American Gas Foundation

Ability of the United States to Compete in the Global LNG Marketplace

An Assessment of Challenges and Opportunities

October 2008

American Gas Foundation
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American Gas Foundation

Founded in 1989, the American Gas Foundation is a 501(c)(3) organization that focuses on being an independent source of information research and programs on energy and environmental issues that affect public policy, with a particular emphasis on natural gas. For more information, please visit www.gasfoundation.org or contact Jay Copan, executive director, at (202) 824-7020 or jcopan@gasfoundation.org

Benjamin Schlesinger and Associates, Inc.

Benjamin Schlesinger and Associates, Inc. (BSA) is a leading management consulting firm specializing in all strategic aspects of the energy industries worldwide. In their core practice area of natural gas, focus includes economic and regulatory analysis, market research, spot and futures trading, gas rate development, and related technical and environmental analyses. Recent restructuring and emerging spot markets in the power industry has expanded their practice to encompass electricity, with particular focus on those electricity issues impacting the natural gas

1 The use of the term BSA in this section refers equally to its subcontractors, Poten and Altos.

industry. For more information, please visit www. bsaenergy.com or contact Ben Schlesinger, president, at (301) 951-7266 or bschles@bsaenergy.com.

Poten & Partners, Inc.

With a long history extending over 65 years and more than 160 professionals located on four continents, Poten provides a broad portfolio of services to clients - ship and commodity brokerage, project development, commercial advisory, consulting and financial services. Poten's LNG and natural gas consulting team, with more than 30 full-time professionals and five senior advisors, provides strategic advisory services along the entire natural gas and LNG value chain from gas reserves, pipelines, liquefaction plants, shipping and terminals through to trading and gas marketing.

Altos Management Partners, Inc.

Through its top-drawer analysts, Altos conceives and provides unique decision technology, methods and models for resolving complex, real-world engineering-economic decisions. Altos's World Gas Trade Model (WGTM) links together regional gas supply-demand-transportation submodels to create a comprehensive, integrated analysis tool of unparalleled usefulness to the LNG industry. The Altos WGTM provides answers to such critical questions as: In every producing basin in the world, what is the forward price of gas, and how will it evolve into the future? What volume of gas will the market be willing to absorb at that price, i.e., what is the size of the gas market at each producing basin worldwide?

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A. PURPOSE

The American Gas Foundation (AGF) commissioned the firm of Benjamin Schlesinger and Associates, Inc. (BSA) to analyze the adequacy of the world's liquefied natural gas (LNG) producing capacity to meet the needs of the United States (U.S.) natural gas industry and to assess the current and likely future competitiveness of the U.S. in the global marketplace over the next decade.

The overall goals of this study were to:

1) Provide an analysis of world LNG availability, import levels, regional demand and prices;
2) Evaluate the adequacy of U.S. infrastructure (pipelines, distribution, storage) to accommodate increased LNG imports;
3) Project future market mechanisms for the global LNG industry – particularly long-term versus spot contracts and oil-indexation versus domestic gas prices – and identify what the U.S. will need to do to obtain their needed LNG supplies;
4) Assess state and federal regulatory developments that have stimulated LNG imports, as well as measures that may be needed in the future to enable the U.S. natural gas industry to participate in the emerging global LNG markets; and
5) Analyze geopolitical risks that may impinge upon LNG supplies and offer mitigation strategies for the U.S. natural gas industry.

BSA is an independent management consulting firm in Bethesda, Maryland, specializing in all strategic aspects of the natural gas and energy industries since 1984. BSA teamed this effort with Poten and Partners, Inc., the nation's pre-eminent specialists in LNG trading, strategic information and technology, and Altos Management Partners, Inc., developers of the industry-leading tool for economic forecasting in the natural gas field, the World Gas Trade Model ("WGTM"). Together, BSA, Poten and Altos are referred to in this report as the "BSA Team."

B. MAJOR FINDINGS

- U.S. LNG imports in late 2007 and through mid-year 2008 have been less than 50% of year-earlier periods as a result of stronger year-on-year demand in Europe, particularly Spain, and cargo diversions from the Atlantic Basin to Asia. These diversions, many at exceptionally high prices, have been needed to offset supply shortfalls caused by startup delays in Pacific basin supply projects, production declines in Indonesia, and increased demand in Japan due to the shutdown of a major nuclear facility following the July 2007 earthquake.

- In the short term, until worldwide LNG supplies increase more substantially and U.S. demand requirements increase as projected, the study shows relatively little LNG headed toward this country. The high, albeit volatile, level of U.S. natural gas prices makes shale and other domestic unconventional gas supplies economic. The development of these unconventional supplies will enable the U.S. to meet demand as LNG goes to other markets.

- In the medium and longer term, far more LNG will be available to meet U.S. buyers' needs. Nineteen gas liquefaction trains at twelve LNG complexes on four continents are now in or nearing their construction stages. Together, these will increase by more than 50 percent the availability of LNG in world markets in the next decade. Sellers in 8-12 countries will be providing LNG to the U.S. market by 2016, with the largest two suppliers likely to be Trinidad and Nigeria.

- The U.S. will need increased LNG imports to supply growing gas demand for electricity generation in new U.S. power plants and to help the nation comply with climate change strategies. LNG importation to the U.S. is expected to surpass that of Europe within the next decade, although the Asian market for LNG will remain the world's largest in the meantime, especially as China and India increase their LNG imports.

- Long-term sales and purchase agreements are the norm in the global LNG business to enable the industry to raise the significant amounts of construction capital it requires. Therefore, it may be necessary for buyers, including importers of LNG into the U.S., to maintain a substantial portfolio of long-term contracts to ensure predictable LNG supply levels. Reliance on spot LNG cannot ensure reliable supplies for U.S. utilities for the foreseeable future because 'spot' LNG typically consists of cargoes that have been temporarily diverted from their primary destinations under existing long-term contracts.

- Oil-indexed gas prices will continue to be the norm in Asia and Europe. However, if crude oil prices remain very high, e.g., around $100 per barrel or more, continuation of this practice could reduce worldwide gas demand. This, in turn, could lead to a situation where spot and short-term LNG prices could clear far enough below parity with high oil prices to form an independent gas market apart from oil, as natural gas routinely does in the U.S. commodity markets.

- In summary, as the world's LNG supplies grow and global energy markets stabilize, the U.S. will find that it is more than able to compete in global LNG markets. Even though others will sometimes pay higher prices, the U.S. will offer sustained prices sufficient to support LNG projects from around the world. Additionally, the U.S. will be a desirable and dependable destination for LNG because of the sheer size and depth of its gas markets, its world-leading underground gas storage infrastructure, and the innate flexibility of its commodity gas trade.

C. BACKGROUND

The world's first LNG export terminal was built in Arzew, Algeria, in 1964 to enable gas export to Europe and, later, to the U.S. The first and only U.S. liquefaction and export terminal, located in Kenai, Alaska, was built in 1969 to enable exports of LNG from Cook Inlet producing fields to Tokyo, Japan.

LNG importation into the U.S. began nearly four decades ago. Table 1 lists the first four existing U.S. onshore LNG import terminals. These were products of a bygone era in the U.S. gas industry; merchant pipeline companies built them to help alleviate chronic gas shortages that afflicted much of the nation in the 1970s. Shortages were the result of federal field price controls that depressed U.S. production, and these ended in the early 1980s as gas deregulation took effect under the Natural Gas Policy Act of 1978.

Why LNG? Why now?

There has been an increasing tendency worldwide for new gas reserves to be discovered far from where they are needed, including, in many cases, overseas. To enable transportation across oceans, natural gas is liquefied for more economical shipping. In other words, LNG is nothing more than natural gas that has been chilled to a liquid state for more compact transport aboard ships, where it takes up only 1/600 of the space that it does as a gas. In this liquid form, LNG is then transported aboard specially insulated cryogenic ships – at mid-2080, there were more than 280 LNG tankers operating in the world. After it has been received and brought onshore, LNG is then turned back into its normal gaseous form ("regasified") and put into conventional gas pipelines for delivery to customers.

As U.S. domestic gas supplies stabilized in the 1980s, gas prices fell and remained as low as $1.00 to $3.00 per MMBtu throughout most of the 1990s. LNG was economically unattractive at these prices, except during peak periods. As a result, shipments of LNG to the U.S. fell far below contract capacity in the 1980s and 1990s. European buyers purchased part of this quantity under long term contracts, but Algerian liquefaction capacity withered as production trains were shut down. By the 2000s, gas prices were rising in the U.S. and the North American market became an awakened giant from the perspective of numerous LNG suppliers, whose ranks had swelled by then to supply Asian and European markets. At the same time, technological improvements in LNG technology drove down costs so that LNG became a viable alternative in North American markets.

Table 1 - Four Legacy U.S. LNG Import Terminals

LNG Import Terminals (Present Owner)	Initial Operation	Current Capacity (Bcf/day, sustainable)
Everett, MA (Suez)	**1971**	**0.7**
Cove Point, MD (Dominion)	**1978**	**1.0**
Elba Island, GA (El Paso)	**1978**	**0.8**
Lake Charles, LA (Southern Union)	**1981**	**1.8**

Source: Poten & Partners, Inc., BSA.

Today, the U.S. relies extensively on natural gas for its energy needs (23% of total primary energy) – by fuel, gas use in 2007 was second only to oil and petroleum products (40%). Gas heats 64 million U.S. homes and apartments, and is used in 5.5 million commercial buildings and industrial and manufacturing plants of all sizes. Gas also powers 20% of annual U.S. electricity generation, second only to coal, and rapidly gaining. LNG is still a very minor part of the U.S. natural gas supply mix, averaging 2% to 3% in the past three years.

Table 2 - North American Onshore LNG Terminals Under Construction (as of March 2008)

LNG Import Terminals (Owner)	Expected In-Service	Target Capacity (Bcf/day, sustainable)
Ensenada, Mexico (Sempra)	**2008**	**1.0**
St. John, NB, Canada (Irving/Repsol)	**2008**	**1.0**
Sabine Pass, LA (Cheniere)	**2008**	**4.0**
Freeport, TX (Cheniere)	**2008**	**1.5**
Cameron, LA (Sempra)	**2009**	**1.5**
Golden Pass, TX (ExxonMobil)	**2009**	**2.0**

Source: Poten & Partners, Inc.,BSA.; at mid-2008, the Clean Energy LNG terminal at Pascagoula, MS was also under construction.

Now, however, conditions are changing. Two new offshore receiving facilities have been established based on specially designed LNG tankers with on board re-gasification capabilities. These floating regasification vessels are connected via sub-sea pipelines to the U.S. gas transmission grid. Beyond these, and at considerably greater scale, five new LNG import terminals are under construction in the U.S., two major new terminals are nearing completion in Canada and Mexico (see Table 2 above), and more are planned. Gas producers in North America have historically kept pace with demand growth, which has been modest overall. Indeed, several large new natural gas fields have been discovered in the past decade; these have driven an increase in U.S. proven reserves to 211 trillion cubic feet (Tcf), up 27% in the past decade. Especially large gas reserve growth has taken place in the Rocky Mountains and the Barnett Shale region of northeastern Texas. Technological advancements have also reduced the cost of developing unconventional gas supplies which in the past was too costly to produce. U.S. natural gas production has not peaked and will continue to grow, at least for another several years. But nonetheless, U.S. gas demand is poised to grow 3.3 percent annually through the next decade, and will reach the unprecedented level of 27.7 Tcf per year by 2016 – the nation's previous record consumption level of 23.5 Tcf, in 1973, will likely be surpassed by 2010. Because gas-fired electric power plants burn so cleanly and efficiently (up to 70% in combined-cycle combustion turbines), and can be sited, constructed and installed relatively quickly, natural gas is the centerpiece of the world's efforts to maintain clean air and reduce emissions of carbon dioxide and other greenhouse gases in the next decade while renewables, nuclear and other solutions are being developed and commercialized.

The four U.S. legacy terminals were constructed on a cost-of-service basis, and three of them continue to be regulated and terminal capacity was contracted (long-term) to users following rigorous open access service conditions of the Federal Energy Regulatory Commission (FERC) – only Everett among the existing terminals was grandfathered from open access requirements.[1] New LNG import terminals in the U.S., however, fall within the FERC's policy established in its approval of the Hackberry (Cameron) LNG terminal, namely, all are exempt from open access requirements that would otherwise require auctioned capacity rights. As a consequence, unlike U.S. gas pipelines and storage facilities, owners of new terminals need file cost-of-service rates, they need not auction capacity, and they may assume capacity rights themselves or through affiliates. This exemption, which was codified by the Congress in the Energy Policy Act of 2005, will remain in effect through 2015.

Although LNG has been around for decades, it has never formed a very significant part of the North American gas industry's portfolio of supplies.[2] Now, however, the U.S. is poised to expand its involvement in LNG markets, with 11 Bcf/day of import terminal capacity under construction that will triple U.S. LNG receiving and regasification capacity by year-end 2009. Even at today's relatively low volumes, the U.S. is already a significant potential player in the global LNG market. The simple truth is that LNG is now often competitive with domestic production – a fact that was not true a decade ago, and hence North America will be able to attract supplies once near-term supply bottlenecks are relieved.

[1] Existing capacity at the three open access LNG terminals in the U.S. is booked under long-term contracts; access is available through capacity releases or potentially upon expiration of those agreements.

[2] New England, the exception to this statement, receives one fourth of its gas energy supplies from the Everett LNG terminal, on an annual average basis.

D. WHERE WE ARE TODAY – GLOBAL LNG SUPPLIES

Table 3 through Table 6 provide a comprehensive inventory of current, in-construction, and planned LNG liquefaction capacity worldwide. Through the progression of tables, it should be noted that these listings are subject to increasing interpretation and judgment, and arise out of explicit definitions and caveats as footnoted in each case.

Table 3 - Current LNG Supply Projects by Basin and Country in MMtpa (Bcf/day)

Liquefaction Project	2007	2008
Atlantic Basin		
Algeria	**19.6 (2.5)**	**18.6 (2.4)**
Egypt	**11.9 (1.5)**	**12.1 (1.6)**
Equatorial Guinea	**1.8 (0.2)**	**3.2 (0.4)**
Libya	**0.9 (0.1)**	**0.9 (0.1)**
Nigeria	**18.3 (2.4)**	**20.1 (2.6)**
Norway	**1.0 (0.1)**	**4.2 (0.5)**
Trinidad	**14.8 (1.9)**	**16.4 (2.1)**
Subtotal, Atlantic Basin	***68.3 (8.7)***	***75.5 (9.7)***
Middle East		
Abu Dhabi	**5.9 (0.8)**	**5.9 (0.8)**
Oman	**10.4 (1.3)**	**10.7 (1.4)**
Qatar	**28.1 (3.6)**	**29.9 (3.8)**
Subtotal, Middle East	***44.4 (5.7)***	***46.5 (6.0)***
Pacific Basin		
Australia	**15.2 (2.0)**	**15.4 (2.0)**
Brunei	**7.2 (0.9)**	**7.2 (0.9)**
Indonesia	**21.3 (2.7)**	**19.3 (2.5)**
Malaysia	**23.4 (3.0)**	**23.7 (3.0)**
U.S.A.	**1.4 (0.2)**	**1.3 (0.2)**
Subtotal, Pacific Basin	***68.5 (8.8)***	***66.9 (8.6)***
Total, All Basins	***181.2 (23.2)***	***188.9 (24.3)***

Source: Poten & Partners, Inc. database, 2/2008. Note: Existing plant capacity is based on design capacity plus any de-bottlenecking or expansions carried out at the plants.

First, current global liquefaction capacity (2007-08) by country and by major global LNG basin is shown in Table 3. Current estimated worldwide LNG liquefaction capacity is 189 MMtpa or approximately 24 Bcf/day. The Atlantic basin leads the world's liquefaction capacity with 76 MMtpa (9.7 Bcf/day); Nigeria, Algeria and Trinidad & Tobago are the dominant LNG liquefiers. The Pacific basin follows closely at 67 MMtpa (8.6 Bcf/day) with Malaysia, Indonesia and Australia being the leading liquefaction countries. The Middle East basin has 47 MMtpa (6 Bcf/day) liquefaction capacity with Qatar being the dominant LNG provider. Qatar also has emerged as the largest LNG producer globally with 30 MMpta (3.8 Bcf/day) liquefaction capacity. Atlantic LNG Company of Trinidad and Tobago and its shareholders have provided the most LNG supply to the U.S. since 2000 and have been very active in the LNG market since its inception in 1999. To date, Trinidad and Tobago has exported over 1,000 cargoes. They primarily export volumes to Spain and the U.S. (including Puerto Rico).

There is currently 101.2 MMtpa (13 Bcf/day) of liquefaction capacity under construction worldwide, as shown in Table 4, with expected start-up dates ranging between 2008 and 2012. Completion of these facilities, expected within the next three years, will expand current global liquefaction capacity by more than 50%. The greatest construction is taking place in the Middle East (53.5 MMtpa or 6.9 Bcf/day) with the bulk of the new capacity residing in Qatar. New construction in the Pacific Basin is a distant second at 31 MMtpa (4 Bcf/day) with Russia, Australia and Indonesia being the dominant new LNG liquefaction countries. The Atlantic Basin is a distant third, with current LNG construction of 16.9 MMtpa (2.1 Bcf/day) in Nigeria, Algeria, Angola and Libya.

