

U.S. LNG Markets and Uses: June 2004 Update

This article is an update of the Energy Information Administration's January 2003 report [U.S. LNG Markets and Uses](#). Questions or comments on the contents of this article should be directed to Damien Gaul at damien.gaul@eia.doe.gov or (202) 586-2073.

Liquefied natural gas (LNG) has become an increasingly important part of the U.S. energy market. Interest in LNG imports has been rekindled by higher U.S. natural gas prices in recent years, as well as increased competition and technological advances that have lowered costs for liquefaction, shipping, storing, and regasification of LNG. All U.S. LNG import terminals were operational in 2003 for the first time since 1981, resulting in record high LNG receipts, more than double the previous high in 1979. Proposals for more than 20 new import facilities are currently before regulatory authorities and many more are being planned, although it is unclear how many will actually be built. LNG storage facilities continue to be important in meeting peak demand needs of local utilities and as a way to store gas until needed. In addition, several niche markets, such as for vehicle fuel and as a fuel source for industrial sites in isolated areas, demand gas in the form of LNG whether from domestic or foreign sources.

The physical properties of LNG (*a Glossary defining selected LNG and natural gas terms has been provided in the Appendix*) allow for its long-distance transport by ship across oceans to markets such as the United States and for its local distribution by truck onshore. Liquefaction of natural gas also provides the opportunity to store it for use during high consumption periods close to demand centers, as well as in areas where geologic conditions are not suitable for developing underground storage facilities. For example, in New England and the coastal areas of the Middle Atlantic States, where underground storage is lacking, LNG is a critical part of the region's supply during cold snaps. In locations where pipeline capacity from supply areas can be very expensive and use is highly seasonal, LNG storage helps reduce pipeline capacity commitments that are only used during peak periods.

Future developments in regard to LNG's role in the U.S. energy industry likely will depend in part on the public's perception of the need for additional natural gas supplies and the safety and reliability of LNG operations compared with other fuel choices. Several proposed LNG projects have encountered heavy opposition from communities surrounding proposed sites, despite economic incentives promised by project developers. LNG facilities throughout the world generally have had an excellent safety record in over 35 years of operations. However, as with the siting of many industrial complexes, environmental, safety, and security concerns are

paramount. In March 2004, the Federal Energy Regulatory Commission (FERC) announced the formation of an LNG engineering branch that will oversee the commission's LNG safety inspection program and coordinate actions with other agencies. Additionally, FERC issued a technical report in May 2004 that outlines proposed safety analysis methods for evaluating applications for new LNG terminals.¹

This article examines the different aspects of LNG markets and uses in the United States, paying particular attention to marine terminal operations and peak-shaving storage facilities. Current LNG facilities reflect distinctly different uses of LNG-related technology. Marine terminals receive imports or ship exports of LNG and have on-site storage. Natural gas utilities and interstate pipeline companies own and operate facilities for the liquefaction and storage of pipeline gas for use during high demand periods. Natural gas producers and other companies have built new facilities since the mid 1990s in an attempt to serve new demand for LNG vehicular fuel and other niche markets. Moreover, LNG facilities have the flexibility to participate in several markets at once. For example, LNG is trucked regularly from an import point in Massachusetts for storage at local utilities in the Northeast. Also, at least one local utility in the Midwest liquefies natural gas for vehicular fuel while also storing LNG for use during the winter.²

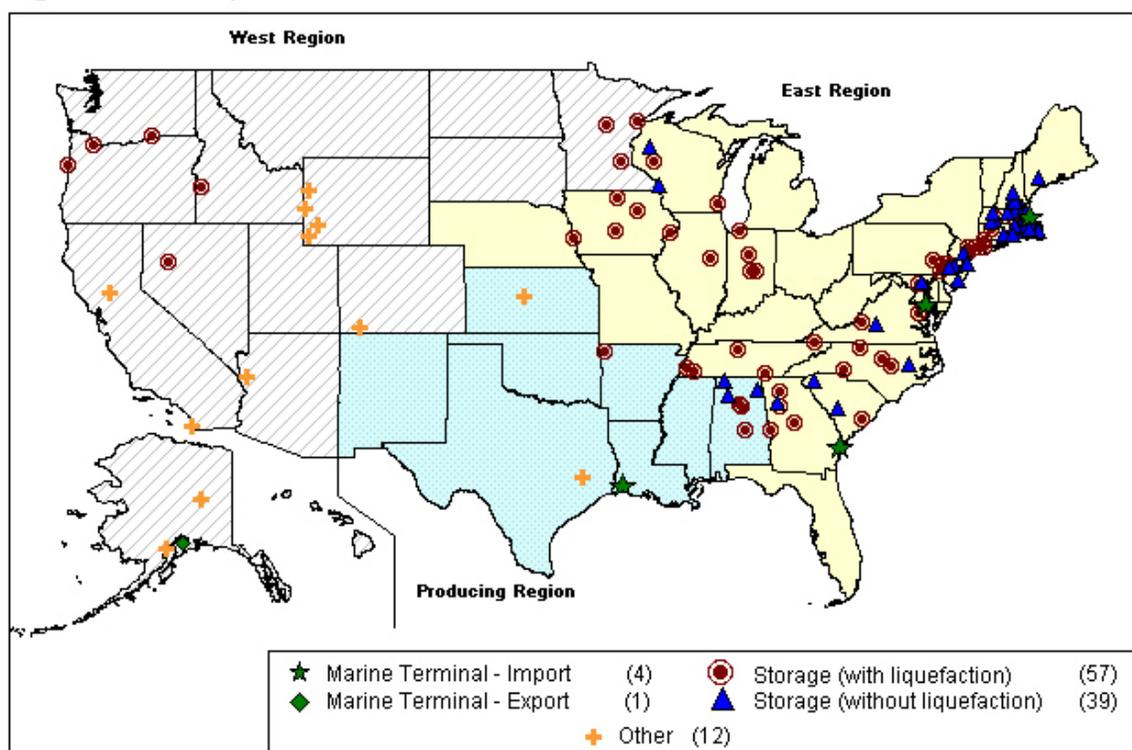
Overview of U.S. LNG Industry

The first commercial liquefaction plant was built by East Ohio Gas in Cleveland, Ohio, in 1941, with the LNG stored in tanks at atmospheric pressure. In January 1959, the world's first LNG tanker *The Methane Pioneer*, a converted World War II liberty freighter, carried an LNG

¹ ABS Consulting Inc., under contract FERC04C40196, *Consequence Assessment Methods for Incidents Involving Releases from Liquefied Natural Gas Carriers*, May 2004 (<http://www.ferc.gov/industries/gas/indus-act.asp>).

² Niche market volumes are small, with trade for LNG as a vehicular fuel or for stranded utilities (distribution companies not connected to the national pipeline grid) at an estimated 5 to 10 Bcf a year. This report will not describe these activities in detail, but interested readers may access more information concerning LNG niche markets in the first version of this report, *U.S. LNG Markets and Uses*, January 2003.

Figure 1. U.S. Liquefied Natural Gas Facilities as of June 2004



Notes: Map excludes the import facility in Puerto Rico. Other includes: stranded utilities, vehicular fuel facilities, nitrogen rejection units and other special processing plants.
Sources: Energy Information Administration, Office of Oil and Gas, and industry sources.

cargo from Lake Charles, Louisiana, to Canvey Island, United Kingdom. While the event showed that large quantities of LNG could be transported safely across the ocean, and LNG international trade began shortly after between Algeria and the United Kingdom, U.S. participation in LNG trade would not begin until almost 10 years later.

The oldest active marine terminal in the United States was constructed in Kenai, Alaska, in 1969. The terminal, which is owned by ConocoPhillips and Marathon Oil, has exported LNG to Japan since beginning operations. Although the success of the Kenai operation was a key milestone in the development of international trade of LNG (it marked the first LNG deliveries to the Asian Pacific), the potential role of the United States in the LNG market has generally been viewed as a net importer since the 1970s. Imports to the United States began with the construction of a marine terminal in Everett, Massachusetts, in 1971, by Cabot LNG, a subsidiary of chemicals-maker Cabot Corporation. The construction of marine terminals by a joint venture of Consolidated Natural Gas and Columbia Corporation at Cove Point, Maryland, and El Paso Corporation at Elba Island, Georgia, followed in 1978.

The LNG industry in the United States has experienced periods of prolonged downturns, in part owing to price competition from domestic sources of natural gas. Operations ceased at the Cove Point and Elba Island terminals in 1980. The construction of one more terminal by Trunkline LNG at Lake Charles, Louisiana, was completed in 1982. This facility operated only a short time before closing. When it reopened again as an import terminal in 1989, it would receive minimal shipments for the next decade. Consolidated Natural Gas sold its interest in the Cove Point terminal to Columbia Corporation. The facility was recommissioned in 1995 solely to provide storage services to local utilities using domestic supplies.

When higher domestic natural gas prices, beginning in 2000, and lower LNG costs indicated once again the competitiveness of imported LNG, El Paso subsidiary Southern LNG reopened the Elba Island terminal for imports in late 2001. In August 2003, after being bought by The Williams Companies and then sold to Dominion (which now owns the former Consolidated Natural Gas), the Cove Point terminal began accepting cargoes in international trade once again.

Currently, there are 113 active LNG facilities in the United States (Figure 1), including marine terminals, storage facilities, and operations involved in niche

markets such as LNG vehicular fuel.³ The vast majority of these facilities operate solely to serve as a provider of peak-day supplies, much as the Cleveland plant operated in the 1940s. A disastrous accident at the Cleveland facility in 1944 stalled development of LNG storage facilities for nearly two decades, until renewed interest owing to safer technologies and stricter design standards led to more than 60 storage facilities being constructed between 1965 and 1975.⁴ Construction of LNG storage facilities slowed in the latter half of the 1970s. However, restructuring of the natural gas industry in the early 1990s renewed interest in storage facilities as a way to reduce expensive interstate pipeline capacity requirements, and the construction of several new LNG storage facilities followed. Over 90 LNG facilities in the United States are dedicated solely to meeting the storage needs of local utilities.

