CALIFORNIA LNG TRANSPORTATION FUEL SUPPLY AND DEMAND ASSESSMENT

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CALIFORNIA LNG TRANSPORTATION FUEL SUPPLY AND DEMAND ASSESSMENT

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PREFACE

This is a final report on work performed for the California Energy Commission (CEC) Transportation Technology Office by USA PRO & Associates and St. Croix Research. This work was carried out under Work Authorization 15, "California LNG Transportation Fuel Supply Assessment," issued to USA PRO & Associates by Arthur D. Little, Inc. as part of CEC Contract 500-00-002.

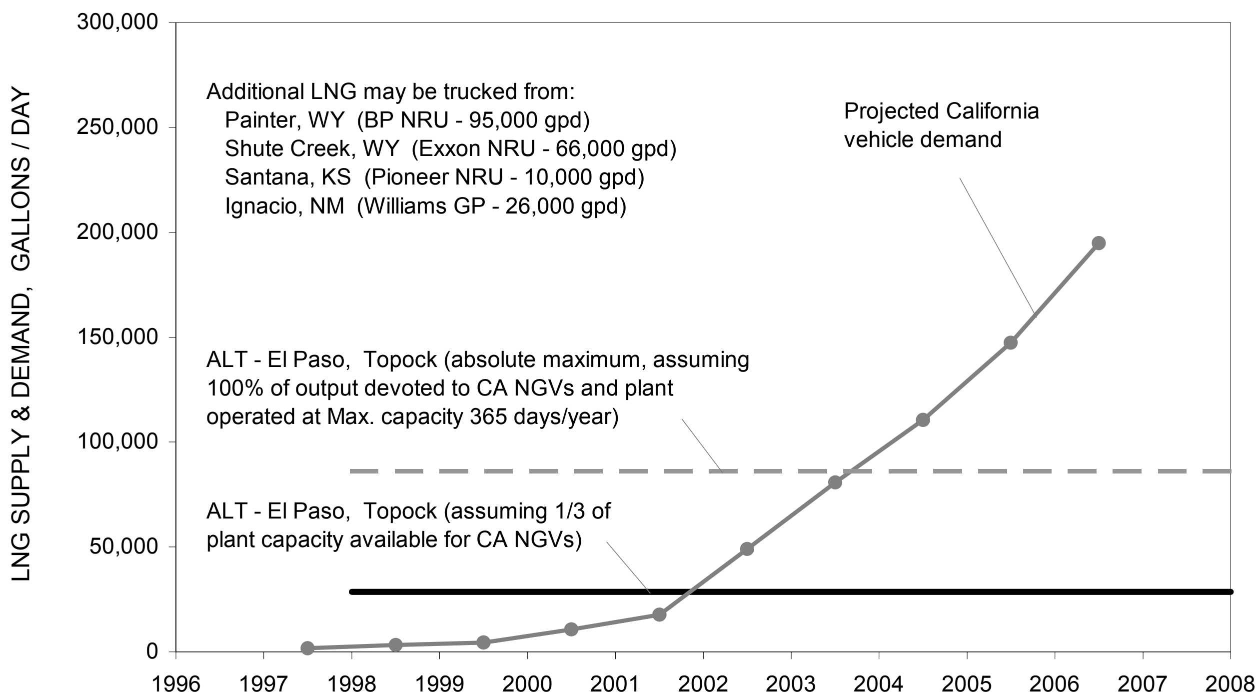
This final report is a revision and expansion of an interim report dated November, 2001. The interim report was prepared to provide input for a larger-scope CEC Staff report to the California Legislature on A California Strategy to Reduce Petroleum Dependence, which is required under AB2076 (Chapter 936, Statutes of 2000).

The subject matter of this report is literally and figuratively very fluid. Numbers of LNG vehicles, total LNG consumption, and the status of LNG transportation fuel supply plans are changing rapidly. Readers of this report should be aware that certain of the data and information are likely to be out of date soon after the report is published.

EXECUTIVE SUMMARY

The objective of this report is to provide an assessment of existing, planned, and potential sources of liquefied natural gas (LNG) transportation fuel for California, and to compare these with the projected demand. Factors such as economic incentives and fleet rules designed to improve air quality are encouraging truck and bus fleets to replace diesel vehicles with LNG-fueled vehicles. There is concern that the resulting LNG demand will soon exceed the economically available supply, and this will impact fuel prices.

The LNG demand was analyzed in three phases: historical and current data (1997-2001), near-term projections based on existing orders and plans (2002-2004), and longer-term projections which include some extrapolations (2005-2006). Data regarding the number of current and planned LNG vehicles were obtained from fleet managers, project developers, State agencies, and other studies. Most LNG vehicles in California are either transit buses, refuse trucks, or other return-to-base heavy-duty trucks. Numbers of vehicles by model or type, fleet, and year were entered into spreadsheets. Additional spreadsheets applied mileage and fuel economy data or estimates to project fuel consumption by year. Numbers of compressed natural gas (CNG) vehicles fueled at LNG-to-CNG (L/CNG) stations, and their LNG consumption, were also projected by year. The figure below shows an example result: the average daily California LNG transportation fuel consumption by year, historical data for 1997-2001, and projections for 2002-2006.



California LNG Transportation Fuel Demand Projection
Compared to Current LNG Supplies

Numerous uncertainties are associated with these projections. For example, the projections do not include unannounced or confidential plans, and there is no adjustment to account for the fact that schedules slip more often than they accelerate (these two factors may be partially compensating). Also, no adjustments are made to address the effects of new diesel emission certification standards in October, 2002, on available incentive funding.

The economic and technical choices affecting any new LNG plant are briefly summarized. There are three basic cost factors that sum to the delivered LNG cost: feedgas cost, liquefaction cost (capital and operating), and transportation costs. Different strategies involve different tradeoffs among these elements. The options for liquefaction plant thermodynamic cycles are generally well established. They range from simple but less-efficient nitrogen and precooled Joule-Thomson cycles to more efficient but also more complicated cascade and mixed-refrigerant cycles. In special situations, highly efficient turboexpander cycles may be employed to produce LNG. All liquefiers require gas pretreatment, and this is a bigger challenge for some feedgas sources (e.g., landfill gas) than others.

Nearly all the LNG currently delivered to California is produced at an 86,000-gpd maximum capacity liquefaction plant in Topock, Arizona, which is adjacent to the California border. The liquefier is owned by El Paso Field Services and the LNG storage and truck-loading facilities are owned by Applied LNG Technologies USA (ALT). LNG from this plan is delivered to three categories of customers: industrial, municipal (i.e., gas utilities), and transportation (Arizona and California). The proportions supplied to each category vary, and ALT has the flexibility to supply LNG customers from sources other than the Topock plant. However, we estimate that roughly one-third of the plant output (i.e., approximately 29,000 gpd) is available for California LNG fleets without substantially perturbing customer category allocations. The prior figure shows this supply level compared to the demand projection.

There is one LNG plant in California, but it does not typically supply substantial quantities of LNG transportation fuel. The Quadren Cryogenics plant liquefies high-nitrogen gas from the Robbins field (northwest of Sacramento) and produces ultra-high-purity methane for the specialty gas market. Four out-of-state sources have occasionally supplied LNG to California: the Exxon Mobil nitrogen rejection unit (NRU) near Shute Creek, Wyoming; the BP NRU near Painter, Wyoming; the Pioneer NRU near Santana, Kansas; and the Williams natural gas liquids plant near Durango, Colorado. An obvious consideration associated with sourcing LNG from these plants is the substantial trucking distance to California.

A variety of additional California LNG plants are being developed or considered. These include strategies to utilize pipeline gas, gas reserves that are not connected to a pipeline, and landfill gas (LFG). Current prices of pipeline gas at different stages (e.g., city gate, industrial users) are tabulated to show that the cost of feedgas from this source can be a significant fraction of current LNG prices. Other California natural gas resources are also reviewed with emphasis on low-Btu and remote gas. These "stranded" gas resources, which are not now economical to produce for pipeline gas, might provide low-cost feedgas for small-scale (e.g., skid-mounted) liquefiers. However, prior studies have concluded that the total California gas resources in this category are relatively small, and there are competing uses for this gas such as electric power generation.

LFF, and also digester gas (from sewage plants), is another potential low-cost feedgas source. LFG and digester gas is typically only about 50% methane (most of the balance is carbon dioxide), and so substantial pretreatment is required before the gas can be liquefied. The gas flows available from landfills are relatively low, and they are best suited for small onsite liquefiers. California LFG sources are briefly considered, and uses (e.g., electricity generation) that compete with LNG production are listed.

Specific current, planned, and potential California LNG production projects are reviewed with the objective of comparing their estimated outputs and schedules with the LNG transportation fuel demand projection. CryoFuel Systems (CFS) is developing a small (typically 5,000-gpd) liquefier technology that is well suited to feedgas such as LFG. CFS is teamed with ALT to install four liquefiers at California sites (two LFG, one stranded gas, and one flared gas). These projects are in various stages of final planning and initial installation. Pacific Gas and Electric (PG&E) and Southern California Gas are teamed with the Idaho National Engineering and Environmental Laboratory (INEEL) to install INEEL-developed turboexpander liquefiers at gas pipeline pressure let-down locations. A 10,000-gpd liquefier is currently being installed in West Sacramento, and a similar unit is planned for installation in Southern California. The CFS and INEEL projects employ new technologies, and they have both experienced schedule slips. Realistic projections of their contribution to the California LNG supply indicate that they will probably not completely make up the difference between the Topock plant allocation and the demand projection in the 2002 and 2003 time period.

Other LNG sources that are in the planning stage include the City of Long Beach liquefaction plant project (with up to 70,000 gpd) and expansion of the Quadren plant. In each case, funding has not yet been obtained, equipment has not been ordered, and site work has not started. Our projections characterize these projects as potentially adding to the LNG supply and ramping up during 2003 and 2004. When compared with the projected LNG demand during that time period, they are unlikely to make up the supply deficit unless both projects promptly produce at full capacity.

Longer-term potential LNG sources include additional CFS-type small-scale liquefiers and/or additional INEEL-type turboexpander liquefiers. The likelihood of these additions depends on the success of current projects. It is also possible that a relatively large-capacity (e.g., 100,000-gpd) purpose-built liquefier could be built in California, and that such a liquefier could serve multiple purposes (e.g., LNG transportation fuel production and gas-demand peakshaving for a utility or large electric power plant). Such a plant could utilize proven high-efficiency liquefier technology with a favorable economy-of-scale. However, current market conditions do not appear to encourage investment in this type of plant.

The long-term LNG supply possibility with the biggest potential impact, which is also highly uncertain, is the LNG import terminals being planned for Northern Mexico or possibly California. Three groups have announced plans for LNG import terminals in this region: El Paso teamed with Phillips, Chevron Texaco, and Sempra teamed with CMS. These projects are targeting anticipated California gas demand increases that are driven primarily by electric power plants. The projected LNG transportation fuel market is relatively small. Also, special equipment would need to be included in the import terminal design in order to increase the LNG methane content and load it into tank trucks. None of the above groups has committed to include this capability, but El Paso-Phillips is considering this option. We anticipate that, at most, one LNG import terminal will be built, and it will probably slip one or two years relative to the 2005 and 2006 start-up date targets. However, such a facility could supply all of California's LNG transportation fuel needs in 2006 with only 2 or 3% of its receiving capacity.

In summary, it appears that California LNG transportation fuel demand will exceed supplies from the Topock plant starting in 2002, and this will require significant reallocation of the Topock plant production and/or trucking of LNG from more distance sources. LNG plants currently being installed plus those in the planning stage are unlikely to generate enough additional supply to eliminate a supply-demand deficit in the 2002 to 2005 time period. Long-term LNG supply possibilities include more small-scale and/or turboexpander plants (if initial projects are successful), large purpose-built LNG plants (which do not appear to be profitable investments at current economic conditions), and LNG import terminals (which are highly uncertain).

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

Section 1

INTRODUCTION

1.1 Objective

The objective of this report is to provide an assessment of existing, planned, and potential sources of liquefied natural gas (LNG) transportation fuel for California, and to compare potential LNG supplies from these sources with the projected demand. This assessment is an update and extension of an assessment carried out in 1998 for Brookhaven National Laboratory (Reference 1).

1.2 Report Organization

The demand for LNG transportation fuel in California is projected in Section 2. Some general considerations pertaining to LNG transportation fuel supplies are summarized in Section 3. Current and potential future sources of LNG transportation fuel for California are discussed in Sections 4 and 5, respectively. These supplies are compared to the LNG demand projections and conclusions are drawn in Section 6.

Section 2

CALIFORNIA LNG TRANSPORTATION FUEL DEMAND PROJECTION

2.1 LNG Transportation Fuel Use in California

LNG use as a transportation fuel in California is very briefly discussed here in order to provide a context for the LNG supply and demand assessments. More detailed discussions are available in other readily available documents (e.g., References 2 through 5).

LNG use as a fuel for medium- and heavy-duty vehicles is growing rapidly in California for a number of reasons:

- Economics — Medium- and heavy-duty trucks and buses have relatively high mileage and fuel consumption. Except for one brief time period, the price of LNG has been less than the price of diesel fuel (on an energy-equivalent basis) over the past few years. These facts combine to enable fuel cost savings to amortize incremental equipment costs for many fleets.

- Air Quality Benefits — Medium- and heavy-duty diesel-fueled vehicles produce a disproportionately high percentage of the NO_x and particulate emissions in California. Natural gas engines have lower NO_x and particulate emissions than their counterpart diesel engines (e.g., more than 20 heavy-duty natural gas engines are currently certified to one of the California Air Resources Board (CARB) optional low-NO_x standards, while zero diesel engines are certified to these standards). Natural gas engines also have lower CO_2 emissions, and they reduce concerns regarding diesel exhaust toxicity. These facts have motivated CARB, air quality management districts, and other California agencies, to offer financial incentives and adopt fleet rules which encourage fleets to use natural gas.

- Energy Security Benefits — The use of LNG as a replacement for diesel fuel helps to reduce California's petroleum dependence, which is the objective of AB2076 (see Preface). Recent events have heightened public awareness and concern regarding the fact that the U.S. imports of more than half the petroleum used for transportation fuels.

- Commercialized Technology Available — LNG-fueled trucks and buses are available from original equipment manufacturers. Emissions-certified natural gas engines from 150 to 400 horsepower are available. Ancillary equipment such as LNG fuel tanks and refueling stations are well developed and commercial available.

- Application Suitability — LNG technology is well suited to heavy-duty fleet operations. LNG's relatively high energy density (on both a mass and volume basis) minimizes the impact on heavy-duty vehicle payload capabilities. LNG refueling procedures are easily accommodated in a centralized fleet refueling environment. Most heavy-duty vehicles have consistent use schedules, which alleviate concerns about LNG vaporization and venting during long periods of vehicle inactivity.

Figures 1 and 2 illustrate two examples of California LNG vehicle fleets. The Los Angeles Airport LNG-fueled shuttle buses (Figure 1), which are manufactured in California, have been in routine operation since 1994. Harris Ranch operates 12 LNG-fueled Class 8 trucks (Figure 2) from their feedlot and headquarters in Coalinga, and they plan to expand their LNG truck fleet.

Most LNG-fueled heavy-duty vehicle fleets in California fall into three broad categories: transit buses, refuse trucks, and various return-to-base truck fleets (e.g., for grocery distribution). Somewhat different economic incentives, fleet rules, fuel taxes, and other factors affecting the economics of converting to LNG apply to each category (Reference 2). However, the use of LNG is growing rapidly in all three categories, and this has caused concerns regarding the sources and adequacy of future LNG supplies, i.e., the issue that is the focus of this assessment.

2.2 Demand Projection Methodology

The basic methodology we employed to project the demand for LNG used as a transportation fuel in California was to project the number of LNG vehicles by year, estimate the miles driven and miles per gallon fuel economy for each vehicle type, and compute the resulting annual LNG fuel consumption.

In addition to LNG consumed by LNG vehicles, LNG consumed by compressed natural gas (CNG) vehicles that are fueled at LNG-to-CNG (L/CNG) stations was also considered. The LNG (and L/CNG) vehicle projections were considered in three phases:

- Historical and current data (1997-2001), based on best available documentation and sources
- Near-term future projections (2002-2004), based on existing fleet orders and announced plans
- Longer-term projections (2005-2006), which include extrapolations based on historical growth and future potential considering candidate vehicle populations

Data and information regarding the number of current and future LNG vehicles in California were obtained from multiple sources. These include progress reports by project developers such as Gladstein and Associates under the Interstate Clean Transportation Corridor (ICTC) project (Reference 6), other recent studies (Reference 2), and personal communications with fleet managers and state agencies, such as air quality management districts and the CEC. Care was taken to confirm the validity of future fleet plans and to avoid "double counting" (e.g., because a given LNG fleet project is assigned different designations by different sources). Where specific year-to-year vehicle acquisition plans were unknown, estimates were made based on the number of vehicles on order or the stated fleet goals.

No adjustments were made to account for possible project schedule slips or fleet acquisition plan revisions. We believe that some projects are being developed on a confidential basis by fuel and equipment suppliers. These projects, which are not included in our projection, may compensate for delays in projects that are included. Also, no adjustments were made to account for possible future events such as economic incentive reductions associated with new

Figure 1. Los Angeles World Airports Started Converting to LNG in 1994, and They Now Operate 55 LNG Shuttle Buses (LAWA photo not to be used for commercial purposes).

Figure 2. Many California Return-to-Base Truck Fleets Are Converting to LNG. Harris Ranch in Coalinga is a Successful Example.

diesel emission standards, LNG or diesel fuel price variations, LNG vehicle equipment price and/or performance improvements, or potential petroleum consumption reduction incentives.

We projected the per-vehicle LNG fuel consumption by estimating the average daily miles driven and the miles per LNG gallon fuel economy for each LNG vehicle category. Where possible, these estimates were based on measured results (e.g., References 7, 8, 9, and contacts with fleet operators). Future projections were based on previous results for similar vehicles and engines in similar fleet applications. In particular, the substantially different driving cycles of transit, refuse (collection and transfer), an other return-to-base trucks were accounted for. Also, where the engine type was known, the different LNG-consumption characteristics of dual-fuel engines were distinguished from those of dedicated natural gas engines.

