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The Liquefied Natural Gas Industry

Introduction

Liquefied natural gas (LNG) promises to be a growing strategic component of the global clean energy future. Long considered the ugly stepsister of oil, natural gas's clean-burning characteristics are increasingly prized in an environmentally conscious world just as the resource base has been boosted dramatically by new technologies, which are unlocking unconventional gas resources such as shale gas. Some environmentalists have touted natural gas as a bridge to a clean energy future, but it will be more than that. Given its abundance and lower emissions than other fossil fuels, natural gas seems destined to become the dominant fossil fuel source over the next few decades. But natural gas reserves located far from markets must overcome investment costs and transport hurdles. Today, LNG is the most established and effective way to clear these hurdles. This book addresses all aspects of the LNG industry, particularly the striking transformations since the first edition of this book was published in 2007. In these pages, the reader can learn how the LNG industry has evolved and why—to steal a phrase from the International Energy Agency (IEA)—the "golden age" of LNG is at hand. Since 2007, shale gas has emerged as a dominant supply, floating regasification has entered the mainstream, floating liquefaction is under construction, and, perhaps the biggest game changer of all, North America has shifted from potentially becoming the world's largest LNG importer

to becoming its largest LNG exporter. Any one of these changes might justify a new edition; together they compel it.

Energy demand grows inexorably with expansion of the world economy. Economic growth has slowed dramatically in the industrialized world, but China, India, and other emerging economies are now creating new LNG demand. Concerns over global warming have not abated as renewable energy is developing more slowly than its supporters would wish, even with favorable tax and policy initiatives to support it in many countries. At the same time, prospects for future nuclear developments were devastated by the March 11, 2011, Fukushima nuclear accident following an earthquake and tsunami in Japan.

Remaining reserves of conventional oil are concentrated in increasingly fewer countries, not all favorable to the major consuming nations. Yet technological advances are unlocking new oil and gas resources, upsetting the global producer–consumer balance; the US shale oil and gas revolution is a prime example. National oil companies (NOCs) have grown in importance as higher prices combined with ready access to technology have enabled them to operate independently of the large international oil companies (IOCs) on which they traditionally depended. Despite having access to ample cash flows, the IOCs are struggling to grow profitably as their access to conventional oil reserves becomes more restricted. In addition, IOCs face growing competition from other producers, including the emerging NOCs. Given a broader geographical footprint, the complexity of large-scale projects, the faster growth in demand, and the more benign environmental characteristics, it is no surprise that natural gas, especially as LNG, has become a growing objective for the IOCs. Long gone are the days when the geologist returned home to report the bad and the good news about recent exploration endeavors—the bad news that they had failed to find oil, and the good news that they did not find natural gas.

In the 1970s, an era of worldwide concern over limitations to commodity production, natural gas was seen as a limited resource, too precious to consume in many applications. In fact, some producers described natural gas as the noble fuel, worthy of being sold at a premium to both oil and coal. Government policies among the developed nations encouraged this perception by restricting the use of gas as a matter of policy, and controlling prices. But in the early

1980s, natural gas prices were falling in the large US market, and a glut of the fuel emerged following decontrol of wellhead natural gas prices. Low prices, coupled with its clean-burning characteristics, made natural gas a favored fuel. This trend was spurred on by the development of highly efficient combined cycle gas turbine (CCGT) technology to generate electricity in the United States and globally.

In the 21st century, natural gas has emerged as one of the fastest growing sources of primary energy and the fastest growing fossil fuel. This trend is expected to continue for the foreseeable future because the world's natural gas resource base has been transformed by the exploitation of unconventional gas. Spearheaded by the unexpected boom in shale gas production in North America, this game-changing development may spread elsewhere, significantly adding to global gas supplies. In June 2011, the IEA released a report titled "Are We Entering a Golden Age of Gas?" lauding the potential of unconventional gas. The IEA concluded that "natural gas is poised to enter a golden age, but will do so only if a significant proportion of the world's vast resources of unconventional gas—shale gas, tight gas, and coalbed methane—can be developed profitably and in an environmentally acceptable manner."[1] The report made the general public aware of what the energy industry had already concluded: gas is not merely a bridge to a clean energy future; it is almost certainly an integral part of it.

According to the IEA, natural gas is the only fossil fuel that will increase its share of the global primary energy mix over time, a trend that is already under way in many key markets. In the IEA base case, natural gas will increase from 21% of primary energy in 2010 to 25% by 2035.[2] Although oil remains the largest component of primary energy, accounting for about 32% of total world energy demand in 2010, its share has slipped from over 40% in the early 1980s, while the share of natural gas has increased from 19% to nearly 21% in the same time frame (fig. 1–1). Oil will maintain its top ranking through 2035, but its share will slide to 27%, only slightly ahead of natural gas. Coal will slip to third place, dropping from 28% to 24% as natural gas displaces coal as the preferred fuel for power generation.

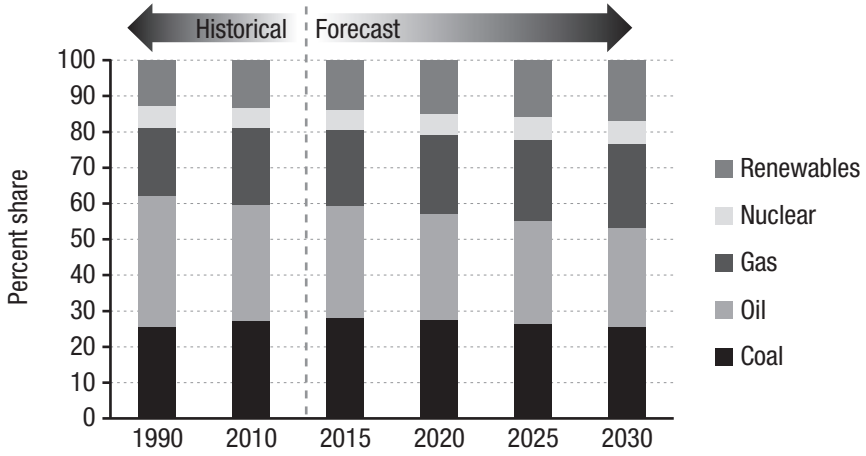

Fig. 1–1. Global primary energy sources. (*Source:* IEA, Poten & Partners.)

The IEA forecasts gas demand to grow by more than half, from 3.4 trillion cubic meters/year (Tcm/y) today to 5 Tcm/y by 2040. In the IEA's view, such growth will primarily be driven by the power sector, which accounts for about 40% of incremental gas demand.[3] Lower prices in some key markets, coupled with the advent of competition in traditional gas and power markets, have promoted increased gas usage (fig. 1–2). Advances in CCGT technology in particular have enhanced the economics of generating electricity from gas, as lower capital costs and markedly higher operating efficiencies of CCGT plants, along with lower emissions, have given natural gas a competitive edge over coal. More competitive natural gas prices will also spur industrial use, particularly in the United States. Natural gas is even showing growing promise in the transportation sector, though this will remain a function of the relative prices of oil and gas, the building of fueling infrastructure, and the rate at which owners of vehicles and vessels will adopt new technologies.

Despite the strong growth in consumption over the past two decades, worldwide reserves of natural gas have grown faster than consumption. Even conservative estimates show gas supplies ample enough to cover global demand for many decades. According to BP, technically proven remaining reserves totaled 185.7 trillion cubic meters (Tcm), or 6,557.8 trillion cubic feet (Tcf), at year-end 2013, representing a reserve-to-production (R/P) ratio of 55 years.[4]

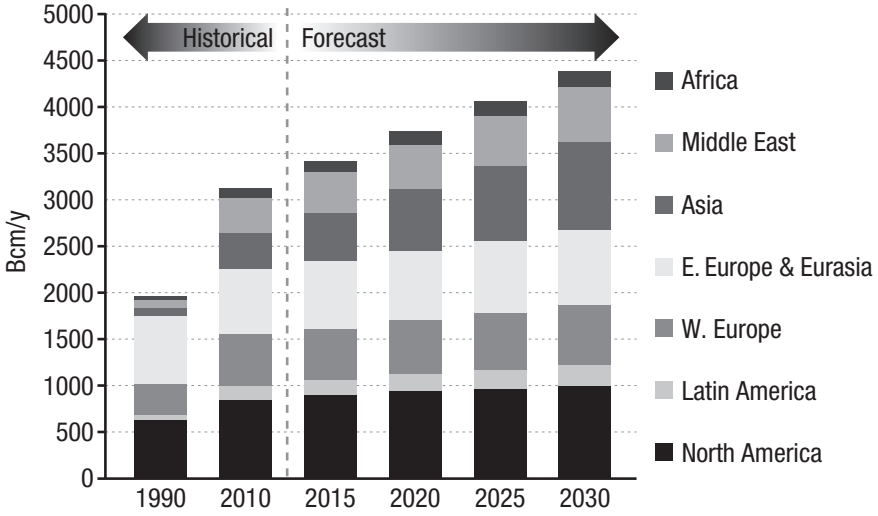

Fig. 1–2. Natural gas demand by region. (*Source:* IEA, Poten & Partners.)

