The end of the LNG megaproject?
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There is broad consensus within the industry, certainly among liquefied natural gas (LNG) producers, that the market for LNG will rebalance by the early to mid-2020s. There is visibility on the supply side of the balance with global LNG export capacity forecast to increase by one-third by 2021, based solely on projects currently under construction, 78% of which originates from the US and Australia. As of April 2017, a little over 100mtpa of new liquefaction capacity was under construction. A further 400mtpa of unsanctioned liquefaction projects are at varying stages of development, half of which is in the US. A key question for the market and investors is whether the market can absorb all this extra capacity. If you build it, they may not come.

A total of 128mtpa of liquefaction capacity, equivalent to eight Gorgon-sized projects, has been delayed or cancelled since the beginning of 2015. Canada has 17 proposed export projects with an aggregate output of more than 150mtpa but none have reached final investment decision (FID) and three have been delayed indefinitely. In fact, an FID was taken on just one major project in 2016, the addition of a third train at the Tangguh LNG plant in Indonesia.

Why have there been so few FIDs for new LNG projects?

• The convergence of regional gas prices has eroded the premium for LNG in some markets.
• The supply surplus has strengthened the negotiating power of buyers who now demand contracts with shorter durations and greater volume and destination flexibility.
• There have been well-documented examples of cost and schedule overruns on greenfield LNG projects.
• There is greater rigor around capital allocation and near-term capital expenditure budgets have been cut.
• Energy investment is being directed to short-cycle projects with capital flexibility and projects outside the industry, which are increasingly attractive.
• The price downturn has reduced the appetite of lenders for exposure to the industry.

Two proposed projects are expected to reach FID in 2017. The Coral South floating LNG project in Mozambique and the Fortuna floating LNG (FLNG) project in Equatorial Guinea will allow relatively small reserves to be economically developed. FLNG costs are typically lower than land-based alternatives and can be deployed relatively quickly. FID for Coral will be supported by BP agreeing to purchase the entire output of the proposed facility, while the introduction of OneLNG as a partner in the Fortuna FLNG project will facilitate the financing, construction, development and operation of the project.
Demand uncertainties complicate the timing of LNG investment decisions

Most of the large industry players forecast a growing role for natural gas, portraying it as an integral and fundamentally greener part of the future energy mix. But the reality is that the market does not currently see gas as an attractive option. Gas has struggled to gain share in the power generation market. Cheap coal and policy-supported renewable energy are displacing gas in the energy mix meaning that the outlook for gas demand is very uncertain. Short-term forecasts of gas demand growth are less optimistic than those generated just a couple of years ago. Sustained low LNG prices may stimulate additional demand but policy support, such as the wider use of carbon trading or carbon taxes, is also needed to encourage the switch to gas in the short term.

On the positive side, demand lead times have become shorter due to the emergence of lower cost floating storage regasification units (FSRUs). These are typically offered to the market on leased terms, allowing projects to be developed with limited up-front investment from the importers. The wider deployment of FSRUs and lower LNG prices are making importing attractive to new, smaller markets that would have been uneconomic to supply previously. There is also growing interest from mature gas producing markets where domestic output is declining and there is spare capacity in existing infrastructure. In the shorter term, however, the demand from these new markets is unlikely to substantially offset the expected decline in demand from the traditional importing economies of Japan, South Korea and Taiwan. For Japan specifically, forecasts of gas demand come with caveats about the timeline for the restart of the country’s nuclear power plants, development of new coal-fired power stations and expansion of renewable energy sources and storage capacity, as well as energy market deregulation.

How fast the market rebalances will largely depend on the appetite of China and India to commit to additional volumes. China’s latest five-year plan sees gas representing 10% of the energy mix by 2020 and the share of non-fossil fuels rising to more than 15%. LNG imports to China have been unpredictable over the last two years due to the interaction between LNG, pipeline supplies and domestic production. Future Chinese LNG demand will partly be influenced by the effectiveness of policies designed to improve air quality, where the switch from coal to gas can be a useful lever. However, increased Chinese gas consumption forecasts should be caveated by China’s stated intention to spend more than US$360 billion through 2020 on renewable energy (source: China National Energy Administration).

LNG demand growth beyond the 4%-5% per annum widely predicted in oil and gas companies’ energy outlooks, coupled with cutbacks in spending and the deferral of projects, may point to a more rapid tightening of the market. Given this uncertainty, when should companies take FID on new projects to take advantage of the next demand growth cycle?

