

U.S. and Canadian Natural Gas
Vehicle Market Analysis:

Liquefied Natural Gas Infrastructure

Final Report

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Table of Contents

Abbreviations

Lower Heating Value Energy Conversion Factors

Natural Gas Properties Comparison

Preface

Executive Summary

Chapter 1

- 1 Introduction
- 1.1 Liquefied Natural Gas as a Fuel
- 1.2 Context for LNG

Chapter 2

- 2 LNG Fueling Infrastructure to Date
- 2.1 Liquefaction Facilities
- 2.2 Stations
- 2.3 Comparison of LNG Fueling Infrastructure with Diesel

Chapter 3

- 3 LNG Station Design
- 3.1 LNG Fueling
- 3.2 LCNG Fueling
- 3.3 Economics
- 3.4 Facility Modification Requirements
- 3.5 Fuel Safety

Chapter 4

- 4 LNG Production Options
- 4.1 LNG Feedgas
- 4.2 Purpose-Built Pipeline Gas Liquefiers and Peakshaving Liquefiers
- 4.3 Pressure Reduction Liquefiers
- 4.3.1 Overview
- 4.3.2 Economics
- 4.4 Nitrogen Rejection Units and Gas Separation Plants
- 4.4.1 Overview
- 4.4.2 Economics
- 4.5 Biomethane to LNG
- 4.5.1 Overview
- 4.5.2 Economics
- 4.6 Onsite Small Scale Liquefiers
- 4.6.1 Overview
- 4.6.2 Economics
- 4.7 LNG Import Terminals
- 4.7.1 Overview
- 4.7.2 Economics

Chapter 5

- 5 LNG Infrastructure Actions and Opportunities
- 5.1 LNG Business Opportunities
- 5.2 Potential LNG Vehicle Market Segments

Abbreviations

AGA	American Gas Association
ALT	Applied LNG Technologies
ANGA	America's Natural Gas Alliance
CO₂	Carbon dioxide
CNG	Compressed natural gas
DGE	Diesel gallon equivalent (=131.7 cubic feet of natural gas)
EIA	Energy Information Administration
GHG	Greenhouse gas
GPD	Gallons per day
GSP	Gas separation plant
INL	Idaho National Laboratory
JT	Joule-Thomson
LFG	Landfill gas
LNG	Liquefied natural gas (1 gallon LNG = 0.58 DGE)
LCNG	Liquefied-to-compressed natural gas
LDC	Local distribution company (gas utility)
MRC	Mixed-refrigerant cycle
NGV	Natural gas vehicle
NRU	Nitrogen rejection unit
O&M	Operations and maintenance
PG&E	Pacific Gas & Electric
psi	Pounds per square inch

Lower Heating Value Energy Content Conversion Factors

Diesel	129,450 BTU/gal
Gasoline	116,090 BTU/gal
LNG	74,720 BTU/gal
Natural gas	983 BTU/cubic foot (=131.4 BTU/gal of volume)

Natural Gas Properties Comparison

Property	Natural Gas	Gasoline	Diesel
Physical state	Vapor	Liquid	Liquid
Ignition temperature	1,080 °F	540 °F	410 °F
Density	22 grams/cubic foot (lighter than air)	2,800 grams/gallon (lighter than water)	3,200 grams/gallon (lighter than water)
Spill behavior	Evaporates and disperses	Pools on surface	Pools on surface
Storage temperature	CNG: Ambient temperature LNG:below -260 °F	Ambient temperature	Ambient temperature
Storage pressure	CNG: 3,000 to 3,600 psi LNG: varies	Ambient pressure	Ambient pressure

Preface

This assessment examines the key technical, economic, regulatory, social, and political drivers and challenges that shape this market.

With the primary objective of identifying the most productive and effective means to increase the use of natural gas vehicles (NGVs) in the U.S. and Canada, the TIAX team has conducted a thorough and independent assessment of the NGV market. To highlight the major opportunities to spur the market's development and expansion, this assessment examines the key technical, economic, regulatory, social, and political drivers and challenges that shape this market. TIAX has partnered with The CARLAB, Clean Fuels Consulting, the Clean Vehicle Education Foundation, Jack Faucett Associates, the Natural Gas Vehicle Institute, and St. Croix Research to provide perspective and insights into the development of the future NGV market.

TIAX's overall approach relies on six key stages

- Segmentation of the vehicle market
- Identification of market decision drivers
- Assessment of market development actions
- Analysis of competing technologies
- Analysis of market scenarios
- Integration of overall market development opportunities

The market perspectives for which decision drivers and opportunities have been identified and assessed are: light- and medium-duty vehicle ownership and production; heavy-duty vehicle ownership and production; compressed natural gas infrastructure; liquefied natural gas infrastructure; and government.

Drawing on the respective expertise of each team member, TIAX presents an integrated assessment of the U.S. and Canadian NGV market in a collection of nine reports (Figure P-1). Each report is capable of standing alone while integrating the data, ideas, and themes of the other eight reports. The collection of reports in this TIAX analysis of the NGV market is supported by America's Natural Gas Alliance and is intended to be transparent and accessible to a broad audience.

Executive Summary

Liquefied natural gas (LNG) has the economic potential to be successful in select vehicle market segments.

Liquefied natural gas (LNG) as a vehicle fuel has the potential to be successful in select vehicle market segments based upon favorable economics. Success for LNG is an integrated network of public access stations and LNG infrastructure across the country that can support significant penetration of LNG natural gas vehicles (NGVs) for long distance, cross-country travel. LNG is unlike most other transportation fuels, and an effective LNG infrastructure business model requires an integrated effort by LNG providers, station owners and operators, and prospective LNG vehicle owners.

Successful LNG infrastructure implementation seeks to minimize one or more of the three main cost components of the LNG supply chain: feedgas cost, liquefaction and upgrade cost, and transportation cost. The most successful strategy to date has been to build a pipeline-fed liquefier dedicated to LNG vehicle fuel production. Other LNG pathway supply options, including peakshaving, pressure reduction liquefiers, nitrogen rejection units, gas separation plants, small-scale liquefaction, and imported LNG, each have had or will have a role in the development of an LNG infrastructure and supply network. Moving forward into a greenhouse gas (GHG) constrained economy, LNG from biomethane will also play a key role, offering significant GHG emissions reductions as the LNG pathway with the lowest carbon intensity as well as a positive public image. An LNG portfolio blending pipeline natural gas and biomethane LNG may be a prudent strategy for reducing GHG emissions, enhancing public perception of LNG as a low carbon fuel, while providing adequate quantities of competitively priced LNG.

With the exception of onsite liquefaction, LNG fueling station requirements and design are independent of the LNG infrastructure pathway. Profitable and sustainable LNG infrastructure development requires careful selection of station locations and capacities and maximum use of standardized designs, in addition to targeting specific market segments for LNG penetration. LNG stations that dispense LCNG (compressed natural gas, or CNG, produced from LNG) have the benefit of supporting both natural gas fuel types. With strategic expansion of an LNG infrastructure network in specific regions, successful capture of the LNG Class 8 tractor market promises attractive economics and large market potential. Figure ES-1 shows that the largest market for LNG penetration is in heavy-duty long range applications, where use of public fueling stations (i.e., truck stops) and significant fuel consumption are attributes conducive to LNG adoption. Development of LNG infrastructure to support this type of market demands commitments from and an coherent plan among LNG providers, station owners and operators, and prospective LNG vehicle owners. As an example, Figure ES-2 shows the locations of current LNG stations in southwestern U.S., with planned LNG stations connecting Las Vegas and Los Angeles. Strategic and coordinated investments along heavily used corridors, such as the establishment of co-located natural gas stations and diesel truck stops, will be required to establish infrastructure networks that make LNG a major transportation fuel.

If policy makers decide to reauthorize federal incentives, LNG, as shown in the Comparative Analysis report of the overall TIAX assessment, has economic security and environmental benefits that justify government incentives. Nearly all LNG vehicles and infrastructure in place today are dependent on incentives and mandates. While mandates are helpful initially, they may not be necessary for long-term success. Incentives that last at least five to ten years without need for renewal can establish the market conditions that allow for sustained growth. LNG vehicles and liquefaction and retail facilities require substantial capital investments, and until sufficient fuel throughput and adequate fueling station availability are in place, government incentives need to be committed to LNG to give security to infrastructure and vehicle investments.

Figure ES-1

Heavy-duty Class 8 trucks consume over 75 percent of commercial truck on-road diesel fuel, 70 percent at public fueling stations (truck stops) and 60 percent by long range vehicles.¹

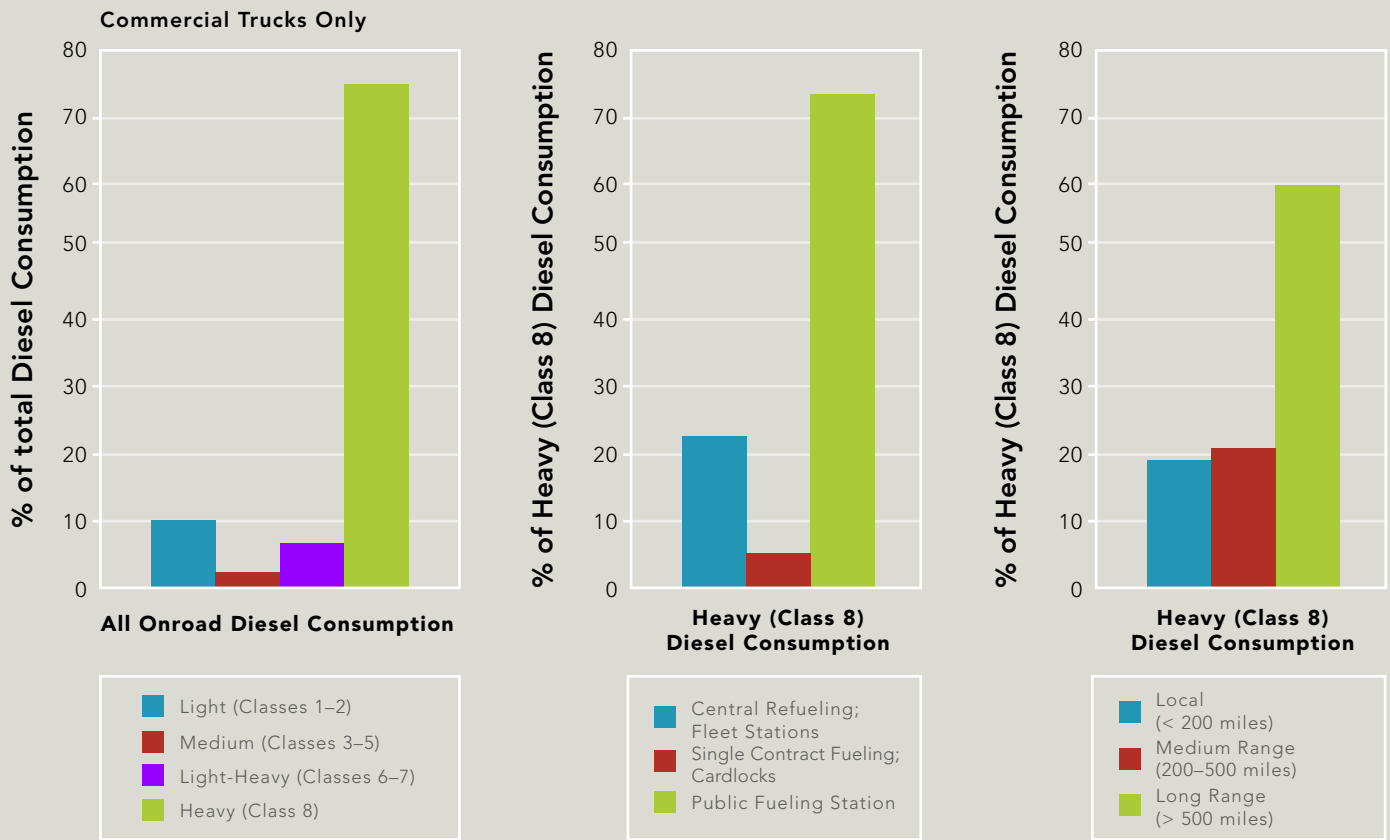
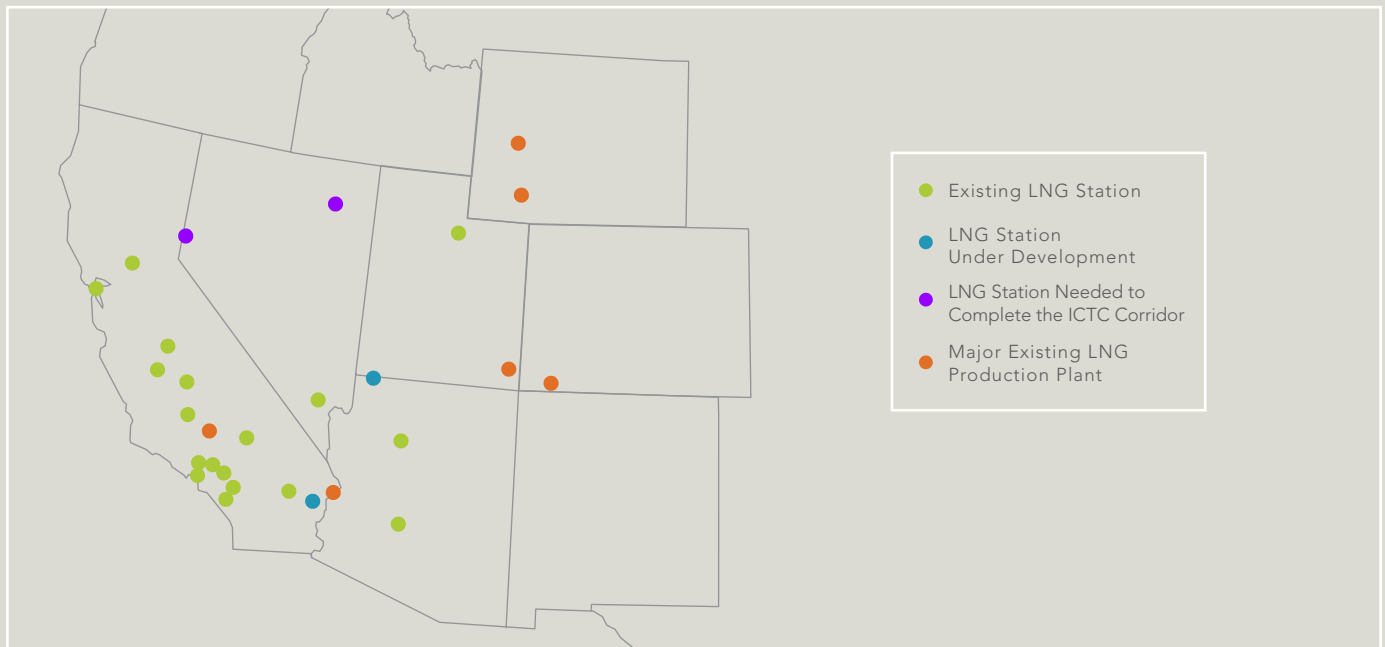


Figure ES-2

The LNG Interstate Transportation Corridor in the West is well under development.²



¹ Adapted from TIAx Report, "Executive Summary for: SCR-Urea Implementation Strategies Update Final Report," prepared for Engine Manufacturers Association, June 2006.

² Miyasato, M. "UPS Ontario Las Vegas LNG Corridor Extension Project: Bridging the Gap." http://www1.eere.energy.gov/vehiclesandfuels/pdfs/merit_review_2010/technology_integration/tiarravt047_saito_2010_p.pdf. June 9, 2010.

1 Introduction

1.1 Liquefied Natural Gas as a Fuel

There are various liquefied natural gas (LNG) production pathways and infrastructure strategy options, most of which are unlike all other transportation fuels, including compressed natural gas (CNG). A successful LNG infrastructure business model requires an understanding of these options, including their technical tradeoffs and past implementation experiences.

LNG is the liquefied form of natural gas, produced by cooling natural gas to temperatures below -260° F. The energy content of a given amount of natural gas remains the same regardless of whether it is in the liquid (LNG) or gaseous (CNG) state. LNG has higher energy density than CNG and thus offers significant potential in NGV market segments where long vehicle ranges are required. Because LNG must be stored at extremely low temperatures, the tanks required to

maintain these temperatures on vehicles are large.³ As such, LNG is most appropriate for heavy-duty vehicles, which can accommodate the volume needed for LNG storage. Using LNG also requires fairly consistent vehicle usage as heat slowly “leaks” into the cold tank from the warmer surroundings, and this boils some of the liquid to vapor. Since fuel tank volume is fixed, more vapor must fit into a given space, and the pressure inside the tank increases. If the pressure is not reduced (e.g., by driving the vehicle), it will eventually reach a level where the first pressure-relief valve opens to vent some of the vapor. The time interval between LNG vehicle refueling and tank venting is called the “hold time.” Typical LNG fuel tank hold times are about one week, if the vehicle is not driven, but venting will not occur if the vehicle is driven every few days. Given that heavy-duty vehicles are the target vehicles for LNG, the development of LNG infrastructure must meet the operation characteristics of these vehicles including ranges, duty cycles, and fueling logistics.

The basic elements of the LNG vehicle fuel cycle are: feedgas extraction, liquefaction, distribution, dispensing, and use in vehicles. Feedgas for LNG may come from the natural gas wellhead, from pipelines, and from landfills or biomethane digesters. Liquefaction may use one of seven types of facilities (Table 1.1-1). Distribution of LNG is primarily performed by tanker trucks that deliver the fuel from the liquefaction facility to the station, where the fuel is dispensed into the vehicles that will use it.

The development of LNG infrastructure and its success as a transportation fuel requires a strategy different from those of other fuels. LNG requires significant infrastructure investment along the supply chain including liquefaction facilities, LNG distribution trucks and LNG stations. Compared to other fuels, LNG production has more options and different business entities may be involved in producing, distributing, and dispensing the fuel. One liquefaction facilities supplies many LNG stations within the distribution radius and an LNG station may have the opportunity of various liquefaction facilities to buy fuel from. Full supply chain infrastructure from liquefaction to dispensing needs to be in place before significant vehicle adoption occurs.

³ LNG tanks require 70% more volume than diesel tanks for the same energy storage.

Table 1.1-1

Seven LNG production pathways will play various roles in a successful overall LNG infrastructure development strategy.

Pathway	Diagram	Potential for Baseload	Examples
Purpose-Built or Peakshaving Liquefier	<p>Natural Gas Transmission Pipeline Purpose-Built or Peakshaving Gas Pretreatment, Liquefaction, and Storage Trucking LNG Fueling Station</p>	Purpose-Built: Yes Peakshaving: No, can be used for peak LNG demand and build-up but base production is for winter peak home heating demand	Purpose-built plant examples: Boron (CA), Topock (AZ), Willis (CO) Peaking plant utilization examples: Northwest Gas (OR), Trussville (AL), BG&E (MD), NIPSCO (IN), SDG&E (CA)
Pressure-Reduction Turboexpander Liquefiers	<p>High-Pressure Transmission Pipeline Gas Pretreatment, Pressure-Reduction Turboexpander Liquefier, and Storage Trucking LNG Fueling Station</p>	Yes	W. Sacramento (CA) (PG&E, INL), SDG&E (CA)
Nitrogen Rejection Unit	<p>High-Nitrogen Natural Gas Source Nitrogen Rejection Unit Modified to Co-produce LNG Trucking LNG Fueling Station</p>	No, can be used for peak demand and build-up but base production is for pipeline gas	Shute Creek (WY) (Exxon), Painter (WY) (BP), Santana (KS) (Pioneer)
Gas Separation (NGL) Plant	<p>Wet Gas Source Gas Separation Plant Modified to Co-produce LNG Trucking LNG Fueling Station</p>	No, can be used for peak demand and build-up but base production is for heavier hydrocarbon removal	Durango (Williams Ignacio) (CO)
Biogas-to-LNG	<p>Biogas Source (e.g., Landfill Gas, Digester Gas) Biogas Cleanup, Pretreatment, Liquefaction, and Storage Trucking LNG Fueling Station</p>	Yes	Altamont and Bowerman (CA), Washington (PA), Columbus (NJ), Rosenberg (TX), Sweden
Liquefier Located Onsite at LNG Fueling Station	<p>Gas from Local Distribution Co. Gas Pretreatment and Small-Scale Liquefier Onsite at LNG Fueling Station</p>	Yes	Sparwood Canada (BC), Australia
LNG Import Terminal	<p>LNG Import Terminal with Truck Loading Facility Trucking LNG Fueling Station</p>	No, can be used for peak demand and build-up but imported LNG does not move the U.S. towards Energy Independence	Lake Charles (LA), Everett (MA), Elba Island (GA)

1 Introduction

1.2 Context for LNG

The LNG transportation market hinges on the economic and societal benefits of LNG over diesel and depends on first establishing the infrastructure needed to support LNG vehicles.

North American dependence on conventional fuel carries with it indirect costs in the form of high energy security premiums and environmental costs. These costs, resulting from the economic effects of oil prices in the long-run, U.S. import costs, short-run disruption premium, effects on output of the overall economy, and impacts on human health, property, agricultural productivity, and terrestrial and aquatic ecosystems, are borne by society as a whole. In order to compare societal costs to the direct costs of conventional fuel, the Comparative Analysis report of the overall TIAX assessment looks at and quantifies the impacts, in monetary value, of switching from diesel to LNG in terms of energy security, air pollutants, and greenhouse gas emissions.

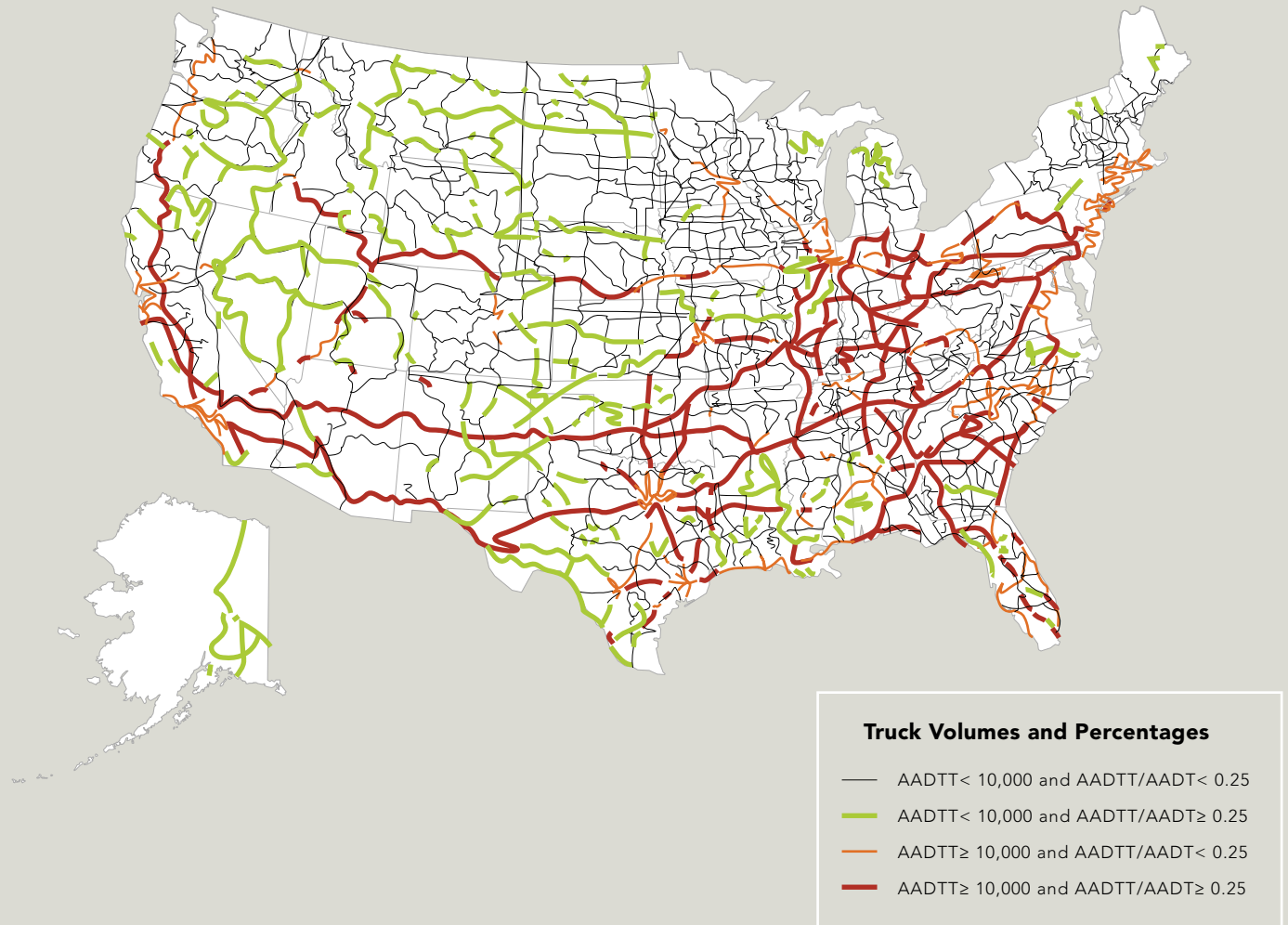
The siting and selection of the type of infrastructure is paramount to the overall success of natural gas as a transportation fuel. There needs to be a minimal availability of infrastructure and refueling so it is not a deterrent for vehicle purchases. Lack of infrastructure and refueling will impede vehicle purchases and overall natural gas penetration.