The demand projection is formatted as a Microsoft Excel workbook with the following worksheets (spreadsheets): California LNG vehicles by fleet and year, L/CNG vehicles by fleet and year, LNGV consumption, L/CNG and total LNG consumption, other data, and various graphs. This is regarded as a "living" collection of spreadsheets, which may be updated as new or more accurate data becomes available.

2.3 Demand Projection Preliminary Results

Figure 3 shows the projected California LNG vehicle population by year. As discussed in Section 2.2, Figure 3 includes three segments: historical data, near-term projections based on existing fleet orders and announced plans, and longer-term projections, which include extrapolations to account for new fleets. This projection indicates that there were 291 LNG-fueled vehicles operating in California as of mid-2001.

Figure 4 shows the projected number of California LNG vehicles plus CNG vehicles that are or will be fueled from LNG (referred to here as L/CNG vehicles). There are not very many L/CNG vehicles in California at this time, but various planned LNG fueling stations will have L/CNG capabilities (e.g., Santa Monica, Long Beach, Omnitrans, Tulare, Sacramento City, Sacramento County). The L/CNG vehicle population projection is less accurate than the LNG vehicle population projection, because the issue is which CNG vehicles will refuel at a L/CNG station instead of a conventional compressor station. However, since many CNG vehicles are light-duty vehicles, their per-vehicle fuel consumption is usually less than that of LNG vehicles.

Figure 5 shows the projected LNG consumption by California LNG and L/CNG vehicles through 2006. The consumption is shown in LNG gallons per day (gpd), which is an average defined as the annual consumption divided by 365. The average California LNG transportation fuel consumption as of mid-2001 was estimated to be 17,600 gpd (17,300 gpd for LNGVs plus 300 gpd for L/CNGVs). The average consumption projected for mid-2006 is 195,000 gpd (161,000 gpd for LNGVs plus 34,000 gpd for L/CNGVs).

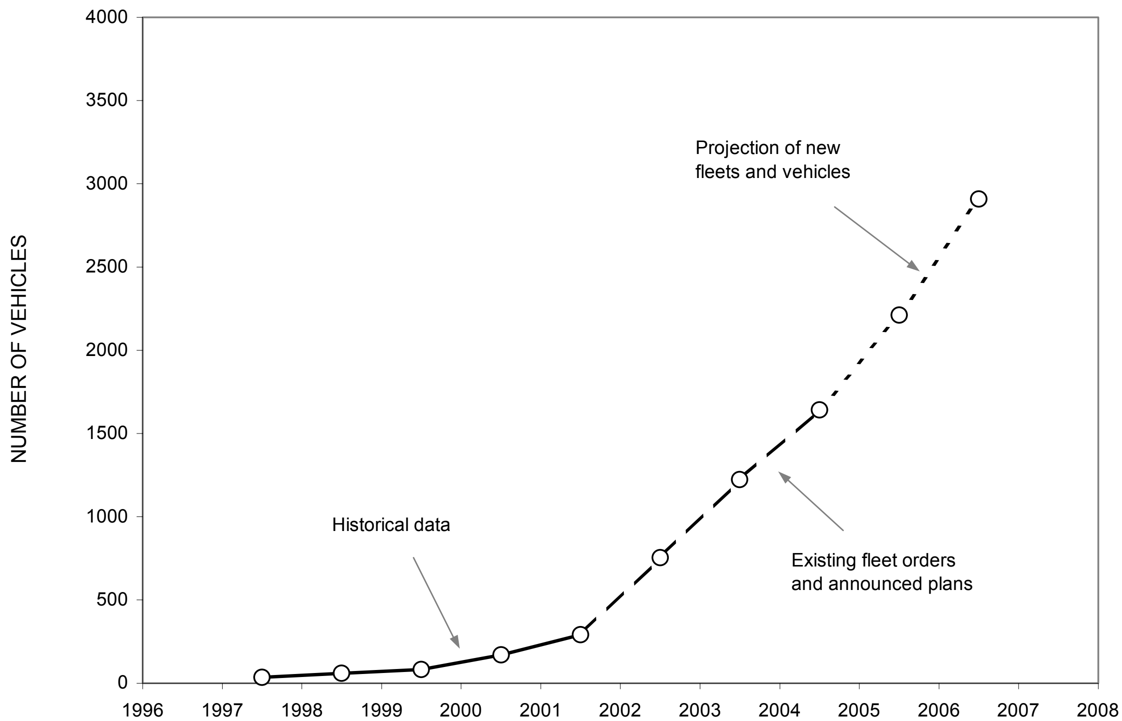


Figure 3. Projection of California LNG Vehicles by Year.

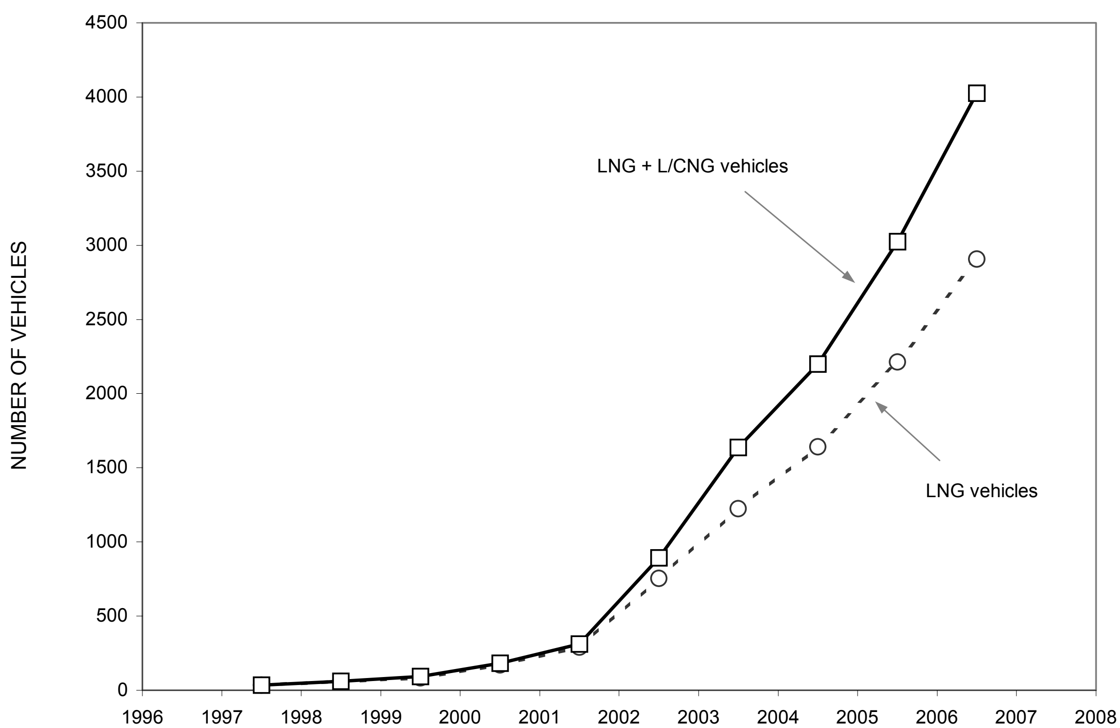


Figure 4. Projections of California LNG Vehicles and CNG Vehicles Fueled from LNG.

2.4 Comparison with Other Projections

Zeus Development Corporation has carried out two LNG vehicle market and infrastructure studies for the Gas Research Institute (GRI, now the Gas Technology Institute, GTI), in 1998 (Reference 3) and previously in 1995 (Reference 10). Information from these studies provided some of the input for the "Historic Data" portion of the projection shown in Figure 3.

Zeus was also a subcontractor to Arthur D. Little, Inc., supporting the GTI/BNL study documented in Reference 2. As part of their subcontract work (which was completed in July 2000), Zeus projected California LNG vehicle population growth from 2000 to 2001 and 2002. This projection is compared to our projection in Figure 6.

Applied LNG Technologies USA (ALT), which is part of the Jack B. Kelley group of companies, is the primary supplier of LNG to California at this time (see additional discussion in Sections 3, 4, and 5). ALT provided helpful information for this study including estimates of LNG consumption (Reference 11). ALT personnel made an estimate of LNG deliveries as of mid-2001, although interpretation of this estimate is complicated by the following facts: Most of ALT's LNG comes from the Topock plant (Section 4.1), but some also comes from other sources (Section 4.2). The LNG is used for industrial purposes, municipal (satellite) gas supplies, and transportation fuel. Transportation fuel LNG is delivered to Arizona and Texas, as well as California. ALT provided general guidelines for estimating relative allocations to these customer categories. They also estimated that deliveries of California transportation fuel LNG roughly doubled over the past year, and they anticipate another doubling next year. Our interpretation of the ALT estimates and guidelines are also shown in Figure 6.

2.5 Key Issues

Following are some key issues affecting interpretation of the projections shown in Figures 3 through 6:

- No adjustments were made to account for the fact that announced project schedules slip more often than they accelerate.

- Only projects that have already been announced are included through 2004. It is possible that some fleets will deploy LNG vehicles by 2004 that have not yet announced their plans to do so. It is also possible that we have failed to identify and include some announced fleet plans.

- The number of CNG vehicles that will refuel from L/CNG stations is particularly uncertain, but, as previously discussed, such vehicles usually have lower fuel consumption than LNG vehicles.

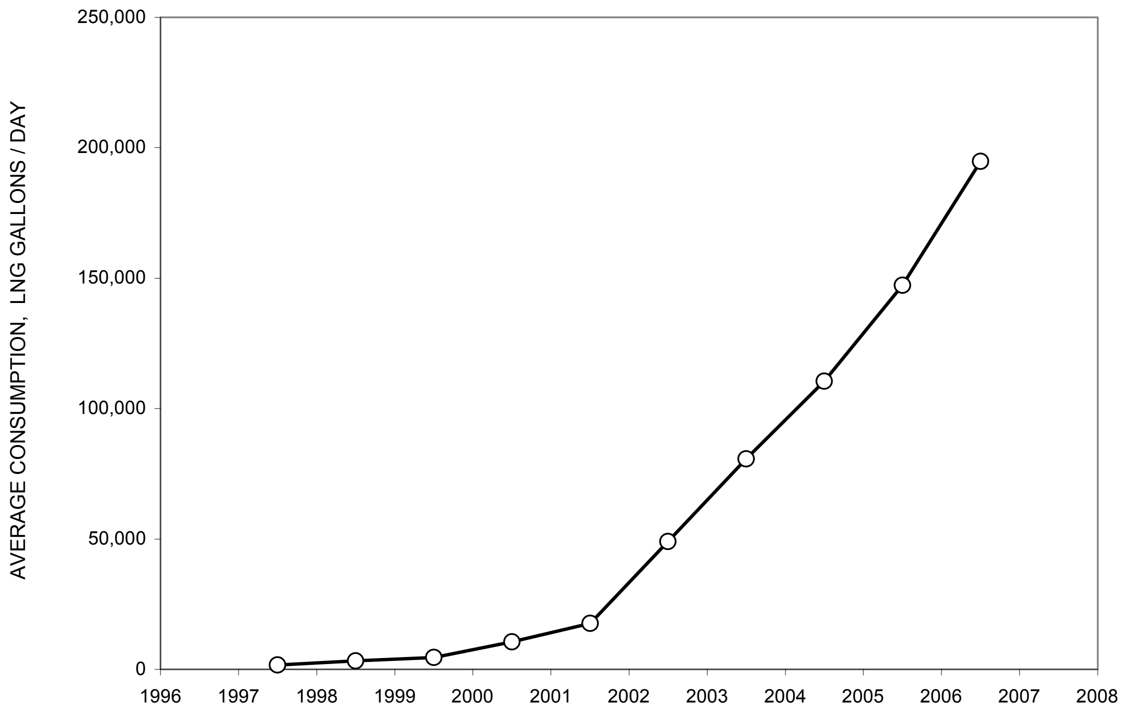


Figure 5. Projected LNG Consumption by California LNG Vehicles and CNG Vehicles Fueled from LNG.

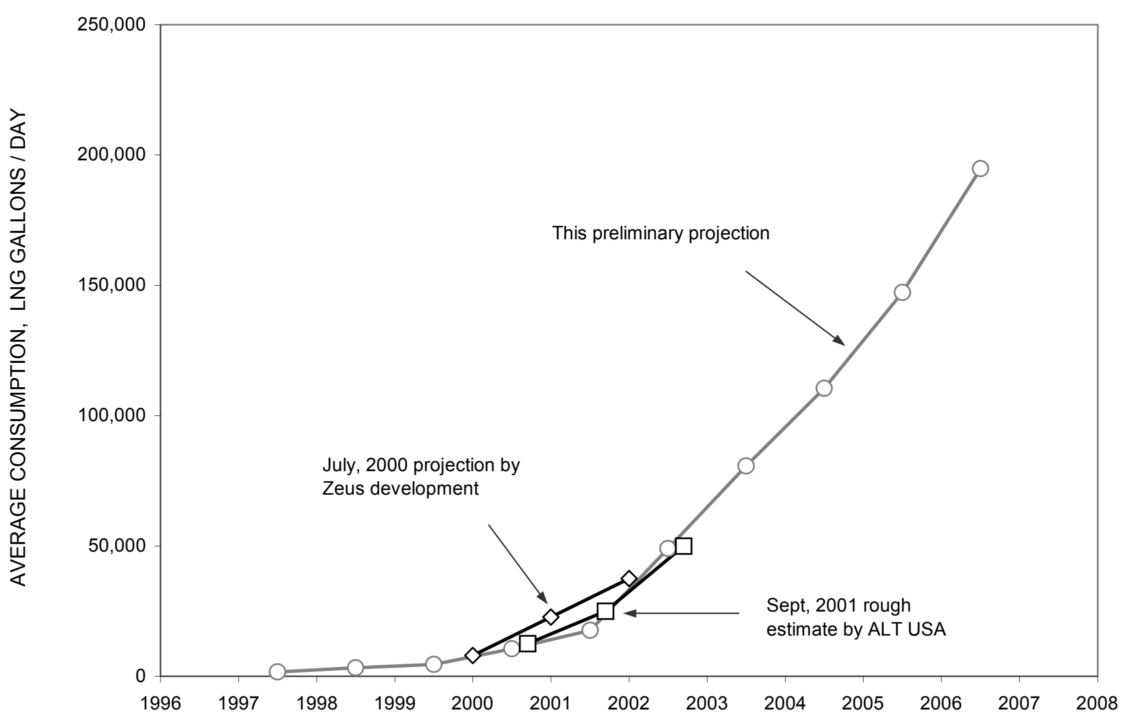


Figure 6. Projected California LNG Transportation Fuel Consumption Compared with Other Estimates.

- The mileage and fuel economy of all future LNG vehicles and many current LNG vehicles has been estimated from currently available measurements for similar vehicles, engines, and applications. However, there are significant uncertainties and ambiguities associated with many of these measurements and estimates.

- The number of LNG vehicles beyond 2004 includes a projection of "new" fleets that will convert to LNG, which is basically an extrapolation.

- Nearly all LNG vehicle projects receive financial incentives based on the optional low-NO_x certification of the natural gas engine relative to the diesel standard. The diesel standard will be reduced in October, 2002, and this will reduce incentive amounts, if nothing else changes. However, other things may change, as discussed in Section 2.2. No projection adjustments were made to account for any of these possible changes.

- These projections are based on the best information available during the second half of 2001. The growth rates of LNG vehicles and fuel consumption may strengthen or weaken, depending on changes in legislation, incentive funding levels, regulatory mandates, equipment performance and costs, and petroleum fuel supply economic trends. It may be prudent to periodically update these projections to incorporate new data and account for these changes.

Section 3

LNG TRANSPORTATION FUEL SOURCES: GENERAL ISSUES

A variety of LNG supply strategies are being used or considered to provide fuel for LNG vehicles in California. General issues affecting all of these supply strategies are summarized here. These include economics tradeoffs (Section 3.1), liquefaction technologies (Section 3.2), and LNG supply infrastructure options (Section 3.3). These summaries provide a basis for discussing specific current and planned future California LNG sources in Sections 4 and 5, respectively.

3.1 Economics Overview

Prior studies such as References 2, 3, 5, and 10 have analyzed the detailed economics of LNG transportation fuel supply strategies including their capital costs, recurring costs, and life-cycle costs (which may be expressed as cost per LNG gallon or diesel equivalent gallon based on an assumed cost of capital, or return-on-investment based on an assumed LNG selling price). Detailed element-by-element life cycle cost analyses will not be repeated here, but an important conclusion is that, for all scenarios, the primary elements affecting the delivered LNG cost are:

FEED GAS COST	+	LIQUEFACTION COST (CAPITAL) & OPERATING	+	TRANSPORTATION COST	=	DELIVERED LNG COST

These three cost elements are like wrinkles in a carpet — it's difficult to push them all down simultaneously.

Feedgas Costs depend on the source of the natural gas. Natural gas that is gathered from wells, transported through pipelines, and delivered to customers through distribution systems is one source of feedgas for liquefaction. The cost of gas from this source is increasingly expensive "downstream" from wellhead to city gate to sales to electric utilities and industrial, commercial, or residential customers. Natural gas prices also vary with time. Commodities futures contracts for natural gas at the "Henry Hub" (in Louisiana) are traded on the New York Mercantile Exchange. Topock and Malin are the gas trading hubs at the southern and northern California pipeline entry points, respectively (Reference 12). Natural gas prices experienced highly publicized increases in California in 2000, but they have subsequently decreased. The DOE Energy Information Agency (EIA, Reference 13) and CEC (Reference 14) provide detailed tabulations of natural gas prices.

The feedgas cost can be a large portion of the LNG cost if it is purchased downstream from the wellhead and city gate. For example, the average price of natural gas sold by local distribution companies (LDCs) to industrial customers in California was $5.52/Mcf in August, 2001 (the most recent month tabulated by DOE EIA, Reference 13). This translates[1] to approximately $0.46 per LNG gallon, even before any costs for liquefaction or LNG trucking are added. Potential feedgas sources in California are discussed in Section 5.1.

Liquefaction cost is perhaps the most complicated element, because it includes both capital and operating costs. The primary capital cost items are the liquefier, gas clean-up system, LNG storage tanks, other plant equipment, and permitting, delivery, and installation costs. Recurring costs are basically the liquefaction plant operating and maintenance (O&M) costs. The main operation cost is for compressor drive power, because most liquefaction cycles (Section 3.2) involve gas compression. This may be a portion of the feedgas if gas engine compressor drive is used, or electric power if electric motor drive is used. Other O&M costs include personnel costs, other utilities and consumables, and repair parts. Other recurring costs (i.e., in addition to what is normally considered O&M) include such things as insurance and property taxes.

