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In this issue:

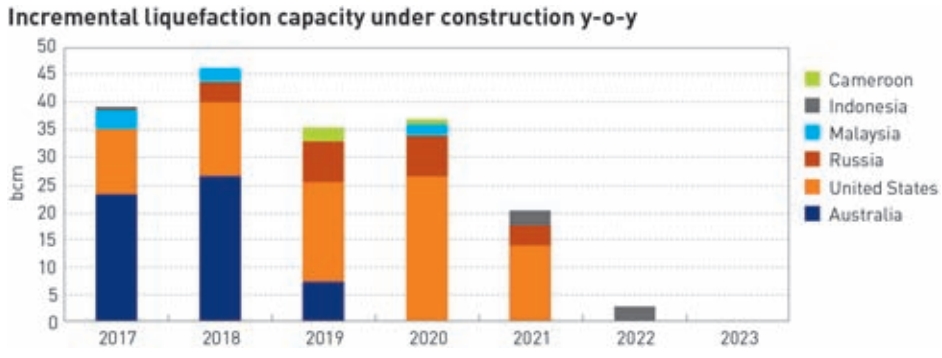
LNG and natural gas security challenges as system becomes more interconnected

Study shows how evolving structure of gas markets is impacting the ability to respond to potential shocks

Natural gas security challenges are evolving with the energy system. In particular, the increasing globalisation of natural gas, through the expansion in the trade of LNG, is creating an interconnected system where shocks in one region reverberate in another.

As a result, there is the need for a broader approach to gas supply security that takes into consideration both the functioning and characteristics of the LNG value chain and the demand-side aspects of supply security.

The International Energy Agency has recently published a report on the issue.



Baseload liquefaction plants moving forward around the world

Comprehensive

"While a comprehensive assessment of global gas security is complex and beyond the scope of this report, this analysis aims to tackle specific aspects that are pertinent to the subject," the IEA said.

"The main aim is to track and analyse how this evolving structure of gas markets is impacting the ability of the market itself to respond to potential shocks," it added.

The current market offers ample supply, low prices with the prospect of additional LNG from the United States and Australia giving credence to the view that a new era of enhanced gas security is coming.

"This is characterized by a rising share of LNG, a more diverse range of suppliers, less rigid contractual structures and greater market flexibility, all of which point to a more fluid movement of gas in response to price signals across increasingly interconnected regions," the IEA said.

But how much slack is there in the system? And how flexible are LNG markets in practice?

The report attempts to answer these questions by providing a detailed analysis (insofar as data allow) of all the elements of this emerging globalised gas system, focusing in particular on LNG, and wherever possible separating out the cyclical factors in a well-supplied market from underlying structural flexibility levels.

"Without such an analysis, there is the risk that the current market situation could give policy makers and consumers an elevated level of comfort about gas security, which could evaporate quickly once market conditions change," it added.

Chapter 1 looks at LNG infrastructure, how much is available and how it is being utilised. It explores in detail the level and cause of various outages in the system, to assess the actual size of the "buffer" in global LNG supply.

Capacity

The world had an export capacity of 445 billion cubic metres (Bcm) of LNG at the end of October 2016, but close to 65 Bcm was off line - equal to combined exports from Malaysia and Indonesia.

The level of unusable LNG export capacity more than doubled between 2011 and 2016 and its share relative to total installed capacity increased as well.

"This implies much less supply flexibility compared with that suggested by gross capacity figures. Lack of feedstock gas is the primary reason for the large underutilisation of LNG plants, accounting for roughly three-quarters of the unusable export infrastructure," the report said.

Combination

"The rest is attributable to a combination of hard security issues and technical problems. Extreme weather accounts for just around 1 percent of unavailable capacity. Average utilisation of LNG export plants - excluding all unavailable capacity - has remained stable at close to full rates in recent years.

"High utilisation reflects a key feature of LNG systems, mainly the fact that liquefaction facilities are built to operate base load. The result is a basic lack of additional liquefaction capacity to readily meet short-term upswing in LNG demand," it added.

The arrival of Australian and US LNG on the market just as growth in global gas demand slows is challenging these basic operational principles.

New capacity additions are now so large that they are outstripping both ongoing disruptions and incremental demand.

The year 2016 could be the first year when actual utilisation of LNG export capacity (utilisation of the capacity technically able to run) is not at maximum. The presence of a supply buffer - through a period of oversupply - will have a positive impact on global gas security.

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"Yet it should be clear that this is not the result of successful gas security policies, nor is it a permanent feature of the market (the supply buffer will be worked off and LNG plants will return to operate base load over time)," said the IEA.

"And it certainly was not the purpose of LNG project developers when they took final investment decisions (FIDs) for those projects. On the contrary, it underscores the challenges of accurately forecasting demand in a rapidly changing energy system: global gas demand proved much weaker than previously expected.

Unwise

"It would be unwise to regard today's oversupply as a permanent expression of the higher level of security that LNG markets offer.

"Due to the capital-intensive nature and the long lead times of the LNG industry, LNG production is shaped by investment decisions that can date back several years. After a FID is taken and enough capital is laid out, project construction tends to remain on course, independently from price moves and demand variations.

"As a result, the short and medium-term profile of LNG production tends to be quite rigid.

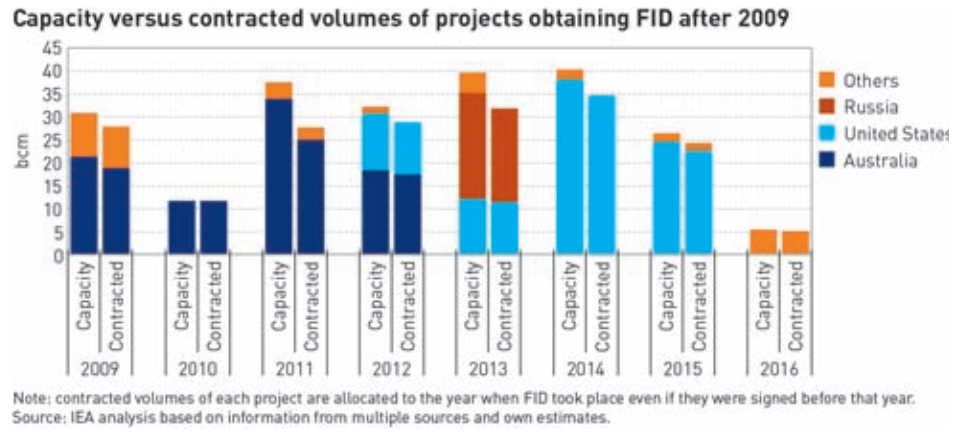
"The large wave of new LNG supplies entering the market between 2015 and 2021 is the product of investment decisions taken between 2009 and 2015 and linked to contracts signed up to 2014, ahead of the oil and gas," the report added.

Robust

"These projects will generate robust growth in LNG production through the end of the decade. As of October 2016, there are 15 LNG projects under construction globally for a total capacity of around 150 Bcm per year, equal to almost half of the traded LNG volumes worldwide today," it said.

"Much lower capital investments and much shorter lead times make timely investment in new regasification infrastructure less of an issue than for export infrastructure.

"Nowadays, floating storage and regasification units (FSRUs) can be ordered, be moored and start operations in around 12 months after an investment decision is taken. Costs are five to ten times lower - on a per-tonne basis - for regasification infrastructure than for liquefaction. "Shorter construction times allow better visibility on demand prospects, and overall investment risks are much smaller. Moreover LNG import capacity is often built to cater for variability in demand," added the IEA.



Note: contracted volumes of each project are allocated to the year when FID took place even if they were signed before that year.
Source: IEA analysis based on information from multiple sources and own estimates.

A comparison of plant capacity and contract volumes sold

Import facilities that unlock new demand have positive security benefits for those individual countries but would tighten up supplies for the rest of the world.

On the other hand, as LNG imports become more diversified across countries, any supply-security event could be more easily addressed by tapping into a larger pool of flexibility options across a wider range of gas systems.

Issues

Chapter 2 of the report turned to the issue of flexibility, starting with the analysis of how demand for flexible volumes has evolved and where it stands today.

The latter part considered how requirements for flexible volumes could evolve in the future, primarily as a function of developments in Asia.

One main feature of LNG production is its tendency to be baseload - in other words for export infrastructure to run at full rate.

This means that under normal circumstances, continued growth of LNG trade does not result in additional "volume flexibility" in the market.

"From a supply-security standpoint, the key question, therefore, is the extent to which current and additional LNG supplies have 'destination flexibility'. In its basic form, this is largely a contractual issue," the IEA explained.

"Traditional long-term LNG contracts often feature destination clauses that prevent buyers from reselling cargoes into the global LNG market. By limiting the free movement of LNG, before and after delivery, destination restrictions are clearly detrimental to the development of a functioning, fully flexible LNG market. (In Europe they were banned at the beginning of the last decade.)

Clauses

"Yet even when destination restrictions do not feature in a contract, optimisation of LNG flows - and full destination flexibility - can be restricted by the selling (and pricing) point of the gas.

"In delivered ex-ship (DES) contracts - where the exchange of ownership occurs at the port of destination - the redirection of cargoes before arrival at the intended port requires negotiations among buyers and sellers.

"Given that, DES contracts tend to result in less destination flexibility than free on board (FOB) contracts (which set the exchange of ownership of the gas at the port of loading). Lower flexibility in rerouting cargoes diminishes the contribution LNG can have in responding to global gas shocks," the report said.

What is the demand for flexible LNG volumes today and how has that demand been met?

Looking at flexibility from the supply side, the major factors to consider are:

- The scale of uncontracted LNG supplies, i.e. LNG volumes that are not sold under short-, mid- or long-term contracts but are routinely marketed by LNG suppliers. By being uncontracted, these volumes are fully flexible and can be directed to the best bidders. By definition these supplies are spot sales.
- The scale of diversions by primary suppliers. These refer to LNG supplies that have a fixed intended destination but are diverted to a different customer from the original intended one. In most cases, these volumes are not subject to contractual destination restrictions and therefore can be diverted by the off-takers to where it makes more sense from an economic or strategic point of view. At other times - when destination

clauses apply - diversions need to be negotiated between the seller and the buyers. Reloading – which refers to a situation when a cargo is actually unloaded and then reloaded at an LNG port to then sail off to a different destination - can be considered a form of diversion. When reloads become a tool to bypass destination restrictions, they are a costly form of diversion.

- The share of aggregators into the markets. These are large LNG players that aggregate supplies from various sources/projects into a portfolio from which they resell to various customers. The customers are entitled to a certain volume and to a certain quality but not to a specific origin. Aggregating volumes has implications that go beyond the provision of flexibility to the global LNG system.

Risk

For example, it allows for better risk sharing and risk management. From a flexibility standpoint - which is the main subject of this analysis - the presence of aggregators allows a specific project to be de-linked from a specific buyer.

This, in turn, allows injecting time flexibility in contractual structures as aggregators (at least in part) can bridge the producers' needs for long-term contracts and the consumers' needs for shorter durations.

"Demand for flexible LNG volumes almost doubled between 2011 and 2013, peaking at around 60 Bcm in 2013 - roughly equal to one-fifth of global LNG trade. Two-thirds of that increase is attributable to Japan's surge in LNG needs post-Fukushima.

"The rest is spread across countries, with Brazil and Argentina in particular accounting for a significant share. The reversal in the trend after 2013 is driven by the unwinding of the increased call from Japan," the report explained.

"Indeed, excluding Japan, the call for flexible LNG volumes has remained stable since 2013 albeit with some notable changes in its composition," it said.

South America

"Latin America's (Argentina and Brazil) high share of global demand for flexible LNG volumes - which stood at roughly one-fourth of the total in 2015 - is significant not just in absolute terms but also compared with the region's limited share of global LNG trade, which is just 4 percent.

"This is due to the lack of long-term contracts for LNG purchases. In fact, neither country has long-term contracts in place. Both tap the LNG market on a spot/short-term basis, thus placing a direct bid for flexible volumes.

"The projected import increase over the next five years is mainly supply driven. This means that the new liquefaction capacity that is coming to the market is largely unaffected by low prices or weak demand," it said.

Most projects have now passed the "point of no return" where too much capital has been invested for the sponsor to pull the plug.

Moreover, the IEA said that long-term contracts underpin the bulk of those new supplies, which ensures producers a minimum cash flow, even in a low demand, low-price environment. As a result, imports will have to increase to match those additional volumes.

"Prices will adjust as necessary in a process that can be defined as a production push rather than a demand pull. (Alternatively, liquefaction plants will need to be shut down or run below capacity. This is possible and at times will likely happen, but it is unlikely to become the primary tool for market rebalancing.)

Demand

"Where the additional demand materialises, it has no real impact on how quickly the global LNG market rebalances. Yet it affects the need for flexible LNG volumes. As long as incremental demand matches the contractual profile of new supplies, there will be no need for additional flexibility.

"By contrast, if new potential demand lies in countries with no contracts in place (or if demand in those countries exceeds their own contract levels), then the call for flexibility would increase substantially.

"This analysis of contracts, demand and import prospects points to a mismatch between the intended contractual destination of new supplies and the location of new import demand.

"Such a mismatch indicates the need for additional market flexibility. Notably, in a supply push, demand for flexibility is more a rebalancing tool than the expression of a supply-security requirement," the IEA stated.

To a large extent, the expected shift in relative contractual positions mirrors different trends for demand prospects and import growth. In particular, the fact that China will gain relevance relative to Japan and Korea as an LNG importer could bring important global security benefits.

Asian customers

The traditional Asian LNG importers of Japan and Korea have isolated energy systems with no domestic upstream potential and no electricity or pipeline interconnections with other countries.

"All of this is translated into price-inelastic LNG demand and switching to oil as the only measurable demand response possibility. China has a continental-scale energy system with a large domestic fuel-switching potential between coal and gas," the report said.

"Increasingly, strict environmental regulations limit this potential to an extent, but the latest generation of Chinese coal-fired power plants is equipped with modern environmental controls, and coal will remain the backbone of power generation there," it added.

"Although China's import dependency is rising, it will see a meaningful increase of domestic production. Tight gas already plays a major role in China and shale is expected to do so, which as in the United States can lead to a domestic upstream that is price-elastic in the medium term.

"Moreover, China has also been successful in building a diversified pipeline import structure, from Central Asia and Myanmar (and the Russian Federation probably in the future) as well as a domestic pipeline infrastructure that is increasingly able to link different regional supplies to demand centres.

All of this means that China is one of the countries that can potentially reduce LNG purchases were LNG markets to tighten unexpectedly," it said.

Flexibility

Chapter 3 of the report looks into who provides that flexibility and how it is delivered.

There are three distinctive elements of such flexibility: first, LNG production that is uncontracted; second, volumes that are contracted to a specific destination but can be diverted or redirected to meet short-term needs; and third, volumes that are contracted but open to multiple destinations (including the volumes held by so-called "portfolio" players or aggregators).

"Due to the lack of short-term upswing production capacity of liquefied natural gas (LNG), demand for flexible LNG volumes can be met in three ways: via LNG production that is fully uncontracted, via volumes that are contracted to a specific destination but redirected, or via contracted volumes open to multiple destinations.

"The analysis shows that demand for flexible LNG volumes peaked in 2013 at around 60 Bcm and then decreased towards 50 Bcm in 2015. On average, 30 percent of that demand was met thanks to the flexibility provided by uncontracted supplies.

"Qatar accounts for around half of these volumes. Supplies initially contracted to a specific country but then shipped to another one cover around 30% of the demand for flexible volumes.

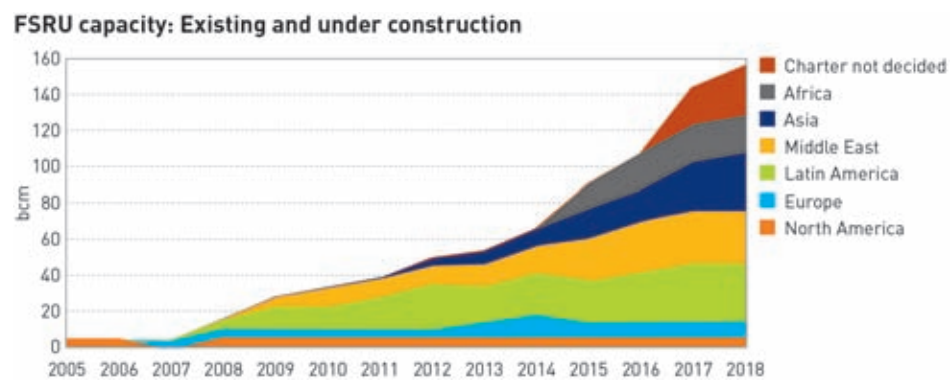
"The rerouting of these supplies has occurred via both direct diversions (i.e. not through portfolio aggregators) and reloading," it said.

"From a technical standpoint, diversions occur when gas is redirected to the final destination before reaching the intended country (and often at the port of loading).

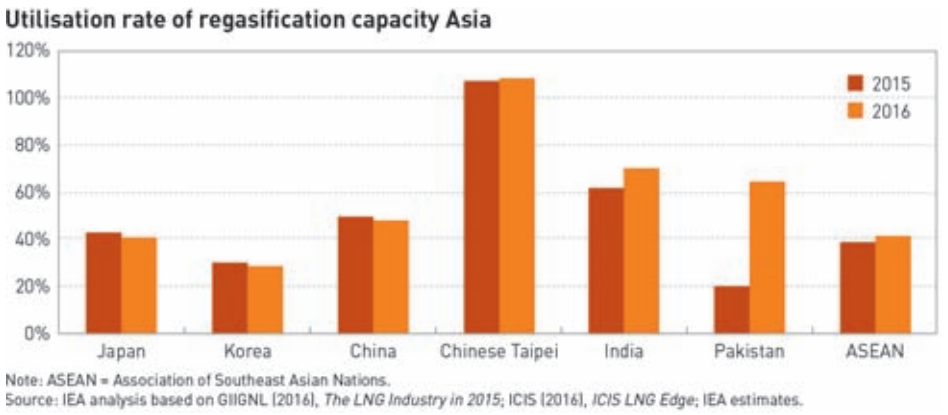
Markets

"Reloads occur when the gas reaches the initial intended destination but is then reloaded and shipped to another - usually higher-priced - market. To occur, diversions require an agreement between the two parties of a contract," the IEA explained.

Data show that some producers -



How the trend towards floating import capability has grown



Recent import and regasification rates in the Asian region

specifically Nigeria and Trinidad and Tobago - are more inclined to allow diversions than others and have accounted for the vast majority of direct diversions that have occurred over the past five years.

Diversions and reloads hinge on exploiting the flexibility embedded in the gas system of the intended country.

Such flexibility can originate from different sources: stronger reliance on pipeline imports and fuel switching in the power sector are the key mechanisms to free up LNG volumes for where they are most needed.

"Over the past five years, structural changes in the European and US gas markets have left many buyers in these regions severely over-contracted.

"Most recently - in 2014 and 2015 - some Asian countries have also been displaying a higher contractual position than needed.

Positions

"Today, the aggregate over-contracted position in global LNG markets is around 70 Bcm, an all-time peak. In practice, the production underperformance of some LNG exports - as described - has offset some of that.

"Overall, however, the flexibility that over-contracted positions offers to global gas markets remains high. The contractual long position of the US and Europe after 2011 was the key underpinning of the large increase in the redirection of gas from these markets to others characterised by a short contractual balance.

"Freeing-up flexibility during the 2011-2014 period of tight LNG markets in Asia was made possible by exceptional changes in the European and US markets. The missing link in tying together demand and supply of flexible volumes is provided by contracts that are not tied to any specific destination," the report said.

"A large proportion of these contracts are in the hands of portfolio players, whose role in global LNG markets has increased substantially in recent years. The need to commit to large volumes and the associated high risks involved in entering a long-term LNG supply agreement mean that such agreements cannot easily be handled by many potential new entrants to the market.

"Portfolio players can distribute those volumes and risks among the aggregation of smaller demand sources more readily than the traditional LNG uptakers can. Consequently, portfolio players have a very important role to play as demand enablers for new pockets of demand," it added.

Capital

The capital-intensive nature of the LNG industry forces promoters of LNG export plants to lock a large proportion of production into long-term sales agreements with offtakers before the project can actually go ahead.

Such deals - by ensuring a minimum level of future cash flows - are a crucial security guarantee for the financial institutions backing the project. Selling production forward is a prerequisite to obtaining project financing which, in turn, is needed to progress to final investment decision.

"Across all projects, therefore, the common approach is to book most of the annual output via long-term contracts and leave small quantities to be sold on a merchant basis," the report said.

"The exact split depends on the lenders' requirements, which are often linked to the specific risk profile of the project. The level of country risk, the desired financial structure (equity versus debt) and the government's control over assets are examples of factors considered that shape the lender's perception of the likely stability of future cash flows," it added.

This analysis - based on the comparison of contracted volumes and export flows - suggests that there are mainly four countries, specifically Russia, Qatar, the United Arab Emirates and Equatorial Guinea, which have consistently provided some production flexibility in the form of uncontracted volumes.

Other producers have occasionally done so. This means that the marketing entities of the respective liquefaction projects are directly responsible for marketing that gas in the spot/short-term market.

Suppliers

Supplies for Equatorial Guinea and Qatar are subject to a 90 percent long-term, 10 percent spot/short-term split (although, of course, in absolute terms this translates to a much higher level of uncontracted volumes for Qatar given the different scale of the two suppliers).

The level of long-term contracts in Russia is around 85 percent, and in the UAE it is around 80 percent. Achieving a higher share of uncontracted volumes in projects has proved difficult due to lenders' objections.

"It is important not to mistake the flexibility offered by uncontracted capacity with short-term swing production capability, which refers to the ability to increase exports, as a function of prices, above the prevailing export level and not relative to contracted volumes.

"Holders of uncontracted capacity routinely sell it in the spot/short-term market. As a result, at any given point in time, they cannot increase sales above what they are already exporting.

"However, the short-term nature of those sales means that primary sellers can swiftly redirect volumes at short notice and as they wish," the IEA said.

"Much of the flexibility provided by the demand side over the past five years is linked to the over-contracted position of a few countries. Spain and the United States rank high among them accounting for almost half of the total," it added.

Linked

"While the flexibility provided by the demand side is closely linked to the aggregate over-contracted position of different LNG importers, it is less than that, due to the fact that in some cases producers have not been able to meet minimum contractual volumes because of a variety of supply problems," the report said.

Estimates are made of the flexibility provided by the demand side once outages are taken into account.

"The volume flexibility made available by both the US and Spain is the consequence of large structural changes in the markets - in other words rapid unexpected shifts in fundamental developments - that left both markets heavily over-contracted for new LNG supplies.

"Other European countries have experienced similar shifts to those that have affected Spain - although not by the same magnitude. In Europe, those structural changes were demand driven; in the United States were supply driven," the IEA added.

"The sheer scale of the shale gas revolution in the US is also responsible for Mexico's role as a flexibility provider. Mexico is importing LNG mainly through three long-term LNG contracts, each linked to one of the country's three import terminals.

