Liquefied Natural Gas (LNG) Markets in Transition: Implications for U.S. Supply and Price

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Summary

Natural gas consumption in the United States is expected to increase substantially over the coming decades primarily because of its usefulness in generating relatively clean electricity. Domestic supplies are projected to be unable to meet increasing demand because existing fields are yielding less production and new drilling efforts are not replicating past success rates. Pipeline imports from Canada are also projected to decline. Various alternatives exist that might close the demand and supply gap, with imports of liquefied natural gas (LNG) being touted as one of the most promising.

As a result of projected supply increases, much of the LNG debate and analysis has focused on the availability of the physical facilities needed to bring larger quantities of LNG into the United States. However, other changes in LNG market structure and practices are also likely to be needed before expanded quantities of LNG can be supplied at competitive market prices.

The traditional LNG market, which developed in the 1970s can be characterized as capital intensive and long term, with restrictive contractual provisions. Risk is managed through the sales contract, and the whole production chain is committed in advance to ensure economic viability of the project. Many of the characteristics of this market are inconsistent with a more competitive market environment.

The LNG market is only in the early stages of a transition which incorporates a viable short term spot market, price discovery through gas-to-gas competition, financial instruments to manage risk, competitive capital acquisition, open access of various links in the supply chain to insure efficient resource allocation, and an expanded set of producers and buyers. Full realization of the potential of LNG to provide a stable source of supply to U.S. markets, as well as providing a price cap to U.S. natural gas prices, awaits changes in market structure, investment in receiving terminals, as well as additional sources of supply.

The extent to which the LNG market develops market-based characteristics may determine the extent to which other sources of natural gas supply are needed. An Alaskan natural gas pipeline, development of restricted prospective resources, and developing advanced technologies to extract natural gas from unconventional sources may be considered as substitutes in closing the projected demand and supply gap.

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Introduction

This report analyzes the potential for liquefied natural gas (LNG) to become a flexible, dependable, source of natural gas supply for the U.S. market, while also setting a cap on natural gas prices. The potential for increasing U.S. LNG use is usually framed in terms of expanding the capacity of existing receiving terminals, and the challenges encountered in siting and constructing new terminals. While adding the physical capacity to receive more LNG is important, significant changes in the structure and practices of the LNG market are also likely to be required before LNG might assume its projected economic role in U.S. energy supply. These changes center on the structure of LNG markets and transactions, including contract design, risk sharing, financing, transportation, and the emergence of a competitive spot market that determines price through a transparent market process. The roles of these factors in the evolving LNG market are analyzed in this report.

Measures introduced before the 108th Congress focused on physical facilities. The Liquefied Natural Gas Import Terminal Development Act of 2004 (H.R. 4413) was aimed at reducing regulatory risk and speeding the federal review of applications to build onshore LNG terminals, as well as assigning authority in this area to the Federal Energy Regulatory Commission (FERC). In the 109th Congress, the Energy Policy Act of 2005 (P.L. 109-58) continued earlier efforts to streamline the process of gaining approvals necessary for the construction of LNG terminals.

Then Federal Reserve Chairman Alan Greenspan testified before Congress, arguing for more LNG terminal capacity to mitigate the economic effects of high energy prices.[1] Some analysts, expanding on Mr. Greenspan's testimony, have pointed to the structure of the LNG market as a limiting factor in providing supply security and a price cap to U.S. natural gas prices.[2]

This report describes the standard LNG market transaction, contrasts it with the competitive market model, and evaluates the transition currently underway between standard transactions and competition. Whether the price of LNG serves as a cap or a floor on U.S. natural gas prices, or whether it follows world oil prices, will have important implications for U.S. consumers. The characteristics of LNG prices will largely depend on how the structure of LNG transactions and markets evolve.

The evolution of LNG supply will contribute to the debate over the relative importance of the proposed Alaskan natural gas pipeline, expanded use of lands now off limits to exploration and production, and investments in technology to expand additional unconventional gas supplies. If secure LNG supplies become available in quantities consistent with an optimistic view of the market, some, or all, of the other gas alternatives needed to close the projected gap between U.S. natural gas demand and traditional North American supply sources in 2025 and beyond might not be needed.

