Final Report

Risk Assessment of Surface Transport of Liquid Natural Gas

March 20, 2019

U.S. Department of Transportation

Pipeline and Hazardous Materials Safety Administration

final report

Risk Assessment of Surface Transport of Liquid Natural Gas

prepared for

U.S. DOT Pipeline and Hazardous Materials Safety Administration, Office of Hazardous Materials Safety

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Overview

The Pipeline and Hazardous Materials Safety Administration's (PHMSA) Office of Hazardous Materials Safety (OHMS) contracted with the Cambridge Systematics Team (CS Team) to assess the risk of transporting Liquid Natural Gas (LNG), with an emphasis on rail. In Task 1, the CS Team completed a comprehensive Literature Review. In Task 2, the CS Team developed a Risk Plan. For Task 3, the CS Team identified the factors and parameters for developing the LNG Risk Model in this report. This final report documents the findings and results from all three tasks.

Risk Assessment of Surface Transport of Liquid Natural Gas outlines LNG supply and demand in the context of the overall energy market, including new trends for using LNG for propulsion in the motor carrier, maritime, and rail industries. The CS Team explored how natural gas and LNG are transported throughout the United States, and the relationship between peak-shaving facilities, merchant plants, and export facilities. We also researched accident rates for motor carriers transporting LNG and Liquefied Petroleum Gas (LPG), and outlined LNG handling characteristics.

Natural Gas by Pipeline

A key aspect of this project is to examine the risks of shipping LNG by surface modes, with an emphasis on rail. This requires a review of existing national gas pipeline network, which is how most gas is transported today.

The majority of natural gas volumes transported in the continental U.S. are moved by pipeline. As natural gas is replacing coal as an energy source, its use is increasing across the country. The appeal of its low price and good pipeline network creates accessibility and competitive pricing. Natural gas—which is principally methane—in its native state is gaseous, but its state of matter depends on the method of transport. With few exceptions, natural gas delivered via pipeline is in a gaseous form. To transport natural gas by a vehicle, it is liquefied via cooling (Liquid Natural Gas), condensing it to 1/600th of the volume in its gaseous form. Keeping the LNG in a liquid state requires maintaining a temperature of −260°F, which is considered a cryogenic temperature.

A facility that is connected to the pipeline supply network may contract their natural gas through interruptible service contracts from the pipeline company. Peak-demand periods, such as during cold winters and hot summers, can exceed pipeline capacity in some regions. To guarantee that service will not be curtailed during peak-demand periods, firm service contracts reserve capacity that must be fulfilled except due to unforeseeable circumstances.[1] Interruptible contracts are lower priority than firm contracts, and flow can be stopped in order to serve the firm contracts, leaving the facility seeking alternative energy sources. Interruptible service is cheaper than firm service, and prices paid for the gas are subject to the rise and fall of the natural gas market.

[1] "Twenty-nine percent of natural gas purchases by U.S. power plants in 2016 were serviced by non-firm contracts. Yet, 57 percent of natural gas purchases by power plants in the Northeast in 2016 were serviced by non-firm contracts. The Northeast has a well-documented shortage of supply during peak periods, which stems from the limitations of the pipeline infrastructure." Energy Information Administration, "Natural gas power plants…"

However, the U.S. pipeline system cannot be quickly or easily modified. Pipelines are fixed in place, expensive to construct, and require an extensive permitting process; because of this, pipelines are becoming increasingly difficult to build. New pipelines with construction plans face increased scrutiny by the public, and they must undergo permitting processes that span years. This limits pipeline owners from expanding their networks to areas not currently served. It takes years for the pipeline owners to accomplish modifications of their infrastructure in response to supply and demand changes. In this situation, delivering natural gas in liquefied form by truck or by rail may be suitable alternative.

Liquefaction

The process of reducing natural gas into a liquid, called liquefaction, reduces the volume significantly for transport. However, this energy-intensive process increases the upfront cost of LNG. Liquefaction is most efficient at a large scale export facilities that use a series of turbines (trains) to cool the LNG to cryogenic temperatures.[2] Small-scale liquefaction also is available, though it is less efficient and more costly. Facilities with liquefaction capabilities can store natural gas as LNG and sell it to other facilities, like those that amass supplies for peak periods that are not connected to the pipeline network. In order to generate LNG, both a natural gas supply and liquefaction capabilities are necessary.

LNG by Truck

Truck delivery of LNG is an alternative to pipeline transportation of natural gas. A very small percentage of the volume of natural gas moved across the United States is moved by truck each year. Once natural gas is liquefied, it can be used as fuel for maritime, rail, and truck operations; it can also provide power generation in remote locations (mining, energy, and production companies, etc.). There are three typical reasons for LNG truck movements:

- A facility is not connected to the natural gas pipeline system;
- A facility has an interruptible pipeline supply contract; and
- LNG can be sourced at a more competitive price than other energy sources.

Areas and facilities may not be connected to the pipeline system because they are remote, not densely populated, have some type of geological formation that makes pipeline construction excessively costly (such as mountainous terrain), or have a temporary demand such as construction. Facilities can purchase LNG through brokers who contract and deliver the LNG at prices that compete with other energy sources, such as propane and diesel. When a pipeline is either not expected to be built, or will not be built for a while, LNG is a viable alternative energy source.

Whether or not a facility is connected to a pipeline, the choice to source alternative fuel is driven by price. If the price of natural gas rises too high, a facility with interruptible pipeline service can choose to source their natural gas needs in other ways, whether that be LNG, other energy sources, or through peak shaving, the stockpiling of natural gas while prices are low in anticipation of a future supply shortfall and price spike. Natural gas can be stored in underground caverns or as LNG in tanks at cryogenic temperatures. A facility

[2] In the context of LNG, the term *train* refers to the series of turbines that are used to cool natural gas to cryogenic temperatures.

without pipeline connections can choose the most competitive fuel source, and as long as LNG is competitive with other energy sources, it could be selected by the consumer.

LNG by Rail

LNG is not shipped by rail in the U.S. because it is not authorized by the Federal Railroad Administration (FRA), except by special permit. The code of Federal regulations, 49 C.F.R. § 172.101 Hazardous Materials Table lists natural gas with high methane content as forbidden to be transported by rail. The FRA has granted special permits to the Florida East Coast Railroad and to the Alaska Railroad. While several Class I railroads have piloted LNG propulsion programs, the comparatively low price of diesel fuel has delayed such programs.

Nevertheless, authorizing LNG rail shipments could change existing demand patterns; demand of LNG transport by rail could appropriate market share from either trucking or pipeline, depending on the network characteristics and other factors. In the case of New England, for example, the railroad network could supplement the existing pipeline network. In addition, availability of LNG transport by rail could affect the market share of other energy sources.

LNG Demand

One of the objectives of this study was to determine future LNG demand. This involves understanding the natural gas industry such that demand can be anticipated based on input factors. Demand for natural gas is determined by origins and destinations for LNG movements, which further determines the possible routing for LNG shipments.

The movements of LNG by truck in Figure ES-1 provides insight into 2016 Interstate truck movements reported to the EIA for the 2016 EIA Annual Report. The CS Team summarized gross Interstate LNG movements and mapped these truck movements with the natural gas pipeline network using the highway Interstate system. The data were not available for the exact origin and destination of each of the movements, so the CS Team employed a "shortest distance method" in GIS using State centroids and ports of entry. Where there are no pipelines, there is truck delivery of LNG—the pipeline system and the highway system are complementary. The truck movements of LNG in 2016 show where demand for LNG has been fulfilled, and where truck movements supplied natural gas to areas that were not sufficiently served by the pipeline network.

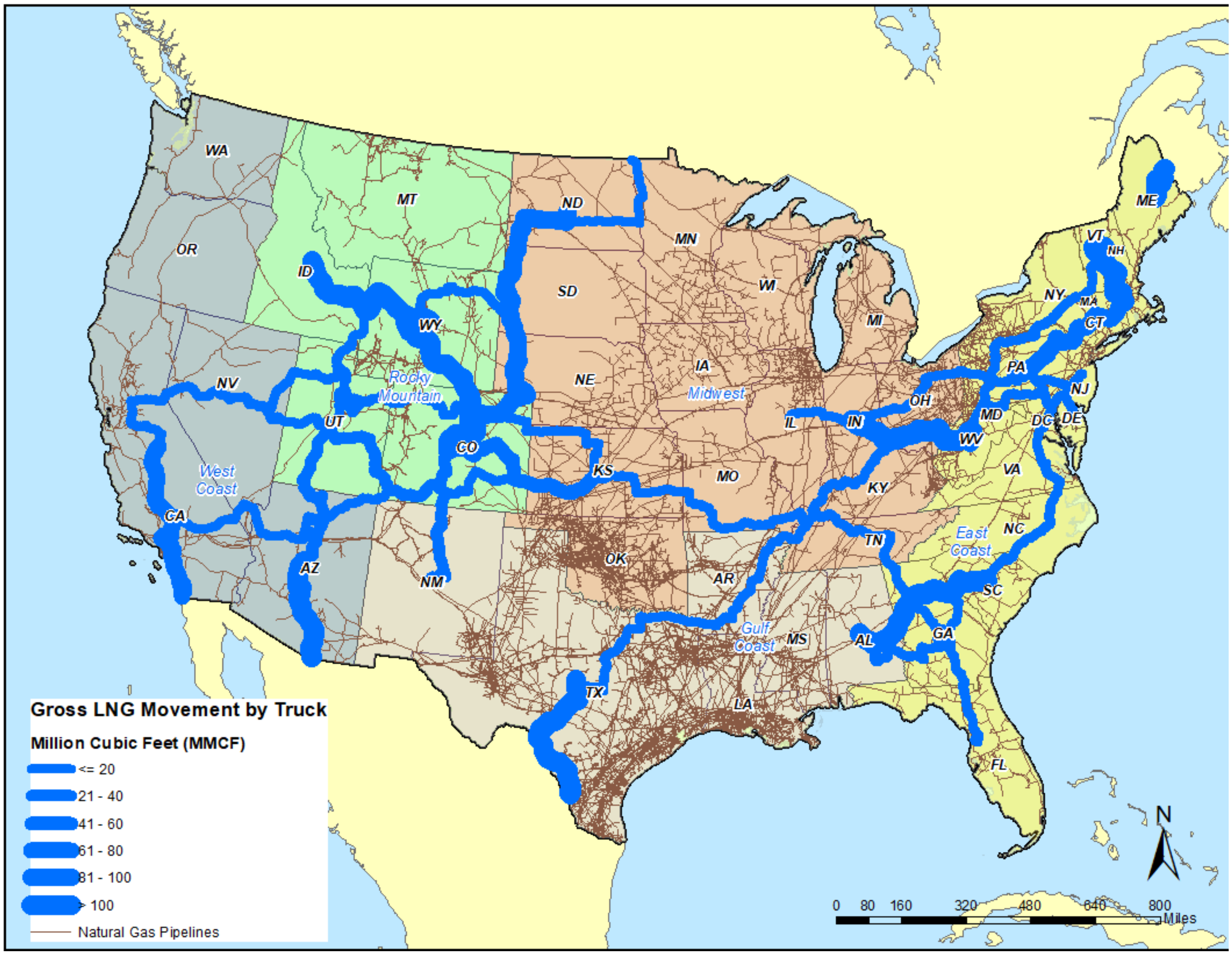

Figure ES-1 LNG Movements by Truck between States

2016, in millions of cubic feet (MMCF)

Source: Energy Information Administration, "2016 Annual Report."

The potential demand of LNG for regions and individual facilities can be anticipated based on several input factors. These include: 1) connection to the natural gas pipeline system, 2) pipeline supply contract types; 3) volume of demand; 4) proximity to LNG sources of supply; 5) prices of other fuel sources; and 6) the price basis of natural gas between regions. Natural gas price differentials are indicators of the supply and demand situation. Areas with stranded supply will have lower prices than the rest of the market, and areas with underserved demand will have higher prices than the rest of the market. The basis between two regions can justify the increased transportation costs of LNG delivery; where natural gas becomes less accessible and more costly, LNG becomes more attractive as an alternative energy source. As such, demand of LNG transport by railway could take market share of LNG delivery from the trucking industry and market share of natural gas delivery from the pipeline industry, or it could further compete and take market share from other energy sources like diesel and propane.

LNG Mode Choice

Rail and truck delivery of goods complement and compete with each other; this could be the same for LNG. For intermodal deliveries, trucks complement the rail network by providing consignees and shippers not directly served by rail lines access to rail terminals. For heavy loads and long hauls, rail delivery is more efficient than truck. One tank car can replace almost three truck cargo tank trailers. However, rail delivery of LNG has limitations particular to the railway network. In addition, rail delivery operationally takes longer than truck delivery because rail loads in manifest trains must be consolidated and sorted onto trains at rail yards, whereas truck delivery is a direct point-to-point delivery. This would be different if unit trains were employed, in which only LNG railcars were transported from origin to destination without requiring railyard sorting. Rail routing also is circuitous because rail companies prefer to stay on their own tracks to avoid interchange fees. There are certain origin and destination pairs that would make rail delivery of LNG more attractive than truck delivery, but since LNG supply points are spread out across the country, the overall distance that LNG would have to travel from the origin is limited, and this could favor truck delivery.

Rail delivery of LNG could replace or supplement the pipeline delivery of natural gas, such as during a supply disruption, where the rail option could provide duplication and redundancy. If a pipeline had to close due to immediate or planned maintenance work, or due to a pipeline malfunction, railroads could move large supplies of LNG to the demand regions. In addition, railroads could supply natural gas via LNG to destinations that the pipeline would not be able to service. For regions not currently served by pipeline, the demand for large volumes of natural gas on a consistent basis triggers the justification process for building a pipeline, which leaves several years for non-pipeline demand and delivery that could be replaced by pipelines if approved for construction.

Rail delivery could reach areas of the U.S. that currently do not use natural gas because it is too expensive to source and other sources are more accessible. If rail delivery of LNG is cheaper than truck delivery, then the LNG could travel longer distances from the supply source, to compete with other energy sources in areas previously out of reach. These are some of the factors to consider comparing LNG transport by truck and by rail.

The potential origins of LNG are facilities that liquefy natural gas or store LNG. These would include peak shaving facilities, export facilities, merchant plants, natural gas processing facilities, market hubs, and market centers that have liquefaction capabilities. Generally, there would be a large number of facilities that currently supply LNG for truck transport that could potentially supply LNG for rail transport to a single destination. For most destinations, that number can be reduced to a much smaller number by considering the alternative modes of trucking and pipeline, and using the costs of those modes to limit the potential rail origins.

LNG Mode Choice Case Study

To understand the economics of LNG transport by mode, the CS Team developed a case study to compare the LNG shipments by bulk rail, truck, and intermodal delivery. This was an economic case study, not a risk case study; information about the proposed quantitative risk assessment (QRA) can be found in Chapter 5. In this economic case study, the CS Team developed several scenarios to detail Interstate LNG shipment costs by mode between western Pennsylvania and Massachusetts. This was a deliberate choice, since western Pennsylvania is in the productive Marcellus and Utica shale region, and Massachusetts is an area in New England where natural gas is in high demand.

Figure ES-2 illustrates three scenarios between a processing facility in Harrisburg, PA and a power plant in Worcester, MA. This hypothetical route assumes that the railroad would keep the delivery on their own lines, whereas the truck routing uses a direct route that passes through population centers in New Jersey, New York, and Connecticut.

Figure ES-2 LNG Movement Alternatives between Harrisburg, PA, and Worcester, MA

Source: Cambridge Systematics.

In addition to the variable costs of transportation, LNG delivery also incurs fixed costs associated with liquefaction, storage, and gasification. The most expensive component in the LNG supply chain is the liquefaction plant, and the costs for liquefaction depend on the size of the facility. Larger facilities generally reduce the cost of liquefaction, due to economies of scale and more advanced equipment that reduces waste.

These three examples illustrate some of the challenges involved with shipping LNG over long distances, and the need to involve multiple modes of transport. Overall, portable International Standards Organization (ISO) containers prove to be the most versatile mode of LNG transport given the variables discussed in these scenarios. Table ES-1 provides a summary of the scenarios and their costs, and the full analysis can be found in Section 4.6.

Table ES-1 Pennsylvania to Massachusetts LNG Cost Scenarios

Scenario	Mode 1	Mode 2	Mode 3	Cost	Transport. Cost per MMBtu	Liquefaction, Gasification, and Storage Costs per MMBtu1	Total Cost per MMBtu
1a—Truck	Truck (MC-338)	–	–	$61,494	$0.85	$4.52	**$5.37**
1b—Truck	Truck (ISO)	–	–	$61,183	$0.85	$4.52	**$5.37**
2—Intermodal	Truck (ISO)	Rail (ISO)	Truck (ISO)	$54,733	$0.76	$4.52	**$5.28**
3—Rail	Rail (DOT-113C120W)	Truck (MC-338)		$46,098	$0.64	$4.52	**$5.16**

Sources: Cambridge Systematics Inc., Norfolk Southern Railway, Chart Industries.

Quantitative Risk Assessment

One of the key tasks for this study was evaluating the risks of transporting LNG by surface modes. This requires a quantitative risk assessment (QRA). In this context, risk is generally defined as the probability multiplied by the consequences of a hazmat release incident. The CS Team developed parameters and factors that would be required to model the derailment and release probability of LNG rail cars to account for a variety of characteristics. Ultimately, this process will help address the likelihood of a release per shipment, along with the resulting hazards to the public in the event of a derailment or other incident.

Currently, the FRA has not codified quantitative risk criteria for LNG hazardous materials transportation. Additionally, QRA analyses are not common regulatory requirements in the U.S. and there are no broadly accepted risk criteria employed by domestic communities or industries. Nevertheless, this study contributes to the body of knowledge required to better assess LNG risks related to surface transport.

QRA is used to assess risks in other industries, including chemical production, oil and gas processing plants, power generation plants, and manufacturing companies. In addition, U.S. Government agencies have developed QRA techniques to quantify hazardous material (hazmat) transportation and storage risks, determine route and mode choices, and identify appropriate packaging solutions.

Understanding the demand for LNG delivery by rail and/or truck helps identify the safest origins and destinations, and proposed routes can be examined for the probability and consequences of train and/or truck accident. Routes should be evaluated based on their proximity to city centers, sensitive populations, and track conditions. Rail risk factors include FRA class, signalization, and traffic density. Truck risk factors include driver behavior, traffic congestion, and truck speed.

One method commonly used to measure the harmful exposure of people or property to a hazardous material is to identify a series of events in an event chain diagram. In such a diagram, each event is probabilistic, in the sense that its occurrence is not certain, given that the prior event in the chain has taken place: one can only assign a probability to its occurrence. In the case of rail travel, the rail accident is identified as the first event in the chain of subsequent events.

The events in the event chain that must be evaluated to perform a rail QRA, from beginning (accident occurs) to end (a potential fatality) are described in Figure ES-3.

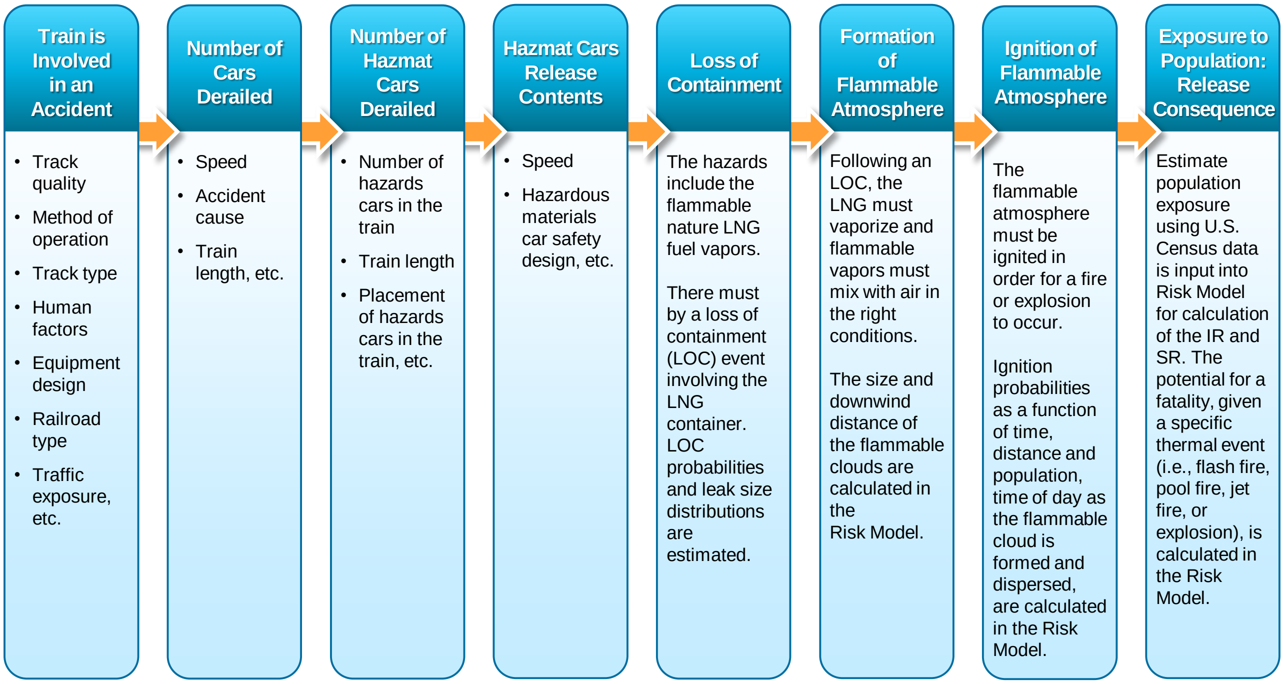

Figure ES-3 Rail LNG Event Chain Diagram

Source: Health and Safety Executive, Exponent, Inc; Liu, X., M. R. Saat, and C. P. L. Barkan, 2017. "Freight Train Derailment Rates for Railroad Safety and Risk Analysis," Cambridge Systematics, Inc.

Risk inputs and calculations further illustrate the relationships between inputs and calculations that determine model outputs. For example, FRA track class, method of operation, and traffic exposure are the inputs used to calculate train derailment frequency. Train speed is an input for both train derailment severity and release probability. Tank car safety design is an input to calculate tank car derailment and release probability. The formation of a flammable atmosphere is an input for calculating size and downwind distance of flammable clouds. These are examples of how risk factors and parameters are connected and interrelated in the QRA process.

LNG and LPG Carrier Analysis

In order to better understand motor carrier transport risk, the CS Team evaluated all U.S. LNG and LPG carriers and crash rates. The results of this research indicate that LPG and LNG motor carriers have very low crash rates relative to other carriers. For example, over the past 45 years, New England LNG carriers completed over 300,000 truck trips up to 150 miles with only two incidents. One incident was a truck rollover and the other was a truck engine fire. In both examples the LNG product in the cargo tank was not released.[3]

[3] ENGIE, Inc., "Facility Overview and Future Trends"

Unlike rail risk factors, such as FRA track class, method of operation, and rail density, truck risk factors include driver behavior, traffic congestion, truck speed, and the volume of trucks on the road relative to other vehicles. Since truck and rail operations have very different risk factors, they need to be evaluated differently.

Conclusion

Natural gas use is increasing in the U.S. due to the prolific production efforts in the Permian and Marcellus shale basins. Natural gas is taking a larger share of the energy market and replacing other energy sources. As a result, consumers are switching from sources such as coal, nuclear, and diesel to natural gas for power, heat, and propulsion. While the U.S. natural gas pipeline network is extensive, some geographic limitations do exist. There are areas of the U.S. that lack pipeline capacity, including the Northeast and Mountain West. Up until five years ago, the U.S. relied on natural gas imports; thanks to the newfound natural gas production capabilities, the U.S. is systematically recommissioning those same natural gas import facilities for export.

With this increased demand for natural gas, LNG transportation complements the distribution of natural gas by pipeline, providing access to areas that are not sufficiently supplied by the pipeline network. While surface transportation of LNG currently is only allowed by truck, and by rail with special permit, modal choice for LNG delivery would increase the opportunity for energy consumers to make competitive choices about their energy supply. There is evidence that a demand exists for shipping LNG by rail, and that rail shipments of LNG can be both competitive and complementary to the truck and pipeline networks. Since railroads have unique advantages and disadvantages compared to trucks, and the public safety implications are not fully developed, risk assessments provide additional insight into the shipment of LNG by rail.

The results of our research indicate that LNG transportation has a good safety record, with minimal maritime, facility, and motor carrier incidents relative to other flammable liquids. In other countries, LNG has been transported safely by rail with no incidents to date. Contributing factors to this safety record include the facts that LNG is not explosive in an uncontained environment, is transported in double-walled containers, and evaporates rapidly when exposed to the atmosphere. Notwithstanding the LNG safety record, it is still important to recognize and plan for LNG risks that do exist.

Developing QRA risk factors and parameters is the first step to modeling LNG transport by motor carrier and by rail. The QRA will help to evaluate the derailment and release probability of LNG rail cars over certain segments of the network, and account for a variety of track and train characteristics. LNG transport by truck does have a successful record; however, understanding truck safety risk factors can help to mitigate or prevent truck crashes and improve LNG motor carrier safety as demand for LNG increases. An LNG risk model can be used to understand the probability and consequences for LNG transportation incidents for both rail and truck delivery. Even though they are treated differently, the underlying event tree analysis approach is the same. When the probability of LNG tank car derailment is understood, better decisions can be made regarding the crashworthiness, placement, and operation of rail cars and the potential consequences from an LNG release due to a derailment. Further study for modeling the probability and consequences of transporting LNG by rail and truck will help decision-makers understand public risks and make informed decisions.

1.0 Introduction

The Pipeline and Hazardous Materials Safety Administration (PHMSA) Office of Hazardous Materials Safety (OHMS) contracted with the Cambridge Systematics Team (CS Team) to assess risk of transporting Liquid Natural Gas (LNG), with an emphasis on rail (LNG Risk Study). In Task 1, the CS Team completed a comprehensive Literature Review. In Task 2, The CS Team developed a Risk Plan. Task 3, identifies the factors and parameters for developing the LNG Risk Model. This report documents the findings and results from all three tasks.

At the outset of the study, CS and PHMSA met on June 29, 2017 to discuss the study scope of work and to review the technical research plan. At this meeting, PHMSA asked CS to determine where LNG would be five years out to determine the domestic and global LNG outlook. On July 17, CS, PHMSA and FRA staff met to review the study scope of work in the context of a recent Risk Study conducted by Exponent, Inc. for the Florida East Coast Railway (FECR). The FECR Report was prepared to support the FECR application to transport LNG by ISO containers (and for propulsion) along a specific transportation corridor (Florida's East Coast) which involved specific risks and potential consequences. FRA said that CS could use a redacted version of this report to help inform the LNG Risk Study. As part of the PHMSA LNG Risk Study, CS agreed to provide a peer review of the rail QRA as part of the Literature Review.

This report outlines LNG supply and demand in the context of overall energy market, including new trends for using LNG for propulsion in the motor carrier, maritime, and rail industries. The CS Team explored how natural gas and LNG are transported throughout the United States, and the relationship between peak shaving facilities, merchant plants, and export facilities. The Study Team also researched accident rates for motor carriers transporting LNG and Liquefied Petroleum Gas (LPG) and outlined LNG handling characteristics.

The overall objective of this project was to examine the risks of transporting LNG by rail, which currently is limited by Federal law. The vast majority of natural gas currently is moved by pipeline, and the U.S has a very developed natural gas pipeline network. Natural gas is increasing in use and replacing other energy sources such as coal and diesel. The low price of natural gas and extensive natural gas pipeline network makes natural gas a very competitive and accessible energy source. Since pipelines are fixed in place and expensive to modify and construct, and the natural gas market is a dynamic market that has changed drastically in the past decade, the dynamic nature of the natural gas market and the fixed pipelines are not always compatible. While pipelines owners make decisions to modify the pipeline network, trucks are available to adapt to the changes in natural gas supply and demand. Railways would also be an adaptable transportation option for trucks, but is limited by current regulations. Railway delivery also is complementary to truck delivery, and both could be used for intermodal delivery of LNG. While LNG by rail has not occurred at a statistically significant level, LPG by rail, and LNG by truck both provide proxies for understanding of the related shipments that have occurred. Since railways have unique pros and cons compared to trucks, and the public safety implications are unknown, a risk assessment provides insight into the shipment of LNG by rail. A full risk assessment of LNG delivery of rail would require a risk model, which is the recommended next phase of this study. When the probability of LNG tank car derailment is understood, better decisions can be made regarding the crashworthiness, placement, and operation of rail cars and the potential consequences from an LNG release due to a derailment.

1.1 Organization of the Report

Section 2.0 describes natural gas pipeline network, natural gas facilities, natural gas markets and U.S. natural gas demand. Section 3.0 describes the LNG outlook and emerging markets. This includes the LNG export market, other emerging LNG fuel uses for high horsepower engine applications in the marine, rail and mining sectors. Section 4.0 evaluates the LNG supply chain, including truck and rail applications. Included in this section is a description of LNG facilities, transportation and economics. Section 5.0 explains the quantitative risk assessment background and context. Section 6.0 provides the QRA methodology, event chain analysis and the parameters and factors that would be used in the LNG Risk Model. Finally, Section 7.0 describes risks of motor carrier LNG transport, including risk factors, and an analysis of LNG versus LPG carriers. Section 8.0 is the conclusion.

Appendix A provides a list of acronyms used in the report. Appendix B is the Bibliography. Appendix C describes the regulatory framework of natural gas transport. Appendix D examines the chemical properties of natural gas and handling of LNG. Appendix E covers aspects of LNG facilities not covered in the body of the report and Appendix F describes cryogenic tank cars, cargo tanks, and portable containers.

2.0 Natural Gas Background

Natural gas is a mixture of several hydrocarbon gases. Although natural gas' main constituent is methane, natural gas can also contain ethane, propane, and butane, as well as other gases such as carbon dioxide, oxygen, and hydrogen sulfide. Natural gas is often described as being "dry" or "wet." Dry gas is principally methane, whereas wet gas contains more of the heavier hydrocarbons, such as ethane, propane, and butane. These heavier hydrocarbons are commonly referred to as natural gas liquids (NGLs).[4] Excess NGLs are usually separated from the gas stream prior to distribution, near the production site at gas-processing facilities. The dry natural gas is then transported under pressure by transmission pipelines directly to large industrial users, power plants, and gas distribution systems. The NGL stream is usually transported by pipeline to fractionator plants that separate the stream for other purposes. NGLs also are used as refrigerants in natural gas liquefaction processes.

Natural gas is essentially a fungible product. In principal, any region connected to the natural gas transmission pipeline network has access to natural gas from across the country.

Liquefied natural gas (LNG) is simply natural gas that has been cooled into a liquid. In many cases, some trace constituents of natural gas are removed before, or as part of, liquefaction. As an extremely cold liquid, at ambient pressure, LNG is a cryogenic liquid. Most sources note a liquefaction temperature of −260°F, which corresponds to methane's ambient pressure boiling point of −258.68° F. Cooling natural gas requires energy and a specialized facility, and the liquefaction process increases the upfront costs of producing LNG.

Natural gas is stored in enormous underground caverns such as depleted oil fields or salt caverns. In its gaseous state, the natural gas requires 600 times more space than in its liquid form. Pipelines are the most effective way to transport natural gas, however, when it is not possible to use pipelines to move the natural gas, or when static storage of natural gas is important, liquefaction increases the density of the natural gas by 600 times. This increased density is more suited to storage and transportation, and is LNG's principal advantage over the gaseous form. LNG is stored and transported in cryogenic tanks. When LNG is re-gasified, the LNG is warmed until the liquid converts back into the gaseous state. The gas is then transferred to a specific facility or to regional distribution pipeline networks. More information on the chemistry of natural gas is provided in Appendix E.

Natural gas is an open market that has recently changed drastically. Natural gas has always been an attractive fuel and has become an important part of the economy in the United States, over the past decade, oil prices initially increased and as the horizontal drilling technology expanded the scope of proven fossil fuel reserves, greater amounts of natural gas became available in North America.[5] While the U.S. is still a net importer of natural gas, the net amount imported has decreased dramatically in recent years. The U.S. may become a net exporter in the near future.[6] And, overall, while LNG currently represents a small fraction of the total gas utilization in the U.S., there is increasing interest in the use of LNG for importing low-cost natural gas, for exporting U.S. natural gas to locations where the cost of natural gas is high, and for utilizing stranded gas.[7]

[4] EIA now uses the term hydrocarbon gas liquids, or HGL.

[5] Energy Information Administration, "Natural Gas Explained."

[6] Energy Information Administration, "Natural Gas Imports and Exports."

[7] For more information on LNG's properties, consult the "Resources on the Properties of Liquefied Natural Gas" section of Appendix B.

(Footnote continued on next page...)

Natural gas accounts for about one third of U.S. energy consumption.[8] More than half of U.S. homes use natural gas as their main heating source. Natural gas also is used to produce electricity in about 30 percent of the country's power plants and natural gas is an important heating fuel for numerous manufacturing processes, including steel, glass, and paper production.

2.1 Natural Gas Pipeline Network

The U.S. has a very developed natural gas pipeline network. There is an extensive natural gas pipeline network in North America for the transmission and distribution to users of natural gas. This network comprises more than 210 natural gas pipeline systems, including 305,000 miles of Interstate and Intrastate transmission pipelines.[9] About two dozen companies operate systems of 1,000 miles or more, and together own 80 percent of the network.

This pipeline network is densest on the Gulf Coast, as the region accounts for nearly 25 percent of the country's transmission pipeline mileage. The network is likewise dense in the Texas panhandle and Oklahoma region, where there are additional oil/gas recovery fields. Because of the central location and large industrial and residential demand of the Midwest, the area also has a dense network of gas transmission pipelines. The Great Lakes States of Illinois, Indiana, Michigan, Ohio, and Pennsylvania account for nearly 25 percent of total line mileage.

As shown in Figure 2.1, the country's natural gas transmission network consists of 300,000 miles of pipeline in the United States, including about 4,000 offshore miles. About two dozen companies own 80 percent of this mileage—with each company operating systems that contain 1,000 miles or more. The natural gas network is densest on the Gulf Coast, as the large gas-producing and gas-consuming States of Louisiana and Texas account for nearly 25 percent of the country's transmission pipeline mileage. Because of its central location and large industrial and residential demand, the Midwest also has a dense network of gas transmission pipelines. The Great Lakes States of Illinois, Indiana, Michigan, Ohio, and Pennsylvania account for nearly 25 percent of total line mileage. In recent years, transmission pipelines have been built to provide natural gas to regions that were once underserved, especially New York and New England.

As shown in Figure 2.1, the country's natural gas transmission network consists of more than 210 natural gas pipeline systems which includes 305,000 miles of Interstate and Intrastate transmission pipelines.[10] It is one of the most extensive pipeline networks in the world. About two dozen companies own 80 percent of this mileage—with each company operating systems that contain 1,000 miles or more. The natural gas network is densest on the Gulf Coast, as the large gas-producing and gas-consuming States of Louisiana and Texas account for nearly 25 percent of the country's transmission pipeline mileage. Because of its central location and large industrial and residential demand, the Midwest also has a dense network of gas transmission pipelines. The Great Lakes States of Illinois, Indiana, Michigan, Ohio, and Pennsylvania account for nearly 25 percent of total line mileage. In recent years, transmission pipelines have been built to provide natural gas to regions that were once underserved, especially New York and New England. Pipeline reversals also are common, as the net-demand regions become net-supply regions, and vice versa.

The majority of natural gas is moved by pipeline, the principal and the most cost-effective means of transporting natural gas domestically. However, there are drawbacks to the pipeline network. In recent years,

8 Energy Information Administration, "U.S. Energy Facts Explained."

9 Ibid., "U.S. Energy Facts Explained."

10 Ibid., "U.S. Energy Facts Explained."

transmission pipelines have been built to provide natural gas to regions that were once underserved, especially New York and New England. Pipeline reversals have also increased, as the net-demand regions become net-supply regions, and vice versa.

These drawbacks to pipeline transport are not compatible with the dynamic natural gas market.

Despite the extensive natural gas pipeline network shown in Figure 2.1, underserved regions remain, such as parts of New England, and the western U.S. Pipeline directionality also is important. Built at different times throughout the past century, some of the pipelines were built to function in only one direction. Underserved regions and pipelines that now run counter to supply and demand, are important because they create natural gas supply and demand imbalances that cannot be met with pipeline transmission. These create a need for alternative transportation, such as surface transport of LNG.

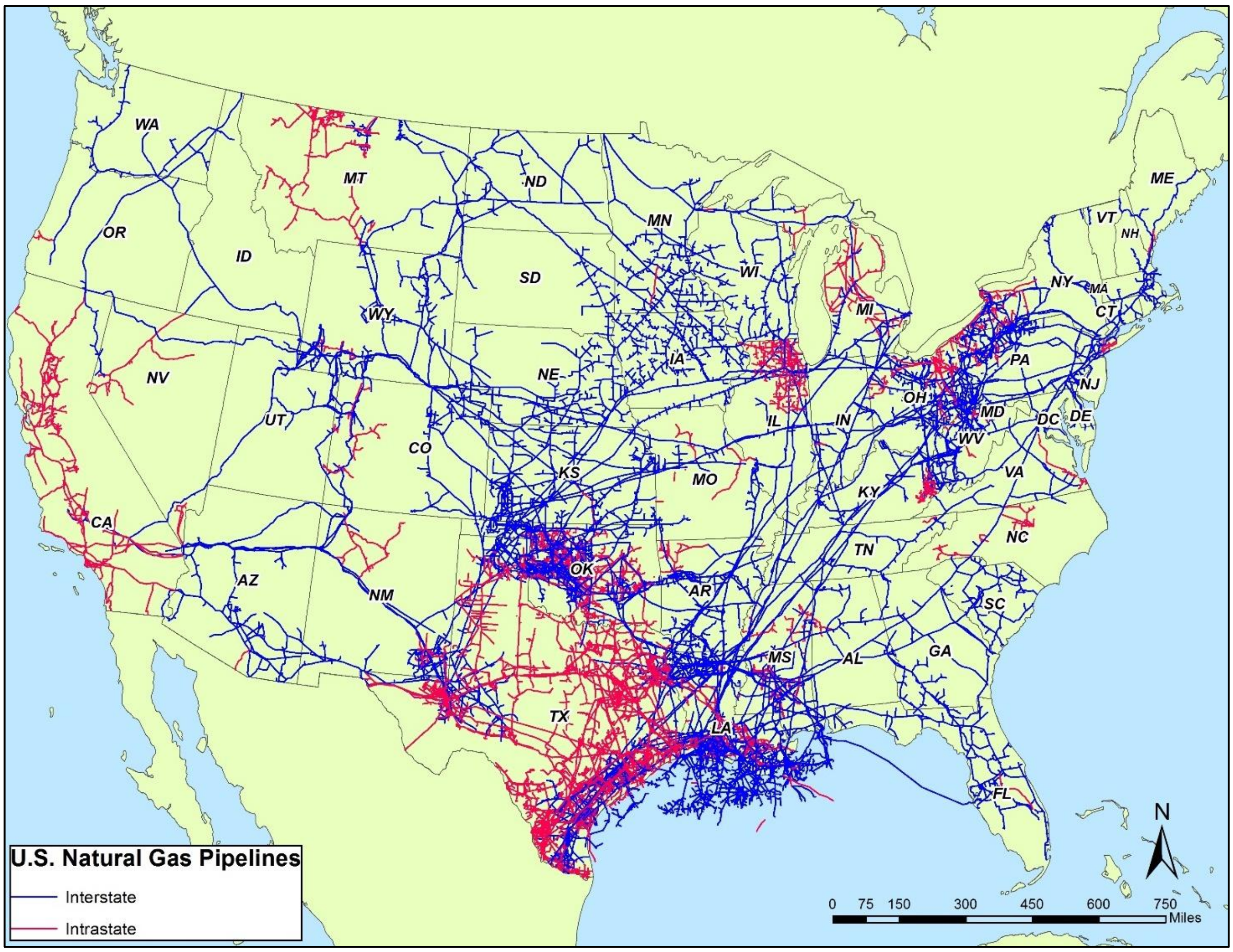

Figure 2.1 U.S. Natural Gas Pipeline Network

Source: Energy Information Administration; Cambridge Systematics, Inc.

The primary networks used in the commodity flow framework will be the North American natural gas pipelines, railroads, waterways and highways. Often referred to as the "midstream" portion of the energy supply chain, pipelines, railroads, waterways and highways move natural gas, natural gas liquids, other fuels in bulk quantities from "upstream" production and processing facilities to distant "downstream" locations, where the shipments are refined, stored, and/or delivered to end customers by barge, truck, or pipeline.

Despite the extensiveness of the pipelines in the U.S. there are areas that are underserved, such as parts of New England, and the western U.S. Also important to note is the directionality of some of the pipelines. Built at different times throughout the past century, some of the pipelines were built to function in only one direction. The recent changes in the shale revolution have resulted in efforts to reverse certain pipelines to meet new natural gas demands. The limit of a one-way capacity is mostly felt in the Appalachian region, where natural gas produced from the Utica and Marcellus shelves have pipeline capacity that is limited by pipelines that are one way between the southeast and the Midwest regions. The disparity of pipeline capacity between regions of production and demand has spurred the need for additional transportation whether it comes in the form of additional pipelines or liquefying for shipment as LNG by truck.

Natural gas is sold as a fungible product. Therefore, any region connected to the Interstate pipeline network has access to natural gas across the country. Areas not served by pipelines need to transport natural gas from a point of supply with a surface mode such as truck or rail. Natural gas on the market is replaceable by any other natural gas product, and the point of supply can be any number of places regardless to the location of the natural gas seller. The point of supply could be any place connected to the seller such as a natural gas hub or center, a natural gas processing plant, or a LNG peak shaver. Any non-pipeline movements will require liquefaction of the natural gas, and efficient liquefaction of natural gas uses cryogenic turbines that are most economical when liquefying a large amount of product. For these reasons, LNG is usually produced at a limited number of liquefaction facilities. Gasification is much easier and simpler to accomplish than liquefaction.

The volumes of natural gas being produced in some regions, like the Utica/Marcellus, do not align with the outbound pipeline capacity. Pipelines are the first and ideal method to transport natural gas, and it is the inability to utilize the pipeline system that requires other transport modes—whether that underutilization is by lack of access, or capacity.

2.2 Natural Gas Supply

In the past five years, U.S. natural gas supply has increased significantly due to the prolific production efforts in the Permian Basin in Texas, and the Marcellus and Utica Shale Plays located in Western Pennsylvania, Southern Ohio and West Virginia. Once natural gas is extracted from shale gas regions in the U.S., the gas is transported to processing plants that convert the raw gas to natural gas suitable for use either in transmission pipelines, or for liquefaction to prepare LNG.

Once the natural gas is liquefied, the liquefaction facilities, LNG merchant operators, and gas processing plants become the suppliers of LNG. On the demand side, power generation plants, pipeline stations, remote operations requiring fuel (such as manufacturing plants, petroleum exploration, mining) and LNG fuel facilities (truck, rail, maritime) all need LNG. Remote operations are those that are not connected to a natural gas pipeline network.

Natural gas processing details vary, depending upon the raw gas, but in general, natural gas processing will remove sulfur containing contaminants, condensable liquids, e.g., water, NGLs, LPGs; carbon dioxide and inert gases, e.g., nitrogen, argon; and important contaminants, e.g., radon.

U.S. natural gas processing plants are located in the shale oil and gas regions (Figure 2.2), including the Gulf Coast; parts of Utah, Wyoming, Colorado, Oklahoma, Michigan; and North Dakota; and the Marcellus/

Utica Shale Region, including Pennsylvania, Ohio, and West Virginia. The most significant growth in recent years has occurred in the Marcellus/Utica and Eagle Ford Shale plays. While the U.S. natural gas pipeline network extends to most of the lower 48 States, there are still areas in the U.S. that are isolated from this network, or have more demand for natural gas than the pipeline network can supply. The most prominent example is New England, where natural gas is primarily imported as LNG and transported by truck to peak shaving storage facilities.

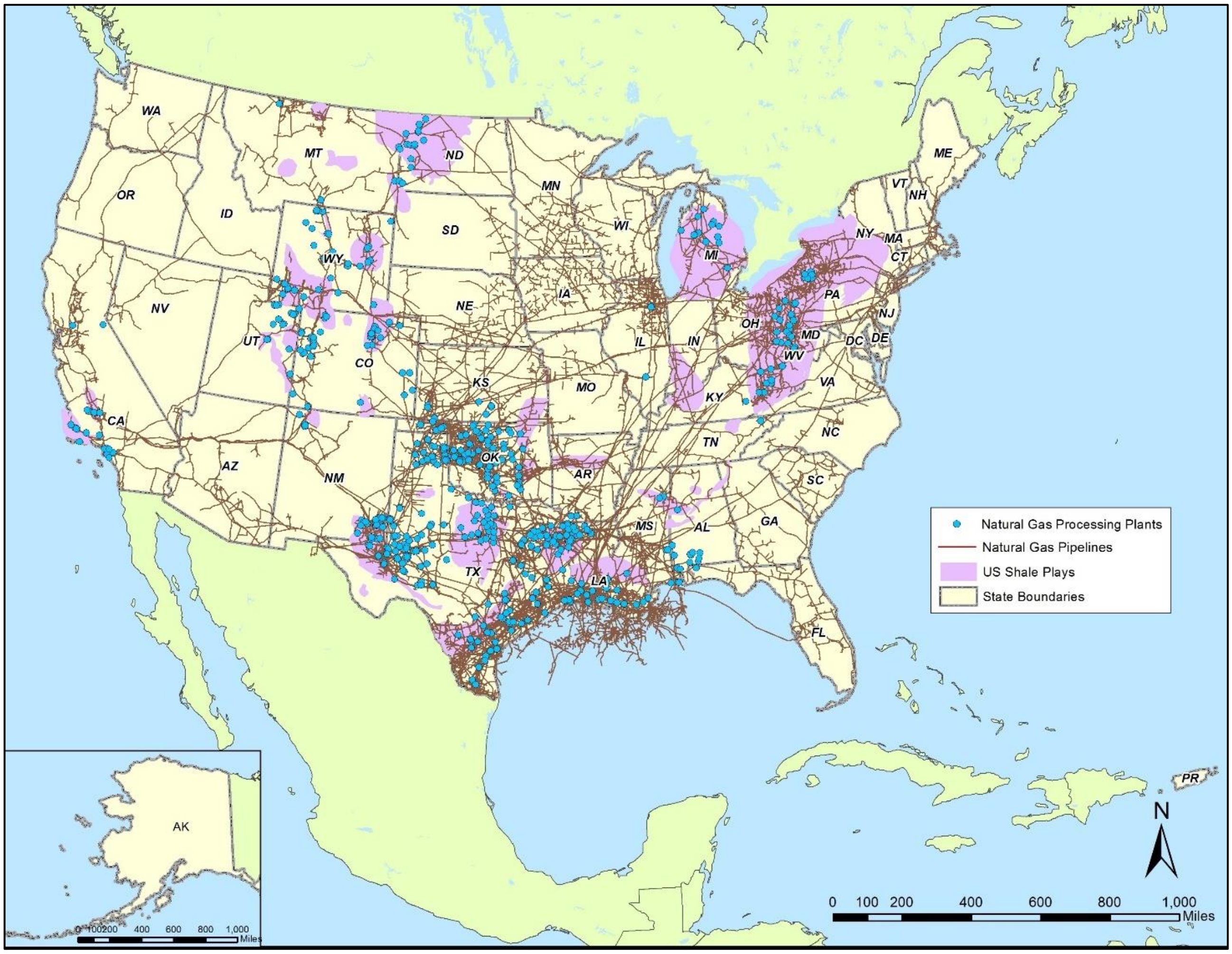

Figure 2.2 U.S. Natural Gas Processing Plants and U.S. Pipeline Network

Source: Energy Information Administration.

Most processing plants are located in States where natural gas wells are located. In 2016, there were 11 States with more than 10,000 gas wells, as listed in Table 2.1. Texas has more than twice as many gas producing wells than any other State. Other high producing gas States include Pennsylvania, Oklahoma, West Virginia, and Colorado.

Table 2.1 U.S. Top 11 Gas Producing States

2016

State	Gas Wells
Texas	133,767
Pennsylvania	66,304
Oklahoma	47,831
West Virginia	46,427
Colorado	45,903
New Mexico	40,535
Ohio	27,403
Wyoming	23,694
Kansas	23,389
Kentucky	18,246
Louisiana	17,760

Source: Energy Information Administration, "Annual Report 2016."

These processing plants are where the natural gas liquids are removed from the gas—ethane, propane, butane, pentane, and natural gasoline—and the gas is treated for impurities, such as hydrogen sulfide. This prepares the gas for transport as dry natural gas. Dry natural gas is considered to be almost pure methane, which typically has a heat content of 1,035 Btu per cubic feet. Depending on the market differential between any of the NGLs and the price of natural gas, dry natural gas may contain some NGLs, and to assure safe transportation the heat properties of natural gas are often limited to 1,100 Btu per cubic feet. This limits the amount of NGLs in the natural gas to one to two gallons per 1,000 cubic feet of natural gas. After processing, the dry natural gas is fungible.

Other processing plants that conduct "deep processing" also produce LNG as an output of the process. This includes plants that reject nitrogen, recover helium, or recover ethane gases.

Natural gas-fired power generation plants are located throughout the U.S. (Figure 2.3), particularly in more populated areas. This number is increasing as more nuclear power plants retire or convert to natural gas. Figure 2.4 depicts the locations of these plants in relation to the U.S. gas processing plants. Note the proximity of the gas processing plants in the Marcellus Region to the populated area of the Eastern Seaboard. This is resulting in a large number of new gas processing plants and connecting pipelines in this region to supply has to the Northeast.