"However, LNG received is significantly lower than the annual contract quantity (ACQ). This might indicate that some contracted volumes have been released to supply gas consumers elsewhere, while the originally intended LNG volumes to Mexico might have been replaced by pipe imports from the United States.

"US gas exports to Mexico have offered an attractive alternative to LNG - particularly up to 2014 when HH prices were trading at a several-dollar discount to other benchmarks around the world," it said.

Europe

"Alongside the United States and Mexico, Europe was the major contributor to the provision of volume flexibility to global LNG markets between 2011 and 2015, led by Spain, and to a lesser extent France and the United Kingdom.

"Similar to the case of the US, large structural changes in the market left most European countries - but especially Spain - with over-contracted volumes for LNG.

"Unlike the US, however, the dramatic shift in Europe's gas market fundamentals proved mainly demand driven rather than supply driven," report explained.

"The combination of the euro crisis and a much larger deployment of renewables than initially anticipated resulted in a steep downward adjustment in

expectations for gas demand and much lower import needs.

"In the Europe region of the Organisation for Economic Co-operation and Development (OECD) power generation from renewables grew robustly, reaching 34 percent of total power generation in 2015.

"As power demand growth stagnated between 2011 and 2015 and the share of nuclear and coal was roughly the same in 2015 as it was in 2011, gas demand in the power sector declined by 25 percent from 185 Bcm to 140 Bcm over the period 2011-2015," it noted.

Adding to this, Europe's ability to arbitrage between pipeline gas and LNG further reduced Europe's call for LNG imports as LNG prices generally yielded better returns elsewhere and could be diverted (when an agreement with suppliers could be found)," it said.

Spain

"While the storyline is more or less the same across Europe, Spain stands out as the most dramatic example. There are four factors that make the Spanish case worth highlighting.

"First, Spain is fundamentally more dependent on LNG than any other country in Europe. This is due to lack of indigenous production, small underground storage capacity and limited interconnections with the rest of the continent.

"Second, the economic crisis was more severe in Spain than other main European countries (at least over the period 2009-2013), which resulted in larger losses for power and gas consumption.

"Third, deployment of renewables was much higher in Spain than in other European countries.

"Fourth, legislation to support domestic coal was introduced in Spain in 2011 (and remained in force until 2014), and it further deteriorated the position of gas in the energy mix," the IEA said.

"In accordance with the royal decree, a group of coal power plants consuming domestic coal were dispatched with priority by the transmission system operator.

"Although the volumes dispatched through this mechanism were moderate

(13 terawatt-hours [TWh] in 2011, 12 TWh in 2012, 4 TWh in 2013 and 3 TWh in 2014), this should be put in a context of shrinking demand, higher renewables and stable nuclear generation," it stated.

"Gas demand in Spain grew steadily until 2008, driven by the power sector. This led to a rapid deployment of combined-cycle gas turbines (CCGTs), both to supply incremental demand and to replace older, less efficient power plants.

"This created a rapid change in market structure, with the share of CCGTs reaching 40 percent of total power-generating capacity in 2008 from zero in 2000.

"In anticipation of continued robust electricity demand growth, 25 gigawatts (GW) of CCGTs were built between 2000 and 2010 and more than 20 GW were planned for this decade, although they were ultimately cancelled.

Utilities

"As a result, Spanish utilities entered into long-term LNG contracts to procure the required feedstock to run this large, brand-new CCGT fleet," the report said.

"At the time, most plants were built to run around 5 000 hours per year. The final outcome turned out to be very different, with the average load factor for CCGTs in 2014 below 10 percent, roughly equivalent to 900 hours of full working capacity.

"As a result of the financial and economic crisis, gas demand in the power sector fell by more than 70 percent between 2008 and 2014.

"Electricity demand reverted from a positive growth trend of around 2-3 percent per year to a negative trend post-2008. The fallout of the economic crisis meant a step back of more than ten years in terms of demand, with today's projections for 2020 at the level of demand in 2008.

"Adding to this, the fast roll-out of renewables together with the prioritisation of domestic coal introduced in 2011 further worsened the situation for CCGTs," added the IEA.

While destination clauses continue to underpin most Asian LNG contracts, they were made illegal in Europe at the beginning of the last decade.

Investigation

Full investigation of suspected cases and executing decisions when necessary took some time, however, highlighting the complexity of effectively eliminating those anti-competitive practices.

In the case of fixed destination contracts, destination flexibility can be provided either through profit-sharing mechanisms or through different pricing structures for deliveries to markets not recognised under the original destination clause, normally by means of net-back calculations based on the more relevant hub price in the traded area.

"Where destination clauses are not present - but the gas is sold delivered ex ship (DES) - diversions also require negotiations between the two counterparties involved as the gas does not change ownership until it reaches the port of destination," the report said.

"Diversions are usually the product of amicable commercial negotiations between buyers and sellers in search of a shared upside. When common ground cannot be found, a solution can be forced only in the event of major structural changes in the market that allow buyers to invoke specific review clauses," the report explained.

"It is commonly accepted that offtakers must manage both seasonal demand fluctuations through the year (usually via annual delivery programme) and volume fluctuations across years. In this respect, downward tolerance in long-term contracts is a useful tool.

Structural

"However, in the case of steep structural declines in demand, which are very difficult for the offtaker to manage and somewhat outside its control, then the general practice is for both parties in the SPA to negotiate in good faith towards a shared best outcome to keep honouring the contract and preserve a good commercial relationship," it added.

"In this case it is more likely that the supplier will agree to relax destination restrictions to keep the contract economically viable and avoid its anticipated termination. Yet a price adjustment should normally be expected in these circumstances, although within reasonable ranges of prevailing prices at global or regional/national level.

"Overall, diversion activity - according to the definition utilised here - has increased rapidly, reaching in 2015 a level seven times higher than that in 2011," the report said.

"Early this decade, LNG diversions were not common, but they took off between 2011 and 2014, helped by several factors - including a widening gap across regional benchmarks prompted by the Fukushima nuclear accident and generally a growing mismatch between who holds the contracts and who needs (or is willing to take) the gas.

"Nigeria and Trinidad and Tobago have accounted for the majority of diversions since 2011, reflecting specific characteristics of their projects that are described in detail in the following sections," it said.

Reloading

"Another tool to deliver volume flexibility to importers that require it is reloading. Reloads are often used when diversions cannot be agreed between the two original parties of a contract. Because unloading and reloading incur a cost, direct diversions are a more efficient way to reroute the gas," the IEA explained.

"Reloads generally require higher regional spreads than diversions for them to be economic. As a consequence, the destination countries for reloads tend to be those commanding a higher premium.

"Reloading activity experienced steady growth between 2011 and 2014, with reloads peaking at almost 9 Bcm in that year," the report said.

"The initial impetus of this activity came from the United States. While contracted volumes from Trinidad and Tobago were fully flexible, and most Nigerian volumes were likely diverted, reloads data suggest that volumes under different contracts might have been less flexible.

"Over time, changes to the initial contracts are likely to have been agreed to reflect the permanent shift in US gas market balances. By 2013, North America reloads were all but gone.

Since 2012, reloading activity has been driven by European countries. This is in line with the growing over-contracted position of the region at a time of tight markets in Asia (and corresponding high price differentials)," it added.

Trends

"In 2013 and 2014, Europe accounted for virtually all reloading activity. In 2015, reloads fell to around 6 Bcm, reversing the trend of steady growth that had been in place since 2011," according to the IEA data.

"Data for the first three quarters of 2016 point to levels for the full year broadly in line with those of 2015. When considering the massive fall in regional spreads, today's reload levels look quite robust," it said.

"As for diversions, this probably stems from a persistent mismatch between who owns contracts and who needs additional LNG supplies," the report added.

From a country perspective, Belgium and Spain dominated the picture in Europe until 2014.

The role of Spain in particular increased dramatically in 2014 when the country's reloads accounted for 60 percent of the global total.

In 2015, reloading activity collapsed in Spain and diminished as well in Belgium. By contrast, reloads have increased in both France and the Netherlands.

"The different role of various European countries with respect to reloading is linked to two main drivers. First, the availability (or lack) of reloading facilities, and second, the supply portfolio of each country.

Capability

"Most reloading facilities in Europe were added to terminals early this decade. For example, the Netherlands did not have reloading infrastructure until 2013 and the United Kingdom had none until 2014.

Other importers, such as Italy, still do not have this capability. Moreover, upgrades at existing infrastructure allowed improvement of the operating efficiency of reloading services over time. Better efficiency and lower costs have helped make reloads more widespread. The composition of the supply portfolio of each country is also a driver for reloading activity," it stated.

The IEA report then went on to cover two case studies.

First, it assessed the way that LNG markets responded to the impact of the Fukushima nuclear accident which led to the closure of Japan's nuclear power plants, and the circumstantial and structural elements that allowed LNG to be diverted to meet Japan's needs.

Second, a detailed analysis of the elements of flexibility within the European gas market, noting in particular the declining flexibility coming from indigenous production and, to a degree, storage and fuel-switching capabilities. ■

These studies can be obtained from the full report: "Global Gas Security Review 2016 - How Flexible are LNG Markets in Practice?"

Chiyoda outlines its standardization methods for LNG plant design based on new concept

Japanese engineering and construction company outlines latest offerings for liquefaction facilities

Forecasters predict that many LNG projects are under planning (pre-Final Investment Decision) and if all LNG projects currently in the planning stage are completed, future global LNG supply will exceed demand and that low LNG price trends could continue for longer than expected.

Therefore the fastest and most cost effective supply of competitively-priced LNG to the market will be the key to success for clients planning LNG projects.

One of the most effective measures to achieve faster LNG project delivery and cost effectiveness is the standardization of LNG plant design.

Although much time and effort have been spent by various companies to standardize design of LNG plants, there are not so many success cases which have been achieved the objective.

Effective

This paper analyses the difficulties in achieving an effective standard LNG plant design and proposes a new concept for realizing this objective based on Chiyoda's vast expertise accumulated through many years of successful EPC LNG project completion worldwide.

The standard design concept and package (CHIYODA LNG-XTM) achieve faster project delivery and the lowest capital expenditure based on unique value improvement ideas which consider footprint, major piping and cable length and construction work volume, all with appropriate safety, quality and operation reliability considerations.

The standard design package can also be easily modified to satisfy different requirements with the selection of the most suitable combination of "Ready-designed Blocks".

Projects

It is currently estimated that the global population will rise to over 9.7 billion by 2050. With this increase, it is explicit that energy demand will also increase.

Furthermore, history has shown that the increase in energy demand exceeds the incremental increase in global population.

Although the utilization of renewable sources of energy will steadily increase, fossil fuels will continue to be the major source of global energy. Among the fossil fuels, natural gas and LNG will continue to play a vital role in countering global warming.

It is estimated that global LNG demand will reach approximately 450 MTPA by 2025. Supply by existing and 'under construction' plants in the same period will reach 350 MTPA.

The 100 MTPA gap between supply and demand must be filled in by new LNG projects. If all projects currently in the planning stage (Pre-FID) are included in the estimate, the LNG supply forecast of over 700 MTPA by 2025[1] will exceed demand.

Although certain projects may be delayed or cancelled due to negative impacts such as low oil prices, LNG supply is forecast to exceed demand in 2025.

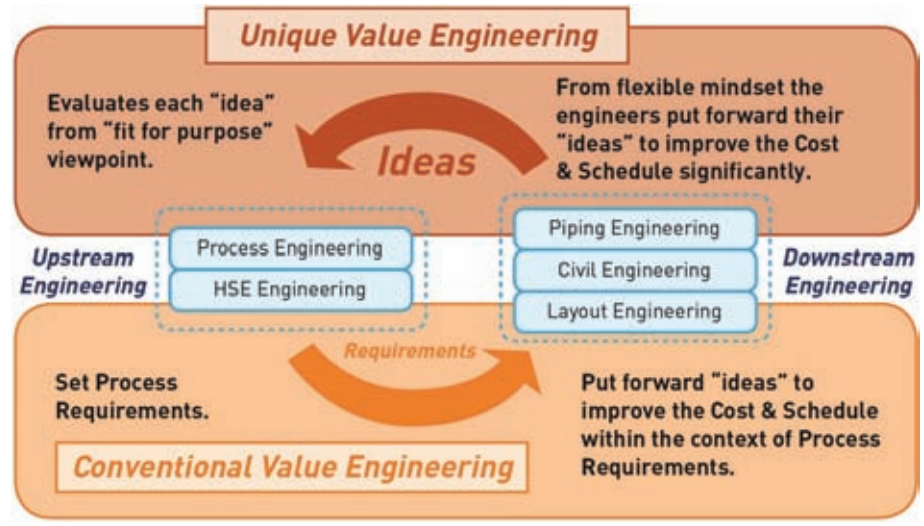
Which projects will be realized in the severe market conditions as described? Projects fulfilling the following two key criteria, essential for client success, will have the highest possibility of realization from planning stage to Front End Engineering Design (FEED)/Engineering, Procurement and Construction (EPC) and start-up and fill the gap amount of 100 MTPA between supply and demand.

1. The lowest CAPEX (Realize economical LNG supply by minimizing client capital investment throughout the project lifecycle from planning to start-up.)
2. The fastest project delivery (Realize rapid LNG supply to the market by minimizing the project schedule, including decision making.)

To fulfil the above two criteria for a project, a client defines a basic of project such as plant site, gas field, plant capacity, and potential customer considering distance of the project from the gas source and consumers, local political circumstances, labor cost / availability, environmental considerations, climate, geographical location, feed gas conditions etc.

One of the most effective measures a contractor can propose to support clients in realizing successful LNG projects is the standardization of LNG plant design.

For the floating LNG plant design, Shell has proposed a standardized approach, "design one, build many", for floating LNG plants in the development of small gas fields (1-5 trillion cubic feet range).



Unique value engineering versus conventional value engineering

Methods

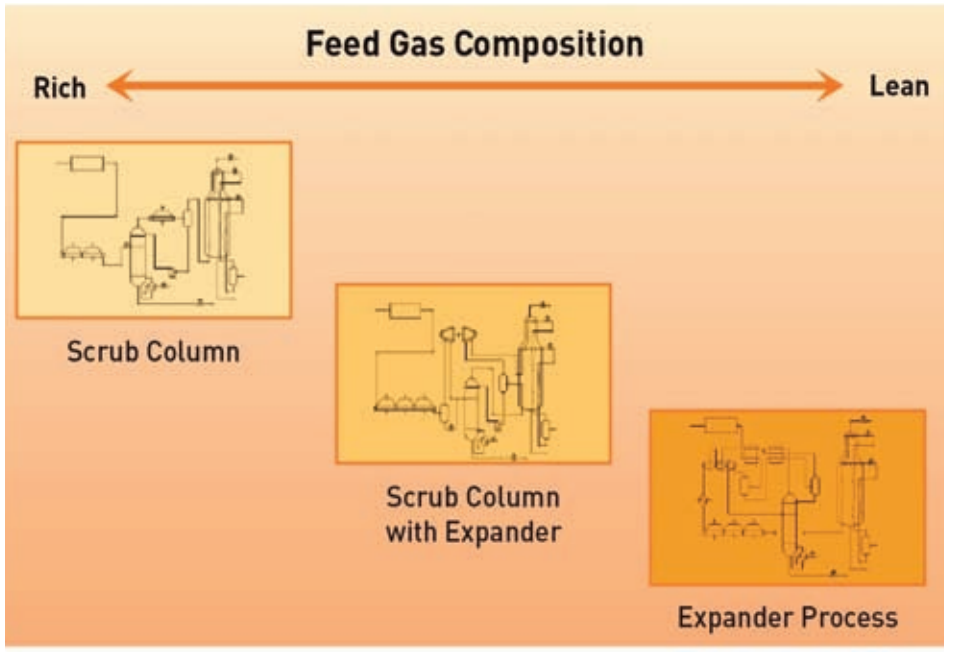
As for other contractor, Bechtel applies a form of standardization for the Cascade Process, but for the broadly applied propane pre-cooled mixed refrigerant (C3-MR) process, design standardization has not been adopted for middle to large scale LNG plants.

Notwithstanding Chiyoda's abundant EPC expertise and experience accumulated through the completion of over 40 percent of global LNG plant capacity over the past 10 years, successful design standardization has not been completed except for small-sized LNG train projects.

Though Chiyoda had made several trials for the design standardization and they had been completed to some extent, actual plant designs were not standardized because of following reasons:

1) Most of value improvement initiatives were originated from the process design view point (upstream) and intended to flow downstream into detailed design (civil, mechanical, piping, instrumentation etc.) and construction where there is the greatest potential to reduce cost and shorten a projects schedule. However the downstream and construction engineers just followed the ideas determined by the upstream engineers. Therefore some of the value improvement ideas originated by the downstream engineers were not incorporated effectively to reduce cost and shorten schedule.
2) Standard design specification was given to contractor by client and each client has different standard specification. Therefore LNG plant designs were different on a plant to plant basis and designs are not standardized.
3) A major client objective was to maximize production and/or operation efficiency according to plant site conditions necessitating different designs to achieve targets. Therefore the standardized design was not suitable for the purpose.
4) Feed gas compositions, such as acid gas content (CO2, H2S and sulphur components) and heavy hydrocarbon content, differ from site to site and so the design of gas treating sections (acid removal unit, dehydration unit, and heavy hydrocarbon removal unit) could not be standardized.
5) Pre-2010, client's priority had been to increase plant capacity to pursue capacity.

Consequently, the size of the gas turbine driver also gradually increased. For example, on Qatar Gas Train 1-3 (LNG Production: 2 MTPA/train), a GE Frame 5 (MS5002C ISO Power 26MW) was applied; on Oman LNG Train 1-3 (LNG production: 3.3 MTPA/train), a GE Frame 6 (MS6001B ISO Power 43MW) and a GE Frame 7 (MS7001EA ISO Power 86MW) were applied and for the largest LNG trains (LNG production: 7.8 MTPA/train), a GE Frame 9 (M9001E ISO Power 130MW) was utilized.



The Chiyoda process method for heavy hydrocarbon removal

Firstly, the target LNG production rate was placed then the suitable liquefaction process and refrigerant compressor drivers which are capable of producing the predetermined target LNG production rate were selected. So standardization was not adopted.

Post-2010, around 3 to 5 MTPA LNG trains have become a main stream of LNG projects, replacing the trend of continually increasing plant capacity. Therefore, it is worth re-examining the concept of plant design standardization.

Most of LNG projects have to pass through many stages including Pre-FEED, FEED bidding, FEED contractor selection, FEED, EPC bidding, EPC contractor selection, and EPC, resulting in long lead times prior to LNG production.

The FEED design package, developed according to specification requirements in collaboration with the client, would ordinarily be utilized as the basis for EPC bidding.

As a result, the successful EPC contractor may differ from the FEED contractor who could not therefore propose in-house standard design to client during the FEED stage.

Support

What form of design standardization is most effective in supporting clients to realize successful LNG projects? The conventional standardization approach, e.g. the value improvement scheme from upstream (process) to downstream (detailed design), cannot effectively realize the required cost and time schedule reductions.

Then we investigated the bases which were used for the conventional approach and reached to new concept of standardization that is unconstrained by conventional thinking and approaches.

Offerings

1) Downstream detailed design (civil and structural, piping, mechanical, instrumentation etc.) and their construction work form a major portion of total project cost and schedule. As previously indicated, value improvement initiatives originated by piping engineers, civil/structure engineers and construction engineers should be more effective in reducing work volume, cost and schedule than conventional methods. Process engineers will ensure that the initiatives do not spoil plant performance significantly and do not adversely affect health and safety, environmental considerations.
2) Specifications prepared by the experienced contractor are to be applied to standardized LNG plant design in lieu of a client's individual specifications. The standardized design might deviate the client's specifications. However no problem is expected for project execution since the specifications prepared by the contractor are developed based on the vast experience of contractor and assure the necessary and sufficient safety and operability of plant.
3) The standardized design is developed prioritizing the lowest CAPEX and the fastest project delivery rather than maximizing production and/or efficiency.
4) In general, the LNG process train consists of several units such as inlet unit, acid gas removal unit, dehydration unit, mercury removal unit, heavy hydrocarbon removal unit, and liquefaction unit. Although the design of the respective units is not completely the same at for every project because of client's policy or preference, the basis of design is similar.
   Each unit can therefore be pre-designed by the experienced contractor as "Ready-designed Blocks" based on the philosophy of safe operation and cost effectiveness. The basic design of the LNG train can be completed within a short time period just with connection of the blocks.
   Using this concept, although the LNG production or the operation efficiency may not be maximized, cost and schedule can be reduced.
5) Design of process units has to be changed according to feed gas composition. For example, the design of the heavy hydrocarbon removal unit depends on feed gas leanness.
   If the feed gas contains sufficient ethane (C2), propane (C3) and butane (C4) required for reflux flow, the straightforward and common scrub column scheme can be applied.
   However, if the C2-C4 fraction in the feed gas is not enough, a lower temperature at separation column /vessel is required.
   In this case, the expander process can be applied. This example, and other possible options learned from previous LNG project experience, can be listed and designed in advance as "Ready-designed Blocks".
   Using this concept, a configuration of the process train can be selected in a short period for different feed gas conditions and the project schedule can be reduced since each block is already pre-designed.
6) In most LNG plants, gas turbines are selected as the main refrigerant compressor drivers because a simple configuration for the liquefaction unit can be realized with gas turbine application.
   The cost is lower compared to alternative drivers such as steam turbines with steam generation facilities and motors with a power plant.
   The selection of the gas turbine drivers is limited to the frames prepared by manufactures and the available power from each frame is fixed.
   Therefore, once a frame of gas turbine drivers and its number is selected, the available power for refrigeration is also determined (although it can be increased to a limited extent by the addition of an inlet air chilling facility or helper driver).
   Since LNG production rate is limited by the available power, the LNG production rate is calculated as a result. This concept can realize the most efficient utilization of available driver power.
7) The EPC bidding stage in the "Dual FEED & EPC Contract" schedule can be reduced as EPC cost estimation is executed on the basis of each bidder's FEED design.
   If the client utilizes an alliance contract for FEED design, the intermediate stages from Pre-FEED to FEED such as FEED bidding, bid evaluation and the FEED contract can be eliminated.
   At the early stage of a project (pre-FEED), if a client decides to adopt the standardized design and one contractor executes through FEED and EPC, the contractor can offer the fastest project delivery.

The Package

Chiyoda has developed a standardized design LNG package, "CHIYODA LNG-XTM", using the new standardization concept described above and expertise and experience accumulated through many years of successful EPC project execution.

Through CHIYODA LNG-XTM, the company can support clients in the current challenging market conditions by realizing the lowest costs and the most expeditious project delivery without compromising safety, impact on environment and reliability.