A detailed analysis of the capital costs of specific natural gas liquefaction plant types and sizes is beyond the scope of this study. However, following are some simple generalizations regarding capital costs:

- Economy of Scale — The per-capacity cost (e.g., $/gpd) of LNG plants is usually lower for large plants than for small plants.

- Efficiency — Different liquefaction cycles have different efficiencies (e.g., the gpd of output relative to the input power) as summarized in Section 3.2. More efficient cycles usually require more complicated equipment and therefore cost more than less efficient cycles.

- Gas Clean-Up — Constituents such as carbon dioxide, water, sulfur compounds, and certain other components must be removed from the feedgas before it is liquefied. The cost of the clean-up equipment generally increases as the methane purity of the feedgas decreases. There is also a significant economy-of-scale factor affecting clean-up equipment costs.

- Feedgas Pressure — High-pressure feedgas requires less compression for liquefaction, and this reduces both capital and operating costs. If feedgas is available at a very high pressure, and only a small fraction needs to be liquefied while a larger fraction may be discharged as low-pressure gas (e.g., to distribution pipelines), then various turboexpander cycles may be utilized (see Section 3.2), which substantially decrease operating costs and may slightly decrease capital costs.

[1] The conversion (which depends on the natural gas composition and LNG saturation pressure) is approximately 12 LNG gallons/Mcf. Note that if gas is consumed as part of the liquefaction process (e.g., to fuel gas engine-driven compressors), less than 12 gallons of LNG will be produced per Mcf of feedgas.

Generalizations regarding O&M and other recurring costs include:

- Efficiency — More efficient liquefaction cycles have lower operating costs in terms of either feedgas or electric power consumption.

- Feedgas Pressure and Low-Pressure Gas Send-Out — As previously mentioned and summarized in Section 3.2, if the feedgas pressure is being substantially reduced to send out low-pressure gas, then a fraction of this gas can be liquefied with little or no compression power expense by using a turboexpander liquefaction cycle.

- Economy of Scale — The per-capacity operating costs ($/gpd) are larger for small plants than for large plants. For example, a very small liquefaction plant that cannot operate unattended has a fixed minimum operating cost equal to at least one full-time person plus fringes, etc.

Transportation costs increase with the distance between the liquefaction plant and the LNG fueling station. Transportation costs are obviously zero if the liquefaction plant is collocated with the station (i.e., "onsite liquefaction").

LNG is transported in tractor-trailer cryogenic tank trucks (Figure 7) that typically hold approximately 10,000 LNG gallons. Most LNG tank trucks serving California are operated by ALT USA.

Figure 7. LNG is Transported in Cryogenic Tank Trucks.

Prior LNG economics analyses (e.g., References 2, 3, 5, 10) have either estimated LNG trucking costs by considering the capital and operating costs for the truck, driver, fuel, etc., or by using an approximate cost-per-mile estimate. These approximations are typically in the range of $1.50 to $3 per mile (one way) for 10,000-gallon LNG deliveries. Costs may be higher for short-distance or sporadic deliveries, or less for steady long-distance deliveries. Using this approximation, a 200-mile delivery of 10,000 gallons at $2.50 per mile equates to $0.05 per LNG gallon, for example.

Finance and investment considerations also affect LNG fuel supply economics. For example, high cost of money and/or high risk aversion tends to favor options with low capital costs relative to operating costs.

3.2 Liquefaction Technologies

LNG production involves feedgas pretreatment, liquefaction, and usually LNG storage. These are the basic functions of the three major LNG plant components. This breakdown is somewhat of an oversimplification because some functions are often partially integrated (e.g., pretreatment and liquefaction), and various additional plant equipment is or may be required (e.g., control and safety systems, truck-loading dock). However, this simplification facilitates a summary discussion of the key technology choices, which is consistent with the scope of this report. The key step of liquefaction is considered first, and this is followed by very brief discussions of gas pretreatment and storage.

Liquefaction involves transforming heat from the cleaned feedgas, first to cool it to its saturation temperature, and then to condense the vapor to a liquid. A variety of thermodynamic cycles have been developed for liquefying gases such as methane or natural gas. Table 1 lists some basic cycles that have been used or considered for small- to large-scale LNG production plants. More detailed technical descriptions of these cycles are available in many textbooks and technical papers (e.g., References 15 through 18).

It is helpful to establish a few basic principles and definitions in order to understand the tradeoffs associated with alternative natural gas liquefaction cycles. Refrigeration refers to a thermodynamic process that absorbs heat at temperatures below that of the environment. A refrigeration cycle usually involves compression of a working fluid, rejection of the heat-of-compression (and usually condensation of the working fluid) at ambient temperature, absorption of heat (and usually vaporization of the working fluid) at a low temperature, and repeat of the cycle. A key refrigeration cycle efficiency parameter is the coefficient of performance (COP), which is the rate of heat removal divided by the compression power.

Refrigeration is usually considered to be a closed cycle, i.e., the working fluid is not discharged. Gas liquefaction is inherently an open-system process. The objective is to withdraw the liquid. One or more refrigeration cycles can be applied to liquefy gases. Heat is transferred, in heat exchanger(s), from the gas to the refrigerant working fluid(s).

For some liquefaction technologies, the gas being liquefied is in fact the working fluid, e.g., it may be compressed, cooled, and expanded in an "open cycle." In this case, the COP efficiency doe not literally apply. But, an important efficiency figure-of-merit for all liquefiers is the rate of liquid production divided by the input power.

Table 1. Summary of Candidate Liquefaction Cycles for LNG Plants.

LIQUEFIER TYPE	OPERATING PRINCIPLE	REMARKS AND TRADEOFFS
Precooled Joule-Thomson (J-T) Cycle	A closed-cycle refrigerator (e.g., using freon or propane) precools compressed natural gas, which is then partially liquefied during expansion through a J-T valve.	Relatively simple and robust cycle, but efficiency is not high. Used in Anker Gram onsite liquefier for LNG truck fueling in British Columbia, which is no longer operating.
Nitrogen Refrigeration Cycle (also called closed Brayton/Claude cycle)	Nitrogen is the working fluid in a closed-cycle refrigerator with a compressor, turboexpander, and heat exchanger. Natural gas is cooled and liquefied in the heat exchanger.	Simple and robust cycle with relatively low efficiency. Efficiency can be increased by using multiple refrigeration stages. Used in CryoFuel Systems Hartland, WA, LFG liquefier demonstration.
Cascade Cycle	A number of closed-cycle refrigerators (e.g., using propane, ethylene, methane) operating in series sequentially cool and liquefy natural gas. More complex cascades use more stages to minimize heat transfer irreversibilities.	High-efficiency cycle, especially with many cascade steps. Relatively expensive liquefier due to need for multiple compressors and heat exchangers. Cascade cycles of various designs are used in many large-capacity peakshaving and LNG export plants.
Mixed-Refrigerant Cycle (MRC)	Closed-cycle refrigerator with multiple stages of expansion valves, phase separators, and heat exchanger. One working fluid, which is a mixture of refrigerants, provides a variable boiling temperature. MRC cools and liquefies natural gas with minimum heat transfer irreversibilities, similar to cascade cycle.	High-efficiency cycle that can provide lower cost than conventional cascade because only one compressor is needed. Many variations on MRC are used for medium and large lique-faction plants. ALT-El Paso Topock, AZ, LNG plant uses MRC.
Open Cycles with Turboexpander, Claude Cycle	Classic open Claude cycle employs near-isentropic turboexpander to cool compressed natural gas stream, followed by near-isenthalpic expansion through J-T valve to partially liquefy gas stream.	Open cycle uses no refrigerants other than natural gas. Many variations, including Haylandt cycle used for air liquefaction. Efficiency increases for more complex cycle variations.

Table 1 (continued)

LIQUEFIER TYPE	OPERATING PRINCIPLE	REMARKS AND TRADEOFFS
Turboexpander at Gas Pressure Drop	Special application of turboexpander at locations (e.g., pipeline city gate), where high-pressure natural gas is received and low-pressure gas is sent out (e.g., to distribution lines). By expanding the gas through a turboexpander, a fraction can be liquefied with little or no compression power investment. A variant of this cycle can produce LNG and reject nitrogen gas from high-pressure, high-nitrogen gas sources.	This design has been applied for peakshaving liquefiers, and it is currently being developed by INEEL in cooperation with PG&E and SoCalGas to produce LNG transportation fuel. Very high or "infinite" efficiency, but special circumstances must exist to employ this design. A similar system is used at Quadren LNG plant in Robbins, CA.
Stirling Cycle (Phillips Refrigerator)	Cold gas (usually helium) closed cycle using regenerative heat exchangers and gas displacer to provide refrigeration to cryogenic temperatures. Can be used in conjunction with heat exchanger to liquefy methane.	Very small-capacity Stirling refrigerators are catalog items manufactured by Phillips. These units have been considered for small-scale LNG transportation fuel production
TADOPTR	TADOPTR = thermoacoustic driver orifice pulse tube refrigerator. Device applies heat to maintain standing wave, which drives working fluid through Stirling-like cycle. No moving parts.	Currently being developed by Praxair and LANL for liquefaction applications including LNG transportation fuel production. Progressing from small-scale to field-scale demonstration stage.
Liquid Nitrogen Open-Cycle Evaporation	Liquid nitrogen stored in a dewar is boiled and superheated in heat exchanger, and warmed nitrogen is discharged to atmosphere. Counterflowing natural gas is cooled and liquefied in heat exchanger.	Extremely simple device has been used to liquefy small quantities of natural gas. More than one pound of liquid nitrogen is required to liquefy one pound of natural gas. Nitrogen is harmless to atmosphere. Economics depends on price paid for liquid nitrogen.

The "operating principle" column in Table 1 indicates if each cycle is open, closed, or a combination of the two. The "remarks and tradeoffs" column characterizes the relative efficiency of each cycle. This column also usually indicates example applications, particularly with respect to natural gas liquefaction. Note that, as a generalization, more complex cycles are usually more efficient. LNG plant selection choices in this regard involve capital cost vs. operating cost tradeoffs (Section 3.1). When combined with economy-of-scale considerations, this usually results in more complex cycles being used for large plants and simpler cycles being used for smaller plants.

However, the importance of efficiency (i.e., cost of inefficiency) depends on the specific application. Where feedgas or electric power is expensive, liquefier efficiency may be a key factor in the life cycle cost. But, in other extremes, such as landfill gas liquefaction, compression power costs may be secondary, and it may be prudent to compromise efficiency in order to minimize capital costs and facilitate convenient cleanup and liquefaction equipment integration (Reference 19).

The capital cost of natural gas liquefaction equipment depends on many factors including the liquefier type and capacity, as well as the feedgas composition and pressure. Our preliminary survey of costs indicates a substantial variation in this regard. Natural gas liquefier equipment cost estimates range from \$100/gpd to \$600/gpd for a 5,000-gpd liquefier, and from \$50/gpd to \$150 for plants larger than 100,000 gpd. It is difficult to generalize LNG plant cost estimates, because of the cycle and feedgas differences mentioned above, and because different quotes and estimates often include or exclude different equipment costs (e.g., feedgas pretreatment). A generalization we have observed is that cost estimates from firms that have built and installed liquefiers tend to be higher than estimates from organizations that have not built and installed liquefiers.

<u>Feedgas pretreatment</u> (or cleanup) equipment costs depend strongly on the gas source. For pipeline natural gas, usually only small amounts of carbon dioxide (typically 0.5% to 2%) and water (typically about 50 ppm) must be removed.[2]

On the other extreme, gas from landfills typically contains carbon dioxide in the vicinity of 50%, and water at saturation. Landfill gas may also contain sulfur compounds and volatile organic compounds (VOCs) that must be removed prior to liquefaction.

Various stranded gas reserves in California that might be candidates for small-scale liquefaction contain large concentrations of nitrogen. While nitrogen does not foul or plug liquefier heat exchangers, it is an "inert" that is not desired in high-purity transportation fuel in concentrations greater than the 1% range. Nitrogen "rejection" is part of the gas liquefaction process and not the gas pretreatment system, and it may be used to an advantage under certain conditions (Table 1).

[2] Non-methane hydrocarbons, such as propane, butane, and ethane, may also need to be removed if high-purity transportation fuel LNG is required. However, these "heavies" are usually removed by fractionation equipment, which is part of the liquefaction process and is not part of the pretreatment system.

Detailed technical discussions of feedgas pretreatment technologies are available elsewhere (e.g., Reference 20) and are beyond the scope of this report. However, general categories of technologies employed to remove water, carbon dioxide, and certain other constituents from natural gas include:

- Molecular Sieves—These are adsorbants (desiccants), which must be regenerated periodically. Therefore, two or more vessels (containing the adsorbant media beds) in parallel are required for continuous liquefier operation.

- Wet Chemistry Separations—These include amine, glycol, and methanol systems. The gas is typically passed counterflow with respect to these liquid chemical solutions in towers or columns.

- Membrane Separations—These require pumping the gas through porous media so that the constituents are separated by diffusion phenomena.

- Phase-Change Separations—These typically depend on the condensation (freezing) of water and/or carbon dioxide. The separation may be integrated with the liquefaction process (e.g., carbon dioxide is soluble in high-pressure LNG, and it can be removed as it precipitates during pressure reduction).

Feedgas pretreatment systems involve issues affecting scale economy, operating costs, and facility permitting. Pretreatment equipment costs have a significant economy-of-scale effect. In particular, the per-capacity costs (e.g., $/gpd) of gas cleanup systems for small-scale liquefiers receiving gas from landfills or other low-methane content sources can constitute a large fraction of the plant life cycle costs, and this has stimulated research to develop technology tailored for this purpose (e.g., Reference 19). An issue affecting both operations and permitting for most gas pretreatment strategies is what to do with waste streams such as molecular sieve regeneration gas. The most common solution is to feed this gas to a natural gas engine driving the compressor. However, this solution does not apply for turboexpander liquefiers or electric motor-driven compressors. Also, there may be challenges associated with permitting gas engine operation with some potential waste streams.

3.3 LNG Fuel Supply Infrastructure Options

This section considers some generic strategies for producing and delivering LNG to vehicle fueling stations. Sections 4 and 5 discuss current and planned projects that are specific examples of these strategies.

Figure 8 is a graphic illustration of six district LNG fuel supply scenarios. This graphic was developed in 1992 by Acurex Environmental (now part of Arthur D. Little, Inc.), slight variations have been used in various reports (e.g., References 2 and 5), and it has proven to be reasonably accurate with respect to LNG fuel supply strategies that are being pursued. In general, each of these scenarios seeks to minimize one or more of the principal cost elements affecting the delivered LNG price (as discussed in Section 3.1): feedgas, liquefaction, and transportation.

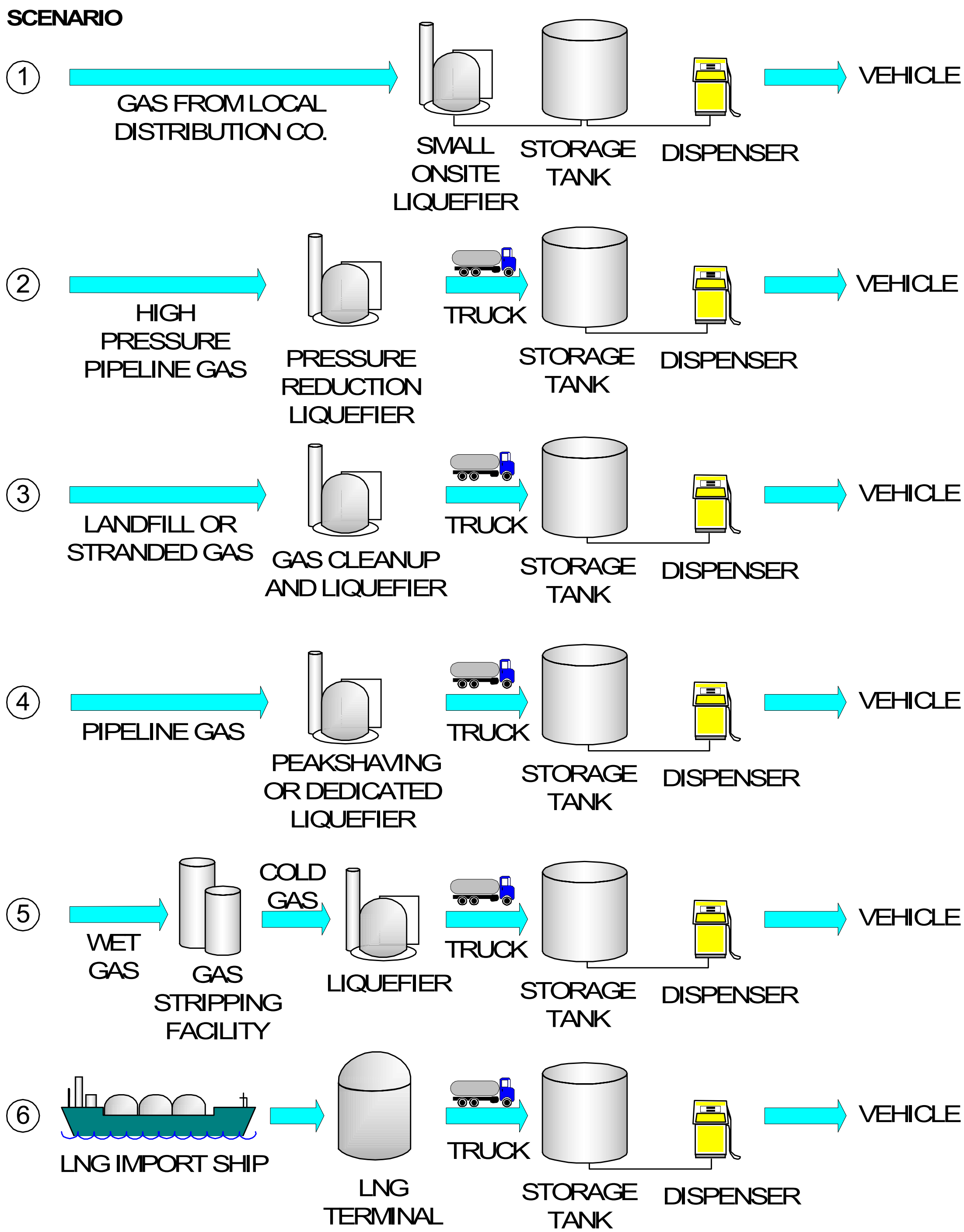


Figure 8. Six Candidate LNG Transportation Fuel Supply Scenarios (from Reference 2).

