# Final Report

# Hydrogen Delivery Infrastructure Options Analysis

**DOE Award Number: DE-FG36-05GO15032**

**Project director/principal investigator: Tan-Ping Chen**

**Consortium/teaming Partners: Air Liquide, Chevron Technology Venture, Gas Technology Institute, NREL, Tiax, ANL**

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## 1.1 HOW THE RESEARCH ADDS TO THE UNDERSTANDING OF THE AREA INVESTIGATED

In the long run, central hydrogen production is a less costly option than the on-site production at point of use due to the economy of scale for the larger central production facilities. This project provides an in-depth analysis to determine the cost effective mechanism for the transport and delivery of hydrogen from the central production facilities to the point of use at a refueling station.

## 1.2 TECHNICAL EFFECTIVENESS AND ECONOMIC FEASIBILITY OF THE METHODS OR TECHNIQUES INVESTIGATED OR DEMONSTRATED

The investigation involved only paper study and had no laboratory or pilot scale testing. There are no special techniques used in the investigations.

## 1.3 HOW THE PROJECT IS OF BENEFIT TO THE PUBLIC

The project benefits the public in determining the effective roadmap to build hydrogen economy for providing carbon-free fuels in transportation sector.

# Section 2 Comparison of Actual Accomplishments with Project Goals

In this project, the Nexant team conducted an in-depth analysis of various hydrogen delivery options to provide basis for determining the most cost effective infrastructure for the transition and long term. The major objective of the project is to assist DOE to understand hydrogen delivery options and plan required R&D efforts.

The project evaluated and analyzed the following seven hydrogen delivery options:

Option 1: Dedicated pipelines for gaseous hydrogen delivery
Option 2: Use of existing natural gas or oil pipelines for gaseous hydrogen delivery
Option 3: Use of existing natural gas pipelines by blending in gaseous hydrogen with the separation of hydrogen from natural gas at the point of use
Option 4: Truck or rail delivery of gaseous hydrogen
Option 5: Truck, rail, or pipeline transport of liquid hydrogen
Option 6: Use of novel solid or liquid H2 carriers in slurry/solvent form transported by pipeline/rail/trucks
Option 7: Transport methanol or ethanol by truck, rail, or pipeline and reform it into hydrogen at point of use

Delivery includes the entire infrastructure needed to transport, store, and deliver hydrogen from the point of production at 300 psi (central, semi-central, or distributed) to the point of use at the dispensing nozzle at a refueling station or stationary power site.

The Nexant team conducted the analysis in seven tasks:

Task 1: Collect and Compile Data and Knowledge Base

- Subtask 1.1: Pipeline/truck/rail GH delivery and truck/rail LH delivery
- Subtask 1.2: Natural gas pipelines
- Subtask 1.3: Novel solid/liquid H2 carrier processes
- Subtask 1.4: H2/natural gas separation processes
- Subtask 1.5: H2/carrier storage needs and technology for delivery infrastructure
- Subtask 1.6: Methanol/ethanol production, transport & conversion
- Subtask 1.7: Previous system analysis and modeling work completed

Task 2: Evaluate Current and Future Efficiencies and Costs of Hydrogen Delivery Options

- Subtask 2.1: Establish Analysis Bases
- Subtask 2.2: Conduct Conceptual Design
- Subtask 2.3: Cost Estimate and Financial Analysis

Task 3: Evaluate Existing Infrastructure Capability for Hydrogen Delivery

Task 4: Assess GHG and Pollutant Emissions in Hydrogen Delivery

Task 5: Compare and Rank Delivery Options including the use of cost models

Task 6: Recommend Hydrogen Delivery Strategies

Task 7: Project Management and Reporting

A comparison of actual accomplishments in these seven tasks with the project goals is provided below.

## 2.1 TASK 1: COLLECT AND COMPILE DATA AND KNOWLEDGE BASE

### Project Goal

In Task 1, the goal is for the Nexant team to collect and compile the relevant data and knowledge base for each delivery option to facilitate the analyses in Tasks 2-6. Task 1 consists of the following seven subtasks:

Subtask 1.1: Pipeline/truck/rail GH delivery and truck/rail LH delivery

For the GH delivery by pipelines, the Nexant team will:

- Collect information on the existing hydrogen gas pipelines in US
- Summarize experiences in the construction, operation, and maintenance of hydrogen gas pipelines in US and other parts of world
- Identify issues related to the use of hydrogen gas pipelines
- Survey the new technologies, which might have impacts on the efficiency, cost, and reliability improvements of hydrogen pipelines, including the key players, development status, and the projected progress as a function of time

For the truck and rail transport of GH and LH, the Nexant team will:

- Collect information on the current GH and LH delivery by trucks and rails from merchant hydrogen plants in US
- Identify issues related to these transport modes
- Survey the new technologies, which might have impacts on the efficiency, cost, and reliability improvements of GH and LH truck/rail deliveries, including the key players, development status, and the projected progress as a function of time

The information collected and compiled will be used as the basis to design and estimate the current and future capital and O&M costs of hydrogen pipeline transport in Task 2, to provide the necessary input to evaluate the existing infrastructure for hydrogen transport in Task 3, and form the basis to assess the GHG/pollutant emissions in Task 4.

Subtask 1.2: Natural gas pipelines

In this subtask, the Nexant team will:

- Collect information on the existing natural gas pipeline network (transmission and trunk lines) in US in terms of where the transmission and trunk lines are, flow rates, line sizes, delivery pressures, transport distances, locations of the feed and boost compression stations, construction materials, capital costs, compression energy consumptions, emissions from the compression stations, leakages and losses, maintenance requirements, and other O&M expenses.

- Collect information on the capital cost and O&M costs of the distribution system in US
- Assess the ability of the current transmission and distribution network to isolate a certain portion of the system to transport hydrogen without interfering the natural gas transport

The information collected and compiled will be used as the basis to design and cost estimate the retrofit of current NG pipeline to transport hydrogen or mixture of natural gas/hydrogen in Task 2 and provide the necessary input to evaluate the existing infrastructure capability for hydrogen delivery in Task 3.

Subtask 1.3: Novel solid/liquid H2 carrier processes

In this subtask, Tiax will survey and screen novel processes using solid/liquid hydrogen carriers. It will cover the following four classes of processes:

- Reversible processes in using metal hydrides (such as LaNi5 and Mg2Ni) and alanates (such as NaAlH4)
- Irreversible processes in using chemical hydrides, such as LiH, NaH, and sodium borohydride
- Advanced reversible processes utilizing solid materials (e.g. carbon nano-structures, other nano-structures
- Reversible liquid hydrocarbons (such as naphthalene/decalin or similar but more advanced systems
- Other processes that may be relevant

For each carrier class, the existing state of knowledge will be examined. Model system parameters will be developed for current technology capability and projected future potential capability by class. Delivery infrastructure options for liquids, flow-able powders, slurries, and packaged solids will be considered for each class as appropriate. The information collected will be used to design and cost estimate the promising novel solid/liquid H2 carrier processes under Option 6 in Task 2.

Subtask 1.4: H2/natural gas separation processes

In this subtask, the Nexant team will survey and review applicable technologies, existing or in development, for the separation of hydrogen and natural gas, which is required in Option 3. The separation technologies to be surveyed will include the following types:

- Pressure swing absorption (PSA)
- Molecular sieve membrane separation
- Methane hydrate
- Hydrogen sorbents, such as metal hydrides
- Metallic and ceramic transport membranes separation

Subtask 1.5: H2/carrier storage needs and technology for delivery infrastructure

In this subtask, the Nexant team will survey and review applicable technologies, existing or in development, for the required storage of hydrogen and/or carriers within the delivery infrastructure. This information will be used in Tasks 5 and 6. The technologies to be surveyed include:

- High-pressure gaseous storage and liquid hydrogen storage for terminals and refueling sites
- Geologic gaseous hydrogen storage
- Storage for carriers within the delivery infrastructure as needed and appropriate

Subtask 1.6: Methanol/ethanol production, transport & conversion

In this subtask, the Nexant team will compile the cost, efficiency, and emission data related to conversion of coal, natural gas, biomass and corn grain to methanol and ethanol and the on-site reforming at the point of use to convert them back to hydrogen.

Subtask 1.7: Previous system analyses and modeling work completed

In this subtask, the Nexant team will review previous system analysis conducted under DOE funding and by others:

- The hydrogen delivery options evaluated previously
- The efficiencies, costs, and emission data developed for the various options evaluated
- The system models developed in terms of the database and methodology used
- The delivery strategies recommended in the previous work

### Actual Accomplishment

The results of Task 1 are summarized in the Task 1 Topical Report shown in Appendix A. The Topical Report actually contains more information than the goal (or scope of work) indicated above as shown in the table below:

| Subtask in the Original Scope of Work (Goal) | Section Number in the Task 1 Report (Appendix A) | |
|---|---|---|
| | 1.1 | Energy resources and carbon sequestration sites in US |
| | 1.2 | Light duty vehicle fuel demand and supply in US |
| Subtask 1.1: Pipeline/truck/rail GH delivery and truck/rail LH delivery | 1.3 | Gaseous hydrogen delivery by pipelines |
| | 1.4 | Gaseous and liquid hydrogen delivery by trucks and rail |
| Subtask 1.2: Natural gas pipelines | 1.5 | Natural gas transmission and distribution |
| Subtask 1.3: Novel solid/liquid H2 carrier processes | 1.6 | Novel solid/liquid $H_2$ carrier processes |
| Subtask 1.4: H2/natural gas separation processes | 1.7 | $H_2$/natural gas separation processes |
| Subtask 1.5: H2/carrier storage needs and technology for delivery infrastructure | 1.8 | $H_2$/carrier storage needs and technology for delivery infrastructure |
| Subtask 1.6: Methanol/ethanol production, transport & conversion | 1.9 | Methanol, ethanol, and ammonia production, transport, and conversion |
| | 1.10 | Power transmission and delivery systems in US |
| Subtask 1.7: Previous system analysis and modeling work completed | 1.11 | Previous system analysis and modeling work completed |

The table shows the Task 1 report has included Sections 1.1, 1.2, and 1.10, which are not required in the scope of work. These sections were included because they provided the background information required to conduct subsequent tasks.

It should be noted that Section 1.10 includes production, transport, and conversion of not just methanol and ethanol but also ammonia. This expansion is per DOE's request.

## 2.2 TASK 2: EVALUATE CURRENT AND FUTURE EFFICIENCIES AND COSTS OF HYDROGEN DELIVERY OPTIONS

### Project Goal

In Task 2, the Nexant team will analyze and estimate the efficiency and cost for each delivery option as a function of the technology advancement and at different LDV market penetrations (eg. 1%, 10%, 30%, and 70%) to provide the bases for comparing and contrasting the delivery options in Task 5. It consists of three subtasks.

Subtask 2.1: Establish Analysis Bases

In this subtask, the Nexant team will define the system boundary for the hydrogen delivery, conditions at the point of use, delivery flow rates and distances, and cost economic criteria for all the delivery options so that they can be compared on an equal basis.

Subtask 2.2: Conduct Conceptual Design

In this subtask, the Nexant team will prepare a conceptual design to determine the required delivery and site facilities for each delivery option. The design will be in compliance with required codes and standards and use the information/data base collected and compiled in Task 1.

Subtask 2.3: Cost Estimate and Financial Analysis

In this subtask, Nexant will estimate the capital cost and O&M cost for each delivery option based on the design in Subtask 2.2.

### Actual Accomplishment

The work conducted by the Nexant team deviated substantially from the goal stated above. Instead of providing independent analysis of the seven delivery options, DOE instructed the Nexant team to provide upgrade to the existing H2A delivery model.

The existing H2A model included only Options 1, 4, and 5. DOE planned to expand the model to include Option 6. As a result, the Nexant team focused the efforts on these options. Options 2, 3, and 7 were excluded. They have been analyzed in Task 1 and the analysis (see the Task 1 report provided in Appendix A) showed that:

- Option 2 can accommodate only a small fraction of the long term hydrogen delivery requirements.
- Option 3 is impractical.
- Option 7 has many production/transport/regeneration issues and DOE instructed the Nexant team not to further pursue it.

The work conducted by the Nexant team for Options 1, 4, and 5 is summarized in the Task 2 report shown in Appendix B. It included an enrichment and upgrade of the following elements for these options in the H2A delivery model:

- More up-to-date performance and cost curves for the refueling station compressors
- More up-to-date performance and cost curves for the transmission pipeline and gas terminal compressors
- The need of a low pressure (~2,500 psi) gas storage
- More up-to-date performance and cost curves for the cascade system (6,250 psi) gas storage
- More up-to-date performance and cost curves for the liquefaction plants, which are part of the delivery chain (the hydrogen production before the liquefaction is not part of the delivery chain)
- More up-to-date performance and cost curves for the liquid storage vessels, pumps, and vaporizers
- More up-to-date cost curves for installing and operating hydrogen distribution pipelines within a city
- Larger power supply lines (480 or 4,160 Volts) required to deliver the large amount of electricity for compression and dispending of hydrogen in refueling stations
- Larger refueling station and distribution terminal land areas due to the setback distance required for hydrogen

The original H2A delivery model has not taken into account the fueling profile in a gas station, i.e. the fact that the fuel demand at a gas station may vary within a day, within a week, and with seasons. While the fuel demand varies, the fuel (hydrogen) delivery/supply is constant. There is an optimum combination of hydrogen compression to the refueling pressure and hydrogen storage to deal with this mismatch between the demand and supply. In Task 2, the Nexant team also searched for this optimum combination, which was then incorporated in the H2A delivery model for it to properly take into account the fueling profile in a gas station.

The work conducted by the Nexant team for Option 6 is summarized in the supplemental report to Task 2 shown in Appendix C.

## 2.3 TASK 3: EVALUATE EXISTING INFRASTRUCTURE CAPABILITY FOR HYDROGEN DELIVERY

### Project Goal

In Task 3, the Nexant team will evaluate the existing infrastructure in US to determine its ability to facilitate the hydrogen delivery. The information developed in this task will be input to prepare the hydrogen delivery strategy in Task 6. The existing infrastructure includes natural gas and hydrogen transmission and distribution systems, oil pipelines, existing and the potential for future right of way (ROW) and cost for pipelines, and the truck/rail delivery systems used to distribute hydrogen from the merchant hydrogen plants.

### Actual Accomplishment

The work in this task was conducted in Task 1. The results were included in the Task 1 report (Appendix A). So, there is no separate report for this task.

## 2.4 TASK 4: ASSESS GHG AND POLLUTANT EMISSIONS IN HYDROGEN DELIVERY

### Project Goal

In Task 4, the Nexant team will assess the GHG and pollutants emitted for each delivery option. The results of this task will be used as the additional criteria for selecting the delivery option in Task 5 and as additional input for formulating the hydrogen delivery strategy in Task 6.

### Actual Accomplishment

DOE indicated to the Nexant team that the H2A delivery model has built in GHG and pollutant emission estimate capability based on ANL's GREED program. The GREED program has a very thorough life cycle analysis of the emissions. In order to focus the effort more to upgrade the component performance and cost data in the H2A delivery model, DOE instructed the Nexant team not to conduct this task. The upgraded H2A model now includes the GHG and pollutant emission estimate for each of the delivery option analyzed.

## 2.5 TASK 5: COMPARE AND RANK DELIVERY OPTIONS INCLUDING THE USE OF COST MODELS

### Project Goal

In Task 5, the Nexant team will compare and rank all the hydrogen delivery options as a function of the hydrogen delivery volumes and distances.

### Actual Accomplishment

DOE indicated that they will run the upgraded H2A delivery model to compare and rank various delivery options. They wanted the Nexant team to devote more effort to Task 2. As a result, the Nexant team did not perform Task 5.

## 2.6 TASK 6: RECOMMEND HYDROGEN DELIVERY STRATEGIES

### Project Goal

In Task 6, the Nexant team will recommend to DOE both the short-term and long-term hydrogen delivery strategies for the urban and rural areas based on the evaluation of the existing infrastructure in Task 3 and the ranking of various delivery options in Task 5.

### Actual Accomplishment

DOE indicated that the development of hydrogen delivery strategies is very complex. It requires the consideration of both the production and delivery issues and the projection of economic development in the future. It would coordinate the efforts to develop the strategies and wanted the Nexant team to devote more effort in upgrading the H2A delivery model. As a result, the Nexant team did not perform Task 6.

## 2.7 TASK 7: PROJECT MANAGEMENT AND REPORTING

### Project Goal

In Task 7, the Nexant team will report to DOE the project progress and submit to DOE the final deliverables.

### Actual Accomplishment

Nexant has performed this task according to DOE's requirements.

The project was a study without tests and development of technologies in laboratory and pilot facilities. The approach to be used was to:

- Conduct extensive literature survey
- Discuss with operators and developers of the key delivery technologies evaluated
- Provide input to the H2A delivery model to expand the options covered from

The project was executed along the approach mentioned above. There was no deviation from it. However, the focus of the study was shifted as pointed out in Section 2 above.

# Section 4 Products Developed and Technology Transfer Activities

There is no product development in this project. As a result, there are no technology transfer activities.

# H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results

## DE-FG36-05GO15032

## Supplemental Report to Task 2

## Novel Hydrogen Carriers Analysis

**Nexant, Inc., Air Liquide, Argonne National Laboratory, Chevron Technology Venture, Gas Technology Institute, National Renewable Energy Laboratory, Pacific Northwest National Laboratory, and TIAX LLC**

**June 2008**

# 1. Introduction

A great deal of research has sought to identify or develop on-board hydrogen storage materials and methods that have the ability to store hydrogen more efficiently than compressed gas or liquid tanks. The gravimetric and volumetric densities of compressed or liquid hydrogen do not meet the technology development goals set by the Department of Energy's (DOE) Vehicle Technologies Program. The DOE goals are rooted in the practical constraints that limit the size and weight of on-board fuel storage. As a result, researchers are evaluating the potential for alternative hydrogen carriers to meet the DOE on-board storage goals. Potential alternative hydrogen carriers include metal hydrides, chemical hydrides, high surface-area carbon sorbents and liquid-phase hydrocarbons. The Department of Energy's Vehicle Technologies Program technology development goals for on-board hydrogen storage are shown below in Table 1.

| **On-Board Storage Goals** | **2010** | **2015** |
|---|---|---|
| Gravimetric Energy Density (kWh/kg) | 2.0 | 3.0 |
| System Weight Percent Hydrogen | 6% | 9% |
| Volumetric Energy Density (kWh/liter) | 1.5 | 2.7 |
| Storage System Cost ($/kWh) | $4.00 | $2.00 |

**Table 1: DOE Vehicle Technologies Program Hydrogen Storage Goals [11]**

While these alternative hydrogen carriers have the potential to provide on-board storage, alternative hydrogen carriers may also be used to improve the efficiency and cost of hydrogen delivery. Certain hydrogen storage technologies may not meet all of the requirements for use on-board vehicles, but hydrogen delivery has less restrictive requirements regarding volumetric and gravimetric capacity. As a result, technologies that fail to meet the on-board goals may still be viable mechanisms for hydrogen delivery.

For the purposes of this analysis and in accordance with H2A assumptions, hydrogen delivery is defined as the process of transporting hydrogen from a hydrogen production facility to the fueling station. In cases where chemical processing is required to store hydrogen using an alternative carrier, those processes are evaluated as a part of hydrogen delivery.

This paper attempts to address the possibility that alternative hydrogen carriers could serve as viable hydrogen delivery options. Given the variety of alternative hydrogen carriers and the numerous loading processes associated with each carrier, it is difficult to make definitive conclusions for each specific material or material type. (*Note: the specific process of "loading" a hydrogen carrier depends on the material type, but potential processes include adsorption, hydrogenation, or multi-step chemical reactions such as the Brown-Schlesinger process used to manufacture sodium borohydride. For simplification and unless referencing a specific process this paper will refer to the processes of adding and removing hydrogen from the carrier as "charging" and "discharging."*).

The process of charging and discharging an alterative carrier material may require complex processes that can add cost and complexity to the overall delivery system. In many instances there are multiple processing options available for each carrier material which can make a simple quantification of cost and energy-use far more difficult. For example, sodium borohydride can be reprocessed through a number of different reactions, each with unique energy and material requirements. As a result, it is difficult to easily assess the cost of using sodium borohydride as a delivery mechanism. Further complicating matters is the potential for new or improved processes that can change the overall economics of a particular carrier option. Such future developments could make non-viable carriers an economically available solution.

In light of these concerns, this analysis seeks to identify the pathways (liquid truck, solid-state truck, pipeline, etc) in which various carriers can be used for hydrogen delivery, provide an analytical tool that accounts for all of the costs associated with the various carrier pathways, establish which characteristics contribute significantly to the delivery cost, and provide acceptable ranges for those characteristics.

## 2. Alternative Hydrogen Carriers

This analysis focuses on four types of alternative hydrogen carriers that may be viable hydrogen storage mechanisms. Table 2 lists the types of materials considered in this analysis and highlights example materials and some of their unique characteristics.

| Material Type | Example Material | Storage State | $H_2$ Discharge |
|---|---|---|---|
| Metal Hydrides | Sodium Alanate | Packed Powder | Endothermic Desorption |
| Chemical Hydrides | Sodium Borohydride | Aqueous Solution | Catalyzed Exothermic Hydrolysis |
| Liquid-Phase Hydrogen Carrier | N-Ethylcarbazole | Liquid | Endothermic Dehydrogenation |
| High Surface Area Carbon Sorbents | AX-21 | Low-Temp Solid Powder | Endothermic desorption |

**Table 2: Hydrogen Carrier Classes and Example Materials**

This paper will not provide a detailed discussion of each carrier type, as research into unique material characteristics was not a focus of this analysis. Specific material characteristics that affect the potential use as a delivery mechanism will be identified in relevant sections.

## 3. Delivery Mechanisms

Before evaluating the cost of delivering hydrogen with alternative hydrogen carriers, the specific pathways must be defined. When identifying possible pathways, certain assumptions must be made regarding the manner in which different material types may be used in a delivery infrastructure. These assumptions are presented throughout the report, where relevant. To determine the available pathways, the DOE H2A Delivery Analysis was used as a baseline, as it evaluates multiple methods to deliver compressed gaseous or liquid hydrogen. The H2A Components Model – one of the analytical tools developed as part of the H2A Delivery Analysis project – was modified to represent the various available pathways for alternative hydrogen carriers. The existing version of the H2A Components model evaluates three different delivery pathways:

- **Hydrogen Tube Trailer**: Compressed hydrogen is transported in high-pressure tubes which are dropped-off at the fueling station and used as on-site storage. Delivery includes picking-up an empty trailer and replacing it with a full trailer.
- **Liquid Hydrogen Trailers**: Liquid hydrogen is transported in cryogenic truck trailers. The liquid hydrogen is off-loaded into liquid storage tanks at the fueling station. Unlike compressed hydrogen tube trailer delivery, the trailer is not left at the fueling station.
- **Compressed Hydrogen Pipeline**: Hydrogen is distributed to fueling stations through a pipeline network that operates at low pressure (300-1,000 psi). To avoid large upstream demand spikes, hydrogen is supplied continuously to the fueling stations and compressed to high-pressure (6,250 psi) for immediate vehicle fueling, or compressed to 2,500 psi for storage in buffer storage tanks.

It is clear that each of these delivery pathways will require different types of components and will be evaluated with different sets of assumptions.

To specify the pathways that could employ alternative hydrogen carriers, it is necessary to evaluate the limitations of each carrier-type defined in Section 2 and determine what types of delivery systems could work within these limitations. The first differentiating feature is whether a carrier is a liquid or could be transported in a liquid form. Liquid carriers generally fall into one of three categories: pure liquids, solutions and slurries. This analysis assumes that all liquid carriers can be transported either in trucks or liquid pipelines. Specific carriers may require different assumptions, components, or processes, but given the proper inputs, these carriers can be evaluated for both the truck and pipeline delivery methods. When transporting via truck, it is assumed that liquid carriers can be rapidly off-loaded at the fueling station and stored in on-site storage tanks. In most cases, pure liquids are easier to transport than solutions or slurries, as there is no risk of the hydrogen carrier separating from the solvent. Certain potential carriers, such as the dehydrogenated phase of n-ethylcarbizole, have melting points that are above the ambient temperature, making it necessary to insulate, and potentially heat, the pipelines and trucks that return the carrier to the reprocessing facility.

Solid carriers have limitations that will require them to be transported via a slightly different pathway. In the case of solid materials such activated carbon, it is assumed that the material can only be transported in a truck trailer and that the material remains in the trailer at all times. While it may be possible to off-load and store a solid carrier material, there are a number of practical difficulties associated with handling solids (usually in the form of a powder). As a result, the off-loading of hydrogen carrying solids is not considered in this analysis. All solid materials are assumed to remain permanently on the delivery trailer. When employing a solid transport material that must remain in the trailer, hydrogen can be delivered via two different pathways: 1) the trailer can be dropped-off at the fueling station and used as on-site storage, or 2) the hydrogen can be off-loaded from the trailer and stored in low-pressure storage tanks at the fueling station. For many solid-state carriers heat transfer is required to discharge the hydrogen from the carrier. The endothermic desorption processes required for activated carbon or metal hydride materials are good examples. As a result, it is assumed that heat exchange components are integral pieces of the delivery trailers, making them more expensive than conventional trailers. The heat source or sink will likely be off-board the trailer at the fueling station or reprocessing facility.

Given these initial assumptions the H2A Components Model was modified to evaluate the following delivery pathways:

- **Liquid Carrier Trailers**: Liquid carrier trailers transport pure liquids, solutions or slurries between a processing facility and the hydrogen fueling station. The liquid carriers are off-loaded at the hydrogen fueling station and either stored in tanks where the carrier is delivered to the vehicle or the hydrogen is discharged at the fueling station and compressed hydrogen is delivered to the vehicle.
- **Solid Carrier Trailers**: Solid carrier trailers are assumed to permanently contain the carrier material. The charging/discharging of the carrier material occurs in situ. This often requires integral heat transfer equipment in the trailer, and will likely require and off-board heat source or sink. The model includes two options for delivery: 1) the trailer is dropped-off at the fueling station and hydrogen is desorbed over the demand period or 2) the trailer remains with the tractor and hydrogen is rapidly desorbed during the delivery period and stored in low-pressure storage tanks at the fueling station.
- **Liquid Carrier Pipeline**: A two-pipe pipeline network is established to transport alternative hydrogen carriers from a processing facility to multiple fueling stations. Two pipes are employed so that charged and discharged material can be transported simultaneously. A single-pipe system that transports the charged/discharged materials at different times may be possible (similar to a plug-flow type pipeline that delivers

different types of petroleum products), but was not considered in this analysis, as there are numerous flow management issues that add significant complexity to this type of system. As with the liquid truck pathway, the alternative carrier can be delivered to the vehicle or discharged at the fueling station.

The following sections outline the specific details of the evaluated transport pathways, and how those details were incorporated into a modified version of the DOE H2A Model.

## 4. General Truck Transport

It is highly likely that truck transport will be a primary method of transporting alternative hydrogen carriers. There are multiple types of delivery methods that utilize trucks as a delivery mechanism, including: liquid truck transport and solid-state truck transport. In addition, trucks can either be dropped off at fueling stations or a product (either hydrogen or the carrier material) can be off-loaded during a standard delivery stop. As a result, it is clear that there are multiple methods of truck delivery. Nevertheless, a metric that is important across all trucking methods is the quantity of hydrogen that can be delivered in a single truck trailer.