According to the IEA, ultimately recoverable resources, the measure of long-term production potential, are dramatically higher, at 790 Tcm (27,900 Tcf) for an R/P ratio of 241 years.[5] This broader classification includes large volumes of unconventional gas resources expected to eventually be discovered and included in the proven category.

As new gas basins are exploited, they are often surplus to local needs and far from demand centers. Compared to other fossil fuels, natural gas is more expensive and technically more challenging to transport over long distances, whether by pipeline or by ship as LNG. As a result, the global natural gas industry has remained divided into a series of regional and even local markets. Nevertheless, there is a growing international natural gas trade, which Cedigaz estimated to be 1,048 billion cubic meters (Bcm; 37.0 Tcf) in 2013, accounting for about 30% of global gas supply.[6] This trade was split with about 70% by pipeline and 30% in the form of LNG, compared to 24% just five years earlier. Most industry experts expect the LNG share to continue to grow. The IEA forecasts the global LNG market will grow from 300 Bcm in 2012 to almost 600 Bcm in 2040.[7]

As of February 2015, Brent crude oil had fallen to approximately $60 per barrel (WTI to about $50/bbl) from a two-year run at or near

$100/bbl, and natural gas prices had reached record highs in many markets (though they are now falling with oil prices). The price of coal has fallen as coal has been pushed out of the US generating mix. Oil, a globally traded commodity, is priced accordingly. Natural gas is still traded mostly regionally. Natural gas prices in some markets (Asia and partially in continental Europe) are determined under long-term sale and purchase agreements (SPAs) at prices linked to oil, and in other markets (the United States, the United Kingdom, and increasingly northwest Europe) by gas-on-gas competition. Where gas trades on its own fundamentals, the trend has been for gas prices to fall below oil-linked equivalents (particularly in the United States). As a result, arbitrage opportunities and spot/short-term trades now account for about 30% of the global LNG trade, encouraging existing players to adopt new business models and new firms to enter the industry. North America is emerging as a potentially large LNG export region. Bringing US LNG to the global market is creating price linkages to Henry Hub rather than oil and offering buyers supply and price diversity, which carry their own benefits and risks. The dynamics of global gas pricing appear likely to shift under the combination of US supplies and lower oil prices.

The Global LNG Industry

LNG consumption has more than doubled, from 103.3 million tons per year (140.5 Bcm/y) at the turn of the century to 243 million tons (330 Bcm) in 2014, according to Poten & Partners.[8] A combination of growing environmental pressures, new LNG production capacity, future economic growth, and competitive pricing promise a substantial expansion of LNG demand in the future (fig. 1–3). Poten & Partners projects LNG demand to surpass 360 million tons per year (490 Bcm/y) by 2020 and 415 million tons per year (565 Bcm/y) by 2025.[9] Growth in LNG demand is anticipated in every major region except North America, which has been impacted by domestic shale gas production. The United States, once expected to become a major LNG importer, now promises to become a leading LNG exporter, even though lower domestic gas prices in the United States may revitalize segments of the nation's industrial base and promote domestic natural gas demand.

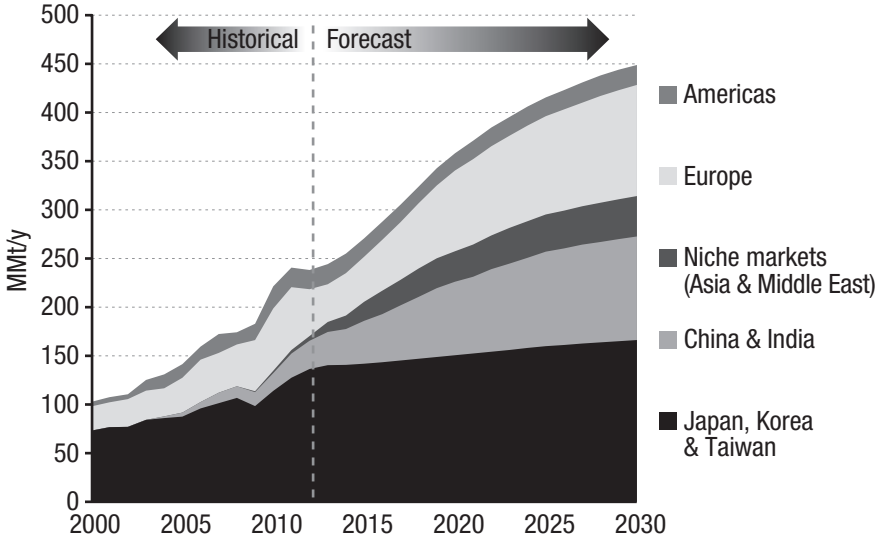

Fig. 1–3. LNG demand by geography. (*Source:* Poten & Partners.)

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

from pipeline gas for the end user (fig. 1–4). In its liquid form, natural gas shrinks to less than 1/600th of its gaseous state, making its transportation and storage more efficient. However, little is simple about LNG. Bridging the natural gas gap between supply and demand via LNG is one of the energy industry's most challenging issues and also one of the most expensive.

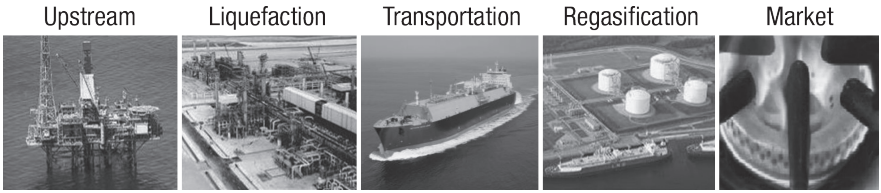

Fig. 1–4. The LNG value chain. (*Source:* Poten & Partners.)

The traditional LNG industry is based largely on a series of virtually self-contained projects made up of interlinking chains of large-scale facilities, requiring huge capital investments, bound together by complex, long-term contracts, and subject to intense oversight by host governments and international organizations at every stage of the process. Ironically, this effort is applied to the simplest hydrocarbon—methane—and involves no chemical or other changes to the commodity (except to its temperature and purity) from the time it is produced until it reaches the final consumer.

Even though LNG has represented a major source of natural gas and a significant share of primary energy for decades in Japan and other areas of the world, it was for many years considered a high-cost niche segment within the energy industry. Given the numerous hurdles and uncertainties that faced each project and the need to coordinate the multiple disparate elements involved, many projects failed to achieve realization or collapsed before they had run their course. Skeptics warned of impending disasters that would threaten the safety and economics of operations, especially import terminals, which are generally located much nearer to population centers. Still, the LNG industry has not only prevailed, it has flourished.

Each project took years to develop, so that decades had to elapse for the industry to reach a critical mass of well-functioning projects and prove that the technical and commercial model could be successful. For the first few decades, the industry had relatively few participants, loosely known as the "club." Yet club members were

already cognizant of what the rest of the world would later realize—that well-executed LNG projects can generate solid profits and stable financial returns over many decades.

The industry has proved its reliability and stability under a variety of market and economic conditions, accompanied by a safety record second to none for an operation of its scale. Demand growth and high energy prices through mid-2014, coupled with advances in technology, are driving more planned and proposed LNG projects than at any point in history. The commercial structure of the LNG industry is changing, revitalizing the business and opening it to new entrants. LNG is now playing an important and growing role in meeting global natural gas demand. More and more, LNG is traded in flexible spot and short-term trades, demonstrating its ability to serve energy markets on relatively short notice. This was amply demonstrated by the dramatic increase in LNG deliveries into Japan to generate electricity when the nation's nuclear plants were closed after the Fukushima Daiichi nuclear accident in March 2011.

The Global Natural Gas Industry

Although the ancient Greeks, Romans, and Chinese made limited use of natural gas, it was only in the 20th century that it became a significant source of energy. Thanks to technological advances in long-distance, high-pressure pipeline transportation, natural gas became widely distributed, allowing it to substitute for town gas produced from coal, which had been introduced to many cities in the late nineteenth century. These technological advances contributed to the steady growth of world natural gas demand throughout the 20th century, with the pace of growth accelerating in the later decades of the century and into the 21st century. During the second half of the 20th century, gas traded in the form of LNG became an important component of international trade, particularly in Asia. According to BP, global natural gas demand has more than doubled since 1970 to 3.35 Tcm (325 Bcf/d) in 2013.[10]

Natural gas is used extensively for heating and cooking in residential and commercial settings, and as a process fuel and feedstock by industrial consumers. However, while the number of customers for these applications continues to grow, overall consumption

growth is muted as equipment efficiencies improve. The power sector has emerged as the main demand driver accounting for about 40% of future incremental gas demand in the IEA's view, because of environmental benefits and efficiency of natural gas compared with other energy sources.[11] Technological advances in CCGT power plants have shifted the economics of power generation away from coal in favor of natural gas, even with gas's higher prices. Historically, gas-fired power generation was primarily used for peak generation in simple cycle gas turbines, or as a direct substitute for residual fuel oil (resid), since the variable costs of generating baseload electricity using other fuels, such as coal and nuclear, were lower. Now CCGTs are increasingly being operated in mid- and baseload mode, particularly in North America where the shale gas boom has lowered gas prices, leading to direct competition with coal in power generation.