[1] Greenspan, Alan, Chairman, Federal Reserve Board of Governors. "Natural Gas Supply and Demand Issues," Testimony before the House Energy and Commerce Committee, June 10, 2003.

[2] Jensen, James T. "The LNG Revolution," *The Energy Journal*, Volume 24, Number 2, 2003, pp.1-43.

Background

The Energy Information Administration (EIA) in the Annual Energy Outlook 2007 (AEO), projects the United States becoming increasingly dependent on imported natural gas in the coming decades. The EIA reports that in 2005 natural gas imports of 4.34 trillion cubic feet (Tcf) accounted for 19.4% of the 22.4 Tcf total of natural gas consumed in the U.S. market. Under the EIA's base case reference scenario, the share of imported natural gas is projected to rise to 26.6%, or 6.3 Tcf, by 2015.[3]

Not only are the share and volume of imported natural gas projected to rise, but the sourcing and physical form of the gas are also expected to change as well. In 2005, over 85% of natural gas imported to the United States came from Canada via pipeline. By 2020, the AEO projects that contribution declining to less than 50%. Virtually all of the remaining projected natural gas imports are expected to be in the form of LNG. In 2002, the United States imported 0.17 Tcf of LNG, which accounted for less than 5% of U.S. imported natural gas, and less than 1% of the total natural gas supplied to the market. In 2005, LNG imports rose to 0.57 Tcf, less than 3% of U.S. consumption. The 2030 LNG import projection of 4.5 Tcf, represents over a seven fold increase in LNG supply from overseas compared to 2005.[4]

The average wellhead price of natural gas was $1.91 per thousand cubic feet (Mcf) in the 1990s, the average price in the 2000s is $4.74 per Mcf, over double that of the previous decade. The wellhead price of natural gas averaged over $9.00 Mcf from November 2005 through February 2006 before moderating through January 2007. Increased prices have put pressure on residential consumer budgets, raised the cost of electricity, and reduced the competitiveness of industries that are consumers of natural gas. Higher prices, coupled with the competitive cost of LNG, have led to revived interest in supplying LNG to the U.S. market.

Whether LNG can provide a cap on U.S. natural gas market prices, or a floor below which prices are unlikely to fall, depends on the way the price formation process develops in the LNG market as well as the fundamental demand and supply balance. The large quantities of LNG potentially available on world markets lead some to envisage the U.S. imports of LNG expanding sharply in response to escalating domestic prices, keeping prices capped, and competition driving the price of LNG down to its cost of production and delivery. Others see LNG providing a high cost, relatively inflexible, incremental supply to the market that might well be critical in avoiding supply shortages, but at the same time keeps the price of all gas high enough to justify the cost of importing LNG. How prices are formed, and whether they lead or follow the market price, will be important in defining the role played by LNG in the U.S. natural gas market.

Standard LNG Markets

The LNG market is based on a four-link supply chain. The critical links are field development, which might also include a producing country pipeline, the liquefaction plant, specialized tankers for delivery to the consuming country, and a receiving plant to convert the LNG back to a gaseous state. Each link in the chain is capital intensive, and the system does not produce any revenue

[3] Energy Information Administration, *Annual Energy Outlook 2007,* Table A1,A2.

[4] Ibid. Table 13.

until the entire chain is operational. Investment requires a large initial capital outlay which is offset by earning from a long-term stream of net revenues. If risk, related to projected gas volumes or price, rises, the cost of capital for the project increases, threatening its economic viability.

The key to facilitating transactions in the LNG market has been the Sale and Purchase Agreement (SPA), a twenty year or longer, relatively inflexible, contract between the owners of the upstream portions of the supply chain and the purchaser of the LNG.[5] The length of the contract is determined by the relationship between the size of the gas field, the capital investment required for the project, and the consumer's needs. Since capital expenses are high, fields supplying the feedstock natural gas must be large volume producers with a long expected life, leading to long-term contracts to supply long-term consumption needs.