CHIYODA LNG-XTM has been developed on the following basis:

- Liquefaction Process: Propane Pre-cooled Mixed Refrigerant Process

GT Type	Heavy Duty		Aero derivative			
Name of Frame	FR7	H-100*2	PGT25+ G4	LM6000	LM6000	TR60
ISO Power/GT	86MW	103MW	34MW	44MW	44MW	53MW
Number of GT	2	2	5	5	6	5
LNG Production Rate *1	5MTPA	5MTPA	3.5MTPA	5MTPA	6MTPA	6MTPA
Liquefaction Process	C3-MR					

LNG Production based on typical GT driver selection

- Cooling: Air Cooling
- Refrigerant Compressor Driver: Select the lowest price and the fastest delivery gas turbine driver from the market at the time
- LNG Production Capacity: Middle to Large Scale

The optimized design has been embedded in CHIYODA LNG-XTM to realize the lowest CAPEX considering:

- HSSE requirements;
- Value improvement items;
- Minimum footprint;
- Minimum major pipe length/cable length;
- Minimum construction work volume;
- Constructability, operability & maintainability;
- Chiyoda's own design standards/ specifications.

Equipment layouts and piping arrangements have been optimized to minimize plant footprint and piping length, especially high cost stainless steel and large bore pipe.

As a result, the footprint can be reduced by approximately 20 percent with CHIYODA LNG-XTM.

Major pipe lengths can be significantly reduced.

CHIYODA LNG-XTM considers one-through execution from FEED to EPC and applies the "Ready-designed Block" concept, providing significant schedule improvements by eliminating the schedule relating to bidding and the following prerequisite works at the early engineering stage:

- Conceptual and basic studies;
- General specifications / procedure preparation;
- Initial process engineering;
- 3D modeling setup.

Projects utilizing CHIYODA LNG-XTM will have an estimated 5 percent reduction in CAPEX per LNG train. For an LNG project with multi trains, the total cost savings will be higher. Furthermore, LNG production can be started much earlier than usual. Therefore it would have a big impact on investment recovery of client.

Conclusions

The importance of LNG as a source of energy will continue to grow in response to escalating global clean energy demands. Furthermore, low LNG prices and the challenging world economic environment will continue for longer than previously expected. In order to meet anticipated future LNG demand, only the most competitive LNG projects out of those ventures currently at the planning stage will be realized.

Therefore, the "lowest CAPEX" and the "fastest project delivery" are key criteria essential to realizing successful future LNG projects.

Design standardization with a new concept is critical to achieving these two vital targets. As a No.1 LNG contractor, Chiyoda will continue to support clients and make ever increasing contributions to the realization of successful projects. ■

This paper was presented at a 2016 conference. It was compiled by Toshiya Momose, Deputy Division Director of Technology and Engineering Division, Masao Ishikawa, Division Director, Takamasa Oba, General Manager of Gas & LNG Process Engineering Unit Chiyoda Corp., Yokohama, Japan. The writers would like to thank Yasuhiro Yoda and Kenichi Kobayashi for developing the new plot plan and piping layout. Their unconventional ideas and diligence form the basis of the standardized design package CHIYODA LNG-XTM.

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For the Record

ANADARKO Petroleum, the US exploration and production company, said it expected to invest around $770 million in its deepwater and international exploration programme and onshore LNG project in Mozambique. "The company expects to continue advancing the Mozambique LNG project where it has made good progress on the legal and contractual framework, and recently submitted a Development Plan to the Government of Mozambique for the Golfinho-Atum discoveries," said the company, based in Houston, Texas. Anadarko is the licence holder of the Area 1 zone of the Rovuma Basin where it says "enormous recoverable resources" of more than 75 trillion cubic feet of natural gas will help in the development of several LNG projects, including the US company's large onshore venture. The US company had been reluctant to move forward on its onshore liquefaction plant because of economic uncertainty in Mozambique following a state loans scandal. The Anadarko plant, located in the northern Mozambican province of Cabo Delgado, is still moving forward on the basis of building an initial two LNG Trains, each with capacity of 6 million tonnes per annum and able to accommodate expansions from 12 MTPA up to 50 MTPA. The marketing company of the joint venture is called Mozambique LNG and in addition to Anadarko it consists of the other shareholders in the licence. These are subsidiaries of Japanese trading house Mitsui & Co., Thailand energy company PTT, and three Indian energy companies, ONGC Videsh Ltd., Bharat PetroResources and Oil India Ltd. As Anadarko's Mozambique LNG investment gets back on track, Italian energy company Eni is also progressing with its plans. Eni is developing the Coral floating LNG project located in waters more than 2,000 metres deep in the Rovuma Basin and about 80 kilometres offshore Cabo Delgado, where the Anadarko onshore plant will be located. The Eni plan of development foresees the drilling and completion of the six wells and the construction and installation of a floating production facility before the Anadarko onshore project starts building. Anadarko Chief Executive Al Walker said his company's 2017 capital investment programme was designed to leverage the streamlined portfolio after restructuring and to sharpen the company's focus. "Further sustained oil production from our deepwater Gulf of Mexico, Algeria and Ghana assets is expected to generate significant free cash flow to support growth and fund future value creation through exploration success and our LNG business," added Walker. Anadarko said its plans overall involved between $4.5 billion to $4.7Bln of spending and it also expected to invest around $1.1Bln in its deepwater Gulf of Mexico, Algeria and Ghana assets. During the year, Anadarko will drill up to 10 exploration and appraisal wells in the deepwater Gulf of Mexico, the Ivory Coast and the South American country of Colombia, where Anadarko recently added to its previous exploration success with another discovery at the Purple Angel prospect.

ATLANTIC GULF and Pacific Co., the LNG module maker and fabrication yard operator based in the Philippines, has signed an accord to cooperate with the engineering unit of French industrial gases company Air Liquide to develop small-scale LNG infrastructure and distribution across Asia. AG&P and Air Liquide said they planned to offer fully integrated and cost-optimized solutions for LNG entrants with a focus on liquefaction, transportation and downstream infrastructure to deliver LNG for power, shipping, ground transport and other industrial applications. Both companies have signed a memorandum of understanding to integrate the technologies offered by Air Liquide with its expertise in planning, design engineering and financing to build "technologically-advanced blocks that can plug into any part of the LNG supply chain." AG&P Chairman Jose P Leviste Jr. said the agreement with Air Liquide will enable the integration of downstream LNG infrastructure, including small-scale regasification terminals, distribution hubs, truck-loading stations and boil-off gas handling systems. "Our aim is to streamline Air Liquide's know-how in gas processing technology and patents with AG&P's experience in design, engineering and construction to bring the most competitive solutions to customers across Asia," said Leviste. "We offer unique products for both onshore and offshore applications," he added. The accord will see the Air Liquide Engineering and Construction subsidiary and AG&P begin to develop standardized downstream LNG modules (some as skids) that optimize costs and shorten delivery time. "The MOU as well covers innovative boil-off gas (BOG) management systems eliminating the need for investment in BOG compressors, while ensuring that no gas is vented or flared, bringing environmental and economic benefits to the customer," the companies said. AG&P has been building its module expertise in supplying liquefaction project modules to countries such as Australia, while Air Liquide has little specific experience in the LNG business even though it is a global player in the industrial gas market. The Philippines company has signed other cooperation agreements over the past 12 months, including a technical and licensing agreement for membrane tank design with another French company GTT. In addition, AG&P owns a stake in Gas Entec, a leading south Korean-based engineering firm. It was also recently chosen by Indian project company Hindustan LNG to help develop an import facility on India's East Coast. Domenico D'Elia, Vice President and Chairman of Air Liquide Engineering and Construction, said: "We chose AG&P to be our partner because of their reputation for innovation, safety record and fast delivery. Through this agreement, we will be able to meet the dynamic requirements of customers in the vast region of Asia where small quantities of LNG need to be delivered efficiently to end-users scattered across vast distances."

AUSTRALIAN liquefied natural gas exports and income have surged with the second of three LNG Trains at the Gorgon plant on Barrow Island in Western Australia being ramped up and shipments rising from coal-seam-gas-to-LNG plans in eastern Australia. The nation's Bureau of Statistics has reported record monthly LNG export revenues of A$1.90 billion (US$1.5Bln) compared with the $1.39Bln logged back in July 2016, despite sluggish oil prices continuing to pressure the LNG market. The increase in exports from the Australian plants on the west and east coasts will be helped by a new north coast plant, Ichthys LNG near Darwin, also coming on stream before the end of 2017. Following almost $200Bln of investment in liquefaction and export plants, Australia is expected to become the world's largest exporter with 80 million tonnes per annum by 2020, overtaking Qatar. The Gorgon plant, operated by Chevron Corp. and built at a cost of $US54Bln, has now overcome technical problems that have plagued the facility since it came on stream in early 2016. Two Trains are now operating and a third will soon by started up to give nameplate capacity of 15.6 MTPA. Chevron Chief Executive John Watson has said the second Train was performing extremely well and production was rising. "Lessons from Train 1 were applied to Train 2 and, consequently, Train 2 ramped up over 90 percent of capacity within a week and continues to exceed expectations," said Watson. "Train 3 is also expected to benefit. Construction is complete and we're well into start-up and commissioning and we expect first LNG early in the second quarter," added the CEO. The Chevron CEO said he was optimistic about the LNG market going forward in the Asia-Pacific region. "If you look at some of the environmental objectives, particularly throughout Asia, it's actually an encouraging sign," he said. "I temper that with the understanding that we've got projects that are coming online, but the long-term trend for LNG demand is good because it's competitive on price in many locations and it certainly has desirable environmental characteristics," stated Watson. The Australia Pacific CSG-to-LNG plant, whose shareholders are Origin Energy of Australia, ConocoPhillips and China's Sinopec, is also adding to the rising shipments from the Queensland Port of Gladstone. APLNG is located on Curtis Island near Gladstone, along with the Royal Dutch Shell-owned Queensland Curtis plant and the Gladstone LNG facility, operated by Australia's Santos. The latest Port Authority data from Gladstone shows that LNG exports from Queensland increased from 1.5 million tonnes in October 2016 to 1.75MT in December.

BEACH ENERGY, a leading shale gas and oil exploration and production company, said it was preparing to drill a conventional onshore gas exploration well in the Otway Basin in South Australia, supported by the state government under a grant scheme aiming to bring new gas to market within three years. Under the terms of the grant, if the discovery is deemed to be commercial, Beach will

enter bilateral negotiations with prospective South Australian customers for supply of gas from the targeted well at prevailing market terms. The state of South Australia during March suffered a series of major power cuts, the first of which blacked out the state capital Adelaide. This led Federal Prime Minister Malcolm Turnbull to point blame at the state's sizeable renewable energy projects and unreliable wind and solar power sources before announcing financial backing for a hydroelectric project. Beach, which also has assets in the Browse Basin and Bonaparte Basin offshore northwest Australia, said it was targeting the Haselgrove-3 gas well in South Australia with a prospective 34 billion cubic feet of reserves. The company is the former shale-gas partner of leading Australian LNG producer Chevron Corp. before the US major in 2015 pulled out of the country's largest unconventional exploration venture in the Cooper Basin in central Australia, citing cutbacks because of the oil price plunge. The decision was a setback for Beach and Australia's emerging shale-gas exploration sector centred in the Cooper Basin. With Chevron's shale exit, all the US player's equity interests in several shale joint ventures returned to Beach at no cost. That left Beach with 100 per cent of two permits in South Australia and one in Queensland. Adelaide-based Beach is now pressing ahead with its Otway Basin drilling and will receive around A$6 million (US$4.6M) from South Australia to support its drilling costs. Beach has widespread interests in Australia and some overseas and in its latest half-year earnings published in February 2017 posted a net profit of $103M compared with a loss of over $600M in the same period of the previous year. "The onshore Otway Basin in South Australia is a proven gas province close to existing infrastructure and pipeline networks," said Beach. "The region has produced approximately 70 Bcf of raw gas and has supported local industry," it added. "Beach has operated in the region for over 50 years and most recently undertook exploration drilling in 2014, which identified prospectivity beneath

previously productive reservoirs," Beach explained. "Haselgrove-3 will be drilled in PPL 62 (Beach 100 percent) close to Beach's Katnook gas processing facility and pipeline network, and the SEA Gas transmission system," it said. "We are pleased to once again be exploring for gas in the onshore Otway Basin in South Australia," said Beach CEO Matt Kay. "The region is well known to Beach and we are confident that in a successful case, it can supply new gas to the market. We also acknowledge the support provided by the South Australian Government through its gas grant scheme. Haselgrove-3 is a conventional gas well that will not be fracture stimulated. Beach will undertake extensive community and stakeholder consultation throughout the planning, drilling and post completion phases of this drilling activity," said the CEO.

BP, the UK major has agreed to acquire the upstream bio-methane portion of the fueling business established by Clean Energy Fuels Corp. of the US as part of its build-out of a network of LNG stations in North America. The US company, based in Newport Beach, California, supplies LNG, compressed natural gas and bio-methane as trucking and transport fuel. The forerunner company of Clean Energy was Pickens Fuel Corp., founded by US oil tycoon and LNG fuel pioneer T. Boone Pickens. Under the terms of the agreement, BP will pay $155 million for Clean Energy's existing bio-methane production facilities, its share of two new facilities and its existing third-party supply contracts for bio-methane made from waste. Bio-methane is produced entirely from organic waste and is used as a fuel for natural gas vehicle fleets, including heavy-duty trucks. Using LNG, liquefied bio-methane or CNG in vehicles is estimated to result in 70 percent lower greenhouse gas emissions than from equivalent gasoline or diesel-fueled engines. Clean Energy in October 2016 opened its first public LNG fuel station in Washington State and completed the connection of a US Pacific Coast supply chain aimed at the trucking industry from southern California, through Oregon to the Canadian border. Clean Energy said it would continue to have access to supplies to sell to the growing customer base of its "Redeem" bio-methane fuel brand through a long-term contract with BP. "Demand for 'renewable' natural gas is growing quickly and BP is pleased to expand our supply capability in this area," said Alan Haywood, Chief Executive of BP's supply and trading business. "BP is committed to supporting developments towards a lower carbon future and, working with Clean Energy, we believe we will be well-positioned to participate in the growth of this lower carbon fuel in the US," added Haywood. Andrew Littlefair, Clean Energy's President and Chief Executive, said the company started its "Redeem" fueling business from scratch less than four years ago and it has grown it into a significant enterprise. "This transaction will help to take it to the next level. BP's investment in and focus on 'renewable' (bio-methane) natural gas supply will ensure that Clean Energy can meet the growing demand of our customers for low carbon, 'renewable' fuel," added Littlefair. "Clean Energy will buy 'renewable' natural gas fuel from BP and collect royalties on gas purchased from BP and sold as 'Redeem' at its stations. This royalty payment is in addition to any payment under BP's contractual obligation," the statement added. The assets which BP will acquire are Clean Energy's existing bio-methane production facilities in Canton in Michigan and North Shelby in Tennessee as well as its share of two facilities under construction in Oklahoma City and in Atlanta, Georgia.

BRITISH COLUMBIA, the Canadian Province, welcomed the decision by pipeline company TransCanada Corp. to inform the National Energy Board it was proceeding with the construction of the North Montney Mainline project to transport shale-gas to North American markets. If the NEB application is approved, TransCanada will be able to move forward with the construction of the pipeline, an estimated $1.4 billion investment. The North Montney pipeline was previously mostly linked to a final investment decision, still being considered, on the Pacific NorthWest LNG project of Malaysia's Petronas and to other plans for liquefaction plants on the coast. The Petronas partners in its proposed LNG venture are China's Sinopec, Japan Petroleum Exploration Co., Indian Oil Corp. and Petroleum Brunei. Canadian Federal approval of the TransCanada pipeline had originally been conditional on the entire Pacific NorthWest LNG venture moving forward, though now it can be a stand-alone project. TransCanada said it had secured new 20-year commercial contracts with 11 commercial producers and shippers for approximately 1.5 billion cubic feet per day of firm service. "This project adds significant pipeline capacity that connects new gas supplies from the prolific Montney basin to the Nova Gas Transmission Ltd (NGTL) system and will provide access to markets across North America," said Karl Johannson, TransCanada's Executive Vice President and head of natural gas pipelines. "This investment further affirms our commitment to build key natural gas infrastructure in BC and ensures that the NGTL system can continue to efficiently and competitively meet the transportation needs of our customers," added Johannson. Subject to regulatory approvals, TransCanada plans to begin construction in the first half of 2018, with facilities being phased into service over a two-year period, beginning in April 2019. "This is another significant development for the natural gas industry, showcasing both the market interest and economic advantage of our province's most-promising resource plays," said Rich Coleman, Deputy Premier of BC and Minister of Natural Gas Development. "Our government welcomes TransCanada's commitment to invest in this pipeline, securing a stronger future for First Nations and communities across the province," he added without mentioning LNG projects. The provincial government pointed out that it issued an environmental assessment certificate for the project on January 26, 2017. "There were 21 conditions imposed on the pipeline as part of BC's approval, strengthening safety and environmental management," it noted.

CHENIERE ENERGY, the owner of the sole operating US export plant on the Gulf Coast at Sabine Pass in Louisiana, has signed agreements with foundation shippers to support construction of a 200-mile interstate natural gas pipeline from Oklahoma to southeast markets. Cheniere's subsidiary, Midship Pipeline Co., has also launched a binding open season to solicit additional long-term commitments from natural gas producers and volume owners who wish to transport their resources to Louisiana and Texas. The company has already commissioned three liquefaction Trains at its Sabine Pass plant, each unit with a capacity of 4.5 million tonnes per annum. A total of six are planned for a total nameplate capacity of 27 MTPA. It is also developing a second export facility at Corpus Christi on the Texas Gulf Coast to produce an initial 13.5 MTPA of LNG. Cheniere unlike most other US LNG export plant developers produces its own cargoes for long-term customers - as well as volumes to market itself - rather than using the tolling method of selling liquefaction capacity to third parties for fixed fees. The Midship pipeline is being developed to create capacity connecting production from emerging resource plays in the Anadarko Basin in Oklahoma to the growing Gulf Coast markets. This will include Cheniere's own increasing requirements for LNG production. Midship will have a pipeline diameter of 36 inches and will have several laterals, compressor stations and interconnects that will provide receipts from processing plants and provide deliveries to Bennington, Oklahoma, the TexOk hub near Atlanta, Texas, and the Perryville Hub near Tallulah, Louisiana. The pipeline has secured commitments from subsidiaries and affiliates of Cheniere as well as the following companies: Devon Energy Corp., Marathon Oil Corp. and Gulfport Energy Corp. "We are pleased to help facilitate a market solution to producers as they continue to make exciting progress in this important resource basin," said Jack Fusco, Cheniere's President and Chief Executive. "Not only will the Midship project help meet the Anadarko Basin's need for additional natural gas takeaway and serve demand along the Gulf Coast, it also demonstrates the uniquely integrated market solution Cheniere can provide by leveraging our LNG platform along the entire value chain," the Cheniere CEO added. Cheniere said the open season bidding opportunities will run from March 17 until March 30. The company added that following the open season, the Midship project will submit its official Federal Energy Regulatory Commission application and current in-service targets in early 2019. "Cheniere would require acceptable commercial and financing arrangements, which may include project financings and offerings by it or its subsidiaries of debt or equity, and regulatory and other approvals before the proposed project begins construction," the statement said.

CHENIERE posted a net loss of $610 million for 2016, though forecast rising income in 2017 from the coming on stream of the third processing Train. Cheniere's annual net loss was lower

than the $975M loss registered in 2015 before the Sabine Pass plant began exporting cargoes in February 2016, setting up an income stream. On a quarterly basis Cheniere reported a profit of $109.7M, or $0.48 per share, for the three months to the end of December 2016, compared with net loss of $291M in the same three months of 2015. "The fourth quarter of 2016 was another milestone quarter for Cheniere, as we report financial results driven by nearly a full quarter of LNG production from the first two Trains at Sabine Pass," said Jack Fusco, Cheniere's President and Chief Executive. "Transition and execution will remain central themes for Cheniere in 2017, as we expect Trains 3 and 4 at Sabine Pass to begin commercial operations, with Train 3 having produced its first commissioning cargo in January. The financial and operational results we are reporting reflect our employees' steadfast dedication to execution on our goals," added Fusco. Each of the liquefaction Trains has a capacity of 4.5 million tonnes per annum of output and the Houston, Texas-based company will have nameplate capacity of 27 MTPA when all six Trains come on stream. It is also developing a second export facility at Corpus Christi on the Texas Gulf Coast to produce an initial 13.5 MTPA of LNG. "Based on the current construction schedule, we expect Trains 1 and 2 to reach substantial completion in 2019," Cheniere said of the Corpus Christi venture. Cheniere said total overall operating costs and expenses increased by $139.7M and $592.3M respectively during the three-month and 12-month periods in 2016 compared with 2015. "General and administrative expense during the three and twelve months decreased from the comparable 2015 periods, primarily due to the timing of share-based compensation recognition and the recognition of certain employee-related costs within restructuring expense," it added. Cheniere reported several one-off losses, including on early extinguishment of debt associated with the write-off of issuance costs by Sabine Pass Liquefaction and Cheniere Corpus Christi Holdings in connection with the refinancing of a portion of their credit facilities. Cheniere noted among its quarterly highlights, the first commercial delivery from the 20-year LNG sale and purchase agreement for Train one inherited by Royal Dutch Shell after its takeover of BG Group of the UK. The company also repaid some substantial debts linked to senior secured notes amounting to $420M and $1.66Bln.

CHICAGO BRIDGE and Iron, the US energy and LNG engineering and construction company, said it was optimistic for substantial backlog growth from new projects in the US and the Middle East during 2017 after posting an operating loss in 2016. CB&I said engineering and construction awards in the fourth quarter amounted to $325.6 million compared with $1.7 billion in the same three months of 2015. Its net loss from operations was $665.6M versus a loss of $65.7M in the three months of 2015. The annual loss from operations was down to $313.1M from $504.4M in the previous year. CB&I said that for the fourth quarter, adjusted net income was $85.6M, or $0.85 per diluted share. The company added that for the year, adjusted net income was $438.1M, or $4.23 per diluted share and adjusted operating income was $658.2M "The fourth quarter was impacted by charges for material increases in cost-to-complete estimates in our Engineering & Construction and Fabrication Services operating groups," said Philip K. Asherman, CB&I's President and Chief Executive. "Despite this result, operating cash flow was extremely strong both in the quarter and for the year. In addition, upon financial close we will allocate the entire proceeds from the recently announced divestiture of our Capital Services business to reducing debt consistent with our stated objective of optimizing the balance sheet for future growth," Asherman said. "I'm optimistic that stability in commodity prices and continuing development of major capital programs, particularly in

North America and the Middle East, will result in resumption of substantial backlog growth by mid-year of 2017," he added. Engineering revenue was up over 8 percent at $6.1Bln compared with $5.6Bln in 2015. The annual E&C contracts awarded were $3.1Bln during 2016 versus $6.03Bln in 2015, down 48 percent. Fourth-quarter net income was $34.6M compared with $227M in the same three months the previous year. CB&I annual net income was $658.2M versus $865.5M in 2015, a decline of 24 percent. Its E&C backlog was $9.9Bln in December 2016 versus $12.8Bln at the end of 2015.

