2005

Liquefied Natural Gas: An Overview of the Issues for State Public Utility Commissions

NARUC

Prepared by
ICF Consulting

For Consideration of
The DOE/NARUC LNG Partnership, NARUC,
and the U.S. Department of Energy

June 2005

The National Association of Regulatory Utility Commissioners

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FOREWORD

In September 2003, Secretary of Energy Spencer Abraham announced the U.S. Department of Energy/National Association of Regulatory Utility Commissioners Liquefied Natural Gas (LNG) Partnership as a means to assist in the education and outreach of critical energy decision-makers on the opportunities as well as the impediments related to the increased development of LNG resources. A key goal of the Partnership is to create a series of dialogues to assist in the development of state and regional strategies relating to LNG resource development and deployment. Three reports were prepared for consideration of the LNG Partnership: a LNG communication plan authored by ICF Consulting; a LNG primer authored by the U.S. DOE; and this white paper, also authored by ICF Consulting. The LNG Partnership presents this white paper as an informational piece regarding the major issues related to the importation and use of LNG. ***This document is not intended to represent the views and opinions of the National Association of Regulatory Utility Commissioners (NARUC), the U.S. Department of Energy, or any particular state or federal regulatory commission***. With over 55 new LNG import terminals proposed for North America, PUCs along with federal agencies face a number of serious issues about LNG as a reliable source of gas supply.

LNG occurs through a proven commercial technology by which natural gas is cooled to a temperature of approximately -260°F, thereby condensing it into a liquid, enabling both efficient and economic transportation and storage. It is subsequently re-vaporized to allow it to be injected into the transportation and distribution pipelines. According to the U.S. Energy Information Administration (EIA) Annual Energy Outlook for 2005 (AEO2005), the U.S. is projected to face an 8.7 trillion cubic feet (Tcf) gap in domestic natural gas production by 2025. Consequently, increased imports of natural gas will be required to meet future shortfalls. Canadian imports are forecast to decrease to 2.6 Tcf by 2025 due to both the depletion of conventional resources in the Western Sedimentary Basin as well as Canada's own increasing demand for natural gas. The EIA expects LNG imports to reach 6.3 Tcf a year by 2025, or about 21 percent of our total consumption, which will assist greatly in relieving the supply gap.

I gratefully acknowledge the funding assistance provided by the U.S. Department of Energy's National Energy Technology Laboratory to support this important effort. I would like to give special acknowledgement to Leonard Crook and his team at ICF Consulting, the primary authors of this document. In addition, I would also like to thank Charles Gray, Andrew Spahn and Tracey Kohler of NARUC, Christopher Freitas and John Duda of DOE, Marilyn Ross of the Massachusetts Department of Telecommunications and Energy, and David Maul of the California Energy Commission.

The Honorable W. Robert Keating
Chair of DOE/NARUC LNG Partnership and
Commissioner of the Massachusetts Department of
Telecommunications and Energy

If North American natural gas markets are to function with the flexibility exhibited by oil, unlimited access to the vast world reserves of gas is required. Markets need to be able to effectively adjust to unexpected shortfalls in domestic supply. Access to world natural gas supplies will require a major expansion of LNG terminal import capacity and development of the newer offshore regasification technologies. Without the flexibility such facilities will impart, imbalances in supply and demand must inevitably engender price volatility.

Alan Greenspan, before Senate Committee on Energy and Natural Resources, July 10, 2003.

Natural gas is a critical energy commodity for the economic and environmental well being of our nation. Recently a number of major energy studies from the Energy Information Agency (EIA), the National Petroleum Council (NPC) and others all report that our country's existing major natural gas fields are maturing placing upward pressure on demand/prices and that new sources of supply need to be developed. Liquefied Natural Gas (LNG) could provide one viable option to address our growing need.

The potential for successful siting of LNG facilities requires sound education, good communications and a need among all parties, the industry and public policy maker and the public, to respectfully and honestly address the concerns of one another.

W. Robert Keating, Massachusetts Department of Telecommunications and Energy, June 2005

State regulatory commissions are more appropriately situated to help ensure that any LNG development is consistent with state energy policy balancing environmental protection, public safety, and local community concerns. . . . The siting of LNG facilities raises several significant public policy issues for which state commissions have both regulatory authority and statutory obligations. State commissions have the responsibility to assure that LNG projects that are ultimately approved and constructed, do not unduly compromise public safety or the effective and efficient operations of state energy markets.

Jack Blossman, Louisiana Public Service Commission, Testimony before the House Subcommittee on Energy Policy, Natural Resources, and Regulatory Affairs, June 22, 2004

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EXECUTIVE SUMMARY

Importing LNG and the Role of Public Utility Commissions

The purpose of this white paper is to discuss the major issues related to the importation and use of liquefied natural gas (LNG) and to provide a perspective for state public utility commissions (PUCs). With 55 new LNG import terminals proposed for North America[1], PUCs along with federal agencies face a number of serious issues about LNG as a reliable source of gas supply. Based on this paper the following recommendations are offered for State commissioners' consideration.

- PUCs need to understand the potential role of LNG to supply a critical part of the U.S. demand for natural gas, and be prepared to educate and discuss the importance of LNG facilities to meet this need. Increasing gas supply to the United States with LNG can help moderate prices and may reduce gas price volatility caused by current tight supply.

- PUCs should evaluate the benefits to consumers from LDCs and regulated power generators securing long term gas supply contracts with LNG importers. Such contracts can provide security of supply and depending on the terms can provide price certainty and a hedge against volatile gas prices.

- PUCs should pay close attention to the ongoing debate over how to address the issue of the high heat content of LNG-based supply relative to domestic supply, given the implications of this debate for the performance of gas appliances.

- PUCs, where appropriate, the Federal Energy Regulatory Commission (FERC) and U.S. Coast Guard should implement recommendations to further reduce the risks from accidental and intentional LNG spills. PUCs can help build confidence that the management of these risks is consistent with public safety, while recognizing the major benefits that LNG terminals can bring to gas markets.

The Growing Importance of LNG as a Supply Source

The interest in LNG is being driven by three long term fundamentals. First, the growth of natural gas consumption led by the increasing use of natural gas for power generation is a trend that is expected to continue over the long run. Compared to coal or oil, natural gas is a relatively clean burning and desirable fuel for power plants. Second, the U.S. supply of gas is undergoing a major shift away from traditional conventional gas production towards more unconventional and hard-to-reach resources. Third, these two trends have led to record high gas prices and pronounced gas price volatility in the last four years. PUCs across the country are struggling with how to respond to these prices.

[1] Federal Energy Regulatory Commission web site. The FERC periodically updates the list of proposed, approved, and operating terminals.

LNG imports may provide a cost competitive solution to the tight supply problem. There are abundant natural gas resources around the world which, because they have few local uses, can be converted to LNG and delivered to the United States at costs that are well below the current price of natural gas. LNG imports will increase gas supply and may help to address some market issues that could lead to a moderation in the volatility of the price of gas in the US.

Regional LNG Issues

Supply interchangeability is an issue that must be evaluated for any terminal with direct market area supply impact. The subject of interchangeability is not unique to LNG, nor is it a new subject of discussion for the industry. The FERC has held technical conferences anticipating possible rulemakings in conjunction with the industry through the Natural Gas Council. Interchangeability of gas supply has been a subject of discussion since the early 1900's with the introduction and "mixing" of traditional well supplies and manufactured gas. More recent evaluation of interchangeability involves mixing of "peak shaving supplies" (SNG, LNG, propane-air) with pipeline supplies and earlier manufactured gas. In the classical sense, interchangeability is simply defined as the ability to substitute one gas supply for another without impacting the safety, reliability and efficiency of combustion end use applications. However, as utilization of natural gas has evolved and become an increasingly important feedstock for the petrochemical and manufacturing sectors, so has the definition of interchangeability. Today, the definition of interchangeability includes the ability to substitute one gas supply for another for all end use applications including LNG peak shaving liquefaction plant feedstock, petrochemical feedstock, vehicle fuels, fuel cells and others.

Generally speaking, the heating value of LNG imports is greater than traditional pipeline supplies due to higher concentrations of non-methane hydrocarbons including ethane, propane and butanes. However, heating value alone is not a measure of interchangeability. Other parameters coupled with heating value can provide information to help predict one gas's ability to substitute for another without end use impacts. A variety of methods have been developed to predict the interchangeability of fuel gases These methods are in general based on empirical parameters developed to fit the results of interchangeably experiments.

One such parameter, the Wobbe Index, when combined with heating value, can adequately describe this phenomenon for conventional appliances as well as some industrial combustion applications. However, for some industrial process applications, simply applying an interchangeability parameter may not be sufficient and detailed constituent analysis of the gas may be required for such feedstock applications.

A new gas supply, such as LNG, can be made interchangeable with historically acceptable supplies through blending either with other "leaner" pipeline supplies or through the introduction of inerts such as nitrogen, or in some cases compressed air. While nitrogen injection is the preferred blending option for most terminals and pipelines alike, air blending continues to be successfully utilized in parts of the country for interchangeability management of domestic supplies. Interchangeability issues with certain LNG imports can also be managed at the supply source by removing non-methane constituents resulting in a product that better resembles domestic pipeline supplies.

Ultimately, the future diversity of gas supplies in the North America is dependent on our ability to reasonably assess both the political and technical risks associated with new supplies including LNG imports. Most believe the technical issues can be most effectively and efficiently addressed through a combination of strategies that will ultimately depend on additional research to help fill some of the technical and information gaps that exist today within the North America utilization infrastructure. The FERC, Natural Gas Council (NGC), North American Energy Standards Board (NAESB) and others are working to resolve these issues.

LNG Economics and Contracting

LNG is a capital intensive enterprise. For example, the liquefaction plant for a 390 Bcf per year plant costs about $1.5 billion, tankers between $150 million and $200 million each, and on-shore regasification terminals begin around $300 million. Even with this heavy investment, the current delivered cost of LNG (as opposed to the price received at terminals) ranges between about $2.00 per MMBtu to about $3.95.[2]

The LNG trade has developed through a system of back-to-back long-term contract commitments that include strict take or pay clauses and delivery restrictions. This resembles in structure to the U.S. gas market in the pre-FERC Order 380 and Order 636 era. The purpose of these contract terms is to ensure reliable supply and markets. Trading is usually bilateral – with facilities and ships dedicated to a particular market. Prices are set in relation to an index of crude and product oils traded in the consuming markets. Some limited spot trading has begun to develop, but bilateral contracts will continue to dominate the industry.

A major concern to the international LNG suppliers is how to accommodate the traditional contracting approaches to U.S. market realities. These realities include floating prices tied to Henry Hub, open access transportation rules, and very important, the reluctance of parties to sign long term contracts with quantity commitments.

PUCs can have a major role in deciding the prudence of LDCs and regulated power generators entering into long term contracts. The arguments in favor of these arrangements are that they could provide a baseload supply at possibly lower and more stable prices (in exchange for take or pay commitments).

The Safety of LNG

The general lack of public familiarity with both the characteristics of LNG and the many safety precautions that are already in place for its use and storage contribute to concerns over the safety and security of the transport and storage of LNG. LNG is stored at atmospheric pressure (it is not stored under pressure) and only when, and if, the natural gas vapors reach a proper mixture of air and gas (approximately 5-15 percent) can it become a fire hazard. A LNG spill on water, which would lead to a rapid gasification, can create flammable mixtures and potentially create a fire over a larger area depending on the size of the spill.

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[2] We are careful to note the difference between the cost, which is estimated from a build up of the cost of facilities and transportation, and the price received in the open market. LNG prices are set in the market place along with all other sources of natural gas.

Regulations and best practices (for operations, management, handling, and fire safety) have been developed over the last 40 years to help to manage and minimize LNG spill risks. Accidents at modern LNG facilities have been rare because of the enormous advances in facility design, metallurgy, and operating practices. This record of safety notwithstanding, the large storage tanks and distinctive tanker design make LNG facilities highly visible, increasing general concern about intentional damage incidents. To date, no LNG facilities have been involved in terrorist events. The U.S. Coast Guard and other agencies have implemented procedures to minimize these threats.

Recent studies sponsored by FERC and the U.S. Department of Energy (DOE) have focused on whether the current approaches are adequate for understanding the consequences of LNG spills and managing the risks of spills, whether accidental or intentional. The recently released report by Sandia National Laboratory (SNL) concluded that the effects of accidental spills are minimized by current design and siting practices, and that the effects of intentional spills caused by terrorists can be further minimized through appropriate security, planning, prevention and mitigation measures.

Environmental Impacts of LNG Terminals

While safety issues have tended to dominate the LNG siting debates, environmental issues are also important. LNG projects are essentially large industrial plants that have local impacts on terrestrial, marine, air and scenic resources and which can be mitigated through design, operations, and location. At the same time LNG plant construction may have significant economic benefits for local economies in the form of increased employment, local expenditures, and taxes.

The FERC asserts it is the lead federal agency for reviewing on-shore LNG plant proposals and has implemented an extensive environmental review process that puts a premium on public communication and the input of federal, state and local agencies. The U.S. Coast Guard is the lead agency for reviewing off-shore LNG plant proposals. State governors have a significant role in the Coast Guard's decision making process. The California Public Utilities Commissioner (CPUC) has asserted its jurisdiction in the case of proposed LNG import facilities located in California.

PUCs' interest should be to ensure that the environmental record is fully developed for informed and judicially reviewable decision making.