Truck capacity can be limited by either the overall volume or weight of the truck. While standards differ between states and types of roadways, typical maximum trailer dimensions are 8 feet wide and 53 feet long (75 $m^3$, assuming a cylindrical trailer), with a maximum overall GVW of 85,000 lbs (maximum cargo weight of 25,200 kg, not including the tractor). The cargo density that would yield the maximum volume and weight is approximately 336 $kg/m^3$. All of the carriers evaluated are significantly denser than 336 $kg/m^3$. As a result, the capacity of the trucks is limited by the weight, not the volume of the material. This limitation makes the gravimetric hydrogen capacity (referred to as the material weight percent) a very important metric. Figure 1 below illustrates the relationship between weight percent and overall capacity and in relation to conventional carriers.

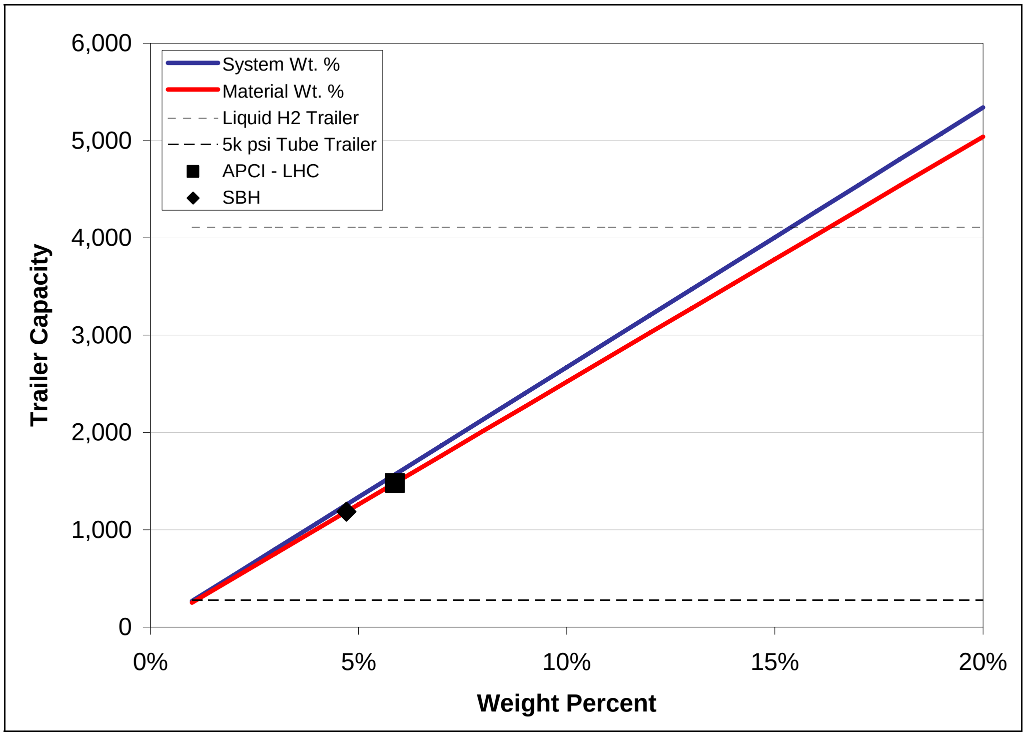


**Figure 1: Novel Hydrogen Carrier Truck Capacity (kg)**

Figure 1 illustrates the overall hydrogen capacity as a function of weight percent. Two types of weight percent are shown: material weight percent and system weight percent. The material weight percent refers to the amount of hydrogen that can be stored in the carrier material, as related to the carrier weight. It is assumed that this material can be transported in a relatively standard stainless steel trailer similar to a gasoline trailer. The system weight percent considers not only the weight of the carrier material but also the weight of the tank and any components that must be included to charge or discharge the hydrogen. For example, AX-21, the low-temperature carbon sorbent requires a heavily insulated, high-pressure vessel that has integral heat transfer tubes to facilitate the charging and discharging process. Given that this system is far more substantial than a typical gasoline tank trailer, the weight percent for AX-21 should be given as a system weight percent, not a material weight percent. The cargo weights used to determine the overall capacity are 25,200 kg for material only, and 27,200 kg for the entire system (assumes that the standard gasoline trailer weighs approximately 3,300 lbs. not including the glider). Figure 1 also illustrates the capacity for two liquid hydrogen carriers: sodium borohydride slurry and ethylcarbizole.

It is evident that some carriers have the potential to offer better overall capacity than tube trailers, but fall considerably short of the capacity of a liquid trailer. If this is the case, it is necessary that the alternative carriers offer some benefit beyond capacity, such as cost, energy-use, or ease of handling. This model attempts to quantify some of those metrics to allow for a more complete and consistent evaluation of the various alternative carriers.

## 5. Liquid Truck Transport

Alternative liquid hydrogen carriers include pure liquids, solutions, and slurries. Examples of these liquid carrier types are shown in Table 3.

| Carrier Type | Material Class | Example Material | Developer and Notes |
|---|---|---|---|
| Pure Liquid | Liquid Hydrocarbon | Ethylcarbizole | Develop by APCI;<br>Dehydrided melting temperature: 80 °C |
| Solution | Chemical Hydride | Aqueous Sodium Borohydride | Developed by Rohm & Haas/M-Cell;<br>Water-based solvent consumed in reaction |
| Slurry | Metal Hydride | Magnesium Hydride Slurry | Developed by SafeHydrogen;<br>Oil-based solvent |

**Table 3: Liquid Transport Materials**

This analysis assumes that in a delivery scenario all carrier types are loaded and off-loaded at the processing facility and fueling station. Unlike gasoline or diesel, the alternative hydrogen carrier is a reusable material, not a consumable fuel; therefore, it is necessary to transport charged carrier from the processing facility to the fueling stations and return discharged material from the fueling station to the processing facility. There is an unloading and loading process at each end of the transport leg. This analysis assumes that a single transport trailer can perform both operations.

After the charged carrier is off-loaded at the fueling station, it is stored in underground or above-ground tanks. If compressed hydrogen is to be delivered to vehicles, hydrogen discharge occurs at the fueling station. The method of discharge will depend, partially, on the material kinetics. This analysis, and the corresponding model, allow for two discharge options: steady-state or on-demand. These options are described below:

- **Steady-State Discharge**: In this case, the material kinetics is sufficiently slow as to necessitate a continuous flow of material through the discharge reactor. In periods of low-demand, the hydrogen being discharged will be stored in low-pressure (2,500 psi) storage tubes at the fueling station. The assumptions that define the capacity and cost of the compressor and low-pressure storage in the alternative carrier model are the same as the assumptions found in the H2A model of conventional pipeline-fed fueling stations. H2A assumes that fueling stations fed by pipeline accept hydrogen at a constant flow rate. The discharge reactor is sized to meet the average hourly demand at the fueling station.
- **On-Demand Discharge**: In this case, the material kinetics is fast-enough to discharge hydrogen at a rate necessary to meet the individual hourly demand at the fueling station. As a result of the on-demand discharge, there is no requirement for low-pressure storage, buffer storage at the fueling station. The compressor assumptions used in the alternative carrier model are the same as the assumptions found in the H2A model of tube trailer fueling stations. H2A assumes that the tube trailers can supply

hydrogen to the compressor as needed. The discharge reactor is sized to have the same capacity as the forecourt compressor.

These two discharge mechanisms will have a significant tradeoff between low-pressure storage (required for steady-state discharge) and a high-throughput discharge reactor (required for on-demand discharge).

The details of the various hydrogen fueling station configurations are specified in Section 8, Fueling Stations.

For liquid carriers that are off-loaded at the fueling station, the material characteristics that most significantly impact the cost of the trucking portion of delivery are the material's capacity to carry hydrogen (weight percentage of hydrogen) and the capital cost of the trailer. The carrier material's hydrogen weight percent directly affects the overall capacity of the trailer, as the total cargo weight is limited to approximately 25,200 kg based on standard highway requirements limiting the overall GVW to a maximum of 80,000 lbs. To determine the effects of these variables, a sensitivity analysis was performed using plausible ranges for the input parameters. The ranges selected for material characteristics and equipment costs are explained in Table 4.

| | | |
|---|---|---|
| **Hydrogen Weight Percentage** | 24% Solution $NaBH_4$ | 4.71% |
| | Ethylcarbizole | 5.88% |
| | 2015 DOE Goal | 9.00% |
| **Trailer Capital Cost** | Gasoline Trailer | $90,000 |
| | $cH_2$ Tube Trailer | $225,000 |
| | $LH_2$ Cryo Trailer | $625,000 |

**Table 4: Liquid Carrier Trucking Sensitivity**

Figure 2 illustrates the cost of truck-delivery when employing a variety of liquid-phase alternative carriers. The results are presented as a function of hydrogen capacity and capital cost. Other assumptions such as transport distance and fuel economy, that are assumed constant for all liquid hydrogen carriers, are specified in Appendix A.

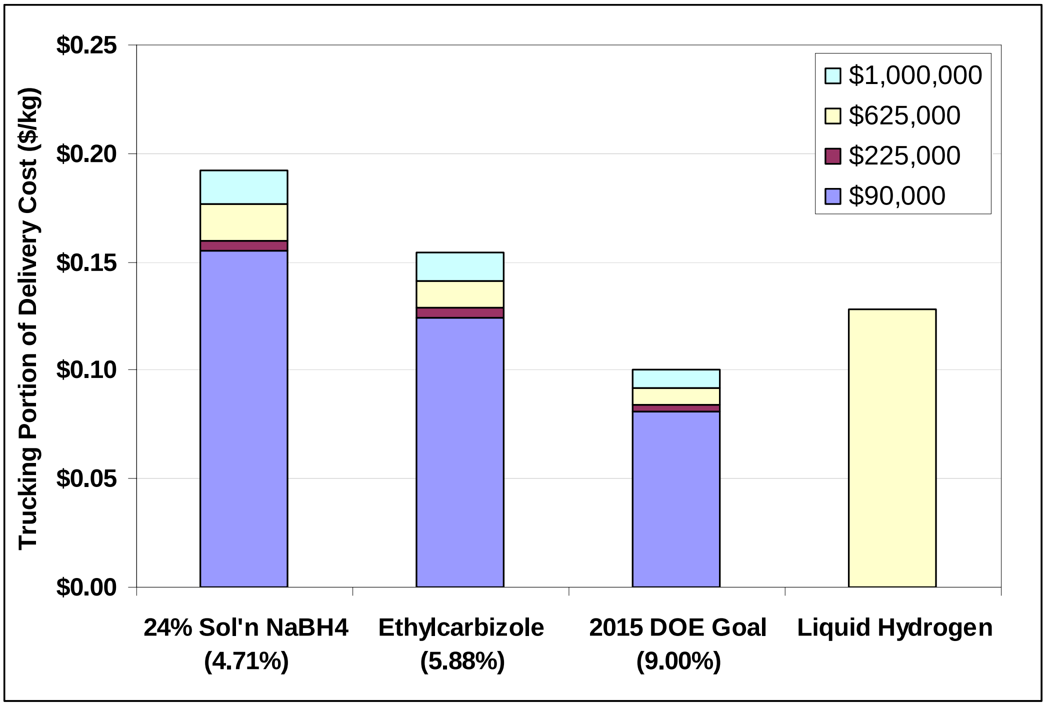


**Figure 2: Liquid Hydrogen Carrier Truckling Cost (with variable trailer capital costs)**

Figure 2 yields two important conclusions. First, the weight percent of hydrogen carriers has a far more significant impact on the overall cost than the trailer capital cost. As shown in Figure 2, a 24% improvement in hydrogen capacity (4.71% to 5.88%) yields, on average, a 20% reduction in cost, whereas a 10-fold increase in trailer capital cost ($90,000 to $1,000,000) yields a cost increase of, on average, only 24%. Second, Figure 2 indicates that compared to the cost of trucking liquid hydrogen, these alternative carriers are competitive and have the potential to be less expensive than liquid hydrogen if the DOE technology goals are achieved.

Detailed cost breakdowns for the liquid carrier ethylcarbizole and liquid hydrogen are shown below in Figure 3.

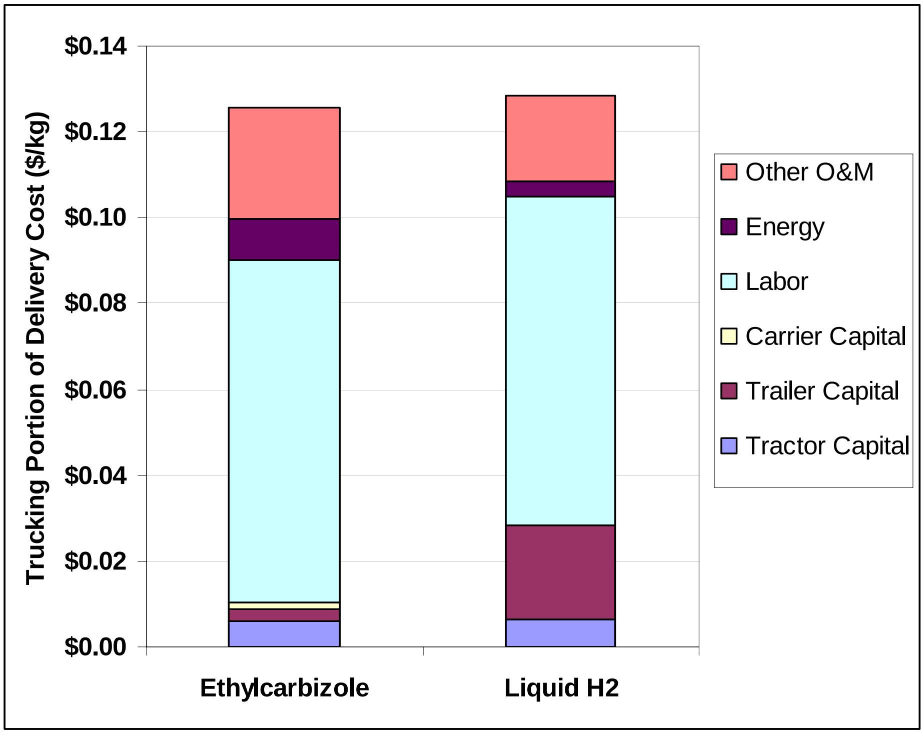


**Figure 3: Cost Breakdown of Ethylcarbizole and Liquid H2 Trucking**

Figure 3 illustrates that labor costs account for a significant portion of the total trucking cost. As a result, it is important to deliver as much hydrogen as possible in each trip. This explains why the weight percent of hydrogen has such a large effect on cost, as it directly effects how much hydrogen a truck driver can deliver in a given period of time. The energy cost discrepancy illustrated in Figure 3 is created by the assumption that a truck carrying ethylcarbizole can make more deliveries in the course of the day due to a shorter drop-off time than a liquid hydrogen truck. This increased number of deliveries is offset by the lower capacity of a truck carrying ethylcarbizole.

The H2A-based model developed to support this analysis will allow technology developers to evaluate the cost of trucking various liquid alternative hydrogen carriers on a consistent basis and compare those results against standard carrier options.

## 6. Solid-State Truck Transport

Unlike liquid hydrogen carriers that are off-loaded from the transport trailer at the fueling station, this analysis assumes that solid-state hydrogen carriers (usually in the form of powders) will remain on-board the transport trailers at all times. Solid-state hydrogen carriers include carbon sorbents and metal hydrides. Potential solid-state materials are listed in Table 5.

| Carrier Type | Material Class | Example Material | Developer and Notes |
|---|---|---|---|
| Solid-State | Carbon Sorbent | AX-21 | Low-Temperature Adsorbent; Argonne/NREL |
| Solid-State | Complex Hydride | Sodium Alanate | United Technologies |

**Table 5: Solid-State Transport Materials**

Unlike liquid carriers, there are multiple delivery options available when using solid-state carriers:

- **Trailer Drop-Off**: In this delivery scenario, a trailer is dropped-off at the fueling station and the discharge process takes place over the course of the demand period (>1 day). Trailers containing discharged material are picked up at the fueling station and returned to the processing facility. This delivery method is similar to tube-trailer delivery in that every station needs to have a trailer on-site in order to meet demand and the trailer serves as on-site storage.
- **Hydrogen Off-Load**: In this delivery scenario, the discharge process takes place during the delivery (<1 hr). This necessitates a carrier material with relatively rapid kinetics to facilitate the off-loading of hydrogen in a timely fashion. Off-loading hydrogen negates the need to have trailers at each fueling station, but will require low-pressure storage and a dedicated compressor at the fueling station.

In the trailer drop-off scenario, hydrogen will be discharged at the fueling station. This process can be steady-state or on-demand, as described in Section 5, Liquid Truck Transport. Because the solid-state material cannot be easily transferred on and off of the trailer, this material cannot be delivered to the vehicle, but it is possible for the same or similar materials to be contained in on-board storage tanks. In either case, the hydrogen must be discharged from the material at the fueling station. Fueling station details for a solid-state carrier are specified in Section 8, Fueling Stations.

The specific delivery scenario has a significant effect on the overall cost of delivering hydrogen using solid-state carriers. To determine the cost effect of the various scenarios, two carriers were compared: AX-21, a carbon sorbent and sodium alanate ($NaAlH_4$), a complex hydride. Researchers have indicated that the kinetics of AX-21 is sufficient to allow for hydrogen to be desorbed rapidly, as would be required for a hydrogen off-load pathway. Given the rapid kinetics of AX-21, this analysis assumed that AX-21 would be employed in a hydrogen off-loading pathway. Despite this assumption, it is possible that AX-21 could be used in trailer drop-off scenario, but the low-temperature required may make it difficult to leave the trailer at the fueling station for long periods of time without the possibility of over-pressuring the trailer. The kinetics of sodium alanate is significantly slower and as a result trailers must be dropped-off at the fueling stations. Hydrogen discharge takes place over a longer period of time and at a constant rate. Details of the carriers analyzed are shown in Table 6.

| Variable | Material | Value | Notes |
|---|---|---|---|
| Hydrogen Weight Percentage | AX-21 at 150 bar | 4.60% | Temperature: 100 K |
| | AX-21 at 390 bar | 5.40% | |
| | Sodium Alanate, sys.* | 1.70% | Reactive material |
| | Sodium Alanate, max. | 5.60% | |
| Delivery Type | AX-21 at 150 bar | Off-Load | Rapid kinetics, LN2 requires to hydride |
| | AX-21 at 390 bar | Off-Load | |
| | Sodium Alanate, sys. | Trailer Drop-Off | 20 MJ/kg,H2 desorption energy req. |
| | Sodium Alanate, max. | Trailer Drop-Off | |

*Cannot deliver to 1,000 kg/day stations, insufficienct capactiy

**Table 6: Solid-State Carrier Trucking Sensitivity**

Figure 4 illustrates the per-kilogram trucking costs for the scenarios described in Table 6. The capital costs of the trailers used to transport solid-state carriers has not been sufficiently estimated by researchers or industry, therefore a range of options is shown. Of the trailer prices shown, $90,000 is the approximate price for a full-size petroleum trailer and $625,000 is the H2A assumption for liquid hydrogen trailers. $1,000,000 is an assumed upper-bound for trailer price. Other assumptions such as transport distance and fuel economy that are assumed constant for all solid-state hydrogen carriers are specified in Appendix A.

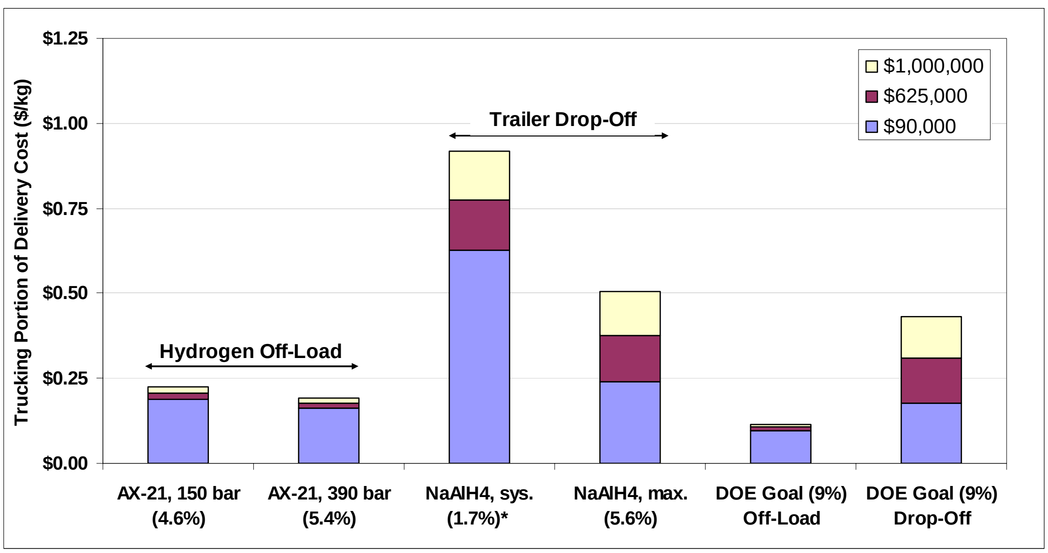


**Figure 4: Solid-State Hydrogen Trucking Cost**

Figure 4 illustrates the how highly variable the cost of delivery can be depending on the chosen pathway. The trucking costs under the trailer drop-off scenario are from 1.5-3.7 times more expensive than the hydrogen off-loading scenario. The primary driver of the high trailer drop-off cost is the distributed capital (trailers) at each fueling station. These cost differences, however, must be evaluated as a part of the overall delivery system. Additional low-pressure storage and a dedicated compressor are required at the fueling station to meet the needs of the hydrogen off-load delivery scenario. These additional fueling station costs are described and evaluated in Section 8, Fueling Stations.

# 7. Liquid Pipeline Transport

Another option for delivering alternative hydrogen carriers from the process facility to the fueling station is the use of pipeline networks that transport liquid carriers such as pure liquids, slurries, and solutions. Unlike a hydrogen, natural gas, or gasoline pipeline that transports a consumable product, a pipeline network delivering an alternative hydrogen carrier transports a recyclable material which must be returned to the processing facility. As a result, this analysis assumes that an alternative carrier pipeline network consists of two parallel pipelines throughout the network. The H2A model structure breaks the pipeline network into three levels: transmission, trunk and distribution. The transmission line transports liquid from the processing facility to the city, a variable number of trunk rings circle the city center, and distribution lines connect the fueling stations with the trunk rings. Figure 5 is a simplified illustration of how a three-level pipeline network might be designed. When transporting alternative carriers, each line shown in Figure 5 represents two parallel pipes, on for charged material and one for discharged material.

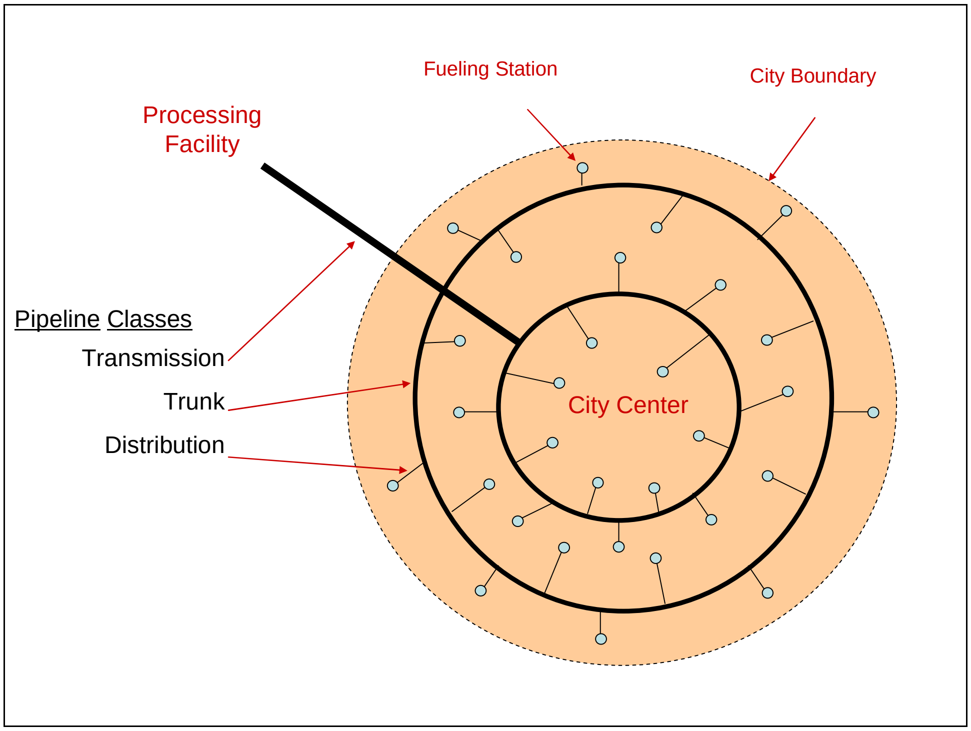


**Figure 5: Simplified Pipeline Diagram**

To assess the cost of delivering hydrogen, this analysis uses a number of assumptions taken from the H2A compressed hydrogen pipeline delivery model. The refinement of this cost estimate requires additional research to improve the accuracy of certain assumptions.

To estimate the capital cost of the alternative carrier pipeline, this analysis uses the cost equations employed in the existing H2A compressed hydrogen pipeline model. These equations are dependent on pipeline diameter and pipeline length and include labor, materials and other miscellaneous costs. For the alternative carrier analysis, the evaluated pipeline distance is twice the delivery distance to account for the two parallel pipes that carry hydrogenated and discharged material. Further research is required to improve the estimate for alternative carrier pipelines, but the assumptions included in the present analysis should provide a reasonable approximation of the costs for labor and materials.

In addition to the capital cost of the pipeline, the total capital cost includes the carrier material contained in the pipeline and sets of liquid pumps for the transmission and trunk rings. The capital cost of the liquid pumps is based on the cost for comparably sized gasoline pumps. In addition to pipeline capital cost, the purchase or lease of right-of-way rights can be a relevant contributor to the overall cost of operating a pipeline network. The right-of-way cost estimate (also a function of diameter and distance) for the alternative carrier pipeline is the same as the H2A right-of-way cost estimate for compressed hydrogen pipelines. Unlike the capital cost estimates, the evaluated distance is the delivery distance, not the total amount of pipeline laid, as it is assumed that the two parallel pipelines will be laid side-by side and only one right-of-way is required. The diameter evaluated in the right-of-way cost equation is the sum of the diameters for the two pipelines.

Additional inputs used to evaluate pipeline delivery cost are shown in Table 7. Only a pure liquid carrier was assessed in this analysis. Slurries and solutions may also be transported by pipeline, but the potential for the carrier material to precipitate or fall out of solution could cause potential problems in a pipeline system. It should also be noted that carrier evaluated here, n-ethylcarbizole, has a melting point of 70°C when dehydrogenated. As a result, it is necessary to transport the dehydrogenated material in an insulated pipeline (provided the resonance time is not too long), adding to the capital cost of the overall pipeline network.

| Model Input | Unit | Value | Notes |
|---|---|---|---|
| Hydrogen Carrier Capacity | wt.% | 5.88 | n-Ethylcarbizole |
| Carrier Density | kg/m3 | 1,000/3,000 | n-Ethylcarbizole estiamte |
| Carrier Cost | $/gal. | $7.00 | n-Ethylcarbizole |
| Maximum Pipeline Velocity | m/s | 1.8 | Based on average speed of Colonial pipeline, 4 mph |
| Average Throughput | kg/day | 240,000 | Size of potential liquid hydrocarbon plant |
| Average Station Demand | kg/day | 3,000 | TIAX assumption |
| Transmission Pipeline Length | miles | 63 | H2A Components Model, cH2 Pipeline |
| Truck Rings | | 2 | H2A Components Model, cH2 Pipeline |
| Average Trunk Pipeline Length | miles | 70 | H2A Components Model, cH2 Pipeline |
| Ditribution Pipeline Length | miles | 1.6 | H2A Components Model, cH2 Pipeline |

**Table 7: Alternative Carrier Pipeline Model Inputs**

Initial analysis illustrates that the capital costs dominate the total delivery cost; therefore the sensitivity evaluated was aimed at reducing the capital costs associated with pipeline delivery. Given the expense of burying pipe, particularly in an urban area, the total cost is very sensitive to the amount of distribution pipeline in the system. In a scenario with constant hydrogen throughput (240,000 kg/day), the total length of the distribution pipeline depends on the length of each leg and number of distribution pipelines. If a pipeline network includes fewer large fueling stations, as opposed to more smaller stations, than the overall length of distribution pipeline required will be reduced. The results of this sensitivity are shown in Figure 6.

