The Future of Asian LNG 2018

(The Road to Nagoya)

A Joint Project
of the
Institute of Energy
Economics Japan
(IEEJ)
and the
Energy Policy
Research
Foundation, Inc.
(EPRINC)

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IEE JAPAN The Institute of Energy Economics, Japan

EPRINC Energy Policy Research Foundation Inc. Est. 1944

ABOUT THE IEEJ – EPRINC JOINT PROJECT

The Institute of Energy Economics Japan (IEEJ) and the Energy Policy Research Foundation, Inc. (EPRINC) have undertaken a follow-on assessment to their 2017 joint report on the future role of liquefied natural gas (LNG) in Asian power and fuel markets. Findings from the 2017 report were presented in Tokyo on October 18, 2017 at the 6TH Annual LNG Producer Consumer Conference.[1] This second year of our joint effort has taken a more in-depth evaluation of trends and longer-term uncertainties in Asian natural gas markets and the potential role of U.S. LNG exports in serving those markets. Some of the 2017 recommendations have been implemented, but more work needs to be done. Of special note is the Japanese initiative announced by Minister Hiroshige Seko at the 2017 Conference that committed $10 billion to provide both financing for infrastructure development throughout the LNG value chain and a companion program to provide capacity building to lift technical skills in Asian countries seeking to expand natural gas use through LNG imports. This program will contribute to increased LNG supplies for Asia by providing support for upstream export capacity and downstream regasification as well as the delivery of natural gas for power generation, industrial, and residential sectors.

Subsequent to the 2017 Tokyo conference, the U.S. has undertaken several initiatives to improve the regulatory process for LNG exports, and considerable progress has been made to ensure adequate feedstock for new LNG facilities. Nevertheless, bringing new LNG liquefaction projects to Final Investment Decision (FID) remains challenging in a market in which buyers are reluctant to make long-term purchase commitments. Much of Asia continues to seek fuel diversity, improved air quality, and strategies to address longer-term climate risks, and natural gas can be a cost-effective fuel choice even for countries relying heavily on renewable fuels.

This research and survey project includes specific recommendations for policy makers and other stakeholders on strategies to both support LNG demand in Asia and to improve the competitiveness of U.S. natural gas in the region. The policy recommendations in this report will be presented at the 7th LNG Producer Consumer Conference scheduled for October 22, 2018 in Nagoya, Japan. The project has received financial support from the governments of both Japan and the United States.

The two organizations have reached out to a wide range of experts, government officials, and market participants through a series of workshops. The first in a series of three workshops of industry experts, policy research organizations (think tanks), and experts was held under the auspices of the Economic Research Institute for ASEAN and East Asia (ERIA) in Jakarta, Indonesia on July 9, 2018. A subsequent meeting in Tokyo at IEEJ headquarters was held on August 24, 2018 with Japanese industry executives, followed by a third meeting organized by EPRINC in Washington, D.C. on September 5, 2018. The final workshop brought together experts, industry representatives, government officials, and representatives from existing and prospective Asian demand centers. In preparing this report, IEEJ and EPRINC have drawn upon the workshop presentations, ongoing research and assessments in our respective organizations, communications with LNG experts in and out of industry, and input from government officials.

An important focus of the IEEJ-EPRINC research effort is to understand the dynamics of longer-term Asian LNG demand, the capacity of the U.S. resource base to expand natural gas production, strategies that can improve the price competitiveness of U.S. LNG exports, and policy initiatives to address structural demand constraints often prevalent in emerging Asian LNG markets. New LNG demand centers are likely to emerge in both Asian power markets and industrial centers, but their number and magnitude remain uncertain. Many of these markets are highly competitive as they can be served by alternative fuels and pipelined natural gas deliveries. This joint project delves into the challenges that might hamper sustainable development of LNG demand in Asia, and provides recommendations to overcome the challenges.

[1]To download a copy of the 2017 joint report, see http://eprinc.org/wp-content/uploads/2017/10/EPRINC-IEEJ-The-Future-of-Asian-LNG-FINAL.pdf.
For a Japanese edition (executive summary only) see https://eneken.ieej.or.jp/data/7561.pdf

ABOUT IEEJ

The Institute of Energy Economics, Japan (IEEJ) was established in June 1966. The aim of its establishment is to carry on research activities specialized in the area of energy from the viewpoint of the national economy as a whole. This is done in a bid to contribute to sound development of the Japanese energy-supplying and energy-consuming industries and to the improvement of people's life in the country. IEEJ accomplishes this by objectively analyzing energy problems and providing basic data, information, and reports necessary for the formulation of policies. With the diversification of social needs, IEEJ has expanded its scope of research activities to include such topics as environmental problems and international cooperation closely related to energy. In October 1984, the Energy Data and Modeling Center (EDMC) was established as an IEEJ-affiliated organization to carry out such tasks as the development of energy databases, building of various energy models, and econometric analyses of energy. In July 1999, EDMC was merged into IEEJ and began operating as an IEEJ division under the same name, i.e., the Energy Data and Modeling Center.

IEEJ has provided data and information related to energy, environment, Middle East, and other research topics as a non-profit organization.

ABOUT EPRINC

The Energy Policy Research Foundation, Inc. (EPRINC) was founded in 1944, and is a not-for-profit, non-partisan organization that studies energy economics and policy issues with special emphasis on oil, natural gas, and petroleum product markets. EPRINC is routinely called upon to testify before Congress as well as to provide briefings for government officials and legislators. Its research and presentations are circulated widely without charge through postings on its website. EPRINC's popular Embassy Series convenes periodic meetings and discussions with the Washington diplomatic community, industry experts, and policy makers on topical issues in energy policy.

EPRINC has been a source of expertise for numerous government studies, and both its chairman and president have participated in major assessments undertaken by the National Petroleum Council. In recent years, EPRINC has undertaken long-term assessments of the economic and strategic implications of the North American petroleum renaissance, reviews of the role of renewable fuels in the transportation sector, and evaluations of the economic contribution of petroleum infrastructure to the national economy. Most recently, EPRINC has been engaged on an assessment of the future of U.S. LNG exports to Asia and the growing importance of an integrated North American energy market.

EPRINC receives undirected research support from the private sector and foundations, and it has undertaken directed research from the U.S. government from both the U.S. Department of Energy and the U.S. Department of Defense. EPRINC publications can be found on its website: www.eprinc.org.

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Key Findings

▸ Transparent, current, and active spot markets are essential elements for discovering a market price that reflects the fundamentals of supply and demand. This price discovery can provide the necessary incentives to build out additional natural gas storage capacity and larger volumes of variable LNG exports. The absolute volume of flexible LNG supply is still limited as current LNG price benchmarks have yet to gain extensive support by market participants.

▸ China and India have become a source of substantial new LNG demand in the Asian LNG market. Both are demand centers where large and small shifts in demand patterns contribute to uncertainty and volatility in LNG prices. Other Asian LNG emerging buyers are also adding to the uncertainty in LNG markets as demand commitments are tied to short term and seasonal requirements.

▸ In most Asian countries, companies and governments have little direct experience in the operation and construction of LNG regasification facilities and connection to electric power plants and distribution networks. Relevant laws and regulations have not been fully developed, leading to delayed decision-making and project implementation.

▸ As LNG bunkering advances globally, there is the potential that bunker fuel markets will become fragmented. Where maritime operators had a limited selection of choices but ubiquitous availability, there now is the possibility of the inverse: many different fuel choices with gaps in coverage across the globe. For LNG bunkering to succeed and to avoid this sort of adversity, coordination is necessary.

▸ Supply security has taken on new significance in Asian LNG markets as final investment decisions (FID) in new liquefaction capacity have been slow despite the recovery in world crude oil prices and unexpected natural gas demand growth in emerging markets such as China. This is of special concern for emerging markets in Asia with substantial prospective LNG growth. Traditional patterns of risk allocation in financing new LNG export capacity are not adequate to meet likely recent trends in the LNG market. Buyers and sellers may consider taking another type of risk to keep expanding liquefaction capacity as the demand grows. Supportive policies from governments and new risk-sharing strategies are needed to bring more projects to FID.

▸ The Panama Canal Authority (ACP) recognizes its critical role as a transit point and a potential bottleneck of the movement of U.S. LNG exports to Asia. The ACP has taken action and has eliminated unfair practices and physical limitations of their vital portion of LNG transportation infrastructure.

The Workshop on LNG Demand in Asia" Jakarta, Indonesia, July 9, 2018

Summary of Policy Recommendations

The IEEJ – EPRINC assessment of the Future of LNG in Asia recommends relevant stakeholders undertake the following initiatives to support a growing market for LNG in Asia:

- *Acceleration of Destination Restriction Removal:*
  Removal of LNG destination restrictions in LNG contracts among all market participants to stimulate spot markets and price discovery. Further actions by anti-competition authorities to review and follow up competition-limiting behaviors.

- *Development of a Reliable LNG Price Benchmark:*
  An LNG price benchmark is a missing link of beneficial active spot trades and market liquidity and transparency. Removal of destination restrictions and a strong initiative by major players to identify a benchmark are required. Buyers and sellers require full transparency in the fundamentals of supply and demand.

- *Assistance to Private Investment in the LNG Value Chain:*
  Steady efforts to assist private investment in the LNG value chain should be undertaken by revising the conditions for financial assistance provided by export credit agencies (ECAs) in Japan. Congressional reviews are ongoing to consolidate the U.S. ECAs so they can more effectively assist private investments in new Indo-Asian energy infrastructure projects.

- *Engagement with Emerging LNG Markets:*
  Deeper engagement with emerging importers will help market participants to have a better understanding of the demand behaviors in emerging markets. Platforms for policy discussions like the LNG Producer-Consumer Conference should be actively utilized to improve market predictability.

- *Development of a Fast-Tracking Tool for Project Development:*
  - A model project template which includes project structure, alternative patterns of risk allocation, and templates for contract terms and relevant documents for the project will help to fast-track the execution of LNG regasification facilities, especially in countries with limited or no experience with importing LNG.

- *Preparation for the Emergence of LNG Bunkering Demand:*
  Governments can play an important role in assisting the development of regulatory standards and infrastructure to facilitate the emerging use of LNG for powering ocean vessels. An active and international effort is required to formulate and coordinate appropriate regulations for use and handling of LNG as a bunker fuel and to coordinate operations at different refueling centers.

- *Innovative Investment Plans to Ice-Break Stalled FIDs:*
  There is a dire need for innovative ideas to break the current FID deadlock. One such idea may be a packaged investment covering wellhead natural gas production and pipeline and liquefaction plant construction.

- *Collaboration to Avoid Bottlenecks in the Panama Canal:*
  Governments from the U.S., Japan, and other LNG importing countries will collaborate to minimize bottleneck risk by active information sharing and policy discussions.

INTRODUCTION

After the conclusion of the 6th Annual LNG Producer-Consumer Conference in 2017, the U.S. and Japanese governments extended their joint efforts to lay the groundwork for building out natural gas markets and LNG infrastructure into the broader Indo-Asian markets. A confirmation of joint efforts to expand LNG markets as well as several new initiatives were announced at a joint meeting of Japanese and U.S. officials at the Embassy of Japan in Washington, D.C. on September 5, 2018. These efforts build on Minister Hiroshige Seko's announcement in 2017 to provide export credit assistance and capacity building for power and LNG facilities in Asia. The Trump administration's "Asia-EDGE" initiative was announced on July 30, 2018 by Secretary of State Mike Pompeo, entailing $50 million in investment in 2018 to help Indo-Asian partners import, store, and deploy energy resources in an example of the cooperative program.

To provide additional support for the challenges in building out the Indo-Asian LNG market, in addition to other development initiatives, the U.S. Congress passed, and on October 5, 2018 President Trump signed into law, the BUILD Act. The new law creates the International Development Finance Corporation (IDFC), a successor to the U.S. Overseas Private Investment Corporation (OPIC), with the ability to acquire equity as a minority investor in projects. It would allow IFDC to double development coverage from $30 billion to $60 billion and to conduct feasibility studies. The new organization provides an effective partner for Japan's Nippon Export and Investment Insurance (NEXI) and Japan Bank for International Cooperation (JBIC), both of which are active in the Indo-Asian LNG market. (footnote 2) The U.S. – Japan cooperative effort covers more than LNG, and includes advanced nuclear and coal technologies, global gas and energy infrastructure, and designates Southeast Asia, South Asia, and Sub-Saharan Africa as important regions. As part of that effort, the two countries signed an MOU (Memorandum of Understanding) on developing energy infrastructure in other countries.

At the same meeting, the importance of the cooperative program was outlined by Shin Hosaka, METI Deputy Commissioner of the Agency for Natural Resources and Energy, who pointed out that energy security in Asia is directly linked to energy security in Japan, the largest importer of LNG to date. Mr. Hosaka went on to state that development of an LNG market in Asia will mean more supply available to Japan in times of emergency and more reasonable prices due to competition. He also stressed the importance of U.S. and Japanese cooperation because of the potential to supply stable, flexible energy to Asia. The remarks were reinforced by Frank Fannon, Assistant Secretary of the Bureau of Energy Resources, Department of State, who emphasized that the Indo-Asian region will be a key source of global energy demand growth to 2040.

Expansion of the U.S. natural gas resource base offers considerable potential to further develop both LNG and pipeline exports, and contribute to higher economic growth in the national economy. Providing a long-term and cost-effective value chain is an ongoing challenge. Nevertheless, new markets are emerging. Traditional Asian LNG-consuming countries such as Korea and Taiwan, and countries in Southeast Asia (Indonesia, Malaysia, Singapore, Philippines, among others) and South Asia (India, Bangladesh, Pakistan) as well as China offer new markets or expansions to existing markets for natural gas.

Natural gas is a fuel source that can contribute to improved air quality, lower emissions of carbon dioxide, and reduced long-term climate risks. China, which has been a modest importer of LNG to date, has begun to accelerate its purchases. Yet investment in new LNG export facilities stalled from 2015 to 2016. The slow pace of FID for new projects reflects growing uncertainty over long-term demand and inadequate infrastructure in importing countries. The LNG market still lacks adequate transparency in price discovery, and while improvements are underway, the market has not yet fully adapted to delivering supplies in response to short-term shifts in demand. Financing constraints remain, so both on the supply and demand side, projects on their way to FID face inadequate infrastructure and ongoing political risks.

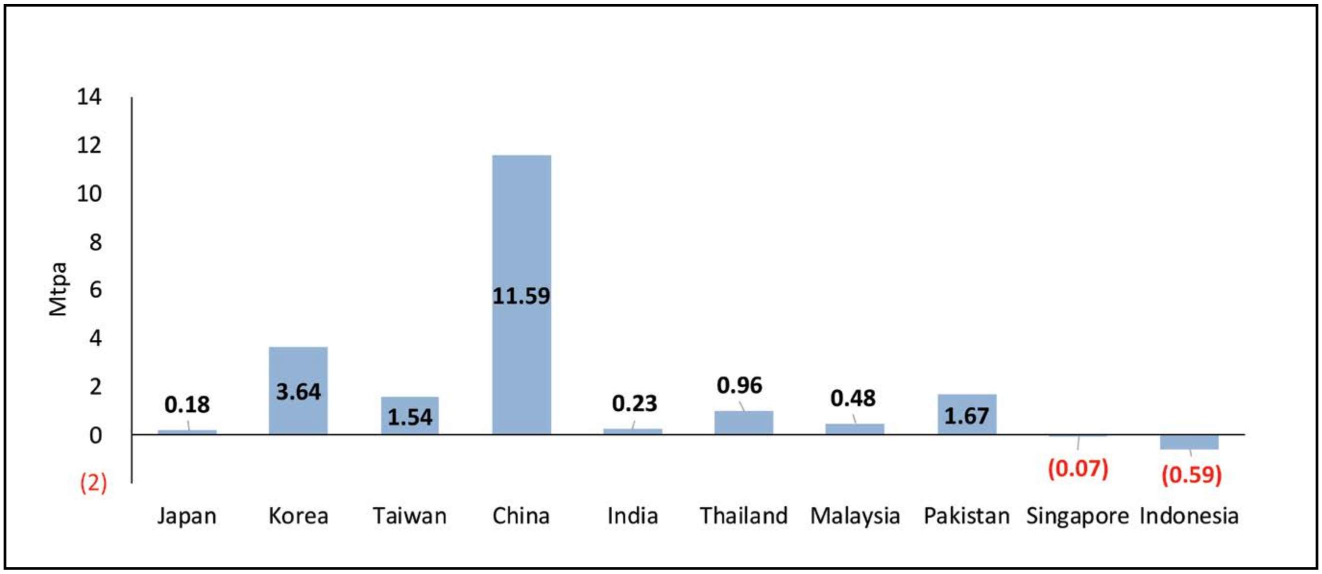
[2] U.S. Department of Energy (DOE) has also committed to deepening its work with METI and to promote U.S. LNG exports and greater LNG use in Southeast Asia and South Asia.

Governmental policies will play a critical role in the future development of Asian LNG markets. Policy support is necessary to reduce investment risks in new LNG infrastructure development in many emerging Asian countries. Financial support and export assistance measures will also play an important role in Asia, particularly for countries which present high credit risks. Technical support would also help Asian countries that have little experience in the LNG business as they embark on LNG imports. This joint research effort recognizes that world LNG markets are heading towards more liquidity and transparency, but these markets have yet to mimic, and may never fully replicate, the open and extensive trading patterns prevalent in the global oil market.

Asian natural gas markets are undergoing an important transition, and much of this new market dynamic is supported by prospects of growing LNG exports from the U.S. For the Asian LNG market to flourish, new supplies and demand centers need to grow and the full range of market participants need to have confidence that price discovery reflects fundamentals of supply and demand. In this regard, IEEJ and EPRINC have continued their assessment of the role of destination restrictions as an impediment to arbitrage in the Asian LNG market, one of several market conditions that inhibit sustainable development of LNG demand in Asia. The U.S. petroleum renaissance has brought about a substantial expansion of natural gas production that has been driven by technological advances which provide access to previously unrecoverable resources. These gas resources will be essential to meet long-term and rising world LNG demand, which for the Asia Pacific region alone is expected to grow rapidly through 2040. This joint IEEJ-EPRINC paper presents our latest assessment of trends in the broader Asia Pacific market and presents a series of recommendations to meet the inevitable rise in LNG demand and accompanying uncertainties faced by both sellers and buyers.

The Future of Asian LNG 2018: The Road to Nagoya" Washington D.C., September 5, 2018

Figure 1
2017 LNG Demand Growth by Country in Asia (Mtpa - million tons per annum)



Source: GIIGNL, The LNG Industry 2018 edition

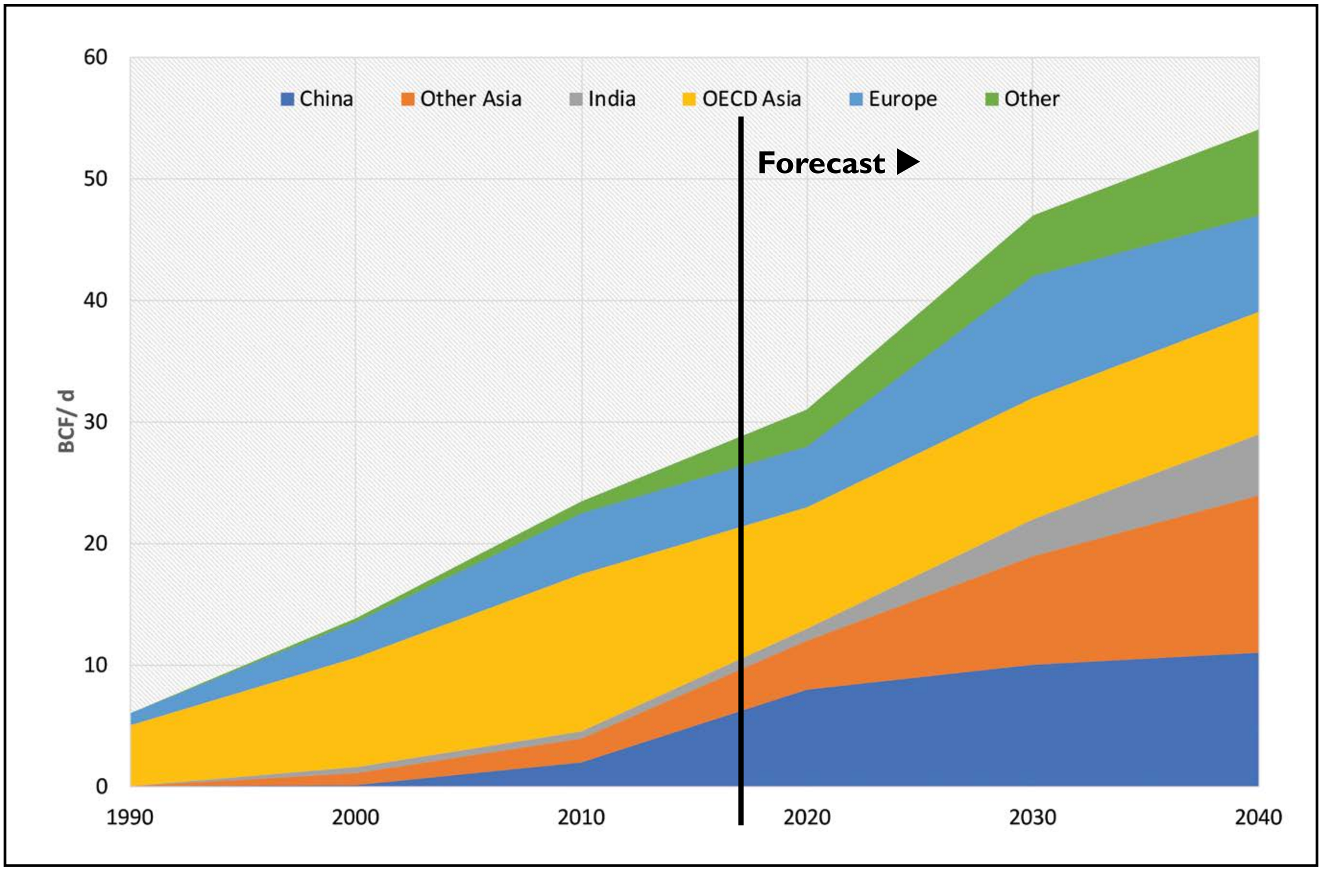
China

Overview

China's liquefied natural gas imports have surged 42%, from 27.4 Mtpa in 2016 to 39.0 Mtpa in 2017, making it the fastest growing LNG market in Asia. Natural gas consumption grew by 15%, more than twice the rate of economic growth. China has become the second largest LNG importing nation, surpassing Korea. The emergence of China as a major LNG market came after years of gas market liberalization reform and government-led coal-to-gas switch in power generation.

Official Chinese government policies will drive rapidly rising natural gas demand growth for at least the next decade, although uncertainties and risks remain. Given the scale of natural gas consumption across the Chinese electric power and urban centers, even small changes in the Chinese energy mix will have oversized and long-lasting effects on global LNG markets. Figure 2 below illustrates the growing market share of China's LNG imports, along with a forecast through 2040.

Figure 2
LNG Imports (1990-2040) by Region (BCF/d - billions of cubic feet per day)



Source: BP Energy Outlook 2018

Current Market Environment

China is likely to become as large (or even larger) of a demand center for natural gas than the European Union (EU) by 2040, presenting a wide range of opportunities and challenges. In addition to the gas demand drivers of greater urbanization and rising per capita consumption, China also is now actively seeking to replace its older coal-fired electricity generation with gas-fired Combined Cycle Gas Turbine (CCGT) technology, a standard technology now prevalent in gas-fired electric power production worldwide. Given rising public concern that the country must improve air quality, China's 13th Five-Year Plan (2016 - 2020) set ambitious goals for increasing the use of natural gas, including almost doubling the share of gas in China's primary energy mix in five years. The 13th Five-Year Plan calls for natural gas to provide up to 10% of China's primary energy by 2020 and 15% by 2030. Table 1 below lays out the past Five-Year Plans and their goals.