For LNG, there are the various production pathways for bringing LNG to market that have decision points based on distribution costs when determining whether it is better to continue to distribute LNG long distances or construct a new LNG liquefaction facility. In the beginning, as stations are beginning to be constructed and there is limited liquefaction infrastructure, LNG will have higher trucking and distribution costs from the limited production facilities. As higher use locations and regions are determined, new liquefaction facilities must be built to meet the increasing demand and will likely be sited near the high demand locations. This will reduce not only the production but distribution costs. Due the high costs of infrastructure, LNG may have a lower rate of return but offers a stable long-term investment. As discussed in the Market Segmentation report of the overall TIAX assessment, identifying the current and future major transportation and goods movement routes will assist in determining the siting of liquefiers and fueling stations to coincide with future nationwide infrastructure development. The projected major truck routes in 2035 shown in Figure 1.2-1 could provide a roadmap and blueprint to LNG infrastructure development in the U.S. This same methodology can also be applied for developing infrastructure in Canada.

An overview of the LNG fueling infrastructure to date, including liquefaction facilities and stations, is presented first in Section 2. Section 3 discusses the key issues for LNG station design and safety, followed by a discussion of LNG production options and their tradeoffs in Section 4. Based on the discussion of infrastructure design, LNG economics, and production pathways, the actions and opportunities for a successful LNG infrastructure development strategy are discussed in Section 5.

Figure 1.2-1

The projected major truck routes on highways in 2035 could be a roadmap and blueprint for developing LNG infrastructure in the U.S.; the same methodology can be applied to Canada.⁴



Note: AADTT is average annual daily truck traffic and includes all freight-hauling and other trucks with six or more tires. AADT is average annual daily traffic and includes all motor vehicles.
Source: U.S. Department of Transportation, Federal Highway Administration, Office of Freight Management and Operations, Freight Analysis Framework, version 2.2, 2007

⁴ U.S. DOT - Federal Highway Administration, "Freight Facts and Figures 2009," FHWA-HOP-10-007, http://ops.fhwa.dot.gov/freight/freight_analysis/nat_freight_stats/docs/09factsfigures/index.htm. November 2009

2 LNG Fueling Infrastructure to Date

2.1 Liquefaction Facilities

From wellhead to LNG retail station, LNG must first be liquefied. Various types of liquefaction facilities have been used to provide LNG and continue to offer capacity to supply LNG as a vehicle fuel.

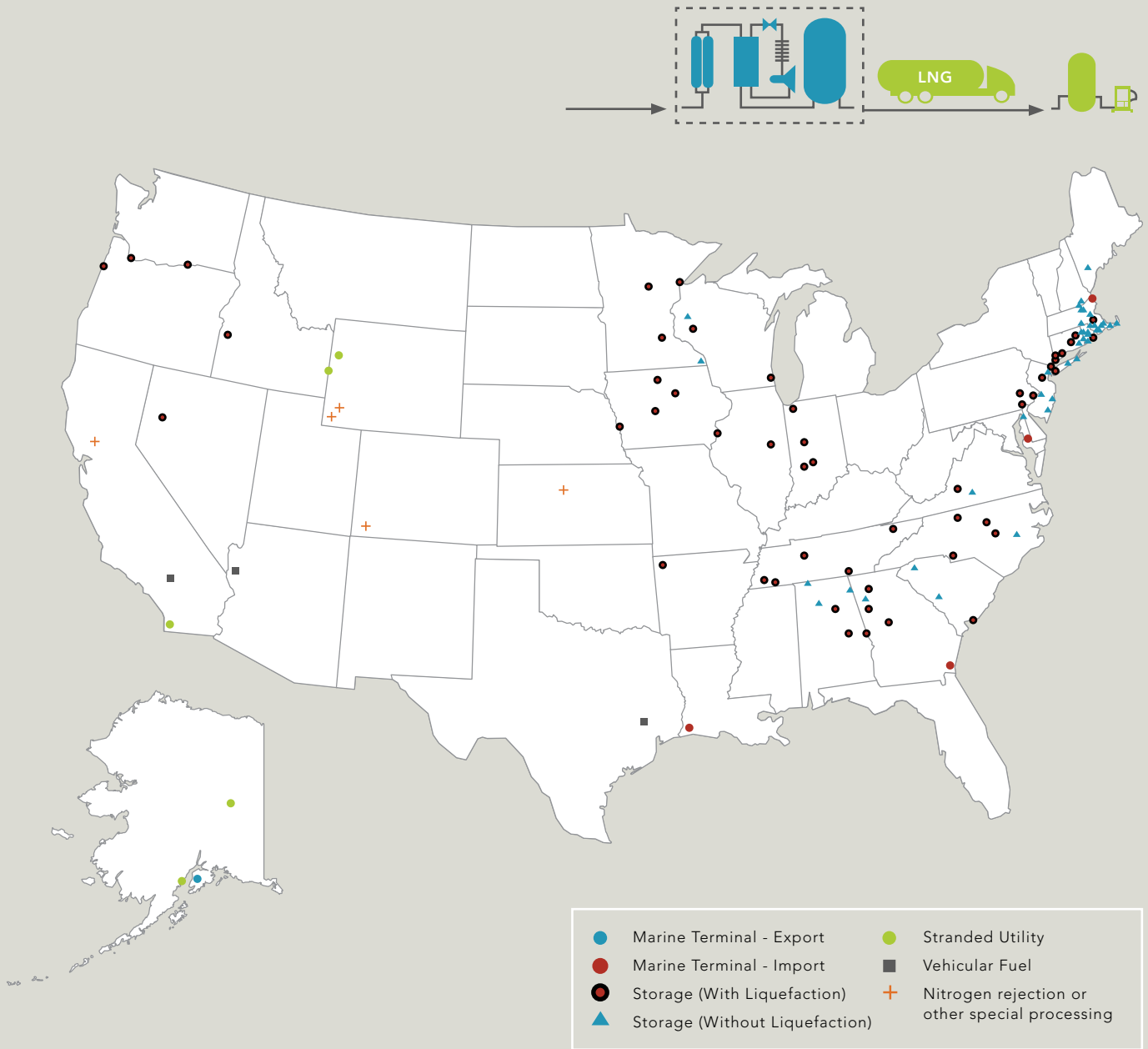
The LNG infrastructure is quite different from the CNG infrastructure. Whereas the CNG infrastructure consists of natural gas moving from wells to pipelines to CNG stations, the LNG infrastructure is more complex. Several possible LNG fuel infrastructure pathways to supply LNG stations are described in the following sections. In the past, all of these pathways have been tried and almost all have been used to some extent. At this time, the most common LNG option, including that which is used at the Boron, California and Topock, Arizona plants, is the dedicated liquefier pathway. Each LNG fuel infrastructure strategy involves different capacity liquefiers, ranging from 5,000 or 10,000 gallons per day for biomethane liquefaction to more than 20 million gallons per day for export terminal liquefiers. These strategies each require different gas upgrade and liquefaction cycle technologies.

Figure 2.1-1 shows the location of various types of LNG facilities in the U.S. Facilities that are or have been used to provide LNG include vehicular fuel facilities, nitrogen rejection units, storage with liquefaction facilities (also known as peakshaving plants), and marine import terminals (now rarely used). Purpose-built vehicular fuel liquefaction facilities can have production volumes ranging from 85,000 – 250,000 LNG gallons per day, while the available LNG from nitrogen rejections units, GSPs and peak shaving plants is on the order of 10,000 -25,000 LNG gallons per day or less. Marine import terminals, which could have significant importation and distribution capacity (possibly over 1,000,000 LNG gallons per day), do not move the U.S. towards energy independence and are commonly located a significant distance from LNG consumers, increasing the distribution costs.

Table 2.1-1 lists the facilities that supply a majority of LNG used as a transportation fuel in U.S. In Canada, there is currently one existing LNG terminal and eight proposed LNG facility projects. Six of the eight projects are for LNG receiving and re-gasification, and one is for LNG storage and transshipment. The project at the Kitimat Terminal was previously approved for LNG receiving and re-gasification but has since proposed to offer LNG liquefaction and export.

Figure 2.1-1

Various types of LNG facilities in the U.S. have been built in the U.S., and many of these facilities continue to be capable of producing LNG for vehicle use.⁵



5 U.S. EIA. "U.S. LNG Markets and Uses." http://www.eia.doe.gov/pub/oil_gas/natural_gas/feature_articles/2004/lng/lng2004.pdf. June 2004.

Table 2.1-1

Current LNG plants that serve transportation fuel markets are located near major LNG markets in Texas and southwestern U.S.

Facility	Location	Capacity (GPD)	Markets Served
California Clean Energy Plant	Boron, CA	Initial: 160,000 Upgradable: 240,000	Ports of Los Angeles and Long Beach
Topock LNG Plant	Topock, AZ	86,000	Arizona and California
The Pickens Clean Energy Plant	Willis, TX	100,000	Dallas, El Paso, Houston and Phoenix (AZ)

2 LNG Fueling Infrastructure to Date

2.2 Stations

The majority of current fueling infrastructure to support LNG vehicles is concentrated in California. This station network largely supports LNG vehicle operation within limited ranges and will enable wider operating areas as it expands.

Currently, there are 48 LNG stations operating in the U.S., 24 of which dispense CNG as liquefied-to-compressed natural gas (LCNG) stations (discussed in Section 3). Of the total LNG stations, 41 percent are private access and 28 percent are public access. All active stations are located in nine states (Alabama, Arizona, California, Connecticut, Louisiana, Nevada, Ohio, Texas and Utah), with 35 of the 48 stations located in California (Table 2.2-1). 100 additional stations are planned to come online in the near future.⁶

The LNG infrastructure that has developed to date is largely clustered in specific hubs (e.g., Los Angeles and Phoenix). As such, LNG vehicles currently in operation are in effect limited in range by the distribution of stations. Unlike diesel vehicles, LNG vehicles are not yet able to traverse the entire country using a system

of public truck stops. However, as the infrastructure develops, broader opportunities for LNG vehicle markets will emerge. Regional deployments of LNG vehicles have been accompanied by development of infrastructure, such as at the Ports of Los Angeles and Long Beach, and the expansion of this infrastructure enable regions to be connected. Already, the establishment of corridors to connect various hubs is in progress, including the joint UPS-Clean Energy effort to connect Southern California to Las Vegas.

LNG vehicles deployed into local and regional haul applications today have a range of approximately 300 miles.⁷ Without a fueling corridor, the 380-mile distance between the major hubs of Los Angeles and San Francisco cannot be traveled by these vehicles without running out of fuel. However, LNG stations near the 180-mile mark in Central California make it possible for this distance to be traveled, opening up greater possibilities for goods movement. Thus, expansion of infrastructure and connections among existing infrastructure are now building up a network to support LNG vehicles. As wider operating areas are enabled, the vehicles used in these applications will offer higher ranges. For longer distance line-haul applications, vehicles will be able to hold approximately 220 gallons of LNG, offering an estimated 720 miles in range.⁸

A key question remains as to whether vehicle drivers will be willing to change their behaviors, even if distance between refuelings is no longer a technical barrier. At present, a line-haul truck may carry enough diesel fuel to enable the driver to travel 1,200 miles without refueling⁹ As a switch to LNG fuel would require the driver to spend more time refueling, consideration needs to be given during station design as to how to incentive drivers to make the required stops, such as alignment with other motivations for stopping, alignment with existing limits on consecutive hours of driving, convenience, ease of use, and station amenities.

6 U.S. Department of Energy Alternative Fuels and Advanced Vehicles Data Center, as updated by ANGA/AGA Natural Gas Transportation Collaborative, March 31, 2012.

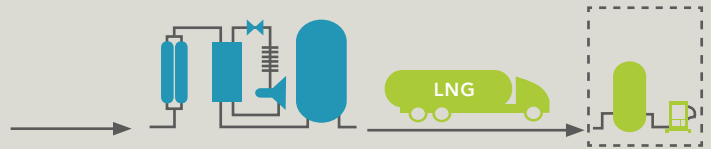
7 Hartley, P. "Sterling LNG Trucks Go into Service." *Fleet Equipment*, February 1, 2009.

8 Kell-Holland, C, "Could LNG Be a Lifeline for Truckers?" *Land Line*, March/April 2009.

9 Assuming diesel capacity of 200 gallons and fuel economy of 6 miles per diesel gallon.

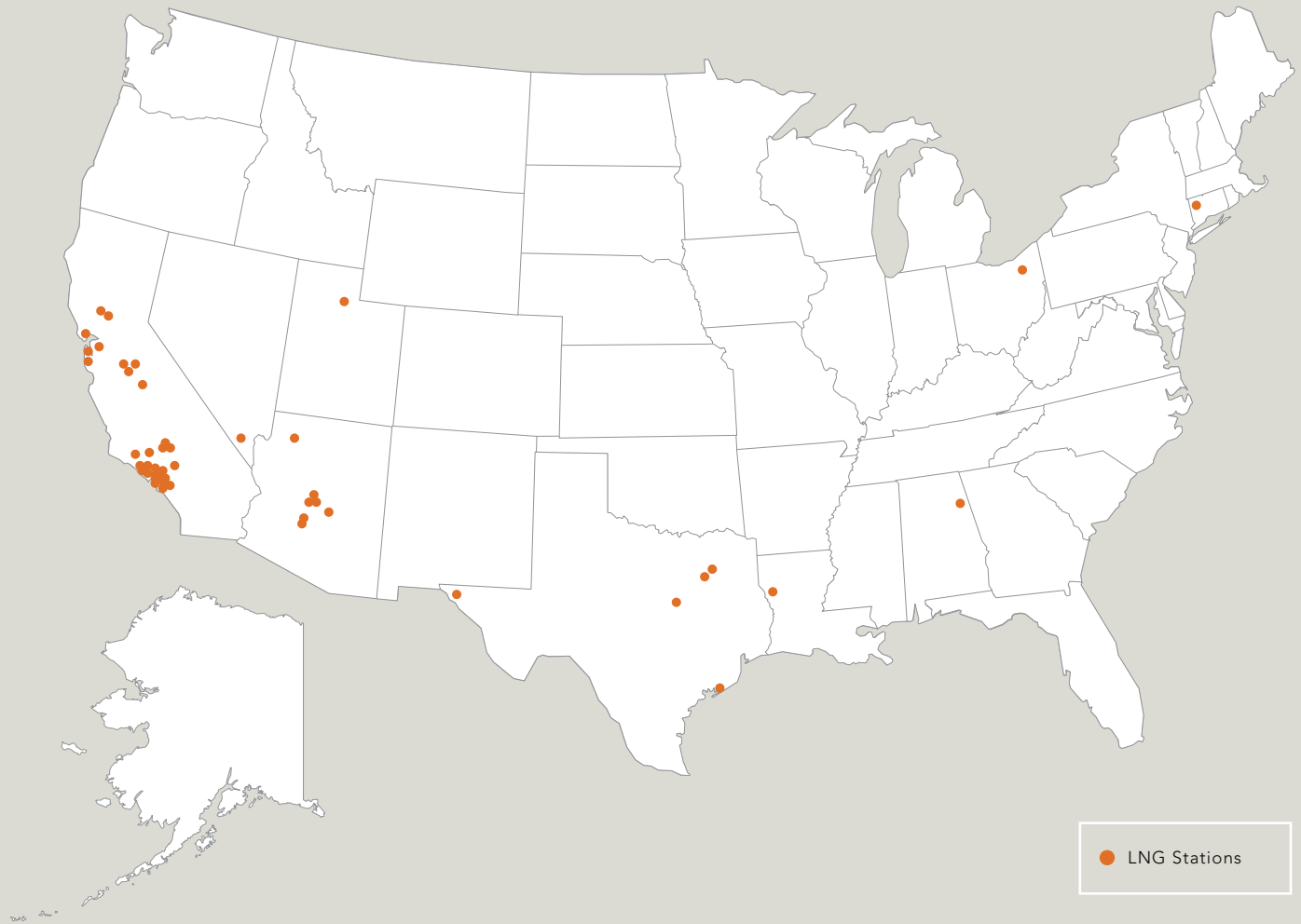
Table 2.2-1

This map depicts the stations noted in Table 2.2-1



<p style="text-align: center;">Alabama</p> <p style="text-align: center;">North American Bus Industries</p>	<p style="text-align: center;">Connecticut</p> <p style="text-align: center;">Enviro Express Natural Gas</p>
<p style="text-align: center;">Texas</p> <p>Clean Energy - Baytown TX LNG - Pilot/TRIMAC Clean Energy - DART Northwest Division Clean Energy - DART South Oak Cliff Division Clean Energy - HEB Grocery Sun Metro</p>	<p style="text-align: center;">Arizona</p> <p>East Valley Bus Maintenance and Operation Facility Tempe Transit Grand Canyon National Park Phoenix Public Transit Department - North Facility Phoenix Public Transit Department - South Facility Phoenix Public Transit Department - West Facility Valley Metro RPTA- Mesa</p>
<p style="text-align: center;">Nevada</p> <p style="text-align: center;">Clean Energy - United Parcel Service</p>	<p style="text-align: center;">Utah</p> <p style="text-align: center;">Flying J Travel Plaza - CH4 Energy</p>
<p style="text-align: center;">Louisiana</p> <p style="text-align: center;">DeSoto LNG Station - Encana</p>	<p style="text-align: center;">Ohio</p> <p style="text-align: center;">Clean Energy - Pilot Travel Center</p>
<p style="text-align: center;">California</p> <div style="display: flex; justify-content: space-between;"> <div style="width: 48%;"> <p>City of Barstow City of Redlands Burrtec Waste Clean Energy - Carson City of Long Beach Clean Energy - City of Tulare City of Los Angeles - East Valley Station City of Los Angeles - North Central Station City of Los Angeles - South LA Station Clean Energy - Downs Truckstop City of Los Angeles - West Valley Station City of Sacramento City of San Bernardino Clean Energy - Port of Long Beach Clean Energy - Apple Valley Walmart Clean Energy - Riverside County Waste Management Clean Energy - City of Commerce Clean Energy - Consolidated Disposal</p> </div> <div style="width: 48%;"> <p>Clean Energy - Los Angeles World Airports (LAX) Clean Energy - Norcal Waste Systems Clean Energy - Republic Waste Services of Southern California Clean Energy - Solano Garbage Clean Energy - Waste Management County of Sacramento LA County Sanitation District Southwest Education Support Service Center Speedy Fuel Norcal Waste - Recology San Francisco United Parcel Service Waste Management Waste Management Santa Monica - Big Blue Bus Waste Management - USA Waste of California Waste Management - USA Waste of California Waste Management - USA Waste of California</p> </div> </div>	

Figure 2.2-1



2 LNG Fueling Infrastructure to Date

2.3 Comparison of LNG Fueling Infrastructure with Diesel

LNG currently has only 0.1 percent of the public access Class 8 truck stops of diesel and will require significant investments to mimic the diesel fueling station model.

Given that the heavy-duty transportation sector has been successfully built up around diesel infrastructure, expansion of the LNG infrastructure may require replicating the diesel model. If so, significant investment will be required for public access LNG stations (truck stops) in the near future. Currently, there are only 19 public LNG stations, with one requiring call ahead and five requiring a cardlock key for access.¹⁰

In contrast, there are an estimated 36,000 stations in the U.S. that dispense diesel fuel including truck stops, cardlock stations, and central fleet stations. 5,000 stations are public access diesel truck stops serving the heavy-heavy duty (Class 8) truck fleet. These 5,000 stations dispense 54 percent of the on-road diesel and range in capacity from 10,000 gallons per month (gal/mo) to 1,000,000 gal/mo, with an average of 200,000 gal/mo. Table 2.3-1 shows the breakdown of all diesel stations by throughput. 74 percent of diesel is dispensed from stations with capacities greater than 200,000 gal/mo. A 200,000 gal/mo diesel station has an average daily throughput of 6,700 gallons. For the same throughput on an energy basis, an LNG station would dispense just under 12,000 gallons of LNG per day.

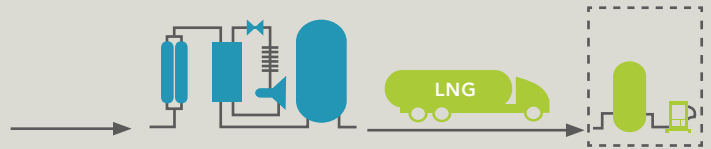
In mimicking the diesel infrastructure model, LNG infrastructure may need to consider a greater density of stations due to the inherently lower energy content of LNG compared to diesel. The range of single-tank LNG trucks today is around 300 miles,¹¹ half that of diesel trucks, and may require up to twice as many stations for the same coverage as diesel. A solution is dual-tank LNG trucks, but this has a significant added cost per vehicle and may not be suitable except on trucks with the longest distance duty cycles. With a possibility of doubling the investment required to have the same coverage as diesel, the more cost-effective solution could be to concentrate LNG stations along heavy traffic trucking routes to limit station investment.

10 U.S. Department of Energy Alternative Fuels and Advanced Vehicles Data Center, as updated by ANGA/AGA Natural Gas Transportation Collaborative, March 12, 2012.

11 Hartley, P. "Sterling LNG Trucks Go into Service." *Fleet Equipment*, February 1, 2009.

Table 2.3-1

Seventy-four percent of diesel fuel is dispensed at stations with monthly throughput of greater than 200,000 gallons.¹²



Monthly Diesel Fuel Throughput (Gallons/Station)			
High	Low	Number of Stations	% of Diesel Sales
2,000,000	1,300,000	310	17%
1,300,000	1,000,000	1,128	44%
1,000,000	300,000	515	11%
300,000	200,000	262	2%
200,000	140,000	2,436	14%
140,000	80,000	1,115	4%
80,000	10,000	2,491	4%
10,000	100	24,251	4%

12 TIAX LLC. "Executive Summary for: SCR-Urea Implementation Strategies Update Final Report." Prepared for Engine Manufacturers Association. June 2006.

3 LNG Station Design

3.1 LNG Fueling

Except for onsite liquefaction, LNG fueling station requirements and designs are independent of the LNG production pathway. However, a profitable and sustainable LNG vehicle infrastructure strategy requires careful selection of station locations and capacities and maximum use of standardized designs.

LNG fueling stations today generally receive their LNG supply from a liquefaction plant via tanker truck specially designed to distribute cryogenic fuels. At the fueling site, LNG is offloaded into the facility's storage system. In most LNG stations, the fuel passes through a pump to an ambient air vaporizer that serves as a heat exchanger. In this vaporizer, the temperature of the LNG is increased to approximately -200°F. The pressure also increases, but the fuel remains a liquid. This process is called "conditioning." After conditioning, LNG is stored in large cryogenic vessels either above or underground. These vessels can be configured horizontally or vertically, and are typically found in capacities of 15,000 or 30,000 gallons. When needed, LNG is dispensed as a liquid into cryogenic tanks onboard the vehicle.

Unlike conventional fueling stations, LNG stations must address various unique design and functionality requirements, including tank truck offloading, fuel conditioning, cryogenic fluid storage and processing, vapor management and venting minimization, codes and standards compliance, and special metering and dispensing challenges. For example, most current LNG vehicles must be fueled at a saturation pressure near 100 psi, which requires stations to have special conditioning equipment to provide fuel at this pressure. However, unconditioned LNG is a better choice for other LNG vehicles, such as those equipped with Westport GX engines. There is no consensus regarding the best approach for addressing this conditioning challenge. Furthermore, two different LNG fueling couplings, manufactured by Carter and Parker, are currently used. A Carter nozzle is incompatible with a Parker receptacle and vice versa, and efforts to specify a standard configuration have been unsuccessful.