The outlook for LNG's role in the U.S. natural gas industry is quite strong with a renewed interest in baseload supplies of LNG through international trade, and continuing interest in the construction of LNG storage facilities to meet peak demand periods.

LNG Marine Terminals

The opportunity for economic trans-ocean trade has been a driving motivation behind the growth of the LNG industry. As a result, a distinguishing characteristic of the U.S. LNG industry is the need for the construction and operation of marine terminals to handle ocean-going vessels. These marine import terminals receive LNG tankers at port facilities operated under the regulation of the U.S. Coast Guard, much as port facilities in other industries. Additionally, beginning July 1, 2004, LNG port facilities will operate under maritime and security regulations called the International Ship and Port Security code (see Box, "LNG and Maritime Security Regulations," p. 3).

Marine facilities include large storage tanks, vaporization equipment, and jetty facilities designed to berth and

³ In Puerto Rico, which is a territory of the United States, an LNG receiving terminal was constructed in 2000 in order to provide natural gas to a nearby electric generation plant. For the purposes of this report, statistics concerning imports to the United States do not include volumes received by this facility. Discussion will focus on the four mainland terminals.

⁴ Modern LNG plants are designed and constructed in accordance with strict codes and standards that would not have been met by the Cleveland plant. LNG safety standards have been issued by the National Fire Protection Association in NFPA 59A. For more information on LNG safety, see University of Houston Law Center, Institute for Energy, Law & Enterprise, *LNG Safety and Security* (Houston, Texas, October 2003) and New York State Planning Board, *Report on Issues Regarding the Existing New York Liquefied Natural Gas Moratorium* (Albany, New York, November 1998).

LNG and Maritime Security Regulations

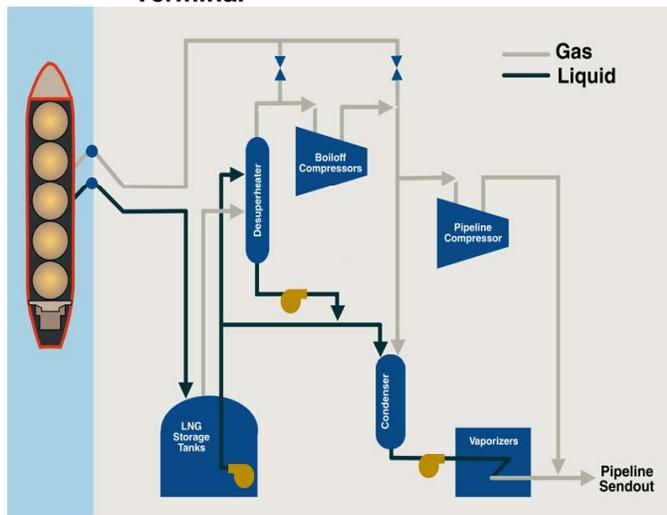
New maritime anti-terrorist regulations become effective on July 1, 2004, that will directly affect operations at U.S. LNG marine terminals. All vessels and ports worldwide that engage in international trade are to comply with the International Ship and Port Security code. In addition, foreign-flagged vessels entering U.S. waterways must meet the security requirements of the Maritime Transportation Security Act of 2002 (MTSA). According to the legislation, all LNG tankers entering U.S. waters must have certified security plans that address how they would respond to emergency incidents, identify the person authorized to implement security actions, and describe provisions for establishing and maintaining physical security, cargo security, and personnel security. These plans must be updated at least every 5 years and be re-approved whenever a change is made to a tanker that could affect the vessel's security. The tankers must be equipped with automatic identification systems that will allow vessel tracking and monitoring while traveling on U.S. navigable waters. The U.S. Coast Guard can assign sea marshals to accompany tankers as they transit in and out of U.S. ports to ensure harbor safety and security.

The MTSA also specifies that all U.S. port facilities deemed at risk for a "transportation security incident," such as LNG marine terminals, must prepare and implement security plans for deterring such incidents to the "maximum extent practicable." Plans were to be submitted to the U.S. Coast Guard by December 31, 2003, so they can be in place by July 1, 2004. All four LNG marine terminals in the Lower 48 States expect that their plans will be operational by the deadline.

According to Distrigas, the Coast Guard has approved the company's security plan for the Everett LNG terminal in the port of Boston. LNG tankers must give advance notice before entering the harbor so the Coast Guard can inspect the vessel to verify what the ship is carrying, who is aboard, and the country of origin. Coast Guard personnel stay aboard the vessel as it moves through the harbor to the terminal. All LNG tankers entering and exiting the Boston port must be accompanied by fire-fighting tugboats and Coast Guard and state police escorts. All other vessels must be at least 1,000 yards away from the tankers. While a tanker is at the terminal, Distrigas provides on-site security and the Coast Guard continues to patrol the harbor.

unload LNG ships sometimes over 900 feet in length. LNG tanker mooring is accommodated with tugboats. Once the tanker is moored, ship pumps transfer the LNG into storage tanks, with offloading generally taking about 12 hours. From onshore storage tanks, send-out pumps

Figure 2. Schematic and Photo of LNG Marine Terminal



Source: Terminal schematic courtesy of Trunkline LNG. Photo of Southern LNG facility in Elba Island, Georgia, courtesy of El Paso Corporation.

transfer LNG to vaporizers, which warm the LNG in order to return it to its gaseous form for delivery into the pipeline grid (Figure 2).

Typically, LNG at marine terminals is stored only until it can be regasified and injected into the pipeline grid or until it can be trucked directly to customers. In order to minimize wait times for the ships and to avoid congestion, operators of LNG marine terminals process cargoes quickly. Each U.S. import terminal is equipped with storage tanks capable of holding between two and three tanker loads of LNG. Some new and expanded facilities in the United States will have a capacity closer to four tanker loads.

Large tankers hold approximately 130,000 cubic meters of LNG in liquid form, or about 2.8 billion cubic feet (Bcf) of regasified LNG, but ships with capacities of up to 200,000 cubic meters, or 4.3 Bcf, are being considered.⁵ While these larger ships would require a considerably higher up-front capital investment than the \$160 million required for a 130,000 cubic-meter tanker, economies of scale found in the reduced tanker trips lessen expenses during operations.

Existing U.S. LNG Marine Terminals

Although much of the impetus for the expansion of LNG trade in the United States results from trends in North American gas prices and global LNG trade, several developments at U.S. LNG facilities have allowed for the increased LNG deliveries over the past couple of years. In 2002, El Paso re-opened the Elba Island, Georgia, terminal, and has since agreed to contract the capacity of the facility to BG Group. In August 2003, Cove Point began full operations, adding 1 Bcf per day (Bcf/d) of deliverability into the pipeline grid. Also during the year, Tractebel's Distrigas facility in Everett, Massachusetts, expanded its baseload capacity by approximately 300 million cubic feet per day (MMcf/d) to 725 MMcf/d (Figure 3).

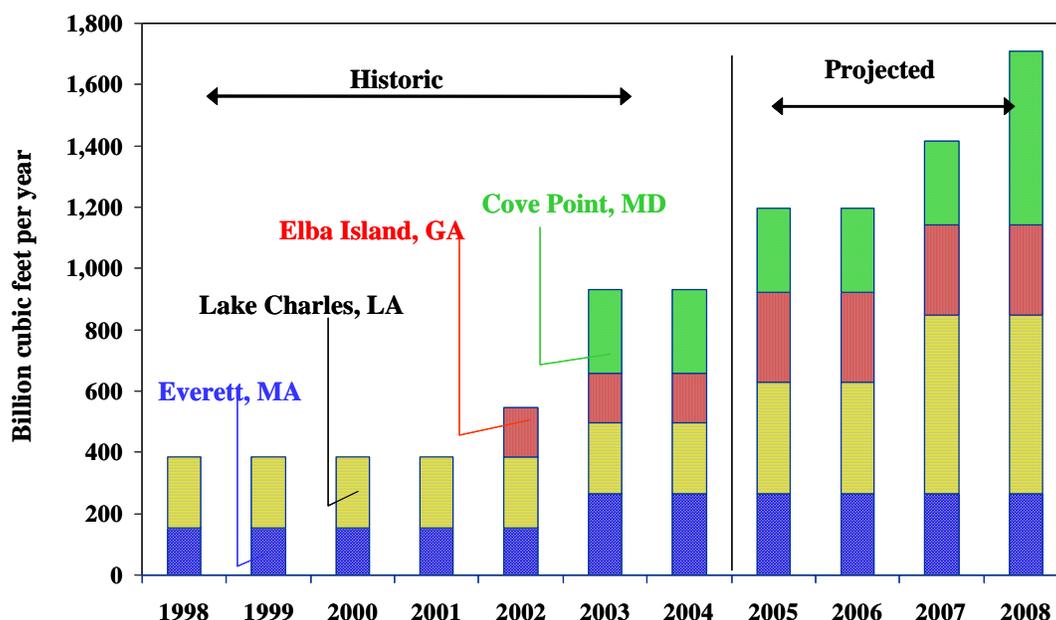
LNG imports, although still a small share of imports, rose to a record high of approximately 507 Bcf in 2003.⁶ The previous annual record delivery volume was established in 1979, when the United States received 253 Bcf from Algeria.

Algeria served as virtually the sole supplier of LNG to the United States until the latter half of the 1990s, when shipments from other countries became more prevalent. The mix of supplies shifted greatly with the opening of the Atlantic LNG facility at Point Fortin, Trinidad and Tobago, in May 1999. Last year (2003), while Algeria supplies totaled just 53 Bcf, Trinidad and Tobago for the fourth consecutive year was the source country with the largest volume imports to the United States, delivering

⁵ The conversion between cubic meters of LNG and cubic feet of gaseous natural gas accounts for both the difference in units (1 cubic meter = 35.315 cubic feet) and the volumetric difference between gaseous natural gas and LNG in liquid form (approximately 610 to 1). A conversion table has been provided at the end of this article (p. 18).