Scenario 1 is onsite liquefaction of natural gas most likely supplied by a local distribution company (LDC). “Onsite” denotes the fact that the liquefier is co-located with the LNG fueling station. No LNG trucking is required and so the transportation cost is zero. The liquefier capabity is relatively small because it matches a single fueling station demand. This scenario is analogous to most CNG stations (with the liquefier replacing the compressor and the LNG tank replacing the CNG cascade)

This scenario has been developed and implemented, but no onsite liquefier LNG stations are operational in California at this time. Such a system provided by Cryogas Engineering was used to fuel large trucks at the Crows Nest Resources coal mine in British Columbia in the late 1980s. More recently, Liberty Fuels developed and demonstrated an integrated liquefier plus LNG and CNG dispenser fueling station, although this facility is no longer in operation. These examples of this scenario are discussed further in Section 5.2.

Scenario 2 corresponds to applications of the “turboexpander at gas pressure drop” type of liquefier listed in Table 1. This option may substantially reduce liquefier operating costs where the requisite conditions exist. Example California projects that plan to utilize this strategy are discussed in Section 5.4.

Scenario 3 seeks to liquefy low-cost gas sources that are not now connected to pipelines. These sources include landfill gas (LFG), digester gas, flared gas, and gas reserves that are “stranded” because of their size, location, or composition. California gas sources in these categories are discussed in Section 5.1.

Liquefaction of gas in these categories often requires substantial pretreatment, e.g., to remove carbon dioxide, water, and other constituents from LFG. Also, many gas sources in these categories are not large (that is sometimes why they are stranded), and so they require small-scale liquefiers. The challenge for economical LNG production for this scenario is to capitalize on the low feedgas cost by applying economical but small-scale pretreatment and liquefaction technologies. Example California products pursuing Scenario 2 are discussed in Sections 4.2, 5.3, and 5.6.

Scenario 4 denotes a relatively large-scale peakshaving liquefier or purpose-built LNG plant. These two types of plants are considered to be the same scenario because the basic elements are the same. Feedgas would most likely be obtained from an interstate or intrastate pipeline. A relatively large-capacity liquefier justifies a complex but efficient cycle and provides a favorable economy-of-scale. On the other hand, LNG trucking is required, perhaps over a considerable distance, because a large-capacity liquefier must supply multiple fueling stations.

San Diego Gas and Electric (SDG&E) operated two LNG peakshaving plants in the 1970s, and these supplied LNG for fueling stations ranging from the San Diego Zoo (which operated LNG tour buses for 14 years) to Yosemite National Park. SDG&E discontinued peakshaving operations in 1980, and these LNG vehicle projects were discontinued. Liquid Carbonic constructed a purpose-built LNG plant in Willis, Texas in 1994 to provide fuel for various LNG vehicle fleets. Operations at this plant were discontinued soon after Praxair purchased Liquid Carbonic in 1998, and the equipment was subsequently purchased by ALT.

ALT investigated installation of the equipment in California, but eventually decided to restart the plant in Texas. Most of the LNG consumed in California today is produced by a plant fitting Scenario 4 (see Section 4.1), and potential future projects in this category are discussed in Section 5.5.

Scenario 5 includes LNG obtained from plants that were built for purposes other than LNG production. This includes various types of gas-processing plants, e.g., to extract liquids or high-value gases from gas streams that are primarily methane. This category also includes nitrogen rejection units (NRUs), which process natural gas to remove nitrogen so that the gas meets pipeline specifications.

The common feature of these types of plants is that a methane-rich gas stream is cooled as part of the process, and straightforward modifications enable the co-production of LNG. This may be an economically attractive proposition because the plant itself is already paid for (and perhaps fully depreciated), the cost of the required modifications is low, and the feedgas cost is also often relatively low. LNG for California stations has been delivered from out-of-state sources in this category (see Section 4.2), and utilization of some California gas reserves (Section 5.1) would require plants of this type.

Scenario 6 denotes trucking LNG from an import terminal to LNG fueling stations. This is conceptually straightforward, but there may be technical issues involved, depending on the terminal and LNG source. For example, all import terminals would not necessarily be equipped with facilities for loading LNG tank trucks (Figure 7). Also, most imported LNG has a methane content less than engine manufacturers' specifications, and so it must be processed to remove some of the heavier hydrocarbons. This has been done, and the equipment is relatively straightforward and inexpensive (Reference 21).

There are currently two active LNG import terminals in the U.S. (near Boston, Massachusetts, and Lake Charles, Louisiana), and both have occasionally provided LNG transportation fuel. LNG import terminals in the planning stage that are near California and their prospects for providing LNG transportation fuel are discussed in Section 5.8.

Section 4

CURRENT CALIFORNIA LNG TRANSPORTATION FUEL SOURCES

Sources of LNG currently used as transportation fuel in California are discussed here. The general locations of these sources are indicated in Figure 9. Section 4.1 describes the Topock plant, which is the primary source of California LNG, and Section 4.2 briefly discusses other sources.

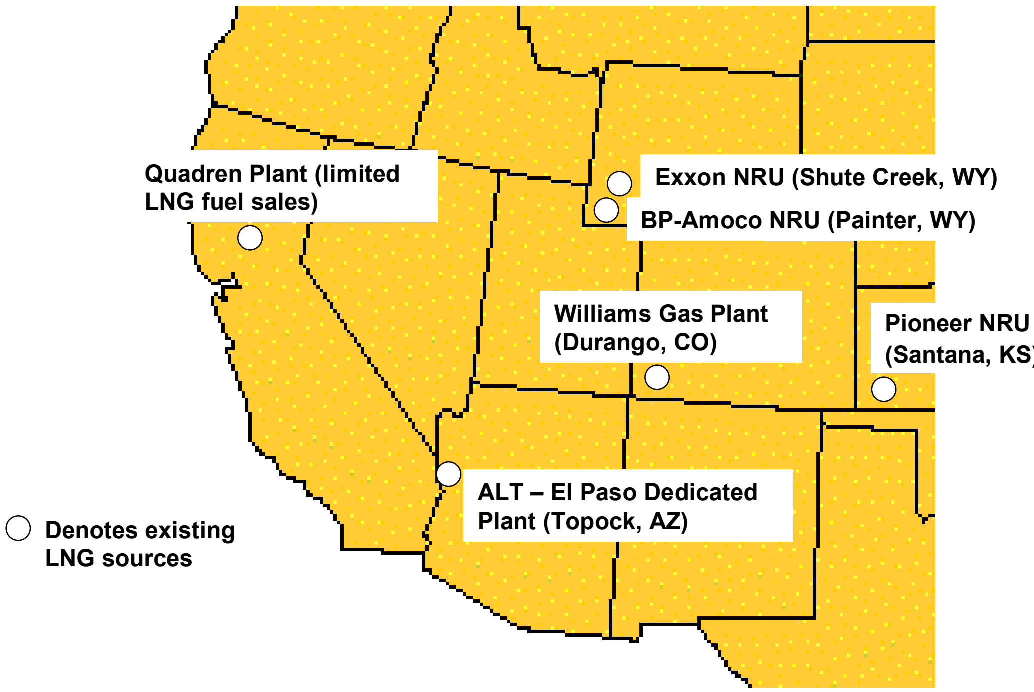


Figure 9. Current Sources of LNG Delivered to California.

4.1 Topock LNG Plant

Nearly all of the LNG currently delivered to California is produced by a liquefaction plant in Topock, Arizona, which is adjacent to the Arizona-California border. Figure 10 is a aerial photograph of the Topock LNG plant. The gas liquefaction equipment is on the left, and the LNG storage tanks and truck loading facilities are near the center.

The Topock LNG plant is located at the terminus of the El Paso interstate pipeline. The liquefier itself is owned by the El Paso Field Services Company, and the LNG storage and loading facilities are owned by ALT USA. The 86,000-gpd capacity liquefier uses an efficient mixed-refrigerant cycle (MRC, see Table 1) to liquefy gas from the El Paso interstate pipeline to produce LNG with a methane content of 97 to 98%. This purpose-built plant liquefies interstate pipeline gas and corresponds to Scenario 4 illustrated in Figure 8.

Figure 10. Aerial Photograph of ALT USA - El Paso LNG Plant in Topock, Arizona (photo courtesy of ALT USA).

As indicated in Figure 9, the Topock plant is roughly 250 miles (one way) from the greater Los Angeles and San Diego areas, and over 500 miles from Sacramento. Therefore, the fuel trucking distances to most California LNG vehicle fleets are significant.

From the Topock plant, ALT USA delivers LNG to three categories of customers:

- Industrial — Plants such as kilns, which have elected to use (vaporized) LNG as a process heating fuel instead of other fuels such as LPG.

- Municipal — Gas utilities (such as SDG&E) that supply small remote communities (such as Borrego Springs) that are not connected to the natural gas distribution network by using LNG satellite facilities.

- LNG vehicle fueling stations — LNG vehicle fleets in California and Arizona.

Each of these customer categories receives a significant portion of the LNG produced at the Topock plant. Arizona fleets receive roughly the same magnitude of LNG as California fleets. ALT has the option of supplying any customer with LNG from various other sources (e.g., in Texas and those listed in Section 4.2) at any time. Also, customer demands obviously vary with time. These factors make it difficult to precisely answer the question, "How much Topock-produced LNG is available for California LNG fleets, now and in the future?" ALT has given us some general, but approximate, guidelines in this regard (Reference 11), and we have applied these to estimate that very roughly one-third of the Topock plant's 86,000-gpd capacity (i.e., approximately 29,000 gpd) is currently available for California LNG vehicle fleets without substantially perturbing the current customer category allocation. The purpose of this approximation is to enable subsequent California LNG transportation fuel supply and demand comparisons. Without this approximation, such comparisons would have to include the entire U.S. as well as other uses of LNG, and this is beyond the scope of this report.

4.2 Other Past and Current LNG Sources

In-state and out-of-state sources of LNG used as a transportation fuel in California are summarized in Sections 4.2.1 and 4.2.2, respectively.

4.2.1 California LNG Plants

The only LNG plant currently operating in California is owned by Quadren Cryogenics and is located in Robbins, which is approximately 30 miles northwest of Sacramento (Figure 9). This facility liquefies gas from a stranded gas field with a high nitrogen content. There are many such high-nitrogen gas fields in this geographic area, although the nitrogen content of the Robbins gas field is exceptionally high (see Section 5.1). Quadren produces and sells ultra-high-purity methane for the commercial specialty gas market. This plant occasionally sells LNG for transportation fuel applications, and Quadren is formulating expansion plans to provide much larger quantities of LNG for this market (see Section 5.6).

The Quadren plant can be categorized as a nitrogen rejection unit (Section 3.2), although its purpose is not to produce pipeline gas. The plant utilizes a turboexpander cycle, which derives part of the refrigeration from the expansion of rejected nitrogen. The plant has typically operated at 4,000-gpd or less, although the original liquefier was designed to be expandable to a much larger capacity. Quadren is currently replacing the original liquefier with a new improved-design liquefier. They are also exploring utilization of gas from additional wells in the Robbins field.

Other LNG plants previously operated in California. A plant similar to the Quadren plant was once operated by McCulloch Oil to produce pipeline gas from a high-nitrogen gas field near Chowchilla, but this operation has been discontinued. As discussed in Section 3.2, SDG&E operated two peakshaving plants in Chula Vista (approximately 24,000 and 84,000 gpd, respectively) in the 1970s, but these plants were shut down and dismantled in 1980.

4.2.2 Out-of-State LNG Sources

Before 1999, and to a more limited extent since 1999 (i.e., after production at the Topock LNG plant began), LNG has been trucked into California from the relatively distant out-of-state sources indicated in Figure 9. Coincidentally, each of these sources is a gas plant with a primary purpose other than LNG production, but each has the ability to co-produce LNG as discussed in Section 3.2. These out-of-state LNG sources are (see also Reference 4):

- The Exxon (now Exxon Mobil) NRU near Shute Creek, Wyoming — This nitrogen rejection unit (NRU) processes gas from the Rocky Mountain Basin and can co-produce 66,000 gpd of LNG with a methane content greater than 97%.

- The BP (previously Amoco) NRU near Painter, Wyoming — This NRU also processes gas from the Rocky Mountain Basin and can co-produce 35,000 gpd of LNG with a methane content of at least 98%.

- The Pioneer Natural Resources USA (previously Mesa) NRU near Santana, Kansas — This NRU processes gas from the Anadarko Basin and can co-produce 10,000 gpd of LNG with a methane content of approximately 97%.

- The Williams Field Services "Ignatio" NGL plant near Durango, Colorado — This natural gas liquids (NGL) plant processes gas from the San Juan Basin and has been modified to co-produce 26,000 gpd of LNG with a methane content greater than 98%. This plant employs a proprietary design, which Williams projects could be applied to 135 NGL plants in the U.S. to produce relatively low-cost transportation fuel LNG (Reference 22).

Obviously, a key consideration to utilizing these out-of-state plants to provide LNG for California is the substantial trucking distance involved, which ranges from roughly 600 to 900 miles (one way) to the Los Angeles area. Another out-of-state LNG source that could indirectly affect California supplies is the 108,000-gpd ALT plant in Willis, Texas. This plant, which is scheduled to restart production at about the same time this report is published, is discussed in Section 5.5.

FUTURE CALIFORNIA LNG TRANSPORTATION FUEL SOURCES

A variety of sources are being developed or considered for providing LNG for California vehicle fleets in the future. These include nearly every strategy illustrated in Figure 8, and they all seek to achieve favorable economics by minimizing one or more of the three principal cost elements discussed in Section 3.1. These potential future California LNG sources cover not only a spectrum of technologies and capacities, but they also range from currently being installed to speculative.

The locations of specific planned facilities that could provide LNG transportation fuel to California are indicated in Figure 11, which also shows the locations of current California LNG sources. Potential future California LNG supplies utilize different types of natural gas sources, which are briefly considered in Section 5.1. Sections 5.2 through 5.8 discuss seven types of projects and specific projects that are being developed or considered for providing LNG for California LNG vehicle fleets. In each case, we summarize what is known about the strategy being pursued, the technology involved, the projected schedule and capacity (i.e., LNG gpd), key issues, and the current status. However, in many cases, this information is limited because plans are evolving or proprietary.

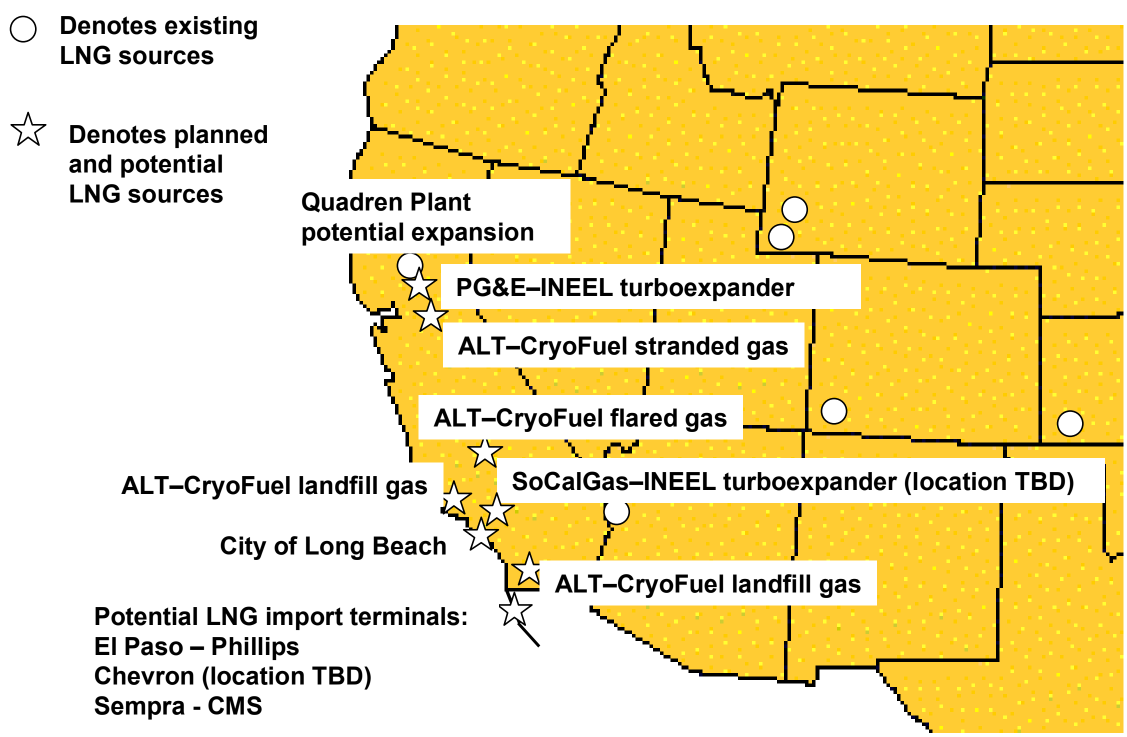


Figure 11. Current, Planned, and Potential Sources of California LNG.

5.1 California Natural Gas Sources for LNG

A variety of feedgas sources are being considered for large and small liquefaction plants that might be installed in California. These include pipeline gas (most of which originates from outside the State) and various types of what might be termed California indigenous natural gas. Different types of potential feedgas sources are discussed here.

It should be noted that there is significant overlap between different gas source categories (e.g., various California natural gas resources that will or could become pipeline gas). Also, there are ambiguities associated with commonly used terminology (e.g., there are various interpretations of what "stranded gas" means). Finally, there are many potential uses for most gas sources (e.g., connection to a public utility pipeline, connection to a private pipeline supplying one or a few private industries, onsite electricity generation) in addition to LNG production. The relative attractiveness of these options can change depending on market and regulatory conditions. The information presented in Sections 5.1.1 through 5.1.4 is intended to provide a context for subsequent discussions of current and potential California LNG production projects.