Most LNG and LCNG (described below) station designers, some of whom are also cryogenic equipment manufacturers, have developed standardized or "cookie cutter" station designs. Installation of a significant number of these standard-design stations would enable substantial per-station cost reductions. However, most stations installed to date have been custom designs in order to accommodate particular site constraints, various dispensing capacities and profiles, special station owner preferences, and the aforementioned saturation pressure and fueling coupling variations. Further progress toward installing LNG stations at truck stops and building more "greenfield" stations (as opposed to trying to fit them within existing return-to-base truck and bus terminals) will enable increased use of more economical standardized designs.

Figure 3.1-1 is a simplified schematic of the basic elements of the most common LNG station design, which includes fuel conditioning capability. Figure 3.1-2 shows an example of an LNG station. This station dispenses both "green" LNG saturated at approximately -200°F and "blue" LNG saturated at approximately -220°F, which requires essentially building two stations at one site. New technology is in development for producing LNG at warmer temperatures, which introduces upcoming opportunities to lower LNG infrastructure costs.

Figure 3.1-1

Greater industry standardization of LNG fueling station elements,¹³ which vary with pressure, temperature, and fueling couplings required by vehicles, will enable lower station costs.

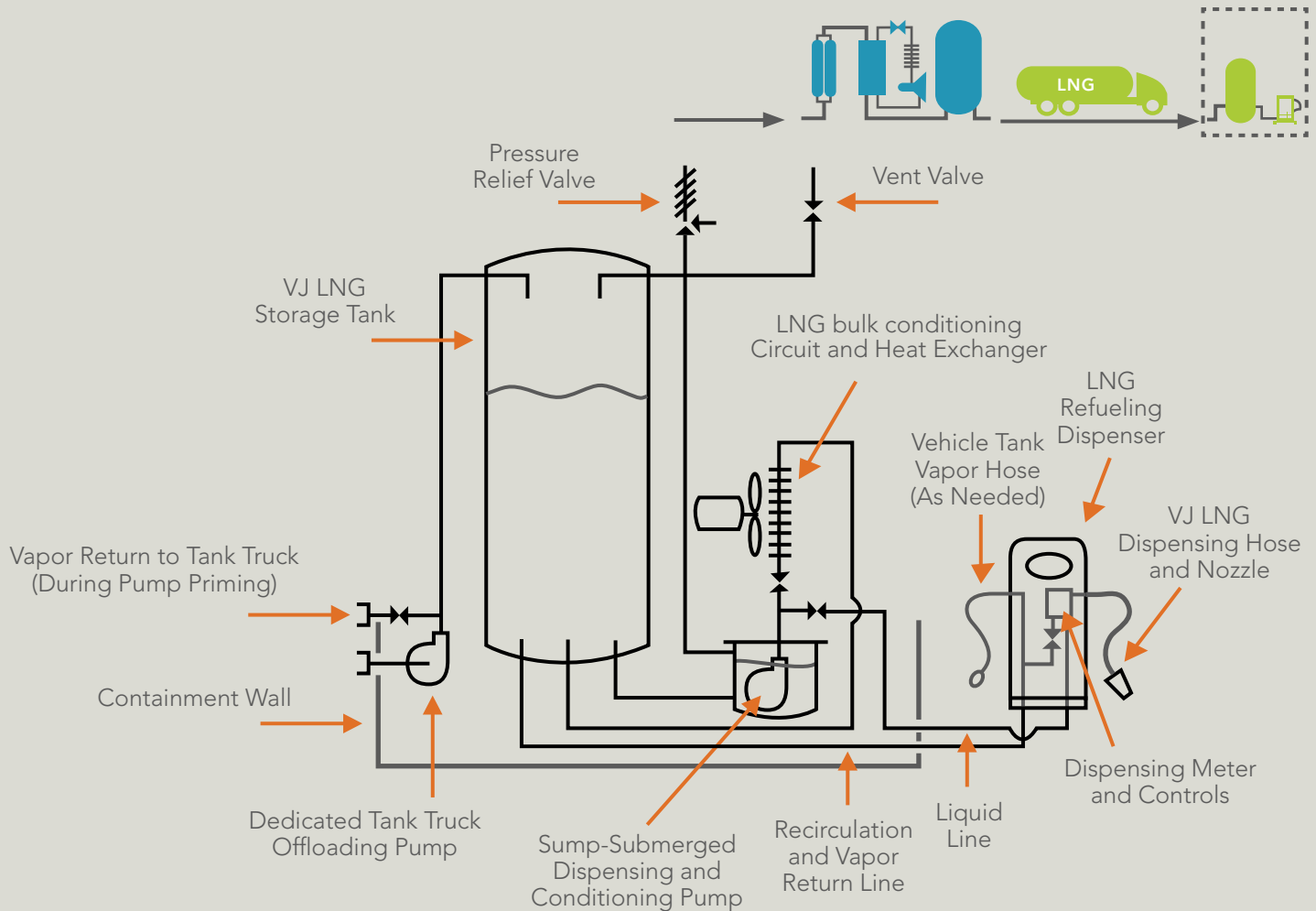
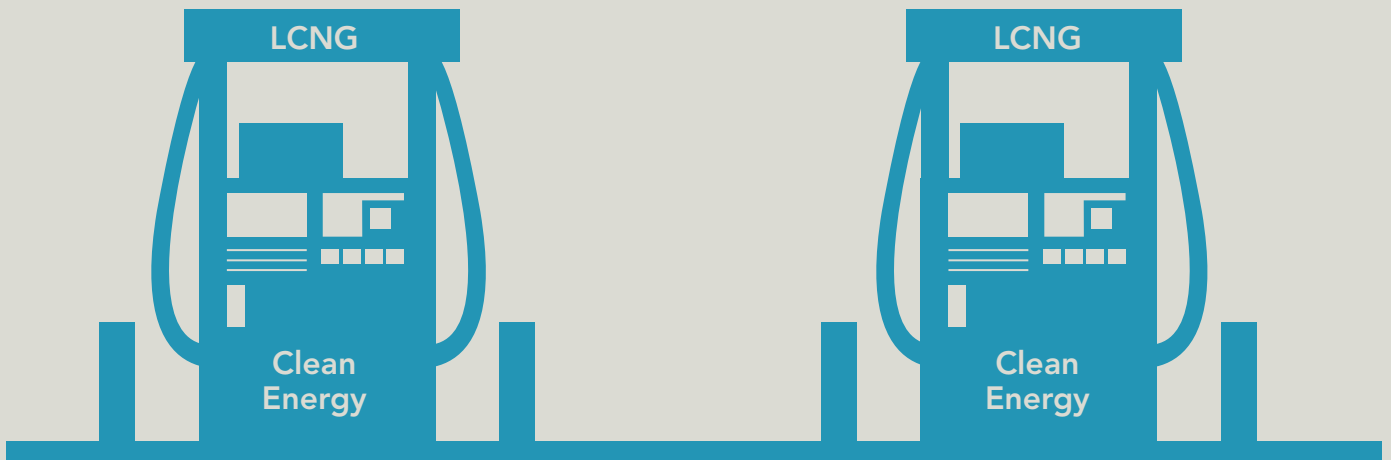


Figure 3.1-2

Clean Energy's 50,000 gallon LCNG fueling station at the Ports of Los Angeles and Long Beach in California is the world's largest public LNG fueling station.¹⁴



13 Powars, C. "Best Practices to Avoid LNG Fueling Station Venting Losses." Brookhaven National Laboratory, Contract 157688. June 2010.

14 "Clean Energy Opens World's Largest LNG/CNG Truck Fueling Station At Long Beach/Los Angeles Ports".

<http://www.allbusiness.com/energy-utilities/oil-gas-industry-oil-processing-products/12378109-1.html>. Accessed November 29, 2010.

3 LNG Station Design

3.2 LCNG Fueling

LCNG stations potentially offer greater fueling flexibility than LNG stations. LCNG and LNG station costs are highly variable and depend on throughput, among other factors. As such, ensuring high throughput will be a key factor in station design.

A variation of the LNG station is the LCNG station, which uses LNG to make CNG. Some LCNG stations can dispense both CNG and LNG, while others, such as the Omnitrans San Bernardino station, can only dispense CNG and were built for reasons ranging from bad experiences with compressors to inadequate natural gas pipeline access. For example, the Santa Cruz Metropolitan Transit LCNG station (Figure 3.2-1) was built because of inadequate pipeline access. For the LCNG station, a separate pump pumps LNG to an ambient air vaporizer, where the LNG is warmed to approximately 40°F and becomes a gas. The gas is then odorized and goes through a priority fill system, fuel storage vessels, a sequential system, temperature compensation system, the dispenser, and into the vehicle.

LCNG stations receive and store truck-delivered LNG, which is pumped to high pressures and vaporized to fuel CNG vehicles. LCNG capability is an inexpensive addition to LNG stations. Figure 3.2-2 shows LNG and LCNG station costs as a function of LNG storage capacity. Station costs depend on many other factors, such as site requirements, number of dispensers, and maximum dispensing rate, so there is considerable scatter in the relationship between cost and storage capacity. In addition, because actual as-built costs are seldom released, this chart also includes projections and budgets, which are often less than actual costs.

Increased use of the modular and standardized LNG and LCNG fueling station designs will significantly reduce the cost of each station. Equipment costs will decrease through manufacturing economies of scale and price competition if substantially more stations were built. Finally, costs will be reduced if stations are purchased in a straightforward manner by commercial entities; most of the LNG and LCNG stations shown in Figure 3.2-2 involved multiple layers of contracting, with onerous conditions such as public works rules requiring separate design and construction contracts and firms.

Figure 3.2-1

Santa Cruz Metropolitan Transit in California installed this 15,000 gallon LCNG fueling station because adequate pipeline access was unavailable.¹⁵

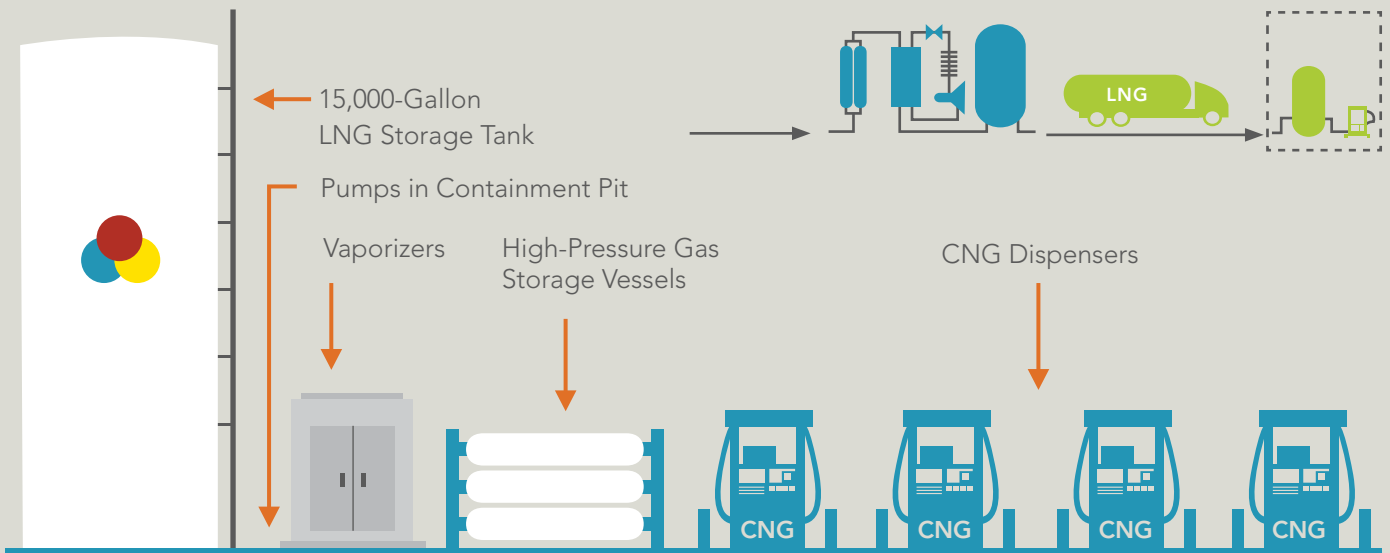
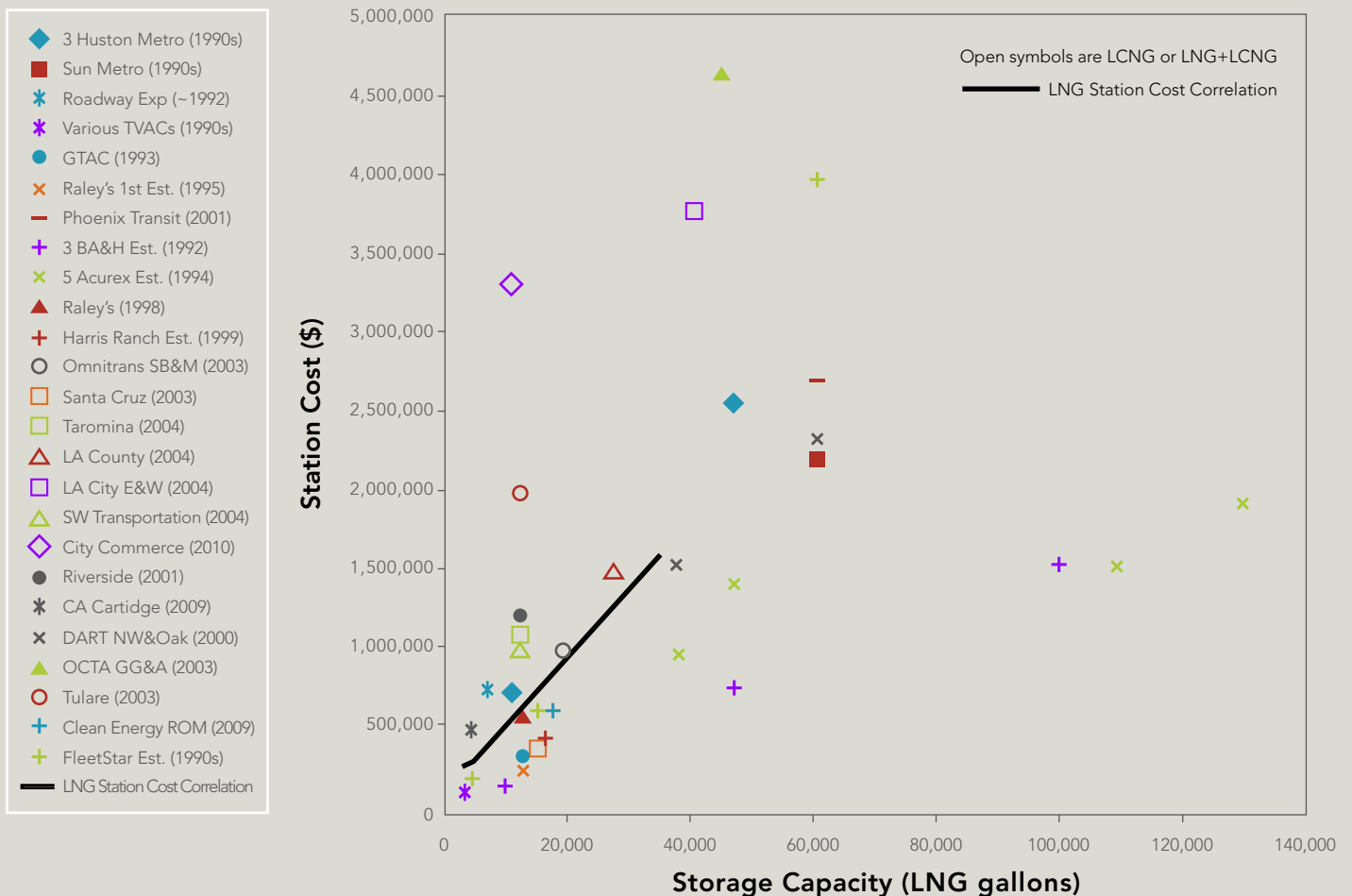


Figure 3.2-2

LNG and LCNG fueling station costs are scattered but loosely correlated with LNG storage capacity.¹⁶



¹⁵ Powars, C. "Best Practices to Avoid LNG Fueling Station Venting Losses." Brookhaven National Laboratory Contract 157688. June 2010.

¹⁶ Data from: analyses to support the ARCADIS DOT Transportation Research Board Fuel Choice Guidebook, 1998; California Energy Commission Alternative Fuel Infrastructure Program database; National Renewable Energy Laboratory "DART Final Data Report," June 2000; South Coast Air Quality Management District Board Meetings October 1, 2001 and March 6, 2009.

3 LNG Station Design

3.3 Economics

After the delivered cost of LNG, which includes liquefaction costs, the most significant components of the retail LNG price are station costs, which are dependent on storage capacity, and federal excise taxes, which are currently levied on the volume of fuel rather than the energy content of fuel, putting LNG at a severe disadvantage relative to diesel.

The planning of LNG fueling stations, including location and size, is fundamental to beginning and maintaining an LNG transportation fuel infrastructure network. The consumers who purchase LNG for their vehicle fleets are generally not concerned with the upstream liquefaction pathway. Instead, their priority is convenient and accessible fueling stations that are compatible with their LNG vehicles.

According to Clean Energy, the estimated cost of a large fleet LNG station with dispensing capacity of 4 to 20 million diesel gallons equivalent (DGE) per year ranges from \$2.25 to \$7.5 million.¹⁷ Figure 3.3-1 shows that LNG fueling station costs are correlated with storage capacity. With storage capacity being one of the main costs for fueling stations, onsite liquefaction has an advantage over other pathways because the storage capacity for the liquefaction facility is shared with the fueling station. As LNG fueling station costs are an order of magnitude higher than those for diesel stations, amortized fueling station costs contribute significantly to the dispensed fuel cost. Figure 3.3-2 shows the dispensed fuel cost for LNG, assuming purpose-built liquefaction and a 5,000 LNG gallons per day (2,900 diesel gallons per day; 87,000 diesel gal/mo), 50 trucks per day (assuming 100 gallon fills per truck) fueling station, which is about one-half the size of the average diesel truck stop.

The fueling station contributes 17 percent of the total dispensed cost. If LNG vehicle use and fuel throughput increase, station capital costs will certainly decrease. Larger capacity stations with lower cost per throughput and more standardized designs would be built. Greater capacities, design standardization, competition, and learning curve effects will lower per-gallon costs for all subsequent LNG stations.

Excise and sales taxes also contribute significantly to LNG retail cost. Taxes account for 32 percent of total LNG cost but only 23 percent of diesel costs. The disparity can be attributed to unfair treatment of LNG compared to diesel: federal motor fuel excise taxes are the same for LNG and diesel on a volume basis but not on an energy basis, and as LNG has roughly half of the energy content of diesel on a volume basis, the effective tax rate on LNG is nearly double that of diesel. Despite the current tax disadvantage for LNG, with diesel prices of \$3 per gallon and natural gas citygate prices of \$5/MMBtu, Figure 3.3-2 shows that LNG has a price advantage of \$0.75 per DGE. From the prospective customer perspective, this price differential will be used to offset higher initial vehicle purchase prices.

¹⁷ Clean Energy presentation to California Energy Commission at Integrated Energy Policy Report hearing, April 14, 2009.

Figure 3.3-1

As shown in a correlation developed by A.D. Little, station cost is dependent on storage capacity.¹⁸

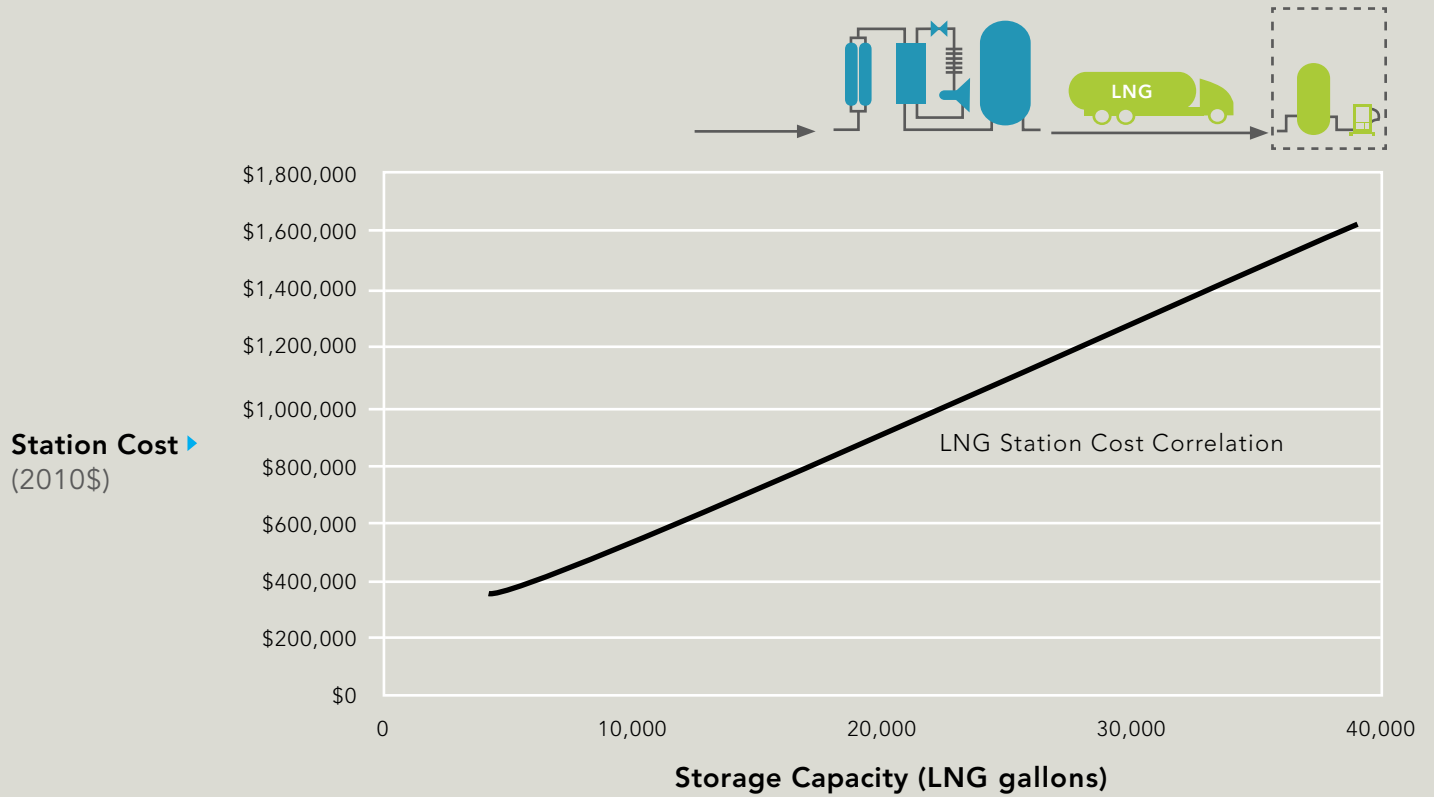
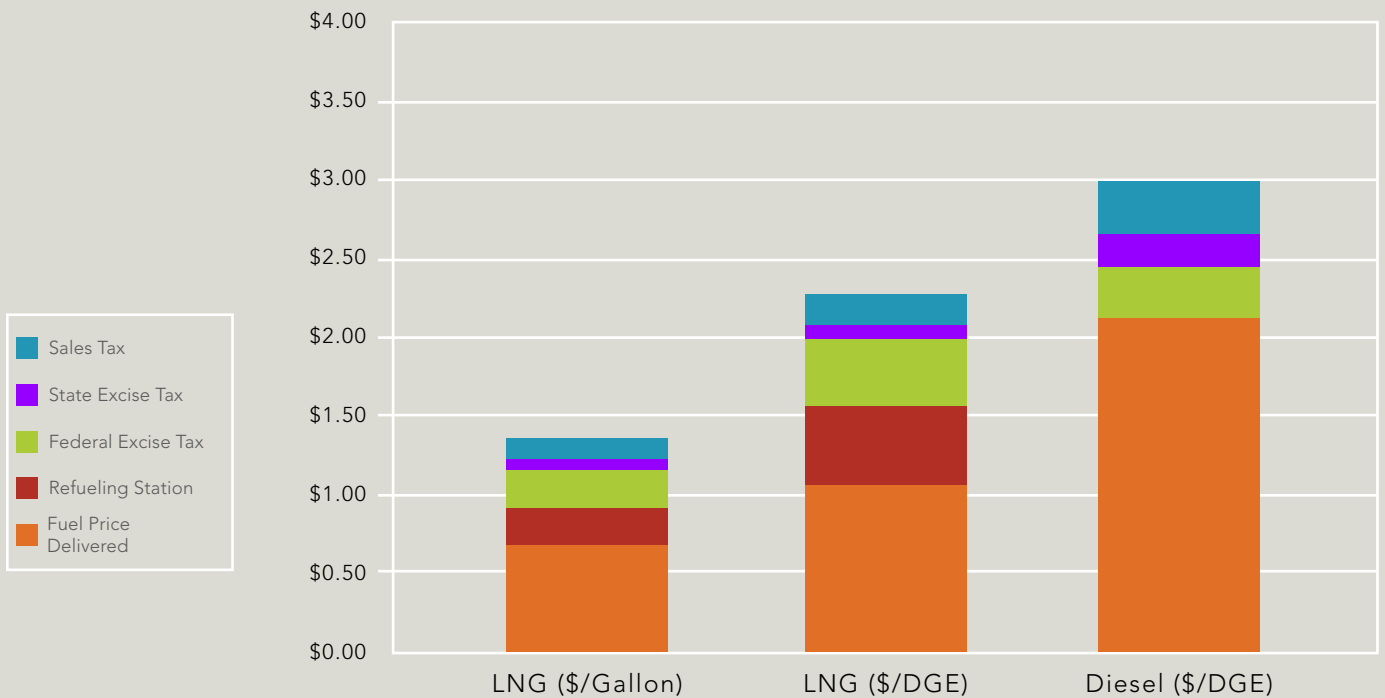


Figure 3.3-2

The cost of LNG when building up from feedgas is less than diesel on a DGE basis while it currently sells for much more.^{19, 20}



18 A.D. Little. "Liquefied Natural Gas for Heavy-Duty Transportation." Prepared for GRI and Brookhaven National Laboratory. May 2001.