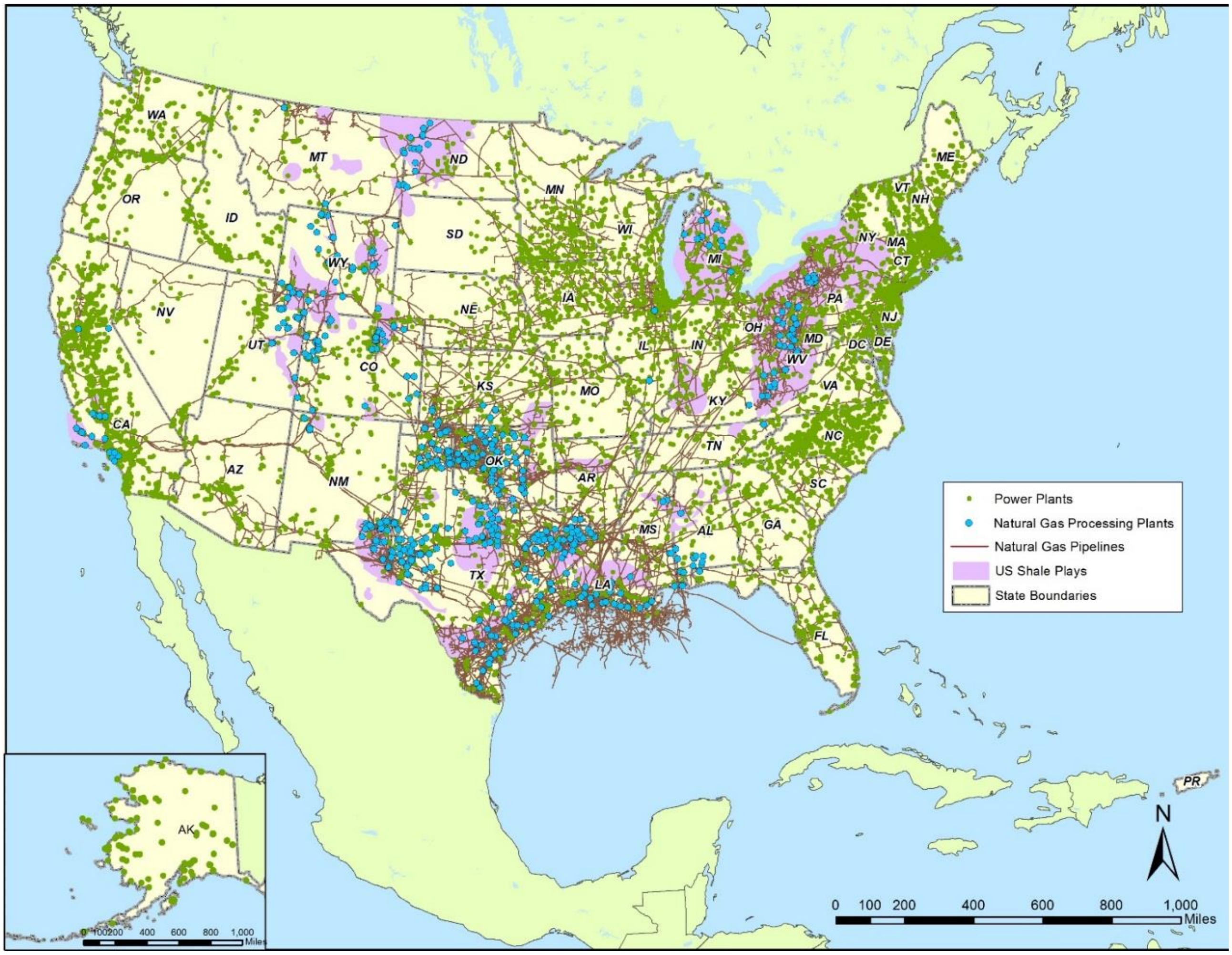

Figure 2.3 U.S. Power Generation and Gas Processing Plants

Source: Energy Information Administration.

There are no gas processing facilities in the Northeast. This is most noticeable in Figure 2.4 where New England is dependent upon other regions for gas processing.

The Northeast region of the U.S. is significant because it has several major population centers that require large amounts of heating fuel during the winter, and high electricity demands in the summer for air conditioning. Figure 2.4 depicts the gas processing facilities in the Northeast. The only gas processing plants in the Northeast are located above the Marcellus and Utica shale plays, while the New England States are devoid of natural gas processing plants.

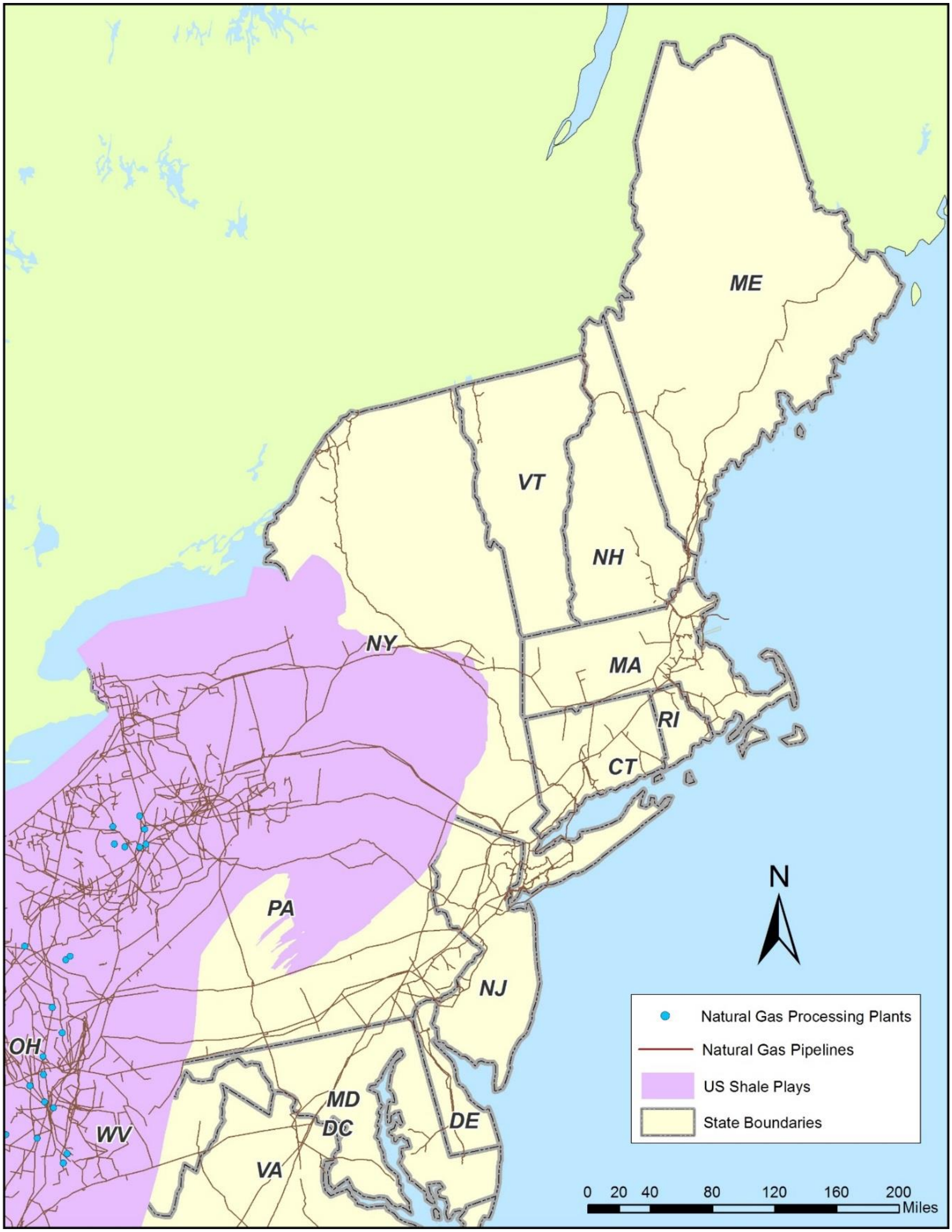

Figure 2.4 Northeast Gas Processing Plants

Source: Energy Information Administration.

2.3 Natural Gas Markets

The pipeline transmission network is a complex mixture of intra and interstate transmission pipelines moving natural gas, and ‘hubs’ that provide physical interconnections for transmission pipelines. Market hubs are centers at which pipelines can trade gas volumes, and transportation can be arranged. Therefore, market hubs play an important role in the pricing and negotiations of natural gas. Hubs also serve as market centers for transactions or to secure transportation and/or storage services. There are over 120 natural gas hubs and market centers in the contiguous United States.[11]

Natural gas hubs and market centers play a role in the pricing and negotiations of natural gas. Between March 2014 and December 2017, the Intercontinental Exchange (ICE) provided price index data of eight natural gas hubs to the EIA for republication.[12] These hubs included: Algonquin (Massachusetts), Tetco M-3 (Pennsylvania), Chicago Citygate (Illinois), Henry Hub (Louisiana), SoCal-Ehrenberg (Arizona), Socal Citygate (California), and Malin (Oregon). Figure 2.5 shows the locations of these hubs.

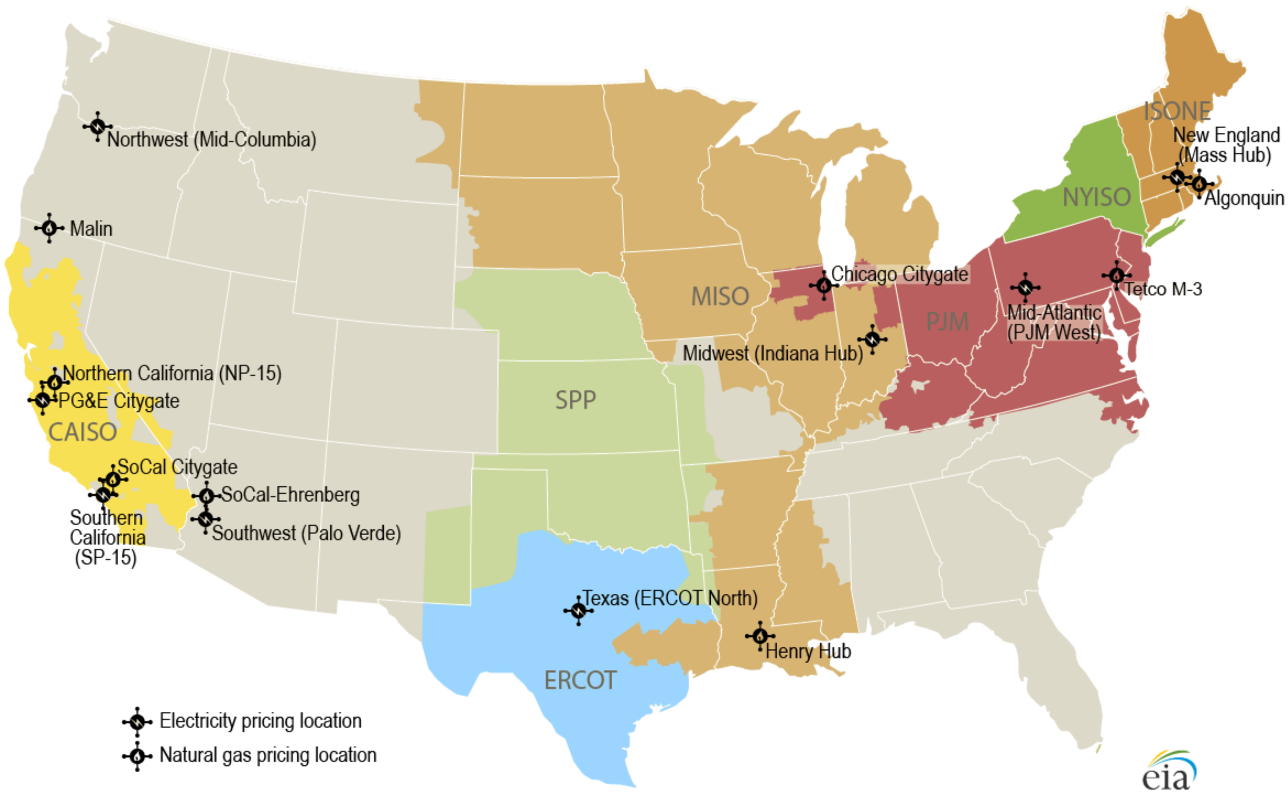

Figure 2.5 Major Natural Gas Hub Locations

Source: Energy Information Administration, “Wholesale Electricity.”

Note: Colored areas denote Regional Transmission Organizations (RTO) and Independent System Operators (ISO).

11 Energy Information Administration, “Wholesale Electricity.”

12 ICE is a major venue for trading natural gas.

2.4 Natural Gas Demand

The low price of natural gas and its expansive natural gas pipeline network makes natural gas a competitive and accessible energy source. Natural gas is increasing in use and replacing other energy sources. As the natural gas supply has flooded the market, the price has been driven down by oversupply.

The rapid development of domestic energy sources has resulted in significant natural gas production in the United States. In particular, shale oil and gas have been produced in increasing volumes over the past 10 years, due largely to the increased use of new extraction and drilling techniques. This has also resulted in changes in hazmat transportation by motor carrier, rail, pipeline, and barge.

Natural gas consumption is illustrated in Figure 2.6 and serves as an indicator of U.S. demand for natural gas. The leading demand is for power generation, followed by residential, commercial, and industrial uses. Output from hydraulic fracturing sources have grown since 2009 to make up nearly half of the U.S. dry natural gas production by 2014, driven by especially large volumes recovered from the Marcellus basin in Pennsylvania and West Virginia.

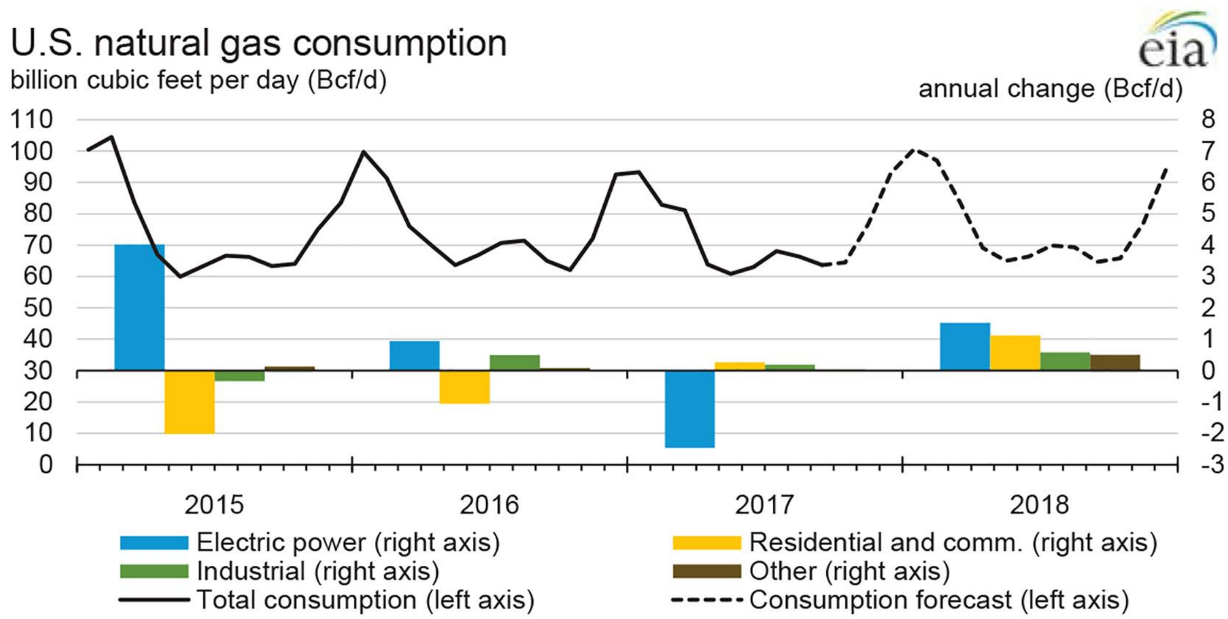

Figure 2.6 U.S. Natural Gas Consumption
2015–2018—Projected

Source: Energy Information Administration.

Other regions of the U.S. will have a role in natural gas demand. For example, gas demand in South Texas will come from consumption from the power, industrial and residential and commercial sectors, and demand from exports to Mexico. Local gas makes up about 2.0 Bcf/d of the total demand in the region. However, overall gas exports to Mexico in 2016 exports increased 0.7 Bcf/d to an average 2.6 Bcf/d. This trend is expected to continue. Significant development is now under way in Mexico’s natural gas-fired combined-cycle power plants, and plans are well underway for an expansive gas pipeline network to serve them.

Crude production is an indicator of gas production, since shale gas is extracted in the same process. Crude production is nearly back up to its peak of 9.6 MMb/d set in April 2015. Dry gas production has been approaching a record 75 Bcf/d, thanks to the Marcellus/Utica shale, as well as associated gas production in crude production regions, such as the Permian and Oklahoma's South Central Oklahoma Oil Province (SCOOP) and Sooner Trend Anadarko Canadian Kingfisher (STACK) shale plays.

As of this writing, market analysts suggest crude oil production is expected to grow even with prices at current levels near $50/bbl for the next five years. This is likely to impact associated gas production, expected to be at 4.0 Bcf/d for each of the next five years, or 9.0 Bcf/d by 2022.

There also is an ongoing trend in the U.S. to convert diesel power generation plants and coal plants to natural gas. This applies to remote utilities, mining and quarrying operations, industrial and manufacturing facilities, asphalt production, commercial food processing and pulp and paper plants. This is happening despite current oil prices suggesting this trend to switch to natural gas fuel will continue.

Power generation from gas power plants is expected to increase from approximately 26 Bcf/d this year to about 28.6 Bcf/d in 2022. That number will be higher if gas prices are lower, particularly relative to coal. That is almost 3.0 Bcf/d higher than this year, but compared to last year when gas prices were even lower, it is up only about 1.0 Bcf/d. Altogether, between exports and gas-fired generation, industry analysts predict just over 13 Bcf/d of new gas demand by 2022. This increase in natural gas supply is due mostly to the prolific production efforts in the Marcellus and Utica Shale Plays located in Western Pennsylvania, Southern Ohio and West Virginia. The northeast region for natural gas production is expected to increase 43 percent from 2017 to 2027.[13]

The most significant growth for natural gas production is occurring in the New England and Mid-Atlantic States, two projects adding up to 0.65 Bcf/d are planned for the Canadian corridor and four projects totaling 4.3 Bcf/d to the Midwest via Ohio and four projects with a combined 5.2 Bcf/d to the Southeast along the Atlantic Coast are under development.[14]

South Texas is the other region in the United States supplying natural gas. Approximately 80 percent of regional gas supply comes from the Eagle Ford Shale while the other 20 percent comes from non-shale drilling activity. Since incremental production will almost entirely come from the shale side, the Eagle Ford shale play will play an important role in natural gas production.

As nuclear power plant retirements increase, natural gas-fired generation capacity will likely grow (Figure 2.7). The retirement of nuclear power plants creates demand for natural gas, as they are usually replaced by natural gas-fired generation capacity; in addition, the low price of natural gas makes it attractive for new capacity in general. In the past seven years, six nuclear power plants announced their intentions to retire early. The most recent announcement came in May 2017 from Exelon's Three Mile Island power plant in Pennsylvania. These six plants have a current operational capacity of about 7.2 gigawatts (GW) with an average capacity factor of 95 percent. In addition to those retirements, construction of South Carolina Electric and Gas Company's 2.2 GW V.C. Summer power plant was halted in July 2017. While nuclear capacity is expected to decrease in the next eight years by 7.2 Exelon announced builds at natural gas-fired power plants will offset some of the lost capacity.[15]

[13] "Bentek Market Call: North American NGLs."

[14] Braziel, "RBN Blog: Too Many Pipelines?"

[15] Energy Information Administration, *Weekly Natural Gas Trends*. September 28, 2017.

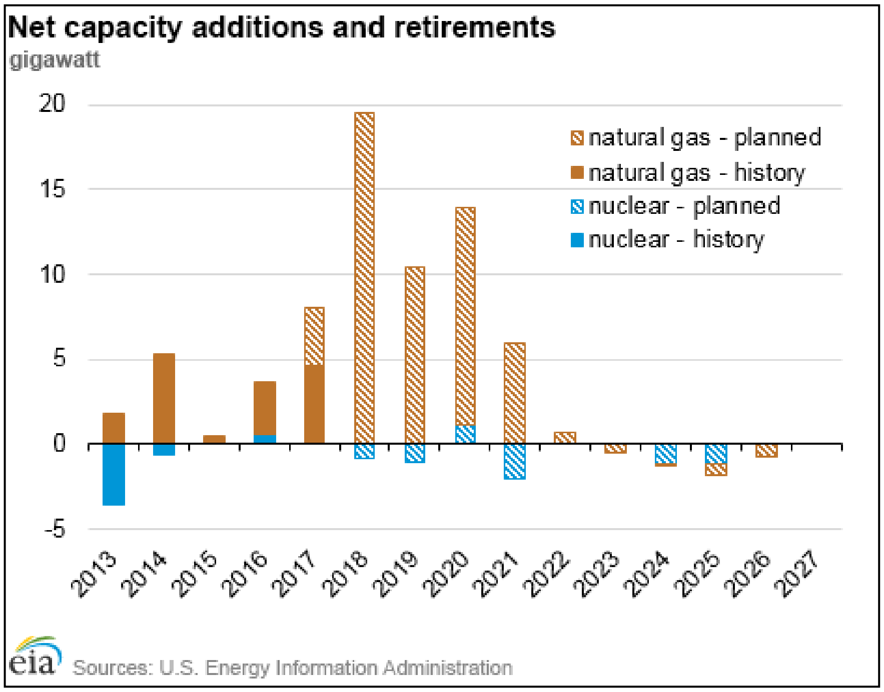

Figure 2.7 U.S. Natural Gas Net Capacity and Additions *2013–2026*

Source: Energy Information Administration.

3.0 LNG Outlook and Emerging Markets

The reason for increased U.S. LNG production and the growing number of fuel and bulk transport opportunities is the domestic availability of shale oil and gas in the U.S., particularly in the Marcellus and Utica shale plays in parts of Ohio, Pennsylvania, and West Virginia. This "energy revolution" has changed both the volume and direction of how hazardous materials are transported in the U.S. by pipeline, rail, motor carrier and ship. We also describe in this report the global and U.S. outlook for LNG to understand how these trends will impact future LNG transportation.

LNG is emerging as a versatile fuel for many purposes in the United States and throughout the World, not just for propulsion and transport, but also for power generation. LNG occupies the world stage, as a growing number of countries are importing and exporting LNG, including the U.S.

Emerging LNG markets are placing additional demand on LNG transportation. These markets include using LNG for remote power generation, and for high horsepower engines in the trucking, maritime and railroad industries. Multiple LNG terminals in the Gulf Coast are being converted from import to export facilities, and with the added liquefaction capacity that became operational in 2017, the U.S. became a net exporter of natural gas.[16] Figure 3.1 shows the growth of U.S. liquefaction capacity expected by 2020. More power generation plants are being supplied by natural gas pipelines as more nuclear and coal power plants retire.

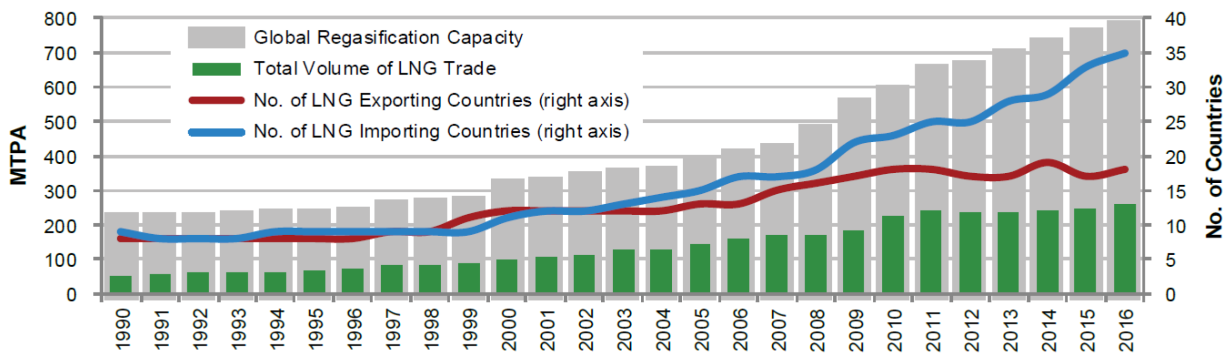

Figure 3.1 Global LNG Trade Volume

1990–2016

Source: IHS Market, IEA, IGU.

The global LNG market continues to expand as countries convert power generation facilities, heavy haul vehicles, vessels and even locomotives to natural gas. The International Gas Union (IGU) reports that 2016 was a record year for global LNG trade with 258 million tonnes (MT) traded. Both regasification capacity and trade volume have been steadily increasing over the last two decades. An increasing number of countries are importing LNG to meet their energy needs. In 2016 LNG trade exceeded 250 million tonnes (MT), as an increasing number of countries imported LNG to meet energy needs. Figure 3.1 shows LNG trade volumes and regasification capacity worldwide in million tonnes per annum (MTPA). The green bars show the total volume of LNG trade, in which the last five years remained constant. The gray bars show global regasification capacity, which has steadily grown for 15 years and is now over 800 MTPA. The number of importing countries (blue trend line) has been steadily increasing since 2000, reaching 35 countries in 2016.

[16] "United States expected to become a net exporter of natural gas this year." Energy Information Administration, August 9, 2017.

The number of exporting countries (red trend line) increased between 2000 and 2010, then remained constant from 2011 to 2016 at between 16 to 20 countries.

Long-term contracts are an indicator of future demand for LNG. For example, MarkWest has secured 100 percent of long-term contracts for the Marcellus Region over the next 11 years and 97 percent for the Utica Region over the next 15 years.[17]

3.1 LNG Imports

Up until recently, LNG has been primarily imported to the U.S. and used for heating and power generation purposes. LNG imports serve areas of the U.S. not well served by the natural gas pipeline network, including New England.

The top five countries importing LNG in 2016 were Japan, South Korea, China, India, and Taiwan. Japan leads by a wide margin, importing nearly one-third of global imports. The Figure 3.2 and Table 3.1 list the volume and market share for the top LNG importing countries.

However, many of these LNG import facilities are being recommissioned as export facilities. In addition, LNG is being used as a fuel for a growing number of sectors, including maritime, rail, motor carrier, mining, oil and gas production, and other "heavy haul" transportation applications.

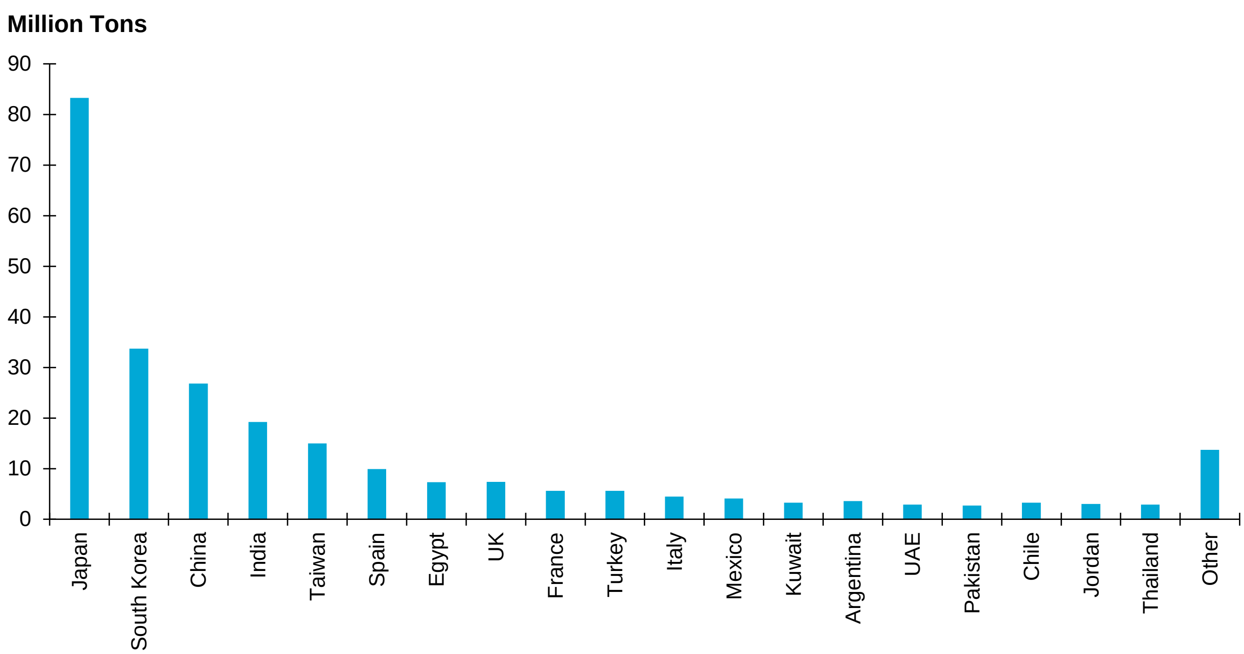

Figure 3.2 Top LNG Importing Countries

Source: International Gas Union World LNG Report, 2017 Edition

[17] Markwest Annual Report 2015.

Table 3.1 Top LNG Import Countries and Volumes

Country	Volume (MT)	Market Share
Japan	83.3	32.3%
South Korea	33.7	13.1%
China	26.8	10.4%
India	19.2	7.4%
Taiwan	15.0	5.8%
Spain	9.9	3.8%
Egypt	7.3	2.8%
UK	7.4	2.9%
France	5.6	2.2%
Turkey	5.6	2.2%
Italy	4.5	1.8%
Mexico	4.1	1.6%
Kuwait	3.3	1.3%
Argentina	3.6	1.4%
UAE	2.9	1.1%
Pakistan	2.7	1.0%
Chile	3.3	1.3%
Jordan	3.0	1.2%
Thailand	2.9	1.1%
Other	13.7	5.3%

Source: International Gas Union World LNG Report, 2017 Edition.

3.2 LNG Exports

LNG exports also contribute to U.S. demand for LNG. Historically, LNG has been imported since the 1970s, but is now being exported in growing volumes. Multiple LNG terminals in the Gulf Coast are being converted from import to export facilities, and with the added liquefaction capacity that became operational in 2017, the U.S. became a net exporter of natural gas.

The EIA stated in their August 9, 2017 article that “The United States’ status as a net exporter is expected to continue past 2018 because of growing U.S. natural gas exports to Mexico, declining pipeline imports from Canada, and increasing LNG exports.” The EIA expects that exports of LNG will continue to increase as liquefaction capacity is added. Figure 3.3 shows the growth of U.S. liquefaction capacity expected by 2020.

Exporting liquefied natural gas is a relatively new phenomenon for the United States. In fact, only one facility in the U.S. currently is operational in Sabine Pass, LA. A common feature of the approved export terminals is that they have all previously been importers of LNG. While the facilities needed to export LNG differ from those needed to import LNG, much of the needed infrastructure already is in place at the existing import facilities. As a result, companies that already have LNG import operations are at a significant advantage in becoming an exporter of LNG.

Cheniere's Sabine Pass liquefaction terminal in Louisiana has seen more cargoes depart the facility in the week ending October 13, 2017. Five vessels with a combined LNG-carrying capacity of 18.4 billion cubic feet (Bcf) have departed the plant since October 4, 2017.[18] This compares to three vessels with a capacity of 11.2 Bcf the week before. Natural gas pipeline deliveries to Sabine Pass averaged 2.8 Bcf/d for the week ending October 13, up 0.8 Bcf from the previous week.

In the near future, plans are shaping up for more LNG exports at five new facilities on the Gulf and East Coasts, summarized in Figure 3.3. Cheniere Energy's Sabine Pass terminal now has four trains producing 2.0 Bcf/d as of 2017. With the start-up of train four in 2017, total deliveries have increased to nearly 3.0 Bcf/d. Cove Point, MD began operations in early 2018, and Cameron LNG, expected to complete the first of three trains by August 2018, a capacity of 2.1 Bcf/d by late 2019 as the second and third trains are constructed. The Elba Island, GA, liquefaction project adds 0.2 Bcf/d by August 2018 and increase to 0.35 Bcf/d by early 2019. Freeport LNG is expected to start one train of 0.67 Bcf/d by November 2018, and increase to 2.0 Bcf/d as trains two and three come online by late 2019. Finally, Cheniere's Corpus Christi LNG will add two trains totaling 2.1 Bcf/d by mid-2019. South Texas is poised to emerge as a premium destination for growing U.S. gas supply over the next few years, driven by demand from new LNG export capacity along the Texas Gulf Coast, as well as power and industrial demand in Mexico.

Therefore, by the end of 2019, it is possible that the U.S. will have reached nearly 11 Bcf/d of LNG export capacity.

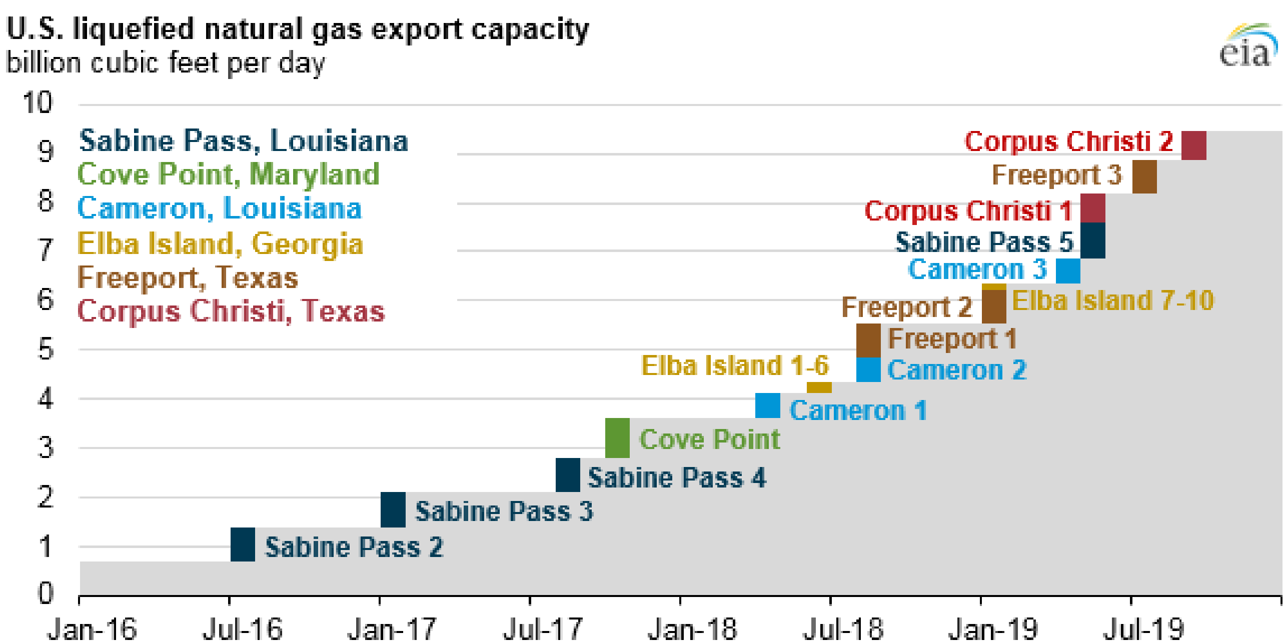

Figure 3.3 LNG Export Demand Growth

Source: U.S. Energy Information Administration, compiled from trade press.

18 Energy Information Administration, October 2017.

The proposed LNG growth from export terminals is expected to exceed 10 bcf/d by the year 2020. Figure 3.4 and Table 3.2 compare the growth of LNG liquefaction capacity with the growth of LNG exports between 2016 and 2017. Any percent of this liquefaction growth not used for the export market may be available for the domestic LNG merchant market. Therefore, there may be opportunities to transport a small percentage of LNG from these export facilities to power generation plants, mining operations, LNG fuel operations and other LNG demand markets.

The top five LNG exporting countries in 2016 were Qatar, Australia, Malaysia, Nigeria, and Indonesia. Qatar is the source of nearly one-third of LNG exports worldwide. The figure and table below list export volume for all 18 LNG exporting countries.

Like with LNG, exports to Mexico also have experienced a boom in the past couple of years, driven by a growing imbalance of supply and demand in Mexico. Delivery capacity to Mexico is expected to grow to over 6.0 Bcf/d by 2022. Additional pipeline projects add 3.1 Bcf/d of capacity into Mexico and is expected to reach 8.0 Bcf/d in 2022. Mexico can be the home for some incremental U.S. production, but not nearly as much as expansion projects suggest.[19]

The Caribbean islands and Hawaii have relied on natural gas, imported as LNG, for years as these islands do not have native fossil fuel resources. Other remote regions include areas of the U.S. not served by the natural gas pipeline network (examples include power plants for the Jamaica Public Service Company, Yukon Energy, and Hawaiian Electric; also boiler fuel for Coca-Cola Puerto Rico Bottlers). The Interior Energy Project will bring increased natural gas to Fairbanks and Interior Alaska. The Alaska Railroad has operated a pilot program to transport LNG by rail for this project. Outside the U.S., examples include remote power for the Pueblo Viejo Mine, and more.

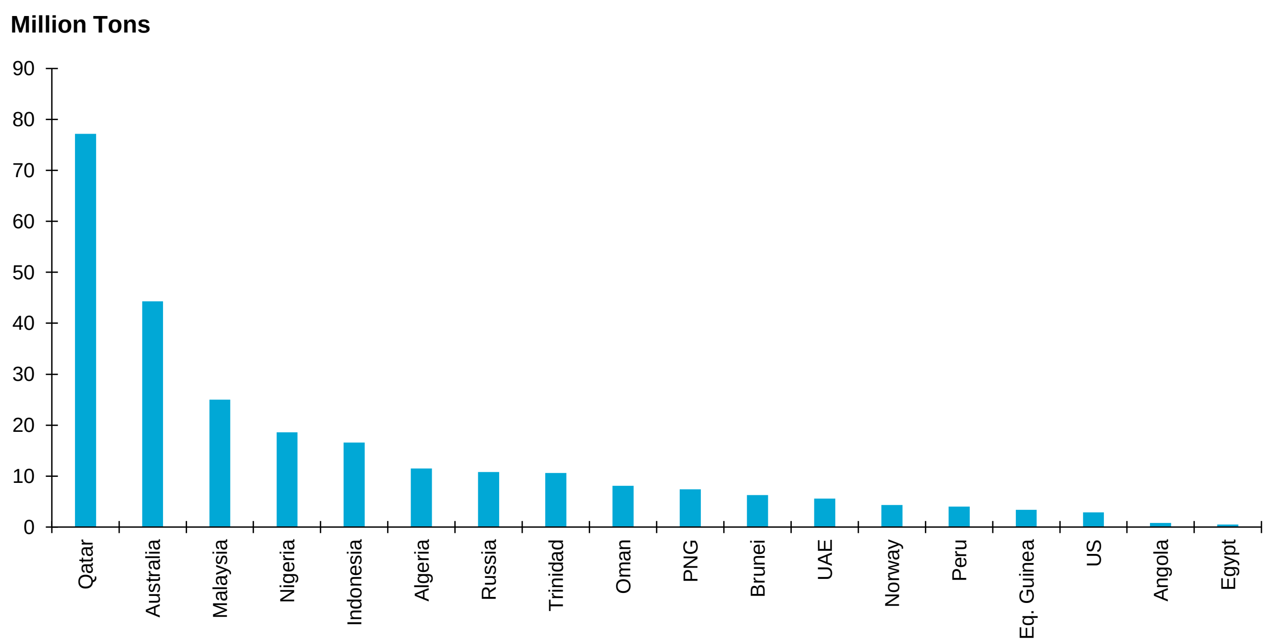

Figure 3.4 Top LNG Export Countries

Source: International Gas Union World LNG Report, 2017 Edition.

[19] Braziel, "RBN Daily Blog October 2017."

Table 3.2 LNG Exporting Countries and Volumes

Country	Volume (MT)	Market Share
Qatar	77.2	29.9%
Australia	44.3	17.2%
Malaysia	25	9.7%
Nigeria	18.6	7.2%
Indonesia	16.6	6.4%
Algeria	11.5	4.5%
Russia	10.8	4.2%
Trinidad	10.6	4.1%
Oman	8.1	3.2%
PNG	7.4	2.9%
Brunei	6.3	2.4%
UAE	5.6	2.2%
Norway	4.3	1.7%
Peru	4	1.6%
Eq. Guinea	3.4	1.3%
U.S.	2.9	1.1%
Angola	0.8	0.3%
Egypt	0.5	0.2%

Source: International Gas Union World LNG Report, 2017 Edition.

The Caribbean islands and Hawaii have relied on natural gas for years, and that trend is likely to continue, since these islands do not have their own natural resources. Other remote regions include areas of the U.S. not served by the natural gas pipeline network. For example, Jamaica Public Service Company converted its Old Harbour Power Plant to combined-cycle operations, capable of switching between oil and natural gas. Yukon Energy utilizes LNG to replace diesel for peaking and back-up transmission at its Whitehorse power plant in Canada. Coca-Cola Puerto Rico Bottlers has converted the boilers at its manufacturing plants in Cayey and Cidra to operate on LNG that is being delivered by Crowley's Caribe Energy from Jacksonville, Florida. Hawaiian Electric and the Hawaii Gas Company have committed to importing LNG to replace crude oil and syngas. The Interior Energy Project will bring increasing volumes of natural gas to customers in Fairbanks and Interior Alaska are being served by natural gas through the Interior Energy Project, thereby reducing fuel costs in these remote, off-pipeline communities. The Alaska Railroad has operated a pilot program to transport LNG by rail to reduce costs and improve gas deliverability for this project. In the Dominican Republic, a power plant is being converted to LNG fuel to provide electricity to the Pueblo Viejo Mine. By replacing heavy fuel oil with LNG, this reduces operating costs. The company also plans to convert the fuel supply at its lime kilns to LNG by 2017.

3.3 Emerging LNG Applications

Emerging LNG markets are placing additional demand on LNG transportation. These markets include using LNG for remote power generation, and for high horsepower engines in the trucking, maritime, and railroad industries. As LNG fuel demand increases, the transportation impact across the U.S. also increases. In our outreach efforts with the North American railroads, we learned there is a demand for LNG in areas with limited or no access to the North American natural gas pipeline network, such as New England, Alaska, parts of the Midwest, Canada, and Mexico. This includes power generation facilities, fueling operations, and remote mining operations. Another emerging area is fueling infrastructure for vessels, including cruise ships, cargo ships, and oil rig support vessels.

3.3.1 Marine LNG Applications

The commercial marine sector has seen growth over the past decade from virtually no LNG-powered commercial marine vessels to 230 units in operation or on order.[20]

The commercial marine sector has seen significant growth and transformative change. In the last 10 years, the global market has gone from virtually no LNG-powered commercial marine vessels to now 230 units in operation or on order, serving a wide range of applications. This significant growth has been witnesses in Europe, Asia, and throughout North America.[21]

3.3.2 Example LNG Vessels

Harvey Gulf International Marine became the first U.S. vessel operator to contract for construction of vessels capable of operating exclusively on natural gas.

Harvey Gulf International Marine became the first U.S. vessel operator to contract for construction of vessels capable of operating exclusively on natural gas.

In addition to being powered by cleaner burning natural gas, the vessels will achieve "ENVIRO+, Green Passport" Certification by the ABS. The requirements for this certification include, among others, that the vessels be continuously manned with a certified Environmental Officer, be completely constructed with certified environmentally friendly materials, and have advanced alarms for fuel tanks and containment systems. Along with Harvey Gulf's other vessels under construction, they will be the first Offshore Support Vessels (OSV) to achieve this certification, making them the most environmental friendly OSV's in Gulf of Mexico.

TOTE Marine has developed LNG operations in use at the Port of Jacksonville, where two vessels are using LNG for fuel. Another example is Crowley Maritime.[22]

TOTE Marine has worked with a number of partners to develop state-of-the-art operations that currently are in use at the Port of Jacksonville. In addition to JAX LNG, TOTE has collaborated with the United States Coast Guard, Sector Jacksonville and the Liquefied Gas Carrier National Center of Expertise; Jacksonville Fire Department, Port of Jacksonville, American Bureau of Shipping; and numerous vendors and trade

[20] Florida East Coast Railway, High Horsepower Summit 2016.

[21] Florida East Coast Railway, High Horsepower Summit 2016.

[22] Crowley Marine, "Liquefied Natural Gas (LNG)."

associations. This collaboration has been central to the success of the truck-to-ship bunkering operations and will play a critical role in the Port's future.

Crowley Maritime will soon homeport two LNG-powered, combination container-roll-on/roll-off ships at JAXPORT's Talleyrand Marine Terminal. The ships, *El Coquí* and *Taíno*, will each have capacity for 2,400 TEUs with additional space for nearly 400 vehicles. In addition, the company also is building North America's first LNG bunker barge, Clean Jacksonville, and provide LNG for vessels calling at Blount Island. Finally, Crowley-owned Carib Energy has already begun small scale exports of LNG to Puerto Rico and has plans for expansion to a number of countries in the Caribbean and Latin America.[23]

Rev LNG received an $800,000 technology innovation award under the Pennsylvania Department of Environmental Protection's Alternative Fuels Incentive Grant Program. The plan is for Rev LNG to make product using gas from local wells. The firm formed Rev LNG Marine for the emerging market for natural gas fueled watercraft. Pennsylvania has ports in Philadelphia, Pittsburgh, and Erie, that serve ocean, river, and Great Lakes vessels.

3.3.3 Rail LNG Applications

North American railroads are actively exploring the use of natural gas-powered locomotives, with new pilot projects and deployments each year. Pilot projects include:

1. North American Railroads (evaluating both GE and Caterpillar gas engines, checking climate tolerance).
2. Indiana Harbor Belt Railroad (Caterpillar dual-fuel CNG-diesel engines and Hexagon Lincoln Type IV CNG tanks).
3. Florida East Coast Rail (24 mainline locomotive converted to LNG gas, and now operating bulk LNG transport).
4. Alaska Rail hauling LNG cargo (via 40-foot long cryogenic ISO tanks) from Anchorage to Fairbanks, Alaska.

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[23] Crowley Marine, "Liquefied Natural Gas (LNG)."

(Footnote continued on next page...)

International railroads also are moving forward with LNG and CNG projects. Russian Railways is working with Gazprom to develop LNG fueling infrastructure to test 40 gas turbine-powered locomotives. Indian Railways is converting existing locomotives to dual-fuel LNG engines and is working with Petronet LNG for fuel supply.[24]

North American Railroads are evaluating both GE and Caterpillar gas engines, while running pilot LNG locomotives across the country to assess their durability in diverse climates. Railroads are exploring both LNG and CNG (compressed natural gas) locomotive fuel options. For example, Indiana Harbor Belt Railroad is converting 21 locomotives to Caterpillar dual-fuel CNG-diesel engines and Hexagon Lincoln Type IV CNG tanks.

Alaska Rail hauled its first LNG cargo in September 2016 using 40-foot long cryogenic ISO tanks from Anchorage to Fairbanks, Alaska. The Florida East Coast Railroad (FECR) is using LNG to fuel locomotives and testing the feasibility of transporting bulk LNG by rail on its Jacksonville to Miami route.

The development of the natural gas market for locomotives is not limited to operations in North America. International railroads are quickly moving forward with LNG and CNG projects of their own. This is spurred by different, and often simpler, regulatory requirements on the transport of natural gas by rail. In June 2016, Russian Railways struck an agreement with Russian gas supplier Gazprom to develop LNG fueling infrastructure at locations approved by Russian Railways to test 40 gas turbine-powered locomotives.

In December 2016, it was announced that Indian Railways will move forward with converting all of its existing locomotives to dual-fuel LNG engines, which will cut diesel consumption by 20 percent. The company has negotiated a long-term deal with Petronet LNG for fuel supply and is retrofitting locomotives with Cummins 1400 HP engines. It is clear from the number and diversity of rail operators looking at natural gas power around the world that this trend may continue as diesel prices rebound.[25]

3.3.4 Mining Applications

The mining sector also includes examples of conversion to natural gas, typically in remote locations, relying upon LNG storage. Examples include:

1. The Renard diamond mine in Quebec, Canada (seven 2.06 MW Caterpillar generators, with fuel supplied by Gaz Metro).
2. Casino Mining Corporation in Yukon and Northwest Territories (A new LNG production plant with 600,000 gallons per day output will be constructed in British Columbia to serve these operations).
3. Barrick Gold in the Dominican Republic (LNG powered electricity for the Pueblo Viejo Mine).
4. Wellgreen Platinum in the Yukon Territory of Canada (GE Jenbacher gas engines with LNG supplied by Ferus).

[24] Dutta, "Railways speeds…"

[25] Indian Infoline News, 2017.

In both the U.S. and Canada, a growing number of LNG projects have been implemented in the mining sector in truck and power generation applications. These investments are a clear sign of the value proposition offered by natural gas in this HHP segment.

Mining LNG examples include Renard Mine, owned by Stornoway, commenced operation on July 15, 2016, with commercial production declared on January 1, 2017. In addition to being the first diamond mine in Quebec, Canada, this project is noteworthy for its massive LNG-fueled power plant. This project was unveiled at the 2015 HHP Summit, and uses seven 2.06 MW Caterpillar generators, with fuel supplied by Gaz Metro.

In September 2016, Ferus Natural Gas Fuels signed an MOU with the Vancouver-based Casino Mining Corporation, to supply LNG to mine projects in the Yukon and Northwest Territories. A new LNG production plant with 600,000 gallons per day of total throughput will be constructed in British Columbia to serve the mining operations. These LNG fueled mining projects will reduce a total of 255,000 tons of CO_2 emissions compared to what would otherwise be diesel-fueled operations.

In the Dominican Republic, Barrick Gold converted the power plant that provides electricity to its Pueblo Viejo Mine to LNG, where it will replace heavy fuel oil to reduce operating costs. The company also plans to convert the fuel supply at its lime kilns to LNG in 2018.

Wellgreen Platinum has deployed GE Jenbacher gas engines for a complete power generation and transmission network operating from a nickel-copper mining project in the Yukon Territory of Canada. Ferus supplies the LNG to power these generators, serving the Yukon communities.

