed temperature.

The subsea choke valves were represented by valves with a typical CV characteristic. For this type of valve, the typical stroke time is 10 seconds per step with 130 steps for a full stroke (which equates to about 21 minutes).

The topside chokes are modelled as typical linear control valves with a stroke time of 20 seconds. The slug catcher and downstream vessels are modelled based on their dimensions.

The subsea chokes are controlled to maintain the arrival pressure within +/-5bar of the set-point.

Each subsea choke is controlled based on the arrival pressure in its own riser. When the pressure at the top of a riser reaches the top of the deadband, the corresponding subsea choke valve is closed by one step (0.77 percent, equal to 130 steps for a full stroke). If the pressure at the top of the riser drops to the bottom of the deadband, then the subsea choke is opened by one step.

The frequency of stepping the subsea chokes in the model is restricted to ensure the well ramp-up rate limitations are not exceeded. The model logic also prevents the maximum allowable gas flow from each well from being exceeded.

The slug catcher pressure is controlled by modulating the topside chokes to maintain a set-point whilst the pressure of the gas entering the pre-treatment is controlled by modulating the valves in the Pressure Reducing Station (PRS).

## Dynamic modelling findings

To test the stability of the proposed control scheme, the model was run for various dynamic operating scenarios. Some of the main scenarios considered include

- diurnal swing for a typical day and a worst case day (high temperature swing);
- a trip causing 50% loss in liquefaction capacity;
- a controlled ramp down to 50% production and then restart to full production;
- a trip of one of the wells.

In each case, the resulting number of subsea choke movements and the impact on the flowline gas and liquid flowrates and the inlet system pressure were determined.

In the case considered, a high diurnal temperature variation of up to 10°C is experienced. Flow and pressure variations at the top of riser as modelled in UniSim for this case

Thanks to tight pressure control at the PRS and slug catcher, even for this high diurnal swing case, the gas flow at the slug catcher inlet effectively tracks the LNG production rate imposed on the system.

As the flow is reduced, the pressure in all the flowlines tends to increase as the topside chokes start to close in. By allowing the pressure to rise, the required action on the subsea chokes is initially reduced, but once the dead band limit is reached it is necessary to step the subsea chokes to accommodate further changes in required flowrate.

The control system maintains steady pressure in the slug catcher (ex-topside chokes) and to the pretreatment units (ex-PRS). For this scenario, with high daily temperature fluctuations, significantly more subsea choke movements are required.

## Production trip scenario

We look at the controllability of a sudden reduction of 50 percent production (for example due to a trip of half the liquefaction refrigeration capacity).

This case is based on a ramp down to 50 percent production in about 15 minutes, representing the thermal inertia in the liquefaction heat exchangers. In order to manage the transient more effectively and also to avoid potential issues with flowline turn-down, some wells are tripped after a short delay.

The rapid reduction in gas flow is managed by allowing the slug catcher pressure to temporarily increase, while the pressure to pre-treatment stays constant. The high pressure overrides on the riser pressures act to prevent their pressures exceeding 100 bara during the well ramp-down, resulting in some spill-off flaring to maintain slug catcher pressure near set-point.

The need for flaring is dependent upon the allowable ramp down rates of the wells.

## Ramp down and Ramp up scenario

This scenario models a steady planned ramp-down in production rate from 100 percent to 50 percent, followed by holding period and then a ramp-up back to 100% production rate.

The scenario represents a partial

shutdown of the liquefaction train for a planned inspection. The dynamic response of the inlet system to this scenario is modelled in UniSim.

The results show that the pressure remains steady in the slug catcher and to pre-treatment units during the ramping operations. (Figures not included for reasons of space)

## Well trip scenario

In the event one production well trips (e.g. closure of master or wing valve), the remaining wells are able to ramp-up and maintain production rate.

After one well/flowline is shutdown, the pressure in the remaining flowlines tends to reduce rapidly and the on-line wells are ramped-up to maintain pressure. Although some disturbance to slug catcher pressure is observed, the pressure to pre-treatment is able to remain stable.

In this scenario, the system response is limited by the constraint imposed on well ramp-up rate. Simulations with more rapid change permitted show that normal throughput can be achieved throughout the trip.

The severity of the impact depends on the proportion of total feed gas lost through one well trip.

For systems with more wells the impact is reduced. When one well is a higher proportion of the feed gas, production will be reduced to a level matching the maximum flow achievable from the remaining wells.

In both scenarios the control system is able to restore stable operation.

## Liquid slugging

One of the secondary effects of diurnal swing and the other operating scenarios is fluctuation in the liquid arrival rates at the slug catcher as the flowlines and risers pack and unpack in pressure.