The age of the gas turbine

Until the 1970s, coal and oil were the principal fuels used to generate electricity. However, the use of oil for electricity generation slowed following the oil shocks of the mid-1970s. This, in turn, contributed to a rapid expansion of nuclear generation from the 1970s until the mid-1980s, when public opposition and escalating construction costs brought nuclear development to an abrupt halt in many countries. At the same time, environmental concerns associated with greenhouse gas emissions began to slow the development of coal-fired generation. Many countries also began a process of liberalizing their wholesale electricity markets, bringing an increased focus on the overall costs and efficiencies of power generation technologies. Costs were no longer guaranteed recoverable as they were under the classic utility regulatory environment. Lower capital cost technologies with shorter construction times began to win favor, setting the stage for the expansion of CCGT plants fueled with natural gas.

When the first gas-fired generating units were built in the United States during the 1960s, they were small and relatively inexpensive to build, but they were inefficient and depended on high-cost natural gas supplied through the classic utilities to run them. Moreover, natural gas supply was often curtailed during periods of peak demand. As a result, these peaking units were employed only to provide a rapid source of power during periods of peak electricity demand, which

largely occurred during the summer months. With the exception of Japan, natural gas was rarely used outside the United States for power generation because it had to be imported, and these imports were expensive and often raised issues of supply security.

Moreover, many countries adopted policies prohibiting the use of natural gas in power generation, such as the Fuel Use Act of 1978 in the United States. An unusual case was that of Japan, where natural gas was used widely by the large power utilities in direct substitution for oil in classic steam turbine power plants. This allowed Japan to diversify its energy supply from an overdependence on Middle East oil to sources closer to home. The baseload nature of Japanese power utility demand helped to underwrite the success of the early LNG export projects by assuring a stable, secure, and financially appealing market with costs passed on to captive electricity customers.

With the introduction of CCGT units in the 1980s, the removal of prohibitions on the use of gas for power generation, and the introduction of competition in wholesale electricity markets, the boom in gas turbine generation was underway. In a combined cycle plant, a gas turbine is combined with a steam turbine, which uses the waste heat from the gas turbine to increase efficiency. Modern CCGT plants have thermal efficiencies of approximately 61%, compared to efficiencies of closer to 46% in modern coal-fired power plants. During most of the 1980s, annual sales of gas turbines were around 300 to 400 units, with an average size of only 30 megawatts (MW) reflecting their use in peaking applications. By 1990, annual sales exceeded 600 units, soaring to 900 units by mid-decade and 1,500 units in 2000. They remained at approximately this level through 2013. Turbine sizes increased dramatically as well. The largest gas turbines are currently from General Electric (470 MW in simple cycle) and Mitsubishi Heavy Industries (460 MW), while Siemens' largest is 375 MW.

Deregulation has also set in play factors favoring CCGTs. The introduction of wholesale competition in the power sector is increasing demand for these units. Gas turbines can be deployed rapidly, which reduces market risk, since developers can match their decisions more closely with market requirements. Unit capital costs are much lower, making financing easier and reducing the risk that the developer may be left with stranded assets. Finding a site for a gas-fired power plant is easier than for a coal plant, widely viewed

as dirtier, or for a nuclear facility, widely perceived by the public as too dangerous.

These developments contributed to a major increase in the use of gas for power generation since the early 1970s. In the United States for example, the share of natural gas in the power generation mix has increased from 16% in 2000 to 29% in 2012.[12] Concurrently, coal's share has fallen from 52% to 39%. In the US Department of Energy's (DOE) view, by 2040, the coal share at 34% will match natural gas at a 33% share. Despite subsidies, the share for renewables increased slowly from 9% in 2000 to 12% by 2012 and is forecast to rise to 16% by 2040 according to the DOE.

The growing share of natural gas in the power sector has contributed to a slide in oil's share of primary energy in the United States. From 1980 to 2012, oil's share of the energy mix dropped from 46% to 36%, while natural gas's share rose from 19% to 27%.[13] By 2040, in the view of the DOE, oil's share of primary energy will still top gas, but not by much. The oil share will have declined to 31%, compared to the 30% contributed by gas. Yet, natural gas–fired power is not the answer to everything. The bankruptcy of companies such as Calpine and Mirant demonstrated that single-minded bets on natural gas carry their own risks, in this case associated with rapidly increasing fuel prices. This risk now appears to have been mitigated by the surge in unconventional gas production, which is contributing to more stable and predictable natural gas prices in the United States.

Internationally, similar patterns have emerged. The IEA is forecasting 7,000 gigawatts (GW) of new electricity supply capacity will be added between 2013 and 2040, compared to the 6,000 GW installed today. Of this, the largest contributions will come from renewables (a very ambitious and unlikely to be realized 4,000 GW) and natural gas (2,000 GW). The IEA sees coal, nuclear, and oil as only making small contributions (1,000 GW combined) to global electricity capacity additions in the next 35 years.

Competing against other fuels

While natural gas may continue to gain market share at the expense of other hydrocarbon resources, coal remains very much in the picture, nuclear was showing new signs of life until Fukushima, and renewables are helping to change the energy mix, dramatically,

if the IEA forecast is realized. Addressing coal's environmental issues is not a trivial undertaking, expectations for renewable fuels and associated technologies may be overstated, and the nuclear industry is severely challenged by public opposition as well as by issues presented by the disposal of nuclear wastes and the high cost of building a nuclear plant. Meanwhile, the expansion of renewable energy supplies is dependent upon government subsidies that could be challenged by financially stretched treasuries.

Oil, long the king of energy consumption, comprises the biggest share of global primary energy and will continue to do so for the foreseeable future. Oil is relatively cheap to ship globally, and international markets are well established. Vehicle transportation markets, especially in India, China, and other emerging countries, will continue to expand. Natural gas still struggles to compete with oil for transportation. Until technological breakthroughs occur and/or legislation passes favoring natural gas or other alternative transportation fuels, oil will continue to dominate this market in most areas of the globe, and transportation use will continue to drive oil demand, accounting for some 70% of the petroleum market. Even in the transportation sector, oil demand growth promises to be moderated by more fuel-efficient vehicles.

In the past, the lack of infrastructure to transport and distribute natural gas was a barrier to increasing natural gas consumption. However, the 1970s oil shocks provided an impetus for improving infrastructure, leading to the construction of major pipelines from the North Sea, Russia, and North Africa to Europe and significant expansion of existing pipeline networks in North America. With oil trading at over $100/bbl for several years until mid-2014, the competitiveness of the LNG delivery chain had been enhanced significantly, promising to make LNG the most rapidly growing segment of natural gas. Today, it constitutes the fastest growing hydrocarbon.

In regions where downstream natural gas pipeline infrastructure is limited, oil continues to be used for residential and commercial heating purposes. Natural gas is slowly making inroads in developing countries, especially Latin America (Mexico), South America (Venezuela, Brazil, Argentina, Chile), eastern Europe and Russia, and Asia (China, India, Thailand). The IEA concludes that natural gas demand growth will shift to more nations like China and India.

According to the agency, these two nations are expected to register the biggest gains, with Chinese demand growing by 7% per year to 545 Bcm (19.2 Tcf) and the Indian market expanding by nearly 5% per year to 180 Bcm (6.4 Tcf) in 2035.[14] The Middle East is also expected to experience significant growth, increasing from 404 Bcm (14.3 Tcf) to 640 Bcm (22.6 Tcf) in 2035 for power generation and gas-based industries. The two largest gas markets, the United States and Russia, will show steady expansion according to the IEA, but the outlook could be understating demand in the United States. According to BP, US demand reached 737.2 Bcm (26.0 Tcf) in 2013, already outstripping the IEA's 2020 outlook as power generators switched to cheap gas from coal. Demand in Europe continues to struggle because of economic recession and is only expected to regain its 2010 peak towards the end of the decade. Europe has seen significant growth in both coal consumption and renewable energy during the past several years, further threatening the role of gas in that region.

Another reason for the recent growth in popularity of natural gas is that it is the cleanest burning fossil fuel. Its low carbon content (compared to oil and coal) contributes to its attractiveness. Following the Kyoto Treaty, many developed countries have adopted targets to reduce carbon dioxide (CO_2) emissions and intend to enforce these targets through a combination of emission trading regimes and fines for noncompliance, further improving the comparative economics of natural gas.

Although coal, nuclear, and hydroelectricity have historically been the dominant fuels for power generation, the improved economics of CCGTs coupled with environmental benefits are allowing natural gas to capture new markets where delivery infrastructure can be built and natural gas can be delivered on a cost-effective basis. New gas-fired power plants have the lowest capital costs per megawatt of any power plant and are easier to site than most other types of plants.