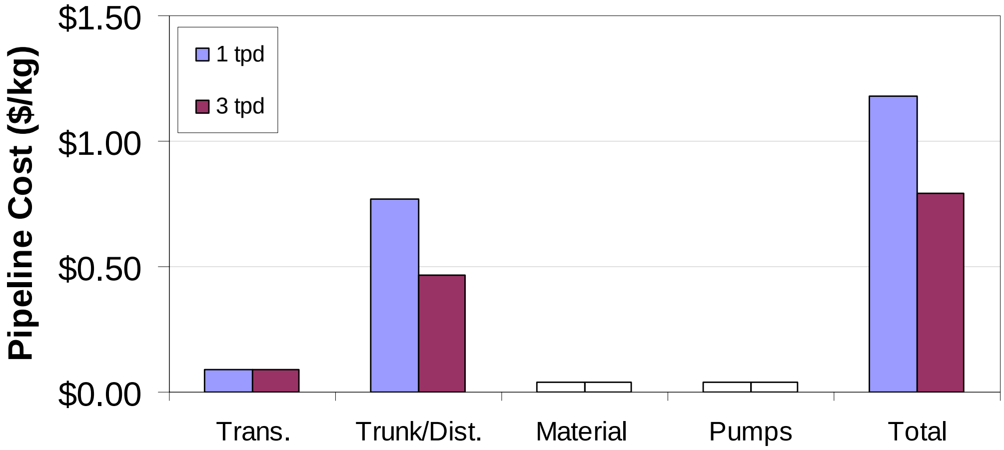


**Figure 6: Pipeline Delivery Cost Breakdown**

The difference in the total costs presented is a result of the reduced distribution pipeline that results from having fewer stations in the network.

Given the present assumptions – which require additional refining – delivering alternative hydrogen carrier in a pipeline may be prohibitively expensive. The need for two parallel pipelines is the primary driver of the overall cost. The second leg of the pipeline system is responsible for $0.37/kg of the $0.79/kg total cost of delivering hydrogen carrier in a pipeline network (assuming 3,000 kg/day stations).

## 8. Fueling Stations

Hydrogen fueling stations are the final component in the hydrogen delivery infrastructure. In conventional (compressed or liquid) delivery scenarios, the fueling station is likely to account for 30-60% [2] of the total hydrogen delivery cost, thus highlighting the need to properly evaluate and estimate the fueling station cost. The use of alternative carriers has the ability to significantly alter the design and required components at a hydrogen fueling station. This analysis attempts to identify all of the fueling station components required if alternative carriers are to be employed as a delivery mechanism. A single H2A-based model was developed to model the various fueling station configurations associated with different materials and delivery methods.

To systematically assess the various fueling station types and required components, the fueling stations types were defined by a number of metrics, including: the vehicle fueling method, the delivery method, and the method of discharge.

**Vehicle Fueling Method**

In the context of this analysis, hydrogen can be delivered to the vehicle in one of two ways: as compressed hydrogen or as a charged alternative carrier.

- **Compressed Hydrogen Fueling**: Hydrogen is delivered to vehicles to fill 5,000 psi on-board tanks (requires 6,250 psi cascade storage at the fueling station). This fueling pathway includes discharging hydrogen from the alternative carrier at the fueling station. For purposes of estimating cost, much of the compressed hydrogen fueling station infrastructure (compressor, cascade storage) is assumed to be the same as that included in H2A models for tube trailers or pipeline stations (depending on assumptions regarding hydrogen discharge). In addition to the compressed hydrogen components, this fueling method may require discharge reactors, alternative carrier storage, trailer bays, and/or low-pressure gaseous hydrogen storage. Further metrics used to classify fueling stations will determine the specific components required
- **Alternative Carrier Fueling**: Hydrogen is not discharged from the alternative carrier at the fueling station. Instead, the carrier is delivered to the vehicle and hydrogen discharge occurs on-board. In addition to on-board discharge equipment, this fueling pathway requires that the discharged carrier be removed from the vehicle at the fueling station for return to the processing facility. This likely necessitates additional storage on-board the vehicle and an advanced dispenser that can remove the discharged carrier. Delivering the alternative carrier to the vehicle reduces the need for on-site discharge equipment and compressed hydrogen hardware at the fueling station. This will likely result in a significant reduction in fueling station capital cost. This cost reduction, however, may be offset by the increased cost and complexity of storing and discharging the carrier on-board the vehicle. A synthesis of on-board and off-board analyses is necessary to evaluate the total cost associated with this fueling pathway.

**Delivery Method**

Within the scope of alternative hydrogen carrier delivery pathways, multiple delivery options are available. The details of the specific delivery pathways are discussed in Sections 4-7. The effects that these various pathways have on fueling station equipment are discussed below.

- **Liquid Carrier Drop-Off**: As discussed earlier, this delivery pathway relies on trucks to transport the alternative carrier from the processing facility to the fueling station where it is off-loaded into liquid storage tanks. If the vehicles are being fueled with compressed hydrogen, a discharge reactor is required at the fueling station, as well as liquid storage for both the charged and discharged carrier. Depending on the discharge method selected, the compressed hydrogen infrastructure (compressor and storage) will be the same as the infrastructure at tube trailer or compressed hydrogen pipeline fueling stations.
- **Solid Carrier Off-Load**: Section 6 discussed solid carrier trucking. In the hydrogen off-load pathway the kinetics of the material is fast enough to allow for the hydrogen to be off-loaded during a regular delivery stop (1 hr. assumed max. drop-off time). The off-loading scenario reduces the need to leave a trailer at every fueling station, but does create a need for hydrogen storage and a dedicated off-loading compressor at the fueling station (analysis assumes 2,500 psi storage at fueling station). The off-loading compressor must compress the entire truck's worth of hydrogen for storage in the span of the drop-off, necessitating a compressor with very high throughput (assuming a reasonable material storage capacity). Discharge equipment is likely required at the fueling station, but will generally consist of equipment required to provide heat transfer fluid to the trailer, as the solid-state materials generally store hydrogen through adsorption. As a result, the desorption process is activated by increasing the temperature of the storage medium.
- **Solid Carrier Truck Drop-Off**: Similar to the tube-trailer scenario, it is possible to drop-off alternative carrier trailers at the fueling station and use the trailers for on-site storage. This pathway is required if a solid material with slow material kinetics is employed. If the kinetics is fast enough, the discharge process can occur on-demand (reducing the need for low-pressure buffer storage) or at a constant rate. The distributed capital – in the form of trailers at each fueling station – is one of the drawbacks of this delivery method. The large number of trailers required to deliver hydrogen to the fueling stations makes the overall delivery cost more sensitive to the per-trailer capital cost.
- **Pipeline**: Liquid alternative carriers can potentially be delivered by pipeline. If the vehicle fueling method is compressed hydrogen, the discharge process will occur at the fueling station. This analysis assumes that the pipeline is continually supplying the fueling station and hydrogen is subsequently discharged at a constant rate. This assumption agrees with the compressed hydrogen, pipeline-supplied fueling stations that are assumed to draw on the pipeline network at a constant rate throughout the day. It is possible for the liquid carrier to be stored in buffer storage and hydrogen discharge to occur on-demand, but this scenario is not evaluated in this analysis. Assuming discharge at a constant rate, hydrogen is subsequently stored in 2,500 psi storage vessels. In this case, the compressed hydrogen infrastructure (compressor and gaseous storage) is

the same as the fueling station infrastructure modeled in the H2A assessment of compressed hydrogen pipeline-supplied fueling stations. Pipelines may also supply alternative carrier for delivery onto vehicles. The alternative carrier could be stored on-site in liquid tanks and distributed to vehicles using the same advanced dispensers that would be required for dispensing an alternative liquid hydrogen carrier at a truck-supplied station.

**Discharge Method**

The potential exists for slow material kinetics to severely limit the ability to discharge hydrogen when needed to meet vehicular demand at the fueling station. As a result, the model considers two discharge options.

- **Steady-State**: If material kinetics limit the ability to discharge as needed, a steady-state scenario discharges hydrogen at a constant rate and stores it in low-pressure (2,500 psi) buffer storage. This discharge option can be employed for liquid drop-off and trailer drop-off, and is required for the pipeline scenario (given present modeling assumptions).
- **On-Demand**: If the kinetics allow, the model will also evaluate a fueling station that discharges hydrogen to meet the hourly demand at the fueling station. This scenario reduces the need for buffer storage, but does require a larger reactor to meet the more variable demand. The compressed hydrogen infrastructure is assumed to be the same as that at a tube-trailer station, which also supplies hydrogen to the compressor on-demand, and not at a constant rate.

After identifying the various fueling station configurations, an H2A-model was modified to allow the user to evaluate all of the various fueling station scenarios within one modeling framework. The characteristics discussed above serve as inputs to determine the components (and associated costs) that need to be included for each fueling station scenario. The capacities of these components are also a function of the material properties and demand at the fueling station. Table 8 illustrates the components that are included for the various fueling station configurations that can be evaluated using this model.

| Delivery Method | Vehicle Fueling Method | Steady-State or On-Demand | Trailer Bay | Off-Load Comp. | Liquid Storage | Dehydrogenation Reactor | Low-P Storage | High-P Comp. | Cascade Storage | Dispenser Type |
|---|---|---|---|---|---|---|---|---|---|---|
| Liquid Carrier Off-Load | cH2 | SS | | | Y | Y | Y | Y | Y | cH2 |
| | | OD | | | Y | Y | | Y | Y | cH2 |
| Liquid Carrier Off-Load | Liquid Carrier | ND | | | Y | | | | | Liq |
| Solid Carrier H2 Off-Load | cH2 | OD | | Y | | Y | Y | Y | Y | cH2 |
| Solid Carrier Truck Drop-Off | cH2 | SS | Y | | | Y | Y | Y | Y | cH2 |
| | | OD | Y | | | Y | | Y | Y | cH2 |
| Pipeline | cH2 | SS | | | | Y | Y | Y | Y | cH2 |
| | | OD | | | | Y | | Y | Y | cH2 |
| Pipeline | Liquid Carrier | ND | | | Y | | | | | Liq |

***SS= Steady-state; OD = On-demand; ND = No Dehydrogenation at Fueling Station**

**Table 8: Fueling Station Components**

One of the most glaring facts illustrated inn Table 8 is the amount of equipment required to dispense compressed hydrogen to vehicles. The liquid carrier fueling options only require alternative carrier storage and a dispenser. While both of these components have their own complexities (insulated/heated storage for charged and discharged material; dispensers that supply and remove carrier to and from the vehicle), the lack of reactors, compressors, and storage is likely to significantly reduce the overall fueling station cost. It should be noted again that by supplying alternative carrier to the vehicle, many of the issues and costs are transferred from the fueling station to the vehicle, such as the cost and complexity of discharging the carrier to meet variable vehicular demand. This transfer of components and costs to the vehicle has the potential to increase the cost of the entire hydrogen delivery system, including the vehicle.

This model does not claim to include all possible delivery options that could employ novel carriers. For example, it may be possible to successfully off-load a solid carrier in the form of a powder or paste. This option is not explicitly indentified and considered in this model, but may deserve attention in the future. Other delivery possibilities are also potentially available and warrant consideration if presented.

### Cost Assessment

Given the lack of compressed hydrogen equipment at fueling stations that supply alternative carrier to vehicles, it is clear that those stations will have a cost benefit relative to the fueling stations supplied by alternative carriers and distributing compressed hydrogen. This analysis did not model the on-board costs required to utilize alternative carriers and thus cannot provide the full cost analysis of using alternative carriers for both delivery and on-board storage. As a result, this analysis of fueling stations focuses on evaluating the costs of alternative carrier stations dispensing compressed hydrogen.

A potentially important cost variable is the cost of the discharge reactor. At present, little research has gone into evaluating the costs of reactors for use at fueling stations. Most existing alternative carrier analysis focuses on the cost of on-board equipment or the capital costs associated with large-scale processing facilities. As a result, there are very few existing studies available that specify the costs of fueling station-scale reactors. Furthermore, the variability in capability makes it difficult to assume a universal cost for reactors used at fueling stations that are using different types of carrier material. For example, desorbing hydrogen from AX-21 will require – at most –supplying heat transfer fluid to the sub-cooled material in order to increase the temperature of the material and desorb hydrogen. This heat transfer mechanism is likely far cheaper than the catalytic reactor required for the endothermic hydrolysis process required to discharge hydrogen from sodium borohydride or the high temperature reactor that supplies significant amounts of heat to dehydrogenate hydrogen from a liquid hydrocarbon. As a result, this analysis evaluated the various fueling station scenarios with a variety of discharge reactor costs. The range of reactor costs used was $0-20,000/(kg/hr) of hydrogen reacted. In estimating this range, costs for a variety of different reactors and processing plants were considered, including: plant-scale reactors for n-ethylcarbizole ($5,600/(kg/hr)), a complete n-ethylcarbizole plant ($16,600/(kg/hr)), sodium borohydride reprocessing plants ($45,000-53,000/(kg/hr)). While fueling station reactors will not have the systematic complexity of processing plants, they also do not have the advantage of scale and still require all of the safety equipment required when working with hydrogen. As a result, the costs considered are $0/(kg/hr), which was included to evaluate the cost without the reactor or with a very low-cost reactor such as an ambient temperature heat exchanger, $5,000/(kg/hr) for the natural gas-fired heat transfer systems that will likely be used with some solid-state carriers, and $10,000-20,000/(kg/hr) for the more complex reactors likely required for liquid hydrocarbons or chemical hydrides. Ascertaining the proper costs for these components is a primary research objective in the second phase of this analysis.

Given the costs assumptions for dehydrogenation reactors and the additional assumptions listed in Appendix A, fueling station cost estimates were determined for a variety of fueling station configurations and presented in Figure 7.

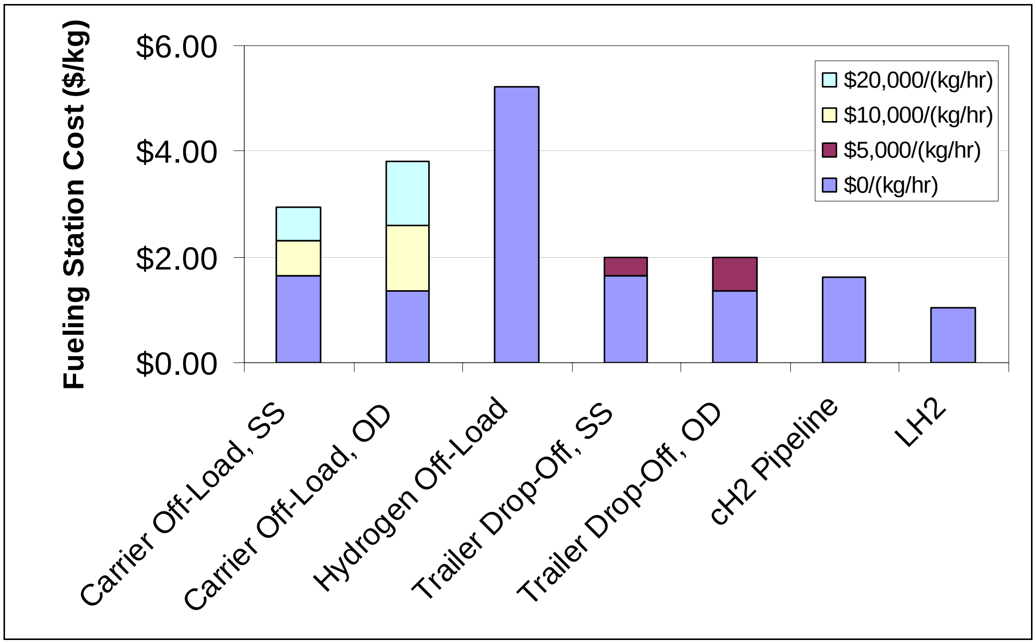


**Figure 7: Fueling Station Costs for a Variety of Delivery Options w/ Variable Costs for Discharge Reactors**

The results shown in Figure 7 only magnify the need to better quantify the cost associated with the discharge reactors, as the discharge reactors may potentially contribute more than $2.00/kg to the overall cost of delivered hydrogen.

The carrier off-load scenario was evaluated under two different discharge options: steady-state and on-demand. Unless the discharge equipment is extremely affordable, the results indicate that it will generally be more cost effective to have a lower capacity reactor in combination with low-pressure storage than have a high-capacity reactor and no low-pressure storage.

The results of the hydrogen off-load scenario clearly indicate that the cost associated with adding a high-capacity compressor and significant low-pressure storage (assuming a delivery of ~1,450 kg and 1,000 kg/day station demand) is prohibitively expensive. Hydrogen off-loading was considered as a way to reduce the need for the distributed capital associated with leaving trucks at each fueling station, but the results illustrate that compressing and storing hydrogen at low-pressure is not an effective method for minimizing that cost of distributed trailers.

Due to the potentially low cost of discharge equipment for solid-state carriers, the fueling station costs for the trailer drop-off pathway are comparable to the costs of pipeline-supplied or liquid-supplied fueling stations. In all of these scenarios, the baseline costs for high-pressure hydrogen compressors and cascade storage are included. From a delivery perspective, the potential for alternative carriers to really offer a cost advantage over conventional transport options lies in the ability to supply alternative carriers to vehicles and reduce the need for compressed hydrogen equipment at the fueling station.

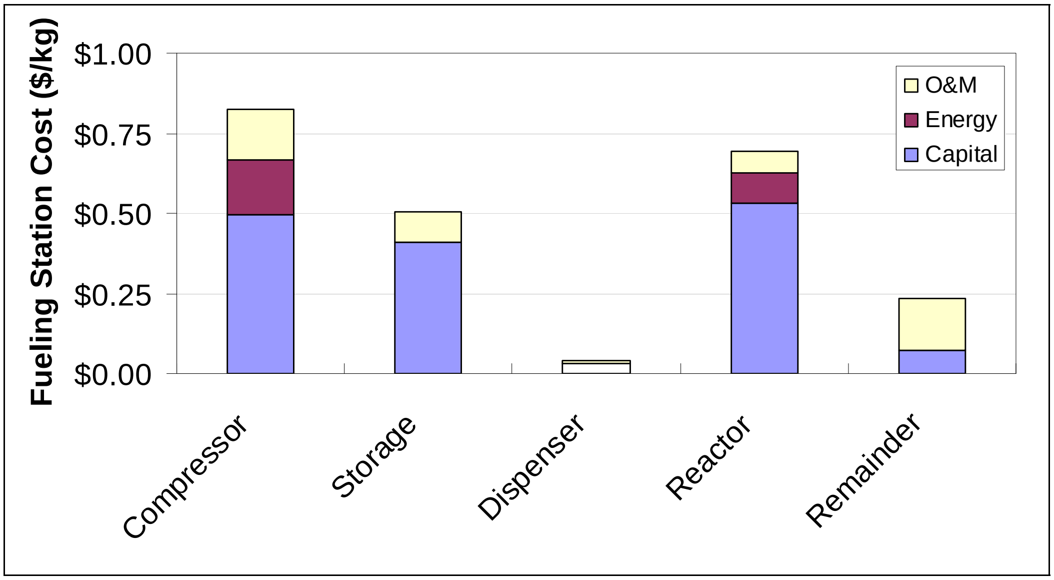


**Figure 8: Cost Breakdown for Carrier Drop-off/cH2 Station**

Figure 8 shows a cost breakdown of a carrier drop-off scenario that illustrates the significant effect that the compressor, reactor and storage components have on the overall fueling station cost. Delivering alternative carrier to the vehicle will significantly reduce or remove those three contributors to the overall cost. The potential for such a reduction favors liquid carriers that can easily be transferred from storage at the fueling station to a tank on the vehicle.

## 9. Other Issues

In addition to the considerations discussed above, there are other issues that must be addressed when evaluating the viability of a novel carrier. One such issue is material toxicity. The present analysis does not explicitly address whether a particular carrier has the potential to negatively affect human health, cause environmental damage, or lead to the degradation of storage containers and material processing and handling equipment. When selecting a carrier, the potential hazards must be considered. In some instances the dangers or drawbacks associated with a carrier will immediately remove that carrier from consideration. In other situations, it will be necessary to weigh the potential hazards with the energy or cost benefits associated with that carrier.

A good example of potential hazards is the reactivity of sodium alanate. When in the presence of water or air, sodium alanate can undergo a highly exothermic chemical reaction. Such a situation could be highly problematic in a delivery scenario where there will be large amounts of material in storage tanks or trucks.

Considerations such as the toxicity or reactivity of a material are highly subjective and are not appropriately handled in a modeling architecture such as an H2A

Delivery Model. As a result, developers and investors must evaluate these issues when deciding whether to move forward.

## 10. Selecting a Carrier

When determining the viability of an alternative carrier, there are multiple metrics on which a carrier can be evaluated, such as energy-use, greenhouse gas (GHG) emissions, total cost, or potential hazard. In addition there are multiple roles that an alternative carrier can play in the development of the hydrogen infrastructure. An alternative carrier could offer an improvement over tube trailers for small-scale delivery in the near term, could compete with liquid hydrogen for larger-scale delivery, or could provide an alternative to compressed hydrogen pipelines in a fully developed infrastructure. Given the variety of evaluation metrics and use-scenarios, it is very difficult to offer a simple method for down-selecting carriers. In addition, many of the processes used to charge and discharge hydrogen are continually improving, causing the characteristics of a particular carrier to vary with time. As a result, it is inappropriate to explicitly rule-out certain carriers based on the present generation of technology development.

When assessing the viability of an alternative hydrogen carrier, the first necessary step is to determine how a carrier is likely to be used. After specifying the anticipated use or application of the carrier, it is then easier to establish baselines for such parameters as cost or energy-use. For example, if a carrier is being developed to provide small-scale deliveries in a nascent hydrogen infrastructure, the compressed hydrogen tube trailer is probably the most comparable conventional delivery mechanism available. As a result, the alternative carrier should not be evaluated against a low-cost delivery method such as hydrogen pipelines, but against the standards defined by a tube trailer and competing alternative carriers.

After determining the role that the carrier is hoping to fill, some questions can be asked to determine the viability of the carrier.

1) Does this carrier offer a transport capacity that can practically meet the hydrogen demand at the fueling stations to which it is delivering?
    a. Practically meeting the demand includes considering such factors as the need to have no more than one delivery in a day to a single fueling station.
    b. It is not necessary for the capacity be better than the conventional alternatives because the carrier may have other advantages such as cost or energy consumption.
2) Are the costs competitive with conventional carriers and other alternative carriers?
    a. When evaluating the costs it is important to evaluate the entire delivery and fueling pathway from generation or processing to vehicle fueling. Given the complexity of the delivery systems and

the distributed costs, it is easy to exclude steps that have considerable costs. This must be avoided by performing a thorough analysis of the delivery pathway.

   b. If it is determined to utilize the carrier for onboard storage as well as for delivery, it is important to consider that the discharge equipment – and the associated costs – that may no longer be necessary at the fueling station will be shifted onboard the vehicle. While resulting in lower-cost delivery, it might yield a significant increase in vehicle costs. This tradeoff should be considered.
   c. It is not absolutely necessary to select the lowest cost option because there are a number of other important factors to consider, but if the cost is not within an acceptable range of other carriers – conventional or alternative – it is likely that said carrier is not a viable option. This is especially true if a significant portion of the cost is related to a component or process that cannot be performed more cost effectively through technology development.

3) What advantages does a carrier offer compared to competing methods and what is the regulatory regime that it will enter into?
   a. While practicality and cost are important drivers, it is also important to evaluate such considerations as overall energy use and GHG emissions.
   b. For example, if it is anticipated that GHG regulations are in place, the GHG emissions of a particular carrier are far more important than in an unregulated environment. Such a factor might make a more expensive option more attractive.
4) Does the carrier have properties that will unequivocally prevent it from safely being implemented?
   a. If a carrier has clear safety hazards that cannot be reconciled, such as severe toxicity or high volatility, these carriers should be considered with increased caution.

While it is clear that there are a number of factors that must be considered when evaluating alternative carriers, it is not impossible to objectively analyze various carriers using some of the questions described above. Of utmost importance is considering all of the delivery and production steps before making comparisons and choices between carriers. In addition, it must be remembered that many alternative carriers are in the development stage and offer the potential for improved characteristics in the future.

## 11. Conclusions

This analysis has only served to scratch the surface of alternative carrier delivery analysis, but it has provided direction for further research and identified places where an improved cost assessment is required. For example, the fueling station analysis indicates that using alternative carriers in a pathway that discharges hydrogen at the station and supplies compressed hydrogen to vehicles will offer little or no benefit for fueling station costs because the alternative carriers have not reduced the need for compressed hydrogen equipment at the fueling station. In addition, a costly reactor can significantly increase the overall cost of the fueling station. Alternative carriers have the ability to significantly reduce fueling station costs if the alternative carriers are delivered to the vehicle. Liquid carrier options offer the best case for such a pathway, as they benefit significantly from the ease with which they can be transferred between storage mediums. The transport difficulty inherent in the solid carriers makes it difficult to envision a pathway in which the alternative carrier material is used for delivery and on-board storage without a discharge process in between the delivery mode (such as a truck) and the vehicle.

The trucking analysis indicated that the focus should be on improving the hydrogen capacity of the carrier without regard to the costs of the transport trailer, as it has little effect on the overall delivery cost (at least in a carrier drop-off scenario). The benefits of the hydrogen off-loading pathway (no distributed trailers) are almost certainly not worth the additional costs for a high-capacity compressor and significant low-pressure storage at the fueling station.

While there are other small conclusions that can be taken from this analysis, the major success is the development of a model that identifies a variety of pathway options and identifies all of the components required for each pathway. In addition, this analysis has illustrated the need to perform delivery cost analyses across the entire delivery spectrum from the processing facility to the vehicle. For example, results of this analysis indicate that dispensing liquid alternative carriers to vehicles offers the cheapest pathway for hydrogen delivery. However, without identifying the costs of the equipment on-board the vehicle, this analysis and the subsequent conclusions are incomplete. The various pathways for hydrogen production and delivery must be evaluated throughout the delivery pathway to determine the overall cost and allow various pathways to be compared against one another. This model will provide the framework for evaluating a portion of that entire lifecycle cost.