Figure 1 – LNG supply surplus (deficit)

Source: EY analysis
Assuming 4% per annum growth in demand, LNG supply, including projects under construction, overshoots demand until 2024 when the market should rebalance. Following these assumptions, beyond 2023-24, new supply is needed to meet the anticipated demand growth. The lead time from FID to first LNG for traditional greenfield projects is typically four to five years, assuming no delays. This suggests that to meet demand forecasts, FIDs on new projects are necessary from 2019. However, the traditional project development model looks to be under threat given the uncertainties surrounding future demand. Large, capital-intensive projects have economic lifespans that vastly exceed the lifespan certainty of the oil and gas industry.

Without increased confidence in demand growth forecasts, or a significant reduction in planned project costs, attracting financing for new LNG projects will be difficult. And without investment grade buyers or long-term sales agreements, bespoke solutions may be required if gas resources are not to be left stranded. Companies can’t control demand, although, they can have an influence in developing new markets through downstream investments and alliances. Therefore they should focus on what they can control – project cost and execution. The next generation of LNG needs to be competitive with Henry Hub-priced LNG. Developers need to lower costs to compete in an environment where they won’t have US$100/bbl oil to support projects. Cost deflation alone over the last three years has not been sufficient to justify new investments.

**What would it take to get LNG projects to FID in the new pricing environment?**

For nearly all the proposed LNG projects to progress, development cost would need to come down and delivery certainty, to budget and schedule, increased. Improving project planning and delivery capability, reconsidering project scale, diluting equity positions, developing local markets, collaborating with neighboring resource holders and exploring alternative financing options will be required in the new pricing environment.

Research by EY has shown that development and execution performance on large projects is extremely poor, with overruns an unfortunate industry standard. Indeed, EY’s Spotlight on oil and gas megaprojects report showed that 64% of projects overrun their cost estimates, that 73% of projects overrun their schedule estimates and that the average cost overrun was found to be 59% (across a database of 365 current megaprojects). Even before the
oil price fall in 2014, there was demand from investors to improve performance to target, but now overruns of this nature are wholly unacceptable. Indeed, the risk of such overruns is a contributing factor behind many projects stalling in the development cycle prior to FID.

Now, this pressure to demonstrate improved project fundamentals prior to FID might be increasing the risk of optimism bias in the estimation of delivery costs. Project teams are expected to significantly reduce the target cost of projects (to achieve FID) and to deliver to those targets with greater success, but all with the same or diminished project team capability, the same suppliers and the same technology. This risk is something which must be carefully scrutinized by project and corporate leadership.

These performance results, together with industry man-hour productivity statistics\(^1\) and escalation of project costs over the past decade, suggest that there is huge opportunity to increase project delivery efficiency, stripping out project cost and variability to improve overall economics. When considering the development, approval and delivery performance of LNG projects, project leadership and company executives must focus on three strategic imperatives:

Oversight —
to deliver sufficient oversight over both project targets and performance:
- Increase transparency over key decisions and project performance for stakeholders
- Improve operated and non-operated project performance through effective assurance
- Effectively govern project portfolios to manage risk and select optimum projects for investment

Capability —
to build and maintain appropriate project team capability to develop and execute to target
- Create sufficient capacity and proficiency to manage front-end engineering design (FEED) and development contractors
- Meet man-hour requirements across the portfolio of development projects, creating effective development activities without prohibitive expense
- Maintain consistency in development of project plans (e.g., assumptions, P value assessments) in a market where the workforce is mobile and not retained

Efficiency —
to develop and execute projects as efficiently as possible — to sustainably reduce cost, rather than just to hit targets:
- Reduce project development costs (while maintaining or improving quality) to meet increasingly stringent planning budgets and continue to drive cost efficiency over time
- Reduce inefficiency in interactions with key contractors and suppliers through effective collaboration in FEED work and detailed design
- Drive standardization of equipment and common units (e.g., trains, utilities) across projects to reduce time spent redesigning similar items

Each of these three strategic imperatives are explored in more detail in our megaprojects paper to be released in June 2017.

Key to delivering against these strategic themes will be the industry’s ability to engage its supply chain and EPCs to aid the efficiency drive. So far, since the 2014 oil price fall, cost reduction initiatives have been largely binary in nature, relying on headcount reductions, rather than true efficiency. These not only risk long-term damage to the industry, but also fail to deliver on the opportunity to minimize project-wide inefficiencies in the way clients, contractors and the supply chain interact.