CLEAN ENERGY Fuels Corp., one of the main LNG fuel distributors in the US, said its sales of gas fuel during 2016 amounted to 329.0 million gallons, a rise of 6.6 percent compared with the previous year. The company, based in Newport Beach, California, said it delivered 84.1M gallons in the fourth quarter of 2016, a 7.4 percent increase from the 78.3M gallons in the fourth quarter of 2015. The earnings were issued a week after UK major BP agreed to acquire the upstream bio-methane portion of the fueling business. The US company supplies LNG, compressed natural gas and bio-methane as trucking and transport fuel.

The forerunner company of Clean Energy was Pickens Fuel Corp., founded by US oil tycoon and LNG fuel pioneer T. Boone Pickens. Under the terms of the agreement, BP will pay $155 million for Clean Energy's existing bio-methane production facilities, its share of two new facilities and its existing third-party supply contracts for bio-methane made from waste. In the earnings, Clean Energy said revenue for 2016 was $402.7 million, a 4.8 percent increase from $384.3M in 2015. However, the company posted an overall net loss for 2016 amounting to $12.2 million as it continued its LNG and CNG station network build-out. The latest annual loss was lower than the $134.2M registered in 2015. The fourth-quarter net loss was $3.9M, lower than the loss of $50M logged in the same three months of the previous year. Volume-related revenue and revenue from station construction sales increased in 2016 compared with 2015. "The positive momentum continued in 2016 for Clean Energy," said Andrew J. Littlefair, Clean Energy's President and Chief Executive. "We continue to leverage our natural gas fueling infrastructure by increasing volumes while lowering capital expenditures and expenses," he said. "Clean Energy remains the market leader for the increasing number of fleets choosing to take advantage of natural gas and renewable natural gas as an immediate, affordable and environmentally friendly alternative vehicle fuel solution," added Littlefair.

CROWLEY MARITIME Corp., the US shipping line, has launched its newbuild Commitment Class ship "El Coqui", one of the world's first combination container and roll-on-roll-off vessels powered by liquefied natural gas. The launch took place at the VT Halter Marine shipyard in Pascagoula port in Mississippi. The LNG-fueled "El Coqui" is part of Crowley's $550 million project to expand and modernize the company's shipping and logistics services between Jacksonville in Florida and the US territory of Puerto Rico. Crowley pointed out that the vessel is named after a species of frog native to Puerto Rico and will now proceed through the final topside construction and testing phase before beginning service in the US Jones Act trade during the second half of 2017. The Jones Act requires vessels in domestic waterborne trades to be owned by American citizens, built in the US and crewed by US mariners. Fueling the ships with LNG will reduce emissions significantly, including a complete reduction in sulphur oxide and the emission of less carbon dioxide compared with other fuels and in line with new requirements for expanding Emission Control Areas in North American and globally. The Crowley LNG-powered ships will be part of only around 200 clean-fuel vessels in service worldwide and will be able to be re-fueled at a bunkering station currently under construction in Jacksonville. The facility is at the Jaxport's Talleyrand Marine Terminal and will soon receive two 260-ton, cryogenic LNG tanks constructed in Europe by US equipment maker Chart Industries. The Jaxport site is leased by Crowley and the bunkering facility is scheduled to be completed in several months and is adjacent to Crowley's operating terminal. Tom Crowley, company Chairman and Chief Executive of the family-owned shipping line, said the launch of the "El Coqui" at the VT Halter Marine yard was special for all those who had designed and constructed the ship."We are extremely appreciative of all the work that has been accomplished so far and look forward to the successful delivery of 'El Coqui' later this year and her sister ship, 'Taino' in the first half of next year," said Crowley. The company explained that the "El Coqui" and sister ship "Taino" will be able to transport up to 2,400 twenty-foot-equivalent container units (TEUs) and a mix of nearly 400 cars and larger vehicles in the enclosed, ventilated and weather-tight Ro/Ro decks. It said a wide range of container sizes and types can be accommodated for customers on the Florida-Puerto Rico trade route, ranging from 20-foot standard, to 53-foot by 102-inch-wide, high-capacity units, as well as up to 300 refrigerated containers. "The launch of the 'El Coqui' is a strong indication of our commitment to the success of our customer Crowley," said Paul J. Albert, CEO of VT Halter Marine. "Our thanks to both the shipbuilders of VT Halter Marine and the Crowley project team for all their hard work in delivering such a significant vessel. This is a great accomplishment for both teams. We very much appreciate this opportunity to build such a magnificent ship," stated Albert.

DAEWOO Shipbuilding and Marine Engineering of South Korea said it was awarded an order for two LNG carriers due for delivery in August 2019 and worth over $360 million to add to the multiple options sought by floating storage and regasification project company Excelerate Energy of the US. DSME said in a stock market statement that the deal included an option to build two more LNG carriers, which would double the value if confirmed, and gives the troubled shipyard something to show the bankers amid continued debt negotiations. The shipbuilding contract is the first for conventional ships by DSME in 2017 and comes as the troubled shipbuilder is scheduled to repay part of its huge debts in April. DSME and the other two major shipyards, Samsung Heavy Industries and Hyundai Heavy Industries are carrying substantial debts because of the slump affecting the shipping industry and the flow orders for newbuilds. For its part, DSME has to refinance up to 1 trillion won, or more than $850M of debt, that matures this year. State and commercial banks in Korea say the company has three repayments scheduled for 2017 comprising $350M in April, $262M in July and $175M in November. Analysts said DSME may be helped going forward by the potential large order from Excelerate amounting to around $1.6 billion. The US company signed a Letter of Intent with DSME in February 2017 for the delivery of up to seven FSRUs. Under the accord, Excelerate has taken the option to order one FSRU in the second quarter of 2017. Excelerate said it was looking to be able to respond to the market demand for natural gas as its existing fleet of nine FSRUs become committed to long-term projects. The initial specifications for the potential DSME orders are for FSRUs with 173,400 cubic metres of capacity and equivalent baseload send-outs. The US company last helped organize an FSRU for the first import project in Pakistan and has vessels scheduled for deployment in Bangladesh and Puerto Rico. Excelerate's agreement for a Bangladesh terminal will see it set up infrastructure at Moheshkali Island in the Bay of Bengal. DSME has said it hoped to finalize the letter of intent with Excelerate into a formal agreement before its next debt tranche is due in April.

ENERMECH of the UK has been awarded a pre-commissioning subcontract by Technip Oceania, part of TechnipFMC, on the Royal Dutch Shell Prelude floating LNG project under development for offshore northwest Australia. The work scope for EnerMech includes the pre-installation filling of the risers, riser leak testing, pressure monitoring of the umbilical and electrical steel flying lead during pipelay, and electrical flying leads and umbilical testing. The group is headquartered in Aberdeen with bases in the UK ports of Great Yarmouth and Bristol and has operations in Norway and in other oil and gas centres worldwide. EnerMech specialises in providing lifting and cranes as well as core services in valves, hydraulic products, processing, pipelines and umbilicals. The Prelude FLNG work will be conducted in-field, located approximately 230 kilometres from mainland Northwest Australia, with engineering and project management conducted from EnerMech's Perth Australia facility. "Experience of similar pre-commissioning work scopes in Australia and the high calibre of our Perth Australia based staff who have strong credentials in process, pipeline and umbilical contracts, put us in a good position to win this contract," said Jamie McIntyre, EnerMech's Australia Manager for Process, Pipelines & Umbilicals. "We are looking forward to continuing our

relationship with TechnipFMC in Australia and to working for the first time in-region on a project with Shell Australia as the end-client," added Jamie McIntyre.

Shell's Prelude FLNG project will monetize the Prelude and Concerto natural gas fields located about 475 kilometres offshore the Western Australian city of Broome, producing 3.6 million tonnes per annum of LNG. The liquefaction and processes equipment are on a hull constructed at the Samsung Heavy Industries shipyard in Geoje, South Korea, while the topsides were overseen by the now enlarged TechnipFMC. The Prelude FLNG facility has been designed to withstand the most powerful tropical cyclones. It will remain permanently moored at the Australian location for at least 20 years. Prelude is owned 67.5 percent by Shell and 17.5 percent by Japanese energy and LNG developer Inpex Corp. A further 10 percent is held by LNG buyer Korea Gas Corp. and 5 percent by CPC Corp. of Taiwan.

ENGIE, the French energy, utility and LNG trading and importing company, narrowed its net losses to 415 million euros ($437M) for 2016, though it took a massive hit of over $4 billion for impairments in the power market and one-off items as it restructured in the commodities downturn. The 2016 net loss was an improvement on the 4.6Bln euros in losses posted in 2015. The latest asset impairments that weighed on the European natural gas and utility player amounted to 3.8Bln euros. "These impairments mainly relate to the power production activities in merchant markets in Europe (1.9Bln euros) impacted by the decrease in prices, but also to the revision of the nuclear provisions in Belgium (1.0Bln euros) due to the change in the discount rate and to the market environment on some of its global businesses (600M euros)," Engie said. "Beyond an unfavourable impact of exchange rates mainly related to the pound sterling and the Brazilian real, this decrease was mainly attributable to lower commodity prices which impacted LNG and gas midstream activities, gas and electricity

sales businesses, exploration-production and power generation businesses," stated Engie. "The decrease was partially offset by the positive effect of slightly colder than average temperatures in France in 2016 compared with a very warm 2015," it said. Net revenues dropped 4.5 percent to 66.6bln euros from 69.8Bln in 2015. The French company said that gross earnings in its LNG and Global Energy Management division declined compared with 2015. This was mainly due to the fact that there was "a greater positive impact of revisions to gas supply conditions in 2015 than in 2016" and to the halting of LNG shipments from Yemen as of April 2015 because of the civil war. External LNG sales were stable and were the equivalent of 108 cargoes, though the division posted a loss. The impacts of the Yemen losses were partially offset by LNG sale opportunities in Asia in the fourth quarter of 2016. "The (LNG and energy management) business incurred a current operating loss - after the share in net income of entities accounted for using the equity method - of 74 million euros in 2016, representing a deterioration on both a reported and organic basis," it stated. Engie, whose Elengy subsidiary owns three import terminals in France, pointed to several positive events during the earnings period in its LNG operations. These included its inauguration of the first floating LNG import terminal in Turkey, deployed offshore Izmir in the form of the Floating Storage and Regasification Unit "Neptune". Engie also signed an agreement with the Dominican Republic LNG import terminal in the Caribbean to provide supplies for small-scale operators and fuel users in the region. "In China, Engie and Beijing Gas Group strengthen their strategic partnership in security of supply with a delivery of 10 LNG cargoes to Beijing," added Engie. The Engie Group anticipates "strong organic growth compared to 2016" during 2017 with a net recurring income share of between 2.4Bln euros and 2.6Bln euros. Engie's net debt stood at 24.8Bln euros at the end of December, down by 2.9Bln euros compared with 2015. "Our results for 2016 are robust, in line with guidance," said Isabelle Kocher, Chief Executive. "We are ahead of schedule on our 3-year transformation plan. In one year, we have already signed more than 50 percent of the planned disposals and identified 75 percent of the investments. We are focusing and accelerating the development of our three core businesses: low-carbon generation, global networks - mainly gas ones - and integrated solutions for our customers," stated Kocher.

EXXONMOBIL Corp. and Italian energy company Eni signed an agreement to enable the US major to acquire from Eni a 25 percent interest in the Area 4 block of the Rovuma Basin offshore Mozambique where LNG projects are planned for a cash price of around $2.8 billion. Eni currently holds a 50 percent indirect share in the block through a 71.4 percent stake in Eni East Africa, which owns 70 percent of the Area 4 concession. The deepwater Area 4 block contains an estimated 85 trillion cubic feet of natural gas, which will provide resources for world-class LNG projects in which the partners expect to invest tens of billions of dollars. The acquisition will be completed following satisfaction of a number of conditions, including clearance from Mozambican and other regulatory authorities. "This deal represents material evidence of our exploration strategy based on the early monetization of our exploration discoveries, as a part of our 'dual-exploration' model," said Eni Chief Executive Claudio Descalzi. "Through this strategy, Eni has been able to cash in more than $9 billion in the last four years. Moreover, the agreement confirms the world class quality, production potential, technical and financial robustness of the entire project," added Descalzi. Darren W. Woods, Chairman and Chief Executive of ExxonMobil, said the asset is a major addition to the company's global development portfolio. "This strategic investment will enable ExxonMobil's LNG leadership and experience to support development of Mozambique's abundant natural gas resources," said Woods. "Our industry-leading project execution, advanced technologies, financial strength and marketing capabilities will help deliver reliable, affordable energy to customers and create long-term economic value for the people of Mozambique, project partners and ExxonMobil shareholders," he stated. Eni will continue to lead the Coral floating LNG project and all upstream operations in Area 4, while ExxonMobil will lead the construction and operation of natural gas liquefaction facilities onshore. This operating model will enable the use of best practices and skills within Eni and ExxonMobil with each company focusing on distinct and clearly defined scopes while preserving the benefits of a fully integrated project. Following completion of the transaction, Eni East Africa will be co-owned by Eni (35.7 percent), ExxonMobil (35.7 percent) and CNPC of China (2.6 percent). The remaining interests in Area 4 are held by the state energy company of Mozambique (10 percent), Korea Gas Corp (10 percent) and Galp Energia of Portugal (10 percent).

EXXONMOBIL Chief Executive Darren Woods is expanding the energy major's capacity along the US Gulf Coast through planned investments of $20 billion over a 10-year period to take advantage of the American energy revolution, including the LNG export build-out. Woods, whose predecessor Rex Tillerson joined the administrations of US President Donald Trump as Secretary of State, said the projects at 11 proposed and existing sites are expected to generate thousands of new high-paying jobs and increased economic activity in Texas and Louisiana. Woods explained his plan at a US energy conference in Houston. The projects include the Golden Pass LNG export joint venture in Texas being developed by ExxonMobil, Qatar Petroleum and ConocoPhillips and already authorized by the US Federal Energy Regulatory Commission. Golden Pass LNG already exists as an import terminal and will add three liquefaction Trains with a total production capacity sufficient to produce 15.6 million tonnes per annum of LNG. The FERC has also approved permits for the associated 2.6 miles of the proposed Golden Pass Pipeline linking the terminal to the major pipelines bringing shale-gas resources to the US Gulf Coast. "The United States is a leading producer of oil and natural gas, which is incentivizing U.S. manufacturing to invest and grow," said Woods. "We are using new, abundant domestic energy supplies to provide products to the world at a competitive advantage resulting from lower costs and abundant raw materials. In this way, an upstream technology breakthrough has led to a downstream manufacturing renaissance," stated the ExxonMobil CEO. "ExxonMobil is strategically investing in new refining and chemical-manufacturing projects in the US Gulf Coast region to expand its manufacturing and export capacity. The company's growing Gulf expansion program consists of 11 major chemical, refining, lubricant and liquefied natural gas projects at proposed new and existing facilities along the Texas and Louisiana coasts. Investments began in 2013 and are expected to continue through at least 2022," added Woods. Woods said that ExxonMobil's Gulf expansion projects are expected to provide long-term economic benefits to the region, noting the creation of direct employment opportunities and the multiplier effects of the company's investments. "Importantly, growing the Gulf also creates jobs and lasting economic benefits for the communities where they're located," Woods said. "All told, we expect these 11 projects to create over 45,000 jobs. Many of these are high-skilled, high-paying jobs averaging about $100,000 a year. And these jobs will have a multiplier effect, creating many more jobs in the communities that service these new investments," the CEO added.

FORTUNA FLNG, the project offshore Equatorial Guinea in West Africa, remains firmly on schedule for a final investment decision in the next few months. That's according to the project's developer, the UK company Ophir Energy, which has just issued its latest update on the venture and its other activities in its full-year earnings report. "A green light for Fortuna, expected in mid-2017, will unlock 345 million barrels of oil equivalent for monetisation," said Ophir Chief Executive Nick Cooper. "Subject to the volume of gas we choose to term up, this could treble our Group 2P reserves in the process. "Plans to sweat our Asian assets have the potential to monetise up to a further 80 MMboe over the next three years," added Cooper. "All activities are now focused on finding or developing hydrocarbons at the lowest cost and monetising promptly and swiftly; thereby maximising the margin realised for shareholders," the CEO explained. The company has a joint venture agreement to develop the Fortuna FLNG project with Norwegian shipping and project company Golar and oil services firm Schlumberger to produce free-on-board cargoes priced at around $6 per million British thermal units. Ophir signed an accord in November 2016 with a joint subsidiary of Golar and Schlumberger called OneLNG. The shareholders agreement established a joint operating company to develop the Fortuna FLNG project from feed-gas resources in Block R offshore Equatorial Guinea using Golar's production hull technology. OneLNG and Ophir have 66.2 percent and 33.8 percent ownership

respectively of the joint venture entity. The Fortuna FLNG company is now working on facilitating the financing, construction, development and operation of the project, which will own Ophir's share of the Block R licence and the "Gandria" FLNG vessel. "In Equatorial Guinea, we have made material progress toward completing and financing an LNG value chain in the context of a challenging market," said Cooper. "After frustrations in the first half of 2016, an innovative approach to value chain partnering and risk sharing unlocked the problem," added the CEO. "A constructive dialogue with our midstream partner Golar LNG enabled us to find a solution that satisfies the trends emerging in LNG pricing, contracting, financing and risk- sharing," he said. Ophir's strategy is to monetise "smartly" and it is also moving forward on a possible LNG project in Tanzania, East Africa. "In Tanzania, we have to date monetised the majority of our interests and have delivered a material return on our historic investment. In 2016, we saw a renewed push from the Tanzanian Government to deliver the LNG project and the introduction of a new operator in Shell. Both factors should accelerate the project towards an FID later this decade. In 2017, our focus in Tanzania remains to maximise shareholder returns from our remaining 20 percent stake," said Cooper. Ophir said revenue from its main production activities in Indonesia and Thailand for 2016 was $107 million, down from the $178M posted in 2015. The London-listed company's cash on the balance sheet was $360M compared with $615M, including short-term cash deposits. In 2016, Ophir delivered the start-up of the Kerendan gas field in central Kalimantan, Indonesia. The company also has a 100 percent operated interest in the Bualuang oil field in the Gulf of Thailand. Ophir said that in 2016 working interest production was in line with guidance at 10,800 barrels of oil equivalent per day (boepd). "This comprised 8,700 bopd from Bualuang and our first contribution from Kerendan which averaged 200 boep/d for

the year. Bualuang delivered positive post-tax funds flow of $58M or $18 per barrel (2015: $106M or $34 per barrel). The Kerendan field came onstream in August, with pre-production operating costs being charged to the income statement in 2016, Kerendan utilised net funds of $8M," said Ophir. "At the same time, Ophir will be resuming operated exploration at the Ayame-IX well in Côte d'Ivoire and is expected to spud in May 2017. With production, development and exploration programmes gathering pace, Ophir is moving towards our ambition of being a sustainable explorer," the company added.

GIIGNL, the France-based International Group of Liquefied Natural Gas Importers has just released the latest edition for 2017 of its "GIIGNL LNG Custody Transfer Handbook", addressing new commercial and technical developments in the cargo delivery process. The Handbook provides practical guidance on the equipment and methodology for determining the thermal energy of LNG transported by ship for the specific purpose of title transfer. For this updated version, GIIGNL had mandated its Technical Study Group to consult with the LNG industry on a worldwide basis. The goal was to respond to the rapidly changing market conditions and to address the latest commercial practices. The GIIGNL has an international focus and its membership currently includes 78 member companies located in 25 countries, representing nearly all companies in the world active in the import, terminalling and regasification of LNG. The new version of the Handbook includes measurement procedures and equipment in relation to new technical operations such as: partial (un)loading; reloading at LNG import terminals; ship-to-ship LNG transfer; and small ship-to-shore LNG operations. The 2017 version provides answers and solutions for setting up slightly altered or new custody transfer procedures. Stijn Maelfeyt, Plant Operations Manager at Fluxys LNG and leader of the working group of experts, said: "The reason for the proposed changes is of a truly technical nature and GIIGNL considers it as its duty to inform the LNG industry about this and its impact." According to Vincent Demoury, General Delegate of GIIGNL: "The Handbook is intended to serve as a reference manual but not as a standard or a specification. It has been updated to include the most advanced measurement technology, operational practices and international standards available to or used by all parties involved in custody transfer operations." Currently accepted LNG custody transfer requires the accurate measurement of the volume of LNG in the ship's storage tanks at the beginning and end of the transfer, taking account of the ship's list and trim, the chemical composition of the LNG and its temperature. From these basic measurements, the density and gross calorific value are calculated by standard formulae, leading by multiplication to the total energy transferred.

HYUNDAI HEAVY Industries, the South Korean shipbuilder, said it received an order to construct four oil tankers for Russia with liquefied natural gas fuel as part of the propulsion system. Sovcomflot, the largest Russian shipping line, ordered the four ships of 114,000 deadweight tons each. Hyundai said the contract for the midsize Aframax crude tankers was worth around $240 million. The Russian order is a boost for Hyundai as the company and the other two large Korean shipbuilders, Daewoo Shipbuilding and Marine Engineering and Samsung Heavy Industries, are carrying substantial debts because of the slump affecting the shipping industry and the flow of orders for newbuilds. The Aframax crude tankers to be built in Korea have been jointly developed by Sovcomflot and Royal Dutch Shell to reduce greenhouse gases such as nitrogen oxide and carbon dioxide. Hyundai said the ships will be constructed by its subsidiary Hyundai Samho Heavy Industries Co. which specializes in making oil tankers. "The first ship is expected to be delivered to Sovcomflot in the third quarter of 2018, with the last in the first quarter of the following year," Hyundai said. The establishment of Emissions Control Areas (ECAs) in Europe and North America has proven to be a powerful driver for owners and operators to opt for ships with reduced pollution from fuel. The International Maritime Organisation (IMO) has also drawn up regulations for a cleaner shipping industry. The IMO said that from 2020 it would introduce a global marine fuel sulphur limit of 0.5 percent. In addition, China is introducing ECAs in parts of the Pearl River Delta, the Yangtze River Delta and the Bohai region and affecting ports such as Guangzhou, Shanghai and Nantong.

