LNG: Fuel for a Changing World—A Nontechnical Guide

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Introduction: The Liquefied Natural Gas Industry—An Overview

A "perfect storm" of $100 oil (at least until the middle of 2014), coupled with technological developments such as horizontal drilling and hydraulic fracturing, fast-track floating regasification terminals, and a dimming outlook for nuclear power in the wake of the Fukushima disaster, has created a boom in the LNG business. At the same time, the commercial structure of the industry has evolved. Spot and short-term sales now represent more than 25% of the market, while new business models have opened up opportunities for a multitude of new industry participants. As of December 2014, there were far more LNG projects under construction and in the planning stage than ever before. As the number of exporters and importers increases, LNG will continue to be the fastest growing segment of the hydrocarbon industry for the foreseeable future. Although the industry has impressive potential, it also faces major challenges. Companies may have to take greater commercial risks in the hope of reaping larger financial rewards.

In an increasingly environmentally conscious world, natural gas, because of its clean-burning characteristics, is consolidating its position as the fossil fuel of choice. It promises to be the only hydrocarbon that will continue to increase its share of global primary energy supply. Once described as a bridge to a clean energy future, natural gas now seems to be a strategic long-term component of it. This increasing role for natural gas is being enhanced by the development of unconventional gas from shale in the United States and coalbed methane in Australia, contributing to an ever-expanding natural gas resource base. Even as abundant and relatively cheap unconventional gas brings down prices and spurs demand, much of the world's gas reserves will remain surplus to local needs and will need to access distant markets. Developers will turn to LNG as the way to commercialize these resources.

Given the scale and likely rate of development, Poten & Partners projects the global LNG market will surpass 360 million tons per year (Mmt/y) or 490 billion cubic meters per year (Bcm/y) by 2020 and 415 million tons per year (565 Bcm/y) by 2025. The industry has already more than doubled from 103 million tons per year (140 Bcm/y) at the turn of the century to 243 million tons (330 Bcm) in 2014. The consensus view holds that the rate of growth in the LNG industry will be about twice that of global natural gas. But this will only occur if hundreds of billions of dollars are invested to make the additional LNG supply available and to build the ships and infrastructure to deliver it to consumers. Much of this investment is being made in Australia and in North America. These two regions are likely to rival Qatar as the world's largest LNG producer and exporter in the next decade. Longer term, East Africa (Mozambique and Tanzania) may become a key LNG supply region, with potential for multiple projects to monetize more than 120 Tcf of proven reserves, but these projects face greenfield and geopolitical challenges. On the market side, new outlets are opening up in both developed and developing countries, spurred by the advantages of natural gas compared to other fuels and at times by the availability of floating regasification terminals.

This promising future should not be taken for granted. If history has taught us anything, especially recently, it is that industry dynamics can change quickly, and with unpredictable consequences. When the first edition of this book was published in 2007, the consensus among industry experts was that the United States would be the next major LNG import market. Export projects in Africa, the Middle East, and beyond were being built to supply a wave of new import terminals in the United States (by far the largest natural gas market in the world) and Europe—including the United Kingdom. Among the projects developed primarily to supply the United States and the United Kingdom were six so-called megatrains in Qatar, each with a capacity of 7.8 MMt/y (10.6 Bcm/y)—by far the largest ever built. These megatrains made Qatar the largest LNG producer in the world.

At the time, shale gas was in its infancy and few foresaw the impact it would have on the natural gas market and the LNG industry. In short order, US shale gas turned the world's gas market on its head. The development of shale gas reversed the expected decline in US natural gas production, halving the need for Canadian pipeline

imports and almost eliminating the need for LNG imports. In the United Kingdom and Europe, weak economic conditions, coupled with heavily subsidized renewable energy, a broken carbon trading scheme and an onslaught of cheap coal (ironically displaced in the United States by shale gas), curbed natural gas and LNG demand. Prices fell sharply in both regions. Export projects built to supply these markets struggled. For example, Qatar Petroleum and its foreign partners had built two massive LNG import terminals, one in the United States and the other in the United Kingdom, each capable of receiving the production of two megatrains, nearly 15 MMt/y (20 Bcm/y) each. By 2010, these investments were looking less than stellar. Similarly, the other new LNG terminals built to serve the North American and European markets were largely empty.