3.3.5 Small Scale LNG Applications

There is a trend toward building small scale LNG facilities throughout the world and the U.S. is no exception. The reason for this trend is primarily economics. Instead of investing billions of dollars in large liquefaction plants, investors prefer instead to start up small operations to test emerging LNG merchant markets, including maritime LNG bunkering, mining operations, energy and production sites, LNG truck fueling operations and remote power generation sites. This trend is accompanied by new liquefaction technologies that include “modular” elements to scale operations according to customer needs.

This small scale LNG market is developing rapidly, especially for transportation fuel and to serve end users in remote areas or not connected to the main pipeline infrastructure.

1. **Production—**“Micro LNG” production plants can produce from 10,000 to 60,000 LNG GPD.
2. **On Road—**Truck and cryogenic trailer, each hauling approximately 9,300 gallons of LNG.
3. **Rail transport on the horizon—**at approximately 30,000 gallons per rail car.
4. **LNG as Marine Fuel—**examples include Harvey Gulf & Tote Maritime using LNG as fuel.
5. Marine transport options also increasing with barges, smaller LNG transport ships and specialized ISO delivery vessels (Figure 3.5).

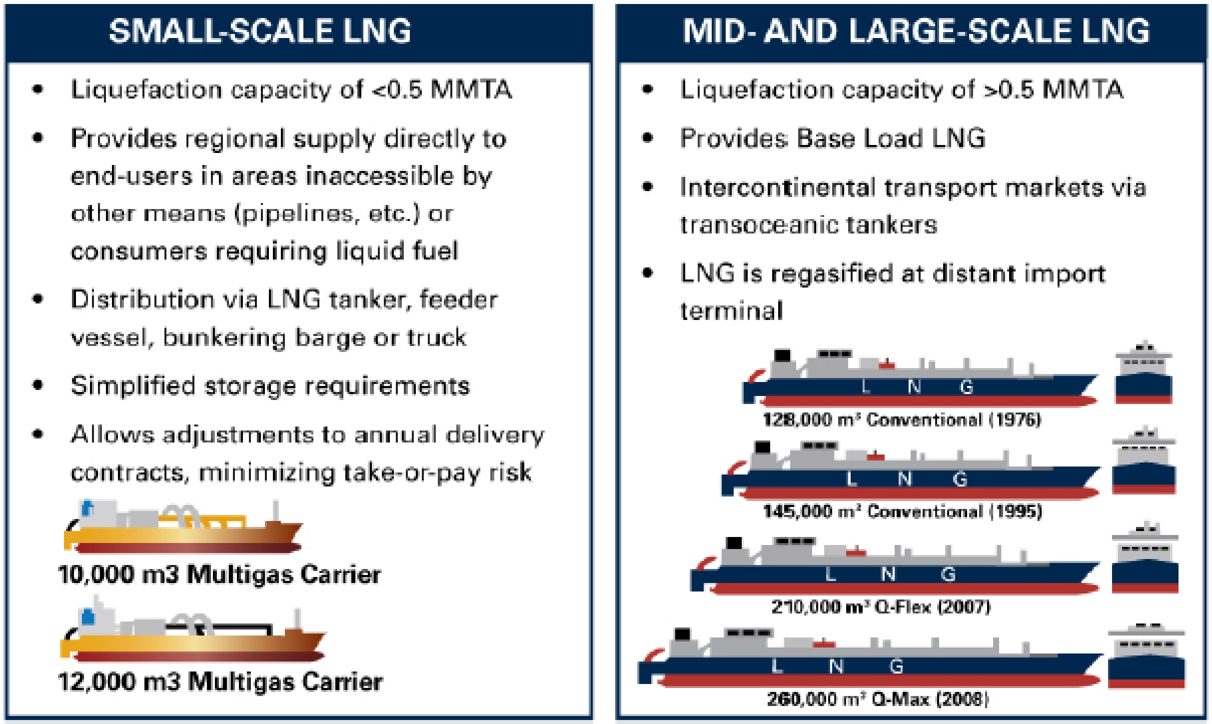

Figure 3.5 Scale of LNG Applications

Source: SSLNG Report, 2015.

4.0 Supply Chain Analysis

During the development of the Risk Plan, the CS Team compiled elements of the movement of natural gas in order to determine potential exposures and risks for different transportation modes. This section describes the supply chain analysis and includes descriptions of the transportation networks, facilities, processing, power generation, movements, and economics of LNG in the context of the changing energy sector in the U.S. We used a commodity-flow framework to describe LNG origins, destinations, and different methods of transport. The networks included in the framework are the highways, pipelines, railroads, and seaports that are used in the transportation of natural gas and LNG; and the facilities included in the framework are those that liquefy, store, and gasify LNG.

4.1 Commodity Flow Framework

The CS Team developed a commodity-flow framework to specify the origins, destinations, and different methods of transport used for LNG. The commodity flow framework includes transportation networks, facilities, transportation flows, and the economics of the evolving U.S. energy sector. Table 4.1 lists the elements of a commodity flow framework that are specific to LNG. LNG requires access to natural gas, liquefaction facilities, and cryogenic containers for transportation and storage.

Table 4.1 Elements of Commodity Flow Framework Specific to LNG Supply Chain

LNG Networks	LNG Facilities	LNG Transportation	LNG Economics
Base load facility supply and demand.	LNG liquefaction facility locations.	Interstate LNG Flows (State to State).	LNG projected import supply.
LNG rail network analysis.	LNG facility storage capacities.	Intrastate LNG Flows (within a State).	LNG projected export demand.
LNG maritime network analysis.	LNG liquefaction capabilities.	Truck trips serving liquefaction facilities.	LNG projected domestic LNG demand.
Projected rail network for LNG transport.		LNG fuel operations and demand.	Peak shaver supply and demand.
Natural gas pipeline network.			
LNG truck network analysis.			

Source: Cambridge Systematics

4.2 LNG Networks

The primary networks used in the commodity flow framework are the North American natural gas pipelines, railroads, waterways and highways. Often referred to as the “midstream” portion of the energy supply chain, pipelines, railroads, waterways and highways move natural gas, natural gas liquids, other fuels in bulk quantities from “upstream” production and processing facilities to distant “downstream” locations, where the shipments are refined, stored, and/or delivered to end customers by barge, truck, or pipeline.

4.2.1 Highway Network

The highway system in the U.S. is most ubiquitous transportation network with roads uniformly distributed across the country. Roads that are a part of the U.S. National Highway System (NHS) are required to be kept in good maintenance, and broadly provide access to locations that are not served by pipelines or rail.

Highways provide flexible access between natural gas processing plants, gas power generation plants, and LNG facilities throughout the U.S. Gas producers rely on the highway network to transport LNG to and from peak shaving facilities, and merchants rely on the highway network to access natural gas and LNG for commercial and industrial operations. (See Figure 4.1).

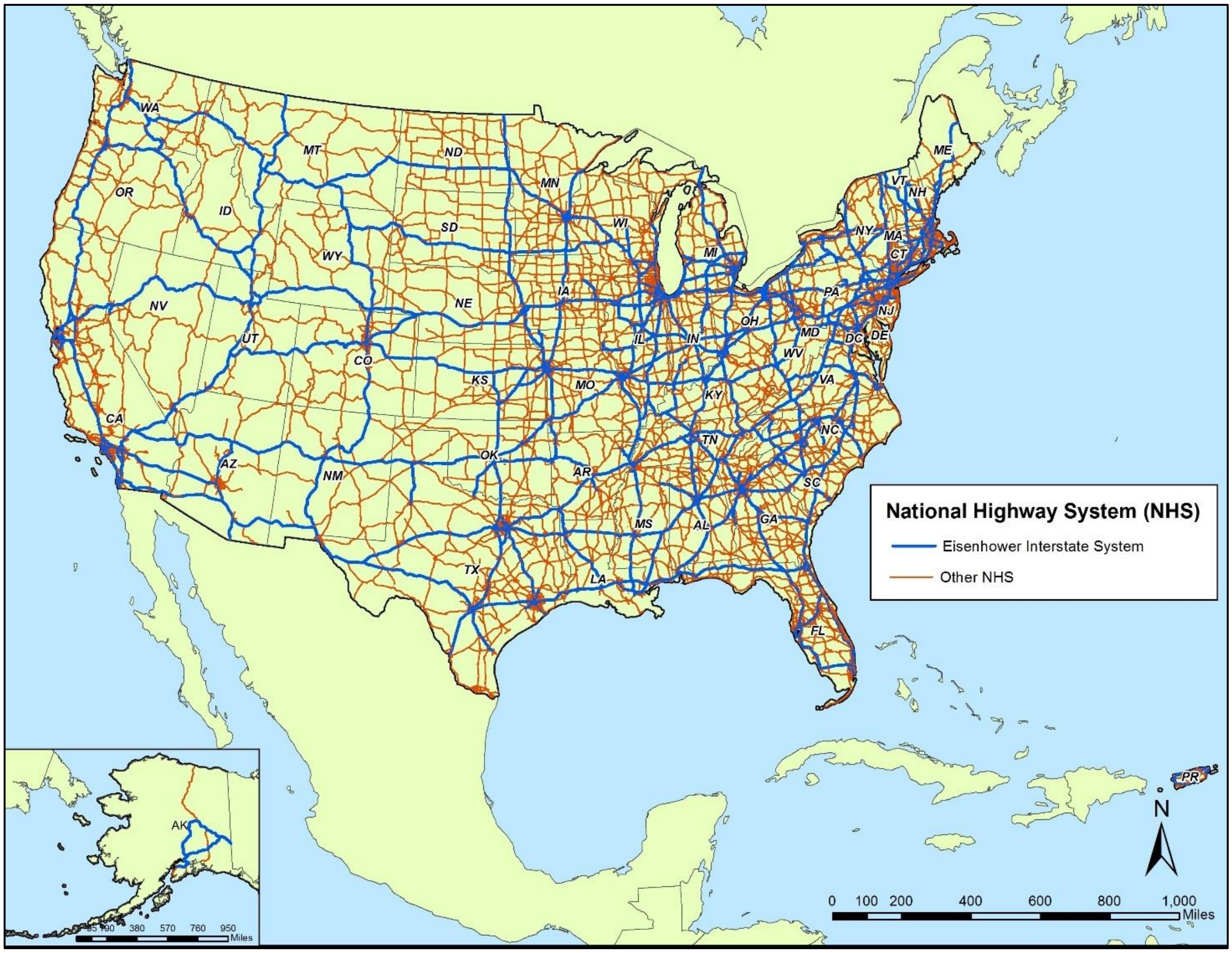

Figure 4.1 U.S. National Highway System

Sources: FHWA Data, November 20, 2017; Cambridge Systematics, Inc.

4.2.2 Freight Rail Network

While LNG currently is not allowed for shipment by rail except by special permit, railroads have historically shipped petroleum and chemicals, including crude oil, ethane, ethylene, and liquid petroleum gases using the extensive North American freight rail network. Because rail transportation is more economical than highway transportation for large quantities over great distances, railroads could be more cost-effective than trucks in circumstances where pipeline service is not sufficient.

Most of the U.S. freight rail system is owned and operated by these four Class I railroads:

- Union Pacific Railroad and BNSF Railway own most of the mainline track west of the Mississippi River.
- CSX Transportation and Norfolk Southern Railway (NS) own most of the track to the east.

The other three Class I railroads include:

- Canadian National Railway (CN) operates in Canada and owns a large number of subsidiary railway companies in the U.S., which operate on several thousand miles of mainline track in the upper Midwest, and the Great Lakes region, as well as southward to the Gulf Coast.
- The Canadian Pacific Railway (CP) also operates in Canada and owns subsidiary railway companies in the U.S. which operate on track in the Midwest and the mid-Atlantic.
- The Kansas City Southern Railway Company operates in the Mississippi Valley on mostly north–south routes, including extensions into Mexico as Kansas City Southern de Mexico.

Collectively, these seven Class I railroads own, operate, and maintain about 162,000 miles of track in the United States. As shown in Figure 4.2 the freight rail network is highly integrated, exchange traffic with one another to provide connectivity to markets across the country allowing service to locations throughout North America. Class I railroads provide long-distance freight transportation and during the past 30 years, they have fundamentally restructured their networks and operations to concentrate traffic on high-capacity trunk lines by using increasingly longer and heavier trains.

Coal has been a low-value/high-volume commodity that has, for years, been a large portion of railroads' unit train services. Unit trains consist of a single commodity such as bulk commodities like grain, coal, and chemicals; and due to the reduced logistics required by the railroads, the shipper receives speedier service. In recent years, coal demand and shipment volumes have reduced the number of unit trains shipped, while commodities like intermodal traffic and manifest trains have increased over the years.[26] Manifest trains are less profitable for the railroads, consist of multiple different commodities and cars, require more sorting and logistics, and have higher operations costs. As Class I railroads have already consolidated their routes to focus on high-density lines and minimize their operation expenses, short-line railroads have begun performing some of the transfer work in terminals. Regional and short line railroads operate more than 40,000 miles of branch-line track to provide feeder service, often for the "last mile" of freight operations in urban areas and U.S. ports.

[26] "Safely Transporting Hazardous Liquids and Gases in a Changing U.S. Energy Landscape."

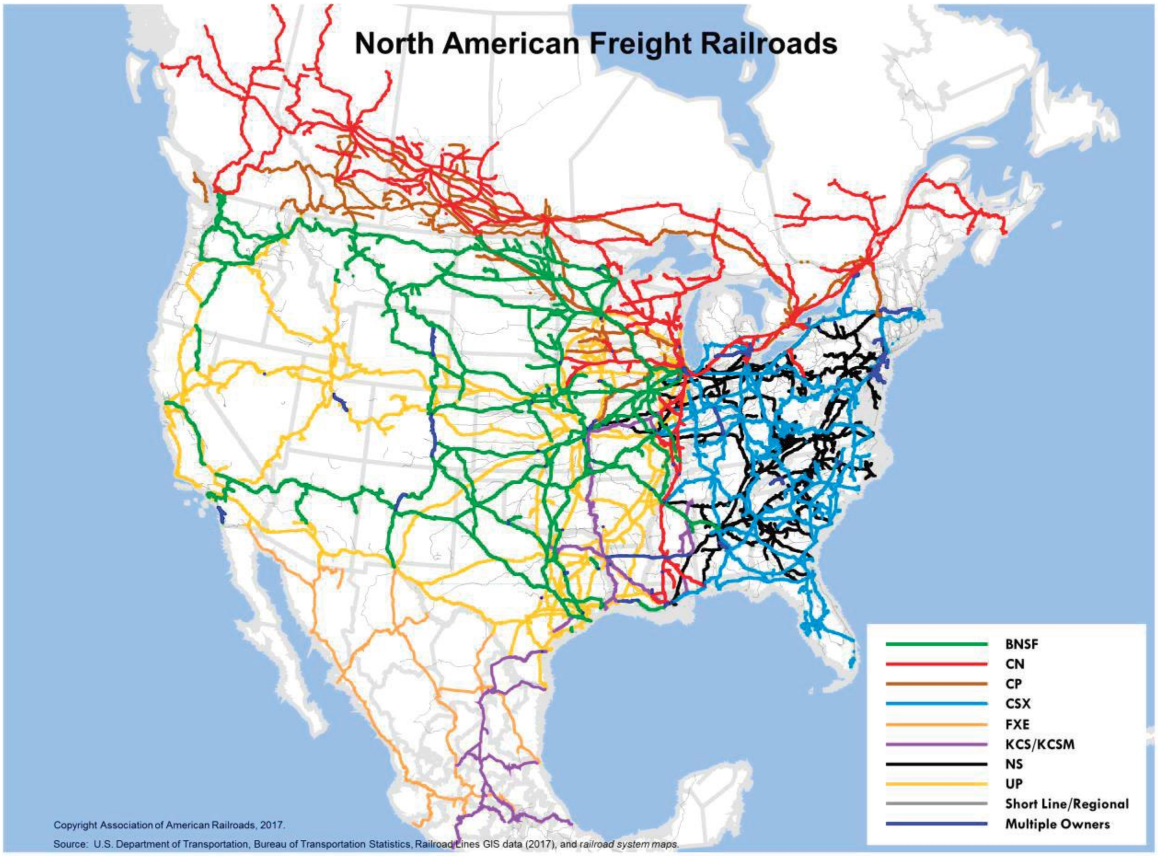

Figure 4.2 North American Freight Rail Network

Source: U.S. DOT Bureau of Transportation Statistics, Association of American Railroads, 2017.

4.3 LNG Facilities

LNG production and surface transport in the U.S. relies upon both specialized facilities dedicated to LNG, and on the underlying infrastructures for natural gas production and distribution, as well as surface transport infrastructure such as highways and railroads.

LNG facilities encompass facilities which liquefy, transport, store, or gasify LNG. Some facilities import or export LNG, others provide natural gas supply to the Interstate pipeline system or local distribution companies, while others are used to store natural gas for extended periods of peak demand. There also are facilities which produce LNG for vehicle fuel or for industrial use. Depending on location and use, an LNG facility may be regulated by several Federal agencies and by State utility regulatory agencies.

There currently are 153 LNG facilities operating in the U.S. performing a variety of services (Figure 4.3). Some facilities import natural gas to the U.S., one now exports natural gas from the U.S., some provide natural gas supply to the Interstate pipeline system or local distribution companies, while others are used to store natural gas for extended periods of peak demand. There also are facilities which produce LNG for vehicle fuel or for industrial use. Depending on location and use, an LNG facility may be regulated by several Federal agencies and by State utility regulatory agencies.

LNG accounts for only a small portion of working gas in storage, but on days when the price of natural gas peaks, LNG often represents a significant part of a company's supply portfolio. The deliverability of LNG is higher than traditional underground storage facilities such as depleted reservoirs, aquifers, and salt caverns, making LNG especially useful for stockpiling natural gas for periods when demand is high, supply is low, and prices are at a peak. This ratio between the heat content of the supply and the volume of the inventory is known as a high degree of "deliverability." Under peak conditions, LNG facilities are often constructed with the ability to supply a much larger amount of gas than the amount of space that their inventory occupies, thanks to the six-hundred-to-one gas-to-liquid ratio. Being able to purchase natural gas when the market is at a low, such as during the summer when it is not being used for heating, and store it for the winter when demand may exceed supply, enables LNG facilities to level out the resources throughout the year.

Figure 4.3 shows the 153 LNG facilities operating in the U.S., performing a variety of services, in relation to the U.S. natural gas pipeline network. LNG peak shavers with liquefaction are identified in green, and satellite peak shavers without liquefaction in purple. The import/export facilities are identified by red squares and emerging LNG facilities as blue stars. These "emerging" LNG facilities are mostly merchant plants that have been constructed but do not yet appear in the PHMSA and EIA databases. They include facilities built in Florida, Louisiana, Pennsylvania, Texas, and Vermont.

Additional information on import and export facilities is available in Appendix E. There are 12 import facilities in the United States, nearly all of which are in the process of converting from import-only to import-and-export facilities due to the domestic availability of shale gas.

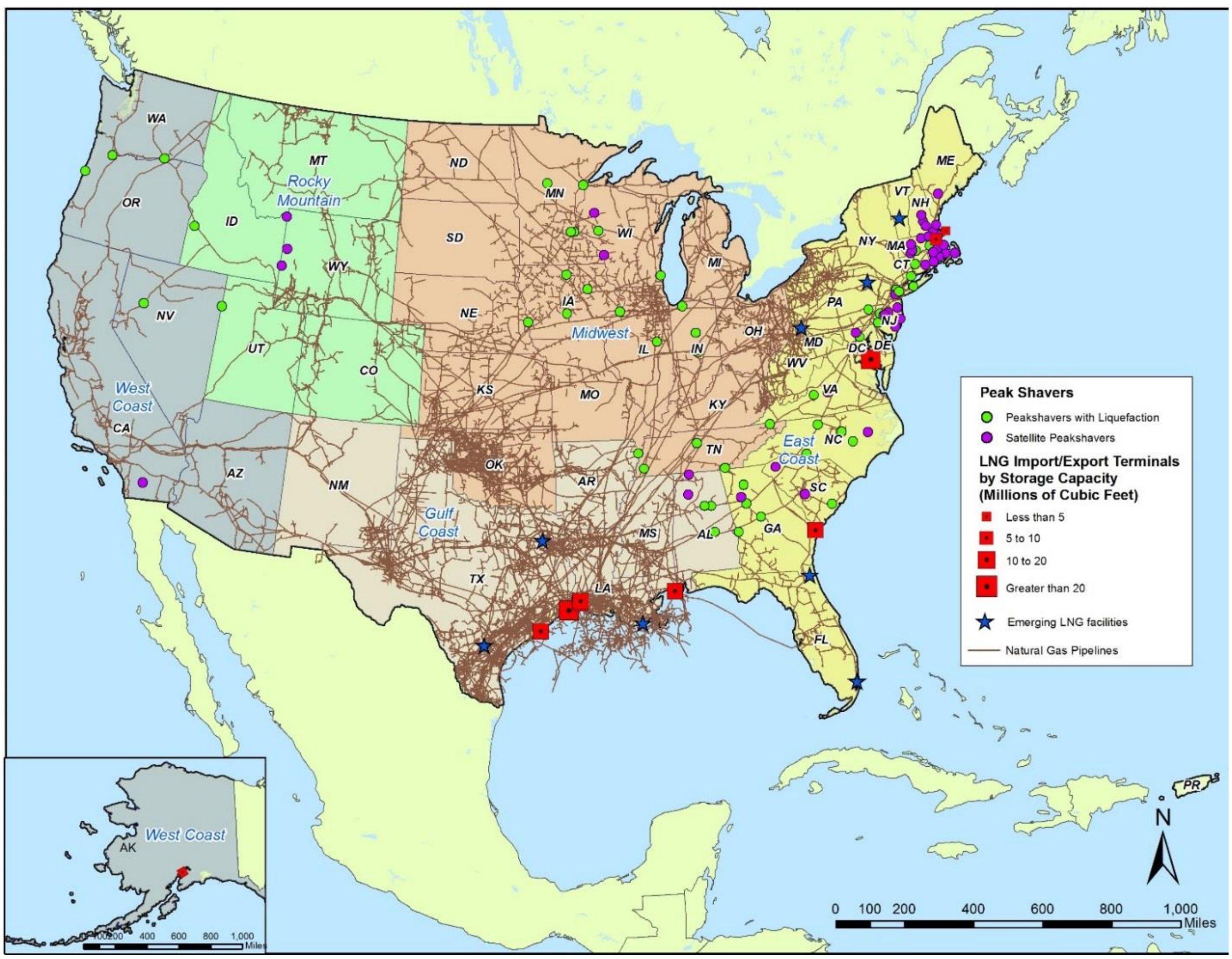

Figure 4.3 U.S. LNG Facilities with Natural Gas Pipeline Network

Sources: Energy Information Administration; Cambridge Systematics, Inc.

As part of understanding the possibility of shipping natural gas as LNG by rail, the placement of LNG facilities relative to the national rail network. Figure 4.4 illustrates the U.S. LNG Facilities and U.S. Railroad Network on a national scale.

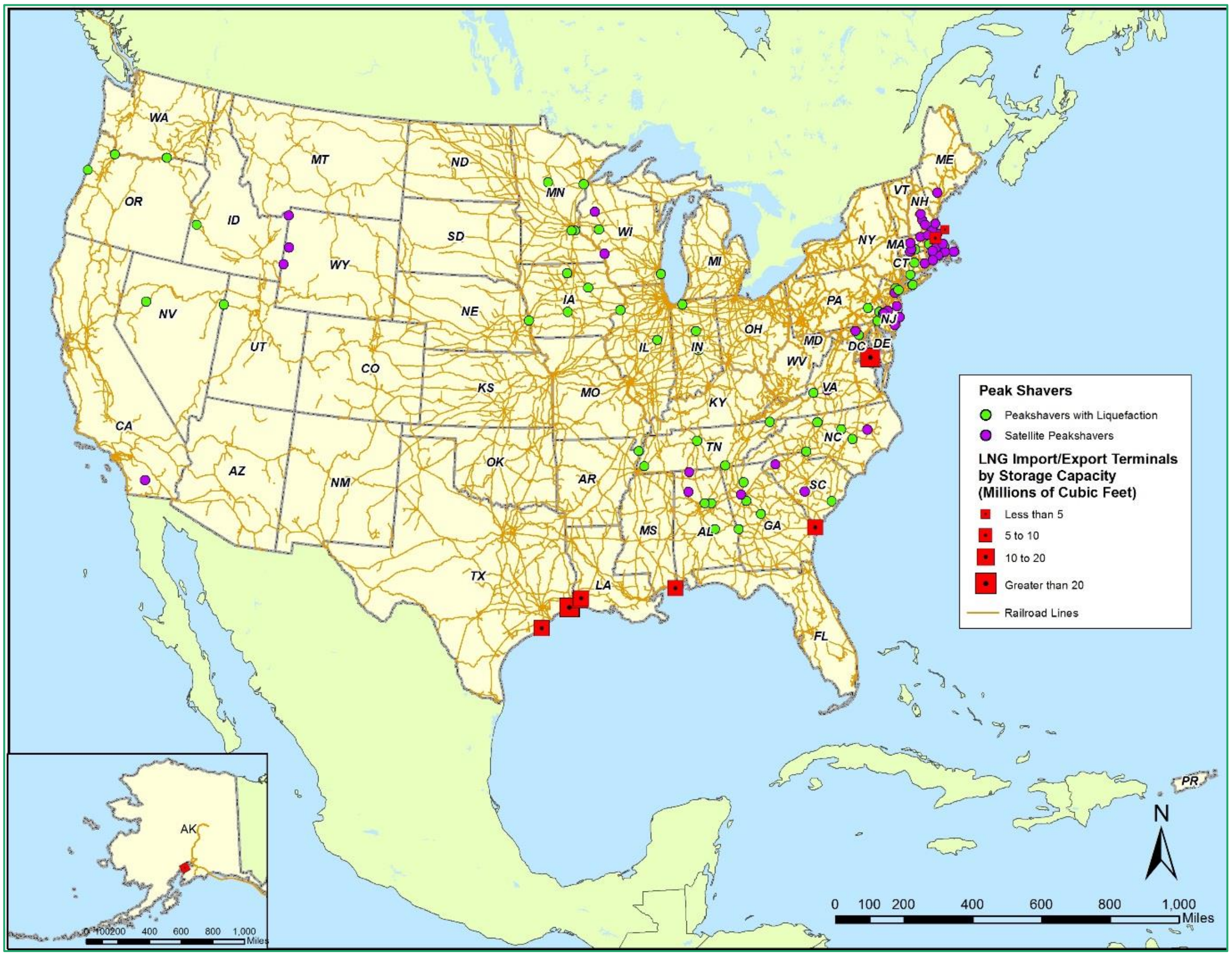

Figure 4.4 U.S. LNG Facilities and U.S. Railroad Network

Sources: Energy Information Administration; Cambridge Systematics, Inc.

The railroad and pipeline networks do show similar patterns when viewed on a national scale, and railroads access some areas that are not reached by pipelines, such as South Dakota. Each of the networks are not homogenous in construction; pipelines have directionality and capacity differences, railroads have track classifications, tonnage differences, and geometric limitations.

Railroad and pipeline networks share some similarities, and also differ in important ways. Both pipelines and railroads have high capital costs, engineering challenges, and permitting requirements that make building new infrastructure costly and time consuming. Neither network is homogenous in construction; pipelines have directionality and capacity differences, railroads have track classifications, tonnage differences, and geometric limitations.

Highways are the most ubiquitous of the network, with the most access. Truck transport of LNG is the only alternative to domestic movements of natural gas that are not handled by pipeline (except for LNG by vessel between California and Hawaii).

This figure does not address the actual feasibility of connecting a LNG facility to a railroad. The intent is simply to provide a network-level view of U.S. rail network and its relationship to LNG facilities. It should also be noted that utilizing an existing rail network is much easier with ISO containers, which can be trucked to a transfer yard and transferred to a flatbed rail car without having to transfer the cryogenic liquid from one container to another.

The Northeast natural gas market has a very high demand and limited pipeline supply. This is particularly the case in New England. This is because New England has limited access to four different pipelines that primarily serve other markets. The lack of public support for additional pipeline infrastructure in New England has been a factor in the history of LNG in this region. Therefore, LNG has been imported by ship to Everett, MA for the past 40 years and transported by truck to 43 peak shaving facilities throughout New England. Natural gas also supplies power generation facilities nearby and in the region. Nearly all of the peak shaving facilities are used for storage only in peak demand, such as the winter, and do not have liquefaction capabilities.

For the majority of the year, New England's natural gas system of pipelines and LNG delivery system operates at less than 50 percent capacity. However, for approximately seven weeks each year, the region's natural gas distribution system does not meet demand. It is during this peak winter period that the LNG import terminal in Everett, MA helps to provide gas to meet this peak demand. The Everett LNG import terminal is managed by Distrigas of Massachusetts LLC, a subsidiary to ENGIE.[27] "Everett has also been the primary supplier of LNG to a network of 46 utility-owned, above-ground LNG storage tanks that meet New England's natural gas storage needs. More than 360,000 truckloads of LNG have left the Everett Marine Terminal over its 40-year history, or about 10,000 per year, primarily to refill these storage tanks and prepare for the peak winter heating season. Because of the geological conditions in the region, underground natural gas storage is not feasible. It serves nearly all of the gas utilities in New England and also key power producers, including a direct connection to a neighboring 1,550-megawatt power plant capable of generating enough electricity for about 1.5 million homes in Greater Boston."[28]

New England has both LNG vaporization capacity from large import terminals as well as from LNG storage facilities owned by the local gas distribution utilities, or "LDCs." One solution that has been used is for LDCs to contract for a baseload level of LNG vaporization during the December 15–March 15 winter period. Engie provides more frequent truck refills of their existing LNG storage facilities, thereby maintaining local gas reliability while freeing up existing pipeline capacity for sale on the secondary market to power plants.

Figure 4.5 shows the LNG facilities in the Northeast overlaid with the natural gas pipeline network. There are 18 peak shavers with liquefaction capabilities that are adjacent to transmission pipeline networks. These facilities liquefy natural gas, accumulating and storing LNG when natural gas is cheapest and available—

[27] According to the ENGIE website: "ENGIE manages a range of energy businesses in the United States and Canada, including retail energy sales and energy services to commercial, industrial and residential customers, natural gas and liquefied natural gas (LNG) distribution and sales, and electricity generation and cogeneration. In 2015, ENGIE recorded €69.97 billion in global revenues ($77.6 billion USD). More than 3,500 employees work in the region, and Houston serves as corporate headquarters."

[28] ENGIE, Inc., "Natural Gas & LNG."

during the summer. There are 28 satellite peak shavers, storing LNG supplied exclusively by truck. This is especially obvious in southern New Jersey.

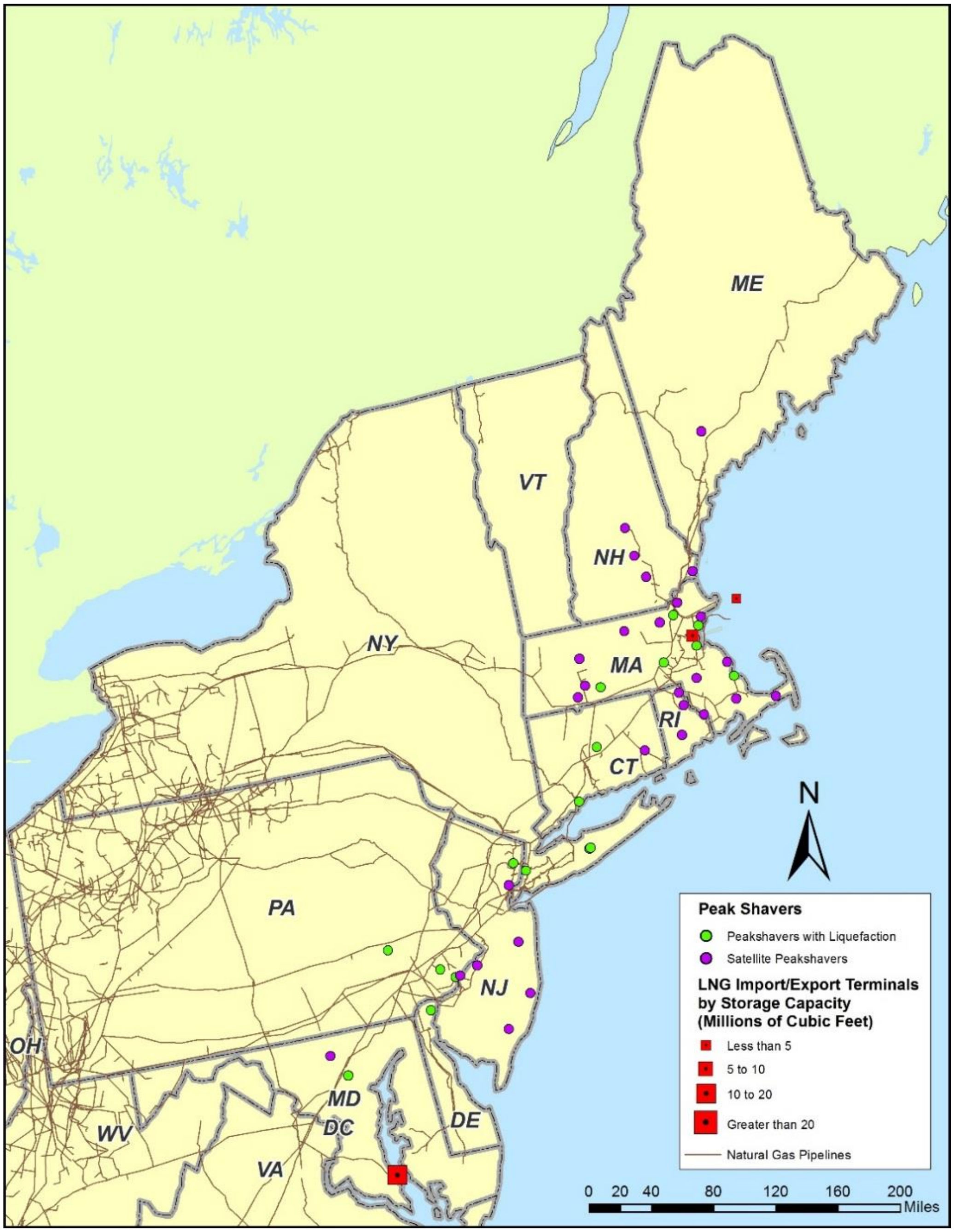

Figure 4.5 Northeast LNG Facilities

Source: Energy Information Administration; Cambridge Systematics, Inc.

New England is an example of a "stranded" gas market that currently is served by truck delivery of LNG. New England could be a candidate for LNG delivery by rail. Figure 4.6 illustrates the proximity of railroads to LNG facilities in the Northeastern United States. It is not the only stranded gas market in the country, but it is a market with high demand and limited access to the pipeline network. Since the majority of LNG is delivered in New England by truck, the only other alternative without great investment in pipelines (which have been opposed by the local population) would be railroad transportation, and under certain conditions, New England could be a candidate for LNG by rail.

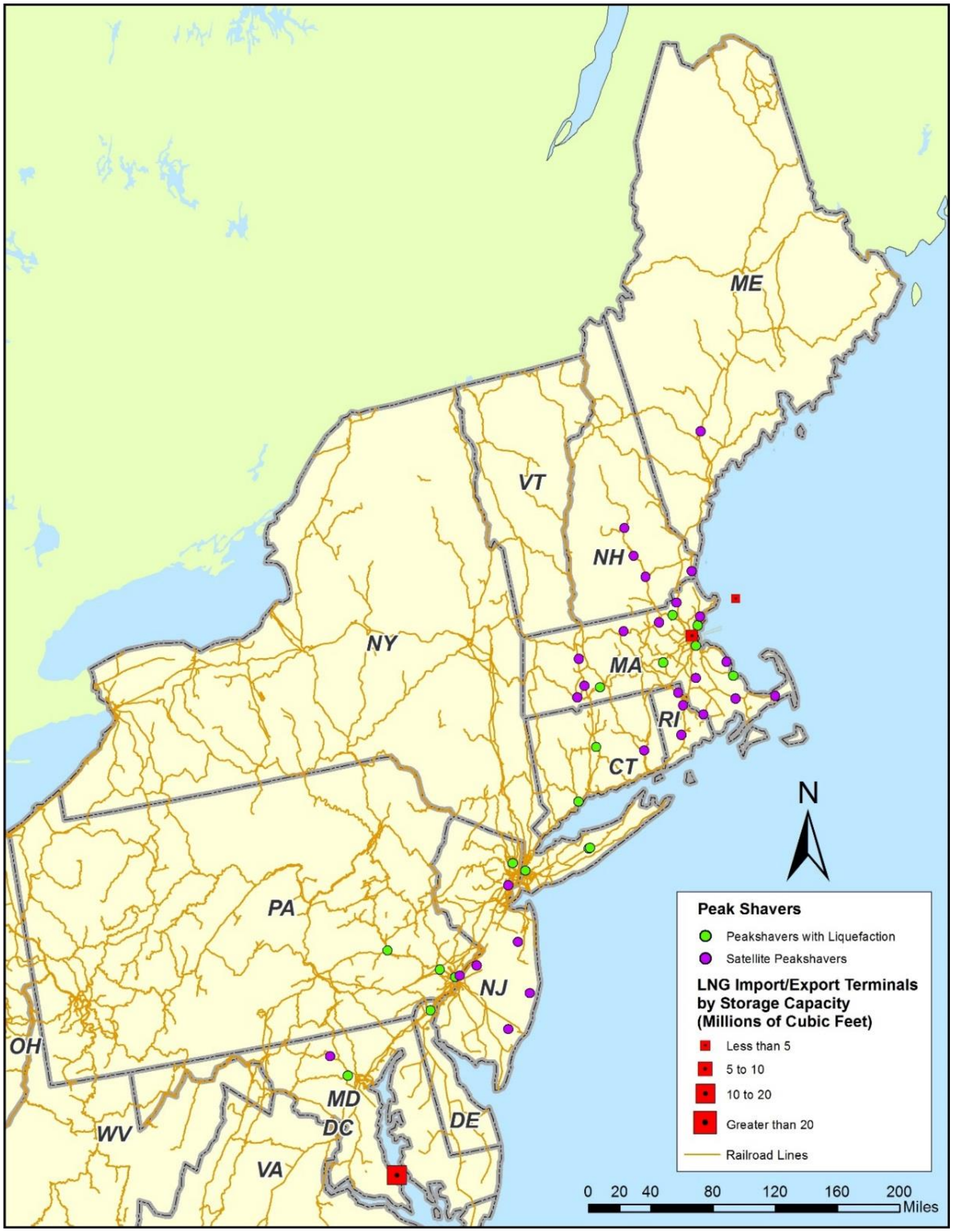

Figure 4.6 Northeast LNG Facilities and Railroads

Source: Energy Information Administration; Cambridge Systematics, Inc.

In both Figure 4.5 and Figure 4.6, there is a cluster of LNG facilities in the Northeast. In this area, the winters are cold, natural gas is one of the fuels used for heating, and the transmission pipeline network is underdeveloped. New England has limited access to four different pipelines that primarily serve other markets. The lack of public support for additional pipeline infrastructure in New England has been a factor in the history of LNG in this region. Consequently, LNG has been imported by ship to Everett, MA for the past 40 years and transported by truck to distribution points. The seasonally varying—and unpredictable on a short-term basis—nature of the demand for natural gas also creates a need for distributed natural gas storage, against peak demand (peak shaving facilities). For that reason, there are 43 peak shaving facilities in New England. Relatively few New England peak shaving facilities have liquefaction capabilities, because of the limited access to transmission pipeline networks.

4.3.1 North American Merchant Facilities

LNG transportation is a key capability for LNG merchant plants and operators. Merchant operators are commercial energy providers that compete to sell energy on the wholesale energy market. These merchant operations differ than typical utilities in that they are not beholden to the natural gas rate payers in the area. Therefore they can buy and sell LNG on demand and effectively supplement the natural gas and LNG users during times of peak demand. Merchant operators are important players in the natural gas trading market. Table 4.2 lists of some of the merchant power plants in the U.S. that have been identified as trading natural gas. Some of these plants are solely merchant plants and others are merchant plants connected to a utility.

Table 4.2 Sample of U.S. Natural Gas Merchant Plants

Pivotal (owned by Southern Company Gas)	Trussville, AL
UGI (Pennsylvania)	Fortress (Hialeah, FL)
Reading, PA	Memphis, TN
Scranton, PA	Oklahoma, Texas
Citizen's Gas (Indiana)	Jacksonville, FL (two under construction)
Gas Metro (Montreal)	

Sources: Cambridge Systematics, Prometheus, Inc.

The emerging uses for LNG to supplement power generation, remote power generation and LNG fuel has resulted in multiple supply sources across the U.S. Figure 4.7 illustrates the widespread availability of LNG through multiple sources, which are a combination of merchant operators, peak shavers, and gas processing plants.

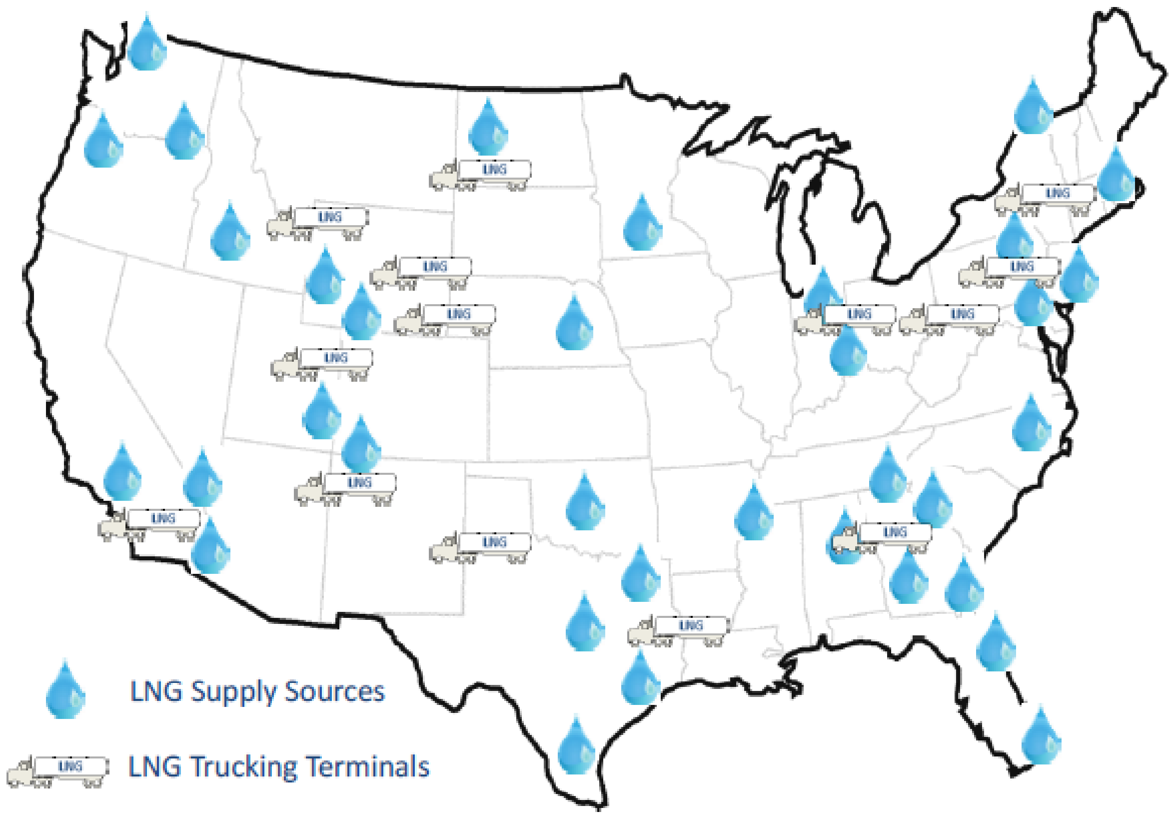

Figure 4.7 Example of Selected U.S. LNG Suppliers

Source: Prometheus, Inc.

4.3.2 Small-Scale LNG Facilities

The NFPA 59A Committee meets to review facilities that liquefy natural gas, facilities that store, vaporize, transfer, and handle LNG, the training of all personnel involved with LNG and the design, location, construction, maintenance, and operation of all LNG facilities. The committee currently is reviewing the issue of "small scale" versus "large scale" LNG facilities.[29] At present, the consensus is the threshold is 500,000 GPD. In other meetings with industry representatives, "midscale" LNG facilities also are considered, as illustrated in Figure 4.8.[30]

29 Meeting with FERC Representative, October 2017.

30 Chart, Praxair Industry Meetings, September and October 2017.

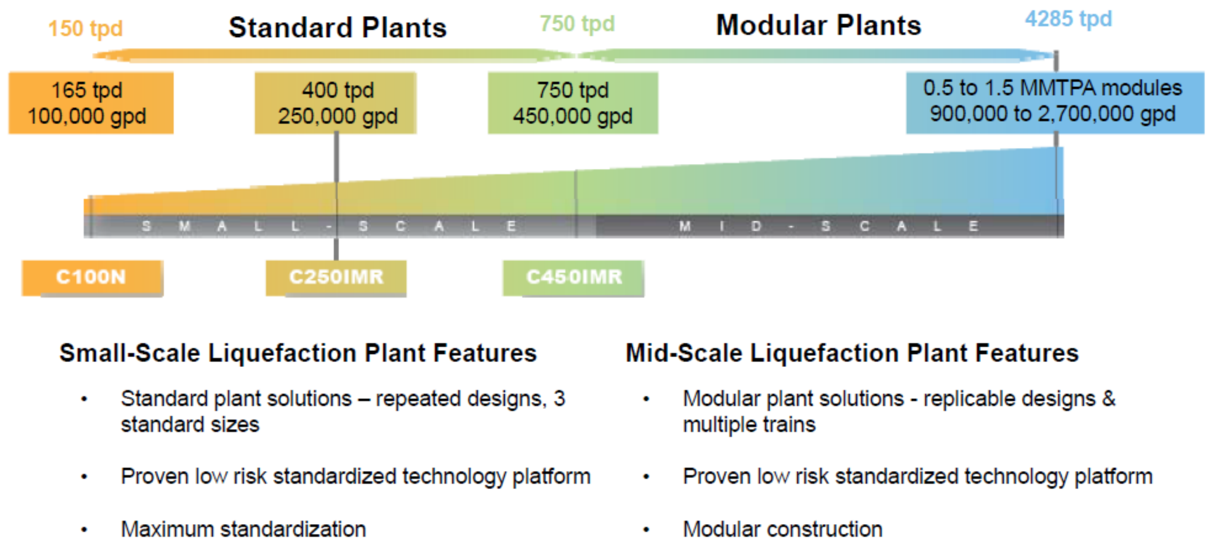

Figure 4.8 Small and Midscale LNG Facility Features

Source: Chart Industries, NFPA.

4.4 LNG Transportation

Natural gas is principally moved by pipeline. When natural gas is moved by truck or vessel it is assumed that it is moved in liquefied form, as LNG. Given the numerous locations across the U.S. for LNG supply, trucks currently are meeting LNG transportation demands in the current market.

Vessel movements cover long distances, and these distances are more efficient by vessel than by pipeline which would require building capital intensive infrastructure. Over short distances, pipeline movements are the most efficient, and in the continental U.S., pipelines move most of the natural gas. However, truck movements of natural gas in its liquefied form do occur, and truck transport is the main alternative to pipeline delivery. Trucks are adaptable to changes in dynamic natural gas market.

Preliminary analysis of the EIA Survey 176 data shows that roughly 65.1 million MMCF of natural gas were moved across the U.S. in 2016—99.574 percent by pipeline, 0.421 percent by vessel, and 0.004 percent by truck. Figure 4.9 shows movements of natural gas that are captured by the EIA Survey 176. This figure shows net Interstate movement, imports, and exports of natural gas, so actual total flows may be larger. Truck movements are very small compared to pipelines.

The majority of natural gas in and out of the U.S. market is moved by pipeline, and when natural gas is moved by truck and barge it is assumed that it is moved in liquefied form. Preliminary analysis of the EIA Survey 176 data shows that roughly 65.1 million MMCF of natural gas were moved across the U.S. in 2016—99.4 percent by pipeline, 0.4 percent by vessel, and 0.004 percent by truck.[31] The vast majority of natural gas in the world is moved by pipeline, and when natural gas is moved by truck and vessel it is assumed that it is moved in liquefied form. Preliminary analysis of the EIA Survey 176 data shows that roughly 65.1 million MMCF of natural gas were moved across the U.S. in 2016—99.574 percent by pipeline, 0.421 percent by vessel, and 0.004 percent by truck. There is a limited ability to capture current truck

[31] Energy Information Administration, "Annual Report 2016;" Energy Information Administration, "Survey 176."

movements. These net Interstate movement, imports, and exports of natural gas are represented by the mode of transportation: pipeline, truck, and vessel; the international movements are shown in red, and the domestic movements are shown in blue. These movements are the net result of movements that may occur in either directions, showing the dominating direction of flow. Since pipeline gas goes into the network, pipeline movements do not extend beyond the next State into which the product flows. Vessel and truck movements, however, represent physical movements of LNG between States and other countries. This information is important in the context of this study to show LNG movements between States by truck.

International movements are shown in red, while the domestic movements are shown in blue. Specific transportation modes also are indicated. Because pipeline movements may extend beyond a State, only net cross-state movements are shown; if gas moves across a State, that volume of gas may be double counted (e.g., show as both entering and leaving the State), so it is not meaningful to total the pipeline flows shown in Figure 4.9. Vessel and truck movements, however, represent physical movements of LNG between specific locations; transshipment or pipeline injection remains possible, however, so again total figures should be treated with care.

Figure 4.9 Net Interstate Natural Gas Movements

Million Cubic Feet MMCF

Source: Energy Information Administration, "Annual Report 2016."