Table 4 - Liquefaction Projects Under Construction as of March 2008

Country, Plant Name	Expected Start Date	Nameplate Capacity, MMt/y (Bcf/day)
Atlantic Basin		
Nigeria LNG	**2008**	**4.2 (0.5)**
Algeria – Skikda	**2011**	**4.5 (0.6)**
Libya – Brega	**2012**	**3.2 (0.4)**
Angola LNG	**2012**	**5.0 (0.6)**
Algeria – Gassi Touil	**2012**	**4.7 (0.5)**
Subtotal, Atlantic Basin		***21.6 (2.6)***
Middle East		
Qatargas II	**2008-2009**	**15.6 (2.0)**
Yemen LNG	**2009**	**6.7 (0.9)**
Qatar – RasGas III	**2009-2010**	**15.6 (2.0)**
Qatargas III	**2009-2010**	**7.8 (1.0)**
Qatargas IV	**2010**	**7.8 (1.0)**
Subtotal, Middle East		***53.5 (6.9)***
Pacific Basin		
Russia – Sakhalin LNG	**2009**	**9.6 (1.3)**
Australia NWS	**2008**	**4.4 (0.6)**
Indonesia – Tangguh LNG	**2009**	**7.6 (1.0)**
Peru – Camisea	**2010**	**4.2 (0.5)**
Australia – Pluto	**2011**	**5.0 (0.6)**
Subtotal, Pacific Basin		***30.8 (4.0)***
Total, All Basins		***101.2 (13.0)***

Source: Poten & Partners, Inc. database, 2/2008. Note: Plants are considered to be under construction when an engineering, procurement and construction (EPC) contract is signed between the contractor and project sponsors. Poten monitors construction progress throughout the construction process to assess a reasonable start-up date and start of commercial operations. Plant capacity is based on design specification reported by sponsors and contractors.

Discovered in 1971, the giant North Field (~900 Tcf) – the world's largest non-associated natural gas field – will fuel Qatar's LNG growth plans. Qatar has turned to LNG to monetize their assets given their low production costs and vast reserves. Qatar has two LNG export ventures (Qatargas and RasGas). By 2010, Qatar will emerge as the undisputed King of Liquefaction with fourteen trains (10 Bcf/d) online (An LNG train is the term used to describe the liquification and purification facilities in an LNG plant). Given its central location, Qatar will provide supplies for Asia-Pacific, India, Europe and the U.S. With worldwide supply contracts, Qatar should be able to link prices between the Atlantic and Pacific Basins, with potentially broad implications for the world's LNG industry, i.e., unprecedented flexibility in the ability to exchange Atlantic for Pacific LNG supplies and vice versa, thus enabling competition on a broader scale than heretofore.

The final category of liquefaction plants consists of planned future capacity, including liquefaction projects in advanced planning stages versus all others. Table 5 lists projects with start-up dates between 2012-17 while Table 6 lists projects in less advanced planning stages, i.e., that may enter service between 2013 and 2020. The projects in advanced stages encompass 65 MMpta (8 Bcf/day) of liquefaction plant that, if constructed, would increase current capacity by another 37% in addition to the 50% represented by projects currently under construction. The projects in advanced planning are predominantly in the Atlantic basin with the great majority in Nigeria. Australia in the Pacific Basin holds the remaining projects that are in advanced planning stages. It is noteworthy that all projects in this category are potential future suppliers to the US. No projects exist in this category in the Middle East. It is noted that, given the cost of an LNG project including upstream production, liquefaction and shipping; projects are typically constructed only after nearly all of the LNG is sold under long-term contracts. Therefore, market availability is a key consideration, including potential markets in the U.S.

Table 5 - Global LNG Projects in Advanced Planning Stages

Country, Plant Name	Expected Start Date	Nameplate Capacity, MMt/y (Bcf/day)
Atlantic Basin		
Nigeria LNG	**2012**	**8.5 (1.1)**
Nigeria – OK LNG	**2014-2016**	**11.0 (1.4)**
Nigeria – Brass LNG	**2014**	**10.0 (1.3)**
Nigeria – OK LNG	**2016-2018**	**11.0 (1.4)**
Subtotal, Atlantic Basin		***40.5 (5.2)***
Pacific Basin		
Australia – Browse LNG	**2013-2014**	**14.0 (1.8)**
Australia – Gorgon LNG	**2014-2016**	**10.0 (1.3)**
Subtotal, Pacific Basin		***24.0 (3.1)***
Total, All Basins		***64.5 (8.3)***

Source: Poten & Partners, Inc. database, 2/2008. Note: Please see Table 6.

Table 6 shows the potential future LNG liquefaction projects by basin and country. These projects represent 126 MMpta (16 Bcf/day) liquefaction capacity and are located in 13 countries within all three LNG basins. Once again, the projects predominate in basins that represent potential LNG supply to the U.S. with the Atlantic basin leading the pack followed by the Pacific basin with Middle East being in the last category.

Table 6 - Potential Additional Global LNG Projects

Country, Plant Name	Expected Start Date	Nameplate Capacity, MMt/y (Bcf/day)
Atlantic Basin		
Egypt – Segas	**2013**	**5.0 (0.6)**
Egyptian LNG	**2014**	**3.6 (0.5)**
Equatorial Guinea	**2015**	**4.4 (0.6)**
Algeria – Gassi Touil	**2015**	**4.0 (0.5)**
Trinidad – Atlantic LNG	**2016**	**5.2 (0.7)**
Russia – Shtockman	**2017**	**10.0 (1.3)**
Algeria – Gassi Touil	**2017**	**4.0 (0.5)**
Lybia	**2017**	**3.2 (0.4)**
Norway – Snohvit	**2018**	**4.3 (0.6)**
Angola LNG	**2018**	**5.0 (0.6)**
Venezuela LNG	**2020+**	**4.7 (0.6)**
Subtotal, Atlantic Basin		***53.4 (6.9)***
Middle East		
Iran – Pars LNG	*	**5.0 (0.6)**
Iran – Persian LNG	*	**8.5 (1.1)**
Iran – Pars LNG	*	**5.0 (0.6)**
Iran – Persian LNG	*	**8.6 (1.1)**
* Iran – Qatar (post moratorium)	**2016**	
Int'l oil company sponsors of proposed Iranian LNG projects have delayed development of Pars & Persian projects		
Subtotal, Middle East		***27.1 (3.4)***
Pacific Basin		
Russia – Sakhalin LNG	**2013**	**4.8 (0.6)**
Indonesia – Tangguh LNG	**2013**	**3.5 (0.5)**
Australia – Sunrise LNG	**2014**	**5.3 (0.7)**
Australia – Ichthys LNG	**2016**	**6.0 (0.8)**
Papua New Guinea	**2017**	**5.0 (0.6)**
Australia – Gorgon LNG	**2018-2020**	**10.0 (1.3)**
Australia – Ichthys LNG	**2020**	**6.0 (0.8)**
Subtotal, Pacific Basin		***40.6 (5.2)***
Total, All Basins		***126.1 (16.1)***

Source: Poten & Partners, Inc. database, 2/2008. Note: Re Advanced Planning and Potential, project sequence and suggested start-up dates are based on Poten's assessment of Front End Engineering and Design contracts (FEED); Final Investment Decision (FID) by the project sponsors, signed EPC contracts, gas resource availability; strength of project participants; sponsor announced plans, and expansion prospects of existing plants. Judgments are also informed by assessment of EPC contractor resource availability compared to the LNG plant construction backlog. Poten also estimates the Cost of Service based on proprietary calculations to determine the cost ($/MMBtu) to produce LNG and supply projected markets, considering LNG demand.

LNG liquefaction capacity will rise dramatically, with considerable diversity by location over the next decade. A 50% increase in LNG supply is anticipated within approximately the next three years when projects currently under construction are completed. A 100% increase is anticipated in the next decade if many of the planned projects in both advanced stages of planning and future potential reach fruition. The sharp increase in LNG supply will have wide implications on how it is priced and traded.

E. MAJOR REGIONS IN THE LNG MARKETPLACE

The LNG global market has traditionally been divided into two distinct markets: the Atlantic market and the Pacific market. The Pacific market covers buyers in Asia Pacific (Japan, South Korea and Taiwan), India, China and the nascent markets of North America West Coast (NAWC). The Pacific market is currently supplied by liquefaction ventures in Indonesia, Malaysia, Australia, Brunei, Alaska, and the Middle East.

The Atlantic Basin market, covering European and North American buyers, is currently supplied by North Africa, West Africa, The Caribbean, the Barents Sea and Middle East LNG ventures. While there is some short-term trade between Atlantic and Pacific LNG markets, long-term trades are largely regional.

It is important to note that the growth in Middle East supply in recent years, particularly out of Qatar, has made the trade much more global. The Middle East is ideally located to serve both markets. In addition, Qatar, with huge reserves of natural gas, has invested heavily in developing multiple LNG mega-trains, all of which are scheduled to commence operation between 2008 and 2010. This incremental capacity to the world trade has an inherent flexibility as far as destination, and Qatar Petroleum, along with foreign partners, has targeted European, U.S., as well as Asian markets for these volumes. To achieve a solid understanding of the industry therefore requires today a global perspective and a familiarity with specific regional markets.

The major LNG market regions are as follows:

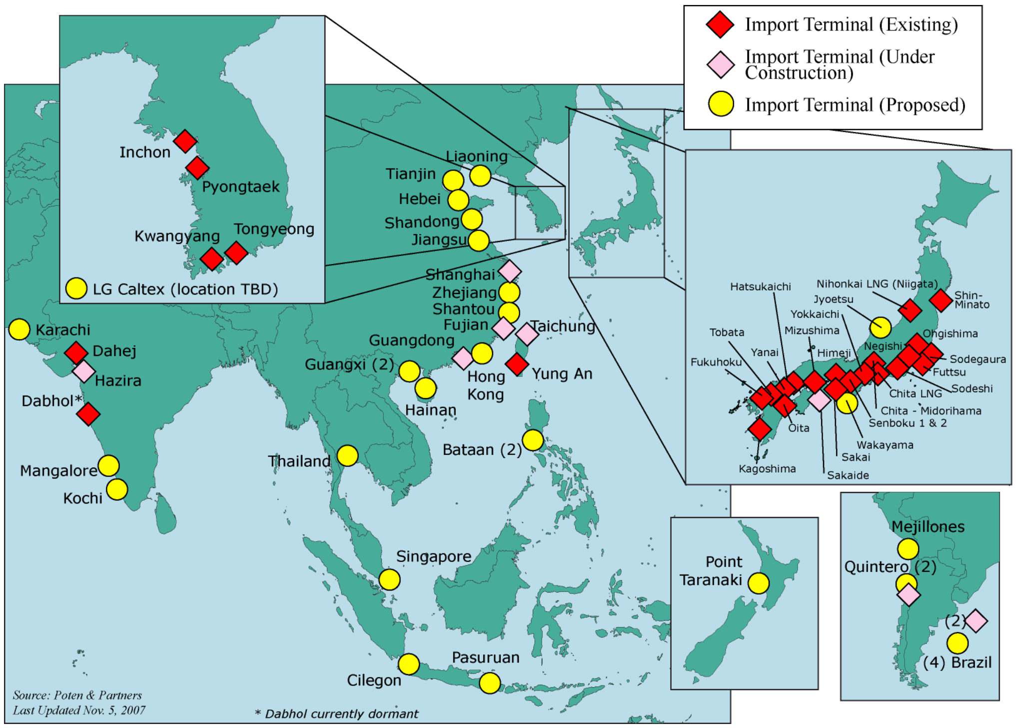
Pacific Basin

Pacific Basin buyers (see Figure 1) have dominated the world LNG industry for the past two decades. Gas and electric utility buyers in Japan, Korea, and Taiwan rely heavily – almost exclusively in some cases – on LNG; Pacific Basin markets now include China and India as well.

Total Pacific Basin imports for 2007 are likely to exceed 110 million tonnes per annum (tpa), i.e., 14.2 Bcf/day, or about 62% of total world trade. In all likelihood, LNG demand in the Pacific Basin is going to continue to increase in the coming years.

Japan, Korea and Taiwan are the long-standing LNG buyers in Asia; they together consumed 55% of all LNG sold globally in 2007. These countries have limited domestic energy resources and rely heavily on imports of crude oil, coal and liquefied natural gas. Moreover, none of the three have access to pipeline natural gas supplies other than minor domestic production in each country volumes. Therefore, natural gas in all domestic markets – residential, commercial, industrial and electric power generation – relies almost entirely on LNG shipments. Because they use LNG so extensively in high priority markets for which there are no available substitute fuels, Pacific Basin buyers tend to contract for LNG under long-term sales and purchase agreements (SPA).

Figure 1 - Asia-Pacific Basin LNG Markets



Source: Poten & Partners, Inc. 2008.

Japan is the world's largest LNG-buying country, importing 38% of the world's total LNG in 2007. About 35% of LNG imported into Japan is consumed in the gas utility sector. Japan has no national gas transmission system. Rather, eight gas distribution companies serving Japan's major metropolitan areas import, store and vaporize LNG; they distribute and sell gas to residential and commercial buyers within their individual service areas. Demand growth in the residential and commercial sectors is driven primarily by market growth and increased gas penetration within existing gas distribution areas. A secondary factor is the sale of regasified LNG to smaller city gas companies outside the distribution areas of existing LNG supplied cities.

Nascent gas deregulation in the industrial sector allows the gas companies to sell at "market" prices to industrial buyers, and to potentially face competition for sales to these customers. Demand increases in the industrial sector are driven primarily by economic growth, including manufacturing for both domestic consumption and exports.

Japan's electric power sector consumes about 65% of total LNG imported into the country. Here, ten electric power companies (six of which import LNG) with defined service areas dominate the generation, transmission and distribution, and sale of electricity. Electric power companies also purchase power from independent power producers (IPPs) and third party generators, from whom they also face competition in sales to large industrial electricity consumers.

Japan's primary sources of power generation are nuclear for base load, coal for base and mid-load, and oil or LNG for mid and peak loads. Electric utilities have experienced operating and maintenance problems at their nuclear plants. Recently, a significant rise in Japan's LNG demand resulted when the Chuetsu earthquake in July 2007 caused a suspension of operations at the 8.2 GW Kashiwazaki Kariwa nuclear complex. Public and government concerns about nuclear power could slow future growth of nuclear power and raise LNG demand.

Korea has emerged as the world's second largest LNG buyer. Nearly all LNG is imported by Korea Gas Corporation (Kogas), which owns and operates three large-scale LNG receiving terminals; Kogas also owns the national transmission system that connects to Korea's main metropolitan areas. Regasified LNG is used heavily in the residential and commercial sector with 60% of LNG going to gas distribution utilities. Of the country's retail gas demand, 75 percent is in the residential and commercial sectors and 25 percent is industrial, thus explaining Korea's highly seasonal demand pattern. The non-gas utility component of Korea's consumption of regasified LNG, approximately 40%, is used in power generation, where subsidiaries of Korea Electric Power Company purchase re-gasified LNG from Kogas.

Taiwan's LNG business is operated by CPC Corporation, a government-owned energy company. With 80% of LNG going to power generation, demand in Taiwan depends on electricity generation fuel consumption and the generation mix among nuclear, coal, oil and LNG.

A pressing need for Japan, Korea and Taiwan is to replace the LNG from expiring Indonesian contracts that will not be renewed or renewed at lower contract quantities because of declining gas reserves at both the Arun and Bontang liquefaction complexes. This is driving Japanese utilities, Kogas and CPC to seek new LNG supplies from liquefaction facilities that are presently under construction and/or planned.

China and India are relatively recent LNG importers, with China commencing in 2006 and India in 2004. Both countries have large populations, high economic growth rates and growing energy demand that cannot be completely met by indigenous production and existing pipeline supplies. Moreover, both governments play a major role in natural gas pricing, thus there is no clear, transparent natural gas market in either country. Consequently demand projections for China and India are tenuous.

China has two operating LNG receiving terminals, three under construction, and one more approved. However, plans to construct as many as five additional receiving terminals to support plans to increase LNG imports have been mooted. LNG receiving terminals are located in prosperous coastal regions, and supply natural gas for power generation and town gas applications. In 2006, natural gas accounted for only 3% of total energy consumption in China, and the IEA projects that gas consumption will grow to 4% of total energy by 2015. The Chinese government is more optimistic about the gas demand growth rate and that domestic gas production and LNG imports will grow to meet demand. China's initial long-term LNG supply contracts with Asia Pacific suppliers were concluded at very favorable prices compared with other Pacific Basin contracts. However, Chinese oil companies, CNOOC and PetroChina recently executed long-term LNG purchase contracts with Asian and Middle East suppliers at "prices that are reported to approach crude oil parity."

India began LNG importation in 2004 through the Dahej LNG receiving terminal, which is owned by a consortium consisting of four Indian public sector corporations, Gaz de France, the Asian Development Bank (ADB), and public shareholders. LNG supplies for this terminal were secured from Ras Laffan LNG under a long-term contract understood to have favorable, although rising pricing terms. A second LNG receiving facility currently operating in India was built, owned and operated by a consortium of international energy companies, but this facility is reported to operate at low throughput rates. A third Indian LNG receiving terminal was under construction to supply the failed Dabhol Independent Power Project (now owned by Ratnagiri Gas, a consortium of public corporations and Indian banks.)

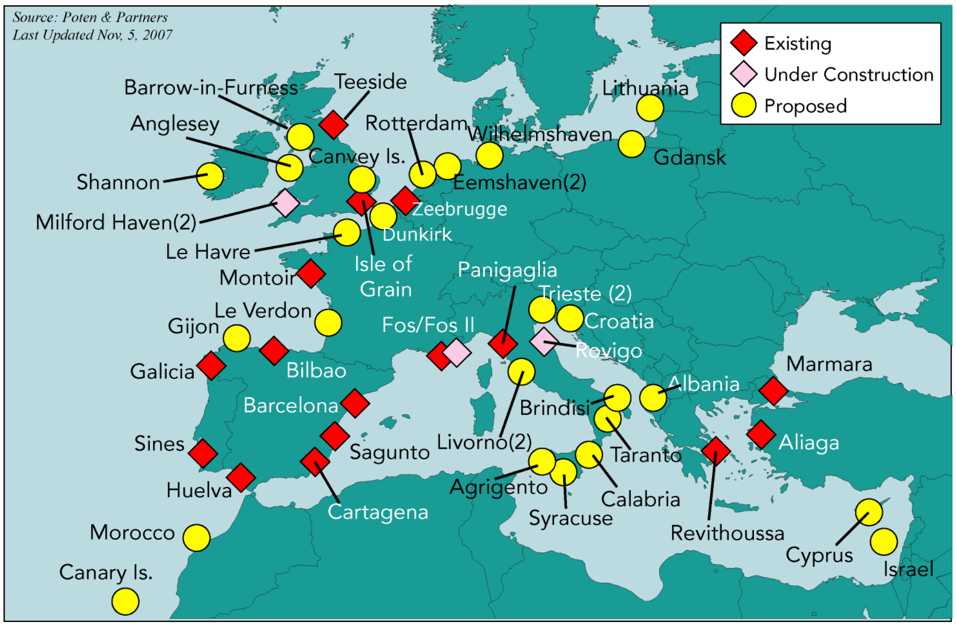
Development of natural gas discoveries offshore India's east coast and expansion of production from fields offshore India's west coast will soon lead to increased indigenous supply, which will ramp up to approximately 4 Bcfd at relatively low prices. Nevertheless, Indian gas demand appears robust as natural gas competes with oil products in peak power generation and fertilizer manufacture. Petronet LNG, operator of Dahej LNG terminal, has imported significant quantities of spot LNG in recent years and plans to increase long-term imports.