## 12. Analytical Contributors

DOE: Mark Paster; Monterey Gardiner
ANL: Amgad Elgowainy
NREL: Matt Ringer
Nexant: Bruce Kelly
TIAX: Steve Lasher; Kurtis McKenney

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# 14. Appendix A

## Trucking Assumptions

| Model Input | Unit | Value | Notes |
|---|---|---|---|
| Truck Cargo Weight | kg | 25,200 | Cargo for max GVW (80,000 lbs) |
| Material Cost | $/gal | $7.00 | n-Ethylcarbizole |
| Carrier Density | kg/m3 | 1,000 | n-Ethylcarbizole estimate |
| Truck Useable Fraction | | 97.5% | H2A assumption |
| Round Trip Distance | km | 80 | H2A assumption |
| Average Station Demand | kg/day | 1,000 | TIAX estimate |
| Time to Fill Liquid Trailer | hrs | 0.75 | TIAX estimate |
| Time to Empty Liquid Trailer | hrs | 0.75 | TIAX estimate |
| Time to Drop-off & Pick-up Trailer | hrs | 1.00 | Max acceptable delivery time |
| Average Truck Speed | km/hr | 58 | H2A assumption |
| Truck Gas Mileage | km/L | 2.6 | H2A assumption |
| Tractor Cost | | $75,000 | H2A assumption |

## Pipeline Calculation Assumptions

| Model Input | Unit | Value | Notes |
|---|---|---|---|
| Hydrogen Carrier Capacity | wt.% | 5.88 | n-Ethylcarbizole |
| Carrier Density | kg/m3 | 1,000/3,000 | n-Ethylcarbizole estiamte |
| Carrier Cost | $/gal. | $7.00 | n-Ethylcarbizole |
| Maximum Pipeline Velocity | m/s | 1.8 | Based on average speed of Colonial pipeline, 4 mph |
| Average Throughput | kg/day | 240,000 | Size of potential liquid hydrocarbon plant |
| Average Station Demand | kg/day | 3,000 | TIAX assumption |
| Transmission Pipeline Length | miles | 63 | H2A Components Model, cH2 Pipeline |
| Truck Rings | | 2 | H2A Components Model, cH2 Pipeline |
| Average Trunk Pipeline Length | miles | 70 | H2A Components Model, cH2 Pipeline |
| Ditribution Pipeline Length | miles | 1.6 | H2A Components Model, cH2 Pipeline |

## Fueling Station Assumptions

| Model Input | Unit | Value | Notes |
|---|---|---|---|
| Hydrogen Carrier Capacity | wt.% | 5.88 | n-Ethylcarbizole |
| Carrier Density | kg/m3 | ,000/3,000 | n-Ethylcarbizole estiamte |
| Carrier Cost | $/gal. | $7.00 | n-Ethylcarbizole |
| Discharge Pressure | atm | 20 | |
| Off-Load Discharge Rate | kg/hr | 1,000 | |
| Carrier Storage Factor | storage/demand | 1.5 | |
| Discharge Energy | MJ/kg,H2 | 25 | n-Ethylcarbizole estimate |
| Heat Recovered | % | 25% | n-Ethylcarbizole estimate |
| High-Pressure Storage | psi | 6,250 | H2A assumption |
| Low-Pressure Storage | psi | 2,500 | H2A assumption |
| Number of High-Pressure Compressors | | 3 | H2A assumption |
| Number of Compressors in Operation | | 2 | H2A assumption |
| Compressed H2 Infrastructure Cost | All cH2 Infrastructure Costs based on H2A Assumptions; see H2A documentation | | |

# Hydrogen Delivery Infrastructure Options Analysis

# DE-FG36-05GO15032

# Task Report
# Task 1: Data and Knowledge Base

**Nexant, Inc.**

**December 2006**

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## 1.1 ENERGY RESOURCES AND CARBON SEQUESTRATION SITES IN US

### 1.1.1 Natural gas

#### *1.1.1.1 Resource Locations, Production, and Reserves*

The principal natural gas production regions in North America are shown in Figure 1-1, and the corresponding resources in the various regions shown are summarized in Table 1-1.


Figure 1-1 North American Natural Gas Production Areas
(US National Petroleum Council, Balancing Natural Gas Policy, Volume 1, Summary and Recommendations, September 2003)

Table 1-1 North American Natural Gas Reserves and Resources
Trillions of Cubic Feet

| Region | Developed Resource | Estimated Remaining | Estimated Total Resource | Estimated Production In 2002 | Years At Current Production |
|---|---|---|---|---|---|
| Alaska | 19.6 | 321.8 | 341.4 | 0.4 | 804 |
| West Cost Onshore | 34.5 | 32.6 | 67.1 | 0.3 | 109 |
| Great Basin | 2.4 | 4.0 | 6.4 | 0.1 | 40 |
| Rockies | 116.8 | 213.3 | 330.2 | 3.4 | 63 |
| West Texas | 121.8 | 54.2 | 176.0 | 1.7 | 32 |
| Gulf Coast Onshore | 359.0 | 176.5 | 535.5 | 4.9 | 36 |
| Mid Continent | 203.9 | 72.6 | 276.5 | 2.2 | 33 |
| Eastern Interior | 68.6 | 122.1 | 190.7 | 0.9 | 136 |
| Gulf of Mexico | 192.3 | 316.0 | 508.3 | 4.9 | 64 |
| US Pacific Offshore | 3.2 | 1.2 | 4.4 | - | N/A |
| West Canada Sand Basin | 183.5 | 206.5 | 390.0 | 6.4 | 32 |
| Arctic Canada | 0.1 | 73.9 | 74.0 | - | N/A |
| Eastern Canada Onshore | 1.5 | 7.2 | 8.7 | - | N/A |
| Eastern Canada Offshore | 2.5 | 96.1 | 98.6 | 0.2 | 480 |
| Western British Columbia | - | 11.5 | 11.5 | - | N/A |
| North American Total | 1,309.7 | 1,709.5 | 3,019.3 | 25.4 | 67 |

The largest remaining resources are in the Gulf of Mexico, the Gulf Coast onshore, the Rocky Mountains, and in Alaska. Although these resources are generally distant from the principal population centers, an extensive and efficient pipeline transmission and distribution system, described below, readily transports the gas from the producers to the consumers.

#### *1.1.1.2 Trends in Domestic Production*

As shown in

Table 1-2, natural gas production in the lower 48 states has been relatively constant over the past several years. However, domestic demand is increasing, as shown later in Figure 1.6. The development of the gas resource in Alaska will, to some extent, ameliorate the supply situation. Nonetheless, imports of natural gas from Canada, and liquefied natural gas from the Caribbean, will become an increasingly important component of the gas supply, and illustrated in Table 1-3.

Table 1-2
Recent Trends in Natural Gas Production in the Lower 48 States
Billions of Cubic Feet

| Region | 2000 | 2001 | 2002 | 2003 |
|---|---|---|---|---|
| West Coast Onshore | 286 | 291 | 289 | 294 |
| Great Basin | 90 | 95 | 100 | 92 |
| Rockies | 3,097 | 3,260 | 3,376 | 3,486 |
| West Texas | 1,756 | 1,761 | 1,712 | 1,695 |
| Gulf Coast Onshore | 5,070 | 5,085 | 4,945 | 4,897 |
| Mid-continent | 2,317 | 2,287 | 2,238 | 2,223 |
| Eastern Interior | 938 | 936 | 890 | 887 |
| Gulf of Mexico | 5,196 | 5,233 | 4,928 | 4,882 |
| Pacific Offshore | 48 | 47 | 47 | 47 |
| Lower 48 Total | 18,798 | 18,995 | 18,526 | 18,504 |

Table 1-3
Domestic Production, Consumption, and Imports of Natural Gas in 2003
Billions of Cubic Feet

| | |
|---|---|
| Production | 19,036 |
| Consumption | 22,375 |
| Imports | 3,996 |
| Exports?? | 692 |
| Liquefied natural gas imports | 507 |
| Proven reserves | 189,044 |

Source: EIA Statistics, Annual Energy Outlook, February 2005

#### *1.1.1.3 Natural Gas Demand and Uses*

Currently, the United States consumes about 25 trillion cubic feet of natural gas each year; this represents about 24 percent of the domestic energy supply. As of 2004, it was the nation's fastest growing source of energy, with demand forecasted to increase more than 40 percent by 2025, including an over 50 percent increase for electric power generation. However, recent increases in natural gas prices, plus a high volatility in those prices, may have ameliorated this trend.

Natural gas supplies about 60 million of residential customers, and 5 million commercial and industrial customers. It provides almost half of the energy for commercial facilities and nearly 38 percent for industrial operations. Natural gas also fuels nearly 130,000 buses, taxis, delivery trucks, and other gas-powered vehicles. Natural gas is the raw material for a wide range of products, such as plastics, steel, glass, synthetic fabrics, fertilizer, aspirin, automobiles, and processed food. A distribution of natural gas use by sector is shown in Table 1-4.

Table 1-4
US Natural Gas Consumption by Sector

| 1998-2002 | Residential | Commercial | Industrial | Power Generation | Other | Total |
|---|---|---|---|---|---|---|
| Annual Average ($10^9$ $ft^3$/year) | 4,785 | 3,106 | 7,822 | 5,126 | 1,745 | 22,584 |
| Percent of Use | 21.2 | 13.8 | 34.6 | 22.7 | 7.7 | 100.0 |

Source - http://www.eia.doe.gov/neic/quickfacts/quickgas.htm

#### *1.1.1.4 Natural Gas Production and Distribution*

The natural gas production, processing, transmission, and distribution chain is illustrated schematically in Figure 1-2.

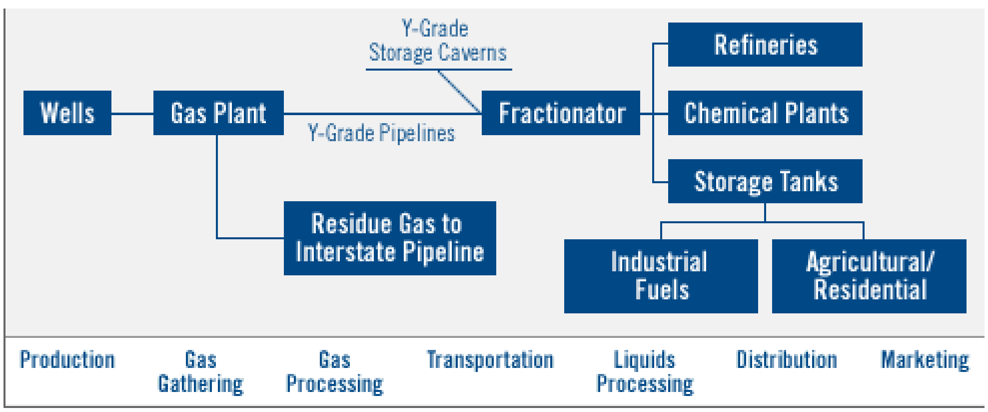



Figure 1-2 Natural Gas Production and Distribution System

The US currently has about 393,000 natural gas producing wells. Gathering systems collect raw (unprocessed) gas at the wells and transport to processing plants or other separation and purification facilities. The purpose of these facilities is to remove natural gas liquids or to remove other impurities.

Gathering lines are typically smaller in diameter compared to the large transmission lines. Transmission pipelines consist of both higher pressure and larger diameter pipelines to quickly move natural gas long distances. Distribution systems then deliver the natural gas to homes, businesses, and power plants. There are over 2 million miles of pipelines in the United States.

Compression plays a major role in the transportation of natural gas through pipelines. Natural gas entering a pipeline is compressed to move the natural gas effectively and to increase the volume a pipeline can transport. Compressor stations are spaced along interstate pipelines at regular intervals to maintain this pressure and to control the movement of the natural gas. Currently, about 1,700 compressor stations are in operation.

Natural gas is transported at pressures that vary from 200 to 1,500 psi (13.8 to 103.4 bars). Another important role of compression is natural gas storage. Since natural gas is used for heating in many parts of the U.S., demand for gas is higher in the winter than in the summer. Natural gas is stored under pressure in some 465 underground reservoirs or caverns to meet this seasonal need. Underground storage accounts for about 20 percent of the natural gas consumed each winter.

#### *1.1.1.5 Transmission Pipelines*

The high pressure (200 psig (13.79 bars g) and higher) transmission pipelines consist of a ductile carbon steel material, engineered to meet standards set by the American Petroleum Institute (API). The pipe is covered with a specialized coating to prevent corrosion after the pipe is placed in the ground. Cathodic protection systems, which deliver a small electric voltage to counter the normal chemical tendency for the ferrous pipe to return to its preferred oxidized state (i.e., rust), are often provided.

Typical characteristics of pipeline construction include the following:

| | |
|---|---|
| Pipeline Size | 3 in. to 48 in. (7.62 cm to 122 cm) |
| Large Trunk Lines | 24 in. to 48 in. (60.96 cm to 122 cm) |
| Right of Way | 50 feet (15.2 m) on either side of the pipe, or 100 feet (30.48 m) total |
| Easement | 50 feet (15.2 m) |
| Pipeline Pressure | 200 to 1,500 psig (13.79 to 103.45 bars g) |
| Pipe Material | Carbon steel with specialty coating |
| Cathodic Protection | Approximately every mile |
| Valve Stations | 15 to 20 miles (24 to 32 km); block valves or as required |
| Pipeline Markers | At road and canal crossings, and at fences |
| Life Expectancy | Indefinite |
| Minimum Depth | 36 in. (91.44 cm), to top of pipe |

Reference - Title 49 - Transportation, Code of Federal Regulations Part 192, Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards.

The principal transmission lines are illustrated in Figure 1-3, and the average flow rates are shown schematically in

Figure 1-4. The principal gas flows are from the Gulf Coast up through the Midwest and the Southeast, and from Western Canada into the Midwest and the Northeast.

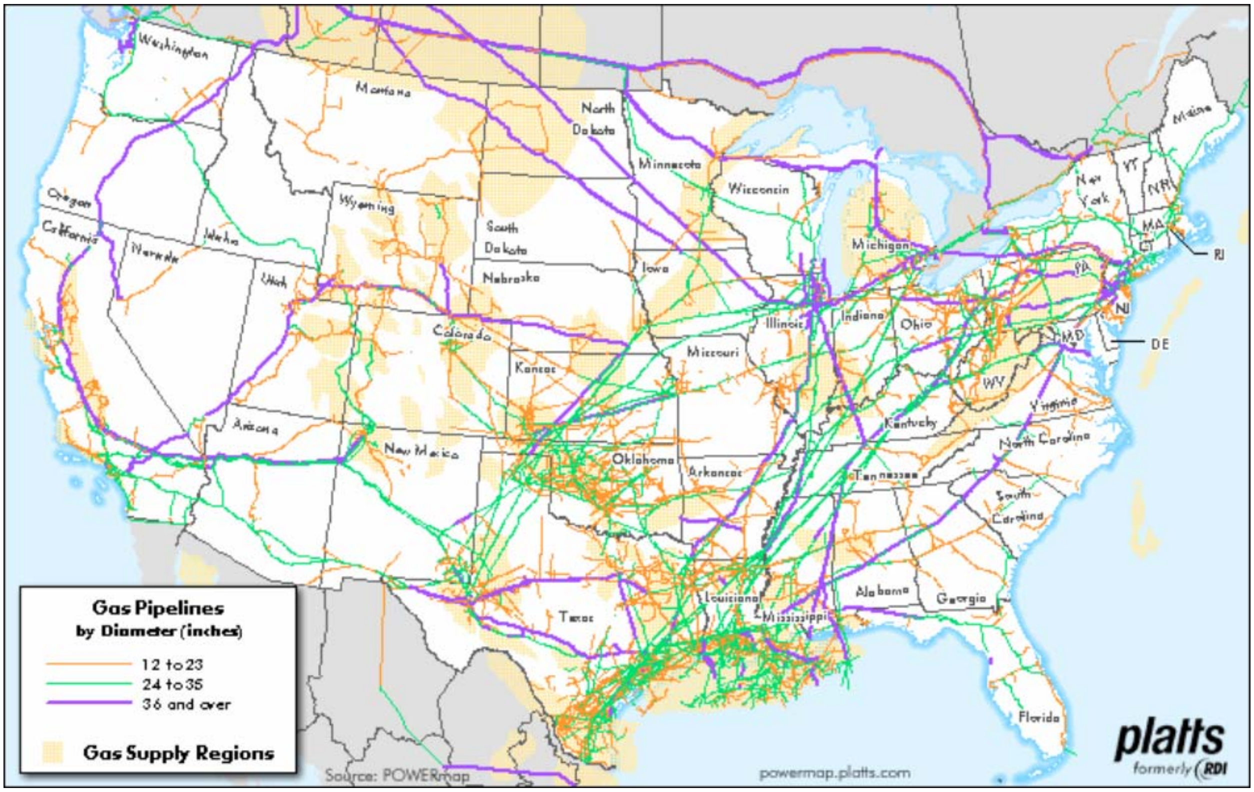



Figure 1-3 Principal Domestic Natural Gas Transmission Pipelines

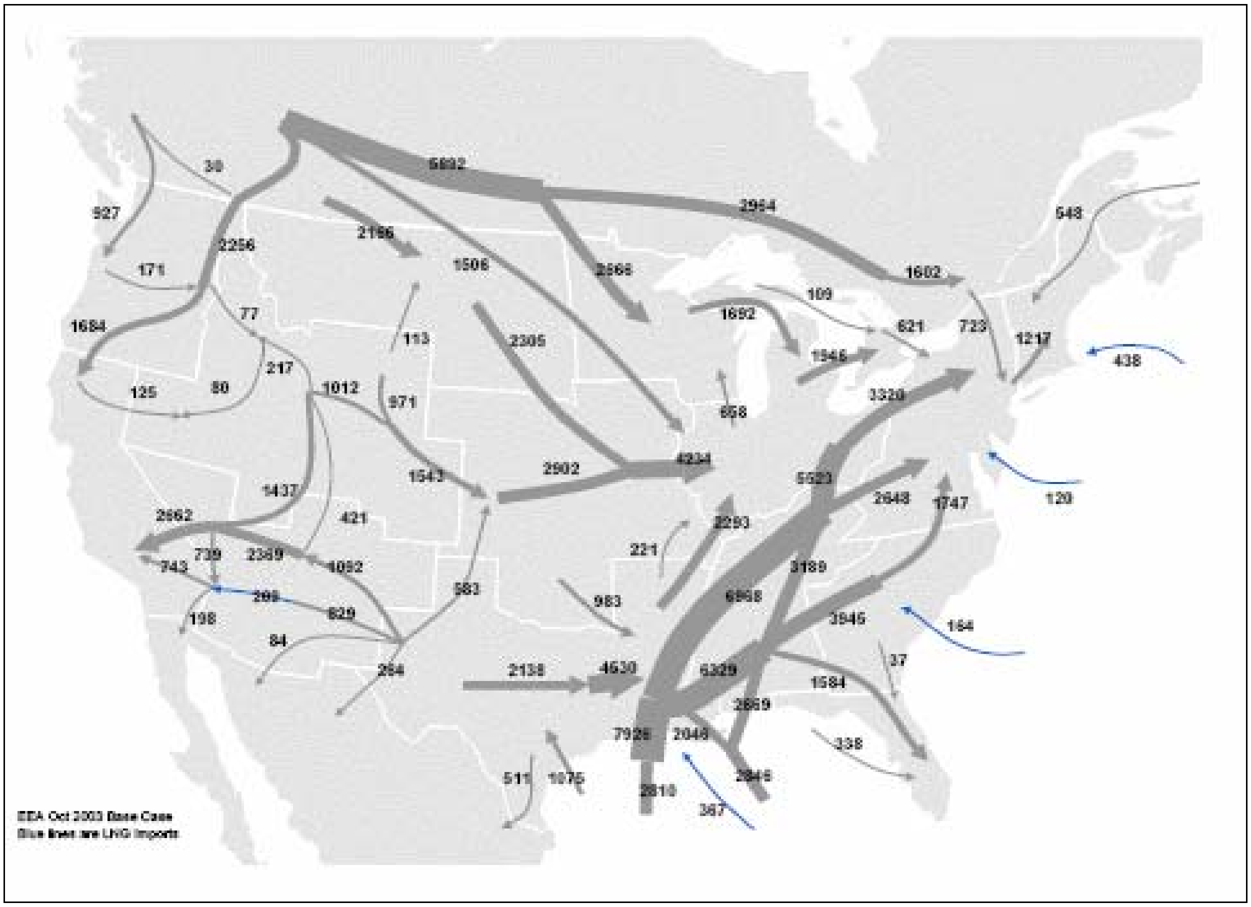



Figure 1-4 Natural Gas Distribution Flow Rates in 2003
Million Cubic Feet per Day

### *1.1.1.6 Distribution Pipelines*

As discussed in Section 2.7, H2/Natural Gas Separation Processes, one method for distributing hydrogen as a delivery option in the transition period is to mix hydrogen with natural gas, transmit the mixture through the existing natural gas distribution system, and then separate the hydrogen from the natural gas at the point of use. Some characteristics of the natural gas distribution system pertinent to the discussion in Section 2.7 are outlined below.

1) As pipelines are federally regulated, new projects must be approved by the Federal Energy Regulatory Commission (FERC). Several factors are involved in determining which route a pipeline will take: where the gas is needed and where it will come from, costs, the terrain over which the gas will be transported, whether the pipeline can use an existing utility right-of-way, and whether there are routes that are less populated. Attention is also focused on minimizing river crossings, avoiding recreational areas, minimizing the number of homes bordering the pipeline, and trying to use existing utility corridors. FERC also regulates natural gas pipelines rates and tariffs.

2) Transmission and distribution pipelines also fall under the jurisdiction of the US Department of Transportation, and must comply with the design requirements presented in Title 49 Code

of Federal Regulations Part 192, Transportation of Natural Gas and Other Gas by Pipeline. It is generally the responsibility of the state public utility commissions to administer the DOT pipeline safety regulations.

3) Most transmission pipelines are owned and operated by pipeline companies. The transmission lines can be relatively short, but mostly extend for hundreds of miles and carry gas from various sources to a range of consumers. Transmission line pressures are generally 500 to 1,000 psig (34.5 to 69 bars g). Along the pipeline, there are interconnects to either inject gas from other sources, or to remove gas for consumers. Some interconnects serve as points for blending or mixing of gas from different pipelines to achieve either preferred or contractual heating values.

   Near the primary consumption areas, such as cities, towns, and large industrial facilities, a city-gate station is built to measure and regulate gas pressure into a secondary pipeline. A city-gate is defined as the metering point between a transmission line and a local distribution company. Many of the secondary pipelines, also known as feeder lines or inter-station pipelines, operate at pressures from 100 psig (6.9 bars g) to about 300 psig (13.8 bars g) and may deliver gas directly to an industrial customer, a town, or an area of a large city. Large industrial customers, withdrawing gas from the transmission lines feeding the city gate, often reduce the gas pressure upstream of the city gate to about 250 psi (17.2 bars).

   Additional stations along these secondary lines, known as district regulator stations, reduce the gas pressure to the typical distribution line pressures of 60 to 100 psig (4.14 to 6.9 bars g). Gas distribution pressures are selected to limit the chemical energy stored in the lines. At peak demand periods, gas pressures at the end of the distribution lines can fall to 20 psig (1.38 bars) or lower.

4) Intrastate transmission lines operate at pressures somewhat lower than interstate transmission lines, typically ranging from 500 and 900 psi (34.5-65 bars). Within a state, the local utility often owns and operates the compressor stations, which maintain the pressures in the intrastate lines. Compressors can be either reciprocating or centrifugal. The reciprocating compressors are run from reciprocating engines using gas from the pipeline as fuel. The centrifugal compressors are run from gas turbines, also using gas from the pipeline as fuel. The selection of compressors would be based on the natural gas flow rate, the compressor inlet pressure, and the required outlet pressure.

5) Natural gas in interstate transmission lines does not typically carry an odorant. However, all natural gas within a state, including that in transmission lines, is often odorized. In California, as in other states, the use of an odorant is a Public Utility Commission requirement, and it is more stringent than the Federal Energy Regulatory Commission (FERC) / Department of Transportation (DOT) requirements.

   Odorization is primarily an issue for the feederline between the city-gate station and a hydrogen fueling station. The feederline is likely to be located in Class 3 or 4 locations, where odorization is mandated for natural gas lines. The location classifications are defined as follows:

- Class 1: Less than 11 buildings intended for human occupancy
- Class 2: 11 to 45 buildings intended for human occupancy
- Class 3: 46 or more buildings intended for human occupancy, or public meeting places
- Class 4: Buildings with four or more stories above ground are prevalent.

The DOT has a series of exemptions for odorization, including 1) a grandfather clause for industrial facilities built before 1975, 2) pipelines located primarily in Class 1 and 2 locations, and 3) chemical processes which would be damaged by the presence of the odorant.

6) As noted above, the use of an odorant is influenced by the location classification. Additional influences include the following:

- The principal effect of a classification on the pipeline design is the allowable material stress; the higher the classification, the lower the allowable stress.
- For transmission lines, isolation valves are required every 10 miles in Class 1 areas, 7.5 miles in Class 2 areas, 4 miles in Class 3 areas, and every 2.5 miles in Class 4 zones.
- Lines must be patrolled, and leak checks conducted, on regular bases; the intervals are typically once a year for Class 1 areas, and 4 times a year in Class 4 areas.
- Pipeline regulations on public rights-of-way are generally more stringent than on private rights-of-way. However, the classification area width generally extends 200 meters on either side of the pipe centerline. As such, the classification area is much wider than most private rights-of-way, and the availability of a private right-of-way generally does not provide a mechanism for avoiding the DOT regulations.

7) The design and characteristics of local distribution systems share common features throughout the country. The following information was developed from discussions with transmission and distribution personnel at Pacific Gas and Electric Company (PG&E), the principal utility in northern California:

- PG&E does not have formal city gates because PG&E is responsible for both transmission and distribution within the state. San Francisco has a number of city gates but these are mostly for pressure reduction from 250 (17.24 bars) down to the 60 psi (4.1 bars) required within the city.
- San Francisco has a mix of cast iron, steel, and plastic distribution lines. The cast iron was installed in the 1930s. Subsequent lines were steel, but the current choice is high density polyethylene. The plastic lines are essentially corrosion proof. For lines sizes between 2 in. and 6 in., the pipe is supplied in spools. For larger lines, the pipe is rigid, and supplied in lengths to 20 ft. Joining is by heat fusion, not solvents. The pipe is buried to depths of 24 to 30 inches.
- For an urban area such as San Francisco, distribution pipeline installation costs are dominated by labor. Typical installation costs run $100/ft in residential areas,

increasing to $300/ft in congested urban areas like San Francisco. Installation labor costs represent 70 to 80 percent of the total; thus, the installed costs are, to a large degree, independent of the pipe size and the material. Part of the high labor costs are due to city-imposed limits on hours for installation (9:00 am to 3:00 pm), a requirement to return the street to traffic access at the end of every day, and prohibitions on storing construction materials at the site overnight. The city inspectors normally insist the street is returned to its original condition after the pipeline installation is complete. Naturally, costs can be expected to vary, depending on the degree of pavement excavation and restoration, and on local labor rates (highest in large urban cities on the East and the West coasts, and lower in the Midwest and the South).

- PG&E does not own the rights-of-way for the distribution lines. The rights-of-way are leased from the city under a franchise arrangement, in which PG&E pays an annual fee to the city. Utility pipelines are generally located on city, state, and federal roadway rights-of-way, but some are located on private property easements. New installations are generally placed on city and roadway rights-of-way. All new pipelines must be designed to meet federal regulations. Some state requirements exceed federal requirements for constructing gas lines that operate at pressures above the highest distribution pressure of 125 psig (8.62 bars g). While states, such as California, New Jersey, and New York, require state approval for construction of high pressure lines, Illinois does not require such approval.
- Regarding rights-of-way, mixing energy transmission methods in one right-of-way is permissible; i.e., a natural gas line can be located beneath an electric transmission line. Further, a hydrogen pipeline could be located adjacent to a natural gas line but with some restrictions. For example, the two pipelines must be separated by at least 12 inches, and the catholic protection system for the hydrogen pipeline must take into account the electric effect of other structures. An example of the latter: a pipeline below a transmission tower must accommodate lightning strikes.
- To add or modify a distribution line, a construction permit must be obtained from the city. However, the city permit is for cutting the pavement, not for making changes or repairs to the gas line. The permits are normally granted on a routine basis. The city will send an inspector after the pipe is placed to ensure the backfill, compaction, and street re-paving are performed properly, as the responsibility of the city extends only to the quality of the street repairs, not to the gas line repairs. In general, no permits are needed to work on private property.
- PG&E utilities can share trenches, as PG&E will often run an electric line directly below a gas line. Locating gas lines next to each other in a common trench is also done. However, gas lines and liquid hydrocarbon lines, such as propane, are never located in the same trench because leaks and fire in the liquid line would make for a dangerous situation next to a gas line. PG&E will, in some cases, share trenches with other utilities. For example, the Sacramento Municipal Utility District and PG&E have electric lines in a common trench. However, PG&E is not obligated to share trench access. In these cases, a minimum 5 foot separation is required between utility trenches.