5.1.1 Pipeline Natural Gas

Pipeline natural gas is defined as gas that might be delivered to a liquefier from an interstate pipeline, intrastate pipeline, or gas utility local distribution system. It does not include gas from California wells delivered through a private pipeline to a small number of industrial customers. Pending California legislation, which is aimed primarily at California producers of low-Btu gas (which is defined in Section 5.1.3), would permit such private pipelines to operate without being subjected to Public Utilities Code provisions if they serve no more than five end users (Reference 23). In this analysis, we consider this gas to be in the categories considered in Section 5.1.2.

At the present time, on the average, approximately 15% of the natural gas delivered through pipelines to California consumers comes from wells within the State, and approximately 85% originates from wells outside the State. Approximately 46% of the gas supplied from outside California comes from the Southwest (San Juan, Anardarko, and Permian Basins), 10% comes from the Rocky Mountain Basin, and 28% comes from the Western Canadian Sedimentary Basin (Reference 14).

Reference 12 provides a description of California gas pipelines and their capacities, and References 13 and 14 report on recent pipeline gas prices. Pipeline natural gas is an obvious potential source of feedgas for liquefaction to provide California transportation fuel LNG. However, it may not be a source of low-cost gas, particularly if it is purchased "downstream" in the pipeline system where its price includes significant transportation and other costs. For example, Table 2 lists California natural gas prices reported by the DOE EIA (Reference 13) for August, 2001 (the most recent month for which data are available for all categories). The average August, 2001, city gate price reported by DOE EIA is very nearly the same as the average August, 2001, Northern and Southern California hub prices reported by the CEC (Reference 14). For reference, Table 2 also shows the prices expressed as $/LNG gallon. This may be regarded as the price per product gallon produced that would have to be paid for liquefier feedgas if no gas was consumed by the liquefier itself (e.g., for compressor power).

Pipeline Stage or Distribution Customer	**Average Price Paid ($/Mcf)**	**Approximate Equivalent LNG Feedgas Price * ($/LNG gallon)**
City Gate	2.80	0.23
Electric Utility	5.98	0.50
Industrial	5.52	0.46
Commercial	6.45	0.54
Residential	8.15	0.68

*At 12 LNG gallons / Mcf, i.e., neglecting any gas that might be consumed for compressor power or other purposes

Table 2. California Natural Gas Prices Reported by the DOE EIA (Reference 13) for August, 2001, and Equivalent LNG Feedgas Prices.

5.1.2 California Natural Gas Resources

California natural gas resources are considered here in two categories: reserves[3] that are or could be economically sold as pipeline gas, and resources[4] that are unsuitable for pipeline gas. It is important to emphasize that there is a significant "gray area" between what resources are and are not suitable for supplying pipeline natural gas. These two categories are defined here because this facilitates a simplified discussion of the potential for California natural gas resources to be used as feedgas for LNG transportation fuel production. The California Department of Conservation, Division of Oil, Gas, and Geothermal Resources (DOGGR, Reference 24), as well as various other references cited, should be consulted regarding the subtleties associated with supplying pipeline natural gas from California resources.

California Gas Reserves that Are or Could Be Sold as Pipeline Gas

California proven reserves of natural gas (both onshore and offshore) were estimated to be approximately 3.5 Tcf as of the end of 1999 (Reference 12). Slightly more than 1,000 MMcfd (about 15%) of California's gas consumption comes from within the State.

[3] Gas reserves are a subset of gas resources. See publications available from References 13, 14, or 24 for precise definitions of oil and gas terminology.

[4] *Ibid.*

The California DOGGR divides the State into six oil and gas districts, the boundaries of which are shown in Figure 12. There are two distinct types of gas produced in California: associated gas and non-associated gas. Associated gas, also called wet gas, is produced in association with petroleum production. Associated gas is produced primarily in central and southern California. Approximately 78% of California's production is associated gas. Elk Hills, which is in DOGGR District 4 (Figure 12), is the highest-producing gas field in the State. Non-associated gas, also called dry gas, is produced from gas fields not associated with petroleum production. Most of California's non-associated gas fields are in the northern part of the State (DOGGR Division 6), but there are also dry gas fields in other parts of the State. Non-associated gas accounts for approximately 22% of California's current production.

The price that would have to be paid for natural gas (e.g., for liquefier feedgas) from California wells that do or could sell gas to pipelines is obviously affected by pipeline gas prices. The precise relations between gas wellhead prices and hub, city gate, and other gas commodity and contracting prices are subtle (e.g., see Chapter 7, Natural Gas Prices, in Reference 12), but they generally fluctuate in unison. For example, following the "spike" in nearly all California gas prices in late-2000, the hub prices for gas entering California (at Topock and Malin) eventually stabilized in the \$2 to \$3/Mcf range as of late-2001 (Reference 14). This is equivalent to approximately \$0.17 to \$0.25 per LNG gallon for liquefier feedgas (assuming 100% of the feedgas is liquefied). This provides a very approximately point-of-reference regarding the potential economics of purchasing California gas that could also be sold to pipelines, as feedgas for a transportation fuel LNG plant.

However, there are additional factors associated with gas gathering equipment, allowable fluctuations in the purchased gas flow rate, and contracting issues that may affect LNG feedgas prices relative to pipeline gas prices. For example, there are concerns that California gas pipeline operators have been slow to provide appropriate market access to California gas producers (References 12, 23, and 25). Pipelines also prefer contracts that enable them to modulate gas purchases to meet demand requirements, and this can be challenging for some California producers. These factors may enable a liquefaction plant operator to contract with California producers to purchase feedgas at prices somewhat less than prevailing pipeline prices.

<u>California Gas Resources That Are Unsuitable for Pipeline Gas</u>

California gas resources in this category are those of geological origin that are either of inadequate quality (i.e., inappropriate Btu content) or uneconomical for supplying pipeline natural gas. These are sometimes referred to as stranded gas resources, but the designation "stranded" often has different meanings in different contexts. These gas resources have been frequently cited as a potential source of low-cost feedgas for transportation fuel LNG production.

There are subtleties associated with both the quality and economic reasons why natural gas resources may be stranded. The higher heating value of pure methane is 1014 Btu/ft^3, and the minimum acceptable pipeline gas heating value (dictated by the requirements of gas appliances) is usually about 870 Btu/ft^3. Many of the non-associated gas fields in Northern California have substantial concentrations of nitrogen and some also contain significant carbon dioxide, both of which are noncombustible and therefore lower in the gas heating value. Heating values of 700 to

Figure 12. The Six Oil and Gas Districts of the California Division of Oil, Gas, and Geothermal Resources. Indicated Cities are District Offices. (Map courtesy of DOGGR)

800 Btu/ft^3 are common for fields in this region, values as low as 141 Btu/ft^3 (the Robbins field) have been recorded. However, California utilities routinely purchase "low-Btu" gas with heating values as low as 700 Btu/ft^3, because this gas can be mixed with high-Btu gas to meet the 870 Btu/ft^3 criteria.

High-Btu gas has significant concentrations of heavier hydrocarbons such as ethane, propane, and butane. Much of the gas imported from Canada is high-Btu gas, and some of the associated gas produced in central and southern California is also high-Btu gas (e.g., gas from the Kettleman City field is approximately 1,230 Btu/ft^3). Coincidentally, the use of natural gas as a transportation fuel has created a problem for some high-Btu gas producers. In order to be responsive to California Air Resources Board (CARB) compressed natural gas (CNG) specifications (Reference 26), the Southern California Gas Company has restricted purchases of certain high-Btu gas. In response, the California Independent Petroleum Association (CIPA, Reference 25) has lobbied for relief from this restriction, which they do not believe to be in the best interests of the State or their members.

Low-Btu gas can be cryogenically processed to remove the nitrogen (i.e., like the NRUs discussed in Sections 3.5 and 4.2.2). However, the economics of NRU operation do not favor California low-Btu gas field conditions and pipeline sales opportunities at this time. One NRU in California has supplied pipeline natural gas in the past (the Chowchilla plant mentioned in Section 4.2.1), but none are known to be operating for pipeline gas production at this time.

Low-Btu gas in California has been considered as a potential source of low-cost feedgas for LNG production, because certain liquefaction cycles (Table 1) are well suited to efficient operation with high-nitrogen feedgas. However, there may be competing demands for low-Btu California gas, and these are likely to affect its pricing. First, the gas must be less than approximately 700 Btu/ft^3, otherwise it is sellable as pipeline gas as previously discussed (assuming the gas field is not too small or remote or otherwise stranded). Also, as discussed in Section 5.1.1, pending California legislation will enable producers to deliver even lower-Btu gas through a private pipeline to a limited number of customers without coming under the jurisdiction of the PUC.

Another competing demand for low-Btu gas is independent electric power generation, i.e., locating a gas-fueled genset at the wellhead or so as to be fed by multiple wells within a field. There has been considerable interest in this application of low-Btu and remote California natural gas for many years (e.g., Reference 27), and many of the issues involved are similar to those associated with small-scale and skid-mounted liquefiers. Yet another competing demand, which applies to some associated gas, is on-site firing of steam boilers that support enhanced oil recovery.

There is considerable uncertainty regarding the quantity of low-Btu natural gas resources in California. This is partially because when an exploratory gas well tests out as low-Btu, it is often capped, further tests to measure the size of the field are not usually carried out, and no reporting occurs (Reference 28).

There are various other reasons why natural gas resources may be unsuitable for supplying pipeline gas. For example, the gas field may be so far from existing gas lines that constructing a connecting line or drilling additional production wells is not economical. These are sometimes referred to as remote or shut-in resources. The size of the field is also an important factor. Distant but large fields may justify an investment for production that closer but smaller fields do not. Not all associated gas is suitable for supplying pipelines. Besides the previously discussed high-Btu gas, this can also be because the quantity is too small to justify any investment for utilization. This gas is usually flared.

The most comprehensive attempt to project the availability of “stranded” low-Btu and remote natural gas resources in California was carried out by Schrecongost for the CEC Siting and Environmental Division (now the Systems Assessment and Facilities Siting Division) in 1984 (Reference 27). This study was prompted by the belief that there are large volumes of low-btu and remote gas in California that are not being developed for pipeline gas, and this gas could be profitably utilized by locating electric generators at the wellhead. For the purposes of the Schrecongost study, low-Btu gas was defined as 800 Btu/ft^3 or less, and remote gas wells were defined as those that were distant from existing gas lines and were not producing within two years of their discovery date. The overall conclusions of this study are listed in Table 3, and aspects that are pertinent to liquefier applications are summarized in the following.

The Schrecongost study analyzed data from DOE, DOGGR, and California utility files, which included searches of well records in selected areas. Reference 27 includes graphs used to project the electricity production potential (in MW-years) as a function of gas reserve size and heating value, and the annual gas production (in MMcf/year) needed to support various capacities of electrical generation (i.e., MW). These parameters are analogous to LNG production, where 1 MW is equivalent to approximately 2,800 LNG gpd, and so 1 MW-year is equivalent to approximately 10^6 LNG gallons (for the heat rate used in the Schrecongost study and neglecting any gas consumed by a liquefier).

It was observed that multiple gas wells would generally be required to supply electric generators larger than about 1 to 2 MW (equivalent to approximately 2,800 to 5,600 gpd), because the average gas well in this category produces only 165 MMcf/year. It was also observed that California dry gas fields have an average life of roughly six years, and so generators (or liquefiers) would have to be used successively at two or more fields in order to economically utilize equipment lifetimes.

Twenty-six gas fields in Northern California were identified that could be classed as low-Btu, remote, or both. The total reserves in these fields were estimated to be approximately 72 Bcf (in 1984). Low-Btu and remote gas reserves in other California locations were also identified, but these were estimated to total no more than 5 Bcf. The study observed that this is an extremely small fraction of the total California natural gas reserves. If all these reserves could be used for electricity generation, they would produce only about 500 MW-year (which is equivalent to one typical large power plant operating for one year). If 5 Bcf of reserves were utilized for LNG production, they could produce up to approximately 60 million LNG gallons.

A.	The total reserves of low-Btu and remote natural gas discovered to date in the Sacramento and San Joaquin Valleys are an insignificant fraction of California's total dry gas reserves.
B.	Most of the low-Btu and remote natural gas reserves are currently being produced and sold and are neither idle nor going to waste.
C.	Even the lowest-Btu and most-remote natural gas may be exploited using existing technology and innovative marketing practices.
D.	The number of private investment and development firms now active in the State probably exceeds the number of uncommitted idle wells available for exploitation.
E.	Because high-Btu gas near existing fields and gas pipelines continues to be the target for most exploratory drilling, the reserves of low-Btu and remote natural gas are likely to continue to be an insignificant fraction of the total dry gas reserves.

Table 3. Conclusions of the 1984 Schrecongost Investigation of Low-Btu and Remote Natural Gas in Northern California (Reference 27).

The Schrecongost study (Reference 27) was carried out in 1984, and we know of no more recent studies addressing the subject of California low-Btu and remote gas utilization. However, our discussions with CEC and DOGGR staff (References 29 and 30) indicate that, while the quantities have probably changed somewhat in the last 17 years, the basic outlook for low-Btu and remote California gas for on-site electric power generation or LNG production probably has not changed very much. One thing that has changed, however, is that the previously mentioned CARB ruling pertaining to CNG standards has caused certain central California high-Btu gas reserves to also be considered "stranded." The potential of using this gas for LNG production depends on the outcome of efforts by CIPA and others to reverse CARB and/or SoCalGas policies on high-Btu gas, the incremental cost of liquefiers capable of removing the "heavies," and the feedgas price that would make this prospect economically attractive for all parties.

Two recent studies carried out for the CIPA also relate to California natural gas utilization and the corresponding costs. In mid-2001, McCann (Reference 31) surveyed selected CIPA members to estimate the amount of California gas that is now stranded but "could be brought into production given changes in current gas collecting and transportation policies." (The specific changes required were not defined in Reference 31.) McCann concluded that the potential additional California gas production is in the range 96 to 200 MMcfd, which corresponds to a 10 to 22% increase. It could be interpreted that some or all of this currently stranded California gas could be feedgas for LNG production, particularly if the desired policy changes (to enable sale as pipeline gas) are not implemented. Note that 96 MMcfd corresponds to approximately 1.1 million LNG gpd (neglecting gas consumption by the liquefiers).

It is difficult to compare the McCann study (Reference 30) with the Schrecongost study (Reference 27), because McCann projected potential production (i.e., MMcfd) while Schrecongost projected potential resoureces (i.e., in MMcf) and also because the studies were 17 years apart. However, if the 77 Bcf approximate projection by Schrecongost is divided by the 97

MMcfd lower estimate by McCann, the result is only 2.2 years of production, which appears to imply an inconsistency.

The other recent study carried out for the CIPA was by Premo (Reference 32) in mid-2001. Premo analyzed 1995 USGS forecasts of California onshore gas resources[5] in order to project potential additions of proved reserves[6] as a function of development and production costs (capital plus operating). The USGS regions are not generally the same as California DOGGR divisions (Figure 12), except that the USGS Northern California Onshore Region consists essentially of DOGGR District 6. Figure 13 is a reproduction of Premo's analysis of the potential additional gas reserves in this region as a function of their development and production costs. For reference, the current proved gas reserves in this region are approximately 0.5 Tcf. Premo's analysis indicates that substantial additions to California gas reserves are possible with higher development and production costs. It is reasonable to assume that some of these potential reserve additions could be used for liquefaction plant feedgas, but the price of this feedgas would probably be significantly greater than the cost shown in the abscissa of Figure 13.

5.1.3 Landfill Gas

Landfill gas (LFG) has received considerable attention as a potential feedgas for transportation fuel LNG production using small-scale liquefiers with suitable gas clean-up equipment (e.g., References 18, 29, 33). LFG is generated by the decomposition of organic waste in municipal waste landfills. The rate at which landfills produce LFG, and the time duration over which LFG is produced, depends on many factors such as the ratio of organic to inorganic waste in the landfill and the moisture content in the wastes. The average rate of LFG generation is often in the magnitude range 0.3 to 3 scfd/ton, although it may be higher or lower than this range in some cases (Reference 34). The LFG production rate following landfill closure usually resembles a bell-shaped curve with an effective duration in the 10- to 30-year range (although lifetimes can be longer and LFG generation rates can be slower for landfills with low moisture content, e.g., due to plastic sheeting covering closed landfills). The fraction of the LFG that can be captured depends on many factors including the design of the recovery system (e.g., horizontal perforated pipes installed while the site is still active can usually capture more LFG than vertical "wells" drilled after the site is closed).

The methane content of LFG is typically in the 40 to 60% range. Most of the rest of the LFG is usually carbon dioxide, although some LFG can contain substantial nitrogen as well. Methane and carbon dioxide are both greenhouse gases, but methane has a much higher ozone-depletion potential. The LFG is usually saturated with water vapor, and it contains small amounts of sulfur compounds (which cause the odor) and VOCs (some of which may be toxic). As briefly discussed in Section 3.2, feedgas pretreatment is a key issue for LFG-to-LNG strategies.

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[5] See publications available from References 13, 14, or 24 for precise definitions of oil and gas terminology such a resources and reserves.

[6] *Ibid.*

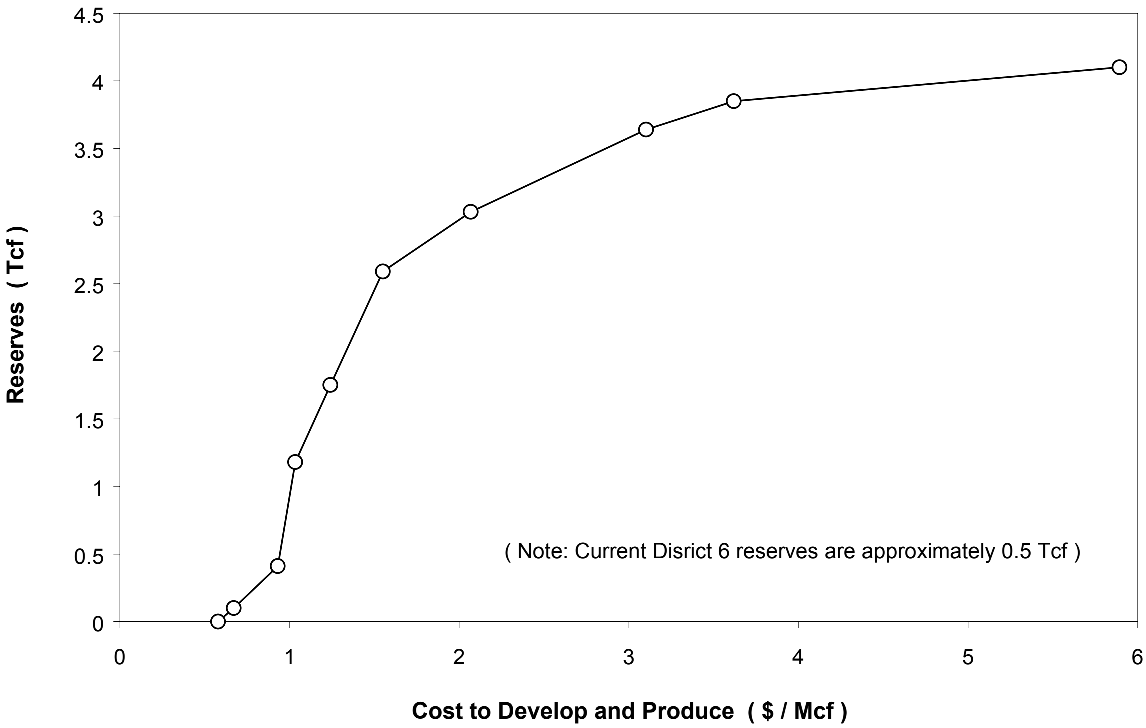

Figure 13. Northern California Onshore Cumulative Added Gas Reserves Versus Development and Production Cost. Projection by Premo based on USGS Data (Reference 31).