Risk is a critical factor in the LNG market. The SPA is designed to manage and reapportion the risk. Most long-term contracts have included a "take-or-pay" provision. This provision requires that the buyer guarantee purchase of agreed upon gas volumes, or pay for non-delivery. By requiring the buyer to take contracted volumes of gas or pay for non-delivery, the SPA vests the purchaser with the quantity risk of the contract, virtually assuring the producer of full production levels of output. Full production is important to the producer because less than full capacity production usually translates into poor economic performance for the investment. Price risk is managed through a price escalation clause in the SPA. In most existing SPAs, the price escalator is tied to the price of oil, which traditionally has been the prime competing fuel for natural gas.[6] LNG prices have typically been determined through this negotiated, administered process of contract negotiation based on an external index price.

Price and volume risk do not exhaust potential risk. Even though the producing nation's national oil company is typically a principal, or partner, in the upstream investment, country risk with respect to changing tax and business policy remains. Additionally, political instability has played a role in increasing the risk in LNG markets.[7]

Investment costs have been high for LNG projects.[8] As recently as mid-1990s, the capital investment cost of a liquefaction plant was over $400 per ton of annual capacity, implying a cost of over $2.5 billion for a plant with an annual capacity of 6.6 million tons.[9] Additional costs, of approximately equal magnitude, are also required for natural gas field development and a possible pipeline from the field to the liquefaction plant.[10] More recently constructed facilities have gained significant cost reductions. Trains 2 and 3 in Trinidad were constructed for less than $200 per ton of annual capacity.[11] Although some of these cost reductions are related to improved technology, a

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[5] The SPA usually excludes the receiving terminal, which is left to the consuming country to provide. "Upstream," then refers to the gas field, the liquefaction plant, and the specialized tankers that deliver the LNG to the receiving terminal.

[6] This is especially true for the Japanese market where a "Japanese Crude Cocktail" serves as the reference price for LNG.

[7] Guerilla activity in Sumatra, Indonesia in 2001 resulted in the temporary disruption of production at the Arun liquefaction plant which supplies Japan. In 2006, gas pipelines were attacked in Nigeria as well as in Georgia.

[8] While consumption of LNG is measured in cubic feet, production is measured in tons. The conversion factor is 1 million tons is equivalent to 48 billion cubic feet of natural gas.

[9] Institute for Energy, Law & Enterprise, University of Houston Law Center, *Introduction to LNG*, January 2003, p. 20.

[10] Jensen, James T., "The LNG Revolution," *The Energy Journal*, Vol. 24, No.2, 2003, p.3.

[11] Train is a term to describe a liquefaction production facility. Any given plant may include several trains. The largest trains currently are 5.0 million tons per annum.

major factor in cost reduction is economy of scale. Large plants, now more technically feasible, allow for reduced capital costs per ton of LNG produced. However, economies of scale are likely to be exhausted once an optimal facility capacity is attained. It is not known whether LNG facilities have reached, or are approaching, an optimal scale.

Capital costs, scale of the production facility, and risk continue to be related. As larger scale operations reduce the unit cost of gas, the economics of the project become more favorable, risk is reduced and project financing and completion becomes more probable. However, if an SPA is not in place, as the size of production capacity increases, the risk associated with marketing ever larger quantities of LNG grows. As a result of marketing risk, producers still have a bias toward long-term contracts which virtually ensure favorable economics for the project.

In 2005, and continuing through 2006, capital costs for new LNG facilities rose. A variety of construction related factors, including limited prime contractor capacity, increasing costs for steel, aluminum, pumps, compressors, and turbines, as well as labor costs, contributed to the increase. Additionally, national oil companies in the producing countries played a more active role in LNG projects, causing delays and increasing project cost.[12] Examples of the influence of national oil companies on LNG projects include Gazprom's involvement in the Sakhalin Island and Shtokman project in the Barents Sea, as well as the Nigerian National Petroleum Corporation's efforts to control the Olokola project.[13]

Transportation costs, to include a fleet of specialized, dedicated tankers, have been significant in LNG projects. No clear ownership pattern exists in LNG tankers; some are owned by importing companies, some by exporting companies, and some by shipping companies. Very few LNG tankers are owned by independent shipping companies and available to handle spot cargoes. The SPA typically includes a "destination clause" which prevents the buyer from re-selling purchased LNG to a third party, further discouraging the development of a spot market.