- Hypothetically speaking, if PG&E were to enter the hydrogen distribution system, they could locate a hydrogen line adjacent to a natural gas line.  Both gases have lower densities than air; as such, no additional safety considerations would need to be imposed on workers in a below-grade trench.
- Again hypothetically speaking, if a company separate from PG&E were to distribute hydrogen, PG&E would likely not share access to existing trenches or rights-of-way Because PG&E leases the right-of-way from the city, and so would be reluctant to share the benefits of going through the paperwork and the expense to secure the right-of-way.  Also, maintenance on non-PG&E pipelines could damage the PG&E pipelines.  If this separate company were to install a hydrogen distribution system in a place like San Francisco, and could not use the PG&E trench layouts under the existing franchise agreements, the installation cost would likely be well above $300/ft.

#### *1.1.1.7 Natural Gas Prices*

One of the most important gas pipeline in the US is Henry Hub Pipeline.  The Henry Hub is owned and operated by Sabine Pipe Line, LLC, which is a wholly owned subsidiary of Chevron. The Sabine Pipeline starts in eastern Texas near Port Arthur, runs through south Louisiana, not far from the Gulf of Mexico, and ends in Vermillion Parish, Louisiana, at the Henry Hub near the town of Erath.

The Henry Hub connects nine interstate and four intrastate pipelines, providing access to markets in the Midwest, Northeast, Southeast, and Gulf Coast regions of the United States.  Sabine currently has the ability to transport 1.8 billion cubic feet per day across the Henry Hub, which represents about 3.0 percent of average daily gas consumption in the US.  Approximately 49 percent of U.S. wellhead production either occurs near the Henry Hub, or passes close to the Henry Hub as it moves to downstream consumption markets.  As such, natural gas prices at the Henry Hub are representative of national wholesale prices.  Gas prices for the past year are shown in Figure 1-5.

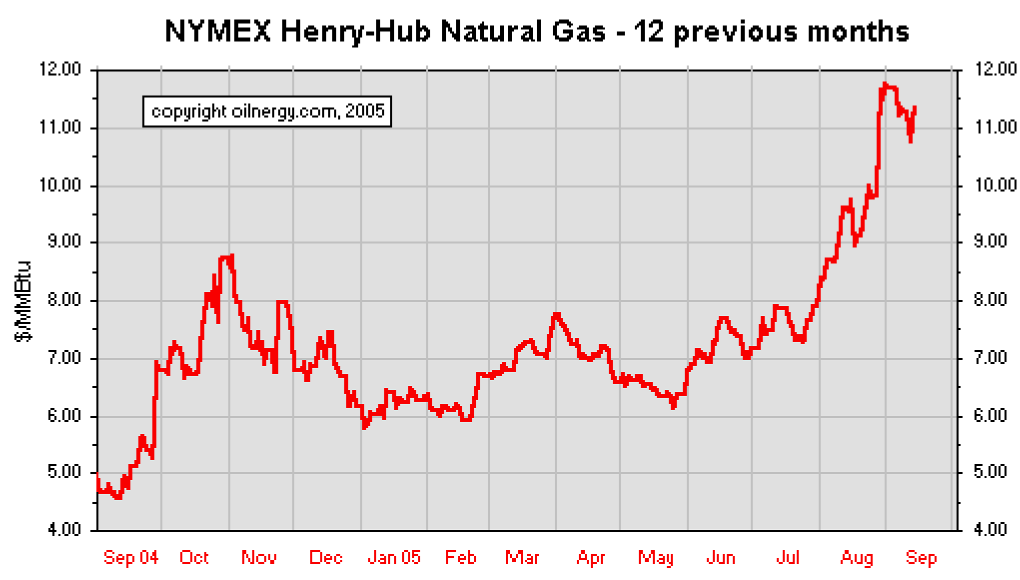


Figure 1-5
Henry Hub Natural Gas Prices
http://www.eia.doe.gov/oiaf/analysispaper/henryhub/; http://www.oilnergy.com/

#### 1.1.1.8 Natural Gas Demand Projection

Projections for domestic natural gas consumption through the year 2020 are shown in Figure 1-6. The largest increase is anticipated in the power generation industry, where the low emissions of natural gas-fired combined cycle plants have found favor among numerous utilities and permitting agencies. Whether all of the projected increases in gas consumption will come to pass, particularly in light of the recent volatility in natural gas prices, remains to be seen.

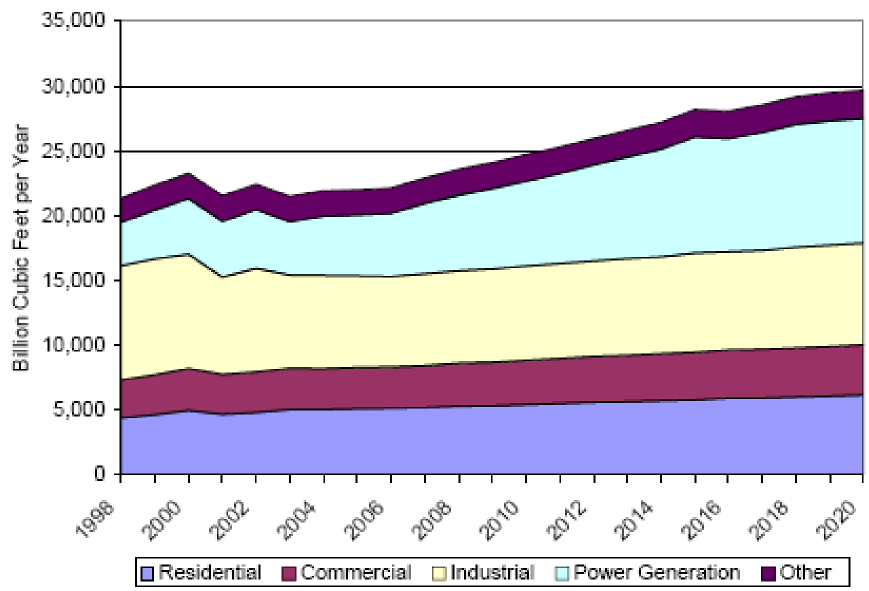



Figure 1-6 Projected Domestic Natural Gas Consumption
Billions of Cubic Feet Per Year

#### 1.1.1.9 Planned Natural Gas Infrastructure

Major new transmission pipelines planned are illustrated in Figure 1-7. As might be expected, the lines follow the areas in which population growth is anticipated.

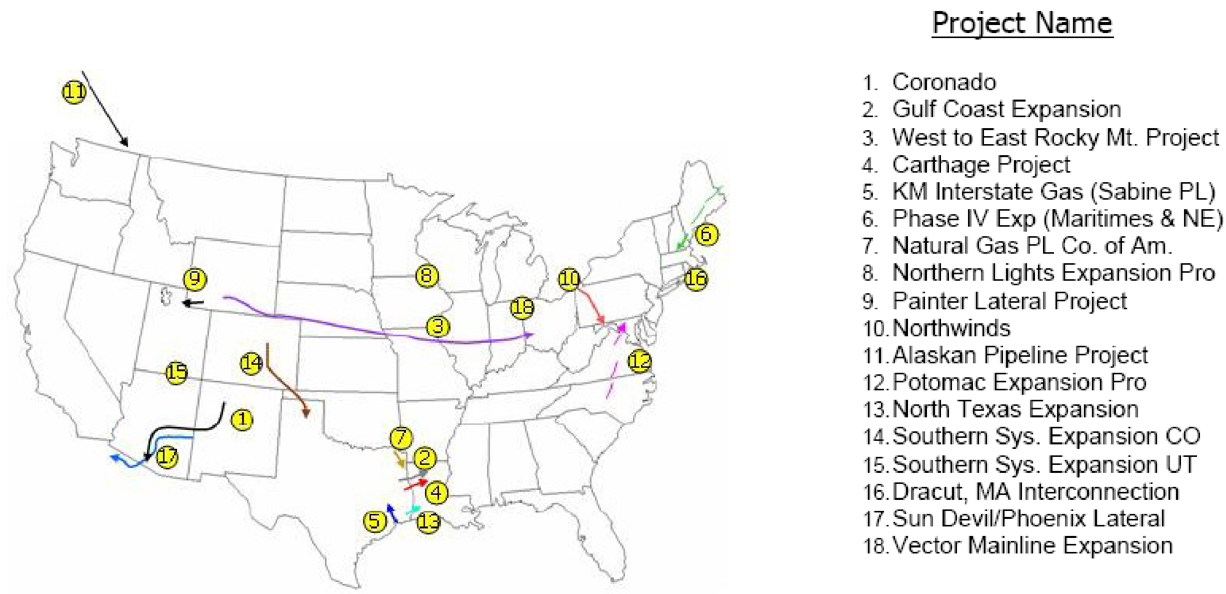


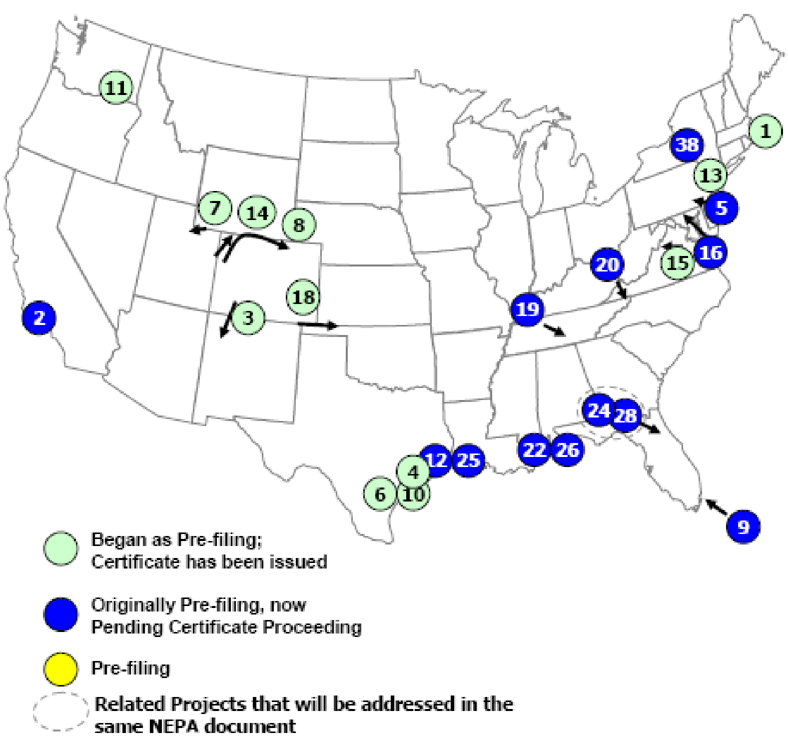

Figure 1-7 Proposed Natural Gas Transmission Lineshttp://www.ferc.gov/industries/gas/gen-info/horizon-stor.pdf

In concert, new natural gas storage facilities are planned for the locations shown in Figure 1-8, and new liquefied natural gas terminals for the locations shown in Figure 1-9. The proposed gas terminals locations are determined from both existing distribution centers (i.e., the Gulf Coast), and from expected new demand centers (i.e., Southern California and the Northeast).

**Project Name or Company Name**

1. Bluewater Gas Storage LLC
2. Copper Eagle Salt Cavern Storage
3. EnCana Gas Storage
4. Hill Lake-Phase II
5. Worsham-Steed Gas Storage Project Phase II (new)
6. MoBay Storage Phase I
7. Worsham-Steed Gas Storage Project-Phase I (revised)
8. County Line Storage Project
9. Petal Gas Storage, LLC
10. Port Barre Gas Storage Phase I
11. SemGas LP
12. Windy Hill Gas Storage Project
13. Eastern Expansion Project (new)

Figure 1-8 Proposed Natural Gas Storage Projects
http://www.ferc.gov/industries/gas/gen-info/horizon-pipe.pdf




Project Name

1. Weaver's Cove LNG & Mill River Pipeline
2. Sound Energy Solutions Long Beach LNG
3. San Juan Expansion
4. Golden Pass LNG
5. Crown Landing LNG /Logan Lateral
6. Vista del Sol LNG
7. Southern System Expansion
8. EnCana Project
9. Seafarer US Pipeline System
10. Ingleside Energy Center LNG
11. Capacity Replacement Project
12. Port Arthur LNG
13. Central NJ Expansion Project
14. Piceance Basin Expansion Project
15. Hardy Storage Field/Virginia Pipeline Looping Project
16. Dominion Cove Point LNG
17.
18. Raton Basin 2005 Exp. Project
19. Midwestern Gas Transmission Eastern Extension Project
20. Jewell Ridge Pipeline
22. Gulf LNG Energy Project
24. Cypress Pipeline Project
25. Creole Trail LNG and Pipeline Project
26. Casotte Landing LNG
28. Phase VII Expansion Project
38. Ramapo Expansion Project

Figure 1-9 Proposed Liquefied Natural Gas Terminals http:/www.ferc.gov/industries/gas/gen-info.asp

#### *1.1.1.10 Federal Energy Regulatory Commission*

The Federal Energy Regulatory Commission (FERC) regulates the transmission lines. It does not set natural gas prices but monitors operation and transparency in gas contracts.

Natural gas is a commodity that is produced and consumed at many different locations throughout North America. It is also physically and financially traded at many different locations, often referred to as market centers. The North American natural gas market is a deregulated, competitive, and fairly integrated and liquid market where gas prices represent market-clearing prices between supply and demand. Further, because the market is fairly integrated, price basis differentials between regions represent the opportunity cost to move gas between the market centers.

<u>Producer Response to Price Changes.</u> In the natural gas market, producers have limited ability to respond quickly to changing price conditions. Natural gas and oil production are capital intensive industries, with relatively low marginal costs for producing oil or gas from an existing well. In addition, increasing the supply of natural gas requires new drilling activity, which takes three to nine months to have a noticeable influence on the supply. As a result, near-term wellhead production is generally quite price inelastic. For example, when prices increase, the supply remains essentially fixed for several months before new resources can be developed. When prices decrease, most wells remain economical to operate, as marginal revenue will exceed marginal lifting costs for all but the least productive wells at the lowest prices. The positive cash flow provides a strong incentive to continue production even with prices lower than expected. As a result, under all but the lowest price conditions, producers market a very high percentage of their total wellhead gas deliverability.

<u>Natural Gas Storage Response to Price Change</u> Natural gas can be stored economically. As a result, storage injection and withdrawal behavior act to moderate gas price volatility to a certain extent. However, a number of factors other than economic price arbitrage impact injection and withdrawal behavior.

Most pipeline carriers in cold weather climates rely on storage to meet winter season and peak day loads. The pipeline's gas supply plan relies on target levels of storage at different points in the season. Moreover, tariff penalties and price ratchets based on storage inventory levels can limit the flexibility needed to optimize storage economically by creating a price penalty for storage activity outside of set parameters. Nevertheless, implementation of storage management programs and the development of high deliverability storage provide a significant physical hedge - and actually serve to mitigate daily and seasonal price volatility.

<u>Infrastructure Response to Price Changes</u> Energy infrastructure constraints, particularly of natural gas pipeline capacity, and electricity generation and transmission capacity constraints, appear to be one of the key causes of recent price volatility. In the last several years, both California and New York City have experienced periods during which both electricity and natural gas demand have exceeded the available power generation capacity and natural gas pipeline capacity.

When use of these physical assets approaches capacity, prices tend to increase, sometimes increasing very rapidly in reflection of scarcity rents associated with the assets. Infrastructure constraints can lead to both short-term price volatility, when demand exceeds capacity due to short-term factors such as weather, and long- term price volatility, when capacity fails to increase with demand growth or (in the case of some natural gas pipelines) natural gas production capacity.

#### *1.1.1.11 Natural Gas - Hydrogen Mixtures*

It is generally understood the lowest cost method for transporting hydrogen is by pipeline. Since the cost to install a new gas transmission line is on the order of $1 million per mile, the cost to install a domestic hydrogen pipeline system would involve multiple trillions of dollars. Thus, on a near term basis, it could make economic sense to distribute hydrogen by forming a mixture of natural gas and hydrogen, and then transmitting the mixture in the natural gas pipeline system.

Technically, there are few problems with developing and distributing such a mixture, as illustrated by the following references:

- Several existing petroleum and natural gas transmission lines have been converted to pure hydrogen service, and have excellent safety records. In particular, no failures due to hydrogen embrittlement have been known to occur.
- Although much of the latest natural gas distribution piping is medium or high density polyethylene, and the polyethylene is not impervious to hydrogen, the distribution pressures are typically in the range of 20 to 100 psig (1.38 to 6.9 bars g), and at these pressure, the permeation is low enough to be acceptable.
- The addition of hydrogen to natural gas reduces the potential for the heavier hydrocarbons to condense from the gas phase [37].

However, the situation is not so unambiguous regarding a number of economic and institutional issues, including the following:

- The hydrogen purity specification for the project sets a limit of 2 parts per million for total hydrocarbons on a $C_1$ basis. This, in turn, requires a hydrogen purity of 99.9998 percent (six 9s) at the outlet from the natural gas - hydrogen separation equipment. Conventional separation equipment can achieve the required purity, but the efficiency will be in the range of perhaps 70 to 80 percent. In effect, 20 to 30 percent of the delivered hydrogen is lost during the separation process, which increases the effective cost by 25 to 50 percent.
- On a related point, mixing the two gases exposes the hydrogen to the odorant commonly used in natural gas systems. The hydrogen purity specification for the project sets a limit of 0.004 parts per million for total sulfur, which would apply to common odorants, such as mercaptan. This, in turn, requires a hydrogen purity of 99.9999996 percent (nine 9s) at the outlet from the gas separation equipment. The common sulfur odorants are removed as follows: 1) the gas mixture is heated to a nominal temperature of 650 °F, at which point the complex sulfur compounds react with hydrogen to form $H_2S$; and 2) the $H_2S$ is converted to zinc sulfide in a zinc oxide

bed by the following reaction: $ZnO + H_2S \rightarrow ZnS + H_2O$. The process is commercial, but gas heating and recuperation equipment must be provided.

- In Pennsylvania, natural gas supplier have a contractual requirement to supply natural gas with a minimum higher heating value of 950 Btu per standard (36.5 million J /Nm$^3$) and a minimum Wobbe Index of 1310. The latter is a measure of the energy content of a heating gas, which can pass through an orifice, and is defined as follows:

$$\frac{\textit{Higher heating value}, \dfrac{Btu}{Standard\ \ ft^3}}{\textit{Gas specific gravity}}$$

  , where the specific gravity is with respect to air at standard temperature and pressure. Natural gas and hydrogen have higher heating values of 1,035 Btu/standard ft$^3$ (39.76 million J /Nm$^3$) and 323 Btu/standard ft$^3$ (12.4 million J /Nm$^3$), respectively, and Wobbe Indices of 1346 and 1019, respectively. Thus, adding hydrogen to natural gas decreases both the higher heating value and the Wobbe Index. To meet the state requirement, the maximum hydrogen content must be limited to 11 percent. Although analyses of other states have yet to be made, the restrictions in Pennsylvania are likely to be typical for the country as a whole.

- According to the 2005 edition of the Oil & Gas Journal Data Book, "The US natural gas pipeline system appears headed for serious delivery-capacity constraints…" The capacity of natural gas lines in and around large cities, especially in the Northeast, is currently less than that required during peak demand levels. For example, gas distribution companies supplement the heating value of the natural gas by adding propane and air to the lines at various times in the winter; the technique is called 'peak shaving'. Thus, adding hydrogen to a natural gas distribution system will only compound the current problems with delivery capacity constraints.

- In a similar vein, the ability of the natural gas distribution system to accept hydrogen will vary with the time of the year; it will be the highest in the summer, and the lowest in the winter. As such, the gas separation equipment for the hydrogen consumers must be designed to accommodate a range of hydrogen fractions. This will, on average, reduce the efficiency of the separation processes, and increase the delivered price for the hydrogen. A quantitative analysis of the effect has yet to be conducted.

In summary, the natural gas transmission and distribution system offers a ready means for transporting significant quantities of hydrogen at a very modest cost . Nonetheless, this capability must be tempered by the capacity constraints in the existing pipelines, and the thermodynamic penalties incurred in the gas separation process.

#### *1.1.1.12 New Hydrogen Pipelines*

The 1$^{st}$ Hydrogen Pipeline Working Group meeting, which brought together representatives from hydrogen producers, the national laboratories, and DOE, was held in mid-2005. The purpose of the meeting was to share operating experience on existing hydrogen pipelines, and to outline possible research efforts to reduce the costs of future pipelines. Some information relevant to the current infrastructure study included the following:

- Hydrogen embrittlement occurs as atomic hydrogen diffuses into the base metal. The equilibrium concentration is determined by the hydrogen solubility in the metal, the hydrogen gas pressure, and the local tensile stresses in the metal. With hydrogen present in the metal lattice, both the metal ductility and the resistance to fracture are decreased.
- The most important material property for steel pipelines in hydrogen service are low hardness and high ductility. The properties are achieved by a combination of low carbon content and the control of the microstructure through the addition of small quantities of alloying elements, such as niobium and vanadium. The cost premiums for the these microalloyed steels are very small, and in some cases, are zero.
- DOT 49 CFR Part 192 is currently being used for to define the allowable stresses for hydrogen pipelines in Class 1 through Class 4 locations; i.e., 72 percent of specified minimum yield strength in Class 1 locations, 60 percent in Class 2, 50 percent in Class 3, and 40 percent in Class 4. However, various research engineers in the field of hydrogen embrittlement believe an allowable stress of 72 percent of the yield strength is not adequately conservative based on 1) the current understanding of the long term (50 year) effects of hydrogen diffusion, and 2) the potential for stress concentrations at welds, or in material defects, to significantly decrease the fracture toughness. Until additional long term data become available, allowable stresses in the range of 30 to 40 percent of the yield strength are recommended for all transmission pipelines, regardless of the Class.
- The relevant ASME code section for hydrogen pipeline service is B31.12. It is currently under development, with an initial release scheduled for mid-2007. It will cover both steel and fiberglass reinforced polymer lines, and will address pipeline designs for industrial, commercial, and residential uses.
- It can be noted that hydrogen embrittlement is fundamentally different from hydrogen attack. Embrittlement is a function of the hydrogen solubility in the metal, and is a maximum at ambient temperatures. Hydrogen attack is the diffusion of atomic hydrogen into the metal, and the subsequent reaction with carbon in the metal to form methane. The resulting gas pressure within the lattice leads to a loss in ductility. The potential for hydrogen attack increases with increasing temperature and pressure. As a result, the potential for hydrogen attack within a transmission pipeline is essentially nil.
- Air Liquide, Praxair, and Air Products have a total of about 3,000 miles of hydrogen pipelines. None of the companies have experienced a pipeline failure due to embrittlement to date, even though most of the lines are converted from earlier natural gas or hydrocarbon service. Pressures are typically modest at less than 800 psi (55.2 bars), but Praxair has one line running at 1950 psi (134.5 bars).
- New hydrogen pipeline costs run from $750,000 per mile for a 10 inch steel line in a Class 1 area, to $1,500,000 for any size line in a Class 4 area. The costs are above the DOE goal of $200,000 per mile for new hydrogen distribution lines in urban areas For urban areas, the pipe material represents about 10 percent of the total cost, and welding (or fusion joining for polyethylene) is about another 10 percent. The balance of the costs is labor expenses for excavation, pipeline placement, backfilling,

compaction, re-paving, and material handling. Right-of-way and easement costs would be additional expenses.

- There is considerable interest in hydrogen - natural gas mixtures with hydrogen concentrations in the range of 5 percent to perhaps 20 percent. Several participants believe these mixtures may achieve commercial operation. The principal constraints are the minimum contractual value on the fuel higher heating value, and the Wobbe index on burner performance. NATURALHY is looking at 5 percent mixtures for the Netherlands, with near-term goals of both reducing natural gas use by 5 percent and improving the public perception of hydrogen use.
- Gas Technology Institute has briefly explored the potential for transporting mixtures of hydrogen and natural gas with equal volume fractions; i.e., a 50-50 mixture. The principal benefit is reducing the thermodynamic losses associated with separating the two gases. The principal liability is limiting the approach to only those pipelines in which the only gas customer is the one at the end of the line. A brief survey shows that perhaps 5 percent of the natural gas lines, typically with lengths of 50 miles or less, would be suitable. (Very important for determining the practicality of the mixture approach.)
- As a rule, the gas supplied to a pipeline by a gas company always has a very low dew point. As such, pipeline corrosion is almost exclusively external.
- Both natural gas and hydrogen pipes are normally seam welded; seamless pipe would be the exception.
- Air Products operates a hydrogen line, which runs through a Class 3 location. However, no odorant is used, as the odorant would damage the chemical processing equipment at the end of the line. This is an allowable exception to odorant use under DOT 49 CFR Part 192.

### 1.1.2 Coal

As illustrated in Figure 1-10, total recoverable reserves of coal around the world are estimated at 1,083 billion tons - enough to last approximately 210 years at current consumption levels. Although coal deposits are widely distributed, 60 percent of the world's recoverable reserves are located in three countries: the United States (25 percent), the Former Soviet Union (23 percent), and China (12 percent). Another four countries - Australia, India, Germany, and South Africa - account for an additional 29 percent. In 2001, these seven countries accounted for 80 percent of total world coal production.

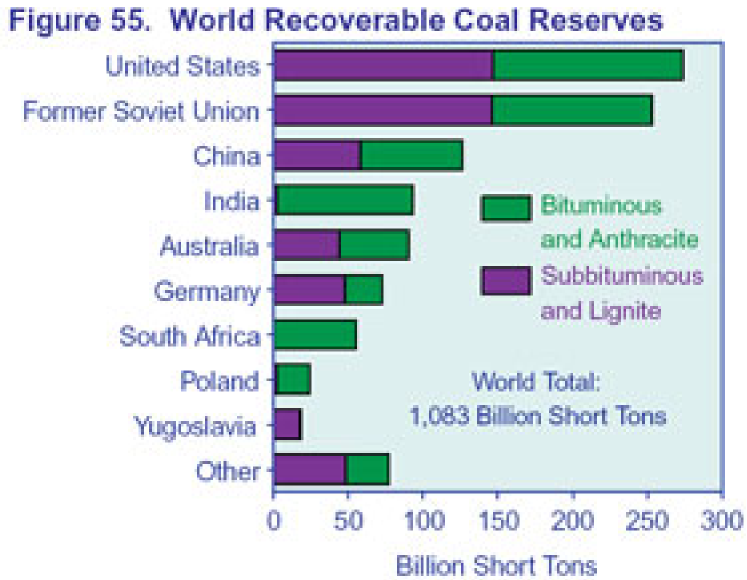



Figure 1-10 World Coal Reserves

U.S. Coal Supply and Demand: 2004 Review

Production

U.S. coal production increased in 2004 by 3.7 percent to a total of 1,111.5 million short tons, a production level still below the 2001 record level of 1,127.7 million short tons.[1] A distribution of the coal production by region is illustrated in Figure 1-11. Both the Appalachian and Western Regions had increased coal production in 2004 while the Interior region remained almost steady, declining by 0.1 percent. Exclusive of refuse production, the increase in coal production in the Appalachian Region accounted for about one third of the total increase in U.S. coal production, while the Western Region was responsible for the rest of the increase.