There are strong motivations for capturing and productively utilizing LFG, but there are other potential LFG uses that compete with LNG production. The primary reason for considering LFG utilization for some productive purpose such as LNG production is economics, i.e., LFG is potentially very low-cost feedgas. Another reason is that many laws and regulations pertaining to landfill management encourage or require LFG collection and control of LFG emissions. Key laws in this regard include Subtitle D of the Resource Conservation and Recovery Act (RCRA) and New Source Performance Standards (NSPS) under the Clean Air Act (CAA), including various amendments. Reference 35 includes a simple tabulation and explanation of regulations affecting LFG. The EPA and the California Integrated Waste Management Board (CIWMB) both provide many resources to assist landfill operators in developing LFG capture, management, and utilization projects (e.g., References 36 and 37).

There are a variety of potential uses of LFG, which compete with LNG production and influence potential feedgas pricing, and all of these are being applied at various landfills:

- Electricity generation (using reciprocating engines, gas turbines, boilers and steam turbines, or fuel cells)

- Industrial process heat

- Building space heating

- Chemical process feedgas
- Pipeline gas
- Vehicle fuel (CNG or LNG)
- (Flaring)

Note that, with very few possible exceptions, none of the above LFG utilization strategies require as much feedgas clean-up processing as LNG production. This observation was a key aspect of the LFG-to-LNG study conducted by Vandor (Reference 33).

The CIWMB maintains a listing of California MSW landfills (Reference 37). This table lists over 300 landfill sites and includes information such as the size in acreage and estimated MSW tons-in-place as of 2000, the actual or projected closure date, and existing or planned LFG control or utilization systems. This list includes 24 sites that are estimated to have over 10 million tons of MSW as of 2000. Most of the large California landfills (i.e., 1 million tons or larger) do or plan to productively use the LFG. Electricity generation is the most common use. Specific past, current, and planned projects, which use LFG as feedgas for LNG production, are discussed in Section 5.3.

5.1.4 Digester Gas

Digester gas refers to the gas generated from the anaerobic (i.e., without oxygen) decomposition of organic wastes. The primary source of digester gas that might be feedgas for LNG production is municipal wastewater (i.e., sewage treatment) plants, although high-volume agricultural operations such as feedlots or dairies can also generate useful quantities of methane-rich digester gas.

Prior studies (Reference 33) indicate that digester gas generally has a higher methane content than LFG (and therefore less pretreatment is required for liquefaction), but most wastewater treatment facilities produce inadequate gas flows for economical LNG production. However, some large facilities do, although many of these already utilize the digester gas for other purposes. For example, the San Jose Department of Water Quality plant near Alviso uses digester gas as fuel for reciprocating gas engines that generate electricity and drive blowers used in the wastewater treatment process (Reference 38). The digester gas, which is about 450 Btu/ft^3, can be mixed with purchased pipeline gas in various amounts. The facility can generate up to approximately 4 MW from digester gas and 14 MW from digester plus pipeline gas. Plant management adjusts electricity generation and purchases based on the relative prices of pipeline gas and electric power.

The issues pertaining to digester gas utilization for LNG production appear to be analogous to those for LFG utilization. The gas pretreatment and small-scale liquefaction technologies discussed in Sections 3.2 and 5.3 are potentially applicable to either LFG or digester gas.

5.2 Onsite Liquefier and LNG Dispenser Systems

There are three known past and present efforts to build or package small liquefiers integrated with LNG dispensers and located onsite at an LNG refueling station (i.e., Scenario 1, as depicted in Figure 8):

The "Anker Gram" liquefiers have a long and colorful history. The first small liquefier was designed and built by Anker Gram while he was the principal of Cleanair Combustion Systems of Vancouver, British Columbia. This liquefier provided fuel for LNG-fueled delivery trucks operated by Hudson's Bay Co. in Vancouver in the 1970s. Cleanair and the liquefier were acquired by Geosource (a large multinational company) in the early 1980s, and they promoted onsite liquefaction and LNG conversion kits for trucks. An improved and more compact 500-gpd liquefier was built by Gram in 1982, and it was used in Argentina to support an LNG vehicle demonstration project.

In the mid-1980s, Geosource's LNG interests (including the liquefier) were bought by Cryogas Engineering of Vancouver. In 1985, the liquefier was installed at the Line Creek Mine (near Sparwood, British Columbia) to support LNG-fueled mine trucks operated by Crows Nest Resources. Feedgas was provided by Inland Natural Gas, and the liquefier operated satisfactorily (Reference 39). Elders Resources (a large Australia-based company that was a Cryogas investor) subsequently assumed ownership of the liquefier and moved it to Australia.

In 1992, Elders sold the liquefier to EcoGas, a new Houston-based company that was promoting LNG vehicle projects. EcoGas installed the liquefier near Houston Metro's West terminal to provide fuel for their LNG bus fleet, but this goal was never achieved because the feedgas pressure was lower and CO_2 content was higher than the liquefier was designed for. In the late-1990s, the liquefier was purchased by John Gibson who is the principal of CryoSystems International. The liquefier is stored at the Quadren cryogenics LNG plant (Section 4.2) and it is not in use at this time.

The Anker Gram liquefier utilizes precooled dual-pressure Joule-Thomson cycle (Table 1) and produces approximately 500 gpd. A natural gas fueled Caterpillar engine drives the non-lubricated compressor. Molecular sieves with automatic adsorption and regeneration sequencing are used for feedgas pretreatment. While this liquefier is no longer in use, it is noteworthy because it is the only small liquefier that we know of that has ever operated routinely to provide fuel for an LNG vehicle fleet.

Liberty Fuels, Inc., designed, built, and demonstrated an onsite natural gas liquefier integrated with LNG and CNG dispensers (References 40 and 41). This development began in the early 1990s, when American Gas and Technology (AG&T) of San Jose designed a modular liquefaction system targeting the 250 to 2,000-gpd capacity range. In 1995, AG&T estimated the cost of a 1,000-gpd liquefier to be approximately $420,000, and they built and tested a 50-gpd pilot-scale liquefier (Reference 42).

Development and promotion continued through the late 1990s and into 2000 as Liberty Fuels. A 1,500-gpd liquefier integrated with 900-gal LNG storage, an LNG dispenser, and a

CNG dispenser was built and demonstrated in Santa Cruz (References 40 and 41). This unit liquefied 50-psi feedgas from a PG&E line. Desiccants and a triple-tower molecular sieve remove water and CO_2. A precooled Joule-Thomson cycle (Table 1) is employed. The cleaned gas is compressed to approximately 2,700 psi in a lubricated 4-stage compressor driven by a 454 cu. in. spark-ignited natural gas engine using a hydraulic pump and motor system. Lubricating oil is removed from the gas by coalescing filters. The gas is precooled by a R-22 refrigeration loop and cold gas returned from the J-T valve. Roughly 75% of the gas is liquefied as it passes through the microprocessor-controlled J-T valve, and the vapor is recirculated through the heat exchanger.

Liberty Fuels promoted onsite liquefiers and fueling stations in sizes from 1,500 gpd to 15,000 gpd, which would incorporate improvements including a Cummins natural gas engine and non-lubricated compressor. Options were offered including Liberty Fuels ownership (with customer purchase of the fuel on a take-or-pay basis), in addition to outright purchase. The liquefier is no longer in operation, and it is unclear if Liberty Fuels is still actively promoting onsite liquefiers and fueling stations at this time.

Pacific LNG Systems, Inc., is offering to package a liquefier, LNG storage tank, LNG dispenser, and optional CNG dispenser for onsite fueling of natural gas vehicle fleets (Reference 43). Their literature indicates that they plan to use a 5,000 gpd or higher capacity nitrogen-cycle liquefier (Table 1) manufactured by Cosmodyne (part of the Cryogenic Group, Murrieta, California) and feedgas from pipelines or wells. Pacific LNG literature indicates that financing can be provided by Edge Capital so that the user fleet does not have to directly pay the initial capital cost of the equipment. No onsite liquefiers and fueling systems are known to have been packaged and installed to date by Pacific LNG.

It should be noted that many other companies are well qualified to design and manufacture natural gas liquefies of the size range discussed here, and many of these companies would be pleased to package these liquefiers with dispensers to provide an onsite liquefaction and LNG or L/CNG fueling facility. The three examples highlighted here were selected because they involve systems that have actually been built, or the firm has distributed literature indicating that they are in this business. There is in fact a relatively artificial distinction between the onsite liquefier and dispenser systems considered here, the small skid-mounted liquefiers considered in Section 5.3, and the small pressure-drop liquefiers discussed in Section 5.4. These sections should be considered together with respect to small natural gas liquefier design and manufacturing capabilities.

Onsite liquefiers seek favorable economics by eliminating LNG trucking costs (and also duplicate LNG storage costs at the liquefier and the fueling station) as discussed in Section 3.1. An important issue for this strategy is the cost of the feedgas, particularly if it is pipeline gas purchased from an LDC. Example California pipeline gas prices, as of August, 2001, were listed in Table 2. Favorable economics for this strategy would appear to require either lower-cost feedgas or an assumption that LNG trucked from other sources will be relatively expensive.

5.3 Small Skid-Mounted Liquefiers

This section addresses the strategy of using small skid-mounted liquefiers to produce LNG transportation fuel from low-cost feedgas sources such as landfill gas (LFG), digester gas, associated gas that is otherwise flared, and/or gas reserves that are stranded. This is Scenario 2 in Figure 8.

LFG typically contains roughly 50% carbon dioxide, and it may also contain significant volatile organic compounds (VOCs), sulfur compounds, and/or inerts. Digester gas, which is gas produced by anaerobic decomposition at wastewater treatment plants (and may also be produced from agricultural wastes) usually contains slightly more methane than LFG. Liquefaction of LFG or digester gas obviously requires substantial pretreatment of the feedgas using technologies such as those listed in Section 3.2. Vandor (Reference 33) studied LNG production from LFG or digester gas with a particular focus on pretreatment options, candidate landfill sites, and economics.

As discussed in Section 5.1, natural gas reserves are sometimes uneconomical to develop, produce, and sell as pipeline gas. These reserves may be stranded for any number of reasons, e.g., they are small, far from existing pipelines, or have a low Btu content. We also consider other small gas sources, such as associated gas that is normally flared, to be in the same category as stranded gas. Even though they are quite different, LFG, digester gas, and stranded gas are all addressed here because some of the issues associated with using them as a feedgas to produce LNG are similar.

The concept of placing a skid-mounted liquefier near a landfill to produce LNG has been considered for well over a decade. Various companies have designed equipment and integrated systems for this application. There have been at least two demonstrations, and one company is actively developing and promoting systems of this type at this time.

In 1995, EcoGas, a Texas-based company, installed and operated a LFG-to-LNG plant at the Fort Bend County Landfill near Rosenburg, Texas (Reference 44). Technical design details are sketchy, but this installation used a skid-mounted liquefier and gas pretreatment system. Maximum LNG production is reported to have been 6,200 gpd. Problems were encountered with the gas pretreatment equipment, which included membranes and a pressure swing adsorption (PSA) system. Molecular sieves were added, but little information is available regarding the final configuration and performance. In 1996, Ecogas planned to install more LFG-to-LNG systems, which were to benefit from legislation mandating LFG recovery and providing tax credits (Reference 45), but we are not aware that these plans materialized.

A company that is currently active in developing skid-mounted equipment for LFG-to-LNG is CryoFuel Systems, Inc. (CFS), of Monroe, Washington. In the mid-1990s, researchers at the University of Victoria, British Columbia, identified small liquefiers as an economical approach for CNG and LNG vehicle fueling (Reference 18). Research was carried out to identify the best-suited liquefaction cycle. LFG emerged as the primary feedgas source of interest, and CFS was formed. Many technical papers and presentations, which are too numerous to cite here, document the evolution of CFS technology and market focus.

In 1999, CFS, teamed with ALT, was awarded a contract by the CEC to demonstrate a LFG-to-LNG system and LNG fueling facility in San Diego. CFS and ALT subsequently received additional sponsorship from DOE and other agencies for additional small liquefier development work on a demonstration near Sacramento. The schedules for these demonstrations have slipped, plans have changed, and CFS has recently completed demonstration of a LFG-to-LNG pretreatment and liquefaction system at the Hartland Road Landfill in Victoria, British Columbia (Reference 19).

The CFS unit tested at Hartland (Figure 14) evaluated the technologies selected for gas pretreatment and liquefaction. Condensables are removed from the feedgas in a phase separator and activated carbon unit. Most of the carbon dioxide is then removed by dual freezing heat exchangers followed by a temperature-swing absorber bed. Most of the methane in the gas is liquefied using a nitrogen refrigeration cycle (Table 1). An electric motor drives the nitrogen compressor, and a dual-fuel engine-generator is available to provide electric power. The Hartland LFG has an exceptionally high nitrogen content (roughly 30%). Flash vessels remove nitrogen gas (and some methane gas) from the LNG.

Figure 14. CryoFuel Systems LFG-to-LNG Pilot Plant Tested at the Hartland Landfill (photo courtesy CryoFuel Systems, Inc.).

The CFS pilot facility tested at the Hartland produced approximately 225 gpd of LNG with a composition of roughly 96% methane and 4% nitrogen. Output decreases as the nitrogen content of the feedgas increases, and CFS interprets that these tests validate their prediction of approximately 1,300 gpd with 9% nitrogen LFG. CFS points out that conventionally defined liquefier efficiency figures-of-merit are not very relevant when the feedgas is free, and the energy aspects of the feedgas cleanup process should also be considered (Reference 19).

ALT and CFS Systems recently announced plans to install four CFS liquefier skids in California. The applications and locations (which are also noted on the Figure 11 map) are:

- San Diego - LFG liquefaction
- Simi Valley - LFG liquefaction
- Kern County - Flared gas liquefaction
- Stockton - Stranded gas liquefaction

Applications of relatively small-scale skid-mounted liquefiers to produce LNG from LFG, digester gas, or stranded gas sources seek favorable economics by utilizing low-cost (often zero cost) feedgas. Critical requirements for favorable economics include acceptable costs for equipment, operation, and LNG transportation. Low equipment costs may be a challenge, especially if substantial gas pretreatment is required, because of economy-of-scale reasons (i.e., $/gpd costs generally increase as gpd capacities decrease). As discussed in Section 3.2, we have observed price quotes and estimates for small-capacity (e.g., 5,000-gpd range) liquefaction systems ranging from $100/gpd to $600/gpd.

The fuel or power (e.g., for compression) costs are low or zero for this strategy, but labor costs may be challenging to down-scale. For example, if full-time attended operation is required, this alone will consume about a third of the revenue produced by a 5,000-gpd LNG plant. Average LNG trucking distances should be shorter for small-scale plants relative to large-scale plants, and they may be zero if a large fleet fueling station can be co-located with the liquefier. It remains to be seen how achievable this will be. Note, for example, that refuse collection trucks do not usually drive to landfills. They drive to transfer stations, and transfer trucks usually take the compacted refuse to landfills. A strategy for improving LFG-to-LNG economics is to sell the cleaned carbon dioxide, but concerns have been expressed regarding the likelihood of achieving this goal (References 19 and 33).

This section highlighted a few companies because published information regarding their skid-mounted liquefiers is available. Other companies are known to be suppliers of skid-mounted liquefaction equipment, including: Cosmodyne (Marrieta, California, part of The Cryogenic Group), Kryopak, Inc. (Lenexa, Kansas), NexGen Fueling (Burnsville, Minnesota, a Chart Industries company), and Praxair (Tonawanda, New York). The Gas Technology Institute (GTI, Chicago, Illinois) is working with ETI to develop a low-cost small-scale liquefier technology (a MRC using mass-produced compressors) that would be suitable for a skid-mounted LNG plant,, but this system is not yet commercialized. Also, other companies that specialize in large-scale liquefaction plants, but are also capable of designing and fabricating small skid-mounted liquefiers, are listed in Section 5.5.

5.4 Small Pressure-Drop Liquefiers

The concept of using a turboexpander to liquefy part of a gas stream experiencing a substantial pressure drop was noted in Section 3.1 and Table 1. This concept has been applied to natural gas peakshaving plants (Reference 17), and its potential applicability for LNG transportation fuel production has been recognized for some time (Reference 5).

The Idaho National Engineering and Environmental Laboratory (INEEL, which is a contractor-operated DOE laboratory) began researching this approach for producing LNG transportation fuel in the mid-1990s. INEEL is developing an innovative approach that substantially lowers the cost of small turboexpander liquefaction plants relative to prior technology. Details of their design are proprietary, but INEEL's published capital cost target is $350,000 for a 5,000-gpd liquefier (i.e., $70/gpd), which is quite low indeed (Reference 46).

In 1999, CEC awarded contracts to PG&E and Southern California Gas, both of which teamed with INEEL to install and demonstrate small-scale liquefaction facilities and LNG fueling stations based on the INEEL technology. Several schedule revisions, technical plan changes, and technology funding additions have occurred. Site permitting and installation design is currently underway for the PG&E demonstration, which will be a 10,000-gpd turboexpander liquefier bridging two pipeline pressure drops in Sacramento. Equipment installation is now targeted for early 2002 (Reference 47). The SoCalGas demonstration liquefier will be installed in Southern California following completion of the PG&E unit.