Through 2006, many tankers were used inefficiently. Since they hold dedicated cargoes, they follow set point-to-point routes, and are unable to take advantage of arbitrage possibilities or the re-allocation of shipments through cost reducing cargo substitution. Many tankers also make return trips empty, further increasing costs. Competitive incentives are minimal in this part of the market due to the SPA destination clause as well as the ownership linkages of the LNG supply chain.

The role of the spot, or short term, purchase market in the traditional LNG market structure is minor. Although short term purchases are not unknown, as of 2006, no LNG facility has been built that is not at least partially secured by a long-term agreement. Competitive spot markets aid in price discovery, but in traditional LNG markets, prices are negotiated and administered and likely linked to oil prices. Spot, as well as futures and derivative markets, allow market participants to manage risk, but in the traditional LNG market, quantities are set in the SPA and the producer's need to operate at full capacity to cover financing costs and generate a profit dictates contract terms. Since most large LNG buyers under the SPA system are electric utilities who were, until recently, operating as regulated monopolies, there was only limited impetus for reform.

[12] "A Seller's Market," *Petroleum Economist*, Vol.73/No.11, November 2006. pp. 12-15.

[13] "Buyers Beware," *Petroleum Economist*, Vol.73/No.11, November 2006. pp. 8-10.

Competitive LNG Markets

The long-term case for an "idealized" competitive market is based on the premise that price competition between large numbers of buyers and sellers results in lower costs and better quality service for consumers. To adapt the traditional LNG world market to this model, much of the existing supply chain would need to be broken down and re-assembled, based on market principles. The supply chain would need to be more competitive within each link in the chain, as well as the links themselves becoming more independent.

The competitive market model would have many countries developing currently stranded gas resources, and, either independently, or more likely in practice, with the assistance of international energy companies, producing volumes of LNG for the open market.[14] Partners in LNG projects would market their production shares independently of other owners, further increasing competition. Consuming countries would grow in number, and they would shop around the world to find the best available price among competing sellers. Price would be formed in an international market through gas-to-gas competition with home market sources, driving down prices to cost effective levels. Buyers could re-sell purchased gas if economic incentives indicated that was the profitable strategy. Tankers would be operated by shipping companies that competed against one another for cargoes, and managed the available fleet in such a way that shipping costs were minimized. LNG offloading would take place at receiving facilities that were open to all who brought cargoes to the facilities and were located in a variety of locations around the consuming market to minimize the delivery costs to the ultimate consumers. The SPA, if it was available in a competitive market, would have to offer increased flexibility to accommodate changing conditions.

Supporting the supply chain would be the availability of financial capital to develop new projects, fund new tankers, and build new receiving terminals without the necessary collateral of an SPA. The market would be sufficient in size, depth, and transparency, to assure investors that demand was stable and deep enough to justify investment. Although risk would remain a part of the transaction, it could be managed through the creation of a financial derivatives strategy based on swaps, futures contracts, and options, to allow each class of market participant the ability to transfer risk to those more willing and able to hold it. These derivative markets would exhibit sufficient financial liquidity so that creating and backing out of strategic positions could be accomplished at low cost. Purchase contracts would tend to be of short duration because both buyers and sellers would find it advantageous to continually search the market for the transaction offering the best economic return.

Structural Transformation

A structural transformation began in international LNG markets in the late 1990s. This transformation was driven by both time and technology. At that time, contracts signed during the market expansion of the 1970s and 1980s began to expire. At expiration, LNG buyers faced less regulation in their home markets. Technology had also improved, allowing for larger, more cost

[14] Stranded gas resources are economically viable to produce, but currently have no transportation system in place for delivery to market.

efficient LNG production and transportation systems. The dual pressures of changing buyer requirements and lower costs set in motion a market transformation that continues today.