1. INTRODUCTION

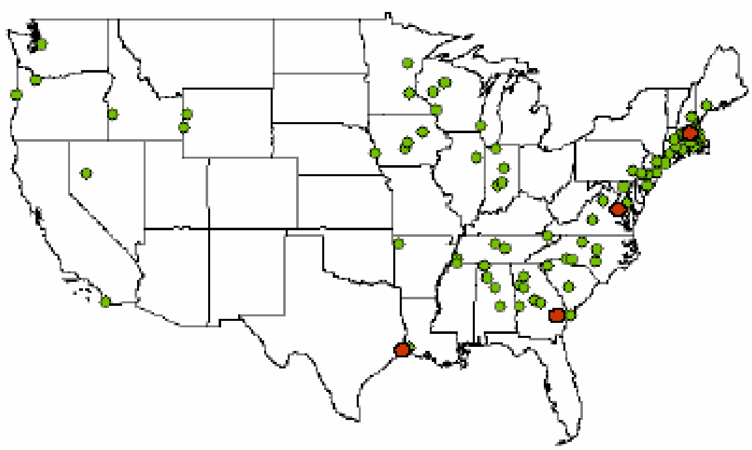
A Brief History of LNG

Liquefying natural gas was hit upon early in the 20th century as a convenient way to store natural gas for when it was needed to meet peak winter heating demand. In 1941, East Ohio Gas Company built the first commercial LNG storage facility in Cleveland, Ohio. This plant experienced a major accident in 1944 when the metal storage tank failed, LNG spilled into sewers, and ignited.[3] Lessons learned from this accident led over the ensuing half century to vast improvements in LNG safety, which along with technology advances have now made LNG storage safer and more widespread. By the early 1980s, LNG storage had become commonplace across the U.S. Today, 96 LNG liquefaction, storage, and regasification plants operate in 29 states (see Exhibit 1-1) and LNG tanker trucks are a common site on many highways.

What is LNG and how is it used?

Natural gas cooled to -256° F becomes a liquid at atmospheric pressure. In the liquid state, LNG occupies one-600th of the space of natural gas and weighs 3.5 lb/gal., less than 50 percent the weight of water. A metric ton of LNG is about 52 MMBtu of natural gas. LNG is colorless, odorless, non-corrosive, non-toxic, and when regasified it is lighter than air. LNG is almost pure methane that can be easily stored and transported in trucks and tanker ships without pressurization. Regasified LNG is used interchangeably with pipeline natural gas in homes, factories, and power plants. Local distribution companies most often store and regasify LNG to supplement gas supplies on cold winter peak days. Bottled LNG is used to operate motor vehicles.

Exhibit 1-1. LNG Plant Locations, 2004



Source. Energy Information Administration (EIA), U.S. LNG Markets and Uses, Jan. 2003

International transportation and trade in LNG arose in the late 1950s when the United Kingdom imported a cargo of LNG from Lake Charles, Louisiana, on *The Methane Pioneer*, a converted World War II Liberty ship. The Phillips Petroleum Company began exporting LNG to Japan from Kenai Peninsula in Alaska in 1969. That plant still operates. With the large discoveries of

[3] See, Tussing and Barlow, The Natural Gas Industry, 1984. p. 63.

natural gas in Algeria and Libya in the 1960s, the United Kingdom became the first large scale importer of LNG on a regular basis.[4]

Since that time, LNG has become a major fuel for Japan, Korea, and Europe. Japan is the largest importer of LNG with 29 receiving terminals taking in over 54 million metric tons (almost 3 Tcf) in 2002. Europe has 10 LNG import terminals and South Korea has four. India, China, and Europe are all planning major expansions of LNG import capabilities. Total worldwide trade in LNG in 2002 was about 5.3 Tcf.

Imports of LNG into the United States began with construction in 1971 of the first import terminal at Everett, Massachusetts, near Boston. Three other terminals subsequently were constructed at Cove Point, Maryland (1978); at Elba Island, Georgia (1978); and Lake Charles, Louisiana (1982). Imports peaked in 1979 at 253 Bcf and declined thereafter due to low gas prices and contract disputes with the LNG supplier, Algeria. Throughout the 1980s and 1990s, LNG imports averaged less than one-third of the 1979 level, entering though the terminals at Everett and Lake Charles. With the increase in gas prices since 1999, the LNG import facilities were refurbished and imports have increased through all of the plants. In 2004, the United States imported over 600 Bcf, almost three times the imports of 2000.[5]

Why is LNG Important Now?

LNG is important for two reasons. LNG gives the United States access to the vast resources of natural gas that are located around the world. Having access to these resources can help to lower the price of natural gas from the unprecedented levels of the last two years and can also reduce the volatility in gas prices.

Natural gas is relatively abundant in many places of the world where there is little local demand for gas. In some cases, the cost of producing gas from these regions and delivering it to the United States as LNG is lower than the cost of producing in North America. DOE projects that in order to meet future gas demand, the United States will have to import substantial amounts of LNG from overseas sources.[6] Today, over 55 LNG import terminals have been proposed for construction on the east, west and Gulf coasts. Some analysts project that by 2020, 15 percent of our natural gas, or about 5,000 Bcf per year, will come from overseas sources in the form of LNG.[7]

Some Facts

The U.S. consumes about 22 trillion cubic feet (Tcf) per year of natural gas, approximately 60.3 billion cubic feet (Bcf) per day. We import about 3.5 Tcf (9.6 Bcf per day) from Canada.

Current LNG sendout *capacity* at the four operating import terminals is about 2.6 Bcf per day. Current imports through these plants are about 1.6 Bcf per day.

(Source: EIA, June 2004)

[4] Institute for Energy, Law & Enterprise, University of Houston, Introduction to LNG, January, 2003.
[5] EIA, U.S. Natural Gas Imports by Country, Estimate based on extrapolating from first 10 months of imports.
[6] EIA, Annual Energy Outlook, 2004.
[7] National Petroleum Council, *Balancing Natural Gas Policy, Fueling Demands for a Growing Economy*; 2003 and EIA, *Annual Energy Outlook, 2004*.

Where does LNG Come From?

LNG can come from two sources. Domestic pipeline gas can be liquefied, stored, and regasified. This is the most common source of LNG in the United States. Internationally, LNG comes from a variety of countries. The major LNG exporters have two things in common: large reserves of natural gas and little or no local markets for that gas. LNG exports offer a way to turn this stranded gas into a salable product. Exhibit 1-2 presents the reserves of the currently exporting countries and those countries that have announced entry into the LNG market.

Exhibit 1-2 Natural Gas Reserves of LNG Suppliers

Country	Proved Reserves (Tcf)
Russia	1,680
Iran*	942
Qatar	910
U.S. & Canada	244
U.A.E.	214
Nigeria	176
Algeria	160
Venezuela	147
Indonesia	90
Australia	90
Norway	87
Malaysia	85
Egypt	62
Libya	46
Oman	33
Trinidad & Tobago	26

*Not currently an exporter or with known plans
Source: BP Statistical Review of World Energy, 2004

The United States today imports the vast bulk of its LNG from Trinidad-Tobago; in 2003, out of 506 Bcf of LNG imports, 378 Bcf came from Trinidad-Tobago. The next largest suppliers of LNG were Algeria (53 Bcf) and Nigeria (50 Bcf). Thirteen Bcf were imported from Qatar. Oman and Malaysia combined for 12 Bcf.[8]

Who Regulates LNG?

Under various statutes, State Governors, PUCs and Coastal Commissions, FERC and the U.S. Coast Guard regulate the siting of LNG marine import facilities in the United States. Other local and state siting and permitting agencies also have a say in the siting of LNG terminals.

FERC asserts its authority to regulate LNG derives from the Natural Gas Act. Under this authority, FERC reviews developers' applications and grants certificates of public convenience and necessity to LNG import facilities. FERC also has an ongoing responsibility for safety inspections for LNG import terminals under FERC's jurisdiction. Under the Deepwater Port Act (as amended in 2002 by the Maritime Transportation Security Act), the Coast Guard has responsibility for approving all offshore LNG facilities in federal waters. Certain State PUCs assert they have siting and safety jurisdiction under state laws, and are certified by the United States Department of Transportation (DOT) if they have adopted the federal LNG safety standards as their minimum standards. The CPUC asserts it has exclusive jurisdiction for LNG terminals sited in California that are intended to serve California gas markets.

Both the FERC and the U.S. Coast Guard have instituted procedures to encourage participation by states and the public in the decision making process. These are described in section 5 of this report.

[8] EIA, U.S. Gas Imports by Country (2004).

What is the Role of the State Public Utility Commissions?

State PUCs can play a key role in educating the public on the need for importing LNG into their region or state and can influence how LDCs contract for their gas supplies.

- PUCs can educate and inform federal facility siting decision makers by participating in the environmental review process and in the site approval process. Both FERC and the Coast Guard siting procedures provide for state agency input in the decision making process.
- In addition to siting, PUCs have authority to approve interconnections between the LNG facility for intrastate regulated pipeline and distribution facilities as well as certain other related facilities such as LNG satellite storage tanks located on the distribution system.
- State PUCs exercise oversight of gas purchasing practices of LDCs as part of the state obligation to ensure reliable gas and economic gas services for customers. How states view LNG-based gas supply contracts will have significant effect on LNG imports and whether LNG import terminals will be financially viable.

This white paper addresses the following:

- What is the role of PUCs?
- What are the issues important to regulatory commissioners in the key LNG import decisions?
- What is the economic rationale for LNG?
- What are the key questions PUCs must address to ensure that LNG imports provide a safe and reliable source of gas supply for their states?

2. THE RATIONALE FOR LNG

What is the Role of LNG in Today's Gas Market?

All indications are that the United States has entered a new era of natural gas supply. The North American supply of natural gas cannot meet the expected growth in demand at prices that can sustain continued development of gas-fired electricity generation. Federal Reserve Board Chairman Alan Greenspan's quote at the beginning of this paper sums up why LNG is important. Without access to the larger supply of worldwide natural gas made possible by LNG, the United States will face higher natural gas prices and be more susceptible to unexpected supply shortfalls. LNG brings us flexibility to respond to price volatility brought on by imbalances between supply and demand.

Gas Market Need for LNG

A growing demand for natural gas combined with a shrinking supply of low cost domestic natural gas and resulting record high gas prices provide the logic for LNG. The nation and PUCs are faced with hard questions about how to achieve moderate prices and a measure of gas price stability. In this context, LNG presents a significant source of incremental gas supply.

In this section of the report, we review the driving features of the market, and the rationale for LNG imports.

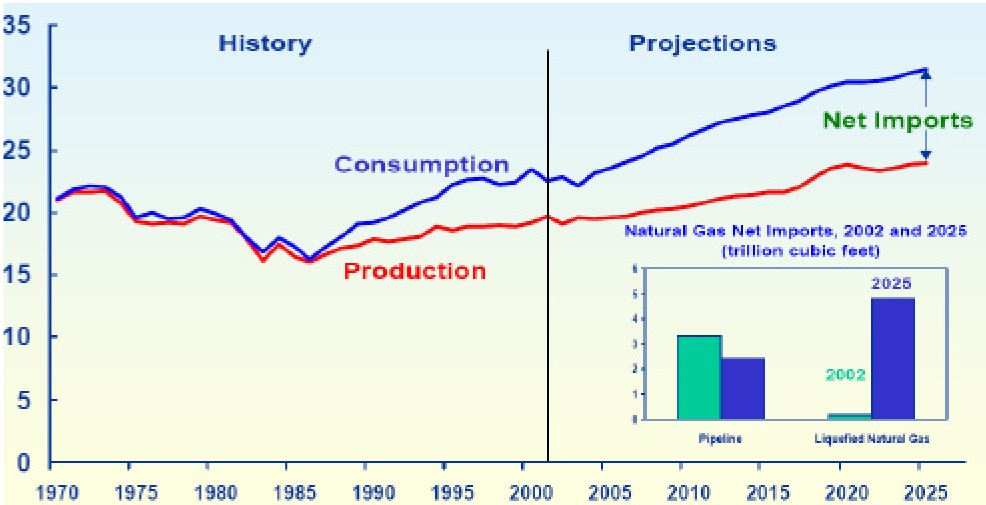
Market Fundamentals: Demand and Supply for Natural Gas

The United States consumed about 17 Tcf in 1985; by 2002, consumption grew 28 percent to over 22 Tcf. The major source of the increased demand has been in power generation. In the last 10 years, the United States has added over 100,000 MW of gas fired power generation. The demand for electricity will continue, driven by population and household growth, a growing economy, and the increasing electrification of our daily lives. Natural gas-fired generation will remain an attractive option because of its low emissions and the ease of siting these plants compared with coal-fired generation.

EIA has estimated that total gas consumption will reach over 30 Tcf per year by 2025, as shown in Exhibit 2-1. At the same time, U.S. domestic production will meet only about 75 percent of the demand with the balance coming from imports.[9] Since the late 1980s, imports from Canada have supplied an ever growing percentage of U.S. consumption.

[9] EIA, *Annual Energy Outlook, 2004*.

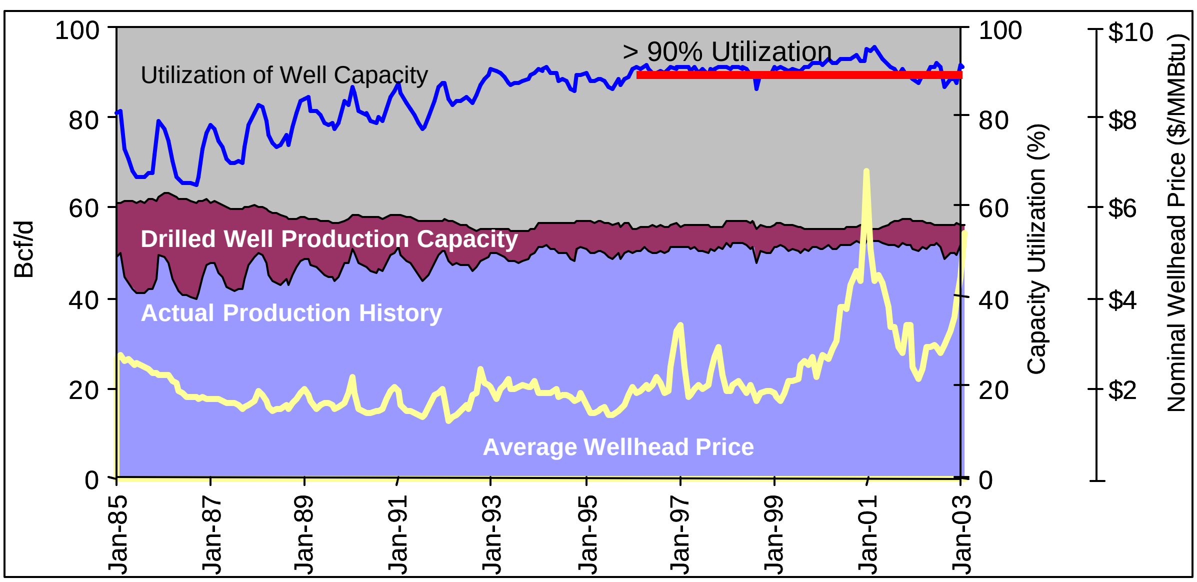
Exhibit 2-1. U.S. Gas Consumption and Production, 1970 – 2025



Source: EIA, Annual Energy Outlook, 2004.