A number of other Pacific Basin countries have shown interest in importing LNG to either replace declining domestic supplies or to supplement existing pipeline gas and meet growing natural gas demand – Chile, Hong Kong, New Zealand, Pakistan, Singapore and Thailand are all prospective LNG importers.

Atlantic Basin

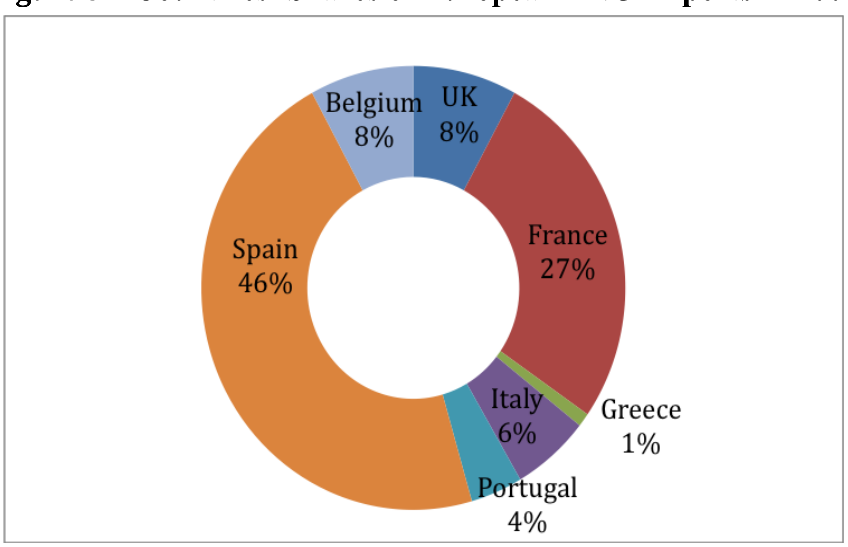
Atlantic Basin LNG markets are in the midst of a period of rapid demand growth, with highly competitive procurement. Figure 2 illustrates the locations of existing and planned LNG terminals in Europe, while Figure 4 presents the comparable array of existing, planned and proposed LNG terminals in North America, including those located in the U.S., Canada and Mexico.

Figure 2 - European LNG Terminals



Source: Poten & Partners, Inc. 2008.

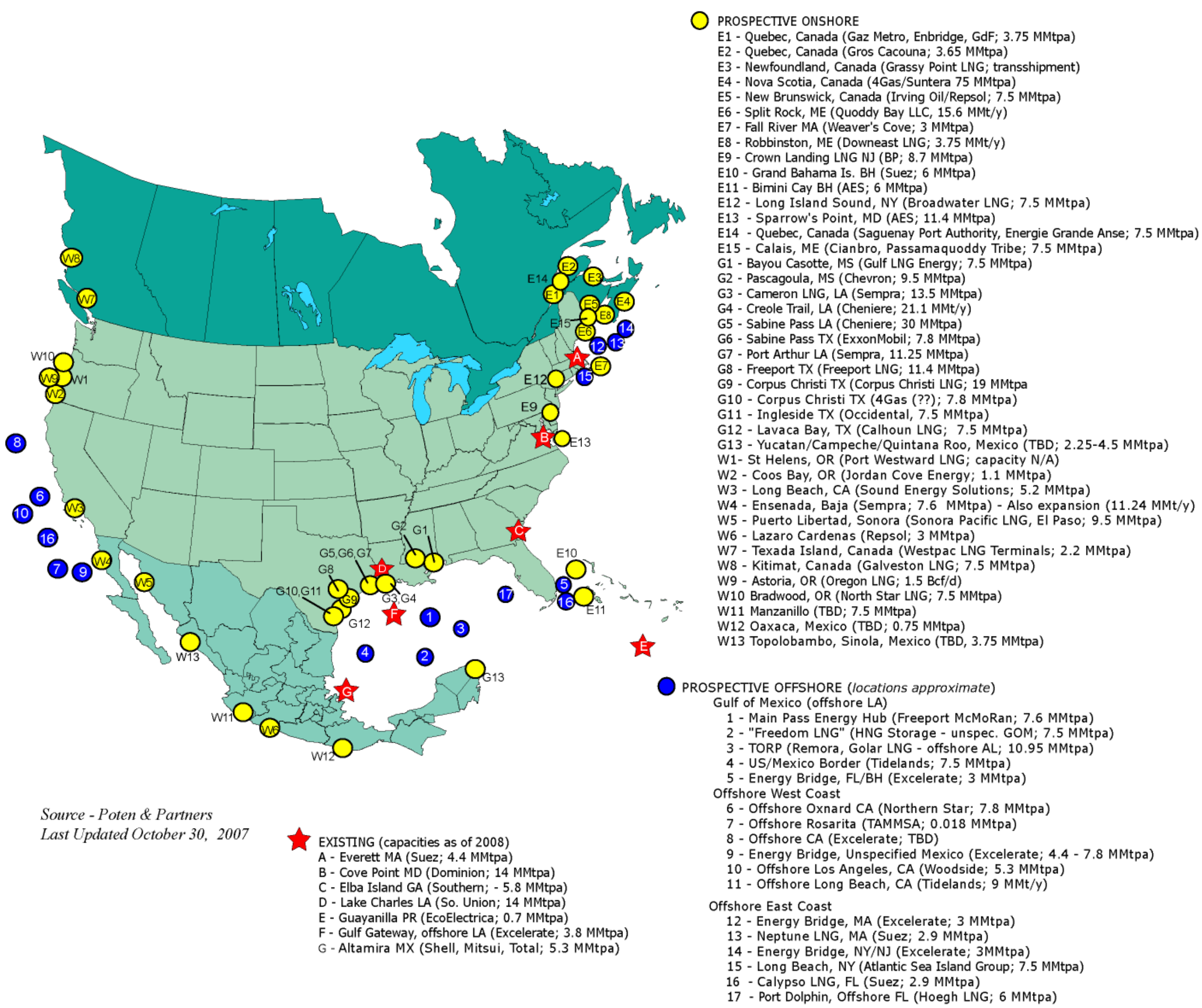
Figure 3 – Countries' Shares of European LNG Imports in 2006



Source: Francisco de la Flor, Enagas, "Role of Liquefied Natural Gas to Enhance Energy Security in then UNECE Region," Geneva, 1/22/2008.

Despite the fact that LNG trading in the Atlantic Basin began in1964, the Atlantic LNG market is still in its relative infancy. Until the late 1990s this market was quite limited, with Algeria and Libya supplying France, Spain, Italy and Belgium. Even smaller volumes were delivered to the four existing U.S. LNG import terminals – located at Everett, MA; Cove Point, MD; Elba Island, GA; and Lake Charles, LA (see preceding section). Atlantic Basin growth commenced in earnest in 1999, when the Atlantic LNG (Trinidad) commenced operation with sales to Spain and the U.S., Nigeria LNG began LNG deliveries to European buyers, and Algeria ramped up production following completion of a major renovation of its liquefaction facilities. Spain, which imports 46 percent of all LNG bound for Europe, (see Figure 3) is the most LNG-dependent country in Europe and was a foundation customer for both Atlantic LNG and Nigeria LNG. With Spain's gas market freed for competition, LNG buyers have assembled a supply portfolio that includes contracts with Trinidad, Algeria, Nigeria, Egypt, Norway, Qatar and Oman; and Spanish companies have constructed three new receiving terminals since 2000.

Figure 4 - North American LNG Import Terminals



Source: Poten & Partners, Inc. 2/2008.

However, steady growth in established markets such as Belgium, France, Italy, Spain and Portugal, coupled with higher growth rates in the UK and US where LNG is supplementing domestic and imported pipeline gas should result in the Atlantic Basin representing about half of the global LNG market in the 5-8 year time frame, driven by increased U.S. purchases. Indeed, rapid growth in Atlantic Basin and Middle East LNG facilities is already straining material and manpower availability, raising construction costs and causing delays in the availability of key equipment, material and qualified engineering-procurement-construction (EPC) contractor services.

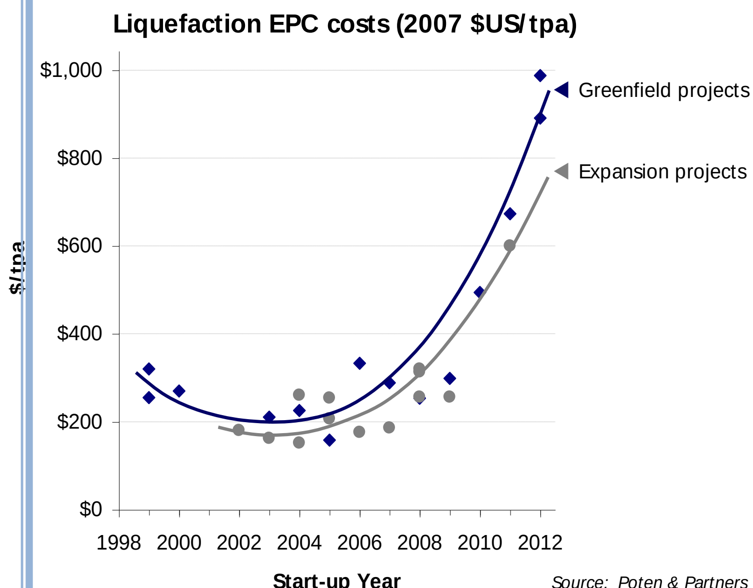
In summary, LNG markets have evolved and prospered in the Pacific Basin, driven by gas and electric utilities and their service requirements that could only be met by LNG imports. Some portions of Europe are highly dependent on LNG as well, such as Spain and France, for gas utility requirements and growing electricity generation needs. As the U.S. enters both of these markets with increasing purchases, its increasing demands will be met by a growing list of suppliers.

Escalating capital investment requirements of the kind described in the inset have not been unique to the LNG industry, but have afflicted the entire energy chain. As very high oil prices have pushed developers to install every

The Cost-Price Dilemma

A key worry in the LNG business is rapidly rising engineering and construction costs for new LNG facilities of all kinds, including liquefaction trains, import terminals and tankers. Using its models, Poten estimates that the $/tonne cost to construct new liquefaction capacity has increased on the order of 3 to 4 times between plants that started operating in 2004 and plants that would enter into construction now for a 2012 start up. Indeed, soaring costs have forced some projects to go "back to the drawing board" to re-evaluate their engineering design and construction plans.

In other words, in spite of today's exceptional energy prices, LNG developers and lenders cannot diligently anticipate continued $90 to $100 per barrel crude oil or concomitantly high gas prices into the future. Instead, they conservatively assume a lower future price path for fuels. Severe cost escalation has, therefore, raised concerns that future LNG prices may not remain high enough to support project economics of new liquefaction plants, and that the resulting delays in development of new plants may keep enough new LNG supplies off the market to prolong the current market tightness. It is tempting to expect that if and when oil prices decline material, equipment and labor costs will also decline, but instead, cost declines may lag lower long-term price expectations. Thus LNG project sponsors will continue to be trapped for the foreseeable future between low projected revenue and high construction costs, at least until the current construction backlog is cleared.



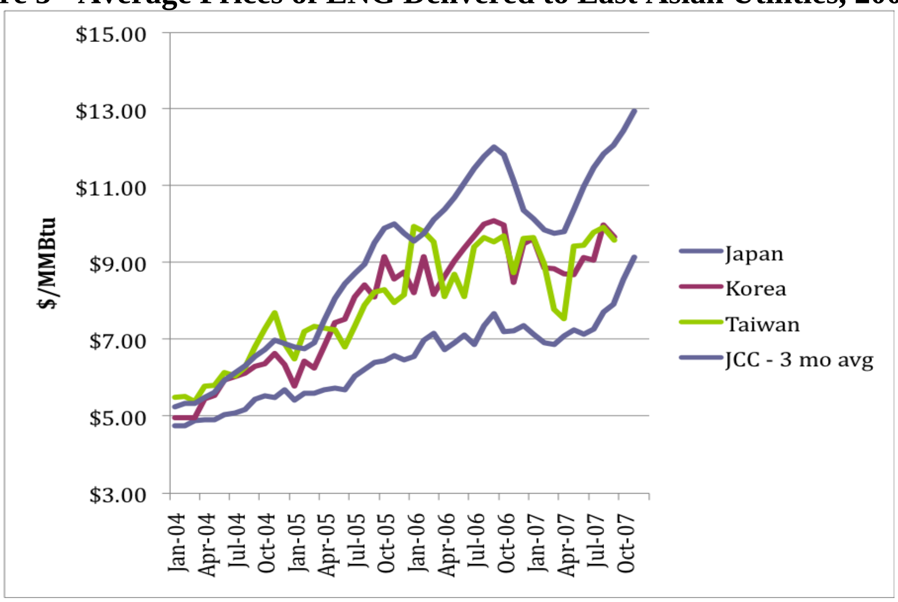
alternative possible, pipeline costs have risen, as have oil and gas production equipment, refineries, EPC contractors (engineering, procurement, and construction) – indeed, all energy-related materials, construction and personnel have grown tight in the current environment. The consequences of escalating capital costs in the energy industries remain to be seen. Potentially, a large decline in world gas prices could delay or defer planned LNG production facilities, reducing LNG available for growing markets, but that seems unlikely. Furthermore, while oil and gas prices remain high, LNG suppliers are weathering this spate of heightened capital costs; however, a sudden decline in gas prices worldwide could strain the ability of LNG suppliers to service the debt component of their LNG supply chain investments, let alone reduce returns to their investors.

F. OUTLOOK FOR LNG PRICES

Pacific Basin LNG Prices

LNG prices in the Pacific Basin are primarily indexed to crude oil, specifically the weighted average price of all crude oil imported into Japan, which is called the JCC. Figure 5 shows average prices of LNG imported into Japan, Korea and Taiwan; and the JCC to which LNG prices are indexed.

Figure 5 - Average Prices of LNG Delivered to East Asian Utilities, 2004-07



Source: Poten & Partners, Inc., 2/2008.

While Japanese prices currently lag those of Korea and Taiwan, negotiations are underway with Japanese buyers on how to incorporate current high oil prices within existing LNG price formulas. If we assume that Japanese prices rise to the level similar to Korea and Taiwan prices, we would estimate that Pacific Basin prices would be at about 90% of crude oil heating value parity. This is a reasonably conservative estimate of the average of contract prices under long-term LNG Sale and Purchase Agreements.

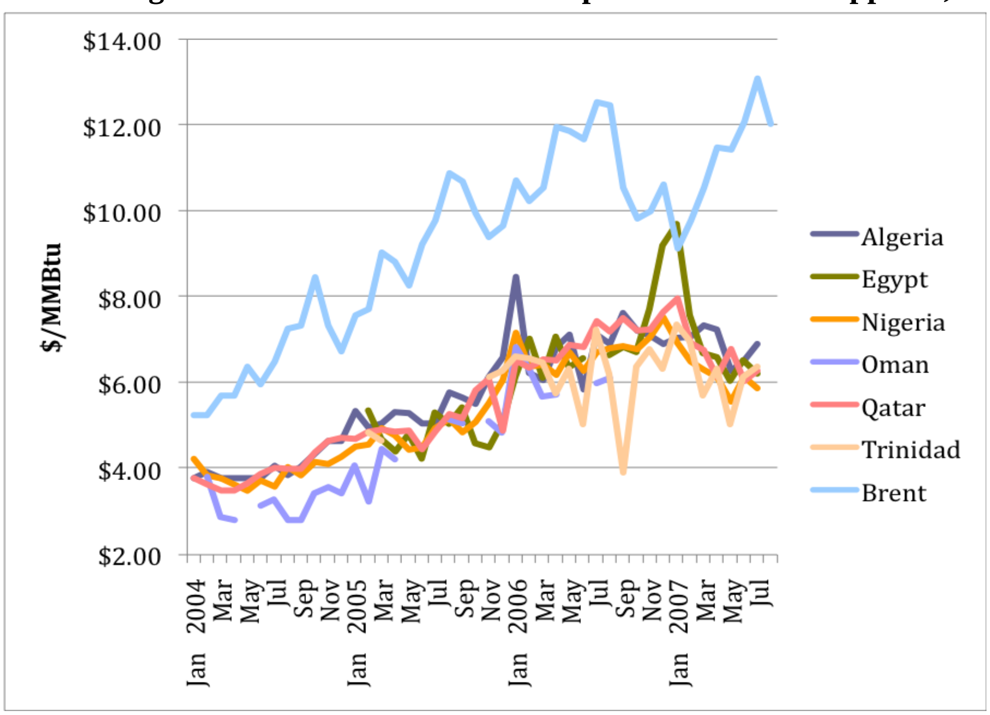
In the long-term, ample supplies will fundamentally alter the way that LNG is priced in the Pacific Basin. The region will likely transition from an oil-parity pricing mechanism to a market based prices where gas-on-gas competition sets the price. As total supply far exceeds regional demand, competition among suppliers will likely set the price. This phenomenon was last seen during 2001-2003, when LNG suppliers accepted "S" curves and crude oil price caps in the crude oil indexed pricing formulas used in Asian LNG contracts.

Market-based prices are already setting values in short-term or spot LNG. As described above, gas demand of the utilities in Japan, Korea and Taiwan is relatively inelastic, particularly in the short-term. Therefore, when the utilities are short LNG supply, they pay whatever price is necessary to secure spot cargoes. At peak times, this price has even exceeded oil parity. As a result of their portfolio of long-term contracts, however, the immediate impacts upon their consumers of such high-priced spot LNG purchases is somewhat muted.