The CS Team compiled net natural gas movements from Figure 4.9 to create a gross natural gas movements map in Figure 4.10. We did this to document gross LNG movements between States by truck. This provided a basis and methodology for determining where LNG demand exists in the United States. Most of the truck movements are concentrated in areas not well served by natural gas pipelines, such as the Northeast and Mountain West areas of the United States. Truck transport is the main alternative to pipeline delivery, so the CS Team analyzed the gross movements of LNG by truck between States using EIA data for origins and destinations. Using the same data that the EIA used to produce the above map, Figure 4.10 shows the gross Interstate movement of LNG by truck. A single truck carries 10,943 gallons of LNG, which is equivalent to 0.9 million cubic feet of natural gas. Therefore, the movement of one million cubic feet of natural gas between Texas and Delaware can be estimated to represent one truck. Knowing the current movements provides valuable insight into likely volumes and types of LNG transport origins and estimations and packaging operations across the U.S. and at import/export facilities. Assuming that approximately six percent of the export capacity may not be sold to other countries, this natural gas may still be on the U.S. market and could be sold domestically. This makes liquefaction trains at export facilities relevant to the domestic market with implications for surface transport by truck or by rail.

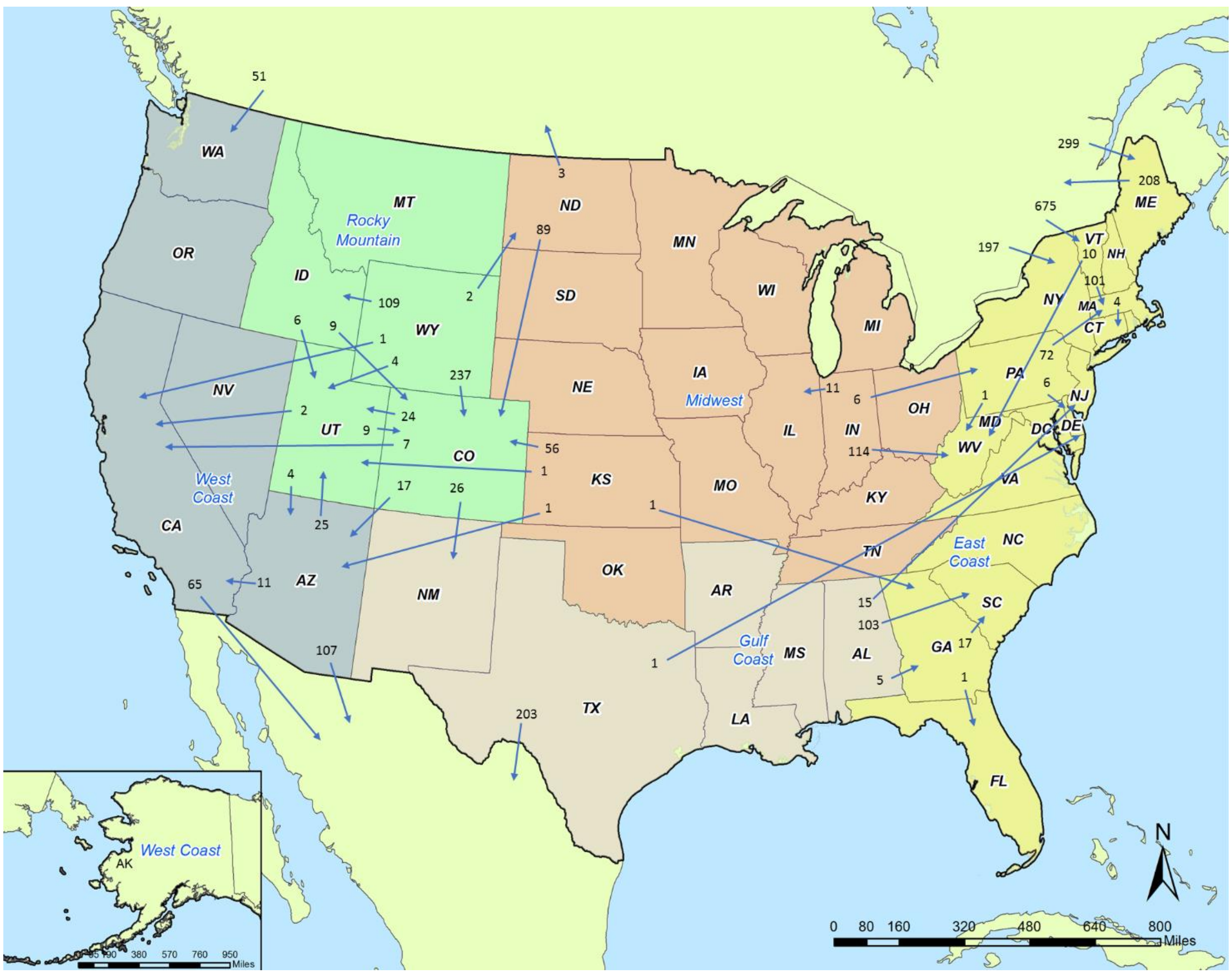

Figure 4.10 Gross Interstate Natural Gas Movements by Truck

MMCF

Source: Energy Information Administration, "Survey 176;" Cambridge Systematics, Inc.

A single truck carries close to 11,000 gallons of LNG, equivalent to almost 1 million cubic feet of natural gas. Therefore, the movements in millions of cubic feet correspond roughly to truck counts. Viewing the current movements of LNG by truck reveals how the market handled the inability to service the consumers by pipeline in 2016. This helps understand the origins that that have liquefied LNG supply and the destinations that demand natural gas beyond what the pipeline transmission network can supply.

Reviewing the larger movements reveals some useful information.

- There is significant truck movement from California, Arizona, and Texas to Mexico, reflecting the demand for natural gas in Mexico. That also suggests some liquefaction facilities in each of those States.
- There also is significant truck movement from Canada into the U.S. Northeast, reflecting the strong demand already noted for that region. Though, some movement for ME may simply be transshipment from Canada to Canada.
- Wyoming is a significant source of truck movements of LNG. This is likely due to the Exxon LaBarge facility which removes CO_2 from natural gas in that region, harvests Helium from the natural gas, and liquefies some of the dry gas output.
- Given the relatively large volume of LNG trucked into CO, much of the outbound volume from CO is likely trans-shipment.
- Other States that appear to be more significant sources of LNG truck shipments are Alabama, Indiana, and North Dakota.

It should be noted that this LNG is being transported by truck for distances that per would ordinarily be more cost effective by pipeline. This could be because the local supply prices spiked during a supply shortage, or because the destination is not well connected to the pipeline network, or both.

Figure 4.11 depicts the same truck movements by volume across the U.S. Interstate system. The method for developing this map was to use the data from Figure 4.10 regarding LNG volume, State origin and State destination and assign the corresponding trips to the Interstate highway network. Since the data do not include the exact origins and destinations, the CS team used State centroids to assign the network. This results in some inaccuracies, such as in Florida, where we can assume that LNG is likely transported to Jacksonville to fuel ships, not to Tampa.

Note the LNG truck movements correspond to those areas in the U.S. not well served by the natural gas pipeline network.

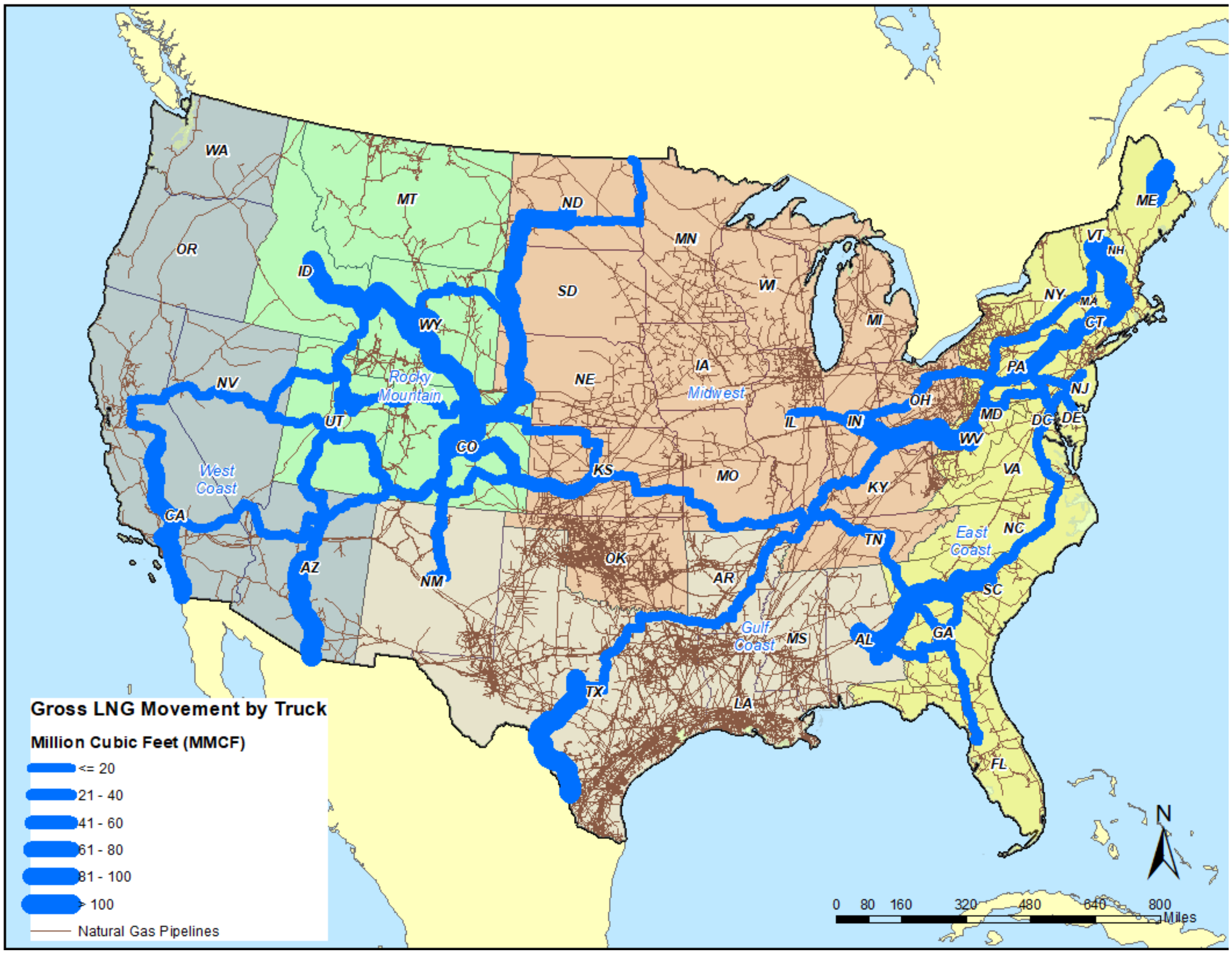

Figure 4.11 Gross LNG Truck Movements by State

Source: Energy Information Administration; Cambridge Systematics, Inc.

Figure 4.12 gives an additional perspective by showing the truck movements solely between production and consumption natural gas regions as defined by the EIA. This figure illustrates that the majority of the movements are within the natural gas regions, but some of the LNG movements do move more than 1,000 miles.

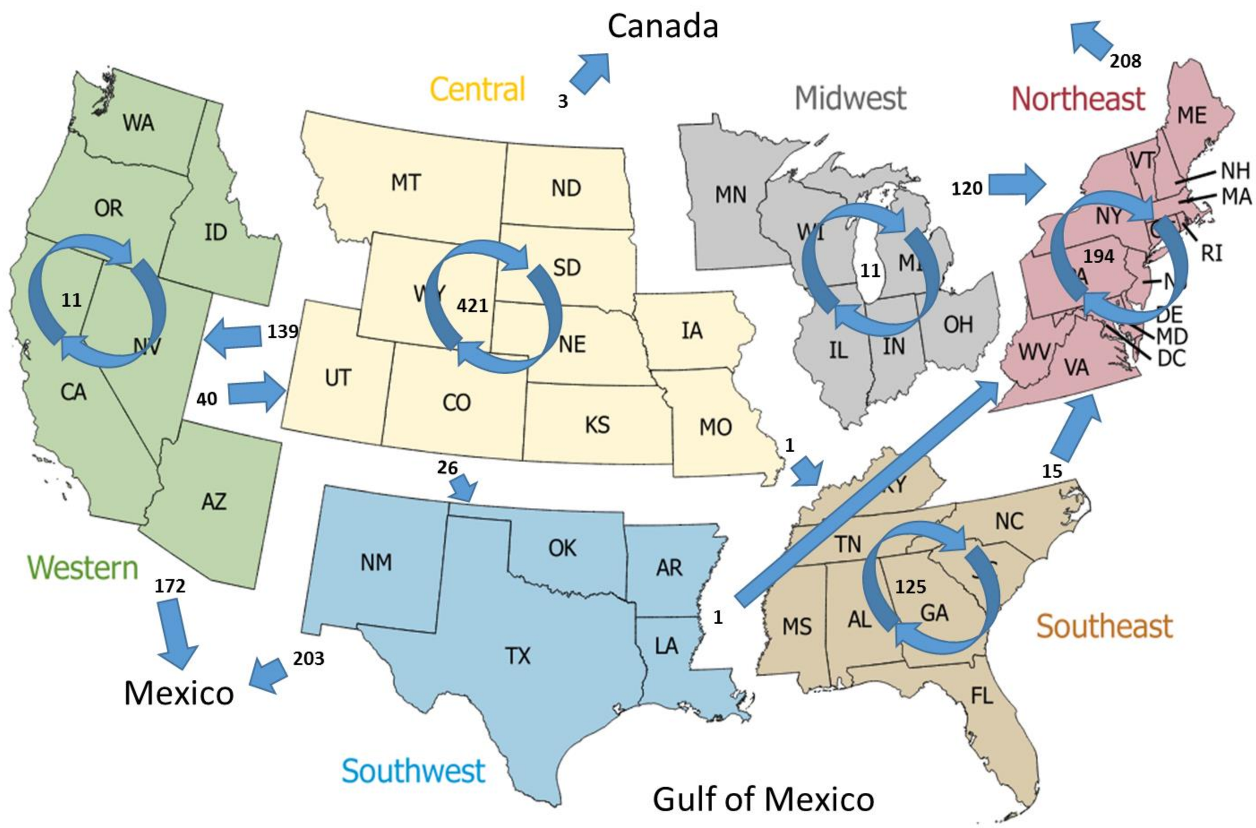

Figure 4.12 LNG Truck Movements between EIA Regions

MMCF

Source: Energy Information Administration, "Annual Report 2016;" Cambridge Systematics, Inc.

A comparison of Figure 4.12 above (truck) to Figure 4.13 (below, showing pipeline movements) highlights the difference in the volumes of LNG moving by truck in comparison to natural gas moved by pipeline. Viewing the current movements of LNG by truck reveals how the market handled the inability to service the consumers by pipeline in 2016. This helps understand the origins that that have liquefied LNG supply and the destinations that demand natural gas from off the pipeline grid.

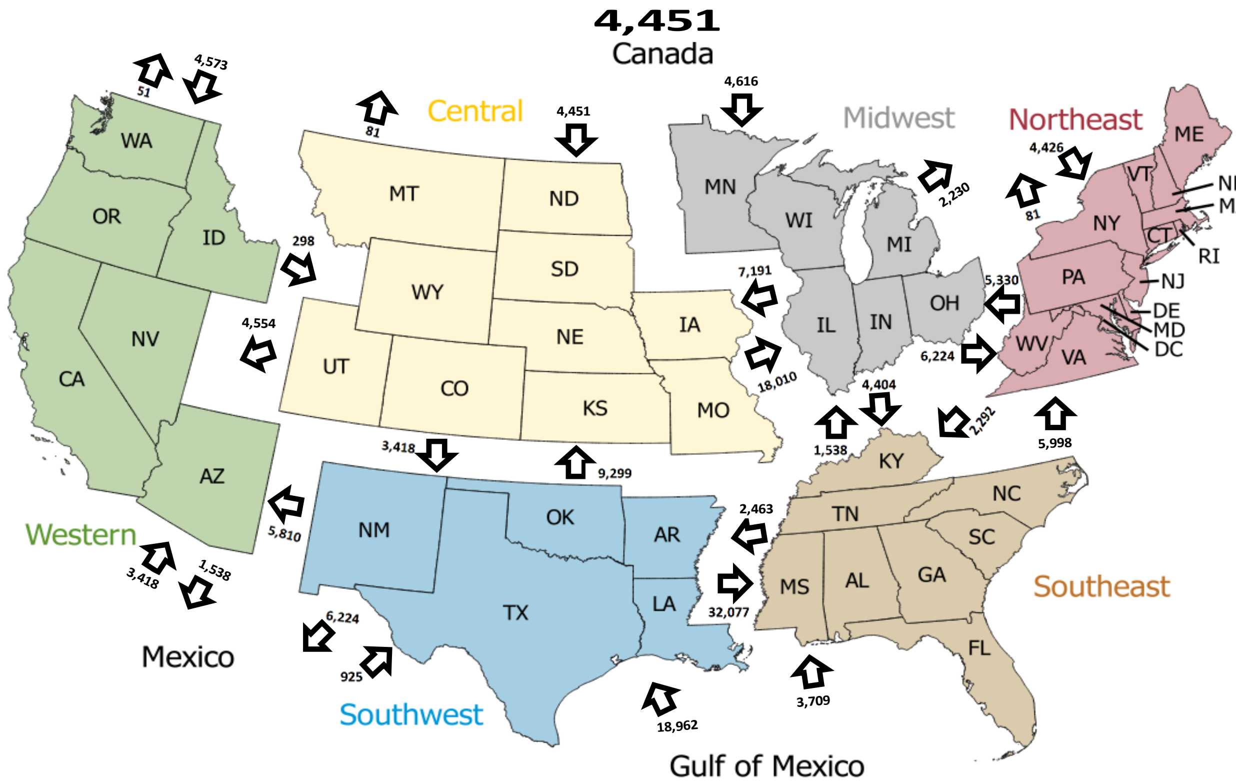

Figure 4.13 U.S. Pipeline Capacity between EIA Regions
MMCF/d

Source: Energy Information Administration, "U.S. State to State Capacity."

4.5 LNG Economics

Natural gas is sold as a fungible product but, as noted above, when there are supply and demand imbalances and it is difficult to move gas through pipelines between specific regions, hub prices can become disconnected. Transportation economics reveal that the price of the natural gas and the transportation costs play a large role in where natural gas or LNG are sourced.

Transportation economics presented in this report reveal that the price of the natural gas and the transportation costs play a large role in where it is sourced. The cost to produce and deliver LNG is typically about two to three times the price of natural gas. The LNG can be sold at roughly three to four times the cost of natural gas, as long as it is still cheaper per Btu than propane or diesel.[32] Natural gas movements are a function of price and delivery convenience. Truck and rail delivery are a "flexible and competitive complement to traditional pipeline transportation" for the transport to market from "remote locations not adequately served by pipelines."[33]

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[32] Information gathered from an interview with an LNG broker.

[33] Braziel, "The Domino Effect."

4.5.1 Natural Gas Prices

According to the EIA, three major supply-side factors and three major demand-side factors affect prices (see Table 4.3. And these prices ultimately inform the natural gas users of the most efficient method to obtain natural gas, whether it be from a pipeline or in the form of LNG.

Table 4.3 Supply-Side and Demand-Side Factors Affecting Prices

Supply-Side Factors	Demand-Side Factors
Amount of natural gas production	Variations in winter and summer weather
Level of natural gas in storage	Level of economic growth
Volumes of natural gas imports and exports	Availability and prices of competing fuels

Source: Energy Information Administration, "Factors Affecting Natural Gas Prices."

As the natural gas supply has flooded the market, the price has been driven down by oversupply. Spot natural gas prices at local hubs give a good idea of the price differential between regions, and these prices drive sourcing and contract decisions. Spot prices are commonly linked, with differences reflecting the transportation cost of moving gas between regions. However, if delivery is not possible between two areas, the prices can move more independently of each other. Figure 4.14 charts the spot prices for the hubs from March 2014 through December 2017.

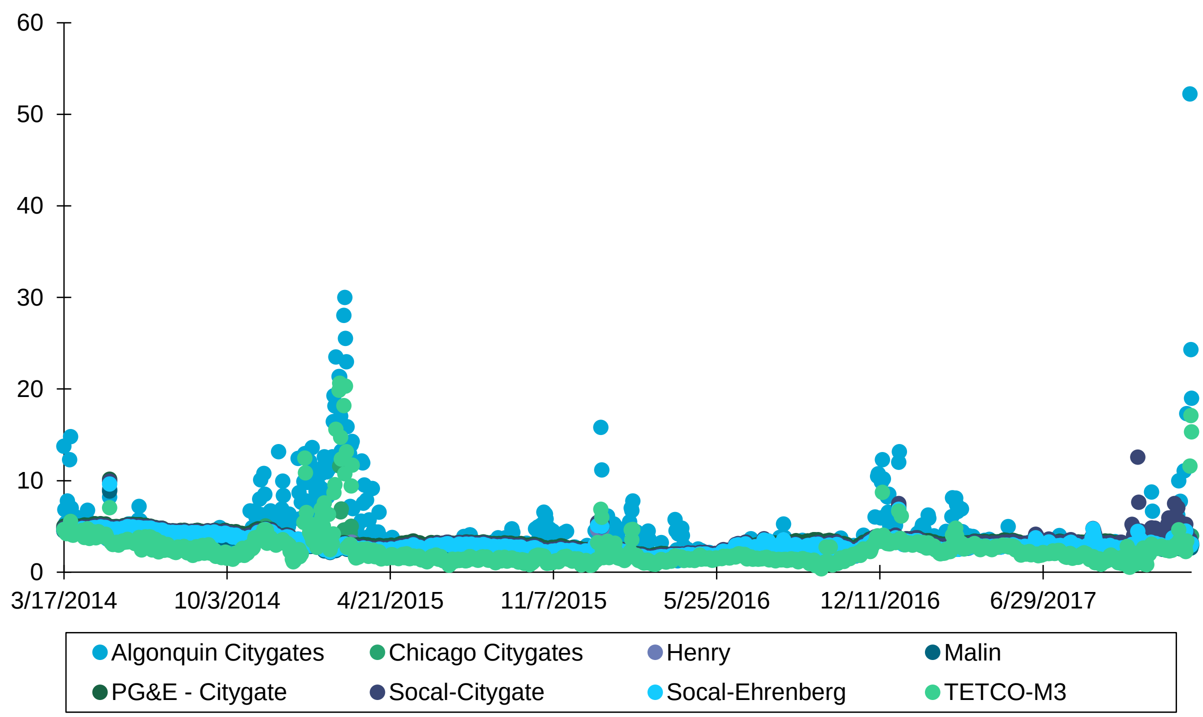

Figure 4.14 Natural Gas Hub Spot Prices
2014–2017

Source: Energy Information Administration.

The Henry hub is the most important natural gas hub in the U.S., and Henry Hub prices are reported internationally as representative of the North American natural gas market. Hub prices can be reported in the form of a basis, which is the price differential between two delivery points, and are often reported as a basis with the Henry Hub.

Local imbalances in supply and demand, where the transmission pipeline network has insufficient capacity to meet demand, can make natural gas more expensive in one region than another.

Two natural gas Hubs, the Algonquin (for Massachusetts), and TETCO (for Pennsylvania) can be compared in this analysis. The Algonquin is a close representation of the natural gas prices in Worcester, MA, and the TETCO-M3 is a close representation of the natural gas prices in Harrisburg, PA. For this analysis, the Henry Hub is included as a reference since it is the primary natural gas hub in North America. When the Algonquin Citygates or the TETCO-M3 hub prices dip below the Henry Hub, this indicates that the region experienced oversupply, which could be from less demand than normal, or more likely for the Utica-Marcellus shale region would be that production exceeded the infrastructure ability to move the natural gas out of the region, creating a local situation of oversupply. When Algonquin Citygates or TETCO-M3 exceed the Henry Hub price, this indicates that the demand exceeded the local area’s access to natural gas supply. Market hub prices are reported in $/MMBtu. Figure 4.15 depicts the hub prices between 2014 and 2017 for the Algonquin, TETCO-M3 and Henry Hubs.

Spot natural gas prices at local hubs give a good idea of the price differential between regions, and drives the sourcing and contract decisions. Spot prices commonly reflect the transportation cost of moving gas between regions, but if delivery is not possible between two areas, the prices act independently of each other.

The typical pattern for the Northeastern region natural gas prices follows the weather. It is normal for prices to fall below the Henry Hub during the summer, when the local demand for natural gas is lower. This is because natural gas is the primary energy source for heating during the winter in the Northeast, and the winters may be especially harsh. During the summer, natural gas may be used for electric power, and this also can be affected by the weather because a hot summer will increase the air conditioning usage and drive up electricity usage. Typically, the winters are harsh, and the summers are mild, leading to undersupply in the winter and oversupply in the summer. The oversupply in the summer is caused by a lack of outbound network infrastructure for the natural gas processed in the Utica-Marcellus shale region, creating stranded supply. The undersupply in the winter is caused by the steep increase in demand during cold periods, and the under capacity of the network to supply the peak demand of the region. To show the price differential between the two regions, look at the spread between the Algonquin hub and the TETCO-M3 hub in Figure 4.15. When the differential is positive the Algonquin Citygate hub prices were greater than the TETCO-M3, and when the differential is negative, the TETCO-M3 hub prices were greater than the Algonquin Citygate hub. The highest price differential shown by the data occurred on December 26, 2017, when the Algonquin hub was $40.6334 greater than the TETCO-M3 hub. Typically, a price differential is representative of the relative shipping costs between the two regions. When price differentials peak, this acts as a driver to provide more transportation options. Most, but not all, suppliers and users bid on contracts every month during bid week, so they are not generally vulnerable to price spikes. Prices overall will increase for several months during the winter, while the highest price spikes only last a few days.

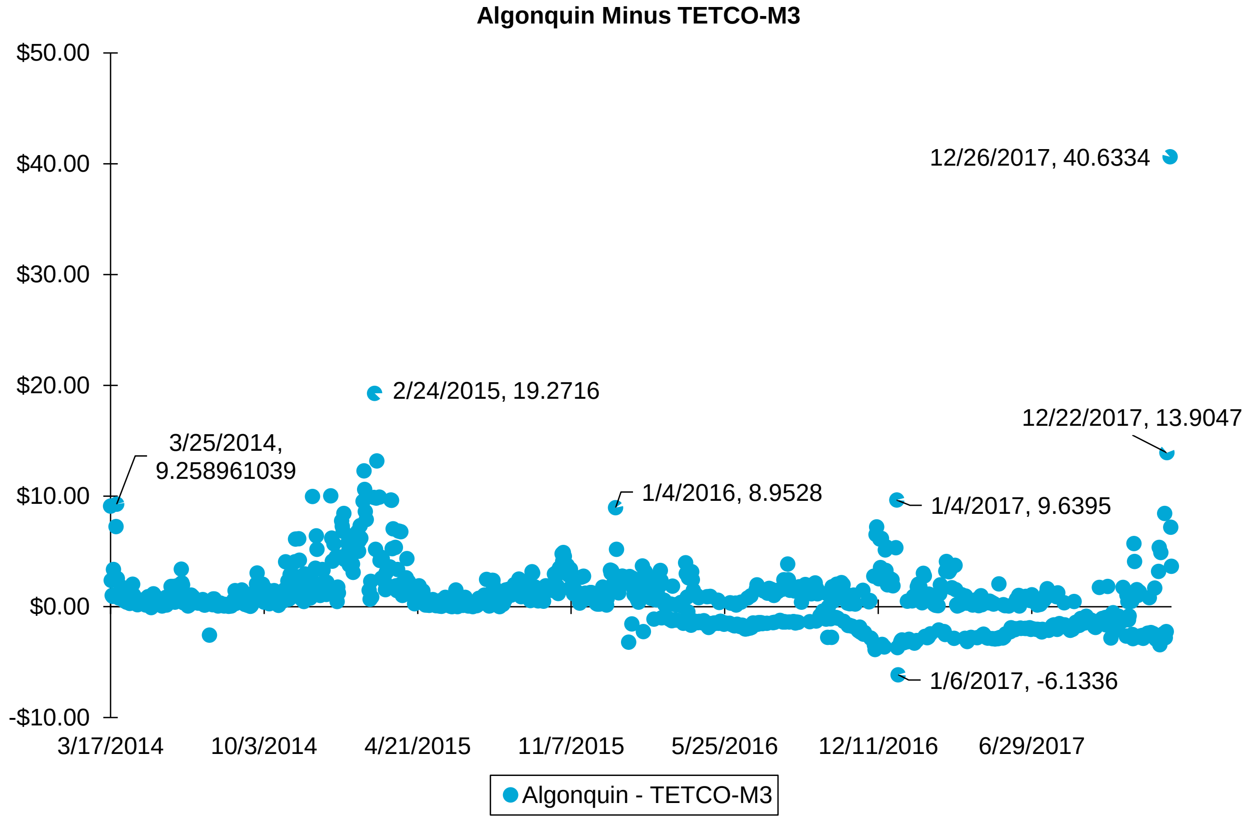

Figure 4.15 Market Hub Price Differential
2014 to 2017

Source: Energy Information Administration.

The cost to produce and deliver LNG is typically about two to three times the price of natural gas. The LNG can be sold at roughly three to four times the cost of natural gas, as long as it is still cheaper per Btu than propane or diesel.[34]

4.5.2 Transportation Costs of LNG

The natural gas pipeline network in the U.S. is the most extensive in the world, but it does not reach everywhere. Even in densely served areas, there are pockets of geography that are not directly connected to the overall network. Finally, there will be regions (as discussed for the Northeast) where there is a local natural gas distribution infrastructure, but limited access to the transmission pipeline network.

Essentially, pipeline is the most efficient and cost-effective transport of natural gas. However, pipeline delivered gas comes with a cost. When pipeline gas prices go up and other markets can provide the gas for cheaper, there is an alternative supply, making trucking and rail delivery of natural gas feasible. Figure 4.16 illustrates this relationship between natural gas pipeline and LNG transportation costs relative to distance, and is merely an example of how the different transportation modes could compare with each other.

[34] Information gathered from an interview with an LNG broker.

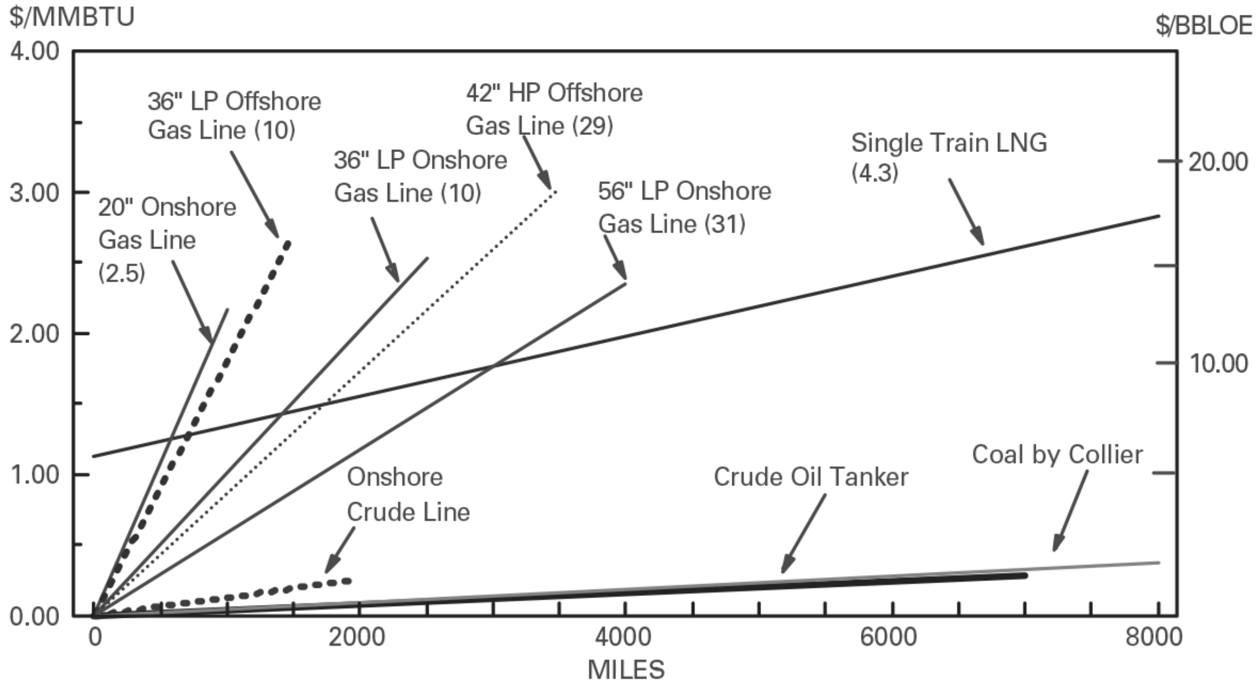

Figure 4.16 Example of Natural Gas Delivery Costs
By Mode Relative to Distance

Source: Jensen, *The Development of a Global LNG Market…*

The above figure was developed in 2004, and represents the costs of transporting natural gas at that time, but the relative shape of the graph does show the relative relationships between the transportation modes. Also, the above figure shows LNG being transported by vessel only. Ultimately, LNG has higher start-up costs, which come from the costs of liquefaction. After the initial cost, LNG typically becomes more economically attractive at longer distances. Intuitively, it would be cheaper to move LNG by vessel across the ocean than to construct an offshore gas line. When comparing the delivery of LNG by truck and rail, the initial costs of liquefaction are there, but the mode of transport is more expensive than by vessel.

Once constructed, pipeline transport is generally the most cost-effective means of transporting natural gas. For the continental U.S., this is generally true for domestic shipments, since the breakeven point between LNG and pipeline delivery is around 3000 miles. As liquefaction costs decrease, LNG delivery breakeven point with pipelines will decrease. LNG will also be more cost effective than pipelines at shorter distances.

Truck movements of LNG are known to occur for mainly economic reasons. For this reason, it is spikes in prices, capacity shortfalls, takeaway constraints, and constrained supplies that drive the movement of LNG by truck, not overall economies of price.

From Figure 4.16, LNG surface transport from a large, single-train LNG facility may be more economical than a pipeline. This depends upon whether or not a given pipeline is available, or can be built. Other factors, such as the possibility of substituting other fuels or the advantages of natural gas versus other fuels are important as well. Additional factors include short-term fluctuations in local pricing, because pipelines take time to construct. However, truck transport is more flexible as trucks can be dispatched quickly. So, when supply and demand imbalances make local pipeline gas expensive, LNG delivered by truck can become competitive, even if more expensive than what might be possible were a pipeline to be built.

Natural gas movements are a function of price and delivery convenience. Truck and rail delivery are a "flexible and competitive complement to traditional pipeline transportation" for the transport to market from "remote locations not adequately served by pipelines."[35]

LNG is sourced because the LNG is the most economical, and competes with other fuel sources such as pipeline gas, propane, and diesel. If another fuel source were more economical to procure, the users could switch products. As long as a supply source is close enough that the cost to transport it and supply it is cheaper than other energy products, the LNG will move.

4.5.3 Competitiveness of LNG

A facility that is connected to the pipeline supply network may contract their natural gas through interruptible service contracts from the pipeline company. Peak demand periods, such as during cold winters and hot summers, can exceed pipeline capacity in some regions. To guarantee that service will not be curtailed during peak demand periods, firm service contracts reserve capacity that must be fulfilled except due to unforeseeable circumstances.[36] Interruptible contracts are lower priority than firm contracts, and flow can be stopped in order serve the firm contracts, leaving the facility seeking alternative energy sources. Interruptible service is cheaper than firm service and prices paid for the gas are subject to the rise and fall of natural gas market.

Examples of regions not well served by pipelines include New England and the Mountain West. A major net-demand region, the Northeast, has become a net-supply region thanks to the Utica and Marcellus shale plays, which produce natural gas economically. The proximity of this supply region is close to a major market of the eastern seaboard. However, the existing pipeline network has limitations in pipeline capacity and directionality. For decades, natural gas has flowed into the Northeast from the Southwest, and now the Northeast is the fastest growing natural gas supply region. Projects already are underway to reverse the flow of pipelines so that the Northeast can provide supply to the Southeast and the Midwest. Additional pipeline capacity and flow reversals take time, and while they await permitting and construction, the Northeast is an example of a region experiencing capacity constraint. New pipelines also face increasing public opposition which further delays and sometimes prevents construction. This will reduce local prices of natural gas, driving investment into new infrastructure. Once the new infrastructure is in place, the price differentials between regions will reduce to the marginal cost of transport. Whenever the pricing differential has enough spread to cover the cost of transport, there is incentive to sell the product in another market. In the case of LNG, the price differential would have to be enough to cover the additional cost of liquefaction, storage, transportation, and regasification. LNG would have to compete with local prices for natural gas or for other fuel sources such as propane.

One of the LNG truck movements apparent from the EIA data was transport from Alabama to New Jersey, a 700 mile trip, one-way. This is a possible example possible price arbitrage, or a supply solution where pipeline construction is not possible or timely. Initial examination of truck rates show that truck delivery can range from $0.4 to $1 per MMBtu for this distance. Adding the costs of liquefaction, regasification, and storage, then the overall price of LNG delivery is $2.00 to $3.70 per MMBtu. That suggests that any time the

[35] Braziel, "The Domino Effect."

[36] Energy Information Administration, "Natural gas power plants…"

spot price of natural gas in Alabama is $4/MMBtu less than the spot price of natural gas in New Jersey, then transport via truck may be a viable option.

One of the LNG truck movements we identified from the EIA data was from a merchant plant in Alabama to a peak shaving facility in New Jersey. We examined this example because it is a long distance by truck, or over 700 miles one way. This is a good example of how the price differential between market hubs can influence transportation decisions for moving LNG. In this example, if the spot price of natural gas in Alabama is $4/MMBtu less than the spot price of natural gas in New Jersey, than this large $4/MMBtu price differential provides incentive for the merchant plant in Alabama to figure out how to move product to New Jersey. Even if the merchant plant sold it to the New Jersey peak shaving facility for a little less than the going rate, the merchant plant in Alabama can make money and the peak shaving facility in New Jersey can save money, so it is mutually beneficial. Also, if the price surge is temporary, there is not enough time to even consider adding a pipeline to fill the demand, the product must be shipped soon, and truck is the only option. All the merchant plant in Alabama has to do is figure out how to get natural gas to New Jersey for less than $4/MMBtu. Initial examination of truck rates show that truck delivery can range from $0.4 to $1 per MMBtu. If you add on the costs of liquefaction, regasification, and storage, then the overall price of LNG delivery is $2.00 to $3.70 per MMBtu, which is less than $4/MMBtu market price differential.

There are limits to how far natural gas can be moved economically via pipeline. Many researchers already have evaluated the economics of LNG shipment versus natural gas shipment. Given an alternative method for transport (such as truck or rail transport of LNG), price arbitrage becomes possible. Using information regarding LNG economics, and our knowledge of the LNG markets, the CS Team developed three scenarios for LNG transport, comparing cargo trailers to rail tank cars or ISO containers on flat cars. Over distances greater than 300 miles, rail transport of bulk materials becomes competitive with road, *provided that the shipments are not time sensitive*.

4.6 LNG Transportation Scenarios

In this section, the CS Team evaluated the movements of LNG by bulk rail, truck, and intermodal delivery to determine which method would be most economical. This was an economic case study, not a risk case study. More information on the quantitative risk assessment (QRA) can be found in Chapter 5. To conduct the case study, the CS Team developed several scenarios to detail Interstate LNG shipment costs by mode. Using information from multiple sources, The CS Team estimated the costs of shipment, and represented how shippers could economically evaluate and view the transportation modes when the pipeline delivery is not feasible or possibly not preferred. Though not presuming to be the method by which such decisions are actually made, the scenarios illustrate the competitive nature between transportation modes.

4.6.1 Methodology

Assuming that pipeline delivery of natural gas is either not an option due to capacity shortfall or a stranded market, this economic model compares the economics of a truck delivery of LNG with two alternative rail deliveries. This economic model, along with industry input, hypothesizes that rail can be economically competitive in some origin-destination scenarios.

First, we identified the parameters in which rail would be a competitive choice based on possible routes for LNG if allowed by rail. This is a start to developing certain parameters to the risk model. Industry input on the logistics of LNG by rail confirms that the ISO container form of delivery would provide conveniences that would enable faster transport, and could be a preferred rail container in scenarios that may involve drayage movements. Certain rail routes that do not require drayage are favorable for bulk liquid transfer directly to a facility or storage unit. The process of transferring LNG between tanks at a bulk liquid transfer facility requires special equipment that can handle the cryogenic temperatures, and workers trained in the safe handling of cryogenic liquids.

To understand the costs of transporting LNG by truck, portable container, and rail, the CS Team investigated one of the Interstate movements in the EIA data between a natural gas processing facility in western Pennsylvania and a power plant in Worcester, MA. This was a deliberate choice for such scenarios, since western Pennsylvania is in the productive Marcellus and Utica Shale region, and Massachusetts is an area in New England with high natural gas demand.

The shippers' cost for this proposed movement was analyzed in three scenarios. Scenario one is the movement of the natural gas in liquefied form by truck, in a MC-338 cryogenic tank trailer. This is the only scenario that currently is legally available without a special permit. Scenario two is the movement of the LNG by intermodal container. In this scenario, the LNG is loaded into an ISO container, which is placed on a railcar at the facility, moved by rail to an intermodal facility in Ayer, MA and then trucked the remaining 35 miles to the power plant in nearby Worcester, MA. Scenario three is the movement of the LNG by bulk railroad tank car. In this scenario, the LNG is loaded into a DOT 113C120W railcar, and moved by rail to Worcester, MA. Once in Worcester, MA, the material could be delivered to the power plant if a rail spur goes to the power plant. However, since it is less likely that power plants will be able to add rail lines in densely populated areas, it is assumed that the material would go to the bulk liquid transfer facility in Worcester, be transferred to MC-338 truck trailers, and then delivered to the power plant. The summary of these scenarios is shown in Table 4.4 and a map of the scenario routes is in Figure 4.17.

Table 4.4 Truck, Railroad and Intermodal LNG Transport Options

Scenario	Mode 1	Mode 2	Mode 3
1a—Truck	Truck (MC-338)	–	–
1b—Truck	Truck (ISO)	–	–
2—Intermodal	Truck (ISO)	Rail (ISO)	Truck (ISO)
3a—Rail	Rail (DOT-113C120W)		
3b—Rail	Truck (MC-338)	Rail (DOT-113C120W)	Truck (MC-338)

Source: Cambridge Systematics

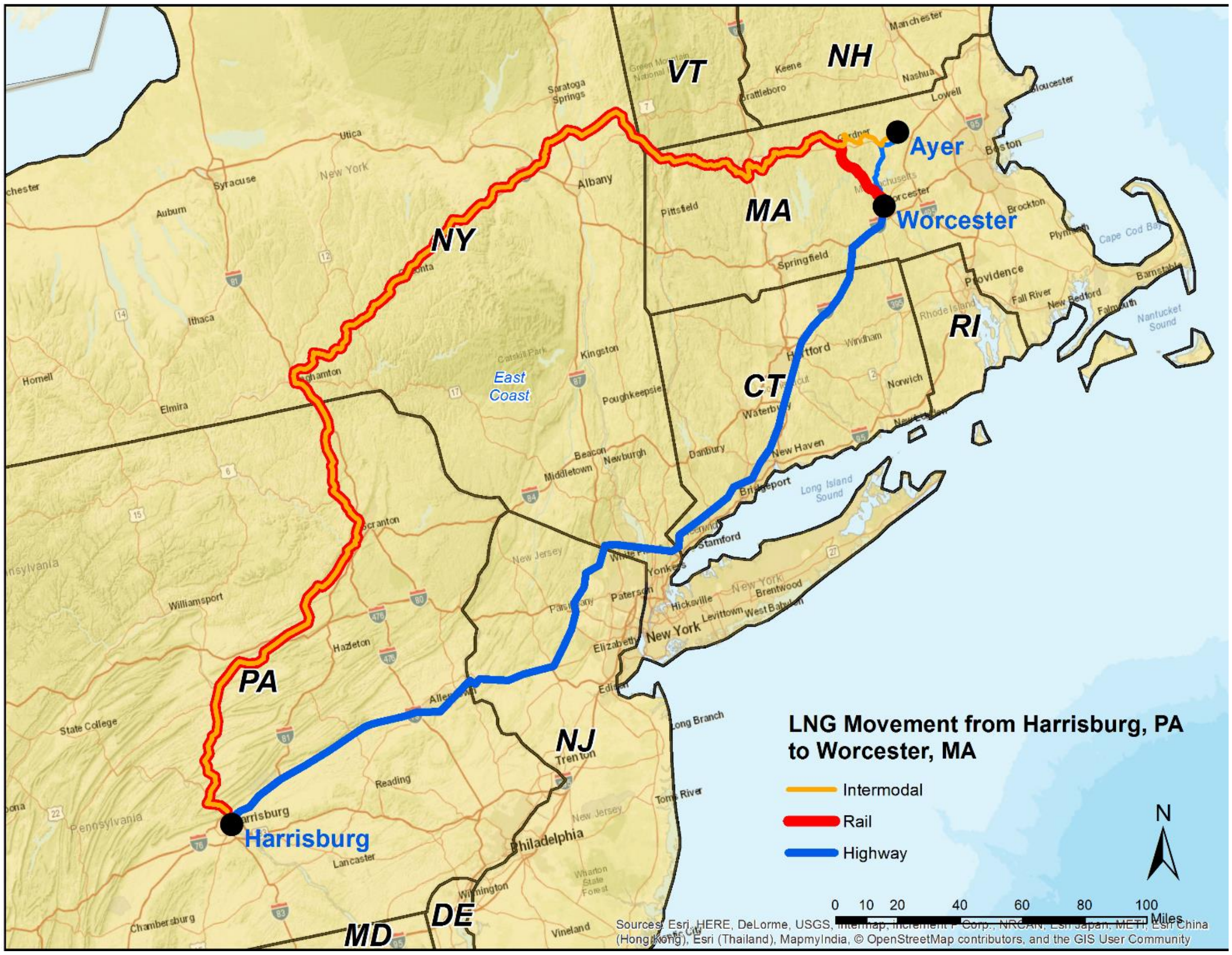

Figure 4.17 Pennsylvania to Massachusetts Routes
By Mode

Source: Cambridge Systematics.

4.6.2 Scenario 1: Pennsylvania to Massachusetts by Highway

Scenario 1 assumes 72,041 MCF of natural gas is transported from Harrisburg, PA to Worcester, MA. The highway route, shown in 4.17 has a trip length of 353 miles. Scenario 1a assumes that the LNG would be shipped in a MC-338 truck trailer, and Scenario 1b assumes that the LNG would be shipped in an intermodal ISO container.

A MC-338 cryogenic tank trailer has a gross capacity of about 12,700 gallons, depending on the manufacturer. Most Interstate highways have a weight limit of 80,000 lbs. GVWR. The truck tractor is typically between 15,000 and 20,000 pounds. Assuming a 16,500-pound tractor weight, and an empty trailer weight of 25,200 pounds, the net allowable payload of LNG would be 38,300 pounds or effectively 10,943 gallons at 3.5 pounds per gallon of LNG.[37] Since the volume that can be carried by the truck is limited by the weight limit, the delivery of LNG by truck "weighs out" before it "sizes out." Truck volumes are limited by weight, not the volume or capacity of the container.

[37] Chart Model ST-12700 MC-338 LNG trailer—12,700 gallons gross volume.

An intermodal ISO container has more weight in the trailer due to the need to have a chassis. A chassis could weigh between 5,500 to 8,000 pounds. Assuming a 6,500 chassis weight, a 23,500-pound empty ISO container weight, and the same tractor weight and gross vehicle weight limit as Scenario 1a—16,500 pounds and 80,000 pounds, respectively—the available payload weight would be 33,500 pounds. Although some ISO containers are being built up to 12,200 gallons gross volume, at 3.5 pounds per gallon of LNG, the capacity of an ISO container by highway weighs out at 9,571 gallons of LNG.

At a distance of 353 miles and cost of $0.114 per ton mile, the total cost to move 72,041 MCF of natural gas by truck is estimated to be $61,651 by MC-338 and $61,339 by ISO container. The details of the calculation assumptions are shown in Table 4.5. Even though the MC-338 cargo tank can carry more LNG per vehicle than the ISO container, the overall cost difference is a negligible 0.5 percent. For this scenario, the user would choose the most convenient option, depending on the availability, purchase price, leasing costs, and supply chain fluidity of the containers. For example, ISO containers are easily offloaded and can function as short-term storage, but the opportunity costs of occupying an ISO container would have to be examined. Similarly, a MC-338 trailer could be disconnected from the tractor, with similar opportunity costs for an idle piece of transportation equipment. In a direct truck movement, the benefits between the containers would be dependent on the individual situation and needs of the shipper and receiver. These externalities are not represented in the cost model.

Table 4.5 Scenario 1: Pennsylvania to Massachusetts
By Highway

	Constant Properties	Scenario 1a Highway (MC-338)	Scenario 1b Highway (ISO)
MCF of Natural Gas per gallon of LNG	0.0826		
MMBtu per gallon of LNG	0.082644		
Pounds per gallon of LNG	3.5		
Volume of Natural Gas, MCF	72,041		
Volume of LNG, gallons	872,167		
Container/Tank Gross Capacity, gallons		12,700	12,200
Payload Weight Limit, pounds		38,300	33,500
Payload Weight Limit, tons		19.15	16.75
Payload Volume Limit, gallons		10,943	9,571
Payload Energy Content, MMBtu		904	791
Number of Trucks		80	91
Miles per trip	353		
Truck Miles		28,240	32,123
Ton Miles		540,796	538,060
Cost per Ton Mile	0.114[1]		
Total Cost		**$61,494**	**$61,183**
Highway Unit Cost		$769	$672
Cost per MMBtu		$0.85	$0.85

Note: One Thousand Cubic Feet, MCF. Million British Thermal Units, MMBtu. Tons are in U.S. short-tons, 2,000 pounds per ton.

