WORKING PAPER SERIES

Global Natural Gas Markets Overview: A Report Prepared by Leidos, Inc., Under Contract to EIA

August 2014

This paper is released to encourage discussion and critical comment. The analysis and conclusions expressed here are those of the authors and not necessarily those of the U.S. Energy Information Administration.

Overview

The attached report, prepared by Leidos, Inc., under contract to EIA, provides a broad overview of today's global natural gas markets, possible drivers of the evolution of the global gas market, and a high level overview of select economic theories that may be applied to describe basic market interactions in current and future global natural gas markets.

Understanding the development of the global natural gas market is of great importance to EIA. In particular, EIA is working to better understand future world natural gas prices and the interplay between U.S. exports and the world market.

Natural gas is increasingly becoming a global commodity that is traded between regions. As such, international natural gas markets are undergoing a substantial change in market structure and organization, as well as in supply and demand. These on-going changes create challenges for modeling and forecasting global natural gas supply, demand, and price. Understanding the underlying drivers of market evolution is an essential underpinning for identifying both new market trends and shifts in the rate of change of ongoing trends.

The relationship that the United States has with the global gas market is poised to change considerably in the immediate future. In the early -2000s, with growing natural gas supply concerns, substantial liquefied natural gas (LNG) import infrastructure was planned, with 12 billion cubic feet per day (Bcfd) of regasification capacity ultimately constructed. Significant growth in domestic natural gas production started in the mid-2000s, largely due to the development of the nation's shale resources. LNG imports peaked in 2007 at 2.1 Bcfd, and in 2013 fell to 0.3 Bcfd. Dry gas production has increased over 25% from 2000-2013, allowing increasing amounts of consumption to be satisfied by domestically produced gas This has shifted the relationship of the United States with the global market from that of a prospective large-scale natural gas importer to a potentially significant natural gas exporter.

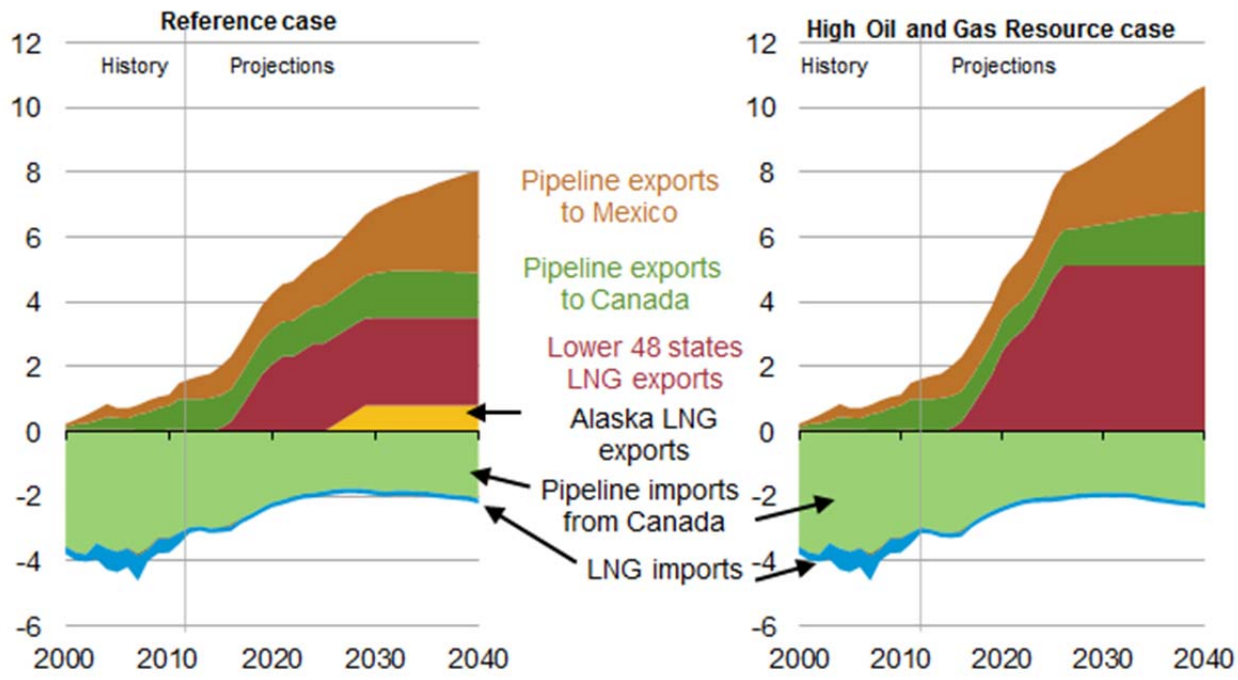
As of July 2014, there are over 40 proposals to the U.S. Department of Energy's Office of Fossil Energy for approval to export domestically produced LNG. Many of these proposals are for LNG exports sited at former LNG import terminals. As of July 30, 2014, only three facilities, Cheniere Energy's Sabine Pass facility in Louisiana Sempra Energy's Cameron facility in Louisiana and Freeport LNG Development's Freeport facility in Texas have received regulatory approval to export LNG from both the Department of Energy[1] and the Federal Energy Regulatory Commission. The Sabine Pass liquefaction facility, with 2.2 Bcfd planned export capacity, is currently under construction with an anticipated start date of late-2015.

In the *Annual Energy Outlook 2014* (AEO2014) Reference case, EIA is projecting that the United States will be a net exporter of natural gas by 2018. This is driven by a combination of decreasing pipeline imports from Canada, and increasing pipeline exports to Mexico and LNG exports into the global market. EIA's projections for imports and exports vary depending on resource, economic growth, and other assumptions. For example, under High Oil and Gas Resource case assumptions in the AEO2014, which increases the productive capacity of the U.S. natural gas and oil resource, gross exports of natural gas

[1] For the Cameron and Freeport facilities, DOE approval is conditional.

grow to 11 trillion cubic feet (Tcf) by 2040 (29 Bcfd). This is greater than the levels of gross exports of natural gas in the Reference case, which reach over 8 Tcf by 2040, or 22 Bcfd (Figure 1).

Figure 1. U.S. natural gas imports and exports (trillion cubic feet)



Source: EIA, Annual Energy Outlook 2014

The Leidos Global Natural Gas Markets Overview has three sections. The first section provides a summary of the global natural gas market with respect to worldwide supply, demand, and prices. Special address is given to the role of LNG as this is the physical form in which natural gas can be traded as a truly global commodity with transoceanic shipment from any region of supply to any region of demand.

The second section of the Leidos report discusses the key drivers of natural gas supply, demand, and market evolution. A synopsis of each driver is presented in largely independent subsections. Nevertheless, these drivers have interdependent elements. Natural gas supply and demand imbalances and resulting regional price differences in conjunction with increasing international trade are collectively driving market structural and organizational changes. These marketplace changes then in turn affect the supply and demand balance that helped drive them.

The final section of the Leidos report reviews some economic theories and how theory may be applied to assist in recognizing and projecting possible market trends. The first theory discussed is the economic Law of One Price, the expected result of international price convergence, and current barriers to this outcome. The potential of the dominant firm model and game theory are subsequently explored as means to analyze regional natural gas markets.

The attached paper is being shared as a contribution to the literature and the on-going dialogue on an energy topic of great importance. The views expressed in this contractor report are those of the authors, and do not necessarily reflect the views of the U.S. Energy Information Administration. EIA intends to sponsor and pursue further work related to this important topic.

An Introduction to Global Natural Gas Markets, Drivers, and Theory

For the U.S. Energy Information Administration

Prepared by Leidos, Inc.

May 6, 2014

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1 The Global Natural Gas Market

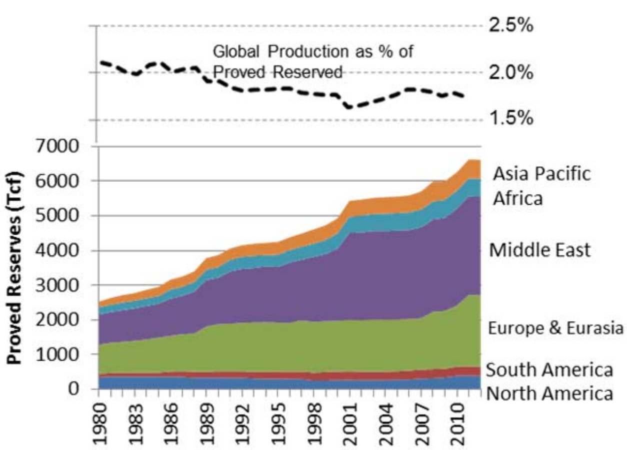
The global natural gas market is comprised of regional markets that are often grouped based on either the historical patterns of transoceanic shipping (i.e., the Atlantic and Pacific Basins), or the primary supra-regions for natural gas trades (i.e., North America, Europe, and Asia). Distinctions between sub-regional and inter-basin markets, or conversely the extent of globalization, vary with the extent of natural gas transport across the regions and basins. In recent years, roughly 70% of natural gas flows across the globe are transported to market destinations within the country of production, while an additional 20% flows cross international borders through pipelines, and nearly 10% is moved to market destinations as liquefied natural gas (LNG). The evolution of the global natural gas market is dependent on natural gas reserves and production in conjunction with demand, and the ability to meet demand with supplies from other regions and oceanic basins, the latter of which is exclusively traded as LNG.

The following sections provide an overview of natural gas supply and production (Section 1.1), demand and end-use shifts (Section 1.2), prices (Section 1.3), the role of LNG (Section 1.4), and the future of natural gas markets (Section 1.5).

1.1 Supply and Production

From a global perspective, proved reserves of natural gas have continually increased over the last several decades, while natural gas production as a percentage of reserves has generally decreased (Figure 1). Increases in the volume of proved reserves from 1997 to 2012 have been greatest in Qatar, Turkmenistan, and Iran, and correspondingly, the largest reserves are currently found in the Middle East and Eurasia.

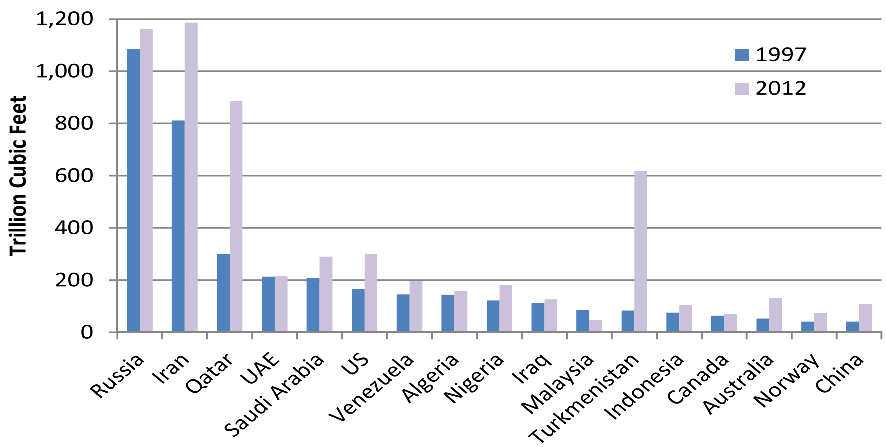
Figure 1 Global Proved Natural Gas Reserves and Production as % of Proved Reserves, 1980 to 2012



Source: Leidos, Inc., proved reserves based on BP Statistical Review of World Energy, 2013; production based on EIA.

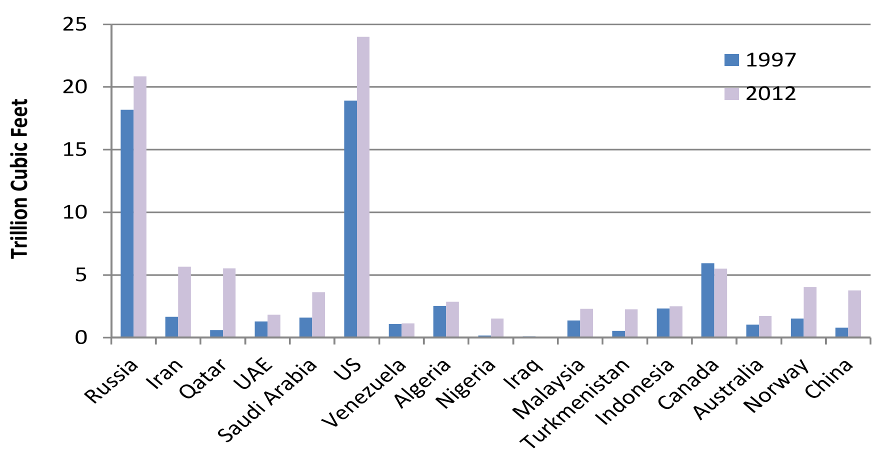
Among the countries with the largest natural gas reserves, there is little correlation between annual production levels and reserve volume, as seen by comparing Figure 2 and Figure 3. While this discrepancy could suggest that high-production countries such as the US and Canada are running down their reserves at a faster rate than in other countries, the final outcome of higher production to reserve ratios is far from clear. The longer term (multi-decade) view is complicated by the historical outpacing of production by growth in proved reserves (Figure 1), and differences among countries in regulations for booking reserves and incentives to prove up reserves. Further, with long-term projections of a gradual shift away from fossil fuels, the per unit value of unproduced gas reserves may decline in the long term. Nonetheless, the projected short, mid, and long term value of natural gas as determined by the balance of supply and demand is a basic concept that guides the development of natural gas resources.

Figure 2 Countries with the Greatest Volumes of Proved Natural Gas Reserves



Source: BP Statistical Review of World Energy, 2013, Historical Data Workbook

Figure 3 Annual Natural Gas Production in Countries with the Largest Reserves



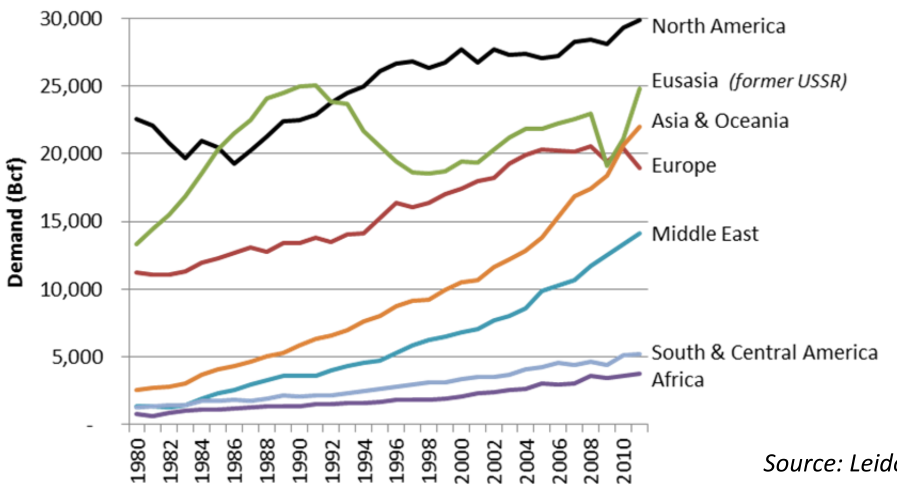
Source: BP Statistical Review of World Energy, 2013, Historical Data Workbook

1.2 Demand and the Energy Mix

Natural gas demand is currently greatest in North America, and is approximately 30,000 Bcf. Natural gas demand in Eurasia (the former USSR), Europe, and Asia were at roughly similar levels on a global scale in 2011, around 20,000 to 25,000 Bcf each (Figure 4). A key distinction among these three regions is that demand in Asia and Oceania has been steadily rising over the last two decades, and appears poised to become the single largest demand region within the next decade. Steady, multi-decade growth in natural gas demand is also seen in the Middle East, and lower, but increasing demand is seen in South and Central America and Africa.

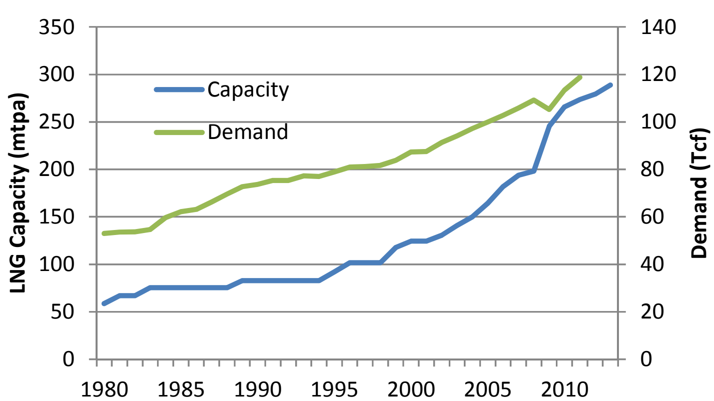
While there are fluctuations in natural gas demand in more developed regions over the last few decades, overall global demand has risen steadily with the exception of a downturn associated with the 2009 recession (the first downturn ever recorded for global natural gas consumption). Over the same period, the rate of increase in capacity to liquefy natural gas for overseas transport outpaced the rate of increase in natural gas demand as indicated by the narrowing gap in Figure 5. LNG demand is projected to continue to grow (Figure 6), suggesting an increasing importance of natural gas transport beyond the cost-effective limits of pipeline systems. However, LNG remains a small portion of the total natural gas market. In 2011, global LNG production of 241 MT was slightly less than 10% of the 2,493 MT natural gas demand.

Figure 4 Global Natural Gas Demand by Region, 1980 to 2011



Source: Leidos Inc., based on data from EIA.

Figure 5 Global LNG Capacity (mtpa) and Natural Gas Demand (Tcf)



Source: Leidos Inc., based on LNG capacity data from Gas Strategies and natural gas demand data from EIA.

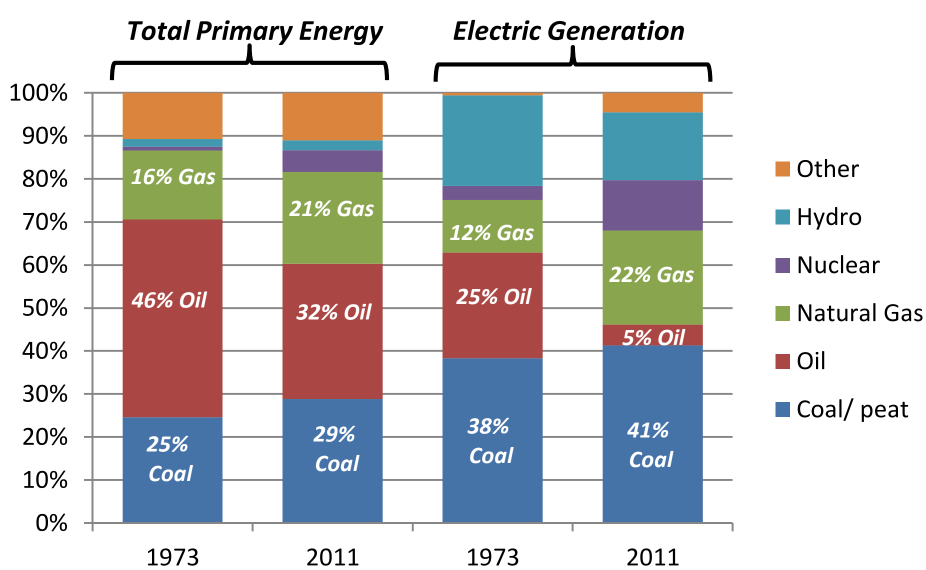
Figure 6 Projections of Global LNG Demand to 2030

Source: Ernst & Young, as referenced in the Petroleum Economist, May 13, 2013, "The New World Order".

* *JKT = Japan, South Korea, and Taiwan*

Over the last 20 years, the share of gas in the global energy mix has increased, while the share for oil has decreased. These two trends are even stronger for the share of these fuels used for electric generation. Gas used to generate power has nearly doubled its share of the total generation mix since 1973, representing 12% of the global electric generation mix in 1973 and 22% in 2011. In contrast, the share of oil in the global electric generation mix has declined by 80% over the same period, representing 25% of the electric generation mix in 1973 and only 5% in 2011 (Figure 7). This shift is driven by the generally lower price of natural gas compared to oil on an energy content (Btu) basis and the relatively lower costs of new natural gas electric generators. Further, the reduced emissions associated with natural gas use are increasingly important as many countries impose tighter emission standards.

Figure 7 Global Fuel Shares of Total Primary Energy Supplies and Electric Generation

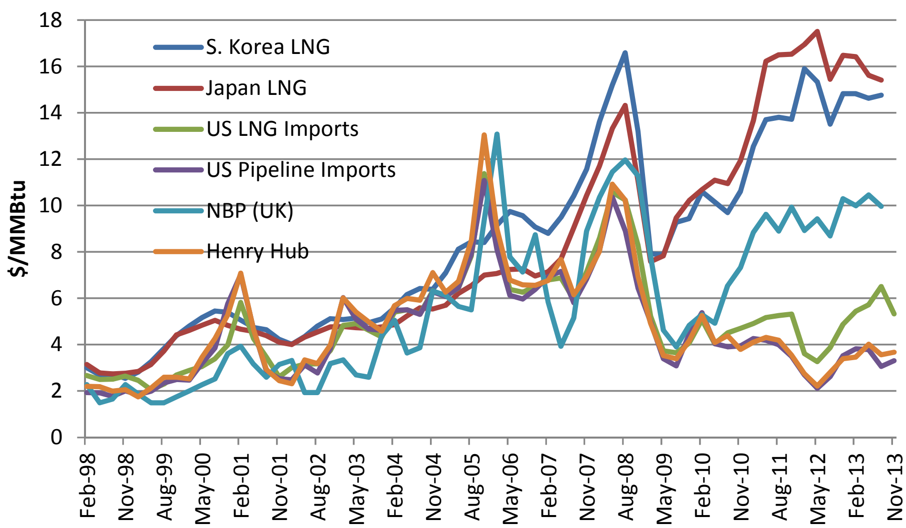


Source: Leidos, Inc., based on IEA, Key World Energy Statistics, 2013.

1.3 Natural Gas Prices

As indicated by the often considerable divergence of prices, natural gas has distinct regional markets across the globe, and the correlation in prices among these regional markets has eroded since 2009 (Figure 8). The more pronounced divergence of market prices in recent years is a result of the presence of two different pricing systems in conjunction with market circumstances that are accentuating pricing system differences and a limited market access for arbitrage. The Asian prices shown in Figure 8 are based primarily on an oil-indexed pricing system while the US prices are based on the North American natural gas market where prices are determined in a competitive process between multiple natural gas suppliers (i.e., gas-on-gas based prices). The UK prices are also gas-on-gas based, although they are more readily influenced by oil-indexed prices in continental Europe when arbitrage opportunities exist.

Figure 8 Natural Gas Prices in Selected Regional Markets

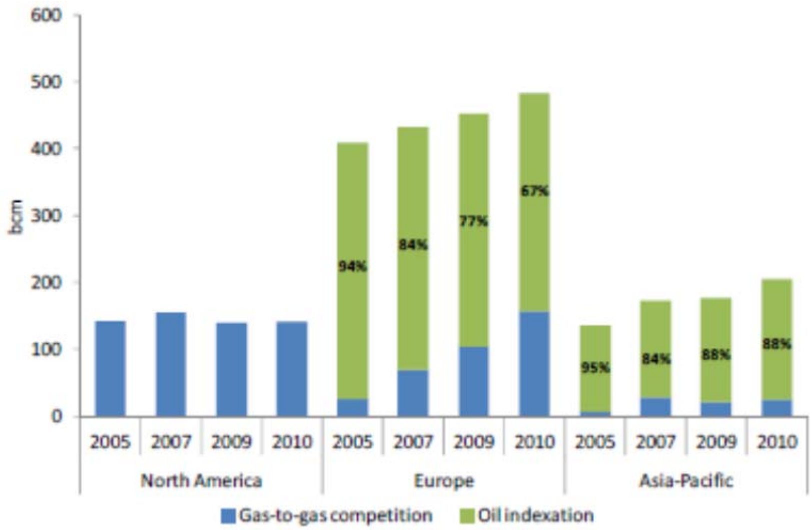


Source: Leidos, Inc., based on EIA and Gas Strategies LNG Data Service

1.3.1 Pricing Systems

There are two basic pricing systems that are commonly used for international trade of natural gas: oil-indexed pricing and gas-on-gas based pricing. Under gas-on-gas pricing, the price of natural gas is indexed to competitively determined gas market spot prices which change in response to natural gas supply and demand. Under oil-indexation, the price of natural gas is determined from oil market spot prices which change in response to oil supply and demand. As seen in Figure 9, virtually all international trade in North America uses the gas-on-gas pricing system. In Europe, oil indexation is dominant for international trade, but the use of gas-on-gas pricing steadily increased from 6% of trades in 2005 to 33% of trades in 2010. In the Asia-Pacific, oil indexation is dominant, but unlike in Europe, has not shown steady decline, and was used for 88% of gas trades in both 2009 and 2010.