The export ventures were largely saved by another unforeseen event—the March 2011 tsunami and the resulting Fukushima nuclear disaster in Japan, which resulted in the eventual closure of the nation's 54 nuclear units. This closing created a huge jump in LNG demand to fuel the nation's gas-fired power plants. In 2012, the first full year without nuclear production, Japan's LNG imports climbed 17.5 MMt/y (24Bcm/y) to 87.5 MMt (119Bcm/y). This increase amounted to nearly 8% of global LNG production. In addition to imports into Japan, imports into Latin America also surged during this period, driven by a number of factors.

The resulting "tight" LNG market—anticipated by neither buyers nor sellers—boosted spot LNG prices to over $20/MMBtu and encouraged buyers to scour the globe for LNG supplies. This contributed to a wave of investment in Australian LNG projects, where robust oil-linked sales prices and firm purchase commitments underwrote project viability in the face of overheated construction costs. Project sponsors there made extensive use of modular construction in an attempt to shift work overseas to avoid high-cost local labor. In addition, Australia witnessed the first sanction of a project based on a floating LNG production unit—Prelude LNG led by Shell—and the first LNG export projects based on unconventional natural gas (coalbed methane). As more projects moved through the development process, sponsors began offering equity in both the upstream and the liquefaction complex as an inducement to the buyers to commit to their projects. These arrangements were designed to share risk as well as financial returns with the buyers.

With high construction costs and increasing overruns, spurred on by severe labor constraints, Australian LNG project development slowed down and essentially halted by 2012. Buyers began to turn their attention to North America, where the flood of shale gas was hitting the market, driving down prices and virtually eliminating the appetite for LNG imports. With falling North American prices, high prices and high demand in Asia opened up the possibility of capturing the widening arbitrage value between the two regions. Growing short- and medium-term volumes of LNG, increased trading, and the emergence of LNG "portfolio" aggregators all helped to challenge and change the conventional wisdom of the LNG market. Entrepreneurial US terminal owners, with their import facilities lying fallow, saw the opportunity to add liquefaction trains at their sites—at far lower unit capital costs than new greenfield projects—that would transform North American gas into LNG.

Terminal owners adopted a capacity tolling model to commercialize their underutilized import facilities (Cheniere's model involves the free on board [FOB] sale of LNG, placing responsibility for the supply of feed gas on the terminal owner, but is otherwise commercially indistinguishable from tolling). In this model, capacity holders, who include utility companies, LNG aggregators, and trading firms, lease liquefaction capacity, buy their own feed gas from the grid, and take the resulting LNG from the plant on an FOB basis. Terminal costs, including capital charges, are guaranteed through fixed charges, with the "tolling" customers taking both price and volume risks. For Asian utilities, these projects offer the attraction of Henry Hub–linked prices, which diversify the pricing in their LNG purchase portfolio away from traditional oil-linked terms. The LNG also provides destination flexibility absent from most of the utilities' other supplies. For the aggregators and traders, LNG supply linked to Henry Hub opened up the opportunity to benefit from price arbitrage by reselling volumes to markets where oil-linked LNG prices set a higher benchmark. But, while margin plays between Henry Hub and oil-linked prices could have generated huge arbitrage profits in the conditions prevailing in early 2014, they could also result in significant losses when the price relationship between Henry Hub and crude oil tightens, as it did in early 2015.