The United States was an early participant in the modern international LNG market, dating back to the late 1960s with exports from Alaska to Japan.[15] In the 1970s and 1980s, Japan, currently the world's leading importer of LNG, expanded its imports from Indonesia, Brunei, Abu Dhabi, and other countries. Japan, which has no domestic sources of natural gas, and no access to pipeline imports, uses natural gas mostly as a fuel for the electric power industry. As a result of these origins, LNG prices have been derived from, and determined contractually by, the price of oil. Oil was the substitute fuel for Japanese utilities at the time. As a result, the LNG price structure is based on a "net back" to the producer based on the local market natural gas price, if available, and the reference price of oil, if not. As a result of this pricing mechanism, LNG investment decisions are made on the basis of the actual and forecast prices in target markets and what the net back to the project might yield.

Historically, there is little evidence to suggest that LNG prices have adjusted to competition in the market. More common is the result that if prices for domestic natural gas are weak, LNG tends to exit the market, returning when prices recover. For example, four LNG receiving facilities were built in the United States in the 1970s.[16] With the decline of natural gas prices in the 1980s, and the low prices prevalent for most of the 1990s, these facilities either were closed, or remained open at very low utilization rates in the latter decade. The higher natural gas prices of the last five years, supported by demand growth for natural gas, coupled with the declining costs of LNG, have provided economic incentive for these facilities to re-open and expand. Additionally, an off-shore facility, Gulf Gateway located in the Gulf of Mexico, opened in 2005.

Contract Provisions

The LNG market is showing signs of undergoing a transition. Contracts signed 20 to 25 years ago are expiring. Even in the Asian market, the regulatory environment for utilities is becoming more open. Before they enter into new LNG supply agreements, consumers are requesting, and receiving, liberalized contract terms compared to the typical SPA of the 1980s. Take-or-pay provisions now typically only apply to a part to the contract volume, giving the consumer some flexibility to expand or contract purchases as dictated by demand. Even the destination clause is being liberalized in some cases. On the supply, or producer, side of the market, more sources of LNG are becoming available to the market, potentially giving buyers more choice.[17]

Although liberalized contract terms are generally beneficial for consumers, the question of whether they are evidence of progress toward an idealized competitive market remains. To the extent that newly negotiated contracts remain long term, they may fix the market structure and practices at their current state for the next 10 to 20 years, possibly slowing further liberalization.

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[15] These exports continue, with about 63 billion cubic feet (Bcf) of gas sent to Japan from the Kenai Peninsula terminal in Alaska in 2003.

[16] These facilities are at Cove Point, Maryland, Elba Island, Georgia, Everett, Massachusetts, and Lake Charles, Louisiana. Their combined peak capacity is about 1.2Tcf, with a baseload capacity of about 880 Bcf. All four have either increased their capacities or plan to have completed expansions by 2006. Peak capacity of about 1.6 Tcf is expected at the four facilities after expansions are completed.

[17] Energy Information Administration, *The Global Liquefied Natural Gas Market: Status and Outlook*, December 2003, pp. 8-16.

For example, if new contracts allow 10% of contract volumes to be exempt from take or pay provisions, this could be interpreted as 10% of contract volumes being available for trade on a short term, or spot, market, or it could be interpreted as an allowance for the demand volatility that even long-term customers might experience, based on earlier contracts with no specific relationship to spot market transactions.

The general attractiveness of long-term agreements in the LNG industry continues in 2007. For example, Austria's OMV had planned to build an LNG terminal in Croatia, but questioned the decision when it became difficult to identify a long-term supply source of LNG. In the United States, Cheniere, with interests in four U.S. terminal projects, including Sabine Pass, Louisiana, and Freeport, Texas, is seeking a mixed usage contract base. Seventy percent of their capacity is said to be underwritten by, and allocated to long-term agreements with Total and Chevron, and Conoco Phillips and Dow Chemical, respectively. However Cheniere plans to take its chances in the arbitrage market with the remaining 30% of capacity.

Spot Markets and Prices

Whether the increasing number of buyers and sellers participating in the LNG market means it is becoming more competitive and flexible depends on whether the price of LNG is the signal that affects the balance between demand and supply. To the extent that the relationship between buyers and sellers is still characterized by the SPA, the additional market participants may do little to change the fundamental nature of the market. If the market follows traditional practice, if all new supplies of LNG are tied to specific consumers, no net new gas will be available to secure the operation of a viable spot market. Existing market relationships will be scaled up to meet the new, larger size of the market, but the fundamental relationships will remain the same. The existence of a viable spot market is important because it allows consumers the flexibility to sell off excess supply to eliminate surpluses, and acquire additional supplies to ameliorate shortages as well as aiding in price discovery. These activities are central to the market process and the key to achieving lower prices and driving down costs. Market determined prices will also help determine future investment decisions in LNG capacity in a more efficient way.