Figure 9 Use of gas-on-gas and oil indexed pricing for natural gas trade in North America, Europe, and Asia-Pacific, 2005 through 2010.



Source: IEA, 2013. Developing a Natural Gas Trading Hub in Asia: Obstacles and Opportunities.

Under oil-indexation, the exact formula used to calculate natural gas prices is contractually set, and these formulae vary among contracts. In general, the formula is typically a set base price plus the average price of oil at a designated benchmark over a preceding period of time multiplied by a coefficient. The coefficient essentially sets the relationship of the price per energy unit of oil versus natural gas, where a steeper curve indicates closer to a one-on-one relationship. The formula may also include an S-curve component to curb the LNG price at high or low oil prices. This pricing system applies oil supply and demand driven prices to natural gas, and natural gas prices can continue to increase even when there is an oversupply of natural gas.

In contrast, a gas-on-gas pricing system generally reflects the balance between natural gas supply and demand, and includes multiple suppliers. As the ratio of natural gas supply to demand decreases, natural gas prices increase, which under the prevailing theory of supply and demand, may both temper demand and stimulate greater investment in natural gas production. Increases in natural gas production subsequently increase the supply to demand ratio which acts to moderate prices, beginning the cyclic behavior of prices anew.

1.3.2 Price Ups and Downs

Prices in all the gas markets shown in Figure 8 increased sharply between 2006 and 2008 due to tighter market balances for both gas and oil in conjunction with higher construction costs associated with price increases for steel and other commodities and escalation in labor costs. Subsequently, the worldwide drop in natural gas prices in 2009 corresponded with a downturn in global demand (Figure 5) due to several factors, one of which was reduced economic growth associated with the global recession. Additionally, there was unrealized growth in the share of natural gas in the European electric generation mix due to increases in renewable energy use, as discussed in Section 2.3.2. Finally, there were increases in North American production from shale gas, which in turn reduced the previously projected need for significant increases of US LNG imports. These factors combined to create an oversupply of natural gas in the Atlantic basin which set the stage for gas-on-gas prices to drop regardless of the global economic recession. The global recession, with concomitant reductions in manufacturing and shipping, further reduced demand for both natural gas and oil. Resulting decreases in oil prices (and associated oil-based gas prices) were significant, but not as severe as gas-on-gas price reductions. As a result, Pacific basin prices were roughly twice Atlantic basin prices in 2009, creating a substantial arbitrage opportunity. As may be expected, during this period global exchange of LNG accelerated, notably from the Atlantic basin to the Pacific basin.[1] Both the magnitude and duration of price differentials among regional natural gas markets from 2009 to the present have promoted greater attention to market organization and natural gas pricing systems (this is addressed in greater detail in Section 2.4.1).

2010 brought greater global economic growth and energy demand, which enabled a rebound in oil-indexed natural gas prices, and a cold winter further strengthened European demand which influenced increases in UK gas-on-gas prices. In North America, however, shale gas production continued to increase, and natural gas prices have stayed relatively low, excepting modest increases in LNG import prices which are affected by natural gas prices in other buying regions. In 2011, the Fukushima Daiichi nuclear disaster caused an increase in Japanese LNG imports, which were largely supplied through the spot market. The larger spot purchases by Japan since 2011 have increased the average price of natural gas in the Asia-Pacific market.

1.4 The Role of LNG

LNG represents approximately30% of international natural gas trade, and is used to meet both primary and peak natural gas demand. Japan and Korea, the two largest LNG importers jointly comprised 52% of the global LNG market in 2012.[2] Both of these countries meet their entire natural gas demand with LNG. In contrast, other importers use LNG to balance regional supply and demand (i.e., Europe), or to meet a relatively small demand for gas (e.g., Taiwan, Puerto Rico, Dominican Republic, Chile, which jointly represent less than 10% of the global LNG market). Figure 10 shows the percent of natural gas demand that was met by LNG in 2012 by global region and for selected countries.

In recent years, the Middle East (and Qatar in particular) has emerged as a swing producer, supplying both Atlantic and Pacific basins. Moreover, the expansion of the Panama Canal provides an opportunity for US Gulf Coast LNG to be traded in the Pacific Basin. Some of the challenges for inter-basin LNG trade are relatively high transportation costs compared to other energy products, and quality differences between Atlantic (lean) LNG streams and Pacific (rich) LNG streams.

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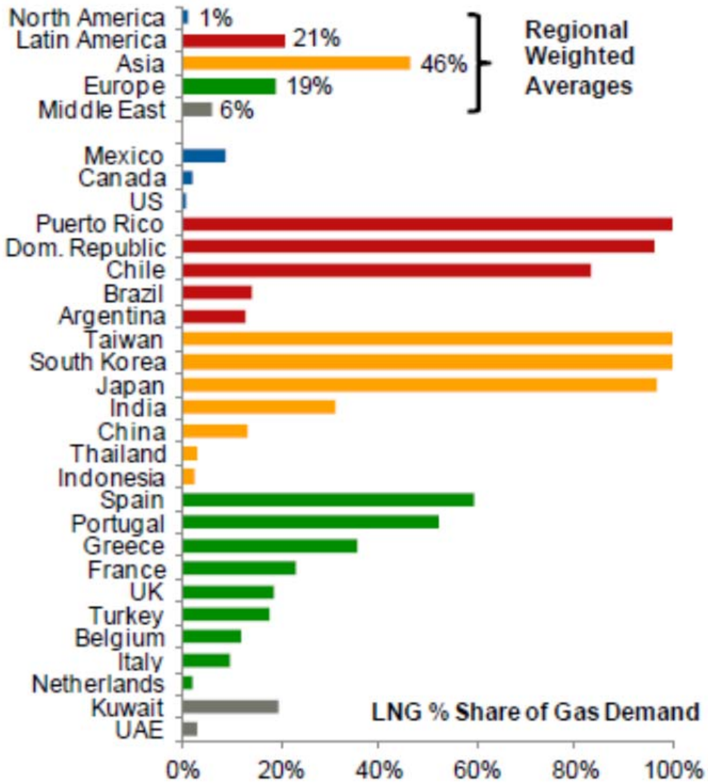
[1] Hashimoto, Hiroshi, 2011. "Evolving Roles of LNG and Asian Economies in the Global Natural Gas Markets". 2011 Pacific Energy Summit, February 21-23, 2011, in Jakarta, Indonesia. http://www.nbr.org/downloads/pdfs/eta/PES_2011_Hashimoto.pdf

[2] IGU, World LNG Report, 2013.

Figure 10 LNG Percent Share of Natural Gas Demand



Source: As shown in IGU 2013, based on Waterborne LNG Reports, US DOE, and PFC Energy Global LNG Service.

1.4.1 The LNG Market

Roughly two-thirds of global LNG is supplied under long-term, take-or-pay contracts that cannot exploit arbitrage opportunities. The price divergences seen in Figure 8 indicate that the remaining volumes of LNG (i.e., the volumes available for arbitrage) are not sufficient to create a global LNG market. However, at least some convergence in prices seems likely if the trend in growth of LNG production capacity and regasification (i.e., import terminals) continues (Figure 12) along with spot market share (Figure 11). Wood Mackenzie analysts have suggested that spot market volumes will be largely stagnant until at least 2017.[3] In contrast, a recent report from Poten & Partners projects that short-term LNG trade volumes will increase at an average rate of 11% per year up to 2015.[4] A fuller discussion of the potential for global price convergence is provided in Section 3.1.

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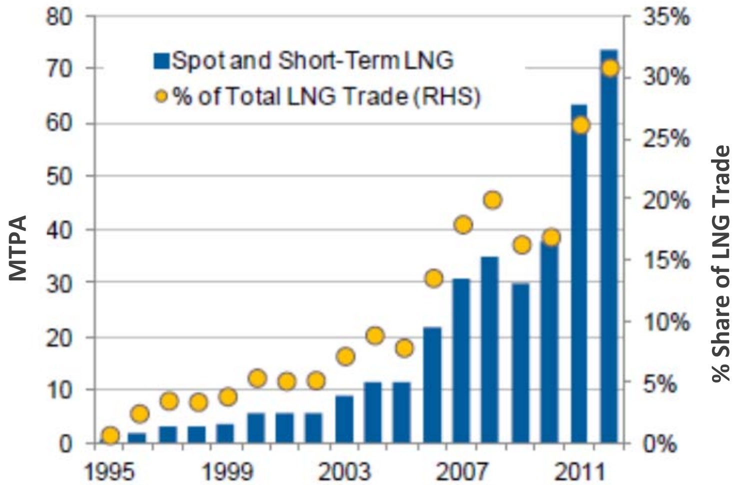
[3] Koh, Ann, and Pratish Narayanan, October 30, 2013, "Singapore Challenged as LNG Hub by Trading Delay: Southeast Asia," *Bloomberg News*, http://www.bloomberg.com/news/2013-10-30/singapore-plans-two-new-lng-import-licenses-as-pipe-cap-lifted.html

[4] Daiss, Tim, November 22, 2013, "Japan's LNG Price Tag Not Likely to Change in Near Term," *Energy Tribune*, http://www.energytribune.com/79795/japans-lng-price-tag-not-likely-to-change-in-near-term

Figure 11 Spot and Short-Term Trade Volumes of LNG, 1995 to 2012

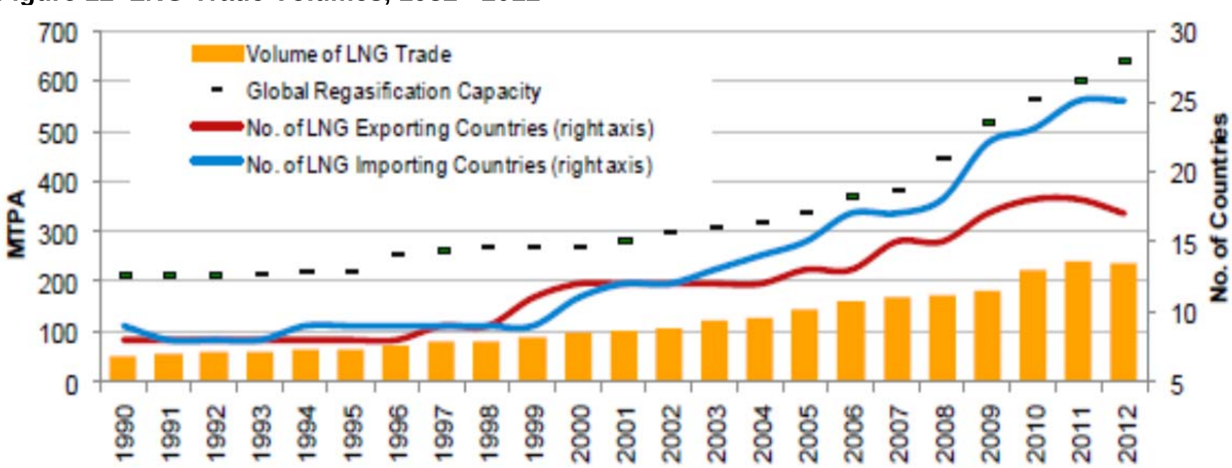


Sources: As shown in IGU 2013, based on Waterborne LNG Reports, US DOE, and PFC Energy Global LNG Service.

Continued growth in LNG's share of the natural gas market is further indicated by both the number of different countries that are suppliers and buyers of LNG. In 2006, 13 countries were LNG exporters while 15 countries were importers. In 2012, 17 countries were exporters while 25 countries were importers (Figure 12). After 30 years of consecutive growth, LNG trade fell in 2012 for the first time (by 1.6%), from 241.5 MT in 2011 to 237.7 MT in 2012 (Figure 12).

The 2012 decrease in LNG trade was largely driven by supply-side issues in Southeast Asia (Indonesia and Malaysia) and domestic and political challenges in Egypt, Libya, and Yemen (e.g., the Libyan Marsa el Braga facility has made no deliveries since the 2011 civil war, and is assumed to be decommissioned). Increased production in Qatar and Nigeria partially offset these losses. Despite this year-on-year decline in 2012, LNG trade has increased by 36% over the last 5 years.[5]

Figure 12 LNG Trade Volumes, 1982 - 2012



Source: IGU, World LNG Report - 2013 Edition

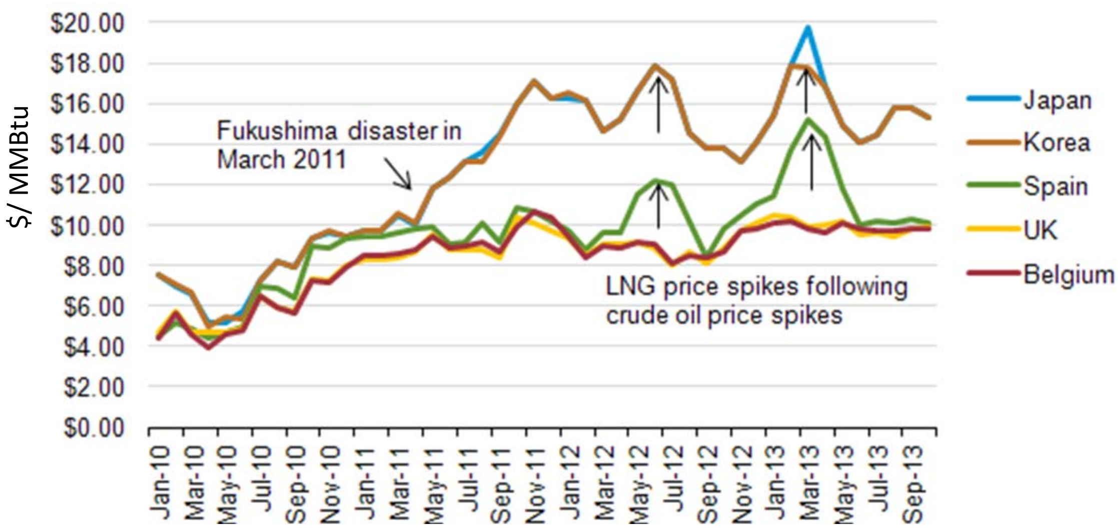
[5] International Gas Union (IGU), 2013, *World LNG Report - 2013 Edition*, http://www.igu.org/gas-knowhow/publications/igu-publications/IGU_world_LNG_report_2013.pdf

LNG demand exhibits seasonality as demand tends to increase from Japan, Korea, and other Asian markets in October and November to replenish inventories before winter heating and power demand ramps up.[6] The upward movement of LNG prices in the winter is becoming increasingly defined by Chinese gas demand,[7] particularly as policies to reduce coal use are implemented (further discussed in Section 2.3.2).

A recent Bank of America report projects that Japanese imports will raise from 86 mt in 2013 to 87 mt in 2014 as nuclear generators remain offline. Over the same period, China will boost its regasification capacity to 38 mtpa, three times higher than in 2010, and Latin American imports will increase by as much as 16%. Both the Bank and the International Gas Union project a continued tightening of LNG supply until the Australian projects start to come online in 2015.[8,9]

LNG prices for recent years are shown in Figure 13 for major delivery destinations, with arrows indicating the timing of the Fukushima disaster and crude oil price spikes. The price spikes for LNG delivered to Spain, Korea, and Japan are indicative of long-term, oil-indexed contracts, while these spikes are not seen in deliveries to other destinations at LNG spot market prices. This exemplifies the price differences that may occur when natural gas pricing is set under two different systems that are based on two different commodities.

Figure 13 Landed* LNG prices in Europe and East Asia, January 2010 to October 2013



**** Landed prices represent the price of LNG after arriving at an import terminal but before regasification and pipeline distribution, sometimes known as delivered ex ship or DES prices. October 2013 prices are estimated.***

[6] Hong, Chou Hui, November 15, 2013, “South Korea LNG Imports Climb 19 Percent on Higher Power Demand,” *Bloomberg Businessweek*, http://www.businessweek.com/news/2013-11-15/south-korea-lng-imports-climb-19-percent-on-higher-power-demand
[7] Vukmanovic, Oleg, November 15, 2013. “Global LNG-Asian premium draws in Atlantic production.” Reuters, http://www.reuters.com/article/2013/11/15/markets-lng-idUSL5N0IZ5KL20131115
[8] Tuttle, Robert, November 13, 2013. “ LNG seen at record as high demand expands five-times pace of supply.” Bloomberg News. http://www.bloomberg.com/news/2013-11-13/lng-seen-at-record-as-demand-expands-five-times-pace-of-supply.html
[9] *World LNG Report - 2013 Edition*

Source: U.S. Energy Information Administration, September 27, 2013, "Multiple Factors push Western Europe to use less natural gas and more coal," http://www.eia.gov/todayinenergy/detail.cfm?id=13151

1.4.2 Contract Structures

Contract structures affect the liquidity of the natural gas market. Traditional long-term LNG contracts, or Sale and Purchase Agreements (SPA) address LNG quantity, price, duration, and transportation responsibility. The quantity of LNG that the buyer must purchase is usually "take or pay", in which the buyer must pay for the agreed volumes regardless of whether or not they take the volumes. An initial "buildup" period that is not subject to the take-or-pay requirements may be specified to allow the importing market to absorb and find buyers and to accommodate potential delays in the completion of the liquefaction plant. After the buildup period has ended, the quantity generally remains constant over the duration of the contract, although there may be some limited volume flexibility, such as allowing the buyer to reduce the volume obligation by a fixed amount, usually about 5%.[10] These traditional terms of long-term contracts are changing, with an increasing number of contracts that incorporate divertible options, allowing a buyer to re-route their LNG shipments as long as the new destination does not compete with other seller deliveries at the specified import terminals.

In recent years, shifts in the terms of long term contracts have been promoted by the generally lower gas-on-gas prices compared to oil indexed prices. In addition to clauses to allow cargo re-destination and resale, long term contracts are increasingly using hybrid pricing schemes in which a portion of fixed volume sales (e.g., 10% to 30%) may be under gas-on-gas prices with the remainder under oil indexation. A third area of ongoing change in long term contracts is the inclusion of opportunities for price re-negotiation (e.g., every 5 years).

In contrast to long-term contracts, short-term and spot trade contracts typically include a divertible option that allows re-destination of the contracted cargo. The IGU reports that the major driver in spot and short-term trade growth has been the increased use of divertible options in flexible contracts (both short and long term) that allows companies to arbitrage.[11]

Poten & Partners has suggested that through 2015, LNG trade volumes will increase at a rate that exceeds increases in LNG production as a result of the shifting of some long-term contract sales to the spot market.[12] This concept is also implied in a comment by Total's president of Gas and Power, Philippe Sauquet, that LNG suppliers "will need to find new commercial terms and more flexible ones" due to increased gas market liberalization and heightening pressure from Asian governments to price long-term supply contracts on a hub basis rather than being indexed to oil prices.[13]

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[10] Tusiani, Michael, 2007, *LNG: A Nontechnical Guide*. PennWell Books, Page 319-325.
[11] *World LNG Report - 2013 Edition*
[12] Daiss, Tim, November 22, 2013, "Japan's LNG Price Tag Not Likely to Change in Near Term," *Energy Tribune*, http://www.energytribune.com/79795/japans-lng-price-tag-not-likely-to-change-in-near-term
[13] Robertson, Helen, November 15, 2013. "LNG suppliers mist price flexibly." *Petroleum Economist*, (online version).

1.4.3 Business Models

The traditional business model for natural gas markets, and LNG in particular, has been a vertically integrated market in which upstream production, midstream liquefaction, and sometimes also midstream shipping is owned by the producer and sold under relatively inflexible long term contracts. Under this model, natural gas sent to the liquefaction facility is owned by the producer, who then sells it after liquefaction. This vertical integration has been declining as other groups, including buyers, become investors in upstream and midstream operations.

Vertical integration is also reduced with the introduction of tolling business models in which the liquefaction plant is owned by a group that is distinct from the gas owner, and long term contracts are signed to provide the service of liquefaction. The liquefaction plant owner collects a toll for their services that is independent from the price of the natural gas feedstock or the LNG product price. Typically, customers pay a fixed charge for the right to receive the service, regardless of whether the service is used or not, plus a variable charge that is determined by the actual volume of LNG produced for them. This allows the customer to pay the fixed charge and purchase LNG or pipeline gas elsewhere when they choose. While tolling facilities are not able to collect windfall profits, they also do not have the risk of low natural gas prices.

As the LNG spot market grew in the mid-2000's, two other business models began to emerge that offer more flexibility of supply while maintaining the security of long-term contracts required for project financing. The first is self-contracting, in which producers sign long term contracts to purchase a portion of their own production to then sell wherever they choose. [14] Similarly, long-term contracts may also be signed with a third-party aggregator that acquires a portfolio of LNG from different sources to be sold in a variety of markets. In both cases, the LNG will be either resold under short- or medium-term contracts or will be sold as regasified LNG in a liberalized market. These business models have higher risks related to both revenue and volume because in the event of a change from a sellers' market (times of tight supply) to a buyers' market (times of oversupply), short-term and spot gas prices may be less than long-term contract prices resulting in financial losses.

Overall, the increasing variety of business models being used in natural gas markets today is facilitating a reduction in market rigidity.

1.5 The Future Natural Gas Market

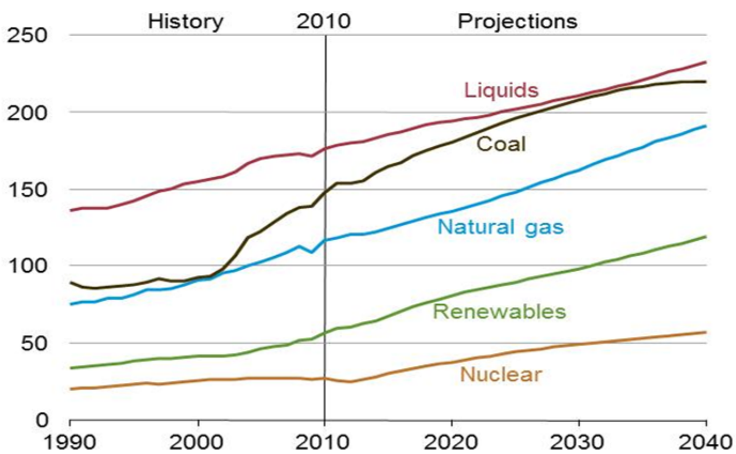
As described above, the role of gas in the global energy market has been steadily growing over the last decades, with increases in volume produced and consumed, and in the number of international suppliers and demand centers. As the global natural gas market matures with respect to both structure and organization, the overall effect is an enhancement of market security for players at both ends of the gas value chain. This encourages the development of more secure and more efficient infrastructure, lower cost of capital, and greater trade flexibility – all of which help feed the cycle of market growth. The greater efficiencies and lower prices anticipated with

[14] Jong, D. de, Coby van der Linde, and Tom Smeenk, 2010. "The Evolving Role of LNG in the Gas Market." In: Andreas Goldthau and Jan Martin Witte, Eds, Global Energy Governance: The New Rules of the Game. Page 230 – 231. Available at http://www.ourenergypolicy.org/wp-content/uploads/2012/10/2010_CIEP_LNG_De-Jong-Van-der-Linde-and-Smeenk.pdf

this market evolution encourage greater natural gas demand, which is also affected by exogenous factors such as national policies for reductions in greenhouse gas (GHG) emissions and nuclear power, and improvements in air quality.