On current and future projects, owners must seek to build collaborative models that overcome both the challenges, and history, of adversarial EPC/owner relationships and the inherent disincentive, which exists to drive efficiency and which is imposed by the industry’s prevailing commercial models.

In addition to improved project planning and execution, the industry will also need to consider greater modularization of projects and standardization of design and construction activities.

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\(^1\) Wages and salaries, employment and productivity, by industry, Table 09174, Statistics Norway.
Modular projects: with oil and gas prices set to remain low, investors are starting to favor smaller, more targeted investments with quicker economic returns over the megaprojects of the last decade. New capacity could be added in smaller increments with capex development delivered to higher performance standards. This would facilitate rapid investment decisions, reduce risk and allow companies to build flexibility into their portfolios to align to market demand.

Modular plants provide the option to scale up quickly and cost effectively in response to demand signals. This would involve smaller trains of up to 1mtpa compared with the 4-5mtpa for trains that have entered service in the last two years. The trains would be built to proven, repeatable designs to facilitate more predictable and stable operations. In an effort to maintain the cost advantage of US LNG, several planned export projects are being developed using modular liquefaction trains. These trains could operate individually providing a flexible, low-cost supply source.

Figure 2 — Pre-FID US LNG export projects

Source: EY analysis
A modular train can be constructed offsite at a fabrication yard, which reduces the risk and complexity of the on-site installation effort. Work can take place at the fabrication facility and in the field simultaneously, allowing for faster project execution and time to first revenues. Individual modules can also be pre-commissioned, which could provide a competitive edge given the delays and intermittent stoppages during the start-up of some LNG projects in 2015 and 2016. Individual modules could be easily and cost-effectively replaced or updated enhancing operational efficiencies. Modular is often associated with small-scale LNG but modular construction can also be used to build larger trains of up to 5mtpa.

**Brownfield developments**: there is an additional tranche of LNG that could come to the market at considerably lower prices when compared to the cost of developing new plants and the associated gas supplies. Supply from brownfield developments could make a meaningful contribution to closing any supply gap that emerges before new greenfield capacity is built.

Some large-scale LNG producers could maximize economies of scale through debottlenecking, plant expansion or tying in new supplies. These options offer significant economic advantages over new developments. LNG plant owners will likely want to get the most out of their existing facilities before considering expansion. Investors in these projects are faced with longer payback periods due to oil and gas prices being lower than when they were sanctioned. Some of the earlier LNG projects in Australia will have spare capacity in the next five years as the upstream fields that feed them begin to deplete. The focus for these operators will be on securing supply sources to keep their existing plants full. Costs could be kept down by taking volumes from nearby undeveloped resources that owners had intended to progress separately and perhaps put them through competing new LNG plants. Although, this approach would require greater collaboration, an area where the industry does not have a strong track record.

When the next tranche of LNG is required, project owners wanting to expand their operational facilities will have the advantage of access to low-cost sources of gas and existing infrastructure and developed relationships with host governments. Project owners would not need to secure buyers for the full output of any additional trains before proceeding because they have cash flow from their existing trains.

**Improving the reliability of existing plants**: according to the IEA, almost 15% of LNG capacity globally is estimated to be unavailable today due to unplanned outages, security concerns or lack of feed gas. Output from five LNG plants, accounting for 6% of global capacity, was temporarily unavailable for a time due to unplanned outages in 2016. Even small improvements in reliability could tip the market into oversupply.

**Equity investment by buyers along the LNG value chain**: Asian buyers invested in the wave of Australian LNG projects now coming online. Faced with deregulation in their home markets and increased competition, they are looking for investment opportunities across the global LNG value chain. With NOCs largely absent from the M&A market, there will be investment opportunities for LNG buyers to integrate upstream. Companies could reduce the costs of procuring LNG through access to equity production and would not be compelled to sign new long-term contracts to replace volumes from expiring purchase agreements. Over-contracted companies may also be willing to invest capital to help develop new markets for LNG where they would be the supplier.