Table 1
Chinese Natural Gas Production Plans and Achievements (Bcm - billion cubic meters)

Plan	Beginning Level (year)	Planned Achievements	Planned Annual Growth	Actual Achievement	Actual Annual Growth	Fulfillment
10th (2001-2005)	27.2 Bcm (2000)	50 Bcm (2005)	13.2%	49.3 Bcm (2005)	12.63%	Almost
11th (2006-2010)	49.3 Bcm (2005)	92 Bcm (2010)	13.3%	95.2 Bcm (2010)	14%	Yes
12th (2011- 2015)	95.2 Bcm (2010)	156.5 Bcm (2015)	10.5%	135 Bcm (2015)	7.20%	No
13th (2016-2020)	135 Bcm (2015)	207 Bcm (2020)	8.9%	N/A	N/A	N/A

Note: 207 bcm/y is equivalent to approximately 20 bcf/d

Although the role of the Chinese government is central to the likely energy mix within the Chinese economy, the government has undertaken a process of gradual price liberalization for natural gas. Gas prices for nonresidential customers were liberalized starting in 2015. In 2017, the government announced that third parties could negotiate prices and gain access to pipelines and LNG import terminals. These reforms have already produced impressive results. In the last 18 to 24 months, just four non-government players in China now make up almost 10% of the current contracted deliveries to the Chinese gas market (with first deliveries in 2018), which are expected to cumulatively amount to 480 MMT (million metric tons) by 2040.

Development Path of Chinese Oil and Gas Industry and Emerging Actors

China has followed a central planning model to develop the oil and gas industry with a strong and long-standing military connection. In the 1950s, the 5th Division of the 19th PLA Army was transformed into an "Oil Corps" to provide the organization, planning, and engineering to develop the domestic oil and gas (O&G) industry. However, oil enterprises' ownership rights were separated from the state in the 1980s with the establishment of the national oil companies (NOCs). The three major NOCs, known as the "Big Three," are the China National Petroleum Corporation (CNPC), China Petroleum and Chemical Corporation (Sinopec), and China National Offshore Oil Corporation (CNOOC). Initially, they were separated by specialization in onshore upstream production, refining, and offshore O&G exploration. Nevertheless, after the industrial reform initiated in 1998 by then premier Zhu Rongji to create a more competitive O&G industry, CNPC and Sinopec were reorganized as two vertically integrated companies. Both have expanded to involve themselves in all areas of the O&G industry, and the distinction between them has disappeared over the years. The NOCs enjoy a certain degree of freedom in their operations to be competitive in domestic and international markets. However, the state owns the NOCs and the are susceptible to state and party influences. Like other state-owned enterprises, all three NOCs are under the State-Owned Assets Supervision and Administration Commission (SASAC), a powerful agency directly under the State Council.

Due to the government's efforts to liberalize gas markets, other actors are emerging in the LNG sector in China. Public utilities (Beijing Gas and China Gas) and private companies (ENN, Jovo, Sinochem, etc.) are taking advantage of the third-party access to infrastructure and expanding their reach in China's LNG market. For instance, Beijing Gas plans to import its LNG supply directly through its own anticipated LNG receiving terminal with an annual receiving capacity of 18.25 Bcm (12.25 MMT) near Tianjin.

Table 2
China's Oil & Gas Industry: History, Trends, and Challenges

1949- 1959	1960-1978	1979- 1991	1992-1998	1998-2008	Today
5th Division of 19th PLA Army formed into an "Oil Corps"	PABs rapidly start to develop oil & gas industry	China launches its economic liberalization policy (1978)	PABs de-centralization is recognized as "manageable disaster" (1995)	Big bang industry reform (1998)	Sinopec Group, CNOOC and CNPC today control 90% of production in China
Ministry of Petroleum Industry formed in 1955	China starts exports of petroleum surplus to Japan at significant discounts to Russian prices - undermining Russian export earning		First price rationalization intervention to align with international prices	Petroleum Industry qualifies as National Security	PetroChina resembles any other financially successful NOC
China imports oil products from Russia			Industry losses balloon, productivity drops and imports rise	Re-centralization though asset swaps	CNPC - PetroChina duality and sector governance issues are center stage as China gas imports start to grow
Regional Petroleum Administration formed (PABs)				CNPC, Sinopec Group and PetroChina are created (1999)	
Oil & Gas production increases and relationship with Russia starts to become strained	Relationship with Russia deteriorates			Growth in international activity.	
Petroleum as a strategic risk	**Opportunistic moves to playing off Russia**	**Reorganization of domestic industry**	**Course Correction in Restructuring**	**Preparing for Rapid Growth**	

Source: EnerStrat Consulting

Despite the new emerging structure of the Chinese gas market there are several major risks for LNG exporters given the historic pattern of development. Table 2 above contains a snapshot of the history and trends of that development.

While China developed the Ministry of Petroleum Industry in 1955, there has never been an independent national regulatory organization for the industry in China. The China National Petroleum Company (CNPC) spawned Sinopec Group, CNOOC, and PetroChina. The Chinese government's desire to be in direct control of the industry is very evident, and strategic energy security continues to remain high on the list of priorities for the administration.

Technical cooperation with Russia has been critical in Chinese development of its O&G industry since the mid-1950s. When a temporary surplus in oil production emerged in the mid/late 1960s, the nation did not hesitate to export this surplus to Japan as a retaliatory measure when relations with Russia had soured in the late 1950s. This oil, sold to Japan at a discount to the prices offered to Japanese buyers by Russia, had the effect of undermining Russian energy export earnings. This is an important historical precedent for U.S. gas exporters to consider. China may adopt a similar strategy for LNG cargo re-loads and re-exports within the region and undermine its supplier strategies.

China has toyed with the idea of creating regional, vertically integrated O&G players when it created Petroleum Administrative Boards (PABs), but historically has been unsuccessful in driving operational performance efficiencies. In the electricity sector, regional vertically integrated monopolies have operated successfully in China.

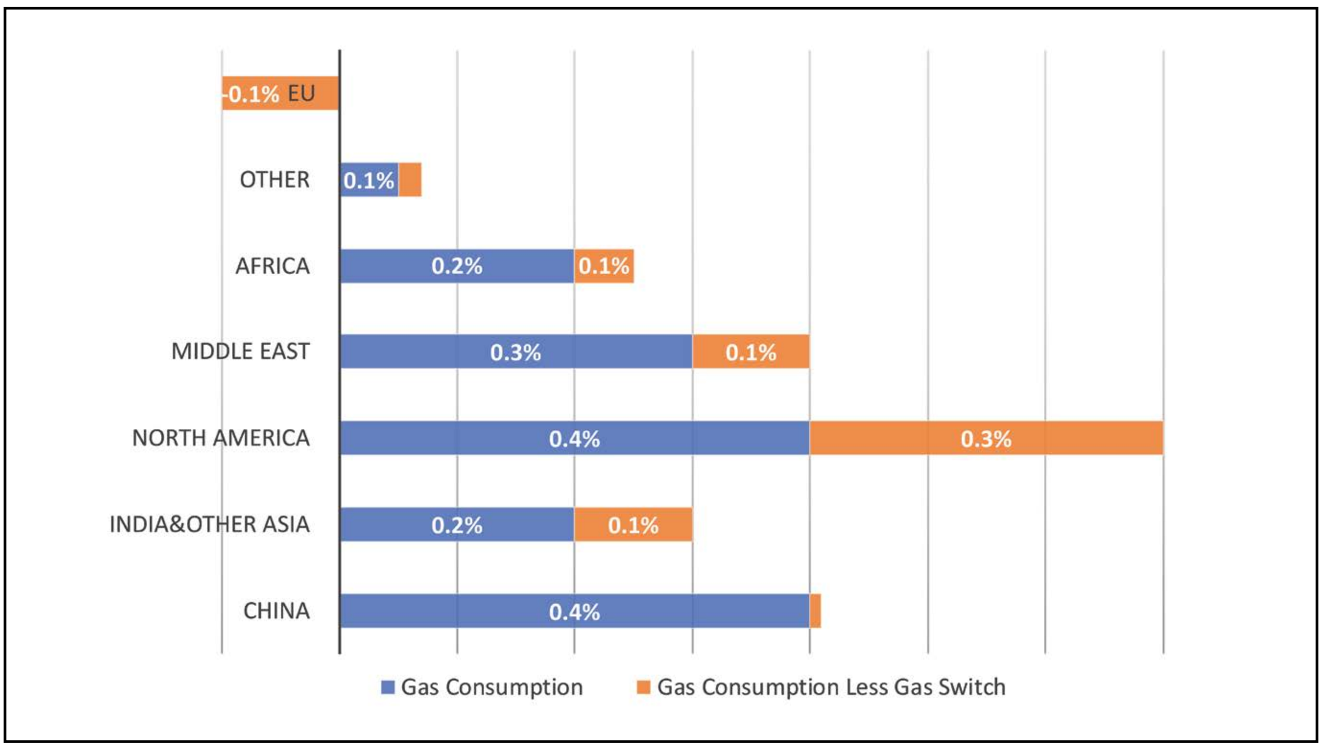
Factors of Uncertainty

During the winter of 2017–2018, much of northern China experienced significant natural gas shortages. Demand surged, owing to the government's ambitious coal-to-gas switching programs, and domestic production and pipeline imports could not meet growing demand requirements.

Ambitious coal-to-gas switching initiative

During the winter of 2017–2018, much of northern China experienced significant natural gas shortages. Demand surged, owing to the government's ambitious coal-to-gas switching programs, and domestic production and pipeline imports could not meet growing demand requirements. Public opinion is one of several factors that have contributed to these severe shortages which will shape the demand outlook for Chinese LNG imports Figure 3 clearly shows that Chinese gas consumption growth would be very adversely affected without government support of a coal-to-gas switch policy in the power sector.

Figure 3
Gas Consumption Growth with Regional Contributions, 2016-2040 (% per annum)



Source: BP Energy Outlook 2018, Industry Reports, and EnerStrat Consulting

Inadequate storage capacity

China's natural gas storage capacity is small by international standards, at about 11.7 Bcm, equivalent to just 5% of total consumption. In comparison, the ratio of gas storage capacity to consumption in the United States is 17% and Europe is 27 percent. One constraint on the sustained Chinese LNG demand is the rate at which new underground gas storage is installed, a key feature in delivering gas for shifts in seasonal demand.

Overstretched LNG infrastructure

In the winter of 2017, China's 16 LNG receiving terminals became highly overstretched with an average utilization rate above 105% and utilization at some northern terminals exceeding 120 percent. The pipeline infrastructure to move natural gas from southern terminals to northern demand centers also proved inadequate. To bridge this infrastructure gap, Chinese companies, notably CNOOC and Sinopec, dispatched hundreds of trucks to deliver LNG from receiving terminals in the south to cities in the north at distances of more than a thousand miles. These truck deliveries reportedly came at a cost of more than $30 per MMBtu during the winter peak demand, nearly three times the spot LNG price during this period. The efficiency and speed at which the Chinese government could build the missing links between southern LNG terminals and northern demand centers is another uncertainty point which will have a long-term impact on LNG imports.

Pipeline gas shortfalls

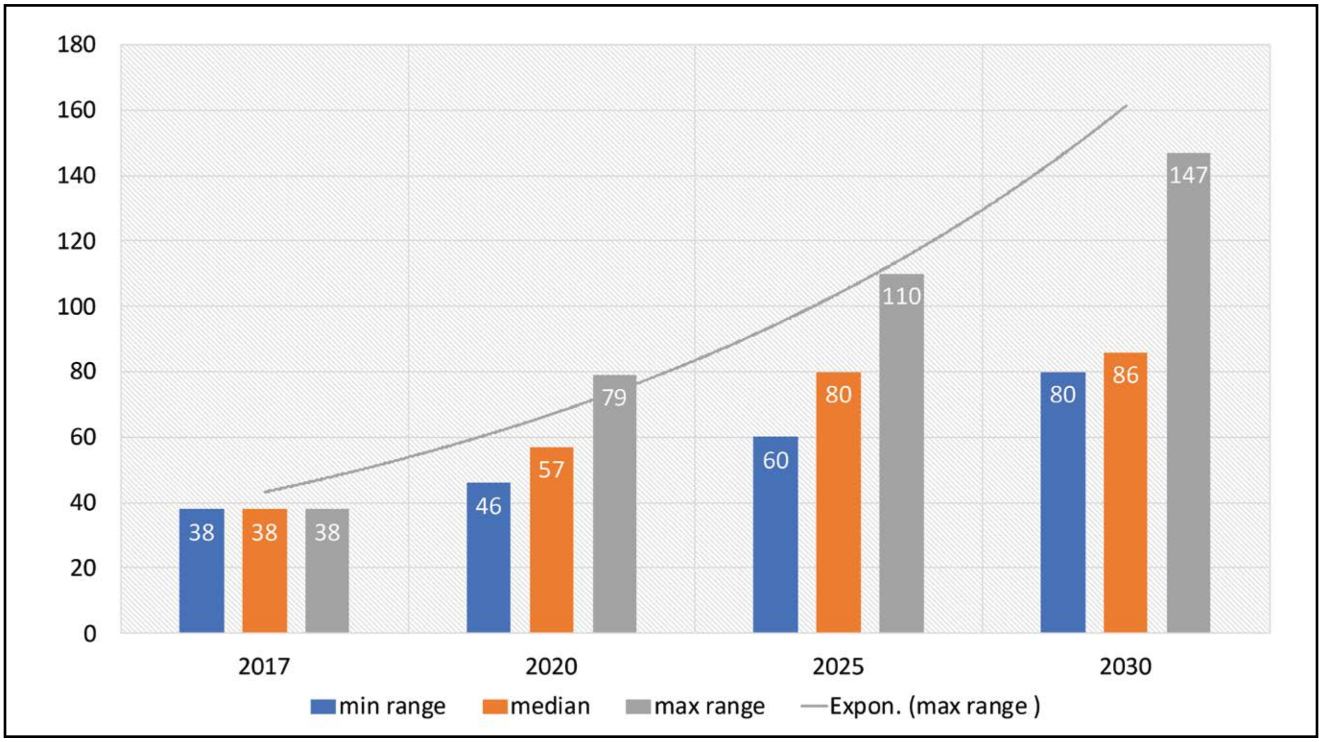
China relies heavily on pipeline gas from Central Asia for natural gas supplies. In the second half of 2017, pipeline gas deliveries from Turkmenistan fell substantially. Chinese buyers attempted to offset the reduced volumes from Turkmenistan with more supply from Kazakhstan and to a much lesser extent, Uzbekistan. CNPC rushed to bring natural gas wells online ahead of schedule at its Amu Darya project in Turkmenistan. However, pipeline gas imports from Central Asia remained largely flat during the months of peak winter gas demand. These lower-than-expected volumes put considerable pressure on the natural gas market in northern China and was one of the causes for LNG imports surge.

Despite several rounds of reform in recent years, China's natural gas prices remain semi-regulated. In the absence of such market mechanisms, it is the regulator's job to keep the system in balance. As China's recent winter gas shortage illustrates, it can be exceedingly challenging to respond quickly to shifts in gas demand.

Demand Outlook

The lack of market-based price signals and the large and influential role of the central government on gas policy adds to uncertainty in any forecast of Chinese LNG demand. The potential range of uncertainty in future demand is shown in Figure 4 below.

Figure 4
LNG Demand Projections for China (Mtpa)



Source: Bloomberg and EIA

India

Overview

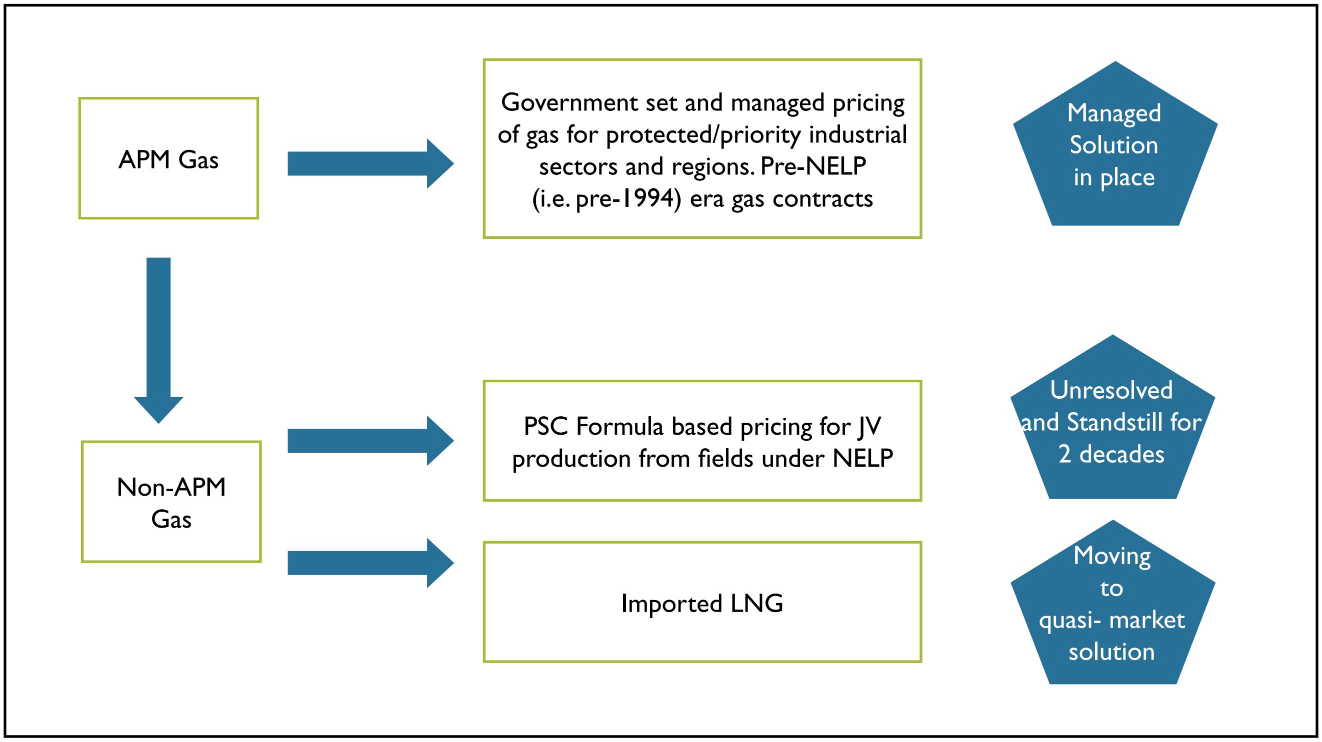
There are many reasons why the term "wild card" is apt for the Indian gas market. In contrast to most Asian gas markets, power generation is not likely to be a driver of gas growth in India. Other forces, such as rapid urbanization, industrialization, and transportation will be the drivers in the short/ medium term (up to 2025) for natural gas demand growth. Two other features in the Indian gas market are worth noting; (i) gas demand will likely be more price sensitive than other Asian markets and (ii) demand growth will be met largely through LNG imports as there are limited opportunities to develop international pipeline connectivity. The bargaining power of buyers in India is therefore likely to be limited, though recent experience suggests that Indian buyers have managed to secure attractive prices through renegotiations.

Gas Pricing in India

India has historically had an "Administered Pricing Mechanism" (APM) for gas pricing from domestic gas fields. This was a government-administered price for gas allocated from specific fields to priority sector gas users such as fertilizers, the philosophy behind this being that fertilizer is viewed as critical for food production and hence for food security in India.

As gas requirements have grown, there has been a concerted initiative in India to develop its own gas fields for production and several policy reforms were introduced. These include a production sharing formula, implemented through a model production sharing contract (PSC), that would provide sufficient incentive for international investors to participate in the Indian E&P program. An Open Acreage Licensing Program (OALP) has been introduced in India that will allow for a competitive gas price to be offered to the PSC counterparts. The program is not fully implemented due to legal challenges. Figure 5 below captures the various pricing methodologies currently being applied in India.

Figure 5
Understanding Gas Pricing in India



Source: EnerStrat Consulting

The Problems Facing Gas-Fired Power Generation in India

Gas-fired power generation capacity of around 24,000MW constitutes a mere 7% of the installed power capacity in India, and of the 24,000 MW (megawatts) it is estimated that less than 50% of the capacity is fully operational due to chronic non-availability of gas. Of late, India has experienced a rapid growth in renewable power generation, mainly solar power, which now makes up around 20% of capacity. The effect of growing energy efficiency (many Indian cities are moving towards LED street lighting, as an example) is in turn growing renewable generation, and reducing dispatch from gas fired generating plants.

India has also launched (with much fanfare) a policy to install super-critical boiler-driven High Efficiency Low Emission (HELE) plants, and while quite a few plants have already been built and are operational, they are running substantial financial losses as the distribution companies that have signed power purchase agreements with these plants are unable to fulfil their payment obligations. About 25 GW (gigawatts) of such projects (some operational and some yet to be commissioned) are facing receivership.

Table 3 is the breakdown of the current power generation capacity in India. The lenders who are funding new projects are staring into a $25 billion asset bubble. The situation has highlighted a long-standing concern of fuel suppliers. With regulated fixed tariffs for electricity consumers and fertilizers, the plant owners are asking for long-term fixed-price contracts, and gas suppliers are unable to offer fixed-price gas at levels required to service customers profitably.

Table 3
Power Generation Capacity in India

	MW	% of Total
Thermal Capacity	222693	64.76%
Coal	196958	57.27%
Gas	**24897**	**7.24%**
Oil	838	0.24%
Hydro Capacity	45403	13.20%
Nuclear Capacity	6780	1.97%
Renewable Capacity	69022	20.07%
Total Generation Capacity	343898	

Source: Cunningham, Edward; The State and the Firm: China's Energy Governance in Context, working paper. https://ash.harvard.edu/files/chinas-energy-working-paper.pdf

Among gas-based power plants, 5,000 MW capacity, including GMR Rajamundry, Lanco Kondapalli, Reliance Power Samalkot, RVK Energy, and Panduranga Energy, would land in the National Company Law Tribunal (NCLT), said officials. Of the 24,000 MW of stranded gas power projects, 14,000 MW were allotted gas at subsidized rates by the government and, hence, are receiving part of their tariff from their respective power buyers.

Given declining credit ratings of many power generation utilities, gas suppliers are often unable to identify credible, creditworthy counterparties. The location of these plants, often far from natural gas pipelines, and poorly developed regulatory programs to gain access to gas transportation has further constrained gas demand growth. Unless access to gas transport systems on a non-discriminatory and transparent pricing basis is available, the power sector demand will continue to remain soft.