The coal industry is moving to address the concerns associated with emissions. New technologies are more fuel-efficient and produce lower CO_2 emissions. Power companies are looking at the development of carbon sequestration as a way to address this issue. While these are expensive solutions, government policy in many countries could favor them to further energy supply diversity and security and to preserve jobs in their coal mining regions. The advantage natural

gas has over nuclear energy has much to do with public perception. There are widespread safety concerns about nuclear power because of the perceived risks associated with potential radiation leaks, long-term spent fuel disposal, and nuclear proliferation; by contrast, public opinion of natural gas–fired generation is typically positive or neutral. The negative sentiment associated with nuclear power, heightened by Fukushima Daiichi, makes constructing new plants difficult and will encourage the retirement of aging ones. Nuclear facilities have enormous capital costs, and even though new technologies and standardization of designs could decrease the costs of constructing new plants, natural gas is unlikely to lose market share to nuclear.

With the exception of hydroelectricity, renewable sources have historically not been economically competitive with fossil fuels. However, hydroelectric power generation is restricted to certain areas and subject to variations in weather. Major hydroelectric power projects carry their own environmental risks and can force the migration of local populations, as was seen in the Three Rivers project in China. New construction is more likely in locations remote from local populations and can be very expensive. The cost of long-distance power transmission becomes another factor.

Solar power and wind power have clear environmental benefits over natural gas for power generation. The economics of wind energy have changed as costs decline, and wind increasingly appears competitive with other fuels, aided by favorable government tax treatment. Large-scale wind farms, virtually nonexistent before the 1990s, are becoming increasingly common in North America and Europe. Wind stands to be the fastest growing of all energy sources in the coming decades. However, the construction of massive wind farms, both onshore and offshore, is facing opposition in some communities. While wind will undoubtedly capture some of the power generation market, natural gas is considered more reliable and economic, and will be required as a backup when the wind does not blow. Solar power is also advancing but at a slower pace than wind; however, this could change as costs continue to fall. Indeed, some producers forecast that solar power in regions with favorable sunlight conditions may be a competitive source of electricity before 2020. While alternative energy has a rapidly expanding future, it will still account for less than 10% of US primary energy supply by 2040, according the DOE in its 2014 outlook.[15]

The IEA is far more bullish on renewables, forecasting them to outstrip all other forms of power generation capacity additions over the next three decades and become the world's largest source of electricity by 2040. The IEA forecasts hydropower to grow from 3,700 terawatt hours (TWh) in 2013 to 6,200 TWh by 2040, with wind and solar growing from 800 TWh to 4,700 TWh in the same time frame.

Natural Gas Resource Development

Natural gas supply

Historically, natural gas reserves remote from markets were viewed as a nuisance potentially capable of impeding the development of oil reserves. These remote gas reserves are often called "stranded." As the options for monetizing natural gas have expanded, some previously stranded reserves, discovered decades earlier, are now being developed. For many of the major energy companies, increasingly denied access to oil reserves or being forced to settle for onerous financial conditions to develop them, gas is becoming the "new oil." Coupled with technology improvements in exploration and production, the energy industry increased proven worldwide natural gas reserves by 2.6 times between 1980 and 2013 according to BP statistics, and reserves continue to climb as unconventional gas resources are exploited.

Natural gas resources

Proponents of the natural gas era point to the large size of the world's natural gas resource. At the end of 2013, world proven natural gas reserves totaled 185.7 Tcm (6,558 Tcf).[16] Prospects to increase the proven category are excellent as the energy industry increasingly focuses on natural gas, in particular unconventional gas, a relatively new and underexploited resource.

While natural gas resources are ample on a global basis, they are not evenly distributed. They are often far from major demand centers and have not been developed. About 61% of the world's reserves are located in the Russian Federation and the Middle East, though this share promises to be reduced as potential unconventional gas reserves

(including shale gas) move into the proven category.[17] However, consumption is dominated by North America and Europe (including Russia), accounting for at least 60% of global gas consumption. The comparative R/P ratio, which indicates the number of years it would take to deplete proven reserves at current production levels, also points out the regional disparity. For example, proven reserves in the Middle East would last for 141 years. By contrast, the R/P ratio in North America is 13 years, demonstrating a more economically efficient use of this valuable resource. However, these R/P ratios alone do not tell the full story of the ultimate resource base, since the US proven gas resource base does not include vast unconventional gas potential. The United States' R/P ratio has increased from less than 10 in the 1970s to its current level as the industry has added proven reserves faster than consumption. In fact, the United States is now the top global natural gas producer, toppling Russia from this ranking.

The continuing imbalance between the location of gas resources and demand centers promises a major expansion in the international gas trade by long-distance pipelines and in the form of LNG. International gas trade totaled 1.0 Tcm (37 Tcf) in 2013: approximately 70% by pipeline and 30% in the form of LNG. But building the infrastructure to move natural gas long distances requires multibillion dollar investments, which raises the question of whether or not incremental gas supply can be delivered long distances to markets at competitive prices.

Pipelines

One of the first modern commercial applications for gas was in street lamps in the eastern United States and Europe in the nineteenth century. This application became obsolete when nations electrified, and natural gas did not play a major role in the energy picture until pipelines were constructed to transport the fuel from producing areas to consumers. Although natural gas had been transported in wooden pipelines much earlier, the first metal natural gas pipeline was built in 1872. Stretching five and a half miles, it brought gas from a producing well to the town of Titusville, Pennsylvania. These first metal pipelines were extremely inefficient. It was not until after World War II, when pipeline technology dramatically improved, that natural gas became a major part of the energy mix. In Europe,

the foundation of the gas transmission system was laid between 1970 and 1975, fueled by a giant gas discovery in Groningen, the Netherlands.[18]

Natural gas pipeline systems are characterized by three applications: gathering systems, transmission pipelines or trunklines, and distribution grids. For the most part, in this book the term "pipelines" refers to trunklines, which transport natural gas from supply areas to markets. These long-haul pipelines are usually between 16 and 48 inches in diameter and can extend for thousands of miles, operating at high pressures maintained by compressor stations along the route. In mature markets such as the United States and Europe, a complex web of trunklines connects to other trunklines, storage facilities, large end users, and distribution grids.

Gathering systems generally comprise smaller diameter pipelines that take gas from the wellhead to central processing facilities where impurities are extracted. However, offshore gathering systems may be physically indistinguishable from transmission lines. Gathering line pressures can vary significantly, usually as a function of the wellhead pressure of the producing well. Distribution pipelines also tend to be smaller in diameter and disseminate natural gas to consumers in market areas. Distribution lines normally operate at medium-to-low pressures. While very large consumers such as a steel mill or an electric generator may be directly connected to a trunkline, the vast majority of medium-to-small consumers obtain their gas through a distribution grid, which is run by a local distribution company (LDC).

From an environmental and safety perspective, pipelines pass with flying colors. Aside from the initial impacts associated with construction, the pipelines themselves have very little environmental impact. Thanks to safety and security systems that detect corrosion or leaks, most problems can be identified and corrected before they become significant. Although accidents happen from time to time, these systems are considered to be among the safest modes of energy transportation.

Pipelines remain the major means of transporting the world's natural gas to consumers, accounting for over 90% of natural gas deliveries. The United States alone has over 305,000 miles of interstate and intrastate pipelines.[19] Interstate lines, which cross state borders, account for 71% of the total. The industry has overcome

increasingly complex challenges of distance and terrain, and long, deep underwater crossings. Some existing and proposed pipeline projects are nearly 4,000 miles long and cost billions of dollars to build. Pipelines to deliver shale gas from fields in eastern British Columbia to planned liquefaction projects on Canada's Pacific coast could each cost billions of dollars to build. Generally speaking, an offshore pipeline is more expensive than a similarly sized onshore one.

It is not always possible or desirable to link supply to market by pipeline because of terrain, right-of-way issues, politics, and/or distance. Sometimes geographical features such as underwater faults or coral reefs may prevent construction, or a planned pipeline may interfere with an environmentally protected area or other public infrastructure already in place. Landowners may not allow (and may not be required to allow) the pipeline to be built on their land. A route may traverse politically unstable regions or countries that are on unfriendly terms with the supplying or consuming country, or it may simply not be a viable option to supply an island nation like Japan and Taiwan or small local demand centers in an archipelagic nation like Indonesia or Malaysia. LNG is often preferred because it is transported by ship, which minimizes the number of international borders that must be crossed and provides destination flexibility not available from a pipeline.

LNG Industry Development

Historical background

Petroleum products were first transported by tankers in the 1860s.[20] A century passed before natural gas was transported by ship. While it is relatively easy to store, load, and transport oil or other petroleum products, natural gas has to be turned into a liquid at very low temperatures, then stored and transported in this form.