**Integration with end use applications**: company investment in its gas business has typically focused on the supply side. Producers have targeted higher output despite natural gas not being cost competitive relative to other fuels in many markets. To make gas a more attractive option, companies will need to invest in gas infrastructure and applications. Companies need to harvest value from every gas molecule produced. Involvement in the complete supply chain, from well to end customer, creates optionality. Investment in end-use applications in the transport sector and electricity markets through integrated LNG-to-power schemes creates demand certainty. The LNG value chain continues to expand, opening up new opportunities.
The gas value chain is becoming more complex

Source: EY
LNG relevance in a market of gas abundance

In a world where LNG development costs remain high, oil and gas prices have shifted structurally lower, and where there is growing opposition to globalization and more protectionism, it is worth considering whether more gas resources should be consumed locally or within region? It could be more attractive both from a security and price viewpoint.

However, some countries, such as Japan and South Korea, currently have no alternatives other than LNG to secure access to gas supplies. LNG, unlike pipeline gas, can be redirected to different parts of the world in response to regional price signals. Spare regasification capacity allows regions such as Europe and China to arbitrage between pipeline gas and LNG based on pricing. However, there can be delays in the LNG supply chain response, as seen with the price spikes in early 2017. LNG cargoes were diverted to Northeast Asia from Europe because the southern half of the continent was experiencing tight supplies amid an unusually cold spell. A pipeline binds the seller to the buyer, while LNG offers a more flexible approach, although that flexibility comes as a cost; the closer suppliers are to buyers, the lower that cost is.

“Why do we compress gas into liquid form to transport it around the world? It’s about as ridiculous as climbing to the top of a mountain to bring back a bucket of water.”

Espen Norheim
Partner, Ernst & Young AS

Figure 3 — Gas imports in 2015 (Bcm)

The relevance of LNG in a low-carbon future

Despite some success in driving LNG development costs lower, these efforts may not be sufficient to improve project economics. Gas is still expensive to liquefy, LNG is expensive to transport and it is expensive to convert back into a gaseous state. Costs would need to be lowered at every stage of the LNG production cycle, from finding and developments costs, to liquefaction technology, shipping rates and tanker build costs, and connections to existing distribution infrastructure or new build import capacity. Furthermore, gas project developers are not just competing with other gas producers. Regulators and consumers are supporting more significant action to mitigate CO2 emissions and a shift to cleaner energy sources is now inevitable. The threat posed by recent step-changes in the cost-competitiveness of renewables and advances in energy storage technology mean that LNG demand growth projections may be overly optimistic. At the moment, renewables are replacing gas rather than cheap coal in the generation mix.

IEA estimates indicate that in 2016, Organisation for Economic Co-operation and Development net electricity production grew by 0.9%. Within this small overall change, there was a large increase of 9.5% in solar, wind and geothermal and other renewables generation. These increases are forecast to continue as energy storage technologies enable greater use of renewables to provide baseload capacity. At current and forecast rates of growth, the point at which renewables growth is able to meet global marginal energy demand increase – a time of potential peak fossil fuel demand – is not far off.²

The levelized cost of generating electricity (LCOE) is a widely used measure of the competitiveness of different generating technologies. It compares the costs of financing, building, operating and maintaining a power plant. This approach does have a number of limitations, though LCOE does provide a useful summary measure of the overall competitiveness of different generating technologies. The unsubsidized LCOE for baseload power generation from natural gas is competitive with onshore wind, new coal and nuclear. Onshore wind power technology is relatively mature and proven at scale.

The economics of offshore wind and utility-scale solar PV generation have improved dramatically over the last couple of years. The unsubsidized LCOE for utility-scale solar PV power generation has declined a staggering 85% since 2009.³ While the unsubsidized LCOE for wind power has fallen 66% over the last seven years. With advances in technology, such as more efficient wind turbines, and increasing economies of scale, there is reason to think that costs will continue to fall, albeit less dramatically. The strong delivery performance of large renewables projects to increasingly ambitious schedule and cost targets is also a challenge to an LNG sector that in recent years has been blighted by project cost blowouts and delays.⁴

If oil and gas companies delay building the LNG supply chain because the needle on development costs is not moving quickly enough, they will miss the opportunity to grow the share of gas in the evolving transport and power generation sectors. In this scenario, investor cash will be invested into developing the network for competing fuels and renewable sources. The new market environment requires new LNG business models geared towards lower-cost, more flexible portfolios and greater engagement in demand creation.

If the industry keeps doing the same things, it will keep getting the same outcomes. It’s time to challenge the LNG producers’ crowd-sourced view of project development and the future of the energy industry.

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EYG no. 04513-174GBL
BMC Agency
GA 1005402
ED None

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