Several trends have characterized U.S. gas production over the last 20 years and present a stark picture of the natural gas supply outlook. These trends are illustrated in Exhibit 2-2 that presents the performance of lower 48 gas production.

Exhibit 2-2. Gas Productivity and Prices, 1985 through 2002



Source: EIA, Natural Gas Productive Capacity for the Lower 48 States, 1985-2003, web report.

Several observations can be made from this exhibit.

- Drilled well productive capacity has remained flat since 1994 despite increasing gas prices and increased rates of well drilling. Production since 1995 has averaged 90 percent of productive capacity.

- Large gas price movements and volatility began to occur once well utilization reached 90 percent of capacity.
- Since 1993-1994, gas production patterns changed and no longer exhibit seasonal swings to meet seasonal demand. This is due to a loss of excess capacity and to the growth in gas-fired power generation.

As shown in Exhibit 2-3, overall production from the lower 48 states has increased slightly since 1996, while supply has shifted away from the major historic producing regions in the Gulf of Mexico and Mid-continent to the Rockies.

Exhibit 2-3. U.S. Gas Production, 1996-2002

Basin	1996 Production (Bcf)	2002 Production (Bcf)	Percent Change
Gulf of Mexico	5,452	5,615	3.0
Gulf Coast	4,991	4,423	-11.4
Mid Continent	2,939	2,483	-15.5
Permian Basin	1,454	1,470	1.1
Rocky Mountains	1,502	2,638	75.6
San Juan Basin	991	998	0.7
Rest U.S.	1,532	1,726	12.7
Total U.S.	18,861	19,353	2.6

Source: EIA, U.S. Natural Gas Gross Withdrawals and Production.

Since the mid-1980s, Canada has supplied an ever increasing amount of U.S. gas demand. In 1996, we imported about 2.5 Tcf of natural gas; by 2002 imports had grown to 3.8 Tcf. Imports from Canada, however, declined for the first time in 2003 to 3.5 Tcf, despite record high gas prices.[10] Canada's National Energy Board (NEB) has issued a relatively pessimistic forecast for Canadian production in its recent *Energy Market Assessment*. The NEB believes Canadian supply will remain flat through 2010 as conventional resources decline and unconventional resources gradually replace them. Increases in supply after 2010, will be consumed largely in Canada.[11]

National Petroleum Council

In late 2003 the National Petroleum Council (NPC) issued its study of the U.S. natural gas supply situation.[1] The NPC forecasts that most of the continental sources of gas will decline over the next 20 years. Increases in gas supply to meet growing demand will have to come from Alaskan gas and increased imports of LNG.

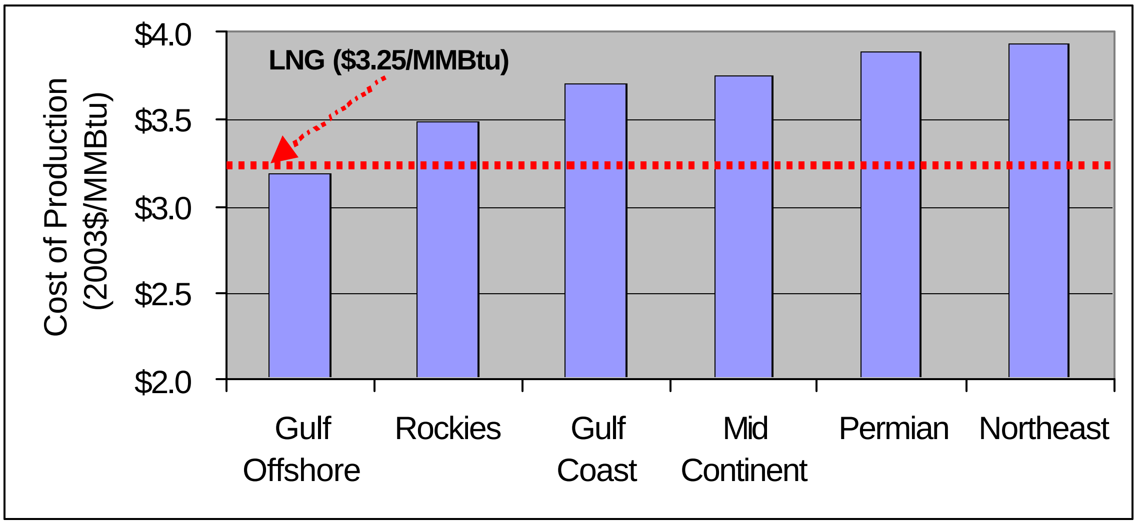
These trends in the United States and Canada suggest a fundamental shift in the resource characteristics of North American natural gas. While resources are plentiful, they are to be found in higher cost, more distant settings. This is reflected in gas prices. Natural gas prices in 2004, quoted at Henry Hub, Louisiana, have averaged for the year $5.88 per MMBtu through

[10] Source: Energy Information Administration.
[11] National Energy Board, *Looking Ahead to 2010, Natural Gas Markets in Transition*, August 2004.

August 1, 2004. This is $0.40 higher than in 2003, over $1.50 higher than in 2000, and three times the price of gas in 1995.[12]

Exhibit 2-4 presents one attempt to rank the major U.S. producing regions for 2005 by an estimated full replacement cost of gas.[13] This is the compared with the midrange estimate of delivered costs of regasified LNG into the U.S. pipeline network. At an average cost of about $3.25/MMBtu at the outlet of the LNG regasification plant, LNG is a lower cost source of supply than most of the domestic sources. This is just an estimate of the cost of delivering LNG to the interstate system; the price LNG receives from the market is considerably higher, consistent with prices of natural gas everywhere.

Exhibit 2-4. LNG and Natural Gas Replacement Cost, 2005



Source: Estimate of regional replacement costs, ICF Consulting; estimate of delivered LNG cost Institute for Energy, Law & Enterprise, University of Houston, September 2004.

Importing more LNG can increase supply and may lower the overall price of gas, depending on how much LNG is imported. LNG can have even more significant effects on local markets where the terminals are sited. Large infusions of natural gas supply can reduce local prices relative to the national price at Henry Hub, and can provide significant supply at the tail end of the long-haul pipeline systems. Furthermore, because LNG ships can be scheduled, LNG can serve seasonal demands for gas.

Regional Markets and LNG

At last count, approximately 55 LNG terminals were in some stage of planning or proposal, including expansions at the four existing terminals for the United States and an additional 12 terminals for Mexico and Canada. The geographic distribution of the proposed terminals, as shown in Exhibit 2-5, suggests various strategies by developers.[14]

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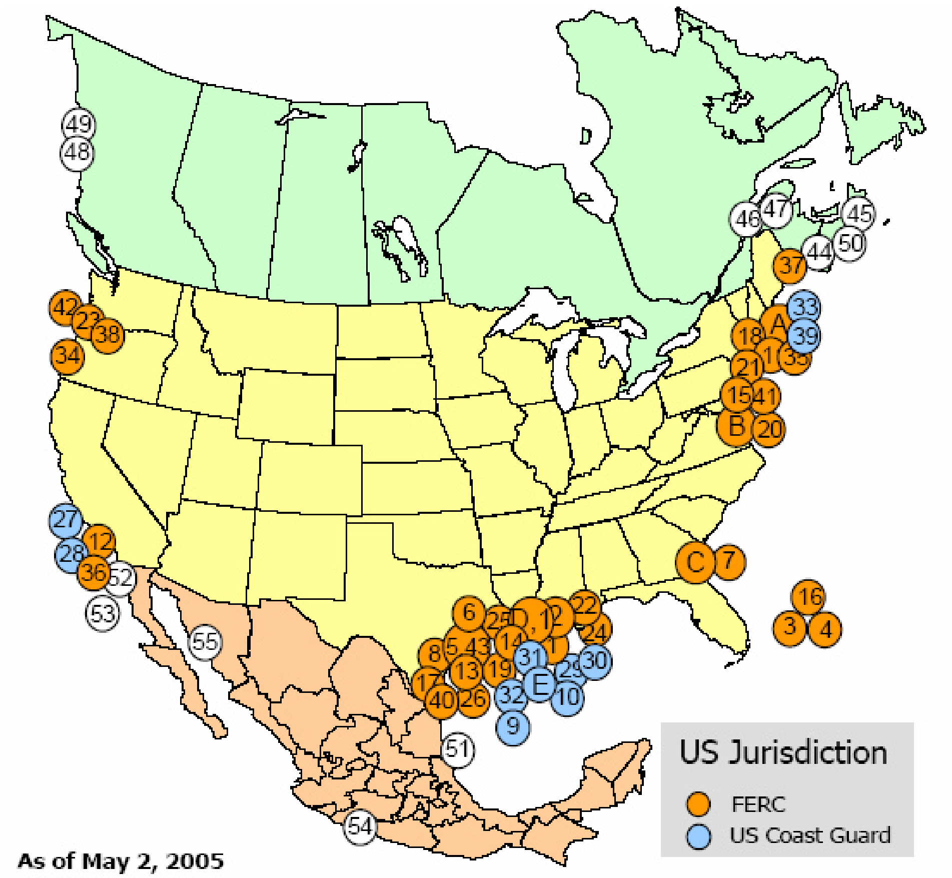
[12] Natural Gas Week, various issues.

[13] Full replacement cost includes exploration, development, and operating costs; taxes; royalties; and return on investment. The estimates in Exhibit 2-3 incorporate the productivity of new wells in addition to costs.

[14] See FERC Website: http://www.ferc.gov/industries/gas/gen-info/horizon-lng.pdf

Half of the terminals are targeted for the Gulf Coast. About 25 percent are planned for the northeastern United States and Canada. Four terminals are planned for southeastern markets – Georgia and Florida. Seven terminals are proposed for southern California, including Mexico; and five are proposed for the Pacific Northwest. In the following sections we discuss the issues particularly relevant to these regions. (For a full list of the proposed terminals, their size, sponsors and current status, see Appendix A of this report.)

Exhibit 2-5. Locations of Proposed LNG Import Terminals



Source: Federal Energy Regulatory Commission (FERC)

U.S. Gulf Coast

The attractions of the Gulf Coast are both economic and logistical. There is strong demand for gas in the Gulf Coast and a large pipeline infrastructure that provides access to the rest of the U.S. market. All of the approved new LNG terminals are in the Gulf Coast. (See Exhibit 2-6.)

The Gulf Coast of Texas and Louisiana have heavy concentrations of petrochemical plants and refineries that use natural gas as a feedstock and for other process uses, as well as gas-fired power generation. In 2002, these states consumed 5.5 Tcf of natural gas or 23 percent of the national total.[15]

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[15] Source: EIA Website, Natural Gas Consumption by State.

Exhibit 2-6. Approved U.S. LNG Terminals in Gulf of Mexico

Project Name	Location	Capacity (Bcf/d)	Developer
Lake Charles	Louisiana	2.1	Southern Union
Cameron	Louisiana	1.5	Sempra
Port Pelican	Offshore LA	1.6	Chevron Texaco
Louisiana Energy Bridge	Offshore LA	0.5	El Paso and Excelerate Energy
Freeport LNG	Texas	1.5	Freeport LNG Development
Source: FERC Website, Dec. 2004; NGI Power Market Today, Jan. 8, 2005			

The other attractions of the Gulf Coast are the available capacity on the pipeline network, access to other markets, near-by market hubs, and local storage. The decline in U.S. production in the Gulf Coast has created spare pipeline capacity that connects to virtually every pipeline serving the eastern half of the country. Between South Texas and Alabama, approximately 30 market pricing points (or hubs) are found where 40 percent of all gas consumed in the United States is sold.[16] Henry Hub, Louisiana is the national market center where the NYMEX futures contract is traded. Local high deliverability storage is highly desirable to LNG importers seeking to provide steady base load deliveries because storage allows them to better balance cargo deliveries with sales from receiving terminals.

Southeastern U.S.: Florida and Georgia

The attraction of LNG for the southeast is the growing gas market there driven by high electricity growth. At the same time, the southeast is at the end of major pipeline systems and is distant from production. Because the region lacks underground storage, LNG deliveries can be scheduled to meet seasonal demands Thus LNG offers the opportunity to increase supply at a lower cost than expanding the existing pipelines in addition to helping meet peak gas demand. Currently this region is served by the Elba Island terminal operated by El Paso, with a send-out capacity scheduled to increase to 800 MMcf per day.

Florida in particular is expecting substantial gas demand growth driven by its growing population and the demand for more electricity. Currently all of the gas for Florida comes from Gulf Coast production and several developers have proposed LNG projects to serve Florida from the Bahamas. One of the major utilities in the state, Florida Power & Light (FPL), through an affiliate FPL Group Resources, is a cosponsor along with Tractebel and El Paso of a Grand Bahamas Island LNG project that would bring initially up to 800 MMcf per day of gas to south Florida over the Seafarer Pipeline (FERC approval pending). Previously, a FPL affiliate entered into a LNG supply agreement with Qatar's RasGas in a bid to diversify its sources of gas.[17] AES is also a sponsor of a Bahamas LNG facility aimed at the Florida market.

[16] See, Intelligence Press, *Major North American Natural Gas Pipelines Map*, 2003.
[17] FPL Group, Inc., Press Release, December 14, 2004.

Middle Atlantic

The Middle Atlantic, from New York to North Carolina, is a major growth market for natural gas. Population growth and electric power demand will see substantial additions of gas-fired generation in the future. At present, this region is served by the Cove Point LNG import terminal in Maryland on the Chesapeake Bay. Cove Point opened in 1982 and is slated to expand to 1.6 Bcf per day by 2008. Several large pipeline liquefaction, LNG storage, and regas facilities are located in northern New Jersey, Philadelphia, and in North Carolina.