⁶ Energy Information Administration, *Natural Gas Monthly*, March 2004 (Washington, DC, April 2004), Table 5.

Figure 3. Historic and Proposed Baseload Capacity at Existing U.S. Receiving Terminals



Source: Energy Information Administration, Office of Oil and Gas, Natural Gas Division.

378 Bcf.⁷ Trinidad and Tobago supplies accounted for approximately 75 percent of LNG imported to the United States in 2003. Other source countries included Nigeria, Qatar, Oman, and Malaysia. The list of importers underscores the extensive number of countries monetizing their natural gas reserves. The list is growing, and includes several countries with their first liquefaction projects under construction.

The Lake Charles, Louisiana, terminal, now owned by Southern Union, received the largest annual volume of any U.S. terminal in 2003 with receipts of 238 Bcf, all through short-term or “spot” cargo sales. The facility is situated near seven major interstate pipelines, allowing access to most major markets in the United States. Located 48 miles from the Gulf of Mexico on the Calcasieu River, it has one berth that can receive vessels more than 900 feet long and about 140 feet wide. Four unloading arms receive LNG from vessels at a flow rate of about 12,500 cubic meters of LNG per hour. Vaporization trains, or sets of process units consisting of all equipment necessary to regasify LNG from its liquid form, provide for a maximum send-out of 1 Bcf/d, which was nearly reached many days during the summer of 2003. The Lake Charles facility has three storage tanks, each with a capacity of 2.1 Bcf. Following the completion of expansion plans, the facility will add a fourth tank for a total storage capacity of 9 Bcf at the facility. Terminal

owner Southern Union also intends on adding a second berth so the terminal can receive two LNG cargoes at once, providing added flexibility to receive supplies.

Dominion’s Cove Point is the only other U.S. terminal that rivals or exceeds the Lake Charles terminal in size, although the facility received just 66 Bcf in 2003 after operating for only a part of the year. Cove Point, which is located on the Chesapeake Bay in southeastern Maryland, recently began construction of a fifth storage tank with a capacity to store 2.8 Bcf of the gaseous equivalent of LNG, bringing the facility total storage capacity to 7.8 Bcf by early 2005. Similar to the Lake Charles facility, the Cove Point terminal can handle vessels more than 900 feet long, and can send out regasified product at a peak rate of 1 Bcf/d through use of 10 vaporization trains. Through a 36-inch pipeline into Virginia, the facility gives customers access to three interstate pipelines and major markets in the Middle Atlantic States. Unlike the Lake Charles facility, the Cove Point terminal has the capability to handle two tankers simultaneously. In February 2004, Dominion announced plans to increase storage capacity by 6.8 Bcf (above the projected 7.8 Bcf of capacity in 2005) in two additional storage tanks for a total capacity of 14.6 Bcf in 2008. Following completion of these planned expansions, peak send-out capacity will be nearly 2 Bcf per day.

Tractebel’s Distrigas facility near Boston (Everett) is the longest continually operating terminal in the Lower 48 States. In 2003, Distrigas received 158 Bcf at the terminal, all from Trinidad and Tobago. The facility is

⁷ U.S. Department of Energy, Office of Fossil Energy, *Quarterly Focus: 2003 Year in Review* (Washington, DC, March 2004), Table 1.

smaller than the Cove Point and Lake Charles terminals, but nonetheless is a critical receipt point in New England, providing approximately 20 percent of the region's natural gas supplies on an annual basis. Storage capacity of the two tanks at the terminal totals 3.5 Bcf, while average send-out capability is about 725 MMcf/d. The Everett facility is the only U.S. marine terminal in which some LNG is trucked from the facility to customers. Everett supplies are distributed by truck throughout New England and as far south as Pennsylvania and Delaware.

The scale of El Paso's Elba Island facility resembles the Distrigas terminal. The facility is located on the Savannah River and is equipped with five vaporization trains capable of maximum send-out of 675 MMcf/d. In 2003, the terminal received the least of the four operating terminals with 44 Bcf during the year. The contracting of

Elba Island capacity to BG Group is expected to increase the utilization of the terminal, which has been low owing to owner El Paso's announced plans to withdraw from the LNG marketplace. BG has plans to bring LNG in the coming years from Trinidad and Tobago, where it is a stakeholder in the Atlantic LNG plant at Point Fortin, Trinidad.

Although LNG imports exceeded historical highs in 2003, even at the current pace they represent only about 2.7 percent of U.S. consumption and 13 percent of imports. Through expansions at three of the four facilities, the United States will increase its peak regasification capacity by more than 40 percent from the 2002 level (3.2 Bcf/d) to approximately 4.6 Bcf/d in 2005. Additionally, through recently announced additional expansion projects at Lake Charles and Cove Point, capacity would reach about 6.2 Bcf/d by 2008 (Table 1).

Table 1. Existing Capacity and Planned Expansions at LNG Import Terminals in the Lower 48 States, June 2004
(Billion Cubic Feet)

Facility (Owner)	Storage Capacity	Daily Sendout Capacity		2003 Receipts
		Baseload	Peak	
Everett, MA (Tractebel/Distrigas)				
Existing	3.5	0.725*	1.035**	158.3
Lake Charles, LA (Southern Union)				
Existing	6.3	0.630	1.000	238.2
Planned Expansion (2005)	3.0	0.570	0.300	
Planned Expansion (2007)	0	0.600	0.800	
Total w/Expansion	9.3	1.800	2.100	
Cove Point, MD (Dominion)				
Existing	5.0	0.750	1.000	66.1
Planned Expansion (2005)	2.8	0	0	
Planned Expansion (2008)	6.8	0.800	0.800	
Total w/Expansion	14.6	1.550	1.800	
Elba Island, GA (El Paso/Southern LNG)				
Existing	4.0	0.446	0.675	43.9
Planned Expansion (2005)	3.3	0.360	0.540	
Total w/Expansion	7.3	0.806	1.215	
Total Receipts 2003				506.5
Total Existing Capacity	18.8	2.551	3.710	
Total Planned Expansion	16.4	2.330	2.440	--
Total w/Expansion	35.2	4.881	6.150	--

*The Everett terminal has an additional 0.09 to 0.1 billion cubic feet (Bcf) per day of sendout by truck.

**Three 150 million cubic foot per day (MMcf/d) vaporizers operate at reduced load to meet sendout requirements (about 290 MMcf/d) of the Mystic power plant in Everett, MA. A fourth 150 MMcf/d vaporizer is intended solely as backup for use during routine maintenance or repairs.

Sources: **Capacity:** Federal Energy Regulatory Commission (FERC), industry trade press, company Internet sites, press releases, and other. **2003 Receipts:** U.S. Department of Energy, Office of Fossil Energy.

The United States also exported 64 Bcf of LNG to Japan in 2003 from the ConocoPhillips/Marathon facility in Kenai, Alaska.⁸ The Kenai facility consists of a single liquefaction train, which is a set of process units consisting of all equipment necessary to produce LNG from a natural gas feedstock and having a predetermined design capacity. The Kenai train has a capacity of approximately 1.9 million tons per annum (mtpa), or 90 Bcf.

Proposed LNG Import Terminals in North America

A competition to build LNG receiving facilities is taking place among U.S. and foreign companies in many regions of North America because of the perceived opportunity in the growing LNG industry. EIA has tracked at least 35 company announcements of proposed terminals targeted for North America. Many of these projects are already before regulators (Table 2), and, as of June 2004, some have achieved regulatory success. Successful completion of any project requires an extensive permitting process (see Box, "Application Process for New U.S. LNG Import Facilities," p. 9).

One proposal has received final approval from the Federal Energy Regulatory Commission (FERC). FERC's approval on September 10, 2003, of Sempra's Cameron LNG terminal in Hackberry, Louisiana, was the first such U.S. regulatory approval for an LNG import terminal in 25 years. It also marked a landmark shift in FERC policy in that authorization was granted under import provisions of Section 3 of the Natural Gas Act rather than under the certificate requirements of Section 7 (c). Instead of being considered facilities for interstate commerce, the Cameron LNG import facilities were deemed gas supply facilities and thus not subject to cost-based rates and open access bidding requirements. FERC has stated its intention to apply the new policy to other proposals for land-based LNG import facilities. Under the new policy, developers will be able to import supplies for their own use and marketers can contract privately for terminal services at market-based rates.

Offshore LNG facilities come under the regulatory oversight of the U.S. Coast Guard and the Maritime Administration (MARAD) within the U.S. Department of Transportation, rather than the FERC (see Box, p. 9). ChevronTexaco's Port Pelican project received licensing approval from MARAD in November 2003 and Excelebrate's Energy Bridge project received approval in December 2003. If construction is completed, these terminals will be the first offshore LNG import facilities

in the world. In Excelebrate's Energy Bridge project, the LNG is regasified aboard ship and then delivered to an offshore pipeline through use of a mooring system.

For the purpose of this report, terminal proposals have been grouped in four geographic regions in North America: the U.S. and Mexican West Coast; the Gulf of Mexico region of the United States and Mexico (onshore and offshore); the Bahamas; and the U.S. and Canadian East Coast. Projects in Canada would move regasified product south through existing pipelines, while LNG deliveries to terminals in Mexico would either displace current U.S. exports to the country or result in localized exports to the United States. Bahamas-based projects include proposals to build pipelines into Florida.

Locating terminals along the North American West and East coasts provides access to markets otherwise served by long-haul pipelines. The integration of the Mexican and U.S. markets and, perhaps just as importantly, the decision of Mexican energy regulators to promote natural gas as a fuel for power generation have contributed to opportunities for project sponsors in Baja, where at least two projects have been announced. The recognized need for baseload supplies in the U.S. market, as well as the presence of industry infrastructure, has expanded the opportunities to locate regasification terminals in the Gulf region.