INEOS, one of the largest global chemical companies and the importer of the first US shale-gas cargo into the UK, is now broadening its presence in British shale gas exploration to lessen its future reliance on imports. The first shipment of US shale gas in the form of ethane needed for chemical plant feed-stock was unloaded at the Grangemouth petrochemical plant in Scotland in September 2016. The 27,500 cubic metres capacity Evergas LNG-LPG tanker "JS Ineos Insight" brought the shipment to the Grangemouth facility located on the banks of the River Forth from a plant at the Marcus Hook port in Pennsylvania. However, Ineos has just broadened its UK shale-gas interests by acquiring more licences to take ethane and other derivatives from its own shale-gas production. Ineos said its shale gas subsidiary plans to drill two coring tests in the UK where it recently expanded its holdings to more than 1.2 million acres by acquiring all onshore exploration and development licence interests held by French energy and utility company Engie. The Ineos Shale unit said the transaction involved minority interests in 15 licences, seven of which Ineos holds an existing interest in. The remaining eight complement the company's existing licence interests in Yorkshire, Cheshire and the East Midlands. Three of the licences are operated by Ineos, eight by IGas Energy and four by Cuadrilla. Ineos, whose main offices are in the UK and Switzerland, has said it requires shale gas to secure a supply of competitively priced energy and feedstock for its UK and European petrochemicals businesses. Over the past few years as the North Sea's supply of ethane has dwindled Ineos has been forced to run its plant at Grangemouth at half capacity with limited supply of the raw materials necessary to produce its products. With an abundant supply of ethane emerging from the US from shale gas, Ineos has now invested in new import terminals at its sites in the UK and Norway to import US ethane from shale gas. Ineos has said that importing gas from the US is the only current way to bring in sufficient supplies to maintain a competitive global operation for its speciality olefins and polymers business. Ineos founder and Chairman Jim Ratcliffe believes shale gas could revolutionise UK manufacturing as it has done in the US. "I believe Ineos has the resources to make it happen, the skills to extract the gas safely and the vision to realise that everyone must share in the rewards," Ratcliffe has said. Ineos is advancing with its shale-gas plans after announcing it would give 6 percent of its shale revenues to homeowners, landowners and communities who live above its shale-gas operations. It anticipates being a major player in the UK shale-gas industry and believes it will give away more than 2.5 billion pounds ($3Bln) over the life of its shale business. The sharing of shale-gas profits with residents near production facilities is commonplace in the US.

JAPANESE liquefied natural gas imports jumped for a second straight month in 2017, increasing by 4.8 percent in February with prices also rising for both long-term contracted cargoes and spot shipments. More cargoes were shipped in February from Australia and the spot market while volumes imported from Asia and the Middle East dropped compared with the same month of 2016. Japan's LNG imports last month amounted to 7.79 million tonnes compared with 7.43MT in February 2016. The nation's shipments of the fuel had jumped 14.6 percent in January to 8.30MT after falling in the December peak winter season. Thermal coal imports declined by 1.4 percent to 8.89MT after soaring by over 10 percent in January 2017, showing that LNG was preferred to coal for power generation. The latest LNG imports cost Japan 359.16 billion yen ($3.21Bln), a rise of 1.6 percent versus February 2016 when the cost was 353.48Bln yen ($3.16Bln). The Finance Ministry provisional figures featured US imports for a second successive month. The cargoes from the US Gulf Coast amounted in February to 127,000 tonnes compared with 211,000 tonnes in January 2017. The Ministry data also showed that Asian imports from nations such as Malaysia and Indonesia, Papua New Guinea and Brunei dropped by 12.9 percent to 2.21MT. Imports from the Middle East region fell by 18 percent compared with February 2016. The shipments from countries like Qatar, the United Arab Emirates and Oman totalled 1.68MT. Monthly Russian shipments, mostly from the Sakhalin Island plant in the Far East, more than doubled in February versus the year-ago month to total 844,000 tonnes. The balance of February LNG imports from other nations in the preliminary figures amounted to 2.92MT, covering shipments from countries such as Australia and Nigeria, as well as from the spot market.

Japan's annual LNG imports had declined for a second year in 2016 as shipments from the Middle East fell and were offset by more cargoes from the Asia-Pacific region and the spot market. The 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. The year before the Fukushima disaster, after which most of the nation's nuclear power capacity was shut down, Japan imported 70.00MT of LNG. In 2011 when the disaster occurred in March, the annual LNG imports were 78.53MT, followed by 87.31MT in 2012, 87.49MT in 2013 and the record 88.51MT in 2014. Japan said on March 14 that the average price of delivered spot LNG cargoes in February 2017 jumped to their highest level in two years to reach $8.80 per MMBtu, $1.90 per MMBtu higher than the $6.90 per MMBtu price logged in the same month a year ago. Japanese spot cargoes were last at a higher price than now in February 2015 when they were recorded at $10.70 per MMBtu on a delivered basis. The 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.

JORDAN COVE liquefied natural gas export venture and its affiliated 230-mile Pacific Connector transmission pipeline in the northwest state of Oregon are viewed as long-term projects for Calgary-based Veresen Inc., with first LNG cargoes unlikely before 2024. "The venture planned for Coos Bay would only move forward if it was fully contracted with customers," according to Don Althoff, President and Chief Executive of Veresen. According to the latest plans, Jordan Cove will have a capacity to liquefy about 7.8 million tonnes per annum of LNG exports for Asia. "Following the Federal Energy Regulatory Commission decision to deny the request for rehearing on December 9, 2016, the board has undertaken a thorough review of the Jordan Cove LNG project, including engagement with the FERC to gain greater visibility into a re-filing process," the CEO said during a post-earnings conference call. "Discussions have taken place with existing and potential buyers as well as an evaluation of alternatives for the project to create the most value on a risk-adjusted basis," Althoff added. "Veresen will continue to pursue the Jordan Cove LNG project on the basis of the constructive nature of discussions with both existing and potential buyers. The project development budget for 2017 will remain at US$30 million, with the expectation that the Jordan Cove project will finalize agreements with existing buyers and secure additional off-takers. This would position the project for a potential final investment decision in 2019 with an in-service date in 2024," said the CEO. Jordan Cove was given permission by the FERC in February 2017 to file a new application with an amended design that is expected to improve its chances of being approved. The new filing followed project design changes by Veresen. Jordan Cove has now formally removed its proposal to construct a 420-megawatt power plant adjacent to the facility. Veresen said that removing the power plant from the plan results in a facility that can be more efficiently and effectively operated with a smaller infrastructure footprint. In March 2016, the project signed a preliminary LNG supply deal with Japan's JERA Co. Inc., a joint venture between Tokyo Electric Power Co and Chubu Electric. Jordan Cove subsequently signed a second preliminary supply accord in April 2016 with the Japanese trading house Itochu Corp.

KINDER MORGAN, the US pipeline company, has taken investment fund firm EIG Global Energy (EIG) as its partner in the US LNG export project at Elba Island in the state of Georgia. Kinder said EIG had purchased a 49 percent joint venture participation in Elba Liquefaction Co. EIG Global Energy Partners for an upfront cash payment of around $385 million and has agreed to fund its share of future capital expenditures under commissioning of the LNG plant. Elba Island is an existing LNG import terminal being transformed into an export plant to produce an initial 2.5 million tonnes per annum of LNG. Royal Dutch Shell was the former partner of Kinder in the Elba island project and while it sold its stake, it remains the main customer for the completed venture. The Elba Island project involves the installation of 10 small-scale liquefaction units and modifications to the terminal infrastructure. Under the current schedule, the Georgia liquefaction plant could be producing LNG by the end of 2018 or early 2019. Kinder awarded the engineering, procurement, construction, commissioning and start-up contract in April 2016 to the US subsidiary of Japan's IHI Engineering & Construction, based in Houston, Texas. The existing terminal on Elba Island is about eight miles upstream from the mouth of the Savannah River. It was first authorized by the FERC in 1972 as an import facility. "EIG has agreed to fund its share of future capital expenditures necessary to complete construction and commissioning of the liquefaction facility. The total project cost is estimated to be approximately $1.3 billion, excluding capitalized interest," Kinder said. Steve Kean, Kinder Morgan President and Chief Executive, said he was excited that EIG will become an equity owner as construction continues at Elba Island. "The project, which began construction on November 1, 2016, is supported by a 20-year contract with Shell," added Kean. "As we have told the market in past months, this JV is another strategic step towards achieving our stated goals of strengthening our balance sheet and positioning the company for long-term value creation," Kean said. Wallace Henderson, Managing Director of EIG, said Elba Island was a tremendous project. "It builds on our long-standing and extensive experience in LNG and LNG-related infrastructure," said Henderson. "We are delighted to partner with Kinder Morgan and its outstanding development team to make the Elba Liquefaction Project a reality," he added. EIG specializes in private investments in energy and energy-related infrastructure on a global basis and had $14.4 billion under management as of the end of 2016. Initial liquefaction units at Elba Island are currently expected to be placed in service in mid-2018, with final units coming on line by early 2019.

LNG LTD, the Australian developer of the Canadian Bear Head export project in Nova Scotia, has completed Transport Canada's technical review of marine terminal systems and trans-shipment sites. The Bear Head liquefaction plant is to be constructed on the shore of the Strait of Canso on the Atlantic Coast in Richmond County, Nova Scotia. The proposed facility will comprise an initial development of an 8 million tonne per annum facility, with the capacity and approvals for further expansion. LNG Ltd explained that the review was

mandated under the separate environmental assessment process to identify navigational and marine transportation-related recommendations to support a safe shipping environment. Greg Vesey, LNGL's Managing Director and Chief Executive, said the review was "an important regulatory component" that furthers Bear Head LNG's goal to be the leader in helping Nova Scotia realize the LNG opportunity, benefiting the province and community. The company said these recommendations and observations relate to the future operations on the maritime routes by LNG carriers and tugboats around the approaches to the terminal and the facility itself. "Bear Head LNG will address and comply with all recommendations throughout the life of the project," said Vesey. "Our focus is to provide overseas markets with access to North America's natural gas resources based on competitive economics," he added. "Bear Head is uniquely positioned to provide liquefaction services to Western Canadian, the Northeast US and offshore Nova Scotia resource owners desiring to sell natural gas to the global LNG market," added Vesey. The Nova Scotia venture is already in possession of all other federal and provincial permits such as those to build the plant, import feed-gas from the US and export processed cargoes overseas. LNG Ltd is also developing the Magnolia liquefaction plant in Louisiana on a 115 acres site next to the Calcasieu Shipping Channel. The company has said it is awaiting some further firm LNG volume commitments in the next wave of global demand before moving forward and building its two North American plants.

MARSHALL ISLANDS, the Pacific republic and its (RMI) registered fleet, including a growing number of liquefied natural gas carriers, is making big advances. The RMI fleet now stands at 223,262,177 deadweight tons (DWT), making it the second-largest registry in the world in terms of DWT after Panama and ahead of Liberia, Hong Kong and Singapore. Marshall Islands flags fly on the world's largest LNG carriers such as the 261,700 cubic metres capacity Q-Max "Al Ghuwairiya" and the 210,000 cubic metres capacity Q-Flex vessel "Al Aamriya", which transport the fuel for Qatar. It also flies on many of the most modern LNG average-sized carriers owned by European shipping lines such as Greece's Dynagas and its ships like the 160,000 cubic metres capacity "Clean Ocean". Additionally, the RMI flag is carried on floating storage and regasification units deployed as import terminals such as the "Hoegh Grace" FSRU chartered for the South American nation of Colombia. The Marshall Islands is a wide spread chain of volcanic islands and coral atolls in the central Pacific Ocean and is located between Hawaii and the Philippines. Its best known islands are Bikini atoll, used as a ship graveyard after the World War II and now a popular wreck dive site, and Majuro atoll, the largest settlement and the RMI capital. International Registries Inc. has provided administrative and technical support to the RMI Registry since 1990. "This is a very significant milestone for the RMI Registry," said Bill Gallagher, President of IRI. "A strong legislative framework, customer driven service ethos, and a commitment to quality have all been key to our continued success," he continued. "From long-standing traditional shipowners, particularly our standing as the number one flag for Greek owners, to a new wave of Chinese leasing companies, the RMI Registry is the registry of choice for owners looking for an innovative and quality driven partner," he stated. "The RMI is not only the world's second-largest registry, but the Greek shipping industry's leading flag as well," he added. "The RMI has been gaining market share year-on-year and the flag today has 791 ships totaling 62,190,301 DWT (over 18.9 percent of total DWT of the Greek owned fleet) in its registry, making it the largest flag used by Greek-controlled ships," added Gallagher. Theo Xenakoudis, who is Director of Worldwide Business Operations and Managing Director of the office in the Greek port of Piraeus, explained the attraction of the RMI Registry. "Prior to registration, we vet the owner, operator and vessel before acceptance in the RMI Registry and during the vessel's time in the Registry we continue to conduct risk assessments and work with our owners and operators to ensure their vessels meet the Registry's quality standards," said Xenakoudis. "This process along with our service-oriented philosophy has ensured the RMI Registry has maintained its excellent reputation and as such has attracted quality owners, including the Greek owners to the RMI flag," he added. The RMI Registry has received preliminary confirmation that it will continue its United States Coast Guard (USCG) Qualship 21 status for 2017. "This is the 13th year in a row that the RMI Registry has held its Qualship 21 status," Gallagher pointed out. "It's significant because this achievement is no easy undertaking for a major registry, whose ships make thousands of US port calls," he added. "The Qualship 21 designation means that ships flying the RMI flag are less likely to be detained in US ports, which assists owners and operators in keeping their ships moving," Gallagher explained.

OIL SEARCH, a stakeholder in the Papua New Guinea LNG plant and the joint venture planning its expansion, has released mixed results from the latest field drilling for additional feed-gas resources onshore the Oceania nation. The latest results come after the "substantial uplift" recorded earlier in 2017 in the natural gas resources for additional LNG production. Oil Search gave a positive outcome from the test operations at the Muruk 1ST1 well drilled to a depth of 3,754 metres. "The well drilled through a fold axis, resulting in the Toro reservoir being penetrated twice. Preliminary log data analysis indicates that the reservoirs are gas bearing," Oil Search said. "After plugging back the ST1 wellbore, Muruk 1ST2 was kicked off from 3,470 metres to drill a near-vertical wellbore, down the inferred steeply dipping fold limb, to extend the gas column," said the report. Oil Search is operator of the Muruk well in which an affiliate of ExxonMobil Corp. also holds a stake along with Australian energy company Santos. However, the news was not positive after the latest appraisal well test on the Antelope Deep exploration target at the end of February. "The Antelope 7ST1 well was drilled to 2,300 metres, the total depth for the appraisal component of the well. The well did not encounter carbonates, in line with Oil Search expectations. The well was subsequently deepened, to test the Antelope Deep exploration target and at the end of February was at a depth of 2,773 metres. A 7-inch liner has been run and the forward plan is to acquire vertical seismic profiles prior to coring and drilling ahead in a 6-inch hole to a provisional total depth of 3,000 metres," the report added. The Antelope 7ST1 well is operated by French energy company Total and other shareholders include Oil Search and ExxonMobil. The existing two Trains at the PNG LNG plant, located northwest of the capital Port Moresby, produced at an average rate of 7.9 million tonnes per annum during 2016 compared with their combined nameplate capacity of 6.9 MTPA. An independent gas certification of the Elk-Antelope fields, which would provide additional LNG production for PNG, took place in 2016. Together with existing resources and the upgrade in PNG LNG reserves, the certification supported Oil Search's view that there are sufficient gas resources available to support further expansion of PNG LNG production as well as two new PNG LNG-sized Trains. Oil Search, whose main oil and gas operations are centred in PNG, also said its 2017 annual meeting would be held in the ballroom at the Crowne Plaza Hotel in Port Moresby on Friday 19 May at 9:30am (Port Moresby time).

PETRONAS, the Malaysian energy company, has signed an LNG supply agreement with Japanese utility Hokkaido Electric Power for a period of 10 years that will see shipments delivered to one of Japan's newest and expanding import terminals. Under the terms of the agreement, the Malaysian LNG subsidiary of Petronas will deliver up to 130,000 tonnes of LNG per annum to the Ishikari import terminal where two utilities, Hokkaido Electric and Hokkaido Gas Co, share capacity. Malaysian LNG Chairman Mohd Anuar Taib said the 10-year accord to supply Hokkaido Electric demonstrated the country's commitment to providing long-

Diary of events

LNG 2nd International Summit
April 24-25, 2017
Cannes, France
http://lngsummit.org

Flame Natural Gas & LNG Conference
May 8-11, 2017
Hotel Okura, Amsterdam,
The Netherlands
https://energy.knect365.com/flame-conference

Canada LNG Conference & Exhibition
May 16-18, 2017
Vancouver Convention Centre East Building, Canada Place, Vancouver, Canada
www.Canadalngexport.com

World LNG & Gas Series 15th Americas Summit
June 20-23, 2017
The Houstonian Hotel,
Houston, Texas, USA
http://lngamericas.cwclng.com/

term LNG solutions to its customers. "We would like to thank HKE for the trust placed in Petronas for a secure and reliable supply of this cleaner energy source and we look forward to building this relationship into the future," said Taib. The contract signing ceremony was held in the Malaysian capital Kuala Lumpur, with Hokkaido Electric represented by Executive Vice President Yutaka Fujii. MLNG operates the Petronas LNG complex in Bintulu, Sarawak, one of the world's largest and where a new Train 9 recently began exporting shipments. The nine-Train facility now has combined annual production capacity of about 30 million tonnes. The Malaysian cargoes will be delivered to the Ishikari import terminal in Hokkaido, Japan's main northern island. The Ishikari terminal completed the commissioning of a second storage tank of 200,000 cubic metres capacity in 2016 and has begun construction of another tank with 230,000 cubic metres of capacity. Ishikari, which takes its name from the Ishikari River on which it stands, is one of Japan's newest and began commercial operations in 2012. Two of the storage tanks belong to Hokkaido Gas Co., including the first one put into operation of 180,000 cubic metres capacity, while two others still to be completed will be owned by Hokkaido Electric. It is the only large-scale LNG import base in Hokkaido, whose capital is Sapporo, and mainly imports cargoes from Sakhalin Island in the Russian Far East and from Australia. The Ishikari terminal has been operating for four years and also has a berth for coastal LNG vessels and a truck-loading facility. Ishikari LNG terminal is being expanded to support future demand from the Ishikari Bay New Port gas-fired power plant currently under construction. The power plant comprises three 569-megawatt gas-fired power units. The start of commercial operations for the Ishikari Bay generating plant is scheduled for February 2019 and will boost gas-fired power capacity in the continued absence of most nuclear power.

QATAR GAS Transport Co., the Qatar LNG carrier operator also known as Nakilat, gave an upbeat message at its annual meeting in the Qatari capital Doha as it continued the process of taking back all its vessels from the operatorship of the Shell shipping unit and posted an annual net profit of 955 million Qatari riyals ($262M). "Despite the volatile market condition, Nakilat continued to achieve growth and development across our various operations, capitalizing on the strength of our integrated businesses and talents within the organization," said Nakilat Managing Director Abdullah Fadhalah Al Sulaiti. Nakilat is in the midst of the largest ever transition of LNG fleet operations. It involves 25 vessels which have so far delivered more than 320 million cubic metres of Qatar's LNG to over 20 countries. Shell has provided a range of shipping services to Nakilat's LNG fleet since it was established in 2006. "We successfully consolidated the management of four wholly-owned LNG carriers to our in-house ship management arm, Nakilat Shipping Qatar Limited, in the last quarter of 2016, and embarked on an organization-wide cost optimization exercise to further enhance synergies," added Al Sulaiti. "These initiatives together with our sound business strategy have formed a solid foundation for Nakilat to achieve its vision to be a global leader and provider of choice for energy transportation and maritime services," he said. Shell had previously provided ship management for 14 Q-Max and 11 Q-Flex LNG carriers as well as Shell's shipping expertise. The fleet's vessels comprise the 266,000 cubic metres capacity Q-Max carriers and the 210,000 cubic metres capacity Q-Flex ships. The fifth vessel to be handed back from Shell's management is the Q-Max LNG carrier "Al Dafna". The 266,366 cubic metres capacity "Al Dafna" is wholly-owned by Nakilat and chartered by RasGas, which itself is merging with Qatargas. The LNG fleet is being transitioned in three phases. When the transfer accord was signed in October 2016, Nakilat expressed its thanks to Shell for its professional management of the fleet over the previous eight years and was determined to uphold the same excellent standards for the vessels.

SHELL has formally withdrawn its plans for a Canadian liquefied natural gas liquefaction and export plant inherited as part of its acquisition of BG Group of the UK and located on Ridley Island near that port of Prince Rupert in British Columbia. However, the Anglo-Dutch company will leave its LNG Canada joint venture planned for near Kitimat in BC on the table, though with no progress being made for now. Shell had made no advances with the BG Prince Rupert LNG proposal after its takeover. "The Prince Rupert LNG project has been part of a global portfolio review of combined assets, which resulted in the decision to discontinue further development," Shell said. Shell said it had decided that the Prince Rupert project had been assessed and was not being developed and the company was withdrawing from BG's lease arrangements at the site. Shell had also announced it was selling most of its oil sands assets in the province of Alberta to Canadian Natural Resources Ltd. as part of a US$8.5 billion sale agreement. The government of Canadian federal Prime Minister Justin Trudeau with its aggressive anti-hydrocarbons policies has led many international oil and gas companies to re-assess their investments. While BC province itself formerly had 20 LNG export ventures on the table, there are now fewer than 10 proposed for the whole of Canada and the federal government's far-reaching environmental mitigation demand will make them uneconomic with oil under $60 a barrel. The Shell-led LNG Canada project has also had its final investment decision postponed indefinitely. Shell's partners in the LNG Canada venture are three of the largest Asian companies involved in LNG, Korea Gas Corp., Chinese energy group PetroChina and Japanese trading house Mitsubishi Corp. Canada's National Energy Board in January 2016 had awarded its first 40-year LNG export licence to the Shell-led venture. Shell said while pushing back its FID that LNG Canada remained a promising opportunity at some time in the future. "This project continues to be actively progressed by Shell and the joint venture participants as an opportunity to bring Canadian gas resources to the growing global gas markets," Shell added.

SONATRACH, the Algerian state energy company, has been called on by the Algerian government to move forward and adapt to changes after the appointment of a new chief executive three months after an unscheduled shutdown of liquefied natural gas production and as a venture to increase gas pipeline supplies to Europe is scheduled to come on stream. Sonatrach has named Abdelmoumen Ould Kadour as the company's new chief executive, replacing incumbent Amine Mazouzi who had served in the role for two years. Algerian Minister of Energy Noureddine Boutarfa announced the change after a Sonatrach board meeting, though gave no specific reason why Mazouzi was departing and Kadour taking his place. However, Energy Minister Boutarfa called on the new CEO of Sonatrach "to act responsibly and with full confidence to make quality changes allowing Sonatrach to evolve and flourish in a good business climate, conducive to initiative taking and decision making". The minister also said the CEO and other senior executives of Sonatrach should "show an unfailing commitment to preserving the group's interests and managerial practices to allow it to adapt to changes." While Sonatrach boosted overall oil and gas output in the first two months of 2017, there were unscheduled outages at its two LNG export plants on the Mediterranean Coast, which reduced deliveries to customers in France, Spain, Greece and Turkey during early January. The Algerian energy company has the capacity to produce more than 20 million tonnes per annum from its Arzew and Skikda liquefaction plants, though rarely has the feed-gas on tap. Newly appointed Kadour is described as holding a chemical engineering degree from the Massachusetts Institute of Technology. He had previously worked at Brown & Root Condor, an Algiers-based company which operates as a subsidiary of Sonatrach designing and constructing petrochemical and oil and gas production facilities in Algeria. Under outgoing CEO Mazouzi, natural gas output hit 22.4 billion cubic metres in the first two month of 2017, an increase of 6 percent compared with the start of 2016. Crude oil production reached 8.13 million tonnes, up by 3 percent compared with late February 2016. Additional oil production capacity of 110,000 barrels a day is currently available, but it has not been produced in accordance with the latest output accord of the Organization of Petroleum Exporting Countries. The latest Sonatrach production reports said natural gas exports to Europe would be increased once the GR6 pipeline project from the Sahara is completed in May. Sonatrach had said that once the 450-kilometres pipeline comes on stream the company will be able to send an additional 4 Bcm of gas to European customers. Algeria inaugurated its newest LNG production Train in November 2014 at the Arzew liquefaction plant. The facility, located 385 kilometres west of the capital Algiers, has the capacity to produce up to 20 MTPA of LNG, though because of feed-gas shortages and smaller, inefficient Trains

it does not achieve even half of that. The smaller Skikda plant, located about 400km east of the capital, has capacity to produce around 7.7MTPA. Algeria also has three transcontinental natural gas export pipelines to Europe. Two transport natural gas to Spain and one sends gas to Italy.