The technologies that drove the North American shale gas revolution were first viewed as a threat to the LNG industry because they

largely eliminated the need for LNG imports. But as a benefit, they spawned an LNG export business, which was entirely new. However, these same technologies have been driving US shale oil growth as well, leading to rapid declines in oil imports. Just as the United States has become the global leader in natural gas production, the country is on track to replace Saudi Arabia as the world's largest oil producer. Thanks to shale oil, by the end of 2014, US crude oil production climbed to nearly 9 MMb/d from 5 MMb/d in 2005. Saudi Arabia produces 10 MMb/d. Coupled with slowing demand for oil in the world economy, this growth contributed to a collapse in crude oil prices. As 2015 opened, Brent was trading at under $55/bbl and WTI (West Texas Intermediate) at less than $50/bbl. Saudi Arabia has declared that it will defend its oil market share without regard to the price consequences. In the process, it apparently hopes to curb the growth in US oil production.

If the fall in crude oil prices proves to be more than a temporary event, it will have significant consequences in the LNG industry and could undermine the financial viability of new liquefaction projects—including those grassroots projects based on unconventional natural gas resources. For example, each project in Queensland, in eastern Australia, where coalbed methane supplies the feed gas, will require an ongoing A$1 to A$2 billion (US$0.75 to US$1.5 billion) annual investment after the project is commissioned, in order to maintain feed gas levels. This will result in a higher marginal cost of production than any other integrated LNG project. In the United States, customers who are not utilities buying for their supply needs could find the trading margin between the Henry Hub–linked price and other regional pricing has disappeared, or worse, turned negative. With crude oil prices between $60 and $70/bbl—equivalent to about $9–$10/MMBtu for LNG delivered in Asia and $7–$8/MMBtu in Europe—margins will shrink to unsustainable levels. To break even at $9/MMBtu in Asia, Henry Hub would have to fall to about $2.50/MMBtu. New US liquefaction ventures, especially ones based on grassroots development, may have a difficult time finding the customers required to proceed, let alone the $50–$100 million up-front investment to secure the necessary permits. Potentially adding to the problem, lower prices for associated liquids could boost the break-even production cost for shale gas in the United States and Canada.

LNG demand could present another challenge to the industry. Just as Fukushima helped spur the current generation of LNG export projects, the restart of nuclear plants in Japan could contribute to a supply surplus. The Abe government has indicated a determination to restart many of the nuclear plants. However, local opposition is very strong and could slow the pace of restarts and in turn, slow the decline in Japanese LNG imports.

These developments will increase the pressure on sellers to find other outlets. While lower LNG prices should spur demand, the United States, the largest natural gas market, will be an exporter and not a net importer. Meanwhile, continuing tough economic conditions threaten to undermine the LNG import outlook in Europe, and previous peak import levels may not be reached before the end of this decade. Of course, unforeseen events could change this, particularly given the political climate in Russia, the largest pipeline gas supplier to Europe.

Lower prices could spur demand in China, India, and other emerging markets. Since the first edition of this book was published, China and India have become major LNG importing markets, and lower prices will further enhance their natural gas demand. Slowing economic growth in China, however, coupled with rapidly increasing pipeline imports from Turkmenistan, Myanmar, and Russia, could temper China's appetite for LNG. Full realization of their import potential, however, awaits progress on downstream market reforms. Concurrently, new markets have flourished (primarily by implementing fast-track offshore floating regasification terminals), particularly in Southeast Asia, the Middle East, and South America.

Another positive development, not foreseen in the earlier book, is the maturation of floating regasification terminals. These regasification ships have opened new markets in many locations, and under a variety of new commercial approaches to the LNG market. The new markets would benefit immensely from competitively priced and ample LNG supplies. However, many of them are characterized by less-than-steady baseload demand, and often less-than-creditworthy buyers.

While it is impossible to identify the circumstances that will impact the LNG industry in the future, this book aims to provide an understanding of the commercial and technical underpinnings of the industry, and a method for analyzing unfolding industry-impacting

events. One thing is certain—there will be unforeseen events or "wild cards" that will cause the LNG industry to develop in new and unanticipated ways. Just as the past few years have witnessed vicissitudes such as the "shale gale," a sustained economic slump in Europe, the Japanese nuclear crisis, a sudden and steep drop in oil prices, and the maturation of new technologies, the next decade holds the promise of more to come. The forecast may call for a few strong winds and thunderstorms, but the future of natural gas, and especially LNG, remains bright.