19 Assumes a 5,000 gallon per day LNG station, 50 trucks per day at 100 gallons per fill, cost based on storage equal to 1 week of throughput (i.e., 5,000 GPD station has 35,000 gallons of storage). Refueling station cost based on 10% discount rate and 15-year finance life. Taxes based on Federal Excise Tax of \$0.243/LNG gallon and \$0.244/diesel gallon, California Excise Tax of \$0.06/LNG gallon and \$0.18/diesel gallon and 9.75% sales tax in Los Angeles. Delivered fuel price includes \$5/MMBtu feedgas from a 100,000 GPD liquefaction plant that is located 100 miles away.

20 U.S. Department of Energy Clean Cities "Alternative Fuel Price Reports," October 2009 to July 2010.

3 LNG Station Design

3.4 Facility Modification Requirements

LNG infrastructure requires unique modifications that have been well-established by a variety of national codes and standards and implemented by developers.

The temperature and insulation requirements of LNG necessitate modifications to conventional fuel infrastructure. In the U.S., LNG fueling stations are designed and constructed to meet specific national codes and standards:

- Code of Federal Regulations
 - CFR Title 49, Part 193 – LNG Facilities Federal Safety Standards
- Codes and Standards
 - API 620 – Recommended Rules for Welded Low-Pressure Storage ASME Boiler and Pressure Vessel Code, Section VIII, Division 1 CGA 341 – Insulated Cargo tank Specifications for Cryogenic Liquids
- National Fire Protection Agency
 - NFPA 59A – Production, Storage, and Handling of LNG
 - NFPA 30 – Flammable and Combustible Liquids Code
 - NFPA 385 – Tank Vehicles for Flammable and Combustible Liquids
 - NFPA 88A – Parking Structures
 - NFPA 88B – Repair Garages

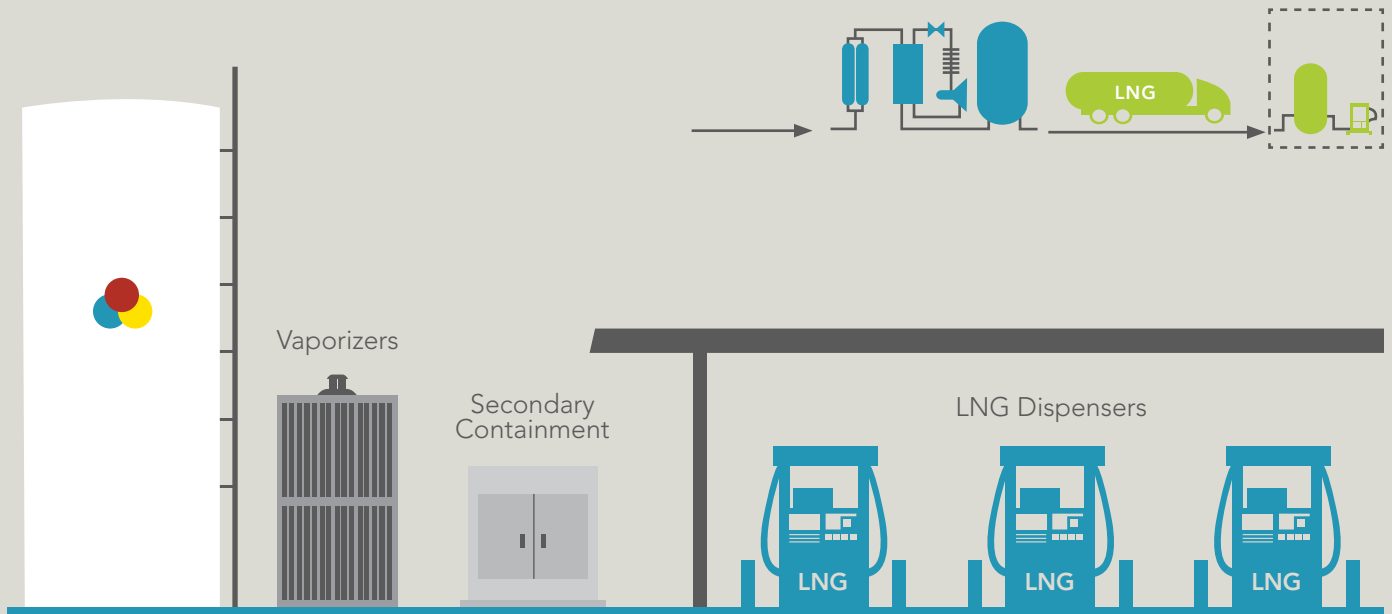
In Canada, the single primary regulatory agency responsible for LNG design and safety is the Canadian Standards Association, which provides codes and standards for all natural gas fueling stations and related equipment.

To ensure safety, secondary containment structures must be built around the areas where the tanks, pumps, and vaporizers are located (Figure 3.4-1). The purpose of these structures is to contain the entire volume of liquid stored at the stations that may leak in case of an incident. However, unlike conventional liquid fuels, if a tank is punctured, LNG will evaporate away instead of pooling on the ground. In working with this cryogenic fuel, handlers must wear a face shield, insulated gloves, apron, and boots. Because of the need to maintain low temperatures, LNG storage and dispensing systems must be insulated. Other unique requirements for LNG fueling stations include:

- Methane detection system
- Fire detection system
- Temperature detection system
- Emergency shut-down device
- Fire suppression system
- Eye wash/splash station

Figure 3.4-1

LNG infrastructure requires several unique modifications to conventional fueling infrastructure as shown here for the County of Sacramento 15,000 gallon LNG storage station.



3 LNG Station Design

3.5 Fuel Safety

LNG poses very different safety issues than conventional liquid fuels including accidental spills.

As a cryogenic liquid, LNG is stored at a much lower temperature than CNG—as low as -260°F. To keep LNG in its cryogenic state, it must be stored in insulated, pressurized tanks. If LNG is released to the atmosphere, it readily evaporates because the boiling point of natural gas is significantly lower than atmospheric conditions. As a result, any spills or leaks from LNG tanks will result in a release of natural gas. To mitigate the risks associated with any leakage and spills, any indoor maintenance areas must be ventilated to avoid the collection of flammable natural gas mixtures. In addition to improved ventilation, any facilities or vehicles equipped with LNG systems typically have methane detectors to warn of tank leakage. These sensors provide an additional layer of safety to those working around or near LNG tanks. The evaporation of exposed LNG also provides some environmental advantages. If an LNG vehicle or station were damaged in a way that punctured fuel tanks, any spilled fuel would ultimately evaporate to the atmosphere. Unlike diesel spills, LNG spills do not contaminate soil or groundwater. LNG fuel offers some protection against the expense of cleaning up an accidental fuel spill and potential site remediation obligations.²¹

A sample Material Safety Data Sheet is presented in Figure 3.5-1 to illustrate “typical” LNG properties.

²¹ Arthur D. Little, Inc. - Acurex Environmental. “Liquefied Natural Gas for Heavy-Duty Transportation.” Prepared for GTI and Brookhaven National Laboratory, May 2001.

Figure 3.5-1

Material Data Safety Sheets offer information on LNG safety.²²

EL PASO ENERGY 1 of 6
MATERIAL SAFETY DATA SHEET OFFERS
LIQUEFIED NATURAL GAS #103

1. CHEMICAL PRODUCT and COMPANY INFORMATION

EL PASO ENERGY
 1001 LOUISIANA
 HOUSTON, TEXAS 73002

NFPA HAZARD RATING
 HEALTH: 1
 FIRE: 4
 REACTIVITY: 0
 OTHER: -

EMERGENCY TELEPHONE: INFOTRAC (800) 535-5053 (24 HOURS)

CHEMICAL FAMILY Complex mixture of conventional fuel hydrocarbon

SYNONYMS Dry Natural Gas, Compressed Natural Gas (CNG),
 Liquefied Natural Gas (LNG) Methane, Processed Gas,
 Sweet Natural Gas, Treated Gas.



**BE SAFE! READ OUR PRODUCT SAFETY
 INFORMATION AND PASS IT ON!
 (PRODUCT LAW REQUIRES IT!)**

2. COMPOSITION and INFORMATION ON INGREDIENTS

Ingredient Name	CAS Number	OSHA PEL	ACGIH TLV	ACGHH (STEL)	Concentration (Percent by Weight)
Methane	74-82-8	N/A*	N/A*	N/A*	85-90
Ethane	74-84-0	N/A*	N/A*	N/A*	4-5
Carbon Dioxide	124-38-9	5000 ppm	5000 ppm	30,000 ppm	1-5

A complex mixture of light gases separated from raw natural gas consisting of aliphatic hydrocarbons: having carbon numbers in the range of C1 through C4 predominately methane (C1) and ethane (C2). May be odorized with trace amounts of odorant (typically well below 0.1% t-butyl mercaptan).

EMERGENCY OVERVIEW DANGER!
**EXTREMELY FLAMMABLE GAS—MAY CAUSE FLASH FIRE OR
 EXPLOSION IN HIGH CONCENTRATIONS**
 High concentrations may exclude oxygen and cause dizziness and suffocation.
 Contact with liquid or cold vapor may cause frostbite or freeze.

22 Material Safety Data Sheet provided courtesy of El Paso Energy of Houston, Texas.

4 LNG Production Options

4.1 LNG Feedgas

The different feed gas options (wellhead, pipeline and biomethane) require varying amounts of upgrading before liquefaction and distribution.

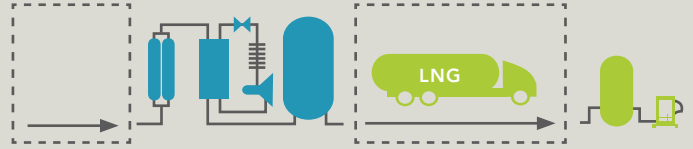
Prior to liquefaction, all feedgas requires some amount of pretreatment to remove carbon dioxide (CO₂), water, significant concentrations of sulfur compounds, very heavy hydrocarbons, and any other contaminants prior to liquefaction. Wellhead gas can contain significant amounts of water, nitrogen and heavier hydrocarbons while pipeline gas, which has had these contaminants removed, contains mercaptans which must be removed before use as a transportation fuel.

Biomethane requires extraordinary conditioning because it contains very high CO₂ (typically in the 40 to 60 percent range) and sometimes other compounds that may have destructive effects on natural gas engines or cause toxic exhaust gases. The cost of natural gas upgrade equipment also does not downscale linearly, and thus, gas upgrade can be very expensive for low throughput plants (e.g., biomethane production plants). Biomethane as a feedgas may not make economic sense by itself, it is viable today because of economic subsidies for the its GHG benefits. Table 4.1-1 is a list of the major feedgases and qualitatively how much clean-up costs compare between them.

The three major feedgases have varying distribution distances to LNG stations. Liquefaction facilities located near the wellhead, and similarly gas separation and nitrogen rejection plants, are located a significant distance from potential LNG consumption locations. Biomethane production facilities are located the closest to populations centers and have the shortest distribution distances and lowest cost, but have the highest upgrading costs. In the middle are liquefaction facilities that pull gas from the pipeline usually close to, but upstream from the citygate. These facilities have distribution costs in between wellhead production locations and biomethane production locations, but have the lowest production cost. Figure 4.1-1 shows the estimated increases in costs based on distribution distance of LNG fuel per gallon.

Table 4.1-1

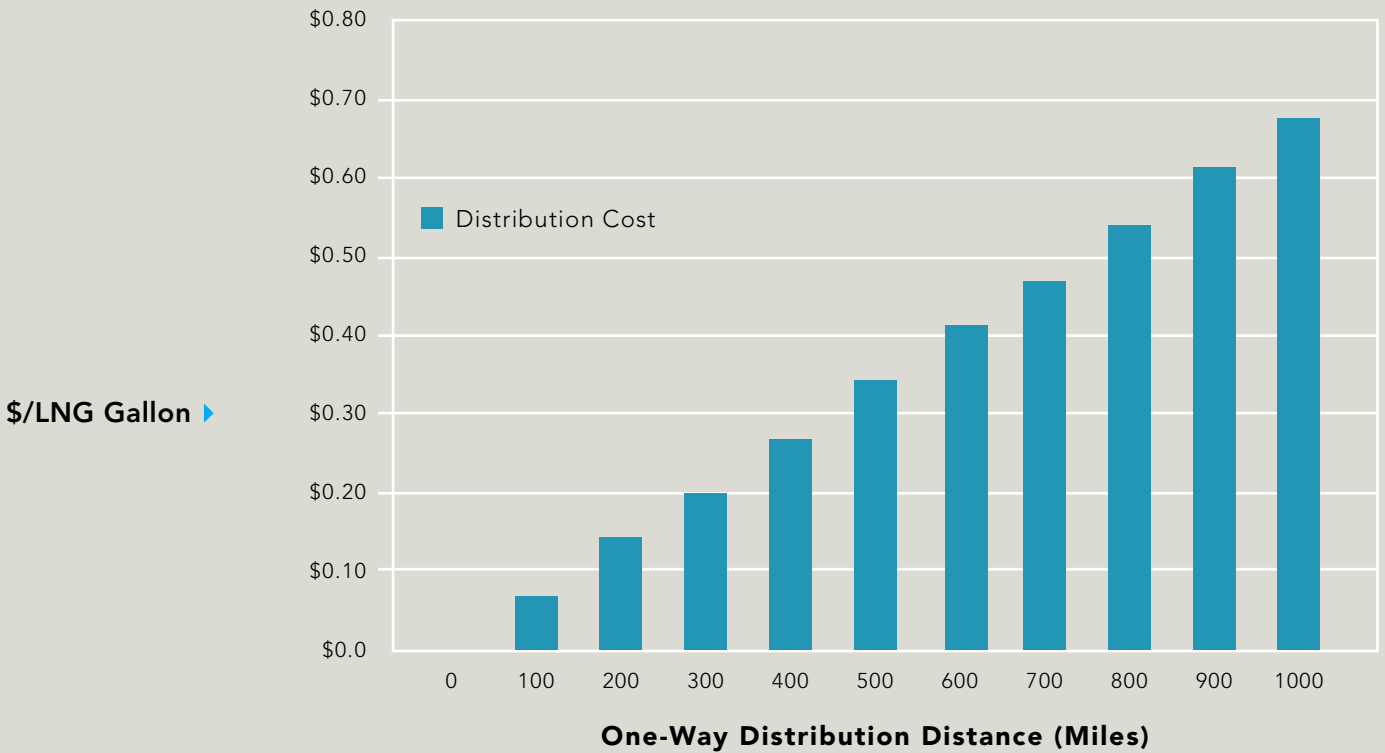
Landfill gas is the most expensive gas to upgrade for LNG use and pipeline gas is the cheapest. Wellhead gas can contain and need removal of water, nitrogen and heavier hydrocarbons.



Feedgas	Cost (\$-\$\$\$\$)
Wellhead Gas	\$\$
Pipeline Gas	\$
Biomethane	\$\$\$\$

Figure 4.1-1

The farther the liquefaction location is from the LNG station, the greater the distribution costs per gallon.



4 LNG Production Options

4.2 Purpose-Built Pipeline Gas Liquefiers and Peakshaving Liquefiers

4.2.1 Overview

The most successful strategy to date has been to build a pipeline-fed liquefier dedicated to LNG vehicle fuel production. Peakshaving plants, which have the same basic infrastructure elements as dedicated liquefiers, have also supplied LNG vehicle fuel.

There are multiple infrastructure pathway options for bringing LNG vehicle fuel to the marketplace. A successful strategy requires prudent selection among these options and will necessitate a time-phased integration of infrastructure pathways to match and accommodate growth in LNG vehicle fuel demand. While each of the options shown previously in Figure 1-1 has been used to some extent, the most successful to date (and the option that has provided the most LNG fuel) has been to locate and construct a natural gas liquefier specifically for producing LNG for use as a vehicle fuel. For this reason, this infrastructure pathway, illustrated in Figure 4.2.1-1, is discussed first and is considered as a baseline for comparison with other pathways discussed in subsequent sections. Peakshaving liquefiers are similar to purpose-built liquefiers with respect to the basic infrastructure elements, but were built for meeting peak winter home heating demand. Therefore only a small percentage of peakshaving liquefier capacity is available for transportation.

The advantage of purpose-built liquefiers is that they can be located in or near areas of high LNG vehicle fuel demand, thereby minimizing the required distribution distances. However, other factors may also influence LNG plant location. For example, it is usually impractical to locate plants in urban areas for reasons associated with land cost, permitting challenges, and not-in-my-backyard attitudes. Niche opportunities to simplify plant requirements and enhance economics also affect the plant location. For example, the 86,000 GPD Applied LNG Technologies (ALT)²³ plant near Topock, Arizona is co-located with an El Paso interstate pipeline compression station, which minimizes land and feedgas distribution costs while still being near demand centers in Phoenix and Los Angeles. Similarly, the Clean Energy liquefier in Boron, California (Figure 4.3.1-2) is co-located with the U.S. Borax plant, which facilitates resource sharing opportunities (e.g., regeneration gas and heavy hydrocarbons are fed to the U.S. Borax power plant for electricity generation that is sent back to the Clean Energy Plant).

Peakshaving plants are operated by natural gas utilities to liquefy and store large quantities of gas for later regasification to meet peak demand requirements. This store would appear to be an ideal (but limited) source of LNG vehicle fuel because the plant investment has already been made. In fact, many peakshaving utilities (e.g., San Diego Gas & Electric, Northwest Gas, NIPSCO, Trussville Utilities, and Baltimore Gas & Electric) have supplied LNG vehicle fuel in the past. There are, however, challenges associated with this pathway. Some utilities are reluctant to draw on their stored LNG reserve for reasons other than their primary purpose. Similarly, utility regulatory agencies are cautious about approving such plans and may require partial reimbursement of ratepayers' original capital investment. Finally, peakshaving plants are not necessarily located near areas of LNG vehicle fuel demand.

23 ALT is now part of Applied Natural Gas Fuels, Inc., previously PNG Ventures.

Figure 4.2.1-1

Purpose-built and peakshaving liquefaction plants have large production capacities, thereby reducing the liquefaction cost per gallon of LNG produced.

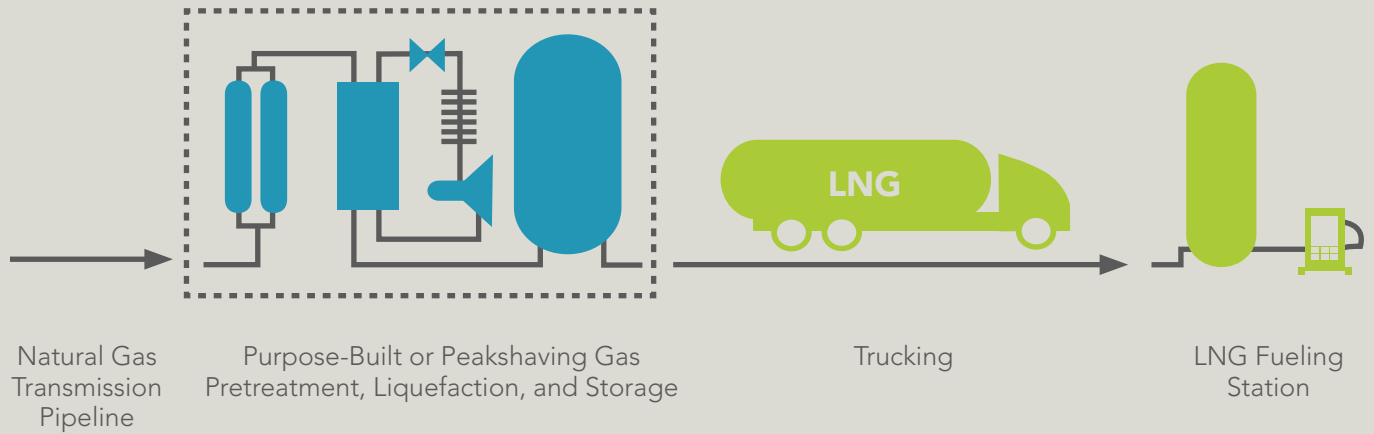
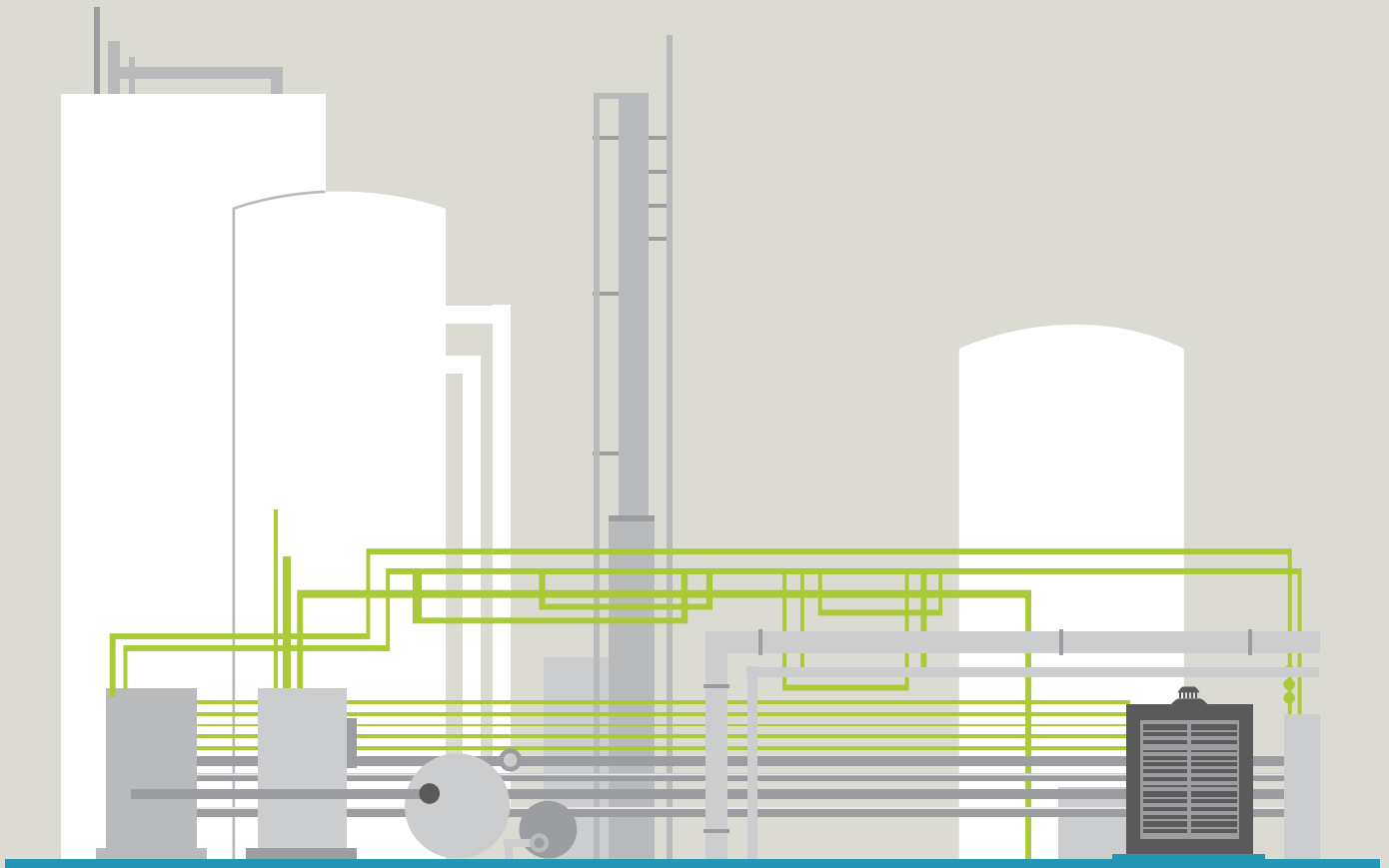


Figure 4.2.1-2

The Applied LNG Technologies (ALT) liquefier in Topock, Arizona is a purpose-built LNG vehicle fuel production plant currently producing over 2,000,000 LNG gallons per month (67,000 LNG gallons per day).²⁴



24 "LNG Production," Applied LNG Technologies, December 7, 2010. <http://altlng.com/lng_pro.asp>

4 LNG Production Options

4.2 Purpose-Built Pipeline Gas Liquefiers and Peakshaving Liquefiers

4.2.2 Economics

The capital costs of purpose built liquefiers range can be compared to large-scale liquefaction plants. LNG costs are more dependent on feedgas costs compared to distribution costs.