SOVCOMFLOT, Russia's largest shipping company with a growing LNG fleet and a new vessel marking French LNG industry ties to Russia, posted a more than 40 percent drop in annual net profit dropped to $206.8 million from $345.5M the previous year in the depressed spot and time charter markets. The company said its gross annual revenue was just 7 percent lower at $1.38 billion as the tanker spot market dropped by more than 40 percent and time charter market was down 25 percent. Among its LNG highlights at the end of 2016 was the completion of a 172,600 cubic metres capacity Arc7 LNG carrier designed to serve Russia's Yamal LNG project. The vessel is named "Christophe de Margerie" after the late Chief Executive of French energy company Total and was built at the South Korean shipyard of Daewoo Shipbuilding & Marine Engineering. The Total CEO De Margerie was killed in October 2014 when his corporate jet collided with a snow plough at an airport near Moscow. All four people on board were killed. De Margerie was aged 63 at the time and had been CEO of Total since 2007. At the company, where he spent his entire career, he was nicknamed "Big Moustache" because of the large whiskers which made him an instantly recognisable character within the industry where he was highly regarded. After his death, Total appointed Patrick Pouyanne as his successor and the new CEO pledged to continue with Yamal LNG and its partnership with and shareholding in Novatek, the Russian natural gas company developing the plant, set to come on stream by early 2018. "With our commitment to operating in some of the world's harshest environments, we were particularly pleased to see the launch of 'Christophe de Margerie', the world's first icebreaking LNG carrier," said Evgeniy Ambrosov, Senior Executive Vice-President and Chief Operating Officer in the Sovcomflot earnings report. "Together with other developments, it has strengthened Sovcomflot's reputation as an owner and operator of some of the most advanced vessels afloat," added Ambrosov. Sovcomflot also noted in the report that all fleet technical management operations were now within a single governance structure under the new uniform brand of SCF Management Services. The Russian company raised $1.26Bln of debt capital, including $750M of unsecured public debt and $512M of bank loans to fund the SCF fleet renewal programme and for the refinancing of maturing debt. "Sovcomflot has delivered a solid set of results for 2016, despite market volatility in a year that has severely tested our industry," said Sergey Frank, President and Chief Executive of Sovcomflot. "As growth in oil refinery throughput and up-front demand ran ahead of end-consumption underpinning tanker rates in 2015, so 2016 witnessed a material softening in demand that impacted negatively spot tanker freight rates, albeit with some respite in the final quarter," added Frank. "Sovcomflot strengthened its position as the World's largest harsh environment tanker operator through the opportune acquisition of nine well-maintained tankers that became available as part of the PRISCO bankruptcy proceedings," the CEO said. The Russians also built upon their leadership position in ice-breaking platform supply vessels to operate in Arctic waters with the acquisition of two existing vessels and the launching of a new IBSV all committed to the Sakhalin II project, the LNG plant in the Far East. "In a year when we celebrated our 10th anniversary as an independent owner and operator of gas carriers, we launched the first of a new class of pioneering Arctic LNG carriers, in which our technical experts have played a vital developmental role," said Frank. The SCF Group said it would actively facilitate the use of LNG fuels in the marine transportation of commodities which will pave the way for a cleaner and more environmentally friendly shipping industry profile. "This is very much in line with the company's environmental policy especially in ecologically sensitive areas and matches well the aspirations of oil majors and the International Maritime Organization's Marine Environment Protection Committee in their drive for cleaner fuels," the company stated.

TELLURIAN INC., the developer of the Driftwood LNG project in Louisiana and whose Chairman is former Cheniere Energy Chief Executive Charif Souki, has issued a prospectus for a proposal to sell shares on the Nasdaq Capital Markets stock exchange valued at up to $200 million. The share offering when it goes ahead could be one of many future financial transactions as Tellurian develops its Driftwood venture to produce 26 million tonnes per annum from a liquefaction plant near Lake Charles. "We intend to use the net proceeds from the issuances and sales of common stock for general corporate purposes and working capital," Tellurian said. Tellurian also recently appointed SG Americas, a US broker-dealer subsidiary of France's Societe Generale Corporate and Investment Banking, as its financial advisor. Tellurian founder Souki, who last year brought Martin Houston, former head of LNG at the UK BG Group, into his company completed a reverse takeover in February 2017 to gain a listing for Tellurian on the Nasdaq to ease the path to fund-raising. Meg Gentle, another former senior employee of Cheniere, operator of the Sabine Pass LNG plant in Louisiana, joined her former CEO at his new company as Tellurian's President and CEO. In publishing the share sale prospectus, Tellurian also announced the signing of a distribution agency agreement with Swiss bank Credit Suisse Securities "to sell Tellurian shares from time to time" on the Nasdaq. "The distribution agreement provides that Credit Suisse will be entitled to compensation for its services at a fixed commission rate equal to 3.0 percent of the gross sales price per share," said Tellurian, whose shares were last priced on the Nasdaq at $12.81 per share. Construction of the Driftwood liquefaction plant is scheduled to begin in 2018 and first cargoes could then be shipped by 2022. The project will be unique in having 26 MTPA of output coming from 20 small-scale processing Trains provided by US equipment company Chart Industries, based in Cleveland, Ohio. Each of the Trains with Chart heat exchangers will produce 1.3 MTPA of LNG. Before the completion of the reverse takeover and the gaining of the Nasdaq listing, the Tellurian company signed prominent industry players as stakeholders. French energy company Total acquired a substantial stake in Tellurian in December 2016. Total bought 23 percent of Tellurian after agreeing to pay $5.85 per share for an investment amounting to $207 million. General Electric's energy subsidiary GE Oil & Gas also in late 2016 acquired $25M of preferred equity investment in Tellurian. Tellurian and the Driftwood project were set in motion by Souki after he left Cheniere just before the Houston, Texas-based company's Sabine Pass plant came on stream in February 2016. Souki departed from Cheniere amid disagreements over remuneration and strategy with the new major investor in Cheniere, US billionaire Carl Icahn. The Tellurian Chairman aims to replicate Sabine Pass in terms of production volumes with the Driftwood venture, currently in the engineering design and pre-filing phase of the permitting process.

WOOD GROUP, the UK energy services company based in Aberdeen, has reached an agreement to take over the London-listed energy and LNG project engineering company Amec Foster Wheeler in an all-share deal valued at more than 2.25 billion pounds ($2.75Bln). Under the terms of the combination, each Amec Foster Wheeler shareholder will receive for each Amec FW share 0.75 of new Wood Group shares. The Wood deal to acquire Amec FW is the latest in the industry following the $13Bln merger agreement in 2016 between France's Technip and FMC Technologies of Houston, Texas. Combining Wood Group with Amec FW creates a leader in subsea and upstream oil and gas industry services with a major player in the onshore energy and LNG projects sector. "Opportunities for cost and revenue synergies have been identified which support the significant shareholder value creation opportunity of the combination," Wood said. "The Wood Group directors, having reviewed and analysed the potential cost synergies of the combination, based on their experience of operating in the engineering and technical services industry, and taking into account the factors they can influence, believe that the combined Group will be able to achieve significant sustainable cost synergies of at least 110 million pound, equivalent to approximately US$134m per annum on a recurring basis," Wood added. Wood said it also believed that "significant additional revenue growth opportunities may be realised" by the takeover. Robin Watson and David Kemp, currently Chief Executive and Chief Financial Officer of Wood Group respectively, were named as CEO and CFO of the combined group. Wood Group Chairman Ian Marchant will also continue as Chairman of the merged company. Four members of the

Amec FW board will join the board of the combined company on completion of the deal as non-executive directors, with Roy Franklin joining as Deputy Chairman and Senior Independent Director. Amec FW was most recently appointed as owner's engineer for the Chile LNG terminal company GNL Quintero for services related to an expansion. While the various subsidiaries of the Wood Group take part in the upstream sections of LNG projects, Amec FW has expertise in engineering, procurement and construction management. The company was awarded a five-year global enterprise framework agreement from Shell Global Solutions International on 7 March 2017 to provide engineering services for its downstream ventures worldwide. Amec FW said at the time the award from the projects unit of Royal Dutch Shell marked significant progress in its global engineering consultancy's strategy to build the business and deploy its capability. UK-based Amec took over US company Foster Wheeler to create the current Amec FW firm in November 2014. "The combination represents a transformational transaction for Wood Group, which accelerates our strategy and creates a global leader in project, engineering and technical services delivery across a range of industrial sectors," said Ian Marchant, the Wood Chairman. "It extends the scale and scope of our services, deepens our existing customer relationships, facilitates further development of our technology-enabled solutions and broadens our end market, geographic and customer exposure," added Marchant. Commenting on the takeover by Wood, John Connolly, the Chairman of Amec FW, said: "Since the arrival of Jonathan Lewis as CEO, the executive management team of Amec Foster Wheeler has made significant progress towards the transformation of the business." Connolly added that this had been achieved through cost reduction initiatives, the disposal of non-core assets and a reorganisation of the business. "The Amec Foster Wheeler board have fully supported the revised strategy and the preparations to deliver the appropriate balance sheet to support the standalone prospects of Amec Foster Wheeler," said Connolly. "However, the Amec Foster Wheeler Board believes that a combination with Wood Group adds to the standalone prospects of Amec Foster Wheeler, by accelerating the delivery of the future value inherent in the business and, at the same time, helps to realise the full potential," he added. "The all-share structure of the offer allows our shareholders to benefit from the significant synergies and other strategic benefits that are expected to be realised from the combination," stated Connolly.

WOODSIDE, the Australian liquefied natural gas producer, is planning to help the growth of a market for LNG as a fuel for shipping and onshore transport and is targeting the Pilbara region of Western Australia because mining companies use billions of litres of replaceable diesel and heavy fuel oil for their operations. Woodside's main LNG plants, the North West Shelf plant and Pluto LNG are near Karratha, the gateway to the Pilbara mining region and its own cargo exports are shipped from the port town of Dampier. The Wheatstone LNG plant, to be operated by Chevron Corp. and in which Woodside has a stake is located at nearby Onslow and comes on stream later in 2017. Pilbara is Australia's main mining area for iron ore exported to Asia and global group Rio Tinto alone has 15 iron ore mines and exports from four independent port terminals, all potential users of LNG fuel. Woodside said that with LNG proven to produce 25 percent less greenhouse-gas emissions than diesel and up to 30 percent lower than for heavy fuel oil it was expanding its presence in the market and gave more details of its new venture in the northern part of the state of Western Australia. With the International Maritime Organisation deciding to restrict sulphur levels in global shipping fuels from 2020 and to start tracking greenhouse emissions from large ships, Woodside said that now was the time to join the fuel market for shipping and heavy-horsepower machinery and trucks. "This represents a major opportunity for LNG to replace fuels that will no longer be viable when the new caps on sulphur take effect," the company said. "Woodside considers the Pilbara region in Western Australia to be an ideal location from which to drive the transition to LNG as a transport fuel, with world-class LNG production facilities close to fuel-intensive industries that rely heavily on imported diesel and heavy fuel oil," it said. "Around 3 billion litres of diesel are imported into the Pilbara each year and the mining industry alone uses around 5 billion litres of heavy fuel oil to ship its exported products," said Woodside. "If we can switch just a portion of this to LNG, the emissions reductions are considerable. Woodside is collaborating with many parties to convert these energy-intensive operations in the Pilbara to LNG," it explained. "It has potential to provide an important new market for Woodside and make a significant contribution to meeting Australia's emission reduction targets," the company said. "To demonstrate the flexibility of LNG as a transport fuel, Woodside took delivery of the "Siem Thiima" in January 2017. This is the first LNG-fuelled supply vessel in the southern hemisphere and joins our fleet as the primary supply vessel for Woodside's offshore operations," it said. The company described its LNG fuel ambitions in its 68-page "Sustainable Development Report 2016". The report gives company details of issues such as environmental measures, workplace integrity and company values shared by shareholders, employees and the community. "Increased use of gas-fired power presents an opportunity for those countries with severe air-pollution concerns and growing energy systems, notably China and India," Woodside noted in the report. "Our producing assets in Australia include the landmark North West Shelf Project, which has been operating since 1984," said an introduction by Chief Executive Peter Coleman. "In 2012, we commenced production from the Pluto LNG Plant and will add additional volumes from our non-operated Wheatstone LNG interests in mid-2017," added the CEO. "Today, we continue to be at the forefront of our industry by seeking to grow new markets for LNG. To achieve this we are planning for Australia's first LNG fuel hub to capture growing land and marine LNG fuel markets," he said in reference to the Pilbara project. "We recognise the impact of climate change and are committed to being part of the solution," said Coleman. "We believe that natural gas will play an increasingly important role globally, both in the energy mix and in reducing greenhouse-gas emissions. This belief underpins our decision to support the emergence of a market for LNG as a fuel," he stated. As regards the climate change issue in general, Woodside said: "Our approach highlights our belief that the benefits of natural gas will see gas and LNG play an increasingly important role globally in reducing greenhouse-gas emissions, supporting intermittency of renewable energy and improving local air quality. We will also continue to pursue energy efficiency, support global carbon pricing and will evaluate the resilience of our portfolio against a range of scenarios," it added.

WORLEYPARSONS, the Australian engineering company, whose past projects have included working on the Singapore LNG import terminal and liquefaction plants in Western Australia such as Wheatstone LNG, has signed a long-term, multi-regional agreement with Chevron for engineering and procurement services. The scope of the WorleyParsons-Chevron agreement covers all engineering phases of Chevron's capital project programme from conceptual engineering to final design. The statement said Australian-listed WorleyParsons, which has worldwide operations from the Asia-Pacific region to the US, would have several of its office bases eligible to work under the agreement. "WorleyParsons has enjoyed a strong relationship with Chevron over many years and this agreement further solidifies the relationship between our companies," said Andrew Wood, Chief Executive WorleyParsons. "As Chevron grows in the years ahead, we are proud to be a trusted partner," said Wood. WorleyParsons holds a current engineering services contract for the Chevron-led Wheatstone liquefaction and export project in Western Australia, due to come on stream later in 2015. Recently WorleyParson was the subject of takeover speculation after a Middle East group based in the United Arab Emirates acquired a substantial stake and said it could buy more shares. WorleyParsons confirmed in early March 2017 to the Australia Securities Exchange that had spoken with the Dubai-based Dar Group about a full offer in November 2016. The Australian company is currently valued at A$2.55 Billion (US$1.92Bln) and the share moves by Dar come at a time of widespread restructuring and rising costs in the industry. WorleyParsons has been a leading designer and builder of global and Asia-Pacific facilities and has worked on ventures such as the Northwest Shelf, Pluto LNG and Wheatstone LNG export plants in Western Australia in addition to Singapore's sole regasification terminal. Dar Group operates a multi-branded portfolio consisting of a global network of architecture and engineering consultancy firms. The UAE-based company said in acquiring its stake that it viewed WorleyParsons as the "preeminent energy and design consultancy globally" and respected the current management. ■

Widespread adoption of LNG as a marine fuel faces step change by 2020 with sulphur cap

Stephen Cadden, Chief Operating Officer of industry coalition SEA/LNG

The shipping industry has seen environmental regulations regarding sulphur content in marine fuel becoming gradually more stringent over the years.

In October last year, the International Maritime Organisation (IMO) made an historic decision to introduce a 0.5 percent global sulphur cap on marine fuels from January 2020.

To comply with these new global limits, and amidst financially challenging operating conditions, ship owners and operators - as well as the associated supply chains – must fundamentally change the way they conduct business.

LNG fuel for propulsion is the way ahead for global shipping to adhere to environmental regulations

Pressure

Ship owners and operators are under increasing pressure to adhere to existing and incoming environmental regulations which have the clear objective of dramatically reducing emissions produced by vessels using heavy marine fuel oils.

With more than 90 percent of global trade carried by sea, shipping is the lynchpin of the global economy, and it is widely agreed that this form of transportation remains the most efficient mode of moving freight on a tonne per kilometre basis.

Maritime transportation, however, particularly ocean-going vessels, has the potential to emit levels of sulphur oxides (SOx), nitrogen oxides (NOx), and particulate matter (PM) that can negatively impact populations living near ports and coastlines, as well as those living further inland.

There are several compliant solutions available for the deep-sea shipping industry, including Liquefied Natural Gas (LNG); the continued use of high sulphur fuel oil (HFO) with exhaust gas cleaning systems (commonly referred to as scrubbers); and new formulations of low-sulphur marine fuels such as low-sulphur fuel oil (LSFO) and marine gas oil (MGO).

Of these, LNG provides an essential solution for the long term, as it is the only currently available solution that addresses the core issue: the fuel itself.

A key concern for ship owners and operators is the associated cost of compliance with various environmental regulations.

At present, LNG-fuelled propulsion is already proving to be a cost-effective solution to meeting emissions limits in certain US and European Emission Control Areas (ECAs). It also has the capability to be an economically viable solution for deep-sea shipping trades where vessels spend an estimated 50 percent or more of their time in ECAs.

While the economics are currently more challenging in the deep-sea container and bulk commodity shipping sector, the implementation of the IMO's 0.5 percent global sulphur cap will likely drive up the demand – and consequently prices – for MGO and LSFO, thereby improving the economic case for LNG as a marine fuel.

Expenditure

By contrast, scrubbers require significant additional capital expenditure, can be operationally complex, and have waste management issues.

Despite all its advantages as a marine fuel, several commercial barriers still exist which stifle widespread adoption of LNG.

Barriers

These include a lack of understanding of LNG's ultimate benefits among end users, investors, governments, and civil society; LNG infrastructure and market maturity; higher capex levels for gas equipment such as LNG fuel systems; and fragmented and evolving regulation.

However, current and forthcoming environmental regulations are driving the uptake of non-traditional marine fuels such as LNG.

LNG emits zero SOx and virtually zero particulate matter. Moreover, depending on the technology used, it has the ability to emit approximately 90 percent fewer NOx emissions. Compared to existing heavy marine fuel oils, LNG's greenhouse gas (GHG) performance represents a major step forward.

By utilising best practices and appropriate technologies to minimise methane leakage, realistic reductions of GHG by 10-20 percent are achievable, with potential for up to 25 percent compared with conventional maritime fuels.

Safety is of paramount importance. The industry has always worked diligently to ensure that LNG is used and transported safely and reliably.

Safety

In the bulk LNG transportation industry, where LNG is commonly used as a fuel for the transporting vessel, LNG has an exceptional safety record.

Over the past 50 years, more than 77,000 commercial LNG cargoes have been safely delivered and global LNG shipments have covered more than 100 million miles - about 4,000 times around the earth - without any major safety incidents in port or at sea.

The use of LNG as a marine fuel outside the LNG carrier business is a relatively new development, as are gas-only and dual-fuelled engines. However, since its introduction as a marine fuel at the turn of the century, LNG-fuelled vessels and associated bunkering operations have had an exemplary safety record.

For example, the "Viking Grace" cruise ferry has bunkered without incident more than 1,000 times in Stockholm since its entry into service in 2012. This is testament to the LNG industry's rigorous design guidelines for both ships and shore facilities, as well as high standards of safety training and operational procedures.

The world's first dual-fuelled container vessels entered service in late 2015 for TOTE Maritime in the trade between the US and Puerto Rico.

Technology

Since their introduction, they have been running on LNG for the vast majority of their operating hours. These vessels again prove that the technology works safely and effectively.

Furthermore, LNG is widely available. It is a global commodity with 20 countries exporting to 35 importing countries.

The market has seen notable structural changes in recent years, spurred on by the expansion of LNG trade and an increase in the number and diversity of LNG players in the upstream sector.

In addition, small to mid-scale LNG has taken off, increasing market penetration and servicing demand from power projects in areas not covered by power grids. These areas include surface transportation such as heavy duty trucks, buses and trains, industries such as mining, and the maritime sector.

As a consequence of the new entrants and the added competition, a more flexible approach to LNG contracting and pricing is emerging.

Bunkering

Although the current LNG bunkering infrastructure is concentrated in North West Europe, and the US Gulf and East Coast, more LNG bunkering facilities are being developed and built to reflect growing demand.

This is most evident in the infrastructure being developed by the world's busiest bunker port, Singapore, and in the activities in major ports in eastern China, for example Shanghai and Ningbo-Zhoushan.

As of the start of 2017 there were 97 LNG-fuelled ships in operation - mostly smaller vessels such as ferries - operating extensively in the ECAs of North West Europe and North America.

There are currently at least 91 LNG-fuelled ships on order and approximately another 70 LNG-ready ships either in service or on order. LNG-ready vessels are designed for a streamlined conversion from conventional fuels to LNG when the time is deemed appropriate by the ships' owners.

The existing order book - while depressed due to over-tonnage - is showing a growing number of deep-sea vessels including cruise ships, container vessels, and bulk carriers being built to LNG dual-fuel standards.

LNG provides an essential solution for the long term. Barriers to entry need to be better understood and overcome if LNG is to reach its full potential. A collaborative approach is the only way to overcome these challenges.

Agenda

Creating the infrastructure to enable quick, safe and cost effective LNG bunkering in key global ports; diminishing the price premium for LNG-fuelled vessels; and establishing the consistency of international and national regulations globally, will all be essential if LNG is going to fulfil its potential as a future-fit solution for the international maritime industry.

Launched in July 2016, SEA\LNG unites key players from across the marine value chain for a common purpose - to drive the change needed across the entire marine transportation system.

The multi-sector industry coalition brings together LNG suppliers, bunkering companies, shipping lines, shipyards, OEMs (original equipment manufacturers), classification societies, and port authorities.

SEA\LNG believes that a collaborative approach to understanding and then tackling the barriers to LNG use is crucial to encouraging investment and continuing to stimulate innovative solutions, thereby accelerating the adoption of this viable alternative to traditional bunker fuels.

The year 2020 has the potential to represent a step change for LNG as a marine fuel. But only by taking a collaborative approach will the various barriers to uptake be overcome, to assure LNG's vital role as a clean and economically viable alternative to traditional bunker fuels. ■

Author:

Stephen Cadden, COO of industry coalition SEA/LNG

Developers of LNG and energy ventures have diverse hurdles to overcome in British Columbia

Canadian Energy Research Institute of Calgary identifies project issues with people and the environment

A report was recently issued by the Canadian Energy Research Institute of Calgary in the province of Alberta identifying major environmental and Indigenous Peoples issues facing development of the natural gas and LNG industry in British Columbia.