Due to these and other factors indigenous to the gas industry, EIA projects natural gas demand will increase by about 64% from 116.8 Quads in 2010 to 191.3 Quads in 2040, as illustrated in Figure 14. These projections are based on assumptions for GDP growth and fossil fuel prices along with consideration of specific supply and demand issues. [15] The relative importance of specific drivers of natural gas supply and demand are likely to change as events, circumstances, and policies continually evolve, which makes demand projections scenario-dependent. The next section identifies and discusses key drivers of the global natural gas market from the perspectives of supply, demand, and market evolution.

Figure 14 Historical and Projected World Energy Demand by Energy Source (Quadrillion Btu)



Source: US Department of Energy, Energy Information Agency (EIA), International Energy Outlook, 2013; World Energy Demand and Economic Outlook, Figure 16.

[15] EIA uses the energy equilibrium model WEPS+, which "consists of a system of individual sectorial energy models, using an integrated iterative solution process that allows for convergence of consumption and prices to an equilibrium solution. ", US Department of Energy, Energy Information Agency (EIA) 2013, July 2013, "Models used to generate the IEO2013 projections," *International Energy Outlook*, http://www.eia.gov/forecasts/ieo/models.cfm

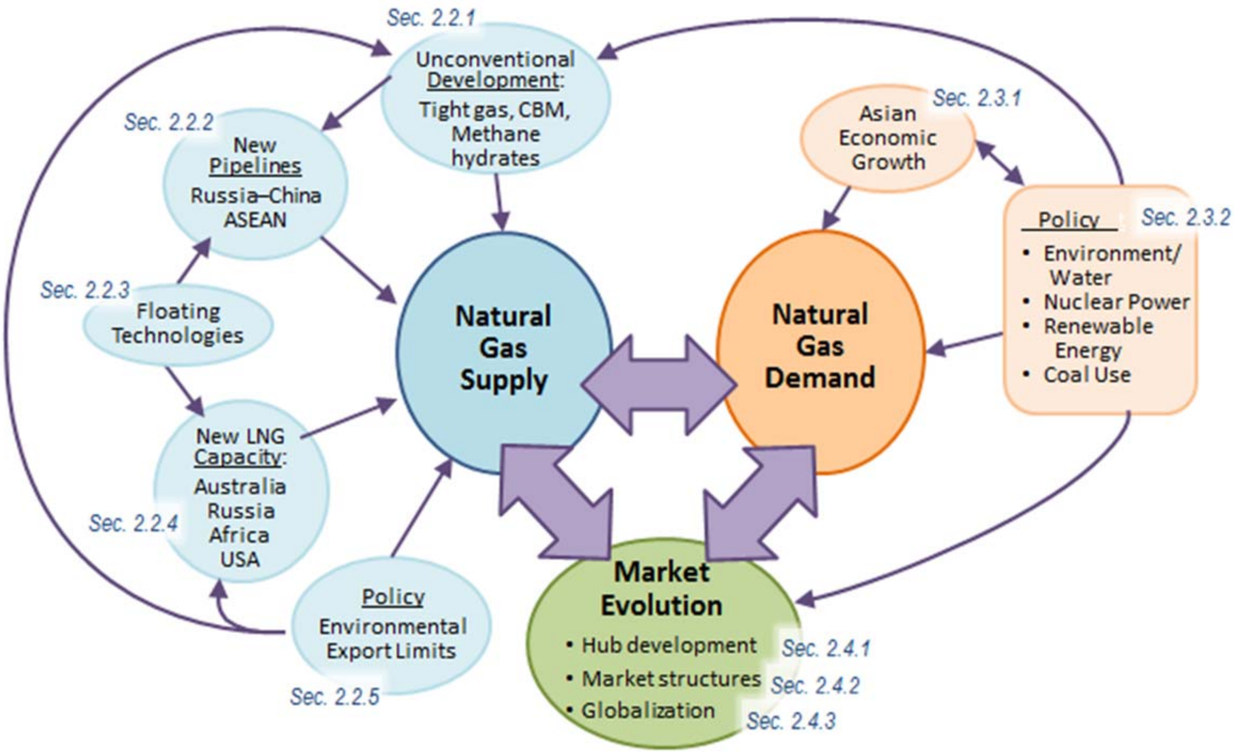
2 Drivers of Natural Gas Markets

2.1 Overview of Key Drivers

The key end-use sector that is driving continued growth in natural gas demand is the electric power sector, in which natural gas has largely replaced oil and is successfully competing with coal. While gas pipelines have and will likely continue to increase international gas trade on connectable landmasses, the primary means for natural gas trade that connects continents, utilizes stranded resources (e.g., Australia), and supplies island markets (e.g., Japan) is through LNG shipments. These are foundational concepts for today's global natural gas markets.

The main drivers of global natural gas markets are the drivers of natural gas supply and demand and evolution of the natural gas market itself, vis-à-vis structure and organization. Drivers of supply, demand, and change in market structure are discussed in the subsequent sections. Key drivers of natural gas supply include unconventional development (Section 2.2.1), new pipelines (2.2.2), floating technologies (2.2.3), new LNG capacity (2.2.4), and national-level policies that affect supply (2.2.5). Key drivers of current global demand are Asian economic growth (Section2.3.1) and national-level policies that affect demand (Section 2.3.2). Policies that affect natural gas supply and demand generally have roots in environmental, safety, and energy security objectives. Finally, there are three key areas of ongoing change in the structure and organization of global natural gas markets, these are the development of natural gas hubs (Section 2.4.1), spot markets (Section 2.4.2), and market globalization (Section 2.4.3). The primary relationships between these drivers of the global natural gas markets are shown in Figure 15, along with the section numbers in which the driver is discussed. The interrelationship of these drivers is discussed at a summary level in Section 2.5.

Figure 15 Key Natural Gas Market Drivers, Relationships, and Report Organization



The drivers identified in this section reflect current factors, and the brief overviews provided for each driver cannot fully capture the associated complexities that would be apparent in a thorough assessment. The evolving nature of events dictates that the importance of the drivers discussed below will shift over time, hence this paper provides a perception of global natural gas market drivers that reflects the time of this writing.

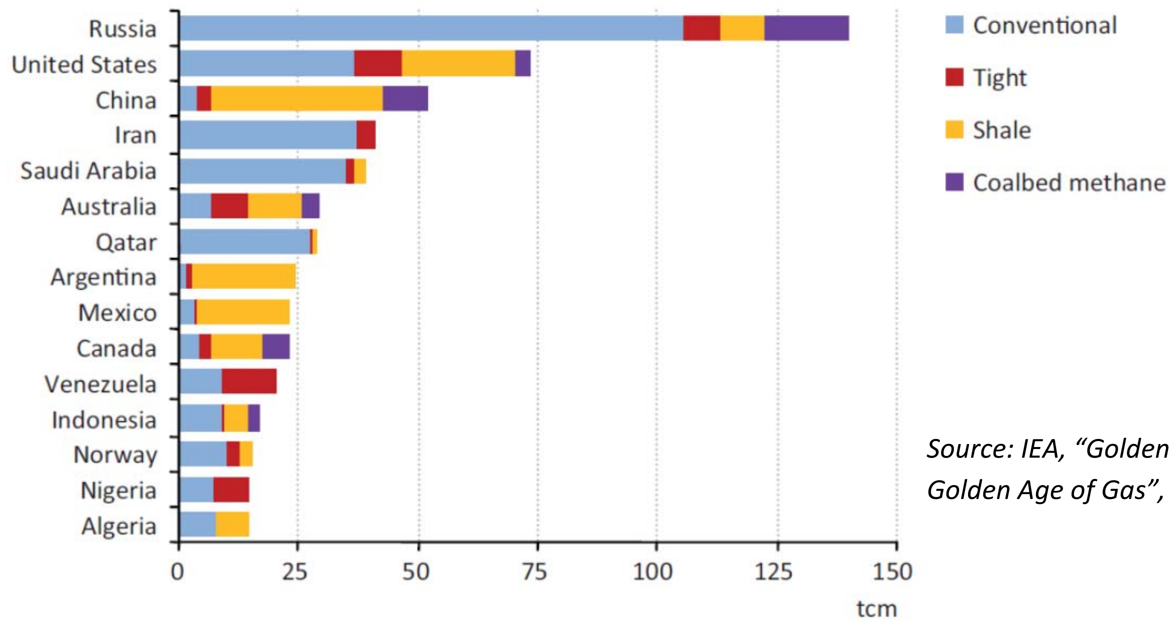
2.2 Supply-Side Drivers

The development of unconventional energy resources, including shale gas and coalbed methane in the near and medium-term, and methane hydrates in the longer term, are generally expected to be the primary sources of growth in global natural gas supplies. Particularly in regions with less developed natural gas pipeline systems (i.e., China, Southeast Asia), new pipeline development substantially affects the availability of new gas supplies. The development of pipelines in some of these emerging markets is in turn, affected by the deployment of floating LNG technologies, both liquefaction and regasification. In some cases (i.e., Southeast Asia), the relative ease and low cost at which floating technologies can be deployed may effectively postpone or preclude the development of new pipelines to emerging demand centers. Moreover, advances in floating liquefaction technologies, and in particular, the realization of cost reductions offered by these technologies, are likely to be a primary driver of the development of new LNG capacity. These key drivers of global natural gas supply are subsequently discussed in sections for unconventional development (2.2.1), new pipelines (2.2.2), floating technologies (2.2.3), and new LNG capacity (2.2.4). A final section (2.2.5) discusses policy drivers of natural gas supply.

2.2.1 Unconventional Development

Recent technological advances have vastly increased the quantity of economically recoverable unconventional reserves across the globe. Unconventional reserves typically refer to shale gas, gas in other tight formations, and coalbed (or coal seam) methane. Even though the unconventional resource base has not been fully assessed or tested for feasibility, for many countries, unconventional reserves offer greater potential to meet their energy needs than do conventional reserves, as seen in Figure 16. However, there is substantial variance among estimates of both the amount of unconventional reserves in place, and how much of these reserves can be economically extracted. While production of shale gas in particular has grown fastest in the US, other countries are expected to pursue production from this newly available resource. Nevertheless, the rate of increase in unconventional production will be greatly affected by the applicability of current technologies to the distinctive challenges presented by each play. Global advances in shale gas, coalbed methane, and methane hydrates are further detailed in the subsequent subsections.

Figure 16 Remaining Recoverable Gas Resources in Top 15 Countries, end of 2011



Source: IEA, "Golden Rules for a Golden Age of Gas", p69.

The overall development of unconventional resources in new regions of the globe will in many cases, necessitate the development of new or expanded pipelines to deliver the product to market. While environmental (i.e., groundwater, air quality, and greenhouse gas) policies are likely to temper the rate of unconventional gas development in North America and Europe (further described in Section 2.2.5, "Key Supply-Side Policy Drivers"), in emerging countries, energy demand and security concerns will provide stronger competition against environmental concerns, shifting the balance between these policies. This is exemplified by China, as discussed in Section 2.3.2, "China Coal Use and Environmental Concerns". However, a lag in development is expected in emerging regions in particular, as the new technologies are acquired and optimized.

Unconventional gas development, and shale gas development in particular, has already had and will continue to have a significant impact. As such, unconventional gas development has the potential to be the most important driver of the future global natural gas market. Understanding where, how much, and how soon unconventional gas is developed across the globe is vital to understanding future natural gas market development.

- ***Shale Gas***

The EIA estimated that in 2013, 32% of global natural gas reserves (proved and unproved) were in shale formations.[16] Additional natural gas reserves in other unconventional reservoirs include other tight formations and coalbed methane. In addition to the technological developments that launched the shale gas revolution in the US, new technological advances for exploiting tight formations continue to be made, suggesting the potential for continued development in technologies for extracting this resource.[17]

In recent years, technology advances such as 3 and 4-dimemsional surveys, and horizontal drilling and hydraulic fracturing (fracking), along with increased production efficiency, have substantially reduced the costs of production. Survey improvements have enabled success rates on exploratory wells to increase from 30% in the 1990s to 65% in the late 2000s.[18] While increased success rates of exploratory drilling are a benefit to both conventional and unconventional natural gas development, the timing of these advances have coincided with substantial improvements in tight gas production. Advances in fracking technology, in particular, have been described as “leading to a seismic shift in production”.[19] The pace of technological advances in shale gas development has enabled continued decreases in production costs, which in 2010, were reported to be $3 per Mcf to $8 per Mcf. The upper half of this cost range was stated to incorporate the anticipated costs of water reclamation and chemical cleanup requirements.[20, 21] In contrast, the IEA estimates that additional environmental requirements for shale gas production will only add about 7% to production costs.[22] Since 2010, costs have continued to drop. A leading Marcellus producer recently claims to have “slashed its cost structure from $2.47 per million cfe to $1.67 per million cfe in 2012 and is aiming for $1.21 per million cfe in 2014, with the bulk of the efficiencies coming through lower operating costs.”[23]

The economics of shale gas development is also substantially influenced by natural gas liquids (NGLs), which at $100/bbl WTI, provide an equivalent to $2.00 to $7.00/Mcfe in addition to the natural gas produced.[24] This suggests that the economics of shale gas development will degrade after richer plays are developed and only

[16] US Department of Energy, Energy Information Agency (EIA), 2013. *Technically Recoverable Shale Oil and Shale Gas Resources: An Assessment of 137 Shale Formations in 41 Countries Outside the United States*, http://www.eia.gov/analysis/studies/worldshalegas/

[17] National Energy Technology Laboratory (NETL), 2013. “Ultra-Deepwater and Unconventional Natural Gas & Other Petroleum Resources Program Consortium”, http://www.netl.doe.gov/technologies/oil-gas/Petroleum/projects/EP/Explor_Tech/42677RPSEA.html

[18] California Energy Commission (CEC), May 2012, *2012 Natural Gas Market Trends, In Support of the 2012 Integrated Energy Policy Report Update*, p. 32. http://www.energy.ca.gov/2012publications/CEC-200-2012-004/CEC-200-2012-004.pdf

[19] Peter Tertzakian, chief energy economist, ARC Financial Corp, reported in *Natural Gas Intelligence*, April 27, 2009.

[20] Chesapeake Energy, “2010 Annual Report”, p. 4. http://phx.corporateir.net/External.File?item=UGFyZW50SUQ9OTEzODB8Q2hpbGRJRD0tMXxUeXBlPTM=&t=1

[21] 2010. “Survey of Energy Resources: Focus on Shale Gas,” World Energy Council, p. 14. http://www.worldenergy.org/documents/shalegasreport.pdf

[22] International Energy Agency, 2012, *Golden Rules for a Golden Age of Gas*. World Energy Outlook Special Report, http://www.worldenergyoutlook.org/media/weowebsite/2012/goldenrules/weo2012_goldenrulesreport.pdf

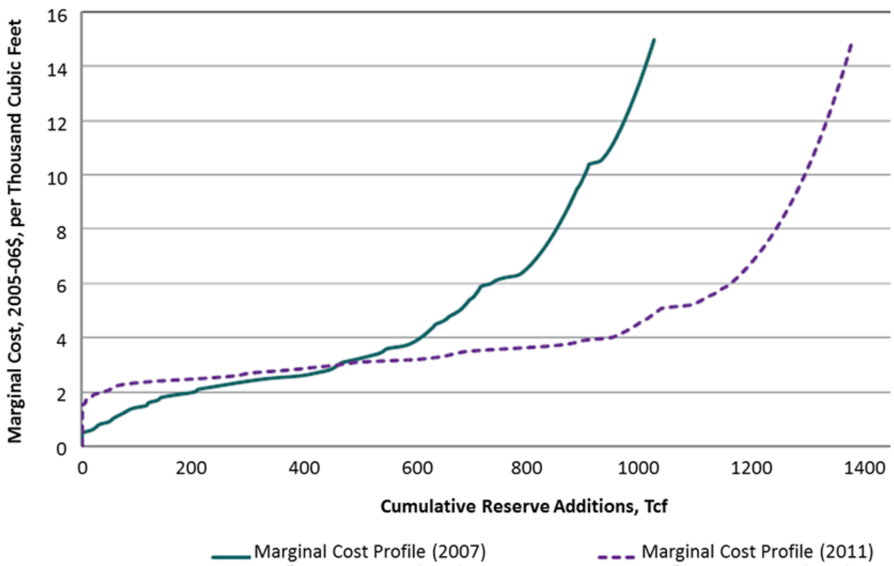
[23] December 2013/January 2014, “US shale gas still thriving,” *Petroleum Economist*, Vol 80, p. 50

[24] Donnelly, Michael F., 2011. “The Cost of Unconventional Gas Supply and its Future Influence on Florida Basis”. http://www.flgas.com/annual_meetings/2011/mike-donnelly-fgu-2011-presentation.pdf

leaner plays remain. Further, the greater decline rates associated with shale gas versus conventional reservoirs[25] suggest a higher rate of drilling may be needed to maintain a similar level of production.

Technology improvements in shale gas and tight sands development are largely responsible for recent significant shifts in the amount of natural gas reserves available at a given cost. For example, in the typical marginal capital cost curves[26] shown in Figure 17, a reserve addition of 800 Tcf has capital costs of about $7.00/Mcf to produce in 2007, while the capital costs for production of the same size reserve are $3.50/Mcf in 2011.[27]

Figure 17 Change in Marginal Capital Cost Profile, 2007 to 2011



Source: Rice World Gas Trade Model, Baker Institute and California Energy Commission (CEC), as cited in CEC, May 2012, "2012 Natural Gas Market Trends, In Support of the 2012 Integrated Energy Policy Report Update", p. 33.

As a leader in shale gas technology development, the US has also been the early leader in shale gas production. This has caused a major disruption of the global gas market, particularly with respect to LNG trade due to the lack of anticipated growth in US LNG demand, and due to the future development of the US as an LNG supplier.

Several other countries have begun exploration of these types of resources, and shale gas in particular. These countries include: Canada, China, Australia, Poland, Argentina, the Ukraine, India, Indonesia, Hungary, and others. Canada already produces some tight gas including small amounts of shale gas.

China, the country with the largest amount of shale gas reserves, generally lacks the infrastructure (water, pipeline, etc.) to support near-term use. However, the massive future Chinese demand for natural gas is a strong motivator for development of this indigenous resource. China has set ambitious targets of 60 to 100 bcm of shale gas production by 2020.[28] Wood Mackenzie has suggested that beyond 2025, there is a possibility that

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[25] "Survey of Energy Resources: Focus on Shale Gas," 2010.
[26] Marginal costs curves are unique for each well, and vary substantially among wells. A "typical" well is described in this example.
[27] "2012 Natural Gas Market Trends", 2012, p. 33.
[28] *Golden Rules for a Golden Age of Gas*, 2012.

the successful development of China shale will influence a major portion of the supply/demand balance.[29] This may be analogous to the effect of US shale gas development on the natural gas market in recent years (i.e., price impact, LNG oversupply, shift from coal).

While there is strong interest in development of European shale gas reserves, development has been slowed by public concerns such as nearby high population densities and environmental impacts.[30] The European Commission has recently adopted recommendations to provide environmental and GHG safeguard for shale gas development,[31] but it is too soon to know the effect of these recommendations on public concerns. For Russia, with its massive, developed, conventional gas supply, shale gas development "will be a minority pursuit for marginal players".[32]

Overall, within the next decade, some countries are expected to begin or to expand their development of shale gas activities.[33, 34] While some of these sources will not be economically recoverable, production at meaningful levels from reserves that are economically recoverable is still years away.

- ### *Coal Bed Methane (CBM)*

CBM is formed by both microbiological and thermal processes. Methane formation in near-surface coals such as lignite is typically biogenic, while methane formed in deeper, higher-rank coals tends to be more thermogenic in origin.[35] While CBM is traditionally considered a fossil fuel, if suggestions to define biogenic CBM (or a portion thereof) as a renewable fuel increase in sway,[36] interest in biogenic CBM production may accordingly increase. Regardless of whether CBM is biogenic or thermogenic, methane is adsorbed onto coal surfaces and may also be in groundwater within the coal beds, hence coal is both the source and reservoir for the methane gas while the combination of water and pressure provide the seal. CBM production typically entails pumping water out of the coal, thereby allowing the gas to escape.

CBM is much more developed in the US than in other countries. US CBM production began in the 1980's, and has been between 1,700 and 1,900 MMcf in recent years, representing around 7 to 10% of total US natural gas production, and roughly 80% of global CBM production.[37] Around 13 bcm (460 MMcf) of coalbed methane was produced outside the US in 2012, primarily in Australia and Canada.

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[29] October 2, 2013. "Reality bites Asian LNG buyers", *Petroleum Economist*. http://www.petroleum-economist.com/Article/3261769/Search/Reality-bites-Asian-LNG-buyers.html?Keywords=storage&OrderType=0&PeriodType=0&StartDay=0&StartMonth=1&StartYear=1999&EndDay=0&EndMonth=12&EndYear=2013&ScopeIndex=0&PartialFields=(CATEGORY_858_IDS%3a11628).(CATEGORYIDS%3a11654)&Brand=PE&tabSelected=True

[30] *Golden Rules for a Golden Age of Gas*, 2012

[31] European Commission, January 22, 2014, "European Commission recommends minimum principles for shale gas." *Press Release*, http://europa.eu/rapid/press-release_IP-14-55_en.htm

[32] December 2013/January 2014, "Russia's embarrassment of riches", *Petroleum Economist*, Vol. 80, p.62.

[33] *Technically Recoverable Shale Oil and Shale Gas Resources,* 2013.

[34] *Golden Rules for a Golden Age of Gas*, 2012.

[35] "Coal Seam Gas Fact Sheet," Australian Atlas of Minerals Resources, Mines and Processing Centres, http://www.australianminesatlas.gov.au/education/fact_sheets/coal_seam_gas.html

[36] Urynowicz, Michael, A., "Coal Bed Natural Gas Center", as viewed at: http://images.sdsmt.edu/learn/speakerpresentations/Urynowicz.pdf

[37] EIA, international natural gas data tables, as viewed 1/20/14 through http://www.eia.gov/naturalgas/data.cfm#summary

Australia began CBM production in 1996, and in 2013, approximately 10% (around 170 Bcf) of Australian natural gas production was from CBM, which in addition to meeting local demand, will be supplying two LNG projects in Queensland scheduled to begin operations in 2014. Additional CBM to LNG projects are scheduled to begin exporting between 2014 and 2016.[38] Canada began CBM production in 2002 in the Horseshoe Canyon, Alberta. CBM reserves are largest in Alberta, British Columbia, and Nova Scotia. In 2010, 7.2 bcm (254 MMcf) of CBM was produced, up from 2.5 bcm in 2005. A 2005 forecast of Canadian CBM production suggests that 14.5 bcm will be produced in 2015.[39]

CBM production in China is still quite new, and while production has fallen short of government targets, it has increased from less than 1 mcm in 2005, to 1.5 bcm in 2010, and 2.7 bcm (95 MMcf) in 2012. These volumes are in the same range as China's utilized volumes of coal mine methane (i.e., fugitive methane emissions associated with mining activities), which were 3.5 bcm in 2012.[40]

- ***Methane Hydrates***

The timeframe for significant production from methane hydrates (i.e., gas hydrates, methane clathrates, fire ice)[41] is likely further in the future than for shale gas and CBM. The development of cost competitive technologies for gas production from hydrates is still underway. With estimates of 100,000 Tcf of methane hydrates across the globe,[42] even with recognition that only a small percentage of this resource may be economically viable, research and development is ongoing with particularly strong interest from energy-poor countries.

The existence of methane hydrates depends on a combination of pressure and temperature, with less pressure needed at colder temperatures. Methane hydrates are typically found in deep ocean areas with relatively rapid sediment deposition (i.e., continental slopes), where the methane is formed by anaerobic microbial processing of the sediment. Other areas of methane hydrate production include permafrost layers and deepsea regions where some methane hydrate deposits are formed by thermal rather than (or in addition to) microbial processes. Different formation conditions and different surrounding sediments may require different technologies for extraction.