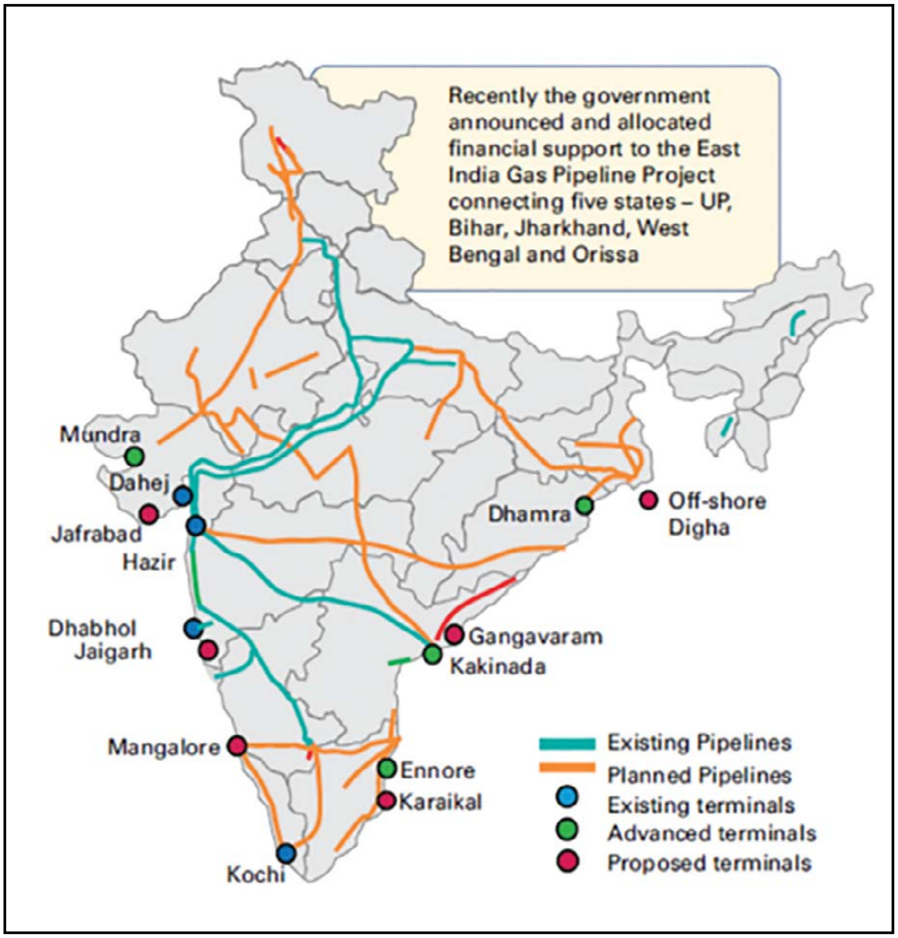
There is still a possibility, though remote, that if proposals by the Ministry of Power in India for financial restructuring of the power sector are undertaken, then more opportunities will emerge for gas-fired electric power generation. However, the principal source of optimism for gas in India is not the power sector but growing trends of urbanization for residential use and for surface transportation.

Urbanization and Transport Driven Gas Growth

Urbanization is now an irreversible trend across India and a "gas quadrilateral" across India is beginning to take shape. A program driven by the gas regulator (PNGRB) is allocating development of City Gas Distribution (CGD) networks through public private partnerships (PPP) in many cities in India.

As Figure 6 below shows, large cities across India are already in the process of building their gas distribution networks, whereas another 56 are to be allocated over the next two years. This will materially change the demand patterns across the country.

Figure 6
Gas Distribution Network in India



Source: Enincon Research, PNGRB, PPAC, KPMG

Another aspect of the CGD Network is the connectivity to the large number of special industrial zones in or around these cities This is expected to bring a new wave of both large and small and medium enterprise (SME) industrial consumers. With 43% of the 1.25 billion Indian population living in cities and with more than 53 cities in India with a population over one million, even assuming a low per capita gas consumption, the growth contribution of this segment to Indian natural gas demand is substantial.

In addition to the urban energy demands, another new set of customer segments are now beginning to develop: urban mass transportation in cities and inter-city bus and trucking services experiments are being piloted including the usage of LNG-fueled large trucks.

There remain many uncertainties related to the pace of the city gas network development, the ability of the national gas marketing companies to connect customers with speed, and also the issue of right of way allocations and land clearance. These are in the process of being resolved.

An important issue that is relevant to Asian gas and LNG in particular is the pricing formula used in LNG contracts, specifically the role of oil indexation vis-à-vis the gas-on-gas price competition developing at gas pricing hubs like the Henry Hub in the U.S., the UK NBP, or the German NCG. In contrast, India has had a long-running public consultation on its preference for developing a traded market for gas within the country.
Indian policy makers have been unequivocal in articulating a gas pricing mechanism/methodology

that allows India to connect its market to the globally traded gas market and a gas pricing formula that de-couples gas pricing from oil pricing with an objective to securing a lower import price for LNG. This would essentially be a formula with minimal to no oil indexation component

Indian Gas Demand Projections

Table 4 below shows a range of estimates from IEA, EIA, BMI, McKinsey, and the government of India's (GoI) Vision 2030 forecast from an industry study undertaken by India's Petroleum and Natural Gas Regulatory Board (PNGRB). PNGRB's forecast is clearly an outlier, and it is worth noting that this forecast assumed no constraints from natural gas prices, infrastructure, or supply availability. EnerStrat Consulting undertook an estimate building on regional patterns to provide a separate view of Indian gas demand. Note that with the size of the Indian population, a small shift in demand growth of 1% per annum would move total gas demand in 2040 by well over 100 Bcm.

Table 4
India Gas Demand Forecast Estimates (Bcm)

	2020	2025	2030	CAGR
IEA NPS	64	90	114	6.6%
IEA CPS	67		118	6.5%
EIA REF	70	87	112	5.4%
BMI Research	69	85		
McKinsey	72	92	113	5.1%
GoI Vision 2030	138	179	272	7.8%
EnerStrat Consulting	75	107	137	6.9%

Source: EnerStrat Consulting

The Gas Vision 2030 demand projections (prepared in 2013) are at odds with other forecasts for Indian gas. The PNGRB's estimates include an expectation that the power sector will emerge as a major gas consumer, a feature of Indian gas market that shows no signs of moving towards large scale use of natural gas as a fuel source.

Several features of all the forecasts are worth noting. Gas demand will grow in India through 2025, but it will be driven by forces outside the power sector. India demand trends from the Q2 2018 data point to final demand for 2018 at about 66 Bcm. It is also likely that by 2025 the potential for more rapid gas demand growth as more urban centers get connected to the Indian gas that a total volume of 105-110 Bcm is possible by that time. As mentioned earlier, almost all this demand will most likely need to be met in the form of LNG due to the lack of international pipelines and domestic production.

Gas Demand Uncertainty in India and China Drive by Different Forces

Both China and India are major growth markets for gas and LNG. Both markets will remain net importers in the near- to medium-term. Both countries have made substantial commitments to developing other energy sources; China is expected to emerge as the largest nuclear power-generating country and will deploy its own nuclear technology. Both countries have well-developed plans and implementation programs to deploy clean coal technologies and carbon capture underground storage (CCUS) technologies. In addition, both countries have multiple choices and alternative paths to achieve their stated strategic energy goals. These factors will influence the buy-sell dynamics of international LNG.

Updates in Other Countries

Japan, Korea, Taiwan

Japanese LNG demand in 2017 showed a slight increase to 83.5 Mtpa thanks to colder weather and demand growth in the industrial sector, although its power sector demand shrank due to the restart of nuclear power plants. While the recovery of oil prices since 2017 may provide some help for the demand in the industrial sector, the demand in Japan is set to decline, at least for the short- to mid-term, due to the maturing city gas demand and the successive restart of nuclear power generation.

LNG demand in Korea, once forecasted to gradually decline in the long run, will have a gain in the coming years thanks to the Moon administration's new energy policy vision. President Moon announced in June 2017 that Korea would phase out nuclear power plants by limiting the operation of older units. Reflecting Moon's remarks, the Korean government published the 8th Basic Plan for Long-Term Electricity Supply and Demand in December 2017, and it aims to lower the share of nuclear power generation to 23.9% as of 2030 from 30.3% in 2017 while raising the share of renewable and natural gas power generation as of 2030 to 20.0% from 18.8%. The government also published the 13th Natural Gas Plan in April 2018, which expects natural gas demand in Korea will grow to 40.5 Mtpa in 2031, reflecting the expected demand growth in the power sector.

Taiwan has a similar energy policy direction as Korea, and will boost LNG demand in the future. Like the Moon administration in Korea, the Tsai administration aims to reduce the dependence on nuclear power generation by increasing the supply from renewable sources, but within a much shorter time horizon (by 2025). Due to the limited availability of renewable energy and the need for backup power generation capacity in the country, the role of LNG in the Taiwan's power mix must grow significantly. One of the potential bottlenecks in such a rapid growth of LNG demand is the country's receiving capacity. Taiwan has two receiving terminals that receive more LNG cargoes than their named capacities even as of today.

Taiwan plans to build the third receiving terminal to accommodate the increasing LNG demand, but if the completion of the third terminal is delayed, the expected demand growth will be checked.

The LNG demand of the three countries combined will grow to 133.9 Mtpa in 2030. The demand will show a slight increase overall, as demand growth in Korea and Taiwan will offset the demand decline in Japan.

Southeast Asia

In Southeast Asia, LNG demand growth has stalled. The total demand in the region in 2017 grew only slightly by 0.8 Mtpa to 10.4 Mtpa, and Indonesia even decreased its demand by 0.6 Mtpa. The stagnant demand in the region is largely attributed to price increases. Both JLC and spot LNG price regained in 2017 as the crude oil price recovered from 2016 to 2017. Since LNG is mostly used in the power generation sector in the region, it always competes with other energy sources and the price increase worsens the relative competitiveness of LNG in the fuel choice. Another factor that discourages LNG demand in the region when the price rises is price regulation. Many countries in the region have price regulation on energy supply, particularly electricity. The rise of LNG prices can be diluted to some extent with the prices of other natural gas supply sources; but as the share of LNG to the total natural gas supply grows, its price increase becomes intolerable for local power producers. In Indonesia, in fact, energy prices have been frozen since March 2018 and it will be so until the end of 2019, when the current administration's term ends.[3] This decision worsens the economics of LNG imports and worked unfavorably to the country's LNG demand.

Despite the stalled demand growth in 2017, the demand fundamentals in Southeast Asia are strong. Energy demand growth is backed by expanded economic activities, depletion of domestic natural gas production, and increased attentions to air quality and environmental issues, and will surely raise the region's LNG demand in the long run. Natural gas will be undoubtedly a more important energy source and continue to play

[3] http://jakartaglobe.id/news/govt-will-keep-fuel-electricity-prices-stable-end-2019/

a large role in the region's energy mix, and LNG will be the only realistic and sustainable supply source to the region. LNG demand in the region is expected to grow to 52.7 Mtpa by 2030.

South Asia (Excluding India)

The LNG market in South Asia is rapidly expanding. As of 2018, India, Pakistan and Bangladesh are importing LNG. Bangladesh has just started to import LNG via an FSRU off Matarbari Island. Sri Lanka does not yet have an LNG receiving facility, but it has several plans to import LNG in the early 2020s.[4] Although in Southeast Asia the higher LNG price discourages LNG imports, LNG demand in South Asia is relatively less sensitive to price levels. This is because oil-fired power generation has a high share of the power mix and LNG can maintain relative competitiveness against imported oil products even when the price rises as the crude oil price increases. Stagnating domestic production in Pakistan and Bangladesh, existing gas supply infrastructure, and adoption of FSRUs as a quick solution to LNG import terminal shortages will facilitate LNG import in the region.

Combined demand in Pakistan, Bangladesh, and Sri Lanka will grow at a faster rate than Southeast Asia given their energy demand and supply profile, infrastructure, and capacity to accept international LNG prices. In Pakistan, the gap between natural gas supply and potential demand is still large and the country expects increased LNG will fill in the gap. In Bangladesh, the power shortage is also a serious issue and the demand potential for power sector is significant. The future demand in the three countries will be 17 Mtpa as of 2030.

Growing Uncertainties in Asian LNG Market

Uncertain Demand Behavior

As the share of emerging LNG buyers expands, LNG demand in Asia becomes more difficult to foresee. There is no doubt that the demand potential in Asia is large and likely to expand rapidly; but when, where, and how soon such potential demand will be realized is highly uncertain. This is because, unlike traditional markets such as Japan, Korea, and Taiwan, these emerging markets have alternative natural gas and energy supply options such as domestic natural gas, pipeline import gas, or other domestic energy sources such as coal and renewable energy. Developments in receiving, transportation, and utilization infrastructures are not catching up with the growing demand due to the lack of financial resources. Even when such infrastructure is developed, many countries will still have an affordability issue when the international LNG price rises.

Some emerging Asian countries have already set energy mix or power generation mix targets, but in many cases there is insufficient capability or clear policy actions by the government to realize the target. Such a lack of governmental policy commitments and administrative capability makes the future energy or power mix more uncertain. In some Asian countries, the government provides their own demand outlook, but such an outlook tends to be too large as it is developed based on optimistic assumptions. Providing a more accurate and realistic demand outlook is very important to mobilize necessary political, financial, and human resources in an efficient enough manner to realize the infrastructure development. Such a demand outlook will be helpful to provide an appropriate signal to international investors who have an interest in investing in natural gas infrastructure in the region.

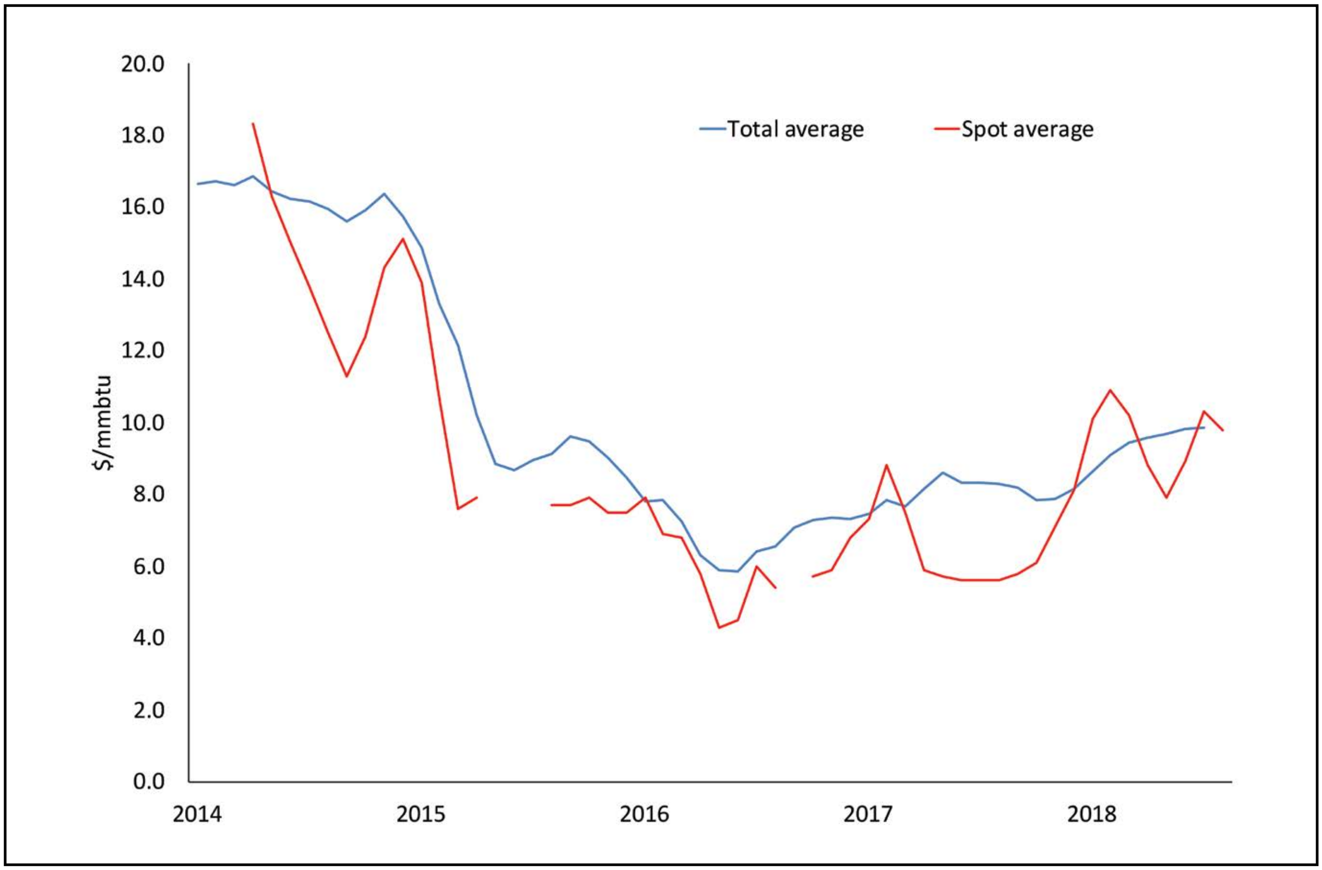
Larger Seasonal Demand Fluctuation

As LNG demand in Asia grows, the fluctuation of seasonal demand also is magnified, and it begins to cause large price swings in the spot market, especially in winter time. This seasonal demand swing is most notable in the Chinese market, where the difference of LNG imports between the peak and the off-peak month in 2017 was 2.5 times. The development of the LNG market in Asia, however, has not caught up with the rapid expansion of the market and is not fully able to accommodate the widened seasonal demand difference. Although most LNG buyers try to moderate their cargo procurements by utilizing cargo swaps with other

[4] http://www.dailymirror.lk/article/Sri-Lanka-to-hold-ownership-in-proposed-LNG-import-terminal-146578.html

buyers or build up inventory before the peak season, such preparative arrangements are not enough to meet the incremental seasonal demand, and many buyers try to procure additional cargoes from the spot market. The size of international spot LNG market has significantly expanded, but it has not been sufficiently liquid to accommodate the demand surge in winter time in recent years. As Figure 7 shows, the spot price tends to be far more volatile compared to the average LNG price, which suggests relative shortage of liquidity in the market. Because the LNG demand in emerging Asian countries is considered to be more sensitive to price level, such volatile price movement may discourage prospective users of LNG in the future.

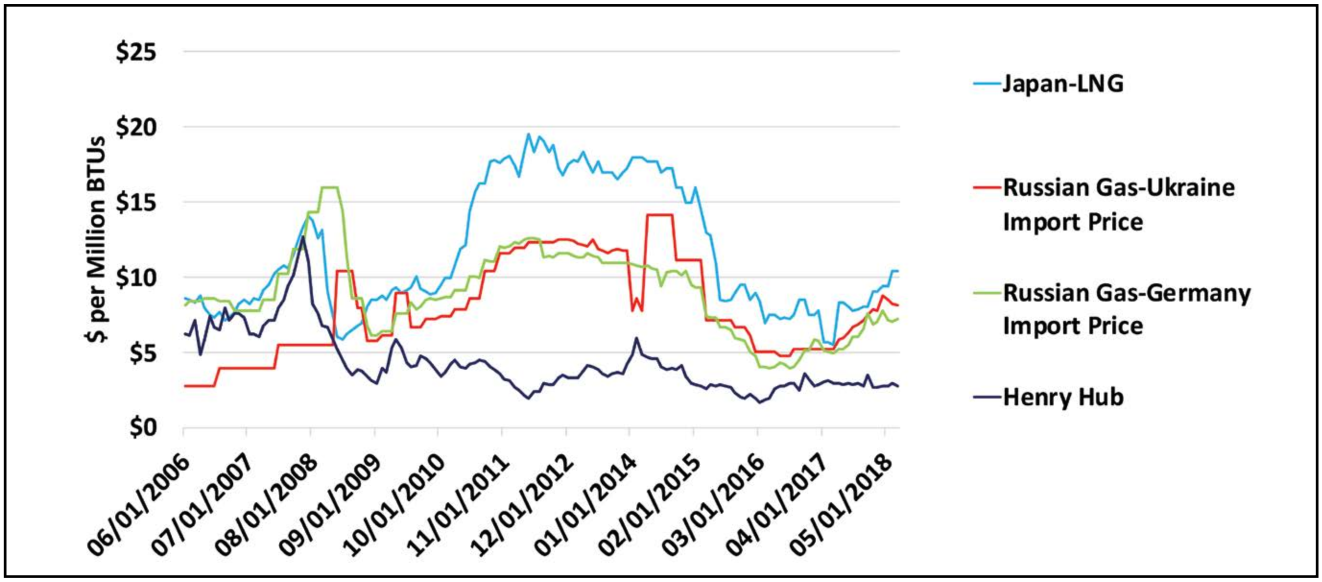
Figure 7
Average LNG Import Price and Average Spot Price to Japan (Dollars per million BTU)



Source: Ministry of Economy, Trade, and Industry (METI)

Despite this volatility in the market, the Japan LNG import price has remained consistently the highest among the major importing regions. The average Japan LNG import price from June 2006 to February 2018 was $11.6 per MMBtu, while Russian Gas - Ukrainian import price at the same period was $7.89 per MMBtu and average Henry Hub price remained the lowest with the least volatility index at $4.31. This is shown below in Figure 8.

Figure 8
Global Natural Gas Prices in Four Regions (Dollars per million BTU)



Source: IMF Data

Lack of Clear Legal and Regulatory System

In cultivating natural gas demand, infrastructure development is critically important. Because the required infrastructure investment tends to be very large, risks for investors must be minimized, so clear legal framework to protect investors' interest must be in place. In an independent gas-fired power producer project, for instance, the viability of the project is largely subject to the provisions of the power purchase agreement. The conditions of the price and offtake volume must be strictly kept by local contractual counterparts to ensure the economic viability of the project.

Revisions to the initially agreed-upon conditions from domestic political or economic reasons will deteriorate the project economics and harm the interests of the investors. Regulatory uncertainties also discourage the investors from proceeding with the project. Unclear regulatory arrangements for the foreign entity's investments, currency remittance, customs clearance of equipment, or environment compliance cause confusion among investors, leading to delays. Clear legal and regulatory arrangement with transparent decision-making by host governments will be instrumental in expediting the project development.

Lack of Formal Coordination Platform

In realizing a successful infrastructure project, the project must be mutually beneficial to all parties involved, and to ensure this condition, investment risks must be allocated in a fair and appropriate manner. Close coordination and information exchange are crucially important to obtaining mutual understanding and confidence so that the projects can proceed.

In the current project development activities, such coordination is being made among investing companies, local counterpart companies, and host governments on an ad-hoc basis, and no formal or regular communication framework or platform is established in most of emerging Asian countries. This ad-hoc coordination style usually takes time and becomes a reason for project development delay.

A natural gas infrastructure project in Asia tends to adopt an unbundled system where different companies undertake different value chains. This means that in the project development phase, a variety of companies with different backgrounds and interests must work closely to complete the project on a designated schedule. Closer and more intimate communication and coordination among relevant parties will be more important, and the need for a formal established platform becomes heightened.

CHALLENGES AND INITIATIVES FOR LNG SUPPLY SECURITY IN ASIA

Why is Supply Security Relevant Under the Current LNG Market Context?

Supply security has been one of the major policy goals for all energy policy makers, particularly in import-dependent Asian countries. It is never a new nor unfamiliar topic in the region. Yet, under the ongoing LNG market developments, ensuring supply security is gaining more and more significance.

While the LNG market experiences unprecedented market expansion, serious discussions about the supply security issue with consumers have been nonexistent. Platforms such as Gastech, the World Gas Conference, and the LNG Producer– Consumer Conference have been utilized as an opportunity to discuss various issues including gas supply security, but there is no platform that specifically deals with the gas supply security issue.

Despite the fact that the world LNG demand has grown by 1.7 times in the last decade until 2017, and the number of LNG importing countries has more than doubled from 17 to 39 during the same time period, there is no official framework where LNG consumers can share the issues and countermeasures about gas supply security like International Energy Agency in the oil market. The international LNG market is expected to be in a supply surplus condition where LNG liquefaction capacity largely exceeds LNG demand for the time being, and any serious supply security issues has not emerged so far despite the rapid market expansion of LNG market. Yet as the demand from China and other Asian emerging buyers has grown at an unexpected speed, the "rebalancing" moment of the LNG market from supply surplus to supply shortage may come earlier than widely perceived at the early 2020s. Supply security risk will be recognized as a more acute issue among market players once the market is in a more strained condition. Policy makers in Asia now need to revisit the concept of supply security in the LNG market, identify the issues, and consider policy actions to address those issues.