The extent of this liquid slugging was separately studied using OLGA software which is better able to model multiphase operations.

From the model the rate of slugging and size of slugs under the different scenarios were calculated, and these results in turn were used to check the sizing of the slug catcher and the required drain rates.

The slugging is also seen to amplify the pressure swings at the top of riser.

## Conclusion

KBR has recognised the unique operating aspects when an FLNG facility is closely coupled to a subsea system with a small gas inventory in the flowlines and risers.

Through the use of dynamic modelling, KBR has demonstrated that in all the cases considered, stable operating conditions in the LNG pre-treatment units and liquefaction unit can be achieved by using active control of the subsea chokes. The combination of topside chokes and PRS allows for coarse and fine control of pressure to gas pretreatment, and allows good control in all scenarios evaluated.

The required movements of subsea chokes is minimised as far as possible, although manipulation will be required on a daily basis for such a system. The number of choke movements has been determined to be well within the choke valves' capability.

The work completed was in the nature of a "proof-of-concept" study. There are further options for optimisation in the scheme that should be studied for specific project conditions as each will be a little different.

The work emphasises the importance of treating the subsea and topside process as an integrated system and not in isolation when designing a complex FLNG facility and also highlights the importance of attention to detail to ensure successful long-term, reliable operations. ■

*This article is based on a paper and presentation entitled: "FLNG to Subsea – are you following me?" by Andy Loose, Technical Director FLNG and LNG, KBR, and Stewart Taylor, Process Controls Chief Engineer, KBR. For reasons of space, some graphics in the original have not been reproduced.*

# Changing patterns during 2017 give reasons for optimism for development of more LNG projects

*Andreas Silcher, Partner in international law firm Haynes and Boone CDG*

There have been significant new developments in the liquefied natural gas sector, which support the view that we are about to enter a golden era for liquefication projects

First, global demand is supported by continuously low LNG prices and high availability. Around fifteen new projects are expected to come online worldwide in the next four years, and existing supply is returning to market following planned or unplanned downtimes.

## Output

Global production is forecast to reach 292 million tonnes in 2017, marking a significant increase of 34MT compared with 2016.

Secondly, there is huge potential for gas in markets such as China, the world's largest consumer of energy, with the Chinese government targeting 15 percent of all energy use from gas (currently the number stands at 6 percent) by the end of the next decade.

China is also forecast to overtake Korea as the world's second largest LNG import country.

Meanwhile, Africa has already seen its afirst final investment decision (FID) of 2017 with Italy's ENI agreeing to develop a floating LNG unit in the Coral South gasfield offshore Mozambique with 3.4 million tonnes per annum of capacity.

ENI's Coral joint venture is billed as the world's first ultra-deepwater floating LNG project.

The Fortuna floating LNG in Equatorial Guinea, whose investors include companies such as Ophir Energy of the UK and Golar LNG, was also set to annonce a positive FID.

*China is forecast to overtake Korea as the world's second largest LNG import country*

## Imports

Europe will also increasingly look to import LNG to help meet the growing gap caused by the decline in domestic gas production.

Other markets in the spotlight are India and Singapore, the latter aiming to become Asia's LNG trading and bunkering hub where large cargos can arrive and be broken up for regional distribution by smaller vessels.

All this is of course good news for the LNG carrier market, which has suffered under painfully low rates for the past two years.

The clear expectation here is that new LNG production Trains will help improve fixture activity and reduce idle time, which should result in more sustainable rates in the spot market.

Another significant development for the LNG shipping sector is the severance of diplomatic relations between Qatar, which last year produced nearly one third of the world's total LNG, and its neighbours.

## Impacts

While it is still difficult to predict with certainty what impact this might have on LNG shipping, it is likely that inefficiencies caused by cargo diversions due to the blockade may soak up some of the tonnage oversupply in the spot market, which should have a positive impact on rates.

New projects and a tightening spot market should also help end the current dry spell for LNG carrier orders, which would bring some relief to the battered Korean shipyards.

Recently there have been plenty of "firsts" in the LNG ship sphere: the "Engie Zebrugge", the world's first LNG bunkering ship, delivered its first LNG bunkers when it completed a ship-to-ship transfer, loading gas as marine fuel on two car carriers.

Additionally, the "Christophe de Margerie", the world's first icebreaking LNG carrier, has been delivered to its owners Sovcomflot of Russia to work on the Yamal LNG project being completed by Novatek and its partners.


**Floating output: 'PFLNG Satu' offshore Sarawak for Malaysia's Petronas**

Hyundai Samho Heavy Industries has, meanwhile, received an order to build the world's first four LNG-fueled Aframax tankers, scheduled for delivery in the third quarter of 2018.