Entitled "Risk Analysis of British Columbia Natural Gas Projects: Environmental and Indigenous Peoples Issues" and written by Anna Vypovska and Laura Johnson, it examines the key approaches to mitigate, manage and monitor the issues effectively.

Liquefaction plants are supplied by pipelines hundreds of miles long from inland to the Pacific coast

Gas producer

Currently, BC is the second largest producer of marketable natural gas amongst the Canadian provinces, with the most economically viable natural gas wells, both vertical and horizontal.

Since 2013, approximately 65 percent of the wells drilled in BC have been in its unconventional Montney formation where shale-gas is in abundance, with the remainder of the drilling split fairly evenly between the rest of the province's formations.

"As shale gas has increased North American supply of natural gas, investor focus is moving to exports, specifically of LNG.

"In 2012, the Province issued a Natural Gas Strategy which recognizes natural gas, particularly LNG exports, as a provincial priority and lists a series of actions the Province will undertake to promote the industry.

" Since 2012, 20 LNG projects have been proposed in BC, 18 export licenses have been issued by the National Energy Board (NEB), and 9 environmental assessments (EAs) have been completed by BC Environmental Assessment Office and the Canadian Environmental Assessment Agency, with a few more underway," it noted.

"Environmental assessments at the provincial level, and often at the federal level as well, are typically required for all major natural gas pipeline and LNG projects developed in BC.

Framework

A legal framework for provincial EAs includes three main sources: the BC Environmental Assessment Act as the primary EA legislation; regulations under the BC EAA and common law regarding Indigenous Peoples consultation.

All natural gas pipeline and LNG projects that are considered as 'reviewable' under the BC regulations and are subject to the provincial EA process, with BC EAO as the main regulator and provincial responsible authority.

The majority of provincial permits are provided through the BC Oil and Gas Commission, the primary operational regulator of oil and gas activities.

Process

"A federal EA may be required for a proposed natural gas pipeline or an LNG facility that meets the thresholds set out in the Regulations Designating Physical Activities (Canada 2012) under the Canadian Environmental Assessment Act," the report said.

"The CEAA, 2012 provides the framework for the federal EA process, with the CEA Agency as the main regulator for intra-provincial pipelines and related facilities, and the NEB as the regulator for pipelines that cross provincial and international boundaries," it added.

Authorization or approval from the NEB is also required for the export of natural gas liquids (NGLs), and export or import of natural gas.

An EA application is typically organized around its potential to impact. The application must describe the technically and economically feasible mitigation measures to prevent or reduce to an acceptable level any potential adverse effects of the project," the report said.

"A critical step in the EA process is to determine if the residual adverse effects (i.e. effects remaining after the implementation of all mitigation measures) are significant, based on the defined criteria.

"Another major objective of the EA application is to measure the impacts of the project and all other past, present, and reasonably foreseeable projects and activities in the region," it added.

The study reviewed EA applications and assessment reports for 29 major natural gas, NGLs and LNG projects in BC that have undergone a typical EA process (active or complete) with the provincial and/or federal responsible authority since 2010.

"The reviewed projects are representative of the entire geographical region and involve a wide range of output capacities, with the projected average daily production from 0.15 billion cubic feet per day (Bcf p/d) to 0.40 Bcf p/d for natural gas processing facilities, from 0.23 Bcf p/d to 2.2 Bcf p/d for natural gas pipelines, and from 0.32 Bcf p/d to 3.47 Bcf p/d for LNG facilities.

"The anticipated daily productions of these projects at full build-out range is even higher, up to 0.6 Bcf p/d for natural gas processing facilities, 8.4 Bcf p/d for natural gas pipelines, and 4.0 Bc f p/d for LNG facilities," it explained.

Residual

The residual adverse effects on the environment identified by the proponents in the EA applications were reviewed by the provincial or federal responsible authorities to determine their significance.

"An analysis of the regulators' assessment reports for the 18 natural gas pipeline and LNG projects where the provincial or federal EA process has been completed identified the following key environmental issues associated with the natural gas development in BC:

- Significant residual adverse effects related to greenhouse gas (GHG) emissions;
- Significant residual adverse effects and cumulative effects to rare and threatened wildlife species (specifically, to caribou, grizzly bear and harbour porpoise);
- Cumulative adverse impacts of natural gas development.

Significant residual adverse effects related to GHG emissions have been one of the major environmental issues reported on seven projects out of 18 with the EA process completed.

As assessed by the regulators, some of the proposed projects would be amongst the largest sources of GHG emissions in the oil and gas sector in Canada, with

estimated emissions up to 4.5 million tonnes of CO2 equivalent per year.

"Significant residual adverse effects on caribou and caribou habitat were determined on three major natural gas pipeline projects out of 18 with the EA process completed, and were also determined as a key issue that should be fully compensated for on two other natural gas pipeline projects," it said.

Impacts

These impacts were mostly attributed to enhanced predator access to caribou and loss of caribou habitat due to the habitat fragmentation.

For two reviewed projects, impacts to threatened wildlife species (caribou and grizzly bear) were considered as significant in terms of cumulative effects, but not in terms of project specific effects.

"The analysis of EA reports for six provincially and/or federally approved natural gas pipeline and LNG projects that include the Marine Resources VCs revealed impacts to marine mammals to be a concern for several projects," it said.

"Residual adverse effects and cumulative adverse effects on marine mammals (particularly, on harbour porpoise) were considered to be significant for one LNG project.

"Potential cumulative effects from the natural gas and LNG development in BC discussed in this study are a growing concern for both stakeholders and the general public" according to the report.

Cumulative impacts are also of particular concerns for Indigenous Groups, with many of them unsatisfied with the adequacy of cumulative effects assessment of past, present and reasonably foreseeable industrial activity in their traditional territory, in relation to their respective Aboriginal interests.

The leading cause of failure for both sour natural gas and natural gas pipelines in 2010-2013 was related to metal loss...

The most common potential accidents or malfunctions associated with project activities, as considered by the proponents in the EA applications for 19 natural gas pipeline and LNG projects, were also reviewed.

In addition, the study provides examples of actual sour natural gas and natural gas pipeline incidents reported in BC in 2010-2015.

"The analysis of publicly available data shows that in 2015, sour natural gas pipelines recorded the lowest incident rate with a frequency of 0.14 per 1,000km, whereas crude oil pipelines had an incident frequency of 2.81 per 1,000km," the report said.

Failures

"The leading cause of failure for both sour natural gas and natural gas pipelines in 2010-2013 was related to metal loss, e.g., wall thickness reduction due to corrosion," it added.

While British Columbia has fewer than one-fifth of Canada's Indigenous and First Nations peoples, it is characterized by the greatest diversity of Indigenous population and culture in Canada, representing 198 First Nations (about one third of all First Nations in Canada, more than 60 percent of the First Nations' languages and 64 percent of unique language families in Canada.

The Province also presents a unique landscape of Aboriginal rights and interests, with the history of treaty making this process different from the rest of Canada and with lands that are subject to modern-day treaties, treaty negotiations or unresolved land claims.

This study examines and summarizes the most common potential adverse impacts on Indigenous Peoples interests based on the review of 18 natural gas pipeline and LNG projects where the provincial or federal EA process has been completed since 2010.

"The identified potential adverse effects include but are not limited to effects to the environment on health and socio-economic conditions; physical and cultural heritage; the current use of lands and resources for traditional purposes; and structures or sites that is of historical or archaeological significance," the report stated.

Reviews

"For 17 out of the 18 reviewed projects, the regulatory authorities have been of the view that no significant adverse effects on the Aboriginal interests will occur as a result of the proposed projects, with the implementation of impacts and benefits, and other agreements established by the proponents with Indigenous Groups to address Aboriginal interests in relation to the proposed projects," it said.

The EA reports concluded that the majority of issues raised during the review processes by Indigenous Groups were satisfactorily addressed through existing, revised or new commitments, and project design changes made by the proponents.

The study also considered key approaches to address the identified environmental and Indigenous Peoples issues, and best practices for proponents of natural gas pipelines and LNG projects.

The discussed mitigation measures were split by the type of mitigation, starting with the highest priority in the mitigation hierarchy, and included measures to avoid, minimize, restore on-site and offset potential adverse effects from the reviewed projects.

The majority of proponents have also proposed a number of pipeline route changes implemented as project design restrictions, in order to avoid or reduce significant residual adverse effects to the environmental VCs and Aboriginal interests, based on input from Indigenous Groups and technical working groups during the EA process.

Proposals

The Province of BC has proposed, designed and implemented a number of key strategies, progressive programs and policies to reduce potential adverse effects of industrial development on the environmental VCs.

In particular, numerous regulatory and legislative measures to reduce GHG emissions across the Province have been implemented since 2008.

The BC Ministry of Environment has announced management plans and recovery strategies to reduce the expected decline in caribou populations in BC.

"The Province is also moving forward with initiatives that aim to assess and manage cumulative effects to key values, and to consider the impact to Aboriginal rights," it said. "Examples of those initiatives include, but are not limited to, the Cumulative Effects Framework, Area-Based Analysis, Northeast Water Strategy and Water Tool, LNG Environmental Stewardship Initiative, and Regional Strategic Environmental Assessment," it added.

While the duty to consult Indigenous Peoples rests with the Crown, the procedural aspects of consultation may be delegated to proponents.

They are encouraged to engage with Indigenous Peoples as early as possible in the planning stages in order to build relationships, and continue throughout the lifecycle of the project.

Guidelines

The Province of BC, BC EAO and BC Ministry of Aboriginal Relations and Reconciliation have developed a number of guidelines to assist proponents with meeting obligations to consult with Indigenous Peoples.

The proposed guidelines adopt a four-phased approach to the consultation procedures, including the preparation, engagement, accommodation, decision and follow-up phases each consisting of three to five steps.

"The courts have repeatedly encouraged the resolution of Indigenous issues by negotiation rather than litigation," the report noted.

"There are various types of agreements with Indigenous Groups that have been negotiated within the Province to date; those specific to the natural gas and LNG industry include, but are not limited to, the LNG Environmental Stewardship Initiative, capacity building initiatives and economic benefit agreements," it said.

Examples of economic benefit agreements include natural gas pipeline benefits agreements (currently reached with 29 out of 32 eligible First Nations for four major natural gas pipelines); the Coastal First Nations LNG Benefits Agreement (signed by 9 First Nations for 10 proposed LNG projects); revenue sharing agreements, etc.

Economic benefits agreements are not legally required and must be kept separate and distinct from the duty to consult.

The report went on to say that it must be noted that by entering into impact benefits agreements, Indigenous Peoples are not waiving their right to review, comment and approve or not, any environmental studies, permit applications or environmental monitoring regimes related to the project. ■

Companies take opportunity to introduce small to mid-scale LNG solutions at Gastech 2017 just held

The Conference and Exhibition, which has just taken place in Chiba, Japan, gave participating companies a showcase for innovations in the energy sector

One of the many concepts presented was a Floating Transfer Terminal promising "jettyless" LNG ship-to-shore transfer.

Three companies, Houlder, Wärtsilä and Trelleborg took the opportunity of introducing their new small-scale to mid-scale LNG distribution infrastructure at Gastech held from April 4-7.

Gastech 2017 was at Makuhari Messe convention centre, located east of the capital on Tokyo Bay

Bunkering

The transporting and bunkering of LNG is becoming increasingly important to the energy strategies of archipelagos and coastal communities across the world.

Such communities, however, have limited appetite for major civil works required for new harbours, quaysides and jetties due to environmental sensitivities and lack of readily available investment.

Recognising this, marine design consultancy Houlder, LNG Infrastructure provider and power generation expert Wärtsilä and hose supplier Trelleborg have combined their talents for innovation to develop an alternative solution that was formally unveiled at the event in Chiba.

Gianpaolo Benedetti, Houlder's LNG business development manager, described the floating transfer terminal as "taking the jetty to the LNG vessel, rather than have the LNG vessel come to the jetty."

The floating transfer terminal comprises a self-propelled barge that shuttles to and from LNG vessels moored at up to 800 metres offshore.

The barge provides a base for a Houlder transfer system developed with Klaw LNG. They company said it was a hybrid hose-handling system that facilitates a safe and secure connection with the LNG vessel.

Transfer

Trelleborg Cryoline LNG Floating Hoses are then used to transfer of LNG and boil-off gas between the barge and any shore facility.

They combine high flexibility, reliability and long service life ensuring that LNG operators' and contractors' offloading requirements related to safety, flow rate and operational availability are fully met.

"The FTT is a flexible, quickly deployable solution that, thanks to a low draft barge and floating hoses, can operate in the widest possible range of locations at a fraction of the cost of fixed infrastructure," the companies said.

Gianpaolo Benedetti continued: "Our challenge has been to develop a safe and cost effective solution which also reduces impact on some of the world's most environmentally sensitive areas."

Kenneth Engblom, Director, Sales and Marketing, LNG Solutions at Wärtsilä described the benefits of the system.

"Wärtsilä as an EPC contractor sees this new technology enabling us to do even smarter total LNG terminal solutions for various types of small-scale LNG opportunities, where a jetty would be an expensive and time-consuming solution to execute" said Engblom.

Arup tanks

In another presentation of equipment, energy engineering company Arup, which specializes in terminals and storage, advised visitors to Gastech to recognise the potential of prefabricated storage tanks as a cost-effective approach to storage in the small and mid-scale LNG-to-power market.

The Arup energy team predicted that a move to "plug and play" modular cryogenic storage units could save the industry up to 20 percent on the construction of mid-scale storage tanks - important at a time when LNG prices are being driven down.

"In countries that have an established gas distribution network, the capital costs of receiving, storing and regasification at each power station can inhibit the development of LNG to power projects," Arup said.

Prefabricated

"The traditional solution for large scale in-situ-constructed LNG storage has typically utilised 9 percent nickel steel single, double or full-containment, flat bottomed, storage tank systems - with the technology hardly progressing in the past 20 years," it added.

These systems can be costly because of the bespoke design required for each tank, and the on-site man hours required for building and assembly.

Arup is urging the industry to consider prefabricated LNG tank solutions, using cryogenic, membrane technologies, as a technically feasible alternative.

It said there was a need to develop "plug and play" tanks based on standard solutions, that are robust enough to be transported anywhere in the world.

"Modular LNG tanks bring significant savings as they can be designed in advance to suit a range of site conditions. They can be constructed off-site in advance to facilitate ordering off the shelf and transported to site in an as-built form," Arup said.

"This will reduce the man hours required for a project and allow significant savings in achieving first gas. In addition, labour intensive activities are transferred from often remote project sites to a dedicated fabrication yard, with greater availability of specialised labour," it added.

Tank parts can also be prefabricated under cover, further increasing productivity and the quality of workmanship.

Single containment systems may not be appropriate for all projects.

The Arup team is progressing with double and full containment designs using precast wall panels and wired wound pre-stressing combined with membrane lining technology that will reduce site area and deliver significant cost savings.

Mid-scale

"There are projects being proposed all around the world that are showing membrane, modular solutions are both needed and viable.

"However, what has surprised us most is that there is no major coordinated push towards prefabricated solutions at mid-scale," the company stated.

The engineering division of the Linde Group of Germany showcased its entire gas and LNG offerings at Gastech.

Several important processing steps are required before natural gas can make its way from the well to the point of use.

Linde told visitors it has the technologies to support every step in this process flow.

"As a one-stop partner, we supply our

customers with cryogenic technologies and logistics concepts at every step of the LNG value and process chain," the company said.

"We plan and build natural gas liquefaction plants across the full size spectrum – extending from small- and mid-scale plants to world-scale facilities and entire LNG import terminals," it added.

Manufacturer

Heat exchangers are at the heart of every LNG plant. Linde is the only manufacturer worldwide to offer proprietary coil-wound and plate-fin heat exchangers.

Linde's plate-fin heat exchangers were on display at the exhibition in Tokyo. The company also offered innovative technologies for removing unwanted nitrogen from natural gas streams (nitrogen rejection units, NRUs).

In addition to this, Linde supplies plants for processing natural gas, recovering natural gas liquids (NGLs) and for extracting and liquefying helium.

Linde noted that increasingly, LNG will be used as a fuel for ships and other vehicles, and it offers end-to-end LNG fuelling solutions for these applications.

"Modularisation in plant engineering is one of the buzz topics," the company said.

"Linde created the 'Modularisation Competence Centre' to focus on developing natural gas reserves in regions that are difficult to access or have challenging climates," it added.

Modular

With this modularisation concept, process units or even entire plants are premanufactured by experienced personnel at well-established locations and then transported to remote sites.

"Modularisation enables us to reduce production costs, assembly timelines and risks, while raising production quality," Linde said.

The company has developed a modularisation concept for midscale LNG plants with a liquefaction capacity between one and two million tonnes per year that enables the entire process plant to be installed on barges.

"The individual process modules are assembled in yards. They are then installed on a single barge and transported from the yard to the respective near-shore end destination," it added. ■

World LNG Carrier Fleet

LNG carrier	Capacity m^3	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
Bilbao Knutsen	138,000	Knutsen / Marpetrol	IZAR Sestao	Jan-04	Spain	S	GT NO 96	4	Atlantic LNG
Bilis	77,730	Brunei Shell Tankers	La Seyne	Mar-75	Brunei	S	GT NO 82	5	Brunei LNG
Bishu Maru	162,000	K Line-Transpacific	Kawasaki Sakaide	Dec-15	Panama	S	Moss	4	Australia-Japan
British Diamond	155,000	BP Shipping	Hyundai	Sep-08	IOM	DFDE	TZ Mk. II	4	Indonesia-Various
British Emerald	155,000	BP Shipping	Hyundai	Jun-07	UK	DFDE	TZ Mk. III	4	Tangguh LNG
British Innovator	138,200	BP Shipping	Samsung	Jul-03	Isle of Man	S	TZ Mk. III	4	Various
British Merchant	138,000	BP Shipping	Samsung	Apr-03	Isle of Man	S	TZ Mk. III	4	Various
British Ruby	155,000	BP Shipping	Hyundai	Jan-08	U.K.	DFDE	TZ Mk. III	4	Various
British Sapphire	155,000	BP Shipping	Hyundai	Sep-08	IOM	DFDE	TZ Mk. III	4	Tangguh

British Trader	138,000	BP Shipping	Samsung	Dec-02	Isle of Man	S	TZ Mk. III	4	Engas
Broog	135,466	J4 Consortium	Mitsui Chiba	May-98	Japan	S	Moss	5	Qatargas
Bu Samara	266,000	QGTC	Samsung	Dec-08	Qatar	DRL	TZ Mk. III	5	Qatargas
BW Suez Paris	162,400	BW Gas	Daewoo	May-09	N.I.S.	DFDE	GT NO 96	4	Yemen-Atlantic
BW Suez Brussels	162,400	BW Gas	Daewoo	May-09	N.I.S.	DFDE	GT NO 96	4	Yemen-Atlantic
Cadiz Knutsen	138,826	Knutsen / Marpetrol	IZAR Puerto Real	Jun-04	Spain	S	GT NO 96	4	Engas
Castillo de Santisteban	173,600	Elcano	STX	Aug-10	Malta	S	GT NO. 96		Various
Castillo de Villalba	138,000	Elcano	IZAR	Nov-03	Spain	S	GT NO 96	4	Sonatrach
Catalunya Spirit	138,000	Teekay LNG Partners	IZAR Sestao	Mar-03	Liberia	S	GT NO 96	4	Atlantic LNG
Celestine River	145,000	KLNG	Kawasaki	Dec-07	Bahamas	S	Moss		Various
CESI 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
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

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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 Abuja	126,530	Bonny Gas Transport	GD Quincy	Sep-80	Bahamas	S	Moss	5	Nigeria LNG
LNG Adamawa	141,000	Bonny Gas Transport	Hyundai	Jun-05	Bermuda	S	Moss	4	Various
LNG Akwa Ibom	141,000	Bonny Gas Transport	Hyundai	Nov-04	Bermuda	S	Moss	4	Various
LNG Aquarius	126,300	MOL/LNG Japan	GD Quincy	Jun-77	Marshall Is.	S	Moss	5	Various
LNG Barka	153,000	NYK	Kawasaki	Jan-09	Bahamas	S	Moss	4	Various
LNG Bayelsa	137,500	Bonny Gas Transport	Hyundai	Feb-03	Bermuda	S	Moss	4	Nigeria LNG
LNG Benue	145,700	BW Gas	Daewoo	Mar-06	Bermuda	S	GT NO 96	4	Nigeria LNG
LNG Bonny	177,000	Bonny Gas Transport	Hyundai	Oct-15	Bermuda	DFDE	TZ Mk III	4	Nigeria LNG
LNG Borno	149,600	NYK Line	Samsung	Aug-07	Japan	S	TZ Mk. III	4	Nigeria LNG
LNG Capricorn	126,300	MOL/LNG Japan	GD Quincy	Jun-78	Marshall Is.	S	Moss	5	Pertamina
LNG Cross River	141,000	Bonny Gas Transport	Hyundai	Sep-05	Bermuda	S	Moss	4	Various
LNG Dream	145,000	Osaka Gas	Kawasaki	Sep-06	Japan	S	Moss	4	Woodside Energy
LNG Ebisu	147,500	MOL	Kawasaki	Sep-08	Bahamas	S	Moss	4	Various
LNG Edo	126,530	Bonny Gas Transport	GD Quincy	May-80	Bahamas	S	Moss	5	Nigeria LNG
LNG Enugu	145,000	BW Gas	Daewoo	Oct-05	Bermuda	S	GT NO 96	4	Nigeria LNG
LNG Fimina	175,000	Bonny Gas Transport	Samsung	Oct-15	Bermuda	DFDE	TZ Mk III	4	Nigeria LNG
LNG Flora	127,700	J3 Consortium	Kawasaki Sakaide	Mar-93	Japan	S	Moss	4	Pertamina
LNG Fukurokuju	165,000	MOL	Kawasaki	June-15	Japan	S	Moss	4	Various
LNG Gemini	126,300	MOL/LNG Japan	GD Quincy	Sep-78	Marshall Is.	S	Moss	5	Pertamina
LNG Imo	148,300	BW Gas	Daewoo	Jun-08	Bermuda	S	GT NO 96	4	Nigeria LNG
LNG Jamal	135,330	Osaka Gas/J3 Consortium	Mitsubishi Nagasaki	Oct-00	Japan	S	Moss	5	Oman Gas
LNG Jupiter	145,000	NYK Line	Kawasaki	Jul-09	Bahamas	S	Moss	4	Various
LNG Jurojin	155,300	MOL	MHI Nagasaki	Nov-15	Japan	S	KM	4	Various
LNG Kano	148,471	BW Gas	Daewoo	Jan-07	Bermuda	S	GT No. 96	4	NLNG
LNG Lagos	177,000	Bonny Gas	Hyundai	Oct-15	Bermuda	DFDE	TZ Mk III	4	Nigeria LNG
LNG Leo	126,400	MOL/LNG Japan	GD Quincy	Dec-78	Marshall Is.	S	Moss	5	Pertamina
LNG Lerici	65,000	Exmar	Italcantieri Sestri	Mar-98	Italy	S	GT NO 96	4	Sonatrach
LNG Libra	126,400	Hoegh LNG	GD Quincy	Apr-79	Marshall Is.	S	Moss	5	Various
LNG Lokoja	148,300	BW Gas	Daewoo	Dec-06	Bermuda	S	GT No. 96	4	Nigeria LNG
LNG Mars	155,000	MOL/Osaka Gas	Mitsubishi	Oct-16	Marshall Is.	S	Moss	5	Various
LNG Ogun	148,300	NYK Line	Samsung	Aug-07	Japan	S	TZ Mk. III	4	Nigeria LNG
LNG Ondo	148,300	BW Gas	Daewoo	Sep-07	Bermuda	S	GT NO 96	4	Nigeria LNG
LNG Oyo	140,500	BW Gas	Daewoo	Dec-05	Bermuda	S	GT NO 96	4	Nigeria LNG
LNG Pioneer	138,000	MOL	Daewoo	Jul-05	Bahamas	S	GT No 96	4	Idku
LNG Port Harcourt	175,000	Bonny Gas	Samsung	Oct-15	Bermuda	DFDE	TZ Mk III	4	Nigeria LNG