Investments in Value Chain

Growing Importance of Upstream and Liquefaction Investments

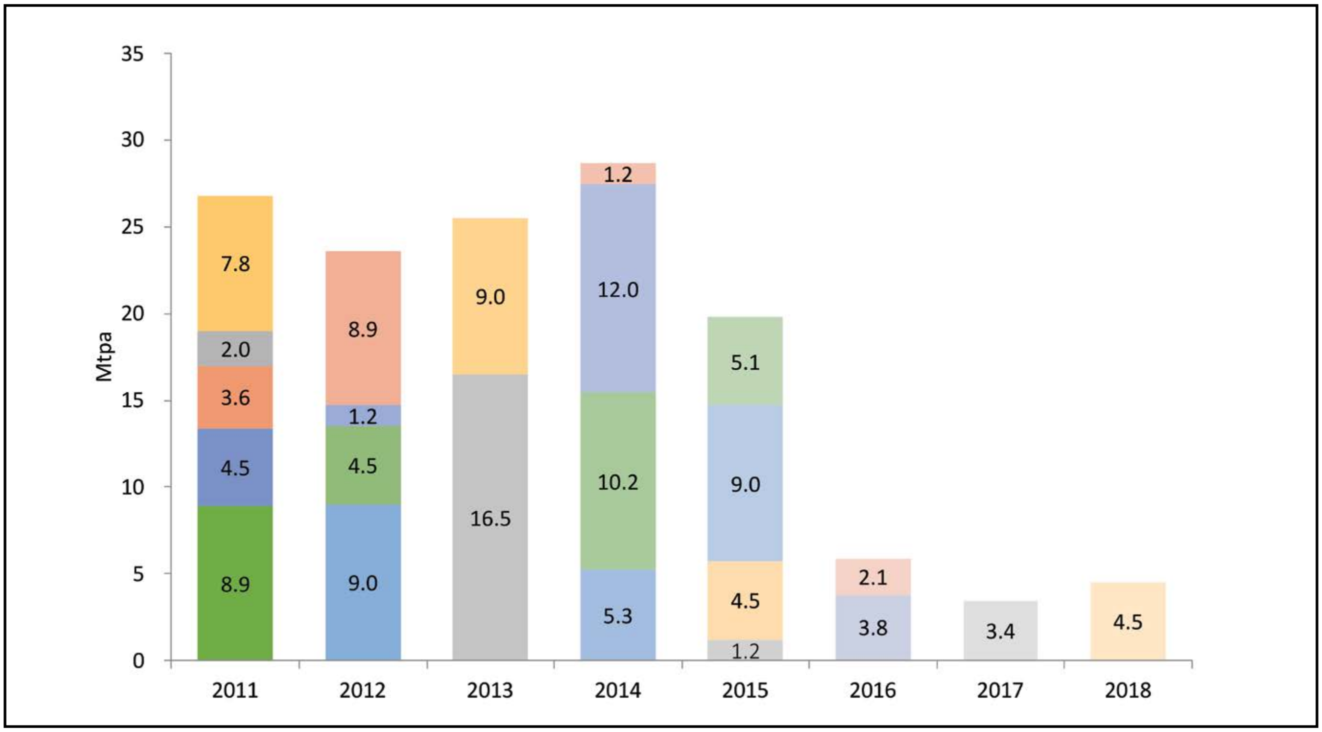
Securing supply security in the LNG market will pursued by two elements: value chain investments and market creation.

Sufficient capacity of supply infrastructure must be in place to ensure supply security. Sustained investment to the whole value chain from wellhead production, liquefaction, transportation and finally to regasification must be secured. In the liquefaction capacity, after the oil price collapse in the summer of 2014, only a handful of projects had reached final investment decision (FID) per year. Since 2017, when the crude oil price began to recover, the conditions for FID have significantly improved because the balance sheet of the oil and gas industry has improved and the demand growth from emerging countries has become more evident.

Despite this improvement in the investment environment, only two projects (Corpus Christi Project Train 3 and LNG Canada) have achieved FID so far in 2018. While the nature of liquefaction projects requiring huge upfront investment and long-term recovery of investment remains the same, many buyers are willing to commit only to shorter-term purchases and are seeking more volume flexibility as part of longer-term purchase agreements. The divergence of interests between sellers and buyers has widened and this is contributing to the apparent slow pace of new FIDs. Traditional patterns of risk allocation are not adequate to get LNG development commitments from sellers. Buyers and sellers will need new strategies to allocate the long-term development risks to realize liquefaction capacity expansion as demand grows.

Some exporters have plans to proceed without long-term purchase commitments. For example, Qatar announced plans to expand its liquefaction from 77 million tons per annum to 100 million tons per annum by 2024. Mr. Al-Kaabi, CEO of Qatar Petroleum (QP), suggested the country's liquefaction capacity can be raised to 110 million tons per annum. These new supplies, if realized, will also help to meet growing LNG demand in Asia.

Figure 9
Final Investment Decision (FID) for LNG Projects in the World Since 2011
(Capacity in million tons per annum)



Source: IEEJ *Note: each block is a separate LNG project

Due to the physical nature of natural gas, supply infrastructure (pipelines) must be built to each individual consumer to create natural gas demand, and thus the creation of natural gas has the same meaning as investment in the downstream sector in an emerging natural gas market. As the last year's report shows, $80 billion investment in downstream is required to meet the growing natural gas demand in Asia.[5] Natural gas demand has been growing in Asia; but the growth is still checked by the limits of the downstream investment, so demand potential is not fully realized. Accelerated investments in the downstream sector is equally strongly required to develop the LNG market in Asia.

Ensuring Legitimacy in an Investment Project

In the stage of project formation and development, securing legitimacy of the project becomes increasingly important. Understanding the rationale for the project, why a specific project developer is chosen from several other companies, and why the location of the project was selected among other candidate sites must be determined in a transparent method and be clarified to the public in a convincing manner. In Asia, LNG-related projects such as gas-to-power or FSRU (floating storage regasification unit) installment sometimes have been done on a private and bilateral basis. Such a negotiation style may enable the host government and prospective project developer to have close and intensive discussions and to share more privileged information with each other to fast track the project development. The development process, however, may be perceived as lacking transparency and thus the project may lack legitimacy in the host country. Perceived lack of legitimacy may place the project in a more precarious state and cause interruption or even cancellation depending on the domestic political and economic conditions of the host country.

[5]Countries in this category includes members of the Association of South East Asian Nations (ASEAN), and India.

Some of the ongoing negotiations of the project development therefore may contain an inherent risk of interruption or cancellation. The project developer is required to ensure the project's legitimacy to manage such risk.

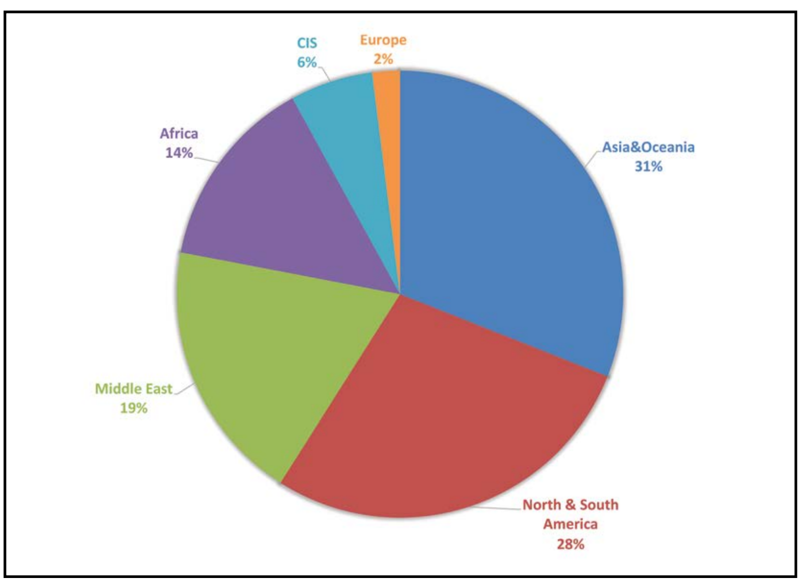
Export Credit Assistance and Other Official Assistance Programs

The Japan – U.S. Strategic Energy Partnership (JUSEP) consists of a wide range of joint projects across the energy value chain. Of special importance is the joint effort to expand natural gas electric power generation and regasification facilities in Asia and U.S. LNG export facilities and export credit or other official assistance programs are the keys to encouraging these projects, as the last year's report pointed out. Official credit and financial assistance for these programs includes direct involvement of export credit and trade development agencies of both governments. These agencies address political or commercial risks inherent in building out power generation and regasification facilities. Government-supported agencies such as the Export-Import Bank of the United States, OPIC, U.S. Trade Development Administration (USTDA), Japan Oil Gas and Metals National Corporation (JOGMEC), JBIC, and NEXI have all been directly involved in LNG projects in the U.S. and throughout Asia.

Several initiatives are worth noting. JOGMEC has provided financial assistance through equity capital and loan guarantees of $5.8 billion USD for oil and gas upstream development (including LNG export projects) worldwide. The distribution of equity capital by region is shown in Figure 10. JOGMEC's Value Chain Training Program, beginning in 2018, provides capacity building for nine local industry experts and regulatory officials in the areas of energy policy, legal structures, facilities development, and transportation solutions for the development of electric power stations, natural gas distribution networks, and LNG regasification facilities.

JBIC has been active in supporting LNG projects. The bank has extended project finance to the Cameron and Freeport LNG projects. For these two projects, JBIC has also extended financing for vessels to bring LNG to Asian markets. These projects have been deemed important for Japan as they contribute to the capability of Japanese utilities to manage LNG price spike risks. Also, as U.S. projects are absent destination restrictions, they contribute to improving the competitive market for LNG in Asia. JBIC played an important role in financing for expansion of the Panama Canal as well, a critical transport link to provide a low-cost transport route to Asian markets.

Figure 10
JOGMEC Supported Equity Capital for Upstream Oil and Gas Projects by Region



Source: JOGMEC

NEXI also has been active providing political risk insurance for both Japanese and U.S. businesses in LNG projects where U.S. and Japanese companies are jointly undertaking LNG projects. Amidst international consensus on the benefits of developing LNG markets, NEXI has also shifted its mandate from supporting infrastructure projects only if they supplied LNG to Japan to supporting the projects if they involve Japanese companies (such as Japanese exporters, equity investors, operators, or off-takers). NEXI has provided insurance guarantees for several LNG import projects in Indo-Asian which have contributed to the regional gas supply security as well as to U.S. LNG projects. Table 5 shows recent projects where NEXI is participating and the amount of financial insurance.

Table 5
Recent NEXI-Insured Projects

Year	Country	Project	Insurance Amount (USD$m)
2016	Indonesia	Tangguh LNG Project Expansion	Non-disclosure
2014	Indonesia	Donggi-Senoro LNG Project	382
2014	USA	Freeport LNG Project	1,150
2014	USA	Cameron LNG Project	2,000
2012	Australia	Ichthys LNG Project	2,750
2009	Russia	Sakhalin II LNG Project	1,400
2009	Papua New Guinea	PNG LNG Project	950

Source: NEXI

The Japanese government and Japanese companies have a strong interest in developing LNG and power projects in the Indo-Asian region. A growing LNG market provides fuel diversity and energy security for the region. The Asian LNG market is on trajectory to more than double by 2030 and this growth will require over $80 billion in infrastructure investments. In particular, Asia is set to play a larger role in global gas-to-power demand by 2030.

The United States government agencies, including the U.S. Trade and Development Agency (USTDA) and Overseas Private Investment Corporation (OPIC) have also launched several initiatives aimed at developing gas and LNG markets in the Asia-Pacific region. The USTDA announced the U.S. Gas Infrastructure Exports Initiative, which is designed to connect American companies to new export opportunities across the gas value chain in emerging economies. As part of the initiative, the USTDA has identified project sponsors in high growth emerging markets for gas related project proposals for U.S. companies.

Overseas Private Investment Corporation (OPIC), which provides financing through loan guarantees to allow American businesses to take advantage of commercially attractive opportunities in emerging markets, has also launched an initiative to promote the expansion of LNG markets in the Indo-Asian region. OPIC expressed its intent to support Virginia-based AES for construction of an LNG terminal plant and a 2,250MW combined-cycle power plant in Vietnam, which would provide around 5% of the country's power generation capacity and support its continued economic development. This initiative is a step forward to facilitate critical investment into Vietnam's energy infrastructure and gas supply chain.

Market Creation

Making the Market Work

Ensuring the LNG market works is the other critical element of gas supply security. In case of emergency where an unexpected supply disruption happens or an unexpected demand surge occurs as observed in Japan after the great earthquake in 2011, marginal supply must be shipped to the highest priority buyers through market mechanisms and price signals. As in the international oil markets, if a number of spot cargoes are actively traded and enough liquidity exists in the market, emergency demand can be absorbed by such market transactions with limited impacts to the price level.

Under the current LNG trading system, flexible allocation of cargoes is not easy due to the existence of destination restrictions in the traditional long-term contracts. Even if diversion is allowed with the consent of seller in the contract, cumbersome procedures required to obtain the seller's consent may have a chilling effect for the buyers to divert the direction of its cargo. The LNG market is still too inflexible to allow for optimal allocation of LNG cargoes in an emergency. While the removal of destination restrictions is often cited as an essential step to realize a more transparent LNG price discovery as well as to create a more reliable LNG price benchmark, it has another imperative to ensure supply security to LNG importers. Promoting such developments and urging the market player to be more active in spot trading are needed to enhance and strengthen the resilience of the world LNG market.

Increased export of U.S. LNG is expected to play a major role in enhancing supply security. U.S. LNG provides Asian buyers with another supply source besides the Middle East, Oceania, and Russia. Although there is relatively low dependence on geopolitically unstable countries for the world LNG supply, emergence of new and large-scale supply capacities in the U.S. will bring numerous supply security benefits for Asian LNG importers. Another advantage of the U.S. LNG supply is that it does not have destination restrictions. It therefore does not need to take a cumbersome process to obtain seller's consent to redirect the cargo destination and thus will work as a convenient and effective source of additional LNG supply.

Updates on Destination Clause Removal

Japan Fair Trade Commissions (JFTC) published a study on the trading practices of the LNG market in June 2017.[6] The study reviewed three contractual provisions in the LNG long-term contract, namely, destination restriction, profit sharing, and take-or-pay. Their findings are:

- On destination restrictions, the study finds that providing destination restrictions in the contract is likely to violate Japan's Anti-Monopoly Act (AMA) for Free on Board (FOB) contracts. As for Delivered Ex-Ship (DES) contracts, these types of restrictions are likely to violate AMA when a seller refuses to consent to diversion, even if a buyer's request is necessary and reasonable.

- On profit sharing, the study says providing profit share clauses is regarded as unfair trade practice for FOB contracts. As for DES contracts, it is likely to violate AMA when such clauses cause unreasonable profit sharing with a seller, or when such clauses to discourage a buyer from reselling because of the seller's request to disclose the deal information.

- On take-or-pay, the study finds that imposing the clause may limit competition when a seller's negotiation position is stronger than buyers, as they may unilaterally impose the clause without enough negotiations after the investment is already recovered.

The study urges Japanese buyers not to accept the above clauses in new and renewed long-term contracts, and review competition-restraining practices for existing contracts as well.

The study had a triggering effect on several

[6]Japan Fair Trade Commission, *Survey on LNG Trades*, June 2017 (https://www.jftc.go.jp/houdou/pressrelease/h29/jun/170628_1_files/170628_7.pdf)

new developments in the LNG market. Several Japanese buyers succeeded in removing destination restriction clauses from new term contracts.[7] In a similar development in another region, DG Competition announced that it will start reviewing the existing LNG long-term contract by EU member countries with Qatar to check whether it has a clause to limit free movement of natural gas in the EU.[8] Further similar studies by anti-monopoly authorities of other countries such as the Korea Fair Trade Commission, if conducted, would deepen the discussions about the appropriateness of destination restrictions in the context of fair market competition.

LNG development is inherently risky for both sellers and buyers because of the large and long-term financial commitments necessary to bring a project to FID. Destination restrictions remove a major risk diversification option for buyers who might be willing to make long-term commitments as long as they have an option to seek an alternative outlet for contracted LNG shipments as the market changes. A likely outcome of persistent destination restrictions in LNG trade is lower volumes of worldwide LNG exports and a more expensive and smaller market for natural gas power development and regasification facilities.

Development of a Reliable LNG Benchmark and Pricing Indices

An established and widely utilized price benchmark will facilitate active spot trading, and these increased trades will in turn solidify the position of the benchmark. Reliability and physical trading activities reinforce the reliability of price benchmark as observed in the international crude oil market. The LNG market is a unique commodity market where a spot market benchmark is not referenced in the price formula of the term contract pricing. Creation of a reliable benchmark is an important task for making LNG a more commoditized product.

Several benchmarks have been proposed by futures markets, price reporting agencies and online trading platform companies, but none of them have been established as a representative price benchmark in LNG market like the WTI or Brent benchmarks in the crude oil market. One of the reasons behind the gap in pricing is insufficient spot transactions and stakeholders' reluctance to disclose the price level of their own transactions in a timely manner. Although spot activities have grown quite significantly in the last decade, they have not reached to the level that causes a sustainable influence on the term contract prices.

Connection with Atlantic (European) Markets Interactions with Atlantic natural gas market will be one of critical features of the future Asian LNG market. The European natural gas market in particular is regarded as a "balancing place" for the world LNG market, and active cargo transactions with the European market will enhance supply flexibility to the Asian market. This is because the European market has various supply sources such as domestic gas production and pipeline imports from Russia and North Africa alongside LNG. Europe also has a large storage capacity at around 5.0 Tcf compared to 1.4 Tcf in Asia, and the capacity can absorb seasonal demand fluctuation. This growing flexible supply generated from removal of destination restrictions or increased export of the U.S. liquefaction capacity will enable more intense cargo transactions among LNG markets in the world. More intensive transactions, particularly with European markets, will improve supply flexibility and thus contribute to supply security in the Asian market.

[7]JERA press release on 25 October 2018 (http://www.jera.co.jp/english/information/20171025_98.html)
Tokyo Gas press release 15 June 2018 (https://www.tokyo-gas.co.jp/Press_e/20180615-05e.pdf) [8]European Commission - Press release, Antitrust: Commission opens investigation into restrictions to the free flow of gas sold by Qatar Petroleum in Europe, 21 June 2018 (http://europa.eu/rapid/press-release_IP-18-4239_en.htm)

New Demand Creation: LNG Bunkering

Overview

Bunkering had its origins during the early nineteenth century when the earliest commercial steamships began to be developed. The first fuel for these steam-powered vessels was primarily coal that was stored at ports in large fixed containers known as "bunkers." With the expansion and shift in marine fuel-types, "bunkers" and "bunkering" broadened to reference all aspects of storage, handling, and delivery of fuels used by marine vessels.

From 1907 to 1909, per direction of President Theodore Roosevelt, a portion of the U.S. Navy dubbed "The Great White Fleet," sailed the world. Separate from its political goals, it sought to make an operational assessment of the readiness and requirements of its capabilities. Refueling by stopping at ports along the way to acquire coal took place every two weeks. Because the coal that was acquired at these different ports had inconsistent energy content, coupled with the large amount of soot, ash, and other debris that it generated, the United States made the policy decision to shift its fleet from coal to petroleum products that were cleaner-burning and whose energy content was more uniform and predictable.

Similar concurrent determinations were made elsewhere that together augured the global shift from coal to petroleum-derived fuels for marine vessels. Just as steamships were shown to have greater dependability and timeliness than sail, thereby displacing sailing ships from commercial activity, so too, steam-powered ship propulsion systems began to be displaced by motor ones beginning in the 1930s because of their capability to move larger ships at higher speed. During the mid-1960s, more than half of the world's fleet was motor-driven; by the beginning of the twentieth-first century, this proportion had risen to 98 percent.

Long-haul commercial global maritime traffic has developed into two general forms:

- liner shipping, the primary one, which operates on fixed schedules and routes with established ports of call; and
- the "tramp trade," which has no fixed schedules or list of ports of call.

The largest bunkering hubs by sales volumes are Singapore (42.4 million metric tons), Fujairah (24 million mt), Rotterdam (10.6 million mt), Hong Kong (7.4 million mt) and Antwerp (6.5 million mt). They account for almost 60% of global bunker sales. Coinciding with the development of liner shipping, these bunkering hubs prospered by being both port facilities along major maritime routes as well being close to major refining centers. Their location has ensured that long-haul liner vessels deviate little, if at all, from their respective voyages, avoiding time and financial costs when bunkering. Refinery proximity means that there is minimal fuel transportation cost and little chance of shortages. Bunkering (refueling) can be done at the same time that cargo loading and unloading takes place. Tables below offer different summary views on bunker markets, vessel numbers and sizes, fuel requirements and their LNG consumption potential.

Table 6
Global Shipping Fleet by Category and Tonnage for 2017

Category	Number of Vessels	DWT (million)	% of Total DWT	Average DWT/Vessel
Oil Tankers	10,152	535	28	52,685
Bulk Carriers	10,884	797	43	73,188
General Cargo	19,601	75	4	3,817
Container ships	5,154	246	13	47,654
Other	47,370	210	12	4,433
Total	93,161	1,862	100	19,985

Source: UNCTAD 2017

Table 7
Global Fuel Consumption by Ship Type in 2015

Category	Fuel consumed (mte LNG)	Number of vessels	Average consumption (mte LNG)
Container	52.5	5,009	10,491
Bulk carrier	43.6	10,650	4,097
Oil tanker	31.6	6,395	4,938
Chemical tanker	14.2	4,720	2,999
General cargo	13.2	10,973	1,202
LPG/LNG tankers	12.7	1,687	7,509
Cruise	9.6	477	20,170
Ferry (ro-ro and pax)	10.2	5,288	1,933
Vehicle/ro-ro	11.4	2,236	5,658
Service	8.8	25,317	397
Refrigerated	3.8	4,876	779
Offshore	3.5	785	4,477
Other + Unclassified	23.0	21,021	1,094
Total	238.1	99,434	2,393

Source: DNV & ICCT Data from OIES

Regulatory Shifts

Currently, the array of bunkering fuels is on the cusp of a major shift. While it might not be as disruptive as the transition from sail to steam, it is as significant as the transition from coal to petroleum-derived fuels. The primary driver is the IMO's (International Maritime Organization) decision to drastically curtail sulfur emissions in bunker fuels.

IMO

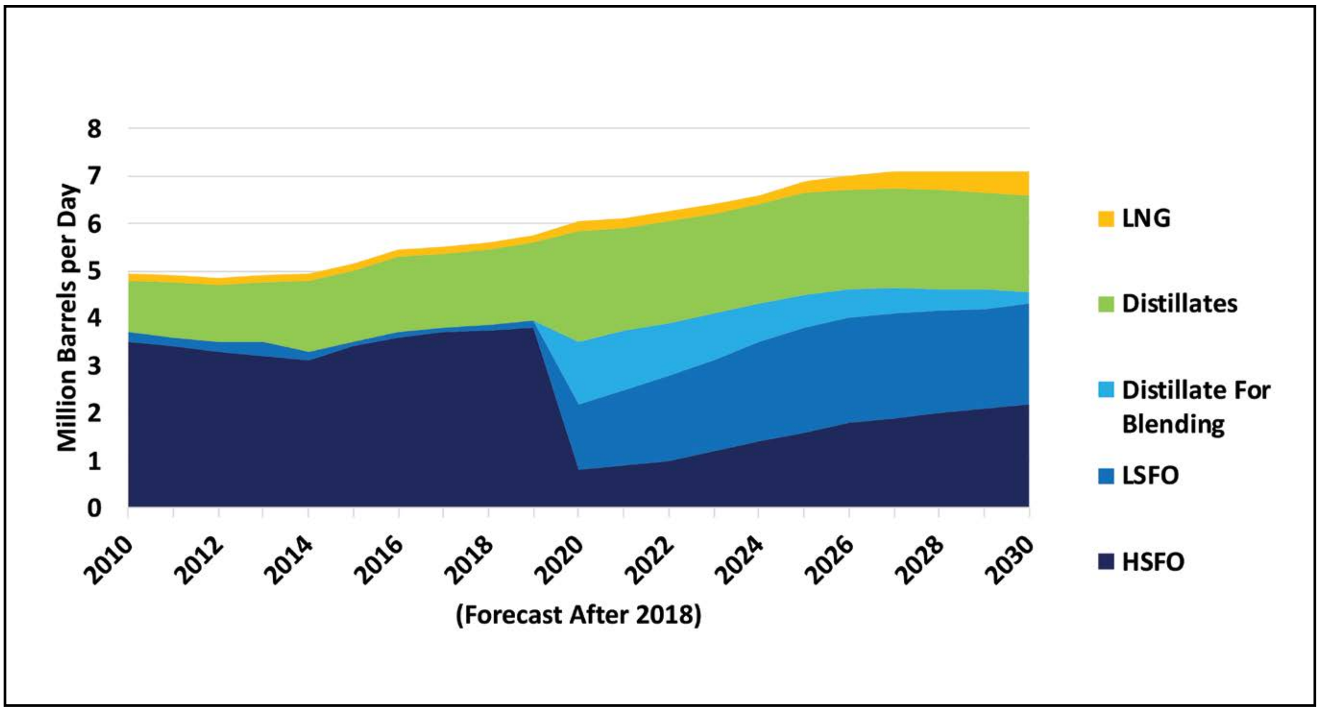
On October 27, 2016, the International Maritime Organization (IMO), an agency of the United Nations, announced that it would require that marine fuels' maximum sulfur levels need to be reduced to 0.5% from current maximum limits of 3.5%; this rule is set to become binding on January 1, 2020.