## Malaysia

And finally, the world's first floating LNG (FLNG) production project is now live with the first commercial cargo having been loaded from the "PFLNG Satu" offshore Sarawak for Malaysia's Petronas.

However, the current buzz is largely about smaller (import) markets and how to penetrate them.

Smaller-scale projects appear increasingly attractive to many observers in light of the pressure which low LNG prices have put on the profitability of large projects.

Peter Coleman, Chief Executive of Woodside Petroleum, the operator of two export plants in Western Australia, said that emerging market demand this year would increase from 5 percent of total LNG demand today to more than a quarter of the total by 2025.

This is leading to the development of a functioning relationship between large- and small-scale LNG projects, an interface that will be an increasingly important aspect going forward.

## Emissions

It is further helped by tighter regulations for emissions from ships, which make LNG an important alternative choice of fuel as it contains virtually zero sulphur.

Marine bunker solutions have the potential to soak up significant supply. In addition, policymakers globally are choosing gas for its critical role in reducing pollution.

Other small-scale opportunities include LNG fuelled buses (the first service has been launched in India) and "retail" ideas such as selling LNG in small mobile containers to commercial or even large domestic customers who currently rely on diesel in regions with poor power infrastructure.

Finally, Jamaica, which joined the growing group of LNG importers recently, is set to brew its iconic Red Stripe beer using LNG, after its brewer concluded a gas-supply agreement with a US-based supplier.

Another interesting development is the numerous gas-to-power projects with regasification on site under consideration in Africa.

In particular in West Africa, several power plants are running below capacity or are idle due to either insufficient supply of gas through pipelines, or because the diesel with which they are fuelled is too expensive.

## Incentives

These come with risks, but there are large financial incentives and these projects are interesting customers for companies with existing gas interests in West Africa.

For this new era of LNG to be truly successful, the interplay between small- and large-scale LNG is becoming ever more important, and solutions will need to be found.

The big names in LNG will have to do

everything they can to develop sufficient supply infrastructure on a smaller scale, e.g. in the bunker market to support the growing number of LNG-fuelled ships and price gas as competitively as possible to support this new demand.

As is often the case when existing markets enter a stage of further development, established contractual terms are likely to be put to the test.

In the context of the situation in Qatar for example, ship owners will want to establish whether their charter parties include provisions specifically addressing blockades.

The numerous developing LNG markets might mean contractual counterparties which are not as sound as the traditional oil major-backed LNG project.

## Guarantees

In light of this, performance guarantees and contractual default provisions should be very carefully drafted to ensure they provide the innocent party with appropriate remedies should the other party no longer be willing or able to fulfil its obligations.

Looking even further into the future, one wonders how the steadily increasing LNG demand will be met post 2020.

What cannot be in any doubt is that significant investment will be needed. Moody's Investor Service, on the other hand, forecasts in 2017 is that strong LNG demand growth from China, India and new markets would not be enough to absorb the fresh supply capacity coming online.

They forecast that the market would not rebalance until the early years of the next decade, when global demand and LNG import infrastructure catch up with supply.

The caution noted post 2020 for the growth in the LNG market is a prudent one. Until then, the LNG industry should be cautiously optimistic, as globally the increasing demand for LNG as a more sustainable form of energy looks set to continue with the development of smaller markets. ■

*Andreas Silcher is a Partner based in London and who focuses the construction, financing and employment of all kinds of commercial vessels and offshore structures for the oil and gas industry, in particular in the LNG and LPG sectors.*

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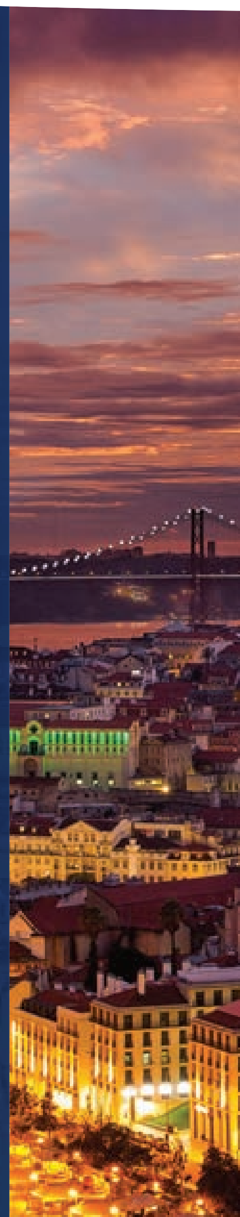

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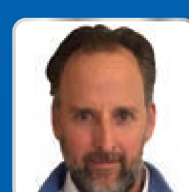