Atlantic Basin LNG Prices

European LNG import prices (other than UK and Belgium) are indexed to crude oil or oil products. Therefore, prices in those regions are best understood by reference to oil prices. Figure 6 contains a graph of monthly average Spanish import prices of LNG purchased under long-term contracts in the 2004–2007 period that also includes the monthly Brent crude oil price. Again, we see that LNG prices follow the crude oil price trend, averaging about 65% - 70% of crude oil parity over the period.

Figure 6 - Average Prices of LNG Delivered to Spain from Seven Suppliers, 2004-07



Source: Poten & Partners, Inc., 2/2008.

U.S. LNG Import Prices

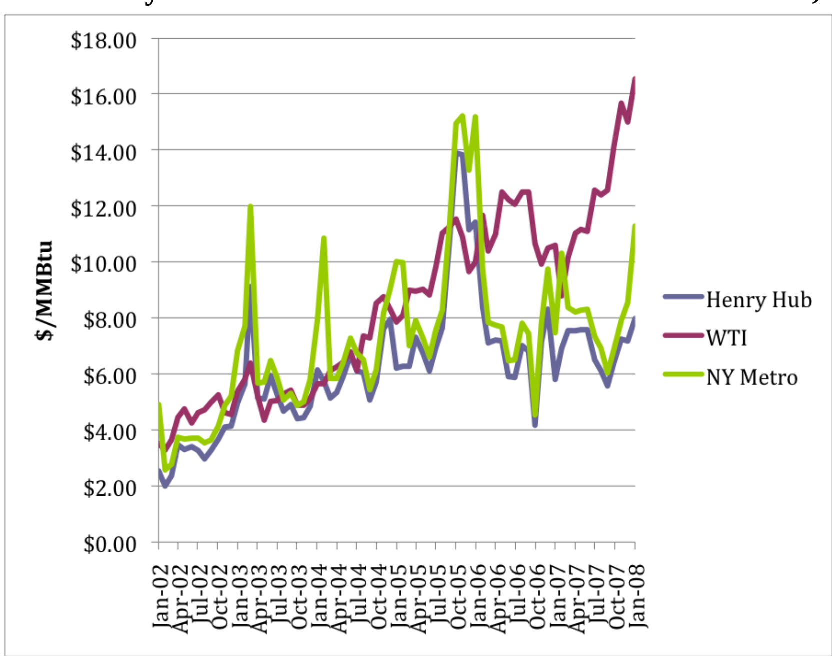
In the context of North American gas commodity markets, U.S. LNG prices are a direct reflection of US natural gas prices in the vicinity of the LNG receiving terminal where the LNG is imported. The following are seen in Figure 7:

- U.S. gas prices bore a strong relationship to crude oil in the early part of the decade, when oil prices were relatively low, i.e., below $50 per barrel.

- Later, in more recent years, there has been no gas-to-oil price relationship at all in the U.S. as crude prices have risen to levels well above market clearing prices of natural gas – consequently, as gas prices in the U.S. lagged generally below prices in Europe and Asia, LNG shipments that might otherwise have been bound for U.S. markets have tended to land elsewhere.

- In the Boston area, as an example, wholesale gas prices have borne a strong relationship to Henry Hub prices, not to oil, throughout most of the year. During winter peak heating seasons, however, Boston area gas prices characteristically peak to levels far above both Henry Hub and crude oil, since gas pipelines to the region are operating at or near full capacity and peaking gas supplies must be withdrawn from higher cost infrastructure components – principally underground storage at considerable distance, LNG peaking plants (not necessarily imported) and propane-air plants. At these times of very high local gas demand and prices, the region becomes an especially attractive destination for LNG cargoes. As a result of the infusion of LNG in local markets, Boston area gas prices are characteristically favorable compared to prices in comparable East Coast regions without an LNG terminal, e.g., the New York metropolitan region.

Figure 7 - Monthly Prices of Gas in U.S. Markets versus Crude Oil, 2002-08



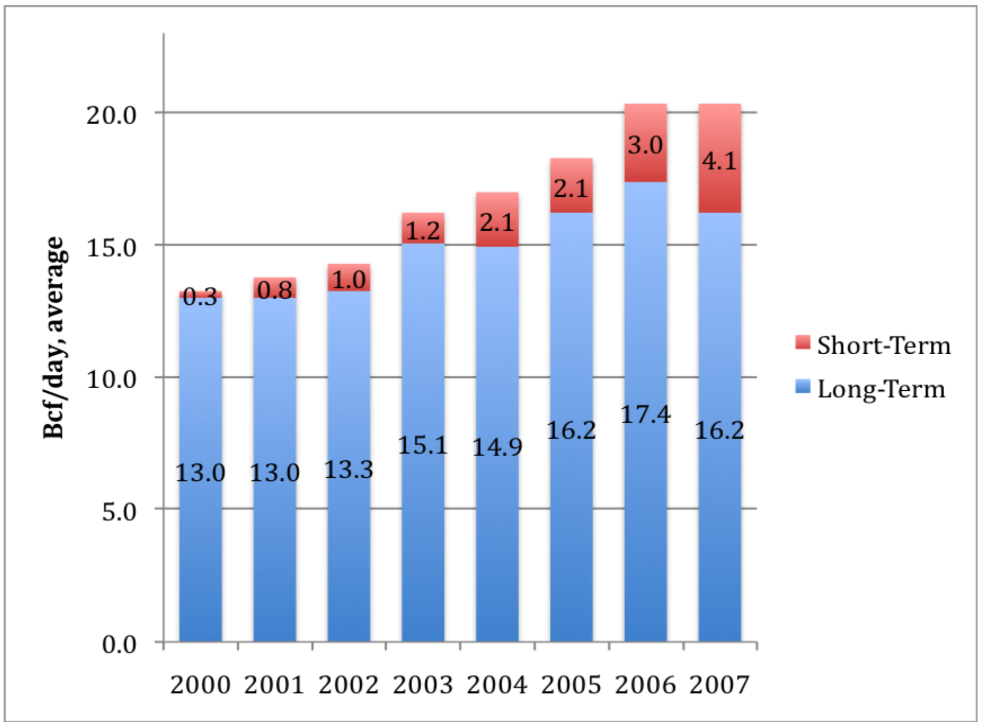
Source: BSA, 2/2008, from Platts, NYMEX.

Because of its commodity-based gas markets, the price of LNG into U.S. terminals necessarily must be competitive in local markets. Too high a price will result in rejection of the LNG in deference to other supplies, e.g., from domestic resources, while too low a price will pull LNG to buyers offering greater netbacks outside of North America.

Emerging Trends in LNG Pricing and Trade

From 2000 through 2007 worldwide LNG trade grew at a 6.3% annual rate from 103 to 158 million tonnes per year, i.e., from 13.3 Bcf/day to 20.3 Bcf/day (see Figure 8). In the same period, short-term LNG trades grew rapidly at nearly a 50% annualized rate and increased from 2% of total trade in 2000 to 23.4% of total trade in 2007. Therefore, short-term trades have grown at over 12 times the rate of the long-term transactions. Preliminary indications for 2008 confirm continued growth of spot and short-term sales in world LNG markets.

Figure 8 - Global LNG Trade in Long-Term versus Spot and Short-Term Markets



Source: Poten & Partners, Inc. database, 2/2008.

Some spot and short-term trades are based on spare or un-contracted LNG production capacity at supply projects. However, in recent years more spot and short term trades have been based on diverting and re-selling LNG that is under a long term contract to a different destination and buyer. This sort of transaction is explicitly contemplated in some modern LNG Sale and Purchase Agreements, and is known as destination flexibility. In contrast, some LNG sales contracts are silent or implicitly prohibit such diversions. Logistics considerations play a role in whether diversions are permitted and are practical. The party responsible for shipping LNG from the supply point to the destination typically secures enough ship capacity to transport contract quantities over specific shipping routes. Diversions that require more ship capacity are not practical unless uncommitted ships are available for short term charters to cover the larger shipping requirement.

The impetus behind diverting LNG cargoes is to sell LNG to the market that provides the highest net-back available at the time to the producer.[3] The U.S. has been both a recipient and supplier of diverted cargoes depending on prices and shipping costs to the U.S. relative to alternate destinations.

As the global LNG business expands, it is reasonable to expect that spot trades will also expand. With more production and export facilities, more LNG receiving terminals, and more ships; there are additional opportunities for spot LNG transactions. Moreover, recent long-term LNG sales contracts have included more destination flexibility than was seen in the past.

Spot and short-term trades are often a function of unforeseen or unplanned events. For example the shut down of a major nuclear generating complex in Japan following an earthquake raised LNG demand for power generation and required the affected utility to purchase spot cargoes to supplement quantities the utility had under long-term contract. Events such as low rainfall resulting in reduced hydro-electric power availability, or unseasonably cold temperatures can increase LNG demand and prompt purchase of spot cargoes. Conversely, warm winters and abundant rainfall can make some of a buyer's long-term contract quantity excess to its needs.

Therefore, LNG buyers who purchase sufficient LNG to meet their base load requirements must recognize that if unplanned events occur elsewhere in the world, cargoes could be diverted to that higher priced market; unless the buyer negotiates a contract with no or limited destination flexibility.

In summary, LNG markets consist largely of long-term take-or-pay contracts between suppliers and buyers. Spot markets, which now comprise one-fifth of the world's total LNG trade, are evolving mostly in the Atlantic Basin, with supplies made available by diverting contracted LNG to willing third party buyers. In the Atlantic Basin, most European and North American buyers have access to alternative sources of pipeline gas and are not entirely dependent on LNG, thus LNG spot trading will remain more of a factor there than in the inelastic Pacific Basin.

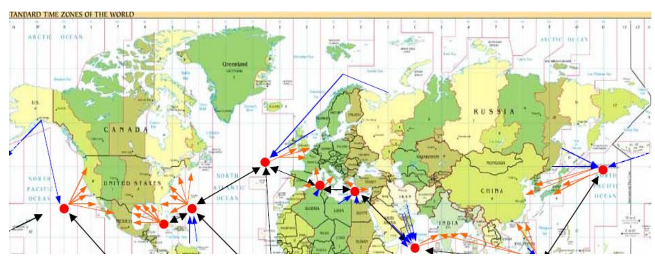
[3] Net-back in this context refers to the ex-ship LNG sales price minus costs of shipping and processing from source to terminal, thus the actual return to the producer.

G. ANALYSIS OF GLOBAL AND U.S. LNG MARKETS

The present and future competitiveness of the U.S. in the global LNG marketplace is assessed in this section. In particular, it reviews forecasts of aggregate worldwide liquefaction capacity in the next 10 years, i.e., including projects that are in operation, under construction, and proposed for development. Regional gas supply-demand balances were prepared using the WGTM model (see box at right) for the world's major natural gas consuming and producing areas, and forecasts are based on projected natural gas prices in the U.S. and in the Atlantic and Pacific basins. This analysis process was designed to assess the LNG supply that may be available to North American gas markets on a competitive basis.

World Gas Trade Model (WGTM)

The WGTM computes monthly prices and flows for every market hub over a forty year time horizon based on market fundamentals. First developed in 1990, WGTM simulates regional interactions among gas supply, transportation, and demand points to determine market clearing prices, flowing volumes, reserve additions, and pipeline entry and exit values through 2040. WGTM represents all major geographic areas (each with production, hubs, demands, terminals, etc.) interconnected by pipelines and LNG tankers. All significant existing and prospective LNG trade routes, liquefaction plants, regasification plants and LNG terminals are represented. Gas-on-gas and interfuel competition is modeled in each region. In all, WGTM comprehends nearly 1,000 regions, supply curves, shipping corridors, pipelines, storage fields, and more (simplified in the illustration below). The North American Regional Gas (NARG) model is embedded in WGTM.

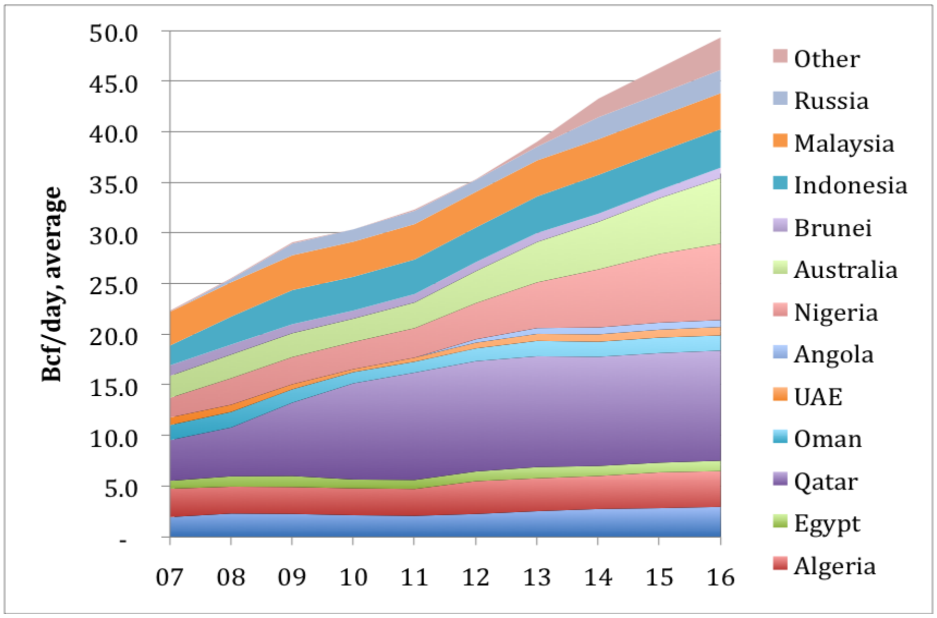


World LNG Supply

Given the tightness in the current market for LNG, the obvious question is: Will future supplies be available to satisfy the growing worldwide appetite for LNG, including that of the U.S.? After all, rapidly expanding economies in Asia will need more LNG to meet their growing energy requirements. Since they have little or no domestic supply alternatives, they have to pay whatever it takes to procure the necessary supplies (as described in preceding sections of this report). For example, Asian buyers paid record prices over $20/MMBtu for spot cargoes during the past winter (2007). Furthermore, European natural gas producers are also struggling with resource depletion, forcing them to turn to LNG for incremental supplies.

Propitiously for the U.S., worldwide LNG supplies are increasing (as described earlier) and will be able to satisfy Asian and European demands with plenty more for the U.S. Although the cost of exploration and production (E&P) and the cost of constructing LNG liquefaction facilities around the world have increased dramatically, there are still sufficient margins in order to make new supply projects economic. One must understand that much of the supply is located in countries with few alternatives besides LNG export to monetize their energy resources. As long as netback prices are sufficient to cover costs and provide acceptable returns, LNG exporting countries will continue to have an economic incentive to expand their LNG export capacities.

Figure 9 – World LNG Production by Country through 2016



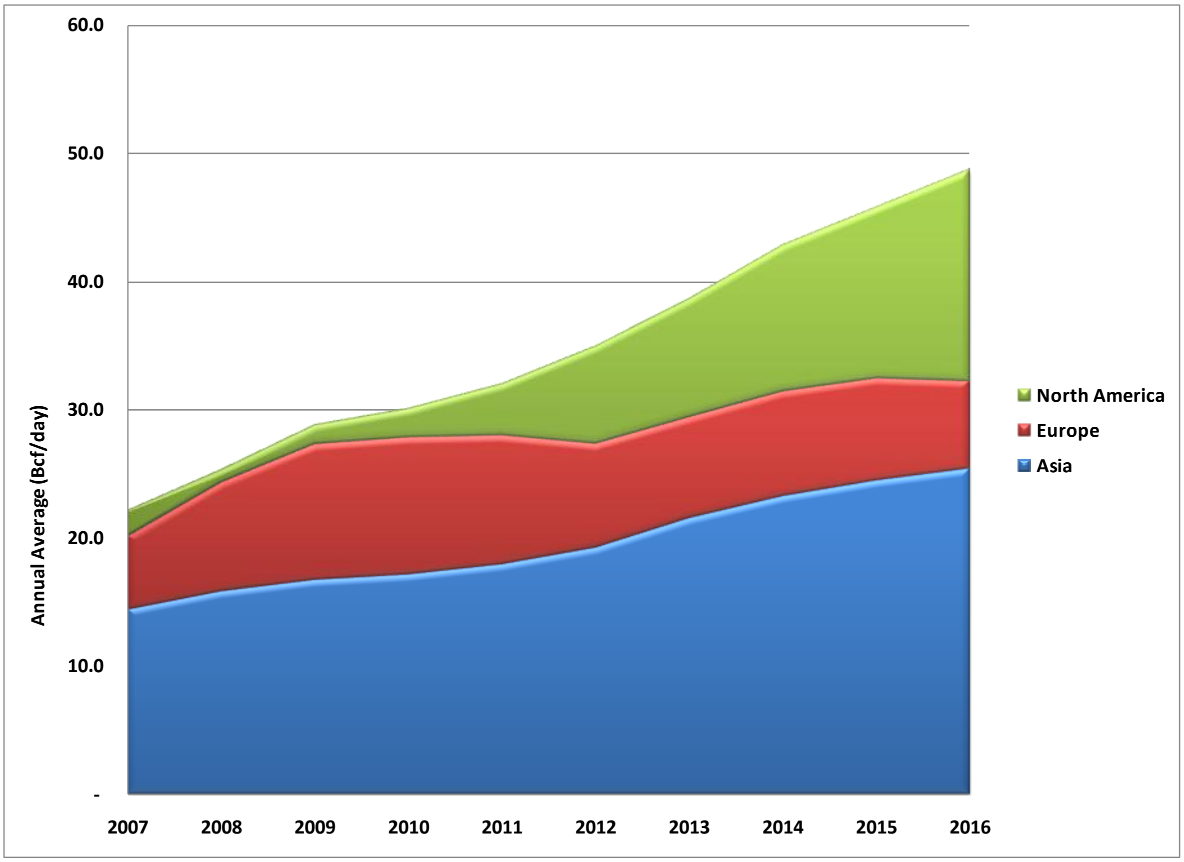
Source: Altos World Gas Trade Model, 2/2008 Base Case.