There are two reasons for the mandate:

- to protect human health, given that marine vessels are a major source of sulfur pollution in coastal cities (ships contribute about 13% of total sulfur-dioxide emissions; this is more that 2,000 times the level allowed for motor vehicles on U.S. highways); and
- to protect the global environment.

This ruling is the most recent in a series that began with the first IMO rule enacted in 1983. Currently, there are over 90,000 marine vessels; all are subject to the IMO decision. Each of the constituencies that are involved and/or subject to this rule-making agree that there will be major impacts on all fossil-derived fuels. However, there is no consensus among forecasts on the demand size of different marine fuel types after this rule goes into effect.

Figure 11
Potential Displacement of HSFO with Other Fuels (Million barrels per day)



Analysis Based on Various Sources — EPRINC

Overview of Bunker Markets, IMO Compliance, and ECAs

Currently, marine fuel demand is approximately 6 MBD (million barrels per day). Of this about 3.3 MBD is high-sulfur heavy fuel-oil (HSFO), 2.5 MBD is the total of low-sulfur heavy fuel oils and middle distillates, and 0.2 MBD-equivalent (or 3% of 6 MBD) is LNG. Breaking this down further, about 2 MBD of the 3.3 MBD of HSFO will have to be displaced by other low- or non-sulfur fuels. Currently, there are four foreseeable solutions:

- use low-sulfur fuel oil (LSFO);
- install or purchase vessels with scrubbers, devices that are attached to exhaust systems to remove polluting matter such as sulfur;
- use variants of middle distillates such as marine gas oil (MGO) or marine diesel oil (MDO);
- convert to or purchase LNG-fueled vessels.

Already high-sulfur marine fuel consumption is restricted in certain continental coastal areas; these areas are known as Emission Control Areas (ECAs). Since January 1, 2015, only fuels with a maximum of 0.1% sulfur content is allowed in ECAs. ECAs include:

- the Baltic Sea ECA (adopted 1997, enforcement began in 2005);
- the North Sea ECA (adopted 2005, enforcement began in 2006);
- the North American ECA, including most of Canada and the U.S. (adopted 2010, enforcement began in 2012); and,
- the U.S. Caribbean ECA, including the U.S. Virgin Islands and Puerto Rico (adopted 2011, enforcement began in 2014).

China has its own ECA where a 0.5% sulfur limit came into effect in 2018.

IMO 2020 Policy Compliance Options

LSFO

LSFO requires no fundamental capital change from a shipping operator's perspective. However, since additional desulfurization is costly, this cost will be passed-through to LSFO consumers, thereby raising overall fuel prices.

Scrubbers

Scrubbers allow shipping operators to continue using HSFO. But the retrofitting costs average about $4.5 million per vessel (however, they can reach as high as $10 million). Operators are then faced with the dilemma of disposing of the sulfur-contaminated residue: release it into the sailing waters or store it onboard for port disposal. Looking at the business case, scrubber investment becomes compelling if the HSFO-LSFO price differential is wide enough. By example, a typical Aframax vessel consumes almost 100 thousand barrels of fuel oil per year. If the differential is such that HSFO costs $5.5 million less per year than LSFO, then a $4.5 million scrubber investment is economically prudent.

Scrubber Installation on a Cruise Vessel

MGO/MDO

Low-sulfur MGO and MDO offer another alternative to satisfying IMO 2020 compliance. However, like LSFO, these fuels will be costlier because of the need to use more desulfurization as well as to divert refinery streams from other fuel production and markets, notably the heating oil, diesel, and jet fuel pools. Furthermore, there is concern regarding the availability of low-sulfur MGO and MDO. In anticipation of the IMO ruling fuel producers have tested several MGO and MDO fuel formulations, but have not announced their respective commitment to which one to use. This elevates the uncertainty of what types of fuels will be available when the IMO ruling will come into effect.

LNG

Of all the available fuels, LNG produces no meaningful sulfur-dioxide pollution. It also contributes significantly to the reduction of particulate and nitrous oxide (NOx) emissions. While on an energy basis natural gas is considerably less costly than petroleum-derived fuels, LNG's critical drawback is that it has less energy density than fuel oil. Therefore, LNG-fueled vessels require larger onboard tank capacity, and the need for more bunkering facilities along maritime routes because of the necessity to refuel more frequently. In addition, current estimates put the cost of LNG-fueled vessels at $8 to $12 million higher than comparable fuel oil-fueled ones with a longer investment recovery period than scrubbers (up to three years).

Possible IMO 2020 Compliance Scenarios

The whole supply chain sees the IMO implementation challenge as perplexing. With fuel representing between 60 to 80% of a shipping operators' costs, the lowest cost alternative is obviously the most appealing. Since three of the compliance alternatives require some sort of capital investment, the challenge then becomes to estimate the direction of fuel prices (as one headline correctly summarizes the situation: "[The] Multibillion-Dollar Quandary: Buy Cleaner Fuel or a Fuel Cleaner?").

The most likely compliance path is expected to be greater reliance on low-sulfur fuels, whether they are LSFO, low-sulfur MGO, or MDO. Nevertheless, scrubber and LNG alternatives are expected to be significant.

Table 8
LNG Fueled Vessels in Use or Under Construction as of May 2018

	In Operation	Under construction	Proportion of total fleet	Potential LNG consumption ('000 tons)
Container	3	21	0.48%	251.8 to 609.3
Oil + Chemical tanker	10	33	0.40%	176.9 to 553.2
Bulk carrier	3	3	0.06%	24.6
Ferry & ro-ro	41	25	0.98%	149.8 to 466.9
General cargo	4	2	0.05%	7.2
Liquefied gas tanker	18	0	1.07%	135.2
Service/tug/psv	31	9	0.13%	16.3
Cruise	0	18	4.82%	463.9 to 1,154.7
Vehicle	2	2	0.49%	31.1
Other	9	17	0.12%	16.4
Total	121	135	0.26%	1,273 to 3,015

Source: DNV & ICCT Data from OIES

Currently, the IMO expects there to be 3,600 vessels with scrubbers by January 1, 2020. Most market analysts see this forecast as being aggressive with the general view being closer to between 1,500 and 2,000 vessels. However, once the IMO 2020 sulfur rule compliance modalities become clearer, and fuel price spreads return to stability and clarity after 2020, these same market analysts expect scrubber installations to increase to approximately 8,000 in 2025, and another 50% above that by 2030, or about 15% of marine vessels.

Unequivocally, all forecasts of LNG marine consumption show that demand growth will be spurred the most by the IMO 2020 sulfur rule. However, the range of forecasts varies considerably. Conservative estimates foresee LNG comprising 7% of global bunker demand by 2030; more aggressive ones project 30% in this same interval. Currently, there are about 650 vessels that can use LNG. However, most of these ships (about 525) are involved in the LNG supply chain - tankers, bunker vessels, or FPSOs (floating, production, storage, and offloading vessels) - and consume "boil-off" (LNG which gasifies while vessels are in transit). About 70 LNG-consuming vessels are medium to large ships, including tankers, containerships, and bulk carriers. They account for about one million LNG tons of consumption per year. The balance are smaller intra-regional ships, the bulk of which are car/passenger ferries in the ECAs primarily the Baltic and North Sea ones, the areas with highest ECAs.

There are currently approximately 135 LNG-fueled vessels on order for delivery in the near-term. Of the large, long-haul variety, this includes 33 tankers, 23 cruise ships, and 20 container ships. All together, these additional LNG-fueled vessels represent between 1.2 and 3 Mtpa of new LNG demand.

With the IMO 2020 sulfur ruling, bunker fuel markets are set to become fragmented: no longer is there a simple choice between a small number of hydrocarbon fuels. Now, the choice has expanded, and this has caused questions to arise regarding fuel availability across all bunkering hubs.

Furthermore, and critically, it is important to add that the IMO 2020 sulfur rule will not be IMO's last. Currently, there are continuing discussions and meetings regarding a subsequent ruling regarding GHG emissions. IMO ruling discussions and negotiations can go on for years and are of indefinite length. This creates considerable uncertainty for entities that are subject to IMO's rulings regarding managing compliance issues. Some entities have short investment time horizons of five years. Others have longer ones that go out to thirty years.

IMO's GHG ruling will seek significant reductions in emissions. While the timing of the final ruling is uncertain, already the IMO has committed to a seven-year, three-step evaluation plan; it consists of a three-step approach: data collection, data analysis, and decision-making on what further measures may be required. The goal is to have an objective, transparent, and inclusive policy debate regarding the implementation of targeted emission limits.

Those maritime operating entities that have long-term horizons already are factoring future IMO rule-making, especially with regard to GHG emissions, into their investment decisions. In these contexts, LNG becomes particularly advantaged; not only does it offer strict compliance with the IMO 2020 sulfur rule as well as low NOx (nitrous oxide) and particulate emissions, it has half the GHG emissions of petroleum-derived fuels. Lastly, LNG has operating cost advantages: given that LNG is cleaner than fuel oil, engines and associated equipment will need less maintenance and last longer.

Additional LNG Considerations - Operations, Policy, and Case Studies

For LNG-fueled ocean-going vessels to be possible, existing ports need LNG bunkering capabilities. As was previously mentioned, bunkering hubs are located at major ports along key maritime routes. Given that LNG has lower energy density, LNG-fueled vessels will either need larger tanks (thereby displacing valuable cargo-carrying capacity) or more bunkering hubs on long-haul routes.

There are two ways that LNG bunkering can take place: ship-to-ship fueling and shore-to-ship. LNG bunkering vessels are ships that store LNG and travel to ships so that they can be refueled. This is particularly useful with large vessels such as containers that have difficulty maneuvering in tight ports or getting to shore-based fueling. Appendix Table 2 (LNG Bunkering Vessels – Current and Planned) lists all current and planned LNG bunkering vessels. Many of these listed have been commissioned in 2017 and 2018.

The overwhelming majority of shore-to-ship fueling is located in northern Europe. Thanks to already longstanding Baltic and North Sea ECA (emission control areas) initiatives (see earlier discussion on ECAs in this section) targeting not only SOx, but also NOx and particulate emissions, demand was increased for ships to have alternative fueling options including LNG along with accompanying infrastructure. All coastal vessels voyaging within these ECAs cannot deviate from these rigorous requirements.

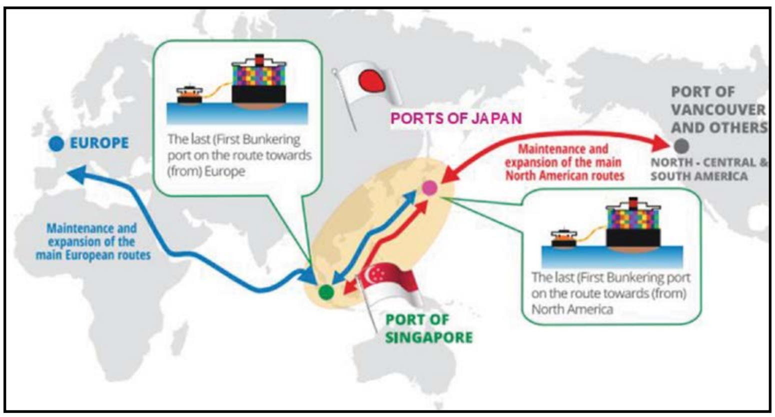
TEN-T initiative

Furthermore, the EU has the Trans-European Transport Networks (TEN-T) initiative. Started in 1996, TEN-T seeks to coordinate, integrate, and improve all transportation systems within the EU, including ports and coastal waterways. With EU Directive 94 promulgated in 2014, all TEN-T core ports need to be equipped with some combination of LNG bunkering and shore power facilities by 2025. This would include not only ports within the Baltic and North Sea ECAs, but also those along the Atlantic Coast and Mediterranean. In 2017, this directive was extended to include all EU Eastern Partnership countries.

The Singapore Initiative

In October 2016 at the Singapore International Bunkering Conference, representatives from the Port Authorities of seven major trading countries (Belgium, Japan, Norway, Netherlands, Korea, Singapore, U.S.-Jacksonville, Florida) signed an MOU on the Development of LNG as a Marine Fuel. The goal of this MOU is to form a network of terminals to promote LNG bunkering as well as to harmonize LNG bunkering standards and specifications. This network of terminals has since been expanded to include French, Canadian, and Chinese Port Authorities.

Figure 12
LNG Bunkering Collaboration Between Singapore and Japan



Source: MLIT (2016)

Case Studies

Japan

Several factors favor Japan's ports and LNG facilities as key components to foster the development of LNG bunkering in Asia.

First, Japan has thirty-five LNG terminals along its coasts. Each of these terminals have sizeable storage facilities.

Second, as Japan's domestic LNG demand plateaus and possibly softens with the restart of its nuclear-powered plants, excess LNG storage capacity can be directed to LNG bunkering uses.

Third, Japan's geographic location, and more specifically the port of Keihin (comprised of Yokohama, Tokyo, and Kawasaki), is optimally situated on the North Pacific route between Asia and North America. Keihin is the first discharging port for westbound long-haul vessels, and the last loading port for eastbound ones. Furthermore, the port is sizeable and can accommodate a variety of vessel types and sizes. Last, weather conditions at Keihin are rarely adverse; therefore, the port is safely accessible year-round.

Already, a consortium comprised of Sumitomo Corporation, Uyeno Transtech, and Yokohama Kawasaki International Port are taking the initial steps to begin LNG bunkering operations. Via joint venture, this consortium is set to commission ship-to-ship LNG bunkering in Tokyo Bay (port of Keihin) projected to start in 2020.

Established in May 2018, another joint venture made up of Chubu Electric Power, Toyota Tsusho, and NYK Line hopes to similarly start ship-to-ship LNG bunkering in 2020 at the port of Nagoya in the Chubu (Central) region of Japan.

China

In August 2018, China's Ministry of Transport issued a draft timetable for developing LNG bunkering in the country. The timetable requested commentary from parties of interest including maritime operators and authorities, trade groups, and national oil companies (NOCs). The draft specified few details, but was aggressive in delineating specific milestones: by 2020 the Ministry hopes to have formulated basic operating standards and to have the foundation for future infrastructure development in place; by 2025, seeks to develop a comprehensive and technologically advanced water transportation for LNG.

The latter would include at minimum 15% of new state-owned vessels and 10 percent of new vessels operating on major inland waterways. Under the initiative key regions that are to be targeted are the Beijing-Tianjin-Hebei (Bohai waters) metropolitan region and the Yangtze River Delta. In addition, the plan seeks to establish two international LNG bunkering hubs.

Also in August 2018, China's Ministry of Finance issued directives granting tax exemptions to LNG-powered ships as well as directing local authorities to reduce transit fees and prioritize port access for LNG-powered vessel operators. Combined, these regulations see to establish a broad, commercially viable LNG bunkering market.

Most of the construction and retrofitting of LNG fueled vessels has been financed by national gas companies such as China Gas Holdings, Kunlun Energy, CNOOC, and China Changjiang Bunker, a subsidiary of Sinopec. As of March 2018, China has 275 LNG fueled ships, of which 160 are new builds and the rest are diesel retrofits. There are also 19 bunkering stations, of which three are operational. Developers of bunkering infrastructure include state-backed entities such as China Gas, CNOOC, and Hubei Energy Group, as well as private companies such as ENN and Jiangsu Haiqi Ganghua Gas Development. In April 2018, Hubei Energy Group announced plans to develop an RMB 2.5 billion LNG storage and bunkering project on the Yangtze River with partial financing from the city of Zhijiang, Hubei province.

Singapore

In 2017, Singapore's Maritime and Ports Authority invested 12 million SGD (Singapore Dollar) to accelerate LNG bunkering in its port.

One part of the funding is allocated for new LNG bunkering vessels; the other part is to facilitate investment in LNG-fueled ships. There are some conditions required by Singapore for this funding, including being registered as a Singapore carrier; but in return Singapore is offering five-year exemptions on port charges.

Fujairah

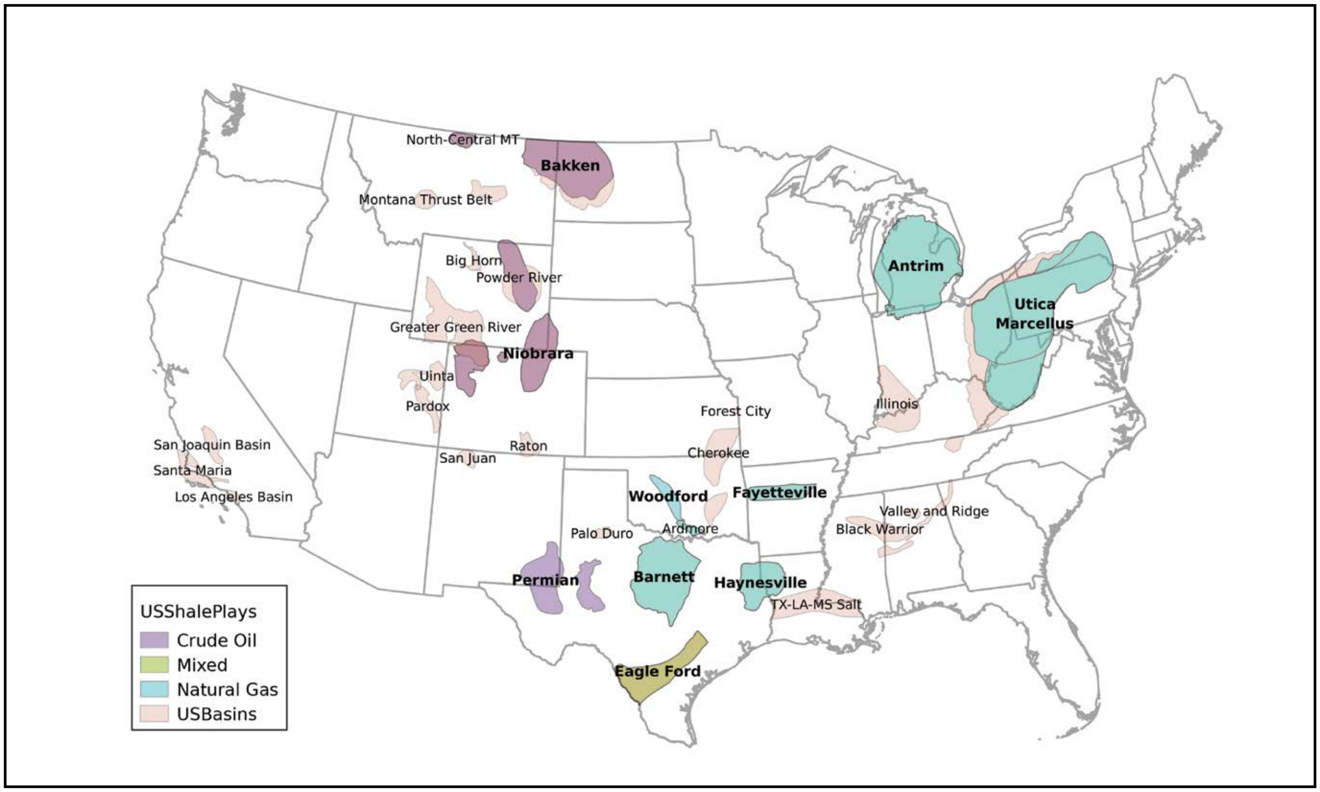
As the second largest bunkering port after Singapore, Fujairah is planning to install LNG storage facilities with no set deadline. Located on the ocean side of the United Arab Emirates, Fujairah is strategically located on major maritime routes, making LNG storage critical ahead of the IMO 2020 rule as well as future IMO GHG-reducing bunkering initiatives.

Pace and Outlook for U.S. Upstream Natural Gas Development

The North American natural gas production platform is drawing upon a low-cost and rapidly growing reserve base. These natural gas reserves are prolific and distributed widely throughout the continental United States. The distribution of these so-called tight (also known as unconventional or shale) gas plays are shown in Figure 13 below.

U.S. natural gas reserves reached an initial peak of 201.7 trillion cubic feet (Tcf) in 1982 before declining to 164 Tcf in 1998. Since then, the U.S. Energy Information Administration (EIA) estimates that domestic dry proved natural gas reserves have almost doubled, and are now estimated at 324 Tcf, most which is tied to additions from certified recoverable shale gas formations. However, reserves alone do not fully describe the potential size of the resource. According to the Potential Gas Committee, U.S. technically recoverable natural gas resources are estimated to be 3,141 Tcf as of year-end 2016.[9] When combined with EIA proved reserves estimates, the U.S. future supply of natural gas now represents highest combined in the history of record keeping for U.S. natural gas reserves.