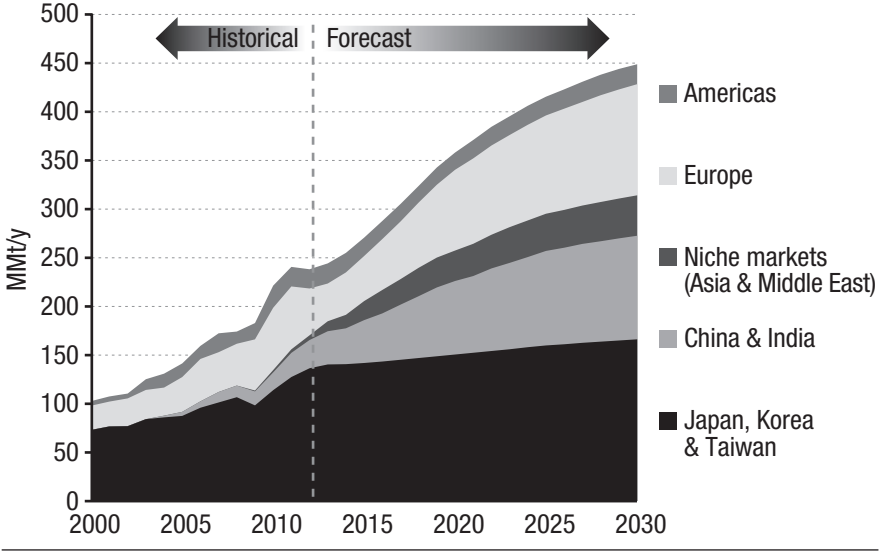

Fig. 1–3. LNG demand by geography. (*Source:* Poten & Partners.)

Hundreds of billions of dollars will need to be invested in order to make this additional LNG supply available. Much of this investment is underway in Australia and the United States, with East Africa and Canada poised to follow. However, dramatic cost escalations and environmental issues in Australia may threaten further growth there, and similar dynamics may be appearing in western Canada, threatening the emergence of an LNG export industry in that region. In contrast to the oil industry, LNG is a more technically, financially, and commercially challenging energy delivery system, well suited to the strengths and competencies of major oil- and gas-producing companies. There is no world price for natural gas or LNG, and some end-markets remain under the control of regulated utilities and essentially closed to competition. Simply having access to large untapped reserves of natural gas is no assurance that these reserves will be monetized easily or quickly or that their development will be financially viable.

In simple terms, the LNG industry involves identifying large reserves of natural gas with little or no prospect of securing local markets, liquefying the natural gas at very low temperatures (–163° Centigrade), shipping the LNG in specially designed tankers to markets, and storing and regasifying (or vaporizing) it before injecting it into a pipeline grid, at which point it becomes indistinguishable

2

The LNG Chain: The Project Nature of the LNG Business

Introduction

The LNG business evolved as a collection of independent, disconnected projects. It originated in an environment with few potential customers or suppliers, where gas was seen as a nuisance rather than as a valuable commodity. When trying to bring remote gas reserves to market, it was logical to develop each business opportunity as a stand-alone project, essentially simulating a long-distance pipeline. Each project was designed to bring dedicated reserves to specific markets through a chain of separate but closely linked stages: upstream gas production and gathering, liquefaction, shipping, and regasification. Each stage was connected to the other by long-term contractual relationships (fig. 2–1). Projects were developed with different technical and commercial considerations, government policies, financing, and fiscal terms so that project developers often had to create unique solutions for the specific problems and opportunities presented by each environment.

ExxonMobil, Shell, Total, ConocoPhillips, and others are integrating forward as well and securing access to and/or ownership in various North American and European LNG import terminals. In Asia-Pacific, there have been comparatively limited opportunities for international companies to participate in the downstream sector, as markets in Japan, South Korea, Taiwan, China, and India have been much slower than their European and US counterparts in implementing energy market liberalization measures.