Figure 9 shows projected liquefaction export volumes by country through 2016 based on competitively driven worldwide regional gas demand and supply analysis in the WTGM. Global LNG supply more than doubles from 22.4 Bcf/day in 2007 to 49.4 Bcf/day in 2016. The supply base is diverse – by 2016 the largest increases come from Qatar, Nigeria, and Australia, which respectively supply 22%, 15% and 13% of the global market. Each possesses large gas resources that have limited outlet other than LNG, hence, each may either export gas as LNG or keep it in the ground – in net present value terms, this would be tantamount to losing much of their gas resources. Their prudent decision has been to build LNG capacity as they have been able to, with the understanding that their net realization from LNG sales will be high enough to support their capital investments plus value for the natural gas resource. In all, Atlantic Basin countries are projected to provide 15.7 Bcf/day of LNG or 32% of total LNG production and the Pacific Basin countries are projected to produce 17.2 Bcf/day of LNG representing 35% of projected global production. The Middle East comprises 13.2 Bcf/day of capacity representing 27% of global production.

World LNG Demand

Based on the study analysis, world LNG demand will experience sharp growth through 2016. As increases in production make more LNG available to energy hungry economies and displace higher cost sources, LNG trade will flourish and comprise a larger piece of the energy worldwide energy balance. As Figure 10 shows, most of the world's LNG demand growth will take place in Asia and North America, rather than Europe.

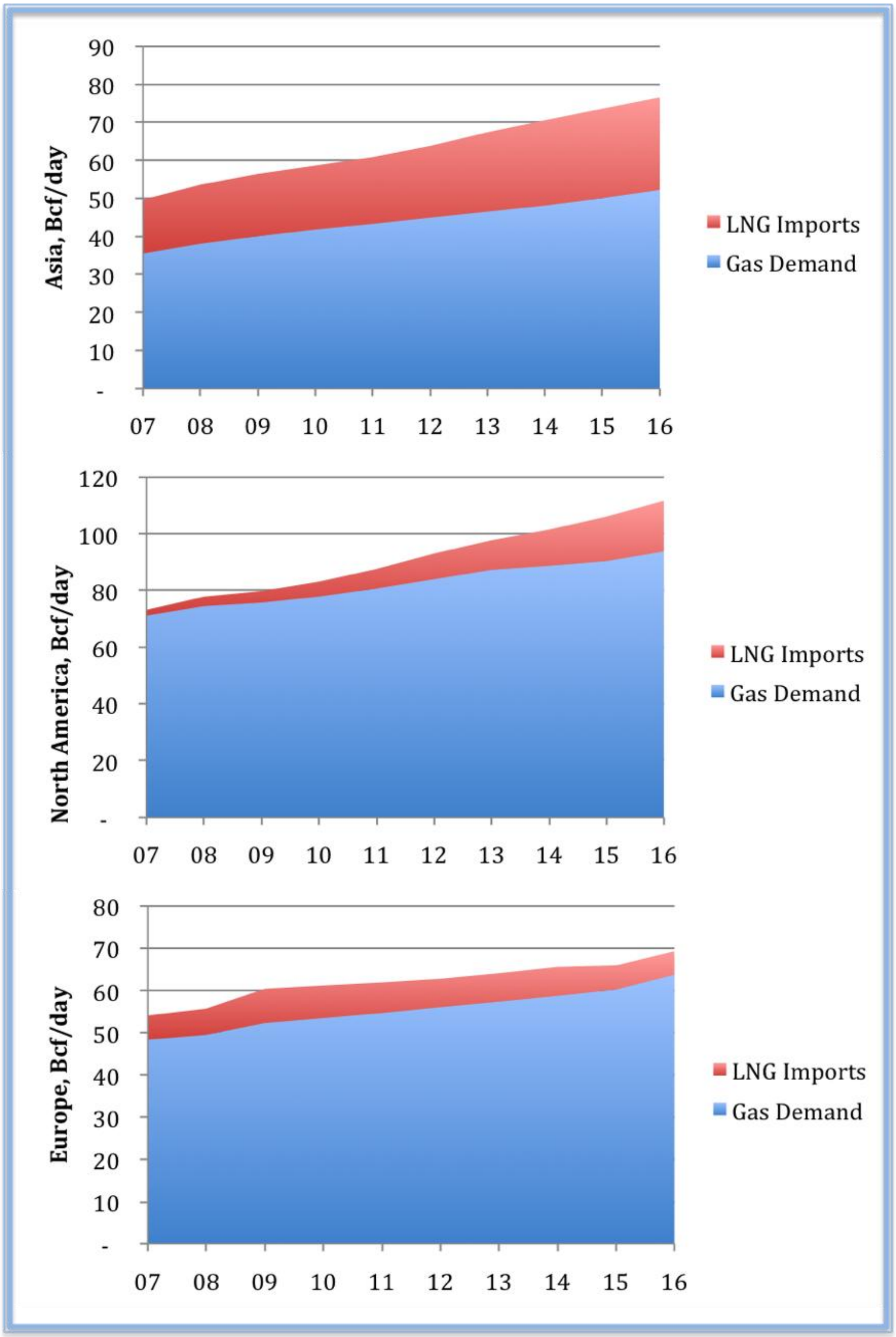
Figure 10 - Global LNG Demand by Region to 2016



Source: Altos World Gas Trade Model, 2/2008 Base Case (update).

Dynamic Asian economies require LNG as a primary source of energy. Newly emerging LNG markets in China, although still small, will more than likely see exponential growth over this period (see Figure 11). South Korean demand is projected to increase by 50% through 2016.

Figure 11 - Gas Demand and LNG Imports in Asia, North America and Europe to 2016



Source: Altos World Gas Trade Model, 2/2008 Base Case.

Based on the study analysis, LNG purchases of Japan, currently the largest buyer of LNG, will also grow steadily. Total Asian demand is forecast to grow by 75% from 2007 to 2016.

The fastest LNG demand growth among the three regions will occur in North America. As more import terminals come on line to accept LNG supplies that will become available, North American LNG consumption will grow more than eightfold from current levels to almost 17 Bcf/day in 2016. LNG will nonetheless still comprise only about 20% share of the total continental market, although it will be a vital and growing component.

European LNG demands, on the other hand, are projected to increase over the next several years and then begin to taper off. The reason for the modest growth is that there will be greater competition for the LNG supplies that will be directed towards Europe and greater competition to serve the European market. Unlike the other regions, Europe is economically accessible from several major supply areas including supply basins in Russia, the Caspian region, and North Africa, as well as domestic European supplies and LNG imports. There are a number of major new pipelines either already under construction or being planned, such as MedGaz from Algeria, Nabucco from Turkey, and Nordstream from Russia.

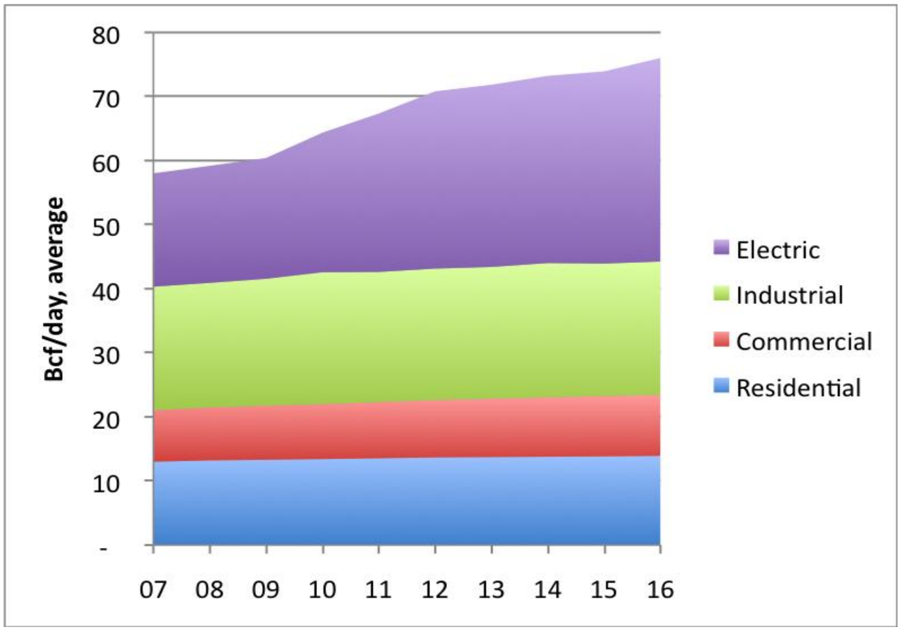
Regarding Russian gas, European gas buyers are understandably concerned about the increasing intensity of their reliance on a single source of supply. Supply diversity is becoming an important goal for the continent for this reason, and LNG represents a way to spread purchases more widely. Nonetheless, Europe's pipeline suppliers are expected to compete successfully for sales to the continent. Consequently, absent an enforceable European Union decision to require its members to secure mostly LNG supplies to further diversify their gas supply portfolios, supply from pipelines discussed above are expected to absorb most of Europe's demand growth in the time frame of this report.

U.S. Demand Forecast

The U.S. natural gas industry is poised to enter a decade of robust growth. Motivated by looming environmental regulations, the electricity sector will select natural gas as the fuel of choice for power generation for a decade or more while equally major alternative sources of electricity supplies can be developed and made available at commercial scale. More stringent regulations to limit emissions of NOx, SOx, and carbon appear to be on the horizon. These regulations will not simply be a tax, but are designed to change behavior by driving out high polluters and replacing them with lesser polluters. When costs of emissions are factored in, natural gas fired plants, especially combined cycle plants, will be the most economic choice in most regions.

U.S. energy markets are already moving in the direction of stricter carbon emission limits in anticipation of likely regulations. For example, TXU's acquirers in 2007 cancelled construction of 9.1 GW of coal-fired power plants in face of regulatory uncertainties. Not only will regulations affect choice of new builds, they will also affect the dispatch order of plants to meet load. Once these regulations are in place, they will bias the generation mix towards lower emissions gas-fired plants. Hence, as Figure 12 shows, total U.S. demand (end use consumption) increases sharply because of rising demand for natural gas in the electricity sector. Total U.S. demand rises from 58 Bcfd (21 Tcf) in 2007 to 76 Bcfd (almost 27 Tcf) in 2016. About 75% of the demand increase is due to growth in the electricity sector. The other sectors are projected to grow at a steady but low rate. The key question is: Where will the incremental supplies come from?

Figure 12 - U.S. Gas Demand by Sector to 2016



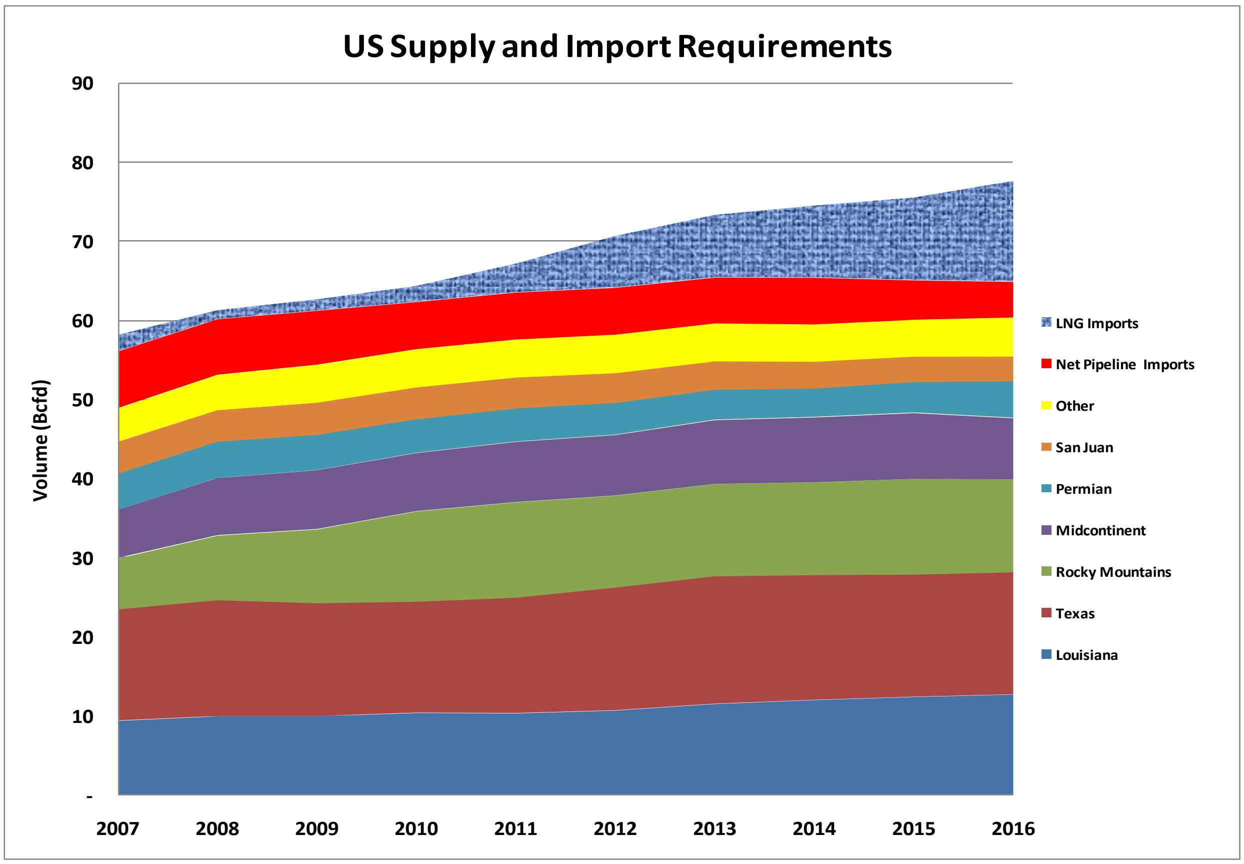
Source: Altos World Gas Trade Model, 2/2008 Base Case.

U.S. Supply Forecast

In the past decade, natural gas prices have more than doubled to levels never before sustained. High prices are indicative of scarcity.   In fact, North American market has burned through much of its traditional low cost, conventional gas supplies that had fueled the economy for decades, e.g., in the approximately $2.00-$3.00 per MMBtu range. The U.S. is not actually running out of natural gas, of course, but it is running out of cheap supplies and is transitioning to harder to find, costlier to produce unconventional gas, such as coal-bed methane, tight gas, and shales. Consequently, domestic gas production in the U.S. will be challenged to keep up with its vigorous demand growth rates.

Figure 13 shows the total projected U.S. supply by source, including domestic production, net pipeline imports and LNG imports based on the analysis by Altos using a customized version of its World Gas Trade Model for this study. It shows that U.S. production will continue to increase, rising by an average of 2.1 percent annually through 2016, but there will be greater reliance on LNG imports in order to meet the robust demand growth discussed above. Near-term production increases will come largely from Rocky Mountain and Gulf supplies. Rocky Mountain gas production will be spurred by increased pipeline capacity including the Rockies Express (REX) pipeline, due to be extended to Ohio in 2008 and fully in-service there by 2009, which will help alleviate the chronic takeaway capacity constraints that have hampered the region. High prices will stimulate production of shales and other supplies in Texas and Louisiana. In the slightly longer term, deep offshore supplies, especially offshore Louisiana, will boost production.

Figure 13 –U.S. Gas Supply Sources to 2016



Source: Altos World Gas Trade Model, 2/2008 Base Case (update).

In total, U.S. natural gas production will not peak for several more years. However, the notions of peak oil or peak gas are misguided. Production rate is not simply a matter of resource availability. It is an economic outcome. The total production rate is determined by cumulative economic decisions that take into account prices, resource potential and costs, and competing supplies. In fact, the growth of LNG imports will displace higher cost domestic production, causing an ultimate decline in production. Without LNG imports, North American production would continue to increase throughout next decade, limited only by demand elasticity, and at prices higher than otherwise projected.

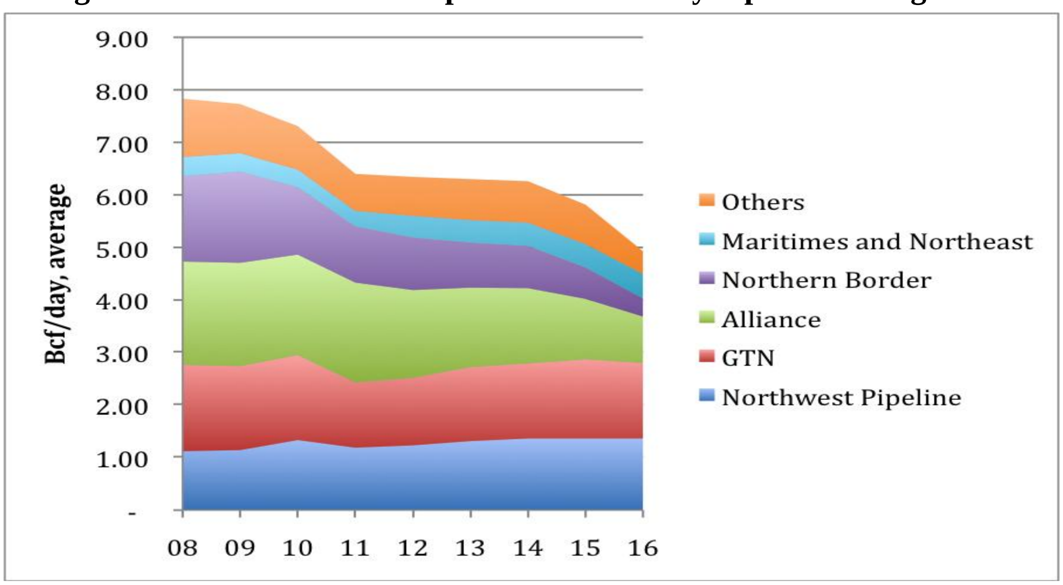
Imports from Canada

The prolific Western Canadian Sedimentary Basin that stretches across Alberta and British Columbia and is the source of the vast majority of Canadian production is in a state of permanent decline. Years of heavy production have largely depleted known reserves and the cost of finding and producing new fields is rapidly rising.