Figure 13
Main U.S. Shale Basins and Plays



Source: U.S. Energy Information Agency

In EIA's 2018 Annual Energy Outlook, U.S. dry natural gas production is expected to increase through 2050 across a large number of alternative assumptions. If there is no major change in U.S. law or policies, U.S. natural gas production is likely to rise in 2018 from approximately 80 Bcf/d to over 100 Bcf/d by 2022. These numbers are after processing and hence lower than wellhead production. More importantly, after 2020, natural gas production in the EIA forecasts grows faster

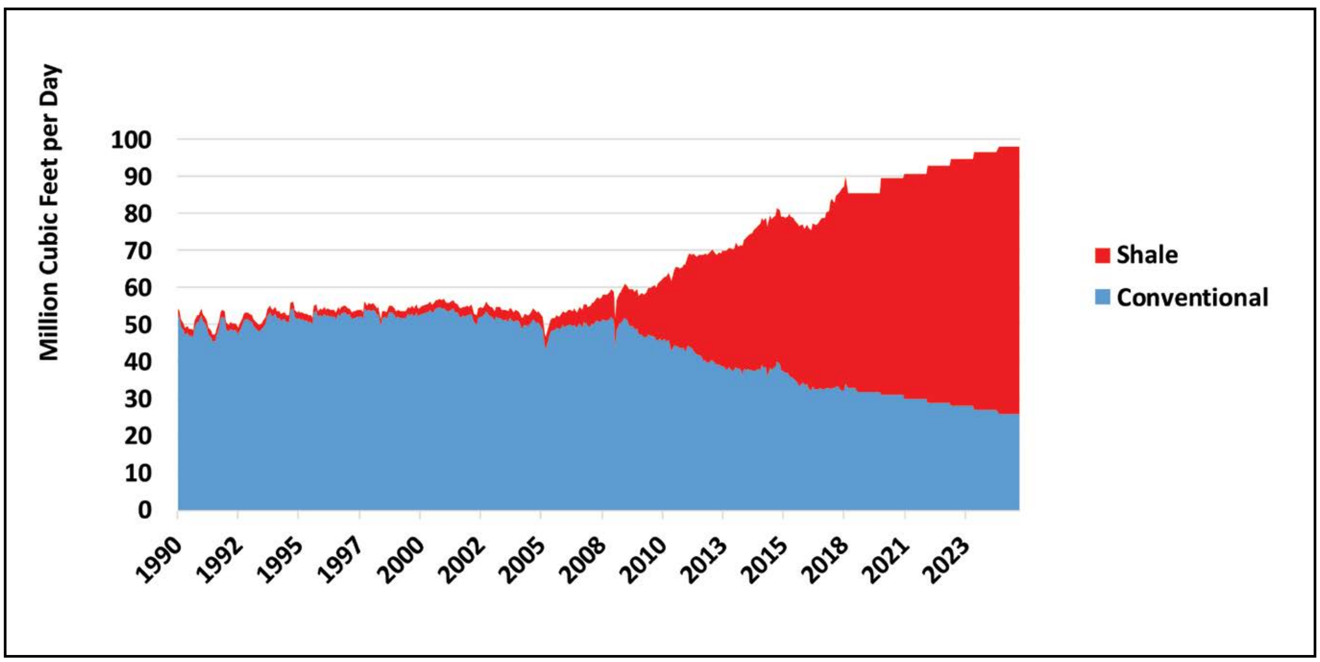
[9]Millkov, Alexei V. "Potential Supply of Natural Gas in the United States: Report of the Potential Gas Committee (December 31, 2016)." *Potential Gas Agency, Colorado School of Mines*, July 2017.

than consumption in virtually all scenarios. EIA's high resource and technology case expects U.S. natural gas production to reach over 150 Bcf/d by 2050. Even in a more constrained outlook, an expansion of 40 Bcf/d (14.6 Tcf/yr) by 2040, or 50% above current production is well within the potential of the U.S. oil and gas resource base.

As gas production continues to increase, the United States is projected to become the third-largest LNG exporter in the world by 2022, surpassing Malaysia and remaining behind only Australia and Qatar. According to EIA data, by that year the United States is forecasted to generate almost 40% of the rise in global gas output between 2018 and 2022, which could position LNG exports to supply over a quarter of the global LNG demand. However, the projected LNG exports may vary significantly depending on several factors like oil prices, economic growth, international pipeline trade, and market share of natural gas versus other fuels.

The size of the unconventional natural gas resource base combined with continuing emergence of new extraction technologies and improved efficiencies in drilling operations all point to significant production growth in the coming decades. Natural gas production in the United States is more likely to be limited by inadequate demand than a lack of advances in technology or growth of the resource base. Figure 14 shows the rapid growth in U.S. natural gas production since the onset the shale discoveries in 1990 and the likely growth through 2025.

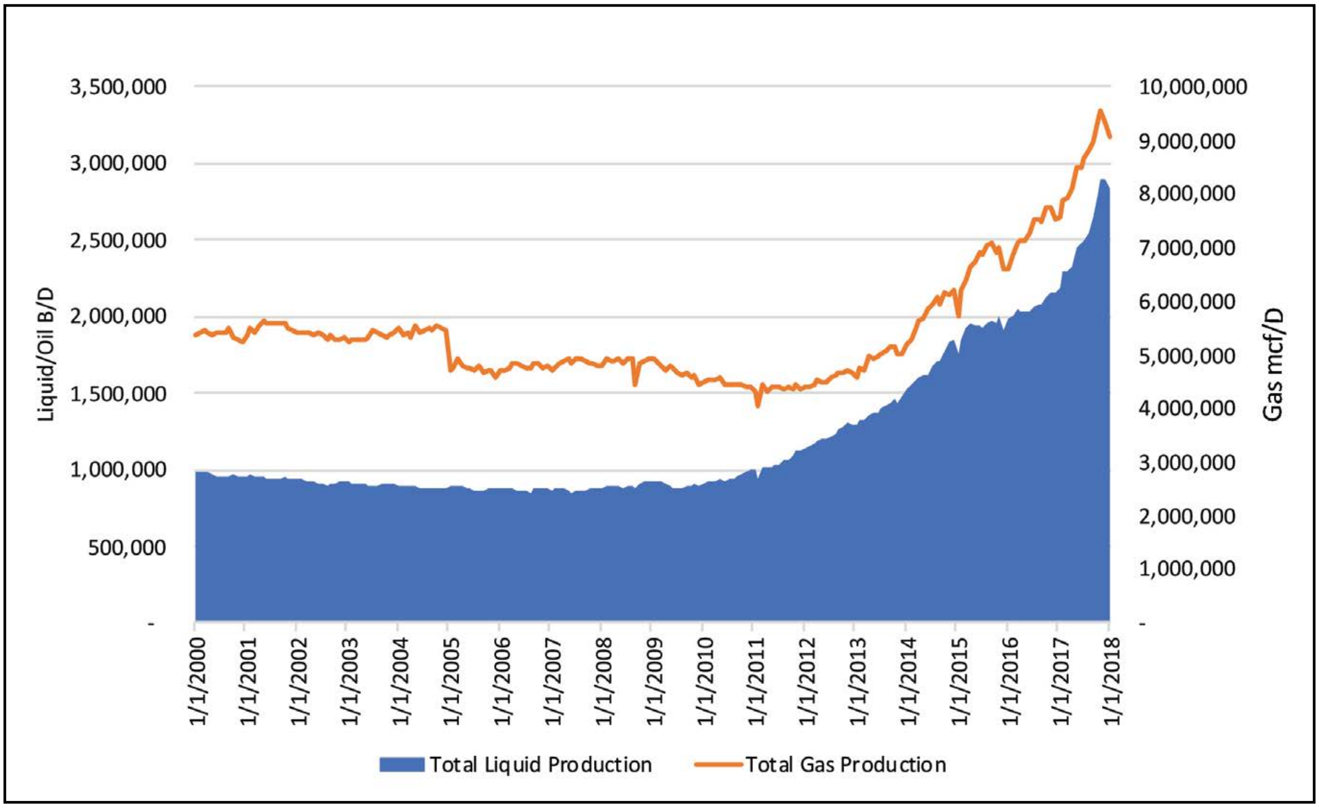
Figure 14
Natural Gas Production in the U.S., 1990 to 2018 (estimated), and Forecast through 2025 (Million cubic feet per day)



Source: EIA

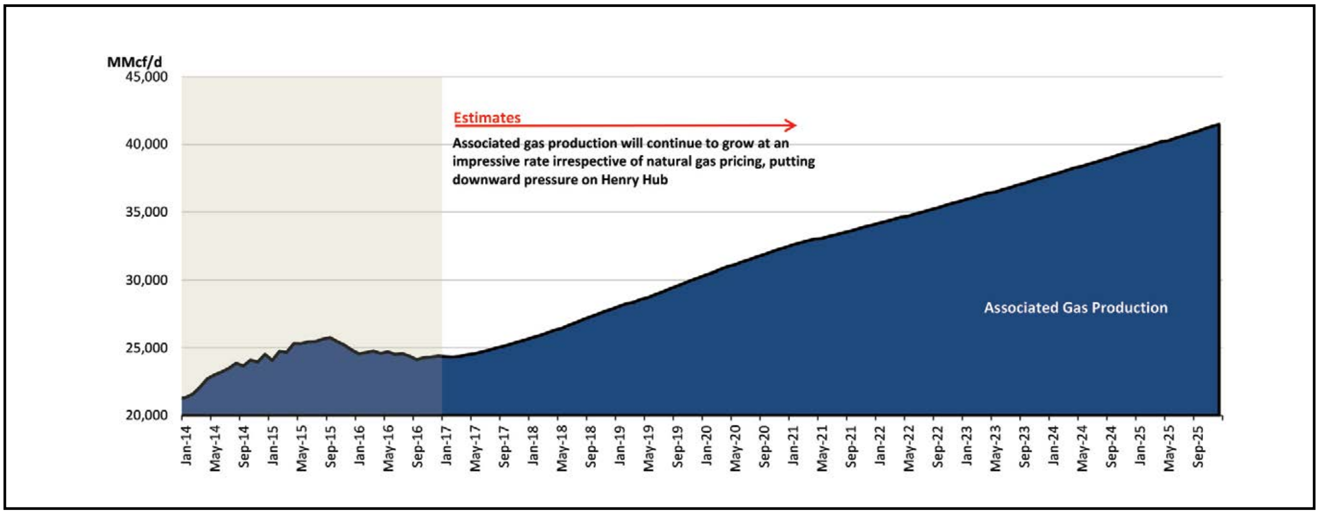
Another important feature of the U.S. natural gas extraction process is the growing volumes of associated gas. This is natural gas production that flows up the well bore during the production of crude oil from shale formations. Associated gas production is a common occurrence in the oil production plays throughout the Permian Basin in Texas and New Mexico, and a by-product of expanding oil production in this geologic formation. As shown in Figure 15, natural gas production in the Permian Basin closely tracks expanded oil production throughout the play.

Figure 15
Permian Basin Oil and Natural Gas Production
(Liquid/Oil in thousand barrels per day, gas in thousand cubic feet per day)



Source: Trisha Curtis, EPRINC Fellow and Founder, PetroNerds. Presentation at EPRINC Natural Gas Workshop, Washington, DC. April 19, 2018.

Figure 16
U.S. Associated Dry Natural Gas Production (Million cubic feet per day)



Source: EIA, HPDI, Raymond James Research

Prospects for Sustained Low Henry Hub Prices for Export Markets

Note, as shown in Figure 16, approximately half of the natural gas production produced in the Permian Basin is classified as associated gas. This is very low-cost natural gas which most producers are willing to sell at whatever price needed to move it to market. The reason for this is that failure to find a market outlet for the gas would require producers to flare the resource at the well site to maintain oil production, an outcome state regulators are not likely to permit for an extended period of time.

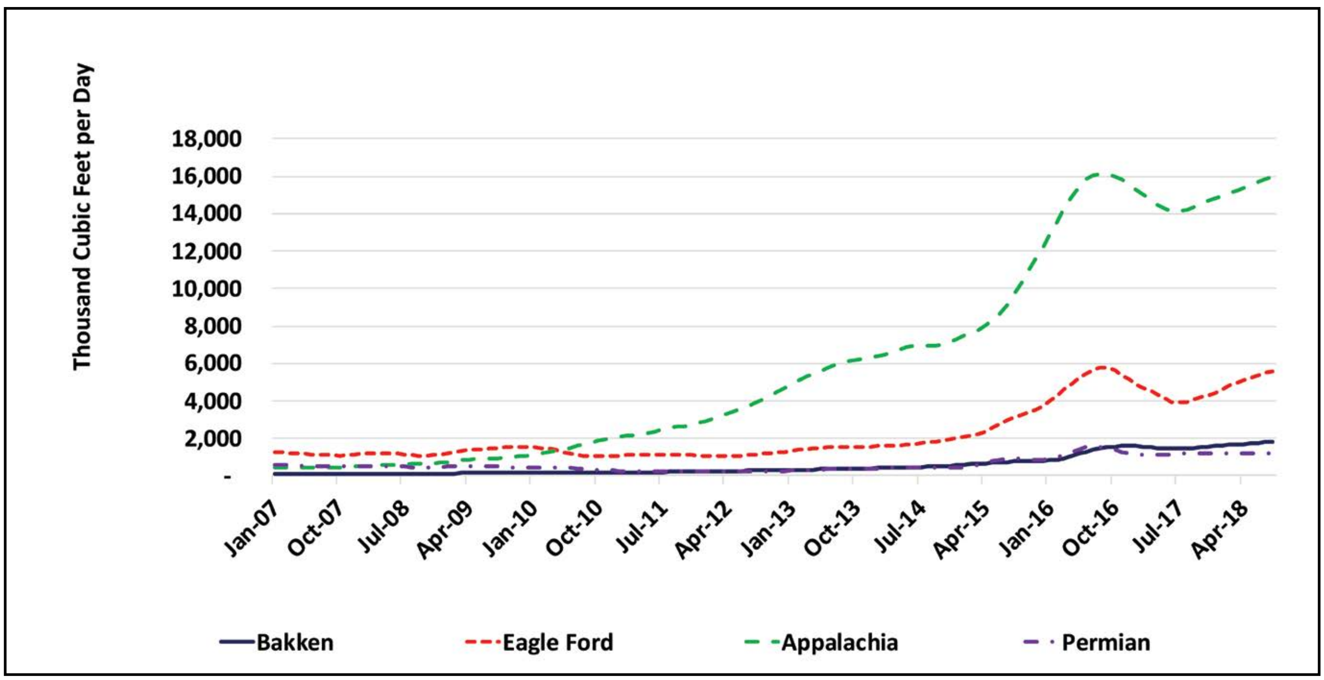
The recent expansion of U.S. natural gas production combined with continued investment and development of new production points to sufficient supplies to limit substantial increases in natural gas prices both for the domestic market and as a feedstock for processing into LNG. There is growing evidence that the U.S. is not reserve limited in terms of the natural gas resource, but that future cost pressures on natural gas are more likely to come from rising costs of production from deploying and operating drilling rigs. Analysis from Vello Kuuskraa, shown in Table 9, shows that in the case of the Haynesville play in Texas, that even with rising drilling costs (day rate and completion costs), combined improvements in estimated ultimate recovery and improved performance with hydraulic fracturing limit increase in development break even costs at current levels through 2025. This assessment reinforces the outlook that the U.S. natural gas production platform can expand without substantial per unit cost increases. Also, Figure 27 below shows that in recent years, rigs in major U.S. plays have experienced a large increase in gas production per rig, another sign of things to come in the U.S. natural gas production boom.

Table 9
Drilling Efficiencies in Natural Gas Production in the Haynesville Play

	Actual 2017 (@$50/B)	Projected 2025 (@$65/B)
Lateral Length	7,400	8,500
1. Well Drilling		
Days to Drill	30	21
Rig Day-Rate ($/day)	$15,000	$23,000
Total Well Drilling Costs ($M)	**$3,400**	**$3,710**
2. Well Completion		
Frac Stages	25	33
Frac Cost ($/Stage)	$60,000	$79,000
Total Completion Costs ($000)	**$5,100**	**$6,430**
Total Well D&C Cost ($000)	**$8,500**	**$10,140**
Gross EUR/Well (Bcf)	**18.4**	**21.2**
"Break-Even" Costs ($/Net Mcf)	**$2.50**	**$2.60**

Source: Vello Kuuskraa, Advanced Resources International. Presentation at EPRINC Natural Gas Workshop, Washington, D.C. April 19, 2018.

Figure 17
U.S. Mayor Plays: Natural Gas Production per Rig (Thousand cubic feet per day)



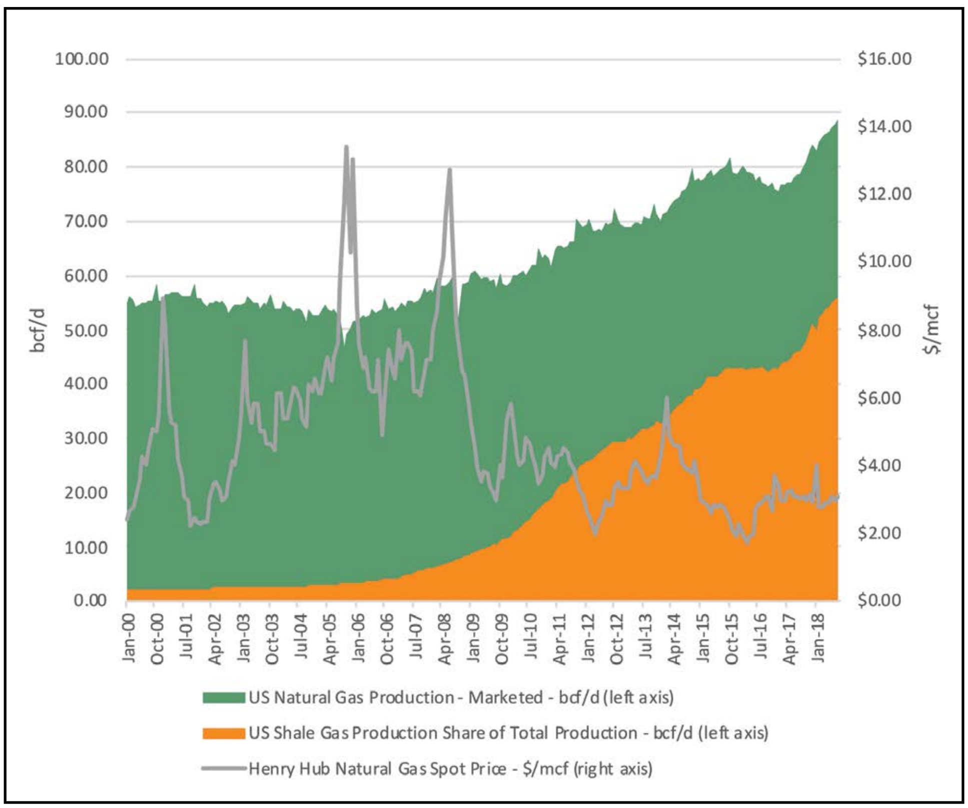
Source: EIA

An often overlooked but important feature of U.S. natural gas production is the high degree of efficiency and liquidity across the entire value chain. Although not entirely unique, the development of U.S. natural gas resources is distributed among many players, subject to constant cost reductions and technology improvements, rapid infrastructure expansion (although delays have occurred in getting essential transportation infrastructure in place). Additionally, the U.S. natural gas market is segmented across its supply chain. Exploration and production entities are generally separate from distribution (pipeline & LNG) and storage operations, and the latter is separate from utilities which make deliveries to final points of consumption.

Lastly, the U.S. market is characterized by widespread transparency in the reporting of gas pipeline capacity utilization, tariffs, and prices at market hubs. There is also broad liquidity in both physical and financial markets. This is due in part to the consistent and coherent regulation and enforcement from government agencies such as the Federal Energy Regulatory Commission (FERC), the Commodity Futures Trading Commission (CFTC), and the Securities and Exchange Commission (SEC). All of these forces are likely to keep the long-term price of U.S. natural gas at its primary trading location, Henry Hub.[10]

The analysis of the Eagle Ford cost structure is reinforced by Figure 18 below that shows that the U.S. natural gas production has continued

Figure 18
Monthly U.S. Natural Gas Production vs. Henry Hub Price
(Billion cubic feet per day)



Source: EIA

[10]Henry Hub pipeline is located in Erath, Louisiana and is the pricing point for natural gas futures on the New York Mercantile Exchange (NYMEX). The NYMEX contract for deliveries at Henry Hub began trading in 1990 and is deliverable 18 months in the future. The settlement prices at Henry Hub are used as benchmarks for the entire North American natural gas market and parts of the global liquefied natural gas (LNG) market. Henry Hub is an important market clearing pricing concept because it is based on actual supply and demand of natural gas as a stand-alone commodity

to expand even as natural gas prices declined to $2/Mcf in late 2015. There was some flattening and even a mild downturn in U.S. natural gas production from the middle of 2015 through late 2016. But this was tied to delays in moving gas supplies out of the Marcellus to domestic processing centers and export markets. Although prices have recovered somewhat and are now approximately $3/Mcf for 2017, shale gas output will continue to expand and take a growing percentage of total U.S. natural gas production.

U.S. Regulatory Outlook for LNG Exports

It should also be noted that under the

Table 10
Large-Scale U.S. Liquefaction Facilities (Existing and Under Construction)

Project Name	Train	Baseload Nameplate Capacity per Train		Peak Name-plate Capacity per Train		Project Status	In-Service Date	Operator
		bcf/d	mtpa	bcf/d	mtpa			
Sabine Pass	Train 1	0.59	4.50	0.69	5.24	Commercial operation	Feb 2016	Cheniere Energy
Sabine Pass	Train 2	0.59	4.50	0.69	5.24	Commercial operation	Aug 2016	Cheniere Energy
Sabine Pass	Train 3	0.59	4.50	0.69	5.24	Commercial operation	Jan 2017	Cheniere Energy
Sabine Pass	Train 4	0.59	4.50	0.69	5.24	Commercial operation	Aug 2017	Cheniere Energy
Sabine Pass	Train 5	0.59	4.50	0.69	5.24	Under construction	Nov 2018	Cheniere Energy
Cove Point	Train 1	0.69	5.25	0.76	5.75	Commercial operation	Feb 2018	Dominion Energy
Elba Island	Trains 1-6	0.20	1.50	0.22	1.64	Under construction	4Q 2018	Kinder Morgan
Elba Island	Trains 7-10	0.13	1.00	0.14	1.09	Under construction	May 2019	Kinder Morgan
Corpus Christi	Train 1	0.60	4.52	0.66	5.00	Under construction	Nov 2018	Cheniere Energy
Corpus Christi	Train 2	0.60	4.52	0.66	5.00	Under construction	Apr 2019	Cheniere Energy
Cameron	Train 1	0.59	4.50	0.66	4.99	Under construction	Dec 2018	Sempra LNG
Cameron	Train 2	0.59	4.50	0.66	4.99	Under construction	Apr 2019	Sempra LNG
Cameron	Train 3	0.59	4.50	0.66	4.99	Under construction	Aug 2019	Sempra LNG
Freeport	Train 1	0.66	5.00	0.71	5.42	Under construction	2Q 2019	Freeport LNG
Freeport	Train 2	0.66	5.00	0.71	5.42	Under construction	4Q 2019	Freeport LNG
Freeport	Train 3	0.66	5.00	0.71	5.42	Under construction	May 2020	Freeport LNG

Source: EIA, energy.gov/fe/services/natural-gas-regulation policies of the Trump Administration, the federal government through the U.S. Department of Interior, is now expanding oil and gas development on public lands on an accelerated schedule. In an oil and gas lease sale held in New Mexico in the first week of September 2018, the federal government collected nearly $1 billion for the rights to develop the oil and gas resources public land in the Permian Basin. These are very large bid values for onshore plays. The lease sale covered over 50,000 acres prospective for oil and gas shale development. One bid alone for 1,240 acres in Eddy County brought in more than $100 million. The lease demonstrates that development of shale reserves on federal lands will supplement U.S. oil and gas production.

U.S. Department of Energy

A large number of local, state, and federal agencies are involved in reviews and permit approvals for the production of natural gas, its distribution to processing centers, and construction and operation of LNG export facilities. Two federal agencies dominate the review process, the U.S. Department of Energy (DOE) and the Federal Energy Regulatory Commission (FERC).

The Department of Energy (DOE), Office of Fossil Energy (FE), is responsible for authorizing exports of domestically produced natural gas under U.S. law. DOE/FE reviews applications to export natural gas to countries with which the United States has not entered into a free trade agreement (FTA). As of June 21, 2018, DOE/FE issued 29 final long-term authorizations to export LNG and compressed natural gas to non-FTA countries in a cumulative volume totaling 21.35 Bcf/d. These authorizations have a term of 20 years, with additional time provided for LNG export operations to commence. Some stakeholders have raised concerns that under the DOE approval process LNG exports face a revocation risk and this risk can raise the cost of financing new projects and limit market access.

In response to buyer concerns over revocation risk, Deputy Secretary of DOE Dan Brouillette publicly reinforced DOE/FE policy on the stability of U.S. LNG exports at the Annual LNG Producer Consumer Conference in Tokyo in 2017. In a public statement in the U.S. Federal Register (June 21, 2018), DOE/FE pointed out that it has never rescinded a long-term non-FTA export authorization for any reason, unless so requested by the exporter or if the exporter abandons efforts to develop the project. Further, DOE has repeatedly stated that it has no record of ever having vacated or rescinded an authorization to import or export natural gas once approval has been granted over the objections of the authorization holder. The one order vacated was strictly due to the exporter's inaction in proceeding with the project.