Two seventeenth-century physicists, Robert Boyle and Edme Mariotte, are credited with discovering that air was compressible; this led to insights into how gas might be pressurized and condensed. Numerous subsequent experiments were conducted to establish the optimum method of reducing the volume of natural gas, and it was determined that increasing gas's density could be achieved by extreme

pressure, extreme cooling, or a combination of the two. Compressed natural gas was generally considered too difficult and dangerous to transport around the world because of the lack of suitable materials to contain the high pressures and the risk of explosion in the case of a sudden release of gas. But with extreme cooling to below its boiling point (in this case, –163°C), natural gas could be reduced in volume by a factor of over 600 times, then stored and shipped at atmospheric pressure. In its liquid form, natural gas exhibits a property known as autorefrigeration, whereby continuous evaporation draws heat away from the liquid and does not require anything more than insulation to maintain the gas in liquid form as long as the evaporated gas, known as boil-off, is removed from the storage tank.

The process of cooling natural gas to extremely low temperatures began as a means of extracting helium from natural gas for use in US military balloons in the early 1900s. Shortly thereafter, advances in metallurgical techniques in Europe and the United States produced metals, notably aluminum and steel alloys, which would not become brittle at extremely low temperatures as most metals do. Storage facilities could thus be built for the supercooled liquid.

The first conceptual scheme for LNG was devised by Godfrey Cabot in 1914, when he patented a liquefaction plant and a barge design to prove that waterborne transportation of natural gas was technically feasible. However, he never pursued the idea. In 1939, the first commercial LNG peak shaving plant was built in West Virginia. Two years later, the East Ohio Gas Company built a second facility in Cleveland. This peak shaving plant operated without incident until 1944, when the facility was expanded to include a larger storage tank. However, World War II created a shortage of stainless steel alloys, resulting in a tank built from steel with inadequate nickel content. In 1944, this tank ruptured and natural gas leaked into the adjacent sewer system and residences. Sadly, it ignited and killed 128 people—the largest disaster in LNG history. Subsequent investigations resulted in new standards for the materials used for the handling of LNG, preventing this from happening again. This incident put LNG development on hold for a decade.

In the 1950s and 1960s, William Wood Prince, president of the Union Stockyards of Chicago, faced with escalating electricity rates, began to study the liquefaction of natural gas in Louisiana to barge

it up the Mississippi River. The British Gas Council was also looking to transport natural gas to supplement supplies in areas stretched thin by manufacturing and household use. Union Stockyards subsequently joined forces with Continental Oil Company and the British Gas Council to turn an old World War II dry bulk carrier into an LNG ship, the *Methane Pioneer*. This vessel was used to transport LNG from Lake Charles, Louisiana, in the Gulf of Mexico, to Canvey Island in the United Kingdom in 1959. It was the first commercial shipment of LNG. After a major natural gas discovery in Algeria, the United Kingdom and France signed contracts with Algeria in 1961 and 1962, respectively, and the first commercial-scale liquefaction plant at Arzew, Algeria, became operational in 1964.

During the 1960s and 1970s, liquefaction plants were built in Alaska, Libya, Brunei, Abu Dhabi, and Indonesia, as well as Algeria. Import terminals were developed in Japan, France, the United States, and Italy, later joined by terminals in Belgium, Spain, Taiwan, and South Korea. However, owing to an oversupply of natural gas in Atlantic markets in the 1980s, only two new greenfield LNG export projects were put into service in that decade (one in Australia and the other in Malaysia), while expansions continued in Indonesia. Most of the capacity added in the 1980s was designed to serve Asian LNG markets, which were growing rapidly as they did not have access to domestic natural gas or pipeline imports as did Europe or North America. In the early 1990s, demand was catching up with supply in the Western world, causing a rebirth of LNG projects targeting those markets, and new LNG export projects were commissioned in Qatar, Nigeria, Oman, and Trinidad between 1996 and 2000.

By 2000, LNG trade had reached 103 million metric tons per year (MMt/y; 140 Bcm/y) (fig. 1–5).[21] Fewer than 20 projects had been commissioned since the start of the commercial LNG business in 1964. The pace of LNG development may have been hampered by an inflexible business structure including the following factors:

- LNG project sponsors were typically large international oil companies (IOCs) partnering with national oil companies (NOCs).
- The buyers, most often large, regulated gas or power utilities, signed purchase agreements that were relatively inflexible on volume and destination.

- Contract prices were linked to those of crude oil, ensuring acceptability in the end-market and providing comfort to lenders.
- Each project evaluated its shipping needs, and dedicated LNG tankers were built and owned by the project or backed by long-term charter arrangements.

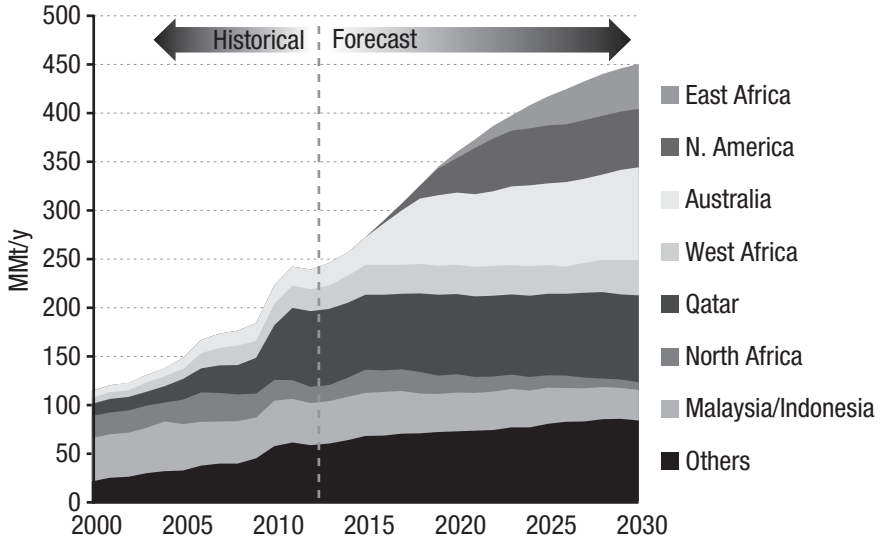

Fig. 1–5. LNG supply by geography. (*Source:* Poten & Partners.)

The pace of change accelerated as the LNG industry entered the 21st century. Downstream markets deregulated and countries such as China and India offered potentially very large markets. Successive trains (i.e., successive liquefaction units) at Trinidad LNG introduced new business models, including tolling arrangements for liquefaction trains with purchase contracts featuring greater destination flexibility. These contributed to the emergence of both spot and short-term trades, which helped balance the market. As a result, trading companies entered the business. Shipowners started ordering LNG tankers on a speculative basis since they could trade these vessels in spot and short-term trades until long-term charters could be secured. They also ordered new LNG ships to benefit from lower costs following the competition created by the entry of South Korean shipyards into the business.

Post-2000—the Qatari era

Qatar implemented a range of options to maximize the value of the North Field, the world's largest nonassociated natural gas field at approximately 900 Tcf, including LNG, domestic sales, petrochemicals, and gas-to-liquids (GTL). The national oil company, Qatar Petroleum (QP), through partnerships with foreign oil majors, delivered LNG results that were hardly conceivable at the turn of the century. The RasGas and Qatargas ventures built six 7.8 MMt/y (10.6 Bcm/y) trains. Dubbed megatrains, these new trains were by far the largest ever built, pushing the country's nameplate, or design, liquefaction capacity to 77 MMt/y (105 Bcm/y), including 30 MMt/y (41 Bcm/y) of existing capacity in eight conventionally sized trains.

Qatar, through its Nakilat shipping firm, stimulated shipping demand by ordering a fleet of giant LNG tankers consisting of 19 Q-Flex vessels sized between 210,000 and 216,000 m^3 and 13 Q-Max vessels of 266,000 m^3 cargo capacity to provide transportation services for the megatrains. The venture partners envisioned a giant "floating pipeline" to deliver cargoes to large purpose-built LNG import terminals developed by QP and its foreign partners in the United States (Golden Pass in Texas), the United Kingdom (South Hook in Wales), and Italy (Rovigo). When LNG was no longer needed in the United States following the surge in shale gas production, or in the United Kingdom as gas demand dropped in the face of a prolonged economic downturn, the cargoes were diverted to LNG-short markets in Asia, where demand was particularly strong after the Fukushima Daiichi nuclear disaster. The economies of scale generated by the Q-class LNG vessels under the point-to-point trade scheme were lost under the diversified trade patterns.

Qatar, which first exported LNG in the 1990s on a relatively modest basis, produced 77.9 MMt (105.9 Bcm) in 2013, dwarfing all other exporters by a wide margin. This contributed to the global LNG trade more than doubling from 103 MMt (140.1 Bcm) in 2000 to 243 MMt (330 Bcm) in 2014.[22] In just 14 years, the business had expanded more than it had in the previous four decades. Concurrently, the number of importing countries more than doubled to 26. While Japan remained the world's top importer, its share of global LNG trade dropped from 52% in 2000 to 36% in 2014, even though the closure of Japan's nuclear reactors boosted demand to a record high of 88 MMt (120 Bcm). The LNG shipping fleet climbed to 369 ships

from around 110 in 2000 with another 113 new buildings on order at year-end 2014, a precursor of a further LNG trade expansion. The average ship size also increased dramatically, resulting in an even larger tonnage increase although no one else ordered Q-class vessels. A new class of LNG vessels with onboard regasification, called floating storage and regasification units (FSRUs), opened up small markets on a fast-track and cost-competitive basis. At the same time, floating liquefaction (FLNG) production units were being constructed.