Furthermore, Canadian demand will continue to grow, primarily due to increases in electricity generation and production from oil sands. Canada possesses immense volumes of oil reserves in form of oil sands, a mixture of oil-rich bitumen, sand, clay, and water, and thus ranks second in the world only to Saudi Arabia in terms of recoverable oil reserves. To produce this vast resource, natural gas is used as fuel to steam the oil sands to extract synthetic crude oil. According to Canada's National Energy Board, oil sands production currently uses about 4% of WCSB gas production and this percentage will likely more than double within a decade.

The bottom line in that declining gas production and rising demand in Canada together portend a sharp decline in exports to the U.S. In recent years, about half of the total Canadian production (6 Tcf/year) was exported to the U.S. As Figure 14 shows, however, Canadian exports are projected to decline by nearly 50% from current levels in the next eight years. It is interesting to see how the flows are affected. Export pipelines into the Midwest show a sharp decline, but flows into the western states are fairly stable. Clearly, Canadian supplies will be relegated to high-value regional markets as lower cost supplies in more distant markets displace them. The Maritimes and Northeast Pipeline is the one exception. Its delivered volumes will grow in the future, even with a decline in Canadian gas production near Sable Island, but that is because the Canaport LNG terminal will open in 2008, targeting Northeastern U.S. markets.

Figure 14 - Canadian Gas Imports to the U.S. by Pipeline through 2016



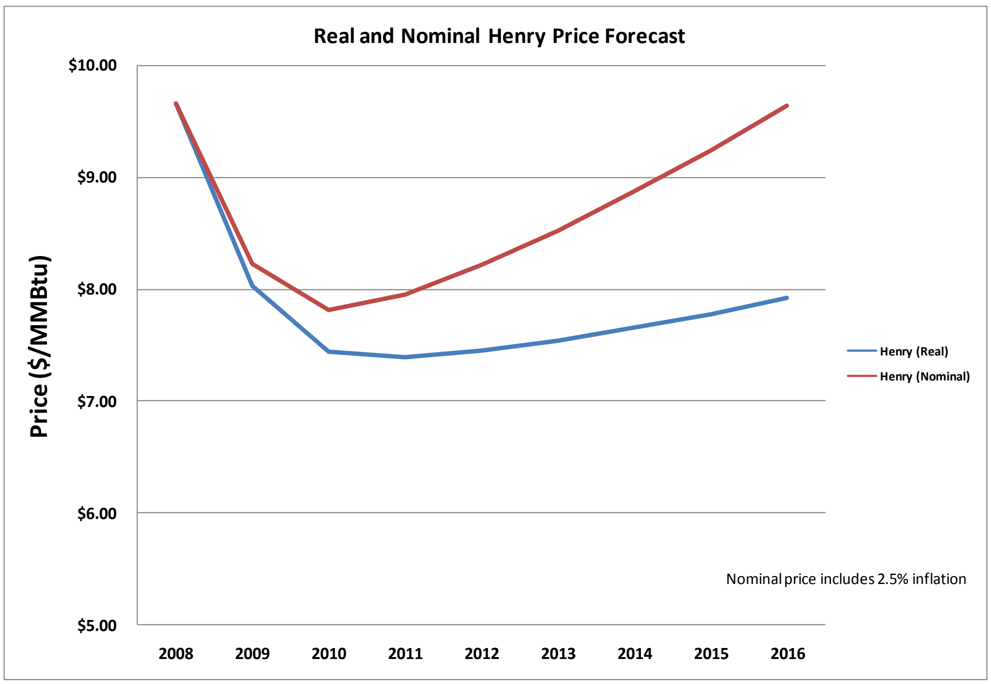
Source: Altos World Gas Trade Model, 2/2008 Base Case.

U.S. Price Forecast

U.S. gas prices will remain high by historical standards, as described above. With the depletion of low cost, conventional supplies that supplied the market for decades, the U.S. has transitioned to a higher price regime. North American natural gas resources remain sufficient for decades more, but prices will have to be elevated in order to induce the necessary investments to bring the supplies to market.

As Figure 15 shows that average annual gas prices at the Henry Hub in Louisiana will remain over $7/MMBtu. A sharp dip in prices is expected from the high 2008 price levels over the next several years as the high prices stimulate domestic supply production and LNG imports will grow as world-wide LNG supply increases. However, even with a massive increase in LNG imports, prices still remain high and do not fall to historical levels. These prices will make the U.S. a premier market for LNG.

Figure 15 – Projected Annual Average Henry Hub Gas Prices through 2016



Source: Altos World Gas Trade Model, 2/2008 Base Case.

Figure 16 shows that forecasted LNG imports grow seven-fold from current levels to meet expanded U.S. gas demand. By 2016, LNG imports grow to about 13 Bcf/day, capturing about 16% of total U.S. demand. Within a decade, a number of new terminals will be in service, including those presently under construction (as listed in Table 2) and some additional U.S. based terminals that will also be built by 2016:

- Cameron
- Freeport
- Golden Pass

- Sabine Pass
- Northeast Gateway (in Boston Harbor)
- Pascagoula, MS
- One new LNG import terminal assumed to be completed in the Pacific Northwest.

All of these terminals are either under construction today (2008) or at least have regulatory approvals in hand and appear likely to be completed within this time frame. In addition to the foregoing, LNG terminals in northwestern Mexico and coastal Canada will also be completed. Other potential U.S. terminals were "offered" to the WGTM but the model decided not to build them.

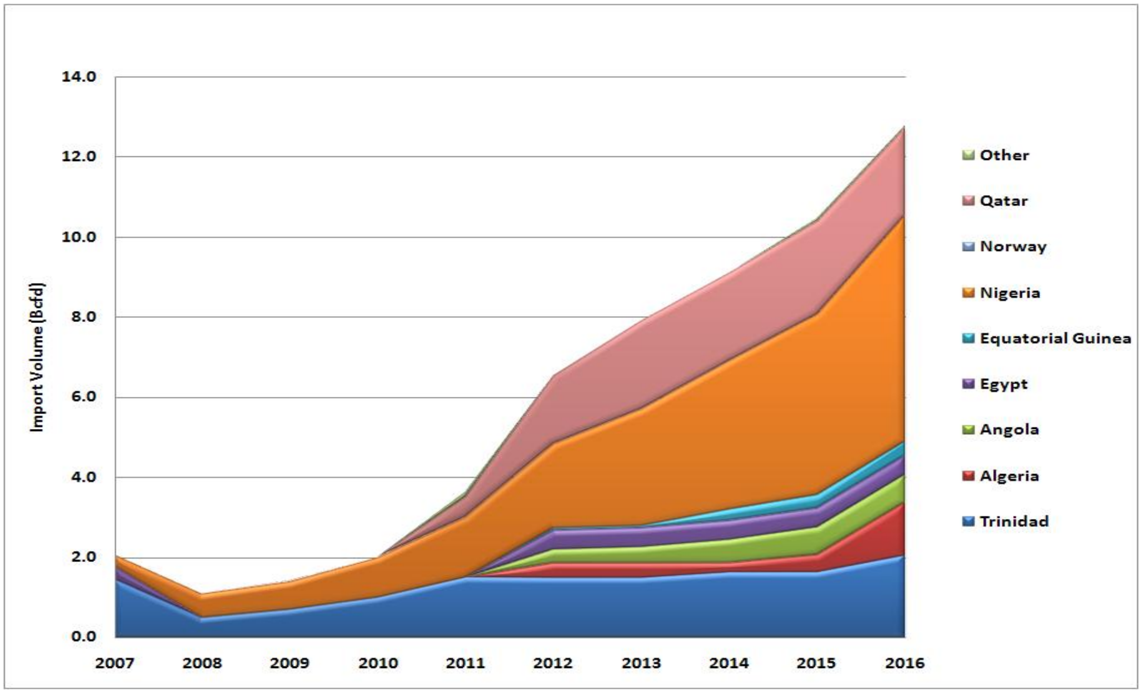
Once the East Asian utility-driven markets have contracted for the limited albeit high-priced supplies they need, then the U.S. will become a premier destination for world LNG supplies by virtue of its size, market flexibility and price. This is a large departure from its historical role as a minor player in the LNG market. However, unlike in the past, when abundant North American supplies drove down prices to the point where LNG imports were generally uneconomic, the U.S. market will be able to absorb and support the large growth in LNG imports foreseen in the future. The U.S. natural gas market is by far the largest of any single country in the world and there is a huge upside for LNG. In contrast, Japan and Korea, which are currently the largest buyers of LNG, rely on LNG for nearly all of their natural gas demand; therefore, future LNG demand growth is limited to replacement of expiring contract quantities and organic growth of their natural gas markets.

Sources of U.S. LNG Imports

Projected LNG imports to US by exporting country are shown in Figure 16 (see Page 31). The figure shows that, while U.S. demand rises 34% from 58.2 Bcf/day in 2007 to 77.8 Bcf/day in 2016, the market share of imported LNG to supply this demand rises from 3.6% in 2007 to 16% in 2016. Nigeria is expected to be the largest LNG supplier to the U.S. followed by Trinidad, Algeria and Qatar. In all, imports are expected to come from eight different countries, with all but Qatar located in the Atlantic Basin.

In particular, Nigeria has a transportation cost advantage to the U.S. over more abundant Middle Eastern supplies, i.e., the U.S. is Nigeria's best market for LNG because it is closer than Asia and its gas demand exceeds that of Europe. While the best market for Qatar will be Asian markets, Qatar will produce enough LNG to supply U.S. and European markets as well. The world LNG market a decade from now will be markedly different from the current market in which there are many LNG receiving projects chasing after limited supplies.

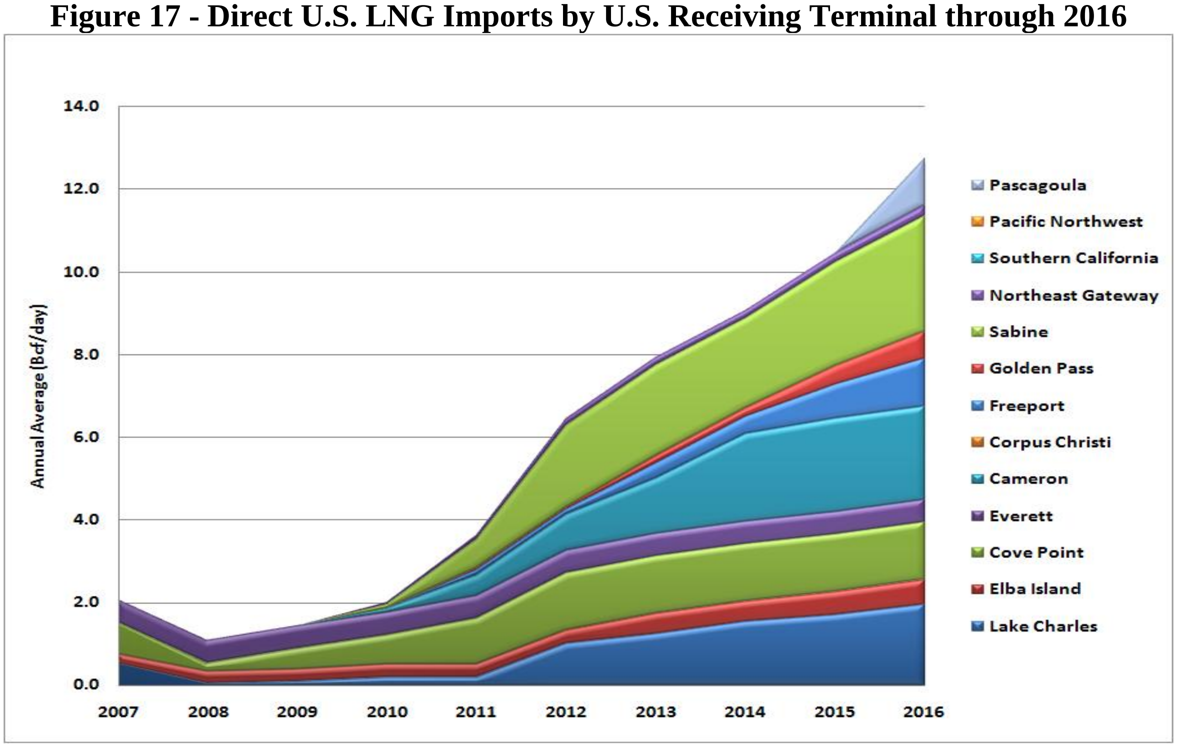
Figure 16 – Direct U.S. LNG Imports by Country of Origin through 2016



Source: Altos World Gas Trade Model, 2/2008 Base Case.

LNG imports to the U.S. are shown in Figure 17 by about a dozen import terminals. The East Coast and Gulf Coast import terminals are expected to receive 95% of projected imported LNG. The remaining 5% is expected to be imported in the West Coast.

Figure 17 - Direct U.S. LNG Imports by U.S. Receiving Terminal through 2016



Source: Altos World Gas Trade Model, 2/2008 Base Case (update). Note: chart excludes LNG received in Canada and Mexico that may enter the U.S. on pipelines.

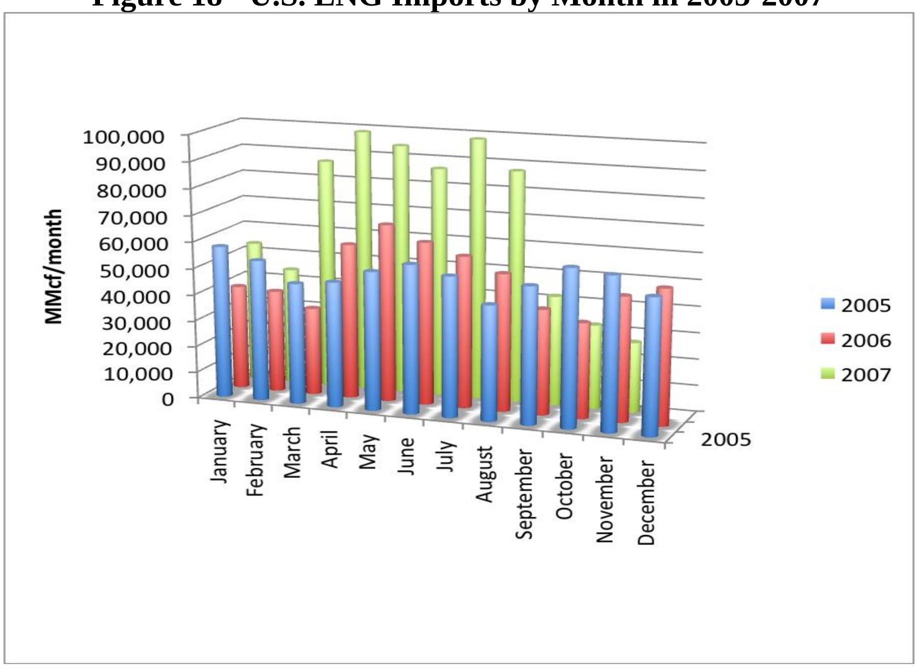
The decisions inherent in this analysis reflect the fact that shipping is the largest variable component of the cost of LNG supply chain. For example, shipping a cargo of LNG from West Africa to the Gulf Coast costs around $1.00/mcf; but the same cargo would cost $1.50/mcf to transport from the Middle East. Because of the higher cost (and voyage time) of longer shipments, LNG is often thought of as being segregated into two separate basins, as described earlier in this report. The Atlantic Basin consists of the US, East and Gulf Coasts, Trinidad, West Africa, and Europe; and the Pacific Basin comprises of Indonesia, Russia, Australia, Japan, etc. The Middle East has the flexibility to supply both the Atlantic and the Pacific Basins.

Because shipping distance matters in the economics of LNG supply, U.S. is likely to receive its LNG supply predominantly from Atlantic Basin countries unless selected countries in other basins have an unusually low gas production cost which would tend to improve the net-back economics for that country.

Seasonal LNG Markets

As world LNG trade grows, markets in diverse regions of the world will become increasingly connected. A true world natural gas market, such as one in oil, is unlikely to ever develop for natural gas due to its high cost of transportation per energy content. However, markets will be inextricably linked as LNG supply sources and receiving terminals become more abundant, and LNG contracts include more flexibility to divert cargoes. Already price arbitrage is taking place in the Atlantic LNG trade, as described above, as spot cargoes seek terminals offering the highest margins. In addition to BTUs, LNG deliveries also transmit price and volatility signals from other competing markets. Consequently, monthly LNG deliveries to the U.S. have varied significantly, as shown in Figure 18.

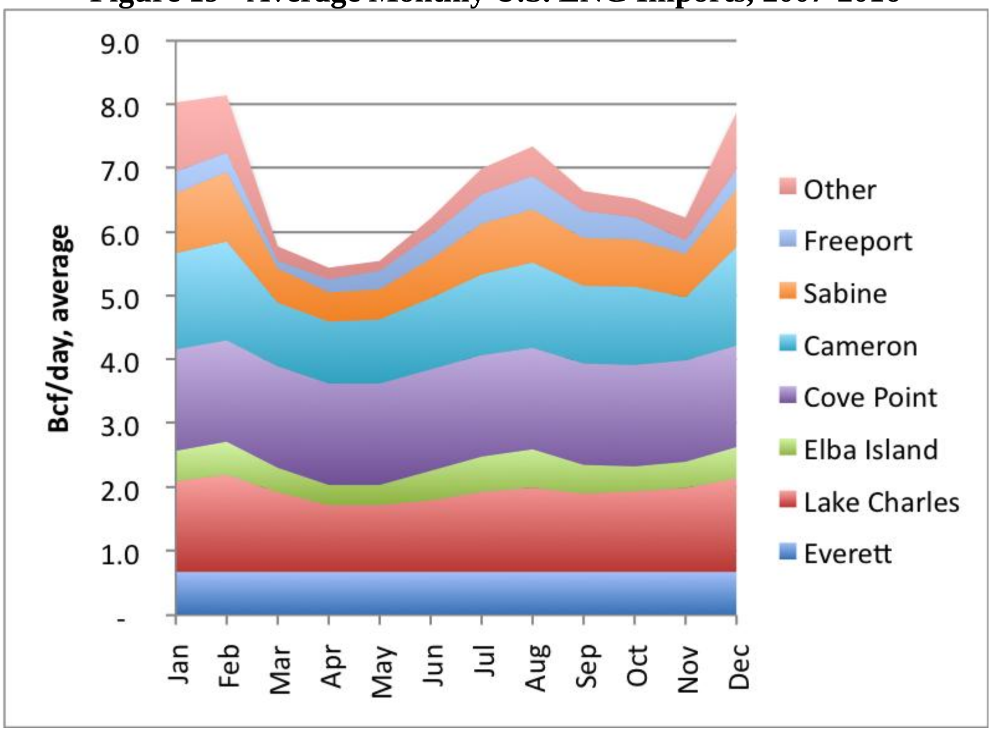
Figure 18 - U.S. LNG Imports by Month in 2005-2007



Source: Altos World Gas Trade Model, 2/2008 Base Case.