These projects and the INEEL technology have been highlighted in this section because they are the only known active projects applying turboexpanders at gas pressure-drop locations and because the INEEL technology seeks to enable very substantial cost reductions. However, many other firms such as those listed in Sections 5.3 and 5.5 are capable of designing and fabricating turboexpander liquefaction plants of various sizes.

5.5 Peakshaving Liquefiers and Large Purpose-Built Liquefiers

Peakshaving refers to the practice of liquefying natural gas and storing LNG during periods of low demand, and regasifying the stored LNG during demand peaks. This practice levelizes the pipeline flow and enables a gas utility to supply a demand peak that is higher than their pipeline capacity or contract. There are approximately 55 LNG peakshaving plants operated by gas utilities in the U.S. and Canada. Peakshaving plants can provide transportation fuel LNG, and this is being done from various facilities including the Northern Indiana Public Service Company (NIPSCO) in La Porte. LNG from peakshaving plants can be especially economical if the LNG price does not include amortization of the plant cost. As discussed in Section 3.2, SDG&E operated two peakshaving plants in the 1970s (which also provided transportation fuel), but they were shut down in 1980. There are no LNG peakshaving plants in California at the present time. The nearest LNG peakshaving plants are in Elko, Nevada, and Newport, Oregon, but these have not been significant suppliers of LNG transportation fuel to California.

A purpose-built liquefier refers to a relatively large (e.g., roughly 50,000 gpd and above) liquefaction plant installed with the specific objective of supplying LNG to be used as a transportation fuel and similar purposes. The El Paso-ALT Topock liquefier discussed in Section 4.1 is an example of a purpose-built plant. The 108,000-gpd LNG plant built for Liquid Carbonic (now part of Praxair) in Willis, Texas, is another example. The Willis plant is now owned by ALT. The plant is being refurbished, and LNG production is scheduled to be restarted near the end of 2001 or beginning of 2002. Peakshaving liquefiers and large purpose-built liquefiers are both considered here because the equipment involved is very similar.

A purpose-built liquefier installation strategy would seek favorable LNG economics through equipment and operation economy-of-scale and perhaps advantageous gas contracting opportunities. Large LNG plants can justify more efficient liquefaction cycles (Table 1), and the unit capital cost ($/gpd) tends to decrease as gpd capacity increases. Operation and maintenance costs per gpd also tend to be lower for large-capacity plants. Consumers such as electric power generators, large industrial users, and LNG plants are also in the best position to negotiate advantageous gas supply and pipeline transportation contracts.

ALT is reported to have considered installation of the previously mentioned "Willis" LNG plant equipment in California. However, attractive location, permitting, and gas contracting opportunities were not identified, and ALT decided to restart the plant at its Willis, Texas, location as discussed above. The City of Long Beach is planning to install an LNG plant that may be considered a purpose-built liquefier, and this plant is discussed in Section 5.7.

California peak-period natural gas consumption is nearing the maximum level that can be supported by the existing pipeline network (Reference 12), and this would seem to open up opportunities for LNG peakshaving plants, which could also supply LNG transportation fuel. There is, in fact, increased use and expansion of underground gas storage facilities in California operated by PG&E, SoCalGas, and unregulated companies (Reference 12). However, no plans for LNG peakshaving plants in California are known to exist at this time.

The potential exists to enhance the economics of a California LNG plant by designing it to serve two compatible purposes: gas-supply peakshaving and LNG transportation fuel production, for example. The peakshaving could be for a gas utility or for a single large gas consumer such as an electric generating station. In this scenario, pipeline gas would be liquefied and stored during periods of non-peak gas demand. LNG could be sold as a transportation fuel, and the natural gas fueled power plant could be operated using vaporized LNG from storage during periods of high gas demand. This is equivalent to contracting for gas on an interruptible basis, which may provide significant savings. A typical-size 500-MW power plant consumes natural gas at a rate equivalent to roughly 1,000 gallons/minute of LNG at peak load. Eight hours of operation from storage therefore requires 480,000 gallons, which is less LNG storage than most existing peakshaving plants. Such an LNG plant could also economically use electric-drive compressors, because electricity would be available from the power plant during periods of low demand, when gas is being liquefied. However, our discussions with large California electricity generation companies have not identified keen interest in this strategy.

U.S. companies that have traditionally contracted for the design, engineering, and construction of large purpose-built and peakshaving LNG plants include Black & Veatch

Pritchard, Chicago Bridge & Iron, Kellogg Brown and Root (now part of Halliburton), and Pitt-Des Moines.

5.6 Quadren Plant Expansion

The only LNG plant operating in California at this time is the Quadren Cryogenics facility in Robbins (Figure 9). As discussed in Section 4.2, this is a small-capacity plant that liquefies high-nitrogen gas from a stranded field. The Quadren facility uses a special liquefaction cycle that provides much of the needed refrigeration through turboexpansion of the waste nitrogen. The plant is currently used to produce ultra-high-purity methane, which is sold to the specialty gas market. They have occasionally sold LNG for use as a transportation fuel, but the current plant is not well suited for this market.

Quadren is developing plans to utilize additional gas wells in Robbins field and to expand their liquefaction plant capacity in order to produce LNG for the transportation fuel market (Reference 48). They are considering partnering options as a means for pursuing this opportunity. Quadren's strategy is to secure low-cost feedgas sources and apply their specifically suited liquefaction cycle design to achieve favorable LNG production economics. They are currently testing a new pilot-scale liquefier at their Robbins plant. Details of Quadren's plans are confidential with respect to specific schedules and capacities.

5.7 Long Beach Project

The City of Long Beach operates its own gas utility, which is part of Long Beach Energy. Long Beach also operates a fleet of CNG vehicles and has one of the largest public-access CNG fueling stations in the U.S. They plan to expand this fleet, and they also plan to procure LNG-fueled refuse collection trucks.

Long Beach Energy is developing plans to build an LNG plant. This plant will liquefy gas purchased by Long Beach Energy, provide LNG and L/CNG for City-operated and other vehicles, and produce LNG to be sold to other California LNG fleets. Tentative plans are to install two 35,000-gpd capacity liquefiers and substantial onsite LNG storage. Long Beach Energy is currently evaluating candidate sites and a variety of fleet fuel-supply contracting options, partnering opportunities, and cofunding sources for this LNG plant.

5.8 LNG Import Terminals

Three companies have announced plans to build (or investigate building) LNG import terminals on the West Coast of North America in or near California:

- El Paso teamed with Phillips Petroleum
- Chevron (now Chevron Texaco)
- Sempra Energy teamed with CMS Energy

These projects seek to ship low-cost natural gas from overseas sources (e.g., Australia) to North America as LNG. The import terminals would include facilities for LNG receiving, storage, and regasification. All plans appear to be driven partially or entirely by the rapidly increasing demand for natural gas in California, which in turn is driven by gas-fueled electric power generation requirements. Available information regarding these three LNG import terminal planning projects is summarized in Table 4.

The trade press has reported that additional companies (e.g., Mitsubishi, Royal Dutch Shell, Marathon Oil) are also investigating the possibility of building an LNG import terminal in or near California, but Table 4 lists only companies that have officially announced (e.g., through press releases) such plans. Also, the combinations of companies partnering[7] to investigate these LNG import terminal projects has already changed, and they will probably change more as the investigations move forward. For example, Repsol YPF (a Spain and Argentina company that owns substantial gas reserves in Bolivia) previously announced plans to investigate exporting LNG to the west coast of Northern Mexico, but they are now part of the Sempra-CMS project (Table 4.).

Most of the specifics regarding these LNG import terminal plans are treated as confidential information by the firms involved, because these are very expensive and competitive projects. They are expensive because the liquefaction plant, LNG ships, and receiving terminal are all large-scale, high-cost items, and contracting commitments for all elements must usually be developed simultaneously. For example, Sempra-CMS press releases identify a $400 million budget for their import terminal. Permitting will potentially be a long and expensive process, certainly for a U.S.-based terminal, and perhaps also for a terminal located in Mexico.

These projects are highly competitive because it is highly unlikely that all three import terminals will be constructed. Once it is clear that one or perhaps two projects are in fact going forward, the other projects will be dropped. We are concerned that this competition may affect the information released by firms pursuing these projects, e.g., target dates may be intentionally optimistic to discourage competitors.

We have had discussions with all the firms planning LNG import terminals. All are very guarded with respect to their specific plans. We have ensured that these firms are aware of LNG transportation fuel demands and opportunities in California. None will commit, at this time, to include the capability to provide LNG transportation fuel in their import terminal facility designs. However, Phillips, who is teamed with El Paso, does acknowledge that they are investigating this possibility as part of their planning process. Besides the obvious challenges of permitting and building an LNG import terminal, there are specific issues associated with the prospect of including LNG transportation fuel capabilities:

- Market size — Compared to the demand for natural gas for electricity generation and conventional purposes, the LNG transportation fuel market appears to be a literal “drop in the bucket.” For example, our 2006 projection of approximately 200,000-gpd demand (Figure 5) is less than 3% of the El Paso-Phillips target capacity of 680 MMcfd (approximately 7.2 million gpd).

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[7] At these early project investigation stages, the companies usually cooperate through memoranda of understanding or letters of intent instead of forming official partnerships or consortia.

Table 4. Summary of California-Vicinity LNG Import Terminal Planning Projects.

COMPANY OR COMPANIES[1]	TERMINAL LOCATION[1]	LNG SOURCE(S)	CAPACITY	TARGET DATE[2]	REMARKS
El Paso-Phillips	Rosarito, Baja California, Mexico	Prior letter of intent to supply LNG from Darwin, Australia, plant to be built by Phillips to liquefy gas from Sunrise field in timor Sea has expired. Other sources including Petramina (Indonesia) have been mentioned in press articles.	~680 MMcfd	2005	El Paso involved in other North America import terminal projects. Kellogg Brown and Root (now part of Halliburton) selected for terminal engineering and construction. LNG offloading capabilities being considered.
Chevon (now Chevron Texaco)	TBD between Ensenada and Los Angeles	Australia (e.g., Northwest Shelf Venture) and other sources being considered.	~500 MMcfd	2006	Chevron Texaco has substantial gas reserves in Australia. This is one of several LNG import terminals being planned for North America by Chevron Texaco.
Sempra-CMS	Baja California, Mexico site between Ensenada and Rosarito	MOU with consortia (Repsol, British Gas, BP, Bridos) to negotiate for LNG from Bolivia gas fields. Other potential sources (e.g., Australia, Indonesia, Malaysia) also mentioned in press articles.	~1,000 MMcfd	2005	Sempra owns SoCalGas and SDG&E. CMS operates Lake Charles LNG import terminal. 300-acre site for terminal has been selected. Connections to two pipelines planned.

1 - In order of public announcement dates.
2 - Initial operation date, sometimes prefixed by “as soon as” in press releases.

- On-shore vs. off-shore regasification — None of the projects have announced firm plans for on-shore vs. off-shore (i.e., floating) facilities, although some have expressed a preference for on-shore. Off-shore regasification of LNG (with gas transported on-shore through a pipeline) presents an obvious challenge for loading LNG tank trucks. However, off-shore regasification may lend itself to LNG transfer to smaller barges (see last item in this list).

- Methane content — The methane content of the LNG imported from most of the candidate sources is less than 90%. The preferred methane content specified by most heavy-duty natural gas engine manufacturers is 95% or greater. Relatively straightforward and economical equipment (which consists primarily of heat exchangers) has been developed for removing heavy hydrocarbons from LNG, and this type of equipment is in routine use at NIPSCO (Reference 21).

- Truck loading facilities and LNG transportation — The capability to load tank trucks with LNG requires extra (but straightforward) features to be included in an import terminal facility design. This also introduces extra (but straightforward) safety requirements. Concern has also been raised about trucking LNG cargos from Mexico to the U.S., but LNG is routinely trucked from the U.S. to Mexico. Another option that has been mentioned is to barge LNG from the import terminal to a much smaller offloading facility in California that is closer to user fleets. While this strategy provides some advantages, it also obviously introduces new challenges.

It is important to monitor LNG import terminal planning developments. This could potentially provide a huge source of low-cost LNG transportation fuel for California, although, for an LNG terminal in Baja, Mexico, trucking distances and costs (to other than the San Diego area) would be significant. Even if an LNG import terminal with no LNG capabilities is built near California, this could still indirectly benefit the LNG transportation fuel market by increasing gas supplies and thereby moderating gas prices.

Section 6

LNG SUPPLY/DEMAND COMPARISONS AND CONCLUSIONS

In Sections 6.1 through 6.4, we compare California LNG transportation fuel demand projections (which were discussed in Section 2) with LNG supply sources in four stages: current supplies, near-term new supplies that are in process, mid-term new supplies that are planned, and longer-term potential future supplies. Conclusions are summarized in Section 6.5.

Projection of future California LNG transportation fuel supply quantities and schedules requires substantial subjective judgment and even speculation. One prediction that is reasonably certain is that not all of the LNG sources discussed in Section 5 will, in fact, produce LNG at their planned capacities and target dates. Therefore, we have taken an "either-or" approach to projecting certain LNG supplies beyond current sources. This approach is explained further in Sections 6.2 through 6.4.

Our tempered approach to projecting future LNG supplies should not be misinterpreted as a lack of confidence in and support for all efforts to develop new supplies of LNG transportation fuel for California.

6.1 Current LNG Sources

Current LNG transportation fuel supplies to California were discussed in Section 4. The main supply is the ALT USA-El Paso LNG plant in Topock. As discussed in Section 4.1, we project that, on the average, approximately one-third of this plant's 86,000-gpd capacity is typically available for California LNG and L/CNG vehicle fueling needs. This LNG supply level is compared to our demand projection in Figure 15.

For reference, the absolute maximum Topock plant capacity of 86,000 gpd is also shown in Figure 15, and the out-of-state sources that have occasionally supplied LNG to California are listed. ALT has some flexibility to supply its various customers with LNG from different sources (e.g., the newly restarted Willis, Texas, plant discussed in Section 5.5 and the listed out-of-state sources) and therefore adjust the portion of the Topock plant production available to California NGVs. However, it is unrealistic to anticipate that this portion will increase to anywhere near the maximum plant capacity. Figure 15 indicates that, if California LNG consumption increases at the projected rate, the portion of the Topock plant output delivered to California does not increase, and no new sources start producing, then LNG will have to be trucked from the more distant out-of-state sources starting in early 2002.

6.2 Near-Term New LNG Sources

New LNG sources that are planned, funded, and at or near being installed include the four initial skid-mounted 5,000-gpd CFS liquefiers being installed by ALT as discussed in Section 5.3, and the two initial 10,000-gpd INEEL turboexpander liquefiers being installed by PG&E and SoCalGas as discussed in Section 5.4. Note that the four CFS units total to 20,000 gpd, and the two INEEL liquefiers also total to 20,000 gpd.

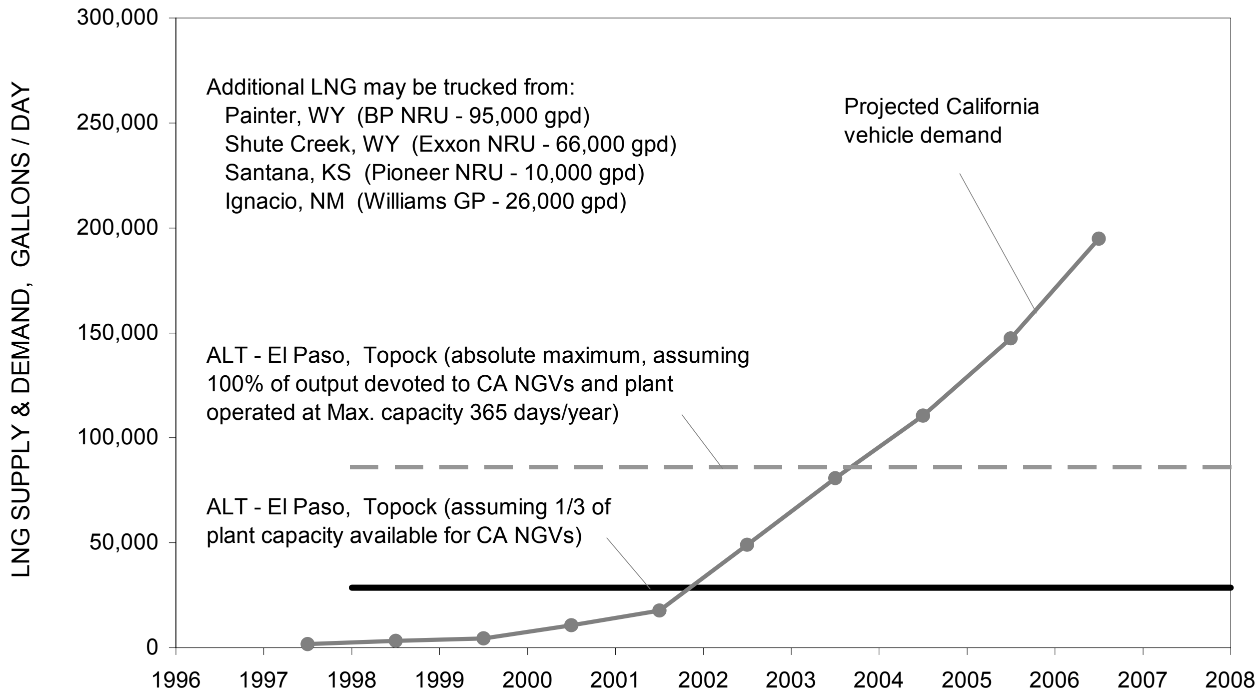

Figure 15. Current California LNG Transportation Fuel Supplies Compared to Demand Projections.

Both of these types of LNG sources involve relatively new technologies that have not yet demonstrated routine LNG production at their projected capacities. Contracts for both liquefier demonstrations have slipped from their original schedules. A projection of on-schedule 100% capacity LNG production from all six plants is judged to be unrealistically optimistic. Our projection assumes full success for one technology, or partial success for both technologies, to produce a total of 20,000 gpd.