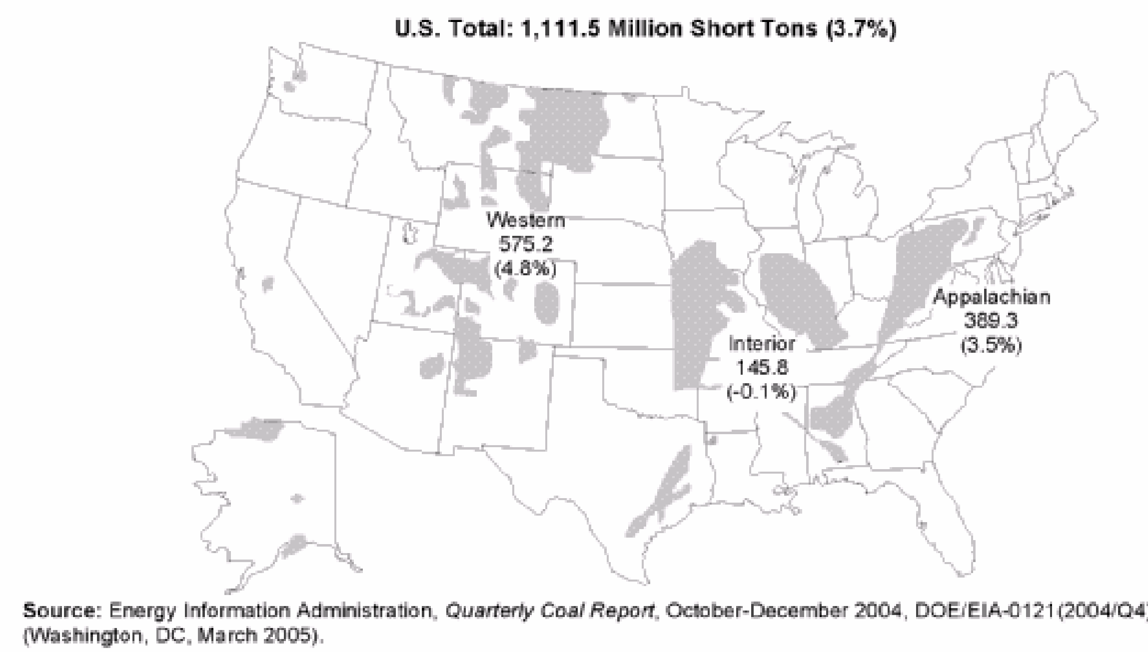



Figure 1-11 Coal Production by Coal Producing Region in 2004
Millions of Short Tons, and Percent Change from 2003

### *1.1.2.1 Consumption*

The continuing economic recovery in 2004 pushed total U.S. coal consumption to another record level. Preliminary data show that total coal consumption increased 9.4 million short tons to reach a level of 1,104.3 million short tons, an increase of 0.9 percent.

The electric power sector (electric utilities and independent power producers) accounted for almost 92 percent of all coal consumed in the United States in 2004. A distribution of the electric power sector coal consumption is presented in Figure 1-12 and Table 1-5. The other coal-consuming sectors (other industrial, coking coal, and residential and commercial sectors) had minor changes in their consumption totals.

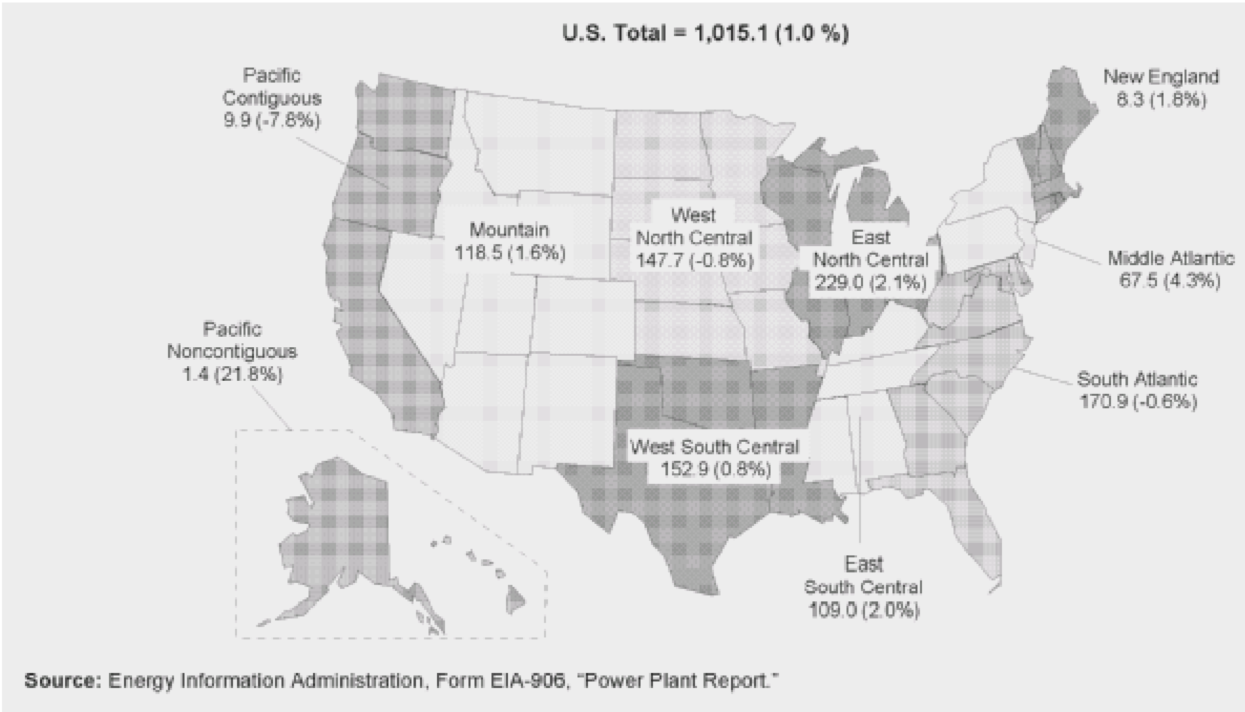



Figure 1-12 Electric Power Consumption of Coal Production in 2004
Millions of Short Tons, and Percent Change from 2003

Coal consumption in the electric power sector increased by 10.0 million short tons to end 2004 at a record level of 1,015.1 million short tons. Although coal consumption by the electric power sector increased by 1.0 percent in 2004, coal-based generation remained almost flat, as increasing volumes of lower-Btu coal (sub-bituminous and lignite) were consumed.

Table 1-5
Electric Power Sector Net Generation: Coal and Total Generation
Million kWhe

| Region | Coal | Total |
|---|---|---|
| New England | 19,045 | 128,064 |
| (Maine, Vermont, New Hampshire, Connecticut, Massachusetts, Rhode Island) | | |
| Mid Atlantic | 150,876 | 406,193 |
| (New York, Pennsylvania, New Jersey) | | |
| East North Central | 450,216 | 633,080 |
| (Wisconsin, Michigan, Illinois, Indiana, Ohio) | | |
| West North Central | 228,914 | 296,345 |
| (North Dakota, South Dakota, Nebraska, Kansas, Minnesota, Iowa, Missouri) | | |
| South Atlantic | 406,489 | 767,199 |
| (West Virginia, Virginia, Maryland, Delaware, | | |

| | | |
|---|---|---|
| (North Carolina, South Carolina, Georgia, Florida) | | |
| East South Central | 234,344 | 361,974 |
| (Kentucky, Tennessee, Alabama, Mississippi) | | |
| West South Central | 227,655 | 520,941 |
| (Texas, Oklahoma, Louisiana, Arkansas) | | |
| Mountain | 218,686 | 340,393 |
| (Montana, Idaho, Wyoming, Utah, Nevada, Colorado, Arizona, New Mexico) | | |
| Pacific | 17,742 | 339,407 |
| (Washington, Oregon, California) | | |
| | ------------ | ------------ |
| Total | 1,953,968 | 3,793,596 |

#### *1.1.2.2 Coal Prices*

Coal prices rose across the board in 2004. While spot coal prices for some of the producing regions set record levels in 2004, average delivered prices in the consuming sectors increased for the year but not as steeply as the spot prices. Due to the fact that coal deliveries to the electric power sector are mostly done through long-term contracts, the delivered price of coal to the electric power sector increased in 2004, but not by huge amounts. According to preliminary data through November 2004, coal prices at electric utilities (a subset of the electric power sector) increased for a fourth consecutive year, to $27.28 per short ton (1.34 dollars per million Btu), an increase of 6.0 percent. Coal prices at independent power producers increased in 2004 to $27.18 per short ton (1.40 dollars per million Btu), but were still lower that the 2002 price of $27.96 per short ton.

An overall summary of the domestic coal industry is presented in Table 1-6.

Table 1-6
US Coal Supply, Disposition, and Prices

| | |
|---|---|
| Production by Region, million short tons | |
| Appalachia | 389.3 |
| Interior | 145.8 |
| Western | 575.2 |
| Refuse Recovery | 1.1 |
| Total | 1,111.5 |
| | |
| Consumption by Sector, million short tons | |
| Electric power | 1,015.1 |
| Coke plants | 23.7 |
| Other industrial plants | 61.2 |
| Residential and commercial | 4.2 |
| Total | 1,104.3 |

| | |
|---|---|
| Average Delivered Price, $/short ton | |
| Electric utilities | 27.28 |
| Independent power producers | 27.18 |
| Coke plants | 61.50 |
| Other industrial plants | 39.30 |

*Coal Transportation*

The majority of coal in the U.S. is moved by railroads exclusively, or in tandem with another method of transportation. A summary of the coal rail shipment in 2004 to the various consumer segments is presented in Table 1-7 [2] .

Table 1-7
US Coal Transportation Methods and Quantities in 2004
Thousands of Short Tons

| | Electricity Generation | Coke Plants | Industrial Plants | Residential and Commercial | Total |
|---|---|---|---|---|---|
| Railroad | 596,720 | 10,429 | 72,265 | 1,108 | 680,523 |
| Great Lakes | 8,184 | 1,437 | 1,471 | 0 | 11,091 |
| Barge | 81,998 | 4,428 | 13,043 | 281 | 99,749 |
| Tidewater piers | 3,228 | 0 | 16 | 0 | 3,244 |
| Tramway, conveyor | 82,248 | 1,039 | 31,975 | 0 | 115,262 |
| Truck | 73,441 | 453 | 51,739 | 2,847 | 128,480 |
| | ----------- | --------- | ---------- | -------- | ----------- |
| Total | 845,819 | 17,786 | 170,510 | 4,236 | 1,104,236 |

In the export market, the wide-ranging economic expansion experienced in China in 2004 drove world markets for many commodities into overdrive and helped to re-establish the United States into Asian coal markets.

Coal-fired power plants must comply with limits on sulfur oxide emissions. The limits can be met either through flue gas desulfurization or by burning low sulfur coals. Many plants in the Midwest have elected to use the latter option, as if offers the lowest cost. However, most of the low sulfur coals are in the Rocky Mountain states. As a result, coal for electric power generation is routinely shipped long distances. Nonetheless, the costs for doing so are modest, as illustrated in Table 1-8 and Table 1-9.

By analogy, hydrogen production plants based on coal gasification need not be located adjacent to coal mines to achieve the published cost targets ($/kg).

Table 1-8
Contract Coal Rail Shipment Distances in Miles, by Sulfur Category

| Year | All Coal | Low Sulfur | Medium Sulfur A | Medium Sulfur B | High Sulfur |
|---|---|---|---|---|---|
| 1988 .............. | 640.2 | 993.5 | 439.7 | 224.8 | 133.7 |
| 1989 .............. | 653.4 | 1,004.7 | 444.2 | 203.4 | 121.1 |
| 1990 .............. | 606.7 | 963.2 | 438.1 | 220.0 | 148.4 |
| 1991 .............. | 623.1 | 982.1 | 422.5 | 208.8 | 154.4 |
| 1992 .............. | 638.8 | 994.6 | 403.8 | 187.3 | 151.3 |
| 1993 .............. | 715.5 | 1,012.0 | 438.2 | 191.2 | 138.7 |
| 1994 .............. | 687.8 | 980.6 | 414.1 | 174.9 | 172.8 |
| 1995 .............. | 725.9 | 977.3 | 422.7 | 124.6 | 195.8 |
| 1996 .............. | 743.1 | 986.2 | 414.0 | 233.5 | 194.3 |
| 1997 .............. | 793.5 | 1,037.7 | 419.0 | 251.0 | 180.2 |

Notes: • Low Sulfur = less than or equal to 0.6 pounds of sulfur per million Btu; Medium Sulfur A = 0.61 to 1.25 pounds per million Btu; Medium Sulfur B = 1.26 to 1.67 pounds per million Btu; High Sulfur = greater than 1.67 pounds per million Btu. Medium Sulfur A coal meets $SO_2$ emission limits for power plants affected by Phase I of the Clean Air Act Amendments of 1990 (CAAA90). Low-Sulfur coal meets the emission requirements those power plants must attain in Phase II of CAAA90, after January 1, 2000. • Statistics based on the Coal Transportation Rate Database (CTRDB) frequently differ from statistics released earlier because between 1995 and 2000 the CTRDB was enhanced with new and supplementary data, including data for years prior to 1995.
Source: Energy Information Administration, Coal Transportation Rate Database.

Table 1-9
Contract Coal Rail Shipment Rates in Cents per Million Btu, by Sulfur Category

| Year | All Coal | Low Sulfur | Medium Sulfur A | Medium Sulfur B | High Sulfur |
|---|---|---|---|---|---|
| 1988 ............... | 72.9 | 101.9 | 59.8 | 48.7 | 28.3 |
| 1989 ............... | 70.8 | 98.6 | 60.6 | 36.6 | 26.6 |
| 1990 ............... | 72.9 | 96.1 | 75.2 | 40.3 | 26.0 |
| 1991 ............... | 61.0 | 84.8 | 50.1 | 38.6 | 24.3 |
| 1992 ............... | 59.7 | 84.2 | 46.0 | 33.3 | 22.7 |
| 1993 ............... | 61.1 | 79.1 | 46.1 | 34.6 | 21.7 |
| 1994 ............... | 55.8 | 73.3 | 40.4 | 27.6 | 23.1 |
| 1995 ............... | 57.1 | 71.1 | 41.2 | 24.0 | 26.3 |
| 1996 ............... | 56.3 | 68.3 | 40.9 | 29.8 | 26.8 |
| 1997 ............... | 56.0 | 67.0 | 39.9 | 33.1 | 24.4 |

Notes: • Low Sulfur = less than or equal to 0.6 pounds of sulfur per million Btu; Medium Sulfur A = 0.61 to 1.25 pounds per million Btu; Medium Sulfur B = 1.26 to 1.67 pounds per million Btu; High Sulfur = greater than 1.67 pounds per million Btu. Medium Sulfur A coal meets $SO_2$ emission limits for power plants affected by Phase I of the Clean Air Act Amendments of 1990 (CAAA90). Low-Sulfur coal meets the emission requirements those power plants must attain in Phase II of CAAA90, after January 1, 2000. • Statistics based on the Coal Transportation Rate Database (CTRDB) frequently differ from statistics released earlier because between 1995 and 2000 the CTRDB was enhanced with new and supplementary data, including data for years prior to 1995.
Source: Energy Information Administration, Coal Transportation Rate Database.

#### *1.1.2.3 Coal Gasification for Hydrogen Production*

The chemical energy in coal can be used to produce hydrogen through a combination of reduction reactions with steam, followed by water-gas shift reactions with carbon monoxide.

Several gasification technologies, together with the requisite gas cleanup processes, are available on a commercial basis.

With current oxygen blown gasifier designs, approximately 9.5 kg of coal is required to produce 1 kg of hydrogen.[3] Included in the 9.5 kg of coal is the energy required to sequester a nominal 85 percent of the $CO_2$ produced during the gasification process. Assuming 1 kg of hydrogen in a fuel cell vehicle is equivalent to 2 gallons of gasoline in a car today, approximately 700 million tons of coal would need to be gasified each year to offset the current gasoline demand of 135 billion gallons. Providing 700 million tons per year of coal for gasification would require an increase in the US coal production of about 65 percent (i.e., 165 percent of today's production rate). With the current coal reserves of 270,000 million tons, the US could supply all of its current gasoline demand in the form of hydrogen, together with all of its electric generating capacity based on coal, for about 150 years.

Under the DOE FutureGen program, the efficiency of hydrogen production from coal is estimated to increase by a factor of one-third by 2015, and the fraction of the $CO_2$ produced during gasfication is expected to increase to 100 percent. Under these conditions, approximately 500 million tons of coal would need to be gasified each year to offset the current gasoline demand. As such, the US coal reserves could satisfy the current demand for both electric energy and gasoline for about 170 years.

### 1.1.3 2.1.3 Hydroelectric

#### *1.1.3.1 Electric Energy Production*

Idaho National Laboratories has divided the country into 20 hydrologic regions, using a hydrologic unit code (HUC). The numbered regions are illustrated in Figure 1-13.

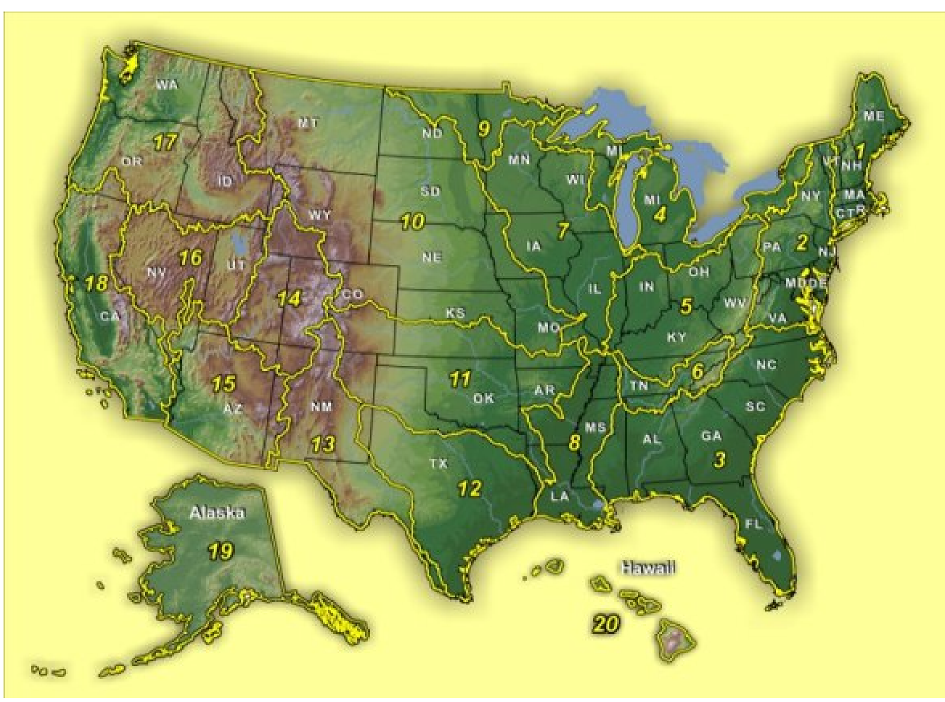


Figure 1-13 Hydrologic Unit Code (HUC) Regional Map

Table 1-10 shows the developed hydroelectric capacities for the 20 HUC regions, sorted by the average annual mean power developed potential. Approximately 60 percent of the domestic hydroelectric generation is in the Pacific Northwest and in California.

Table 1-10
Developed Hydroelectric Power by HUC Regions

| HUC and Name | Average Annual Mean Power Developed Potential, MW | Average Annual Generation, MWh | Developed Capacity, MW | Number of Plants |
|---|---|---|---|---|
| 17 Pacific Northwest | 16,645 | 145,811,168 | 32,365 | 339 |
| 18 California | 4,668 | 40,892,958 | 9,450 | 413 |
| 4 Great Lakes | 2,852 | 24,986,998 | 4,092 | 288 |
| 6 Tennessee | 1,859 | 16,282,814 | 3,855 | 55 |
| 3 South Atlantic-Gulf | 1,849 | 16,195,298 | 6,743 | 165 |
| 10 Missouri | 1,797 | 15,743,664 | 3,722 | 80 |
| 1 North Atlantic | 873 | 7,648,300 | 1,881 | 397 |
| 2 Mid-Atlantic | 840 | 7,359,758 | 2,060 | 206 |
| 5 Ohio | 820 | 7,182,482 | 1,772 | 48 |
| 15 Lower Colorado | 789 | 6,911,489 | 2,556 | 23 |
| 14 Upper Colorado | 724 | 6,339,303 | 1,882 | 41 |
| 11 Arkansas-White-Red | 696 | 6,100,625 | 2,097 | 33 |
| 7 Upper Mississippi | 404 | 3,540,641 | 734 | 119 |
| 19 Alaska | 171 | 1,500,596 | 392 | 40 |
| 8 Lower Mississippi | 136 | 1,192,680 | 398 | 6 |
| 12 Texas Gulf | 127 | 1,115,557 | 428 | 23 |
| 16 Great Basin | 97 | 853,413 | 228 | 81 |
| 13 Rio Grande | 50 | 441,821 | 157 | 7 |
| 20 Hawaii | 20 | 173,300 | 38 | 16 |
| 9 Souris Red-Rainy | 13 | 110,058 | 22 | 8 |
| Totals | 35,432 | 310,382,923 | 74,872 | 2,388 |

#### *1.1.3.2 Potential Generation*

INL has also developed an estimate of the 'available' hydroelectric resources. This classification is derived by subtracting the 'developed' and the 'excluded' from an estimate of total resources. Table 1-11 presents the US totals for the three classifications, with further separations into high power and low power divisions.

Table 1-11
Hydroelectric Resources Summary
Annual Mean Power, MW

| | **Total** | **Developed** | **Excluded** | **Available** |
|---|---|---|---|---|

| | | | | |
|---|---|---|---|---|
| High Power (Greater than 1 MW) | | | | |
| High Head 1 / High Power | 157,772 | 33,423 | 55,464 | 68,885 |
| Low Head 2 / High Power | 72,022 | 1,173 | 21,400 | 49,449 |
| Total - High Power | 229,794 | 34,596 | 76,864 | 118,334 |
| | | | | |
| Low Power (Less than 1 MW) | | | | |
| High Head / Low Power | 35,403 | 373 | 9,163 | 25,868 |
| Low Head / Low Power | 24,544 | 461 | 2,734 | 21,350 |
| Conventional Turbine | 8,470 | 319 | 899 | 7,253 |
| Unconventional Systems | 3,932 | 43 | 527 | 3,362 |
| Microhydro | 12,142 | 99 | 1,308 | 10,735 |
| Total - Low Power | 59,947 | 833 | 11,897 | 47,217 |
| | | | | |
| Total Power | 289,741 | 35,429 | 88,761 | 165,551 |

Notes:

1) High head = more than 30 feet
2) Low head = 30 feet and less

On a conceptual level, the available resource of 165,500 MW approaches 5 times the currently developed resource of 35,000 MW. If the additional hydroelectric resource could be fully developed, and if the additional output was devoted to hydrogen production through electrolysis at a lower heating value efficiency of 75 percent, approximately 71 billion kg of hydrogen could be generated annually. Assuming 1 kg of hydrogen in a fuel cell vehicle is equivalent to 2 gallons of gasoline in today's cars, the hydrogen from hydroelectric energy would displace all of the current gasoline demand.

#### *1.1.3.3 Considerations for New Hydroelectric Projects*

Hydroelectric power plants operate in many parts of the US and North America, and it is the leading renewable energy source in the US. Hydroelectric generation has several advantages: it is inexpensive; there is no fuel combustion; and there are no air emissions. The reservoirs formed for the hydroelectric plants also serve to control floods, store water, and provide major recreation facilities.

The major disadvantages for the technology include the following:

- Many of the best sites have already been developed, and obtaining permits for new projects is, at best, problematic
- A lack of rain or snow can severely limit power production in dry years

- Water flows are, at times, dictated by the health of the fish downstream of the dam; as such, the hydroelectric generation potential may not match the demand for electric energy.

### 1.1.4 Wind

#### *1.1.4.1 Wind Regimes and Turbine Capacity Factors*

Wind regimes are classified as follows:

| Class | Wind power density, W/m$^2$ | Average wind speed, mph [1] |
|---|---|---|
| 1 | <200 | <12.5 |
| 2 | 200 - 300 | 12.5 - 14.3 |
| 3 | 300 - 400 | 14.3 - 15.7 |
| 4 | 400 - 500 | 15.7 - 16.8 |
| 5 | 500 - 600 | 16.8 - 17.9 |
| 6 | 600 - 800 | 17.9 - 19.7 |

Note 1: Mean wind speed at 50 m elevation, based on the Rayleigh speed distribution of equivalent wind power density. Wind speed is for standard sea level conditions.

A distribution of the domestic wind resources by Class is illustrated in Figure 1-14. Isolated regions in California, the Great Plains, and the Northeast offer Class 6 resources. However, the vast majority of the country falls within the Class 3 and Class 4 categories.

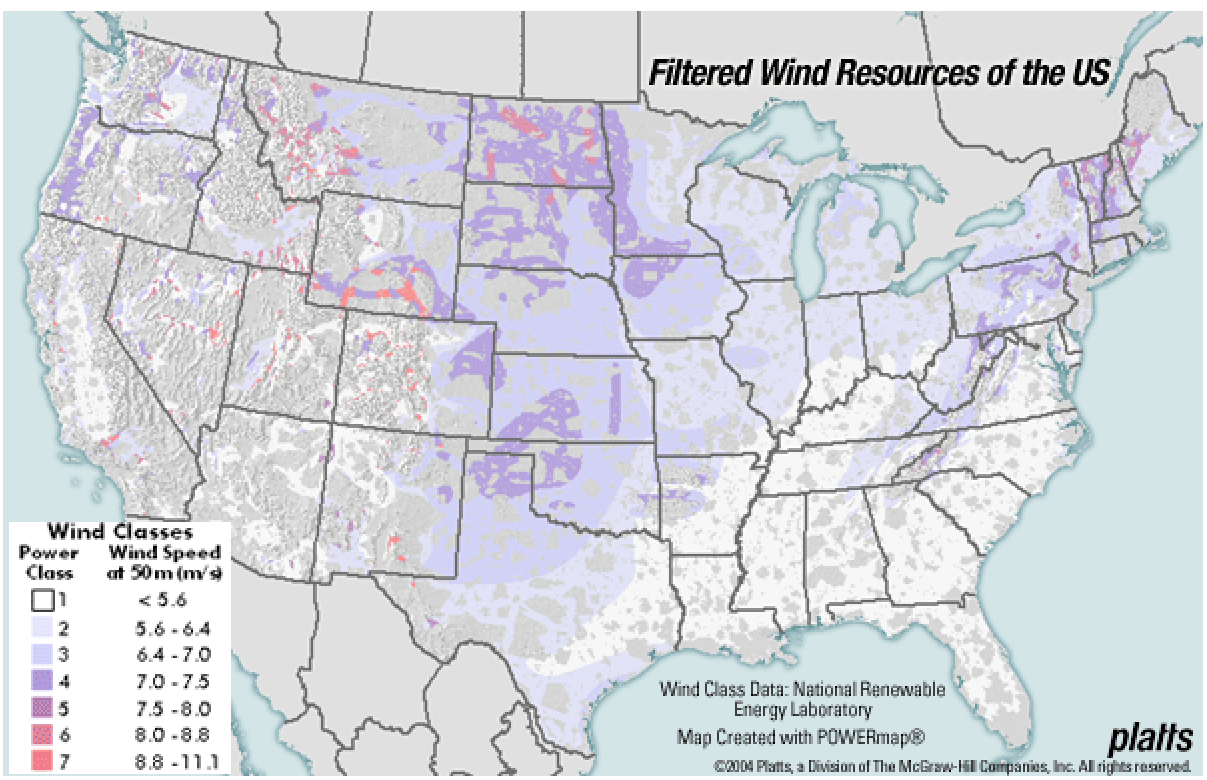


Figure 1-14 US Wind Resources

Annual wind turbine capacity factors are strongly influenced by the site classification, with estimated values of 35 percent at a Class 4 site, increasing to as much as 45 percent at a Class 6 site. The capacity factors include an equipment availability of 98 percent, characteristic of the latest commercial machines.