Recent data suggests that while short term transactions in LNG are becoming more prevalent, the existence of a viable spot market is still in the future.[18] Spot cargoes generally enter the United States mostly in the summer months when world heating demand is lowest, suggesting that the United States was a residual market for LNG.[19] Other data suggest that the deliveries taken at the operational U.S. receiving terminals was adversely affected by world events and competitive price pressures from domestic gas production. Weak U.S. natural gas prices in the winter of 2001-02 resulted in capacity utilization declining at the U.S. receiving facilities, as available supplies went to Europe where prices were higher. The same situation occurred later in the year when nuclear power problems in Japan, and shortages of tanker capacity, again lowered U.S. capacity utilization rates as cargoes were diverted to Japan.[20] This behavior has led some analysts to

[18] Definition and classification problems exist in the LNG market. In 2003, the Energy Information Agency classified 83.2% of U.S. LNG imports as spot cargoes. However, almost all of the cargoes from Trinidad are U.S. allocated, even though classified as spot cargoes. Neil, Chris. "LNG in the U.S." *Oil and Gas Journal.* April 12, 2004. pp. 71-72.

[19] Ibid. p.71.

[20] James T. Jensen, "The Expanding Role of LNG in North American Gas Supply - A Challenge to Gas Supply Modeling," Presentation at the National Energy Modeling System Annual Energy Outlook Conference, Washington, D.C., March 23, 2004. Figure 2.

characterize LNG supply as unreliable.[21] More recently, in 2006, Qatar reallocated supplies that were set aside for the North American market to Asia, mainly Japan and South Korea, because of stronger prices in those markets. During 2006, it was reported that U.S. receiving terminals were operating at close to 50% of capacity, reflecting weak demand conditions and declining prices.[22]

This recent evidence on LNG cargoes and U.S. receiving facility capacity utilization, in conjunction with the experience of the 1990s, suggests that LNG has not yet developed the kind of deep, transparent spot market required for economic efficiency, but is still largely dominated by fixed contractual relationships. Even though these cited transactions are short term in nature, they represent only a beginning in the development of an efficient spot market. A recent report suggested that although the Asian LNG market is more sensitive to market fundamentals as contracts are re-negotiated, this does not equate to the emergence of a global spot market because of infrastructure and logistical problems, a lack of uncommitted LNG volumes, and few pipeline alternatives.[23]

The role of LNG as a stable, large volume supplier to the U.S. market is enhanced by the expectation that expanding supplies can set a price cap on the U.S. natural gas market. For LNG supply to set a price cap for the U.S. market, producers would likely have to maintain excess capacity, or have the ability to rapidly expand production in response to price increases, to allow any upward price pressure to be set against extra quantities supplied. In addition, the price of LNG should lead the market, in the sense of competitively being driven down to delivered cost, rather than following the market and simply netting back returns based on the current market price for natural gas or a competing reference energy source. Because the costs of LNG project development are high with significant variability, price will have to be sufficiently high to cover the costs of the highest cost supplier in the market, or those high cost producers will be forced to exit the market or seek markets that can meet the required price. In this sense, increased U.S. LNG use might actually form a price floor below which natural gas prices cannot fall without risking supply disruption.

A recent development is that Dubai plans to create an LNG storage center and trading hub, to become operational in 2010. The physical proximity of the facility to Qatar, the world's largest LNG producer, as well as other Persian Gulf producers, as well as storage capacity equivalent to approximately 20 LNG tanker cargoes, is expected to allow for trading based on seasonal price differentials as well as geographical arbitrages. The introduction of this facility, which would contribute to the market competitiveness of LNG, is timed to coincide with the opening of several large Gulf LNG projects. Critics argue that LNG will be supply constrained through at least 2013, making it unlikely that surplus cargoes will be available for storage, inhibiting the financial liquidity of the new market center.[24]

Shipping

The LNG tanker fleet is increasing. In October 2003, the LNG tanker fleet stood at 151 ships with 55 ships in construction. Newer ships tend to be larger, which reduces the unit cost of delivered

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[21] Neil, Chris. "LNG in the U.S.—1" *Oil and Gas Journal.* April 12, 2004. p. 72.