In 2013, the first successful extraction of methane from methane hydrates was claimed by Japan Oil, Gas and Metals National Corporation (JOGMEC) from an offshore deposit. Japan has set an ambitious target of commercial methane hydrate production by 2018.[43] One of the largest identified methane hydrate areas in the

[38] International Energy Agency, "FAQ's Natural Gas". http://www.iea.org/aboutus/faqs/gas/
[39] Global Methane Initiative, "Canada", *CMM Country Profiles*, https://www.globalmethane.org/documents/toolsres_coal_overview_ch6.pdf
[40] Huang Shengchu, 2013, "Current Situations of CBM/CMM Recovery and Utilization and Methane emission reduction in China," Global Methane Initiative Expo 2013, Vancouver, March 12 to 15, 2013, https://www.globalmethane.org/expo-docs/canada13/coal_02_Huang_UPDATED.pdf
[41] Methane hydrates are lattice structures (i.e., clathrates) formed by ice that trap methane. The clathrates are dispersed among sand and silt yielding substantial variation in the proportion of methane in different deposits.
[42] US Geological Survey, March 2001. "Natural Gas Hydrates—Vast Resource, Uncertain Future", *Fact Sheet,* http://pubs.usgs.gov/fs/fs021-01/fs021-01.pdf
[43] Brennan, Elliot, May 11, 2013. "The New Prize: Asia's "Fire Ice" Gas Revolution", *The Diplomat*. http://thediplomat.com/2013/05/the-new-prize-asias-fire-ice-gas-revolution/

world is in the Indian Krishna-Godavari basin. However, substantial research is still needed to either adapt the Japanese technology for this geology, or develop an alternative technology.[44]

Given the technological challenges associated with natural gas extraction from methane hydrates in addition to concerns surrounding GHG releases during the extraction process, significant production from these deposits may be a couple decades away, barring large-step technological breakthroughs.

2.2.2 New Pipelines

Overall, the evolution of the pipeline systems to serve growing economies will have a significant impact on natural gas supply and consumption, and can impact the course of the LNG trade. Even the proposal of a pipeline may affect market dynamics (as described below for the proposed Russia-China pipeline). Only two major pipelines, serving the markets of China and Southeast Asia, are addressed below due to their proposed size and potential market influence. In addition to these, there are many gas pipelines in conceptual, proposed, planned, and developmental stages that will define the gas market infrastructure and supply demand characteristics of the market.[45]

Pipeline competition in stranded major markets can have profound impact on the gas market with the possibility of making major markets like Japan, South Korea, and China behave more like the European market. Understanding the pipeline systems path of development is key to understanding the evolution of the global gas market.

- ***Russia –China Pipelines***

With the first framework agreement signed in 1997, Russia's Gazprom and the China National Petroleum Corporation (CNPC) continue to negotiate terms for a pipeline linking Russian gas production with Chinese demand. The primary unresolved term is price. Agreements signed thus far stipulate deliveries to China of up to 38 bcm/year; the start date and volume of gas deliveries; the take-or-pay level; the amount of guaranteed payments; and the gas transfer point.[46] The pipeline to deliver the gas is targeted to be completed in 2018, which may be a challenging schedule even if finalization of the deal is reached as anticipated in May 2014 (a necessary step prior to commencement of construction).[47] The pipeline is proposed to enter China in the northeastern Heilongjiang Province. Russian pricing goals for the pipeline with China have been to not undercut

[44] "The New Prize: Asia's "Fire Ice" Gas Revolution", 2013.
[45] Some of these are the Trans-Alaska pipeline and the Pacific Trail Pipeline to potential LNG export terminals, the Iran-Pakistan-India pipeline, the Sakhalin – Japan pipeline, etc.
[46] September 5, 2013. "China, Russia agree on terms of multi-billion dollar gas deal," *RT.com*, http://rt.com/business/china-russia-gas-deals-467/
[47] Mazneva, Elena, January 22, 2014. "Gazprom Says China Natural Gas Deal Delayed to Putin's May Visit." *Bloomberg News*, http://www.bloomberg.com/news/2014-01-22/gazprom-says-china-natural-gas-deal-delayed-to-putin-s-may-visit.html

its European market and to cover pipeline costs.[48] It has been suggested that China can afford to be patient, while Russia is eager to lock in a price before the U.S. begins flooding the market with cheap LNG.[49]

Delays in the agreement on the Russia-China pipeline have been a contributing factor to the Chinese development of LNG importation contracts with Australia, and Qatar. The CNPC has also signed a deal with Russia's largest independent gas producer Novatek to purchase a 20% stake in its subsidiary, Yamal Peninsula LNG plant located on the Arctic coast. The plant is under construction and scheduled to open in 2016. The deal includes a 15 year contract for sales of the entire production (3 mtpa capacity) from Yamal, with sales indexed to the JCC.[50][51] Overall, LNG is strengthening the position of China in pipeline talks with Russia, which may further delay a final agreement.

- ***Southeast Asian Pipelines***

The Association of Southeast Asian Nations (ASEAN) is comprised of ten nations – Brunei, Cambodia, Indonesia, Laos, Malaysia, Myanmar, Philippines, Singapore, Thailand, and Vietnam. A key program of ASEAN is the implementation of the Trans-ASEAN Gas Pipeline (TAGP) designed to interconnect the natural gas pipeline infrastructure of ASEAN member states. If the plan is completed, TAGP will connect Southeast Asia in one of the largest networks of its type in the world, linking the gas reserves of Indonesia, Malaysia, Singapore, Vietnam, Myanmar, Philippines, Brunei and Thailand.

Currently, there are natural gas pipelines between Myanmar and Thailand, Malaysia and Singapore, and Indonesia and Singapore, but they are not connected regionally to allow countries with surplus natural gas supply to export to countries with unmet gas demand. [52] The TAGP network already has 10 cross-border natural gas pipelines, traverses nearly 4000 km, and transports over 3 Bcfd, but there are at least six additional pipeline projects that remain to be completed. Pipeline sections that have been built generally connect excess supply to nearby demand centers.[53] These interconnections would strengthen the position of Singapore in their goals to become a natural gas hub, as discussed in Section 2.4.1, "Asian Hubs".

TGAP has the backing of the oil and gas majors in each of these countries and was originally projected to be in full operation by 2020. One of the biggest challenges in implementing TAGP has been harmonization of regulations between ASEAN countries. Further, many energy experts claim that the pipeline will not be completed until more proven gas supplies are identified, due in part to disagreements on the size of current reserves. Another issue affecting pipeline development is that many ASEAN countries subsidize the price of natural gas, which deters investors because the end-user price of natural gas is not high enough to guarantee a profit for development of both production and pipeline systems. Some analysts have argued that ASEAN

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[48] *ibid*.
[49] Philips, Matthew, October 23, 2013. "Russia's Shrinking Leverage With China." *Bloomberg Businessweek*, http://www.businessweek.com/articles/2013-10-23/russias-shrinking-leverage-with-china
[50] Japan Customs-cleared Crude (JCC), also known as the Japanese Crude Cocktail, is the standard benchmark for oil-indexed natural gas trades in Asia.
[51] Gas Strategies, LNG Data Service, December 17, 2013.
[52] August 17, 2012. "ASEAN Pipeline Dream Falls Flat". *Energy Tribune*. http://www.energytribune.com/11727/asean-pipeline-dream-falls-flat
[53] Ibid.

demand centers are too small and distant from each other to justify the costs of a pipeline and LNG shipping can be cheaper.[54] In the near and medium term, ASEAN countries are investing in LNG infrastructure.

Malaysia has developed an extensive pipeline network in peninsular Malaysia. In addition to domestic supplies of natural gas, Malaysia imports Indonesian natural gas via pipeline, and has recently added a regasification terminal to broaden supply options.[55] The centers for gas and LNG production in both Malaysia and Indonesia do not have pipeline connection to primary domestic demand centers. As such, LNG is shipped to the demand centers. [56] Indonesia has a floating storage and regasification unit (FSRU) off the north coast from Jakarta and is receiving LNG shipments from Indonesian LNG plants (i.e., Badak). [57] Another Indonesia FSRU will begin supplying gas to the Sumatra region in 2014. [58]

While Thailand and Singapore have historically received pipeline natural gas that is produced both domestically and in neighboring countries, both of these countries have decided to introduce LNG to better realize policy goals to enhance supply security. Since pipeline natural gas supply from Indonesia to Singapore began in 2001, natural gas deliveries were interrupted a few times due to technical issues, causing power outages.[59] The worst outage was in June 2004, causing a two-hour blackout in Singapore. The incident accelerated the government's plans to install an LNG receiving terminal. This suggests that LNG supply is viewed as a complement to pipeline natural gas for energy security.[60]

2.2.3 Floating Technologies

Technologies for both floating LNG regasification import facilities and for natural gas liquefaction at supply sites are rapidly developing and their use is expanding.[61] These technologies are being applied both in port and offshore using either converted or purpose-built vessels. There is no industry standard definition of floating LNG (FLNG). Many sources use FLNG to refer to floating natural gas liquefaction vessels, while others also group floating regasification vessels as FLNG. In this discussion, FLNG refers to both floating liquefaction and floating regasification.

Developers active in the FLNG business range from integrated majors such as Shell to smaller independent technology-focused and lease contracting companies such as Norway's Höegh LNG and Dutch firm, SBM Offshore. The FLNG market is projected to undergo rapid increases in investment and activity from 2014 to

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[54] Ibid.
[55] Nugroho, Hanan, December 30, 2013. "One island, three LNG exporting countries," *The Jakarta Post*, http://www.thejakartapost.com/news/2013/12/30/one-island-three-lng-exporting-countries.html
[56] Ibid.
[57] Ibid.
[58] Ibid.
[59] June 30, 2004, "Electricity Supply Interruption On 29 June 2004", Media Release, Energy Market Authority, Singapore Government, http://www.ema.gov.sg/news/view/66
[60] Hashimoto, Hiroshi, 2011. "Evolving Roles of LNG and Asian Economies in the Global Natural Gas Markets". 2011 Pacific Energy Summit, February 21-23, 2011, in Jakarta, Indonesia.
[61] January 4, 2013. "Floating LNG Market Rises". *Petroleum Economist (online version)*.

2020. Two-thirds of the forecasted expenditures are attributed to liquefaction infrastructure, with the remainder relating to import and regasification facilities.[62]

The upfront costs of FLNG projects can be estimated with greater certainty because construction occurs in the closed environment of a shipyard. This also allows shorter lead times. The selection of FLNG over onshore facilities transfers a portion of economic gains associated with construction from the host country to the country with the contracted shipyard. In countries with large established shipyards, labor rate escalations may be less than for onsite development in countries with a relatively small labor pool. Currently, shipyards in South Korea, followed by Japan, are the most commonly contracted yards for LNG carriers. Recent bids for the construction of floating storage and regasification units (FSRUs) have been in South Korea, Singapore, and the UAE, while top yards for oil Floating Production Storage and Offloading (FPSO) are in Singapore, Malaysia, South Korea, and the UAE. Any of these may be strong contenders for LNG FPSOs, in addition to shipyards in other countries that are seeking to increase their market share (i.e., China and India).[63][64]

While investors may increasingly be in positions to choose between offshore use of FLNG and development of onshore unconventional production, many markets remain that are beyond economic pipeline length, creating a niche for FLNG applications regardless of the extent of unconventional natural gas development.

▪ *Floating Regasification*

The first floating regasification facility began operations in 2007.[65] There are two general types of floating regasification vessels, floating storage and regasification units (FSRUs) that are “permanently” moored at a location, and storage and regasification vessels (SRV or RV) which can transport the LNG from a supplier to the buyer’s destination where it is then gasified using SRV equipment. SRV’s are typically used for smaller operations while FSRUs can have a much greater regasification capacity.

The floating regasification market is set to increase rapidly over the next decade as more countries utilize the technology. The selection of floating regasification projects over traditional onshore regasification are due to the shorter lead times , flexibility in duration of use (e.g., temporary use before the start-up of an onshore terminal, or for periods of peak demand), and lower costs for small to medium sized volumes.[66] FSRU/ SRV vessels are commonly leased under medium and long term contracts, thus shifting a substantial portion of regasification terminal capital expenses to an operating expense, which reduces the amount of financing needed for the initial capital investment and lowers project risk.

Since deployment of the first FSRU in the UK in 2007, at least ten more floating regasification vessels have commenced operations across the globe, including Indonesia, Dubai, Israel, Argentina, Brazil, and the US. There

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[62] Douglas Westwood’s “World FLNG Market Forecast 2014-2020”.as referenced in “Big spending boosts FLNG market”, January 14, 2014, *Petroleum Economist*

[63] Koh, Quintella, October 11, 2012. “Rise of Chinese Shipyards in the FPSO Industry.” *Rigzone*, http://www.rigzone.com/news/oil_gas/a/121299/Rise_of_Chinese_Shipyards_in_the_FPSO_Industry

[64] January 6, 2014. Petronet wants Indian shipyards geared to build LNG vessels”, *The Hindu Business Line*, http://www.thehindubusinessline.com/industry-and-economy/logistics/petronet-wants-indian-shipyards-geared-to-build-lng-vessels/article5545857.ece

[65] Teesside GasPort, project webpage: http://excelerateenergy.com/project/teesside-gasport

[66] January 4, 2013. “Floating LNG Market Rises”. *Petroleum Economist* (online version).

are at least another three floating regasification vessels under construction, and more than a dozen in planning stages.[67] Countries such as Indonesia, with both stranded gas fields and demand centers that are not connected by pipeline, are pursuing both floating regasification vessels and liquefaction vessels.

- ***Floating Liquefaction***

Floating Production Storage and Offloading (FPSO) vessels have been used by the oil industry for several years, but the first LNG FPSO is scheduled for start-up in 2015. The key drivers of the floating liquefaction sector are the desire to monetize stranded offshore natural gas fields, the relative costs of onshore liquefaction terminals, and relocation flexibility. A modular design allows the FLNG vessel to be built in lower cost environments then towed to location. Positioning the liquefaction facility offshore at the field location reduces the requirements for costly port infrastructure and long pipelines to shore which would be required for an onshore development.

As a result of recent Australian LNG project cost and schedule overruns associated largely with skilled labor shortages, FPSO are being considered as a potential lower-cost solution for future development of Australian natural gas. Costs for FPSO are estimated to be in the range of $2,500-3,000 mtpa while recent onshore Australian LNG has been at $4,000 mtpa.[68] As the technology matures, FPSO developers are aiming for costs between $700 and $900 mtpa.[69]

FPSO interest is not limited to Australian waters. Particularly in Southeast Asia where high crude oil prices have improved the economic viability of offshore natural gas fields in remote, underdeveloped areas, the costs of infrastructure and skilled workforce development in addition to the engineering challenges of extensive deepsea pipelines and sometimes challenging politics are driving interest in FPSO. The decreases in onshore development that are implied by FLNG development are causing governments to reassess their development strategies, some of which were previously pinned to the development of traditional oil and gas jobs.[70]

Shell is developing two LNG FPSO design concepts, a large-scale generic facility with a capacity of around 3.6 mtpa and a smaller facility with a capacity of around 2 mtpa. The first larger unit, the Prelude, is under construction by South Korea's Samsung Heavy and France's Technip, and is scheduled for deployment in 2017 on Australia's North West Shelf. Other possible locations for vessels of both sizes include Egypt, West or East Africa, Indonesia, Iraq, and Venezuela.[71]

The Malaysian 's national oil and gas company, Petronas, has begun construction of a 1.2 mtpa LNG FPSO for its Kanowit Kumang project, to be installed offshore Malaysia in 2016. While final investment decisions (FIDs) have been made for the Prelude and Kanowit Kumang projects, there are at least 10 other LNG FPSO projects across the globe that are being planned, with FIDs yet to be made. If all 12 planned LNG FPSO projects are developed

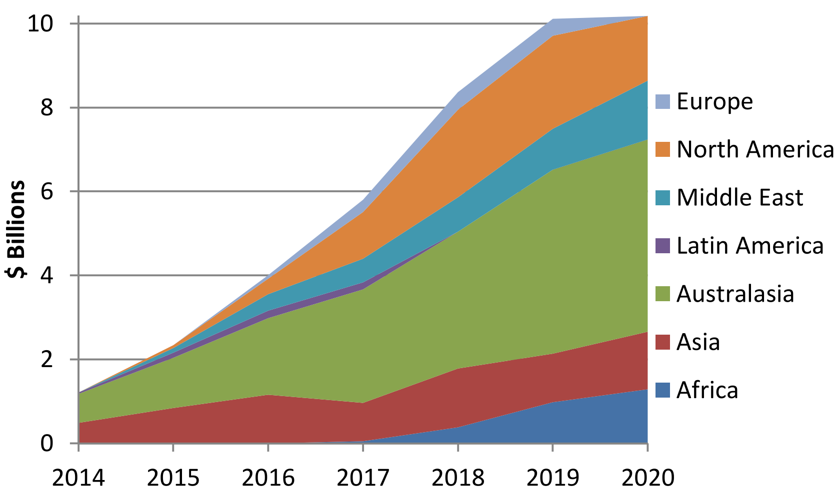
[67] Based on Gas Strategies LNG Data Service, December 17, 2013.
[68] May 13, 2013. "Australia's Cost Problem". *Petroleum Economist*. (online version).
[69] Douglas Westwood's "World FLNG Market Forecast 2014-2020".as referenced in "Big spending boosts FLNG market", January 14, 2014, Petroleum Economist
[70] Hunt, Luke, May 14, 2013. "Floating LNG Upsets Oil and Gas Outlook in Australia, Southeast Asia". *The Diplomat*. http://thediplomat.com/2013/05/floating-lng-upsets-oil-and-gas-outlook-in-australia-southeast-asia/
[71] January 4, 2013. "Floating LNG Market Rises". *Petroleum Economist* (online version).

as planned, they will represent an additional 26.4 mtpa of global LNG capacity with start-ups from 2016 to 2019.[72]

An integrated business model is being applied for the Prelude and Kanowit projects, but roughly half of the planned LNG FPSO projects are proposed to use leased facilities, similar to the leasing structure that has become common for FSRUs. Like oil FPSO projects, the proposed leased LNG FPSO projects tend to have lower capacities than the owned facilities, with leased facilities used primarily by smaller national oil companies (NOCs) and independent operators.[73]

Overall, the rate of increase in LNG FPSO use will likely depend on the problems and successes of Petronas' PFLNG 1 and Shell's Prelude. Barring an excessive magnitude of unexpected issues, Figure 18 displays projected capital expenditures for LNG FPSOs through 2020. The greatest investment is projected to be in Australia (where Prelude will be based), where the next wave of LNG development is expected to include offshore facilities to reduce the effects of workforce tightening and associated cost increases by shifting substantial construction costs to international shipyards.[74] Continual increases in investments through 2020 are also projected in the Middle East and Africa, which may be due in part to the security advantages that are inherent in offshore development.

Figure 18 Projected Annual Capital Expenditures for Floating Liquefaction Facilities by Region, 2014 to 2020.



Source: Douglas Westwood's "World FLNG Market Forecast 2014-2020".as referenced in "Big spending boosts FLNG market", January 14, 2014, Petroleum Economist

2.2.4 New LNG Capacity

Key uncertainties for the development of new LNG capacity include North American gas prices (and associated prices of exported LNG), the pace of LNG demand growth, and the ability of project sponsors to secure contracts

[72] Haney, Michael, R., April 18, 2013. "Offshore Industry Review. 2013", Offshore Power and Rotating Equipment Conference. p. 33. http://www.gaselectricpartnership.com/OffshoreDouglasWestwood.pdf
[73] Ibid.
[74] "Floating LNG Upsets Oil and Gas Outlook in Australia, Southeast Asia", 2013.

from buyers.[75] The capital intensive nature of LNG development requires that a significant portion of planned production capacity have secured buyers in order to obtain financing and assure investors a minimum return on investment. While the magnitude of investor return generally decreases with the greater competition that accompanies increases in market liquidity, the need for long term contracts to secure financing is likely to remain. As such, the high capital costs of LNG development are likely to cause a continued need for long-term contracts to secure financing.

Political stability is another factor that affects the competitiveness of LNG from different regions. Political instability can delay planned projects indefinitely or increase the costs of projects that go forward. Significant shifts in the fiscal balance of some projects have occurred as a result of strife and changes in government. Strife increases security costs and may cause the need for repairs. Changes in government may increase taxes, national ownership requirements, and for upstream operations, royalties. Recent examples include the revolution in Egypt, Libya, Yemen, and kidnappings in Algeria and Nigeria. Equally troubling, although less LNG-relevant, are nationalization of energy assets in Venezuela and Argentina, and the excessive intrusion of Russian politics into energy-related business decisions within Russia and its neighboring counties. In general, Australia, Canada, the US, and Qatar rank relatively highly in terms of stability based on the Fund for Peace's 2013 Failed States Index, while Russia and African countries are viewed as less stable.[76] Financing from international sources is generally not available in regions that are perceived to be politically unstable (although national-level financing may be available).

Overall, while the cost competitiveness of different regions with respect to LNG development will be an important driver of where development occurs, it will not be the only driver, even with the assumption that regional risks are monetized for investment considerations. Buyers and sellers are increasingly interested in portfolio development with diverse supplies of LNG to better assure a minimum level of supply despite unknowable future events.

Further discussion of new LNG capacity is provided below for projects under construction, and potential new development in the US and Canadian, Russia, and Africa.

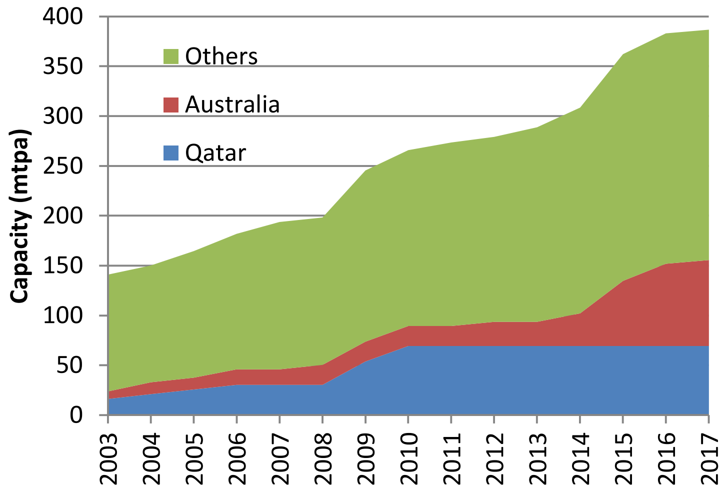
- ***Under Construction Capacity***

As new LNG projects are considered, existing, in development, and planned LNG capacity are evaluated against future demand. Total global liquefaction capacity is shown in Figure 19 along with Qatari and Australian capacity. Figure 19 displays data beginning in 2003 to show the early Qatari ramp up to their peak year of additions (i.e., 23.4 mtpa in 2009). The peak year for Australian additions is 2015, with 32.4 mtpa scheduled for start-up. As scheduled, in 2017 Qatari and Australian capacity will comprise 20% (77 mtpa) and 22% (86 mtpa) of global capacity, respectively.

Figure 19 Global LNG Capacity Based on Operational and Under Construction Projects*

[75] November 22, 2013. "NEB: Canadian LNG exports possible in 2019", *Oil & Gas Journal*. http://www.ogj.com/articles/2013/11/neb-canadian-lng-exports-possible-in-2019.html

[76] Hoekstra, Gordon, November 12, 2013. "LNG: B.C. well-located, but costs here are high". *The Calgary Herald*. http://www.calgaryherald.com/news/well+located+costs+here+high/9147326/story.html



** Start-up year for under construction projects is the media-reported start-up year, i.e., no adjustments have been made for delays beyond the last reported schedule adjustment.*

Source: Leidos, Inc, based on Gas Strategies LNG Data Service, December 17, 2013.