### *1.1.4.2 Current Generating Capacity, Energy Production, and Costs*

The total installed wind generation capacity in the US at the end of 2004 was 6,740 MWe. A distribution of the wind power capacity by state is illustrated in Figure 1-15.[4],[5]

In 2005, with the extension of the Federal production tax credit of $0.017/kWhe, the capacity addition is expected to approach 2,500 MWe. This will bring the total installed capacity and annual generation to 9,200 MWe and 17,700 GWhe, respectively.

Installed plant costs for onshore installations are in the range of $900 to $1,000/kWe, with offshore costs estimated to be 35 to 50 percent higher. Wind turbines are currently available which can generate energy at a competitive price of about $0.04/kWhe, without the benefit of the production tax credit, at a Class 6 site.

The more difficult task is to develop a machine, which can offer the same energy price, or perhaps lower, at a Class 4 location. The US Department of Energy is currently providing research and development funds of $42 million per year towards this, and other wind program, goals over the period from 2005 through 2012.

Energy from a wind project clearly cannot be dispatched; thus, a utility must often provide a backup generating source for periods in which the wind is not blowing. The costs incurred by the utility are a function of the wind contribution to the local capacity, with costs ranging from zero at a small wind contribution, to as much as $0.006/kWhe at a contribution of 20 percent.

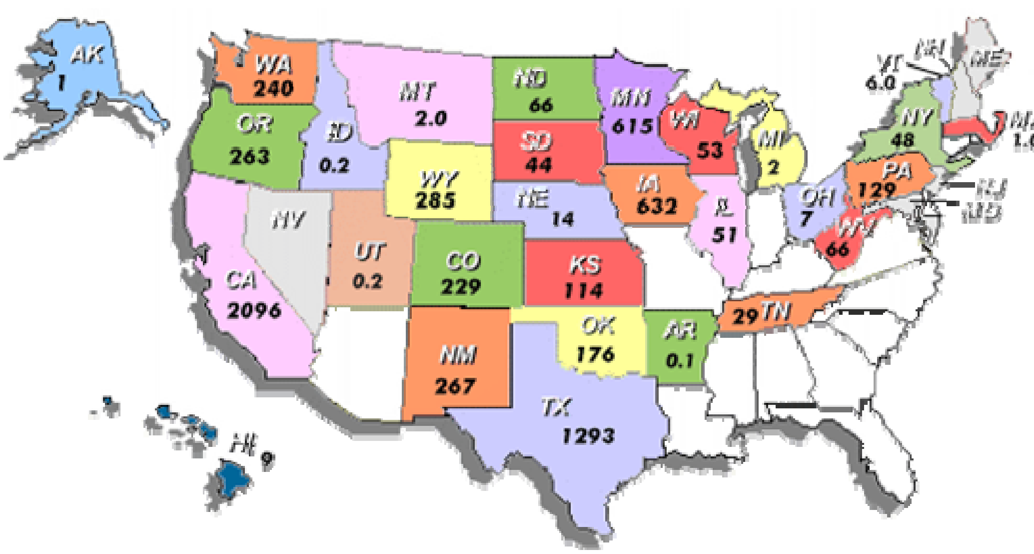


Figure 1-15 Installed Wind Generation Capacity by State, MW

### *1.1.4.3 Potential Energy Production*

California currently has the largest generating capacity among the states. Much of this capacity was installed due to a favorable combination of state investment tax credits in the 1980s, and three locations with Class 6 wind resources. However, most of the Class 6 sites, both within California and the rest of the country, have either been developed or are too far from existing transmission lines to be economically viable.

During the past 25 years, wind turbine designs have evolved to economically exploit the resources in the much more vast Class 3 and Class 4 locations typical of the Midwest and the Great Plains. Today, a large machine, with a capacity of 1.5 to 3.0 MWe, at a Class 4 location can generate energy, exclusive of the production tax credit, at a levelized cost of about $0.06/kWhe. Research efforts on the part of DOE and turbine manufacturers are working toward designs that can generate energy at a nominal price of $0.03 to $0.04/kWhe, exclusive of a subsidy, at a Class 4 site.

In conjunction with technical progress, the resolution of potential regulatory impediments to wind project development is also desirable, including consistency in the regulations which govern wind power access to local utilities, expansion of the electric transmission system in the Midwest and the Great Plains, and, for the next several years, multi-year reauthorization of the Production Tax Credit.

The long term potential for wind technology in the US is summarized in Table 1-12.[6] For comparison, the current domestic electric energy production is about 3,800 TWhe. Clearly, the values in the table overstate the potential for wind energy. Wind is an intermittent resource, and stability problems can appear in the transmission grid when wind contributions exceed 20 percent. Nonetheless, the potential for wind energy is clearly large, particularly for scenarios in which wind energy can be stored locally in the form of hydrogen. For example, dedicating the energy potential from the top 3 states in Table 1-12 to hydrogen production by means of electrolysis with a lower heating value efficiency of 75 percent, approximately 80 billion kg of hydrogen could be produced each year. Assuming 1 kg of hydrogen in a fuel cell vehicle is equivalent to 2 gallons of gasoline to today's cars, hydrogen from wind could offset 100percent of the current domestic gasoline consumption

Table 1-12
Long Term Wind Generating Potential
Top 12 States, Class 3 Locations and Higher

| State | Potential annual capacity, TWhe |
|---|---|
| North Dakota | 1,210 |
| Texas | 1,190 |
| Kansas | 1,070 |
| South Dakota | 1,030 |
| Montana | 1,020 |
| Nebraska | 868 |

| | |
|---|---|
| Wyoming | 747 |
| Okalahoma | 725 |
| Minnesota | 657 |
| Iowa | 551 |
| Colorado | 481 |
| New Mexico | 435 |
| | ------- |
| Total | 9,984 |

### 1.1.5 Biomass

#### *1.1.5.1 Feedstock Types*

Biomass feed stocks are classified into five general categories: forest residues, mill residues, agricultural residues, urban wood wastes, and dedicated energy crops.[7]

Forestry is a major industry in the United States encompassing nearly 559 million acres in publicly and privately held forest lands in the continental U.S. Nearly 16 million cubic feet of round wood are harvested and processed annually to produce saw logs, paper, veneers, composites, and other fiber products. The extensive forest acreage and round wood harvest generate logging residues and provide the potential to harvest non-merchantable wood for energy. Processing of the wood into fiber products creates substantial quantities of mill residues that could potentially be used for energy.

Agriculture is another major industry in the United States. Approximately 337 million acres of cropland are currently in agricultural production. Following the harvest of many of the traditional agricultural crops, residues (crop stalks) are left in the field. A portion of these residues could potentially be collected and used for energy. Alternatively, crop acres could be used to grow dedicated energy crops.

A final category of biomass feedstocks includes urban wood wastes. These wastes include yard trimmings and other wood materials that are generally disposed of in municipal solid waste and construction/demolition landfills.

#### *1.1.5.2 Resources Available*

Table 1-13 summarizes the estimated total annual cumulative quantities of biomass resources available by state and delivered price[8]. It is estimated that substantial quantities of biomass, 510 million dry tons, could be available annually at prices of less that $50 per dry ton delivered.

Dedicated energy crops, such as switchgrass and short rotation wood crops, are not currently produced. The analysis summarized in Table 1-13 is based on estimates of yield, production costs, and profitability of alternative crops that could be produced on the same land. Improving yields and decreasing production costs through improved harvest and transport technologies could increase available quantities at lower costs.

A transportation cost of $8/dry ton for most feedstocks has been assumed, based on a typical cost of transporting materials such as switchgrass bales and wood chips a distance of 50 miles.

Table 1-13
Biomass Quantities in Dry Tons per Year, by Delivered Price and By State
Biomass Feedstock Availability in the United States: 1999 State Level Analysis
Marie E. Walsh, Oak Ridge National Laboratory, Oak Ridge, TN 37831-6205
April 30, 1999, Updated January, 2000

| | < $20/dry ton | < $30/dry ton | < $40/dry ton | < $50/dry ton |
|---|---|---|---|---|
| Alabama | 840,566 | 6,962,610 | 10,712,357 | 17,681,689 |
| Arizona | 219,736 | 575,227 | 863,091 | 1,100,491 |
| Arkansas | 402,364 | 4,092,273 | 7,085,549 | 13,604,348 |
| California | 1,587,813 | 6,158,022 | 8,224,305 | 11,298,705 |
| Colorado | 180,661 | 651,769 | 3,356,589 | 3,581,889 |
| Connecticut | 246,938 | 560,563 | 610,563 | 906,309 |
| Delaware | 38,959 | 94,931 | 194,008 | 461,521 |
| Florida | 2,761,950 | 6,753,122 | 6,778,408 | 9,533,398 |
| Georgia | 934,094 | 6,390,823 | 8,540,684 | 16,111,675 |
| Idaho | 204,265 | 2,572,162 | 4,117,282 | 7,165,782 |
| Illinois | 435,047 | 1,038,411 | 26,838,517 | 33,359,162 |
| Indiana | 347,610 | 993,684 | 13,409,571 | 18,606,863 |
| Iowa | 173,802 | 404,337 | 24,582,843 | 32,786,037 |
| Kansas | 737,289 | 1,283,148 | 12,733,412 | 21,343,522 |
| Kentucky | 454,699 | 1,472,165 | 5,757,811 | 10,809,048 |
| Louisiana | 516,322 | 3,568,870 | 7,976,754 | 11,834,427 |
| Maine | 151,358 | 1,195,597 | 1,571,597 | 2,213,697 |
| Maryland | 204,643 | 543,071 | 899,539 | 1,959,222 |
| Massachusetts | 419,272 | 938,787 | 1,026,787 | 1,435,895 |
| Michigan | 505,734 | 2,468,224 | 4,627,235 | 12,163,103 |
| Minnesota | 990,517 | 2,916,529 | 15,493,892 | 21,247,327 |
| Mississippi | 598,831 | 4,908,719 | 10,673,390 | 17,930,978 |
| Missouri | 477,547 | 1,345,911 | 8,029,706 | 19,522,892 |
| Montana | 69,060 | 1,421,766 | 2,159,358 | 6,761,444 |
| Nebraska | 114,073 | 210,121 | 18,467,094 | 2,1773,296 |
| Nevada | 184,112 | 314,853 | 333,203 | 336,603 |
| New Hampshire | 133,579 | 922,298 | 1,061,298 | 2,016,455 |
| New Jersey | 389,089 | 726,481 | 791,204 | 975,806 |
| New Mexico | 167,896 | 424,160 | 960,689 | 1,081,589 |
| New York | 1,168,080 | 3,328,133 | 3,884,648 | 8,438,083 |
| North Carolina | 669,035 | 4,188,056 | 5,789,513 | 10,855,777 |

| | | | | |
|---|---|---|---|---|
| North Dakota | 326,510 | 558,184 | 2,506,662 | 21,043,177 |
| Ohio | 744,518 | 1,472,864 | 13,018,429 | 18,962,520 |
| Oklahoma | 111,173 | 3,873,692 | 7,816,207 | 12,699,956 |
| Oregon | 192,532 | 3,341,220 | 4,126,075 | 9,809,975 |
| Pennsylvania | 571,963 | 2,205,605 | 2,832,294 | 7,427,043 |
| Rhode Island | 29,803 | 80,671 | 87,671 | 115,514 |
| South Carolina | 1,293,900 | 4,468,833 | 6,332,258 | 9,368,065 |
| South Dakota | 131,982 | 285,637 | 9,601,746 | 16,005,411 |
| Tennessee | 878,029 | 3,381,715 | 10,720,281 | 15,232,952 |
| Texas | 1,227,449 | 4,221,749 | 13,526,432 | 20,747,118 |
| Utah | 158,765 | 388,275 | 647,821 | 722,821 |
| Vermont | 40,802 | 392,004 | 513,004 | 1,022,669 |
| Virginia | 599,454 | 3,058,757 | 5,055,411 | 8,714,941 |
| Washington | 297,432 | 3,979,387 | 5,938,641 | 9,920,241 |
| West Virginia | 241,236 | 1,361,393 | 1,971,651 | 3,736,487 |
| Wisconsin | 425,466 | 2,450,110 | 11,502,364 | 14,963,398 |
| Wyoming | 224,383 | 551,638 | 787,223 | 1,465,684 |
| U.S. Total | 23,820,338 | 105,496,557 | 314,535,067 | 510,855,005 |

#### *1.1.5.3 Ethanol Production from Biomass*

As discussed in Section 1.9.1, the goal for the production of ethanol from cellulosic materials is 100 gallons per dry ton of biomass. If all of the biomass listed in Table 1-13, at a price of $50 per dry ton, were converted to ethanol, approximately 51 billion gallons of ethanol could be produced.[9] Converting this volume of ethanol to hydrogen by means of auto thermal reforming would yield approximately 26 million kg of hydrogen each year. Assuming 1 kg of hydrogen in a fuel cell vehicle is equivalent to 2 gallons of gasoline to today's cars, hydrogen from biomass ethanol could offset about 40 percent of the current domestic gasoline consumption

### 1.1.6 Solar

The principal solar electric technologies are photovoltaic and concentrating thermal. The former uses semiconductor materials to convert the direct and the diffuse component of solar radiation directly into electric power. The latter uses mirrors to concentrate the direct component of the radiation into thermal energy, which is then used to drive a conventional engine.

Over the next 20 years, solar thermal technologies, in the multi-megawatt range, are projected to generate electric energy at prices below that for photovoltaic technologies. Thus, the principal regions of interest for producing hydrogen from solar energy are those in which the direct component of the solar radiation is a high as possible; i.e., the desert regions in Arizona, Nevada, New Mexico, and southern California. The total land area in these 4 states exceeds 500,000 $mi^2$, and the annual solar energy available is quite large. However, if the potential areas for solar projects are limited to those with excellent solar resources (>7 $kWh/m^2$-day), flat land areas, , and exclude sensitive lands (such as National Parks), the electric generation potential can be estimated as shown in Table 1-14.

Table 1-14
Solar Electric Power and Energy Generation Potential in Southwest United States
(Reference?? "Why Arizona Should Develop Its Solar Energy Resource", a presentation prepared by Solar Energy Industries Association, and the US DOE, Office of Energy Efficiency and Renewable Energy)

| State | Land area, $mi^2$ | Generation capacity, MWe | Annual generation potential, GWhe |
|---|---|---|---|
| Arizona | 12,790 | 1,652,000 | 3,909,000 |
| California | 5,750 | 742,000 | 1,757,000 |
| Nevada | 4,790 | 619,000 | 1,466,000 |
| New Mexico | 9,160 | 1,119,000 | 2,649,000 |
| | --------- | ------------- | ------------ |
| Total | 32,490 | 4,132,000 | 9,781,000 |

As a point of reference, the total electric energy generated in the US was about 3,848,000 GWhe in 2003.

Currently, the US consumes about 135 billion gallons per year of gasoline. Assuming 1 kg of hydrogen is equivalent to 2 gallons of gasoline, and assuming the hydrogen is produced by electrolysis with a higher heating value efficiency of 75 percent, the annual electric energy required to replace the current gasoline consumption is about 3,000,000 GWhe. An area of 9,800 $mi^2$ in Arizona alone, representing about 9 percent of the land area in the state, could supply the required electric energy

Solar thermal technologies are environmentally benign, as the power plants produce essentially no solid or gas emissions. Further, the land required for the projects has little or no competing commercial uses. Thus, the principal issue related to the widespread use of solar energy is the capital investment. Developing the solar projects required to offset the current domestic gasoline use would require expenditure roughly equal to the current Gross Domestic Product. Nonetheless, the potential exists for solar energy, unlike ethanol and other biomass, to domestically produce all of the transportation fuels required in the US for as long as is desired.

It can be noted that, rather than through electrolysis, hydrogen can also be produced from solar energy by photolytic processes, thermal decomposition, and various reduction / oxidation reactions.

In photolysis, sunlight is used to split water. Several approaches are being explored, including algal hydrogen production, photoelectrochemical hydrogen production using semiconductors, and photofermentation of hydrogen from alcohols and waste acids. Most of the photolytic processes must overcome problems with low conversion efficiencies, material costs, gas permeation rates, sunlight transmission at the desired wavelengths, chemical stability, biocompatability, and resistance to impact damage. The most direct solar thermal approach to hydrogen production is thermal decomposition of water. However, temperatures approaching 4,000 °F are required, which leads to low system efficiencies and a range of materials problems. Alternate thermal approaches use various combinations of oxidation / reduction reactions with intermediate components. A common approach is as follows:

$$ZnO + \text{Solar energy} \rightarrow Zn + O$$
$$Zn + H_2O \rightarrow ZnO + H_2$$

The reduction and the oxidation reactions proceed at temperatures of 3,100 °F and 700 °F, respectively. Other reaction combinations occur at lower temperatures, but often involve corrosive compounds. In any event, there are numerous engineering issues to be resolved in all of the proposed oxidation / reduction reaction approaches, and the near term prospects for a commercial process must be regarded as low.

### 1.1.7 Nuclear

The nuclear power industry in the United States is well defined. There are currently 104 power plants in operation, and no new plants have been built since 1985. Since it is difficult to obtain a permit for a new project, and since the safety of the existing plants over the past several years has been very good, the value of the existing nuclear plants is very high. With the anticipated live extension programs, the performance of the existing plants over the next 20 years can be estimated reasonably closely. The projected performance for the period from 2004 through 2025 is summarized in Table 1-15.

Table 1-15
US Nuclear Fuel Cycle Projections for 2004 Through 2025

| Year | Net Summer Capability | Electricity Net Generation | Requirement | | Spent Fuel | |
|---|---|---|---|---|---|---|
| | | | Annual Uranium | Cumulative Uranium | Annual | Cumulative |
| | Gigawatts Electric | Billion Kilowatthours | Million Pounds $U_3O_8$ Equivalent | | Thousand Metric Tons Heavy Metal | |
| 2004 | 99.61 | 787.0 | 57.84 | 280.38 | 2.39 | 51.54 |
| 2005 | 100.20 | 793.0 | 55.35 | 335.73 | 2.33 | 53.86 |
| 2006 | 100.40 | 796.0 | 62.72 | 398.46 | 2.44 | 56.30 |
| 2007 | 99.91 | 804.0 | 51.84 | 450.30 | 2.25 | 58.56 |
| 2008 | 99.12 | 797.0 | 60.56 | 510.86 | 2.53 | 61.09 |
| 2009 | 99.12 | 798.0 | 55.87 | 566.73 | 2.19 | 63.28 |
| 2010 | 99.31 | 800.0 | 49.06 | 615.79 | 2.37 | 65.65 |
| 2011 | 99.31 | 801.0 | 66.00 | 681.79 | 2.07 | 67.72 |
| 2012 | 99.40 | 803.0 | 51.75 | 733.54 | 2.52 | 70.24 |
| 2013 | 99.79 | 807.0 | 62.11 | 795.65 | 1.98 | 72.22 |
| 2014 | 99.25 | 811.0 | 50.53 | 846.18 | 2.53 | 74.75 |
| 2015 | 99.53 | 805.0 | 63.70 | 909.89 | 2.02 | 76.77 |
| 2016 | 99.63 | 806.0 | 49.54 | 959.43 | 2.37 | 79.14 |

| | | | | | | |
|---|---|---|---|---|---|---|
| 2017 | 99.63 | 807.0 | 63.49 | 1,022.92 | 2.28 | 81.42 |
| 2018 | 99.63 | 807.0 | 48.50 | 1,071.41 | 2.09 | 83.51 |
| 2019 | 99.63 | 807.0 | 62.72 | 1,134.13 | 2.17 | 85.68 |
| 2020 | 99.63 | 807.0 | 50.57 | 1,184.70 | 2.29 | 87.97 |
| 2021 | 99.63 | 807.0 | 58.99 | 1,243.69 | 2.03 | 89.99 |
| 2022 | 99.63 | 807.0 | 55.27 | 1,298.96 | 2.07 | 92.07 |
| 2023 | 99.63 | 807.0 | 60.83 | 1,359.79 | 2.29 | 94.36 |
| 2024 | 99.63 | 807.0 | 54.05 | 1,413.84 | 2.03 | 96.39 |
| 2025 | 99.63 | 807.0 | 52.33 | 1,466.17 | 1.96 | 98.35 |

#### *1.1.7.1 Fuel Cycles and Sustainability*

There are four general classes of nuclear fuel cycle, ranging through (1) the once-through fuel cycle, (2) a fuel cycle with partial recycle of plutonium, (3) a fuel cycle with full plutonium recycle, and (4) a fuel cycle with full recycle of transuranic elements. The majority of the analyses were based on a projection that nuclear energy would only maintain its current market share of electricity.

As a reference case, the waste generation and resource use were determined for the once-through cycle. This fuel cycle option is the most uranium resource-intensive, and generates the most waste in the form of used nuclear fuel. The existing known and speculative economic uranium resources are sufficient to support a once-through cycle at least until mid-century as shown in Figure 1-16. In the longer term, beyond 50 years, uranium resource availability becomes a limiting factor, unless breakthroughs occur in mining or extraction technologies.

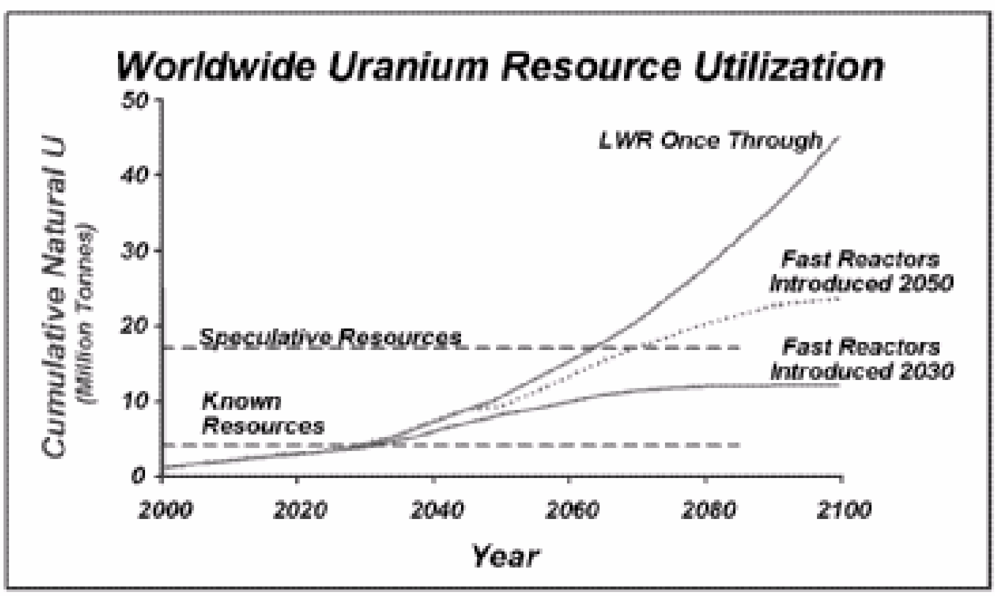



Figure 1-16 Cumulative Uranium Consumption and Resources
LWR: Light Water Reactor

The mid-term (30–50 year) actinide management activities consist of limiting or reversing the buildup of the inventory of spent nuclear fuel from current and near-term nuclear plants. By extracting actinides from spent fuel for irradiation and multiple recycle in a closed fuel cycle, heavy long-lived radiotoxic constituents in the spent fuel are transmuted into much shorter-lived or stable nuclides. Also, the intermediate-lived actinides that dominate repository heat management are transmuted. With closed fuel cycles, a large expansion of global uranium enrichment is avoided.

#### *1.1.7.2 Generation IV Systems*

The US Department of Energy is pursing the development of the next generation of nuclear reactors for both electric power and synthetic fuel (i.e., hydrogen) production.[10] Six candidate designs, briefly described below, are under consideration: four use a closed fuel cycle, one uses an open cycle, and one can use either.

##### *GFR – Gas-Cooled Fast Reactor System*

The Gas-Cooled Fast Reactor (GFR) system features a fast-neutron spectrum and closed fuel cycle for efficient conversion of fertile uranium and management of actinides. The reference reactor is a 600-MWth/288-MWe, helium-cooled system operating with an outlet temperature of 850 °C, using a direct Brayton cycle gas turbine for high thermal efficiency. It is primarily envisioned for electricity production and actinide management, although it may be able to also support hydrogen production. The GFR is estimated to be deployable by 2025.

##### *LFR – Lead-Cooled Fast Reactor System*

The Lead-Cooled Fast Reactor (LFR) system features a fast-neutron spectrum and a closed fuel cycle for efficient conversion of fertile uranium and management of actinides. The system uses a lead or lead/bismuth eutectic liquid metal cooled reactor. Options include a modular system rated at 300–400 MWe, and a large monolithic plant option at 1,200 MWe. The reactor is cooled by natural convection, with a reactor outlet coolant temperature of 550 °C, possibly ranging up to 800 °C. The system is specifically designed for distributed generation of electricity and other energy products, including hydrogen and potable water. The LFR system is estimated to be deployable by 2025.

##### *MSR – Molten Salt Reactor System*

The Molten Salt Reactor (MSR) system features an epithermal to thermal neutron spectrum and a closed fuel cycle tailored to the efficient utilization of plutonium and minor actinides. The fuel is a circulating liquid mixture of sodium, zirconium, and uranium fluorides. The molten salt fuel flows through graphite core channels, producing a thermal spectrum. The heat generated in the molten salt is transferred to a secondary coolant system through an intermediate heat exchanger, and then through another heat exchanger to the power conversion system. There is no need for fuel fabrication. The reference plant has a power level of 1,000 MWe. The system operates at low pressure (<0.5 MPa) and has a coolant outlet temperature above 700 °C, affording improved thermal efficiency. It is primarily envisioned for electricity production and waste burndown. The MSR is estimated to be deployable by 2025.

##### *SFR – Sodium-Cooled Fast Reactor System*

The Sodium-Cooled Fast Reactor (SFR) system features a fast-neutron spectrum and a closed fuel cycle for efficient conversion of fertile uranium and management of actinides. A full actinide recycle fuel cycle is envisioned with two major options: One is an intermediate size (150 to 500 MWe) sodium-cooled reactor with a uranium-plutonium-minor actinide-zirconium metal alloy fuel. The second is a medium to large (500 to 1500 MWe) sodium-cooled fast reactor with mixed uranium-plutonium oxide fuel. The outlet temperature is approximately 550 °C for both. It is primarily envisioned for electricity production and actinide management. The SFR is estimated to be deployable by 2015.

*SCWR – Supercritical-Water-Cooled Reactor System*

The Supercritical-Water-Cooled Reactor (SCWR) system features two fuel cycle options: the first is an open cycle with a thermal neutron spectrum reactor; the second is a closed cycle with a fast-neutron spectrum reactor and full actinide recycle. Both options use a high-temperature, high-pressure, water-cooled reactor that operates above the critical point of water to achieve a thermal efficiency approaching 44 percent. The reference plant has a 1700 MWe power level, an operating pressure of 25 MPa, and a reactor outlet temperature of 550 °C. The SCWR system is estimated to be deployable by 2025.

*VHTR – Very-High-Temperature Reactor System*

The Very-High-Temperature Reactor (VHTR) system uses a thermal neutron spectrum and a once-through uranium cycle. The VHTR system is primarily for high temperature process heat applications, such as coal gasification and thermochemical hydrogen production. The reference reactor concept has a 600-MWth helium cooled core based on either the prismatic block fuel or the pebble fuel. The primary circuit is connected to a steam reformer/steam generator to deliver process heat. The VHTR system has coolant outlet temperatures above 1,000 °C. The system may incorporate electricity generation equipment to meet cogeneration needs. The VHTR system is the nearest-term hydrogen production system, estimated to be deployable by 2020.