Owing to extensive pipeline infrastructure through and out of the region, the Gulf region offers an opportunity for project sponsors to avoid some costs of new construction and take advantage of economies of scale. EIA has tracked at least 14 proposed terminals for the onshore and offshore Gulf of Mexico (Figure 4).

The proposed terminals for the region generally have the capacity to deliver 1 to 2 Bcf/d into the pipeline grid. For example, Freeport LNG has proposed a facility that could deliver up to 1.5 Bcf/d to Texas, which would give customers a choice of delivery to three major interstate pipelines and access to much of the eastern United States. Sempra's Cameron LNG facility would also have the capability to deliver as much as 1.5 Bcf/d into the grid and, with nearly 9 Bcf of storage and two docks, the flexibility to handle two LNG shipments at a time. The use of existing infrastructure in the Gulf includes existing storage facilities. Currently, the U.S. Department of Energy and a cooperative of industry companies led by Conversion Gas Imports are investigating the commercial viability of using salt caverns for the receipt and storage of LNG cargoes. At least one project in the Gulf, McMoRan Exploration's Main Pass Energy Hub, includes salt caverns in the design of the receiving terminal (see Box, "Experimental LNG Storage Process," p. 10).

⁸ U.S. Department of Energy, Office of Fossil Energy, *Quarterly Focus: 2003 Year in Review*, Table 1.

Table 2. Proposed (Filed or Pre-Filed)* LNG Terminals in North America as of Mid-June 2004

Name	Location	Owner(s)	Capacity** (MMcf/d)	Status
West Coast				
<u>Offshore</u>				
Cabrillo Port LNG	Oxnard, CA	BHP Billiton	1,500	Coast Guard accepted application Jan 2004
Crystal	Oxnard, CA	Crystal Energy	1,250	Filed with Coast Guard Jan 2004
Terminal GNL Mar Adentro	Baja CA, Mexico	ChevronTexaco	750	Filed with Mexican regulators 2003
<u>Onshore</u>				
Energia Costa Azul LNG	Baja CA, Mexico	Sempra/Shell	2,000	Approved by Mexican authorities. Procedural protest (Dec 2003) overruled March 2004.
Sound Energy Solutions	Long Beach, CA	Mitsubishi	1,000	Filed at FERC Feb 2004
Gulf Coast				
<u>Offshore</u>				
Compass Port	AL Offshore	ConocoPhillips	1,000	Filed with Coast Guard April 2004.
Energy Bridge	Floating Dock, LA Offshore	Excelerate	500+	License approved by MARAD Dec 2003
Gulf Landing	W. Cameron, LA	Shell	1,000	Coast Guard accepted application Jan 2004
Main Pass Energy Hub	LA Offshore	McMoRan	1,000	Filed with Coast Guard March 2004.
Port Pelican	LA Offshore	ChevronTexaco	1,600	License approved by MARAD Nov 2003
<u>Onshore</u>				
Altamira	Altamira, Mexico	Shell/Total	650	Approved by Mexico May 2003. No supply for US but would reduce US exports to Mexico
Cameron LNG	Hackberry, LA	Sempra Energy	1,500	Approved by FERC Sept 2003
Corpus Christi LNG	Corpus Christi, TX	Cheniere/BPU	2,600	Filed at FERC Dec 2003
Freeport LNG	Freeport, TX	Freeport/Cheniere/ Contango	1,500	FERC issued Final Environmental Impact Statement May 2004
Golden Pass	Sabine Pass, TX	ExxonMobil	1,000	Prefiling underway with FERC and Texas
Ingleside Energy Center	Ingleside, TX	Occidental Petroleum	1,000	Prefiling underway with FERC
Port Arthur	Port Arthur, TX	Sempra Energy	1,500	Prefiling underway with FERC
Sabine Pass	Sabine Pass, LA	Cheniere	2,600	Filed at FERC Dec 2003
Vista del Sol	Quintana Isl, TX	ExxonMobil	1,000	Prefiling underway at FERC
Bahamas/Florida				
<u>Onshore</u>				
Calypso	Freeport, Grand Bahama Island	Tractebel Bahamas LNG	832	Connecting pipeline to FL approved by FERC Mar 2004. Awaiting environmental approval.
Ocean Express	Ocean Cay, Bahamas	AES	842	Pipeline to FL approved by FERC Jan 2004 Application before Bahamian government.
High Rock LNG/Seafarer	Grand Bahama Island	El Paso	820	Prefiling underway at FERC for connecting Seafarer pipeline to FL
East Coast				
<u>Onshore</u>				
Bear Head	Nova Scotia, CN	Access NW Energy	1,000	Draft Environmental Impact Statement filed with Canadian regulators March 2004
Canaport	New Brunswick, CN	Irving Oil	500	Environmental Impact Statement filed with Canadian regulators March 2004
Crown Landing	Logan Township, NJ	BP	1,200	Prefiling underway at FERC. Project dependent on exemption from DE's Coastal Zone Act which prohibits heavy industry on DE River.
Key Span LNG	Providence, RI	Key Span/BG Group	525	Application to convert storage terminal to marine terminal filed at FERC April 2004
Weaver's Cove	Fall River, MA	Poten	800	City voted against terminal Sept 2003. Filed at FERC Dec 2003.
Total			31,469	

*In 2002, FERC instituted a pre-filing process for prospective project applicants so as to identify environmental, permitting, and land-use issues, examine alternatives, and resolve problems before a formal application is filed (usually in 7 to 8 months).

**Capacity data generally represent peak capacity estimates.

MMcf/d = Million cubic feet per day. MARAD = Maritime Administration within the U.S. Department of Transportation.

Source: Federal Energy Regulatory Commission (FERC), industry trade press, company Internet sites, and other.

Application Process for New U.S. LNG Facilities

The approval process for new LNG import or export facilities in the United States has a number of requirements. Once a potential site has been identified, developers assess the project's feasibility and conduct detailed engineering, safety, and environmental studies. Public input is also solicited through community meetings and meetings with local agencies and planners. Results of the preliminary studies, which can take several months (and sometimes years) to complete, are included in the formal application that the developer files with the governmental agencies in charge of authorizing LNG facility construction and operation. Generally, it takes a minimum of 12 to 18 months from the date an application is filed for a project to be approved, and the review time can be substantially longer if significant public opposition is encountered.

Several governmental agencies have roles in determining whether to authorize new LNG facilities. The Federal Energy Regulatory Commission (FERC), in coordination with the U.S. Department of Transportation and the U.S. Coast Guard, has the main responsibility for approving onshore facilities, while the U.S. Coast Guard and the Maritime Administration oversee permits for offshore facilities. The U.S. Department of Energy, the Fish and Wildlife Service, the Minerals Management Service, and the Army Corps of Engineers also have roles in the permitting process, as well as state and local authorities. All LNG facilities must comply with air and water standards established by the Environmental Protection Agency and by state environmental offices. Offshore facilities must also be approved by the adjacent coastal state. FERC no longer has jurisdiction over offshore facilities but does have jurisdiction over interconnecting interstate pipeline facilities that are onshore. Some developers of offshore terminals have asked FERC to grant waivers of certain open access rate and tariff requirements for the short segments of onshore natural gas pipelines that are related to offshore terminals, but as of May 2004 no decisions have been rendered.

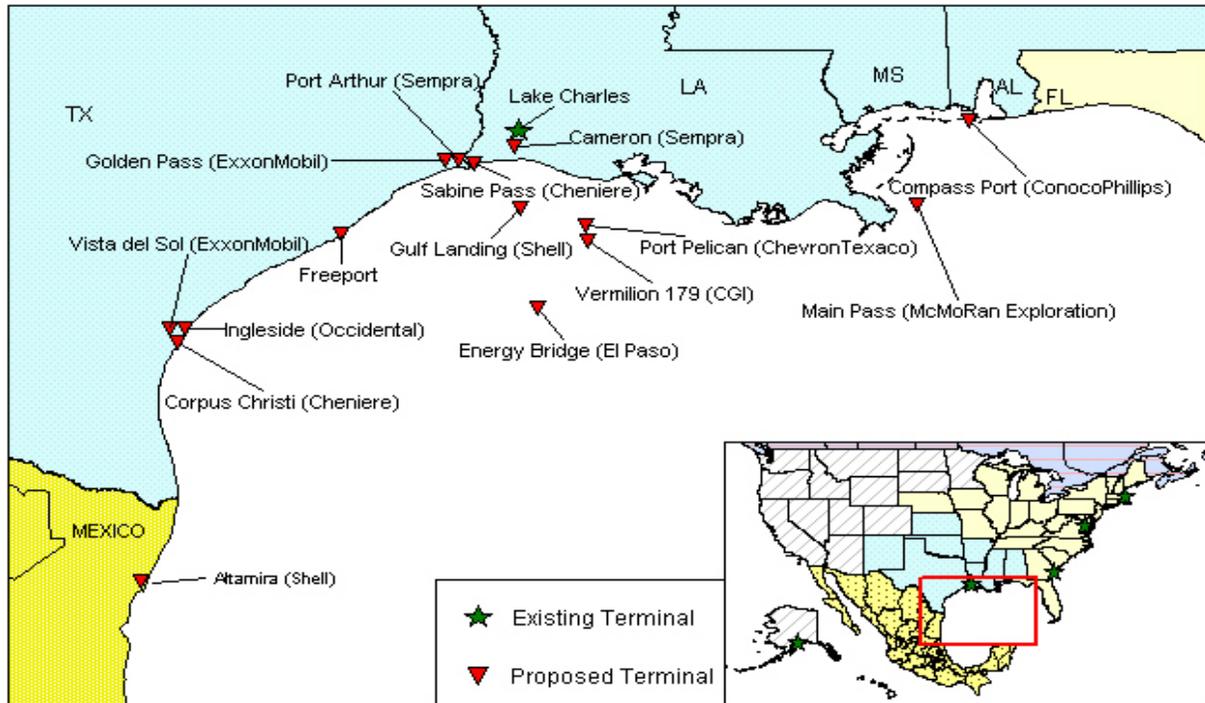
Federal Permitting for Onshore Terminals