LNG Portovenere	65,000	Exmar	Italcantieri Sestri	Jun-96	Italy	S	GT No 96	4	Sonatrach
LNG River Niger	141,000	Bonny Gas Transport	Hyundai	May-06	Bermuda	S	Moss	4	Various
LNG River Orashi	145,910	BW Gas	Daewoo	Nov-04	Bermuda	S	GT No 96	4	Nigeria LNG
LNG Rivers	137,231	Bonny Gas Transport	Hyundai	Jun-02	Bermuda	S	Moss	4	Nigeria LNG
LNG Saturn	153,000	MOL	MHI	Nov-15	Japan	S	Moss	4	Various
LNG Sokoto	137,231	Bonny Gas Transport	Hyundai	Aug-02	Bermuda	S	Moss	4	Nigeria LNG
LNG Taurus	126,300	MOL/LNG Japan	GD Quincy	Aug-79	Marshall Is.	S	Moss	5	Various
LNG Venus	155,000	Osaka/MOL	MHI	Oct-14	Japan	S	Moss	4	Various
LNG Vesta	127,547	Tokyo Gas Consortium	Mitsubishi Nagasaki	Jun-94	Japan	S	Moss	4	Pertamina
LNG Virgo	126,400	MOL/LNG Japan	GD Quincy	Dec-79	Marshall Is.	S	Moss	5	Pertamina
Lobito	160,400	Mitsui/NYK/Teekay	Samsung	Oct-11	Bahamas	DFDE	TZ Mk. III	4	Various
Lusail	138,000	Peninsular LNG	Samsung	May-05	Bahamas	S	TZ Mk. III	4	Qatar
Madrid Spirit	138,000	Teekay LNG Partners	IZAR Puerto Real	Jan-05	Spain	S	GT No 96	4	Engas
Magellan Spirit	165,500	Teekay LNG Partners	Samsung	Sep-08	Denmark	DFDE	TZ Mk. III	4	Various
Malanje	160,400	Mitsui/NYK/Teekay	Samsung	Jul-11	Bahamas	DFDE	TZ Mk. III	4	Various
Maran Gas Achilles	174,000	Maran	Hyundai Samho	Feb-16	Greece	DFDE	GT No 96	4	Various
Maran Gas Agamemnon	174,000	Maran	Hyundai Samho	May-16	Greece	DFDE	GT No 96	4	Various
Maran Gas Alexandria	161,870	Maran	Hyundai Samho	Sep-15	Greece	DFDE	TZ Mk. III	4	Various
Maran Gas Amphipolis	173,400	Maran	Daewoo	Aug-16	Greece	DFDE	GT No 96	4	Various
Maran Gas Apollonia	161,870	Maran	Daewoo	Jan-14	Greece	DFDE	GT No 96	4	Various
Maran Gas Asclepius	145,000	Kristen Navigation	Daewoo	Jul-05	Bermuda	S	GT No 96	4	Qatar
Maran Gas Coronis	145,700	Maran	Daewoo	Sep-07	Greece	S	GT No 96	4	Rasgas II
Maran Gas Delphi	159,800	Maran	Daewoo	Feb-14	Greece	DFDE	GT No 96	4	Various
Maran Gas Efessos	159,800	Maran	Daewoo	Jun-14	Greece	DFDE	GT No 96	4	Various
Maran Gas Hector	174,000	Maran	Hyundai Samho	Nov-16	Greece	DFDE	GT No 96	4	Various
Maran Gas Lindos	159,800	Maran	Daewoo	Jun-15	Greece	DFDE	GT No. 96	4	Various
Maran Gas Mystras	155,900	Maran Gas	Daewoo	May-15	Greece	DFDE	GT No 96	4	various
Maran Gas Pericles	174,000	Maran	Hyundai Samho	June-16	Greece	DFDE	GT No 96	4	Various
Maran Gas Posidonia	161,870	Maran	Daewoo	May-14	Greece	DFDE	GT No 96	4	Various
Maran Gas Roxana	173,400	Maran	Daewoo	Jan-17	Greece	DFDE	GT No 96	4	Various
Maran Gas Sparta	161,870	Maran	Hyundai Samho	April-15	Greece	DFDE	G TZ Mk. III	4	Various
Maran Gas Troy	155,900	Maran Gas	Daewoo	May-15	Greece	DFDE	GT No 96	4	various
Maran Gas Ulysses	174,000	Maran	Hyundai Samho	Jan-17	Greece	DFDE	GT No 96	4	Various
Maria Energy	174,000	Tsakos	Hyundai	Mar-15	Marshall Is.	TFDE	GTT Mk II	4	Various
Marib Spirit	165,000	Teekay LNG	Samsung	May-08	Marshall Is.	DFDE	TZ Mk. III	4	Various
Matthew	126,540	Suez LNG Shiping	Newport News	Jun-79	Bahamas	S	TZ Mk. I	6	Atlantic LNG
Mekaines	266,000	Naklilat	Samsung	Mar-09	Liberia	DRL	GT No 96	4	Qatar-Atlantic Basin
Meridian Spirit	165,500	Teekay LNG	Samsung	Jan-10	Denmark	DFDE	TZ Mk. III	4	Various
Mesaimeer	210,100	Naklilat	Hyundai	Mar-09	Liberia	DRL	GT No 96	4	Qatar-Atlantic Basin
Methane Alison Victoria	145,000	GasLog	Samsung	Aug-07	Bermuda	S	TZ III	4	Eq.Guinea LNG
Methane Becki Anne	170,000	GasLog	Samsung	Sep-10	Bermuda	TFDE	TZ Mk. III	4	Various
Methane Heather Sally	145,000	GasLog	Samsung	Jul-07	Bermuda	S	Tz Mk. III	4	Eq.Guinea LNG
Methane Jane Elizabeth	145,000	GasLog	Samsung	Jun-06	Bermuda	TFDE	TZ Mk. III	4	Engas
Methane Julia Louise	170,000	GasLog	Samsung	Dec-09	Bermuda	TFDE	TZ Mk. III	4	Various
Methane Kari Elin	138,200	Shell	Samsung	Jun-04	Bermuda	S	TZ Mk. III	4	Various
Methane Lake Charles	145,000	Shell	Samsung	Feb-07	Bermuda	S	TZ Mk. III	4	Marathon Oil
Methane Lydon Volney	145,000	Shell	Samsung	Aug-06	Bermuda	S	TZ Mk. III	4	Engas
Methane Mickie Harper	170,000	Shell-GasLog	Samsung	Nov-10	Bermuda	TFDE	TZ Mk. III	4	Various
Methane Nile Eagle	145,000	Shell-GasLog	Samsung	Dec-07	Bermuda	S	TZ Mk. III	4	Engas
Methane Patricia Camila	170,000	Shell-GasLog	Samsung	Oct-10	Bermuda	TFDE	TZ Mk. III	4	Various
Methane Princess	138,159	Golar LNG	Daewoo	2003	UK	S	GT No 96	4	Spot BG
Methane Rita Andre	145,000	GasLog	Samsung	Mar-06	Bermuda	S	TZ Mk. III	4	Engas
Methane Shirley Elizabeth	145,000	GasLog	Samsung	Apr-07	Bermuda	S	TZ Mk. III	4	Marathon Oil
Methane Sprit	165,000	Teekay LNG	Samsung	Mar-08	Singapore	DFDE	TZ Mk. III	4	Various
Milaha Qatar	145,000	Milaha	Samsung	Apr-06	Denmark	S	TZ Mk. III	4	Qatar
Milaha Ras Laffan	138,270	Milaha	Samsung	Mar-04	Denmark	S	TZ Mk. III	4	RasGas II
Min Lu	147,000	China Ships	Hudong	Aug-09	China	S	GT No 96	4	Various
Min Rong	147,000	China LNG Ships	Hudong	Feb-09	Hong Kong	S	GT No 96	4	Australia-China
Mourad Didouche	126,130	SNTM-Hyproc	Atlantique	Jul-80	Algeria	S	GT No 85	5	Sonatrach
Mozah	266,000	QGTC	Samsung	Aug-08	Qatar	DRL	TZ Mk III	5	Qatargas II
Mraweh	137,000	National Gas Shipping	Kvaerner-Masa	Jun-96	Liberia	S	Moss	4	ADGAS
Mubaraz	137,000	National Gas Shipping	Kvaerner-Masa	Jan-96	Liberia	S	Moss	4	Various
Muraq	210,100	J5-K Line	Daewoo	May-08	Marshall Is.	DRL	GT No 96	4	Qatar-Atl'c Basin
Murwab	210,100	J5 Consortium	Daewoo	May-08	Marshall Is.	DRL	GT No. 96	4	Qatargas
Muscat LNG	149,170	Oman Gas/MOL	Kawasaki Sakaide	Mar-04	Japan	S	Moss	4	Oman Gas
Neo Energy	149,700	Tsakos	Hyundai	Feb-07	Liberia	S	GTT Mk II	4	Various
Nizwah LNG	145,000	Oryx LNG Carriers	Kawasaki Sakaide	Dec-05	Japan	S	Moss	4	Oman Gas
Northwest Sanderling	127,525	Australia LNG	Mitsubishi Nagasaki	Jun-89	Australia	S	Moss	4	NWS
Northwest Sandpiper	127,500	Australia LNG	Mitsui Chiba	Feb-93	Australia	S	Moss	4	NWS
Northwest Seaeagle	127,450	Australia LNG	Mitsubishi Nagasaki	Nov-92	Bermuda	S	Moss	4	NWS
Northwest Shearwater	127,500	Australia LNG	Kawasaki Sakaide	Sep-91	Bermuda	S	Moss	4	NWS
Northwest Snipe	127,747	Australia LNG	Mitsui Chiba	Sep-90	Australia	S	Moss	4	NWS
Northwest Stormpetrel	127,600	Australia LNG	Mitsubishi Nagasaki	Dec-94	Australia	S	Moss	4	NWS
Northwest Swallow	127,708	J3 Consortium	Mitsui Chiba	Nov-89	Japan	S	Moss	4	NWS
Northwest Swan	138,000	Australia LNG	Daewoo	Mar-04	Australia	S	GT NO 96	4	NWS
Northwest Swift	127,590	J3 Consortium	Mitsubishi Nagasaki	Sep-89	Japan	S	Moss	4	NWS
Oak Spirit	173,400	Teekay	Daewoo	Jan-16	Bahamas	MEGI-DF	NO. 96 GW	4	Cheniere
Ob River	150,000	Lance Shipping	Hyundai	Oct-07	Marshall Is.	S	TZ Mk. III	4	Various
Onaiza	210,100	Nakilat	Daewoo	Apr-09	Liberia	DRL	GT NO 96	4	Qatar-Atlantic Basin
Pacific Arcadia	147,200	NYK Line	MHI	Oct-14	Bahamas	S	KM		Various
Pacific Enlighten	145,000	LNG MT	Mitsubishi	Mar-09	Japan	S	Moss	4	Various
Pacific Eurus	137,000	LNG Marine Transport	Mitsubishi Nagasaki	Mar-06	Bahamas	S	Moss	4	Darwin
Pacific Notus	137,006	Pacific LNG Shipping	Mitsubishi Nagasaki	Sep-03	Bahamas	S	Moss	5	Darwin
Palu LNG	160,106	TMSC Gas	Daewoo	Jun-14	Malta	TFDE	GT No 96	4	Various
Papua	171,800	MOL-China	Hudong	Jan-15	Hong Kong	DFDE	SSD	4	PNG LNG
Polar Eagle	89,880	Polar LNG	IHI Chita	Jun-93	Liberia	S	IHI SPB	4	ConocoPhillips/Marathon
Prachi	173,000	NYK-SCI	Hyundai	Nov-16	Singapore	TFDE	GT No 96	4	Petronet
Provalys	153,500	Gaz de France	Chantiers	Nov-06	France	DFDE	CS1	4	ELNG
Puteri Delima	130,400	MISC	Atlantique	Jan-95	Malaysia	S	GT NO 96	4	Petronas
Puteri Delima Satu	137,100	MISC	Mitsui Chiba	Apr-02	Malaysia	S	GT NO 96	4	Petronas

Puteri Firuz	130,400	MISC	Atlantique	May-97	Malaysia	S	GT NO 96	4	Petronas
Puteri Firuz Satu	137,100	MISC	Mitsubishi Nagasaki	Sep-04	Malaysia	S	GT NO 96	4	Petronas
Puteri Intan	130,400	MISC	Atlantique	Aug-94	Malaysia	S	GT NO 96	4	Petronas
Puteri Intan Satu	137,100	MISC	Mitsubishi Nagasaki	Dec-01	Malaysia	S	GT NO 96	4	Petronas
Puteri Mutiera Satu	137,100	MISC	Mitsui Chiba	Apr-05	Malaysia	S	GT NO 96	4	Petronas
Puteri Nilam	130,400	MISC	Atlantique	Jun-95	Malaysia	S	GT NO 96	4	Petronas
Puteri Nilam Satu	137,100	MISC	Mitsubishi Nagasaki	Sep-03	Malaysia	S	GT NO 96	4	Petronas
Puteri Zamrud	130,400	MISC	Atlantique	May-96	Malaysia	S	GT NO 96	4	Petronas
Puteri Zamrud Satu	137,100	MISC	Mitsui Chiba	Apr-87	Malaysia	S	GT NO 96	4	Atlantic LNG
Raahi	136,000	Petronet LNG Ltd	Daewoo	Dec-04	Malta	S	GT NO 96	4	Qatargas
Ramdane Abane	126,130	SNTM-Hyproc	Atlantique	Jul-81	Algeria	S	GT NO 85	5	Sonatrach
Rasheeda	266,000	QGTC	Samsung	Jun-10	Liberia	DRL	TZ Mk. III		Various
Ribera del Duero Knutsen	173,400	Knutsen	Daewoo	Nov-10	Nor-NIS	DFDE	GT NO. 96	4	Various
Rioja Knutsen	176,300	Knutsen	Daewoo	Dec-16	Nor-NIS	DFDE	TZ Mk III	4	Various
Salalah LNG	147,000	Oman Gas/MOL	Samsung	Dec-05	Japan	S	TZ Mk. III	4	Oman
SCF Polar	71,500	Sovcomflot	Kockums	Aug-69	Liberia	S	GT NO 82	6	Sonatrach
Seishu Maru	162,000	K Line-Transpacific	Kawasaki Sakaide	Jan-15	Panama	S	Moss	4	Australia-Japan
Seri Alam	138,000	MISC	Samsung	Oct-05	Malaysia	S	TZ Mk. III	4	Yemen LNG
Seri Amanah	145,000	MISC	Samsung	Mar-06	Malaysia	S	TZ Mk. III	4	Yemen LNG
Seri Anggun	145,000	MISC	Samsung	Nov-06	Malaysia	S	TZ Mk. III	4	Yemen LNG
Seri Angkasa	145,000	MISC	Samsung	Feb-07	Malaysia	S	TZ Mk. III	4	Petronas
Seri Ayu	145,000	MISC	Samsung	Oct-07	Malaysia	S	TZ Mk. III	4	Various
Seri Bakti	152,300	MISC	Mitsubishi	Mar-07	Malaysia	S	GT NO 96	4	Petronas
Seri Balhaf	152,000	MISC	Mitsubishi	Sep-08	Malaysia	S	GT NO 96	4	Various
Seri Balquis	152,000	MISC	Mitsubishi	Dec-08	Malaysia	S	GT NO 96	4	Various
Seri Begawan	152,300	MISC	Mitsubishi	Dec-07	Malaysia	S	GT NO 96	4	Various
Seri Bijaksana	152,300	MISC	Mitsubishi	Feb-08	Malaysia	S	GT NO 96	4	Petronas
Seri Camellia	150,000	MISC	Hyundai	Nov-16	Malaysia	S	Moss	5	Petronas
Seri Cenderawasih	150,000	MISC	Hyundai	Jan-17	Malaysia	S	Moss	5	Petronas
Sestao Knutsen	138,000	Knutsen	IZAR Sestao	Jan-07	Spain	S	GT NO 96	4	Atlantic LNG
Sevilla Knutsen	173,400	Knutsen	Daewoo	Jun-10	N.I.S.	DFDE	GT NO 96	4	Various
Shahamah	135,500	National Gas Shipping	Kawasaki Sakaide	Oct-94	Liberia	S	Moss	5	ADGAS
Shangra	266,000	QGTC	Samsung	Nov-09	Liberia	DRL	TZ Mk. III	5	Qatargas IV
Shen Hai	147,100	China LNG	Hudong Zhonghua	Sep-12	China	AB/CC Steam	GT NO 96	4	Various
Simaisma	147,700	Maran Gas Maritime	Daewoo	Jul-06	Greece	S	GT No 96	4	Qatar
SK Splendor	138,375	SK Shipping	Samsung	Mar-00	Panama	S	TZ Mk. III	4	Oman Gas
SK Stellar	138,375	SK Shipping	Samsung	Dec-00	Panama	S	TZ Mk. III	4	RasGas
SK Summit	138,000	SK Shipping	Daewoo	Aug-99	Panama	S	GT NO 96	4	RasGas
SK Sunrise	138,306	I. S. Carriers	Samsung	Sep-03	Panama	S	TZ Mk. III	4	RasGas
SK Supreme	138,200	SK Shipping	Samsung	Jan-00	Panama	S	TZ Mk. III	4	RasGas
Sohar LNG	137,250	Oman Gas/ MOL	Mitsubishi Nagasaki	Oct-01	Malta	S	Moss	5	Oman Gas
Solaris	155,000	GasLog	Samsung	Jul-14	Bermuda	TFDE	TZ Mk. III	4	Various
Sonangol Benguela	160,500	Sonangol	Daewoo	Sep-11	Bahamas	S	GT No. 96	4	Angola LNG
Sonangol Etosha	160,500	Sonangol	Daewoo	Sep-11	Bahamas	S	GT No. 96	4	Angola LNG
Sonangol Sambizanga	160,500	Sonangol	Daewoo	Sep-11	Bahamas	S	GT No. 96	4	Angola LNG
Southern Cross	172,000	MOL	Hudong	May-15	Hong Kong	DRL	GT NO. 96	4	Various
Soyo	160,400	Mitsui/NYK/Teekay	Samsung	May-11	Bahamas	DFDE	TZ Mk. III	4	Various
Spirit of Hela	177,000	MOL	Hyundai	Oct-09	Panama	DFDE	TZ Mk. III	4	Various
Stena Blue Sky	145,700	Stena	Daewoo	Jan-06	Panama	S	GT No 96	4	Various
Stena Clear Sky	171,800	Stena	Daewoo	Sep-10	Panama	DFDE	GT NO 96	4	Various
Stena Crystal Sky	171,800	Stena	Daewoo	Jul-10	Panama	DFDE	GT NO 96	4	Various
STX Kolt	145,700	STX Panocean	Korea Hanjin	Nov-08	Panama	DFDE	TZ Mk. III	4	Various
Suez Point Fortin	154,200	Trinity LNG	Koyo Japan	Nov-09	Panama	S	TZ Mk. III	4	Yemen LNG
Taitar No. 1	145,000	NYK Line	Mitsubishi	Oct-09	Liberia	S	Moss	4	Various
Taitar No. 3	145,000	NYK Line	Mitsubishi	Jan-10	Liberia	S	Moss	4	Various
Taitar No. 4	145,000	NYK	Mitsubishi	Jan-10	Liberia	S	Moss	4	Various
Tangguh Batur	145,700	Sovcomflot/NYK	Daewoo	Dec-08	Cyprus	S	GT NO 96		Tangguh
Tangguh Foja	155,000	K Line	Samsung	Jul-08	Panama	DFDE	TZ Mk. III	4	Tangguh LNG
Tangguh Hiri	155,000	Teekay LNG	Hyundai	Nov-08	IOM	DFDE	TZ Mk. III	4	Tangguh
Tangguh Jaya	145,700	K Line	Samsung	Nov-08	Panama	DFDE	TZ Mk. III	4	Tangguh
Tangguh Palung	155,000	K Line	Samsung	Mar-09	Panama	DFDE	TZ Mk. III	4	Tangguh
Tangguh Sago	155,000	Teekay LNG	Hyundai	Mar-09	IOM	DFDE	TZ Mk. III	4	Tangguh LNG
Tangguh Towuti	145,700	Sovcomflot/NYK	Daewoo	Oct-08	Cyprus	S	GT NO 96	4	Tangguh
Tembek	216,200	OSG/Nakilat	Samsung	Sep-07	Marshall Is.	DRL	TZ Mk. III	4	Qatargas II
Tenaga Satu	130,000	MISC	Dunkerque	Sep-82	Malaysia	S	GT NO 88	5	Petronas
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 m^3
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

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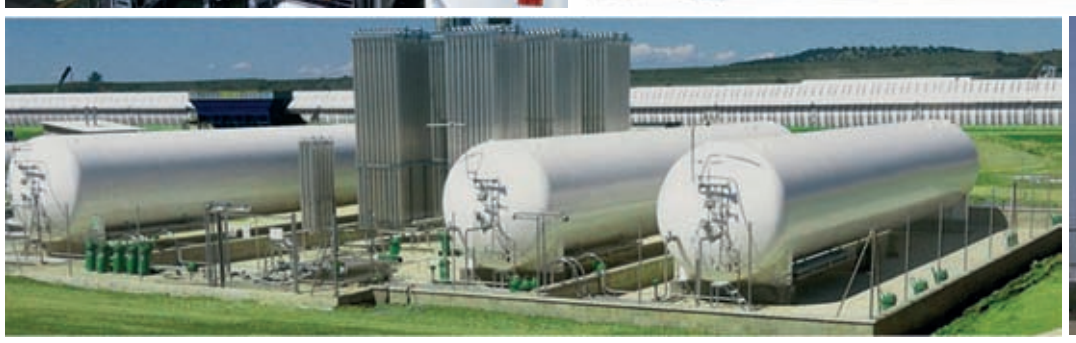

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