[22] "Buyers Beware," *Petroleum Economist*, Vol.73/No.11, November 2006. p.8.

[23] "Asian LNG Feels Winds of Change," *Petroleum Intelligence Weekly.* Volume XLIII, Number 23, June 7, 2004. p. 5.

[24] "A Sellers Market," *Petroleum Economist*, Vol.73/No.11, November 2006. p.15.

LNG. Practical limits on the size of LNG tankers may be related to their ability to berth at existing receiving terminals, at least in the United States.

Virtually all of the new ships currently under construction are to be dedicated to delivering the product from specific projects. Recently, some major importing and exporting companies have ordered LNG tankers not dedicated to a specific project. This construction may or may not signal the emergence of a merchant fleet. While these tankers might be used for spot cargoes, it is also possible that they will be used by these large companies as insurance against the quantity uncertainty associated with incomplete up and downstream projects in which the companies have invested. There is still little evidence of the emergence of an independent LNG tanker fleet in the new construction data. Therefore, the newly constructed tankers are not likely to change the structure of the market in the direction of more competition; their purpose may be largely to service the larger scale of the evolving market. The dedicated structure of the LNG tanker sector suggests that existing practices in shipping will tend to continue. An available, uncommitted tanker fleet is, for many analysts, a necessary condition for the existence of a competitive LNG spot market. Until speculative ships are built in significant number, and shipping companies are willing to risk the approximately $150 to $160 million for a mid-sized tanker, it is unlikely that significant, continual, spot market transactions can be sustained.[25]

Tanker costs have declined. A 138,000 cubic meter capacity ship had an estimated nominal cost of $280 million in the mid-1980s, and an estimated nominal cost of about $155 million in 2003. Ships are also becoming larger over time, reducing the per unit transportation cost of LNG. Actual charter rates are harder to specify because of the non-market use of most of the tankers, but estimates run from $27,000 to $150,000 per day with an average near $60,000 per day.[26] The reduced cost of LNG tanker construction is largely driven by more shipyards competing to build the tankers.[27]

When LNG tankers reach the consuming nation, they must have access to specialized receiving facilities. With respect to receiving terminal policy in the United States, policy may have moved the industry away from market based competition in the interest of certainty of the investment climate. The Federal Energy Regulatory Commission (FERC) determined that LNG receiving facilities do not have to provide open access to all who wish to dock LNG cargoes; they can serve the proprietary interests of their owners, who typically have contracted LNG resources and require dedicated unloading facilities.[28] This decision may have been taken in the interest of enhancing investment feasibility. Given the high costs of LNG facilities, a fear was thought to exist that little, or no, investment in new receiving terminals would take place if the owners/investors in the project could not be assured that their investment would result in their ability to import their own LNG supplies and achieve an acceptable long-term rate of return on their investment. However, the decision is likely to retard the development of a functioning spot market. If receiving terminal capacity is largely structured to the sending capacity of an identified LNG project, it would become more difficult to justify a speculative, non allocated LNG project.

[25] Energy Information Administration, *"The Global Liquefied Natural Gas Market: Status and Outlook."* December 2003, p.30.

[26] Ibid., pp.44-45.

[27] Teo, Karen. "ExxonMobil Seeking Tankers to Move Qatari Natural Gas," *Oil Daily*, May 18, 2004. p. 6.

[28] The Maritime Transportation Security Act of 2002 (P.L. 107-295) transferred regulatory control of offshore LNG terminals from FERC to the Coast Guard, as well as assuring terminal owners proprietary access. The "Hackberry Decision" gave the same proprietary access rights to owners of onshore facilities under the regulatory supervision of the FERC.