The combination of existing pipeline gas peakshaving liquefiers and new purpose-built large liquefaction plants will help begin and sustain a market for LNG vehicle fuel. LNG from current peakshaving units may be distributed to reasonable locations for testing or beginning an LNG transportation market. Once an LNG market has been established, then the capital investments can be made into larger purpose-built liquefaction facilities to sustain and expand the established LNG market.

Purpose-built liquefiers can produce reasonably large quantities of LNG and take advantage of economies of scale. Figure 4.2.2-1 shows that the per-gallon costs for large-scale (over 100,000 GPD) liquefaction are much less than those for smaller scale liquefaction. The 100,000 GPD cost range represents the three currently operating purpose-built LNG vehicle fuel plants: Willis, Texas plant (approximately 100,000 GPD), Topock, Arizona plant (86,000 GPD), and Boron, California plant (80,000 to 160,000 GPD initially, expandable to 240,000 GPD).

Figure 4.2.2-2 shows the basic economics of a purpose-built liquefaction plant in terms of LNG cost per gallon as a function of distribution distance and feedgas price (citygate price). This figure shows that the cost of LNG from a purpose-built liquefaction plant is relatively sensitive to both distribution distance and feedgas price. These LNG costs are used as a basis for comparison with those of other LNG infrastructure alternatives considered in subsequent sections.

Figure 4.3.2-1

Purpose-built liquefaction plants, which have generally ranged from 80,000 to 160,000 GPD, have the relatively large capacities needed to provide economy-of-scale cost benefits.²⁵

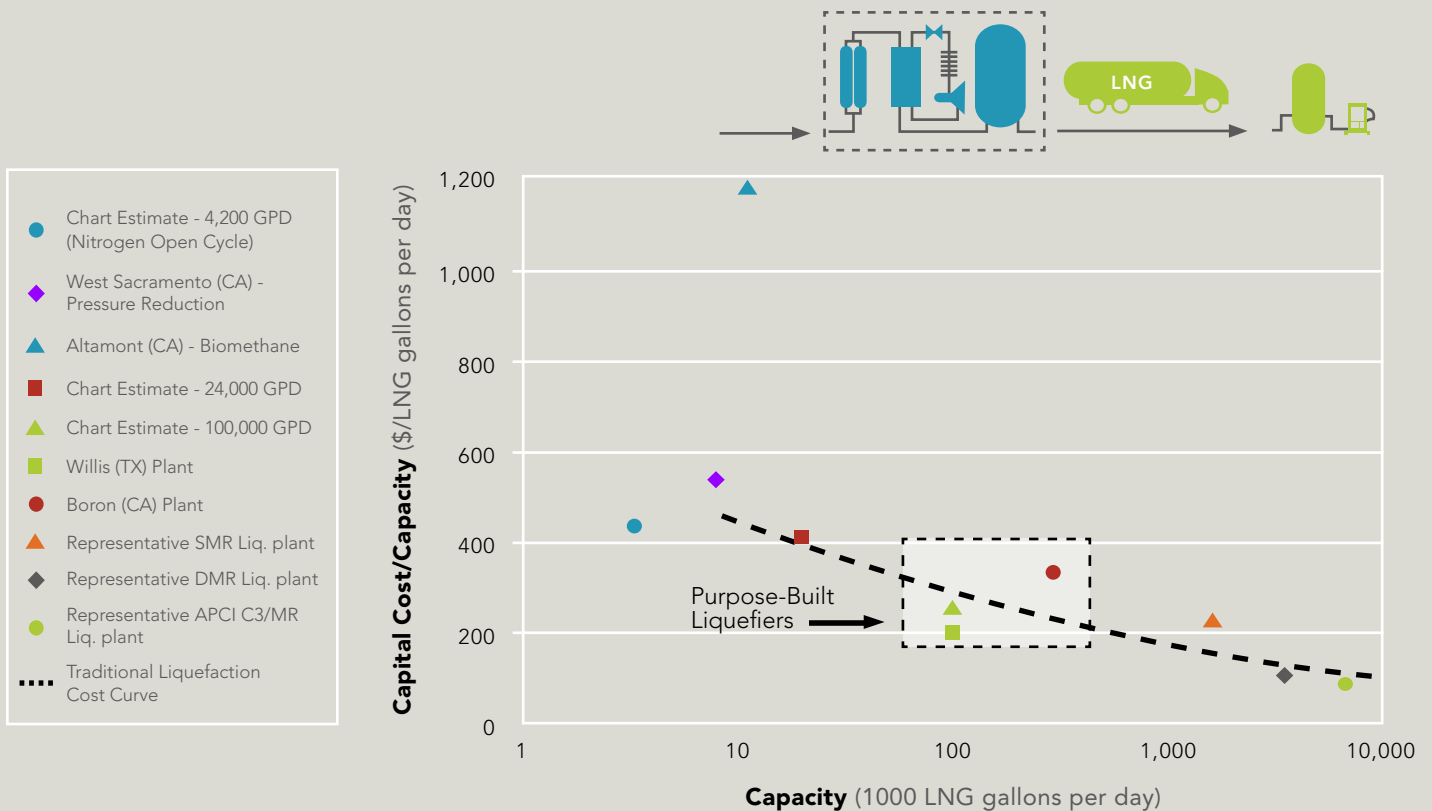


Figure 4.3.2-2

The per-gallon cost of producing and delivering LNG from purpose-built liquefiers is sensitive to the distribution distance and feedgas price.²⁶



25 "World LNG/GTL Review," Zeus Development Corporation, 2001.

26 Assumptions: liquefaction – 100,000 GPD facility - estimated \$32M, amortization period of 20 years, 10% discount rate, estimates for O&M; distribution – \$0.20/gallon LNG, 50,000 miles per year, \$3/gallon diesel, 5.5 miles per gallon tractor fuel economy, full 10,000 gallon LNG load; cost is delivered station cost excluding taxes.

4 LNG Production Options

4.3 Pressure Reduction Liquefiers

4.3.1 Overview

The pressure reduction liquefier is an advanced technology that has special and limited applications but can have substantial impacts on LNG production due to its low operating costs.

The unique pipeline distribution circumstances of high pressure let-down to low pressure gas local utilities distribution lines is an opportunity to utilize an otherwise lost energy source. Installation of turboexpanders at these locations (e.g., the pipeline city gate) can liquefy a fraction of the natural gas with little or no compression power investment.

Utilization of a pressure reduction turboexpander liquefier as part of an LNG vehicle fuel supply chain is illustrated in Figure 4.3.1-1. The primary benefit of a pressure reduction liquefier is the minimization or elimination of compression and compressor drive requirements. This reduces capital costs slightly and O&M costs substantially. Plant emissions are also reduced, and permitting may be more straightforward. Another subtle advantage of using this type of liquefier at a pipeline pressure reduction location is simplified gas pretreatment because, for example, a small CO₂-methane mixture flow can usually be discharged into the downstream low-pressure natural gas pipeline without any environmental or economic consequences.

Pressure reduction turboexpander peakshaving liquefiers have been built in the past. For example, San Diego Gas & Electric built two liquefiers in Chula Vista, California, which were dismantled in the 1980s. More recently, Idaho National Laboratory (INL) developed a turboexpander liquefier technology specifically for LNG vehicle fuel production at pipeline pressure reduction locations. In cooperation with the Pacific Gas & Electric Company (PG&E), a 10,000 GPD liquefier using this technology was demonstrated in West Sacramento, California (Figure 4.3.1-2).

Figure 4.3.1-1

Pressure reduction liquefiers have the key benefit of eliminating compressor capital and operating costs.

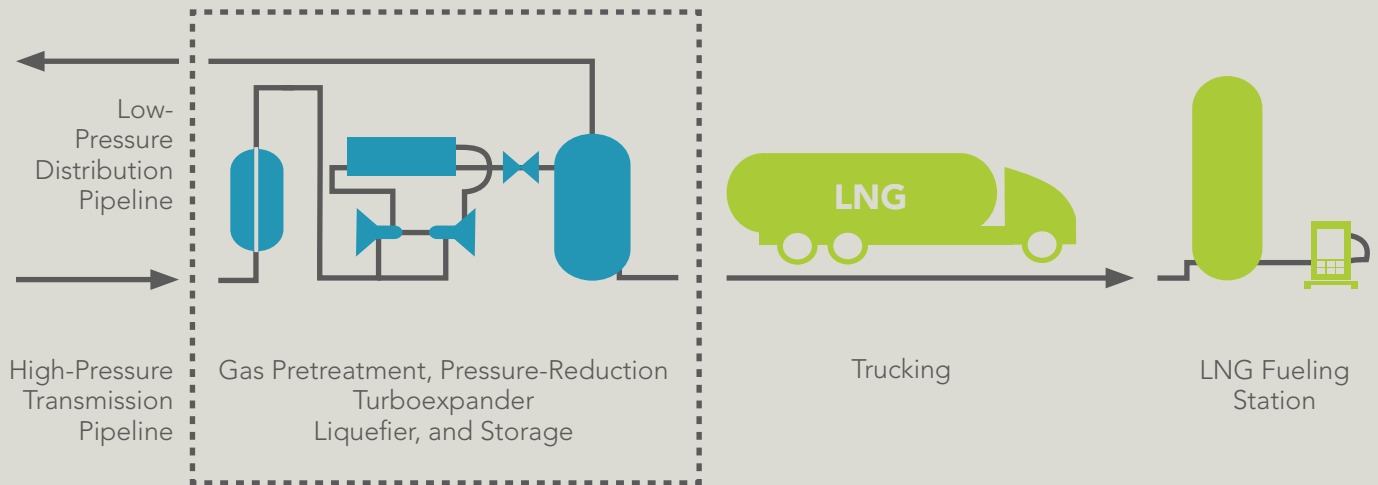
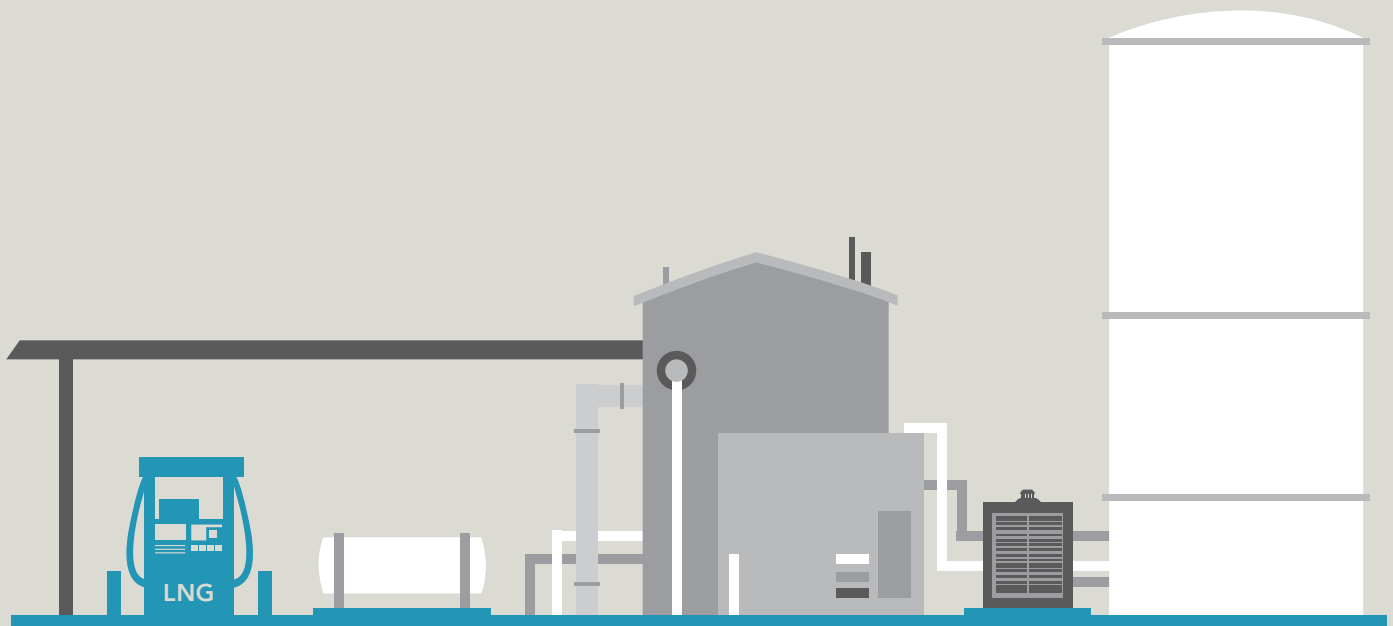


Figure 4.3.1-2

INL and PG&E demonstrated LNG production using this 10,000 GPD pressure reduction liquefier in West Sacramento, California.



4 LNG Production Options

4.3 Pressure Reduction Liquefiers

4.3.2 Economics

The higher capital costs of pressure reduction liquefiers increased the cost of delivered LNG compared to purpose built liquefiers.

The potential locations for pressure reduction liquefaction facilities are fixed, and there is no flexibility for building them close to LNG demand if there is no available pipeline pressure let-down point nearby. This has the potential of increasing distribution costs. Because pipeline pressure let-down stations are usually owned and operated by local distribution companies (LDCs), this LNG option will generally involve subtle issues associated with LDCs' roles as LNG transportation fuel marketers and applicable regulatory agency policies.

The production capacity of this type of liquefier is limited by the gas flow rate and pressure ratio at available pipeline pressure let-down locations. Therefore, although the O&M costs of pressure reduction turboexpander liquefiers are minimal, Figure 4.4.2-1 estimates that since LNG capital cost per gallon increases as capacity decreases, the cost for pressure reduction liquefiers is high. Figure 4.3.2-1 indicates that the budgeted cost for this liquefier is slightly higher than the general cost-capacity correlation. The actual cost of this first installation significantly exceeded this budget, but subsequent similar installations are expected to cost much less once first-time lessons have been learned.

Figure 4.3.2-2 illustrates that the delivered cost per gallon of LNG produced by pressure reduction liquefiers, as a function of distribution distance and feedgas cost, is expected to be similar to, but more than, LNG produced at larger purpose-built liquefiers. However, these estimates are based on the cost of the INL and PG&E prototype liquefier. If subsequent similar units are less expensive, the cost per LNG gallon will be correspondingly less expensive and may possibly be less than that for purpose-built liquefiers.

Because the volume of LNG that can be produced is relatively small, pressure reduction liquefiers can be used to supply the initial demand for LNG as a vehicle fuel and support peak demands in a later, more developed market, but they will not be able sustain large LNG demand. Therefore, even if their costs were as low as projected by INL, the applicability of this infrastructure option will be limited to a developed LNG market.

Figure 4.3.2-1

Pressure reduction turboexpander liquefiers will generally have relatively small production capacities, which increase their per-gallon capital cost.

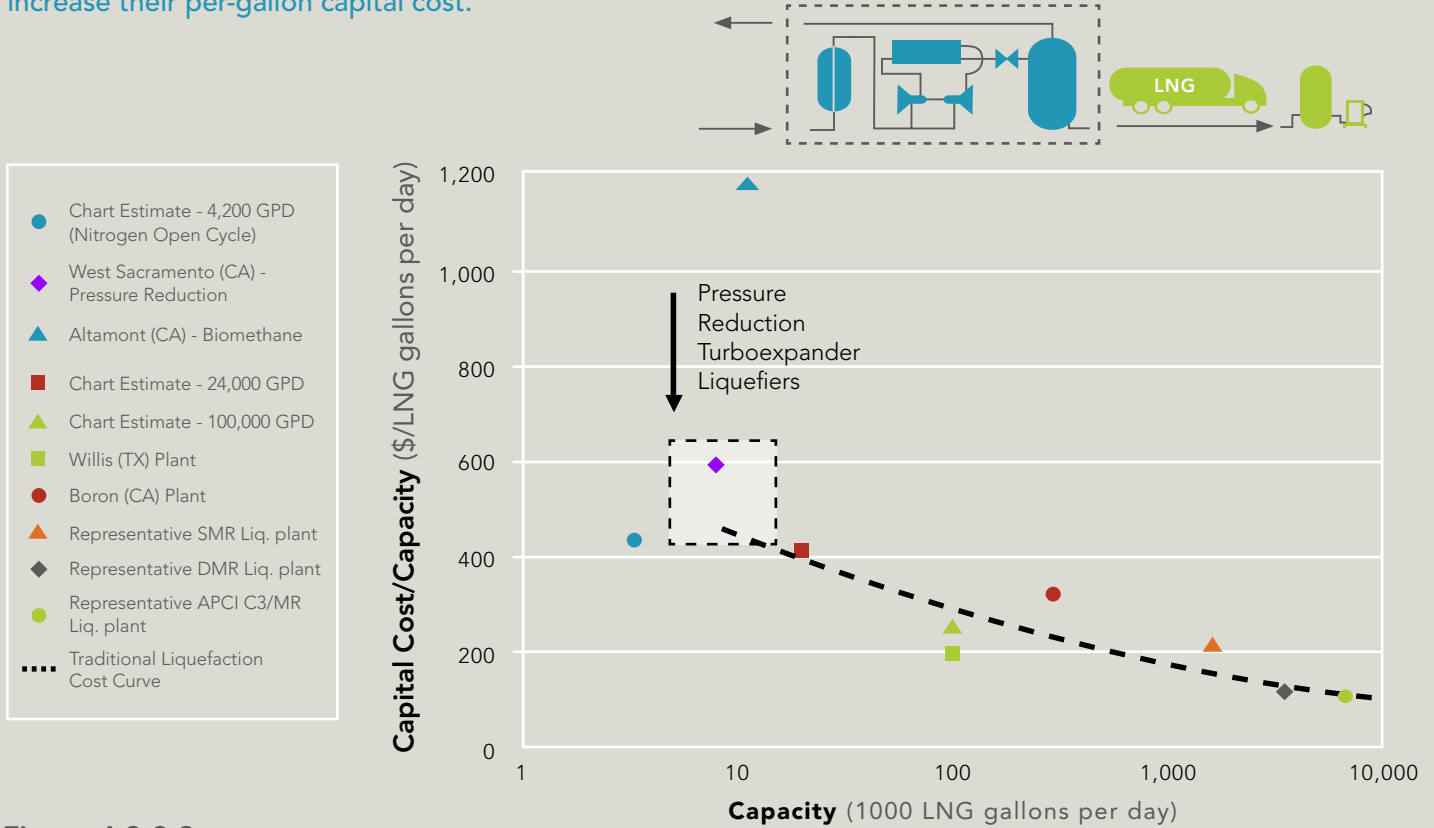
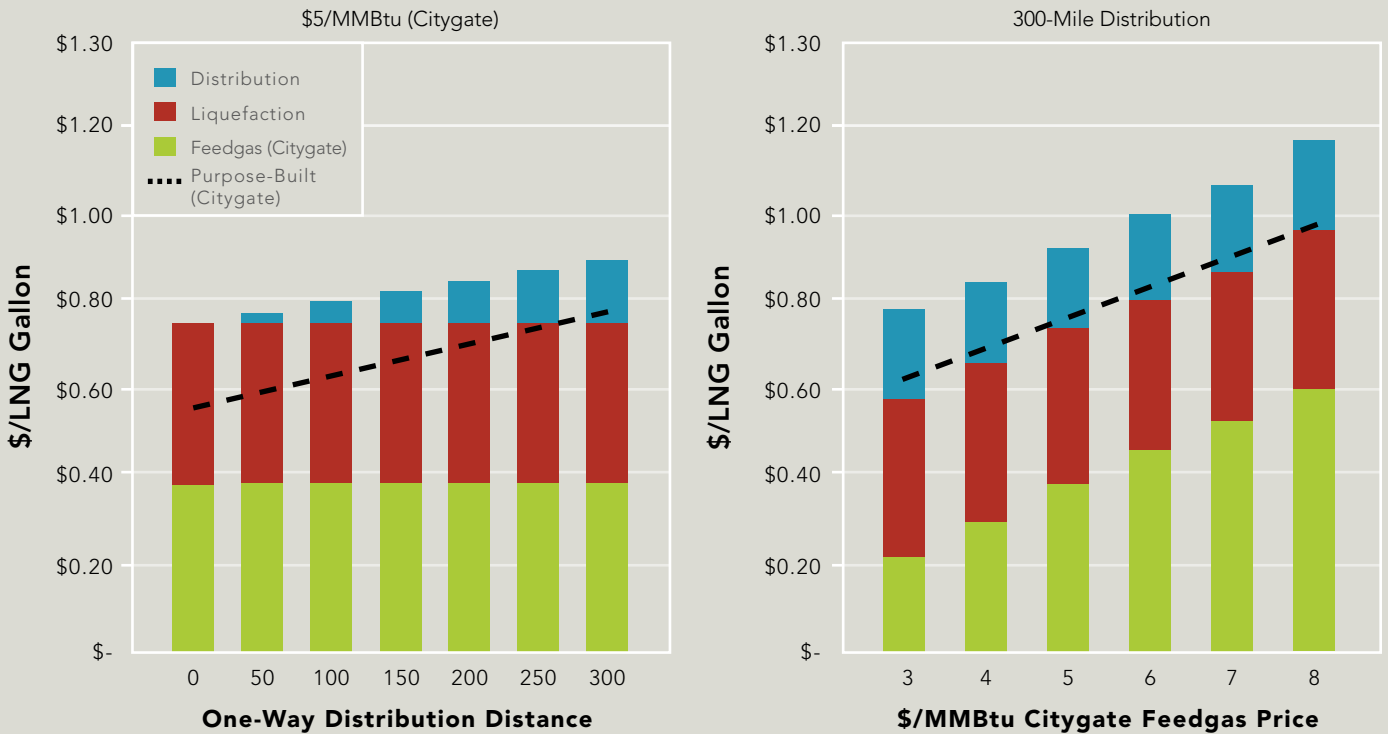


Figure 4.3.2-2

Costs of LNG from pressure reduction liquefiers will be sensitive to distribution distance and feedgas price, and more expensive than purpose-built.²⁷



27 Assumptions: liquefaction - 10,000 GPD facility cost based on data point Figure 3.1-2 (estimated \$5.6M), amortization period of 20 years, 10% discount rate, estimates for O&M; transportation - \$0.20/gallon LNG, 50,000 miles per year, \$3/gallon diesel, 5.5 miles per gallon tractor fuel economy, full 10,000 gallon LNG load; cost is delivered station cost excluding taxes.

4 LNG Production Options

4.4 Nitrogen Rejection Units and Gas Separation Plants

4.4.1 Overview

Nitrogen rejection units (NRUs) and gas separation plants (GSPs) can provide limited quantities of relatively low-cost LNG. They will be helpful in the near term for establishment of LNG transportation fuel demand, and they may assist in the long term with peak demand in an established LNG market.

NRUs reduce the nitrogen content of natural gas produced from wells so that it meets pipeline composition specifications. GSPs, also called natural gas liquids plants or gas stripping facilities, separate ethane, propane, butane, and heavier hydrocarbons from natural gas in order to market these gases and/or increase methane content so that natural gas meets pipeline specifications. NRUs and GSPs usually employ cryogenic separation processes that can be modified to co-produce LNG vehicle fuel, production pathways that have been used in the past. In addition to the relatively minor gas processing equipment modifications needed to co-produce LNG, NRUs and GSPs usually also require installation of LNG storage tanks and tank-truck loading facilities.