Looking at Figure 19, it is seen that LNG imports to the U.S. have tended to peak during the summer and shoulder seasons, not during the winter when U.S. demand and prices are the highest.[4] The reason for this phenomenon is that LNG cargoes were diverted to Europe and Asia where prices were more favorable to suppliers at the time. Compared to Europe and especially Asia, the U.S. has greater storage capacity relative to its demand. Given their cold winters, Northern Europe and Northeastern Asia have more seasonal demands than does the U.S., which also has large regions with mild winters, and are constantly tight on winter capacity. Since the world LNG supply market was so tight, supply was bid away from the U.S. in deference to these other markets. Even when U.S. prices peaked during the winter of 2005-06 following Hurricanes Katrina and Rita, LNG imports actually declined as prices were even more attractive in Europe and Asia. It may be that the fear of the U.S. being unable to compete for supplies in world LNG markets owes in part to the observations of recent history. In contrast, during the summer, when there is insufficient demand and storage capacity in Europe to fully accept domestic production plus contracted pipeline and LNG volumes, LNG cargoes are diverted to the U.S., largely due to its large electricity market and available storage capacity.

Figure 19 - Average Monthly U.S. LNG Imports, 2007-2016



Source: Altos World Gas Trade Model, 2/2008 Base Case.

The WGTM projects the historical pattern will change as more LNG supplies become available. The U.S. will continue to be a prime destination for summer LNG cargoes. However, more LNG will be delivered during the winter months when the U.S. need is the greatest. Asian countries that have no other alternatives will bid whatever is necessary to meet their demand, but there will be adequate supply to maintain LNG prices low enough to make it competitive in the U.S. throughout the year.

[4] The exception has been a peak in LNG deliveries to the Everett terminal in mid-winter, as described elsewhere in this report.

LNG will play a significant and economically viable role in comprising the future U.S. gas supply portfolio to meet its projected gas demand. LNG supplies to the U.S. are likely to be from a variety of sources, the transportation and regasification infrastructure are likewise likely to be in place timely. It is expected that the combined economics of the LNG chain will be competitive in meeting the US gas demand. This conclusion rests on the finding in this study that the availability of global LNG is likely to double from the current levels in the next ten years. With US gas demand rising and North American gas supplies not keeping pace, imported LNG is projected to fill the gap by providing 18% of the gas requirements for the US by 2016. The US market share of available global LNG is projected to be about 26% (13 Bcf/day) in 2016, which is a reasonable and sustainable level. Finally, because of the sensitivity of shipping costs to LNG economics, most of the imported LNG into US is likely to come from countries in the Atlantic basin with deliveries taking place at the import terminals located in the East and Gulf coasts of US.

H. LNG AND ENERGY POLICIES

This section addresses a number of questions surrounding the emergence of LNG as a major component of the nation's natural gas supplies, and its energy supplies in general. For clarity, the question and answer format is used.

How will global LNG spot markets evolve and how will these affect U.S. markets?

LNG spot markets are evolving to occupy a substantial share of the Atlantic LNG trade. U.S. gas buyers and sellers, consumers and suppliers, households and industrial gas users all benefit from the flexibility and price responsiveness inherent in this relatively free trade in LNG as long as they have and continue to cultivate the alternative of domestic gas supplies. In addition, spot markets expand the range of sellers to U.S. markets, thus contributing to supply diversity, hence security.

As described above, LNG spot markets will be centered in the Atlantic Basin for the foreseeable future, with some growth in other regions as well. For more than two decades, U.S. gas markets have functioned largely on a commodity basis in a mixture of spot and contract markets, with pipelines acting as transporters on behalf of shippers. This system has served the U.S. quite well by virtually eliminating gas shortages from the list of the industry's concerns – when markets grow tight, clearing prices rise to attract the necessary supplies, and when markets become flush with gas, clearing prices fall to attract extra demand to soak up the glut. All this happens fairly quickly within a liquid trading environment. As a recent example, high prices in the early part of this decade have stimulated enormous additions to proved reserves from Texas Barnett Shale and other higher-cost producing fields.

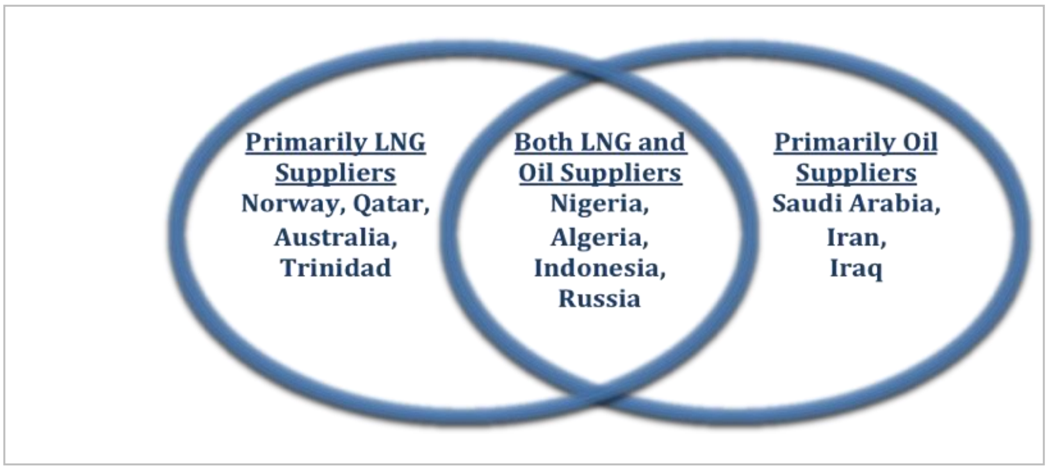
Similarly, spot trading of LNG is evolving as SPA buyers and sellers agree to divert LNG cargoes from contracted destinations to higher-value markets, often at relatively short notice. Consequently, even though the industry functions within a commercial context of long-term contracts, spot flows are common. These provide comfort to the U.S. gas industry accustomed to reliance on spot gas trading that LNG supplies can likewise respond to market pressures.

What are the geopolitical risks inherent in increasing U.S. reliance on LNG?

LNG importation is expanding the U.S.'s spectrum of fuel supplying countries, thus diluting reliance on any one of them, and reducing our concomitant geopolitical risks.

As seen throughout this report, LNG is coming to the U.S. from a wide variety of countries in the Caribbean, West Africa, the Middle East, and Asia. Some major LNG supplying nations such as Norway, Peru, Australia, Qatar, and Trinidad are relatively new to the U.S.'s list of fuel vendors, i.e., they generally do not sell us much crude oil or petroleum. Other important suppliers, such as Nigeria and Algeria, are already key sources of crude oil and petroleum products. Still other countries are major oil producers, but are not expected to sell LNG to the U.S. for many years, e.g., Saudi Arabia, Iran, Iraq, Russia. Thus, in all, LNG importation is expanding the list of fuel supplying nations, not generally relying on our oil suppliers, and is thereby contributing to commercial diversity and competition among sellers.

Figure 20 - Diversity of LNG Supplying Countries



Moreover, LNG liquefaction is extraordinarily capital intensive, as has been seen in this report, thus lender pressure will form a relatively greater pressure on suppliers to maintain flows, despite any civil strife that may take place internally.

What are the major infrastructural risks inherent in LNG, e.g., shipping hazards, transit bottlenecks, and the like, and how will these affect the reliability of U.S. fuel imports?

Infrastructure risks along the LNG supply chain are mitigated by maintaining a diverse supply portfolio on a national basis, and by expanding U.S. market-driven storage capacity. Both of these developments are consistent with the direction the U.S. gas industry is presently taking relative to LNG.

To answer this question, one must step back and review the elements of the LNG supply and distribution chain. As described at the outset of this report, natural gas is often discovered in remote areas with limited local or regional markets (sometimes this is referred to as "stranded gas"). When these discoveries are large enough, and they are located reasonably near navigable ports, they may be suitable to support development of an LNG export venture. Produced natural gas is processed to allow pipeline transportation to a liquefaction plant, where it is processed further before liquefaction and storage. LNG is loaded on specially designed LNG carriers equipped with heavily insulated tanks and transported at approximately -256^{o} F and near atmospheric pressure.

Ships unload LNG at shore-side receiving terminals where it is stored in large insulated tanks before it is vaporized for send-out through natural gas transmission and distribution pipelines. (In some cases LNG tankers with on board regasification units are used in lieu of shore-side facilities.)

From this brief and simplified discussion of the LNG chain of physical assets, one can see there are several key additions to the LNG chain compared to production and distribution of domestic natural gas. The liquefaction, shipping and receiving / storage and vaporization steps occur in facilities that are specially designed and constructed to provide safe and highly reliable service. North Asian buyers in Japan, Korea and Taiwan have little indigenous natural gas production, but nevertheless have well-established utilities that distribute gas and gas-fired electricity to their markets, based on natural gas derived almost entirely by LNG.

Operational disruptions in natural gas production and liquefaction plants, or severe weather at loading ports, on sea passages and at unloading ports can introduce delays in ship arrivals at unloading ports. However, as described in foregoing sections, U.S. supplies of LNG are likely to remain well diversified, with shipments coming from North Africa, West Africa, the Caribbean and Europe, in addition to the Middle East. The effects of short-term operational delays on U.S. supply should be limited through the combination of U.S. LNG supply diversification, LNG storage at receiving terminals, and in-ground natural gas storage. However, longer-term disruptions of large quantities of LNG would be a concern. Qatar will produce a larger share of worldwide LNG and a growing share of US imports with the attendant concern of possible disruptions to ship transit through the Straits of Hormuz. However, the LNG disruption would be less of a concern than the disruption to world oil markets, which currently derive about 45% of their supplies from the Middle East.

A separate issue is the risk of project delays that reduce projected start-up of new supply projects. These are delays and not cancellations or disruptions of supply projects, but they can reduce supply availability in the short-term. Delays have come in two forms, which were discussed earlier in the infrastructure section of this report.

- First is delay in projects taking investment decisions as a result of increased capital costs compared to projected revenues. This can postpone the start of construction while engineering designs and plans are re-evaluated.

- A second risk consists of unforeseen protracted construction periods for new LNG projects, including production, pipeline and liquefaction facilities. Strains on engineering and construction resources are delaying project completion, which is a shorter-term phenomenon.

How should state regulatory bodies and gas utilities think of impending growth in LNG importation?

LNG supplies entering the U.S. will generally be priced to meet local market conditions. Gas utilities, like other LNG buyers, will need to enter into long-term contracts to participate in the business, and can use these agreements as a way to protect the interests of, and minimize cost risks to, their customers.

The energy regulatory community, including both the state and federal levels, appears to recognize the impending rise in LNG importation. In most states where LNG is received directly, or where import terminals have been proposed, regulators have paid considerable attention to a host of issues, including siting of terminals, carriage of regasified LNG from terminals to markets, and inclusion of the gas as part of the mix of gas supplies sold to consumers. Examples of states that have considered these matters include California, Maryland, Massachusetts, Louisiana and others.

In general, the discussion of LNG pricing earlier in this report (Sections D and E) points out that LNG entering the U.S. is going to be priced at prevailing local market indicators reflective of market values wherever the gas meets the grid. In other words, because of the continent's large domestic gas production, LNG will as a rule be a price-taker for the foreseeable future. As long as this is the case, adding LNG to the mix of gas supplies will act to reduce local area gas costs.

There will inevitably be exceptions to this rule, however, since an LNG tanker is not a gas well, but instead, could be diverted to higher valued markets, e.g., Europe of the Far East. Thus, when LNG cargoes are received during times of peak local gas demand, economic pressures could act to increase, rather than decrease, local market prices. It will, therefore, be up to gas utilities and their state regulators to ensure that contracts for LNG are written in a way that protects ultimate gas consumers.

What are the overriding commercial strategies of the key players who might compete with the U.S. for LNG supplies in each region?

Pacific Basin markets tend to be dominated by gas and electric utility buyers who rely critically on LNG, while Atlantic Basin markets tend to be dominated by buyers who can also access major supplies of pipeline gas. Consequently, Atlantic and Middle Eastern markets are experiencing a greater degree of price competition, which is likely to intensify as buyers in North America increasingly participate.

Pacific Basin LNG buyers, which predominantly include Japan, Korea and Taiwan, have limited natural gas supply options other than LNG, thus their primary market focus is to secure and maintain long-term, reliable supplies to fill projected demand. They each hold a portfolio of long-term (20+ years) LNG Sale and Purchase Agreements (SPA) with Pacific Basin and Middle Eastern suppliers that provide supply diversity and reliability. These contracts bind buyers to take-or-pay provisions, but also allow limited ability to divert cargoes to alternate destinations. As noted earlier in this report, these buyers purchase LNG under short-term contracts and spot cargoes to "top up" their supply portfolio and to meet unanticipated demand. Moreover, long-term LNG prices in this region have been near parity with crude oil, with short-term and spot cargo prices even somewhat higher. Therefore, with strong service obligations to their customers and a focus on securing reliable supply, significant buyers are not expected to rely substantially on LNG spot markets in the future.

LNG buyers in India and China, relatively new to the industry, have a similar focus on securing supplies to meet growing market demand. To date, these buyers have been far more interested in securing both short-term and long-term supply rather than diverting cargoes to alternate destinations / buyers.

European LNG buyers predominantly include Spain and France (together, 75% of 2006 LNG purchases in Europe). Transatlantic arbitrage is a topic of growing interest in the European LNG industry, as evidenced by a presentation by Gaz de France (GDF) at the LNG 15 conference. The opening paragraph states “LNG Transatlantic arbitrage has become a fashionable subject of LNG players and experts. But, in fact, very few are doing it, even at a modest scale.” GDF argues that based on its analysis of 2005 data, that 13% of world LNG trade was spot or short-term and less than one quarter of that volume (or 4.5% of global LNG trade) was in arbitrage transactions. Indeed, European LNG gas and electric utility buyers purchase LNG under long-term take-or-pay contracts as part of a supply portfolio that includes pipeline gas. Some newer Atlantic Basin LNG long-term contracts enable buyers to divert cargoes from the originally anticipated market to alternate markets for any or all of the following reasons:

- The original market is fully supplied by pipeline and LNG contract volumes;
- The LNG buyer can meet its market obligations purchasing lower priced alternate supply, allowing it to divert LNG cargoes to higher priced mark; and/or
- The buyer has explicitly purchased LNG with free destination to enable it to engage in arbitrage activities.

When examining short-term and spot trading activity, it is difficult to distinguish the source of cargoes among the three broad categories listed above. However, it is clear that the U.S. received large quantities of short-term and spot LNG in 2005-2007, and that a substantial quantity of this LNG was contracted long-term between Atlantic LNG and Spanish buyers, but diverted to the U.S.