Spot and short-term trades, which comprise single- and multi-cargo transactions as well as term deals up to four years in duration, were once considered a marginal LNG business but now are an established feature of the industry. In 2000, these trades accounted for less than 10 MMt/y (14 Bcm/y) of LNG and amounted to less than 10% of total trade. In 2013, around 70 MMt (95 Bcm) of LNG was moved under these deals and accounted for about 30% of global LNG trade. Many major LNG sellers once considered spot trades too small in volume and value to be worth their time, and were concerned that supplying LNG to the spot market at prices below the level of their long-term contracts would undermine their relationships with their long-term buyers. Furthermore, they added complexity to carefully crafted shipping logistics (fig. 1–6). At that time, buyers were only interested in spot trades if they helped meet an immediate supply shortfall. They were not a part of a long-term supply strategy, even to meet seasonal demand peaks. This has changed. The flexibility provided by these trades is now a critical component of the business for both buyers and sellers, as they adjust to unforeseen events such as nuclear shutdowns in Japan.

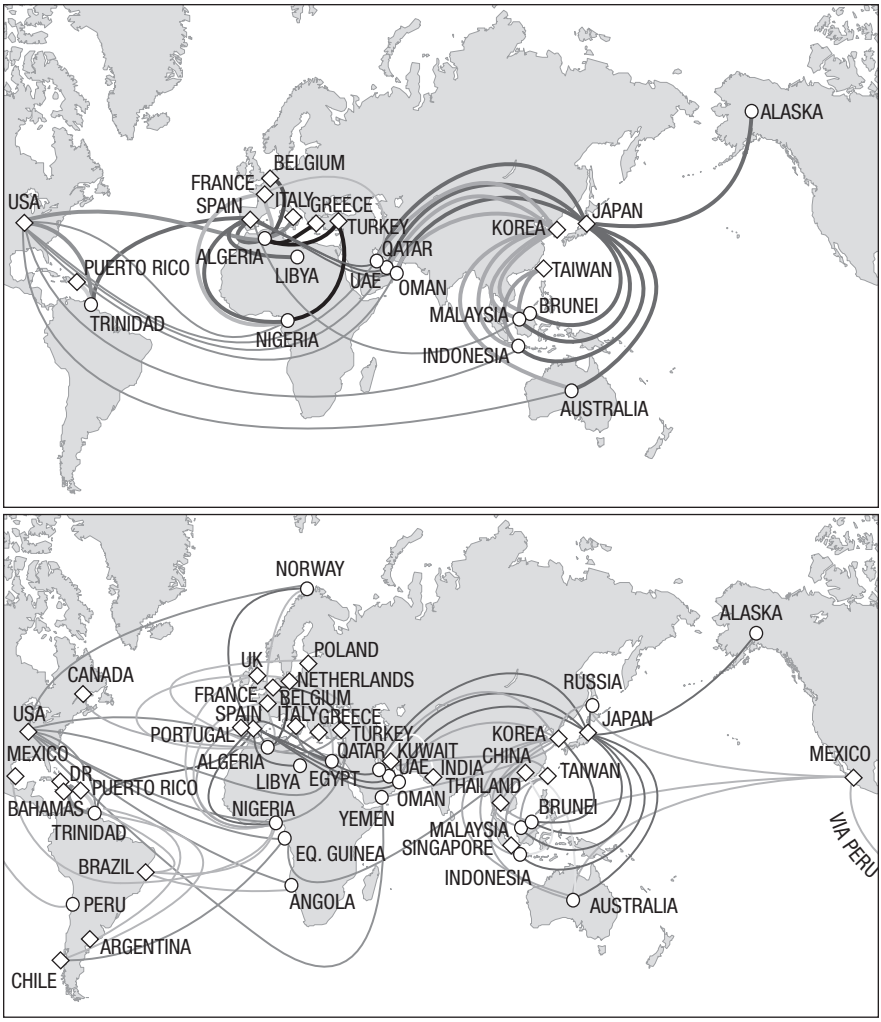

Fig. 1–6. The evolution of global trade of LNG. Top: 2000 World LNG trade routes. Bottom: 2012 World LNG trade routes. (*Source:* Poten & Partners.)

Post-2013—the Australian era

While projects in Qatar drove the last LNG export expansion, Australia is driving the next one. In 2014, Australian LNG production totaled 23 MMt (31 Bcm). By 2018, based upon projects that are already under construction, Australia will be able to produce 85 MMt/y (115 Bcm/y) of LNG at 10 complexes, challenging Qatar's top rank. According to cost estimates, sponsors will lay out upwards of $200 billion to build 15 liquefaction trains with costs inflated by a variety of factors, including a difficult labor market, remote construction sites, exchange rate fluctuations, and water issues for unconventional gas development. Faced with high unit production costs, Australian projects rely on revenues generated by oil-linked term sales contracts at relatively high oil prices for economic viability.

The high-cost construction environment, in large part due to labor constraints, is spurring innovation. Developers are turning to modular construction, extensively employed at Pluto LNG, which was commissioned in 2012, and FLNG production, which is the technology selected at the Prelude LNG project, in an attempt to shift construction to less labor-constrained locations. FLNG is now being promoted at other potential Australian LNG projects, with one project considering as many as three units. The modules and the FLNG units are built in shipyards or construction yards in Asia to benefit from lower construction costs. The Australian industry was also the first to advance liquefaction projects based upon unconventional gas resources. On Australia's eastern coast in the state of Queensland, LNG developers are constructing three projects to convert coalbed methane to LNG for export, with a combined capacity of 25 MMt/y (34.0 Bcm/y) across six trains that are scheduled to be commissioned during the middle of this decade. In contrast to "conventional" integrated LNG projects, where the majority of the capital is invested up front, the eastern Australian projects will need to make significant ongoing capital investments in gas drilling and production given the production profile of coal seam gas wells, which decline very rapidly.

2020 and beyond—the US game changer

US LNG projects could be the next industry game changer. Numerous liquefaction trains are being added at underused import

terminals where they can benefit from the existing infrastructure, thereby lowering capital costs. The numbers are mind-boggling, with proposed projects totaling more than 240 MMt/y (326.4 Bcm/y), though it is very unlikely that they will all be built. Poten & Partners projects that US LNG exports will reach 60 MMt/y (82 Bcm/y) by 2025, with more to follow.

While subject to considerable debate, most analysts have concluded that there will be ample US natural gas resources to enable significant LNG exports with limited impact on US natural gas prices. This has encouraged the US DOE to process project applications for sales, including sales to countries without Free Trade Agreements (FTAs) with the United States. This non-FTA authorization is critical to advancing such projects because most of the large LNG-consuming nations do not have FTAs with the United States, with South Korea and Chile as notable exceptions. As of July 2014, the DOE had issued eight permits allowing the export of 77.8 MMt/y (105.9 Bcm/y) of LNG to non-FTA countries. This could make the United States one of the top three LNG exporters shortly after 2020. As of October 2014, four projects had reached a final investment decision (FID), with the first LNG scheduled to hit the market by late 2015.

What makes US liquefaction a game changer is not just its potential size, but the sharp departures from the commercial structure of traditional LNG schemes. To date, most of the US projects have adopted a tolling model under which firms lease liquefaction capacity at the plant for a fee (Cheniere's Sabine Pass and Corpus Christi projects are exceptions). The capacity holders will often arrange their own feed gas from the grid, rather than the traditional structure where dedicated upstream (and otherwise stranded) reserves are processed at a purpose-built LNG plant and then sold by the venture under destination- and volume-restricted long-term sale and purchase agreements (SPAs) to end users. While many of the capacity holders may deliver volumes into their home markets, their contracts contain no volume or destination restrictions. Many of the capacity holders have active trading operations and are already major players in spot and short-term trades.

The US liquefaction projects sanctioned to date are brownfield, piggybacking on storage, marine, and other infrastructure at existing, underutilized import terminals benefiting from considerable investment savings. (Cheniere's Corpus Christi LNG project on the

Gulf Coast promises to be the first greenfield project and should begin construction in 2015.) There are additional savings because none of the upstream capital costs of traditional LNG projects are required. For example, a three-train project on the US Gulf Coast typically costs around $10 billion, but a comparably sized greenfield project in Australia may cost multiples of this.

Capacity holders will still have to buy feed gas from the grid at US market prices. This final major departure from traditional projects, one that has proved attractive to buyers so far, is the linkage to gas hub prices (primarily at Henry Hub in Louisiana) rather than to crude oil. The lure of this Henry Hub price alternative to traditional oil linkage has proven to be quite effective, assuming that oil prices recover from early-2015 lows. International firms—for their own market use or for trading—have snapped up tolling capacities at these projects in the United States. Henry Hub is now not closely correlated to oil prices, giving the capacity holders the ability to diversify price risk in their supply portfolios. Unlike traditional LNG projects, these projects have no need to fund upstream development and most of the required pipeline infrastructure is quite modest. While this lowers the up-front investment, it also leaves these projects (or more precisely their offtakers) exposed to a supply price risk over which they have no control, other than the option to suspend taking LNG while continuing to make their capacity payments.