One import project has been proposed for New Jersey: BP's Crown Landing project, to be located in New Jersey on the Delaware River, downstream of Philadelphia. It would have a sendout capability of 1.2 Bcf per day. LNG introduced in the Middle Atlantic states can have a significant effect on pipeline flows and on regional markets. Additional supply injected into the market end of the pipeline will tend to make more gas available and lower prices regionally.

New England

New England traditionally has seen the highest priced gas in the United States. This is due to the distance of the region from the producing areas and corresponding costs of pipeline transportation, and the lack of local storage north of New York and along the coast. For this reason, LNG made from pipeline gas and stored in LNG storage tanks, has been used widely as a peaking fuel in New England and the Northeast. Small LNG liquefaction facilities operate in Massachusetts and Connecticut and liquid storage facilities exist in Massachusetts, Connecticut, Rhode Island, Maine, and New Hampshire. The Everett LNG import terminal is the oldest LNG import terminal in the United States Current capacity is 725 MMcf per day with a peak sendout capability of 1.0 Bcf per day.

Several LNG import terminals have been proposed for New England. In early 2004, the proposed Fairwinds LNG project in Harpswell, Maine, was rejected by a vote of the local community. Other proposed projects at Fall River, Weavers Cove, and Somerset, Massachusetts, and Providence, Rhode Island, also have attracted local opposition. Excelerate Energy's Northeast Gateway proposal for an offshore Massachusetts project meets a number of the objections raised by local entities. It would deploy the "Energy Bridge" concept, where LNG tankers with on-board regasification equipment would dock at a submerged buoy system, re-gasify the LNG on ship, and then pipe the gas into an offshore pipeline that would feed the gas directly into the Hubline Pipeline around Boston.

Two Canadian projects proposed for New Brunswick (Canaport) and Nova Scotia (Bear Head) would be able to provide additional supply to New England in addition to growing local demand in the Maritime Provinces. Both projects would rely on the Maritimes and Northeast Pipeline, the single pipe transporting Eastern Canadian gas to the United States.

California

California's gas market is growing and heavily dominated by power generation. Traditional sources of gas for California have been from the southwest, Rocky Mountains, and Canada. Declining production in Canada and the competition from mid-American markets for this supply has raised the price of Canadian gas to California. Increasingly, California is finding itself vulnerable to higher gas prices. LNG, therefore, is an attractive option for state energy planners.

California PUC v. FERC

The California PUC and the FERC are litigating in the U.S. Court of Appeals for the Ninth Circuit which entity has jurisdiction over the proposed Sound Energy Solutions, Inc., (SES) LNG import terminal in the Port of Long Beach, California. The CPUC has challenged FERC's claim that it has jurisdiction under Sec. 3 of the Natural Gas Act. (See FERC March 2004 and June 2004 in CP04-58-000).

Pursuant to state law, the California PUC has also asserted its jurisdiction over proposed LNG projects in California, and requires evidentiary hearings, which would give the public a meaningful opportunity to be heard before the California PUC decides whether or not to approve the siting of LNG facilities at a particular location. The California PUC and the FERC are currently litigating this jurisdictional issue in the U.S. Court of Appeals for the Ninth Circuit.

A number of LNG projects have been proposed for southern California and in northern Mexico where regasified LNG could be shipped into southern California. Two California project have been cancelled, one by Shell-Bechtel in the Vallejo area and one by Calpine near Eureka. Projects in Southern California and the Baja area of Mexico face local opposition as well.

California has been proactive in coordinating the review of LNG proposals. The California Energy Commission, the California Public Utilities Commission and other agencies are working together to define the energy needs of the state and to set policies related to LNG plant siting and gas supply and transportation contracting issues that are relevant to LNG. California has set up a LNG Interagency Permitting Working Group to improve decision making and coordination and a LNG Interagency Working Group to develop a common information base for use by all agencies. California has identified several key issues where information and coordinated decision making is needed, including gas quality standards , defining the role of long term gas supply contracts, identifying necessary pipeline upgrades, and understanding public safety risks in more detail.

California has enhanced its public education activities with local public forums and meetings on safety and permitting, and has established websites on specific projects and on LNG in general. The State is aggressive in developing more detailed information on safety to ensure that the public has sufficient information to address its concerns.[18]

[18] Considerable information is available on what the state is doing at the California Energy Commission LNG web site. Go to www.energy.ca.gov/lng. The site also directs inquiries to David Maul, Manager of the Natural Gas and Special Projects Office at the CEC. Much of the information above came from David Maul, LNG: Meeting California's Energy Needs, presentation to Asia-Pacific Economic Cooperation Project Workshop, April 30, 2004 and available at the above web site.

Pacific Northwest

Five projects have been proposed recently for the Pacific Northwest, three in Oregon and two in British Columbia. These projects are in the early stages of planning. None has filed with the respective approving agencies. The attraction of LNG to the Pacific Northwest is to supplement the perceived declining production from Canada, the major source of gas in this region, as well as to meet the growing gas demand in the Interstate Highway 5 corridor south of Seattle.

LNG Interchangeability with Domestic Gas as a Regional Issue

As the natural gas supply and delivery infrastructure evolved in the United States, regional differences in supply compositions also evolved. As a result, appliances and other end use applications were tuned or adjusted to historically acceptable deliveries into a market area. A potential regional concern for any new supply, including LNG imports is gas interchangeability. Interchangeability is a subject rich in history, dating back to the early 1900's with the introduction and subsequent blending of wellhead supplies with manufactured gas via the introduction of intrastate and interstate pipelines. The term interchangeability is simply a measure of the degree one gas supply can substitute for another without impact to combustion applications and is often a term used to describe one attribute of gas quality. Gas quality on the other hand is a term used to generally describe many attributes of a gas supply including hydrocarbon constituents, non-hydrocarbon constituents (moisture content, sulfur content, inerts including carbon dioxide, nitrogen etc.) and the many calculated parameters associated with a specific composition such as heating value, hydrocarbon dew point and specific gravity.

The heating value, or the energy content of a standard unit volume of gas, has traditionally been the parameter that many LDC's and pipelines have relied upon as an indicator of acceptable gas supply. Average heating values range from 985 to 1,085 Btu per cubic foot with some market areas receiving gas in excess of 1,100 Btu/scf. Regasified LNG in general can have a heating value in excess of 1,100 and in some cases greater than 1,150 Btu/scf primarily due to the increased non-methane higher hydrocarbon content of this gas (ethane, propane and butane's). Considering appliances are certified and tested with a gas of 1,075 Btu/scf, the widespread introduction and use of gas supplies significantly greater than this value may present some challenges including the potential for incomplete combustion, excess carbon monoxide generation, sooting, NOx emissions, knocking in gas engines as well as problems with process controls and metering. Issues relating to non-combustion feedstock, including LNG peak shaving liquefaction plants, may also surface as these processes were designed considering a specific range of feedstock compositions. However, heating value alone is not a good predictor of gas interchangeability. Heating value coupled with traditional interchangeability criteria, such as theWobbe Index and other specific constituent limits better describe one gas's ability to be substituted for another.

A variety of calculation methods have been developed to define the interchangeability of fuel gases for traditional end use applications including single index methods and multiple index methods. These methods are based on empirical parameters developed to fit the results of the interchangeability experiments. The single index methods are based on energy input while the multiple index methods incorporate fundamental combustion phenomena. Science Applications

Inc., (SAI), published a comprehensive review of these and other interchangeability techniques in 1991 under sponsorship of the former Gas Research Institute (GRI), "Catalog of Existing Interchangeability Prediction Methods"[19].

The most common single index parameter is the Wobbe Index, sometimes referred to as the "interchangeability factor". The Wobbe Index is simply the ratio of the heating value to the square root of the specific gravity. The Wobbe Index is a measure of the heat input to an appliance that considers flow through a fixed orifice. While Wobbe is an effective interchangeability screening tool, industry has recognized that Wobbe alone is not sufficient to completely predict gas interchangeability because it does not adequately predict all combustion phenomena. However, when Wobbe is combined with a "boundary parameter" such as heating value, this combination of criteria can predict with a margin of comfort, one gas's ability to be interchangeable with another in a traditional appliance combustion application. One must also recognize that application of this criteria is relative to how the appliance was adjusted at the time of installation and as a result, is directly related to historically acceptable gas (otherwise know as "adjustment gas") within a specific market area.

Wobbe Index Example

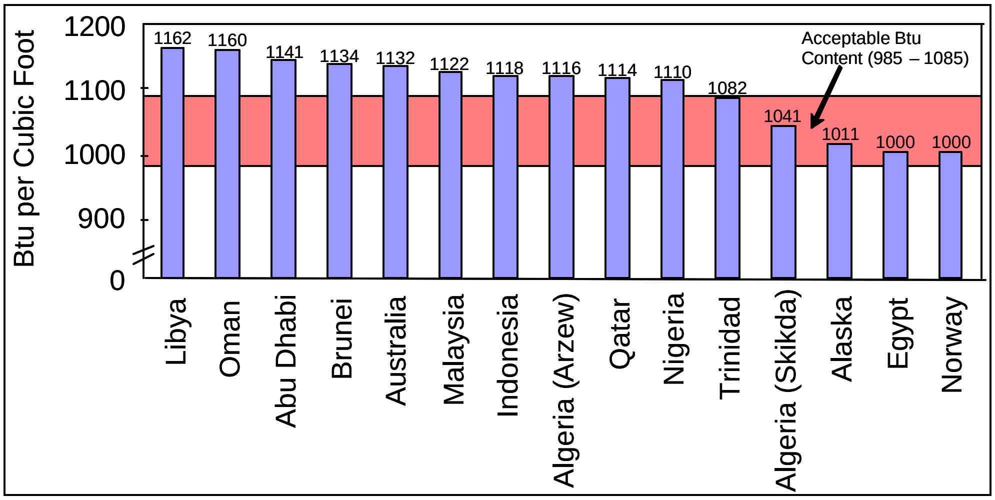
A *Wobbe* calculation divides the heat content (Btu per standard cubic foot or scf) by the square root of the specific gravity of the gas stream. The result is expressed in Btu per scf. Pure methane, for example, has a Btu content of 1009.7 Btu/scf and a specific gravity of 0.55. The *Wobbe Index* for methane is 1,357 Btu/scf. A pipeline gas stream rated at 1,075 Btu per scf and with specific gravity of 0.65 (a general rule-of-thumb for pipeline gas), would have a *Wobbe Index* of 1,333 Btu/scf.

Source: BP America Production Company and BP Energy Company, Post-Conference Comments on Gas Quality and Interchangeability Issues, March 22, 2004, filed with FERC in Docket No. PL04-3-000.

Some LNG imports typically have Wobbe numbers and heating values in excess of 1,400 / 1,110 Btu/scf and as a result, need to be adjusted in order to be interchangeable with traditional pipeline supplies. This adjustment typically involves the introduction of inerts, such as nitrogen. The introduction of nitrogen increases the specific gravity and lowers the heating value of the gas mixture resulting in a lower Wobbe number and a gas mixture that is generally interchangeable with pipeline supplies.

[19] Performance Modeling Of Advanced Burner Systems – Catalog Of Existing Interchangeability Methods, Final Report Phase II, GRI – 80/0021, 1980

Exhibit 3-4. Heat Content of LNG and U.S. Gas



Source:EIA, U.S. LNG Markets and Uses, June 2004 Update

The Rationale for LNG for PUC Consideration

PUCs are interested in ensuring adequate gas supply for the consumers in their states at reasonable prices. Some PUCs also have authority under their state laws to ensure the safety of the location and operation of natural gas facilities. PUCs must examine the extent to which LNG can satisfy these objectives.

From both a national and a regional perspective, LNG is a desirable incremental source of gas supply. It has the advantage of being made available through the traditional pipeline producing regions (i.e., the Gulf Coast) and directly into the consuming markets. LNG can be delivered to the United States at costs (not prices) that are below the current replacement cost of much of U.S. production. LNG suppliers to the United States will be price takers (similar to domestic producers) and the prices they will see at the terminals will be prevailing market prices. Nevertheless, the addition of more supply will tend to reduce the overall price of gas and in some markets, tend to lower the price of gas relative to the national market price at Henry Hub.

Can LNG reduce gas price volatility? The principal driver of gas price volatility has been the volatility of demand in the face of the limited capacity of the supply system to expand to deliver incremental gas supply. Anything that adds to the capacity of the system to meet demand swings can reduce price volatility.

The potential benefits of increased supply from LNG are substantial. In the next section we address the commercial economics of the LNG trade, and consider how PUCs can help actualize these benefits.

3. LNG ECONOMICS AND THE NEED FOR AFFORDABLE ENERGY

One way to lower record high gas prices is to increase the gas supply. LNG imports do this. This section describes how LNG import contracts can provide a more stable pricing platform for natural gas sales because the structure of the LNG industry is grounded on firm and reliable gas supply and purchase agreements. It is in the area LDC and regulated utility purchasing practices that PUCs can have a major say in shaping LNG imports.

Understanding the LNG Value Chain

The key aspect of the LNG market is the high capital investment in infrastructure required to make, transport, and re-gasify LNG. In this sense, LNG is similar to other capital intensive industries that PUCs are accustomed to dealing with – power generation, gas distribution, water, and telecommunications. The LNG value chain consists of four elements: natural gas production, liquefaction of the natural gas, transportation by tanker ship, and regasification at the import terminals. Below we summarize current information about each of the elements in the value chain.

- **Production and its Opportunity Costs.** Production costs range between $0.50 to $1.25 per MMBtu. This includes the full cost of exploration, drilling, and lifting costs.[20] The variable "lifting" cost of this gas is much lower.

  What is more relevant is the "opportunity cost" of the natural gas that has been found. Often it is a byproduct of the search for and the production of oil, and the gas has a small local market. This "stranded gas" therefore has economic value, except what can be developed from export as LNG. Thus, any positive value for this gas that covers the production costs and then some is a substantial benefit to these countries.