[1] National Van Rates 13-month average; dat.com.

4.6.3 Scenario 2: Pennsylvania to Massachusetts by Intermodal Container

The second scenario would involve an intermodal container on a rail flat car from Pennsylvania to Massachusetts using Norfolk Southern (NS) routes. Knowing that railroad interchange fees can be approximately $600 per railcar, the route chosen avoids any such interchanges, and stays on NS, NS shipping partners, and NS joint venture routes. If the ISO containers were only being shipped by rail, they would “size out” before they “weighed out,” and the volume and filling density of the container would determine the amount of LNG per payload. However, since the ISO container would still travel by highway at some point, it is assumed that the containers would weigh out with the same properties as in Scenario 1. Scenario 2 differs in that the route that is traveled is different and that the container will be moved between a truck chassis and a rail flat car, twice. The 91 ISO containers, each containing 9,571 gallons would be transported 507 miles by rail and 35 miles by truck at an average cost of $0.066 per ton mile for a total of $54,752 as shown in Table 4.6. This total cost is 11 percent less than the cost by highway alone. With the lower cost, comes higher transport times. Highway delivery is fast and direct, rail delivery is circuitous and lengthy. Unit trains with high volume of a single commodity often can demand better rail service schedules, but a small number of cars would be shipped by manifest train, which makes frequent stops, and takes longer. The scenarios that we are looking represent an entire year’s worth of volume. It is unknown right now if the movement occurred in a single batch, or in smaller batches throughout the year. It is hard to say if the rail delivery of LNG would benefit from unit train service priority.

Table 4.6 Scenario 2: Pennsylvania to Massachusetts by Intermodal Container

	Constant Properties	Scenario 2
MCF of Natural Gas per gallon of LNG	0.0826	
MMBtu per gallon of LNG	0.082644	
Pounds per gallon of LNG	3.5	
Volume of Natural Gas, MCF	72,041	
Volume of LNG, gallons	872,167	
Container/Tank Gross Capacity, gallons		12,200
Payload Weight Limit, pounds		33,500
Payload Weight Limit, tons		16.75
Payload Volume Limit, gallons		9,571
Payload Energy Content, MMBtu		791
Number of ISO Containers		91
Miles per trip, highway	35	
Miles per trip, rail	507	
Highway Ton Miles		53,349
Rail Ton Miles		772,490
Total Ton Miles		825,839
Cost per Ton Mile, highway	0.1137[1]	
Cost per Ton Mile, rail	0.063[2]	

Table 4.6 Scenario 2: Pennsylvania to Massachusetts by Intermodal Container (continuation)

	Constant Properties	Scenario 2
Total Cost		**$54,733**
Rail percent of Costs		**89%**
Intermodal Unit Cost		$601
Overall Cost per Ton Mile		$0.066
Cost per MMBtu		$0.76

Source: Cambridge Systematics

Note: Million Cubic Feet, MCF. Million British Thermal Units, MMBtu. Tons are in U.S. short-tons, 2,000 pounds per ton.

[1] National Van Rates 13-month average; dat.com.

[2] CS assumption based on review of STB rail line haul rates and estimated lift and drayage costs in Northeast U.S.

4.6.4 Scenario 3: Pennsylvania to Massachusetts by Rail

The third scenario would involve a bulk liquid rail car from Pennsylvania to Massachusetts using Norfolk Southern (NS) routes. Similar to Scenario 2, the route chosen avoids any interchanges, and assumes NS shipping partners, and NS joint venture routes. It also is assumed that a DOT-113C120W railcar would be used to transport LNG. Chart Industries has optimized the design of rail tank car that fits within the Plate 'C' clearance envelope for tracks in North America. The inner tank has a volume 34,500 gross gallons and can hold 30,680 gallons of LNG based on the 49 CFR 173.319(d) maximum allowed filling density. This volume of LNG would weigh 15.34 tons, and even when, including the weight of the empty car, a loaded car is well below the 263 kip railcar limits.[38] Therefore, weight is not an issue with LNG on the rail and the container "sizes out" before it "weighs out."[39]

The rail route in Scenario 3 differs from Scenario 2 in that rail is employed to the final destination, with a minimal distance by truck, if any. If the power plant did not have rail spur leading to the facility, then the shipment could be shipped to the Bulk Liquid Transload facility in Worcester, which would require a short drayage. In Scenario 3, a total of 28 rail cars, each containing 30,680 gallons of LNG would be transported 467.6 miles by rail, before being transloaded into 80 trucks for 10 miles at an average cost of $0.064 per ton mile for a total of $46,028 as shown in Table 4.7. This total cost is 25 percent less than the cost by highway alone, and 16 percent less than the cost of intermodal delivery. However, with the lower cost comes longer transport times. As we explained in Scenario 2, highway delivery is fast and direct while rail delivery can be more circuitous and therefore extend delivery times. Intermodal delivery is known to be generally faster than bulk rail shipments, but this would depend on several factors, including economies of scale, such as unit versus manifest trains. Rail delivery would be the cheapest delivery in terms of direct costs, but the estimate does not capture the costs of labor for transferring the liquid between the tank cars and truck trailers. If the railroad operator is able to drop off the commodity directly to the power plant, then theoretically the double

[38] 286,000 lbs. is the modern weight specifications for rail lines, which equates to about a 110 ton car. 263,000 is the minimum weight limit for most of the country's rail lines, which equates to about a 100 ton car.

[39] Chart Industries, Call with Scott Nason, November 2017.

handling of the material could be avoided. Otherwise, it can be assumed that there would be some extra time and cost necessary for a bulk liquid transload.

Table 4.7 Scenario 3: Pennsylvania to Massachusetts
By Rail

	Constant Properties	Scenario 3
MCF of Natural Gas per gallon of LNG	0.0826	
MMBtu per gallon of LNG	0.082644	
Pounds per gallon of LNG	3.5	
Volume of Natural Gas, MCF	72,041	
Volume of LNG, gallons	872,167	
Container/Tank Gross Capacity, gallons		34,500
Payload Volume Limit, gallons		30,680
Payload Weight Limit, pounds		107,380
Payload Weight Limit, tons		54
Payload Energy Content, MMBtu		2,536
Number of Tank cars		28
Number of Trucks (10,943 gallons or 19.15 tons each)		80
Miles per trip, rail	467.6	
Miles per trip, highway	10	
Rail Ton Miles		702,952
Truck Ton Miles		15,320
Total Ton Miles		718,272
Cost per Ton Mile, rail	0.063[1]	
Cost per Ton Mile, highway	0.1137[2]	
Interchange Fee per railcar	$600	
Number of interchanges	0	
Total Cost		**$46,098**
Rail percent of Costs		96%
Rail Tank Car Unit Cost		$1,584
Overall Cost per Ton Mile		$0.064
Cost per MMBtu		$0.64

Source: Cambridge Systematics

Note: Million Cubic Feet, MCF. Million British Thermal Units, MMBtu. Tons are in U.S. short-tons, 2,000 pounds per ton.

[1] CS assumption based on review of STB rail line haul rates and estimated lift and drayage costs in Northeast U.S.

[2] National Van Rates 13-month average; dat.com.

In addition to the variable costs of transportation, LNG delivery also incurs fixed costs associated with liquefaction, storage, and gasification. The most expensive component in the LNG supply chain is the liquefaction plant, and the costs for liquefaction depend on the size of the facility. Larger facilities generally are able to reduce the cost of liquefaction due to economies of scale and more advanced equipment that has less waste. All three scenarios are summarized in Table 4.8, along with the assumed fixed costs of liquefaction, gasification, and storage.

Table 4.8 Pennsylvania to Massachusetts LNG Cost Scenarios

Scenario	Mode 1	Mode 2	Mode 3	Cost	Transport. Cost per MMBtu	Liquefaction, Gasification, and Storage Costs per MMBtu[40]	Total Cost per MMBtu
1a—Truck	Truck (MC-338)	–	–	$61,494	$0.85	$4.52	$5.37
1b—Truck	Truck (ISO)	–	–	$61,183	$0.85	$4.52	$5.37
2—Intermodal	Truck (ISO)	Rail (ISO)	Truck (ISO)	$54,733	$0.76	$4.52	$5.28
3—Rail	Rail (DOT-113C120W)	Truck (MC-338)		$46,098	$0.64	$4.52	$5.16

Source: Cambridge Systematics Inc.; NS; Chart Industries.

The three examples illustrate some of the challenges involved with shipping LNG over long distances, and the need to involve multiple modes of transport. Overall, portable ISO containers prove to be the most versatile mode of LNG transport given the variables discussed in these scenarios. Rail delivery would be the cheapest delivery in terms of direct costs, but the estimate does not capture the costs of labor for transferring the liquid between the tank cars and truck trailers. As long as the overall cost of LNG is less than the price differential, then it could be more cost effective to transport the natural gas by LNG rather than by pipeline.

4.7 Future LNG Railroad Transportation

Because, if approved, rail transport would be an alternative to truck for surface transport of LNG, Figure 4.18 shows the routes that may be used if volumes of LNG similar to those currently moved by truck were moved by rail. Lacking the details of the specific origin and destinations of these Interstate movements, the CS Team used State centroids, and developed a hypothetical routing of LNG rail delivery across the country. This is not intended to be accurate, but rather to illustrate how rail shipments may be used to supplement or replace existing truck shipments should rail shipments of LNG be allowed in the HMR.

[40] ETSAP, “Oil and Natural Gas Logistics.”

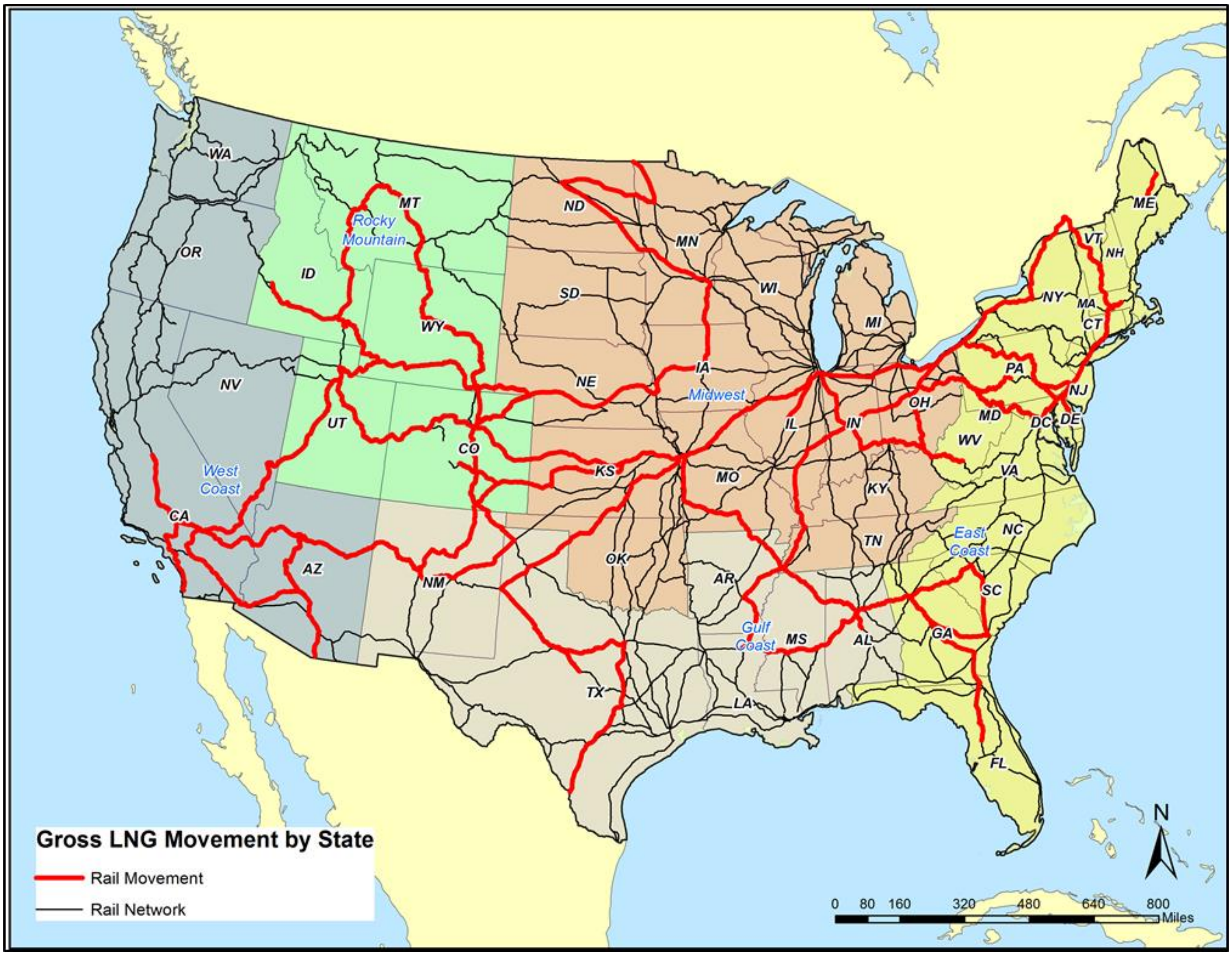

Figure 4.18 (Illustrative Only) Gross Rail LNG Movements by State

Source: Energy Information Administration; Cambridge Systematics, Inc.

These LNG truck movements represent bulk deliveries of natural gas, not in-transit usage as propulsion. The end user could be using the gas for electric power, heat, industrial use, or propulsion. LNG is being transported by truck for distances that per literature would be more effective by pipeline because the destination found it to be the most economical choice. This could be because the local supply prices spiked during a supply shortage, or because the destination is not connected to the pipeline network anyway. If not connected to the network, the destination user could be using LNG to compete with other fuel sources such as propane or diesel. Truck delivery will likely continue until the price differential is less than the marginal costs of transportation. Examples include: 1) pipelines may be in the proposal and permitting process, 2) the region could not have the volumes to justify a pipeline, or 3) a pipeline may not be feasible for geographical, environmental, or political reasons. If the volume is enough to justify a pipeline, then rail might be a more viable option considering its greater capacity over truck. If the volume would not be enough to justify a unit train, than a manifest train would not provide the same level of service, making it difficult to compete with the convenience of truck delivery.

Eventually, the market will find the most economical solution, whether that is an alternative fuel source or an alternative mode of delivery. Until then, price differentials govern the decisions that the consumers make.

Natural gas movements are a function of price and delivery convenience. Truck and rail delivery are a "flexible and competitive complement to traditional pipeline transportation" for the transport to market from "remote locations not adequately served by pipelines." Natural gas delivered by rail would be slower than truck delivery, unless enough natural gas were delivered at once to build a unit train. Unit trains are treated with higher priority than manifest trains. This comes with additional risk, which will be discussed in Part 2. Natural gas delivered by rail and trucks provide more flexibility in their networks ability to access multiple delivery destinations across the country—pipelines are constrained in their access and delivery points.

Different than the development of non-pipeline crude oil rail deliveries, natural gas comes from many sources. Natural gas comes from many suppliers, and goes to even more users. There is enough natural gas supply and demand spread out across the country, and nearly all of it is transported by pipeline. It is hard to predict if rail delivery can compete with the convenience and speed of truck delivery. "Whenever production exceeds pipeline capacity, the railroads can step in. Whenever new production has to wait for a pipe, it will travel by rail. Whenever markets are disrupted by pipeline congestion, railroads will step in to bypass the tangle. In remote plays where there are no pipelines at all, railroads will be the primary transportation mode."[41] This is true except if rail delivery is not allowed. In that case, truck or vessel is the only other option.

[41] Braziel, "The Domino Effect."

5.0 Quantitative Risk Assessment

5.1 Introduction

In the context of this study, Quantitative Risk Assessment (QRA) is used to determine risks associated with LNG transport and handling by surface modes, with an emphasis on rail. QRAs are used to demonstrate the risk caused by the activity and to provide authorities with information needed to make decisions about the level of risk acceptable for site developments or transportation routes.[42] This section describes the QRA history and process, understanding risk, examples of LNG Modeling and the factors and parameters required to construct the LNG Risk Model.

Over the years, researchers have noted considerable variation in the outcomes of the QRA studies. Numerical differences of two to three orders of magnitude are not uncommon, and also rankings between different scenarios often showed large differences. The inherent variability also found in hazard identification techniques, an essential building block for QRA, adds to the unreliable nature of QRA. While QRA techniques ultimately lead to the development of better decisions and safer systems, it must be understood that QRA is only as good as the data and assumptions contained within the process. The validity of particular instances of QRA should be accompanied by scientific confirmation of these claims which help to overcome doubts and criticisms about QRA efficacy.[43]

With this in mind, QRA relies on an estimation of the probability and consequences of a release incident. The CS Team focused on parameters and factors to model the derailment and release probability of LNG rail cars to account for a variety of track and train characteristics. The probability will help to address the likelihood of a release per shipment and resulting hazards to the public in the event of a derailment or other incident. When the probability of LNG tank car derailment is understood, better decisions can be made regarding the crashworthiness, placement, and operation of rail cars and the potential consequences from an LNG release due to a derailment.

5.2 National Fire Protection Administration (NFPA) 59A Protocols

The NFPA has been involved in LNG emergency response for many years. This began primarily with fire protection for LNG facilities constructed in the U.S. in the 1970s, during which time maritime LNG specifications were also developed. Work on the NFPA 59 Standard began in 1960 and the first edition was adopted in 1967 (see Figure 5.1). Recommendations for QRA of LNG plants were issued in the National Fire Protection Association (NFPA) standard, NFPA 59A Standard for the Production, Storage, and Handling of Liquefied Natural Gas (LNG), 2015.

[42] Uijt de Haag et al., *The 'Purple Book…'*

[43] Cornwell and Meyer, "Risk Acceptance Criteria…"

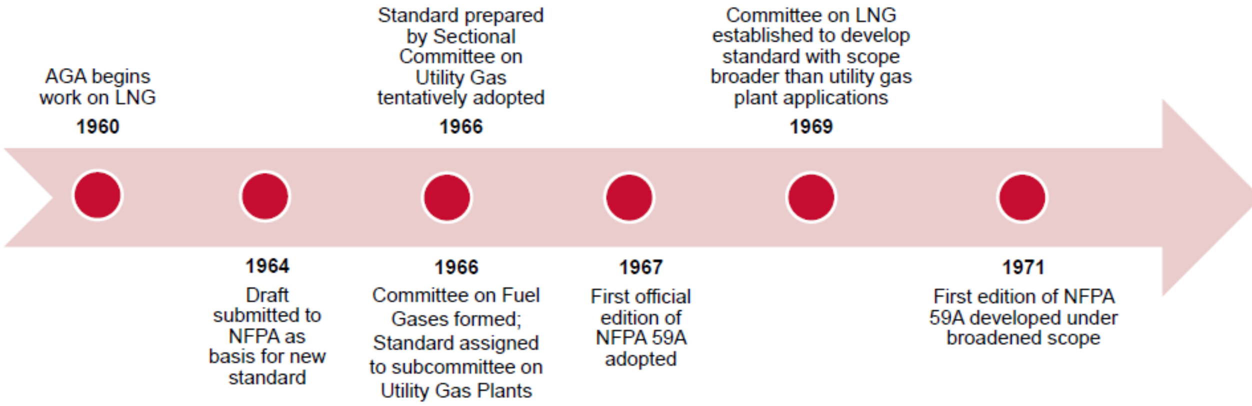

Figure 5.1 NFPA 59A Timeline

Source: National Fire Protection Association, *NFPA 59A: Standard for the Production…*

According to the NFPA 59A (2016 version), the generally accepted QRA techniques and protocols are described in the following publications:

1. Center for Chemical Process Safety's "Guidelines for Chemical Process Quantitative Risk Analysis".
2. Health and Safety Executive's "Five Steps to Risk Assessment".
3. Health and Safety Executive's "Risk Criteria for Land-use Planning in the Vicinity of Major Industrial Hazards".
4. *Risk Management. Risk Assessment Techniques*. European Standard: BS EN 31010:2010.
5. *The 'Purple Book': Guideline for Quantitative Risk Assessment in the Netherlands*.

The CS Team reviewed these documents as part of this study to assess applicable QRA elements for the LNG QRA process. While the literature varies between facility and transport risks, the assumptions, parameters and factors used can be applied to this study effort where applicable.

Contained in the NFPA 59A guidance are descriptions of the terms "individual risk" and "societal risk." These terms have also been defined in Great Britain in the Health and Safety Executive Societal Risk Technical Advisory Group made up of academic, industry and Government specialists. This group has advised HSE and departments over the years on matters relating to societal risk methodology and presents the technical issues which need to be resolved prior to the development and implementation of any system for explicit attention to societal publications. HSE publications have been referenced throughout this report.

5.2.1 Individual Risk

Individual Risk (IR) is defined by HSE (1995) as "the risk of some specified event or agent harming a statistical (or hypothetical) person assumed to have representative characteristics." The 'specified event or agent' may be defined as fatality, injury, or exposure to a defined level of blast overpressure, thermal radiation or dose of toxic material.

NFPA 59A describes IR as “the frequency, expressed in number of realizations per year, at which an individual, with continuous potential exposure, may be expected to sustain a serious or fatal injury.” IR is defined in NFPA-59A as “acceptable IR fatality probabilities” ranging from 10^{-4} yr^{-1} (or a fatality per 10,000 years) to 10^{-8} yr^{-1} (or a fatality per 100,000,000 years). This range is known as ALARP “as low as reasonably practicable.”

5.2.2 Societal Risk

Societal Risk is defined in NFPA 59A as “the cumulative risk exposure by all persons sustaining serious or fatal injury from an event in the LNG plant.” Note NFPA 59A explicitly applies to LNG plants and stationary facilities; it does not apply to LNG transportation or portable LNG containers. Thus, the quantitative risk criteria proposed in the standard are not directly applicable to rail shipping of LNG. However, these risk criteria are discussed here as one potential basis for quantitative risk criteria for rail shipping of LNG.[44]

In the Exponent Report for FECR, the PHAST Risk v6.7 tool was used to model the consequences of potential releases and to calculate the resulting Individual Risk (IR) and Societal Risk (SR) for the FECR mainline and yard/intermodal facilities.

Exponent points out in their report that FRA has not codified quantitative risk criteria for LNG hazardous materials transportation scenarios. Additionally, QRA analyses are not common regulatory requirements in the U.S. and no broadly accepted risk criteria are employed by domestic communities or industries. Therefore, Exponent used LPG instead of LNG as a benchmark for calculated risk since accident rates and hole size probabilities in accidents are considered independent of the hazmat commodity shipped.[45]

The risk criteria presented in NFPA 59A are summarized in the following Table 5.1 and in Figure 5.2.

Table 5.1 Summary of IR and SR Quantitative Risk Criteria

IR Criteria (yr^{-1})	SR Criteria
Zone 1: IR $\geq 10^{-5}$	Unacceptable Risks
Zone 2: $10^{-6} \leq$ IR $< 10^{-5}$	ALARP: (Region between curves)
Zone 3: $3 \times 10^{-7} \leq$ IR $< 10^{-6}$	Tolerable Risks

Source: National Fire Protection Association, *NFPA 59A: Standard for the Production…*

[44] National Fire Protection Association, *NFPA 59A: Standard for the Production…*

[45] Hart and Morrison, *Bulk Transport by Road and Rail*

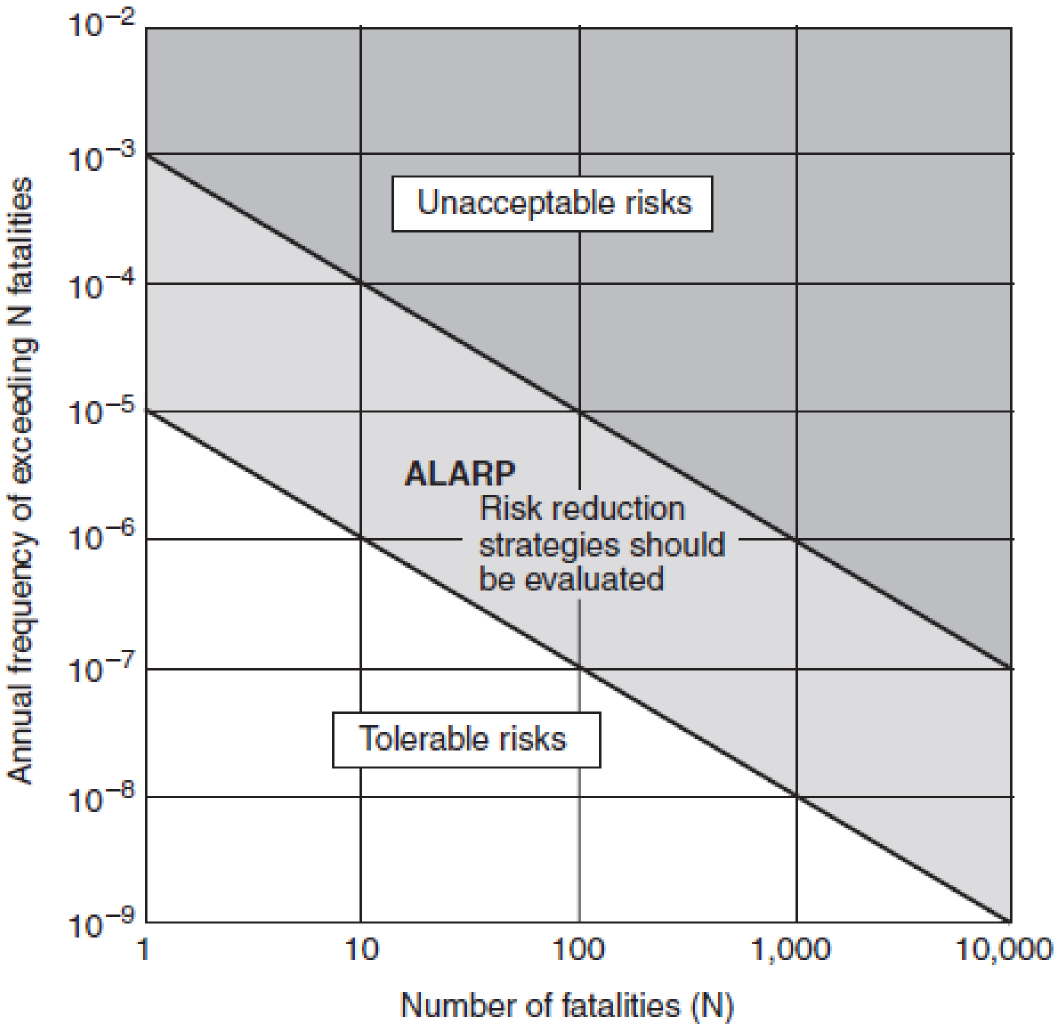

Figure 5.2 Acceptability Regions of Societal (Injuries) Risk in the F-N Domain

Source: National Fire Protection Association, NFPA 59A: Standard for the Production

5.3 Understanding Risk

Risk analysis is a key feature of modern decision-making, for both Government and industry. While not yet mandated by Government regulations, quantitative risk analysis is an increasingly preferred method of hazard evaluation based on numerical estimation of incident frequency and consequences. With regard to assessing hazmat risks, the range of QRA concepts is very broad, given the complexities of hazmat transport and the number of stakeholders involved.

The QRA process requires failure and event data. However, limited reliability or failure rate data has been collected for the equipment in the LNG industry. Usually failure rate data from nuclear, oil and gas industry are borrowed for reliability studies and risk assessment of the LNG facility. Risk modeling techniques include high-level approaches to risk assessment and modeling.[46]

[46] Texas A&M University, May Kay Center.

The literature discusses a variety of initial or governing approaches to risk. Some models take the form of data-driven risk assessments; other models combine risk analysis with route choice. Additionally, economic risk analysis models in some situations are used to determine the costs of certain decisions based on risk.

An important component of QRA is the risk criteria used to define risk. There are several foreign and several domestic examples of quantitative risk criteria. However, there is a significant disparity in risk criteria for public exposure.

Currently, the U.S. Department of Transportation (DOT) Federal Railroad Administration (FRA) has not codified quantitative risk criteria for LNG hazardous materials transportation. Additionally, QRA analyses are not common regulatory requirements in the U.S. and no broadly accepted risk criteria are employed by domestic communities or industries. Nevertheless, this study contributes to the body of knowledge required to better assess LNG risks with regard to surface transport. The Dutch Government and their respective regulatory agencies have been international leaders in utilizing QRA techniques for determining acceptability of fixed facilities and transportation routes. Therefore, the Dutch "Guidelines for Quantitative Risk Assessment," (known as the Purple Book) Netherlands, 2005 was used as an important reference for this research.

5.4 QRA Uses in Industry and Government

QRA is used to assess risks throughout industries, including chemical production, oil and gas processing plants, power generation plants, and manufacturing companies. In additional U.S. Government agencies have developed QRA techniques to quantify hazmat transportation and storage risks, determine route and mode choices and identify the most appropriate packaging solutions. This section identifies how selected U.S. industries and agencies use QRA.

Chemical and manufacturing companies evaluate the risk to human health and the environment from an accident or chemical release during loading and transporting their products. Risk analysis and management is becoming increasingly important to the process industry to meet safety criteria and regulations. QRA is used to determine mode and route choice, packaging selection, application of security measures, manufacturing locations, and emergency response resource planning.

The **Railway Supply Institute** (RSI) and the **AAR** perform research and analyses that support hazmat transportation risk assessment. To meet the Federal regulatory requirements of 49 CFR 172.800—Additional Planning Requirements for Transportation by Rail, AAR developed RCRMS which allows rail operators to consider the 27 required risk factors, including network infrastructure characteristics, railroad operating characteristics, human factors, and environmental and terrorist-related parameters.

The **Environmental Protection Agency** uses an Ecological Risk Assessment Framework to address risk from the transportation and storage of hazardous materials. The EPA's framework is used as a guide to create six steps that can be used to assess the risk of transporting and storing hazardous materials. The steps are 1) evaluate the area for the risk assessment; 2) identify transportation routes and storage site; 3) identified heavily shipped and stored hazardous materials; 4) identify types of releases and possible outcomes; 5) determine risk; and 6) draw conclusions and make recommendations.

FMCSA has decision-making processes that consider risk assessments which are driven by issues conveyed by external parties or through observations from field investigators. Implementation of the Compliance, Safety, Accountability (CSA) program and the Safety Measurement System (SMS) for measuring the safety of motor carriers and commercial motor vehicle drivers collectively take the place of a risk assessment tool.

FRA uses risk assessment to help identify potential risk reduction strategies, including those that consider route choice, packaging selection, application of security measures, operational changes, research prioritization, and inspection and enforcement prioritization. Its focus is on research prioritization. For rail risk, the likelihood of an accident is not considered to be a hazmat-specific factor. FRA focuses on the factors that affect the probability that the package will be involved in a derailment or a major accident and the probability that it will be damaged or punctured and release the product.

PHMSA (OHMS). For most risk assessments performed by PHMSA, a separate analysis process is used, based on the specifics of the analysis and the available data. Their resource allocation is similar to FMCSA's Comprehensive Safety Analysis model. Data on prior incidents, inspections, violations, and complaints are used to assess the safety risks for specific companies. Other factors include the types of materials, quantities handled, and the size of the company.

PHMSA (OPS) does not conduct risk assessments but oversees the individual pipeline operators who are required to ensure the safety, integrity, and reliability of their own pipelines. The Pipeline Risk Management Manual is the industry standard methodology for conducting pipeline risk assessments. A key data source is the PHMSA database of pipeline incidents and accidents.[47]

5.5 Quantitative Risk Analysis Methodology

In a QRA both the frequencies of events and their consequences are quantified, using different techniques. QRA methodologies contains some differences, however, there are many examples in technical literature available.[48] Typically, a QRA will consist of the following steps (Table 5.2):[49]

Table 5.2 Quantitative Risk Assessment (QRA) Steps

Steps	Description
1	Identify the hazards.
2	Summarize hazard identification study findings as set of scenarios to be modeled.
3	Estimate release rates and duration, and quantities of materials involved.
4	Estimate release consequences in terms of an area, inside which a specified level of harm will be met or exceeded.
5	Define mitigation effects (such as shelter-in-place).
6	Define release consequence in a measure of harm (injury or fatality) to individual or population.
7	Estimate event frequency (such as loss of containment).
8	Calculate probabilities and frequencies to determine numerical risk estimates.

Sources: Center for Chemical Process Safety; Exponent Inc.; *The 'Purple Book;'* European Standards; Cambridge Systematics, Inc.

Steps 1 through 3 help to identify scenarios for modeling, together with the necessary data to compute frequencies and consequences. This process is not normally capable of automation. These scenarios should

47 Transportation Research Board, *Hazardous Materials Transportation…*

48 Refer to the list on Section 5.2 for examples.

49 Health and Safety Executive, "Application of QRA…"

be conducted by an experienced analyst or team of analysts. Step 4, however, usually involves modeling of vapor dispersion, pool fires or explosion effects. In some cases these calculations can be performed by hand or with the aid of spreadsheets, although use of computerized models is common, and recommended for this level of analysis on a case by case basis. In simple cases, where the set of scenarios to be considered is small, Steps 5 to 8 can be performed by hand or using spreadsheets. However, it is more usual to employ risk calculation software. It is possible to produce different types of numerical risk estimate at Step 8, depending on the purpose of the QRA study.

6.0 Rail LNG Risk Assessment

6.1 Methodology

This section describes the proposed methods for developing a rail LNG quantitative risk assessment (QRA). It includes descriptions of event and fault tree analyses, the event tree diagram, and the factors and parameters required to complete the QRA.

Several methods used to estimate the frequency and consequences of hazmat release incidents are known as logical diagram-based techniques. These include Fault Tree Analysis (FTA) and Event Tree Analysis (ETA). Fault trees lay out relationships among events, whereas event trees lay out sequences of events linked by conditional probabilities.

6.1.1 Fault Tree Analysis (FTA)

Fault tree analysis permits the hazardous incident (top event in the diagram) frequency to be estimated from a logic model of the failure mechanisms of a system. FTA is a top-down analysis tool used to identify event causes and to quantify accident scenarios that would result in system failure. FTA is used in the aerospace, nuclear power, chemical and process, pharmaceutical, petrochemical, and other high-hazard industries. The model is based on the combinations of potential failures, including more basic system components, safety systems, and human reliability. A basic assumption of FTA is that all failures in a system are binary in nature; that is, a component or operator either performs successfully or fails completely. In addition, the system is assumed to be capable of performing its task if all subcomponents are working.[50] The tool starts with an identified hazard (in this case an LNG, release due to a truck or train accident) at the top of the diagram (or top event) and works backward to determine possible causes (such as derailment, loose valves, etc.) using two logical functions: OR and AND. This method relies on a combination of sufficient historical data or expert judgments.

6.1.2 Event Tree Analysis (ETA)

Unlike the “top-down” FTA approach, ETA is a forward, “bottom-up” logical modeling technique. This analysis technique is used to analyze the effects of functioning or failed systems when an event has occurred. ETA is a powerful tool that identifies all consequences of a system that has a probability of occurring after an initiating event. As a starting point, a system-affecting event is identified, such as a derailment, and the analysis tracks additional events as “branches” of the larger “tree.” Each outcome of a branch is usually binary, meaning the outcome either occurs or does not occur. Probability is assigned to each branch to determine the overall outcome. This method calculates the accident probability of all resulting events with the probability of each event, comparing their probability value and obtaining the possibility of accident sequence. Sometimes FTA and ETA are used in conjunction to identify and quantify possible consequences of the top event in the Fault Tree.

Quantitative analysis in the ETA has been used by researchers to determine the occurrence probability of an accident.[51] In this study, the CS Team examined the ETA modeling technique as a sequence of events illustrated by the Event Tree Diagram (ETD).

[50] Claudio, *Safety Guidelines...*

[51] Tang et al., “A Quantitative Risk Analysis…”

6.2 Describing Risk in the Rail Event Chain Diagram

The harmful exposure of people or property to a hazardous material can be evaluated through a series of events in an **event chain diagram**. Each event is probabilistic, in the sense that its occurrence is not certain, given that the prior event in the chain has taken place: one can only assign a probability to its occurrence. This also is true of the first event in the chain, the occurrence of a train accident.[52]

The events in the event chain that must be evaluated to perform the QRA, from beginning (accident occurs) to end (a potential fatality), are described in Table 6.1, below. Within each of these events, there are factors and parameters required to fully understand the probabilities.

Table 6.1 Rail Event Chain Factors and Parameters

Event	Factors and Parameters
Accident	In order for the identified consequence to occur, a vessel containing LNG must first be involved in an accident. The likelihood of an accident involving the LNG rail car or ISO is estimated.
Number of Cars Derailed	The number of cars derailed can also be described as derailment severity, which is measured by the number of cars derailed after a train derailment. Influencing factors include speed, accident cause, train length and other factors.
Number of Hazmat Cars Derailed	The probability of the number of hazmat cars derailed is measured by evaluating factors such as the number of hazmat cars per train, train length and the placement of hazmat cars in the train consist. The probability of the number of hazmat cars derailed changes between manifest trains and unit trains.
Hazmat Cars Release Some of All of Contents	The term describing single car release is called the Conditional Probability of Release (CPR). The CPR of a derailed tank car depends on its design characteristics and derailment speed. Researchers have found a strong effect of speed on both derailment severity and release probability of hazardous materials cars derailed. Multiple car releases can also be calculated based on individual car CPR.
Loss of Containment	The hazards evaluated for this study include the flammable nature of the LNG fuel vapors. In order for a fire or explosion to occur, there must be a loss of containment (LOC) event involving the LNG container or vessel. The LOC probabilities and leak size distributions are estimated.
Formation of Flammable Atmosphere	Following an LOC, the LNG must vaporize and the flammable vapors must mix with air in the appropriate concentrations. The size and downwind distance of the flammable clouds are calculated in the Risk Model.
Ignition of Flammable Atmosphere	The flammable atmosphere must be ignited in order for a fire or explosion to occur. The ignition probabilities, as a function of time, distance, and population as the flammable cloud is formed and dispersed, are calculated in Risk Model.
Exposure to Population	The populations that may be affected by an incident involving LNG are estimated using U.S. Census data, and the population data is input into the model for calculation of the Individual Risk (IR) and Societal Risk (SR). The potential for a fatality, given a specific thermal event (i.e., flash fire, pool fire, jet fire, or explosion), is calculated in the Risk Model.

Sources: Health and Safety Executive; Exponent, Inc.; Liu, et al., ., "Probability Analysis of Multiple Tank-Car Release Incidents in Railway Hazardous Materials Transportation." Journal of Hazardous Materials, Vol. 276, :, pages 442–451.Cambridge Systematics, Inc.

The events can be viewed in Figure 6.1 Rail LNG Event Diagram, where each event is described as part of an overall sequence of events. The Risk Model identifies probabilities within each event in the event chain. For example, the Risk Model calculates the probability of the number of cars derailed as well as the size and

52 Arthur D. Little, Inc., *Event Probabilities and Impact Zones*, p. 7.

downwind distance of the resulting flammable clouds released during an incident. Disrupting any of the events in the event chain will ultimately mitigate or prevent hazmat releases, thereby reducing overall risk.

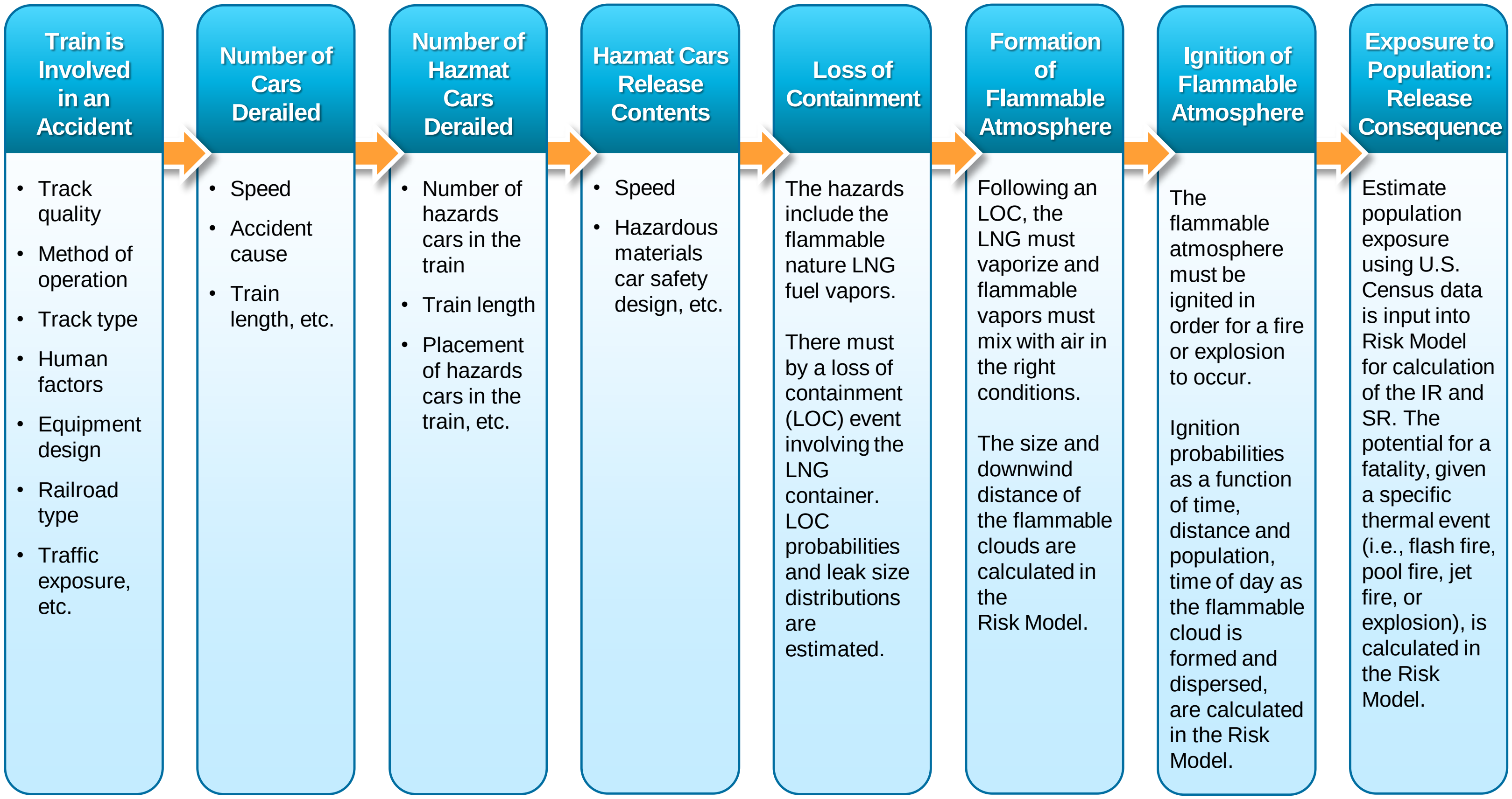

Figure 6.1 Rail LNG Event Chain Diagram

Sources: Arthur D. Little, Inc.; Liu et al.; Exponent, Inc.; Cambridge Systematics, Inc.

Risk inputs and calculations further illustrate the relationships between inputs to the calculations that determine model outputs. For example, FRA track class, method of operation and traffic exposure are the inputs used to calculate train derailment frequency. Train speed is an input to both train derailment severity and release probability. Tank car safety design is an input to calculate tank car derailment and release probability. The formation of a flammable atmosphere is an input to calculating size and downwind distance of flammable clouds. The ignition of the flammable atmosphere created by the LNG release is an input to the calculation of ignition probabilities and the estimated population exposure. Finally, population data and time of day are inputs to estimate population exposure for fatalities (Figure 6.2).

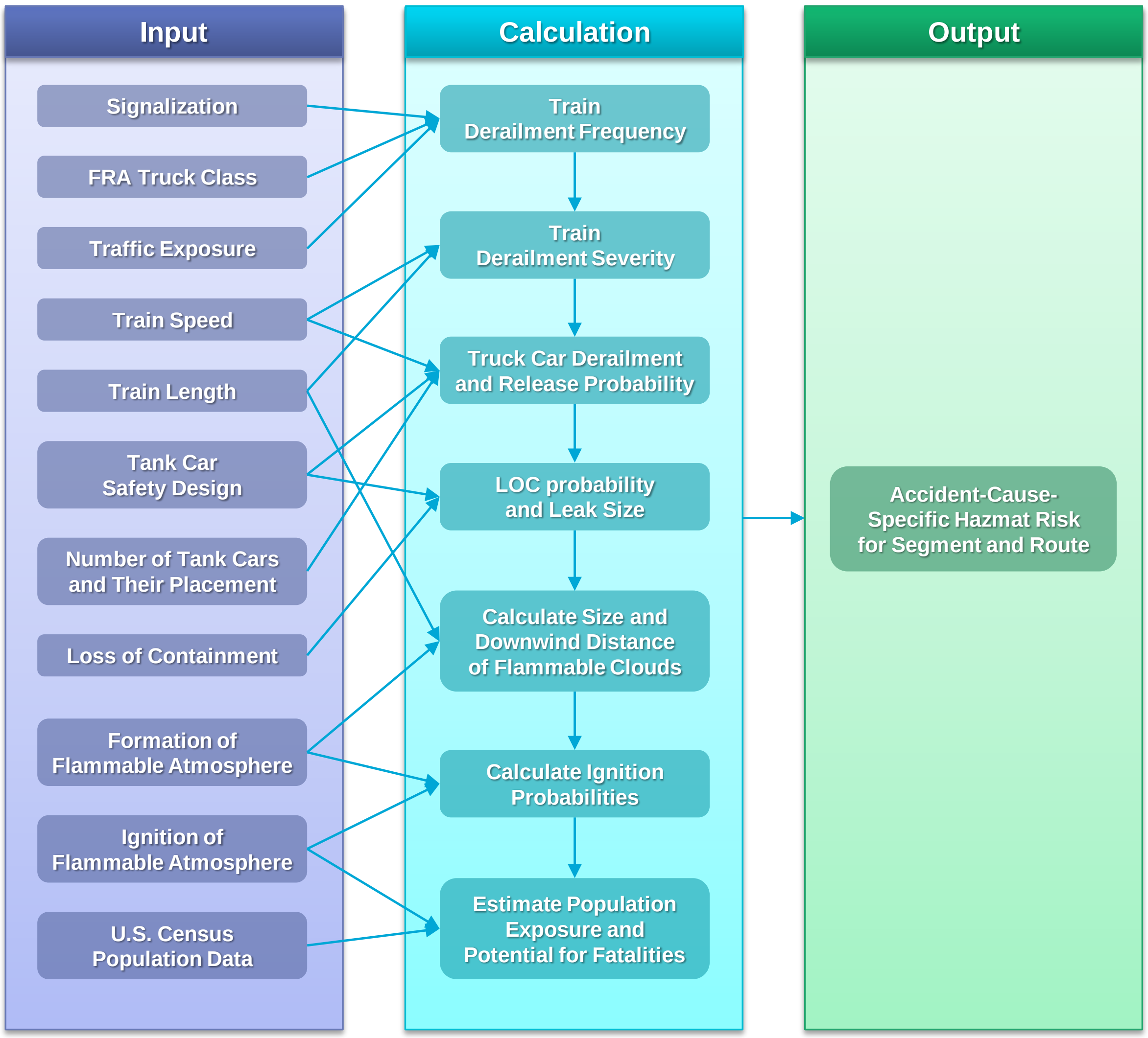

Figure 6.2 Risk Inputs, Calculations, and Outputs for Rail LNG Transport

Source: Liu, et al. "Risk Analysis of Transportation Crude Oil by Rail: Methodology and Decision Support System." Journal of the Transportation Research Record 2547: 57–65.

Each of these risk inputs, parameters, factors, calculations, and resulting outputs are described in the following section, using the sequence of the event tree diagram from Figure 6.1. The model must take into consideration all of these factors and parameters to effectively estimate LNG Risk by rail.

6.3 Train Accident

Grade crossing incidents are the most common type of train accident. Collisions at grade crossings typically account for well over 90 percent of rail-related fatalities. In 2016, the number of grade crossing collisions was down 42 percent from 2000, injuries from collisions were down 31 percent from 2000, and fatalities from collisions were down 38 percent from 2000. As seen in , the grade crossing collision rate has fallen most years since 1980.[53]

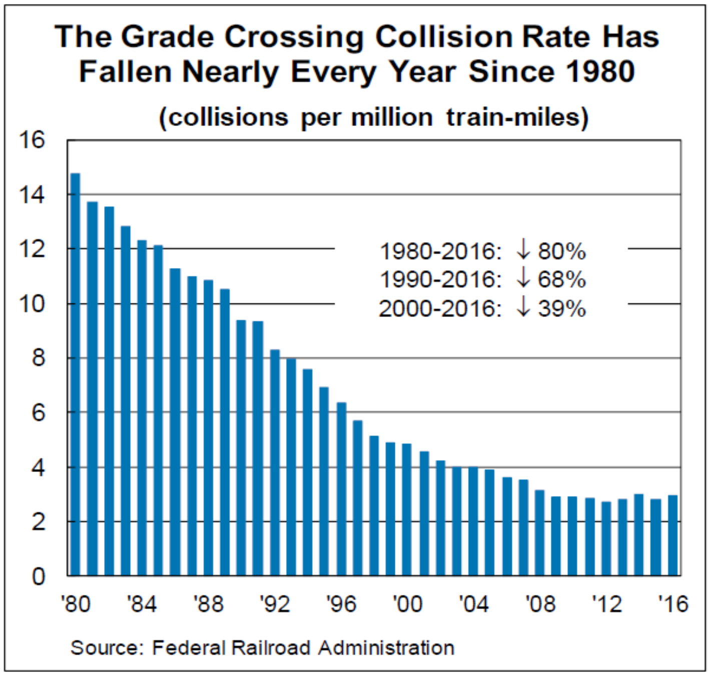

Figure 6.3 Grade Crossing Collision Rate

Source: Federal Railroad Administration

Despite the fact that grade crossing incidents are the most common rail accident, train derailments are the most common type of train accident where monetary damages to track and equipment exceed the FRA reporting threshold. Such derailments damage infrastructure, rolling stock, and can lead to casualties. Factors leading to a train accident include track quality, method of operation, track type, human factors, equipment design, railroad type, traffic exposure, and other factors.