Federal Economic Regulatory Commission

There have been concerns raised by industry experts and policy makers that the approval process for the siting and operation of new LNG export facilities is taking too long and delaying the construction of new export facilities. In response, on August 31, 2018 the Federal Energy Regulatory Commission (FERC) issued a Schedule for Environmental Review (SER) to ten new LNG export projects, and reissued schedules for two (Driftwood and Jordan Cove). Between April 2012 and December 2016, FERC issued 12 certificates to export facilities. Since President Trump took office in January 2017, FERC has issued no orders for new LNG export facilities, and had issued SER for only two projects, Venture Global's Calcasieu Pass, and Tellurian's Driftwood LNG. Of those, FERC has only issued a draft Environmental Impact Statement (draft EIS) to Calcasieu Pass. FERC's stalled LNG export facility review process does not directly follow the Trump Administration's stated objective of accelerating energy infrastructure reviews. In June, Chairman Kevin McIntyre acknowledged to Congressional committees that the Commission was having difficulty keeping up with the enormous workload requirements. However, since August 2018, FERC has made progress in resolving this slowdown.

In September 2018, FERC released a new MOU with the Pipeline and Hazardous Materials Safety Administration (PHMSA). PHMSA is assuming review responsibilities for the design and operation of feedstock pipelines and LNG operations. This should relieve some of FERC's workload and improve the timing of construction permits.

Table 11
New FERC Review Schedule for Pending LNG Projects

Project	Date When Project Will Be Ready for Final Approval
Transco NE Supply Enhancement	9/17/2018
Calcasieu Pass	10/26/2018
Driftwood LNG	1/18/2019
Port Arthur LNG and PA Pipeline	1/31/2019
Texas LNG	3/15/2019
Eagle LNG Partners Jacksonville LLC	4/12/2019
Gulf LNG	4/17/2019
Annova LNG	4/19/2019
Rio Grande LNG	4/26/2019
Venture Global Plaquemines LNG	5/3/2019
Jordan Cove, Pacific Connector	8/30/2019
Alaska LNG	11/8/2019

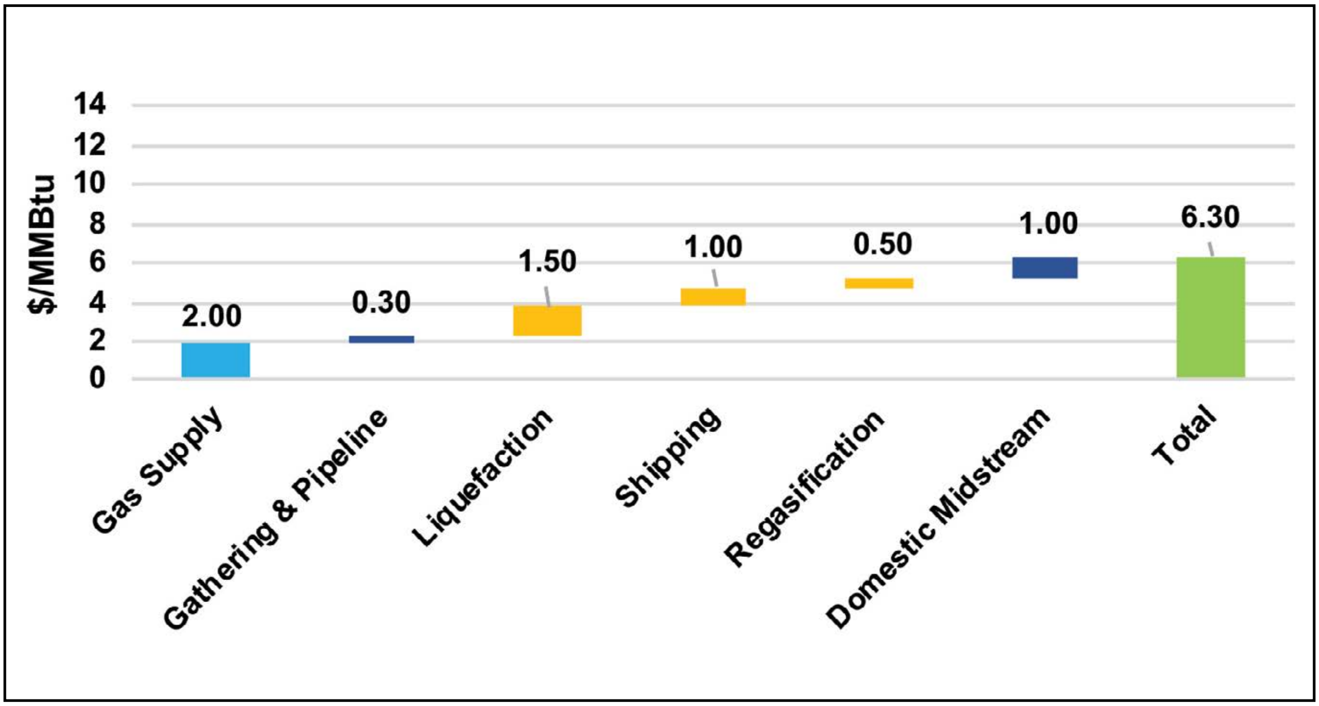
Source: FERC as of 8/2018
https://www.ferc.gov/industries/gas/indus-act/lng.asp

FERC is also preparing full EIS for the eight new projects that received SERs on August 31 (Port Arthur, Texas LNG, Jacksonville Eagle, Gulf LNG, Annova LNG, Rio Grande LNG, Venture Global Plaquemines LNG and Jordan Cove). Driftwood and Alaska LNG received revised SERs. The new SERs indicate that FERC is attempting to adhere to a four-month window between draft and final EIS, a shorter interval than in the past. Only Calcasieu Pass appears to be on a trajectory for potential approval before the end of 2018. Ten other projects could be approved by the summer of 2019.

Cost Competitiveness of U.S. LNG Exports

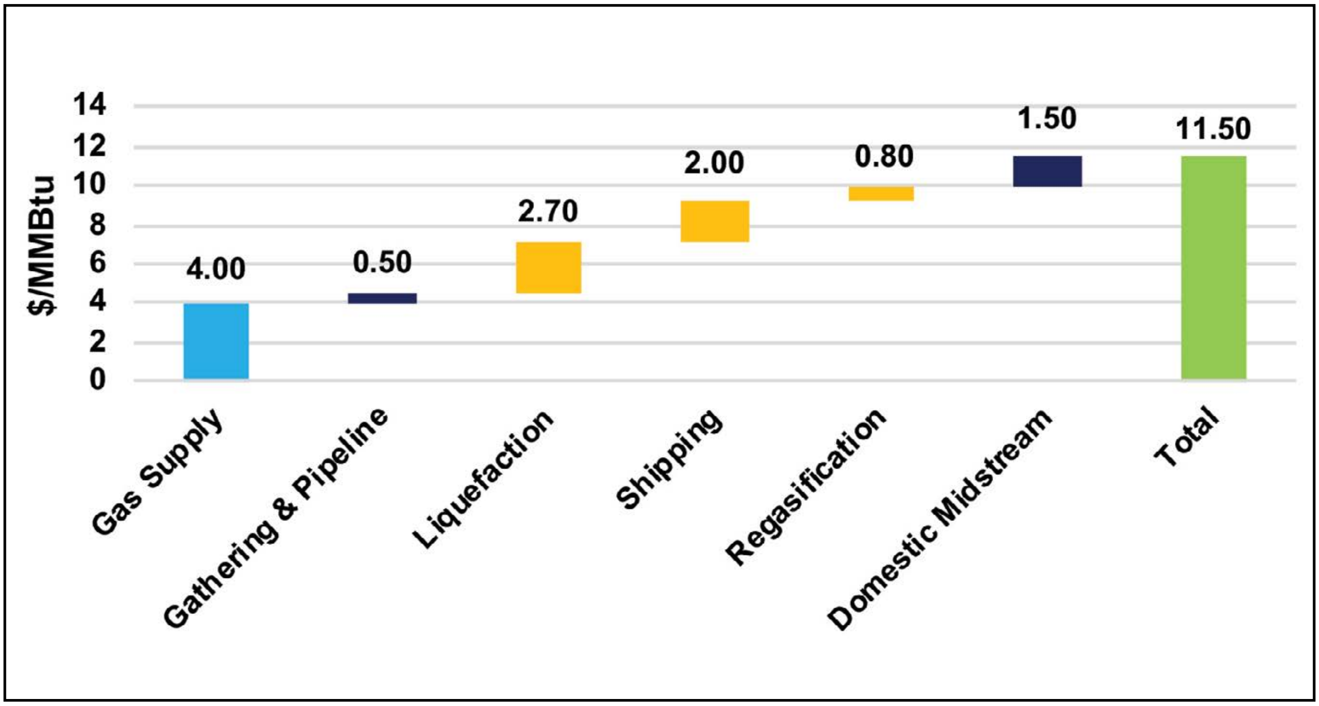
Figures 19 and 20 below capture the range of uncertainty with regard to the competitive position U.S. LNG exports delivered to Asian markets from facilities along the U.S. Gulf of Mexico. As the Figures show, the cost of delivered U.S. LNG to Asian markets will be driven by both the cost of construction and operation of natural gas liquefaction facilities and the availability of low-cost feedstock. The vast scale of the U.S. natural gas reserve base, combined with rising volumes of associated gas, increase the likelihood that U.S. feedstock costs will remain very low across a wide range of export volumes. Challenges remain on sustaining a timely buildout of domestic midstream infrastructure and permits for construction on new liquefaction plants, but considerable progress has been made in implementing a more timely and predictable approval process as part of the Administration's energy policy. Advances in project design and technological innovations can help to keep liquefaction and shipping costs low and U.S. LNG exporters are well positioned to sustain cost structure that is competitive for Asian markets.

Figure 19
Asia Delivered LNG: Low Cost Structure Scenario (Dollars per million BTU)



Source: Bloomberg Data

Figure 20
Asia Delivered LNG: High Cost Structure Scenario (Dollars per million BTU)



Source: Bloomberg Data

Panama Canal

The Panama Canal is an improtant throughway for the movement of LNG from the East Coast and Gulf Coast of the U.S. to selected Asian destinations. The importance of this emerging LNG trade route has increased focus on the Canal by both U.S. LNG producers and Asian countries hoping to meet rising demand with US LNG exports. Expectations on the Canal's capacity to efficiently permit transit of growing volumes of LNG shipments from the U.S. have been subject to misinformation and scheduling practices that have created the appearance that the Canal is a severe constraint on the movement of Gulf Coast LNG shipments to Asia. This prompted the government-run Panama Canal Authority (ACP), which operates and manages the Canal, to adjust their operating policies to expand annual transit capacity of LNG through the Canal.

This is not the first attempt by the ACP to increase the capacities of the Canal. The Canal's original locks, which lift ships at one end of the Canal and lower them at the other, are only 34m wide. Lock size is the limiting factor for the maximum size of the ships that can traverse the Canal. On June 26, 2016, a wider third lane of locks that had taken nine years to build began and can now handle so-called Neopanamax vessels. Such vessels can be up to 294.1 meters long, with a beam of 32.3m and draught of 12.04m. The world's current LNG tankers have an LNG-carrying capacity of up to 3.9 billion cubic feet (Bcf). Prior to the expansion, only 30 of the smallest LNG tankers (6% of the current global fleet) with capacities up significantly affected LNG trade, as it reduced both transportation costs and travel time for LNG shipments and provided additional access to previously regionalized LNG markets.[11]

The ACP has recognized that the canal expansion was insufficient to meet transit requirements for LNG shipments to Asia without some operational changes. Recently ACP released several changes to the regulations surrounding LNG shipping both to accommodate the increase in demand and to mitigate the effects of some undesirable practices of some LNG carriers. One major issue, as the ACP puts it in their Advisory to Shipping No. A-29-2018, is "the current practice by some LNG customers of acquiring booking slots during the first period competition, to the point where these slots are nearly sold out up to 365 days in advance, while in reality these slots are only used on average 60% of the time."[12] Those booking slots are very valuable because until recently, the ACP limited the number of LNG vessels to one per day in one direction. By purchasing booking slots that they didn't intend to use, other nations could limit the amount of U.S. LNG that could make it to Asia, tightening the bottleneck in Panama. This would, of course, keep LNG prices from dropping due to increased supply, and limit the amount of LNG that could be sold west from the Gulf Coast.

On October 1st, 2018, the policy changes laid out by the ACP took effect. Several of them were specifically designed to change this sort of behavior. The text from the ACP's "Advisory to Shipping No. A-29-2018" that addresses the practice of buying booking slots without intending to use them reads:

> *This practice is detrimental since it creates the perception that the Panama Canal does not have the capacity to handle the actual LNG demand, affecting not only the best interests of the Panama Canal Authority (ACP) and the LNG industry, but of other customers as well. These modifications will allow the Panama Canal to better handle the present and expected demand for LNG vessel transit slots by providing the certainty and flexibility required by the LNG market segment.*[13]

Beginning on October 1, 2018, some navigational restrictions were lifted that enable several LNG vessels to inhabit the Gatun Lake. That means that the Canal will be able to transit LNG vessels in different directions on the same day,

[11] https://www.eia.gov/todayinenergy/detail.php?id=26892#
[12] http://www.pancanal.com/common/maritime/advisories/2018/a-29-2018.pdf
[13] http://www.pancanal.com/common/maritime/advisories/2018/a-29-2018.pdf

contrary to recent practice when only one direction was allowed. As a result, the maximum number of LNG vessels has been increased from one to two per day, either two northbound or one northbound and one southbound. There have even been days in 2018 when four LNG tankers transited the Canal.

According to recent communications with the ACP via the Embassy of Panama in Washington D.C., "the beam of vessels allowed to transit at night has been increased, depending on the type (Advisory to Shipping A-31-2018).[14] For example, container vessels of up to 335.28m length overall will be able to transit at night if their beam is less than or equal to 43.28m. This will help liberate some slots during daytime, improving Canal capacity overall." This method of increasing the LNG transit capacity is a direct response to frustration from U.S. LNG transport companies who insisted that safety regulations limiting nighttime operations of their vessels in the Panama Canal were too strict.

Another major regulatory change made by the ACP that will have a direct effect on the Asian LNG market was made in the way their slot booking process works. A special booking period 1a in between Booking Periods 1 and 2 was created for LNG vessels 80 to 22 days before the transit date in which LNG vessels specifically will have one slot allocated to them.[15] That time frame is important too, as under previous system Booking Period 1 was sold 365 days before the transit date, which was a limiting factor on the flexibility of LNG and a variable which hindered the liquidity of the spot market.

Finally, cancellation of slots for LNG vessels will incur an additional fee on top of cancellation fee. LNG vessels that do not cancel and fail to arrive by 0600 on their booked date will be charged a cancellation fee and an additional fee of $35,000 USD. Also, if the vessel fails to arrive within five days of the booked date, the customer who booked the slot "will be penalized with the reduction of 0.5 transits in the transit portion of the customers ranking,"[16] which may affect their ability to win future slots. To avoid accidentally penalizing customers who are missing their booked slot or were late for valid reasons, the ACP has added that the above penalties will not apply if the "vessel's late arrival or cancellation of the reservation is due to a medical or humanitarian emergency, fortuitous event or force majeure."[17]

It is difficult to precisely estimate the shipping volume capacity expansion from the regulatory changes enacted by the ACP. What is clear is that the Panamanians have taken action to address the concerns of their LNG customers, and have eliminated both unfair practices and physical limitations of their vital portion of LNG transportation infrastructure. LNG shippers and buyers should continue to engage the ACP on a regular basis so that canal operations can be adjusted to shifting patterns of LNG transit requirements.

[14]http://www.pancanal.com/common/maritime/advisories/2018/a-31-2018.pdf
[15]http://www.pancanal.com/common/maritime/advisories/2018/a-33-2018.pdf
[16]http://www.pancanal.com/common/maritime/advisories/2018/a-29-2018.pdf
[17]http://www.pancanal.com/common/maritime/advisories/2018/a-29-2018.pdf

POLICY RECOMMENDATIONS

Market Creation

Acceleration of Destination Restriction Removal

After the study of the Japan Fair Trade Commission (JFTC) was published, destination restrictions are being removed from new long-term contracts. Destination clauses in existing contracts, however, seem to have remained although the JFTC study urges Japanese LNG buyers to renegotiate clauses in existing contracts. This is because the destination restriction is still regarded as a "bargaining chip" for LNG sellers and the removal of the destination restriction accompanies the revision of the other contractual conditions including price. Some buyers prefer to maintain a favorable relationship with sellers and are not very willing to discuss this issue with sellers. An additional "driver" is needed to enforce the JFTC study's suggestion on the renegotiation of the destination restriction.

In Japan, it is desired that the JFTC will conduct a follow-up survey with legal authority to ensure the destination restrictions are removed from existing long-term contracts as well. It is recommended that anti-monopoly authorities in other countries, including the U.S. Fair Trade Commission, study this practice and provide a view on this issue.

Development of Reliable LNG Price Benchmark

An LNG price benchmark is a missing link of beneficial active spot trades and market liquidity and transparency. Buyers and sellers require full transparency in the fundamentals of supply and demand. The LNG market cannot be fully expanded without a transparent and reliable benchmark both for buyers and sellers. Existing pricing methods which are linked to the price of crude oil are not rational since most future LNG demand growth will be observed in the power sector, where LNG usually competes with coal and renewable energy. The volume of trading at the existing price benchmark is growing, but it is not reliable enough to gain confidence from all market participants.

An increase of flexible LNG supply through removal of destination restrictions in long-term contracts as well as investment in new liquefaction capacity to supply destination-free LNG cargoes will help to solve this problem. In addition, an initiative by a large market player to pick up a specific benchmark for their term contract price formula may be required to create a representative price benchmark, just as Centrica picked up the National Balancing Point (NBP) as a price benchmark for their term contract. Also, market participants are encouraged to participate in spot trading platforms and disclose the price level for which they transact a particular spot cargo. An established benchmark will enhance both market liquidity and supply security.

Demand Side

Assistance to Private Investment in the LNG Value Chain (Downstream)

The development of the LNG import facilities (regasification, gas distribution pipelines, and power plants) requires billions of dollars in capital outlays, and this capital can be tied up for as much as a decade before any revenue is realized. LNG projects also face important risks across the entire value chain; feedstock costs can rise, interruptions are possible in feedstock delivery systems, regulatory programs can impose new requirements on both exporters and importers, government policy can change, and financial performance of an LNG project can be disrupted from price changes and demand shifts.

Addressing these risks can enhance predictability and bring more LNG projects to FID. Assistance from export credit agencies and insurance for political and non-performance risks can address important obstacles to bring projects to FID. Continuing capacity building for regulatory authorities and development agencies remains essential. Steady efforts to assist private investment should be undertaken by revising the conditions for financial assistance provided by export credit agencies (ECAs) in Japan, and in the U.S., congressional reviews are ongoing to consolidate the U.S. ECAs so they can more effectively assist private investments in new Indo-Asian energy infrastructure projects.

Engagement with Emerging Buyers

As the presence of emerging LNG buyers

increases, closer communication and cooperation with these buyers has become more important. Because the demand in these countries tends to be more unstable, sharing market status information or demand patterns will benefit all players in the LNG market. Emerging buyers will also find it useful to exchange views on how to develop an LNG market. Such collaboration will also improve the natural gas supply security of LNG importers. Unlike the international oil market, there is no equivalent organization or system like the International Energy Agency's emergency response framework.

Communicating and discussing the latest demand and supply balance of the international LNG market, the outlook for demand and infrastructure development, and supply security measures such as inventory holding or developing storage facilities will enhance emergency preparedness in the LNG market.

Building a new cooperative framework from scratch will require huge resources and cost. Utilizing an existing framework such ASEAN+3, APEC, or the East Asia Summit member group will be an effective solution as the members of such frameworks cover most of the major LNG buyers in Asia.

To augment such a framework, the annual LNG Producer - Consumer Conference held in Japan will also be a useful platform to deepen the collaboration for gas supply security, as it is the platform where policy makers and government officials regularly convene and discuss cooperative actions. Adding Asian LNG supply security discussions to the Producer - Consumer Conference is suggested.

Development of a Fast-Tracking Tool for Project Development

Providing a "model" project development structure and required documents will facilitate the process of infrastructure development. This is because many Asian emerging countries have limited or no experience of LNG imports or gas-to-power projects, and such a model will be a useful reference to proceed with the project development. This is particularly the case in an LNG-based gas-to-power project as it contains various value chains from LNG procurement to construction and installment of a receiving terminal and gas fired power plant. It usually requires long-term negotiations to determine the project structure and define responsibilities and potential risks. If there were a model project structure that the host country and project developer could refer to, it would facilitate efficient discussion.

In many Asian emerging LNG importing countries, laws and regulations for LNG import and utilization have not been well developed. Such model documents will be useful as a reference point that each stakeholder can consult with.

Ideally, the project structure would be fully tailor-made to reflect the local conditions and requirements. However, it is also true that such a tailor-made approach requires much more time to realize the projects. There is an acute and urgent need for energy and power supply in emerging Asian countries, and utilizing the model project will be an efficient solution to fast track gas-to-power projects. Multilateral development banks (MDBs) such as the World Bank or the Asian Development Bank will lead the formulation process of the model based on their vast experience and deep expertise in project development.

Preparation for the Emergence of LNG Bunkering Demand

As LNG bunkering advances globally, there is the potential that bunker fuel markets will become fragmented. Where maritime operators had a limited selection of choices but ubiquitous availability, there now is the possibility of the inverse: many different fuel choices with gaps in coverage across the globe. For LNG bunkering to succeed and to avoid this sort of adversity, coordination is necessary.

Operators and other maritime participants, especially those with long investment horizons, need to be vigilant: the IMO 2020 sulfur directive is not the last rulemaking that it will undertake. Already, there are discussions regarding GHG emissions, and this will impact fuel choices. This will critically advantage LNG, but primarily in the longer-term.

For LNG bunkering to develop in Asia, the

EU offers a model through its Trans-European Transport Networks (TEN-T) initiative. Each of TEN-T's efforts are coordinated on many fronts with clear requirements and timetables comprehensively covering operating and financial parameters.

Supply Side

Assisting Private Investment in the LNG Value Chain (Upstream)

A policy measure to encourage and assist private investments in upstream and liquefaction is also critical. Like the case of investments in downstream sectors, assistance from export credit agencies in Japan and the U.S. will continue to play a vital role.

For U.S. exporters, a timely and predictable process for evaluating and issuing permits for both building natural gas pipelines to move feedstock to export facilities as well as permits for liquefaction facilities is essential. Regulatory risks can be a major impediment to reaching FID. In this respect, U.S. regulatory agencies are making progress. DOE has developed a timely, predictable and informed process for issuing LNG export permits. The permitting process for pipelines and LNG export facilities as administered by the Federal Energy Regulatory Commission (FERC) has suffered from a growing workload, but recent reforms offer considerable promise going forward. Continued attention to improving the FERC process is warranted.

New investment structures can also enhance predictability. Tellurian's Driftwood LNG project has built an integrated investment program which includes upstream assets, pipelines, and a liquefaction facility on the U.S. Gulf Coast. In this financial structure, an LNG investor can now "lock-in" the cost of the entire value chain at an equivalent of $3/MMBTU. Other investment structures may also emerge to address other risks from LNG development.

Innovative Investment Plan for Upstream Investments

Ensuring sustained investments in the upstream sector is a vital condition of natural gas supply security. Demand in emerging LNG importers is growing at an unexpected speed, and lack of timely investments will cause a supply crunch and an intolerable price hike, both of which will eventually harm the interests of buyers and sellers alike.