- FERC has the lead responsibility for authorizing the construction and siting of onshore LNG facilities under Section 3 of the Natural Gas Act. It performs environmental and safety reviews of LNG plants and prepares environmental impact statements, as required by the National Environmental Policy Act (NEPA). Public comment is also solicited. FERC also authorizes the construction and operation of interstate pipelines that are associated with LNG facilities, under Section 7 of the Natural Gas Act.
- The U.S. Department of Transportation, Office of Pipeline Safety (Research and Special Programs Administration) has authority over safety regulations and standards for the transportation and storage of LNG in interstate commerce or foreign commerce under the pipeline safety laws (49 USC Chapter 601).
- The U.S. Coast Guard has responsibility for certain safety issues related to onshore facilities and vessels. It is responsible for safety and security of port areas under the Magnuson Fishery and Conservation Act (50 USC Section 191), the Ports and Waterways Safety Act of 1972, as amended (33 USC Section 1221, et seq.), and the Maritime Transportation Security Act of 2002 (46 USC Section 701), and has authority for facility security plan review and siting as it pertains to the management of vessel traffic in and around an LNG facility.

Federal Permitting for Offshore Terminals

- The U.S. Coast Guard has primary authority over construction and siting of offshore LNG facilities, and oversees preparation of environmental impact statements that examine the potential impact of the new facilities, as required by the National Environmental Policy Act and the Deepwater Port Act of 1974 (DWPA), as amended (33 USC 1501 et seq). As specified by the DWPA, the environmental review and analysis must be completed within 356 days of the published Notice of Intent. Coast Guard oversight of the offshore facilities continues as long as the facilities are operational, as the agency has responsibility for the safety and security of LNG facilities and vessels in U.S. coastal waters.
- The Maritime Administration (MARAD) within the U.S. Department of Transportation has authority over the licensing of deepwater ports, based on the application process administered jointly by the Coast Guard and MARAD, under provisions in the DWPA. Originally the DWPA applied only to oil terminals, but the Maritime Transportation Security Act of 2002 amended the law to include LNG facilities developed offshore, including associated pipelines, platforms, mooring lines, etc. Interconnecting facilities are not included. The licensing decision must be made within 90 days after the last public hearing, with at least one public hearing required in each adjacent coastal state.

Figure 4. Proposed Marine Terminals in the Gulf of Mexico as of June 2004



Sources: Map locations are based on company announcements and trade publications.

Experimental LNG Storage Process

The U.S. Department of Energy through the National Energy Technology Laboratory is sponsoring a cooperative research grant that explores the potential of a new method for receiving and storing the cargo of LNG ships. Conversion Gas Imports, the leader of the \$2.7 million cooperative project, is developing the Bishop Process™ in which LNG is unloaded offshore, warmed to 40 degrees Fahrenheit, and then stored as natural gas in underground salt caverns either onshore or offshore. The Bishop Process begins with an LNG ship mooring at an offshore receipt facility. Subsequently, a high-volume LNG pump pressurizes the cargo to 2,000 pounds per square inch and transfers it to the Bishop vaporizer. This unique vaporizer is a coaxial pipe-in-pipe arrangement. A large volume of highly pressurized LNG flows through an inner pipe, while seawater acting as a warming agent flows through an outer pipe. During this procedure, the LNG is warmed from -260 degrees Fahrenheit to 40 degrees and experiences a three-fold increase in volume. The natural gas, existing as a dense phase gas, a state of matter in which there is no distinction between liquid and gas, is then injected into a salt cavern located onshore or offshore. On demand, the stored gas can be delivered to consumers via a connecting pipeline.

The team of collaborative companies is currently performing a “proof of concept” test that will evaluate the viability of the Bishop Process Terminal and its various elements. The test has already demonstrated the success of the Bishop heat exchanger and high-pressure LNG pump capable of delivering natural gas at cavern injection pressure. It is the intent of CGI to field test an offshore mooring system capable of using the Bishop process LNG heat exchanger and LNG high-pressure pump. Offshore LNG transfer systems may become a viable industry option. The utilization of salt caverns as storage facilities has the potential to produce enormous economic benefits for the LNG industry. According to CGI, a salt cavern can be constructed at half the cost of a cryogenic tank, while operating at less than half the cost and possessing twice the storage capacity. Salt caverns also have high-deliverability capability, delivering gas up to a rate of 3 billion cubic feet per day. If proven successful, the Bishop Process could expand the global trade of LNG.

Projects for the Gulf area require a large capital investment of about \$600 million on average, but the investment amount depends heavily on site-specific considerations (including whether or not the terminal is designed for the offshore). These projects generally are larger than those planned for other U.S. locations. The largest U.S. and foreign-based oil and gas companies have projects planned for the region, including ExxonMobil, Royal Dutch/Shell, ChevronTexaco, Occidental Petroleum, and ConocoPhillips. Many of these companies have extensive interests in upstream liquefaction projects, including ExxonMobil's interest in Qatari LNG exports and ConocoPhillips' interest in Nigerian LNG exports. Locating new terminals in the Gulf region with the current industrial base and less resistance by the local population is expected to reduce the length of time and difficulty in obtaining regulatory approval.

In market areas such as the U.S. Northeast and California, the terminals proposed to date are generally smaller and require less investment capital. Average costs are about \$400 million for a new facility with deliverability of about 500-600 MMcf/d, which would result in unit capital costs that are as much as double those for a larger facility in the Gulf of Mexico. These facilities are being proposed for markets that currently experience premium prices relative to prices in the Gulf.

Btu Content Issues

Because of relatively high Btu content of LNG from various countries, operators of marine terminals and their suppliers are often faced with the challenge of lowering the heat content of regasified LNG before delivering the gas into the pipeline grid. U.S. major interstate pipelines have a gas quality standard of 1,035 Btu per cubic foot with a range of plus or minus 50 Btu, while the heat content of LNG imports in 2003 ranged between 1,040 and 1,160 Btu per cubic foot (Figure 5). Such high heat content is incompatible with many U.S. appliances and industrial processes and outside the gas quality standards of local utilities and pipelines.

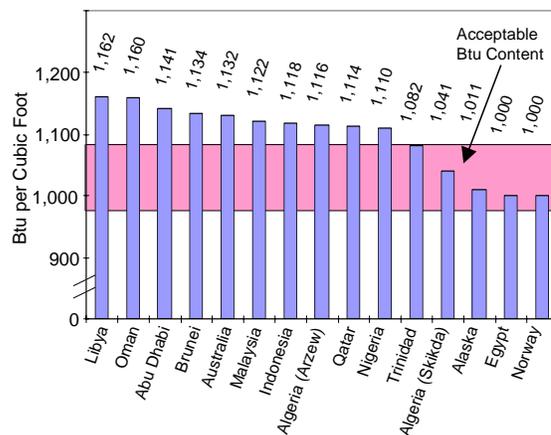
The heat content of LNG became an issue in the re-commissioning of the Cove Point LNG (Maryland) facility in 2003, until specific standards (1,036 Btu) were in place as to the quality of the gas entering Washington Gas Light's (WGL) distribution system from the Cove Point pipeline. Under the agreement, the Cove Point terminal can still receive higher heat content cargoes in certain instances, but all deliveries to the WGL system must be at the lower rate. Similar gas quality issues likely will be obstacles limiting deliveries to certain terminals during 2004 and factors in development of new facilities.

At Lake Charles, Louisiana, Southern Union successfully mixes high heat content natural gas with gas being transported in pipelines. The area has access to relatively

low heat content gas because of the substantial processing infrastructure in the region, including petrochemical and natural gas liquid facilities that use gas for feedstock. As a result, LNG deliveries with high Btu content occur more often at this facility than at the three terminals on the East Coast. At Everett, Massachusetts, Distrigas uses in-tank blending of pipeline gas with LNG to meet standards. Btu levels can also be reduced by injecting a 2-percent nitrogen mixture into the vaporized gas stream at sendout or by injecting a 3.8-percent air mixture. Engineering studies done in preparation for the reopening of the Elba Island, Georgia, facility in 2001 estimated that it would cost approximately \$18.5 million to equip the facility with air injection devices and about \$28 million for nitrogen separation equipment. Dominion is in the process of installing a nitrogen separation plant at its Cove Point facility. Installation of liquid-stripping facilities at marine terminals also would effectively allow Btu reduction, but the costs for such facilities could exceed \$30 million. This relatively high capital cost and the lack of nearby markets for natural gas liquids often make such stripping facilities uneconomical for terminals outside of the Gulf region.⁹

FERC held a public conference in February 2004 to hear industry and consumer concerns about the appropriateness of current gas quality standards, particularly in light of the expected increase in LNG imports. An industry collaborative also has been formed in an effort to reach consensus on LNG interchangeability and other gas quality issues. Unless industry consensus can be achieved, FERC has stated its intention to initiate a generic rulemaking on the subject.

Figure 5. LNG Heat Content by Country



Sources: **Libya:** *World LNG Source Book 2001*. **Other:** Conversion Gas Imports, LLC and International LNG Alliance (ILNGA).

⁹ "Gas 'Interchangeability' and Its Effects on U.S. Import Plans," *Pipeline and Gas Journal* (August 2003).