- ### *US and Canadian Development*

LNG shipments, enabled by the newly developed shale gas resources in the US, are expected to begin in the middle of this decade. A recent Wood Mackenzie report suggests that most of the US LNG exports will likely go to Asia to take advantage of higher prices, although spare volumes may be shipped to the more liquid European markets in the UK and the Netherlands. Europe-based companies such as Centrica and GDF Suez have signed contracts to buy US LNG, but these volumes may be resold across the globe to regions of greatest demand. Beyond 2020, Wood Mackenzie projects that over 10 mmtpa of US LNG will be shipped to Europe with high volatility in monthly volumes as a result of global LNG dynamics. [77]

As of the end of 2013, the Canadian National Energy Board (NEB) approved four LNG export projects, all of which are located on the Pacific coast.[78] The NEB projects that Canadian LNG exports will begin in 2019, with feedgas supplied by production increases from shale and other tight formations.[79] The NEB forecast assumes west coast LNG exports of 1 bcfd in 2019, rising to 2 and 3 bcfd in 2021 and 2023, respectively. Complicating issues for Canadian LNG development include the need to construct hundreds of miles of pipeline from interior reservoirs to ports, and additional hurdles associated with gaining and retaining the support of First Nations for pipelines and production.[80]

Morgan Stanley estimates that the US may become the third largest LNG supplier by the end of the decade. The competitiveness of new US LNG capacity will be improved by the Panama Canal expansion scheduled for completion in 2015. The expanded canal will allow US Gulf Coast LNG production to be shipped to Asian

[77] November 12, 2013, "U.S. to ship 10-15 bcm LNG a year to Europe from 2020 -Wood Mac", *Reuters*, http://www.reuters.com/article/2013/11/12/europe-lng-woodmac-idUSL5N0IX4GS20131112

[78]December 17, 2013." Canadian regulator approves LNG exports from four projects," *Reuters*, http://in.reuters.com/article/2013/12/16/canada-lng-exports-idINL2N0JV1XW20131216

[79] November 22, 2013. "NEB: Canadian LNG exports possible in 2019", *Oil & Gas Journal*, . http://www.ogj.com/articles/2013/11/neb-canadian-lng-exports-possible-in-2019.html

[80] Hoekstra, Gordon, April 16, 2014. "First Nations eyeing LNG cash windfall, Environmental concerns must be addressed before they will give access to land, official says," *The Vancouver Sun*, http://www.vancouversun.com/technology/First+Nations+eyeing+cash+windfall/9746165/story.html

markets. Shipbuilders have already begun developing deals for long-term charters to construct LNG carriers that can traverse the expanded canal.[81] Most LNG is transported under long term contracts in which shipping arrangements are made well in advance, which reduces wait times for passage through the Panama Canal. The extent of longer wait times for spot cargos will determine the frequency with which the Panama Canal is used for these shipments.

Brownfield LNG development opportunities in the US may provide highly competitive production in the world market as a result of the lower capital costs associated with brownfield facilities and associated higher potential internal rates of return.[82] However, the competitiveness of new US LNG capacity will likely be reduced as brownfield opportunities are exploited, leaving only greenfield development for further capacity additions. Nevertheless, the significance of this may depend on the extent to which the US limits LNG exports to curb domestic energy costs.

- ***Russian Development***

Russia entered the Pacific LNG market in 2009 with the commercial start-up of Sakhalin. More than half its output is sold to Japan, and deliveries have also been made to South Korea, India, China, and Kuwait. The project represents the entry of Russian gas into the Pacific market. There are plans for expansion of Sakhalin (i.e., the addition of two more trains). Several LNG projects are planned for the Arctic Ocean basin including two on the Barents Sea (Pechora and Shtokman) one on the adjacent Karsk Sea (Yamal Peninsula). If constructed, these projects will use the Northern Sea Route (NSR), a shipping lane defined by the Russian legislature that connects the Atlantic and Pacific Oceans by a route along the Russian Arctic coast. Continual declines in the duration and extent of icepack on this route are enabling a rapid growth in NSR shipping traffic. In 2012, the LNG carrier Ob River became the first LNGC to transit the Northern Sea Route.[83] These three developments (Sakhalin, the NSR, and Arctic Ocean LNG capacity) are focused on serving buyers in the Pacific Rim, and as such will shift the Russian gas market from a Europe-centric market to a global market. This market diversification may improve price parity between gas market basins as the buyers of Russian gas will seek similar prices. While it is the US that is expected to tweak the LNG market in the near-term, Russian gas may have the broadest and most enduring impact on the development of the world gas market through its robust LNG and pipeline capacity expansions.

- ***African Development***

Although Africa represents 20% of the world's land mass, in 2011 there were only 1,000 wells drilled onshore and offshore in Africa, compared with 18,500 drilled in Alberta, Canada in 2005. The low rate of drilling is not due to a lack of favorable geological formations for fossil fuels. Indeed, drilling rates are expected to increase

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[81] Bockmann, Michelle W., February 1, 2013. "Reshaping Panama Canal Trade Means Boom in U.S. Gas to Asia." *Bloomberg Sustainability*, http://www.bloomberg.com/news/2013-02-01/reshaping-panama-canal-trade-means-boom-in-u-s-gas-flow-to-asia.html
[82] It should be noted that there are also significant brownfield opportunities in Asia, primarily in the current form of expansion of operational LNG project (i.e., Indonesia, Malaysia), and later in the expansion of currently under development projects (i.e., Australia and PNG)
[83] October 31, 2012. "LNG Tanker Ob River Prepares for Northern Sea Route", *World Maritime News*, http://worldmaritimenews.com/archives/68204/

recognizing that all but three of the continent's 54 countries have planned or ongoing oil and gas exploration.[84, 85] In many African countries however, the initial rate of development will be slow as infrastructure and regulatory and legal instruments for an oil and gas industry are developed. The most optimistic plans for production from the 2010 gas finds off the coasts of Mozambique and Tanzania are commercial availability in 2018 with a floating liquefaction facility, but start-up in the 2020 to 2025 timeframe may be more realistic.

Investors in African gas development are varied, but Chinese investment has been noted as particularly large, with the exchange of hefty infrastructure projects for access to resources. China has been Africa's largest trading partner since 2009,[86] with Chinese annual trade and investment in Africa estimated to be around $200 billion.[87] Chinese national companies seek to secure gas imports to help meet their growing demand which is projected to outpace production developments in China until well past 2040.[88]

2.2.5 Policy Drivers of Supply

While many types of policy can affect natural gas supply, two policy issues are particularly relevant in today's natural gas markets. The first is environmental policies and associated regulations that may affect the development of unconventional natural gas supplies, and the second is policies that limit the export of natural gas. Each of these is briefly discussed below.

- ***Environmental Policy and Unconventional Gas Development***

The potential implications of environmental policies on the development of unconventional gas resources is being felt in the US and Canada, where concerns of water contamination due to fracking practices have been raised.[89] Further, a recent internal government document in British Columbia (which has several proposed natural gas liquefaction plants) warns that LNG development may double GHG emissions from the province at a time when it is struggling to meet legislated targets to dramatically reduce GHG.[90]

In other countries that have yet to develop shale gas, current policy and the effects of local concerns on future policy are evolving. The UK has decided to support shale gas exploration; France has a total ban citing ecological concerns; and Germany is reviewing its position on shale. In Eastern Europe, strong local opposition to the

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[84] Countries for which no planned or ongoing exploration was found are: Burkina Faso, Lesotho and Swaziland.
[85] Brown, E. David, 2013. *Africa's Booming Oil and Natural Gas Exploration and Production: National Security Implications for the United States and China*. US Amy War College Press, Publication 1186, http://www.strategicstudiesinstitute.army.mil/pubs/display.cfm?pubID=1186
[86] Dujuan, Chen, 2013. "African Advantage", Global Times, October 13, 2013, as viewed at http://www.globaltimes.cn/content/817523.shtml
[87] Guest, Pete, 2014. "Japan Takes on China Far from Home – In Africa." Newsweek, March 26, 2014. As viewed at: http://www.newsweek.com/japan-takes-china-far-home-ethiopia-238362
[88] *Africa's Booming Oil and Natural Gas Exploration and Production,"* 2013.
[89] Fischetti, Mark, August 20, 2013. "Groundwater Contamination May End the Gas-Fracking Boom," *Scientific American*, http://www.scientificamerican.com/article/groundwater-contamination-may-end-the-gas-fracking-boom/
[90] Hunter, Justine, November 13, 2013. "LNG threatens B.C.'s greenhouse-gas goals, internal notes warn." *The Globe and Mail*, http://www.theglobeandmail.com/news/british-columbia/lng-threatens-provinces-greenhouse-gas-goals-internal-notes-warn/article15405912/

development of shale resources has been expressed, but it is not certain that the promise of greater energy security, lower fuel costs, and more jobs will ultimately outweigh these concerns.[91]

- ***Export Restrictions***

Some nations with natural gas reserves have current policies that limit the exportation of natural gas, and others have ongoing discussions or calls for export limits. Common drivers for export limits include the desire to extend national reserves to preserve energy security further into the future (e.g., the Israeli energy policy),[92] and the maintenance of acceptable domestic natural gas prices (e.g., calls for export limits in Australia).[93] In the US, the Natural Gas Act of 1938, as amended, requires authorization from the US Department of Energy for the export of natural gas to countries that do not have a free trade agreement with the US. Export authorizations are to be granted unless it is found that the proposed exports "will not be consistent with the public interest." Factors for consideration include economic, energy security, and environmental impacts.[94] Policy limits on natural exports have the general effect of lowering domestic prices, which in turn will reduce investment in the development of new natural gas production projects. Imposed export limits effectively reduce the supply of natural gas to the global market, and create a national market that is distinct from the global market.

2.3 Demand-Side Drivers

The key driver of natural gas demand is economic growth. Continued strong Asian economic performance is likely to perpetuate growth in this region as a primary driver of global natural gas demand, as discussed in Section 2.3.1. However, national-level changes in natural gas demand in Asia and across the globe can be substantially influenced by national policies that both directly and indirectly affect natural gas demand. Topics under current policy development that may affect natural gas demand include greenhouse gas policy and energy policies to encourage or discourage use of particular types of energy. These are addressed in Section 2.3.2 with particular attention to Asian nuclear power, European and Asian renewable energy, and Chinese coal policy.

2.3.1 Asian-Pacific Economic Growth

Economic growth generally correlates with energy use, as is seen in Figure 20. As a result, projected economic growth in the Asian Pacific countries indicates growth in energy demand. The Asian-Pacific region is a large and

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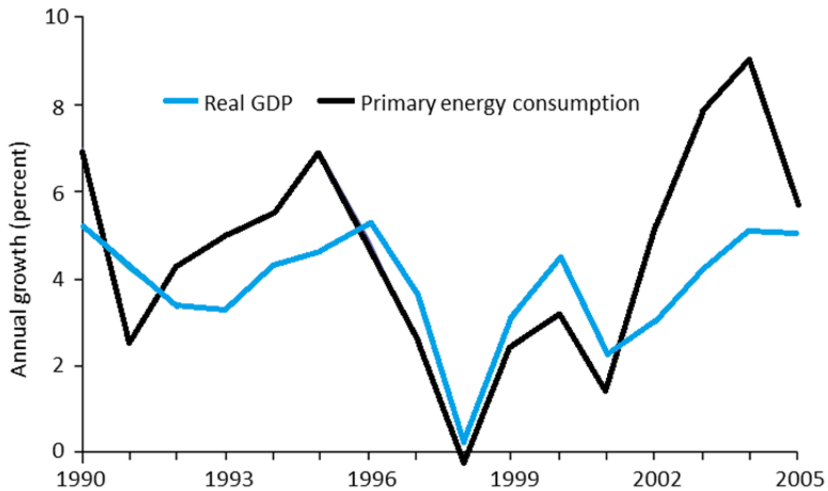
[91] October 27, 2013, "Romanian farmers choose subsistence over shale gas," *Reuters*, http://www.reuters.cexport policy," om/article/2013/10/27/romania-chevron-idUSL5N0IC26Q20131027
[92] Udasin, Sharon, "Governemnt approves natural gas The Jerusalem Post, June 23, 2013. As viewed at http://www.jpost.com/Diplomacy-and-Politics/Government-approves-export-of-40-percent-of-Israels-gas-reserves-317464
[93] Jericho, Greg, "Why increasing coal seam gas supply will result in higher gas prices", The Guardian, March 20, 2014. As viewed at http://www.theguardian.com/business/grogonomics/2014/mar/21/why-increasing-coal-seam-gas-supply-will-result-in-higher-gas-prices
[94] US Department of Energy web page, "LNG Export Study", as viewed at http://energy.gov/fe/services/natural-gas-regulation/lng-export-study

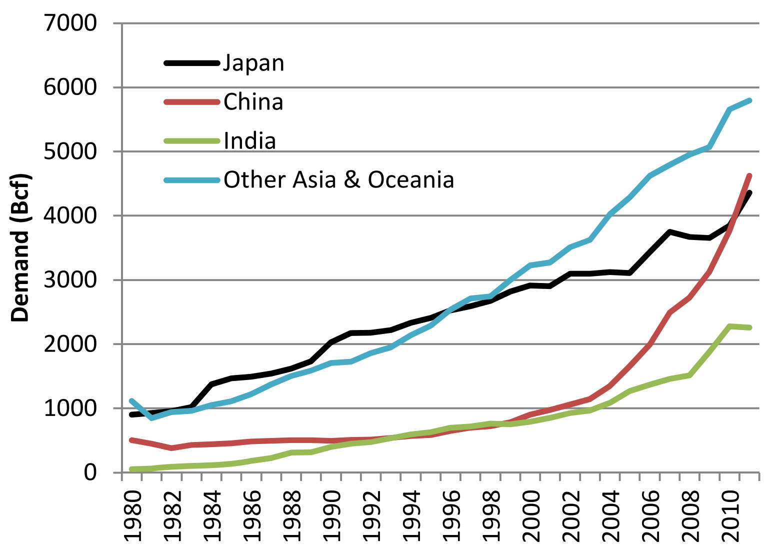
growing consumer of natural gas (Figure 21~~Figure 21~~), importing gas from the Middle East and other regions. As such, their participation in the global markets affects the availability and cost of energy across the globe.[95]

Figure 20 Primary Energy Consumption and Real GDP in the Asia-Pacific Region: Annual Growth Rates, 1990 to 2005.



Source: IMF (2006); BP (2006); OECD/IEA (2006); FACTS Global Energy (2006), as cited in: Wu, Kang, Brown, Jeffrey G, and Siddiqi, Toufig, A., "Chapter 1, The Asian-Pacific Energy Dilemma", In *Asia's Energy Future: Regional Dynamics and Global Implications*, The East-West Center, Kang Wu and Fereidun Fesharaki (eds.), 2007.

Figure 21 Asian Natural Gas Demand, 1980 to 2011



Source: Leidos Inc., based on EIA

China is currently ranked as the second largest economy in the world based on GDP, followed by Japan, while India is ranked tenth. The combined ASEAN countries would rank as the ninth largest economy in the world.[96] Relatedly, Shell Oil Company estimates that energy demand across Asia will double over the next 50 years, with China and India the main growth centers for at least the next two decades, not only "transforming Asia's energy

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[95] Wu, Kang, Brown, Jeffrey G, and Siddiqi, Toufig, A., "Chapter 1, The Asian-Pacific Energy Dilemma", In *Asia's Energy Future: Regional Dynamics and Global Implications*, The East-West Center, Kang Wu and Fereidun Fesharaki (eds.), 2007, http://www.eastwestcenter.org/fileadmin/stored/pdfs/asiaenergyfuture04energydilemma.pdf

[96] August 17, 2012. "ASEAN Pipeline Dream Falls Flat". *Energy Tribune*. http://www.energytribune.com/11727/asean-pipeline-dream-falls-flat

system, but also the world's."[97][98] Growth in natural gas demand has been greatest in China, which surpassed Japanese demand in 2010 (Figure 21~~Figure 21~~). The collective increase in demand from Asian countries beyond Japan, China, and India exceeds the demand from any one of these three countries, and has been growing rapidly, albeit slightly slower than China.

Favorable prices of LNG encouraged initial demand growth in emerging Asian markets. China has been rapidly increasing LNG imports since 2009 following the opening of new commercial receiving terminals with long-term delivery contracts from Indonesia, Malaysia, and Qatar. A tightening in global LNG supplies in recent years has been attributed to increased demand from Asian economies as well as nuclear reactor shutdowns in both Japan and South Korea. Resulting LNG price increases have in turn dampened Asian demand, particularly in India.

The rapid paced economic growth in China, in particular, has been quite remarkable. However, the unique history of China[99] may preclude growth rates of similar magnitude and duration in developing regions that have yet to experience booms in growth (i.e., Africa).

Projections of economic growth in China, India, and the ASEAN countries remain strong, although these projections have recently been moderated as a result of several potential impediments. Potential causes of a slowdown in Asia include: in China, reduced growth due to a banking crises and real estate bubble; in India and Thailand, a decreased value of their currency are considered signs of weakness; and other ASEAN countries are showing signs of both currency issues and growth slowdowns. Considering the projected high demand for natural gas from this region, recent economic events bear attention to the rate of growth in the Asia-Pacific region.

2.3.2 Policy Drivers of Demand

Future natural gas demand is significantly affected by energy and environmental policies. Policies that create stricter control of emissions can encourage a shift from other fossil fuels to natural gas, which is considered the cleanest of the fossil fuels, as well as a shift from natural gas and from the other fossil fuels to nuclear and renewable energy sources. The net result of these policies can be an increase or a decrease in natural gas consumption.[100] Policies that are directed toward nuclear power and renewable energy have had particular impact on natural gas demand in recent years. The effects of some recent policies on natural gas are discussed below with respect to Asian nuclear power, European renewable energy, Asian renewable energy, and Chinese coal policy in response to environmental concerns.

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[97] October 16, 2013, "Breakneck Asian economic growth redrawing global energy landscape," *The Japan Times*, http://www.japantimes.co.jp/news/2013/10/16/business/breakneck-asian-economic-growth-redrawing-global-energy-landscape/

[98] Nugroho, Hanan, December 30, 2013. "One island, three LNG exporting countries," *The Jakarta Post*, http://www.thejakartapost.com/news/2013/12/30/one-island-three-lng-exporting-countries.html

[99] Hu, Zuliu, and Mohsin S. Khan, June 1997. "Why is China Growing So Fast?" International Monetary Fund, *Economic Issues No. 8*, http://www.imf.org/external/pubs/ft/issues8/index.htm

[100] "Evolving Roles of LNG and Asian Economies in the Global Natural Gas Markets", p.3, 2011.

- ***Asian Nuclear Power***

In Japan, a dramatic shift away from nuclear power has increased LNG demand. The massive earthquake and tsunami in March 2011 caused three nuclear reactor meltdowns and hydrogen explosions, and undermined public confidence in the safety of nuclear power. As a result, all Japanese nuclear plants were eventually shut down either as a result of damage or for maintenance and safety checks. Prior to the disaster, nuclear power met about 30% of Japan's electric demand, versus only 2% in 2012.[101]

Reduced Japanese nuclear power generation is expected to continue, with the Institute of Energy Economics Japan stating that only four nuclear reactors may return to operation by March 2015. In the meantime, 1.6 GW of new coal-fueled electric generation capacity is being developed in addition to 5.2 GW of new natural gas-fueled power generation, the latter of which are expected to be supplied with LNG under long-term contracts. The new capacity will both offset recent increases in oil for power generation, and will increase the reserve margin on the Japanese power grid. [102]

Approximately 29% of South Korea's electric generation is from nuclear power. South Korea has reduced its plans for nuclear power from 41% of its electric generation in 2035 to only 29%. A new energy plan states the desire to avoid either an "excessive expansion" or a "sudden collapse" of the country's nuclear capacity. The plan change was apparently stimulated by the shutdown of several reactors for investigations following reported document falsifications. [103] The power generation gap from shutdown of nuclear facilities, which occurred during the summer peak period for power demand, was filled by an increase in LNG imports.

While the reductions in Japanese and South Korean nuclear power are significant for the regional natural gas market, the policies driving these shifts are not shared by other nations in the region. China is currently building 30 nuclear power plants and India seven, while dozens more are planned across the region, which will help temper natural gas demand in these countries.[104]

The continuation of policies that reduce nuclear power use will likely affect the growth in LNG demand from the traditional LNG buyers in Japan and South Korea. However, the interest these countries have shown in diversification of energy supplies suggests not only reliance on acquiring LNG from multiple regions, but demand for other fuel types as well. In contrast, policies in emerging Asian countries may be more likely to encourage the use of nuclear power.

[101] November 15, 2013, "LNG, coal use hits record amid zero nuclear power," *The Japan Times*, http://www.japantimes.co.jp/news/2013/11/15/business/lng-coal-use-hits-record-amid-zero-nuclear-power/
[102] Tsukimori, Osamu and Reebekah Kebede, October 15, 2013. "Japan on gas, coal power building spree to fill nuclear void." *Reuters*, http://www.reuters.com/article/2013/10/16/us-japan-power-outlook-idUSBRE99F02A20131016
[103] December 10, 2013. "Nuclear to remain Korean mainstay," *World Nuclear News*, http://www.world-nuclear-news.org/NP-Nuclear-to-remain-Korean-mainstay-1012137.html
[104] October 16, 2013, "Breakneck Asian economic growth redrawing global energy landscape," *The Japan Times*, http://www.japantimes.co.jp/news/2013/10/16/business/breakneck-asian-economic-growth-redrawing-global-energy-landscape/

- ***European Renewable Energy***

The EU has recently boosted their GHG target from a 32% to a 40% reduction in 2030 compared to 1990. To support GHG goals, a renewable energy target of 27% was also set for 2030. A substantial portion of the renewable energy goal is expected to be achieved through increasing renewable energy use for electric generation from the current levels of 21% to 45% in 2030. The targets are set for the region as a whole, and may include differences among the member states that are balanced through the emissions trading system.[105]

In the early 2000's, it was projected that the power sector in continental Europe would be the primary driver of strong growth in natural gas demand, resulting in an increasing proportion of electric generation fueled by natural gas. With this understanding, commitments made for future purchases of natural gas were under long-term take-or-pay contracts, and infrastructure investments were made to enable the contractual commitments. However, much of the projected growth in power sector demand did not occur as a result of the economic downturn as well as higher oil (and associated natural gas) prices, in conjunction with larger than anticipated growth in renewable and nuclear generating capacity.[106]

As an example, in Spain in 2010, a significant increase in industrial and residential natural gas demand was virtually offset by a reduction in natural gas demand for power-generation due to increased use of nuclear, hydro, and renewable power.[107] This growth was stimulated by a government policy to substantially increase renewable energy use and provision of investment subsidies to promote this policy (although subsidies have since been cut).[108]

- ***Asian Renewable Energy***

Increases in Asian renewable energy are being promoted by policies that are being driven by both energy security/diversification and environmental concerns. In countries such as India, with projections for strong energy demand growth and technically challenging unconventional gas reserves, energy security and diversification appear to be the stronger policy driver. The renewable source that has the greatest potential to displace natural gas demand in India is hydroelectric power. Future growth in this renewable source is indicated by the recent approval of three new hydro projects totaling 2,020 MW by the Indian Cabinet on Investment.[109]

Other Asian countries have large, relatively accessible natural gas reserves that are being produced, but they are still seeking to reduce reliance on natural gas through increases in renewable energy. Brunei is one such

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[105] January 23, 2014. "EU targets 40% reduction in GHG emissions by 2030," *Global Energy Intelligence*, http://www.enerdata.net/enerdatauk/press-and-publication/energy-news-001/eu-targets-40-reduction-ghg-emissions-2030_25257.html

[106] Hughes, Peter, 2011. "Europe's Evolving Gas Market: Future Direction and Implications for Asia". Pacific Energy Summit, February 21-23, 2011, Jakarta, Indonesia. http://www.nbr.org/downloads/pdfs/eta/PES_2011_Hughes.pdf

[107] Hashimoto, Hiroshi, 2011. "Evolving Roles of LNG and Asian Economies in the Global Natural Gas Markets". 2011 Pacific Energy Summit, February 21-23, 2011, in Jakarta, Indonesia.