APPENDIX

A1 - U.S. Gas Demand by Sector, 2007-2016 (Bcf/day)

	Residential	Commercial	Industrial	Electric
2007	13.002	8.059	19.265	17.689
2008	13.214	8.278	19.431	18.265
2009	13.310	8.434	19.816	18.840
2010	13.422	8.581	20.577	21.781
2011	13.544	8.778	20.306	24.722
2012	13.678	8.959	20.508	27.663
2013	13.728	9.137	20.537	28.440
2014	13.784	9.281	20.944	29.217
2015	13.840	9.422	20.669	29.994
2016	13.916	9.539	20.792	31.763

A2 - U.S. Gas Supply by Source, 2007-2016 (Bcf/day)

	Louisiana	Texas	Rocky Mtns	Mid-continent	Permian	San Juan	Other	Net Pipeline Imports	LNG Imports
2007	9.4	14.2	6.4	6.1	4.6	4.1	4.2	7.2	2.1
2008	10.0	14.8	8.1	7.3	4.6	4.0	4.4	7.1	1.1
2009	10.0	14.4	9.3	7.5	4.5	4.1	4.8	6.9	1.4
2010	10.4	14.1	11.4	7.4	4.3	4.0	4.8	6.0	2.0
2011	10.3	14.7	12.0	7.7	4.2	3.9	4.8	6.0	3.6
2012	10.7	15.6	11.6	7.7	4.0	3.8	4.9	6.0	6.5
2013	11.5	16.2	11.6	8.1	3.8	3.6	4.8	5.8	7.9
2014	12.0	15.9	11.7	8.3	3.6	3.4	4.7	5.9	9.1
2015	12.4	15.5	12.1	8.4	3.9	3.2	4.7	5.0	10.4
2016	12.7	15.5	11.7	7.8	4.6	3.1	4.9	4.5	12.8

A3 - Worldwide LNG Production Capacity, by Stage of Project, as of March 2008 (Bcf/day)

	Operating in 2008	Under Construction	In Advanced Planning	Potential
Atlantic Basin	10.061	1.587	6.067	7.787
Pacific Basin	8.919	4.107	3.200	5.413
Middle East	6.196	7.133	0.000	3.613

A4 - Gas and LNG Demand by Basin, 2007-2016 (Bcf/day)

	Asia		Europe		North America	
	Gas Demand	LNG Imports	Gas Demand	LNG Imports	Gas Demand	LNG Imports
2007	35.556	14.418	48.327	5.748	71.175	2.04
2008	38.133	15.842	49.484	8.51	74.540	1.03
2009	40.080	16.731	52.287	10.60	75.796	1.54
2010	41.864	17.150	53.470	10.71	77.907	2.28
2011	43.334	17.938	54.660	10.08	80.750	4.04
2012	44.986	19.228	56.044	8.13	84.053	7.63
2013	46.571	21.521	57.344	7.90	87.330	9.25
2014	48.160	23.226	58.730	8.20	88.746	11.44
2015	50.124	24.443	60.233	7.99	90.439	13.36
2016	52.278	25.377	63.743	6.83	93.871	16.55

A5 - Direct U.S. LNG Imports by Country of Origin, 2007-2016 (Bcf/day)

	Algeria	Angola	Trinidad	Egypt	Equat. Guinea	Nigeria	Norway	Qatar	Other	Total
2007	0.00	0.00	1.46	0.33	0.00	0.29	0.00	0.00	0.00	2.08
2008	0.00	0.00	0.50	0.00	0.00	0.60	0.00	0.00	0.00	1.10
2009	0.00	0.00	0.70	0.00	0.00	0.70	0.00	0.01	0.00	1.41
2010	0.00	0.00	1.03	0.00	0.00	0.97	0.00	0.00	0.00	2.00
2011	0.00	0.00	1.48	0.00	0.00	1.52	0.00	0.50	0.13	3.63
2012	0.37	0.34	1.48	0.48	0.05	2.10	0.00	1.70	0.00	6.53
2013	0.37	0.40	1.48	0.48	0.05	2.91	0.00	2.20	0.00	7.90
2014	0.24	0.58	1.62	0.48	0.28	3.70	0.00	2.19	0.00	9.09
2015	0.44	0.68	1.62	0.48	0.34	4.50	0.00	2.32	0.07	10.45
2016	1.32	0.70	2.00	0.48	0.36	5.68	0.00	2.19	0.04	12.76

A6 - Average Prices of LNG Delivered to East Asian Utilities, 2004-2007, $/MMBtu

	Japan	Korea	Taiwan	JCC, 3-Month Average
Jan-04	4.76	5.01	5.50	5.25
Feb-04	4.82	4.99	5.52	5.34
Mar-04	4.90	4.97	5.39	5.35
Apr-04	4.93	5.46	5.79	5.50
May-04	4.93	5.55	5.81	5.64
Jun-04	5.06	5.96	6.15	5.95
Jul-04	5.09	6.05	6.05	6.13
Aug-04	5.18	6.14	6.28	6.32
Sep-04	5.45	6.32	6.81	6.56
Oct-04	5.54	6.39	7.28	6.74
Nov-04	5.51	6.65	7.71	6.98
Dec-04	5.70	6.36	6.91	6.90
Jan-05	5.44	5.81	6.51	6.81
Feb-05	5.60	6.45	7.22	6.77
Mar-05	5.61	6.28	7.34	6.93
Apr-05	5.69	6.83	7.30	7.50
May-05	5.75	7.45	7.26	8.07
Jun-05	5.70	7.55	6.81	8.46
Jul-05	6.05	8.12	7.34	8.73
Aug-05	6.24	8.44	7.91	8.97
Sep-05	6.41	8.13	8.23	9.53
Oct-05	6.45	9.16	8.31	9.91
Nov-05	6.60	8.59	7.96	10.03
Dec-05	6.47	8.77	8.17	9.76
Jan-06	6.57	8.22	9.95	9.57
Feb-06	6.99	9.16	9.82	9.76
Mar-06	7.18	8.19	9.56	10.12
Apr-06	6.74	8.65	8.13	10.40
May-06	6.93	9.06	8.71	10.71
Jun-06	7.13	9.38	8.13	11.09
Jul-06	6.89	9.70	9.41	11.47
Aug-06	7.36	10.00	9.67	11.77
Sep-06	7.68	10.10	9.54	12.01
Oct-06	7.22	9.98	9.70	11.81
Nov-06	7.24	8.50	8.75	11.13
Dec-06	7.37	9.51	9.63	10.37
Jan-07	7.14	9.63	9.67	10.14
Feb-07	6.92	8.87	8.98	9.87
Mar-07	6.89	8.85	7.80	9.78
Apr-07	7.11	8.73	7.54	9.81
May-07	7.25	8.70	9.44	10.41
Jun-07	7.14	9.14	9.47	11.00
Jul-07	7.29	9.08	9.79	11.48
Aug-07	7.72	9.99	9.93	11.85
Sep-07	7.93	9.68	9.59	12.06
Oct-07	8.57			12.45
Nov-07	9.15			12.95

A7 - Average Prices of LNG Delivered to Spain from Seven Suppliers, 2004-2007, $/MMBtu

	Algeria	Egypt	Nigeria	Oman	Qatar	Trinidad	Brent
Jan-04	3.82		4.22		3.80		5.32
Feb-04	3.95		3.83	3.81	3.65		5.25
Mar-04	3.78		3.77	2.89	3.50		5.72
Apr-04	3.82		3.63	2.81	3.50		5.71
May-04	3.86		3.49		3.68		6.39
Jun-04	3.82		3.73	3.16	3.89		5.98
Jul-04	4.08		3.59	3.30	4.04		6.50
Aug-04	3.88		4.03	2.84	4.02		7.27
Sep-04	4.07		3.83	2.83	4.03		7.35
Oct-04	4.37		4.14	3.44	4.41		8.47
Nov-04	4.67		4.09	3.58	4.66		7.33
Dec-04	4.66		4.26	3.44	4.73		6.73
Jan-05	5.35		4.50	4.08	4.71		7.57
Feb-05	4.97	5.34	4.56	3.25	4.89	4.85	7.73
Mar-05	5.07	4.68	4.93	4.46	4.93	4.66	9.03
Apr-05	5.33	4.38	4.76	4.23	4.88		8.82
May-05	5.30	4.80	4.45		4.90		8.27
Jun-05	5.07	4.24	4.50	4.53	4.48		9.24
Jul-05	5.07	5.31	4.93		4.89		9.78
Aug-05	5.80	5.04	5.15	5.17	5.29		10.88
Sep-05	5.68	5.42	4.85	5.07	5.18		10.70
Oct-05	5.53	4.57	5.08		5.84		9.96
Nov-05	6.15	4.48	5.52	5.11	6.11	6.14	9.39
Dec-05	6.61	5.07	6.07	4.85	4.90	6.28	9.67
Jan-06	8.47	6.13	7.16	6.83	6.52	6.63	10.71
Feb-06	6.24	7.01	6.38	6.34	6.35	6.56	10.24
Mar-06	6.09	6.10	6.42	5.69	6.56	6.47	10.55
Apr-06	6.85	7.06	6.18	5.72	6.52	5.75	11.95
May-06	7.14	6.36	6.71		6.89	6.33	11.87
Jun-06	5.87	6.57	6.29		6.84	5.03	11.66
Jul-06	7.13		6.71	5.99	7.43	7.23	12.53
Aug-06	6.92	6.65	6.81	6.11	7.20	6.21	12.45
Sep-06	7.63	6.82	6.85		7.50	3.91	10.54
Oct-06	7.23	6.70	6.79		7.22	6.38	9.83
Nov-06	7.11	7.72	7.08	6.31	7.24	6.79	9.99
Dec-06	6.90	9.20	7.52		7.65	6.34	10.62
Jan-07	7.06	9.70	6.93		7.96	7.36	9.13
Feb-07	7.07	7.57	6.49		6.94	6.98	9.79
Mar-07	7.33	6.69	6.31		6.77	5.71	10.55
Apr-07	7.25	6.59	6.13		6.13	6.34	11.48
May-07	6.29	6.05	5.55		6.80	5.02	11.43

Jun-07	6.54	6.51	6.13		6.06	6.14	12.08
Jul-07	6.91	6.21	5.88	5.96	6.29	6.38	13.08
Aug-07							12.03
Sep-07							13.12
Oct-07							14.00
Nov-07							15.72
Dec-07							15.46

A8 - Monthly Prices of Gas in U.S. Markets versus Crude Oil, 2002-2008, $/MMBtu

	Henry Hub	Crude Oil (WTI)	NY Metro
Jan-02	2.56	3.52	4.92
Feb-02	2.01	3.29	2.58
Mar-02	2.39	3.67	2.76
Apr-02	3.47	4.46	3.73
May-02	3.32	4.75	3.66
Jun-02	3.42	4.25	3.70
Jul-02	3.28	4.63	3.72
Aug-02	2.98	4.72	3.53
Sep-02	3.29	4.99	3.64
Oct-02	3.69	5.27	4.13
Nov-02	4.13	4.62	4.87
Dec-02	4.14	4.55	5.20
Jan-03	4.99	5.41	6.84
Feb-03	5.66	5.84	7.71
Mar-03	9.13	6.41	11.99
Apr-03	5.15	5.20	5.69
May-03	5.12	4.35	5.70
Jun-03	5.95	5.02	6.48
Jul-03	5.29	5.05	5.87
Aug-03	4.69	5.29	5.08
Sep-03	4.93	5.43	5.32
Oct-03	4.43	4.90	4.89
Nov-03	4.46	4.91	5.01
Dec-03	4.86	5.13	5.80
Jan-04	6.15	5.65	7.96
Feb-04	5.78	5.66	10.84
Mar-04	5.15	6.12	5.84
Apr-04	5.37	6.25	5.85
May-04	5.94	6.43	6.41
Jun-04	6.68	6.80	7.29
Jul-04	6.14	6.15	6.74
Aug-04	6.05	7.37	6.53
Sep-04	5.08	7.29	5.45
Oct-04	5.72	8.54	6.14
Nov-04	7.63	8.78	8.20
Dec-04	7.98	8.35	9.02
Jan-05	6.21	7.87	10.03
Feb-05	6.29	8.09	9.98
Mar-05	6.30	9.01	7.03
Apr-05	7.32	8.97	7.92
May-05	6.75	9.04	7.27
Jun-05	6.12	8.83	6.60
Jul-05	6.98	9.83	7.58
Aug-05	7.65	11.03	8.30
Sep-05	10.85	11.28	11.40
Oct-05	13.91	11.55	14.97
Nov-05	13.83	10.90	15.23
Dec-05	11.18	9.68	13.29

Jan-06	11.43	10.00	15.21
Feb-06	8.40	11.68	9.71
Mar-06	7.11	10.40	7.85
Apr-06	7.23	11.02	7.74
May-06	7.20	12.50	7.68
Jun-06	5.93	12.24	6.49
Jul-06	5.89	12.07	6.50
Aug-06	7.04	12.50	7.83
Sep-06	6.82	12.52	7.44
Oct-06	4.20	10.69	4.54
Nov-06	7.15	9.94	7.82
Dec-06	8.32	10.52	9.74
Jan-07	5.84	10.60	7.48
Feb-07	6.92	8.79	10.34
Mar-07	7.55	10.17	8.40
Apr-07	7.56	11.03	8.21
May-07	7.60	11.17	8.28
Jun-07	7.59	11.12	8.32
Jul-07	6.54	12.59	7.34
Aug-07	6.11	12.41	6.90
Sep-07	5.59	12.59	6.03
Oct-07	6.42	14.14	6.87
Nov-07	7.27	15.69	7.92
Dec-07	7.20	15.00	8.54
Jan-08	8.00	16.55	11.29

A9 - World LNG Production by Country, 2007-2016 (Bcf/day)

	Trinidad	Algeria	Egypt	Qatar	Oman	UAE	Angola	Nigeria
2007	1.974	2.801	0.782	4.018	1.485	0.748	0.000	1.941
2008	2.322	2.657	1.020	4.827	1.534	0.708	0.000	2.618
2009	2.285	2.657	1.089	7.243	1.319	0.499	0.000	2.684
2010	2.157	2.657	0.871	9.503	1.107	0.294	0.000	2.684
2011	2.093	2.657	0.889	10.607	1.078	0.399	0.000	2.916
2012	2.281	3.241	0.958	10.896	1.262	0.562	0.339	3.568
2013	2.555	3.248	1.107	10.946	1.521	0.690	0.578	4.515
2014	2.771	3.260	0.994	10.777	1.488	0.732	0.684	5.734
2015	2.856	3.535	0.958	10.821	1.534	0.777	0.697	6.789
2016	2.981	3.537	1.025	10.874	1.500	0.838	0.682	7.545

	Australia	Brunei	Indonesia	Malaysia	Russia	Other	Total
2007	2.175	1.037	1.951	3.343	0.000	0.107	22.361
2008	2.344	0.985	2.764	3.393	0.326	0.081	25.578
2009	2.360	0.892	3.365	3.441	1.157	0.127	29.118
2010	2.307	0.806	3.330	3.467	1.222	0.000	30.404
2011	2.539	0.834	3.414	3.497	1.311	0.126	32.361
2012	3.167	0.892	3.417	3.520	1.188	0.053	35.345
2013	3.989	0.892	3.605	3.567	1.357	0.490	39.061
2014	4.696	0.808	3.830	3.522	2.174	1.837	43.307
2015	5.510	0.810	3.789	3.515	2.197	2.547	46.335
2016	6.492	1.026	3.797	3.561	2.301	3.206	49.363

A10 - Canadian Gas Imports to the U.S. by Pipeline, 2008-2016, Bcf/day

	Northwest Pipeline	GTN	Alliance	Northern Border	Maritimes and Northeast	Others	Total
2008	1.122	1.643	1.967	1.629	0.361	1.110	7.832
2009	1.142	1.599	1.967	1.737	0.348	0.937	7.730
2010	1.333	1.619	1.911	1.283	0.334	0.828	7.309
2011	1.189	1.242	1.900	1.070	0.296	0.703	6.400
2012	1.233	1.284	1.673	1.000	0.412	0.741	6.343
2013	1.314	1.410	1.511	0.859	0.427	0.781	6.301
2014	1.363	1.429	1.432	0.806	0.443	0.788	6.262
2015	1.363	1.508	1.150	0.598	0.443	0.752	5.816
2016	1.363	1.439	0.882	0.348	0.464	0.430	4.926

A11 - Projected Annual Average Henry Hub Gas Prices, 2008-2016, $/MMBtu

	Henry (Real)	Henry (Nominal)
2008	6.15	6.15
2009	6.37	6.53
2010	6.04	6.34
2011	6.42	6.91
2012	6.54	7.22
2013	6.84	7.74
2014	7.09	8.23
2015	7.12	8.46
2016	7.27	8.86

A12 - Direct U.S. LNG Imports by U.S. Receiving Terminal, 2008-2016, Bcf/day

	Lake Charles	Elba Island	Cove Point	Everett	Cameron	Corpus Christi	Creole Trail
2007	0.533	0.235	0.765	0.547	0.000	0.000	0.000
2008	0.682	0.436	0.765	0.547	0.487	0.000	0.000
2009	0.778	0.411	1.376	0.547	0.318	0.000	0.000
2010	0.837	0.320	1.376	0.547	0.671	0.000	0.000
2011	1.013	0.320	1.376	0.547	0.871	0.000	0.000
2012	1.243	0.494	1.376	0.547	1.335	0.000	0.000
2013	1.539	0.490	1.376	0.547	2.117	0.000	0.000
2014	1.698	0.560	1.376	0.547	2.256	0.000	0.000
2015	1.951	0.601	1.376	0.547	2.256	0.000	0.000
2016	2.064	0.664	1.376	0.547	2.255	0.000	0.000

	Freeport	Golden Pass	Sabine	Northeast Gateway	Southern California	Pacific Northwest	Pascagoula
2007	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2008	0.000	0.000	0.347	0.132	0.000	0.000	0.000
2009	0.000	0.000	0.326	0.132	0.000	0.000	0.000
2010	0.000	0.000	1.111	0.134	0.000	0.000	0.000
2011	0.133	0.039	1.994	0.162	0.000	0.000	0.000
2012	0.373	0.181	2.197	0.185	0.000	0.000	0.000
2013	0.425	0.209	2.174	0.188	0.000	0.000	0.000
2014	0.830	0.454	2.507	0.221	0.000	0.000	0.000
2015	1.166	0.660	2.797	0.256	0.000	0.000	1.147
2016	1.298	0.726	2.937	0.266	0.000	0.765	1.147

	Houston Ship Channel	Total
2007	0.000	2.079
2008	0.000	3.395
2009	0.000	3.889
2010	0.000	4.996
2011	0.000	6.456
2012	0.000	7.932
2013	0.000	9.065
2014	0.000	10.449
2015	0.000	12.757
2016	0.000	14.045

A13 - Total U.S. LNG Imports by Month, Bcf/month

	2005	2006	2007
Jan	57,829	39,466	53,441
Feb	53,538	38,737	44,101
Mar	45,885	33,228	86,848
Apr	47,567	58,792	98,742
May	52,628	67,271	94,319
Jun	56,377	61,705	86,587
Jul	53,141	57,550	98,344
Aug	43,630	52,122	87,471
Sep	51,824	40,004	41,654
Oct	59,576	36,185	31,939
Nov	57,977	47,236	26,539
Dec	51,288	51,240	NA
Total	631,260	583,536	749,985

A14 - Average Monthly U.S. LNG Imports, 2007-2016

	Everett	Lake Charles	Elba Island	Cove Point	Cameron	Sabine	Freeport	Other
Jan	0.679	1.422	0.475	1.589	1.506	0.939	0.343	1.080
Feb	0.679	1.520	0.521	1.589	1.547	1.092	0.300	0.900
Mar	0.679	1.248	0.384	1.589	0.999	0.538	0.114	0.230
Apr	0.679	1.046	0.316	1.588	0.971	0.459	0.204	0.182
May	0.679	1.047	0.314	1.588	1.005	0.475	0.287	0.154
Jun	0.679	1.121	0.463	1.589	1.117	0.613	0.372	0.262
Jul	0.679	1.252	0.555	1.589	1.266	0.795	0.457	0.404
Aug	0.679	1.322	0.600	1.589	1.338	0.834	0.521	0.463
Sep	0.679	1.226	0.451	1.589	1.216	0.748	0.424	0.313
Oct	0.679	1.265	0.388	1.589	1.229	0.742	0.342	0.292
Nov	0.679	1.316	0.410	1.589	0.987	0.680	0.212	0.357
Dec	0.679	1.467	0.490	1.589	1.549	0.907	0.300	0.900