LNG in Storage

Storage supplies are an integral part of meeting consumption needs during the winter, particularly for gas utilities with a substantial residential customer base, which have a highly seasonal demand for gas. Gas utilities have numerous options to meet the increased heating demand during the winter such as supplies from underground storage and propane-air, compressed natural gas, and LNG storage. By far, the most common forms of storage in the industry are underground reservoirs and aquifers located in various regions of the country. However, during the coldest days of the year and the associated “needle-peak” demand times, the properties of LNG provide the industry an opportunity to meet the severe transitory requirements of heating load customers.¹⁰

On these peak demand days, space-heating demand spikes can raise a utility’s overall demand by 25 percent or more in some parts of the country. LNG storage facilities meet this demand with a capability of regasifying and delivering large amounts of natural gas into distribution systems with short-notice, otherwise known as relative high “deliverability.” Deliverability in the storage sector of the natural gas industry is generally defined as the amount of gas a facility can send out under peak conditions on a daily basis.

While deliverability of a given underground storage facility is highly variable and depends on factors such as the amount of gas in the reservoir, generally withdrawal rates relative to capacity are lower in underground storage than they are for LNG storage facilities. The design of LNG storage facilities also varies widely, but many sites were constructed to meet 10-day peak requirements on an annual basis. Stated differently, many LNG storage facilities can deliver 10 percent of storage quantities during each operating peak-day. At some of the largest facilities, this can mean delivery of as much as 300,000 to 500,000 million Btu into the natural gas distribution system. This contrasts with underground storage, the total deliverability of which is about 2 percent of holding capacity.

Most utilities, particularly those in the Midwest and Northeast, utilize a portfolio of supply sources throughout the year, and peaking supplies are just one part of how the utility attempts to meet customer needs. Baseload supplies

are received year-round directly through interstate pipelines from producing basins such as the U.S. Southwest and the Western Canadian Sedimentary Basin. Seasonal storage requirements and system support backup supplies are generally met by underground storage facilities at about 400 sites. Finally, peaking supplies received from LNG or other sources provide reliable supplies during the few times of the year that demand spikes. Such peak usage periods are defined differently by utilities across the country. In the Middle Atlantic States, for example, a needle peak that would result in LNG regasification into utility distribution systems may occur when the temperature has fallen below 10 degrees Fahrenheit.¹¹ However, in New England, a peak day occurs at a slightly lower temperature of 5 degrees Fahrenheit.

An important concept in the design of utilities’ strategies to meet highly variable demand is the notion of “load factor,” which is the amount of pipeline space used throughout the year expressed as a percentage of pipeline space reserved (normally requiring large, fixed costs). The industrial sector tends to consist of high-load factor customers because its gas requirements are related to manufacturing needs, which tend to be stable and predictable. However, space-heating demand, particularly that relating to the spikes resulting from the coldest winter days, is highly uncertain with respect to occurrence and duration and would result in extremely low load factors (Figure 6). This low-load factor indicates that it is relatively expensive to build or contract for pipeline capacity year-round, or to contract for seasonal storage, solely to meet the sudden, short-lived temporary demand increases.

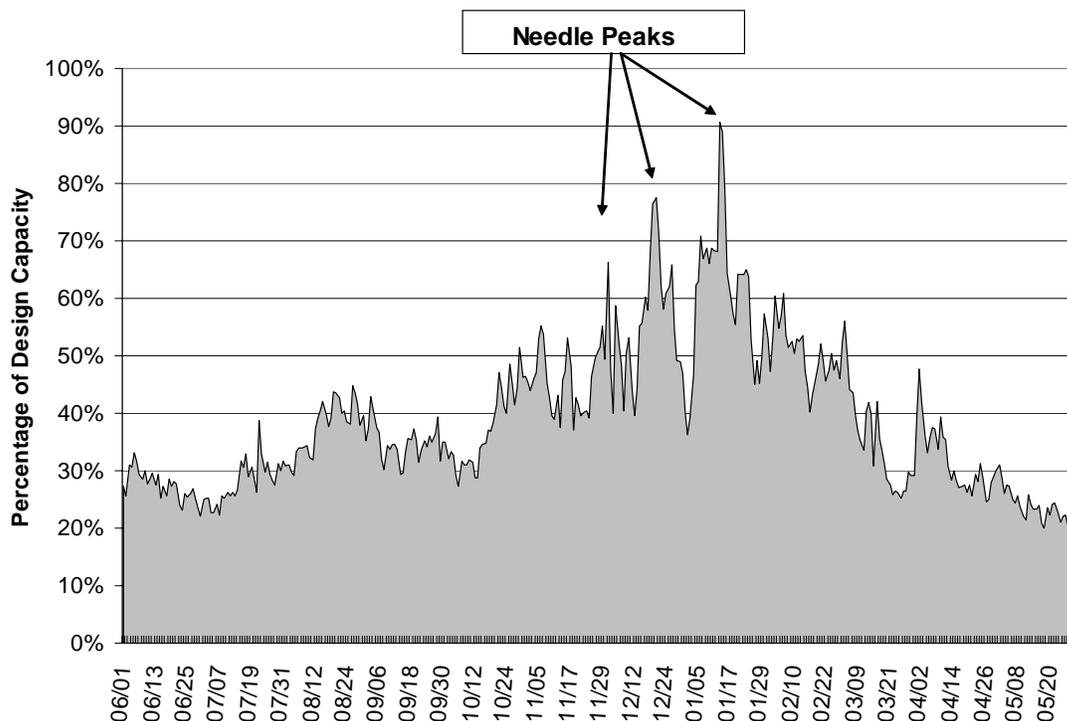
Often, the economic justification for the construction of LNG storage facilities comes from a calculation of savings from avoided pipeline capacity.¹² To meet needle peaks through reserving pipeline space, a utility would pay capacity charges on perhaps a third of its peak-day supply portfolio on an annual basis. If the utility experiences only three or four needle-peak days during a normal winter, the total annual reserved pipeline space would be overbooked significantly and result in substantially higher transportation costs per million Btu (MMBtu) year-round. The key to improving the utility’s overall load factor on upstream pipelines and reducing transportation on an MMBtu basis is identifying the alternative sources of supply such as LNG or other storage options to match the characteristics of demand swings on the distribution system.

¹⁰ Propane-air and compressed natural gas are also used by utilities during peak demand periods and compete with LNG. Other than LNG, propane-air storage is the more common choice. However, propane-air differs from LNG in that operators must blend or mix propane-air into the gas stream because it is not pipeline-quality gas at its release point. Compressed natural gas is less commonly used owing to perceived greater expenses and capital investment.

¹¹ Maryland Public Service Commission, *Staff Report on the Baltimore Gas and Electric Company’s LNG and Propane Facilities* (Baltimore, Maryland, October 2000).

¹² Gas Technology Institute, *World LNG Source Book 2001* (Des Plaines, Illinois, 2001), Section V, pp. 1-15.

Figure 6. PG&E's Percentage of Distribution System Capacity Used from June 1997–June 1998



Source: Pacific Gas & Electric (PG&E).

LNG facilities offer several advantages over alternative storage options. Owners have many opportunities for locating LNG facilities in comparison with underground storage alternatives. Underground storage in the United States requires appropriate underground geological conditions such as depleted reservoirs, aquifers, and salt caverns. LNG facilities usually are located above ground, although they can be located below the surface as they are at some sites in Japan. As a result, LNG storage plants are geographically located in states that either do not have underground gas storage facilities or are at a considerable distance from underground storage facilities.

The need to meet load surges caused by large heating demand also contributes to these facilities being located close to population centers such as Boston, New York, Chicago, and Philadelphia, which are among the cities with the largest residential customer base in the country. While it is technically possible to site LNG facilities closer to demand bases, LNG owners must obtain the land and receive permits from a variety of governmental agencies and adhere to strict safety and environmental regulations while operating the facility.

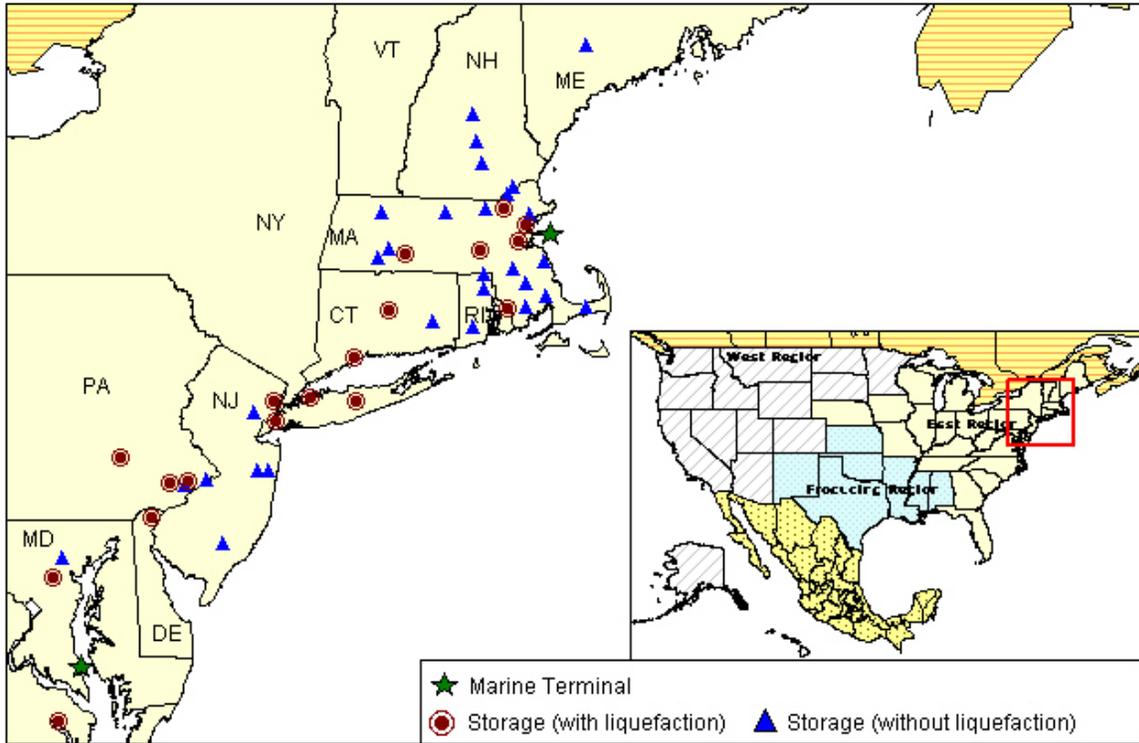
LNG storage facilities in the United States have a combined capacity of about 86 Bcf. This calculation of storage does not include the storage available at marine terminals because, as mentioned earlier, the capacity at marine terminals generally is dedicated to cycling gas

through the facility, which is a baseload process rather than time-shifting of supplies by use of storage facilities. The overall capacity of LNG storage facilities represents roughly 2 percent of natural gas storage in the Lower 48 States. Approximately 82 percent of this LNG storage capacity is located in the East, with most of the capacity concentrated in the Northeast (Figure 7). About 14 percent of LNG storage capacity is in the West Region, and the remaining 4 percent is in the Producing Region (Figure 1).¹³