- **Liquefaction Costs.** Liquefaction is the largest component in the LNG value chain. Typical costs for a 390 Bcf per year (8.2 million tons) liquefaction facility are between $1.5 and $2.0 billion. Expressing the costs on a per unit basis, liquefaction ranges between $0.80/MMBtu to $1.20/MMBtu, with size of the trains being the dominant factor.[21]

- **Shipping Costs.** LNG ships cost from $150 million to over $200 million depending on the size. Sizes range between 25,000 cubic meters to over 150,000 cubic meters. Even larger ships are on the drawing boards. Ships may be purchased outright or chartered under long term charter contracts. Expressed on a per unit basis, shipping costs range from $0.40 per MMBtu to $1.00 per MMBtu for deliveries to the United States.[22] The major determinant of shipping cost is the distance.

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[20] Institute for Energy, Law & Enterprise (IELE), University of Houston, Overview of the U.S. LNG Industry, nd; and ICF Consulting, 2004.
[21] IELE.
[22] IELE.

- **Import Terminal Costs.** The costs of a typical LNG tank-based receiving terminal can range from $300 million to over $1.5 billion depending on design and location. Most shore-based terminals under development in North America are similarly sized (around 8 Bcf to 10 Bcf of storage capacity and 800 MMcfd to 1.0 Bcfd of regas capacity), and are likely to have terminal-service fees in the range of $0.30 per MMBtu to $0.50 per MMBtu.[23]

In summary, the total delivered cost of LNG according to the Institute for Energy, Law and Enterprise (IELE) can range between a low of $2.00 per MMBtu up to $3.95 per MMBtu. On average, 80 percent of the capital investment in the LNG supply chain resides in facilities upstream of a LNG receiving terminal. Most estimates show that exploration and production accounts for 20 percent of the costs, liquefaction for 30 percent, and shipping another 30 percent.[24] Thus, despite the high upstream costs of LNG facilities, at today's market prices for natural gas the United States is an attractive and potentially lucrative market for LNG importers.

Exhibit 3-1. LNG Value Chain

Exploration & Production	$0.50 to $1.25/MMBtu
Liquefaction	$0.80 to $1.20/MMBtu
Shipping	$0.40 to $1.00/MMBtu
Storage & Regasification	$0.30 to $0.50/MMBtu
Total	**$2.00 to $3.95/MMBtu**

Source: Institute for Energy Law and Enterprise, U. of Houston

Commercial Relationships in the Value Chain: Who Does What

The LNG trade is dominated by large integrated oil companies, international trading companies, and national oil companies of the countries sourcing the LNG.

Producers. The major state-run oil companies typically have contract agreements or joint ventures with the international oil companies (the concessionaires) to explore and develop the natural gas resource.

LNG Suppliers. LNG suppliers are almost always joint ventures of integrated oil companies, trading companies, and national energy companies for the purpose of operating the liquefaction facility and exporting the LNG for sale in overseas markets – Japan, Korea, Europe, and the United States. Liquefaction joint ventures purchase the gas feedstock from the gas-producing joint venture under long-term purchase agreements. LNG liquefaction trains are sized to serve specific export markets as defined by long-term sales agreements between the supplier and the buyers in the receiving country.

[23] IELE.
[24] EIA, *The Global Liquefied Natural Gas Market: Status and Outlook*, December 2003.

Ship Transporters. LNG shipping is best thought of as a floating pipeline, where the shippers are the owners of the LNG who sign long term transportation agreements with the ship owners who operate the "pipeline." Ships traditionally have been constructed for specific LNG-production transactions deals and remain dedicated to a particular trade route for the duration of the contract.

LNG Terminal Operators. The import terminal owner/operator takes the LNG from the tanker, cycles it through LNG storage tanks, and regasifies the LNG for injection into the pipeline system. Three kinds of ownership structures appear to be emerging. The terminal owner/operators may simply offer tolling services for handling and regasifying the LNG. In this case they will receive fees from the owners of the LNG for processing it. In the alternative, these plants may operate like pipelines or storage services where third parties own capacity under standard service agreement contracts. These contracts tend to resemble gas storage contracts that define storage service, injection, and withdrawal services. Elba Island, the proposed AES Bahamas Project, and Cove Point are examples of these types of facilities.

FERC's Hackberry Decision

In December 2002, FERC exempted LNG import terminals from rate regulation and open access requirements. Prior to this, FERC treated jurisdictional terminals as pipeline facilities, subject to all the requirements of FERC post-Order 636 regulatory policies. The Decision allows jurisdictional terminal operators to use market rates, and allows jurisdictional terminal developers to reserve or dedicate terminal capacity to upstream suppliers. Hackberry reduced investment uncertainty for LNG developers and assured suppliers a long-term market access.
Hackberry LNG Terminal LLC, 101 FERC, 61,294 (2002)

The second structure is where the suppliers of the LNG also own and operate the plant and sell gas at the terminal outlet to buyers as a one-price bundled supply. The buyers of regasified LNG may be marketers or direct users of the gas. The Distrigas terminal in Everett, Massachusetts operates like this.

The third structure apparent from today's market is where the ownership is an affiliate of a regulated gas or electric utility. In these cases, much of the LNG is destined to provide gas supply to the utility's market. The Energia Costa Azul project being developed by Sempra resembles this type of project.

The FERC Hackberry Decision has been a major impetus to LNG terminal development by removing requirements for open access to the facilities. This means that LNG terminals can be dedicated to particular suppliers, thus providing insurance to upstream LNG suppliers that their LNG will have market access. Europe and Japan have also recently experienced new development of LNG terminals without requiring complete open access, but still requiring managed access whereby a certain percentage of the terminals capacity would otherwise be idle. Of course, the high prices of natural gas have created a significant incentive for new LNG projects.

LNG Importers. Importers or "off-takers" are the entities that commit to taking the LNG and selling it into the gas market. These once would have been the large gas marketers like Dynegy, who could take and manage the LNG contract and market risks. Today, these roles are fulfilled by the LNG suppliers themselves. More than one importer may operate from a given terminal.

Some examples of terminal regasified LNG sales structures include the following.

- At the Lake Charles terminal, British Gas has contracted all of the storage and processing-capacity rights and markets the regasified LNG to the downstream markets.

- At Cove Point, owned by Dominion Resources, LNG suppliers/gas marketers Shell, BP and Statoil have contracted all of its processing capacity for downstream sales for their respective accounts.

- The Freeport, Texas LNG terminal has been developed by Cheniere and will be owned and operated by a special purpose entity consisting of Cheniere and other partners. Financial support of its development is underpinned by long-term capacity tolling to the regasified LNG buyers Dow Chemical and ConocoPhillips.

- ExxonMobil is developing receiving terminals for exclusive receipt of LNG that they are producing and shipping in partnership with the national energy companies of Qatar, and offtake sales will be to their own joint account.

- Sempra Energy is developing the Cameron LNG facility in Hackberry, Louisiana. Sempra will market the gas at the plant outlet after securing upstream LNG supply. Sempra is also developing a project in Baja California, Mexico, to supply natural gas to Baja California, Mexico and Southern California markets.

- An affiliate of Florida Power & Light is developing a LNG facility in the Bahamas to supply gas for power generation in southern Florida. FPL recently announced a supply deal with Qatar's RasGas and partnership with other LNG developers Tractebel and El Paso.

Two observations can be made about this list. First is the key role of large energy companies with strong balance sheets that can manage the risks of upstream and downstream market interactions. Second is the presence of major domestic gas producers who apparently view LNG sales as they would production and who are accustomed with the vagaries of the U.S. gas market.

LNG Pricing

LNG is traded globally in two major markets – the Atlantic and the Pacific. The United States can be thought of as an emerging third market, with participation in each of the markets. Pricing regimes are different for each market.

- In the western Pacific (Japan, Korea), where there is no indigenous oil or gas production or gas-on-gas competition, LNG has been priced at the equivalent of a market basket of world oil prices in the buying countries.
- Europe has its own gas production and other import sources of gas and coal. Here the price of LNG, like gas in general, is tied to Brent crude, distillate fuel oil, and other fuels used in Europe.

- In the United States where gas-on-gas competition sets the market price, LNG prices are based on Henry Hub or other regional market indices where high volumes of trading (liquidity) occur transparently. LNG suppliers are price takers, able to sell their gas only at the locally prevailing prices. In the Gulf Coast this is a price that is slightly discounted to Henry Hub; in more distant markets, the price will be at the Henry Hub price plus the "basis" between Henry Hub and the local market.

Traditional LNG contracts have been long-term (20 years) and have had various restrictions familiar to U.S. buyers in the pre-Order 636 gas market. LNG contracts have included a Downward Quantity Tolerance (DQT), which sets a minimum take-or-pay level of purchases. For example, a 10 percent DQT allows a buyer to take one-tenth less LNG than the contract quantity (i.e., if the contract calls for 10 ship loads, the buyer may decline one of them, without incurring a take or pay penalty.) Destination controls do not allow buyers or sellers to divert cargoes to third-party locations. These contract terms are designed to put the volume risk on the buyer in exchange for assurance of long term source of supply at a known price.

In the coming decade, many LNG contracts expire and will come up for renegotiation. A trend is developing toward more flexibility in the contracts, including less rigid pricing, shorter terms, more delivery flexibility, and less strict take-or-pay provisions. Already, more LNG is now being traded on a short-term basis and spot contract deals have occurred. This market shift is being made possible by a growing LNG market, with more suppliers and buyers, uncommitted production capacity, underutilized ships, and flexibility in contracting.[25]

As the United States further opens to LNG, Henry Hub index pricing may begin to be felt elsewhere in the global LNG marketplace. Indeed, some industry experts envision that the future of the global LNG business will appear to mirror that of today's global oil-commodity trade, with, for example, several worldwide benchmarks for setting gas price (such as the Henry Hub index) and diversion of cargos driven by temporal shifts in market demand. [26]

Economic Benefits of LNG Terminals for Local Communities

The economic impacts of LNG receiving terminals on local communities can be substantial. Estimations of these impacts have been made for the state of Maine by the State Economist.[27] The major local economic benefits would come from employment, local or regional expenditures for goods and services, and the associated secondary impacts of these purchases, state and local taxes, and property taxes.

Most land-based LNG receiving terminals will cost around $600 million. About 40 percent of the total cost will be for labor and services. Most land-based LNG receiving terminals will take up to three years to complete. At peak, 1,000 on-site workers and managers would be employed. Maine estimated the payroll at $45 million per year. For materials and services purchased in

[25] EIA, *The Global Liquefied Natural Gas Market: Status & Outlook*, Dec. 2003.
[26] See for example, New York Times, *Natural Gas Seems Headed the Way of Oil: More Demand, Less Supply, Higher Cost*. August 20, 2004.
[27] See Laurie Lachance, State Economist, *Potential Economic Impacts of a Proposed LNG Facility in Maine at Public Symposium on LNG*, Brunswick, Maine, July 2004.

Maine, the direct expenditures were estimated at $32 million per year. Secondary expenditures and payroll were estimated at about $180 million per year. State sales and income taxes were estimated at $6.5 million.

On an ongoing basis, LNG receiving terminals will require 60 to 80 highly trained, full time operating and maintenance personnel and ongoing services. In Maine, the base payroll was estimated at $3 million per year and base service expenditures at $36 million. Secondary expenditures were calculated at $75 million. Taxes were estimated at $1.7 million.

Economic benefits accruing to local communities from offshore LNG receiving terminals are more difficult to quantify because the varied designs for floating, moored or fixed (gravity based) offshore terminals are works in progress, but should be less than the onshore facilities. In general offshore facilities would tend to have less of a local impact than on-shore facilities.

As with any large industrial engineering project, decision makers will have to balance the substantial local economic benefits with other economic, safety, and environmental impacts.

Key Economic Considerations for State PUCs

In addition to safety and environmental considerations, three other areas where PUCs have a role to play bear on the timely availability of LNG imports. First lies in the area of ensuring reliable gas markets for LNG suppliers. The second concerns addressing the overlapping regulatory and government review responsibilities to render the process less like a maze. The third derives from the first two – to create an environment where the financing of LNG projects is less risky and more reliable and timely.

Contracting for LNG Supply

Importing LNG into the United States at uncertain gas market prices and volumes entails a level of risk that traditional LNG traders are not accustomed to. This risk will vary geographically. The Gulf Coast is relatively less risky than other U.S. markets. It is large and liquid, with substantial pipeline access to the rest of the United States, and the proximity of Henry Hub reduces "basis" risk.[28] In the Gulf Coast, a LNG supplier faces the same risks as a large domestic gas producer. Many large international oil companies are more comfortable selling their LNG in the Gulf Coast for these reasons.

PUCs and Long Term Gas Supply Contracts

One of the main market issue that PUCs face is whether it will be in the public interest to allow or encourage regulated LDCs to enter into long-term LNG-based gas supply contracts containing terms that provide the back-to-back support that LNG providers need in order to minimize commercial risks throughout the LNG supply chain.

Other markets, such as New England, are smaller than the Gulf Coast market, and have limited access to the broader U.S. interstate pipeline system. When LNG enters these markets, local gas prices can become

[28] Basis risk is the price risk faced by buyers of gas at points away from Henry Hub where the NYMEX gas futures contract is traded. This basis risk is more difficult and costly to hedge.

depressed relative to Henry Hub. To succeed in these markets, the LNG importers must have marketing acumen, local relationships, and access to take away capacity on pipelines. A position in storage can help mitigate these risks.

There will be an effort by importers of LNG supply to lay off the risks of their long-term upstream purchase and shipping contracts (including take or pay provisions) on large-volume, credit-worthy buyers who can shoulder such risks, including regulated gas and electric utilities. This will be more critical in the markets outside the Gulf Coast. The situation is not unlike that of independent power producers (IPPs) in the 1990s. Early in the period, IPPs depended on firm power purchase agreements, executed often under state regulatory mandates, to reduce the risks of power plant investments. Later, as these firm fixed-price power purchase agreements became uneconomic and were eliminated merchant power projects depended on access to regional power markets to support their investments. Without long term sales contracts or ready access to large consuming markets, terminals in the less-liquid market areas face more risk, and may be more difficult to develop and to finance.

Overlapping Regulation

The regulation of LNG imports, LNG terminal siting, and LNG operations including LNG contracting policies cuts across federal, state and local jurisdictions. There can be some confusion and uncertainty about who does what, when a decision is final and actionable, and ultimately who has the final say.