The essential ingredients of an LNG project

Unlike many other energy delivery systems, LNG has tended to be organized on a project basis, involving not only the development of the upstream infrastructure, the gas production, gathering, and liquefaction facilities, but also the shipping and import terminals, which are coordinated with buyers. This approach reflected the very high capital investment needed for each unit of energy delivered, as well as the historical separation between the LNG suppliers (large IOCs and NOCs) and the LNG buyers (principally gas and electric utilities, both private and state owned). Until the turn of the century, the industry grew at a measured pace with a relatively limited number of participants who had the ability to finance the projects.

In order to mitigate the participants' financial risks, each project weaves together a complex web of contracts and agreements. Managing a project in which buyer and seller have disparate interests

and are both subject to scrutiny from and/or involvement of their host governments presents a substantial challenge. Other barriers to successful project execution are the many commercial, technical, and legal challenges that must be addressed. Meeting these challenges requires the coordination of dozens of experts, including lawyers, engineers, contractors, shipowners, bankers, government representatives, buyers, and consultants.

The following is a summary of some of the complex issues involved in developing an LNG project, which will be discussed in detail later in this book.

Sufficient gas reserves. By the time an LNG project is being considered, the existence of ample low-cost natural gas reserves has usually been confirmed. A traditional LNG project must have dedicated proven reserves that allow the project to operate at its design level for 20 to 30 years, with an additional reserve margin to protect against unexpected production declines or better-than-expected plant performance. This helps ensure financial viability and is typically a requirement of both the buyers and the funding institutions. The cost of producing the reserves must be fairly low in order to make the LNG project economic. The presence of liquid hydrocarbons along with the gas can improve project economics, as this can create an additional, high-value revenue stream.

Long-term commitments from buyers. The capital costs required to build a facility usually dictate that a downstream buyer or buyers, who will contract for the majority of the plant's output, must be secured via long-term "take-or-pay" contracts. The traditional structure of most contracts in the LNG industry involves the buyer taking most of the volume risk with limited flexibility, and the seller taking most of the price risk, with limited opportunity to revisit those terms. These traditional structures are now being modified as the industry matures and the options and opportunities for buyers and sellers expand.

Unlike the oil business, where the production profile tends to build gradually over time and the commodity may be shipped relatively inexpensively to any number of markets on tankers that can be contracted for on relatively short notice, liquefaction plants generally produce large quantities of LNG shortly after they come on

line, and access to LNG tankers and market outlets is more limited and can be significantly more expensive. Under ideal conditions, production and consumption reach maximum levels as early as possible and maintain this level for the duration of the project. For this reason, it is preferable to market LNG to buyers with access to well-established natural gas markets. In countries with small or nonexistent markets, an LNG sales contract might be anchored by an electric-power generating plant or an industrial buyer that can consume large volumes of regasified LNG. Smaller customers would be added as a distribution network is built out from the terminal.

This commercial structure, the foundation of the LNG industry for many years, is changing. Sellers are moving downstream and buyers upstream. Destination flexibility is becoming widespread and some firms are adopting a portfolio supply strategy to balance uncertain downstream market needs, diversify risks (price and source), and capture arbitrage opportunities.

Access to capital. LNG projects usually require sizable shareholders with the ability to fund major capital investments, either on an equity basis or through borrowings. Project (or limited recourse) financing can play a major role in funding LNG projects, even those involving the largest oil and gas companies. Successful project financing requires a well-constructed project concept with robust and stable commercial arrangements, which can ensure the repayment of billions of dollars of financing over many years in a potentially volatile energy price environment. Financings have traditionally been underpinned by long-term SPAs at oil-linked prices.

Strong relationships. Although the hardest to define in concrete terms, the relationships, reputations, and experience of the various stakeholders are among the most important aspects of an LNG project. Strong relationships between project sponsors, customers, governments, lenders, and contractors are a key condition to long-term project success. The reason that trust and relationships are so important is simple: in an enterprise spanning many decades, subject to many changes unimagined at the outset, the underlying commercial and legal agreements may be inadequate to ensure the project's success, and the relationship between the parties is the only assurance that the business can address the problems that inevitably will arise. These relationships are especially important at the outset

when the project is least defined and the parties are preparing to invest significant sums of money, often before any firm contracts are in place. It can take years to build these types of relationships and reputations, and breaking into the LNG industry can be more challenging as a result.

Technical details. All physical links in the LNG chain require technical analysis, including feasibility studies, engineering designs, project execution, and operational plans. These will determine the technologies that are used, the size, compatibility, and integration of each component of the facilities, and any additional required infrastructure.

Unique logistical challenges must be faced (and overcome) on each project. Planning for these sometimes tangential details may be projects in their own right. For example, when the Nigeria liquefaction plant was being constructed, it was necessary to house over 10,000 people at a remote site where there were no existing accommodations. Such related undertakings can cost the project millions of dollars. Canadian LNG export projects must overcome the cost of building multibillion dollar pipelines to deliver feed gas from shale gas fields in eastern British Columbia across two mountain chains to the coast where the liquefaction projects will be built. In eastern Australia, project joint ventures processing coalbed methane into LNG must manage the vast number of wells that must be drilled over the life of the project to maintain the necessary feed gas.

Commercial issues. At the outset of a proposed project, it is important for the participants to agree on the principal commercial terms. This involves the project structure and ownership of various components of the project, including shareholders' agreements and project development agreements; negotiating and structuring a series of end-to-end contracts (gas supply agreements [GSAs]) covering the production of natural gas at the wellhead all the way to sales to the end users (SPAs); defining the host government's role and revenue share (which may or may not be determined in advance); agreeing on and negotiating the contracts associated with the plant design and construction; and finally financing the project.

Safety and siting. Safety is of paramount importance in the LNG industry. The assets are so expensive that any repairs required by a major accident could amount to hundreds of millions of dollars. The lost production could also mean billions of dollars of lost revenues. A major accident could mar the industry's reputation and set back other proposed projects. Finally, insurance costs are a major expense for project investors, and an accident could drive them so high that profitability would be reduced. Lenders require an independent technical analysis of the facilities' design as well as confirmation of compliance with regulatory requirements and good industry practice. For all of these reasons, companies go to great lengths to design safety into the facilities from the outset, and to provide continual training and resources for employees working on and around LNG facilities and ships to ensure LNG's safe transportation and storage.

These considerations are most acute for regasification terminals since the most desirable locations are often near densely populated areas. There is widespread misunderstanding of the safety of these terminals. In an era when the threats of global terrorist activities have dramatically increased, siting new terminals or moving tankers near populated areas has become even harder due to local regulations and public perceptions. This was particularly evident in the United States and spawned the development of offshore terminals employing a new technology, FSRUs.

In the case of a greenfield project, both supplier and buyer must control sufficient land to accommodate their respective facilities and ensure legal compliance with safety and environmental conditions. These sites must have access to waterways which are deep enough to accommodate the LNG tankers or are capable of being dredged. Expansions of existing facilities generally do not create the same level of concerns.

External advisers. Legal issues are present from the onset of a proposed project. Lawyers with specialized industry knowledge and experience are instrumental in drafting contract and project terms. The contracts and agreements associated with an LNG project are complex, especially when it comes to allocating and mitigating the parties' risks and in addressing contingencies for unforeseen circumstances. Lawyers must also advise on, and in certain cases

help decide, the applicable law that will govern each element of a project. Legal issues are a major component of every project.

Each project will also involve the input of a variety of other technical advisers who will provide expert support to the project sponsors. These will include consultants who will help prepare the necessary environmental impact statements and evaluate the gas reserves and markets, shipping alternatives, insurance, safety, and security, among other tasks. The project sponsors, buyers, and financiers will all seek independent evaluations of the various aspects of the project as part of their own due diligence exercise leading up to the final investment decision.

Government regulations. In most aspects of an LNG project, government regulations can play a significant role. Many liquefaction plants are constructed in relatively remote locations and in countries that often have no defined environmental, safety, or other regulatory guidelines. This can introduce significant project delays as host country governments wrestle with these issues. Often times in these cases, the project sponsors will utilize regulations from other countries, guidelines issued by the World Bank, or best practices promulgated by industry associations. Adopting these guidelines is often a prerequisite to securing international financial support and insurance for the project.

Once the project moves beyond liquefaction, the degree of government scrutiny and involvement remains high. LNG tankers are subject to a variety of regulations and conventions issued by the International Maritime Organization (IMO), the tanker's flag state, and the maritime regulatory bodies of the countries in which the tanker is expected to load and unload its cargo. Regasification terminals also are subject to stringent regulatory guidelines in their host countries that govern safety, security, and environmental aspects of the terminal and the vessels calling on it. In addition, the importing country may exercise economic regulation over the import terminals, requiring open access and the filing of tariffs governing the terminals' use. This will be particularly the case where the LNG terminal is owned by a public utility.