Despite the relatively low amount of LNG storage capacity, LNG storage facilities provide the equivalent of 13 percent of underground storage deliverability, or about 11 Bcf/day. In the East Region, LNG facilities amount to 23 percent of underground storage deliverability during a peak day. In New England alone, deliverability is roughly 3.4 Bcf/d, not including the deliverability of the Distrigas terminal in Everett, Massachusetts. The deliverability of facilities in the West Region is about 1.2 Bcf/d or about 10 percent of underground storage deliverability (Figure 8).

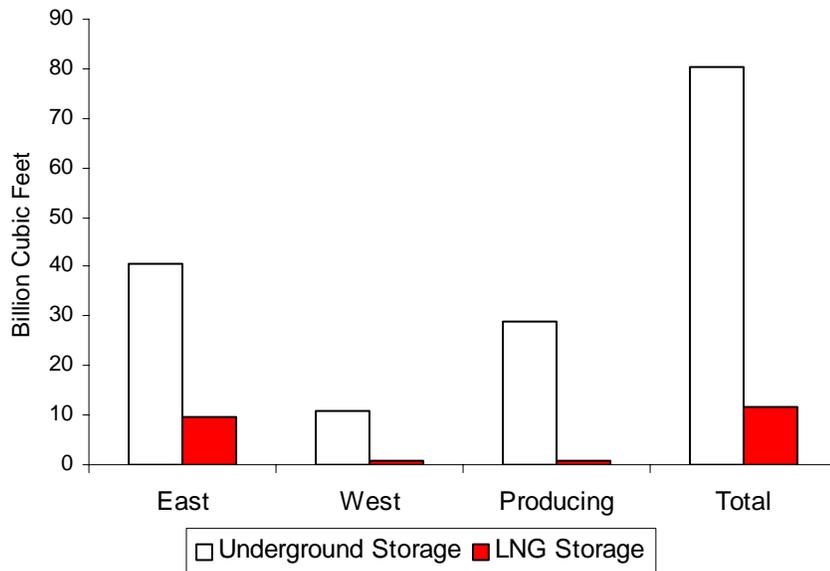
¹³The storage regions identified in this report generally correspond with regions for underground natural gas storage in the Energy Information Administration's *Weekly Natural Gas Storage Report* (<http://tonto.eia.doe.gov/oog/info/ngs/ngs.html>).

Figure 7. LNG Facilities in the U.S. Northeast



Sources: Energy Information Administration, Office of Oil and Gas, and industry sources.

Figure 8. Daily Deliverability of LNG Storage and Underground Storage Facilities, 2003



Source: Energy Information Administration, Office of Oil and Gas, Natural Gas Division.

LNG Storage Facility Design and Operations

The most prominent feature of LNG storage facilities is often large cylindrical storage tanks. The LNG tanks are usually double-walled with a large layer of insulation to keep the LNG in the cool liquid form. The inner tank is composed of nickel steel, while the outer tank is composed of steel or concrete. Regulations require that a dike large enough to contain the contents of the LNG tank surround the facility (Figure 9).

The largest LNG tanks hold approximately 25 million gallons of LNG, which is equal to about 2 Bcf of natural gas in its gaseous form. Another common size is about half of the largest tanks, or about 12 million gallons. However, the size of LNG tanks can vary widely with the smallest tanks designed to store about 50,000 gallons of LNG, or 4.1 MMcf. The LNG is stored in these facilities at or near atmospheric pressure.

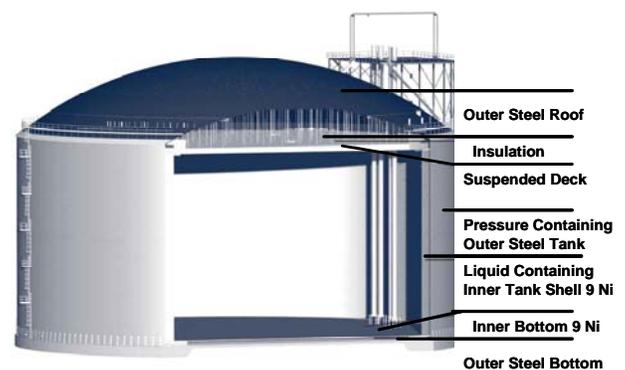
There are 96 LNG facilities in the United States that serve solely a storage function. Often, these facilities are divided into two groups: those with and without liquefaction equipment. EIA estimates that there are 57 facilities with the equipment to liquefy natural gas sourced from the domestic pipeline grid. These operations are usually much larger than the remaining 39 “satellites,” which are named for the fact that they depend on other facilities to receive LNG. In the United States, LNG is transported between facilities by trucks. However, transportation can take place by train or barge between facilities.

The notion of a liquefaction plant serving multiple satellite facilities, sometimes called a “hub and spoke” system, continues to be of interest to the industry owing to less expensive overall production and storage costs. This is similar to the system of inland satellite facilities receiving imported LNG from marine terminals, such as occurs in Massachusetts from the Everett marine terminal and proposed for a marine terminal in Long Beach, California. There is also the potential for transfer of LNG from a single liquefaction plant to facilities with multiple purposes, including peaking and vehicular fuel stations, where LNG production would be otherwise uneconomical.¹⁴

¹⁴ In May 2003, the U.S. Department of Energy’s National Energy Technology Laboratory entered into an agreement with New York State Electric and Gas to build a combined liquefied and compressed natural gas system. The plant will allow wider (and cost-effective) distribution of gas to existing pipeline customers, new off-pipeline customers, and existing and expanded alternative fuel vehicle fleets. The project is expected to be completed in the summer of 2004.

Receipts and additions from LNG in storage on an annual basis range widely, according to data from Form EIA-176, “Annual Report of Natural and Supplemental Gas Supply and Disposition.” For the past several years (1997-2002), additions and withdrawals from LNG in storage have ranged between 27 Bcf and 52 Bcf per year. As of December 31, 2002, LNG storage facilities had the gaseous equivalent of approximately 66 Bcf in storage. During 2002, approximately 43 Bcf was withdrawn, while 42 Bcf was added to storage resulting in a net decline of 1 Bcf for the year.¹⁵

Figure 9. Schematic and Photo of LNG Storage Tanks



Sources: Storage tank schematic courtesy of Chicago Bridge and Iron. Photo of the Pine Needle storage facility in Guilford, North Carolina, from the Chicago Bridge and Iron website (<http://www.cbi-nv.com>).

¹⁵ Energy Information Administration, *Natural Gas Annual 2002* (Washington DC, January 2004). Table 1.

The LNG storage inventory measure at the end of 2002 highlights the fact that LNG storage accounts for a small portion of total U.S. working gas in storage. At the end of 2002, LNG stocks were the equivalent of 2.7 percent of the 2,375 Bcf held in underground storage facilities. Massachusetts was the State with the largest LNG inventory in storage as of December 31, 2002, at approximately 11.5 Bcf. North Carolina had the second largest inventory at about 7.3 Bcf.

Although LNG “withdrawals” normally only occur to meet peak demand, LNG storage operators must account throughout the year for amounts of “boil-off,” which is a natural vaporization from the cool liquid to the gaseous form of natural gas while LNG is held in storage. While LNG facilities hold LNG in storage, approximately 0.25 to 0.50 percent of the inventory is lost to this natural vaporization process every day. Over time, this can be a substantial amount of gas, theoretically adding to the cost of storing LNG. However, many utilities now possess equipment to channel the boil-off into their distribution systems for use, and the value of the product is eventually realized as sales of natural gas.

Injections of LNG at storage plants with liquefaction capacity generally occur over a long period. The design capacity for liquefaction units is usually low relative to the vaporization capacity, requiring months to fill a large tank. For example, the Pine Needle plant in North Carolina requires its customers to allow for a 100-day refill period, while maximum daily withdrawals can be up to 10 percent of a customer’s contracted storage capacity. In the case of liquefaction off the pipeline grid, injections of LNG also normally require about 15 percent of the intake to provide the energy for liquefying the gas. This process adds significantly to the overall cost of LNG supplies.

For those facilities without liquefaction, additions of LNG to storage require truckload deliveries. As a result, additions generally occur on a less consistent basis than for facilities that are liquefying a portion of their requirement on a more or less daily basis. Because trucks carry up to 10,000 gallons of LNG each trip, some of the smallest satellite facilities require only one truckload to fill the tanks. However, at the largest satellite facilities, annual truckload deliveries number up to 2,000.

Whether or not storage facilities have liquefaction, virtually all of these facilities are connected to the pipeline grid or local utility distribution systems. Their owners elected to construct the storage facilities rather than invest in additional upstream pipeline or underground storage capacity. Interestingly, several facilities in the Northeast with liquefaction equipment have chosen to receive LNG supplies via truckload from the Everett terminal in Massachusetts. The inference is that Distrigas is able to offer imported LNG at a lower

price than it would cost the utility-owned storage facilities to liquefy pipeline gas.