The FERC asserts it has lead federal responsibility for authorizing the construction and siting of onshore LNG facilities under Section 3 of the Natural Gas Act. In this regard, FERC performs environmental and safety reviews of LNG plants. This includes the preparation of environmental impact statements of proposed facilities. The U.S. Coast Guard has similar permitting responsibilities for offshore facilities under the Deep Water Port Act as amended. Both agencies coordinate with a variety of other federal and state entities that have specific approval responsibilities for various aspects of terminal operations.

State authority over LNG facilities varies considerably. Certain State PUCs have siting and safety jurisdiction over LNG facilities under their State laws. State PUCs have the primary approval authority over siting intrastate natural gas pipelines and related facilities such as storage, peak shaving and local distribution systems. State and local governments have broad responsibilities for zoning, permitting for water, electricity, construction, and waste disposal. States also have permitting authority under specific federal legislation: the Clean Air Act, the Clean Water Act, and the Coastal Zone Management Act (CZMA). Some observers believe that state authorities notwithstanding, LNG projects authorized by FERC cannot be blocked by contrary provisions found in state regulations or local law.[29] This may not be the case with the Coast Guard where under the Deep Water Port Act, an objection by a state governor can stop a proposed project.

Recently the State of Connecticut refused to issue a permit under the CZMA for construction of

[29] See, Congressional Research Service Report to Congress, Liquefied Natural Gas (LNG) Import Terminals: Siting, Safety and Regulation, January 28, 2004, p. 12. This is an excellent broad discussion of the issues.

the Islander East Pipeline, which had received a certificate from the FERC. Sponsors of the pipeline appealed the decision to the Secretary of Commerce, who ultimately sided with FERC and the pipeline sponsors, overriding Connecticut's objections.[30] The point is that the final decision in this instance, and in others like it, resided with an agency other than FERC.

Another source of state-federal conflict is over the issue of inter- versus intra-state gas facilities. California PUC has appealed FERC orders on the siting of a proposed LNG project in the Port of Long Beach, where the LNG facilities would connect with intrastate pipelines regulated by the CPUC. FERC has asserted it has exclusive jurisdiction over an LNG import facility pursuant to the Natural Gas Act and claimed that there is a need for a uniform federal approach to siting, construction, operation and safety of LNG facilities.[31]

From the standpoint of a LNG developer, overlapping authorities can create uncertainty and slow the process, which affects the economics of development, unless there is coordination between the relevant federal, sate and local agencies. Second, uncertainty of receiving final approvals discourages participants all along the value chain from entering into binding contractual arrangements necessary to import LNG.

Financing

Having all of the government permits is a necessary prerequisite for a LNG terminal but it is not sufficient. Developers ultimately must demonstrate the viability of their projects to lenders to obtain financing. This viability derives from being located where a project has access to strong markets, being sponsored by entities with strong balance sheets, or having contracts with buyers who can assure sales and steady revenues. Regulatory uncertainty and the absence of long term contracts with buyers creates more risk for lenders and can make project development less certain. It should not be surprising then that the sponsors of many proposed LNG terminals are associated with familiar names: ExxonMobil, BP, ConocoPhillips, Shell, ChevronTexaco, or Sempra, Keyspan, and Dominion. In situations where the developers of projects do not have the strong credit of the larger companies, the LNG contracts and contracting terms can have a major impact on the ability of LNG terminal developers to obtain financing. Again, the role of PUCs can be vital in ensuring that projects get built and supply is made available.

[30] See, National Oceanic and Atmospheric Administration, *Decision and Findings by the Secretary of Commerce in the Consistency Appeal by Islander East Pipeline Company, LLC, from an Objection by the State of Connecticut*, May 5, 2004.
[31] See, FERC, *Order Clarifying Previous Order, DCP04-58-002*, August 5, 2004, 108 FERC 61,155.

4. TERMINAL SITING AND OPERATIONS: SAFETY AND SECURITY

LNG safety and security are important to all parties involved in LNG operations, from the local community to regulators to facility staff to owners. Numerous regulations and best practices have been developed over the last 60 years to help manage and minimize LNG risks. The recent increase in attention to safety and security is due to the increased number of projects and the need to site many new facilities.

This section provides an overview of safety and security risks and controls associated with marine terminals and onshore storage facilities. Appendix A provides additional details on siting considerations and Appendix B presents additional information on security practices.

How Safe is LNG?

The hazards associated with LNG are a result of it being an extremely cold liquid and the very flammability that makes it useful as a fuel. LNG is primarily methane (90% or more) and has a boiling point of about -260 °F, with slight variations depending on what other materials (e.g., propane, nitrogen) are present and in what amounts. LNG is shipped and stored in refrigerated tanks or containers at very low pressures, so its temperature is usually right around the boiling point. In its liquid (cold) form, a container can hold roughly 600 times the amount of methane vapor that would otherwise fit in the container at ambient temperature.

Hazards associated with LNG due to its cryogenic state include freeze burns where someone directly contacts the liquid or uninsulated pipes and containers. These hazards are mitigated by insulating equipment and having workers wear heavy clothing and gloves.

Hazards associated with LNG in a mostly liquid state include pool fires, if the vapor from a release ignites and burns back to the pool of LNG. Containment, often earthen berms constructed around tanks, is used to limit the size of the pool and therefore the size of the resulting fire. Pool fires on open water can grow larger than contained pools and thereby pose hazards at greater distances.

Hazards associated with LNG as it vaporizes include:

- While LNG is not considered toxic, asphyxiation can occur if a large amount of LNG vapor reduces the amount of oxygen available to breathe or if a worker is in a confined space with LNG vapors present. Hazard mitigation includes requirements for workers to wear protective breathing apparatus and use buddy systems in areas where they might encounter LNG or other asphyxiates (like nitrogen). Asphyxiation hazards can occur with releases of many different materials, not just LNG.
- Vapor cloud fires could occur if an LNG release encounters an ignition source as the vapor cloud disperses away from the point of release. In addition to reducing the chance

of LNG leaks, best practices and stringent regulations also restrict the presence of ignition sources in the vicinity of LNG storage and vaporization processes.

- Explosions could occur if a sufficient amount of natural gas vapors release or disperse into a confined area and encounter an ignition source of sufficient strength. In addition to controlling ignition sources, layouts of LNG facilities are designed to minimize the presence of confined or partially confined areas where vapor from a release could concentrate.

Safety History

LNG has been in use commercially for over 60 years, with imports into the United States almost continuously since the early 1970s. The serious incidents in modern facilities worldwide have been restricted to the facilities themselves and have affected workers and not members of the public. The types of events that have occurred in the last four decades include several incidents associated with loading or unloading operations at terminals. Of the three events that involved LNG releases with fatalities, only one has occurred in the United States, at an LNG gasification facility. The other two incidents involving fatalities occurred at overseas liquefaction facilities, one in Indonesia and one in Algeria. Specifically:

- A fatality at the Cove Point, Maryland facility in 1979 when gas flowing from a leaking pump reached an electrical substation.
- An incident upon re-commissioning an Indonesian export terminal when an exchange tower was over-pressured. A number of workers were killed.
- The recent explosion of a steam boiler in a liquefaction plant producing LNG in early 2004 in Algeria. The explosion killed roughly 30 workers, but it is still uncertain as to whether any LNG vapors were involved in the explosion or subsequent fire.

There have been no terrorist attacks on LNG tankers or storage facilities and there have been no tanker accidents that have led to serious releases.

Why LNG Accidents have been Rare: Design and Siting Safety Measures

Practices used in site selection are comparable and, in some aspects, even more thorough than those applied to any facility handling large quantities of hazardous materials. There are a number of regulatory requirements designed to enhance the safety of the operations. Appendix A provides an overview of the siting and layout issues.

LNG operations incorporate an array of safety measures, including robust primary containment to limit the potential for a release, secondary containment to control any release that does occur, control systems to shutdown and isolate the sources of a release to limit the total amount that can be lost, and minimum separation distances to lessen the chance of an adverse impact if a release does occur.

Some of the design features that help to minimize the risk of LNG operations are outlined below.

- LNG facilities use very robust storage tanks, both for safety reasons and to provide the insulation necessary in order to minimize the heat transfer with the surrounding air or soil and thereby maintain the low temperature necessary to keep the gas in a liquid state.
- LNG storage tanks and process areas typically have containment areas around them, usually earthen dikes or concrete walls, to limit the size of a pool in the event of a leak, and some LNG tanks are actually partially buried to provide additional protection from leaks and external causes of failure.
- Redundant sensors and shutoff systems are used to rapidly detect a leak and then isolate that system from the LNG supply.
- Regulations establish strict exclusion zones that separate work areas and nearby facilities from LNG storage tanks (more detail is provided on this in Appendix A). Shore side terminals generally have at least one side of the facility that is open to a waterway, which limits the likelihood of workplaces or residential areas on those sides of the facility. Design layout of the terminals, particularly new facilities, minimizes operations in proximity to LNG storage tanks.

Regulatory Safety Oversight

Regulatory oversight of LNG terminals is provided by a number of different agencies as described below. This is not generally true for other hazardous materials installations.

- FERC, besides approving the siting of certain onshore marine terminals and those inland LNG storage facilities, also inspect every two years various facilities (Natural Gas Act of 1938 [18 CFR 153]).

- The U.S. Coast Guard has numerous LNG safety and security related authorities under both longstanding and new regulations, such as:

  Oversee security for LNG shipping as well as marine terminals (Maritime Transportation Security Act of 2002 [68 CFR 126], Ports and Waterways Safety Act of 1972)

  Approve the siting of offshore terminals (Maritime Transportation Security Act of 2002 [33 CFR 148])

  Oversee safety for LNG facilities [33 CFR 127]

  Control access and navigation areas in waterways [33 CFR 165]

- The Department of Transportation (DOT) has overseen LNG facilities and pipelines under the authorities of several acts, most recently the Pipeline Safety Act of 1994 and the Pipeline Safety Improvement Act of 2002. DOT sets minimum safety standards for all stages of LNG facilities—siting, design, construction, and operation as given in 49 CFR 193. The Office of Pipeline Safety under RSPA within DOT oversees the safety and security of LNG facilities.

- The National Fire Protection Association also has numerous standards for LNG, notably NFPA 59A – *Standard for the Production, Storage, and Handling of Liquefied Natural Gas*, many portions of which are called out in federal regulations.
- The Transportation Security Administration also had relevant security authorities transferred from DOT as part of the Aviation and Transportation Security Act of 2001.

Many states and localities have additional requirements for facilities located in their jurisdiction, be they specific to LNG or general permit requirements for similar industrial facilities. Many states are certified by the DOT, and have adopted and can enforce the DOT's safety regulations.

Under NEPA, the FERC and the U.S. Coast Guard prepare an environmental impact statement as part of LNG terminal siting applications. Public safety risks associated with potential accidents are included in the evaluation. Owners and operators of LNG facilities also conduct risk assessments as part of their siting and design evaluations. Public concerns are also incorporated in the NEPA review process.

Security Issues

Their large storage tanks make LNG facilities easy to identify and quite visible, increasing general concerns about such facilities as terrorist targets. To date, no LNG facilities have been involved in terrorist events. There are a variety of measures used to enhance the security of LNG operations and, in response to security concerns, the U.S. Coast Guard and local law enforcement agencies have increased harbor patrols near terminals and enhanced escort capabilities for tanker movements. Additional protections in place include more advance notice of specific LNG shipments, more rigorous inspections at the point of loading, inspections of vessel and crew prior to entering harbors, restrictions on vessel and land-based traffic during tanker maneuvers in waterways and harbors, and restriction of ship traffic during tanker offloading. LNG storage terminals also have enhanced their onsite practices, procedures, and controls. Appendix B provides an additional discussion of pertinent security issues.

LNG Safety: Critical Considerations for State PUCs

Although the LNG industry has a strong safety record, the public's lack of familiarity with LNG and the many design and safety precautions that are in place for its storage and use has contributed to the general concern many feel about LNG siting. Many individuals are unaware of the large improvements in engineering design and best practices that help ensure the safe handling of LNG, which makes it easier for them to believe extreme scenarios that are unlikely given today's design and practices. Two types of scenarios are often put forth by opponents.

- A LNG tanker releases its LNG all at once in a cataclysmic failure (accidental or by terrorist action). In fact, LNG tankers use multiple tanks to limit the amount of LNG that can be released at one time. The detailed analysis recently completed as a part of the Sandia report provides further evidence that while it is possible for multiple tanks to fail as a result of terrorist attacks or some very unlikely accidental cause, according to the

Sandia report the simultaneous failure of all the tanks on a tanker is not considered credible.

- A vapor cloud from released LNG envelopes a populated area, ignites, and then explodes. A LNG vapor cloud needs both some degree of confinement and a strong ignition source to create an explosion. LNG releases that encounter strong ignition sources are far more likely to result in vapor cloud fires than they are in explosions.

Nevertheless, there are hazards with the transport or storage of large quantities of any flammable material, and terrorists unfortunately have demonstrated that even a small quantity of such material can lead to major consequences. It is important to ensure that facilities handling large quantities of any hazardous substance follow the best practices and regulations to minimize risks and promote safety.

The Sandia study made two compelling conclusions:

- Risks from accidental LNG spills, such as from collisions and groundings, are small and manageable within current safety policies and practices.
- Risks from intentional events, such as terrorist acts, can be significantly reduced with appropriate security, planning, prevention, and mitigation.

Sandia made several recommendations for further reducing the risks associated with intentional spills including a six step risk management process.[32]

The key question for PUCs, and indeed all citizens, is whether they have confidence that the existing regulatory framework adequately protects the public from the risks of LNG spills. One way to build confidence is in participating actively in the FERC and U.S. Coast Guard decision making processes and other appropriate state and federal processes.

[32] Sandia, pp. 64-67.

5. LNG MARINE TERMINAL ENVIRONMENTAL ISSUES

This section addresses the environmental impacts most typically addressed by decision-makers reviewing the design, construction and operations of proposed LNG import terminal projects. Federal jurisdiction over LNG terminals is split between the U.S. Coast Guard for off-shore terminals and FERC for certain on-shore terminals. Both agencies' decision-making procedures incorporate input from state regulators and agencies, the public, and other federal agencies. The main question before state regulators is how to ensure that state concerns are incorporated in these reviews and how these processes allow a full and fair airing of the community environmental concerns.