In Canada, Saccomanno et al. analyzed train derailment rates by traffic volume, track type (single track versus multiple tracks), train speed, and region; they also found that train derailment rate varies with infrastructure and traffic characteristics.

A recent paper has developed more up-to-date derailment rates, accounting for the substantial decline in the rate compared to those previously published.[54] This paper contains the most current estimated rates using Liu's three-factor derailment rate model. These current derailment rates will be used in the development of the LNG risk model.

6.4 Train Derailment

As mentioned previously, the train derailment rate is affected by a number of factors, such as FRA track class, method of operation, and annual traffic density.[55] This section describes these factors in detail; taken together, they can be used to assess train derailment probability.

53 Association of American Railroads, September 2017.

54 Wang et al., "Trends in U.S. Freight Train..."

55 Liu, et al., "Freight-Train Derailment Rates…"

(Footnote continued on next page...)

It is worth noting here that researchers assume there is no statistical difference in derailment rate between hazmat trains and other types of trains. Therefore, the research described in this section used the average derailment rate for all freight trains as a proxy for the hazmat train derailment rate.[56]

6.4.1 FRA Track Class

The connection between derailment rates and infrastructure characteristics has been recognized for many years. Research completed by Nayak et al., Treichel and Barkan, and Anderson and Barkan concluded that the higher FRA track class, the lower the subsequent derailment rates. This can be attributed to the fact that higher track classes are required by FRA for higher operating speeds; therefore, railroads apply higher engineering safety standards and take better care of track sections with higher track classes.

The FRA sets minimum standards for tracks, categorized in six different classes. Track inspection is performed by the FRA as well as the railroad companies themselves. These classes include specifications for track structure, geometry, inspection frequency, and method of inspection, with more stringent requirements for higher track classes. Note that the FRA standards represent *minimum* requirements; in fact, railroads often maintain sections of railroad infrastructure to standards that exceed the minimum required by the FRA.

With about 177,200 miles of track in service as part of the Interstate railroad system, the railroads and the FRA must work together to monitor the system's condition.

Classification of specific railroad sections is determined by maximum permissible speed on that section. Therefore, sections of Class I track may be posted at different speeds depending on certain conditions.

As noted earlier, previous studies have estimated derailment rates based on class-specific ton-mile distribution using traffic data from Class I railroads. FRA track classes and ton-mile distribution rates can be viewed in Table 6.2.

Table 6.2 FRA Track Classes and Distribution

FRA Track Class	Speed mph Freight	Speed mph Passenger	Ton-Mile Distribution[1]	Description
1	10	15	0.8%	Yards, branch lines, short lines and industrial spurs
2	25	30	3.3%	Branch lines, secondary main lines, regional railroads
3	40	60	11.1%	Regional railroads and Class I secondary main lines
4	60	80	54.7%	Main line track for passenger and long-haul freight service
5	80	90	30.0%	Standard for most high-speed track
6	110	110		Amtrak Northeast Corridor

Source: Federal Railroad Administration

[1] Liu, et al., “Freight-Train Derailment Rates…”

[56] Barkan and Liu, 2018.

6.4.2 Annual Traffic Density

Traffic density is another model variable. Railroad traffic density represents the total weight of all locomotives, rolling stock, and lading traversing a given section of track; it is commonly measured in million gross tons (MGT). Tracks with a higher traffic density are maintained at a higher track quality.[57] This is because track with a higher traffic density receives more frequent track maintenance leading to higher track quality. For the purposes of derailment probability, track segments with over 20 MGT are considered "higher traffic density." It is important to note that the AAR also uses the 20 MGT as a threshold.

Signaled track segments have track circuits to detect broken rails, thereby potentially reducing the likelihood of derailments due to this cause. Furthermore, given the same track class and method of operation, derailment rate is inversely related to traffic density level. There are several possible explanations for this. As mentioned above rail lines with higher traffic density receive more frequent track inspection and maintenance (Zarembski and Palese, 2010; Sawadisavi, 2010; Peng, 2011) irrespective of speed (i.e., FRA track class). Busier lines may also have a greater number and variety of wayside defect detectors installed (Schlake, 2010) thereby reducing the incidence of certain infrastructure and equipment-caused train accidents.[58]

The traffic density variable for model purposes is assigned two values, more or less than 20 Million Gross Tons (<20 MGT) annual traffic. The demarcation at 20 MGT is selected because it represents the average annual track traffic density on all U.S. Class I railroad mainlines (AAR, 2005–2009) so the two classifications indicate above or below average traffic density.

6.4.3 Method of Operation

At one time, the FRA recorded 12 different values for methods of operation. For the purposes of this analysis, we are interested in a higher level categorization; specifically, whether or not the track has a system of automatic signaling in place (i.e., "signaled" versus "non-signaled" territory, respectively). We collapse the 12 categories to one of these two conditions. Since then, FRA (2011) has simplified their system so it only records these two categories as well. This categorization also is identified as one of the risk factors specified by PHMSA for railroad hazardous materials route analysis and selection (PHMSA 2008). Approximately 60 percent of U.S. mileage and 80 percent of rail traffic operates on signaled trackage (FRA, 2008). Such trackage uses low-voltage, electric current in the rails (known as "track circuits") to detect the presence of trains in a given section.[59]

6.4.4 Determining Train Derailment Rates

Other factors contributing to train derailment include track defects, equipment defects, and other causes (see Table 6.3). Together these causes and factors contribute to derailment rates for U.S. railroads. For the Class I mainline, freight train derailment rate from 2002 to 2014, researchers found an average annual decline rate of 10.6 percent for broken rails and 8.7 percent for track geometry defects.[60] If this trend continues, a statistical model can be used to estimate a more current freight train derailment rate. Possible

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57 Peng, F. "Scheduling of track inspection…"

58 Liu, et al., "Freight-Train Derailment Rates…"

59 Ibid.

60 Liu, "Risk Analysis of Transportation Crude Oil by Rail…"

strategies to reduce train derailments include train speed reduction to reduce the total number of vehicles derailed and placing tank cars in positions that are less likely to derail.

Table 6.3 Derailment Frequency and Severity by Accident Cause *(Excerpt)*

Cause Group	Description	Derailments Number	Derailments Percentage	Cars Derailed Number	Cars Derailed Percentage	Average Number of Cars Derailed per Derailment
08T	Broken rails or welds	665	15.3	8,512	22.7	12.8
04T	Track geometry (excluding wide gauge)	317	7.3	2,057	5.5	6.5
10E	Bearing failure (car)	257	5.9	1,739	4.6	6.8
12E	Broken wheels (car)	226	5.2	1,457	3.9	6.4
09H	Train handling (excluding brakes)	201	4.6	1,553	4.1	7.7
03T	Wide gauge	169	3.9	1,729	4.6	10.2
01M	Obstructions	153	3.5	1,822	4.9	11.9
05T	Buckled Truck	149	3.4	1,891	5.0	12.7
04M	Track—train interaction	149	3.4	1,110	3.0	7.4
11E	Other axle or journal defects (car)	144	3.3	1,157	3.1	8.0

Source: Federal Railroad Administration.

Understanding the most important factors affecting derailments is critical to development of effective risk reduction strategies. Train safety and risk analysis rely on an accurate estimation of the derailment rate, which is defined as the number of derailments normalized by some metric of traffic exposure, such as train-miles, car-miles, or gross ton miles. Methods used to determine derailment rates include the Poisson Distribution.[61]

Having assembled the data from various sources and ensuring its consistency with regard to the predictor variables of interest, researchers prepared two 5 x 2 x 2 matrices for the rail network and time period studied, one for derailments, and the other for traffic. These matrices were classified according to each combination of FRA track class, method of operation and annual traffic density:

- Track Class: 1, 2, 3, 4, 5.
- Method of Operation: Signaled and non-signaled.
- Annual Traffic Density: <20 MGT and 2:20 MGT.

Table 6.4 presents the distribution of freight-train derailments by the predictor factors used in a previous study.[62] More than 50 percent of train derailments occur on higher track classes (Class 3 to Class 5), signaled track with annual traffic density above 20 MGT.[63]

[61] Liu, et al., "Freight-Train Derailment Rates…"

[62] Ibid.

[63] Ibid.

Table 6.4 Distribution of Freight-Train Derailment

Annual Traffic Density (MGT)	Method of Operation (MO)	FRA Track Class (TC)					
		1	2	3	4	5	TC Total
<20	Non-signaled	2.0%	3.5%	4.4%	3.7%	n/a[2]	**13.7%**
	Signaled	1.3%	2.5%	3.3%	4.6%	0.4%	**12.2%**
	MO Total	3.4%	6.1%	7.7%	8.3%	0.4%	**25.8%**
≥20	Non-signaled	0.7%	1.8%	2.0%	6.0%	0.5%	**11.0%**
	Signaled	2.6%	6.7%	11.3%	31.0%	11.6%	**63.2%**
	MO Total	3.3%	8.5%	13.2%	37.0%	12.1%	**74.2%**
Total	Non-signaled	2.7%	5.4%	6.3%	9.7%	0.5%	**24.6%**
	Signaled	3.9%	9.2%	14.6%	35.6%	12.0%	**75.4%**
	MO Total	6.7%	14.6%	20.9%	45.3%	12.5%	**100.0%**

Source: Liu, et al., "Freight-Train Derailment Rates"

[2] There were no instances of non-signaled, Class 5 track with less than 20 MGT of annual traffic.

This information is further illustrated in Figure 6.4, in which derailment rates decrease with increasing FRA Classes.[64]

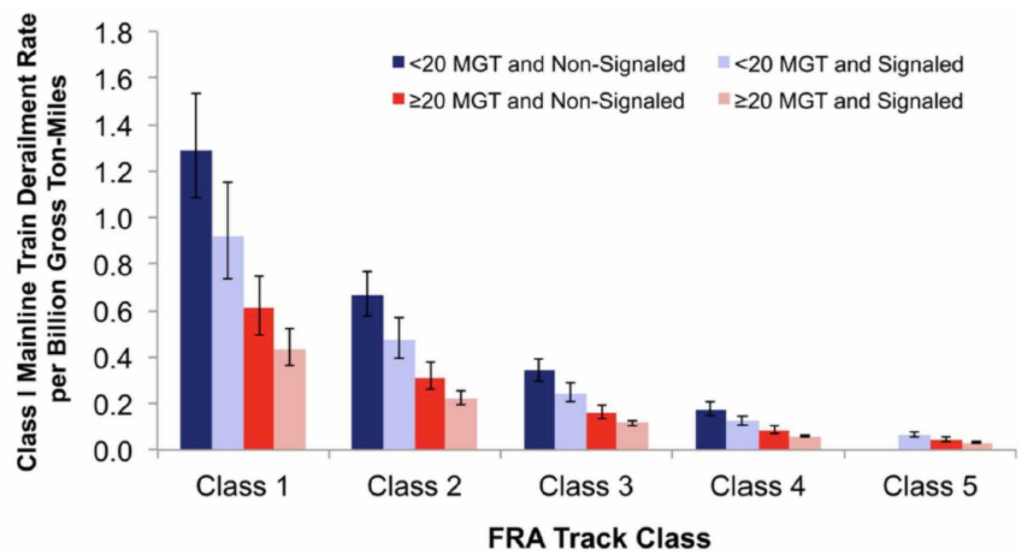

Figure 6.4 Estimated Train Derailment Rates

By Track Class

Source: Liu, et al., "Freight-Train Derailment Rates

Note: Estimated Class I mainline freight-train derailment rates by FRA track class, method of operation and annual traffic density.

[64] Ibid.

6.5 Train Derailment Rate

Different models have been used to analyze train derailment rates. The example below uses a negative binomial (NB) regression model to analyze freight-train derailment rates on U.S. Class I railroad main tracks. The NB model has been widely used in accident rate analysis in highway transportation (e.g., Miaou, 1994; Hauer, 2001; Wood, 2002; Lord et al., 2005; Lord, 2006; Oh et al., 2006; Mitra and Washington, 2007). Below is the Table 6.5 describing derailment rate per billion gross ton miles (GMT) estimates based on FRA Track Class, Rail Density and Method of Operation:[65]

Table 6.5 Parameter Coefficient Estimates of Train Derailment Rates
In billions of ton miles, 2005–2009

Parameter	Estimate	Standard Error	Wald 95% Confidence Limits		Wald Chi-Square	Pr > ChiSq
b_0 (Intercept)	0.9201	0.1115	0.7016	1.1386	68.11	<0.0001
b_{trk} (Track Class)	−0.6649	0.0341	−0.7318	−0.5981	380.37	<0.0001
b_{moo} (Method of Operation)	−0.3377	0.0974	−0.5286	−0.1469	12.03	0.0005
b_{den} (Annual Traffic Density)	−0.7524	0.0859	−0.9208	−0.5840	76.72	<0.0001
Dispersion	0.0048	0.0062				

Source: Liu, et al., "Freight-Train Derailment Rates…"

Notes:

- Over the 5-year period there were a total of 1,420 derailments and 17.5 trillion GTM of freight train traffic assigned to the 20 different categories in the cross-categorical matrix used in the statistical analysis.
- Traffic exposure is measured by gross ton-miles (GTM) and annual traffic density is measured by gross tonnage on a segment.

6.6 Number of Cars Derailed

The number of cars derailed also can be described as derailment severity. Derailment severity is measured by number of cars derailed after a train derailment. Influencing factors contributing to derailment severity include speed, accident cause, train length, and other factors. Quantifying the relationship between train derailment severity and these associated factors helps the rail industry and Government to develop, evaluate, prioritize, and implement cost-effective safety improvement strategies.

Simulation and statistical analysis are the two basic approaches used in previous studies to model train derailment severity. Simulation models predict the response of railroad vehicles to specific track and environmental conditions. These models are typically based on detailed nonlinear wheel-rail interaction models. For example, Yang et al. (1972, 1973) developed a simulation model to determine the effect of ground friction, mating coupler moment, and brake retarding force on the number of cars derailed. They

65 Ibid.

found that the position of the first car involved in the derailment (called point-of-derailment, or POD) and derailment speed could affect the number of cars derailed. Methods for determining the derailment severity and POD include the Truncated Geometric Distribution and the Beta Distribution.[66]

The first vehicle (generally the lead locomotive) in the train is frequently the first to derail. Previous studies found that the nearer the POD is to the front of a train, the more cars derail. Research in 2014 focused on mainline, freight-train derailments on Class I railroads, a group of the largest U.S. railroads accounting for 69 percent of route miles and 88 percent of carloads transported in the U.S.[67] The analysis showed that approximately 25 percent of train derailments had the POD in the first 10 positions of the train (Figure 6.5).[68]

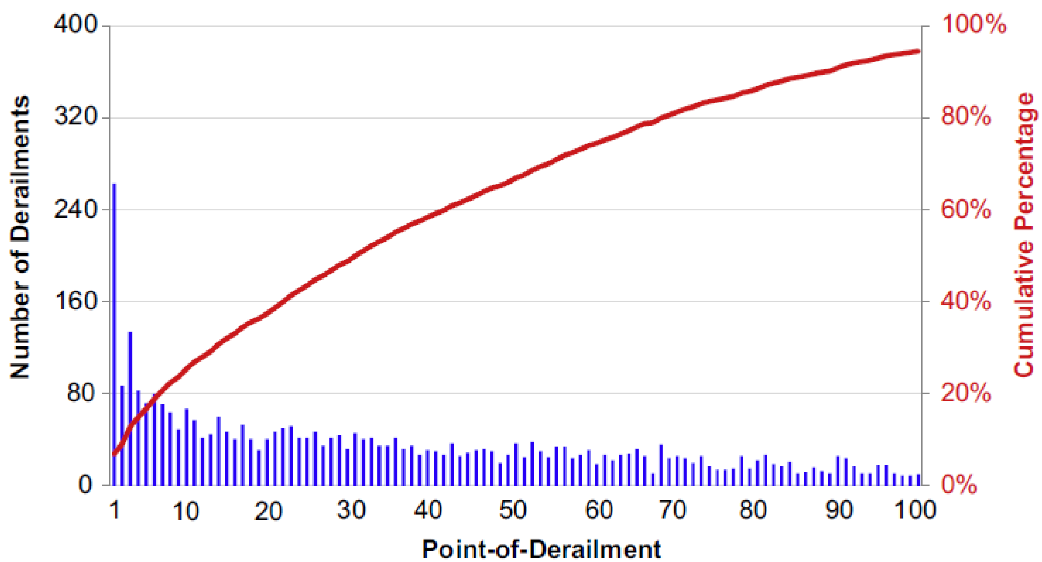

Figure 6.5 Distribution of the Point-of-Derailment *2002–2011*

Source: Saccomanno and El-Hage, "Minimizing Derailments of Railcars;" 1989.

Note: This distribution of the point-of-derailment of 3812 Class I mainline freight-train derailments due to all causes, 2002–2011 (partial distribution of POD up to position 100 shown, accounting for 94 percent of all derailments analyzed).

In the late 1980s, Yang et al.'s model was extended by considering coupler failure and independent car motion (Coppens et al., 1988; Birk et al., 1990). The precision of simulation models is subject to the accuracy of modeling train derailment dynamics.

In addition to simulation models, train derailment severity also can be estimated based on historical data. Saccomanno and El-Hage (1989, 1991) developed a truncated geometric model to estimate the mean number of cars derailed as a function of derailment speed, residual train length, and accident cause.

[66] Saccomanno and El-Hage, "Minimizing Derailments of Railcars;" 1989.

[67] Association of American Railroads *Class I Railroad Statistics*.

[68] Bagheri et al., "Reducing the threat…"

The number of tank cars derailed is related to the total number of cars (both tank and non-tank cars) derailed, and the number and placement of the tank cars in a train. Glickman et al. assumed that the number of tank cars derailed follows a hypergeometric distribution when tank cars were randomly placed in the train. Bagheri et al. estimated the total number of tank cars derailed given their positions.

6.7 Derailed Cars Contain Hazardous Materials

The third part of the event tree describes the probability of tank cars containing hazardous materials derailed in a train accident. Influencing factors include the number of tank cars containing hazardous materials in the train, train length, and the placement of those cars in the train consist. Hazardous materials are transported in tank cars in manifest trains and unit trains. The LNG risk model will include an evaluation of the transportation risk in unit trains versus manifest trains by integrating train-specific risk analysis methodology. In a recent paper, researchers determined that a unit train has a higher probability of a release incident per train derailment than a manifest train. Tank cars can be placed in the lowest-probability derailment positions, and tank cars can be distributed to multiple mixed trains. However, shipping hazmat in a unit train also may reduce the number of shipments if the same number of hazmat cars were shipped in multiple manifest trains. This needs to be taken into consideration developing the risk model and is why it is important to consider tank car placement in a train.[69]

6.8 Number of Tank Cars Releasing Contents

Research has demonstrated that not all derailed tank cars release their contents. Studies have found that the use of a more robust tank car design can reduce tank car release probability, reducing hazmat transportation risk (6–8). The Railway Supply Institute (RSI)—Association of American Railroads (AAR) Railroad Tank Car Safety Research and Test Project has developed a tank car accident database (TCAD) containing information on tank cars involved in accidents in the U.S. Using the current subset of this database, Treichel et al. developed logistic regression models to estimate the conditional probability of release (CPR) for nearly all common designs, as well as new designs that incorporate existing design features. The conditional probability of release (CPR) of a derailed tank car depends on its design characteristics and derailment speed.[70] [71] Tank car release probability is a Bernoulli variable. The sum of independent Bernoulli variables with different probabilities follows a Poisson binomial distribution.[72] If Bernoulli variables are correlated, researchers can use a family of more sophisticated models.[73] Barkan et al. and Treichel et al. found that speed affected both derailment severity and release probability of hazardous materials cars derailed. Kawprasert and Barkan extended Treichel et al.'s analysis by accounting for the effect of derailment speed in estimating release probability.

Figure 6.6 illustrates CPR for selected pressure tank cars (DOT 112 and DOT 105).

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69 Liu, "Risk Comparison of Transporting Hazardous Materials…"

70 Barkan et al., "Safety performance of tank cars..."

71 Barkan, et al., "Benefit cost evaluation…"

72 Wang, Y.H. "On the number of successes…"

73 Liu, X. et al., "Analysis of multiple tank car…"

CHLORINE

Car Spec.	Head Thickness (in.)	Shell Thickness (in.)	Jacket	Head Shield	Shell Inside Diameter (in.)	CPR	Percent Improvement Over Pre-HM-246 Baseline
105A500W	0.812	0.775	YES	NO	100.45	0.042	N/A
105J600I	0.954	0.954	YES	FULL	100.45	0.019	54.8 %

ANHYDROUS AMMONIA

Car Spec.	Head Thickness (in.)	Shell Thickness (in.)	Jacket	Head Shield	Shell Inside Diameter (in.)	CPR	Percent Improvement Over Pre-HM-246 Baseline
112J340W	0.625	0.625	YES	FULL	119	0.033	N/A
112J500I	0.900	0.900	YES	FULL	116.75	0.016	51.5 %

ETHYLENE OXIDE

Car Spec.	Head Thickness (in.)	Shell Thickness (in.)	Jacket	Head Shield	Shell Inside Diameter (in.)	CPR	Percent Improvement Over Pre-HM-246 Baseline
105J300W	0.603	0.562	YES	FULL	117.87	0.041	N/A
105J500I	0.900	0.900	YES	FULL	116.75	0.016	61.0 %

*Average mainline derailment conditions – train speed at time of derailment = 26 mph, 11 cars derailed, tank car is the 6th car derailed.
CPR or "Conditional Probability of Release" is a measure for probability of a spill under certain accident conditions.
The car dimensions shown in Table 1 are meant to be illustrative. They are based on the most commonly built designs as of the publication of this report.

Figure 6.6 Selected Tank Car Conditional Probability of Release
CPR

Source: Railway Supply Institute http://tankcarresourcecenter.com/standards/.

Influencing factors contributing to the number of tank cars releasing contents include tank car design, speed, and the tank car's exposure to other contributing factors such as a pool fire created by the derailment. In some hazmat derailments, pool fires have been identified as the cause of a tank car releasing contents following a derailment, sometimes over a period of up to six hours.[74] In the case of an LNG release, the tank car release may result in a pool fire or vapor dispersion. This will be further evaluated in the Release Consequence section.

6.9 Loss of Containment

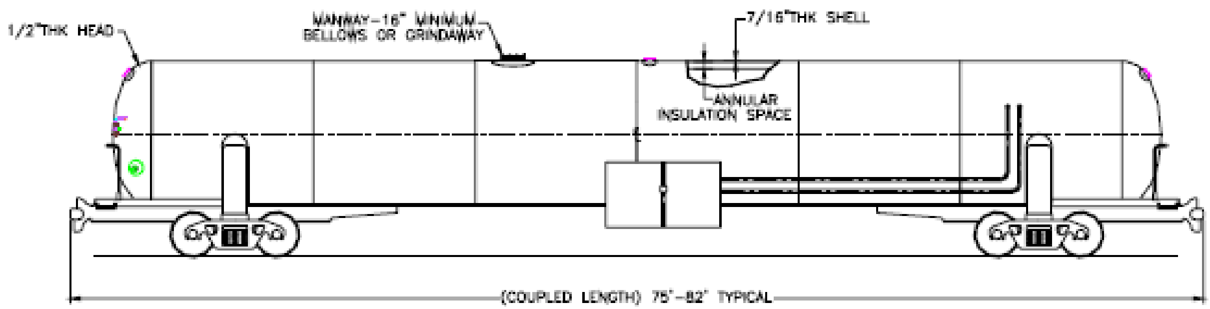
The Loss of Containment (LOC) is when LNG is released from a container, which in this case is either the T75 ISO container in a well car (such as FECR) or the DOT 113 tank car, tests for which currently are in progress. The prior sections detailed the development of accident rate and derailment probability estimates for rail cars. Not every accident will lead to an LOC of LNG. The dynamics of an individual accident such as train configuration, train speed, and the type of container will determine whether or not an LOC may occur. This section discusses the development of LOC and the techniques used to estimate release size probability for the QRA model based on industry data and guidelines. For the purposes of this study, the focus is on the DOT 113 tank car and ISO tank well car. Figure 6.7 illustrates the technical specifications of the DOT 113 tank car.

[74] National Transportation Safety Board, "Report from Mount Carbon Train Derailment."

Inner Tank
Thickness: 3/16" (minimum); 1/4" (nominal)
Material: Stainless steel of ASTM A 240/A 240M, Type 304 or 304L

Outer Tank
Thickness: 1/2" heads, 7/16" shells
Material: Carbon steel

Insulation
Perlite (common in 1960-1990 built cars), or
Wrapped fiberglass or similar material (common in 1990-and-later built cars)



Cutaway Drawing of Tank Car
(Courtesy of Chart Industries)

Figure 6.7 Typical Features of DOT 113 Tank Car

Source: American Chemistry Council, "Handling and Transportation Guide…"

The DOT-113 railcar is a cryogenic non-pressurized liquid tank car with insulated "thermos bottle" construction. While the DOT definition of cryogenic is refrigerated to -130°F and below, cryogenic is a maximum of -155°F. Class DOT-113C120W tank cars began production in the 1970s and they are the most common tank cars now used for cryogenic ethylene service. The rail weight limit is 263,000 pounds with a tare weight in the 117,000 to 120,000 pounds range. The water capacity on these cars is nominally 33,000 gallons, which allows for a payload of approximately 28,500 to 29,000 gallons of cryogenic ethylene. Recently built cars have a gross volume of 34,500 gallons and a net cryogenic ethylene capacity of up to 144,000 pounds (30,380 gallons).

Class DOT-113C tank cars are equipped with one or dual-pressure relief valves and dual-rupture discs. Except for some class DOT-113D tank cars (described above), the valves and fittings for loading and unloading, and the pressure relief devices are located in cabinets on both sides. In some cases, only one of the two cabinets contains the pressure relief devices, and is identified by the exhaust (vent) stack coming out of the cabinet and reaching the top of the tank car. Loading/unloading valves are normally located in compartments on diagonally opposite corners of car for liquid oxygen, liquid nitrogen, and liquid hydrogen.

LOC probability data for LNG ISO containers and for DOT 113 rail cars currently do not exist. Therefore, general rail industry data has been used with certain engineering assumptions to find comparable LOC data.

For example, pressure tank cars (DOT 112) and cryogenic tank cars (113) have an extensive history of operation with corresponding accident data, and with some engineering judgment, this type of accident data can be applied to the Risk Model. PHMSA maintains an online database that provides historical LOC data for rail tank cars, among other transportation containers and vessels.[75] The database complements the FRA database in that the PHMSA database records the inventory of hazmat cargo released for each accident; whereas, the FRA database only identifies that an LOC has occurred. The PHMSA database can be accessed for this purpose in order to estimate the LOC probabilities for the DOT 113 tank car and for ISO containers.

The AAR Tank Car Committee is performing research on the crashworthiness assessment of the ISO tank (VOLPE) and fire test of an ISO tank on a rail car. LNG used as a fuel tender also is being considered through the work of the AAR. A LNG ISO Tank pool fire test was completed in May 2017, and presented at the October 2017 AAR Tank Car Committee. There is another test scheduled for June 2018. Figure 6.8 illustrates the specifications of the T75 ISO container:

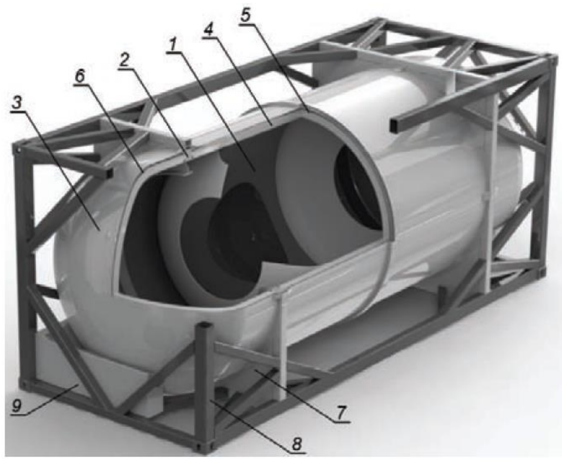


Fig. 1. Model of the LNG tank container for LNG transportation and storage, tank type I and II : 1 – inner tank, 2 – inner supports made of plastic materials, 3 – outer tank, , 4 – insulation, 5 – radiation shields, 6 – the vacuum, 7 – outer supports, 8 – container frame, 9 – fittings

Figure 6.8 ISO Insulated Tank Container Diagram

Source: Lisowski and Czyzycki, “Transport and Storage…”

ISO containers are intermodal containers suitable for multiple transportation methods such as truck, rail, or ship. They are manufactured according to specifications from the International Organization for Standardization (ISO). ISO is a worldwide federation of national standards.

The transport of LNG by rail is allowed only by special permits authorized by the FRA—at least two entities in the U.S. have current, active natural gas dual fuel programs and operate under a “Letter of Concurrence” from the FRA. Two types of tenders are being utilized in the prototype programs: ISO container holding maximum of 10,000 gallons of LNG, and tank car holding between 22,000 and 25,000 gallons of LNG. Both major U.S. freight locomotive original equipment manufacturers are actively involved with the AAR Tank Car Advisory Group activities and with the prototype programs.

[75] Pipeline and Hazardous Materials Safety Administration, “Hazmat Database.”

ISO intermodal containers are used to transport cryogenic bulk liquids—nitrogen, oxygen, argon, methane, nitrous oxide, ethylene, and carbon dioxide. ISO containers with LNG are authorized by rail in the U.S. only by special permit. Containers designed and optimized for LNG also are popular for transportation of ethylene. Containers designed by Chart Industries have hold times of between 44 to 65 days. This means that without intervention, the containers would be insulated and keeping the LNG at cryogenic temperatures for the length of the hold time.

The analysis would assume that LOC could only occur if the DOT 113 rail car or ISO well car was derailed. The PHMSA database does not provide accident data for T-75 ISO portable tank containers, but it does list pressure tank car LOC accidents. Although there are differences between the T75 ISO construction and a DOT-112 pressure tank car, the dynamics and consequences of LOC can be assumed to be reasonably similar. Thus, pressure tank cars were used as a proxy to estimate the probability of an LOC if a car was derailed.[76]

The PHMSA database can be used to collect rail car data from past years for incidents, including spillage, vapor (gas) dispersion, and no release. However, this approach does not account for the substantial differences in rail car design characteristics that are known to affect the probability of release if a car is derailed. The most current published estimates of design-specific tank car release probabilities can be found in a report published by the RSI-AAR Railroad Tank Car Safety Research and Test Project (Treichel et al. 2006). The likely qualitative effect of this is to over-estimate the risk of a release because the LNG 113 tank car is likely to be more robust than average values estimated using hazardous materials cars in the PHMSA database.[77]

The resulting data can then be filtered for pressure tank cars only. Pressure tank car incidents can be sorted by amount released (units are either cubic feet or gallons). The PHMSA data can then be grouped into release volume ranges in order to estimate the probability of a certain leak size. The categories used for the FECR Report are listed in Table 6.6.

Table 6.6 Sample Release Size Types for Loss of Containment (LOC) Estimates

Release Type	Release of Product
No Release	Less than 100 gallons
Small Release	100 to 1,000 gallons
Large Release	1,000 to 30,000 gallons
Catastrophic Release	More than 30,000 gallons

Source: Exponent, Inc.

To understand the history of cryogenic gas incidents by rail, the CS Team examined incidents involving liquid ethylene (UN1038) in DOT-113 Tank cars in the PHMSA Incident Reports Database. The Team identified 73 incidents involving cryogenic ethylene tank cars between 1977 and 2015 reported by PHMSA. Of these 73 incidents, only 5 were listed as “HMS Serious Incident.” Of the 5, 3 included one incident in Moran, KS in which three DOT 113 tank cars containing liquid ethylene derailed and burned. The incident in Brunswick,

76 Exponent, Inc. “FECR Risk Assessment, July 2017 Draft.”

77 Barkan, C.P.L., Liu, X.; Memo detailing mprovements to Exponent Methodology, November, 2017.

MD was due to a broken line in the piping cabinet. Another incident resulted from loss of vacuum in the annular space, due to a failure in the outer tank.

After reviewing the description of each incident, several are related to venting from residue cars. In these cases, a 15 psi (20 percent) increase in the start-to-discharge pressure of the main safety relief valve could have a significant benefit by reducing the number of times cars vent and the amount they vent.

There are no reports of inner vessel punctures. In some cases railcars may be delayed in transit or on a siding or at a plant location. In these situations, there is a chance of venting or the need to flare gas to maintain vapor pressures within acceptable limits.[78]

6.10 Formation of Flammable Atmosphere

Following a loss of containment (LOC), the LNG must vaporize and the flammable vapors mix with air in the appropriate concentrations. The size and downwind distance of the flammable clouds can be calculated in the Risk Model. While the LNG in its liquid state is not flammable, LNG vapors resulting from a release or spill are flammable at concentrations of 5 to 15 percent. When warmed to approximately -112°C (-170° F), LNG vapors become buoyant in air and rise and rapidly disperse into the atmosphere.

Initial vaporization following a release of LNG produces a large quantity of vapor for a short period of time. Flammable mixtures of LNG vapor initially extend downwind for only a short period of time, and as such, the zone of flammability is confined to the immediate vicinity of the release or spill, unless the release is confined in some way. The distance the vapor travels depends on many variables, including the volume of the initial release or spill, its duration, wind velocity and direction, terrain and atmospheric temperature and humidity. If the vapor cloud encounters an ignition source (i.e., with sufficient ignition energy) while still at a flammable concentration, a fire may result. Unless confined, this would result in a flash fire. If the fire propagates back to the source, this would result in a pool fire or jet fire, depending upon the nature of the release. Although LNG is nontoxic, LNG vapors at high concentrations can displace oxygen, resulting in oxygen levels that are too low for safe human exposure.

The release conditions, LNG vaporization, cloud formation, dispersion, and flammable cloud envelope as a function of time can be calculated in various models. In the FECR Risk Study, the Exponent Team used PHAST Risk v6.7. PHAST Risk is a commercial software package developed and distributed by Det Norske Veritas (DNV) which combines a phenomenological release and consequence analysis model with a risk analysis sub model to evaluate spills, sprays, and gas dispersions and the resulting toxic, fire, and explosion consequences on populations.

PHAST is widely used for the calculation of hazard distances from the release of several hazardous substances, including LNG. PHAST is approved by the U.S. Pipeline and Hazardous Materials Safety Administration (PHMSA) for evaluating LNG release exclusion zones.[79] The PHAST code uses the Unified

[78] Pipeline and Hazardous Materials Safety Administration, “Incident Reports Database.”

[79] Pipeline and Hazardous Materials Safety Administration, “Pipeline Safety: Issuance…”

Dispersion Model (UDM) as an integral calculation model to estimate the dispersion following a pressurized release or an unpressurised release. It consists of the following linked modules:

- Near-field jet dispersion;
- Non-equilibrium droplet evaporation and rainout, touchdown;
- Pool spread and vaporization;
- Heavy gas dispersion; and
- Far field passive dispersion.

One consideration using PHAST model calculations is that they assume a completely flat terrain and do not account for any obstructions (either natural or nearby equipment) on the dispersion distance of flammable clouds. In many cases, however, this assumption produces a conservative overestimate of the distance to hazardous outcomes.

6.11 Ignition of Flammable Atmosphere

As a liquid LNG does not burn because liquid LNG does not contain sufficient oxygen to support combustion. LNG vapors are flammable in air, but only when between 5 to 15 percent by volume in air. If LNG concentration is lower than five percent it cannot burn because of insufficient oxygen, and if LNG concentration is higher than fifteen percent it cannot burn because there is too much LNG relative to oxygen. Therefore the potential for an LNG explosion is actually low because of the narrow range of UEL (Upper Explosive Limit)/LEL (Lower Explosive Limit) of Methane in LNG (Figure 6.9).

Despite this, LNG is still hazardous. If spilled, LNG will boil rapidly and create a vapor cloud. Initially the primarily Methane vapor will condense water vapor out of the air, making the cloud visible and causing it to hang close to the ground until it warms up. If an ignition source is present the cloud can ignite and it will burn back to the source. Methane vapors in open air exhibit a very slow flame speed of about 4 mph. If the LNG cloud does not ignite, it can travel some distance under the right conditions however, typically it will quickly warm up, rise and dissipate.[80]

If the LNG vapors resulting from a release or spill reach concentrations of 5 to 15 percent, then ignition can occur if there is an ignition source. The timing of the ignition will impact the consequence outcome because the flammable cloud stops growing after ignition since the flammable vapor will be burned. For example, immediate ignition of the release may result in a pool fire or jet fire (or both). Delayed ignition may result in a pool fire, flash fire, or explosion. For each scenario modeled, models can calculate the outcome due to both immediate ignition and delayed ignition for the range of outcomes in the event tree. The immediate and delayed ignition probabilities can also be found in the guidelines published in the Dutch Purple Book.[81]

[80] Professor George Lane, Director Chemical Security Emergency Response Technology, interview Aug 15, 2018 regarding LNG characteristics.

[81] Uijt de Haag et al., *The 'Purple Book…'*

Figure 6.9 LNG Flammability Range

Sources: Foss, Michelle. 2003. LNG Safety and Security. Center for Energy Economics at the Bureau of Economic Geology, The University of Texas at Austin; Cambridge Systematics.

During the LNG production process or during transportation, some simple failures and events can lead to a series of catastrophic events, with the most common being a LNG spill. The flow diagram in Figure 6.10 shows the likely events that can follow after a LNG spill. These include: 1) pool formation, 2) vapor dispersion, and 3) combustion. Researchers have employed experimentation and mathematical modeling to study LNG spills, with the aim of improving knowledge and further understanding the likely case of events following a LNG spill and how it can be prevented and/or managed. Such knowledge and understanding are essential to maintaining and managing the safety of LNG.

There are multiple types of models used to calculate ignition of flammable liquids or atmosphere depending on the size of the LOC, weather conditions, terrain and other factors. This section briefly describes the types of models along with advantages and disadvantages that have been developed to help manage LNG safety. These models include LNG Pool Formation Models (including four examples of Box or Top Hat Models and four examples of Navier-Stokes Models) and three examples of LNG Fire Models.

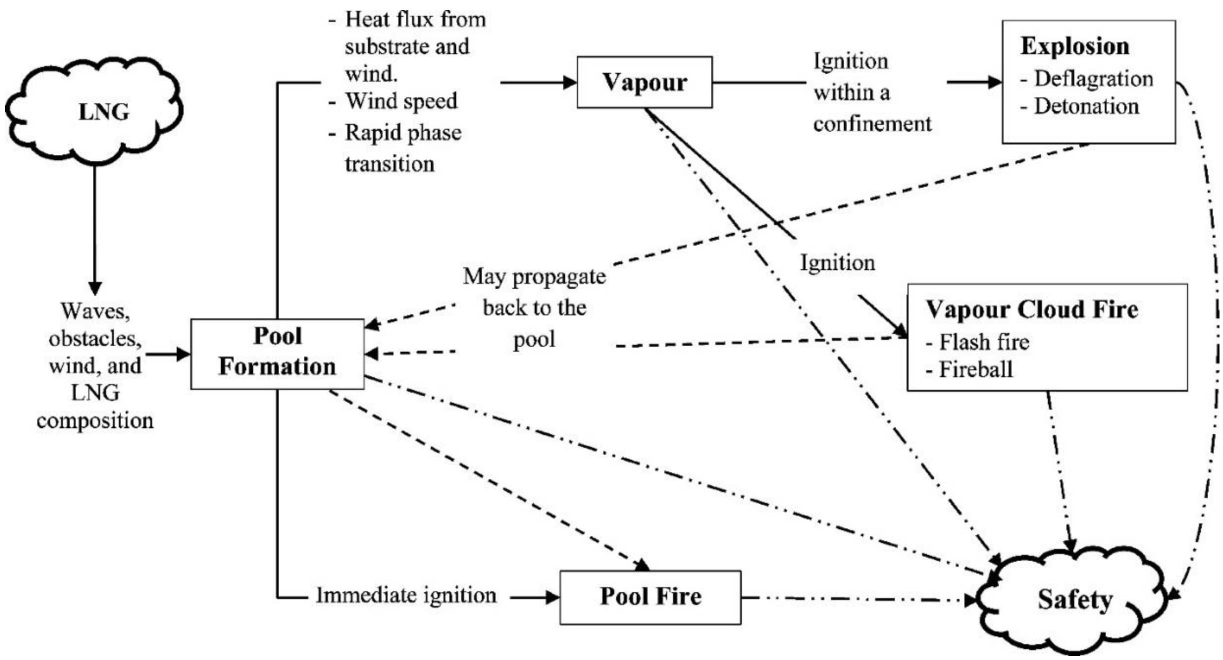


Figure 6.10 LNG Release Consequence Diagram

Source: Ikealumba, W.C. and Wu, H. "Some Recent Advances…"

6.11.1 LNG Pool Formation Modeling

Pools of LNG do not ignite as readily as gasoline or diesel because the auto-ignition temperature of Methane is 1004° F, significantly higher than gasoline at 495°F, and diesel at 600°F. So while open flames and sparks can ignite natural gas, many hot surfaces will not.

Numerical models for LNG pool formation are mainly classified in two categories: the integral model or the Navier–Stokes model. There are numerous models for studying LNG pool formation, including Raj and Kalenkar, Opschoor, SOURCE 5, GASP, SafeSite3G, PHAST, ALOHA, ABS Consulting model, LNGMAP, and FLACS.

The LNGMAP incorporates real-time geographic information, such as wind effects, current effects, atmospheric conditions, etc., into the model. PHAST is an older model than LNGMAP, and it is more widely used because of its ability to model spills on both land and water. PHAST also is more comprehensive than SOURCE5, and GASP models because of its ability to account for noncircular LNG pool formation and inclusion of heat convection/radiation from sources other than the substrate. Navier–Stokes models are more complex and the most complete models. However, modeling pool formation with Navier–Stokes models can be time-consuming because of their complexity. As a result, researchers often model pool formation with integral models and then transfer the data over to Navier–Stokes models for further analysis.[82]

6.11.2 LNG Vapor Dispersion Modeling

Various numerical models have been developed for studying LNG vapor dispersion. The main differences among the models are in the completeness of simulation for the dispersion process, the capabilities in

[82] Ikealumba and Wu, "Some Recent Advances…"

different release processes, the ability of the model to describe processes, the completeness in fields and data used, and the complexity of the terrain for which the model is situated. Other differences that are considered when looking at numerical models include the computational requirements, such as power, speed, and memory. Since the 1980s, various numerical models have been developed for the study of atmospheric dispersion of denser than air clouds. Such mathematical models can be classified as either "box top or top-hat" models or "Navier–Stokes models."

Box-Hat or Top-Hat Models

There are two types of box or top-hat models: modified Gaussian models and similarity-profile models, depending upon the complexity of conservation equations that must be solved. The modified Gaussian models are the simplest because the Gaussian equation is used for the conservation of species while neglecting or simplifying those for momentum and energy. The similarity-profile models use simplified conservation equations with a mathematical complexity of one dimension. Such simplicity is achieved by averaging the LNG cloud properties across the surface of the entire cloud or over the cross wind plane. To regain the structural loss because of averaging, similarity profiles are used, therefore leading to quasi-three-dimensional solutions. Examples of similarity-profile models include SCIPUFF, TWODEE, SLAB, HEGADAS, DEGADIS, ALOHA, and GASTAR. Of these models, the most commonly used are SLAB, HEGADAS, DEGADIS, and ALOHA. ALOHA is the most widely used for safety engineering modeling applications in industry and by first responders because of its fast computational time and reasonable accuracy.

Navier–Stokes Models

The Navier–Stokes models contain the most physically complete description of the LNG dispersion process and are constructed from three-dimensional and time-dependent conservation equations of momentum, mass, energy, and species. Examples of Navier–Stokes models that have been used for denser than air modeling include FEM3, FEMSET, FLACS, HEAVYGAS, and ZEPHYR. FLUENT and CFX numerical models have been the main Navier–Stokes models used for modeling. This is largely due to the key advantages of these models, including robustness, multiple solving methods, high levels of accuracy, and ability to add to the coding for specific simulations.

LNG Fire Modeling

A LNG pool fire can transmit significant radiant heat to an object outside the fire, with the heat flux strongly dependent upon various parameters. These parameters include the properties of fire (e.g., size, shape, and geometry), surrounding atmosphere (e.g., transmissivity), and object (e.g., location and orientation). Technical issues that arise when modeling LNG pool fires are usually due to the scale of the fire. As pool fires become larger, physical phenomena, such as oxygen starvation in the center of the pool fire, smoke generation, and reduction in the emissivity power, become more important (Raj et al). Extrapolation from small fires can lead to misleading results; therefore, developing modeling techniques are in great need for studying large-scale LNG pool fires.

Generally, there are three approaches to modeling LNG fires: 1) the point source method, 2) solid flame method, and 3) field (or Navier–Stokes) method. The point source model can easily produce results; however, the assumptions taken, such as neglecting wind and obstacle effects, assuming that all heat is radiated at the ground level, can lead to questionable accuracy. On the other hand, the solid flame model accounts for wind and atmospheric conditions; however, the cylindrical flame modeling approach can, at times, lead to inaccurate results. Navier–Stokes models are the most complete and robust models that are able to provide the most accurate results.[83]

6.12 Release Consequence: Exposure to Population

Release consequences are described in the model as release scenarios. Risk software can be employed for each phase of LNG ISO tank container operations or LNG 113 tank car route scenarios. Most risk software programs require a definition of the release sizes (e.g., no release, small, large, and catastrophic), release conditions, and the LOC frequency for each size of hole for each release scenario. Model conditions for each scenario need to be developed and event trees are commonly used to estimate the release frequencies.

In the FECR Risk Report, the LNG ISO tank container operations were grouped into three separate categories, distinguished by the type of operations and the unique risks present. ISO containers are lifted on and off specially designed rail well cars as part of the LNG operation. Therefore, two categories include lift on and lift off movements and one category defines main line movement.

Identifying affected populations is a critical part of the QRA, and involves the identification of persons impacted by an LNG event. Sensitive populations include those persons who require assistance to evacuate a facility, including schools, hospitals, child care facilities, senior care facilities and correctional facilities and stadiums. HSE decided it needed to improve the quality of the population data it used, so it commissioned the development of the National Population Database (NPD). Table 6.7 describes affected populations that were identified as part of the NPD.

Table 6.7 Affected Populations during Hazmat Release Events

Population Type	Description
Residential	Daytime
	Nighttime
Sensitive	Hospitals
	Schools (primary, secondary, boarding)
	Child care facilities
	Facilities for persons with access and functional needs
	Senior care facilities
Large Gathering Establishments	Correctional facilities
	Places of worship
	Stadiums, Arenas
	Campsites
Transportation	Arterial Highways, collector and local roads
	Railroads, seaports, airports
Employment	Daytime employer population
	Nighttime employer population
Retail	Daytime population
	Nighttime population

Sources: Health and Safety Executive, “Societal Risk…;” Cambridge Systematics, Inc.

[83] Ibid.

6.13 Emergency Response

Throughout the world, emergency managers are working to prevent chemical accidents and prepare for them. Preparedness is the best means to avoid incidents or mitigate the impact of incidents.[84] Emergency management professionals have expressed considerable interest in LNG, as LNG import facilities are being reconfigured for export and LNG transportation shipments by truck, rail, and ship are increasing. LNG export facilities are now operational in Sabine Pass, LA and in Cove Point, MD. After the recent crude oil and ethanol derailments that occurred around the United States and Canada, first responders are participating in training sessions, including response to incidents involving crude oil and ethanol shipments and high hazard flammable trains (HHFT). In response to the Alaska and Florida LNG rail pilot programs, more firefighters are being trained in LNG rail response protocols and best practices in those States.

The LNG export trend has also resulted in more natural gas liquids used in the liquefaction process. This has led to concerns from fire officials on increasing refrigerants gases and blends containing ethane, propane, ethylene, and isobutane. In discussions with fire chiefs, we learned that unlike Liquefied Petroleum Gas (LPG or propane), LNG releases do not allow first responders to cap off a leak or interact with the container. LNG releases involving cryogenic gas would result in an immediate evacuation of the area and securing the adjacent facilities. Given the warming effect of water on cryogenic gases, putting water on a cryogenic release is not recommended. It is very difficult to clean up an LNG incident; the product would need to gas off naturally, and any nearby ignition sources would need to be eliminated to prevent a fire. The most common response involving MC 338 trailer rollovers or crashes is to evacuate the area and maintain a perimeter guard until the LNG has dissipated.

The CS Team also met with representatives from the National Fire Protection Agency (NFPA). The NFPA has been involved in LNG emergency response for many years. This began primarily with fire protection for LNG facilities constructed in the U.S. in the 1970s, during which time maritime LNG specifications were also developed. Recently railroads have been exploring LNG for locomotive propulsion using dual fuel diesel engines. Maritime cargo using LNG propulsion has now expanded to include cruise ships, tugboats, cargo vessels, and offshore supply vessels.

Based in part on simulation analysis and historical data, the U.S. Department of Transportation’s Emergency Response Guidebook (ERG) recommends first responders’ initial isolation and protective action distances for specific toxic inhalation hazards (TIH). However, since LNG is not considered a toxic inhalation hazard, isolation protective action distances are not documented for LNG. In the ERG guidance section (orange pages), the guidance applies to flammable gases transported in both pressurized and cryogenic containers. In this section of the ERG, as an immediate precautionary measure, the guidance recommends first responders “isolate spill or leak area for at least 100 meters (330 feet) in all directions.” For a large spill, the ERG recommends first responders “consider initial downwind evacuation for at least 800 meters (½ mile).” If a tank, rail car, or tank truck is involved in a fire, “isolate for 1,600 meters (1 mile) in all directions; also, consider initial evacuation for 1,600 meters (1 mile) in all directions.”