Because the operational characteristics of LNG storage generally are highly effective in meeting the requirements of natural gas distribution operations, LNG facilities are usually owned and operated by natural gas utility companies. Local distribution companies (LDCs) own and operate 83 facilities, while interstate pipeline companies own 13. Often a single company will own multiple facilities, typically consisting of one liquefaction plant and several satellites that receive LNG by truck from the larger facility. In this case, the smaller facilities may be located at strategic locations on the distribution system where load surges must be met in order to ensure uniform operating pressures are maintained. In contrast, the larger facilities serve to ensure the operating integrity of the entire system instead of targeting these pockets of large loads.

LNG operations that are part of local distribution systems are regulated by state public utility commissions and other governmental agencies, similar to other operations of the company. State public utility commissions regulate the economic aspects of both the construction of new LNG facilities and operations of existing plants. The U.S. Department of Transportation, Office of Pipeline Safety (OPS) regulates the safety of the operations.

FERC regulates the LNG operations of interstate pipeline companies with LNG facilities. Interstate pipeline companies own and operate LNG facilities as part of their integrated systems of pipeline assets, much as many also own and operate underground storage facilities. FERC requires that these operators offer open access and publish tariffs for terms and conditions of service. Whether an interstate pipeline or local utility owns an LNG facility, the ultimate “end users” of LNG storage historically have been distributors attempting to meet needle peak demand on their system. If an LNG facility is operated by an interstate pipeline company, local distributors will reserve storage capacity and acquire regasification rights according to their supply needs. As with LDCs, OPS regulates the safety of the operations.

Conclusion

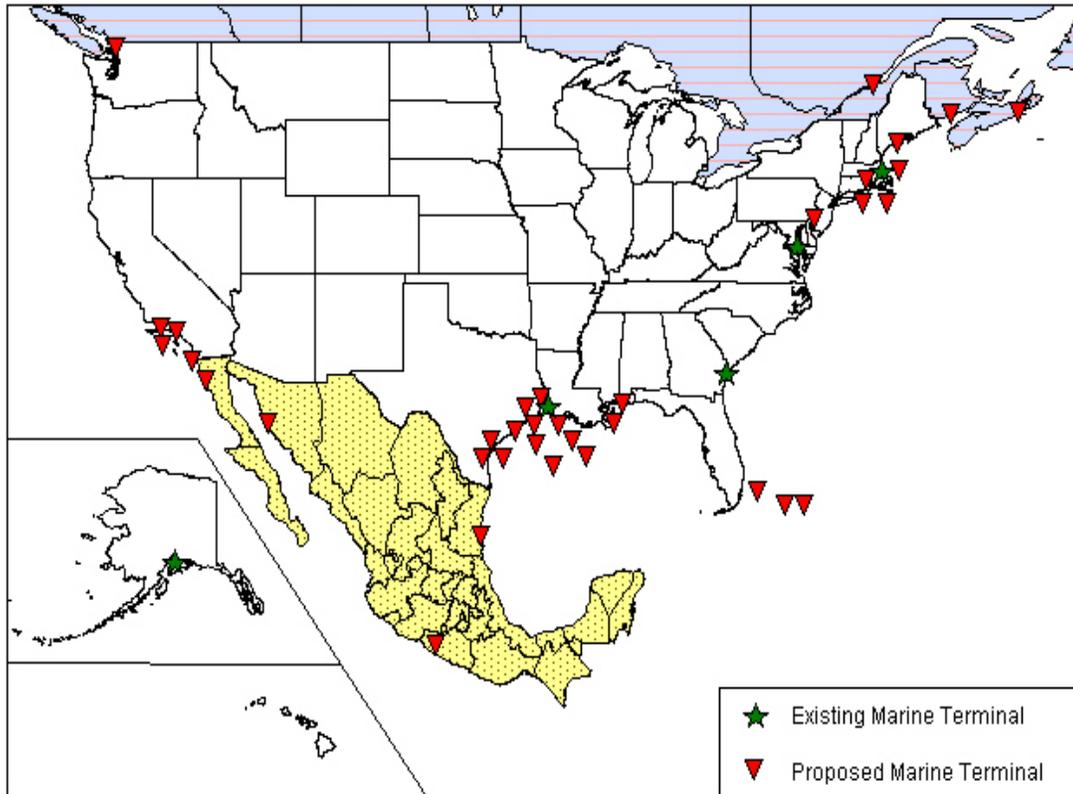
Growth in the LNG sector of U.S. natural gas supply appears likely over the next several years.¹⁶ This growth depends on increased utilization and expansion of current facilities and new construction. The need for additional

¹⁶ Energy Information Administration, *Annual Energy Outlook 2004*, January 2004 (<http://www.eia.doe.gov/oiaf/aeo/index.html>).

supply sources to meet projected U.S. demand generally coincides with numerous developments in LNG trade on a worldwide basis. These developments include lower liquefaction costs as well as lower shipping costs. LNG storage facilities will also continue to be important in meeting peak demand needs of local utilities and as a way to store gas until needed. In addition, the demand for domestic LNG is expected to increase as companies make inroads into several niche markets such as vehicular fuel and as a replacement for propane at facilities off the pipeline grid.

Appendix A Supplemental Information

Figure A1. Existing and Proposed LNG Marine Terminals in North America as of June 2004



Sources: Energy Information Administration, Office of Oil and Gas, and industry sources.

Table A1. Natural Gas and LNG Conversion Measures

Natural Gas (NG) and Liquefied Natural Gas (LNG) Conversion Units				
To:	Billion Cubic Meters NG	Billion Cubic Feet NG	Million Tons LNG	Trillion Btu
From:	<i>Multiply by:</i>			
1 Billion Cubic Meters NG	1	35.315	0.734	37.964
1 Billion Cubic Feet NG	0.028	1	0.021	1.075
1 Million Tons LNG	1.38	48	1	51.9
1 Trillion Btu	0.026	0.98	0.02	1

One-to-One Conversion Table						
To:	Liquid Measures			Vapor Measures		Heat Measure
From:	Metric Ton LNG	Cubic Meter LNG	Cubic Foot LNG	Cubic Meter NG	Cubic Foot NG	Million Btu*
Metric Ton LNG	1.00	2.232	78.827	1,362	48,074	51.7
Cubic Meter LNG	0.448	1.00	35.315	610	21,537	23.161
Cubic Foot LNG	0.0127	0.0283	1.00	17.277	610	0.66
Cubic Meter NG	0.000734	0.00164	0.0579	1.00	35.315	0.04
Cubic Foot NG	0.00002	0.00005	0.0016	0.02832	1.00	0.001

*Based on volume conversion of 610 to 1 and 1,075 gross dry Btu per cubic feet of vapor
Source: Trunkline LNG Company. Available on the Internet at: www.panhandleenergy.com

Glossary

Boil-off: The natural gas that is lost on a daily basis to natural vaporization, often expressed as a percentage.

British thermal unit (Btu): The quantity of heat required to raise the temperature of 1 pound of liquid water by 1 degree Fahrenheit at the temperature at which water has its greatest density (approximately 39 degrees Fahrenheit).

Btu content or Heat content: Measurement: The gross heat content (or heating value), is the number of British thermal units (Btu) produced by the combustion, at constant pressure, of the amount of the gas that would occupy a volume of one cubic foot at a temperature of 60 degrees Fahrenheit, if saturated with water vapor and under a pressure equivalent to 30 inches of mercury at 32 degrees Fahrenheit and under standard gravitational force (980.665 cm per sec.²).

Compressed natural gas (CNG): Natural gas which is comprised primarily of methane, compressed to a pressure at or above 2,400 pounds per square inch and stored in special high-pressure containers. It is used as a fuel for natural gas powered vehicles.

Liquefaction: The process in which natural gas is cooled and pressurized, resulting in a liquid form of natural gas. Liquefying natural gas reduces its volume by a factor of 610. The reduction in volume makes the gas practical to transport and store.

Liquefied natural gas (LNG): Natural gas that is stored and transported in liquid form at atmospheric pressure at a temperature of -260F. Like the natural gas that is delivered by pipeline into homes and businesses, it mainly consists of methane (CH₄).

LNG facility: Any one of the various locations where LNG is imported, exported, liquefied, stored, regasified, processed, allocated for vehicular purposes, designated as stranded, or filtered for nitrogen.

LNG import terminal or import facility: The location where a seaborne tanker delivers and unloads LNG, which may subsequently be stored in cryogenic tanks, re-gasified, and/or delivered.

LNG marine terminal: A terminal that imports or exports LNG by ship.

LNG supply chain: The sequence of processes that contribute as a whole to the marketing of LNG, namely production, liquefaction, shipping, gasification, and delivery.

LNG vehicular fuel: LNG that serves the niche market of fueling specially designed automobiles or trucks.

Load factor: The amount of pipeline space used throughout the year expressed as a percentage of pipeline space reserved OR The ratio of the average load to peak load during a specified time interval.

Peak-shaving storage facility: A facility where LNG is stored and most likely vaporized to meet short-term periods of high demand for natural gas. Some peak-shaving facilities may also have liquefaction capacity.

Pipeline grid: The network of interconnecting pipelines used uniquely for the transportation of natural gas: Not LNG.

Regasification: The process in which LNG is converted back into a gaseous state.

Salt cavern: An underground formation which is hollowed out or "washed" so that it may be suitable for the storage of natural gas or other hydrocarbons; types include salt dome and salt strata.

Satellite facility: A storage facility served by truck where LNG may be stored and re-gasified as needed.

Train: The facility unit where LNG is produced.

Underground storage: The storage of natural gas or other hydrocarbons in subterranean salt caverns engineered specifically for the purpose of hydrocarbon storage

Vaporization: The process in which LNG is converted back into a gaseous state