State jurisdiction over certain LNG terminals is dependent on the particular states involved. For certain states, the PUCs may have siting jurisdiction, which they coordinate with the coastal commissions, and/or other state agencies. Other states may have siting councils or other state agencies responsible for the siting. For off-shore terminals in the federal waters, the Governors of the adjacent states have veto or conditioning rights under the Deepwater Port Act.

The Federal Environmental Review Processes

FERC

Under section 7 of the Natural Gas Act, FERC has the lead federal agency role in the review and certification of certain on-shore LNG terminals. In response to an Executive Order[33] to expedite the review of energy projects, FERC and many of these agencies have entered into an Interagency Agreement to coordinate environmental reviews. In 2004, the FERC executed a similar agreement with the Coast Guard and Department of Transportation on safety issues.[34] The objectives of these interagency agreements are to work with project sponsors to identify and resolve issues early in the design phase of the projects, to build a consensus among agencies and their stakeholders, and to expedite permitting.

FERC has developed a NEPA Pre-Filing Process to help expedite the review of energy projects (including LNG) and to identify early any

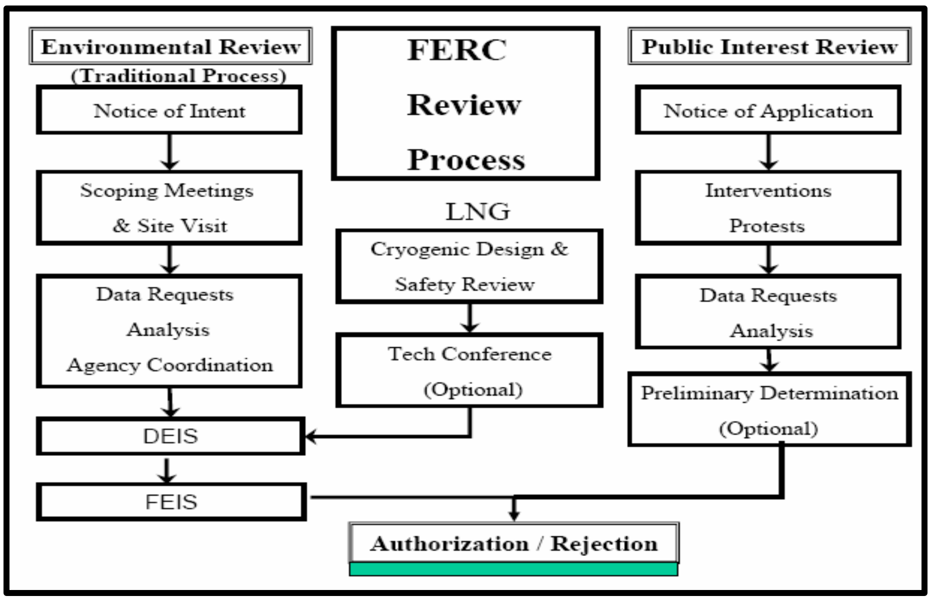
Federal Agencies with Environmental Review Authority over Gas Projects

FERC
Bureau of Land Management (Interior)
National Park Service (Interior)
Minerals Management Service (Interior)
Bureau of Reclamation (Interior)
Bureau of Indian Affairs (Interior)
Forest Service (Agriculture)
Army Corps of Engineers
Research and Special Programs Administration (Transportation)
Environmental Protection Agency
Fish and Wildlife Service (Interior)
National Oceanic and Atmospheric Administration (Commerce)
Advisory Council on Historic Preservation
Department of Energy
Council on Environmental Quality

[33] Executive Order 13212, *Actions to Expedite Energy Related Projects*, 66 FR 28357, Issued May 18, 2001.
[34] See, *Interagency Agreement on Early Coordination of Required Environmental and Historic Preservation Reviews*, May 2002; and *Interagency Agreement for the Safety and Security Review of Waterfront Import/Export Liquefied Natural Gas Facilities*, Feb. 2004.

environmental problems. This process occurs before the developer makes a formal application to the FERC for a certificate of public convenience and necessity.[35] By entering the Pre-Filing Process formally, developers agree to ensure the early involvement of other agencies, state authorities, and the public, and to fund their participation as appropriate. FERC staff, in turn, begins devoting resources to the review effort. During this process, the FERC staff will hold local site meetings to solicit public input. The ultimate intention is to have in place by the time of filing a complete application; including having a draft environmental impact statement (EIS) shortly after the application is filed formally. FERC believes that the Pre-Filing Process should improve and expedite decision-making.[36]

Exhibit 5-1. FERC Review Process



Source: FERC

The EIS process at FERC resembles that of other agencies. The final EIS then becomes part of the record for the Commission's and parties to a proceeding may file comments directly with the Commission. FERC often issues a preliminary determination on a project pending full resolution of environmental issues. Certificates are conditioned on fulfilling the environmental mitigation activities recommended by the EIS.

FERC has implemented a training program to educate developers on how to prepare environmental reports, post-certificate compliance, and better stakeholder involvement. On the latter, FERC has issued a guide for how to better engage stakeholders in project planning.[37]

[35] Richard Hoffmann, FERC, presentation to NARUC Summer Committee Meetings, Salt Lake City, July 13, 2004.
[36] See, FERC. Office of Energy Projects, Division of Gas – Environment and Engineering, *Processes for the Environmental and Historic Preservation Review of Proposed Interstate Natural Gas Facilities*, May 29, 2003, available at www.ferc.gov.
[37] FERC Staff, *Ideas for Better Stakeholder Involvement in the Interstate Natural Gas Pipeline Planning Pre-Filing Process*, December 2001.

U.S. Coast Guard

The U.S. Coast Guard and the Maritime Administration (MARAD) jointly have responsibilities for authorizing the construction of offshore LNG import terminals.[38] These are terminals that would be seaward of state waters, generally about 3 miles (3 leagues for Texas – about 9 miles). The U.S. Coast Guard is responsible for processing applications, reviewing engineering, design, operations, environmental impacts, and waterway safety. MARAD focuses on corporate ownership and financial capabilities of project sponsors and related underwater pipelines. MARAD also prepares the record of decision for the overall process. FERC is responsible for certificating interstate pipelines onshore beyond the high water level.

The U.S. Coast Guard review and approval procedure is fast track – by law it must be completed in 356 days from the date of application. The process has three phases.

1. Project sponsors file an application with the Coast Guard, which has 26 days to determine the application is complete. If incomplete or inadequate the Coast Guard may reject the application which stops the clock until it is resubmitted.
2. After public notice of the receipt of an application in the Federal Register, the NEPA review and the technical design review begins. This is completed in 240 days.
3. At the completion of the project review, public hearings are held and a decision is issued 90 days later.

PUCs have opportunities to participate in the public hearings, as with the FERC process. More significantly, within 45 days of the end of hearings, any governor of an adjacent state – defined as the state where the gas is delivered onshore or any state within 15 miles of the delivering pipeline – can veto or recommend approval (with or without conditions) of a project, based on the project's consistency with state environmental protection, land and water use, or coastal zone management programs. MARAD and the Coast Guard cannot override disapprovals.

Short-term and Continuing Environmental Impacts

Environmental studies covered in an EIS for a proposed LNG terminal include impacts on air quality, biological resources (aquatic and terrestrial), water resources, cultural resources, land use, coastal zone management, transportation (on-shore traffic and marine navigation), socioeconomics, visual resources, waste management, noise, geology and soils, recreation, public health and safety, and environmental justice. State agencies are invited to comment and may play a role in permitting. LNG terminal applicants must obtain permit for air emissions, coastal zone management, water discharge, and land use.

Construction of an LNG terminal facility affects relatively large areas of land and water resources. A recent LNG terminal application described the required land and water area as approximately 188 acres, of which 68 acres would be utilized for temporary construction facilities.[39] Construction typically requires the use of diesel powered heavy construction

[38] Authority derives from the Deepwater Port Act of 1974 as amended by the Maritime Transportation Security Act of 2002.
[39] *Draft EIS for Freeport LNG Development*, November 2003, FERC, Docket No. CP03-75-000.

equipment to dredge ship channels, drive pilings for pier construction, clear vegetation, and construct LNG storage tanks, ancillary buildings and service facilities. The most significant impacts will arise from dredging and material handling.

The most significant impacts occurring during the operational phase of an LNG terminal include impacts to air and water quality and the visual impact of the facility. These will be long-term impacts as LNG terminals are typically designed to operate for at least 25 to 30 years. Impacts to air and water resources are cumulative and mitigation measures are designed and implemented accordingly.

Ultimately, LNG plants will face decommissioning. The most significant impacts resulting from the decommissioning phase of an LNG terminal are associated with demolition and disposal of wastes. Air quality impacts are generated by demolition equipment and truck transportation of demolition wastes. Some components of the facility such as buried pipelines can be safely abandoned in place after being flushed and capped. Site characterization studies may be required by regulatory agencies to determine the extent of (possible or potential) soil or groundwater contamination that may have occurred at the facility during the operational phase. In the event that contaminants are discovered, appropriate remediation plans may need to be developed and implemented.

Summary of Environmental Issues for State PUCs

The environmental impacts of LNG facilities generally have not reached the level of controversy that questions of safety have reached. This is not to say that environmental issues have not been controversial at individual sites, they have been where LNG facilities would have impacts on scenic qualities, land use, and marine habitat.

One of the major issues for PUCs is whether the federal environmental review process, where applicable, gives appropriate weight to the concerns of state and local parties – both in and out of government – and whether the process allows these concerns to be reflected in the federal government decision making. PUCs need to know that the process yields all of the information required for informed decision-making. The FERC environmental review procedures, with their emphasis on pre-filing consultation, coordination of agency review, and public awareness building, appear to meet a threshold requirement of a full airing of environmental concerns. In other cases, when the PUCs may have certain siting authority, the PUCs must make sure their processes provide all of the information that is necessary for their decisions. Ultimately, decision makers will have to balance environmental and other public benefit concerns, and their decisions are subject to review.

6. Conclusion: Guidelines for State PUCs Considering LNG Expansion

As the United States turns toward imported LNG to sustain our gas markets, the voice of the PUCs becomes more vital in the decision making for individual LNG facilities as well as overall national policy. To quote Commissioner Jack Blossman from Louisiana, *"State commissions have the responsibility to assure that LNG projects that are ultimately approved and constructed, do not unduly compromise public safety or the effective and efficient operations of state energy markets."*[40]

To ensure that LNG imports meet the test for effective and efficient operations of state energy markets, PUCs should actively represent their state and public interest in the various forums of decision making. From this paper, we have identified several important activities that PUCs should undertake.

- PUCs need to understand the potential role of LNG to supply a critical part of the U.S. demand for natural gas, and be prepared to educate and discuss the importance of LNG facilities to meet this need. Increasing gas supply to the United States with LNG can help moderate prices and may reduce gas price volatility caused by current tight supply.

- PUCs should evaluate the benefits to consumers from LDCs and regulated power generators securing long term gas supply contracts with LNG importers. Such contracts can provide security of supply and depending on the terms can provide price certainty and a hedge against volatile gas prices.

- PUCs should pay close attention to the ongoing debate over how to address the issue of the high heat content of LNG-based supply relative to domestic supply, given the implications of this debate for the performance of gas appliances.

- PUCs should encourage the FERC and U.S. Coast Guard to continue to implement recommendations to further reduce the risks from accidental and intentional LNG spills. PUCs can help build confidence that the management of these risks is consistent with public safety, while recognizing the major benefits that LNG terminals can bring to gas markets.

[40] Jack Blossman, Louisiana Public Service Commission, Testimony before the House Subcommittee on Energy Policy, Natural Resources, and Regulatory Affairs, June 22, 2004

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Appendix A. Additional Safety Considerations in Site Selection and Facility Layout

A.1 Surrounding Population and Land Use

Best practices in site selection include the following considerations:

- Minimizing residential populations near the site, particularly high-density residential areas, schools, and hospitals.
- Limiting nearby commercial operations to those with workers who are familiar with hazardous materials and who can easily be added to site training efforts and notification and evacuation plans.
- Avoiding operations involving welding or other ignition sources in the immediate vicinity of the LNG facilities.
- Ensuring nearby access to highways, rail lines, and/or pipelines, depending on the location and needs of the end customers for the LNG.
- Buying buffer areas or ensuring that other land nearby will not be sold for use in one of the less desirable applications above. This is sometimes accomplished through land swaps or arrangements where the LNG facility has right-of-first-refusal on other pieces of property.

A.2 Shipping Concerns

For facilities that are receiving LNG via tanker there are a number of additional considerations:

- The depth of the existing channel to minimize the need for dredging, both in the main harbor or port and in the approach to the dock.
- The availability of turning basins to allow vessels to dock with the desired orientation for departure (i.e., backing in to a slip to facilitate rapid departure in the event of an emergency on site).
- The need for tugs and escorts. While these may be required in many ports, it may also be desirable to have the vessel oriented so that it can leave under its own power in an emergency. The shortage of large tugs in many ports means that they may not be standing by during unloading and may not be able to get to the facility quickly.
- The potential need to restrict travel past the vessel while it is at the dock. If the dock is in a narrow waterway, exclusion zones that are applicable during unloading effectively can shutdown all other travel in that waterway. Slips that take the LNG tanker out of the waterway or placement further away from the local shipping channel may permit other operations to continue unimpeded.
- Local waterway concerns (e.g., ferry crossings, high amounts of traffic, a propensity for silt formation) may mean either that other operations would be adversely impacted during

LNG operations or that the maintenance of an adequate channel would involve major recurring expenses.

- The frequency of excessive wave heights or high winds may make a site less desirable because of the amount of time that transfer operations may need to be suspended or that tugs must stand by to offer additional protection. Adverse currents also increase the risk of a passing vessel striking the LNG tanker while it is unloading.

A.3 Facility Layout

The layout and design of the LNG facility should incorporate the buffer or exclusion zones required by regulations as well as any additional separation distances that may be required by insurers. For instance, 49 CFR 193 sets out exclusion zones surrounding an LNG facility where an operator or government agency must legally control all activities for as long as the facility is in operation. These zones offer thermal radiation protection for each LNG storage container and transfer system and flammable vapor-gas dispersion protection for each LNG storage container and transfer system. In addition, there are requirements for the layout and spacing of the marine transfer area. These ensure that any containment areas used to capture LNG spills are located so that the thermal radiation from a fire in the containment area will not cause structural damage to an LNG vessel that is moored or berthed at the facility.