As LNG transportation by motor carrier, rail, and ship continue to increase, first responders in communities where LNG is transported will require additional training. While motor carrier transport of LNG has been conducted safely over the past 40 years, trends suggest that motor carrier transport of LNG will increase. This is due in part to the need for LNG to supplement peak shaving facilities in the U.S. and in part to the growing trend of using LNG for fuel. The USCG continues to examine LNG fueling operations in light of

[84] Halmemies, “Education Modules for Chemical Accident Prevention…”

interest on the part of cargo ships, cruise ships, and petroleum supply vessels to build LNG-fueled vessels. This will impact bunkering operations in ports around the country, including Jacksonville, FL, Miami, FL, Houston, TX, and Fourchon, LA.

7.0 Truck LNG and LPG Risk Assessment

The objective of this study was to assess the risks of LNG surface transport (rail and truck), with an emphasis on rail transport. This section includes selected information on truck risk factors, including relative risks of LNG versus LPG in highway and rail transport, and LNG versus LPG truck accident rates. LNG has been transported by truck for over 40 years with few incidents, an indication that LNG motor carrier risks are manageable. However, with increasing motor carrier traffic volumes and issues with driver fatigue and hours of service, it is important to recognize how these factors may influence LNG truck transport in the future.

7.1 Truck Risk Factors

Unlike rail risk factors such as FRA track class, method of operation and rail density, truck risk factors include driver behavior, traffic congestion and truck speed, and the increasing volume of trucks on the road relative to other vehicles.

Highway safety researchers have conducted a number of studies quantifying the relationship between accident rates and roadway design. These studies have considered the effects of road curvature, traffic volume, grade, shoulder width, number of lanes and other factors (e.g., Miaou, 1994; Maher and Summersgill, 1996; Hauer, 2001; Lord et al., 2005; Lord, 2006; Mitra and Washington, 2007).

Research has indicated that the risk of a fatal truck crash goes up as the percent of trucks on the road relative to other vehicles also goes up. In fact, the crash risk increase is greater than the increase in the truck volume. In other words, a one percent increase in truck volume corresponds to an increased truck accident risk by more than one percent.[85] In another report authored by Taylor and Francis, the danger that speed poses is highlighted. In this study, researchers concluded the chance that a fatal truck accident could happen doubles when a truck driver travels at a speed beyond 45 miles per hour.

Additional research on large truck crash risk suggest vehicle safety technologies can be important in lowering crash risk.[86] This means that as safety technology continues to penetrate the fleet, whether from voluntary usage or Government mandates, reductions in large truck crashes may be achieved. Results imply that increased enforcement and use of crash avoidance technologies can improve the large truck crash problem.[87]

There are many different factors that contribute to commercial vehicle safety, each with its own set of associated technologies and safety practices. Some technologies and practices are intended to improve crashworthiness, or to minimize injuries in the event of a crash (often called “passive safety”). Other technologies and safety measures are designed to reduce the likelihood or severity of a crash (often called “active safety”).[88]

The Federal Motor Carrier Safety Administration (FMCSA) and the National Highway Traffic Safety Administration (NHTSA) conducted the Large Truck Crash Causation Study (LTCCS) to examine the reasons for serious crashes involving large trucks (trucks with a gross vehicle weight rating over 10,000 pounds). From the 120,000 large truck crashes that occurred between April 2001 and December 2003, a nationally representative sample was selected. Each crash in the LTCCS sample involved at least one large truck and resulted in a fatality or injury.

[85] Dixon & Daley, “A new look at truck accident risk factors.”

[86] MaineWay Services and Cambridge Systematics, Inc., “Truck Technology Literature Review.”

[87] Teoh et al., “Crash risk factors…”

[88] MaineWay Services and Cambridge Systematics, Inc., “Beyond Compliance Literature Review.”

The total LTCCS sample of 963 crashes involved 1,123 large trucks and 959 motor vehicles that were not large trucks. The 963 crashes resulted in 249 fatalities and 1,654 injuries. Of the 1,123 large trucks in the sample, 77 percent were tractors pulling a single semitrailer, and 5 percent were trucks carrying hazardous materials. Of the 963 crashes in the sample, 73 percent involved a large truck colliding with at least one other vehicle.

Hundreds of associated factors were collected for each vehicle in each crash. In descending order, the top 10 factors coded for large trucks and their drivers were:

- Brake problems.
- Traffic flow interruption (congestion, previous crash).
- Prescription drug use.
- Traveling too fast for conditions.
- Unfamiliarity with roadway.
- Roadway problems.
- Required to stop before crash (traffic control device, crosswalk).
- Over-the-counter drug use.
- Inadequate surveillance.
- Fatigue.

Researchers have determined that truck accident rates vary with road type and with population density. U.S. databases have been developed to include highway geometrics, truck volumes, and truck crashes. These help researchers to assess factors impacting truck crashes.

7.2 New England LNG Truck Case Study

Engie, Inc. operates the oldest LNG import facility in the United States, located in Everett, MA. Ships transporting LNG to Boston Harbor offload LNG into storage tanks to fuel a nearby gas-fired power plant and to provide natural gas as heat for commercial, residential and industrial facilities throughout New England. Maritime LNG imports in New England are important since there is not enough available pipeline capacity to supply natural gas to the region. Over the past 45 years, Engie has contracted with motor carriers to transport LNG to 42 storage facilities in New England. During this time, these carriers have completed over 300,000 truck trips up to 150 miles with only two incidents. One was a truck rollover and the other was a truck engine fire. In both examples the LNG product in the cargo tank was not released. Engie officials described the situation in New England in which natural gas is only needed during the winter months. LNG is imported to Everett, MA, where it is off-loaded into storage tanks to power generation systems and later loaded into trucks for distribution to 41 facilities throughout New England. This is an example of how motor carrier LNG transportation has been provided safely and efficiently over the past 40 years with minimal incidents.

7.3 Relative Risks of LNG versus LPG in Highway and Rail Transport

In 2015, researchers studied the relative risks of transporting LNG versus Liquefied Petroleum Gas (LPG) by truck and rail. While LNG and LPG hazards both include fires and explosions due to loss of containment, the properties are very different. LPG is pressurized to keep in liquid form, the release of which would result in a rapid release of highly flammable product. By contrast, LNG is a cryogenic liquid stored in double-walled containers, the release of which would result in cryogenic liquid releasing at a lower rate, and only igniting within a limited vapor range. The analysis revealed that accident rates and hole size probabilities in accidents were independent of the hazmat commodity shipped. Therefore, a single accident rate value could be applied to both LNG and LPG shipments. Most rail accidents were the result of equipment or track failures; whereas truck accidents were the result of brakes, traffic flow or driver behavior. The QRA results indicated the individual and societal risks for highway and rail transport were similar. In general, the safety risk for rail transportation is higher than for highway transport; likely due to the larger volumes of tank cars relative to highway cargo tankers.[89]

7.4 LNG and LPG Carrier Analysis

In order to better understand motor carrier transport risk, the CS Team evaluated all U.S. LNG and LPG carriers and crash rates. The number of motor carriers that transport LNG and LPG in the U.S., and associated safety and demographic information on these carriers, was estimated from the Federal Motor Carrier Safety Administration's (FMCSA) Motor Carrier Management Information System (MCMIS) database.

Using a Hazardous Materials Carrier Report from the MCMIS database, the CS Team examined a list of carriers and carriers/shippers that transport or ship hazardous materials.[90] Only those carriers listed as "active" in MCMIS, registered as an Intrastate Hazardous Materials carrier or an Interstate carrier that transports hazardous materials, and whose operation type is listed as "carrier" or "carrier/shipper" were included in the analysis.

The Hazardous Materials Carrier Report also indicated what types of hazardous materials a motor carrier are authorized to haul. As LNG is primarily composed of methane, the field "DIV 2.1 Methane" denotes those carriers that may transport LNG. To estimate the number of motor carriers transporting LNG, the data was filtered on the "DIV 2.1 Methane" field to show only those carriers with the following values:

- **B-A:** a carrier is authorized to both haul and ship ("B") hazardous material in both bulk and non-bulk forms ("A").
- **B-B:** a carrier is authorized to both haul and ship ("B") hazardous material in bulk form ("B").
- **B-N:** a carrier is authorized to both haul and ship ("B") hazardous material in non-bulk form ("N").
- **C-A:** a carrier is authorized to haul ("C") hazardous material in both bulk and non-bulk forms ("A").
- **C-B:** a carrier is authorized to haul ("C") hazardous material in bulk form ("B").
- **C-N:** a carrier is authorized to haul ("C") hazardous material in non-bulk form ("N").

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89 Hart and Morrison, *Bulk Transport by Road and Rail.*

90 The MCMIS Hazardous Materials Carrier Report is updated weekly. The version of the report used in this analysis is based on the 10/13/2017 update.

In addition to these categories, some entities that are listed as shippers in the Hazardous Materials Carrier Report were retained in the analysis. This is because those shipper records indicated that those entities also employed drivers and had access to power units. This suggests that they may be involved in the physical transport of LNG. Thus, those shippers with drivers, power units, and the following values under the DIV 2.1 Methane field were included in the analysis:

- **S-A:** a shipper is authorized to ship ("S") hazardous material in both bulk and non-bulk forms ("A").
- **S-B:** a shipper is authorized to ship ("S") hazardous material in bulk form ("B").
- **S-N:** a shipper is authorized to ship ("S") hazardous material in non-bulk form ("N").

A similar analysis was performed to identify LPG carriers. The field "DIV 2.1 LPG" denotes those carriers that may transport LPG. To estimate the number of motor carriers transporting LPG, the data was filtered to show only those carriers with the same authorizations described in the previous paragraph.

7.4.1 LNG Carriers

In total, 521 motor carriers transport LNG (which includes three Canadian carriers that are authorized to operate in the U.S.). Based on these data, motor carriers that transport LNG are broadly distributed across the United States. As shown in Figure 7.1 and Table 7.1, the State of Texas has the most registered LNG carriers with 74 (about 14.2 percent). Texas is followed by Pennsylvania with 30 LNG carriers (about 5.8 percent). The States of California, Illinois, and Florida have the next highest totals at 27 (5.2 percent), 26 (5.0 percent), and 21 (4 percent), respectively. Collectively, these 5 States represent over one-third (approximately 34 percent) of all registered LNG carriers.

The Hazardous Materials Carrier Report also contains data on carrier involvement in crashes. It is important to note, however, that these represent total crashes and are not limited to instances in which LNG was transported. Thus, an analysis of the crash data in the Hazardous Materials Carrier Report is indicative of overall safety performance and not the transport of LNG specifically.

The data field "Number of Crashes" indicates the number of crashes a carrier has had in the past 12 months. In total, LNG carriers were involved in 2,925 crashes. The top 10 LNG carriers for total crashes accounted for nearly three-quarters (72 percent) of total crashes. These carriers also account for approximately 53 percent of total power units which suggests that collectively they are slightly over represented in the data.

The crash rate is calculated by dividing the total number of crashes by the total number of power units for each carrier. Power units are indicative of the magnitude of a carrier's operations. Thus, the number of power units suggest the extent to which a carrier is exposed to the potential for a crash. Alternatively, vehicle miles traveled could be used as an exposure variable but that information was not available and therefore was not included in the report.

The results indicate that most carriers have no or very few crashes over the previous 12 months relative to their fleet size. Nearly 68 percent of LNG carriers exhibited crash rates below 0.073 crashes per power unit. The largest observed crash rate (among carriers with three or more power units) was 0.25 crash per power unit. It is important to note that these crashes do not exclusively represent incidents involving of LNG-laden vehicles. Instead, they represent crashes in all facets of the carriers' operations that comprise the data (see Figure 7.2).

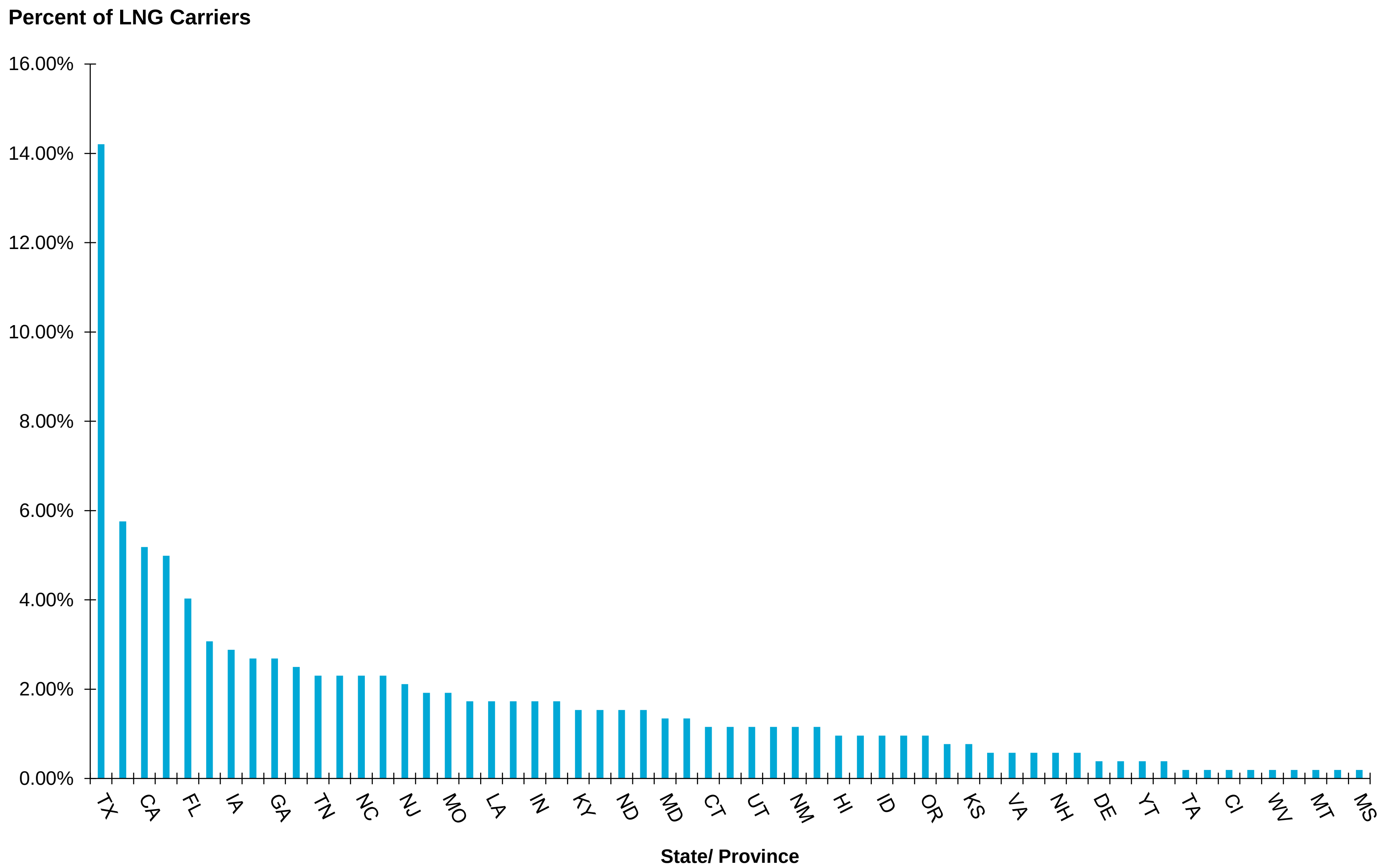

Figure 7.1 Distribution of LNG Carriers
By State

Source: FMCSA, Cambridge Systematics

Table 7.1 States with Most Registered LNG Carriers

State	Number of Carriers	Percent of Total
Texas	74	14.2%
Pennsylvania	30	5.8%
California	27	5.2%
Illinois	26	5.0%
Florida	21	4.0%
Subtotal	178	34.2%
All Other States/Provinces	343	65.8%
Total	521	100.0%

Source: FMCSA, Cambridge Systematics

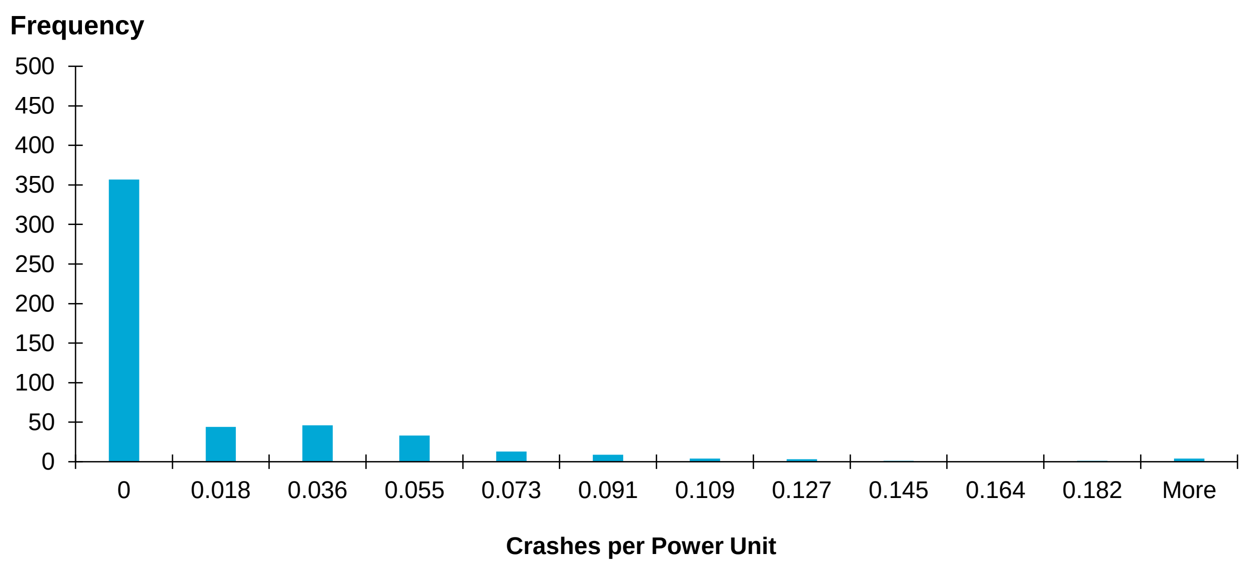

Figure 7.2 Distribution of Crash Rates across LNG Carriers

Source: FMCSA and Cambridge Systematics

7.4.2 LPG Carriers

The CS Team evaluated Liquid Petroleum Gas (LPG) carriers to compare safety performance with LNG. In total, 1,237 motor carriers are estimated to transport LPG (which includes Canadian carriers authorized to operate in the U.S.). Based on these data, motor carriers that haul LPG are broadly distributed across the United States. As shown in Figure 7.3 and Table 7.2 the State of Texas has the most registered LPG carriers with 45 (about 7.9 percent). The State of Minnesota has the next highest total at 107 (approximately 8.7 percent). It is closely followed by Minnesota and Pennsylvania with 61 (4.9 percent) and 58 (4.7 percent), respectively. The States of Illinois and California have 52 (4.2 percent) and 51 (4.1 percent) registered LPG carriers, respectively. Collectively, these five States represent over one-quarter (approximately 27 percent) of all registered LPG carriers.

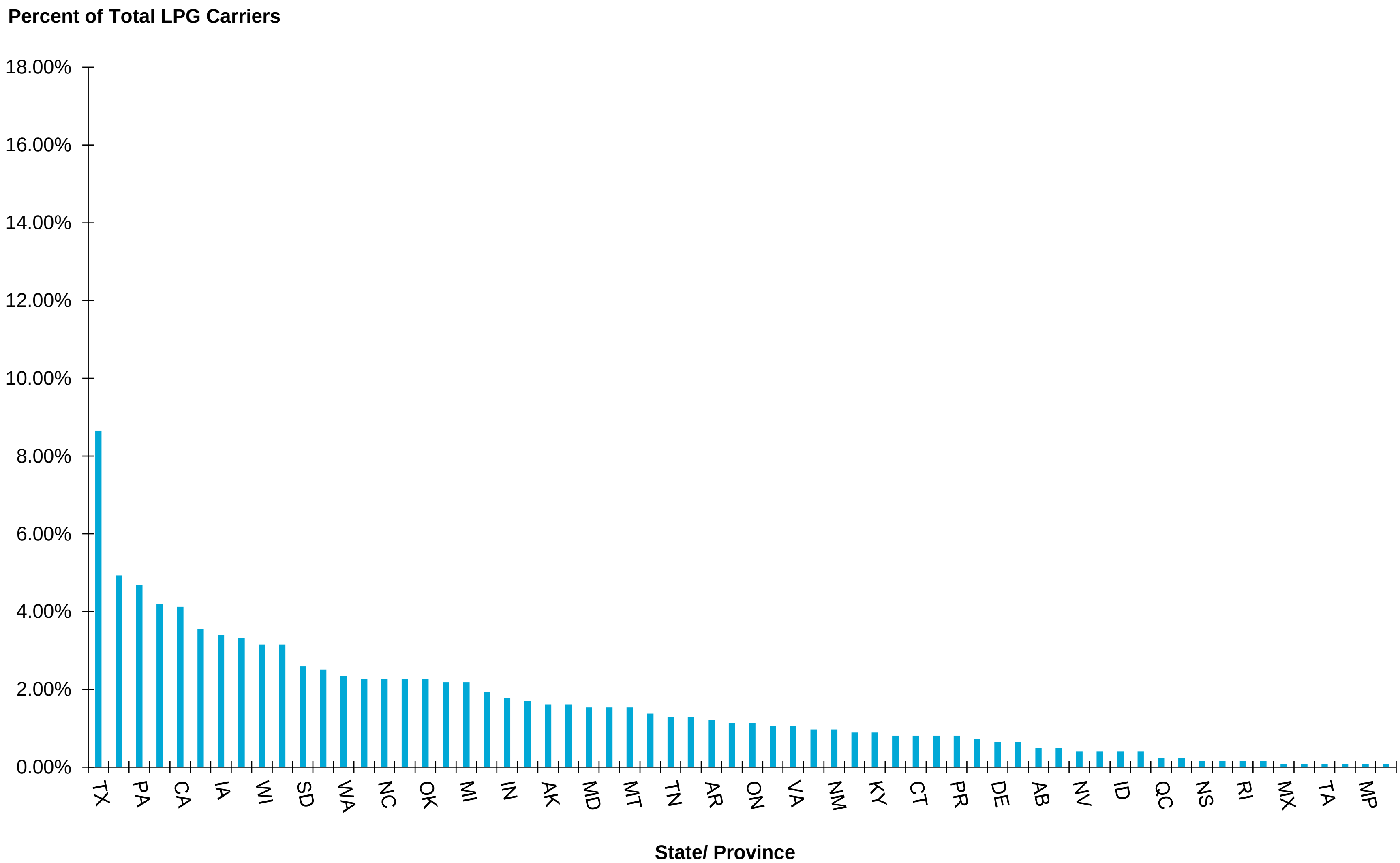

Figure 7.3 Distribution of LPG Carriers
By State and Province

Source: FMCSA and Cambridge Systematics

Table 7.2 States with the Most Registered LPG Carriers (including Puerto Rico)

State	Number of Carriers	Percent of Total
Texas	107	8.7%
Minnesota	61	4.9%
Pennsylvania	58	4.7%
Illinois	52	4.2%
California	51	4.1%
Subtotal	329	26.6%
All Other States	908	73.4%
Total	1,237	100.0%

Similar to the analysis of LNG carriers, the safety performance of LPG carriers is examined using the past 12 months of crash data. As discussed in the LNG analysis, it is important to note that the data represents total crashes and are not limited to instances in which LPG was transported. Thus, an analysis of the crash data in the Hazardous Materials Carrier Report is indicative of overall safety performance and not the transport of LPG specifically.

In total, LPG carriers were involved in 4,925 crashes. The top 10 LNG carriers for total crashes accounted for approximately 60 percent of total crashes. These carriers also account for approximately 41 percent of total power units which suggests that collectively they are slightly over represented in the data.

The crash rate is calculated by dividing the total number of crashes by the total number of power units for each carrier. The results indicate that most carriers have no or very few crashes over the previous 12 months relative to their fleet size. The average crash rate for carriers with three or more power units was 0.015. Nearly 95 percent of LNG carriers exhibited crash rates that fell below 0.073 crashes per power unit (Figure 7.4).

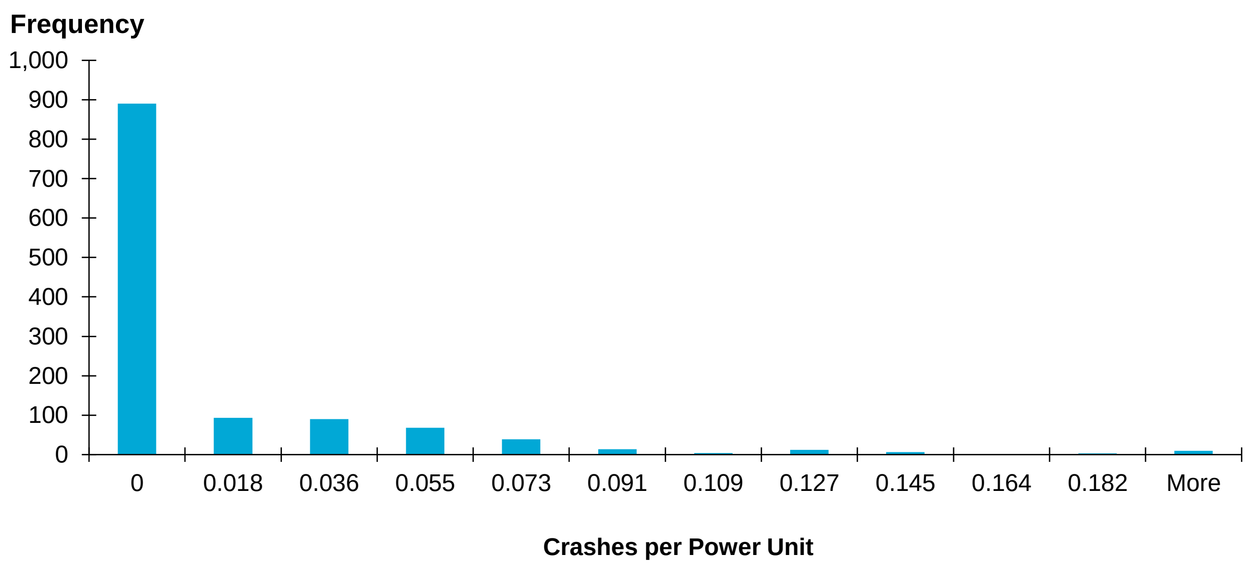

Figure 7.4 Distribution of Crash Rates across LPG Carriers

Source: FMCSA and Cambridge Systematics

7.5 Truck LNG and LPG Risk Summary

The results of this research indicate that motor carriers transporting LNG and LPG have very low crash rates relative to other carriers. For example, over the past 45 years, New England LNG carriers completed over 300,000 truck trips up to 150 miles with only two incidents. One was a truck rollover and the other was a truck engine fire. In both examples the LNG product in the cargo tank was not released.

Unlike rail risk factors such as FRA track class, method of operation and rail density, truck risk factors include driver behavior, traffic congestion, truck speed and the volume of truck on the road relative to other vehicles. Since truck and rail operations have very different risk factors, they need to be evaluated differently.

In comparing LNG and LPG carriers, a total of 521 motor carriers transported LNG over the past year and 1,237 motor carriers transported LPG. Both LNG and LPG carriers exhibited crash rates that fell below 0.073 crashes per power unit. These low crash rates can be attributed to the fact that LNG and LPG carriers represent a small percentage of the overall truck traffic on the highways. In addition, LNG and LPG carriers have high standards for safety and conduct extensive driver training programs to ensure safe transportation and handling of these fuels.

8.0 Conclusion

Natural gas is increasing in use in the U.S. due to the prolific production efforts in the Permian and Marcellus shale basins, taking a larger share of the energy market, and replacing other energy sources. As a result, consumers are switching from sources such as coal, nuclear, and diesel to natural gas for power, heat, and propulsion. While the U.S. natural gas pipeline network is extensive some geographic limitations do exist. There are areas of the U.S. that lack pipeline capacity including the Northeast and Mountain West. Up until five years ago, the U.S. relied on natural gas imports. With the newfound natural gas production capabilities, the U.S. is systematically recommissioning those same natural gas import facilities for export.

With this increase in demand for natural gas, LNG transportation complements the distribution of natural gas by pipeline, providing access to areas that are not sufficiently supplied by the pipeline network. While surface transportation of LNG currently is only allowed by truck, and by rail with special permit, modal choice for LNG delivery would increase the opportunity for energy consumers to make competitive choices about their energy supply. There also is evidence that a demand exists for shipping LNG by rail, and that rail shipments of LNG can be both competitive and complementary to the truck and pipeline networks. Since railroads have unique advantages and disadvantages compared to trucks, and the public safety implications are not fully developed, risk assessments provide additional insight into the shipment of LNG by rail.

The results of our research indicate that LNG transportation has a good safety record, with minimal maritime, facility, and motor carrier incidents relative to other flammable liquids. In other countries, LNG has be transported safely by rail with no incidents to date. This LNG safety record can be attributed to the fact that LNG is not explosive in an uncontained environment, is transported in double-walled containers, and evaporates rapidly when exposed to the atmosphere. Notwithstanding the LNG safety record, it is still important to recognize and plan for LNG risks that do exist.

Developing a QRA with risk factors and parameters is the first step to modeling LNG transport by motor carrier and by rail. This will help to evaluate the derailment and release probability of LNG rail cars over certain segments of the network and to account for a variety of track and train characteristics. LNG transport by truck does have a successful record. However, understanding truck safety risk factors can help to mitigate or prevent truck crashes and improve LNG motor carrier safety as demand for LNG increases. An LNG risk model can be used to understand that probability and consequences for LNG transportation incidents for both rail and truck delivery, even though they are treated differently, the underlying event tree analysis approach is the same. When the probability of LNG tank car derailment is understood, better decisions can be made regarding the crashworthiness, placement, and operation of rail cars and the potential consequences from an LNG release due to a derailment. An added benefit is the ability to also understand the potential consequences from truck LNG movements. Further study for modeling the probability and consequences of transporting LNG by rail and truck will be beneficial to understanding risks to the public.

Appendix A. Acronyms

AAR	Association of American Railroads
Bcf/d	Billion cubic feet per day
BTU	British Thermal Unit
CBRNE	Chemical, Biological, Nuclear or High-Yield Explosives
CMV	Commercial Motor Vehicle
CNG	Compressed Natural Gas
COFC	Container on Flat Car
DOE	Department of Energy
DOT	Department of Transportation
EIA	U.S. Energy Information Administration
ERG	Emergency Response Guidebook
FECR	Florida East Coast Railway
FERC	Federal Energy Regulatory Commission
FMCSA	Federal Motor Carrier Safety Administration
FRA	Federal Railroad Administration
HGL	Hydrocarbon Gas Liquids
ICE	Intercontinental Exchange
IGU	International Gas Union
ISO	International Standards Organization
LDC	Local Distribution Company
LNG	Liquid Natural Gas
LPG	Liquefied Petroleum Gas
MARAD	Maritime Administration
MGT	Million Gross Tons
MMBtu	Million British Thermal Units
MMCF	Millions of Cubic Feet
MCMIS	Motor Carrier Management Information System
MOU	Memorandum of Understanding
MTPA	Million tonnes per annum
NEB	National Energy Board (Canada)
NEPA	National Environmental Policy Act
NFPA	National Fire Protection Association
NGL	Natural Gas Liquid
NHS	National Highway System
PHMSA	Pipeline and Hazardous Materials Safety Administration
QRA	Quantitative Risk Assessment

REA	Rail Equipment Accident [FRA Database]
RTO	Regional Transmission Organization
TCAD	Tank Car Accident Database
TOFC	Trailer on Flat Car
USCG	United States Coast Guard
VCE	Vapor Cloud Explosion

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Appendix C. Regulatory Framework

Federal oversight of LNG throughout the LNG value chain is complex due to the number of Federal agencies involved and the different types and modes of transport, both foreign and domestic.

In the United States, liquefied natural gas (LNG) has the unique distinction of being the only flammable or hazardous material whose storage terminal (siting), handling and terminal operations are regulated by the Federal Government. Regulations are promulgated by the PHMSA. Storage and handling of all other flammable and hazardous materials are regulated by State laws.[91]

FERC authorizes interstate pipelines (red), while PHMSA authorizes LNG transfer piping from plants to transportation assets (green). Gathering pipelines from maritime oil wells are authorized by MARAD. Figure C.1 and Table C.1 illustrates these relationships and Federal oversight of the LNG value chain.

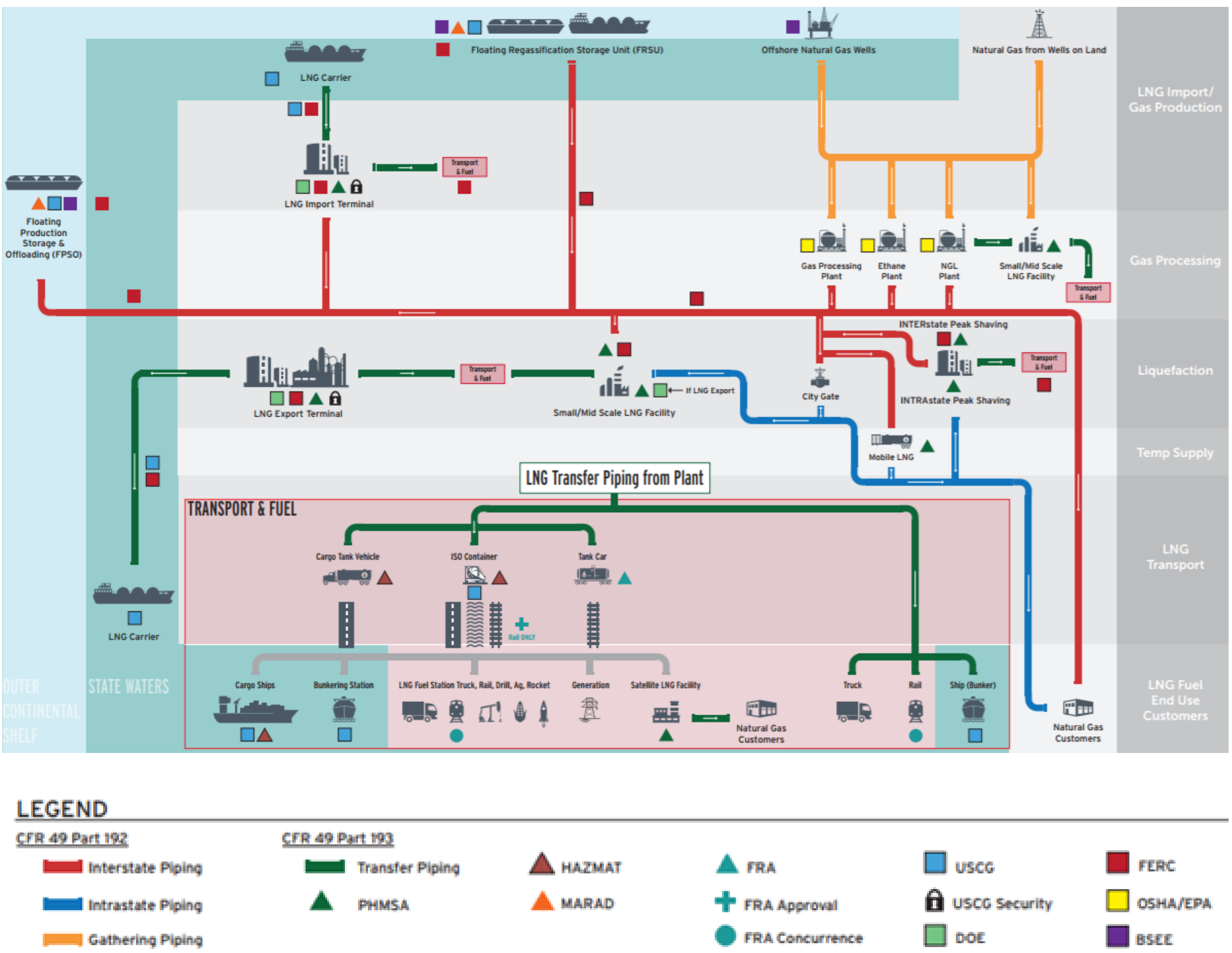

Figure C.1 Federal Oversight of LNG Value Chain

Source: PHMSA, https://www.phmsa.dot.gov/pipeline/technical-resources/liquefied-natural-gas/regulatory-information/special-permits.

91 Raj and Lermoff, "Risk analysis based LNG facility…"

Table C.1 U.S. Federal Agency LNG Oversight

Agency	Description	LNG Oversight
DOE	Department of Energy	Environmental regulation, permitting, import/export
EPA	Environmental Protection Agency	Clean Air Act and the Clean Water Act
FERC	Federal Energy Regulatory Commission	LNG Facility Siting, Permitting, Interstate commerce
FMCSA	Federal Motor Carrier Safety Administration	Cryogenic tanks and cargo tank safety, oversight, regulations, inspections
FRA	Federal Railroad Administration	LNG Locomotive Tenders, bulk transport by special permit
FWS	Fish and Wildlife Service	Endangered species
MARAD	Maritime Administration	Off-Shore LNG facility design, siting, navigation
NOAA	National Oceanographic and Atmospheric Administration	Endangered species
PHMSA	Pipeline and Hazardous Materials Administration	LNG Facility Design, packaging, transportation
USACE	Army Corps of Engineers	Dredging and wetland permits
USCG	United States Coast Guard	Maritime LNG transfer areas, inspections, LNG bunkering

Source: PHMSA, FERC, and Cambridge Systematics, Inc.

DOE is part of an interagency working group on LNG that meets regularly, with the most recent meeting held on October 19, 2017. Participating agencies include PHMSA, DOE, FERC, USCG and EPA.

Section §172.101 contains information on the Hazardous Materials Table (HMT). LNG is characterized as Methane, refrigerated liquid, UN1972, and is classified for transportation as a Flammable Gas, Class 2.1. Section §172.102 contains Special Provisions for LNG portable tank requirements, or the T-75 container. TP5 specifies fill rate and outage for portable tanks. LNG Packaging is shown in column eight of the HMT. There is no “Non-bulk packaging”; Bulk Packaging is described in §173.318 as “Cryogenic Liquids in Cargo Tanks.”

LNG Transportation by Vessel is listed under Stowage “D,” Above Deck on a cargo vessel, or a passenger-carrying vessel, with a restriction on the number of containers.

LNG Transportation by Rail tank car is not authorized at this time. Portable tanks and Cargo tank are authorized on a rail car, but only with approval from Federal Railroad Administration (FRA). Section §174.63 specifies requirements for rail carriers to transport portable tanks of hazardous material in Container-on-flatcar (COFC) and Trailer-on-flatcar (TOFC) service.

LNG Transportation by Highway moves by truck, using double walled, vacuum insulated tanks and cargo tank trailers. There are currently 136 carriers that haul LNG.

LNG Transportation by Pipeline only occurs between LNG storage tanks and ships, locomotives and trucks for loading and unloading purposes. LNG pipelines must be heavily insulated and are generally only used in applications over very short distances.

Appendix D. Liquefied Natural Gas Defined

Liquefied natural gas (LNG) is simply natural gas that has been cooled to convert into a liquid.[92] In many cases, some trace constituents of natural gas are removed before, or as part of, liquefaction. As an extremely cold liquid (at ambient pressure), LNG is a cryogenic liquid. Most sources note a liquefaction temperature of −162° C (111.15 K, −260° F), which corresponds to the ambient pressure boiling point of methane (−161.49° C; 111.66 K, −258.68° F).

To understand LNG as a cryogenic liquid, the discussion should begin with methane (the principal constituent of natural gas, and therefore LNG), make a detour to the term "cryogenic liquid," and then consider natural gas and LNG.

D.1 Methane

Methane needs to be considered first as it is the principal component (usually 90 percent or more) of natural gas. Methane (CH_4 to a chemist) is the simplest "hydrocarbon" (substances predominantly composed of hydrogen and carbon). Most refined liquid fossil fuels (e.g., gasoline, diesel, JP8, etc.) and other common fuels (propane, butane, lighter fluid, etc.) are composed of hydrocarbon compounds. Coal also is principally a hydrocarbon material.

Of the hydrocarbon fuels, methane has the greatest ratio of hydrogen to carbon (4:1), which has important implications. When burned it creates the lowest possible ratio of carbon dioxide (CO_2) to water, so burning methane releases a greater ratio of heat to carbon dioxide than burning any other hydrocarbon. That is, methane as a fuel releases less greenhouse gas (carbon dioxide) than other hydrocarbon fuels, making it "greener." This, along with the facts that methane combustion easily proceeds to completion (thereby releasing no volatile organic compounds, VOCs), usually burns without forming soot, has been increasingly available in recent years, accounts for the rapid increase in interest in natural gas for fuel use.

Because natural gas is mainly methane, the properties of natural gas and LNG are largely determined by those of the contained methane (Table D.2). Key properties of methane include:

[92] Natural gas liquefaction is normally accomplished by one of two processes:

(a) The 'cascade' process, in which another cold gas is used to cool the natural gas until it liquefies; or

(b) The 'Linde' process which relies upon the Joule-Thompson effect. That is similar to the technology used in a conventional refrigeration cycle: The gas is compressed, then cooled to remove heat. It is then passed through an orifice and the pressure reduced. The gas expansion naturally cools the gas (through the Joule-Thompson effect). If that cold gas is again compressed and cooled, the next expansion makes it yet colder, until liquefaction occurs.

Table D.1 Methane Gas Properties[1, 2, 3]

Chemical formula	CH_4
Molar mass	16.04 g·mol^{-1}
Appearance	Colorless gas
Odor	Odorless
Density	0.656 g/L (gas, 25°C, 1 atm) 0.716 g/L (gas, 0° C, 1 atm) 0.42262 g/cm^3 (liquid, −162 °C)
Melting point	−182.5 C; −296.4 F; 90.7 K
Boiling point	−161.49 C; −258.68 F; 111.66 K
Solubility in water	22.7 mg/L
Solubility	soluble in ethanol, diethyl ether, benzene, toluene, methanol, acetone

1 http://webbook.nist.gov/chemistry/faq/.

2 http://webbook.nist.gov/cgi/cbook.cgi?ID=74-82-8.

3 https://en.wikipedia.org/wiki/Methane.

It should be noted that (as is typical) the cold liquid is much denser than the gas. Once liquefied, because it is a cryogenic liquid, it must be transported or stored in insulated tanks.

As noted above, methane is a colorless, odorless gas at ambient conditions. It is, however, flammable in mixtures with air at 4.4-17 percent by volume.[93] For comparison, the explosive (flammability) limits in air for hydrogen are 4-75 percent by volume in air, for propane are 2.4-9.5 percent by volume in air, and for gasoline are 1.4-7.6 percent by volume in air.[94, 95, 96]

Methane also is a greenhouse gas. According to the 2013 IPCC report, methane has a global warming potential of 86 for a 20-year time horizon, and 34 for a 100-year time horizon,[97, 98 99]

93 https://en.wikipedia.org/wiki/Methane.

94 https://en.wikipedia.org/wiki/Hydrogen_safety.

95 https://en.wikipedia.org/wiki/Propane.

96 https://www.ccohs.ca/oshanswers/chemicals/flammable/flam.html.

97 https://en.wikipedia.org/wiki/Global_warming_potential.

98 Myhre et al., “Anthropogenic and Natural Radiative Forcing.”

99 Stocker et al., *Anthropogenic and Natural Radiative Forcing.*

(Footnote continued on next page...)

D.2 Cryogenic Liquids

Cryogenic liquids are simply very cold liquids; this term is normally applied to liquids with boiling points below ambient temperatures.[100] The exact temperature range that constitutes "cryogenic" is not well defined.[101] One "practical definition" would be any temperature below that of "dry ice," which is a commonly used low-temperature refrigerant. The most important definition of cryogenic liquid for the present purposes is probably that of the U.S. Department of Transportation (DOT):[102]

> "**(g)** ***Cryogenic liquid.*** A *cryogenic liquid* means a refrigerated liquefied gas having a boiling point colder than −90 °C (−130 °F) at 101.3 kPa (14.7 psia) absolute. A material meeting this definition is subject to requirements of this subchapter without regard to whether it meets the definition of a nonflammable, nonpoisonous compressed gas in paragraph (b) of this section."[103]

D.3 Natural Gas

The term "natural gas" refers to naturally occurring hydrocarbon gas frequently collected for use as fuel.[104] It is formed in both thermogenic processes, from deeply buried organic material (typically from the carboniferous period), and (principally as methane) in biogenic processes by methanogenic (methane forming) bacteria in various terrestrial locations (bogs, marshes, shallow sediment) or even animals (e.g., fermentation within digestive tracts of mammals) and animal waste (e.g., sewage).

As recovered, natural gas is principally methane, but has a variable composition that includes several additional compounds, such as other hydrocarbons (ethane, propane) and other gasses (carbon dioxide, nitrogen, hydrogen sulfide). There is no formally defined "standard" composition for pipeline/commercial quality natural gas (see more below), though generally there is some processing of natural gas before it is distributed.[105] Water, excessive CO_2, condensed liquids (NGL) and hydrogen sulfide (H_2S) and other objectionable components (mercaptans, thiols, sometimes traces of mercury, traces of radon) must be removed.

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[100] Liquids that boil at temperatures above ambient (such as water) generally need not be handled cold, and therefore are not generally considered to be cryogenic. There are a few examples (e.g., acetone) where liquids have sufficiently low freezing points that they can be made cold and potentially considered 'cryogenic' but that is exceptional.

[101] See, for instance, the discussion of cryogenics in Wikipedia: https://en.wikipedia.org/wiki/Cryogenics. There, one definition is temperatures below -180°C (93.15 K; −292.00 F), while another is below -150°C (123.15 K; −238.00 F); the discussion also considers the term 'high temperature cryogenic' referring to temperatures between the boiling point of liquid nitrogen, −195.79°C (77.36 K; −320.42°F) and to −50°C (223.15 K; −58.00°F).

[102] Dry ice (https://en.wikipedia.org/wiki/Dry_ice) is frozen carbon dioxide. It sublimates at 194.65 K (−78.5°C; −109.3°F) at normal atmospheric pressure, which keeps it cold, and is therefore a common low-temperature refrigerant substance.

[103] Source: https://www.law.cornell.edu/cfr/text/49/173.316.

[104] Resources:
- (a) https://energy.gov/natural-gas.
- (b) Society of Petroleum Engineers' http://petrowiki.org/Natural_gas_properties.
- (c) https://en.wikipedia.org/wiki/Natural_gas.
- (d) https://www.eia.gov/naturalgas/.

[105] https://en.wikipedia.org/wiki/Natural-gas_processing.

(Footnote continued on next page...)

> "Natural gas is a naturally occurring gas mixture, consisting mainly of methane. While most of the gas supplied to Union Gas is from western Canada, some gas is supplied from other sources, including the United States and Ontario producers. While the gas from these sources has a similar analysis, it is not entirely the same. The table below outlines the typical components of natural gas on the Union Gas system and the typical ranges for these values (allowing for the different sources)."[106]

Note that there is no guarantee of the following composition at your location or as an overall system average (Table D.3).

Table D.2 Sample Natural Gas Composition

Component	Typical Analysis (Mole %)	Range (Mole %)
Methane	95.0	87.0–97.0
Ethane	3.2	1.5–7.0
Propane	0.2	0.1–1.5
iso–Butane	0.03	0.01–0.3
normal–Butane	0.03	0.01–0.3
iso–Pentane	0.01	trace–0.04
normal–Pentane	0.01	trace–0.04
Hexanes plus	0.01	trace–0.06
Nitrogen	1.0	0.2–5.5
Carbon Dioxide	0.5	0.1–1.0
Oxygen	0.02	0.01–0.1
Hydrogen	trace	trace–0.02
Specific Gravity	0.58	0.57–0.62
Gross Heating Value (MJ/m3), dry basis	38.0	36.0–40.2"

Source: AGA web-page on Natural Gas Quality and Interchangeability, 2017.

It should be emphasized that the preceding information is simply one company's data on material in their distribution system, and that it, "is *no guarantee of the [preceding] composition at your location*,"[107] which can vary. This obviously complicates any discussion of the properties of "natural gas."

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[106] https://www.uniongas.com/about-us/about-natural-gas/chemical-composition-of-natural-gas. The previously cited Wikipedia page (https://en.wikipedia.org/wiki/Natural-gas_processing) also lists some common pipeline spec requirements and cites sources.

[107] For more information, and/or to illustrate the issue, the reader can consult the following sources:

(a) The American Gas Association, "Natural Gas Quality and Interchangeability."

(b) Williams, "AGA Staff Paper."

(c) The North American Energy Standards Board, Inc. "Natural Gas Specs Sheet."

(d) "Differing market quality specs challenge LNG producers."

(Footnote continued on next page...)

One reason for the variability in composition of natural gas is the range of sources for natural gas.[108, 109] It can be associated—found and produced in conjunction—with crude oil production or non-associated and found in natural gas fields where gas is the predominant product.[110] The latter tends to originate in deeper, hotter carbonaceous deposits.

Ordinarily, natural gas is distributed by pipeline. However, there are examples of associated natural gas that cannot be collected and distributed economically. These are referred to as "stranded" gas assets. In the past this gas may have been flared (burned) but increasingly this gas is now reinjected to the geological formation against possible future extraction. In those locations where it makes sense (ample gas, easy access to suitable transportation networks to customers wishing to import natural gas), it can be liquefied for transport in insulated tanks, in lieu of constructing dedicated pipelines.

"Dry" gas has relatively low amounts of higher hydrocarbons (i.e., molecules with two or more carbon atoms, versus the one in methane). "Wet" gas has greater fractions of higher hydrocarbons; these often condense to form, "natural gas liquids," (NGL) as the gas is brought to the surface and the pressure reduced. When gas has more higher hydrocarbons, it may also be referred to as "rich" as it has a higher heat content; as the composition becomes more dominated by methane, or if there are more inert diluents (like nitrogen), the heat content falls and the gas is referred to as "lean." When necessary, in distribution, natural gas can be adjusted to be leaner (by stripping NGLs), or richer (by injecting higher hydrocarbons like propane or ethane, or NGLs). "Sweet" natural gas is low in sulfur and CO_2; "sour" natural gas contains sulfur and other compounds that need to be removed before use.