[108] July 20, 2013. "Renewable energy in Spain, The cost del sol," *The Economist*, http://www.economist.com/news/business/21582018-sustainable-energy-meets-unsustainable-costs-cost-del-sol

[109] January 22, 2014. "Cabinet committee clears three hydrel [hydro] projects," *India Power Sector.com*, http://indianpowersector.com/home/

example.[110] On a per capita basis, Brunei is the world's seventh largest electricity consumer, and has one of the largest per capita carbon footprints outside the Gulf region. Most of Brunei's electricity is generated from natural gas. The only renewable facility is a solar plant that represents around 1% of installed capacity. The Sultanate has set a target of 10% of electricity production from renewable sources by 2035, and government incentives under consideration target further solar development,[111] despite substantial hydroelectric potential.[112]

The ASEAN, of which Brunei is a member, has committed to 15% renewable energy by 2015. Thailand's Alternative Energy Development Plan 2011-21 targets 25% renewable energy and 2000 MW of solar power capacity. Several of the Thai solar projects have come on-line in, bringing its installed solar capacity to well over 100 MW. In Malaysia, a US-based firm has recently announced that it is investing $39 million to build two solar plants with a combined capacity of 15 MW, while the Malay government is aiming for 1250 MW of renewable power capacity by 2020.[113]

Indonesia, which is one of the world's largest gas producers (see Section 1, Figure 3), has set a target for 25% of its total energy demand to be met with renewable sources for 2015.[114] Currently, renewables supply only 5 to 6% of Indonesia's energy mix. Geothermal is expected to contribute the bulk of new renewable generation.[115]

It has been reported that Asian investments in both wind and solar have been increasing, and with respect to overall use of renewables, an Asia Development Bank study suggests that renewable sources will account for 7.1% of Asian energy production by 2035 compared to just 1.9% in 2010.[116]

Hydroelectric power accounted for 5% of Asian primary energy consumption in 2005, with over half of this located in China. Hydroelectric generation capacity has increased more quickly in Asia and the Pacific than in any other region, representing 20% of total world hydro power in 1995 and 25% in 2005. The majority of additional hydroelectric generation is expected in China. [117]

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[110] Nugroho, Hanan, December 30, 2013. "One island, three LNG exporting Countries," *The Jakarta Post*, http://www.thejakartapost.com/news/2013/12/30/one-island-three-lng-exporting-countries.html
[111] November 3, 2013. "Brunei Darussalam sharpens focus on renewable energy," *Oxford Business Press*, http://www.oxfordbusinessgroup.com/economic_updates/brunei-darussalam-sharpens-focus-renewable-energy
[112] Yakib, Asnawi, December 7, 2007. "Temburong source of hydroelectricity," *The Brunei Times*, http://www.bt.com.bn/home_news/2007/12/10/temburong_source_of_hydroelectricity
[113] "Brunei Darussalam sharpens focus on renewable energy," 2013.
[114] Directorate General of New Renewable Energy and Energy Conservation, Ministry of Energy and Mineral Resources, "Vision 25/25", Energy Efficiency and Conservation Clearing House Indonesia (EECCHI)", as view 1/20/14 at http://www.energyefficiencyindonesia.info/energy/indonesia/vision25
[115] Gipe, Paul, July 20, 2012. "Indonesia Launches "Crash" Renewables Program: Boosts Geothermal FITs," *Renewable Energy World.com*, http://www.renewableenergyworld.com/rea/news/article/2012/07/indonesia-launches-crash-renewables-program-boosts-geothermal-fits
[116] "Breakneck Asian economic growth redrawing global energy landscape," 2013.
[117] Wu, Kang, Brown, Jeffrey G, and Siddiqi, Toufig, A., "Chapter 1, The Asian-Pacific Energy Dilemma", In *Asia's Energy Future: Regional Dynamics and Global Implications*, The East-West Center, Kang Wu and Fereidun Fesharaki (eds.), 2007, http://www.eastwestcenter.org/fileadmin/stored/pdfs/asiaenergyfuture04energydilemma.pdf

While the extent to which these and other Asian renewable energy targets are met is far from certain, a trend in renewable energy growth will reduce Asian growth in regional natural gas demand, freeing up additional natural gas supply for trade in other regions.

- ***China Coal Use and Environmental Concerns***

Air quality concerns in China have been receiving increased attention amid growing domestic protests over both coal mining and coal power plants. Chinese coal consumption is currently about three times higher than it was in 2000, and in 2009 coal was used to meet roughly 70% of China's total energy demand, followed by oil (19%), hydro (6%), natural gas (4%), nuclear (1%), and renewable energy (0.3%). Significant cross-border effects of Chinese coal emissions are claimed in Japan and South Korea, as well as across the Pacific Ocean, in California.

The closing of higher polluting and higher energy use companies in addition to the shut-down of hundreds of smaller, less efficient coal mines has improved air quality in some regions while increasing natural gas demand. In March 2013, Beijing authorities released a plan to replace all coal-fired equipment with cleaner burning natural gas in its core areas by 2015. The plan includes replacement of four major coal power plants with natural gas power plants, a ban of coal-fired winter heating, and more use of clean energy. Other major cities in China are expected to implement similar plans. Implementation of these policies will further increase growing demand for natural gas in China.[118]

[118] September 27, 2012, Beijing Plans To Kick Its Coal Addiction," Energy Tribune, http://www.energytribune.com/20156/beijing-plans-to-kick-its-coal-addiction-3

2.4 Market Evolution

The global natural gas market is evolving with respect to both market structure and organization. This evolution is being pushed by the LNG market. Industry analyst Andy Brogan, Global Oil and Gas Transactions leader at Ernst and Young, has stated that the global LNG market will change dramatically over the next decade because buyers will have a greater choice of supplies.[119]

The natural gas market structure varies among counties with respect to the number of suppliers (or sellers) of natural gas. Traditionally, national natural gas markets have regulated monopolistic structures with no competition. However, this is gradually changing as countries such as the US, Canada, the UK, and Australia have substantially deregulated their natural gas market, opening the door for gas-on-gas, competitive pricing. This downstream market liberalization appears to be having repercussions upstream.

Competition-based market structures encourage the development of common places where natural gas can be traded (i.e., hubs), which facilitate comparison of prices from competitive sellers and provide natural pricing benchmarks. Hub development in Europe and Asia is described below in Section 2.4.1.

At the level of international trades, the natural gas market has traditionally been organized as bilateral trades between buyers and sellers who self-searched for their trade partners. In recent years, over-the-counter (OTC) international trades have increased with growth in LNG spot market trades. OTC trades are managed by LNG suppliers, and increasingly by brokers. While there are currently no central mechanisms or clearing houses for international LNG trading, there are proposals for this development as described in Section 2.4.2. Finally, market globalization is discussed in Section 2.4.3.

Ongoing developments in international natural gas market structure (i.e., hub development) and organization (i.e., OTC and cleared exchanges) may facilitate further growth in the number of LNG suppliers and buyers, increase market competition and liquidity, and reduce market risks. These developments will encourage greater efficiencies and lower global average natural gas prices. In theory, this will make natural gas more competitive compared to other energy options, thereby increasing natural gas demand.

2.4.1 Hub Development

Hubs may be places of physical exchange, as is Henry Hub, or may be places of only virtual (contractual) exchanges, such as the UK's National Balancing Point (NBP). While hubs can develop under any pricing system, they are particularly helpful to provide a benchmark price for competitive trades. As discussed in Section 1.3.1, most international exchanges of natural gas in Europe and Asia use oil-indexed pricings. However, as the natural gas market matures, the use of gas-on-gas based pricing is viewed by many as likely to increase, particularly as energy markets are more liberalized through deregulation.[120,121]

In Europe and Asia, areas of high demand, natural gas is increasingly becoming available from a greater variety of sources shipped by both pipeline and LNG carriers. As the diversification of sources increase, there is also an

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[119] Robertson, Helen, November 15, 2013, "LNG suppliers must price flexibly," *Petroleum Economist,* (online version).
[120] "Europe's Evolving Gas Market: Future Direction and Implications for Asia", 2011
[121] "Evolving Roles of LNG and Asian Economies in the Global Natural Gas Markets", 2011.

increase in the chances for pricing disparities at hubs where trades occur under both gas-on-gas based and oil-indexed pricing systems. With sufficient magnitude and duration of pricing disparities, and with increased use of natural gas by the power sector (in which oil is rapidly becoming an insignificant energy source),[122] demand regions with traditional oil-indexed natural gas prices are likely to continue pressuring suppliers to delink gas and oil prices. However, from a project investment standpoint, the ongoing discussions regarding delinking natural gas prices from oil provide an additional layer of price uncertainty. As stated by Roger Bounds, global head of LNG at Shell, "to avoid a tight market we need more confidence in long-term pricing behavior to enable investment".[123]

The discussion below focuses on the development of hubs in Europe and Asia. These two regions, in the medium-term and long-term, are viewed as most likely to present the conditions that will facilitate future shifts to greater gas volumes traded under gas-on-gas based prices at centralized trading hubs.

▪ *European Hubs*

The number of suppliers of LNG to Europe is increasing as the continent looks to diversify the sources of its natural gas supply, and reduce dependence on pipeline natural gas from Russia.[124] As such, nine European countries (including Turkey) currently operate a total of 28 regasification terminals, and at least nine additional countries are either currently constructing, or have plans to construct one or more LNG import terminals.[125]

A recent extensive analysis of natural gas spot prices at eight major European hubs suggests that despite substantial variation in liquidity among the hubs (i.e., the proportion of short -term trades), the correlation among hub prices has been strong since 2007 and the strength of the correlation appears to be increasing with time.[126] The author of the study concludes that while there have been some periods of diversion for certain European hubs, in general, the European gas market is largely integrated as indicated by common price movements among the eight major hubs, which are listed below.

1. National Balancing Point (NBP), UK
2. Title Transfer Facility (TTF), The Netherlands
3. Zeebrugge Hub (ZEE), Belgium
4. Central European Gas Hub (CEGH), Austria
5. Gaspool (GSL), Germany
6. National Connect Germany (NCG), Germany
7. Points d'Echange de Gaz (PEG), France
8. Punto di Scambio Virtuale (PSV), Italy

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[122] *Golden Rules for a Golden Age of Gas*, p. 87, 2012.
[123] October 2, 2013. "Reality bites Asian LNG buyers", *Petroleum Economist*, (online version).
[124] While percentage vary from country to country, on average Russia supplies roughly a quarter of European gas demand. In 2006 and 2009 Russia cut off gas to the Ukraine over price disputes. The events eroded European confidence in the dependability of this supplier.
[125] Based on the Gas Strategies LNG Data Service, December 17, 2013.
[126] Petrovich, Beatrice, October 2013. "European Gas Hubs: How strong is price correlation?", *Oxford Institute for Energy Studie,*. http://www.oxfordenergy.org/wpcms/wp-content/uploads/2013/10/NG-79.pdf

Hubs in continental Europe use both gas-on-gas based pricing and oil indexed pricing. As previously shown in Figure 9, while a greater proportion of trades are priced using oil indexation, gas-on-gas pricing has been growing. Since 2009, there has been significant pressure to increase volumes traded under gas-on-gas based pricing. This push is attributed to an increase in LNG supply availability beginning in 2009. Recession-driven weakened natural gas demand, lower than expected US imports of LNG, and the commercial start-up of multiple new large LNG projects resulted in a surplus of natural gas. The greater availability of LNG allowed the development of a significant disparity between the gas-on-gas based and oil-indexed prices across the globe. However, the disparity was more obvious in Europe due to ongoing market reforms.

During 2009, European spot-market LNG prices fell significantly below long-term, oil-indexed contract prices for pipeline natural gas.[127] This occurred during the early stages of natural gas market liberalization in Germany, where retail customers had just been given the opportunity to purchase a portion of their gas from alternative suppliers that offered spot prices that were half of the oil indexed prices. The price disparities led customers to demand more competitive pricing.[128] While the magnitude of the pricing disparity was reduced in 2010 as the result of a severe winter, strengthening of the European economy, and Asian demand for surplus LNG, the customers have retained a heightened awareness of pricing alternatives.

As a result of customer demands in 2009, European wholesalers purchased more gas on the spot market, which inevitably led to their volumes under long-term take-or-pay contracts falling below minimum levels. Consequently, they were forced to renegotiate pricing terms of their long-term pipeline natural gas contracts with Russia and Norway. [129] A number of supplier concessions were made in 2010, key of which is the application of spot market pricing to a portion of the volumes supplied under existing long-term contracts. While contractual details are confidential, Gazprom announced that 15% of supplied volumes would be offered at gas-on-gas prices for three years, with similar or higher proportions offered at gas-on-gas prices by Norwegian suppliers. [130]

The magnitude and constancy of gas-on-gas price discounts to oil-indexed prices may be a primary determinant of whether continental Europe maintains two pricing systems or shifts to full gas-on-gas pricing. With the continuation of two pricing systems, the NBP (which operates with only gas-on-gas based pricings) will likely maintain the greatest volume of spot market trades in Europe. The next largest hub in terms of spot volumes is the Title Transfer Facility (TTF) in the Netherlands, which in 2011 traded roughly a third of the volume that is exchanged at NBP, while other European hubs traded less than a third of the spot volumes exchanged at TTF.

Spot prices at continental European hubs correlate better with the TTF than with NBP, suggesting the possibility that the TTF may become the benchmark for continental Europe.[131] The developing central role of the

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[127] "Europe's Evolving Gas Market: Future Direction and Implications for Asia", 2011.
[128] Ibid.
[129] Ibid.
[130] Ibid.
[131] "European Gas Hubs: How strong is price correlation?", 2013.

Netherlands for the continental European gas market is further suggested by its recent growth in volume of LNG sales and storage capacity,[132] and recent provision of spot market gas to other continental countries.[133]

- ***Asian Hubs***

It has been suggested that European gas market liberalization may stimulate similar changes in the Asian markets, [134] thereby increasing market liquidity, which may increase the pace of Asian hub development. As described above, hub development, in turn, could facilitate market liberalization. Thus, hub development and expansion of the prevalence of gas-on-gas based pricing can feed each other. The degree of success Europeans have in the introduction of gas-on-gas based pricing in their contracts with Gazprom may substantially influence the success China could have in negotiating an introduction of gas-on-gas based pricings in its contracts with Gazprom. A successful pricing change for China could then lead other countries in the region to negotiate their price terms. [135]

Asian buyers have called for the development of multiple hubs throughout the region as a means to increase LNG liquidity,[136] which may allow "a genuine regional spot market to emerge rather than the fitful one that is prone to spikes."[137] As demand continues to grow in Southeast Asia along with a natural gas network that includes pipelines, liquefaction plants, and receiving terminals, there is growing potential for this region to provide an alternative benchmark for contract gas pricing.[138] Singapore is viewed by many as best-placed to become the center for Asian LNG trading. [139]

Singapore's first LNG terminal opened in 2013 as part of its plan to become a hub, and several expansions are planned. The hub plan includes storage, reload, and cool-down services. LNG industry players that have already established LNG OTC trading desks in Singapore have expressed interest in the LNG terminal's capacity for storage and reloading. To further hub development, the Government of Singapore has introduced a 5% concessionary corporate tax rate for LNG trading income.[140] Perhaps the greatest obstacle to overcome for establishment of a hub in Singapore is the deregulation of cross-border trade. The Singapore market is too small by itself to provide a price benchmark, but a reasonable-sized market could emerge through its pipeline connections to Malaysia and Indonesia -- both LNG suppliers, and both with subsidized gas consumption. While efforts towards market liberalization are underway, the related development of a transparent pricing

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[132] Farey, Ben, September 15, 2011. "Netherlands Gas Trade Beats Peers as LNG Arrives: Energy Markets," *Bloomberg News*, http://www.bloomberg.com/news/2011-09-15/gas-trading-in-netherlands-outpaces-peers-as-lng-arrives-energy-markets.html

[133] Hong, Chou Hui, January 6, 2014. "Spain Set to Receive LNG Spot Cargo From Netherlands at Huelva." *Business Week*, http://www.businessweek.com/news/2014-01-06/spain-set-to-receive-lng-spot-cargo-from-netherlands-at-huelva

[134] "Europe's Evolving Gas Market: Future Direction and Implications for Asia", 2011.

[135] "Europe's Evolving Gas Market: Future Direction and Implications for Asia", 2011.

[136] Robertson, Helen, April 19, 2013. "Asian buyers push for LNG trading hubs to curb import prices," *Petroleum Economist.*

[137], May 13, 2013, "The new world order," *Petroleum Economist*, (online version).

[138] "Evolving Roles of LNG and Asian Economies in the Global Natural Gas Markets", 2011.

[139] Koh, Ann, and Pratish Narayanan, October 30, 2013, "Singapore Challenged as LNG Hub by Trading Delay: Southeast Asia," *Bloomberg News*, http://www.bloomberg.com/news/2013-10-30/singapore-plans-two-new-lng-import-licenses-as-pipe-cap-lifted.html

[140] Singapore LNG Corporation (SLNG) website, http://www.slng.com.sg/business-the-future.html

mechanism in addition to third-party access to pipelines is estimated to take closer to a decade.[141] It should be noted that establishment of other hubs (i.e., NBP and Henry Hub) have taken a decade or more.

As another contender for an Asian hub, China has launched two small, traded markets, but tight capital controls and the dominance of state-owned oil companies present major challenges and there has been little interest from financial parties. However, a key component for hub development is the ability to conduct trades that allow demand centers access to both LNG and pipeline gas that is connected to multiple suppliers. A robust pipeline infrastructure may be easier to establish in a single country (i.e., China) than among the ASEAN for hub development in Singapore. Japan is also far from developing a trading hub. The majority of Japan's imports are under long-term, point-to-point contracts, and there is limited third-party access to LNG import terminals. [142]

2.4.2 Market Organizational Development

Increased liquidity in the international LNG market that has been seen in recent years has been accompanied by a growing number of trading models including open tenders for multiple and single cargo sales, brokered trades, cargoes sold in chains, and speculative trading positions taken up by non-traditional participants including investment banks. These OTC contracts are becoming more streamlined as these types of trade become more common, but a clearinghouse for exchanges has not developed.[143]

Osaka Gas President Hiroshi Ozaki has said that the current OTC system for spot LNG trading (i.e., without a structured trading and clearance system) might be sufficient going forward if there is increased flexibility in re-destinations.[144] This suggests the need for either a loosening of long-term contract terms which typically do not allow changes in delivery locations, or a decreased proportion of purchases under long-term contracts. Sixty-two percent of Japan's projected demand in 2020 (95 MT), will be supplied through existing term contracts,[145] which leaves as much as 38% of the demand to be met through spot trades.

Futures markets provide an essential mechanism for mitigating price risks and enabling a greater proportion of purchases under a gas-on-gas pricing system. While futures markets exist for both Henry Hub and NBP, there is not yet an active natural gas futures market in Asia. However, the Tokyo Commodity Exchange (TOCOM) is developing the world's first exchange for LNG futures. Japan's trade ministry said the LNG futures exchange is targeted to open by March 2015 to help cut its import costs by breaking its reliance on oil-linked pricing. The futures market will enable buyers to hedge risks with orders placed on TOCOM.[146] The LNG futures will be for

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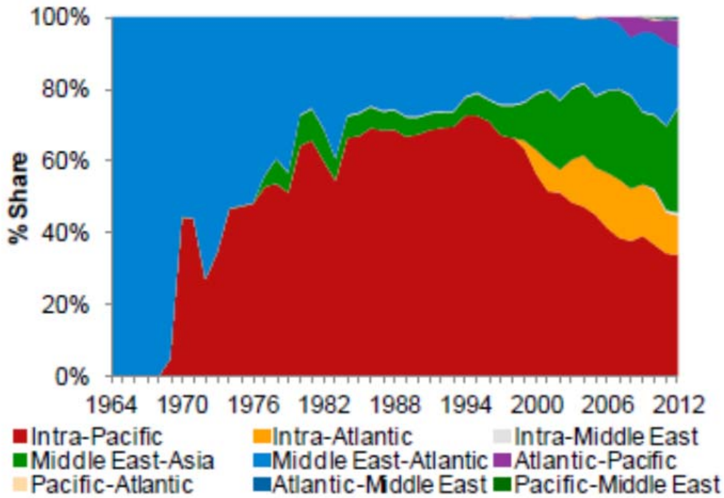
[141] Evans, Damon, October 2, 2013, "LNG traders line up for Asian hub," *Petroleum Economist*, (online version).
[142] Evans, Damon, October 2, 2013, "LNG traders line up for Asian hub," *Petroleum Economist*, (online version).
[143] Norton Rose Fulbright, March 2012. "LNG spot cargo trading - Market trends and challenges", http://www.nortonrosefulbright.com/knowledge/publications/59905/lng-spot-cargo-trading-market-trends-and-challenges
[144] Daiss, Tim, November 22, 2014, "Japan's LNG Price Tag Not Likely to Change in Near Term," *Energy Tribune*, http://www.energytribune.com/79795/japans-lng-price-tag-not-likely-to-change-in-near-term
[145] December 27, 2013. "Japan's Tepco says submits new business plan to boost LNG imports," Platts, http://www.platts.com/latest-news/natural-gas/tokyo/japans-tepco-says-submits-new-business-plan-to-27775061
[146] November 28, 2013, "Tocom plans LNG futures exchange with help from CME – Nikkei," *Reuters*, http://www.reuters.com/article/2013/11/28/tokyocommodityexchange-cme-lng-idUSL4N0JD2QX20131128

cash settlement in dollars and based on an index price for spot LNG cargoes delivered to Japan.[147] The exchange will be run by Japan OTC Exchange, Inc., a joint venture of TOCOM and Ginga Energy Japan.

2.4.3 Globalization of LNG Trade

The growth of the LNG spot market (see Section 1.4.1, Figure 9) is providing a means for balancing of LNG supply and demand between regions. Nonetheless, continued price disparities suggest that global market liquidity is not sufficient to fully arbitrage between Atlantic and Pacific basins, and as discussed in Section 3.2, the lack of price convergence is attributed to limitations in market access. However, increasing globalization of the natural gas market is indicated by inter-regional trades, and more specifically, inter-oceanic LNG trades between the Atlantic and Pacific basins (Figure 22). Increasing intra-Atlantic, Pacific-Middle East, and Atlantic-Pacific flows have occurred over the last decade while previously dominant intra-Pacific flows have steadily declined.

Figure 22 Intra- and Inter-Basin LNG Trade Flows, 1964 to 2012



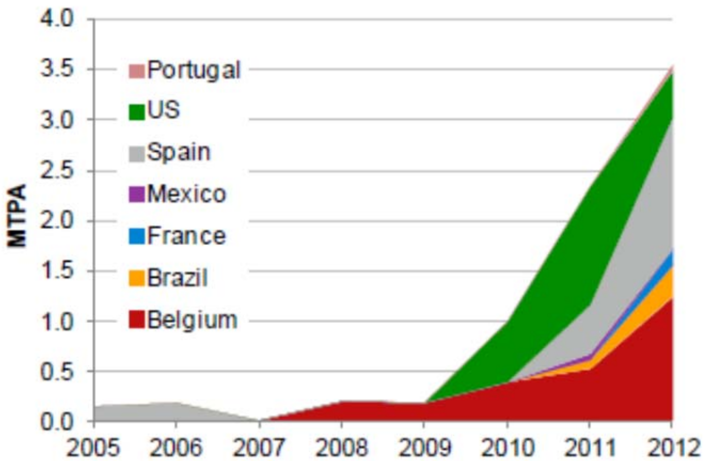
Sources: As shown in IGU 2013, based on Cedigaz, GIIGNL, Waterborne LNG Reports, US DOE, and PFC Energy Global LNG Service.