Even though NRUs and GSPs ordinarily serve different purposes and employ different processes, they are considered together in this section because their role in the LNG supply chain is analogous. Pathways using NRUs and GSPs are illustrated in Figure 4.4.1-1.

NRUs that have co-produced LNG include:

- Shute Creek, Wyoming plant which can produce 66,000 GPD of over 97% methane LNG
- Painter, Wyoming plant which can produce 35,000 GPD of over 98% methane LNG
- Santana, Kansas plant which can produce 10,000 GPD of over 97% methane LNG

One GSP is known to have been modified to co-produce LNG vehicle fuel: the Williams Field Services “Ignacio” plant near Durango, Colorado can produce 26,000 GPD of over 98% methane LNG (Figure 4.4.1-2). This plant employs a proprietary design for LNG co-production, which Williams claims can be applied to at least 135 other U.S. GSPs.²⁸ The technology to produce LNG from NGL is a mature technology that has not changed since it was first introduced in the mid 1990’s.

28 Houshman, M. “Producing High-Quality LNG from NGL Plants.” Presented at Zeus Development LNG-Powered Heavy-Duty Transportation Conference, Los Angeles. January 1996.

Figure 4.4.1-1

NRUs (top) and GSPs (bottom) can be modified to co-produce low-cost LNG, but most of these plants are not located near LNG vehicle fleets.

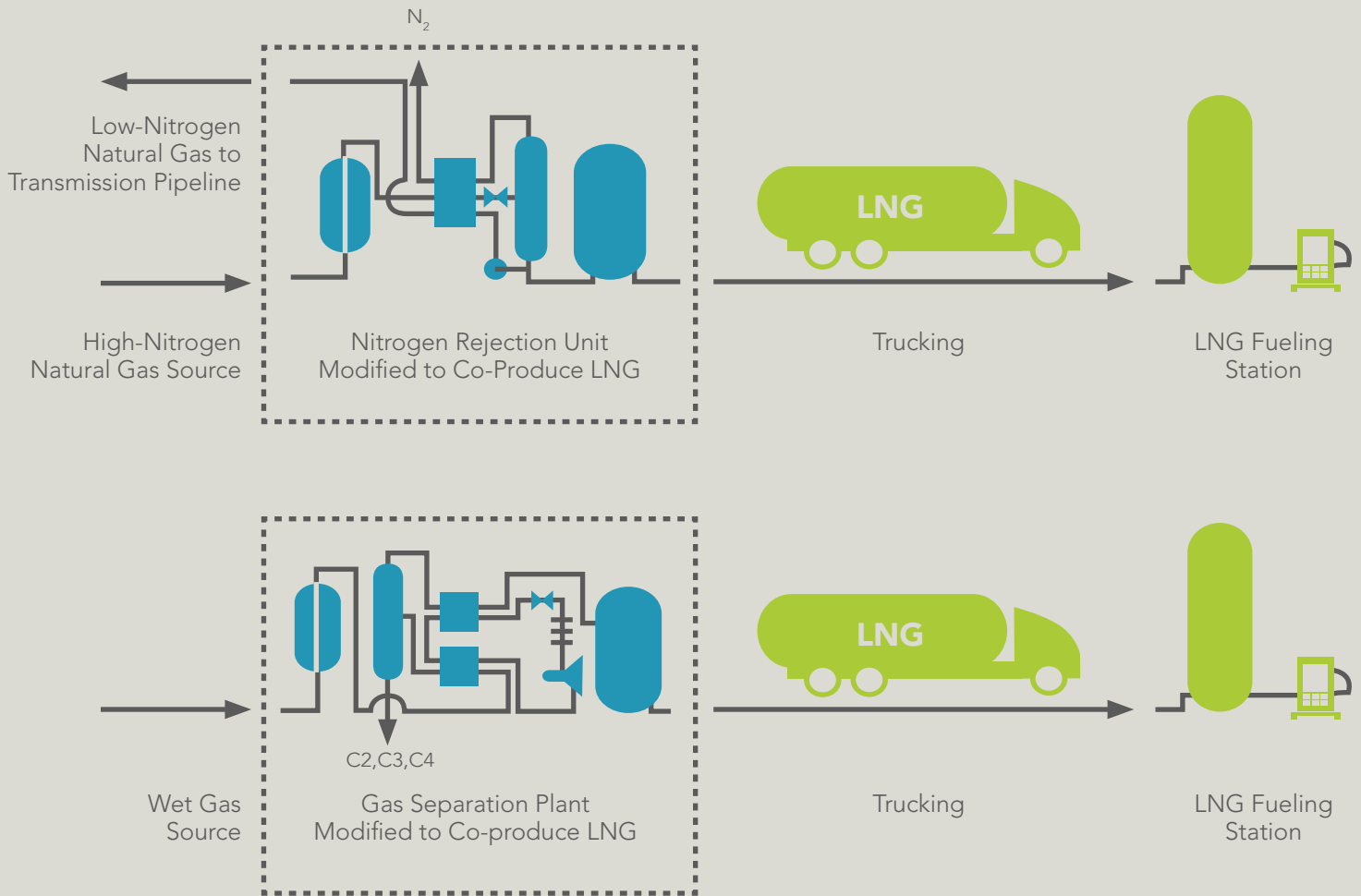


Figure 4.4.1-2

The Williams Field Services modifications for LNG production may enable at least 135 other GSPs in the U.S. to co-produce LNG for transportation.²⁹

LNG Plant Specifications
50,000 gallon storage capacity
26,000 GPD production capacity, expandable to 50,000 GPD
250 GPM loading capacity
Card-lock operation
Truck scales
Automatic truck cooling

²⁹ Houshman, M. "Producing High-Quality LNG from NGL Plants." Presented at Zeus Development LNG-Powered Heavy-Duty Transportation Conference, Los Angeles. January 1996.

4 LNG Production Options

4.4 Nitrogen Rejection Units and Gas Separation Plants

4.4.2 Economics

NRUs and GSPs can provide low cost LNG to the transportation market. Supplies however are constrained and plants are located far from current transportation markets which increases LNG costs.

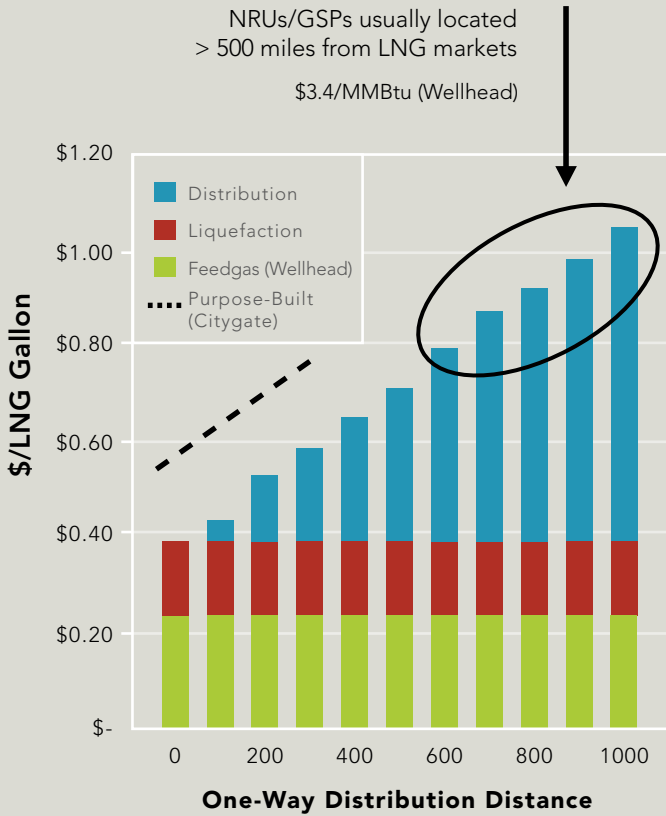
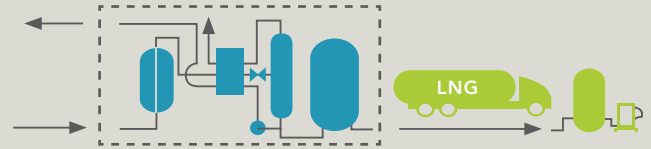
LNG from the ExxonMobil, BP, Pioneer and Williams plants in Colorado, Wyoming, and Kansas has been delivered to LNG fueling stations in locations as distant as Los Angeles, California. However, with three purpose-built LNG plants currently operating in the U.S., LNG vehicle fuel is obtained only occasionally from these sources. While LNG can be co-produced very economically at NRUs and GSPs (because feedgas is relatively inexpensive and most of the equipment expense can be considered a “sunk cost”), these sources have two major drawbacks. First, they are not located near areas where LNG is currently in high demand, so distribution distances and associated costs are substantial. Second, the quantities of LNG that can be economically co-produced are limited because the plants were originally designed with mass and energy balances optimized for other purposes.

However, NRU and GSP pathways can continue to contribute to initiating and sustaining an LNG vehicle fuel market. These facilities can be used to meet nascent LNG demand in the near term and to provide peakshaving for spikes in LNG demand in the longer term.

As mentioned above, the sunk capital cost of NRUs and GSPs allows for a lower cost of LNG production. Figure 4.5.2-1 shows that these facilities have lower costs than purpose-built LNG plants when the same distribution distance is assumed. This is primarily due to the minimal amortized capital cost in the LNG cost and lower feedgas price resulting from shorter or no pipeline transport and lower quality gas. Unfortunately, compared to purpose-built plants, NRUs and GSPs are located much farther from current LNG vehicle fleets (e.g., roughly 800 miles driving distance from Wyoming plants to Los Angeles ports). Figure 4.5.2-1 also shows that costs for NRUs or GSPs at a 500-mile distance from fueling stations are comparable to those for purpose-built LNG plants at only a 100-mile distribution distance. This figure also shows that distribution distance is a significant cost driver for NRUs and GSPs.

Figure 4.4.2-1

The per-gallon cost of producing LNG from NRU/GSP liquefiers is heavily dependent on distribution distance as NRUs/GSPs are usually located greater than 500 miles from their transportation market.^{30,31}



30 Thirty-three percent price difference for onsite feedgas price based on U.S. EIA reported ratio of natural gas citygate prices to wellhead prices. http://www.eia.gov/dnav/ng/ng_pri_sum_dcu_nus_m.htm.

31 Assumptions: feedgas - based on 33% decrease in price compared to purpose-built facility; liquefaction - 100,000 GPD facility cost based on \$180 per GPD capacity to construct truck loading facilities at NRUs and GSPs, amortization period of 20 years, 10% discount rate, estimates for O&M; transportation - \$0.34/gallon LNG - 500 miles; based on assumptions from GRI report for tractor and trailer cost, 50,000 miles per year, \$3/gallon diesel fuel, 5.5 miles per gallon for the tractor, and a full 10,000 LNG gallon load.

4 LNG Production Options

4.5 Biomethane to LNG

4.5.1 Overview

LNG from biomethane offers the lowest carbon intensity pathway. An LNG portfolio combining pipeline natural gas and biomethane LNG may be a prudent strategy for reducing greenhouse gas (GHG) emissions while providing adequate quantities of competitively priced LNG.

LNG produced from biomethane, including landfill gas (LFG) and digester gas, has the greatest potential for significant full fuel cycle GHG emission reductions compared to almost all other conventional and alternative fuels. In addition to providing GHG benefits (discussed in greater detail in section 5), there is very high public interest in this pathway (e.g., refuse trucks fueled by the refuse they collect), and substantial government funding is available for biomethane projects. For these reasons, biomethane-sourced LNG should be considered as part of an LNG transportation fuel portfolio strategy.

The basic biomethane-to-LNG pathway is illustrated in Figure 4.5.1-1. The primary sources for biomethane are LFG and digester gas (e.g., from wastewater treatment and livestock manure processing plants). Many high flowrate biomethane sources, such as large landfills, are already being used for other purposes, including electric power generation. All biomethane sources have high concentrations of CO₂ (for example, LFG is typically 50 percent CO₂), water, sulfur compounds, and inert gases. They sometimes also contain trace amounts of highly problematic components, such as siloxanes, halogenated compounds, and toxics. These issues combine to create the two biggest challenges for biomethane-to-LNG: plants must be small (i.e., on the order of 10,000 GPD LNG) to match available biomethane sources, and the required gas pretreatment systems are expensive. Although the pretreatment and liquefaction equipment is significantly more expensive than that for pipeline gas liquefaction plants, the feedgas cost is much less expensive, or even zero.³² In addition, legislation like the Low Carbon Fuel Standard³³ in California can put a monetary value on the significant GHG reductions offered by biomethane, thereby increasing the economic viability of this LNG production pathway.

The Altamont plant (Figure 4.5.1-2), built by a Linde and Waste Management joint venture at the Altamont landfill east of the San Francisco Bay Area, is perhaps the most successful LFG-to-LNG project to date. While the \$15.5 million cost of this 13,000 GPD project is relatively expensive on a cost per capacity basis, \$2 million of funding was provided by government agencies. Furthermore, it can be expected that subsequent similar LFG-to-LNG plants will cost significantly less than this first plant.

³² Some analyses even consider the feedgas cost to be negative, corresponding to a landfill “tipping fee.”

³³ California Governor Executive Order S-01-07, signed January 18, 2007.

Figure 4.5.1-1

LNG from biomethane has very low feedgas cost but high upgrade and liquefaction costs.

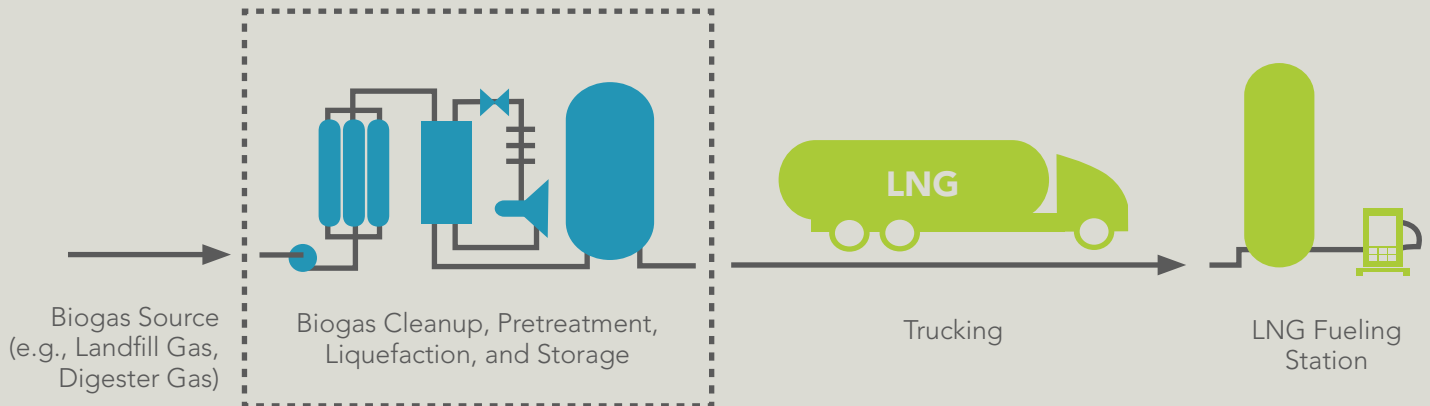
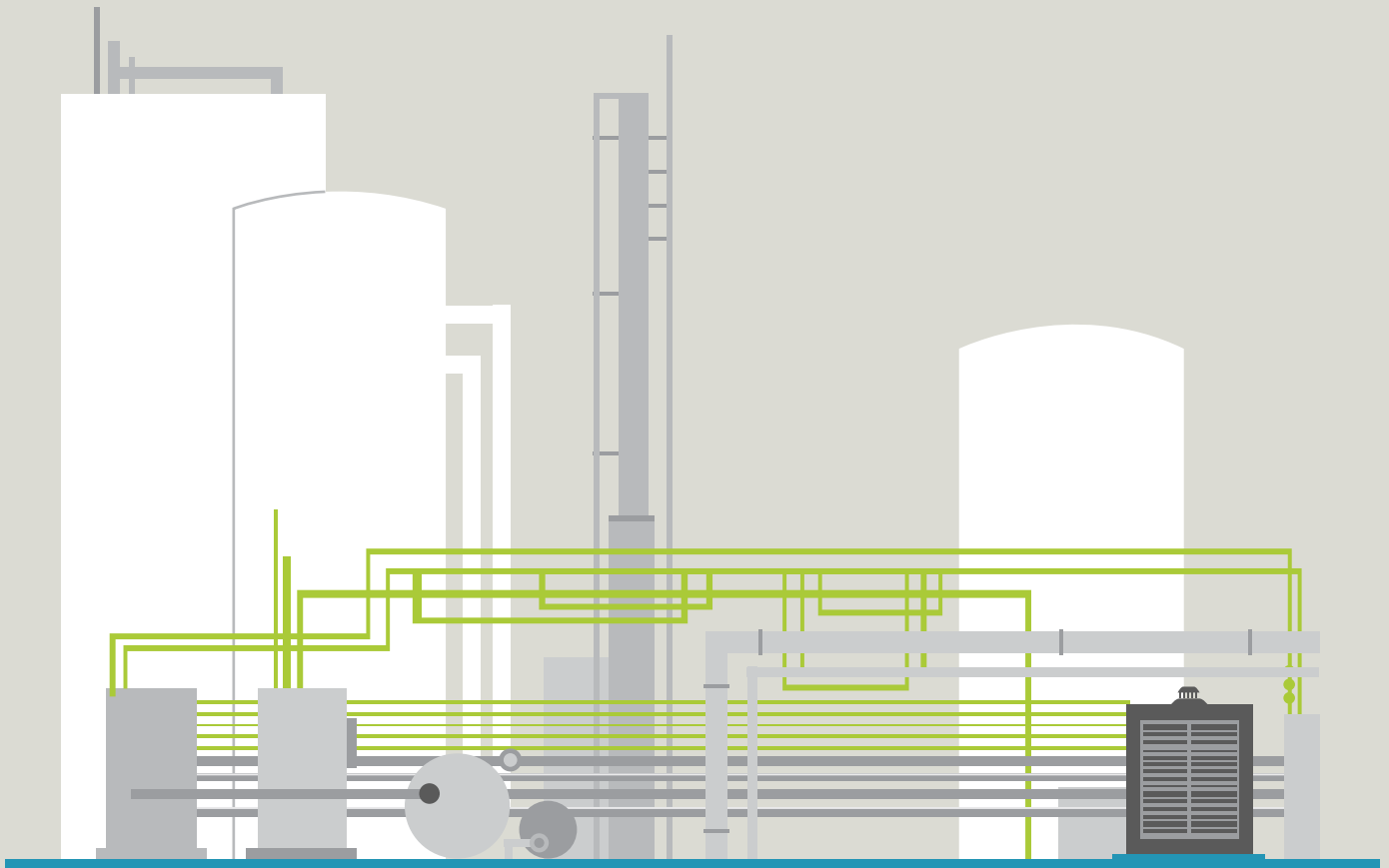


Figure 4.5.1-2

The Waste Management-Linde joint venture at the Altamont Landfill near Livermore, California is the most successful U.S. landfill biomethane-to-LNG plant project of this type to date, producing up to 13,000 gallons of LNG per day.³⁴



34 "Linde and Waste Management Commission World's Largest Landfill to Liquefied Natural Gas Facility." November 2, 2009. http://www.wm.com/about/press-room/pr2009/20091102_Linde_and_WM_Commission_Worlds_Largest_Landfill_to_Liquefied_Natural_Gas_Facility.pdf. Accessed November 29, 2010.

4 LNG Production Options

4.5 Biomethane to LNG

4.5.2 Economics

Waste fuels to LNG can be competitive with conventional LNG pathways when the conventional feedgas costs are high and distribution distances are small.

Figure 4.5.2-1 shows the capital cost of the Altamont LFG-to-LNG plant compared to the general cost per gallon vs. capacity correlation curve. The high cost of biomethane to LNG liquefaction can be attributed primarily to the high cost of required upgrade equipment. Biomethane to LNG is an economically challenged option as it requires significant upgrading of feedgas, but is viable due to subsidies for GHG benefits.

In most cases, transfer trucks but not refuse collection trucks go to landfills. Therefore, location of LNG fueling facilities at landfills to target LNG use in refuse trucks may not be an optimal strategy. Figure 4.5.2-2 shows that with assumed zero feedgas cost, LNG from biomethane is slightly more expensive than purpose-built liquefaction LNG if distribution distances are equal. The zero waste gas feedgas cost is not always valid as it depends on the relationship between the entity that owns and operated the landfill and the entity that will produce and consume or sell the LNG. Figure 4.5.2-2 also shows that with a 50-mile distribution distance, LNG from biomethane can compete with LNG from the baseline purpose-built plant.

Figure 4.5.2-1

The high capital cost of the Altamont landfill biomethane-to-LNG plant is primarily due to the gas upgrade system cost and the fact that this was one of the first projects of this type.