D.4 Liquefied Natural Gas (LNG)

As noted above, LNG is a cryogenic liquid formed when natural gas is liquefied, and is a considerably more compact form of natural gas for storage and transport (at the cost of the energy required to liquefy).[111] Most sources note a liquefaction temperature of −162° C (111.15 K, −260°F), which corresponds to the ambient pressure boiling point of methane (−161.49° C; 111.66 K, −258.68° F), also as noted above.

In most cases, LNG is liquefied when loaded into a vessel for transport by sea; it is then regasified at the destination, typically an off-shore (for safety) terminal from which it is transferred by pipeline to regional

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[108] Resources:

(a) https://energy.gov/natural-gas.
(b) Society of Petroleum Engineers' http://petrowiki.org/Natural_gas_properties.
(c) https://en.wikipedia.org/wiki/Natural_gas.
(d) https://www.eia.gov/naturalgas/.

[109] Also see: http://petrowiki.org/Associated_and_nonassociated_gas.

[110] According to Wikipedia (https://en.wikipedia.org/wiki/Natural-gas_processing), citing an MIT study (no longer available), as much as 89 percent of U.S. production was non-associated as of 2009; other, more recent, sources (https://seekingalpha.com/article/3983989-associated-gas-production-falling-natural-gas-daily) put the non-associated fraction at closer to 80 percent, thanks to production from horizontal/hydraulic fracturing oil wells.

[111] LNG resources

(a) Energy.gov, "Liquefied Natural Gas (LNG)."
(b) As usual, an informative Wikipedia page on LNG: https://en.wikipedia.org/wiki/Liquefied_natural_gas.

(Footnote continued on next page...)

distribution pipeline networks. In more limited cases, such as supply for peak shaving and natural gas distribution in the U.S. Northeast, LNG is transported by truck to distributed locations for regasification.[112]

The principal compositional differences between LNG and ordinary natural gas (i.e., gas that has not previously been liquefied) is that trace amounts of higher hydrocarbon compounds that might freeze, along with non-condensable (at least at −162 C) gases have been removed. With some subtle differences because of the presence of those other hydrocarbon compounds (mostly ethane and propane) LNG behaves like liquid methane. These details are normally dealt with at the detailed engineering level. See, for instance, the Society of Petroleum Engineers information on LNG.[113]

Closely related materials in commerce include Natural Gas Liquids (NGLs, mainly mixtures of ethane and propane, but this can include other hydrocarbons as well),[114] liquefied petroleum gas (LPG; principally propane, with varying amounts of butane),[115] ethylene, and propylene. While some NGLs may be refrigerated (cryogenic liquids) LPG is generally stored under pressure at ambient temperatures. Ethylene is transported as a cryogenic liquid (see Table D.3).

Table D.3 Chemical Properties of Natural Gas and Natural Gas Liquids

Property	Methane[1a]	Natural Gas	NGL	Propane (LPG)[2]	Ethylene[3]	Propylene[4]
Chemical Formula	CH_4	CH_4 + others	C_2H_6, C_3H_8,.[5]	C_3H_8	C_2H_4	C_3H_6
Melting Point (°C)	−182.5°C	*	N/A	−187.7°C	−169.2°C	−185.2°C
Boiling Point (°C)	−161.49°C	*	N/A	~ -42°C	−103.7°C	-47.6°C

112 The usual purpose is peak shaving, and when not transferred as a gas and re-liquefied at the satellite location, it is currently most often transported by road. See:

(a) www.beg.utexas.edu/...inc/.../Overview%20of%20U.S.%20LNG%20Industry.ppt.

(b) http://www.cryostar.com/web/peak-shaving.php.

(c) http://www.ingaa.org/File.aspx?id=21698.

(d) http://www.corbanenergygroup.com/lng-iso-containers/.

(e) http://www.exponent.com/knowledge/alerts/2015/08/bulk-transportation/~/media/03b73782ec76446798c70f6ac403ef84.ashx.

(f) https://www.evollng.com.au/transport.

(g) http://files.chartindustries.com/14722928_TransportTrailers.pdf.

(h) https://www.elengy.com/en/clients/lng-truck-loading.html.

(i) https://ngi.stanford.edu/sites/default/files/7_Groode_IHS.pdf.

113 Resources:

(a) https://energy.gov/natural-gas.

(b) http://petrowiki.org/Natural_gas_properties.

(c) https://en.wikipedia.org/wiki/Natural_gas.

(d) https://www.eia.gov/naturalgas/.

114 Energy Information Administration, "What are natural gas liquids and how are they used?"

115 Resources:

(a) https://en.wikipedia.org/wiki/Liquefied_petroleum_gas.

(b) https://www.afdc.energy.gov/fuels/propane.html.

Property	Methane[1a]	Natural Gas	NGL	Propane (LPG)[2]	Ethylene[3]	Propylene[4]
Liquid Density (g/cm^3)	0.42262 (−162°C)	*	N/A	0.580[6] (-42 °C)	0.569 (-103.8°C)	0.6139 (−47.6°C)
Vapor pressure of liquid at 21.1°C (kPa)	(above critical temperature)[7]	*	N/A	853.16	(above critical temperature)	~ 1200
Critical Temperature (°C)	−82.6 C	*	N/A	96.7°C	9.2°C	92.4°C
Flash point	−188°C	*	N/A	−104°C	−136°C	−108°C
Autoignition Temperature	537°C	*	N/A	470°C	542.8 °C	458°C[8]
LEL (% v/v in air)	4.4	*	N/A	2.4	2.7[9]	2.4
UEL (% v/v in air)	17	*	N/A	9.5	36.0	11
Molar Mass (daltons, g/mol)	16.04	*	N/A	44.10	28.05	42.08
Enthalpy (heat) of combustion	~ -890 kJ/mol (~55.5 MJ/kg)	*	N/A	~-.2 MJ/mol (~50 MJ/kg)	~ -1388 kJ/mol (~ 49.5 MJ/kg)	~ -2048 kJ/Mol (~ 48.7 MJ/kg)

* Similar to Methane; exact data varies by source/exact composition.

1 Most data from https://en.wikipedia.org/wiki/Methane.

2 Data given here is for pure propane (most from https://en.wikipedia.org/wiki/Propane); LPG will be similar.

3 Most data from https://en.wikipedia.org/wiki/Ethylene, https://encyclopedia.airliquide.com/ethylene, https://pubchem.ncbi.nlm.nih.gov/compound/Ethene#section=Solubility, or http://www.airproducts.com/products/Gases/gas-facts/physical-properties/physical-properties-ethylene.aspx.

4 Data from: https://en.wikipedia.org/wiki/Polypropylene, http://www.thermopedia.com/content/1065/, https://www.chemeo.com/cid/23-076-2/Propene.

5 Energy Information Administration, “What are natural gas liquids and how are they used?”

6 http://www.engineeringtoolbox.com/propane-d_1423.html.

7 Cannot be liquefied at this temperature.

8 http://www.engineeringtoolbox.com/fuels-ignition-temperatures-d_171.html.

9 https://www.mathesongas.com/pdfs/products/Lower-(LEL)-&-Upper-(UEL)-Explosive-Limits-.pdf.

D.5 LNG Storage and Handling

An important element in managing the risks associated with LNG are practices and technology for LNG storage and handling. Unsurprisingly, the LNG industry has invested considerable effort in developing these practices.[116]

[116] The general properties and hazards or LNG are thoroughly covered in several sources. These include:

a. La Fleur et al., “LNG Safety Assessment Evaluation Methods.”

b. Mokhatab et al. *Handbook of Liquefied Natural Gas*.

(Footnote continued on next page...)

A recurring theme in the practices associated with LNG storage and handing is the use of multiple layers of protection. At the most general level, these layers are:

- Containment, both primary and secondary.
- Safeguard Systems, such as prevention, protection, emergency response.
- Separation.

The underlying ideas are to ensure that in any incident:

- It is difficult for hazards to extend beyond the facility fence line.
- Multiple adverse incidents must occur before any safeguards are overcome, which lowers the likelihood of a hazard occurring.
- There is sufficient separation from vulnerable persons or facilities so that even if an event occurs and overcomes the safeguards, consequences for vulnerable persons or facilities are minimized.

All three layers are deeply enshrined in the management principles and in the applicable standards and regulations that apply to LNG facilities. These include:

- 18 CFR § 380 (National Environmental Policy Act).
- 33 CFR § 127 (Waterfront Facilities Handling Liquefied Natural Gas and Liquefied Hazardous Gas).
- 49 CFR § 193 (Liquefied Natural Gas Facilities; this incorporates NFPA 59A by reference).
- EEMUA 147 (Recommendations for the design and construction of refrigerated liquefied gas storage tanks).
- EN 1160 (Installation and equipment for Liquefied Natural Gas—General Characteristics of Liquefied Natural Gas).
- EN 1473 (*Installation and Equipment for Liquefied Natural Gas—Design of Onshore Installations*).
- NFPA 59A (*Standard for the Production, Storage, and Handling of Liquefied Natural Gas (LNG)*, note that this has been incorporated by reference into U.S. DOT regulations).[117]

The containment layer involves the use of appropriate materials for LNG facilities as well as proper engineering design of facilities and equipment, and of storage tanks in particular. This layer also stipulates

c. National Fire Protection Association, *NFPA 59A: Standard for the Production…*
d. "Liquefied Natural Gas Safety Research."
e. Volkov et al., "LNG Safety and Security."
f. "Managing LNG Risks——Industry Safeguard Systems."
g. National Association of State Fire Marshals. "Liquefied Natural Gas…"

[117] NFPA 59A Standard for the Production, Storage, and Handling of Liquefied Natural Gas.

secondary containment provisions, such as dikes or secondary containers so that even if primary containers are breached, spills are still confined to the facility.

The safeguard layer includes operations and procedures, alarms and detectors, emergency shutdown procedures and equipment, fail-safe provisions, and the like. This layer is intended to allow early detection and remediation of issues, safe shutdowns and isolations, etc. Extensive and careful documentation and training is stipulated, and there are provisions to continuously capture and implement useful new practices and precautions.

Finally, the regulations universally stipulate setbacks and separation distances, which vary as a function of the hazard or complexity of an operation.

D.6 LNG Storage and Handling

An important element in managing the risks associated with LNG are the practices and technology for LNG storage and handling. Unsurprisingly, the LNG industry has invested considerable effort in developing these practices. A recurring theme in the practices associated with LNG storage and handing is the use of multiple layers of protection. At the most general level, these layers are: 1) containment; 2) safeguard systems, and 3) separation. The underlying ideas are to ensure that in any incident it is difficult for hazards to extend beyond the facility fence line. Multiple adverse incidents must occur before any safeguards are overcome, which lowers the likelihood of a hazard occurring. Finally, it is important that there is sufficient separation from vulnerable persons or facilities so that even if an event occurs and overcomes the safeguards, consequences for vulnerable persons or facilities are minimized. All three layers of protection are deeply enshrined in the management principles and in the applicable standards and regulations that apply to LNG facilities.

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- Containment, both primary and secondary.
- Safeguard Systems, such as prevention, protection, emergency response.
- Separation.

The underlying ideas are to ensure that in any incident:

- It is difficult for hazards to extend beyond the facility fence line.
- Multiple adverse incidents must occur before any safeguards are overcome, which lowers the likelihood of a hazard occurring.

118 Refer to note 118 for additional resources.

- There is sufficient separation from vulnerable persons or facilities so that even if an event occurs and overcomes the safeguards, consequences for vulnerable persons or facilities are minimized.

All three layers are deeply enshrined in the management principles and in the applicable standards and regulations that apply to LNG facilities. These include:

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- 49 CFR § 193 (Liquefied Natural Gas Facilities; this incorporates NFPA 59A by reference).
- EEMUA 147 (Recommendations for the design and construction of refrigerated liquefied gas storage tanks).
- EN 1160 (Installation and equipment for Liquefied Natural Gas—General Characteristics of Liquefied Natural Gas).
- EN 1473 (*Installation and Equipment for Liquefied Natural Gas—Design of Onshore Installations*).
- NFPA 59A (*Standard for the Production, Storage, and Handling of Liquefied Natural Gas (LNG)*, note that this has been incorporated by reference into U.S. DOT regulations).[119]

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Finally, the regulations universally stipulate setbacks and separation distances, which vary as a function of the hazard or complexity of an operation.

[119] National Fire Protection Association, “NFPA 59A: Standard for the Production…”

Appendix E. United States LNG Facilities

E.1 EIA Regions

Discussions of the movement of, and infrastructure for, natural gas in the U.S. need to be informed by the regional base maps for natural gas as defined by the EIA. There are two maps and sets of regions, one based on natural gas production and consumption, and one based on storage (see Figure E.1).

Production and Consumption *Storage*

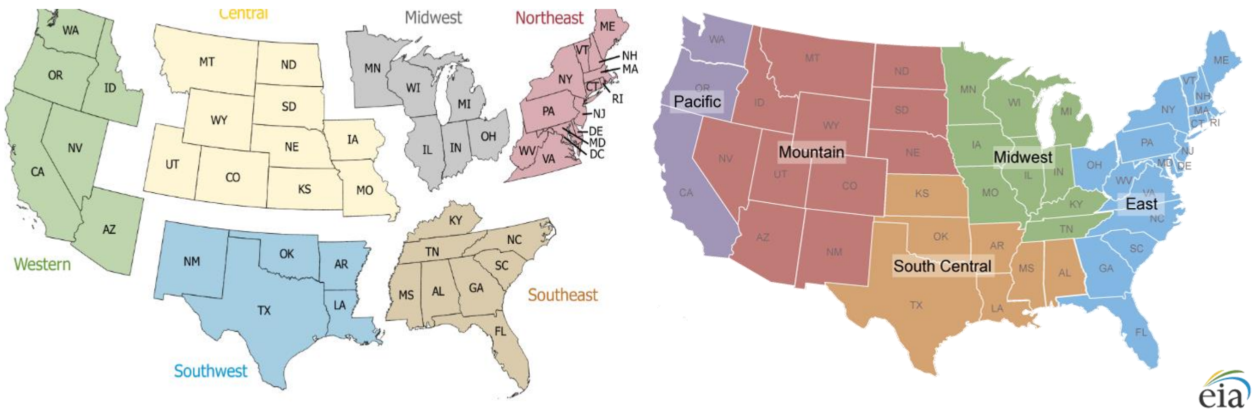


Figure E.1 Natural Gas Regions for Production/Consumption and Storage

Source: EIA. http://ir.eia.gov/ngs/notice_08_31_2015.html.

E.2 Existing LNG Import/Export Facilities

There are 12 import facilities in the United States, nearly all of which are in the process of converting from import-only to import-and-export facilities due to the domestic availability of shale gas. Four of these facilities are described in the following section.

E.2.1 Sabine LNG in Sabine, Louisiana (Existing Import/Export)

- Cheniere Energy has operated an LNG import terminal in Cameron Parish since 2008. In July 2011, the company announced plans to expand its existing facility and transform the Sabine Pass terminal into a bidirectional facility capable of exporting LNG, as well as receiving LNG for regasification. Construction began on the facility in 2012 and is expected to be completed at the end of 2015. When the facility comes online, it will likely be the first domestic export LNG terminal in the contiguous United States and is permitted to export up to 16 million metric tons of LNG. The company has already secured nonbinding deals for 9.8 million metric tons annually.

- Cheniere's Sabine Pass liquefaction terminal in Louisiana, currently the only such a facility to ship U.S. shale gas overseas, exported five cargoes of the fuel in the week ending September 27. According to the Energy Information Administration, five vessels with a combined LNG-carrying capacity of 18.5 billion cubic feet (Bcf) have departed the plant since September 25. This compares to five vessels with a capacity of 17 Bcf the week before. This also means that the liquefaction plant shipped at least 16 cargoes since September 6, when it resumed vessel loadings following Hurricane Harvey, with a total LNG-carrying capacity of 57.4 Bcf. EIA also said in its weekly natural gas report that one vessel with a capacity of 3.8 Bcf was loading at the Sabine Pass terminal on Wednesday. Latin America and Asia-Pacific are continuing to be the preferred regions for shipments of U.S. LNG. The latest data by the Department of Energy shows that Mexico, Korea, China and Chile are the top buyers of the fuel coming from the Sabine Pass plant. In total, more than 175 cargoes of U.S. LNG landed in 25 different countries in the period spanning from February 2016 to August 2017.[120]

E.2.2 Cameron LNG in Hackberry, Louisiana (Proposed Export)

- On October 23, 2014, Sempra Energy broke ground on a new $6 billion liquefaction processing complex in Hackberry, Louisiana. The LNG facility already has long-term agreements with Mitsubishi Corporation and Mitsui & Co. based in Japan, as well as GDF Suez SA based in France; both will purchase the LNG exports produced at the facility. Initial LNG shipments will begin by the end of 2017 and full operations will be in place by 2019.

E.2.3 Freeport LNG in Freeport, Texas (Proposed Import/Export)

- In July 2014, Freeport LNG received FERC authorization to site, construct and operate a liquefaction project. Final approvals were issued by the DOE and FERC in November 2014. The current facility at Freeport has an LNG receiving, storage, and regasification terminal. The additional project will allow Freeport LNG to export approximately 13.2 million metric tons annually. The Eagle Ford, Barnett, and Haynesville shale gas deposits are expected to be significant sources of supply for the project.

- The Freeport LNG facility will consist of three LNG trains. 20-year agreements have already been signed for the entire capacity of the first two trains; companies include Osaka Gas, Chubu Electric, and BP Energy. Tolling agreements have also been signed by Toshiba Corporation and SK E & S for the remaining facility capacity in train three.

E.2.4 Cove Point LNG in Cove Point, Maryland (Import/Export)

On September 29, 2014, the Cove Point LNG project became the fourth approved LNG export terminal in the contiguous United States. The existing Cove Point facility has been an LNG import terminal for almost 40 years. The new project will create one LNG train that will have the capacity to export 5.75 million metric tons of LNG annually. No new pipelines or storage tanks are needed at the facility and export operations started in January, 2018.

Table E.1 summarizes approved and existing LNG Export terminals.

[120] According to a press release from the EIA, September 27, 2017.

Table E.1 FERC Approved and Existing LNG Export Facilities May 2017

United States (Import)	Status	Throughput	Contracts
Cove Point, MD	Approved, existing	0.82 bcfd	Japan, India
Kenai, AK	Approved, existing	0.2 bcfd	Tokyo Gas, Japan Tokyo Electric, Japan
Sabine, LA	Approved, existing	2.0 bcfd	BG Gulf Coast LNG, UK Gas Natural Fenosa, Spain Korea Gas Corp, S. Korea GAIL India Limited Total Gas & Power NA Centrica PLC, UK

Source: Federal Energy Regulatory Commission (FERC) Website, Oct 2017.

E.3 Approved LNG Export Facilities

Table E.2 describes LNG facilities approved by FERC as of May, 2017.

Table E.2 FERC Approved LNG Facilities May 2017

United States (Import)	Status	Throughput
Corpus Christie, TX	Approved, under construction	0.4 Bcfd
Salinas, PR	Approved, not under construction	0.6 Bcfd
United States (Export)	**Status**	**Throughput**
Sabine, LA	Approved, under construction	0.7 Bcfd
Hackberry, LA	Approved, under construction	2.1 Bcfd
Freeport, TX	Approved, under construction	2.14 Bcfd
Corpus Christie, TX	Approved, under construction	2.14 Bcfd
Sabine Pass, TX	Approved, under construction	1.4 Bcfd[1]
Elba Island, GA	Approved, under construction	0.35 Bcfd
Canada (Export)	**Status**	**Throughput**
Port Hawkesbury, NS	Approved, not under construction	0.5 Bcfd
Kitimat, BC	Approved, not under construction	3.23 Bcfd
Squamish, BC	Approved, not under construction	0.29 Bcfd
Prince Rupert Island, BC	Approved, not under construction	2.74 Bcfd

Source: Federal Energy Regulatory Commission

E.4 Proposed LNG Export Facilities

- As of December 3, 2014, there were 16 proposed LNG export terminal applications. At least four of the proposed terminals already have existing LNG import operations in place. As previously discussed, these four locations will be at a significant advantage to begin LNG export operations due to existing infrastructure. At least three of the remaining proposed locations are very close to a current import facility or import facility that is converting to export facility.
- Ten of the 16 proposed terminals are located in the Gulf Coast. Of the remaining proposed terminals, two are located on the west coast in Oregon and Washington; three are located on the east coast in Maine, Georgia, and Florida; and one is located in Alaska.
- At least two of the proposed terminals are far along in the process of becoming an approved export terminal. Corpus Christi LNG had a final Environment Impact Statement issued by the FERC on October 8, 2014. Jordan Cove Energy Project had a final Environmental Impact Statement issued May 1, 2009, but was given several areas to address before continuing the permitting process.
- One MMPA (million metric tons per annum) per module and the Elba Island Plant is proposing 10 liquefaction modules for export. Elba currently has 11 vaporizers for import with 1755 MMcf capacity.
- Smaller peak shavers use bottles of propane, not cargo tank trips by truck. Satellite facilities are usually State controlled. Peak shavers liquefy during low demand, vaporize during high demand. Peak shavers may also inject LNG into an interstate pipeline. When natural gas is not available, sometimes they use a mixture of propane and nitrogen to approximate natural gas BTU levels. (FERC Interview September 2017).

E.5 Emerging LNG Facilities

Emerging LNG facilities are located in Florida, Louisiana, Pennsylvania, Texas and Vermont. They have been constructed but have not yet been documented in PHMSA and EIA databases. This section describes several recent LNG facilities and capacities constructed since 2014.

E.5.1 Scranton and Pittsburg, PA

REV LNG has constructed two liquefied natural gas facilities, primarily for fueling trucks but also for the energy exploration and production sector and eventually for marine customers. One facility is located near Scranton in Bradford County in northeast Pennsylvania and a second plant south of Pittsburgh. Both facilities produce 50,000 GPD with expansion capabilities to 200,000 GPD. Initial onsite storage is 150,000 gallons. Affiliate Rev Hoopes Trucking operates a fleet of 35 LNG tractors. Rev LNG itself has approximately 10 trucks, half of them LNG-fueled, delivering fuel to energy customers. REV LNG trucks serve both facilities and transport LNG to customers across Eastern United States.

E.5.2 Jacksonville, FL

Eagle LNG is building a liquefaction plant in West Jacksonville able to produce 200,000 gallons a day. This plant will serve Crowley Maritime. Eagle also is building a second LNG production and storage facility near the Blount Island Terminal and a holding facility at Talleyrand Marine Terminal. JAX LNG is building a liquefaction and storage facility at Dames Point to fuel TOTE Maritime's ships, with capacity to produce in excess of 120,000 gallons of LNG per day.[121]

The Port of Jacksonville, FL, also known as JAXPORT, has developed multiple transportation, storage and export opportunities for LNG. JAXPORT tenants TOTE Maritime Puerto Rico and Crowley Maritime Corp. are leaders in the emergence of LNG as a preferred fuel source for the maritime industry. TOTE Maritime operates two 3,100 TEU LNG-powered containerships out of JAXPORT's Blount Island Marine Terminal. Isla Bella and Perla Del Caribe are the world's first LNG-powered containerships.

E.5.3 Miami, FL

FECR built an LNG liquefaction plant in 2015 with Chart Industries in Hialeah, FL capable of producing 100,000 GPD of LNG. There are three 90,000 gallon tanks located at the Hialeah Rail Yard used to store LNG. The facility is used to produce LNG for export to the Caribbean and for fueling FECR dual-fuel locomotives in service in Florida.

E.5.4 Hawkins, TX

This LNG facility was built as part of an existing gas processing plant, including 50,000 storage tanks for LNG. The project was completed in 2015 and includes a nitrogen rejection unit and is used for the merchant market. Existing gas compression equipment enables vapor recovery as part of the truck filling process. Excess gas is compressed and injected into the natural gas pipeline system.

E.5.5 George West, TX

This LNG facility was built in 2015 with Chart Industries to support the use of fuel for high horsepower engines used in the oilfield in the Eagle Ford Shale Region. This plant has liquefaction capability of up to 100,000 GPD and three 90,000 gal storage capability onsite. Two truck loading racks can load two transport trailers at the same time.

[121] https://www.jaxport.com/.

E.5.6 Florence, VT

This plant was built with Chart Industries for a mineral processing facility in Vermont in 2013. The facility includes eight 15,000 gallon storage tanks for a total storage volume of 120,000 gallons. This is a storage-only facility with no liquefaction capability. Over a dozen high horsepower trucks are used 24/7 at this mining facility.

E.5.7 Port Fourchon, LA

The Greater Lafourche Port Commission (GLPC) and tenant Energy World USA (EWUSA) is planning to construct a proposed five million tons per annum midscale liquefied natural gas (LNG) production and export facility at Port Fourchon, LA.

Once constructed, Phase 1 of the Fourchon LNG project will produce two million tons of LNG per year for export, with a program to increase capacity up to five million tons in Phase 2. Fourchon LNG also plans to reserve up to half a million tons of LNG per year for domestic use, with the intent of providing LNG to fuel the next generation of Harvey Gulf offshore supply vessels (OSVs) powered by LNG an operating in the Gulf of Mexico. To support the development of the LNG fueling facility, Harvey Gulf has secured CH·IV International of Houston, Texas as the EPC contractor. The facility will consist of two sites each having 270,000 gallons of LNG storage capacity.

GLPC has been working with Energy World to produce a Preliminary Waterway Suitability Assessment with the U.S. Coast Guard, which will help to ensure that current and future port activities are not adversely affected by the operation of the potential facility. GLPC and Energy World currently are working with the Coast Guard to advance to the next stage of the Waterway Suitability Assessment process for the project. This assessment will also serve to support Energy World's application to the Federal Energy Regulatory Commission (FERC) for project approval.[122]

[122] http://portfourchon.com/fourchon_lng_kicks_off_ferc_process/.

Appendix F. Cryogenic Tank Cars, Cargo Tanks, and Portable Containers

Tank and container designs are proprietary to the manufacturers, and must comply with Federal regulations. U.S. regulations for the specifications of cryogenic tank cars, cargo tank trailers, and portable containers were most recently updated in 2016. In the U.S., the UN T75 ISO portable tank and the MC-338 cargo tank are authorized to transport LNG by truck and maritime. Tank manufacturers and subject matter experts in rail engineering give insight into the best practices for handling, safety testing, and issues involving tank car pressure relief valves (PRV), bottom outlets, manifolds and other apertures. Currently there is not a cryogenic tank car approved for LNG, the AAR is reviewing the DOT 113 tank car specifications based on request from shippers to ship LNG by rail, and the AAR petitioned PHMSA to add methane to the list of approved materials transported by the DOT-113.

Reports involving tank safety for LNG gives insight into potential vulnerabilities in tank design, emergency response, loading and unloading processes, and training. Historical incidents for cryogenic containers—as a class, gives insight into the consequences that have occurred as a result of leaks, damage, or other incidents in which cryogenic product was released from the containers. Incidents from other countries in which LNG was released provides insight into what other markets have learned about the safe surface transport of LNG.

Since the DOT-113 has not been used for LNG, there is no record to examine except for the transport of the cryogenic liquid gases that it is authorized to transport. Adding a new flammable gas to the regulation is heavily scrutinized. The creation of a new DOT-117 tank car to replace the DOT-111 used for crude oil and ethanol sets a precedent for tank car redesign and increased safety standards, and reflects concern over tank car safety in derailments. While most derailments are caused by track failure, the track standards and regulations lack technical basis, and tank cars moving hazardous materials should be able to withstand the impact and heat that may arise during an incident.

LNG is permitted to be transported by rail in Europe in specially designed tank cars. Chart and VTG have combined to produce two of these tank cars which have complete approvals and which have completed test runs with LNG. LNG is permitted to be transported by rail in Canada in both DOT-113 tank cars and UN T75 ISO containers. This was approved in 2014, they have to comply with the selection and use requirements of CSA B625-08 clauses 6.1 and 6.4, including the requirement for TC IMPACT APPROVED marking. Even though the DOT-113 is authorized to move LNG in Canada, there has not been enough economical drive, and there are no reports of LNG rail shipments in Canada. The MC-338 and the UN T75 both have documented records in the safe transport of LNG by highway. The UN T75 has a relatively small record on the shipment of LNG by rail in the U.S., but does have a more robust record by other modes such as highway and maritime and in other countries where it is authorized.

F.1 ISO Containers

The transport of LNG by rail is allowed only by special permits authorized by the FRA—at least two entities in the U.S. have current, active natural gas dual fuel programs and operate under a “Letter of Concurrence” from the FRA. Two types of tenders are being utilized in the prototype programs: ISO container holding maximum of 10,000 gallons of LNG, and tank car holding between 22,000 and 25,000 gallons of LNG. Both major U.S. freight locomotive original equipment manufacturers are actively involved with the AAR Tank Car Advisory Group activities and with the prototype programs.

ISO containers are intermodal containers suitable for multiple transportation methods such as truck, rail, or ship. They are manufactured according to specifications from the International Organization for Standardization (ISO). ISO is a worldwide federation of national standards. It is a voluntary organization with one member representing each country in the world, and the aim is to create manufacturing standards such that products may be interchangeable around the world. The work of preparing International Standards is normally carried out through ISO technical committees. The regulations guarantee that a standardized container can withstand the environments endured during transport and the structural integrity needed to be lifted by cranes or other heavy equipment. ISO containers come in various shapes and forms and are used to transport a variety of products.

ISO intermodal containers are used to transport cryogenic bulk liquids—nitrogen, oxygen, argon, methane, nitrous oxide, ethylene and carbon dioxide. ISO containers with LNG are authorized by rail in the U.S. only by special permit. Containers designed and optimized for LNG also are popular for transportation of ethylene. Containers designed by Chart Industries have hold times of between 44 to 65 days. This means that without intervention, the containers would be insulated and keeping the LNG at cryogenic temperatures for the length of the hold time. For the shipment of LNG, the appropriate ISO container is bulk cryogenic liquid container type code T75 (UN T75 / IMO 7). The specifications for these portable tanks are found in 49 CFR 178.274. The chemical ID in UN Standards for LNG is UN 1972. Packing instruction P203 and special provision TP5 apply. Portable T75 tanks do not have any refrigeration equipment, they function by insulating the very cold contents for an extended period of time, much more than the expected travel time.

The ISO tank portable containers have exterior dimensions that are the same standard dimensions as ISO containers, but are a cylindrical tank mounted, protected, and surrounded by a rectangular steel framework. The UN T75 is an insulated stainless steel tank with a surrounding steel frame that conform to typical intermodal container dimensions such as 8 feet wide, 8.5 feet or 9.5 feet tall, and 20 or 40 feet long. The volume of the tanks vary by manufacturer between 5,000 gallons and 11,000 gallons of liquid. ISO container manufactures issue container safety certifications that must be renewed every 30 months by a certified inspector. ISO containers are ideal as their dimensions are standardized by ISO, and containers use space efficiently. Standard ISO container height is 8 ft. 6 in., but they are available in several other specified heights as low as four feet (half-height) and as high as 9 ft. 6 in. (high cube). The standard used to identify intermodal (shipping) containers is ISO 6346:1995. This standardized identification system is used to give each container a unique marking. Figure F.1 shows an ISO portable tank.

Figure F.1 Portable ISO Container

Source: Courtesy Chart Industries.

ISO cryogenic liquid tank containers vary in specifics between manufacturers, but the necessary specifications are the same between the different companies. As shown in **Figure F.1**, UN T75 has a stainless steel tank, which stores the cryogenic fluid, and is mounted by means of the support of insulating material in the outer shielding tank, which is made of carbon steel. In the space between the tanks there is a multilayer insulation material with the radiation shields. The air has been removed from the space between the tanks in order to obtain a medium-level vacuum. The fittings and the tank are placed on external supports in the container frame. The container frame and the outer tank, together with other construction elements must have sufficient strength to meet the requirements of the method of transportation.[123]

The AAR Tank Car Committee is performing research on the crashworthiness assessment of the ISO tank (VOLPE) and fire test of an ISO tank on a rail car. LNG used as a fuel tender also is being considered through the work of the AAR. A LNG ISO Tank pool fire test was completed in May 2017, and presented at the October 2017 AAR Tank Car Committee. There is another test scheduled for June 2018.

Cryogenic ISO containers are generally used for LNG transport between LNG facilities and power generation plants, for exports on cargo ships and to remote inland locations needing natural gas. ISO containers carrying LNG by highway and ship can be coordinated in order to create a virtual pipeline.[124] Hawaii Gas is planning the implementation of a virtual pipeline that moves LNG in 40 foot UN T75 ISO containers between the West coast of the U.S. and Hawaii.

Crowley Maritime Corp. has acquired 16 additional ISO tanks for its Carib Energy group that will be used to supply, transport and distribute U.S.-sourced liquefied natural gas (LNG) to customers in Puerto Rico, the Caribbean and Central America. The 40-foot tanks, each of which contain 10,700 gallons of LNG, now feature technological improvements that increase the offload rate, allowing for faster fuel transfers to customers. Adding ISO tanks to [Crowley's] equipment fleet for established business not only allows us continue delivering an uninterrupted supply of LNG to these regions. Furthermore, the improved offloading performance reduces the amount of time required to transfer the fuel from tank to the storage unit, adding to overall efficiency.[125]

F.2 Cargo Transport Trailers

Trucks using cargo tank trailers also transport LNG by highway throughout the U.S. and the Caribbean Islands. These cryogenic transport trailers are designed for liquid nitrogen (LIN), liquid argon (LAR), liquid oxygen (LOX) and LNG. Trailer cylinders such as MC-331, MC-338 (Figure F.2) and CGA-341 are approved the U.S. DOT. MC-331 trailers are used for gases that are liquefied by pressure application, such as LPG, butane, chlorine, and anhydrous ammonia.

[123] http://yadda.icm.edu.pl/yadda/element/bwmeta1.element.baztech-article-BUJ5-0040-0026/c/httpwww_bg_utp_edu_plartjok32011jok32011195.pdf.

[124] https://vimeo.com/144509960.

[125] Crowley Marine, "Crowley Adds 16 ISO Tanks..."

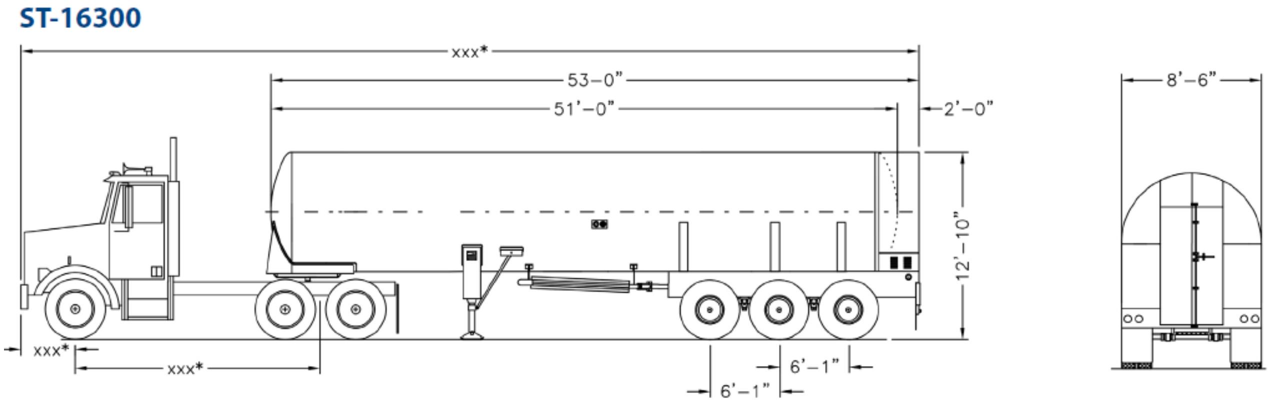


Figure F.2 Cargo Trailer Specifications—ST-16300

Source: Courtesy Chart Industries.

The MC-338 trailer, shown in Figure F.3, is used for cryogenic liquids that must be at least -130 F, such as LNG. MC-338 trailers are a cylindrical shape with loading and unloading pipes on the rear of the tank. The tank is designed as two concentric cylinders, with an annular space that is evacuated of air to vacuum-like conditions. The pressure in these trailers are low pressure, from 23.5 to 500 psi. MC-338 trailers are used for substances which cannot be liquefied by pressure application alone, and must be "super cooled" to become a liquid. This include liquid oxygen, hydrogen, carbon dioxide, natural gas, and ethylene. The CGA-341 specification is for nonflammable cryogenic liquids. MC-338 specifications have a 13,000-gallon capacity. The maximum allowable working pressure is 70 psi. Operationally, carriers may have trailers that they dedicate to specific products, and seek the maximum capacity to give their customer the maximum payload, reducing the unit costs of transport.[126]

[126] http://bulktransporter.com/tank-fleets/genox-transportation-growing-demand-cryogenic-gases?eid=forward.

Figure F.3 MC-338 Cargo Tank Trailer

Source: Courtesy Chart Industries.

Out of a total of over 700 motor carriers, there are 18 motor carriers that transport LNG using cryogenic cargo tank trailers in the United States. Table F.1 shows the U.S. LNG motor carriers reported by MCMIS. The largest carriers by the number of cryogenic cargo tank units are Ryl Corp, Offshore Petroleum, Willcox Fuel LLC, and Broedel Fuel Group LLC. These operate out of Florida, New Jersey, Arizona, New York, and Kansas. There are several carriers in the Caribbean, including Puerto Rico and the U.S. Virgin Islands.

Table F.1 U.S. LNG Motor Carriers

Carrier	Classification	State	Units
Ryl Corp	Interstate	FL	968
Offshore Petroleum Inc.	Intrastate Hazmat	NJ	659
Willcox Fuel LLC	Intrastate Hazmat	AZ	447
Broedel Fuel Group LLC	Intrastate Hazmat	NY	405
Versaair Services LLC	Interstate	KS	140
City Fuel Transport	Interstate	WA	119
Standard Aviation LLC	Intrastate Hazmat	VI	97
Mtm Fuel Services Inc.	Intrastate Hazmat	NY	77
Laurel Fuel Co	Interstate	PA	37
Express Petro Transportation LLC	Interstate	TX	33
Singh Energy Transportation Inc.	Intrastate Hazmat	NY	22
Empire Logistics	Intrastate Hazmat	LA	9
Paradise Gas	Intrastate Hazmat	VI	8
Augusta Service Station	Intrastate Hazmat	MT	8
Sessler Environmental Services LLC	Interstate	NY	4
Maicom Solutions LLC	Interstate	MA	3
Advanced Fuel Delivery LLC	Intrastate Hazmat	CA	3
Sky Transportation Corp	Intrastate Hazmat	PR	2

Source: FMCSA MCMIS Database, accessed October 2017.

F.3 DOT 113 Railcar

The DOT-113 railcar is a cryogenic non-pressurized liquid tank car with insulated “thermos bottle” construction. A cutaway drawing of the typical features for a DOT-113 railcar are shown in Figure F.4.

<u>Inner Tank</u>

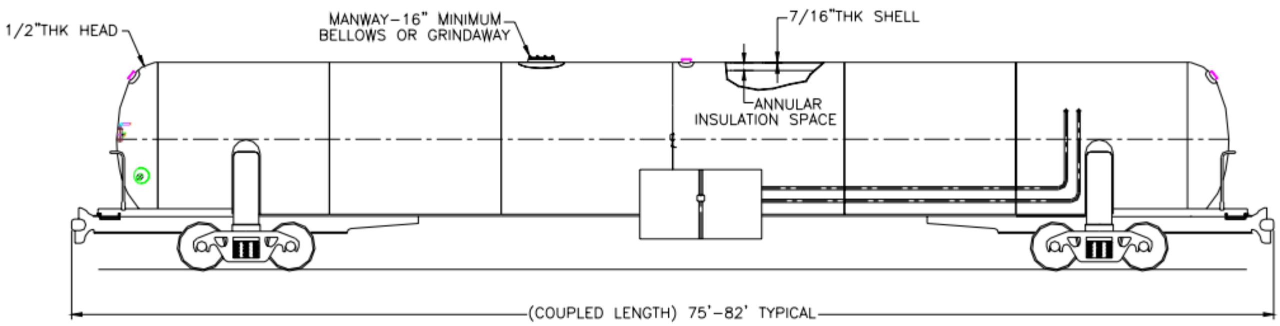
Thickness:	3/16" (minimum); 1/4" (nominal)
Material:	Stainless steel of ASTM A 240/A 240M, Type 304 or 304L

<u>Outer Tank</u>

Thickness:	1/2" heads, 7/16" shells
Material:	Carbon steel

<u>Insulation</u>

Perlite (common in 1960-1990 built cars), or
Wrapped fiberglass or similar material (common in 1990-and-later built cars)



Cutaway Drawing of Tank Car
(Courtesy of Chart Industries)

Figure F.4 Typical Features of DOT 113 Tank Car

Source: American Chemistry Council, "Handling and Transportation Guide…"

While the DOT definition of cryogenic is refrigerated to -130°F and below, as per railroad specification, cryogenic is a maximum of -155°F. Class DOT-113C120W tank cars began to be constructed in the 1970s and are the most common tank cars now used for cryogenic ethylene service. The rail weight limit is 263,000 pounds with a tare weight in the 117,000 to 120,000 pounds range. The water capacity on these cars is nominally 33,000 gallons, which allows for a payload of approximately 28,500 to 29,000 gallons of cryogenic ethylene. Recently built cars have a gross volume of 34,500 gallons and a net cryogenic ethylene capacity of up to 144,000 pounds (30,380 gallons).

Class DOT-113C tank cars are equipped with one or dual pressure relief valves and dual rupture discs. Except for some class DOT-113D tank cars, the valves and fittings for loading and unloading, and the pressure relief devices are located in cabinets on both sides. Figure F.5 and Figure F.6 show both sides of a DOT-113, and the cabinets can be seen in the middle of the car.

Figure F.5 DOT 113 Rail Tank Car (Front End)

Source: Chart Industries

Figure F.6 DOT 113 Rail Tank Car (Back End)

Source: Chart Industries

In some cases, only one of the two cabinets contains the pressure relief devices, and is identified by the exhaust stack coming out of the cabinet and reaching the top of the tank car. Loading and unloading valves are normally located in compartments on diagonally opposite corners of car for liquid oxygen, liquid nitrogen, and liquid hydrogen.

Figure F.7 shows a cabinet that holds the pressure relief devices, and valves and fittings. Figure F.8 shows a close-up and annotated view of the valves and fittings. The cabinets “must be adequate to protect the fittings from direct solar radiation, mud, sand, adverse environmental exposure, and mechanical damage incident to normal operation.” (AAR Field Guide to Tank Cars).

Figure F.7 DOT 113 Ethylene Tank Car Valve Details

Source: Chart Industries

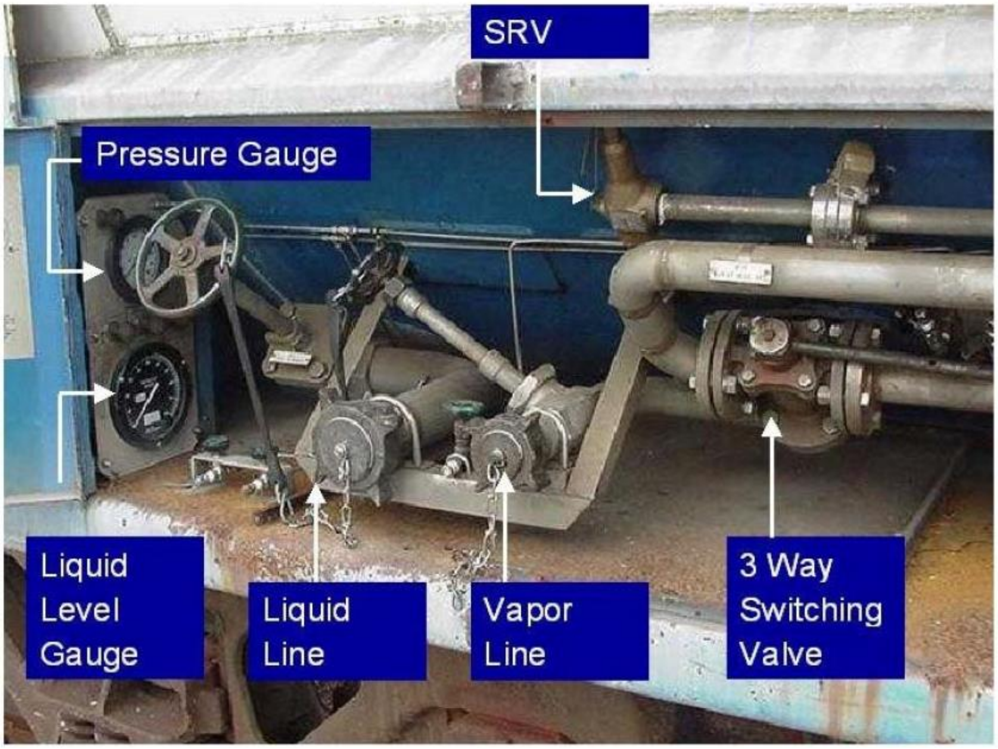


Figure F.8 Major Valves and Fittings of 113C120W Side Loader

Source: American Chemistry Council, "Handling and Transportation Guide…"

The AAR petition to PHMSA on January 17, 2017 (P-1697) requested that PHMSA authorize the transportation of methane, refrigerated liquid ("LNG"), by rail in DOT-113C120W and DOT-113C140W tank cars. While the DOT-113C120W is a tank car used for ethylene, the DOT-113C140W is a modification to the DOT-113C120W that increases the length of time that the tank car maintains the cryogenic conditions. Increasing the hold time could give responders more time to catch a leak and handle an incident. The AAR completed pool fire testing for the ISO container in May 2017, and hopes do similar pool fire testing for the 113 tank car, but the project presently lacks funds.

The first LNG Tank Car in Europe was a project between Chart Industries and VTG AG.[127] VTG invested in the rail tank cars "to create a so-called rolling pipeline to deliver LNG to industries that have sizeable energy requirements. It plans to work with Brunsbüttel to use LNG tank cars to supply Baltic Sea ports."[128]

DPT, TC, and the AAR have specifications for tank cars. Tank car specifications consist of "Authorizing agency"—"three-digit class designation" "delimiter letter" "tank test pressure in pounds per square inch gauge (psig)" "material of construction (other than steel)" "fusion welding (W)" "fittings, linings, material." Therefore, the difference between DOT-113C120W and DOT-113C140W is the tank test pressure and the minimum burst pressure. DOT-113C120W has a tank test pressure of 120 psig and DOT-113C140W has a tank test pressure of 140 psig. This difference changes how long the contents will safely be stored. It also is

[127] http://www.railwayage.com/index.php/mechanical/freight-cars/vtg-unveils-europes-first-lng-tank-car.html.

[128] http://www.lngworldshipping.com/news/view,vtg-load-is-a-rail-landmark-for-europe-lng_42734.htm.

known that the DOT is the authorizing agency, the class is 113, the delimiter is C, the tank test pressure is 120 or 140 psig, the material of construction is carbon steel, and the tank is constructed with fusion welding.

DOT-113 is vacuum insulated with a high alloy (stainless steel) or nickel alloy inner container (tank) and carbon steel outer shell (tank, not jacket). Delimiters for cryogenic liquid tank cars:

- A-authorized for -423F loading.
- C-authorized for -260F loading.
- D-authorized for -155F loading.

From the AAR Tank Car Committee, the Docket T55 Service Trials lists four trials related to LNG tank cars: cryogenic gate valve, actuated cryogenic gate valve, cryogenic globe valve, and actuated cryogenic globe valve.

PHMSA HAZMAT Intelligence Portal lists incidents by bulk container back to 2008.[129] In the most recent decade, DOT113C120W appears with three incidents $5,000 in damages. Other DOT113 cars appear with incidents: 113A60W, 113A90W, 113AW, 113CW, 113D120W, 113DW. 113A90W and 113AW have the most incidents of this class. AAR Field Guide to Tank Cars explains the different tank cars used for cryogenic liquids. Classes DOT-113 and AAR-204 are designed with an inner container within an outer shell. The space between the inner and outer tanks is vacuum insulated.

- DOT-113A60W tank cars have design service temperature of -423F, a minimum burst pressure of 240 psig, and a tank test pressure of 60 psig.
- DOT-113C120W tank cars have a design service temperature of -260F, a minimum burst pressure of 300 psig, and a tank test pressure of 120 psig.
- (Not used for LNG) AAR Class 204W tank cars must meet the requirements for Class DOT-113, with some exceptions. The minimum required burst strength is 240 psig, with a 60 psig tank test pressure. AAR Class 204W tank cars are not authorized for flammable gas materials, and therefore could not be used for LNG.

According to the Umler Component Registry, there were over 414,000 tank cars in North America in 2016, and more than 700 equipment type codes (ETCs) appear in the Umler Component Registry.[130] Nearly all of North America's tank cars are owned by shippers or car-leasing companies. About two thirds of the fleet is used to carry materials regulated by the U.S. Department of Transportation (U.S. DOT) and Transport Canada because they are flammable, corrosive, poisonous, or pose other hazards. The total fleet capacity (in gallons) has increased by 45.2 percent recently as most new tanks are larger than before. Through the Federal Railroad Administration (FRA) and PHMSA, U.S. DOT sets the minimum design standards for the cars. Various design features are required to accommodate differences in the physical, chemical, and hazard characteristics of the materials shipped. The Association of American Railroads (AAR) Tank Car Committee assists in the development of detailed tank car design specifications that comply with U.S. DOT standards.

[129] https://www.phmsa.dot.gov/hazmat/library/data-stats/incidents.

[130] The Umler® system is used to obtain rail equipment data for in North America.

AAR performs this supportive function in accordance with its traditional role in setting industry rules and standards for the interchange of equipment.