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| LNG carrier | Capacity m³ | Owned or Ordered by | Builder | Delivery Date | Flag | Power Plant | Cargo System | No. of tanks | Ship built for Export plant |
|---|---|---|---|---|---|---|---|---|---|
| Aamira | 266,000 | QGTC | Samsung | Dec-10 | Liberia | DRL | TZ Mk. III | 5 | Qatargas IV |
| Abadi | 135,000 | Brunei Gas Carriers | Mitsubishi Nagasaki | Jun-02 | Brunei | S | Moss | 5 | Brunei LNG |
| Abalamabie | 174,900 | Bonny Gas | Samsung | June-16 | Bermuda | DFDE | TZ Mk III | 4 | Nigeria LNG |
| Adam LNG | 162,000 | Oman LNG | Hyundai | Dec-14 | Marshall Is. | DFDE | TZ Mk. III | 4 | Oman LNG |
| Al Aamriya | 210,100 | J5 Consortium | Daewoo | Feb-08 | Marshall Is. | DRL | GT NO 96 | 4 | Qatargas |
| Al Areesh | 151,700 | Teekay LNG | Daewoo | Jan-07 | Qatar | S | GT NO 96 | 4 | Ras Gas II |
| Al Bahiya | 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 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 |

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|---|---|---|---|---|---|---|---|---|---|
| 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 |
| 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 |

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|---|---|---|---|---|---|---|---|---|---|
| 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 |

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|---|---|---|---|---|---|---|---|---|---|
| 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 |

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|---|---|---|---|---|---|---|---|---|---|
| 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*

| Country | Location (Project) | Owners | Start up | Storage Tanks | Storage Capacity |
|---|---|---|---|---|---|
| Belgium | Zeebrugge | Fluxys | 1987 | 4 | 380,000 |
| Canada | Canaport Saint John | Irving Oil, Repsol | 2009 | 3 | 480,000 |
| Chile | Quintero | ENAP, Metrogas, Enagas | 2009 | 3 | 334,000 |
| | Mejillones | Engie, Codelco | 2010 | 1 | 175,000 |
| China | Beihai LNG, Guangxi | Sinopec | 2015 | 4 | 640,000 |
| | Dalian | PetroChina | 2011 | 3 | 480,000 |
| | 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 FSRU | CNOOC | 2014 | 1 | 60,000 |
| | 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)

| Country | Location (Project) | Owners | Start up | Storage Tanks | Storage Capacity |
|---|---|---|---|---|---|
| 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

| Country | Location/Project | Owners/Project Developers | Start up | Storage Tanks | Storage Capacity |
|---|---|---|---|---|---|
| China | Tianjin North | Sinopec | 2017 | 2 | 320,000 |
| | 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

| Country | Location (Project) | Owners | Start up |
|---|---|---|---|
| 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 |
| 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

| Country | Location/Project | Project Developers | Planned Start Up | Number of Trains | Capacity In MTPA |
|---|---|---|---|---|---|
| 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 |
| | Sunrise LNG | Woodside, Osaka Gas, ConocoPhillips, Shell | 2020+ | 1 | 3.5 |
| | Wheatstone LNG | Chevron, Apache, Shell , Kuwait FPEC | 2017 | 2 | 9.0 |
| CANADA | Aurora LNG BC | CNOOC, Inpex Corp. and JGC Corp. | 2024 | 4 | 24.0 |
| | 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 |
| | Grassy Point LNG | Woodside Petroleum | 2024 | studies | |
| | 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 | | |
| | Pacific Northwest LNG, BC | Petronas, Japex, Sinopec, Indian Oil, Brunei Petroleum | 2021 | 2 | 12.0 |
| | 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 and Golar LNG | 2019 | 1 | 2.0 |
| INDONESIA | Sengkang LNG | Energy World Corp. | 2017 | 4 | 2.0 |
| MALAYSIA | Rotan FLNG (Sabah) | Petronas | 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, InterOil, 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 |
| | Cove Point LNG, Maryland | Dominion | 2018 | 1 | 5.25 |
| | 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 | Veresen Inc. | 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 | 2016-19 | 5 | 22.5 |
| | 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

| Country | Location/Project | Shareholders | Start up | Liquefaction | | Storage | |
|---|---|---|---|---|---|---|---|
| | | | | Trains | capacity (nominal) mtpa | No. of tanks | Total capacity m³ |
| 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 |
| 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, Engie, 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, Suez, 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 | 1 | 4.5 | 5 | 800,000 |
| | Kenai - Alaska | ConocoPhilips, Marathon Oil | 1969 | 2 | 1.3 | 3 | 108,000 |
| YEMEN | Bal-Haf | Yemen LNG, Total, Yemen Gas, Hunt Oil, SK Group, Hyundai | 2009 | 2 | 6.7 | 2 | 320,000 |