Risk Management

An important factor restricting the movement toward a competitive LNG market is the limited ability of market participants to manage risk through existing institutions. The New York Mercantile Exchange (NYMEX) offers futures and options contracts on natural gas which can be used to manage some of the transaction risk. However, these are standardized contracts whose contract gas quantity levels are small compared to the size of a typical LNG tanker delivery, making it difficult to establish a contract position.[29] The market also thins out as contracts further than three to six months in the future are considered, again limiting market participants ability to manage long run risk. Additionally, these contracts offer no opportunity for the parties to the agreement to negotiate customized terms which may be required to facilitate large, high value transactions.

The solution to the risk management limitation might lie in an active over-the-counter derivatives market, but that alternative may not be viable in an LNG market environment characterized by tight supplies, no active spot market trading hubs, little product storage capability, and restricted transportation options.

Other Factors

Additional physical and security investments must take place before LNG import expansion can occur. Many problems and policy concerns exist surrounding these investments. Terminal siting, pipeline infrastructure, safety and physical security, and other supply bottlenecks may all require policy responses. The higher energy content of imported LNG, as well as its suitability for pipeline transmission also present technical challenges to rapid expansion of LNG usage.[30]

Conclusions

Growing demand, stagnating domestic production, and the reduced availability of traditional sources of imported natural gas suggest the possibility of imbalance in the natural gas market over the AEO forecast period to 2025. Imbalance could show up as physical shortages, if new sources of production cannot be identified, as well as volatile, high price levels. LNG has been suggested as a possible solution to this problem. Large quantities of stranded natural gas reserves exist around the world to potentially address the quantity problem, while if large quantities of LNG become available, they might establish a price cap for the market based on the cost of LNG.

The debate thus far concerning U.S. LNG imports has focused on the investment in receiving terminals, especially siting, to include jurisdictional issues between FERC and the states, security, environmental safety, and to a lessor extent the magnitude of capital investment. CRS analysis suggests that other institutional and market structure factors might also create impediments to an LNG based scenario, especially with respect to the competitive nature of LNG price formation.

[29] The typical LNG tanker delivery is 650 times the size of a NYMEX contract. See James T. Jensen, "The LNG Revolution." *The Energy Journal*, Volume 24, No. 2, 2003, p.25.

[30] For greater detail concerning these issues see CRS Report RL32386, *Liquefied Natural Gas (LNG) in U.S. Energy Policy: Infrastructure and Market Issues*, by (name redacted).

Since the traditional LNG market structure, largely intact today, is based on long-term contracts designed to ensure business stability, a number of changes would need to occur if a more competitive market structure is to evolve. Recognizing the scale of investment required to start LNG production, one of the primary factors is risk. Without the institutions and financial instruments to supplement or replace the SPA in risk management it will be difficult for a competitive spot market to develop. Existing markets offer market participants only a partial ability to manage risk, and given the size of potential LNG based transactions, they might alter the nature of trading if they were included in the market.

If a competitive market fails to develop, it is likely that future expansion of LNG will be through complex long-term contract negotiations which might limit the role of efficient, market based prices. Traditionally, LNG prices have been netted back to producers based on the price of a substitute commodity, usually oil, or on the price of natural gas in the local market. Without the pressure of a competitive market it is unlikely that the long-term price of gas will be driven to cost based levels. If the price determination mechanism for LNG remains, there is little reason to assume that LNG can provide a price cap to domestic natural gas prices. In this case, a possible scenario would be for LNG to enter the U.S. market when prices are high, and then exit if prices moderate. While this behavior might moderate extreme price spikes, it might not provide a stable supply source for domestic natural gas consumers.

Because increasing LNG supplies is only one of a number of ways to close the projected gap between U.S. natural gas demand and supply over the coming years, any decisions to encourage or discourage this particular source may have implications for other potential sources. Optimists point to the large quantities of stranded natural gas around the world and the plans to develop dozens of receiving terminals in the United States and might conclude that this source alone might close the demand and supply gap. If this was the case, the need for an Alaska natural gas pipeline might be weaker, as would the need for drilling in environmentally sensitive areas and the need for expanding technology to develop gas reserves from new sources. If a more pessimistic view of LNG is taken these other alternatives rise in importance.

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