LNG purchasers have taken similar positions in liquefaction projects throughout Southeast Asia and now in proposed projects in the United States and British Columbia (fig. 2–3). They are also leasing tolling capacities at liquefaction projects in the United States with the intention of arranging their own feed gas supply, and are taking the LNG produced into their supply portfolios both for their home markets and for trading and marketing in general.

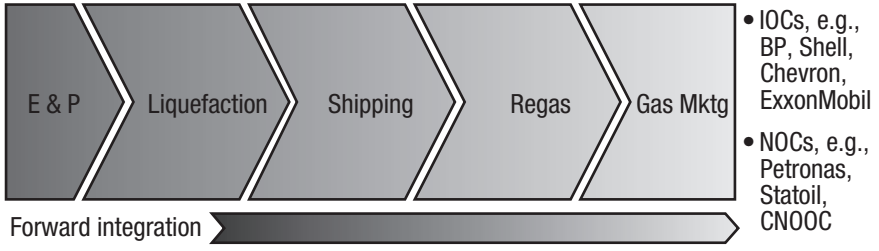

Fig. 2–2. Forward integration. (*Source:* Poten & Partners.)

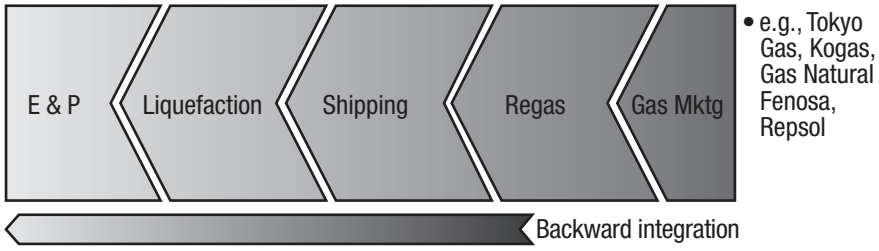

Fig. 2–3. Backward integration. (*Source:* Poten & Partners.)

Panigaglia LNG, Portovenere. Snam's 1971 vintage Panigaglia LNG terminal will require a significant upgrade if it is to remain in operation. The 2.5 MMt/y (3.4 Bcm/y) terminal, built to facilitate small ship deliveries from Algeria, received just one cargo from the North African producer in 2013. The occasional Spanish reload is still being discharged at Panigaglia. The timetable for a decision on a terminal modernization program has been extended to 2015.

Adriatic LNG, Offshore Rovigo, Adriatic Sea. Qatar Petroleum and ExxonMobil linked up with Italy's Edison Gas to construct a gravity-based LNG terminal offshore near Rovigo. The 5.5 MMt/y (7.5 Bcm/y) structure, which can accommodate LNG carriers as large as 152,000 m^3, was commissioned in 2009 to facilitate deliveries from Qatar's RasGas II venture. In 2013, virtually all of the nation's LNG imports were delivered through Adriatic LNG.

OLT Offshore LNG Toscana, Offshore Livorno. The OLT (Offshore LNG Terminal) Offshore LNG Toscana, located 22 miles off the Tuscan coast near Livorno, was commissioned in late 2013 after years of delay. Neither E.ON nor its OLT partners have lined up firm LNG supplies for the 2.7 MMt/y (3.75 Bcm/y) FSRU, suggesting low utilization for at least its first year of operation. LNG carriers up to 137,000 m^3 can berth at OLT. The *Golar Frost* was converted into an FSRU for service at OLT, and the overall cost of the project, including the pipeline connection to shore, is reported to have exceeded $1 billion.

Germany

Germany, the industrial heart of Europe, is also the largest natural gas market on that continent, consuming 83.6 Bcm (8.1 Bcf/d) in 2013 according to BP.[54] German gas demand has fluctuated between 75 Bcm/y (7.2 Bcf/d) and 87 Bcm/y (8.4 Bcf/d) over the past decade. Chancellor Angela Merkel's decision in 2011 to shut all 17 of Germany's nuclear power stations by 2022 promises to be a driver of future German gas demand growth, though overall demand growth tends to be muted by energy efficiency gains and by renewable energy development.