The US model

New LNG export projects in the United States present a different set of challenges. Feed gas will be purchased from the domestic natural gas market with the understanding that these gas supplies will be priced at market levels. Unlike the integrated projects, the emerging US model offers no access to liquids to boost project returns, as the heavier hydrocarbon components have generally been stripped from the gas supply before it enters the transmission grid. Resource adequacy and access are not the risks, but price certainty is another matter, since the feed gas buyer has limited ability to mitigate price risk.

The US LNG projects have adopted a tolling structure (Cheniere's projects are an exception) whereby creditworthy firms lease liquefaction capacity. Under the typical lease, the capacity holders pay a fixed-cost component, which is sufficient to cover all expenses including loan payments and the owners' financial returns but not feed gas. The lease payments are in a form that could be characterized as "hell or high water," and obligate the capacity holder to make the payments irrespective of events, unless for defined (and usually narrow) force majeure events. The tolling agreements (LTAs) bear some similarities to terminal use agreements (TUAs) at regasification facilities. The acquisition and delivery of feed gas to the plant is the capacity holders' responsibility (Cheniere being the exception as it undertakes this obligation itself, though the basic commercial outcome is the same).

Unlike the integrated projects, the US projects rarely involve any of the IOCs in the ownership or operation, with the principal ownership residing with smaller independent companies who have little or no role upstream or downstream of the liquefaction plant (Shell at Elba Island and ExxonMobil/QP at Golden Pass are exceptions). This pattern emerged because the early US liquefaction plants are based on conversions of existing import terminals to export plants, and with a few exceptions, the IOCs took no ownership role in the import terminals. This means the financing is more complicated. While the projects look to the debt markets for up to 70% of the funding on a nonrecourse basis, the equity share requires the project sponsors to raise equity financing through equity issuance (in either the public or private market), bring in partners with financing capability, or even consider initial public offerings to raise the funding.

US safety and regulatory codes present another set of challenges, as the United States has generally more complex regulations governing these plants and permits broad public participation in the siting and approval process. This can add time and cost, as much as $100 million to bring a liquefaction project through authorization to final investment decision (FID).

Finally, the US model has much less of a relationship component. Generally, the LNG purchased from the project is not subject to destination restriction, and many of the buyers are LNG aggregators or traders with no assured access to import terminals. As a result, any failure of the downstream or upstream supply chain is of limited concern to the project owner who is contractually insulated from both sets of risks. It remains to be seen if this model can stand the test of time if the capacity holders find themselves in distress due to inability to secure feed gas on a price competitive basis or secure access to downstream markets.

Alternative methods of monetizing natural gas resources

Options for monetizing natural gas that are available to resource holders and developers include the following:

Local market. Depending on the location of the gas field and its proximity to populous areas, gas can be monetized by simply selling it into a local market. National governments generally prefer such a scheme, which allows the development and internal use of an indigenous resource. A steady supply of local gas can encourage industries that use natural gas as a feedstock (e.g., methanol and fertilizer production) or whose operations require large quantities of cheap power (e.g., aluminum smelters). It also promotes investment in infrastructure and creates jobs in the host country. Sometimes host nations will require project developers of remote natural gas resources to build infrastructure to supply internal markets with a share of the natural gas, as a prerequisite for the right to build LNG export facilities in parallel. This is another area where North American LNG export projects stand in contrast to the conventional integrated LNG project.

LNG or pipeline? In its early evolution, LNG was seen as a high-cost option and the last choice for countries with potential access to pipeline gas. LNG can generally compete with pipeline deliveries over longer distances (generally greater than 2,000 kilometers), and even over shorter distances where there are major impediments to pipeline construction. Today in Japan, LNG remains the preferred import approach because of the disconnected nature of the Japanese regional markets, which would make it difficult to bring a large pipeline to the country and arrange for the onward transmission and distribution. Japan's markets are presently viewed as prohibitively expensive and legally complex to integrate into a single grid, foreclosing the pipeline option.

Security advantages. LNG has security advantages that can override economics. LNG is generally transported across international waters, so that only the seller and buyer governments are involved. Pipelines often have to cross several international boundaries, which means that several governments may be involved, increasing the relative complexity of development. This may also raise the potential of supply interruptions through diversion of natural gas volumes, attack on the infrastructure, or simply having the intermediary country close the valve for political reasons. Gas buyers and sellers in a pipeline trade are essentially hostage to events in the countries crossed by their pipeline. A good example is the potential gas trade between Iran and India. The most obvious and economical method for bringing Iranian gas to Indian markets would be via an onshore pipeline across southern Pakistan, a scenario fraught with obvious political difficulties.

Another example of geopolitical risk is the delivery of Russian pipeline gas to Europe through Ukraine. It has resulted in temporary disruptions in the past because of payment disputes between the two countries. In 2014, these risks have been heightened by the overthrow of the pro-Russian leader in Ukraine, the subsequent annexation of Crimea by Russia, and the emergence of pro-Russian separatist movements in eastern Ukraine. On the other hand, unlike ships, pipelines are not vulnerable to the vagaries of weather and are easily maintained. They can provide a secure and stable method of delivering set volumes of gas on a year-round basis.

Some countries choose to import LNG in order to expand their supply portfolios. They may be diversifying away from another energy commodity, as in the case of Japan, which initially imported LNG to lessen its reliance on oil. Alternatively, they may be reducing their reliance on any single gas supplier, as in the cases of Thailand, Singapore, Poland, and Lithuania. Exporters may favor the LNG option because, unlike a pipeline project, they can diversify their revenue sources by selling to multiple buyers and markets. Exporters reliant on a pipeline are at the mercy of a single market that has to be fully developed at some cost prior to construction. If demand fails to materialize in that market, the asset may be underutilized, whereas LNG may be diverted to other markets when demand patterns change. More flexible LNG schemes can help secure smaller commitments from a number of buyers to reach the necessary threshold for project investment. Security of supply and markets is a central theme in the 21st-century energy market.

Gas-to-liquids. The term GTL refers to the reprocessing of methane into longer chain hydrocarbons that are liquid at atmospheric temperatures and pressures. The GTL process entails the generation of syngas, a mixture of CO and H_2 derived by combining methane with H_2O and/or O_2 at high temperatures. This syngas is then subject to the Fischer-Tropsch (FT) or another similar process in which the syngas is reacted with a catalyst to produce longer chain hydrocarbons that are liquid at normal pressures and temperatures. These hydrocarbons can then be processed by using standard refining techniques. The primary product, a little over 50% yield, is a form of very clean diesel fuel, which can be handled and used in the same way as diesel refined from crude oil. However, the capital cost of GTL is higher than that of LNG for the same energy output.

GTL competes primarily against more traditional refined oil products rather than LNG (although GTL and LNG do compete in terms of the gas monetization choice). An advantage of GTL is that it is a stable liquid under normal conditions (and therefore easily transportable) and very clean. Like crude oil and unlike LNG, GTL is a fungible commodity. These characteristics make GTL especially valuable in developed markets that are highly sensitive to environmental concerns. GTL competes against refined petroleum products for market share, making it highly sensitive to the oil price. Five GTL plants are in operation across the world: two in Qatar, one in

Malaysia, one in South Africa, and another in Nigeria. Shell and Sasol, prominent players in this industry, have proposed projects in North America, while Sasol and Malaysia's Petronas are promoting another one in Uzbekistan.

Compressed natural gas. For shorter-distance trades or for relatively small reserves (<2 Tcf, or 56.7 Bcm), another monetization option in the future may be compressed natural gas (CNG). In a CNG scenario, natural gas is compressed to between 2,000 to 4,000 pounds per square inch (psi) and transported aboard specially outfitted ships to market. These ships are essentially floating pipelines. A number of different containment systems for the compressed gas have been proposed, each consisting of a series of pipes into which gas is pumped at high pressure.

An advantage of CNG is that it does not require expensive infrastructure in the host countries. The facilities for a CNG project in the host nation downstream of the pipeline consist solely of compression and (if necessary) gas-processing facilities, so that substantially less capital is at risk than for an LNG or GTL project. However, a CNG tanker would cost roughly the same as an LNG ship, but could deliver only about a quarter of the volume. If CNG ships are built, the cost is expected to go down, but the shipping cost will still be at a premium to LNG. The nature of the CNG trade, which requires a constant rotation of vessel deliveries to maintain a steady gas flow, is also somewhat of a drawback (although this could be mitigated by gas storage on the receiving end). The weight and complexity of CNG vessels make maintenance difficult.

No CNG project has been developed to date, and most of those being considered are being pursued by independent companies, not oil and gas majors. CNG technology for long-term service is still unproven, which also raises financing issues and market acceptance. Another factor yet to be fully addressed is the acceptability of the high-pressure tankers in importing countries and the siting of the facilities to unload and connect them to the gas grid.