There are also significant uncertainties associated with the LNG production schedules from these planned plants. Site work has begun for the ALT-CFS liquefier installation in San Diego and the PG&E-INEEL liquefier in Sacramento, and these plants are projected to start initial production of LNG in early 2002. Installation of the other liquefiers is projected to start very soon, although delays in installation and production schedules are judged to be likely. Therefore, our projection assumes that these sources come on line and LNG production increases in a linear fashion over two years to reach 20,000 gpd by the end of 2003. Figure 16 shows this projection added to the Topock plant output and compared to our demand prediction. Possible future CFS or INEEL liquefiers, or production increases from these six initial plants, are considered as part of the longer-term projections discussed in Section 6.4.

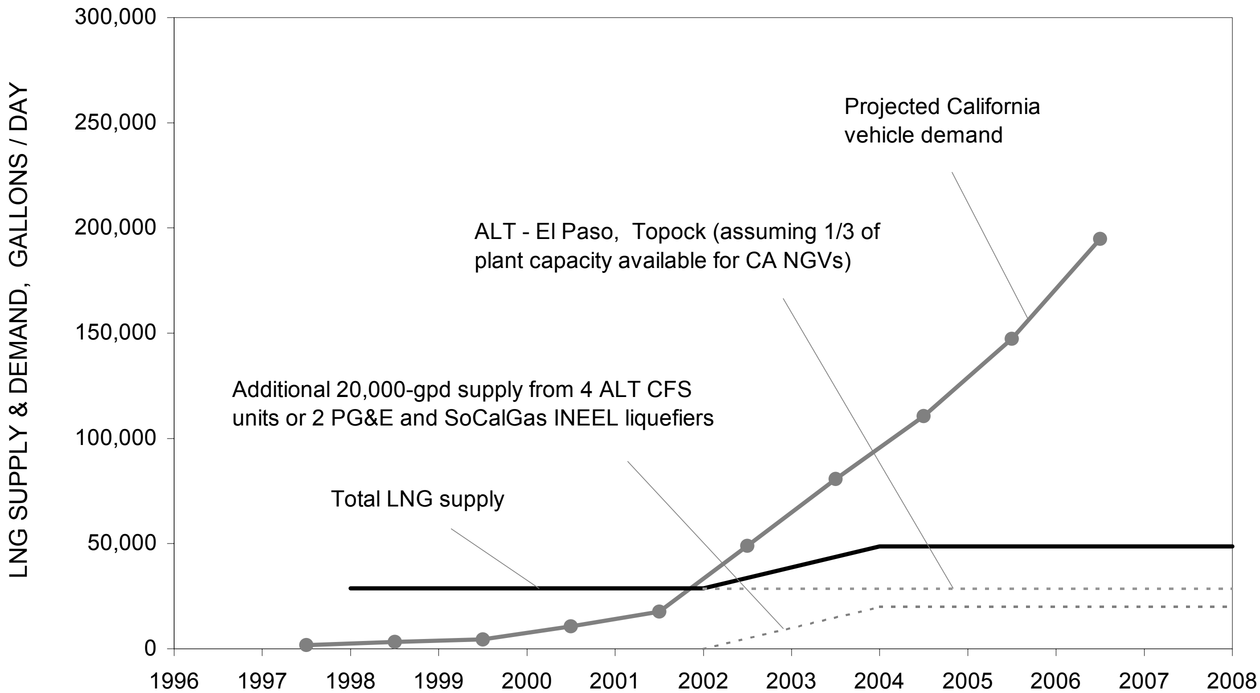

Figure 16. Current Plus Near-Term California LNG Supply Estimates Compared to Demand Projections.

6.3 Mid-Term Planned LNG Sources

New LNG supplies that are being planned, but are not fully funded and no fabrication or installation work has been initiated at this time, include City of Long Beach liquefaction project discussed in Section 5.7, and the Quadren LNG plant expansion discussed in Section 5.6.

The City of Long Beach liquefaction plant is in the planning stage, but needed additional funding has not yet been obtained, equipment orders have not been placed, and site work has not started. Current plans are for two 35,000-gpd liquefiers. Our projection characterizes this as a 50,000-gpd-production level because plans may change and actual production may not be maintained at full peak capacity. The schedule for this project is particularly uncertain because it is at an early stage and multiple government agencies are involved. Our projection assumes that LNG production starts at the beginning of 2003 and reaches 50,000 gpd by the end of 2005.

The Quadren plant expansion is planned to proceed in stages as funding is obtained, additional gas reserve leases are obtained, gas from new wells is piped to the Robbins plant, and new increased-capacity liquefier equipment is installed. Specific plans for the Quadren plant expansion are confidential, and we have no basis for projecting the likelihood that this expansion will go forward or its timing. However, we suspect that the potential LNG production capacity is in the same magnitude range as the Long Beach project, and the time frames may be similar as well. Therefore, for the purpose of this mid-term California LNG supply projection, we regard these as either-or situations, i.e., the possibility of the Long Beach project not going forward is roughly balanced by the possibility that the Quadren plant expansion does proceed. This projected mid-term LNG supply increase of 50,000 gpd between 2003 and 2006 is shown added to the Topock plant output and near-term projection in Figure 17.

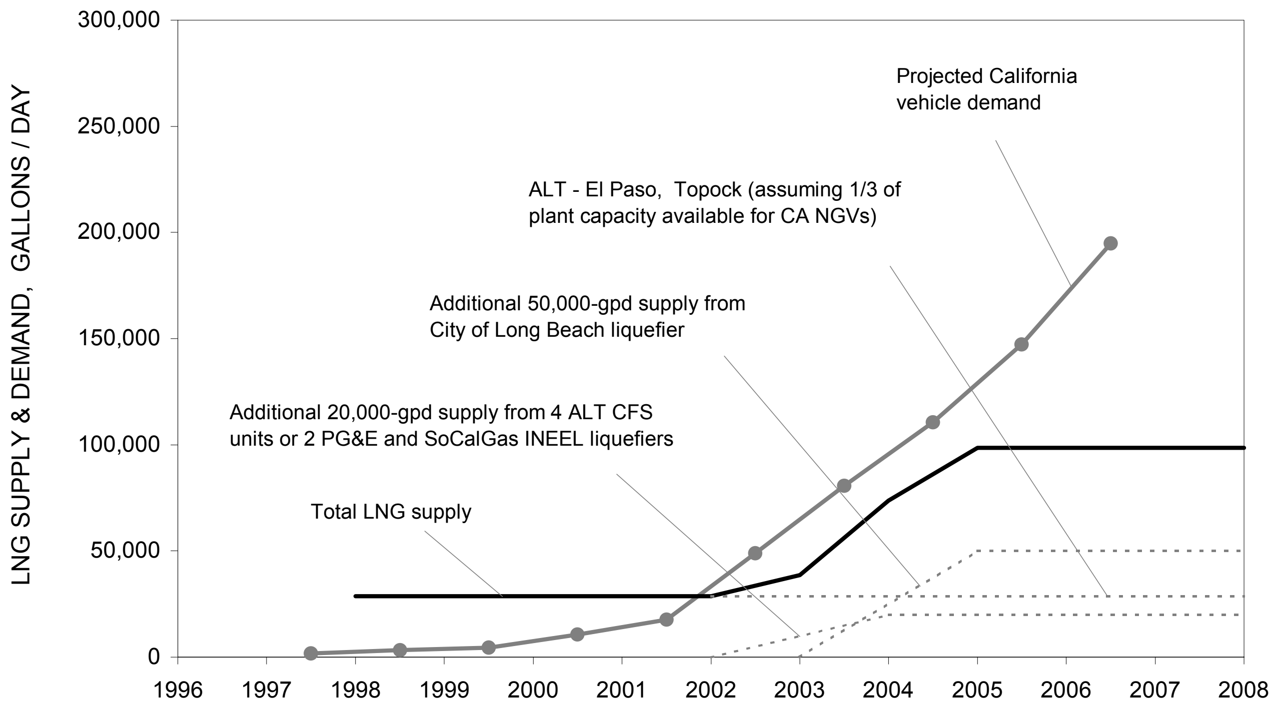

Figure 17. Estimated Mid-Term Planned LNG Supplies Combined with Near-Term and Current Supplies Compared to Demand Projections.

6.4 Longer-Term Potential LNG Sources

Longer-term potential additional sources for California LNG transportation fuel include:

- Additional CFS-type small-scale units liquefying LFG or stranded gas, and/or INEEL-type turboexpander liquefiers at gas pipeline pressure-drop locations.
- One or more relatively large-capacity purpose-built LNG plants, and/or peakshaving plants that could also provide LNG transportation fuel.

Either of the above possibilities could provide additional California LNG supplies in the 100,000-gpd-magnitude range. The likelihood that any of these liquefiers will be built depends on many uncertain factors including the technical and economic success of the initial CFS and INEEL liquefiers, the actual growth of the California LNG market, prices paid for LNG, feedgas prices, and potential interest in LNG for peakshaving or other purposes. It is impossible for us to predict these events and prices at this time. Thus, in Figure 18, we show the effect of a hypothetical 100,000-gpd LNG supply addition in the 2005 to 2007 time period, in addition to the previously discussed LNG supplies, compared to our demand projection.

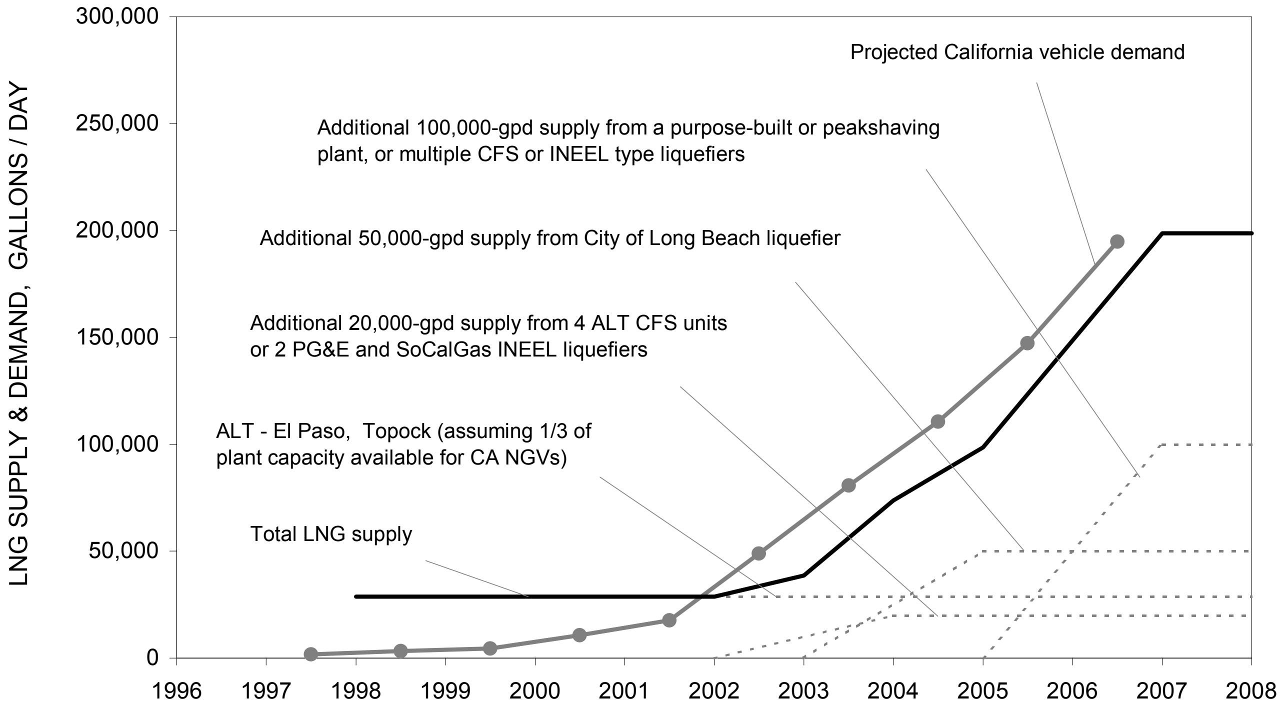

Figure 18. Potential Effect of Future Additional 100,000-gpd In-State Liquefaction Capacity on Projected California LNG Transportation Fuel Supply and Demand.

Another highly uncertain potential future LNG source that could have a big impact is associated with the planned LNG import terminals. As discussed in Section 5.8, there are uncertainties associated with how many, if any, West Coast LNG terminals will actually be built, where they will be located, and when they will begin operation. Moreover, it is uncertain whether they will include capabilities for providing LNG transportation fuel, e.g., LNG purification equipment and tank-truck loading facilities. In view of these uncertainties, it is impossible for us to predict future California LNG transportation fuel supplies from import terminals.

However, in Figure 19, we show the effect of a hypothetical supply equal to 5% of the announced El Paso-Phillips receiving capacity goal (Table 4) starting in 2007 (i.e., assuming a two-year slip from the announced 2005 target date). This is shown as an either-or LNG supply increment with respect to the previously discussed 100,000-gpd increment shown in Figure 18. We assume that if an import terminal planned to sell LNG transportation fuel, this would be known a few years before deliveries started, and this might discourage other liquefaction plant investments.

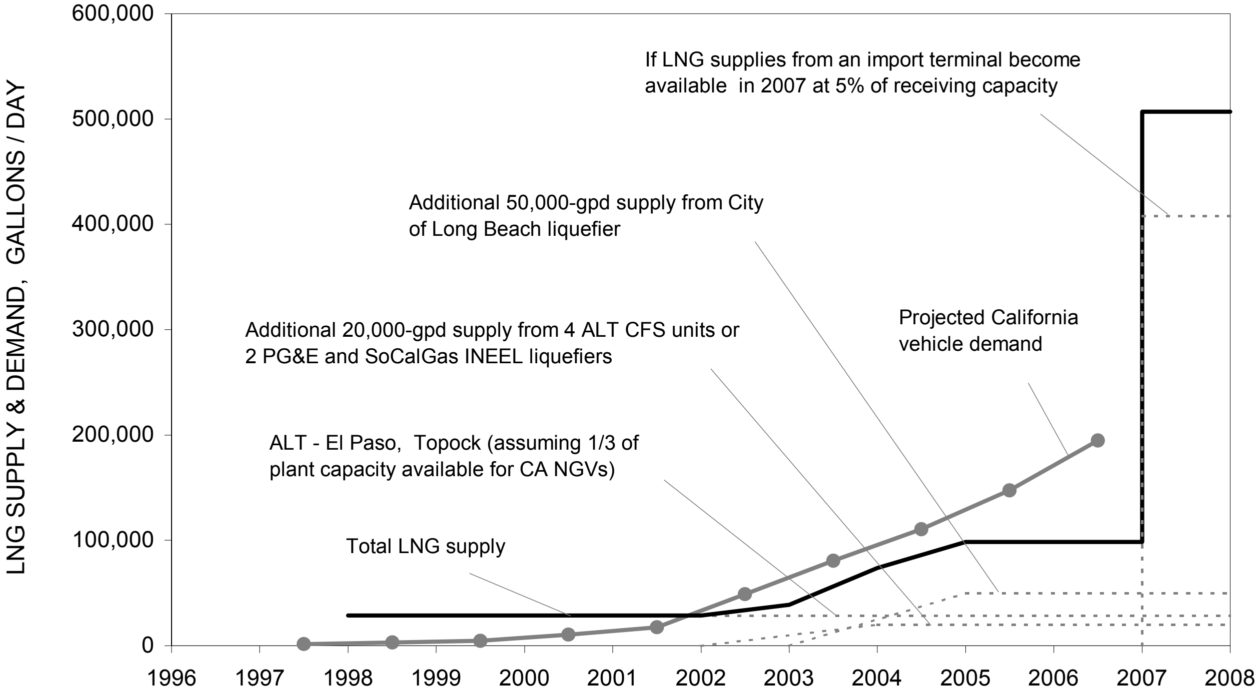

Figure 19. Potential Effect of 5% of Import Terminal Capacity Starting in 2007 on Projected California LNG Transportation Fuel Supply and Demand (note scale change).

6.5 Conclusions

- If California fleets continue to purchase and operate LNG-fueled trucks and buses consistent with their announced plans, the resulting LNG demand will exceed the supply from the ALT-El Paso Topock plant that is normally allocated to California vehicle fleets by early 2002. In this case, if the new projects installing CFS and INEEL liquefiers in California are not yet producing LNG in significant quantities, LNG will have to be trucked from distant out-of-state sources and/or ALT will have to reallocate the Topock plant output among customers (i.e., with some customers receiving LNG from more distant sources). This will probably increase the price of LNG, which will comprise the economics of LNG vehicle operation and discourage California fleets from converting to LNG.

- If the demand for LNG used as transportation fuel in California continues to increase as projected beyond 2002 and 2003, the demand will exceed the supply currently available from the ALT-El Paso Topock plant, plus all currently funded new liquefier projects (i.e., using CFS and INEEL liquefiers). New in-state sources will be needed unless LNG is trucked from distant out-of-state sources, which will likely result in increased LNG prices. While various liquefier projects are in the planning stage (e.g., the City of Long Beach, Quadren Cryogenics expansion, additional CFS and/or

INEEL liquefiers), none of these projects is fully funded at this time, none have ordered equipment, and none have initiated site work.

- The technology and economics of large-scale natural gas liquefiers (e.g., 100,000 gpd) is more established and better demonstrated than the technology and economics of small-scale liquefiers (e.g., 5,000 gpd). However, installation of a large-scale liquefier in California for the singular purpose of LNG transportation fuel production from pipeline gas does not appear to be economically viable at this time, given current pipeline gas prices and LNG price expectations. The economics of such a plant could be improved if it also served as a natural gas peakshaving plant. These two functions (i.e., LNG transportation fuel production and peakshaving) have been demonstrated to be compatible, but no firms are known to be pursuing this strategy at this time.

- An LNG import terminal in or near California could potentially provide large quantities of relatively low-price LNG transportation fuel for California fleets. This is a long-term (i.e., probably beyond 2006), not near-term, prospect. Given the challenges associated with permitting, project financing, and other requirements, it is uncertain if and when a West Coast LNG import terminal will ever be built. If such a facility is built, it is uncertain if it will include LNG transportation fuel load-out capabilities, because this appears to be a relatively small market at this time and it requires extra facility equipment. Agencies that are encouraging the use of LNG instead of diesel fuel to improve California's air quality and reduce petroleum dependence may wish to investigate strategies for encouraging firms planning LNG import terminal projects to include LNG transportation fuel capabilities in their plans.

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