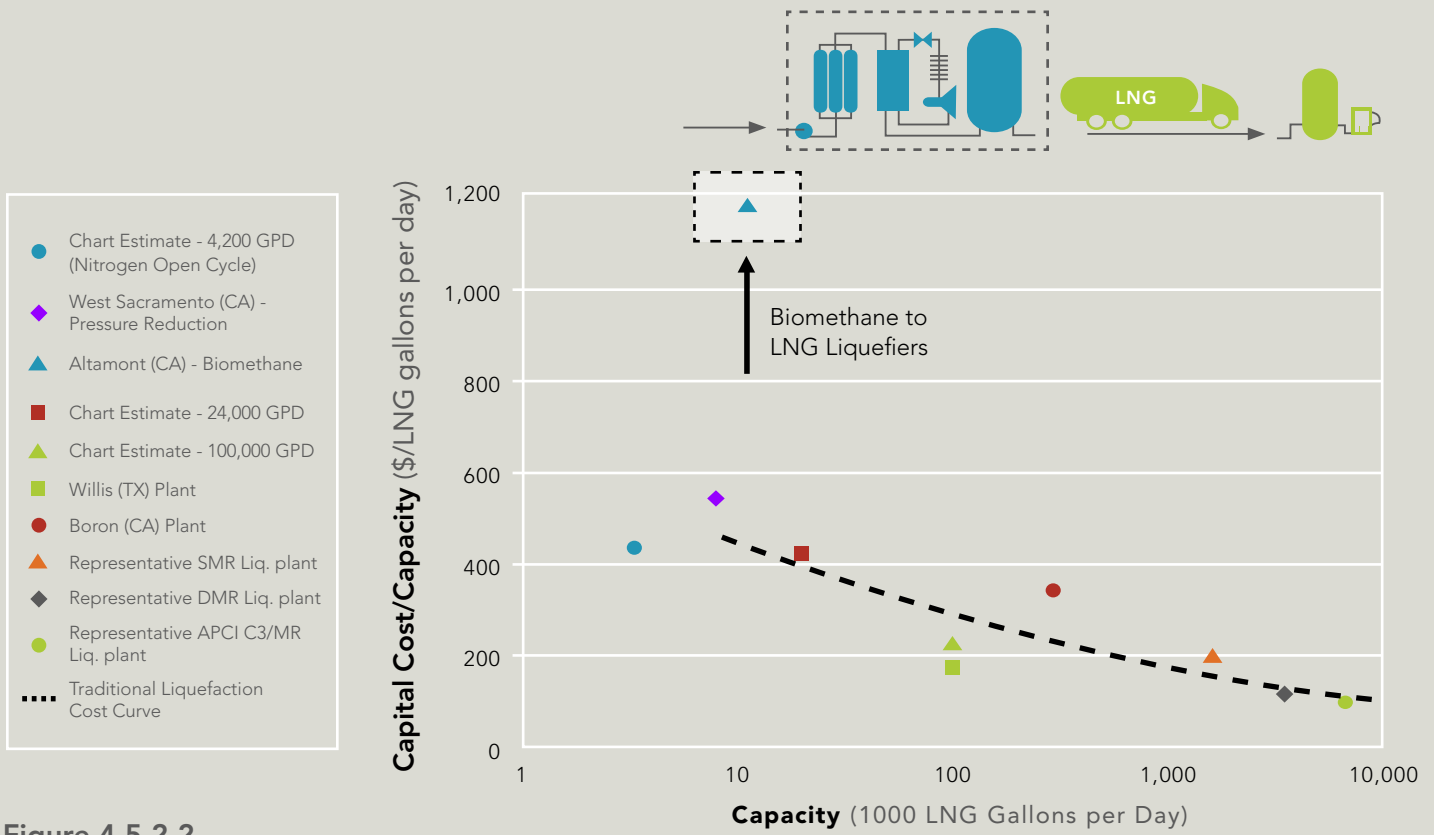
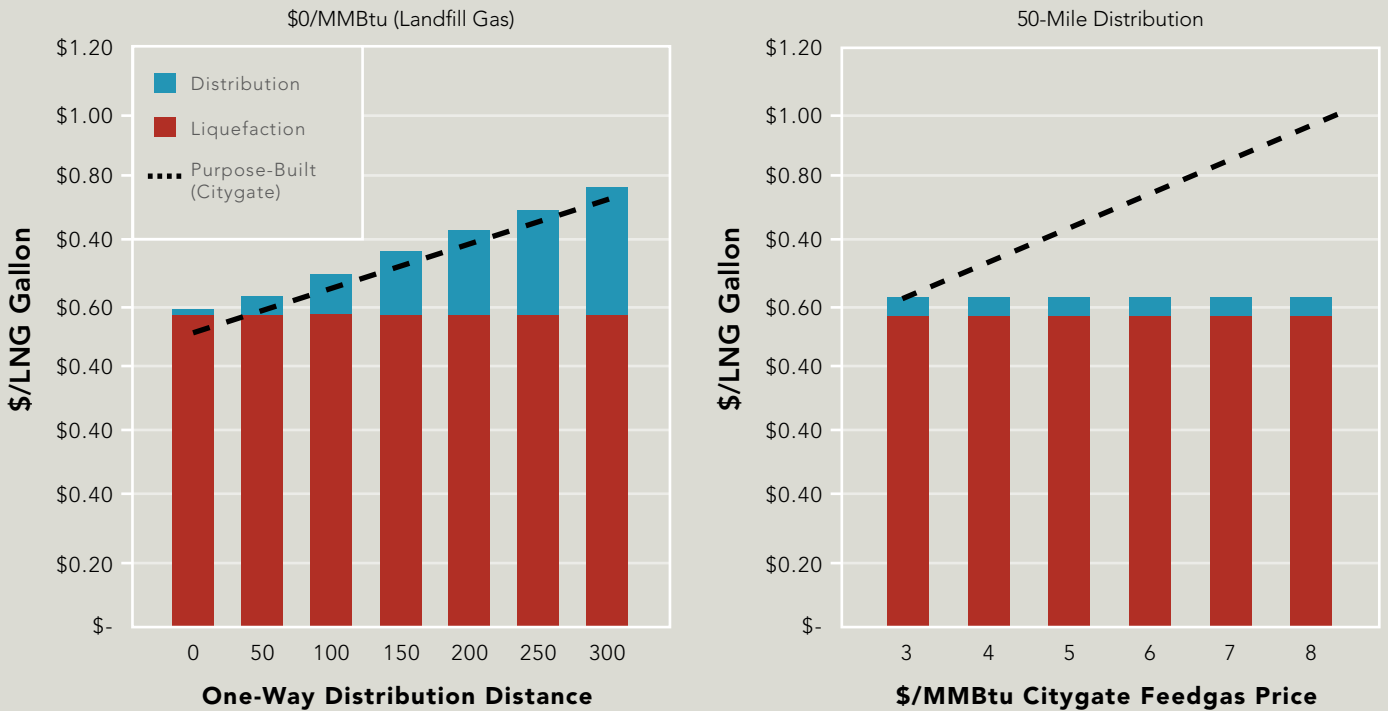


Figure 4.5.2-2

For the same distribution distance, LNG from biomethane is slightly more expensive than LNG from purpose-built liquefiers.³⁵



35 Assumptions: feedgas - \$0/MMBtu for biomethane; liquefaction - 13,000 GPD facility cost based on Altamont data in Figure 3.1-2 (estimated \$15.5M), amortization period of 20 years, 10% discount rate, estimates for O&M; transportation - \$0.0337/gallon LNG, 50,000 miles per year, \$3/gallon diesel, 5.5 miles per gallon tractor fuel economy, full 10,000 gallon LNG load; 50 mile transport distance is used because landfills and other biomethane sources are in close proximity to population centers.

4 LNG Production Options

4.6 Onsite Small-Scale Liquefiers

4.6.1 Overview

Onsite small-scale liquefaction has the benefit of eliminating distribution cost by co-locating liquefaction with refueling. If supplied by LDC pipeline gas, this LNG pathway is analogous to the most common existing CNG vehicle fuel infrastructure.

In this pathway, a small-scale liquefier is co-located with an LNG fueling station as illustrated in Figure 4.6.1-1. The feedgas may come from an LDC or other source and is not limited by supplier. The pathway eliminates the need for distribution from the liquefaction facility to the fueling station, and this infrastructure model resembles that of CNG. The small-scale liquefier can be built to meet local demand and does not require a large, sustained demand to stay in operation. However, there is a subtle tradeoff involving the optimum liquefier throughput and on/off schedule vs. LNG storage tank capacity required to support a given station utilization profile (analogous to the CNG station compressor vs. cascade size tradeoff). Another advantage of this pathway is that it eliminates the need for one of the two LNG storage tanks needed by most other LNG infrastructure options.

A 1,000 GPD prototype of a small-scale liquefier is shown in Figure 4.6.1-2. The main drawback of the onsite small-scale liquefaction option is the relatively high cost of small gas upgrade systems as discussed in section 2. This cost is exacerbated by the fact that LDC-distributed pipeline gas is odorized, and the sulfur-containing mercaptan odorants must be removed prior to liquefaction.

Another challenge is the station capacity flexibility. While liquefier size will initially match demand, the small-scale liquefier will not be able to match any increases in demand, and additional capacity will need to be built or distributed to the fueling station. There are no LNG stations with onsite liquefiers currently operating in the U.S., but such stations have operated in Canada and Australia.³⁶ With available capacity from currently built purpose-built, GSPs and NRUs, there is no demand for onsite liquefiers. These liquefiers have additional operating costs including liquid nitrogen for those units employing external nitrogen loops for liquefaction.

36 Powars, C., C. Moyer, D. Lowell. "LNG Vehicle Technology, Economics, and Safety Assessment." GRI-94/0051. February 1994.

Figure 4.6.1-1

Onsite small-scale liquefaction eliminates the distribution stage, and thus associated costs, from the LNG infrastructure pathway.

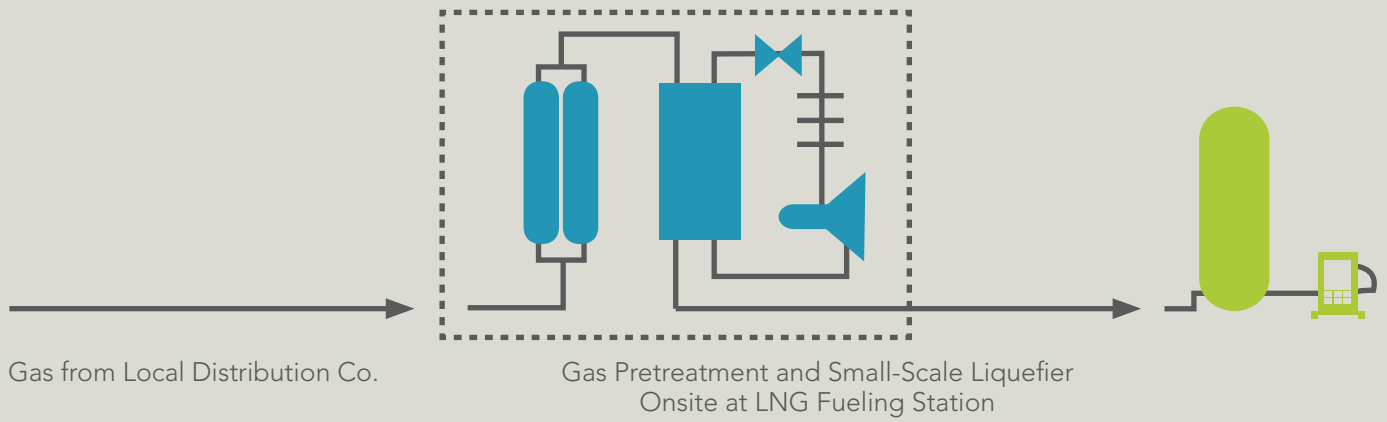
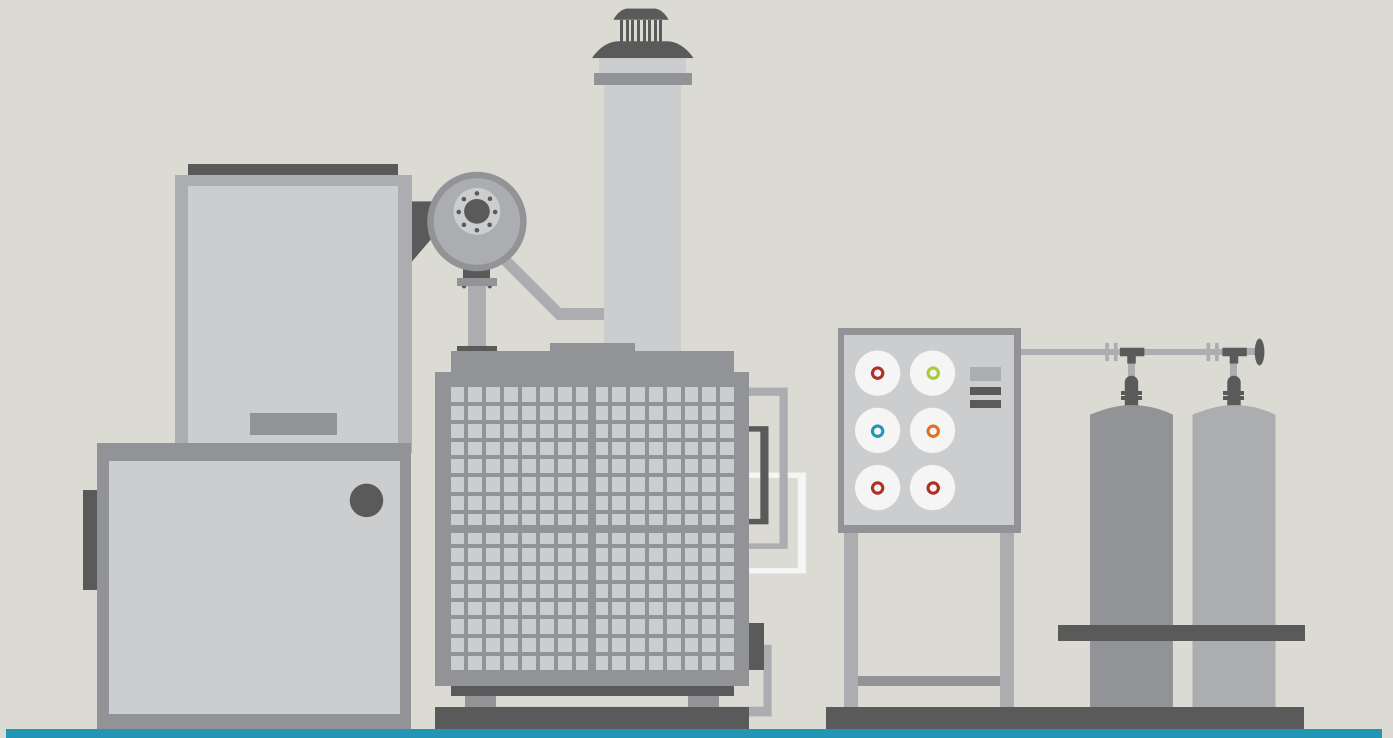


Figure 4.6.1-2

Low-cost small-scale liquefaction technology has been proven by GTI's 1,000 GPD prototype.



4 LNG Production Options

4.6 Onsite Small-Scale Liquefiers

4.6.2 Economics

Onsite liquefaction eliminates distribution cost but small scale increases LNG costs.

The capital cost of small-scale liquefiers is less than that of purpose-built liquefaction facilities that accommodate much larger LNG demand, but they have a higher cost per LNG gallon as shown in Figure 4.6.2-1. However, there have been recent small-scale liquefier technology advances, which were motivated by applications ranging from LNG transportation fuel production to LNG cargo ship boil-off gas re-liquefaction. One example is the GTI-developed small-scale liquefier, which utilizes a MRC cycle (described previously in Figure 4.1-1) and a low-cost commercially produced HVAC screw compressor.³⁷

In onsite small-scale liquefaction, because there is no distribution cost, feedgas price is the most important cost driver. Figure 4.6.2-2 shows delivered LNG price before taxes and excluding fueling station costs and the dependence of small-scale liquefaction LNG cost on feedgas price. Another consideration in overall LNG cost is that onsite liquefaction shares the LNG storage cost with the fueling station, therefore reducing the overall capital and per-gallon LNG cost. There are additional operating costs, especially if liquid nitrogen is necessary for an external nitrogen liquefaction loop.

³⁷ Kountz, K., et al. "Development of a Small-Scale Natural Gas Liquefier." GTI-03/0101. April 2003.

Figure 4.6.2-1

The relatively low liquefier capacity generally designed for onsite liquefaction translates to increased capital costs per LNG gallon.

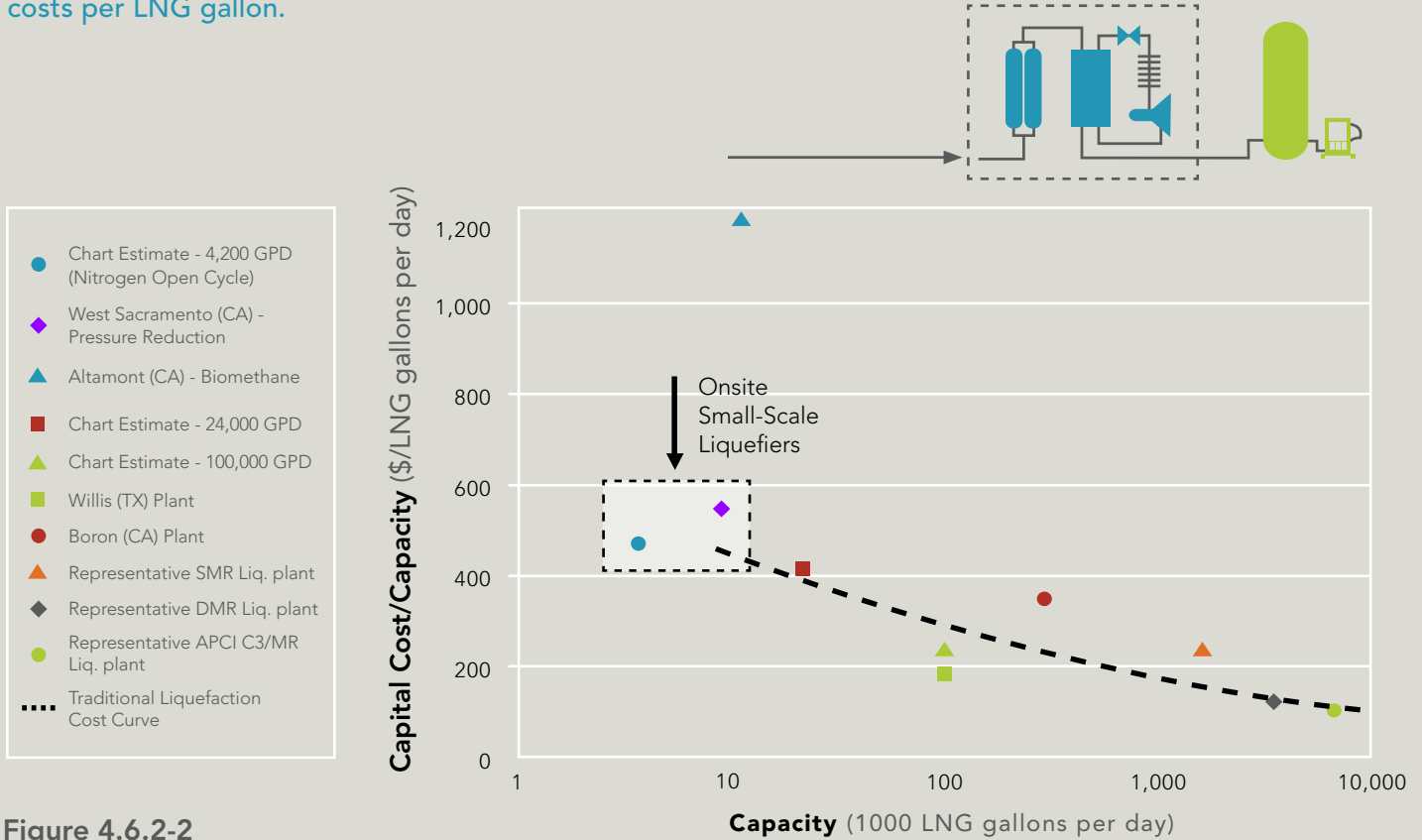
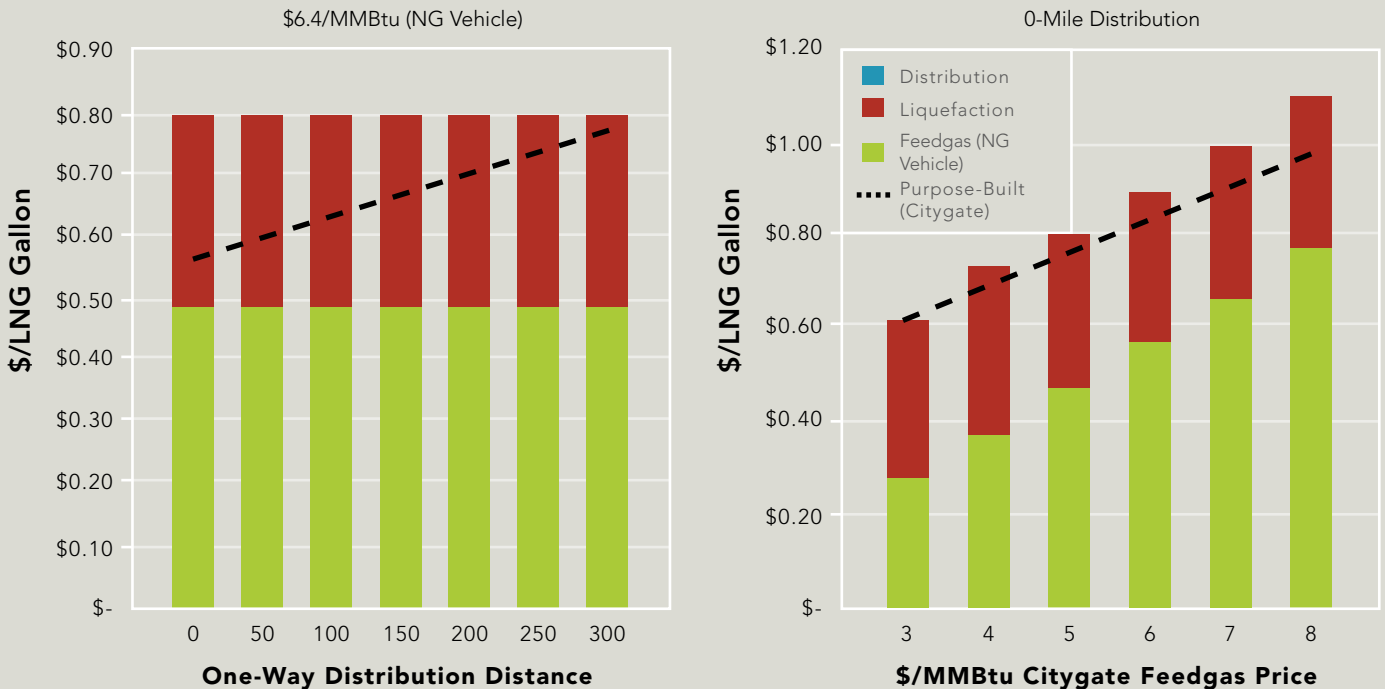


Figure 4.6.2-2

The per-gallon cost of producing LNG from onsite small-scale liquefiers is independent of distribution distance and sensitive to feedgas price.^{38,39}



38 Twenty-eight percent price difference for onsite feedgas price based on U.S. EIA reported ratio of natural gas vehicle fuel prices to citygate prices. http://www.eia.gov/dnav/ng/ng_pri_sum_dcu_nus_a.htm.

39 Assumptions: feedgas - based on 28% increase in price compared to purpose-built facility; liquefaction - 10,000 GPD facility cost based on Figure 1.3.1-2 (estimated \$4.8M), amortization period of 20 years, 10% discount rate, estimates for O&M; transportation - \$0.0337/gallon LNG, 50,000 miles per year, \$3/gallon diesel, 5.5 miles per gallon tractor fuel economy, full 10,000 gallon LNG load.

4 LNG Production Options

4.7 LNG Import Terminals

4.7.1 Overview

While LNG transportation fuel has been sourced from import terminals in the past and there are plans to do so in the future, this LNG vehicle fuel supply option faces many practical challenges.

LNG import terminals receive and store LNG that has been produced overseas at very large-capacity liquefaction plants. Almost all of the LNG stored at import terminals is vaporized and supplied to natural gas transmission pipelines. Occasionally, in the past, import terminals in North America have supplied LNG to be used as a vehicle fuel. Examples include the LNG import terminals in Lake Charles, Louisiana and Everett, Massachusetts. More recently, Southeast LNG Distribution Company (an AGL Resources-El Paso joint venture) announced plans to source LNG from the Elba Island, Georgia terminal for distribution to LNG fleets in the Southeastern U.S.

The LNG from import terminals pathway illustrated in Figure 4.7.1-1 has the potential of providing relatively economical LNG produced from low-cost feedgas in relatively low-cost overseas plants. However, this LNG vehicle fuel supply option faces several challenges:

- LNG import terminals are located on or near the coast, and they are usually not near urban demand centers. Therefore, long and impractical distribution distances would be required for many LNG vehicle fleets.
- It is impractical to supply LNG vehicle fuel from offshore import terminals such as Exceletrate Energy's Gulf Gateways Energy Bridge off the coast of Louisiana.
- The LNG received by North American import terminals often has an ethane content that exceeds natural gas engine manufacturers' specifications and the California Air Resources Board CNG specification. This LNG requires special processing equipment at import terminals to remove heavy hydrocarbons and separate tanks to store the higher-purity LNG. Such facilities were installed at Lake Charles, Louisiana in the mid-1990s to provide fuel for Houston Metro's LNG bus fleet.
- Not all LNG import terminals have tank truck loading facilities (e.g., Semptra's Costa Azul terminal in Baja California, Mexico).
- The strategy of using imported LNG as a vehicle fuel is inconsistent with energy security policies aimed at using more domestically sourced fuels.
- Due to the recent natural gas supply price trends as well as local public concern, there has been a downturn in the interest in installing new LNG import terminals in North America.

Despite these challenges, LNG sourced from existing North American import terminals (like Lake Charles facility shown in Figure 4.7.1-2) may be an appropriate and cost-effective part of an overall integrated strategy for providing the infrastructure needed to support and grow LNG vehicle fuel demand. As this market grows, it is anticipated that the fraction of LNG transportation fuel supplied from import terminals would decrease as purpose-built and perhaps other types of LNG plants are constructed.

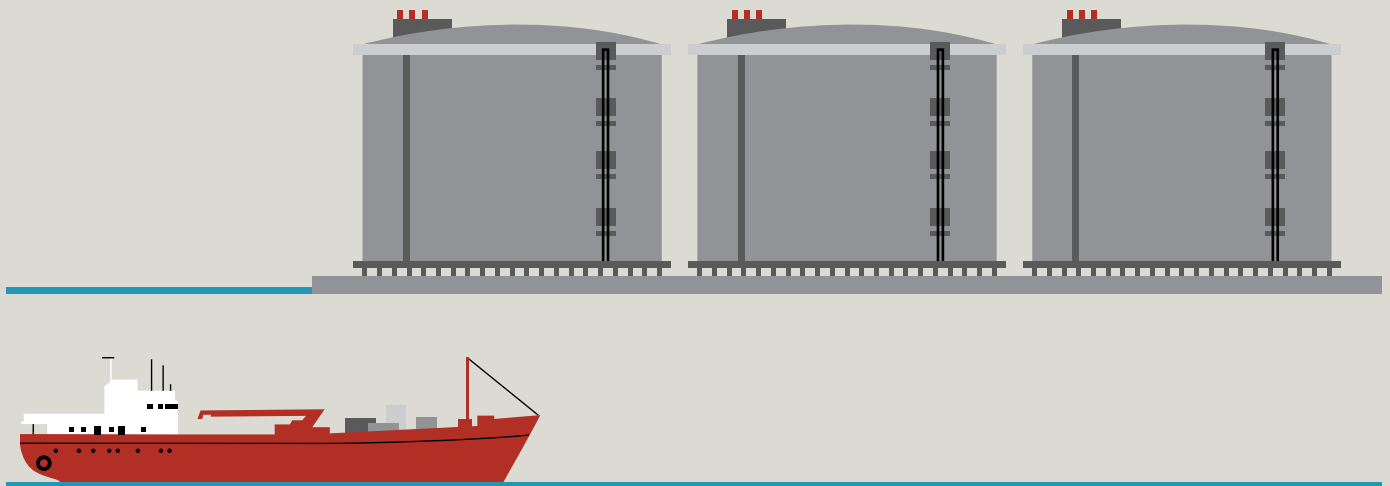
Figure 4.7.1-1

LNG vehicle fuel from import terminals may be a low-price pathway to meeting and growing LNG vehicle fuel demand in the near term.