The appearance of Atlantic-Pacific LNG trades in 2005 marks the early development of LNG re-exports (Figure 9). The largest reported volumes of re-export LNG occurred in 2012, when a strong LNG demand in South America and weaker demand in Europe created arbitrage opportunities in Argentina and Brazil.[148]

[147] Okada, Yuji, and Chou Hui Hong, March 29, 2013, "Japan to Start World's First LNG Futures Within Two Years," *Bloomberg Sustainability*, http://www.bloomberg.com/news/2013-03-29/japan-plans-world-s-first-lng-futures-contracts-within-two-years.html

[148] International Gas Union (IGU), 2013, *World LNG Report - 2013 Edition*, pp 9-10, http://www.igu.org/gas-knowhow/publications/igu-publications/IGU_world_LNG_report_2013.pdf

Figure 23 Global LNG Re-Exports by Country, 2005 to 2012



Sources: As shown in IGU 2013, based on Cedigaz, GIIGNL, Waterborne LNG Reports, US DOE, and PFC Energy Global LNG Service.

The growth in LNG re-selling and in spot trade volumes in general is accompanied by an increasing variety of trading models including open tenders for multiple and single cargo sales, brokered trades, cargoes sold in chains, and speculative trading positions taken up by non-traditional participants including investment banks.[149]

Some of the hurdles that need to be overcome for further globalization of the LNG market are: the removal of limitations in market access imposed by political and regulatory constraints, including removal of import and export restrictions and deregulation of downstream markets; reduction of the physical limitations in market access due to under-developed pipeline infrastructure and LNG import capabilities; and technical issues related to the standardization of LNG carrier loading equipment and LNG sampling and analysis, and mitigation of potential issues related to sequential storage of different qualities of LNG. [150]

2.5 Interrelationships of Natural Gas Market Drivers

The general categories of natural gas market drivers: drivers of supply, demand, and market evolution, are inter-related with feedback from each category to the other categories (see Figure 15). Increases in supply promote increases in demand, which encourages evolution towards a more mature global natural gas market with the requisite structure (i.e., many supply and demand locations) and organization (i.e., competitive, transparent trading mechanisms). In the reverse order, market evolution in terms of the encouragement of more gas-on-gas competition tends to increase market efficiencies which lowers prices and facilitates demand increases -- in time, this stimulates more supply.

In general, political and governmental policies constrain the world market from developing in a manner that is consistent with neoclassical economic theory, in which natural gas prices are an outcome of the balance of global supply and demand. Indeed, without policy constraints, market evolution would arguably be a minimal determinant of the global natural gas market because the market structure and organization would naturally

[149] Norton Rose Fulbright, March 2012. "LNG spot cargo trading - Market trends and challenges", http://www.nortonrosefulbright.com/knowledge/publications/59905/lng-spot-cargo-trading-market-trends-and-challenges
[150] "LNG spot cargo trading - Market trends and challenges", 2012.

develop to support global supply and demand, and the drivers shown in Figure 15 would only need to be those for supply and demand. Overall, no single driver of the global natural gas market can be confidently projected as a dominant driver. While the promise of unconventional development has the potential to be a single dominate driver that could substantially affect other drivers, the realization of unconventional natural gas development in terms of both timing and magnitude is in itself, uncertain.

Another key challenge in projecting the future of the global natural gas market is the uncertain timing and direction of changes in policies that affect natural gas supply, demand, and market evolution. Uncertainty in future policies essentially relegates all natural gas forecasts as scenarios based on a set of policy assumptions in addition to the underlying assumptions that drive supply and demand. The following section explores the potential of several economic theories that may assist in recognizing and projecting possible market trends on both global and regional levels.

3 Theory

Economic theories and models are often used to both help explain historical and current market behavior, and to project future markets characteristics (i.e., supply/demand, and price). The first section below discusses global natural gas market behavior with respect to the "Law of One Price", with address of why the outcome predicted by this economic law has not occurred, and what barriers need removal for one-price to be realized. Recognizing that the global market is comprised of a collection of submarkets, some of which have very different characteristics, the second section below discusses different types of models (i.e., the Dominant Firm Model and Game Theory Models) that may be more appropriate for particular submarkets.

3.1 The Law of One Price

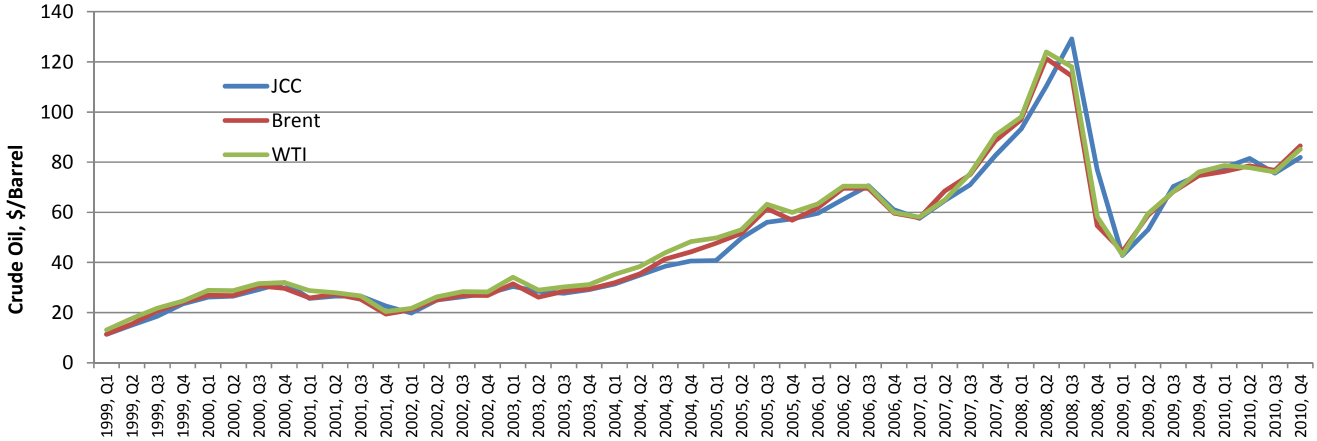
The economic Law of One Price states that over time, the prices of a commodity in a competitive market will converge to a single price, assuming there are no transport costs or economic barriers between supply and demand locations. Implicit in this law is the ability to non-discriminately trade between locations, allowing arbitrage to reduce price differences between locations to the differences in transportation costs. The oil market provides an excellent example of price convergence. As seen in Figure 24, oil prices move together among locations with price differences that are primarily due to differences in transportation costs. In contrast, natural gas prices exhibit a lack of convergence (Figure 25), in which price movements in one region do not necessarily follow price movements in other regions. This begs the questions of why global natural gas prices have not converged, and what changes are needed for price convergence.

The key factors that have reduced the ability of arbitrage to enable the convergence of global natural gas prices are: the presence of different dominant pricing systems in different regional markets, and limitations on access to the arbitrage opportunities that must be exploited for price convergence. Access to arbitrage opportunities is limited by the prevalence of restrictive terms in long term contracts; supply chain limitations; and national policies that limit imports and exports.

Both historically and currently, the high investment risk associated with the high capital costs of certain natural gas supply chain segments has been mitigated through long term contracts with destination restrictions that legally bind both parties to price and quantity, and in many cases, effectively prevent opportunistic behavior (i.e., the possibility of arbitrage). Further, the pricing mechanism of oil indexation has, and continues to be incorporated in long term contracts in a manner that reduces the LNG supplier exposure to natural gas market-based price risks. As such, the barriers to nondiscriminatory market access posed by multiple pricing systems and restrictive long term contracts have origins in the capital-intensiveness of this industry, which for certain supply chain segments is substantially more capital intensive than in the oil industry.

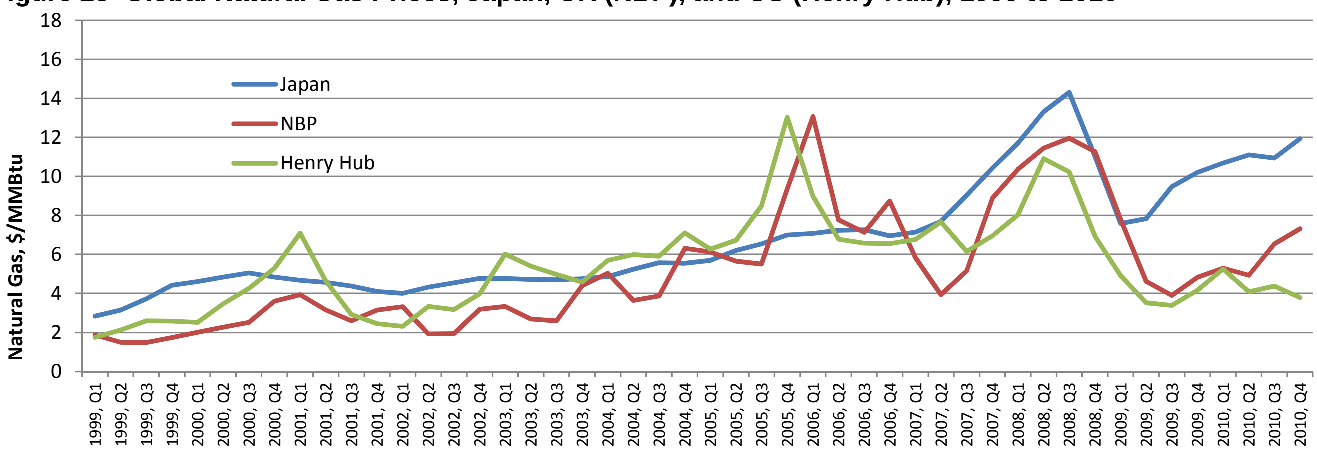
In recent years, the number of natural gas market players has increased and spot market volumes have grown. This increases the opportunities for new trading partnerships, and enables a more liquid market with reduced risks associated with any particular trade arrangement. These shifts notwithstanding, investors still face substantial risks, and as a result, the well-established risk mitigating strategies employed in long term contracts and oil indexed pricing systems have been slow to change.

Figure 24 Global Crude Oil Prices, Japan (JCC), Europe (Brent), and US (WTI), 1999 to 2010



Source: EIA, Gas Strategies

Figure 25 Global Natural Gas Prices, Japan, UK (NBP), and US (Henry Hub), 1999 to 2010



Source: EIA, Gas Strategies

The challenges and barriers to global price convergence and the achievement of one price (*sans* transportation) in the forms of pricing systems, contract restrictions, supply chain limitations, and national policies are further discussed below.

3.1.1 Pricing Systems

The presence of different dominant pricing systems in different markets is a key factor that is contributing to divergence of natural gas prices and challenging the development of an equilibrium with "one-price" (*sans* transportation). Natural gas market liberalization in North America and the United Kingdom has led to the dominance of gas-on-gas market based pricing system in these regions, with price movement largely determined by shifts in natural gas supply and demand.

Regions with a monopoly supplier of natural gas typically do not employ gas-on-gas pricing systems (e.g., Russia, India, China, and much of the Middle East, North Africa, and Southeast Asia). Rather, the monopoly or the government controlled monopoly set prices. Clearly, there can be no convergence among different national average prices within regions that have monopolistic pricing unless the monopoly (or its regulator) designates otherwise. However, monopolistic national market structures do not preclude the convergence of international trade prices (e.g., crude oil pricing).

For international trade of natural gas, North America and the UK have used gas-on-gas market-based prices for all their trade, conversely, in the Asian Pacific region oil-indexed prices were used for 88% of international natural gas trades in 2010.[151] Because these two pricing systems use market prices of different commodities to indicate natural gas prices, large price disparities occur when the supply and demand balances for oil and natural gas are not synchronized. In particular, a high level of divergence is expected when one commodity is in a period of tight supply and the other is in a period of relatively loose supply. Hence, greater price divergences may be expected with the use of two, largely independent pricing systems. Large price divergence among large regional markets (e.g., the Asian Pacific market and the North American market) suggests the need for large arbitrage volumes to achieve full convergence of prices.

Overall, while the presence of multiple pricing systems do not preclude price convergence in itself, it promotes price divergences which may increase the volume of natural gas needed for full arbitrage on a global scale, thereby compounding the effects of reduced access to arbitrage opportunities.

3.1.2 Long-Term Contract Terms

While different pricing systems facilitate price divergence, the lack of subsequent full convergence (*sans* transportation) through arbitrage is prevented by the common use of restrictive terms in long-term oil-indexed contracts which create traded volumes that are not affected by arbitrage. Price convergence among open markets requires the ability to move product from locations with low prices to locations with high prices. This condition is not met when large proportions of natural gas are delivered under oil-indexed, long term contracts with take-or-pay clauses and terms that restrict destinations and resale. While there is a growing trend towards relaxation of terms that limit destinations under long term contracts, particularly in the Asian Pacific market, a substantial portion of contracts still restrict destinations and resale. This both removes these trade volumes from the ability to exploit arbitrage opportunities when oil indexed prices are lower than gas-on-gas market prices, and prevents this demand from being met by other supplies when gas-on-gas market prices are lower than oil indexed prices.

The concept of an appropriate balance of long-term contracts that mitigate the supplier's commodity (gas) price risk through oil indexation is receiving substantial scrutiny. Gas-on-gas pricing has favorable consequences for market entrants that have access to inexpensive gas, and consumers benefit to the extent that gas-on-gas competition results in lower prices. However, from an investment risk perspective, increased competition through the use of gas-on-gas pricing will have the effect of squeezing the profit margins of traditional suppliers and make investments in the associated infrastructure command a higher risk premium. Higher risk premiums result in higher expected returns on investment, which would be passed on as higher commodity prices. Gas-on-gas price risk that is not sufficiently mitigated through passed-on risk premiums will cause projects to be

[151] IEA, 2013. Developing a Natural Gas Trading Hub in Asia, Obstacles and Opportunities. As viewed at http://www.iea.org/publications/freepublications/publication/name,36107,en.html

delayed until the investment environment is favorable, which for global natural gas means higher prices and greater market volatility as a result of a generally tight market.

Alternatively, buyers can avoid the passed-on risk premiums or tight supplies due to delayed capacity expansions by committing to long-term indexed contracts for a greater proportion of their demand. From the perspective of the buyer, oil indexation is a tradeoff between: higher internalization of commodity price risk with lower (but not eliminated) price volatility, and potentially lower average long-term prices with greater price volatility. In essence, some buyers may choose a higher pricing environment if it means a more stable price – this may particularly be the case when buyers represent power companies that are not operating in a fully liberalized power market.

Recent trends in long term contracts include relaxation or removal of destination restrictions in addition to the emergence of hybrid pricing schemes that designate a portion of the fixed traded volume to be indexed to oil (e.g., 80%) with the remainder priced in the gas-on-gas market. These changes in the terms of long term contracts effectively shift the distribution of investment and price risks among market players, which may be viewed as a response to the gradual increases in market liquidity. The extent to which this trend continues will largely depend on buyer acceptance of greater price volatility for potentially lower long-term average prices. Long term contracts with hybrid pricing that include set volumes under oil indexed prices and volumes under gas-on-gas prices offer a means for the gas-on-gas market to gradually expand, and allow buyers to better assess price volatility and long term average prices. With respect to the achievement of global one price (*sans* transportation), the progressive reduction in natural gas volumes that are fixed at oil indexed prices along with the ability to redirect supplies as appropriate for arbitrage opportunities should gradually allow greater global price convergence.

3.1.3 Supply Chain Limitations

There are several segments of the natural gas supply chain that are particularly relevant with respect to limiting the volume of gas that can enter a higher-price market area from a lower-price area. These are the presence of LNG import terminals, the availability of LNG shipping and production capacity, and the availability of pipeline capacity. First, regions with a single pipeline gas supplier that do not have the infrastructure to receive LNG imports are not able to have their gas prices modified through arbitrage from supplies from regions they are not connected to it by pipeline. The Baltic states of Estonia, Latvia, and Lithuania are an example of a high-priced region that has not had an import terminal capable of receiving and degasifying LNG when it is priced below the pipeline supplies received from Russia (although import capability is under development in Lithuania). Responding to an identified need for new LNG import capacity typically takes several years for financing and construction (e.g., 3 to 4 years). This precludes rapid response to increases in demand when an LNG import terminal is not present or demand exceeds an existing terminal's capacity. It should be noted that when LNG import capacity is added, it is often "over-sized" to provide ample room for peak demand periods and demand growth. As an example, in 2012, Asian LNG import terminals averaged use that was about 50% of their capacity. For newer terminals, usages of 30% and less of total capacity is not unusual.

When LNG import capacity is available, the receipt of short-term and spot trades may be limited by the global LNG carrier (LNGC) fleet. Historically, the LNGC fleet, like LNG production capacity, has been developed by securing long-term contracts for service prior to final investment decisions and the typical 2 to 3 year construction period, leaving very little shipping capacity for short term and spot market trades. In recent years, an increasing number of LNGCs have been available for short term and spot trades. As of mid-2012, 46% of the 81 LNGC under construction were not dedicated to long term projects, although some of these will likely enter into long term leases that will not allow them to provide capacity for short term and spot trades.[152] In contrast, around 30% of total LNG traded volumes in 2012 were in the short-term and spot market, the highest in over a decade of spot market growth that began with 10% of total LNG traded volumes in 2002. With LNGC life expectancies of around 30 years, and a 2012 fleet of 362 LNGCs that are predominantly operating under long-term contracts, shipping capacity remains a potential bottleneck that may limit the ability of short-term and spot market trades to access arbitrage regions during periods of peak spot trade.

Like shipping capacity, LNG production capacity has also historically been demand driven, with commencement of the 4 to 5 year construction period only after long-term purchase contracts are secured. This pattern of demand driven capacity has facilitated generally tight LNG supply, with the notable exception of 2007 to 2010 when an unexpected decline in LNG imports (i.e., to the US) gave rise to excess capacity. Similarly, the construction of new long distance natural gas pipelines is commonly demand-driven, with anchor customer contracts for long term capacity secured prior to final investment decisions. Pipeline design capacities, though, often allow for greater proportionate growth in demand than is allowed in the design of LNG production facilities, thereby providing a more elastic supply.

The relative rigidity of the natural gas supply chain, and the LNG supply chain in particular, precludes rapid response to increases in demand beyond an existing capacity. Further, the long lead time for capacity expansion increases the risk that the price differentials of today may not exist several years later, when the project begins operation. Greater risk generally sets a higher threshold for project initiation, further increasing supply chain rigidity.

The inability to rapidly increase LNG supply (or begin LNG supply when an import terminal is not present) does not preclude global natural gas price convergence and the establishment of "one price" (*sans* transportation). However, even under conditions of nondiscriminatory access and perfect competition, supply inelasticity can result in a significant lag between increases in demand (causing higher gas-on-gas prices) and subsequent increases in supply (causing lower gas-on-gas prices). This added element of price variation may contribute to greater volatility in the gas-on-gas pricing system compared to the oil indexed pricing system, which may at times further accentuate divergences in gas-on-gas prices and oil indexed prices.

3.1.4 National Policies

Perhaps the single most obvious restriction on the achievement of global natural gas price convergence is national policies that limit market access. Access limitations may be for either selling into a national market (import restrictions), or for selling from a national market (export restrictions). Import and export restrictions may be in the form of a tariff, a flat ceiling on imports or exports, or a more indirect restriction through discriminatory access to infrastructure (i.e., import or export terminals, pipelines, etc.).

[152] IEA, 2013, Developing a Natural Gas Trading Hub in Asia, p 30.

National-level export limits for natural gas, such as in the US and Canada, can promote divergence in global prices as the result of the development of surplus supply in the North American market. Under these conditions, export limits may not allow full exploitation of global arbitrage opportunities that result from the reduced regional value of natural gas. The current divergence of Henry Hub prices from the NBP is partially or potentially a result of the inability to sell US natural gas in markets beyond North America. The islanding of North America from the global market was an immediate result of the lack of North American LNG production capacity in the Lower 48. The expected lag period for developing new LNG production capacity has been extended by regulatory requirements for export licenses, which may restrict global market access through license denials. Ultimately, North American export limits that prevent access to arbitrage opportunities will contribute to higher natural gas prices in the global gas-on-gas priced market, and lower prices in the North American market to the extent allowed by regional production.

National-level limitations on the importation of natural gas may be explicitly established as a numeric limit, or implicitly established through tariffs, a concerted avoidance of LNG import terminal development, or discriminatory access to the national natural gas infrastructure. Importation limits may achieve various policy goals such as reduced dependence on international energy supplies (e.g., the US), and avoidance of fines associated with take-or-pay clauses under existing long term contracts for pipeline natural gas (e.g., Turkey prior to liberalization). Regardless of the method of access restrictions for natural gas importations, the end result is reduced competition in the national natural gas market which enables higher national prices for natural gas. At the global level, import limits restrict arbitrage opportunities. While this does not prevent convergence to "one price" with respect to international trades, it does send a market signal of lower demand from the nations that impose these restrictions.

There is general recognition that national policies that restrict access to the global market (e.g., export and import limits, discriminatory access to import terminals and pipelines, etc.) work against the development of a global natural gas market. These policies may preclude the achievement of the globally optimized efficiencies that are theorized to develop under perfect competition conditions. However, entrenched practices, shorter-term political goals, and the administrative challenges of market liberalization provide obstacles to the development of an open natural gas market with perfect competition. The relatively liberalized natural gas markets of the US and UK have taken several decades to develop, and still retain some restrictions on global market access. More recently, other nations have begun the process of market liberalization (e.g., Japan, South Korea, Malaysia, Indonesia, China, Turkey, and the European Union countries). As with the US and the UK, the pace of market liberalization is proving to be slow, but seems likely to continue through many small steps over several decades. However, there is always the possibility of rapid change due to exogenous events. For example, the nuclear disaster in Japan has presumably made policymakers in that country more receptive to policies that would reduce the cost of LNG imports.

3.1.5 Conclusion for the Achievement of One Price

Under the neoclassical economic approach, the primary challenge for the global natural gas market is the provision of nondiscriminatory market access through minimization of the barriers posed by restrictive contract terms and national policies. Thereafter, time may be needed to develop the integrated supply chain capacity to enable full arbitrage. While this can start in the presence of both oil indexation and gas-on-gas pricing systems, long-term contract pricing will ultimately need to be indexed to gas-on-gas prices for complete price convergence. The characteristics of such a market may include greater price volatility and greater investment risk as compared to the oil market. Greater price volatility would be a due to the tighter supply capacity of LNG in particular, as a result of the high capital intensiveness of this industry. In any event, a contracting system that better reflects economic fundamentals makes LNG a more competitive source of natural gas. Achievement of the resulting "one price" (*sans* transportation) is a function of the willingness to remove barriers and the time needed to allow this process to occur. Furthermore, it is a function of the contractual preferences of both suppliers and purchasers of natural gas, particularly with respect to the handling of both investment risk and commodity price risk.

3.2 Models for Submarkets

The global natural gas market is truly a collection of submarkets, some of which have very different characteristics with respect to competition and pricing systems. As such, different types of models may be more appropriate for different types of submarkets. Two basic types of models, The Dominant Firm Model and Game Theory Models, are described below along with discussion of their potential applicability to natural gas markets.

3.2.1 The Dominant Firm Model

The Dominant Firm Model (DFM) provides a tool that may offer insights about the structural and behavioral evolution of certain natural gas submarkets and the impact of these changes on competition. Submarkets of particular relevance include those in which a single firm controls significant market share and is a price setter, such as Gazprom's position in parts of continental Europe. Other submarkets in which the DFM may be helpful include those that may undergo market liberalization in a process that involves shifting a monopoly to the status of a dominant firm with fringe competition, such as may develop in countries in Southeast Asia, the Middle East, and South America.