A widened mismatch of interests between buyers and sellers has often been cited as a reason for stalled FID in the last few years. Market players have not been able to utilize a new risk allocation model encompassing a larger number of emerging LNG buyers and the growing demand for short-term and flexible supply. There is a dire need for innovative ideas to ice break the current FID deadlock. An investment package covering wellhead natural gas production and pipeline and liquefaction plant construction such as Tellurian's equity model may be one of such ideas. Both buyers and sellers are required to consider "something different" to proceed with the further expansion of the Asian LNG market.

Collaboration to avoid a Panama-canal bottleneck

ACP recognizes the potential capacity problem of the Panama Canal for LNG tanker passage in the future and has already taken several policy actions to avoid such bottlenecks. However, there is uncertainty whether these actions will be enough to accommodate the rapid expansion of U.S. LNG exports. Given the large seasonal demand fluctuations, the Canal's capacity may be a problem for LNG tanker passage. Governments from the U.S., Japan, and other LNG importing countries will collaborate to minimize such bottleneck risk by active information sharing and policy discussions.

Additional Exhibits for Bunkering

Appendix Table 1: LNG Bunkering Locations – Current & Planned – Part 1

Port	Type	Capacity	Operator	Status	Start Date	Comments
Dunkerque	Ship-to-Ship		Total Marine Fuels	Planned	2020?	Infrastructure being developed to support Ship-to-Ship LNG bunkering of CMA-CGM containerships by Total Marine Fuels. Plan to adapt existing LNG jetty and then construction of dedicated LNG jetty for small-scale LNG operation.
Marseille	Truck-to-Ship, Ship-to-Ship planned	TBD	Molgas	Operational	January 2018	Currently Truck-to-Ship for weekly call of Aida Perla cruise ship. Cold ironing operation. Ship-to-Ship under negotiation for LNG fueled cruise ships and ferries to Corsica.
Le Havre	Truck-to-Ship	TBD	Shell	Operational	May 2016	Weekly call of Aida Prima cruise ship. Cold ironing operation.
Amsterdam	Truck-to-Ship since 2013; Ship-to-Ship planned for Q4 2018	TBD	TBD	Operational	2013	Port of Amsterdam has an annual bunker fuel thoughput of approximately 2.5 million tons per annum. Production of bio-LNG planned for the port in the near future.
Vancouver	Truck-to-Ship	78 cum/ hour delivery per truck; multiple truck capabilities	Fortis BC	Operational		FortisBC provides Truck-to-Ship bunkering to BC Ferries. LNG is supplied from Fortis BC's Mount Hayes liquefaction plant.
Vancouver	Truck-to-Ship	78 cum/ hour delivery per truck; multiple truck capabilities	Fortis BC	Operational		FortisBC provides Truck-to-Ship bunkering to BC Ferries. LNG is supplied from Fortis BC's Tilbury liquefaction plant.
Vancouver	Truck-to-ship	78 cum/ hour delivery per truck; multiple truck capabilities	Fortis BC	Operational		Fortis BC truck-to-ship bunkering of Seaspan ferries. LNG supplied from Fortis BC's Tilbury liquefaction plant.
Bilbao	Ship-to-Ship	Bunkering vessel capacity of 600 cum	ITSAS Gas, part owned by Vasco de la Energía	Operational	February 2018	LNG is sourced from the Bay of Biscay Gas (BBG) regasification plant owned by Enagás and the EVE. Dock and terminal have been remodeled to facilitate the loading of LNG for the ITSAS Gas vessel. Pilot Ship-to-Ship transfer of approximately 90 cum of LNG from the Oizmendi to the cement ship M.V. Ireland moored in the port of Bilbao completed in early February 2018.
Isle of Grain	TBC	TBC	Grain LNG	Proposed	2019	Grain LNG is looking at developing break-bulk facilities for smaller LNG carriers and LNG bunkering.
Chubu region	TBC	TBC	Toyota Tsusho / NYK Line	Planned	TBC	NYK Line is in joint discussions with "K" Line, Chubu Electric Power Co, and Toyota Tsusho Corporation to develop a new business to supply LNG bunkers to ships in the Chubu region (January 2018).

Source: SEA\LNG EPRINC

Additional Exhibits for Bunkering

LNG Bunkering Locations – Current & Planned – Part 2

Port	Type	Capacity	Operator	Status	Start Date	Comments
Valencia	Land based initially	TBC	Gas Natural Fenosa	Planned	2019	Gas Natural Fenosa has announced that it will be developing bunkering infrastructure to support the 10-year liquefied natural gas (LNG) supply deal it agreed in January 2018 with shipping company Baleària.
Jacksonville - Talleyrand Marine Terminal	Tank-to-Ship	500,000 gallon storage tank and loading jetty	Eagle LNG	Under construction	Q3 2019	Eagle LNG (SEA\LNG members LNG bunkering infrastructure case study available at https://sea-lng.org/wp-content/uploads/2018/01/FINAL_SEALNG-case-study_Eagle-LNG_Shore-to-ship-LNG-bunkering-in-Jacksonville.pdf. Case Study Summary: Eagle LNG and Crowley Maritime have developed an innovative supply chain for LNG bunkering in the space of two short years. Their success has been based on choosing the right, experienced partners, and the right business models, enabling risks to be shared which is vital in the early stages of market development when infrastructure is scarce.
Tacoma	Tank-to-Ship	30,000 cum storage	Puget Sound Energy	Planned	2019	LNG will be supplied from Puget Sound Energy's planned liquefaction plant.
Vancouver	Shore-to-Ship and Ship-to-Ship		Seaspan	Planned	TBC	Seaspan is planning an LNG bunkering jetty / bunkering vessel. LNG for Seaspan bunkering project will be supplied from the FortisBC Tilbury liquefaction plan.
Jacksonville - Dames Point Terminal	Truck-to-Ship and Barge-to-Ship (planned for 1H 2018)	Liquefaction plant capacity 120,000 gallons per day; two storage tanks net capacity 2 million gallons	JAX LNG are the LNG supplier; Clean Marine Energy will be the commercial manager of the Clean Jacksonville bunker barge	Operational	2016	Truck-to-ship bunkering to Tote Marine containerships using ISO containers via a custom-built transfer skid. LNG currently sourced by JAX LNG, from AGL Resources' LNG production facility in Macon, Georgia. In 2018, Barge-to-Ship LNG bunkering will commence via the Clean Jacksonville bunker barge, operated by Clean Marine Energy. In the space of just over three years, Jacksonville has gone from a port with limited experience of LNG, no existing infrastructure, and a relatively small market in marine fuel bunkering, to become the leading LNG bunkering operation in the US and one of the first movers globally. The Jacksonville case study illustrates the importance of a forward-looking anchor customer and strong leadership. This is what provided the catalyst for innovative supply chain investments, with both customer and supply chain collaborating closely with the port, regulatory authorities, local emergency services and communities.
Incheon	Truck-to-Ship		KOGAS	Operational	2013	LNG sourced from KOGAS's Pyeong-Taek LNG regas terminal.

Source: SEA\LNG EPRINC

Additional Exhibits for Bunkering

LNG Bunkering Locations – Current & Planned – Part 3

Port	Type	Capacity	Operator	Status	Start Date	Comments
Ulsan				Proposed	2019	Ulsan Port Authority signed a three-year co-op-eration agreement in August 2016 among 14public and private organizations to develop LNG bunkering. Companies include KOGAS, Korea Gas Technology Corporation, Hyudai Heavy Industries, SK Shipping, Korea Research Institute of Ships and Ocean Engi-neering, Ulsan University, Korea Elenji Solu-tions, NK, South Korea LNG Bunkering Industry Associ- ation, Energy Innovation Partners, Daechang Solutions and Unisys International.
Kochi	Tank-to-Ship	2x155,000 cum storage tanks	Petronet LNG	Opera-tional	2015	Petronet LNG (SEA\LNG member) LNG bunkering infrastructure case study available to view at https://sea-lng.org/wp-content/uploads/2018/01/FINALrevised_SEALNG-case-study_Petronet-LNGs-Kochi-Terminal.pdf. Case Study Summary: The Kochi case study illus-trates how LNG bunkering may evolve outside traditional deep-sea bunkering locations on the back of strategically located bulk LNG infra-structure. It shows how opportunities may be captured by new entrants who are prepared to move quickly and work with experienced bunkering partners, as well as emphasizing the importance of effective education and collaboration.
Yokohama	Truck-to-Ship,Plans for Ship-to-Ship by 2020	TBC	Gas4Sea, Tokyo Gas	Opera-tional	2015	Truck-to ship bunkering started in 2015. Strate-gic plan to turn Port of Yokohama into an LNG bunkering hub. Ship-to-ship bunkering planned for 2020 based on the Sodegaura LNG regas terminal in Tokyo Bay.
Shanghai (Zhejiang Zhoushan)	Tank-to-Ship, Ship-to-Ship	Ship-to-Ship	ENN Group	Under construc-tion	2018	ENN is constructing a LNG receiving and bunkering terminal of 3 Mtpa capacity. ENN has ordered a LNG bunker vessel due to be delivered in 2018.
Hamburg	Truck-to-Ship, Tank-to-Ship	5,500 cum storage	Nauticor	Under construc-tion	2017	
Gothenburg	Ship-to-Ship		Skangas	Opera-tional	Sep-tember 2016	LNG bunkering available from LNG carrier Coral Energy.
Hammerfest (Polarbase)	Tank-to-Ship	90 tonnes/h	Barents Naturgass AS	Opera-tional	April 2017	Norway's biggest LNG bunkering facility. LNG sourced from Statoil's liquefaction LNG plant at Melkøya.
Stockholm	Tank-to-Ship, Ship-to-Ship	20,000 cum storage tank	Nauticor, AGA	Opera-tional	2011	LNG terminal in Nynäshamn in operation since 2011 LNG bunkering vessel Seagas in operation since 2013.

Source: SEA\LNG EPRINC

Additional Exhibits for Bunkering

LNG Bunkering Locations – Current & Planned – Part 4

Port	Type	Capacity	Operator	Status	Start Date	Comments
Klaipeda	Truck-to-Ship, Tank-to-Ship, Ship-to-Ship (from 2H 2017)	5,000 cum storage	Port of Klaipeda, Blue LNG, (Nauticor/ Klaipeda Nafta JV)	Under construc-tion	2H 2017	LNG supplied from Klaipedos Nafta's LNG FSRU terminal. LNG bunkering vessel Seagas.
Barcelona	Truck-to-Ship; Ship-to-Ship in 2019?	TBC	Gas Natu-ral Fenosa	Opera-tional	January 2017	LNG supplied from ENAGAS's Barcelona regas terminal. Gas Natural Fenosa has announced that it will be an LNG bunkering vessel to support the 10-year liquefied natural gas (LNG) supply deal it agreed in January 2018 with shipping company Baleària.
Zeebrugge	Truck-to-Ship, Tank-to-Ship, Ship-to-Ship	TBD	Gas4Sea/ Fluxys	Opera-tional	2015	The Port of Zeebrugge has been pioneering the development of LNG bunkering in North West Europe. LNG is supplied from Fluxys LNG regas terminal at Zeebrugge. The ENGIE Zeebrugge, the world's first purpose-built LNG bunker ves-sel, was delivered to Gas4Sea (Engie Mitsubishi and NYK Line) in February 2017. Gas4Sea (SEA\LNG members) LNG bunkering infrastructure case study available at https://sea-lng.org/wp-content/uploads/2018/01/FINAL_SEALNG-case-study_Gas4Sea-ENGIE-Zeebrugge.pdf. Case Study Summary: The ENGIE Zeebrugge LNG bunker vessel case study illustrates the first mover challenges Gas4Sea needed to address to develop LNG bunkering services in North West Europe. These included the design of the bunkering vessel, absence of relevant regulation, the need to create customer confidence, and the lack of understanding in the shipping industry of LNG as a marine fuel. Overcoming these challenges required close collaboration with a variety of stakeholders.
LA/Long Beach				No plans yet		No announcements at present.
Algeciras	Land based initially	TBC	Gas Natu-ral Fenosa	Proposed	2019	Considering LNG as a bunker fuel. Participant in Core LNGas Hive initiative. Gas Natural Fenosa has announced that it will be develop-ing infrastructure to support the 10-year lique-fied natural gas (LNG) supply deal it agreed in January 2018 with shipping company Baleària.
Panama	Port of Colon	TBC	Engie/AES	Planned	2018	Engie and AES to develop LNG bunkering service based on the Costa Norte LNG regas terminal due online in 2018.

Source: SEA\LNG EPRINC

Additional Exhibits for Bunkering

LNG Bunkering Locations – Current & Planned – Part 5

Port	Type	Capacity	Operator	Status	Start Date	Comments
Gibraltar	TBC	5,000 cum storage	Gasnor (Shell)	Planned	2018/ 2019	LNG will be sourced from the Gibraltar LNG re-gas terminal under construction and due online in 2H 2017. Shell has reached an agreement with the Port of Gibraltar to work on an implementation plan for LNG bunkering focusing on technical safety and operating procedures.
Busan	Tank-to-Ship	TBC	KOGAS	Planned	2019	KOGAS is making a $9m investment at its Tongyeong LNG regas terminal 40km from Busan. It will include construction of loading arms and a quay. A bunkering facility also being considered for the Port of Busan.
Antwerp	Truck-to-Ship	TBD	Fluxys Group	Opera-tional	2012	Engie has been granted a 30-year concession by the Antwerp Port Authority to build and operate an LNG bunkering station for inland navigation and road transport. Port authority is planning to develop a permanent LNG bunkering and filling facility by 2019.
Hong Kong	TBC	TBC	China LNG, Chu Kong Shipping	Proposed	TBD	China LNG and Chu Kong Shipping have entered into an LOI to develop LNG bunkering facilities at Chu Kong Shipping's cargo and passenger terminals in the Pearl River Delta. There are a number of LNG regas terminals in the Pearl River Delta and CLP Holdings is planning a FSRU for Hong Kong.
Rotterdam	Tank-to-Ship, Ship-to-Ship, Truck-to-Ship	1000 cum/h at the break bulk terminal	Shell	Opera-tional	August 2016	Rotterdam has pioneered the use of LNG as a marine fuel in NW Europe and aims to turn the port into an LNG bunkering hub. LNG is sourced from the GATE LNG regas terminal via adjacent LNG break-bulk terminal. The Shell bunker vessel Cardissa is due to begin bunkering operations in Q4 2017.
Fujairah	Starting with Ship-to-Ship transfers of LNG		Port of Fujairah - TBC	Planned	2H 2017 (for LNG Ship-to-Ship trans-fers)	Port of Fujairah has plans to become a LNG bunkering hub. First Ship-to-Ship bunkering planned for 2H 2017. Tank-to-Ship bunkering facilities being considered for a later date. Likely source of LNG will be the Emirates LNG FSRU or land-based regas terminal (due online in 2018).
Singapore	Truck-to-Ship Plans for Ship-to-Ship by 2020		Pavilion Gas, FueLNG (Keppel O&M and Shell joint venture), Total Marine Fuels Global Solutions, ExxonMobil	Opera-tional	May 2017	Singapore Government has strategic initiative to make the port a leading LNG bunkering and gas trading hub. Singapore LNG regas terminal provides the supply infrastructure. Maritime Port Authority of Singapore (MPA) is engaged in a three-year LNG bunkering pilot program and has released LNG bunkering standards. It has a co-funding program to support the building of LNG-fueled vessels and LNG bunker vessels. MPA's aim is to be LNG bunker-ready by 202.

Source: SEA\LNG EPRINC

Additional Exhibits for Bunkering

Appendix Table 2: LNG Bunkering Vessels – Current & Planned – Part 1

Location	Vessel	Start Date1	Capacity	Operator	Comments
Singapore	FueLNG LNG bunker vessel - to be named	Q3 2020	7.500 cum	FueLNG (Keppel O&M - Shell Eastern Petroleum JV)	Being built by Keppel Offshore & Marine (Keppel O&M) SGD50m contract Maritime and Port Authority of Singapore (MPA) co-funding - SGD3m ($2.3m)
Bilbao, Spain	Oizmendi	February 2018	600	ITSAS Gas (part owned by Vasco de la Energía)	Oizmendi is a 3,200 dwt former pollution control vessel converted with two 300 cum, deck-mounted, Type C LNG tanks Pilot Ship-to-Ship transfer of approximately 90 cum of LNG, from Oizmendi to the cement ship M.V. Ireland, moored in the port of Bilbao, completed at beginning of February 2018
US Southern East Coast	Shell US East Coast LNG Bunker Barge (to be named)	2020 - TBC	4,000	Shell	Shell Trading (US) has finalized a long-term charter agreement with Q-LNG Transport, LLC for a US-flag 4,000 cum LNG bunker barge.
Sardinia - TBC	Stolt-Nielsen LNG Bunkering Vessel (Mediterranean, to be named)	2Q 2019	7,500	TBC	Stolt-Nielsen Gas BV has signed a contract with Keppel Singmarine for the construction of two LNG carriers capable of ship-to- ship bunkering. Slated for operations in the Mediterranean & NW Europe.
NW Europe	Stolt-Nielsen LNG Bunkering Vessel (NW Europe, to be named)	3Q 2019	7,500	TBC	Stolt-Nielsen Gas BV has signed a contract with Keppel Singmarine for the construction of two LNG carriers capable of ship-to- ship bunkering. Slated for operations in the Mediterranean & NW Europe.
South Korea - TBD	Korea Line LNG Bunkering Vessel (to be named)	2019	7,500	Korea Line	Korea Line has ordered two small-scale 7,500m³ LNG carriers from Samsung Heavy Industries (SHI) for delivery in May and December 2019, to be deployed on domestic coastal trades. The first vessel will deliver small-scale shipments of LNG Jeju island for a 20-year contract and the second will supply LNG as marine fuel.
Rotterdam, Netherlands	Shell Rotterdam LNG Bunker Barge (to be named)	2H 2018	3,000	Shell	Shell entered into an agreement with Victrol NV and CFT for a vessel that will operate on Europe's inland waterways from its base in Rotterdam, the Netherlands
Rotterdam, Netherlands	Total LNG Bunkering Vessel	2019 TBC	18,600	Total Marine Fuels	Total is looking to charter an 18,600 cum capacity LNG bunkering vessel from MOL to supply CMA-CGM's recent order of nine 22,000 TEU box ships
TBC	Coral Methane	TBD	7,551	Shell	Plans to convert the 2009 LNG/LPG/LEG multi-gas carrier, developed for Gasnor (Shell subsidiary), enabling it to function as a LNG bunker vessel, by adding a specialised LNG bunker arm.

Source: SEA\LNG

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Additional Exhibits for Bunkering

LNG Bunkering Vessels – Current & Planned – Part 2

Location	Vessel	Start Date1	Capacity	Operator	Comments
Barcelona, Spain	Gas Natural Fenosa LNG Bunker Vessel	2020 TBC	TBD	Gas Natural Fenosa	Dedicated LNG bunker vessel to service the 10-year LNG supply deal signed in January 2018 with Baleària, for their operations out of Barcelona.
Amsterdam, Netherlands	FlexFueler001	2018	760 initially, increasing to 1480	Titan LNG	LNG Bunkering Pontoon - will supply fuel to inland barges and small seagoing vessels
Zhoushan, China	ENN LNG Bunker Vessel - To be named	2018 (TBC)	8,000	ENN Group	
Klaipeda, Lithuania	Blue LNG	1H 2018	7,500	Blue LNG (Nauticor/ Klaipeda Nafta JV)	
Port of Jacksonville, Florida	Clean Jacksonville	1H 2018	2,200	Jax LNG / Clean Marine Energy	
Port of Zeebrugge	Engie Zeebrugge	April 2017	5,000	Gas4Sea	
Port of Rotterdam	Cardissa	August 2017	6,500	Shell	
Kiel Canal to Southern Norway	Coralius	September 2017	5,800	Skangas	
Stockholm	SEAGAS	2013	187	AGA / Nauticor	

Source: SEA\LNG EPRINC

TABLE OF ABBREVIATIONS

Government Ministries, Departments, and Agencies

METI	Japan's Ministry of Trade, Economy, and Industry
BEA	U.S. Bureau of Economic Analysis
CFTC	U.S. Commodity Futures Trading Commission
DOE	U.S. Department of Energy
DOE/FE	U.S. Department of Energy, Office of Fossil Energy
DOT	U.S. Department of Transportation
EIA	U.S. Energy Information Administration
FERC	U.S. Federal Energy Regulatory Commission
SEC	U.S. Securities And Exchange Commission
PHMSA	U.S. Pipeline and Hazardous Materials Safety Administration
MEE	China Ministry of Ecology & Environment
MEP	China Ministry of Environment Protection
PAB	China Petroleum Administrative Boards
GOI	Government of India
NCLT	India National Company Law Tribunal
OALP	India Open Acreage License Program
PNGRB	India Petroleum & Natural Gas Regulatory Board
APC	Panama Canal Authority

Development Banks and Related Agencies

ADB	Asian Development Bank
ECA	Export Credit Agency
Ex-Im	U.S. Export-Import Bank
IFC	International Finance Corporation
JBIC	Japan Bank for International Cooperation
JFTC	Japan Fair Trade Commission
JICA	Japan International Cooperation Agency
JOGMEC	Japan Oil Gas and Metals National Corporation
NEXI	Nippon Export and Investment Insurance
OPIC	Overseas Private Investment Cooperation
USTDA	U.S. Trade Development Agency
WB	World Bank
IMO	United Nation International Maritime Organization
TEN-T	EU Trans-European Transport Networks

Policy Research Organizations and Related Entities

IEEJ	Institute of Energy Economics, Japan
EPRINC	Energy Policy Research Foundation, Inc.
BMI	BMI Research
ERIA	Economic Research Institute for ASEAN and East Asia
EDMC	IEEJ Energy Data and Modeling Center
NBR	National Bureau of Asian Research
IEA	International Energy Agency

Intergovernmental Economic Organizations

ASEAN	Association of Southeast Asian Nations
OECD	Organization for Economic Co-operation and Development

Regional Designations

EAS	East Asia Summit
JKT	Japan, Korea, and Taiwan

TABLE OF ABBREVIATIONS continued

Natural Gas-Related Terms

LNG	Liquefied Natural Gas
FSRU	Floating, Storage, and Regasification Unit
FPSO	Floating, Production, Storage, Offloading Vessel
CCGT	Combined Cycle Gas Turbine
CGD	City Gas Distribution
HELE	High-Efficiency, Low Emissions
MW	Megawatt

Metrics

Bcf	Billion Cubic Feet
Bcf/d	Billion Cubic Feet per Day
Bcm	Billion Cubic Meters
cum	Cubic Meters
GW	Gigawatts
mcf	Thousand Cubic Feet
MBD	Million Barrels per Day
MMBtu	Million British Thermal Units
MMT	Million Metric Tons
MTE	Million Metric Tons Equivalent
Mtpa	Million Metric Tons Per Annum
MW	Megawatts
Tcf	Trillion Cubic Feet

Abbreviations Not Elsewhere Classified

AMA	Japan's Anti-Monopoly Act
CPP	U.S. Clean Power Plan
DES	Delivered Ex-Ship Contract
ECA	Emission Control Area
EIS	Environmental Impact Statement
FID	Final Investment Decision
FOB	Free On Board Contract
FTA	Free Trade Agreement
GDP	Gross Domestic Product
GHG	Green House Gas Emissions
GIIGNL	International Group of Liquefied Natural Gas Importers
HSFO	High Sulfur Fuel Oil
INDC	Intended National Determined Contribution
LSFO	Low Sulfur Fuel Oil
MDB	Multi-lateral Development Bank
MDO	Marine Diesel Oil
MGO	Marine Gas Oil
NBP	U.K. Natural Balancing Point Natural Gas Benchmark Price
NOC	National Oil Company
NOx	Nitrous Oxide pollutants
NYMEX	New York Mercantile Exchange
PPP	Public Private Partnership
PSC	Production Sharing Contract
SER	Schedule for Environmental Review
SOx	Sulfur Oxide pollutants
WTI	West Texas Intermediate Crude Oil Benchmark Price