Containment or retention areas are to be provided to try to ensure that spilled LNG, flammable refrigerants, and flammable liquids are kept within the limits of plant property. Process areas; vaporization areas; transfer areas for LNG, flammable refrigerants, and flammable liquids; and areas immediately surrounding flammable refrigerant and flammable liquid storage tanks are to be designed to minimize the possibility of accidental leaks endangering important structures, equipment, or adjoining property or reaching waterways. This may be accomplished through grading, draining, or impounding.

The number and size of storage tanks will be determined by the size and frequency of LNG deliveries, as well as the ability to meet the various exclusion requirements. The materials used in the tanks as well as there fundamental design will reflect local considerations such as the height of the water table.

Consequence modeling should be used throughout the design stage to ensure that all of the various requirements will be achieved by the final layout. The modeling can also help determine just how large a site is needed. The basic cases and assumptions used in the modeling should be identified in the application package.

A.4 Facility Operations

The selection of the site will also influence facility operations, and the intended operations will influence site requirements.

- *Unloading frequency and rate* – The desired unloading rate will determine the number of unloading arms required, and the number of unloading arms used at once or manifolded together will affect the release rate and quantity and thus the amount of spill containment required.

- *Restrictions on other transfer operations while unloading* – If the LNG dock must be placed in close proximity to other docks this will affect the ability of those adjacent docks to be used while the LNG tanker is transferring its cargo. This may have an adverse impact on the other operations if the docks were operating anywhere close to capacity.
- *Restrictions on dock access, especially for multi-use sites* – on multi-use sites, the need to limit access during unloading can mean that a shared plant road must be closed.
- *Operator qualifications and training* – the availability of LNG or similarly experienced personnel may be limited in certain areas, requiring far more training of site personnel before operations can commence.
- *Potential for expansion* – if there is a possibility of expansion in the future this should be considered in the original site selection and layout in order to ensure that there will be adequate space to meet all the exclusion zone requirements when an additional tank is built.

A.5 Gas or LNG Transport

The nature of the product to be exported from the facility will also influence the site selection. The regasification or liquefaction capacity must consider the intended form of product export (i.e., gas into a pipeline or LNG via rail or truck). If truck or rail transport is planned, the site must be large enough to accommodate appropriate loading facilities. The number of loading stations will also be influenced by the anticipated number of annual shipments by each mode and the need to store filled rail cars onsite until they can be picked up by the local railroad.

Future expansion into other modes should also be considered as a part of the site selection, again so that adequate space and a sensible layout can be obtained. If truck and rail are to be used, the site selection process will include an examination of the likely routes such containers would take through the nearest city. Will they have to go through a city to reach the nearest switching yard or highway? Risk assessments of the local transportation corridors may be beneficial.

Appendix B: Additional Security Considerations

B.1 Vulnerability Assessments

A vulnerability assessment is a systematic process in which a facility is reviewed to identify areas of weakness (as well as the potential actions that would exploit those weaknesses) and to determine the effectiveness of additional security measures, alone or in combination. An effective assessment of vulnerabilities serves as the foundation of a prioritized plan for security equipment upgrades, modifications of operational procedures, and/or operational changes to reduce the risks and vulnerabilities to critical parts of the facility or transport operation. The assessment process also provides a framework for developing risk reduction options and associated costs.

Vulnerability assessments should be done at several stages of design and construction as well as periodically during facility operations. Regulations and industry guidance are making such assessments a routine part of LNG operations.

B.2 Protective Programs

A protective program is a coordinated plan of action to prevent, detect, and/or mitigate terrorist attacks on a facility, as well as to respond to and recover from such attacks that do occur in a manner that limits the adverse impacts. Some of the strategies that may be employed include:

- *Prevent (or delay) an attack* – enhanced security presence, restricting access, fencing, structural integrity, vehicle checkpoints, and cyber protection features such as more tamper-proof control systems. The appropriate measures are likely to change depending on the threat level (in the local area or for LNG facilities nationwide).
- *Detect a potential incident* – intrusion detection systems, monitoring, LNG detection alarms, and employee security awareness programs.
- *Mitigate or respond to an incident* – adequate response plans can mitigate impacts and potentially enable the facility to resume operations sooner. Such plans may involve the Coast Guard as well as state and local agencies, including first responders. Drills and exercises can also improve performance.
- *Recover from an incident* – continuity of operations or recovery plans that will let the facility return to operations as quickly as possible, perhaps using alternate modes of transport.

B.3 Vessels in Port/Harbor and While Approaching Facilities

Vulnerabilities while in transit include hijackings and physical damage to the tankers with the goal of releasing and igniting some fraction of the cargo. If a terrorist attack were to be successful, it is likely that the blast that caused the damage would also cause early ignition—which would help to limit the area actually impacted by the resulting pool fire or vapor cloud fire.

For both safety and security reasons, all other activities within the exclusion zone are halted while a loaded LNG tanker is in transit in a port or harbor—from major ships to small commuter ferries. So long as the total number of LNG tankers is limited, these movements can be arranged to both improve security and safety while minimizing disruptions to other operations in the harbor.

In response to security concerns, the Coast Guard and local law enforcement agencies have increased harbor patrols near marine terminals and enhanced escort capabilities for tanker movements. Additional protections in place include more advance notice of specific shipments, more rigorous inspections at the point of loading, and inspections prior to entering certain harbors.

General precautions for maritime security include the addition of vessel and port security officers, security plans for each vessel, security assessments, exercises and drills, and specific onboard equipment.

Additional protective measures are described in the Sandia report, focusing on deterrence as well as response when critical infrastructure and population centers are very proximate to the LNG movements and transitioning to just certain response measures when the LNG operations are at a greater distance from critical assets.

B.4 Vessels While Unloading

Safety precautions offer significant security benefits as well. These include limiting access to the dock area, restricting vessel traffic in proximity to the LNG tanker, having employees present throughout the entire unloading process, and using cameras to watch for potential leaks and problems with the unloading operations. At times of heightened security alerts, the Captain of the Port (and local law enforcement agencies) may increase the frequency of patrols, further restrict vessel operations in the area, ensure that tugs are present, and take other appropriate actions.

B.5 Operating Facilities (includes Storage)

Depending on both their location and the amount of buffer zone around an onshore facility, accessibility and visibility can vary tremendously. However, the size of LNG tanks makes them relatively identifiable even from a distance. While sites already had high levels of security to avoid trespassing and potential safety impacts, recent increases in security awareness have further enhanced security precautions. The Maritime Transportations Safety Act has also imposed a number of requirements on facilities located in or adjacent to ports.

Attacks may be targeted at causing damage to the physical equipment or they may focus on disrupting control systems.

Security plans for port facilities are required under the Maritime Transportation Security Act of 2002 (MTSA). They are expected for other LNG facilities under Office of Pipeline Safety and industry consensus guidance. The Sector-Specific plans developed in response to Homeland

Security Presidential Directive 7 (HSPD-7) will also call for vulnerability assessments of critical LNG assets under both the transportation and energy sectors.

The requirements of MTSA include facility security officers, training, security plans, security assessment, access control, and other communications and equipment.

B.6 Truck/Rail Shipments

The desirability and vulnerability of truck or rail shipments will depend on exactly where they travel upon leaving the facility, as well as how controlled the onsite holding areas are. Whereas the tendency was to focus on securing LNG storage tanks and unloading operations in the past, these days there is more attention being given to the truck and rail loading areas as well. The routes taken when leaving the facility should be reviewed not just from a risk perspective, but also in terms of their potential attractiveness or vulnerability to terrorist attack.

B.7 Gas Pipelines

For pipelines, the accessibility of the line onsite as well as the proximity of any new lines to other operations on the site are the main considerations. Typically the natural gas grid is already in the vicinity of the site, so the vulnerabilities for that line are not changed by the addition of the LNG facility. However, the terrorist's awareness of the presence of the line may be increased, as well as the attractiveness of the line given its obvious importance to the LNG facility.

B.8. Technical Safety Debate

In the case of LNG, recent technical disagreements among experts have raised questions the adequacy of current LNG regulations. These disagreements have focused on three issues:

- **Current regulations and system designs are based on "design events" that do not take into account potential larger scale terrorist attacks; thus facility designs and protective systems may be inadequate.** Large spills that could be caused by terrorist actions were considered in the recently released Sandia study. Sandia found that larger spills would yield increased consequences and longer duration fires and that the fires would be quite likely at the spill source since ignition would result from the same event that caused the breach.
- **Different modeling techniques used to assess the consequences of LNG fires are inadequate for estimating the potential impact of spills and LNG fires.** A recent study by ABS Consulting, which was sponsored by FERC, reviewed the common approaches to modeling the consequences of LNG spills and fires. The study showed that variations in the results produced from existing models were often quite small. ABS recommended additional studies be undertaken. The Sandia study also provides guidance on using analytical techniques for LNG spills on water and encourages the use of computational fluid dynamics (CFD) models to address site-specific hazards in locations where there is a potential for significant consequences (to people or property).

LNG import facilities should be sited in remote locations. Current regulatory practice does not mandate remote siting of LNG facilities, although there has been an increased emphasis on remote siting in the reviews of recent LNG permit applications. The question is two fold: how remote should a facility be and do the current regulations, design, and operational protocols adequately minimize the consequences of events on nearby populations. The Sandia study provides guidance on risk management measures that can be taken for LNG operations at a range of distances from critical infrastructure or large populations. The study found that the most significant impacts to public safety are within 500 meters of a spill and fire with lower public health and safety impacts beyond 1,600 meters.

Appendix C. Current Projects and their Status

Note: Numbers correspond to FERC map on page 9, Exhibit 2.5.

	Project Name/Location	Capacity (Bcf/d)	Sponsors
Approved by FERC or Coast Guard			
2	Cameron, Hackberry, LA	1.5	Sempra
5	Freeport, Freeport, TX	1.5	Cheniere, Freeport LNG
6	Sabine, Sabine, LA	2.6	Cheniere LNG
8	Corpus Christi, Corpus Christi, TX	2.6	Cheniere
9	Port Pelican, Offshore Gulf of Mexico	1.6	Chevron Texaco
10	Gulf Landing, Offshore Louisiana	1.0	Shell
Proposed to FERC/MARAD/Coast Guard			
11	Weaver's Cove, Fall River, MA	0.8	Hess LNG, Weavers Cove Energy
12	Sound Energy, Long Beach, CA	0.7	Mitsubishi, ConocoPhillips
13	Vista Del Sol, Corpus Christi, TX	1.0	ExxonMobil
14	Golden Pass, Sabine, TX	1.0	ExxonMobil
15	Crown Landing, Logan Twshp, NJ	1.2	BP
17	Ingleside, Corpus Christi, TX	1.0	Occidental Energy Ventures
18	Providence, Providence, RI	0.5	KeySpan, BG LNG
19	Port Arthur, Port Arthur, TX	1.5	Sempra
21	Broadwater, Long Island Sound	1.0	TransCanada, Shell
22	Gulf LNG Energy, Pascagoula, MS	1.0	Gulf LNG Energy LLC
23	Northern Star, Bradwood, OR	1.0	Northern Star Nat. Gas LLC
24	Casotte Landing, Pascagoula, MS	1.3	ChevronTexaco
25	Creole Trail, Cameron, LA	3.3	Cheniere
26	Calhoun, Port Lavaca, TX	1.0	Gulf Coast LNG Partners
27	Cabrillo Port, Offshore California	1.5	BHP Billiton
28	Crystal Energy, Offshore California	0.5	Crystal Energy
29	Main Pass, Offshore Louisiana	1.0	McMoRan
30	Compass Port, Gulf of Mexico	1.0	ConocoPhillips
31	Pearl Crossing, Gulf of Mexico	2.8	ExxonMobil
32	Beacon Port, Gulf of Mexico	1.5	ConocoPhillips
Announced Projects			
33	Coos Bay, Coos Bay, OR	0.13	Energy Projects Development
34	Somerset, Somerset, MA	0.65	Somerset LNG
35	Offshore California	0.75	ChevronTexaco
36	Quoddy Bay, Pleasant Point, ME	0.5	Quoddy Bay LLC

	Project Name/Location	Capacity (Bcf/d)	Sponsors
Announced Projects (continued)			
37	Port Westward, St. Helens, OR	0.7	Port Westward LNG LLC
38	Northeast Gateway, Offshore MA	0.8	Excelerate Energy
39	Pelican Island, Galveston, TX	1.2	BP
40	Freedom Energy Ctr, Philadelphia, PA	0.6	Philadelphia Gas Works
41	Skipanon LNG, Astoria, OR	1.0	Calpine
43	Neptune LNG, Offshore MA	0.4	Tractebel
Bahamas Projects (Announced/Proposed/Approved)			
3	Ocean Express, Ocean Cay, Bahamas	0.84	AES Energy
4	Freeport, Grand Bahamas Island	0.83	Tractebel
16	Seafarer, Grand Bahamas Island	0.5	Elpaso, FPL
Canada Projects (Announced/Proposed/Approved)			
44	Canaport, St. John, NB	1.0	Irving Oil
45	Bear Head, Point Tupper, NS	1.0	Anadarko
46	Rabaska, Quebec City, QC	0.5	Enbridge, Gaz Met, Gaz de France
47	Cacouna, Riviere-du-Loup, QC	0.5	TransCanada, PetroCanada
48	Kitimat, Kitimat BC	0.6	Galveston LNG
49	Prince Rupert, BC	0.3	WestPac
50	Goldboro, NS	1.0	Keltic Petrochemicals
Mexico Projects (Announced/Proposed/Approved)			
51	Altamira, Tamulipas	0.7	Shell, Total, Mitsui
52	Baja, Baja, MX	1.0	Sempra, Shell
53	Baja MX Offshore	1.4	ChevronTexaco
54	Lazaro Cardenas, MX	0.5	Tractebel, Repsol
55	Sonora, Puerto Libertad, MX	1.3	Sonora Pacific LNG