- ***Background and Principles***

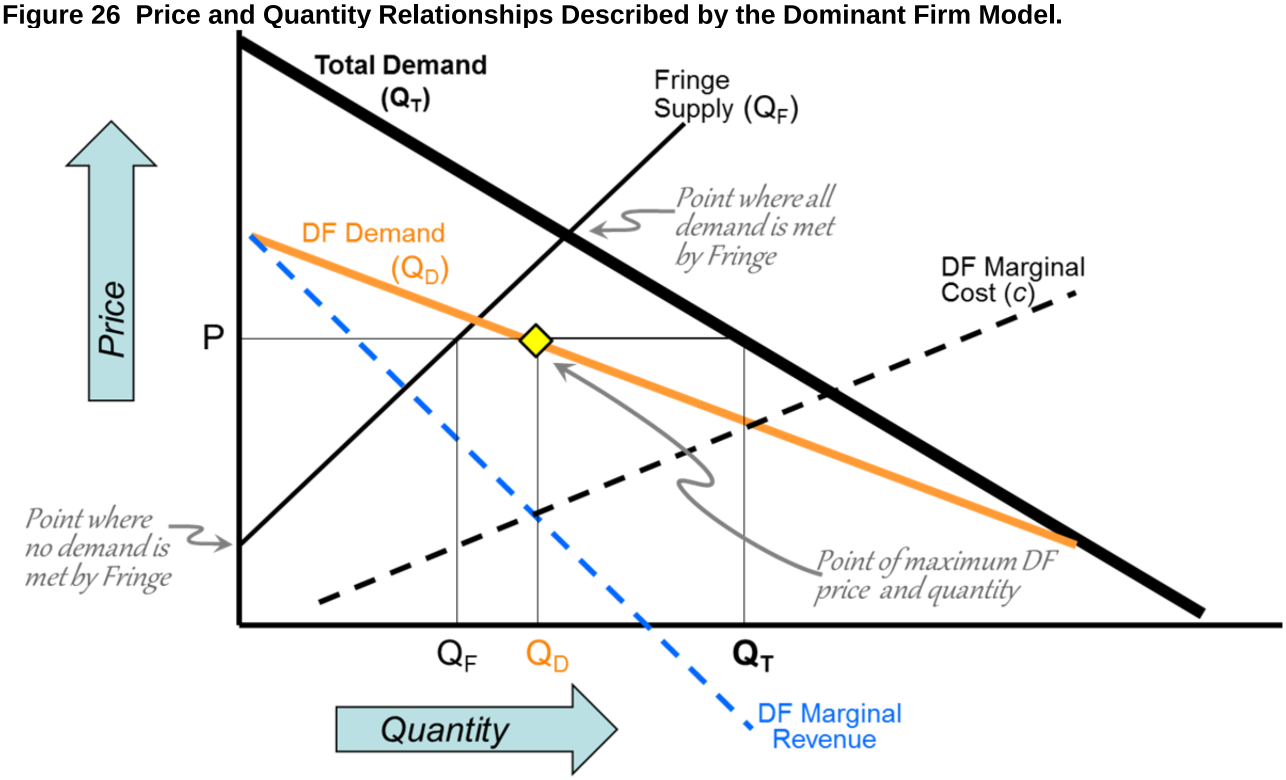
The DFM helps explain the interaction between prices set by a DF and the resulting market share for both the DF and the other market suppliers, collectively referred to as fringe firms. At the extremes of pricing behavior, the DF can set a very low price that could virtually eliminate fringe competition, but also reduces or eliminates DF profit. At the other end of the spectrum, the DF can set a very high price, yielding a high short-term profit (until the fringe can add capacity), but allowing the fringe firms to gain a larger market share.

The DFM can be used to identify pricing under DF objectives of maximizing profits. The model suggests, as shown in Figure 26~~Figure 26~~, maximization of near-term DF profit occurs at the price and quantity that correspond with the point of intersection between the DF's marginal cost and marginal revenue curves. The maximum profit price, where marginal cost equals marginal revenue, is indicated by the yellow diamond in Figure 26~~Figure 26~~. However, the price that maximizes near-term profits will allow greater fringe competition and an associated higher rate of erosion of DF market share than if the DF sets a lower price that reduces competition and may yield a greater present discounted value of profits depending on the discount rate. In either case, as further discussed below, the fringe market share, depending on cost conditions, may expand (albeit slower with a lower price). Fringe expansion can be expected to increase the elasticity of the DF's demand curve. This results in a gradual loss of dominant firm status and lower prices. One possibility is that the long-run equilibrium will approach the perfectly competitive solution.

The key principles of the DFM are:

- **Price Setting** -- When the DF uses a strategy to maximize near-term profits, it attracts broader fringe firm participation. When the DF sets a lower price, profit is reduced but its market share is greater because fewer fringe firms are able to compete. If the price is very low, the fringe may exit the market returning the DF to a monopoly but with little or no profit. In short, charging a limit price to forestall expansion by the fringe is generally not optimal.
- **Durability of DF Status** –DF pricing strategy affects how long its dominant status is maintained, but in the long term, DFM theory, as described in the section below, suggests that the fringe firms gradually erode the DF's market share until dominance is eventually lost. This result is historically supported by the loss of dominant status by firms such as Alcoa, IBM, and US Steel. [153]

Figure 26 Price and Quantity Relationships Described by the Dominant Firm Model.



- ***The Model Algorithm***

Under the DFM, it is assumed that the dominant firm's level of profit is:

[153] Dean A. Worcester, "Why 'Dominant Firms' Decline", Journal Of Political Economy, August 1957, p. 338.

$$\pi_D = PQ_D - c\ Q_D \tag{1}$$

where ***P*** is the price established by the dominant firm, Q_D is the quantity sold by the dominant firm, and ***c*** is the marginal cost. It is further assumed that the total quantity demanded (***Q***) declines as ***P*** increases, i.e. ***dP/dP < 0***, and that ***Q*** is equal to the sum of the production by the dominant firm (Q_D) and production by the competitive fringe (Q_f). When the fringe producers are price takers, and the dominant firm uses price as the decision variable, the first order condition for profit maximization is:

$$d\pi_D/_{dP} = Q_D + (P - c)\, dQ_D/_{dP} = 0 \tag{2}$$

Given $\mathbf{Q_D = Q - Q_f}$, then Equation 2 can be rewritten as:

$$Q_D + (P - c)(dQ/_{dP} - dQ_f/_{dP}) = 0$$

A little manipulation yields:

$$\frac{(P-c)}{P}\left(\frac{dQ}{dP}\ P - \frac{dQ_f}{dP}P\right) = -\,Q_D$$

Further manipulation gives:

$$\frac{(P-c)}{P}\left(\frac{dQ}{dP}\ \frac{P}{Q}Q - \frac{dQ_f}{dP}\frac{P}{Q_s}Q_s\right) = -\,Q_D$$

Which reduces to:

$$\frac{(P-c)}{P}\left(-\eta Q - \ \epsilon Q_f\right) = -\,Q_D, \tag{3}$$

Further, where

Absolute value of the price elasticity of demand is: $\eta = -\frac{dQ}{dP}\ \frac{P}{Q}$.,

Price elasticity of supply exhibited by the fringe producers is: $\epsilon = \frac{dQ_f}{dP}\frac{P}{Q_f}$,

Price cost margin is: $\frac{(P-c)}{P}$, and

Market share for the dominant firm is: $S_D = \frac{Q_D}{Q}$

Equation 3 can be rewritten to solve for the price cost margin as:

$$\frac{(P-c)}{P} = \frac{S_D}{(\eta + \epsilon(1-S_D))}\,. \tag{4}$$

This shows that the competitive fringe may mitigate the market power of the DF (as indicated by the price cost margin) depending on the DF market share (**S_D**) and the fringe's price elasticity of supply (ϵ). In particular, the greater the price elasticity of fringe supply, the greater the ability of the fringe to reduce the DF's price cost margin. This effect becomes stronger with reduced DF market share, suggesting that while the initial rate of erosion in the DF's price cost margin may be small when the DF has a large market share, the rate of erosion will increase as market share decreases.

Recognizing the relative inelasticity of both natural gas supply and demand (particularly in the short term), the loss of DF status may generally be slower in natural gas markets than in more elastic markets with lower market entry thresholds and lead times. Although, under scenarios where the fringe is represented by imported LNG, the relative over-capacity of regasification terminals (as is relatively common) helps increase the elasticity of supply, which may tend to hasten erosion of the DF's status.

Before proceeding, expression (4) represents the price-cost margin that maximizes the DF's short-run profits. Observe that the profit-maximizing margin is a function of the price elasticity, marginal cost, the elasticity of supply by the fringe, and the DF's share of the market. It is not explicitly tied to the price of another product. In this light, oil indexing can, over time, lead to a price-cost margin that is significantly different than (4). While a different price cost margin suggests a change in DF market share and less than maximum short-run profits, this does not occur when quantities are contractually constrained. Unexpected windfall profits or losses may result if the contractual quantities are inflexible and the oil based price deviates from (4).

- ***Model Applications***

Because of OPEC, the DFM has perhaps been more commonly applied to the global oil market than the natural gas market. Even though the cartel contains a set of suppliers with different interests, the members do attempt to act collectively, as if they were a single DF with respect to price setting. In contrast, the global natural gas market does not have a strong cartel. However, at the natural gas submarket level, many national markets are characterized by the presence of a dominant firm with fringe competition, and many more have a natural gas monopoly and potential for future introduction of fringe competition

The DFM may be helpful in the analysis of national-level natural gas markets in which there is currently a dominant firm with a competitive fringe. It may also be applied to national markets that are anticipated to be shifting from a monopoly to a dominant firm with fringe competition. However, the short-run relevance of the DFM to monopoly markets with fringe suppliers depends on several variables, including the extent of open access to the market, and the use of a natural gas pricing system based on natural gas supply and demand. Nevertheless, the model may have longer term reliance to the extent that fringe suppliers can erode the market power of the DF by advocating market reform that facilitates arbitrage and/or innovative solutions to the lack of open access. Interestingly, the DFM's lessons of declining market share and increased competition may be very relevant to the extent the oil indexing has led to prices that are significantly above what a profit maximizing DF would charge.

Natural gas monopoly premium pricings are seen in countries such as Lithuania, Latvia, and Estonia. As an example, Gazprom's average 2013 prices in Lithuania were $14/mcf in contrast to their average prices of just under $11/mcf in the European Union, [154, 155] where Gazprom is a DF with fringe competition rather than a

[154] P2 of: http://www.gazprom.com/f/posts/07/271326/gazprom-2013-09m-ifrs-management-report-en.pdf
[155] http://www.15min.lt/en/article/business/gazprom-2014-gas-price-forecast-for-lithuania-unchanged-from-2013-527-352506 ; http://www.naturalgaseurope.com/lithuania-gas-price-european-commission-gazprom

monopoly. The ongoing development of a regasification import terminal in Lithuania will provide fringe (LNG) firms with access to the Lithuanian market. In general, the DFM suggests that introduction of fringe competition will reduce the price of natural gas in Lithuania, such as in the European Union. However, for the purposes of identifying new Gazprom prices in Lithuania that maximize DF profit, the DFM may not provide a good model of pricing and market share if the primary pricing system applied by both Gazprom and the fringe is an oil indexed system.

Other countries with natural gas national monopolies offer subsidized domestic prices. This occurs in much of the Middle East and North Africa and in many developing nations across the globe (e.g., Indonesia, Malaysia, Thailand, India, China, Argentina, Venezuela, etc.). If these nations liberalize their natural gas markets in a manner that retains national companies while allowing nondiscriminatory market access for fringe competition, domestic natural gas prices will have to increase to a level that allows fringe profitability in absence of subsidy. This is the opposite of what occurs when a more traditional, (unsubsidized) profit-driven company losses monopoly status. To the extent that these countries use natural gas market based pricing systems and remove subsidies, the DFM may assist with projections of market share and price, in addition to aiding in the understanding of the impacts of factors such as DF market share and elasticity of supply on price cost margins.

- ***Model Limitations***

The global natural gas market has multiple suppliers and no one firm controls a significant enough share of the market to have sufficient market power to set prices at the global level. Even within the more limited LNG market, while roughly 27% of LNG capacity has recently been supplied by Qatar, the global use of Qatari-favored oil indexed pricings has been declining, suggesting that Qatar does not fit the price-setting role of a dominant firm. Hence, the DFM has much less relevance to the global natural gas market that it does to the cartel-dominated global oil market.

Within natural gas markets, application of the DFM may offer the greatest value for analysis and examination of national-level submarkets. As previously noted, key limitations to DFM applicability in national-level markets include the need for nondiscriminatory access to infrastructure for the fringe competition and removal of subsidies for national natural gas companies.

While models are generally based on simplifying assumptions, there are a couple assumptions in the DFM that are particularly tenuous with respect to natural gas markets and raise questions about the ability of the model to reflect actual market conditions. For example, at the national level for fringe competition, the model supply curve does not reflect that supply infrastructure is expanded as a stepwise function where each step requires substantial investment, lead time, and risk followed by a potentially significant increase in capacity.

A stepwise supply curve is particularly apparent when the fringe competition is in the form of LNG due to the cost and long lead-time needed to develop liquefaction (export) and regasification (import) facilities. While floating storage and regasification units (FSRU) have reduced cost and lead time for expansion of LNG import capacity, these factors remain significant given that a fleet of FSRU's available on spot has not yet developed. When a new large pipeline is built, the situation is similar to LNG capacity expansion with respect to high investment and long lead time. Whichever group adds new supply infrastructure (DF or fringe firms), their market share may or may not expand because during the long lead-time, the other group's market share may have expanded.

In general, for these types of projects, price elasticity of supply is relatively elastic after new supply capacity is added, and then becomes relatively inelastic as capacity limits are approached and supply is tight. This type of market behavior may best be represented by a stepwise supply function.

The DFM supply function is further complicated by the dissimilar short-term supply characteristics between LNG and pipeline supplies, particularly relevant during LNG on pipeline competition. Whereas LNG is supplied in carrier-size batches, on a set schedule to coincide with storage availability, pipeline gas supply is continuous and sufficiently elastic to relatively quickly react to variations in demand. This gives pipeline gas a market advantage by being able to rapidly respond to new or extraordinary demand. Further complications that impact the applicability of the DFM arise when a market is served by dissimilar entities, such as for-profit corporations and national corporations, the latter of which may place greater value on objectives other than profit.

Overall, the DFM may be helpful as a tool to explore possible outcomes in natural gas submarkets that meet the basic criteria of being served by a dominant firm with fringe competition. However, variations and complexities within these submarkets limit the confidence that can be placed in the modeled outcomes.

3.2.2 Game Theory

An introduction to game theory is provided below, followed by a description of two common game theory models for oligopolistic markets and some of the general market implications from these models. Concluding subsections discuss the possible applications and limitations of gaming models to natural gas markets.

- ***Background and Principles***

Game theory is a mathematical tool for the study of how individuals or groups interact as a result of their decisions. Game theory has been used in particular to model supplier behavior in fossil fuel markets. A variety of games have been developed to explore these interactions. Each game has rules that define the players, the information and actions available to each player at each decision point, and the outcome for each action. A mathematical expression of these elements is used to determine the set of strategies for each player. From these strategies, an equilibrium outcome, or a set of outcomes with known probability can be determined. There are two common game theory models for studying oligopolistic markets (i.e., markets with a small number of buyers and sellers), the Cournot and Bertrand models. These are both static models representing relatively short time periods but may be layered to represent longer time frames and multiple market levels.

A key distinction in the game rules set under the Cournot and Bertrand models is whether the sellers set their quantity produced (Cournot), or the product price (Bertrand). This difference often results in very different outcome predictions. Both common and distinguishing rules of basic models are shown in Figure 27. Numerous variations of the models have also been developed.

Figure 27 Common and Distinguishing Rules for the Cournot and Bertrand Models

Cournot Model Rules	Bertrand Model Rules
• Quantities set by sellers determine the market price. • Each firm's output affects the market price.	• Prices set by the sellers determine the total quantity of demand. • Customers want to buy everything at a lower price, and if firms have the same price demand is evenly split among them.
Competing firms have: • The same homogeneous and undifferentiated product. • The same cost structure. • Make their decisions independently and simultaneously.	

Additionally, both models may be applied in series with firms choosing the capacities in the first step (with the Cournot model), followed by pricing competition in the second step (with the Bertrand model). Variations of the Cournot model, in particular, have been rather commonly applied to the global oil market.

- ***Game Theory Algorithms***

The attributes of both the Cournot and Bertrand Models can be formally assessed by considering the issue of profit maximization in an industry with the inverse demand function P = f(Q) where Q is total quantity, P is the industry price, and dP/dQ < 0. Assume that there are N firms in the industry such that the total cost incurred by firm i, TC_i, equals c_iq_i where c_i is both the average variable cost and marginal cost of production for firm i and q_i is the quantity level chosen by firm i.

Firm i's level of profit can be written as

$$\boldsymbol{\pi_i = Pq_i - c_i\ q_i} \qquad \textbf{(1)}$$

The first order condition for profit maximization for firm i is

$$\boldsymbol{{d\pi_i}/{dq_i} = {dP}/{dQ}\,(1 + \lambda_i)q_i + P - c_i = 0,} \qquad \textbf{(2)}$$

where λ_i is firm i's conjectural variation, i.e. it is firm i's conjecture of the response of a one unit change of q_i on the output level chosen by the other firms in the industry.

In the Cournot model, firms make their output decisions under the presumption that the output of other firms does not change, i.e. that λ_i equals zero. Solving for the price cost margin, one obtains:

$$\frac{P - c_i}{P} = \frac{s_i}{\eta} \qquad (3)$$

Where s_i equals $\frac{q_i}{Q}$, firm's i's market share and $\eta = -\frac{dQ}{dP}\frac{P}{Q}$, the absolute value of the price elasticity of demand. In the special case where costs are uniform across firms, i.e. c_i = c for all i, then one can obtain the following result for the industry:

$$\frac{P - c}{P} = \frac{H}{\eta} \qquad (4)$$

where H equals the sum of the squared market shares (s_i) , i.e. H = $\sum_{i=1}^{N} s_i^2$. This is a measure of industry concentration known as the Herfindahl index, where N is the total number of firms. Under pure monopoly, the value of H equals 1 and thus (4) reduces to the well-known Lerner index of monopoly pricing.[156] H declines as the number of firms increases. It also declines as the firms become more equal in size. In the limit, H goes to zero and N goes to infinity which indicates that the left-hand-side of (4) converges to zero, i.e. prices converges to marginal cost, as N goes to infinity. This result is intuitively appealing in the sense that it finds that industry structure plays a very important role in the market outcome in terms of price vs. marginal cost. Unfortunately, the model has been the subject of criticism because the assumed conjectural variation is not necessarily consistent with profit maximization. For example, in the case of two firms, it is easily demonstrated that the optimal response of firm j to a change in output by firm i is not equal to zero.

The Bertrand model also takes (2) as a starting point. However, in this case firm i is presumed to make its output decision under the belief that the industry price does not change. Implicit in this presumption is the belief that total industry output does not change when q_i increases. The conjectural variation λ_i is therefore equal to minus one since the conjectured change in total industry output from a one unit increase in q_i equals 1 + λ_i. Substituting this value into (2) yields $- c_i = 0$, i.e. price equals marginal cost even under duopoly. This suggests that a duopoly is sufficient to push prices down to the same level that is expected under perfect competition. While some might be inclined to dismiss this outcome out of hand, it does underscore the importance of the perceived interdependence among the firms when modeling the oligopolistic outcome.

- ***Game Theory Application***

Under the gas-on-gas market pricing systems employed in North American and the UK, prices are set by natural gas supply and demand, and production costs set the price floor. Because of the structure of these markets in terms of the number and size distribution of producers, game theory may offer few insights beyond the competitive model. However, the Cournot model and variations thereof may have applications in the less integrated and less dynamic hubs (e.g., South Europe) that have only a few LNG suppliers. Within a smaller, oligopolistic gas-on-gas market, suppliers can have the greatest influence on market prices under stressed conditions (e.g., extreme weather events, supply disruptions, etc.). During these periods, suppliers can manage the timing and quantity of supplies, gamed in a manner that can allow higher prices than under conditions of perfect competition.

The emerging LNG spot market may also be considered an oligopoly with a gas-on-gas pricing system in which gaming may be used to set the timing and quantity of supply, particularly in terms of the development of new production or shipping capacity. The Cournot model may also aid in exploration of LNG spot market pricing when market power is implemented through control of production and storage.

Game theory can also be applied to the issue of investment. Gkonis and Psaraftis (2007) consider the hypothetical case of two LNG ship-owners who are considering ordering new vessels with the knowledge that a total of two slots are available in the shipyard. Their choice is to order now or wait until there is less market

[156] Lerner, A. P. (1934). "The Concept of Monopoly and the Measurement of Monopoly Power". *The Review of Economic Studies* **1** (3): 157–175.

uncertainty. The game rules also state an additional value if both ship-owners choose to wait. [157] This game is a variant of the well-known prisoner's dilemma game[158] but Gkonis and Psaraftis refer to the game as a "Panic Equilibrium" The normal form of the game is presented below:

Table 1 The "Panic Equilibrium" Investment Game

Pay Outs		Ship-Owner 2	
		Invest Now	Wait
Ship-Owner 1	Invest Now	\$250, \$250	\$500, 0
	Wait	0, \$500	\$300, \$300

Source: Gkonis and Psaraftis (2007, p 8)

In this hypothetical case, joint payoffs are maximized, with each firm earning \$300, when both firms wait before adding capacity. This optimum is not an equilibrium in the sense that each party has the incentive to order now if the other waits. For example, firm one will earn \$500 if it invests now when firm two waits. The equilibrium solution is when each party invests now to avoid the "panic" equilibrium of rushing to place an order after waiting. The equilibrium of each party investing now is suboptimal for the group but is nevertheless consistent with rational behavior on the part of each firm. Given the magnitudes of some of the projected investments in worldwide LNG capacity, this equilibrium concept may have some relevance over the next few decades.

- ### *Model Limitations*

Game theory models use simplified market, firm, supply, and pricing assumptions along with defined game rules. Perhaps the most challenging aspect of applying game theory is the development of game rules that accurately depict supplier choices and choice outcomes. The long lead times associated with new LNG production and shipping capacity likely limit real-world use of gaming models in this industry. As a practical matter, reshuffling of the order in which planned LNG projects are developed may more generally be based on relative economic feasibility, where planned projects that are more capital-intensive with higher complexity and risk are postponed while more favorable projects are developed.

The hypothesis that the firms play a Cournot game was tested in a recent study using several decades of oil price and production data for both OPEC and non-OPEC countries. The result was a strong rejection of Cournot behavior among the tested countries. [159] This finding is not surprising given that application of the model to each of the members of OPEC presumes that Saudi Arabia, the dominant producer within OPEC, would be oblivious to how the level of production quota violations by the other members of OPEC varies with Saudi Arabia's production.

[157] Gkonis K.G. and H. N. Psaraftis, Investment Rules and Competition Patterns in LNG Shipping. Available at http://www.martrans.org/documents/2009/energy/IAME07.pdf
[158] See http://plato.stanford.edu/entries/prisoner-dilemma/
[159] Carvajal, A., Deb, R., Fenske, J., and Quah, J.K.-H, 2010.Revealed Preference Tests of the Cournot Model. Department of Economics Discussion Paper Series, Number 506. As viewed at http://www.economics.ox.ac.uk/materials/papers/4624/paper506.pdf

A more general limitation of game theory is that it offers an embracement of riches in the sense that any outcome between the perfectly competitive solution and the monopoly solution can be rationalized depending on the value of the conjectural variation. According to George Stigler, the Nobel Laureate in economics, the perceived interdependence among firms should be deduced, not assumed. In his words:

> “A satisfactory theory of oligopoly cannot begin with assumption concerning the way in which each firm views its interdependence with its rivals. If we adhere to the traditional theory of profit-maximizing enterprise, then behavior is no longer something to be assumed but rather something to be deduced” [160]

In keeping with Stigler’s admonition, game theory’s contributions to understanding the market for LNG may be modest until theorists can more adequately model the likely outcomes.

[160] Stigler, George J., A Theory of Oligopoly, Journal of Political Economy, Vol 72, 1964 p. 44. Available at http://home.uchicago.edu/~vlima/courses/econ201/Stigler.pdf