Figure 4.7.1-2

The Lake Charles, Louisiana import terminal once supplied small quantities of LNG vehicle fuel, but tank truck loading facilities have since been dismantled.



4 LNG Production Options

4.7 LNG Import Terminals

4.7.2 Economics

Imported LNG can provide a low cost source of LNG provided gas composition meets engine specifications and terminals are near regions of aggregated LNG use.

Figure 4.7.2-1 shows that over the past five years, the LNG import price tracked the domestic wellhead price with less than \$1/MMBtu (\$0.07/LNG gallon) difference over the past year. This price differential is much less than the typical cost of liquefaction (considering amortization of capital costs, plus O&M costs), even when the additional costs of imported LNG purification, storage, and truck loading facilities (amortized over a significant quantity of LNG vehicle fuel deliveries) are considered. Imported LNG is cheaper due to much of the overseas LNG from “waste” sources where it is a by-product from oil exploration and production and is produced at large facilities where the cost per gallon is minimal. LNG from overseas, however, does not achieve energy independence. While useful in the short-term for supplementing base supply, it should not be relied upon as a key component of the overall LNG infrastructure strategy.

Figure 4.7.2-2 shows the estimated costs of import terminal sourced LNG as a function of distribution distance. The analysis considers LNG at the most recent price shown in Figure 4.7.2 1 plus estimated costs associated with purification, separate storage, and truck loading facilities. This figure shows that this pathway is potentially a low-cost LNG option unless long distribution distances are required, which, unfortunately, is usually the case.

Figure 4.7.2-1

Over the past 5 years, the imported LNG price has tracked the domestic wellhead price with usually less than \$1/MMBtu (\$0.07/LNG gallon) difference.⁴⁰

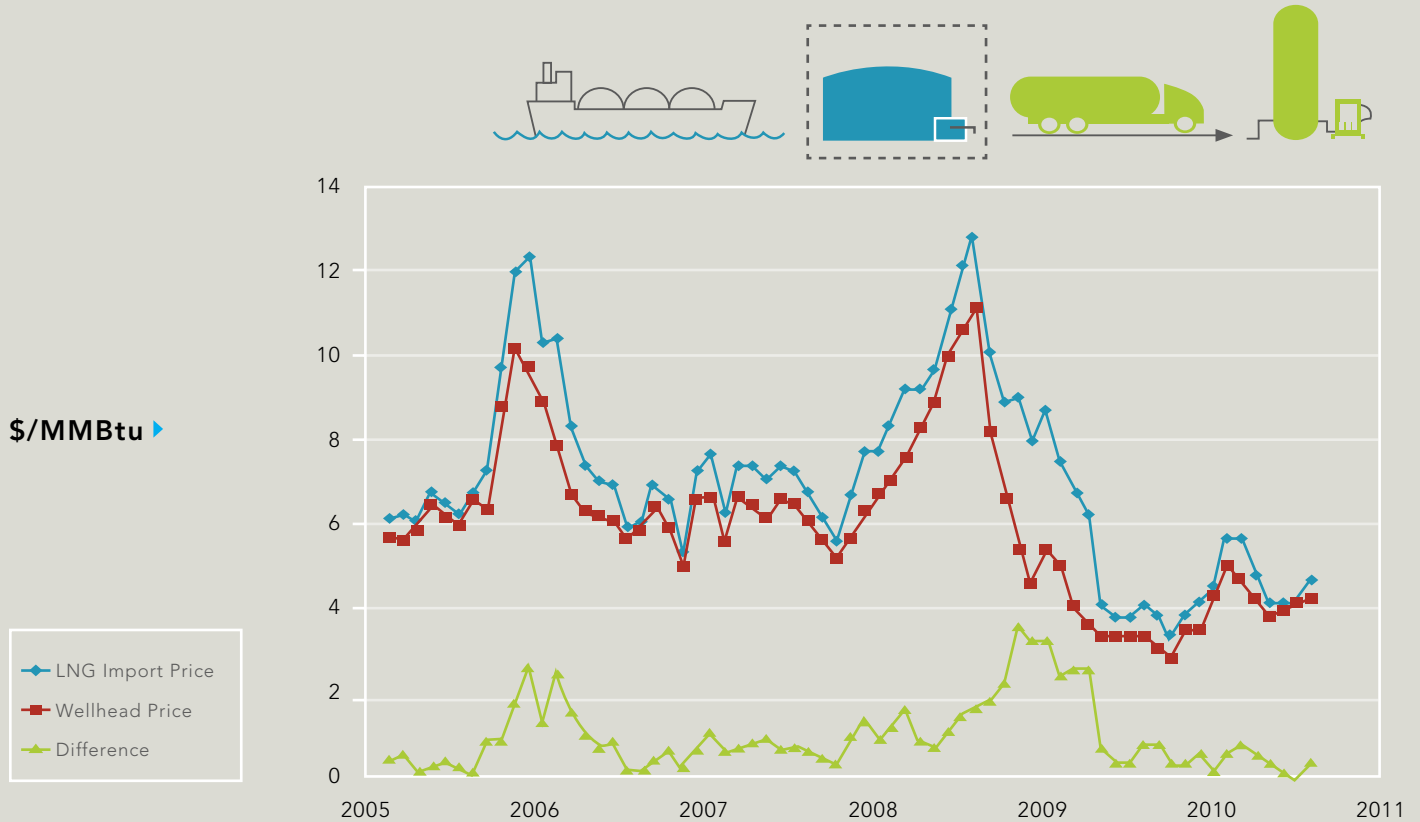
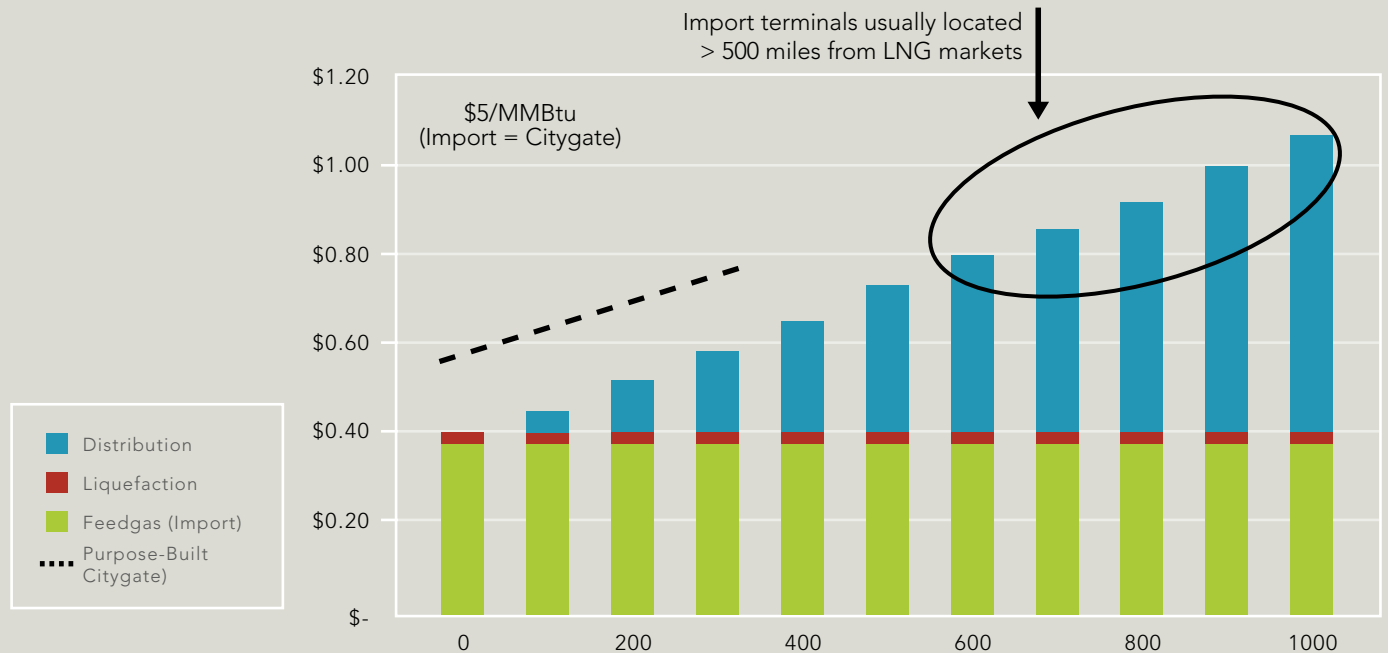


Figure 4.7.2-2

Import terminals may theoretically provide low-cost LNG vehicle fuel if delivery distances are not large, although most are greater than 500 miles from transportation fuel demand.



40 Monthly data from EIA http://www.eia.gov/dnav/ng/ng_pri_sum_dcu_nus_m.htm.

5 LNG Infrastructure Actions and Opportunities

5.1 LNG Business Opportunities

Because of the high capital investment and complexity involved in the LNG supply chain, development of the LNG transportation fuel infrastructure demands commitments from and an integrated effort by LNG providers, fueling station owners and operators, and prospective LNG vehicle owners.

The implementation strategy needed to substantially expand LNG use as a transportation fuel is a combination of all the production pathways integrated over time to match growing demand. The less expensive and smaller scale liquefaction pathways, including pressure reduction liquefaction, NRUs, and GSPs, as well as imported LNG can be used in the near term to meet burgeoning demand. As demand is established and expands, production should transition to larger capacity purpose-built liquefaction, which will likely offer the most economical LNG production. At that time, earlier liquefaction capacity from smaller scale liquefaction pathways can continue to be useful to meet peaks in demand. In order to be successful, this strategy must be coherent in the long term, with commitments from LNG producers, fueling station owners and operators,

and LNG vehicle owners. Substantial investments by all stakeholders are required and for LNG to have a beneficial business case for all involved in the value chain, these stakeholders need to work together. Each of the steps of the process from gas production, liquefaction, distribution and dispensing can have their own margin and expected return on investment. There is a limited margin in the LNG pathway and if one stakeholder attempts to gouge the limited margin, it ruins the business proposition for the rest. The stakeholders need to not focus exclusively not short-term return on investment but be committed to long-term LNG success. These stakeholders need to work together in deciding how the transition will occur to a long-term market.

Table 5.1-1 shows some of the major current players in the LNG production and fueling station business. The dearth of companies, particularly in station design/engineering/construction and operation, suggests that the LNG market may benefit greatly from a larger number of participants.

Line-haul LNG trucks have always promised attractive economics and large market potential due to high fuel consumption per vehicle and high fuel consumption across the segment. Analyses indicate that high consumption of lower-cost LNG by line-haul trucks can easily offset the higher capital cost of the vehicles and stations.⁴¹ Figure 5.1-1 shows that over 75 percent of on-road diesel fuel is consumed by Class 8 trucks. 70 percent of diesel fuel purchased by Class 8 trucks is from public stations, and 60 percent is used in line-haul applications (e.g., goods movement). These statistics indicate that the largest market and most significant target for LNG penetration are in heavy-duty line-haul applications. LNG infrastructure would need to geographically mimic that of diesel with a minimum of one station for every 250 miles of interstate which corresponds approximately to the expected range of LNG vehicles.⁴² There are 46,726 total miles of interstate highway in the U.S.,⁴³ therefore a minimum of 187 LNG stations would be needed to cover this distance with one every 250 miles.

41 Powars, C., C. Moyer, D. Lowell. "LNG Vehicle Technology, Economics, and Safety Assessment." GRI-94/0051. February 1994.

42 Hartley, P. "Sterling LNG Trucks Go into Service." *Fleet Equipment*, February 1, 2009.

43 U.S. Department of Transportation Federal Highway Administration. <http://www.fhwa.dot.gov/programadmin/interstate.cfm>. Accessed December 2010.

Table 5.1-1

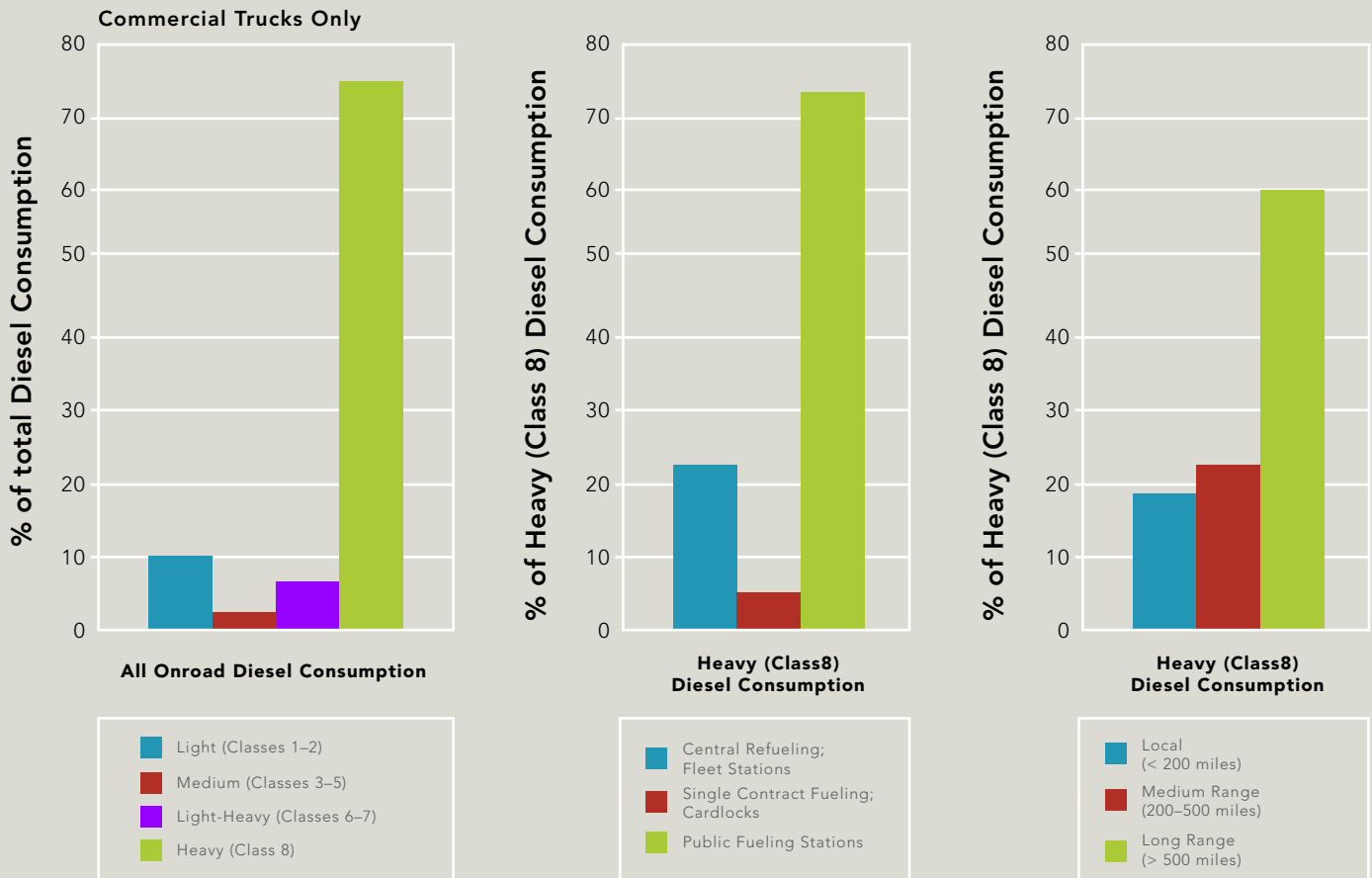
This list of the major companies currently involved in the engineering, construction, and contract management of liquefaction facilities and the design and management of LNG fueling stations suggests that the LNG market may benefit from a greater number of participants.⁴⁴

Companies	LNG Liquefaction Engineering/ Construction	Fueling Station Design/ Engineering/Construction	Fueling Station Owner/Operator
ABB Group	X		
Air Products	X		
Aker Kvaerner	X		
AMEC	X		
Bechtel	X		
CB&I John Brown	X		
Chart	X	X	
Clean Energy		X	X
Cryostar	X	X	
Fluor	X		
Foster Wheeler			
General Physics		X	
Linde	X	X	
M W Kellogg	X		
Northstar		X	
Prometheus	X		
Worley Parsons	X		

44 Adapted from Heath, T., "How to Penetrate the Global LNG Market," presentation at 1st Annual LNG Conference, London, United Kingdom, October 25, 2005.

Figure 5.1-1

Heavy-duty Class 8 trucks consume over 75% of all on-road diesel fuel consumed, 70% of which is purchased at public fueling stations and 60% of which is consumed by long-range vehicles.⁴⁵



45 TIAX LLC. "Executive Summary for: SCR-Urea Implementation Strategies Update Final Report." Prepared for Engine Manufacturers Association. June 2006.

5 LNG Infrastructure Actions and Opportunities

5.2 Potential LNG Vehicle Market Segments

Regional and line-haul trucking applications, through the investment in public fueling stations, are the largest and possibly most prosperous market segment for LNG.

Almost all LNG vehicle applications to date have been return-to-base trucks and transit buses, primarily because their fueling infrastructure is much simpler to implement than that for line-haul trucks. The Market Segmentation report of the overall TIAX assessment lists possible natural gas vehicle applications for which LNG is applicable for transit bus, refuse haulers, package trucks, and Class 8 local and regional delivery trucks and line-haul trucks. Line-haul applications use over 100 DGE per day, carry upwards of 150 to 180 DGE, and travel as much as 500 miles per day.

These characteristics match the attributes conducive to use of LNG: greater than 60 DGE per day use, greater than 80 DGE storage, and greater than 200 mile per day travel (Table 5.2-1). These attributes and characteristics are identified in the Market Segmentation and Heavy Duty Vehicle Ownership and Production reports of the overall TIAX assessment.⁴⁶ Return-to-base fleets have the benefit of constructing onsite stations that meet their specific needs, but these stations do not help in developing a nationwide distribution infrastructure. Over the road line-haul trucks, which are the largest fuel volume market segment, require public access LNG stations along major routes (e.g., at existing truck stops). One natural gas station provider has begun to address this issue by teaming with Pilot Travel Centers, leveraging the current diesel fueling station strategy by constructing, owning, and operating CNG and LNG fueling facilities at existing Pilot Flying J travel centers nationwide, and other natural gas providers are considering this same approach.

Future success of LNG heavy-duty line-haul market penetration hinges on ensuring that fueling stations are located along future trucking routes. This was the original intent of the Interstate Clean Transportation Corridor, conceptualized in the late 1990s but not actually implemented. Figure 5.2-1 shows an example of a planned corridor to connect Las Vegas and Los Angeles. Such strategic investments along heavily used corridors may be the beginning of a complete nationwide LNG fueling network. Based on a 10,000 gallon per day station capacity, a 100,000 gallon per day liquefaction plant can serve ten stations.

Furthermore, LNG as a fuel should be treated on an equal basis as diesel. The current \$0.243 per gallon U.S. federal excise tax on LNG is nearly equal to the \$0.244 per gallon tax on diesel.⁴⁷ Noting that LNG contains less energy per gallon than diesel, these tax rates effectively translate to a tax on LNG that is 1.7 times that of diesel on an energy basis. In contrast, CNG is taxed on an energy basis. Thus, efforts to expand the use of LNG should ensure that LNG is not taxed on a volume basis. The societal value of providing the above incentives are discussed in greater detail in the *Government and Comparative Analysis* reports of the overall TIAX assessment.

⁴⁶ Based on the *Market Segmentation and Heavy-Duty Vehicle Ownership and Production* reports of the overall TIAX assessment.

⁴⁷ U.S. Internal Revenue Service. "Form 720: Quarterly Federal Excise Tax Return." October 2010.

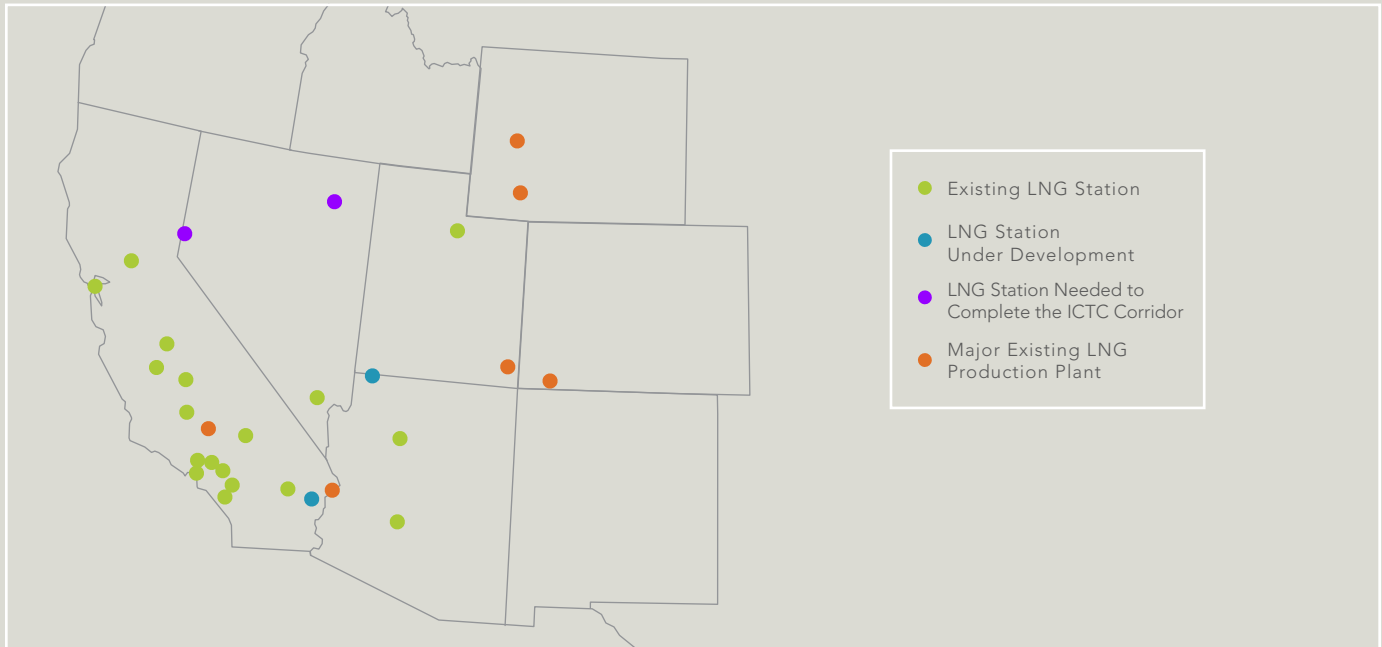
Table 5.2-1

The line-haul application offers characteristics that are conducive to LNG use.⁴⁸

Attributes Conducive to LNG	Characteristics of Line-Haul
> 60 DGE daily Use	Approximately 100 DGE daily use
> 80 DGE storage	15–180 DGE Storage
> 200–300 miles per day	> 300-miles per day

Figure 5.2-1

The LNG Interstate Transportation Corridor in the West is well under development



48 Based on the Market Segmentation and Heavy-Duty Vehicle Ownership and Production reports of the overall TIAX assessment.

49 Miyasato, M. "UPS Ontario Las Vegas LNG Corridor Extension Project: Bridging the Gap." http://www1.eere.energy.gov/vehiclesandfuels/pdfs/merit_review_2010/technology_integration/tiarravt047_saito_2010_p.pdf. June 9, 2010.



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The opinions expressed within the Executive Summaries of Modules 1 and 2 of this market assessment are the work product of America's Natural Gas Alliance (ANGA) and participating American Gas Association (AGA) companies based upon data provided by TIAX LLC.

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