#### *1.1.7.3 Potential for Hydrogen Production*

The current domestic gasoline demand is about 135 billion gallons per year. Assuming 1 kg of hydrogen in a fuel cell vehicle is equivalent to 2 gallons of gasoline in today's car, and assuming the hydrogen is produced by water electrolysis at a lower heating value efficiency of 75 percent, a new nuclear industry, with a capacity of 370,000 MWe, would need to be developed to offset the current gasoline demand. The new capacity represents an increase of about 3.7 times over the current nuclear generating capacity.

A revitalized nuclear industry, adding 370,000 MWe of capacity to the country, is technically feasible. Nonetheless, developing such an industry will require an investment of at least $1 trillion, and will require public acceptance of an industry recycling and processing nuclear proliferation materials, such as plutonium, on a routine basis.

### 1.1.8 Carbon Sequestration

Large-scale generation of hydrogen from coal will need to meet environmental criteria for carbon management. To facilitate carbon management, it will be useful to correlate the future sites of hydrogen production facilities with potential geological sequestration formations. The data available so far indicates there are widespread, large capacity geological formations suited to the very long-term sequestration of $CO_2$.[11],[12]

US DOE is conducting several programs to locate and characterize geological formations for $CO_2$ sequestration. Phase I of the regional carbon sequestration partnerships program sponsored by DOE's National Energy Technology Laboratory (NETL) is basically complete by mid 2005. Phase I focused on data collection about $CO_2$ sources, and geological and terrestrial sequestration options. Phase II will begin toward the end of 2005 and will include the injection of small quantities of $CO_2$ into diverse geological sites around North America.

#### *1.1.8.1 Geological Storage Technology*

Underground storage in geological formation is a major option for $CO_2$ disposal. The principal options for underground storage include: active oil reservoirs; coal beds; depleted oil and gas reservoirs; deep aquifers; and mined salt domes or rock caverns. The relative merits of these options are outlined in Table 1-16.

Table 1-16
Geologic Storage Options for $CO_2$

| Storage option | Relative capacity | Relative cost | Storage integrity | Technical feasibility |
|---|---|---|---|---|
| Active oil wells | Small | Very low | Good | High |
| Coal beds | Unknown | Low | Unknown | Unknown |
| Depleted oil and gas wells | Moderate | Low | Good | High |
| Deep aquifers | Large | Unknown | Unknown | Unknown |
| Mined caverns and salt domes | Large | Very high | Good | High |

The technology for injecting $CO_2$ into the ground is well established. Oil producers in the Permian Basis of West Texas and in the Rocky Mountains have been injecting carbon dioxide for enhanced oil recovery for more than 25 years. In addition, the operation of underground natural gas storage systems, with their annual cycles of injection and withdrawal, offer a considerable base of geologic and engineering experience relevant to carbon dioxide injection and sequestration.

Geological storage of carbon dioxide is currently being demonstrated in saline formations at the Sleipner Field in the North Sea. Approximately 1 million metric tons are being injected annually, with a cumulative 2.5 million metric tons injected to date. A substantially larger project may soon be undertaken by Exxon and Pertamina at the Natuna natural gas field in the South China Sea. The principal uncertainties are the volumes available for storage, the long-term integrity of the storage, and the costs for $CO_2$ transport and storage system maintenance. Storage integrity is important, not only to prevent the return of $CO_2$ to the atmosphere, but also for public safety; $CO_2$ is heavier than air, and if a large release were to occur, air would be displaced near the leak site, leading to asphyxiation.

Deep aquifers may be the best long-term underground storage option. Such aquifers are generally saline, and hydraulically separated from shallower fresh water aquifers and surface water supplies. The estimated storage potential of deep aquifers in the US is 5 to 500 billion metric tons of $CO_2$. This compares favorably with the annual US power plant emissions of about 1.7 billion metric tons of $CO_2$., and with the additional $CO_2$ emissions of approximately 1.2 billion metric tons if the hydrogen required to offset the current gasoline demand is produced by coal gasification

Figure 1-17 shows the locations of deep aquifers underlying the US. For comparative purposes, the distribution of $CO_2$ production from power plants in the US is illustrated in Figure 1-18. The spatial match between storage locations and $CO_2$ sources is somewhat better for deep aquifers than for oil and gas reservoirs; Bergman and Winter (1996) estimate that 65 percent of the $CO_2$ captured from US power plants could be injected directly into deep aquifers without the need for long pipelines.

In general, the commercial interest in deep aquifers is limited; thus, the geologic properties of deep aquifers are not as well known as those for oil and gas reservoirs. Ideally, the aquifer should be located under a relatively impermeable cap, yet there should be high permeability, as well as porosity, below the cap to allow the $CO_2$ to the distributed efficiently.

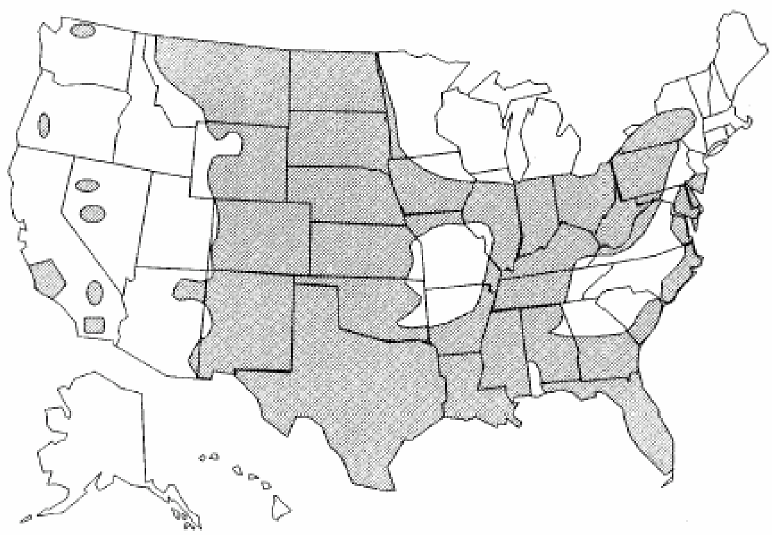


Figure 1-17 Saline Aquifers in the US

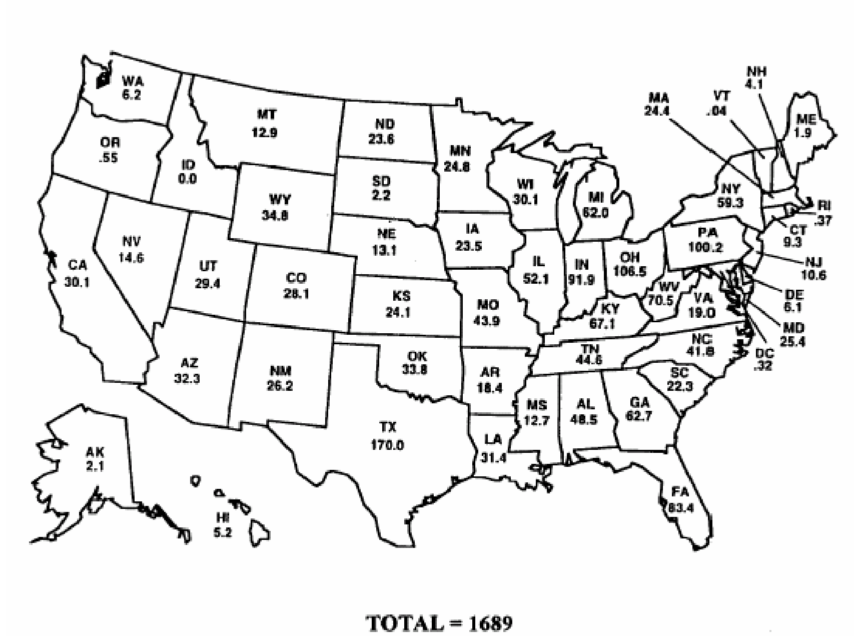



Figure 1-18 Distribution of Power Plant $CO_2$ Production in the US

## 1.2 LIGHT DUTY FUEL DEMAND AND SUPPLY IN US

### 1.2.1 Population Centers and Distribution

The principal domestic population centers are illustrated in Figure 1-19. Within the 100 largest centers, approximately 70 percent of the population resides.

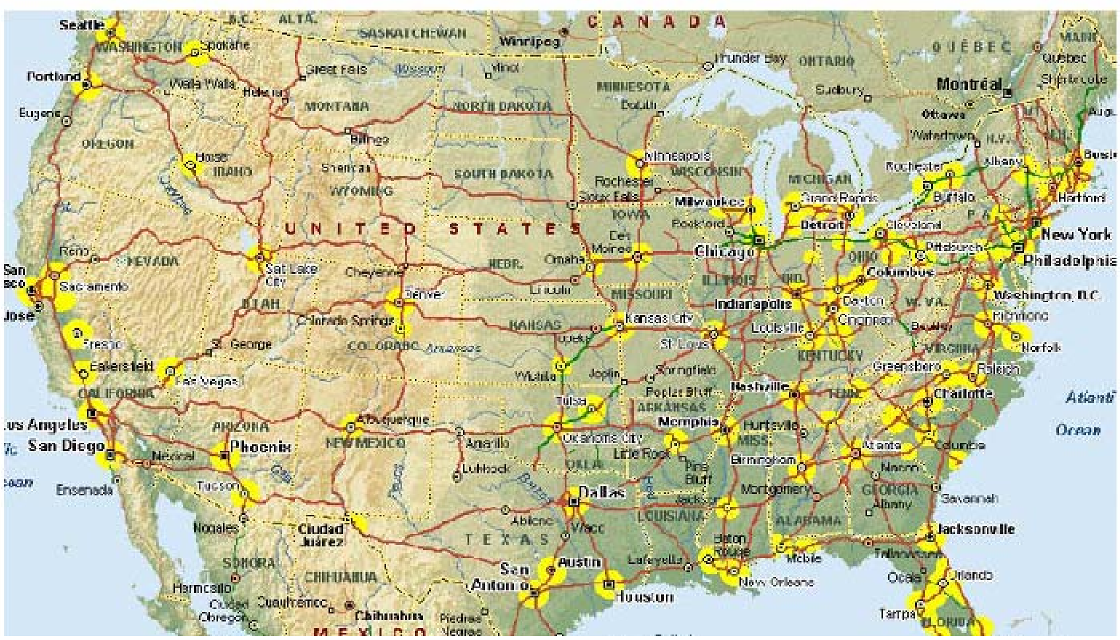


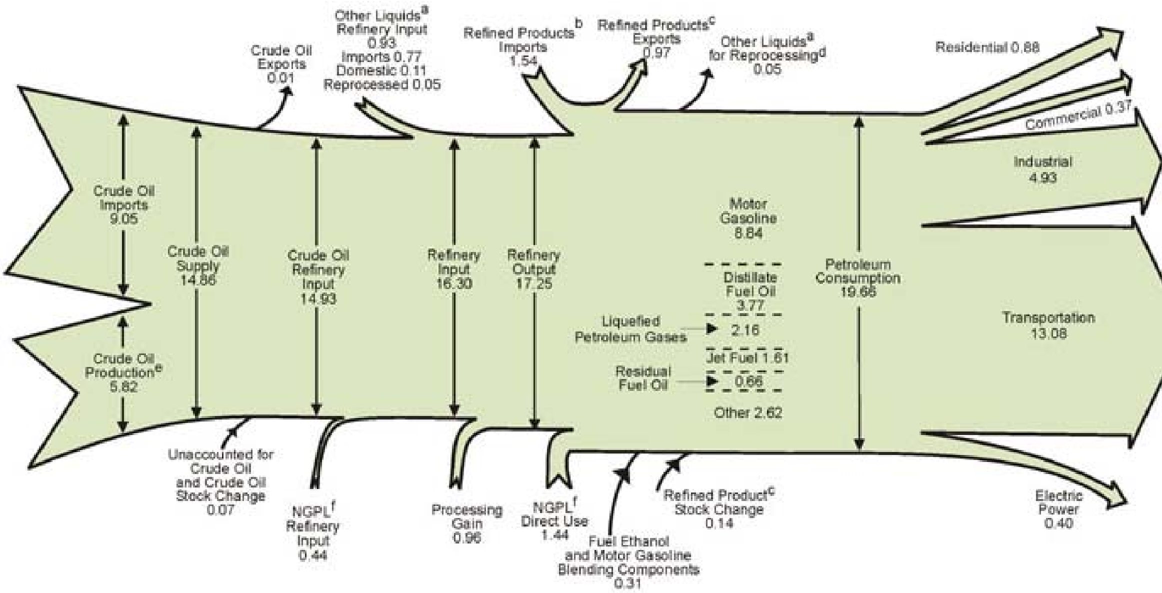

Figure 1-19 Major Population Centers in the United States

The principal interstate highways linking the major population centers are illustrated in Figure 1-20. The combined length of these highways is about 130,000 miles.

Figure 1-20 National Highways Between Major Population Centers

### 1.2.2 Transportation Fuel Consumption

The flow of petroleum in the United States is illustrated schematically in Figure 1-21.




[a] Unfinished oils, motor gasoline blending components, aviation gasoline blending mponents, and other hydrocarbons and oxygenates.
[b] Finished petroleum products, liquefied petroleum gases, and pentanes plus.
[c] Finished petroleum products, liquefied petroleum gases, pentanes plus, and other uids.
[d] Unfinished oils requiring further refinery processing, and aviation blending components.
[e] Includes lease condensate.
[f] Natural gas plant liquids.
Notes: • Data are preliminary. • Totals may not equal sum of components due to independent rounding.
Sources: Tables 5.1, 5.3, 5.5, 5.8, 5.11, 5.12a-5.12d, 5.14, and *Petroleum Supply Monthly*, Februar 2003, Table 3.

Figure 1-21 Domestic Flow of Petroleum in 2003, Millions of Barrels per Day

As shown in Figure 1-21, and below in Figure 1-22, motor gasoline for cars and light trucks accounts for about 45 percent of the total petroleum consumption.

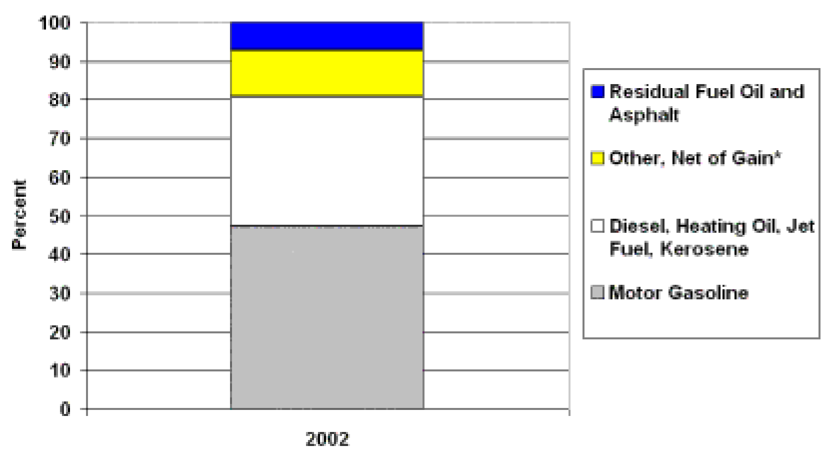



Figure 1-22 Average US Refinery Outputs from Crude Oil
Petroleum Supply Annual, Table 19
http://www.eia.doe.gov/pub/oil_gas/petroleum/analysis_publications/oil_market_basics/Ref_image_Simple.htm

Total vehicles miles traveled in 2004 was approximately 2.8 trillion miles. With some 220million cars and light trucks registered in the US, the annual gasoline demand is about 135 billion gallons, for an average annual gasoline use by each vehicle of about 710 gallons.

### 1.2.3 Fueling Station Characteristics – Gasoline

There are some 170,000 gas stations in the United States, each dispensing an average of 2,000 gallons of gasoline a day. Approximately 200 to 250 cars visit a typical station each day, with each car receiving 8 to 10 gallons of gasoline. With an annual average gasoline use of 710 gallons, a typical car would visit a gas station about every 5 days.

The most common refueling times are the early morning and the late afternoon. Most drivers select a gas station close to home or to work, with a typical driving distance of 2 to 3 miles from home or work to the station.

The number of gas stations has been falling through 2003, but appears to have recently stabilized, as shown below in Figure 1-23.

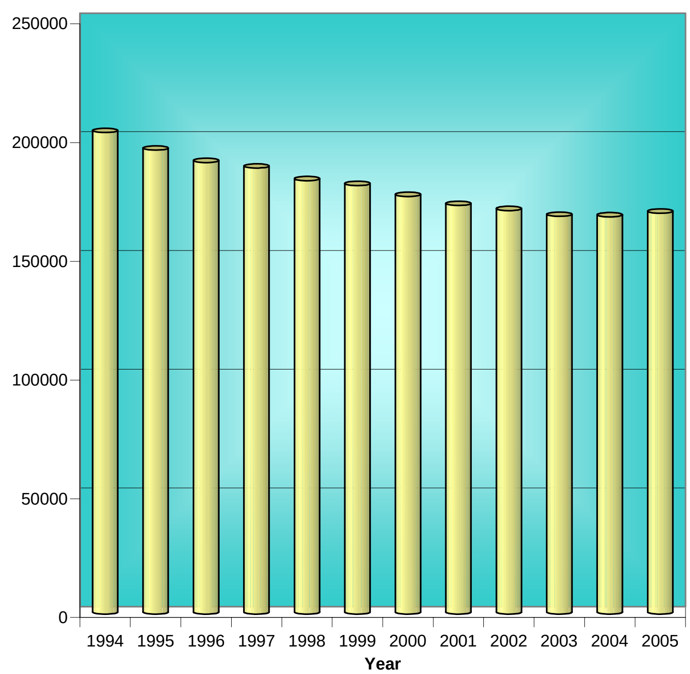



Figure 1-23 Domestic Gasoline Stations
National Petroleum News Market Facts, June 2005

Since gasoline consumption has increased over the past several decades, the trend is toward larger stations, with a greater numbers of pump hoses at each station. Nationally, a typical urban gasoline fueling station dispenses approximately 4,400 gallons per day, or about 135,000 gallons per month. This is a total quantity inclusive of all grades of gasoline and diesel. This type of station would predominantly supply light duty vehicles. Assuming a typical fill of 10 to 12 gallons per vehicle, this equates to 365 to 440 vehicles visiting on an average weekday.

Stations on rural interstates dispense about 50 percent that of an urban station, whereas a busy truck stop, which would include a larger proportion of diesel fuel sales to heavy duty vehicles, dispenses about 50 percent more than an urban station.

The profile of sales by hour of day varies between urban and rural stations, reflecting the influence of commuter patterns of fueling on the way to and from work. Interstate and major freeways in or near urban areas tend to exhibit similar refueling patterns to local urban stations. In both cases, weekend patterns are different than weekday patterns. Examples of the fueling patterns are shown in Figure 1-24, Figure 1-25, and Figure 1-26 for midweek, Monday and Friday, and weekends, respectively.

Figure 1-27 shows the variation in sales over the days of the week, and indicates a peak demand on Friday evenings in anticipation of weekend travel. Also, people fill their vehicle tanks on a Sunday in preparation for the work week, reducing demand on Mondays and Tuesdays. This pattern may be more or less visible, depending on the exact location of a station and the proportion of commuter traffic it serves.

The profile within a day shows demand generally picking up before 6:00 AM, building throughout the day, and then reaching a maximum around 5:00 PM. Again, stations that serve predominately commuters might show a more pronounced pattern of morning and evening peaks.

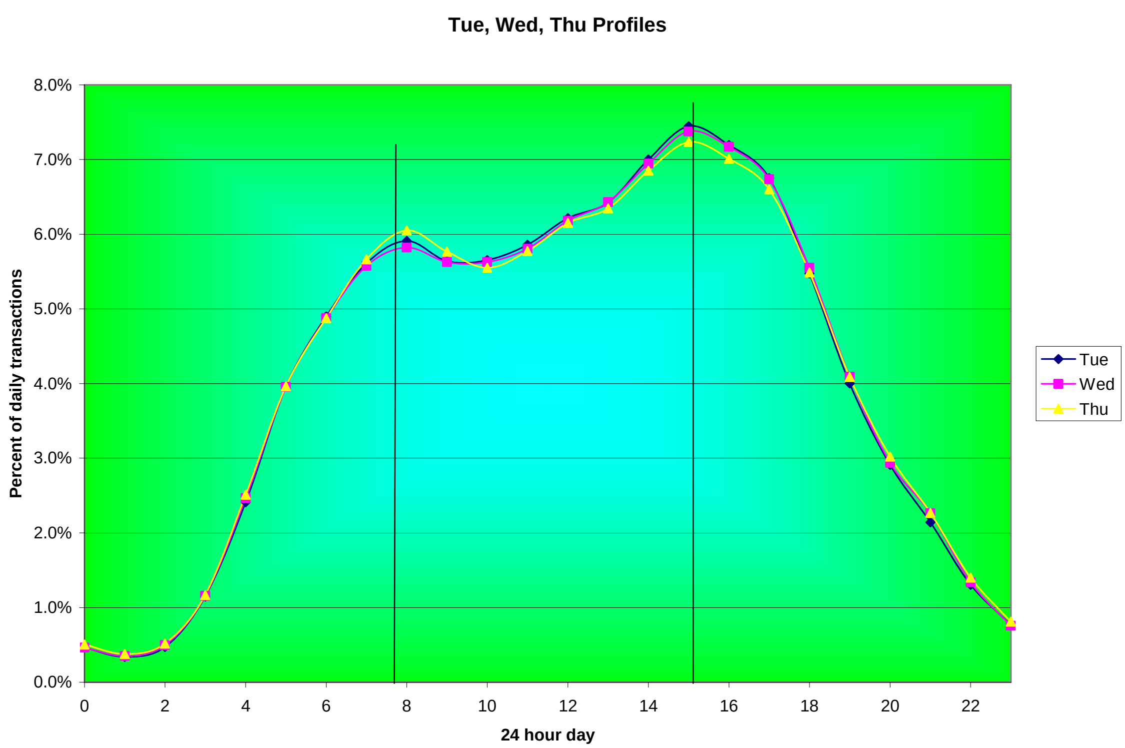



Figure 1-24 Mid-week Fueling Profiles

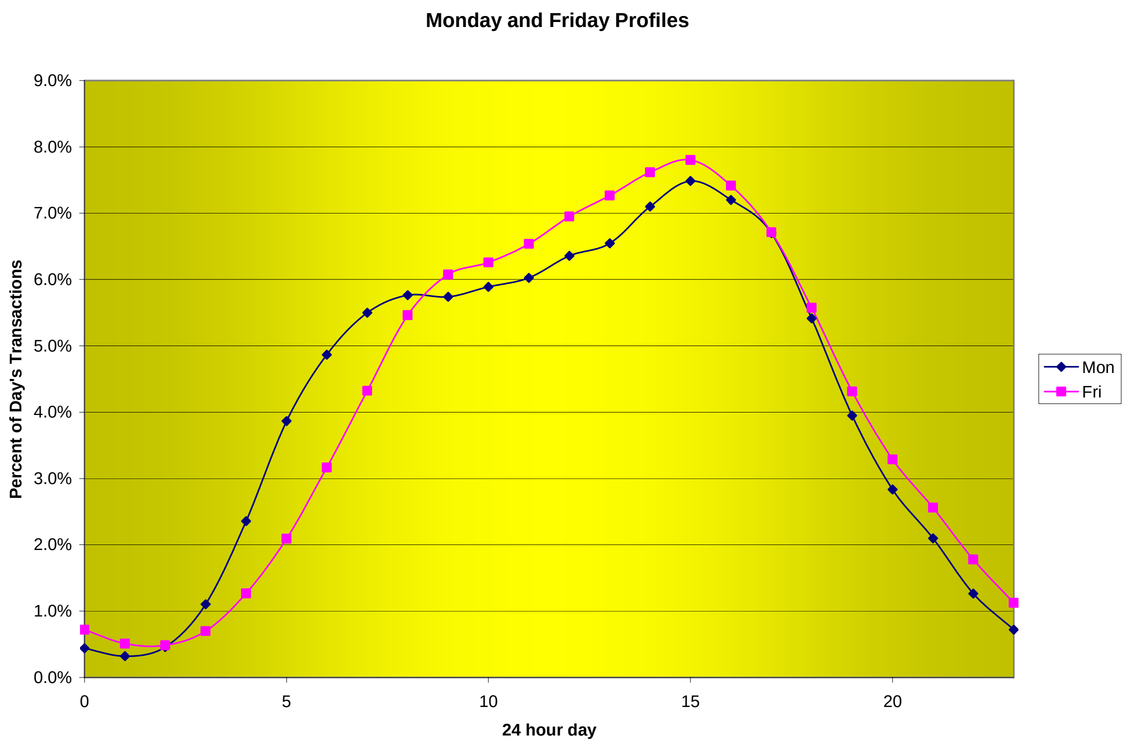



Figure 1-25 Domestic Gasoline Stations

Chart 2 – Monday/Friday within day fueling profile

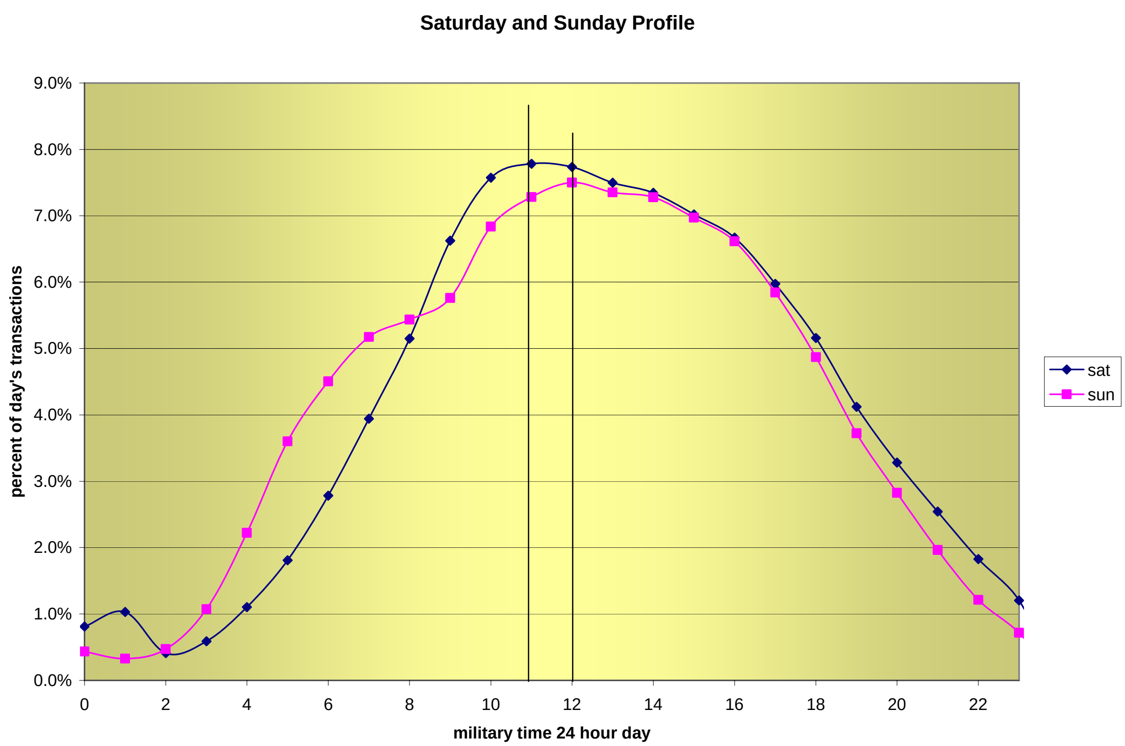



Figure 1-26 Weekend Fueling Profiles

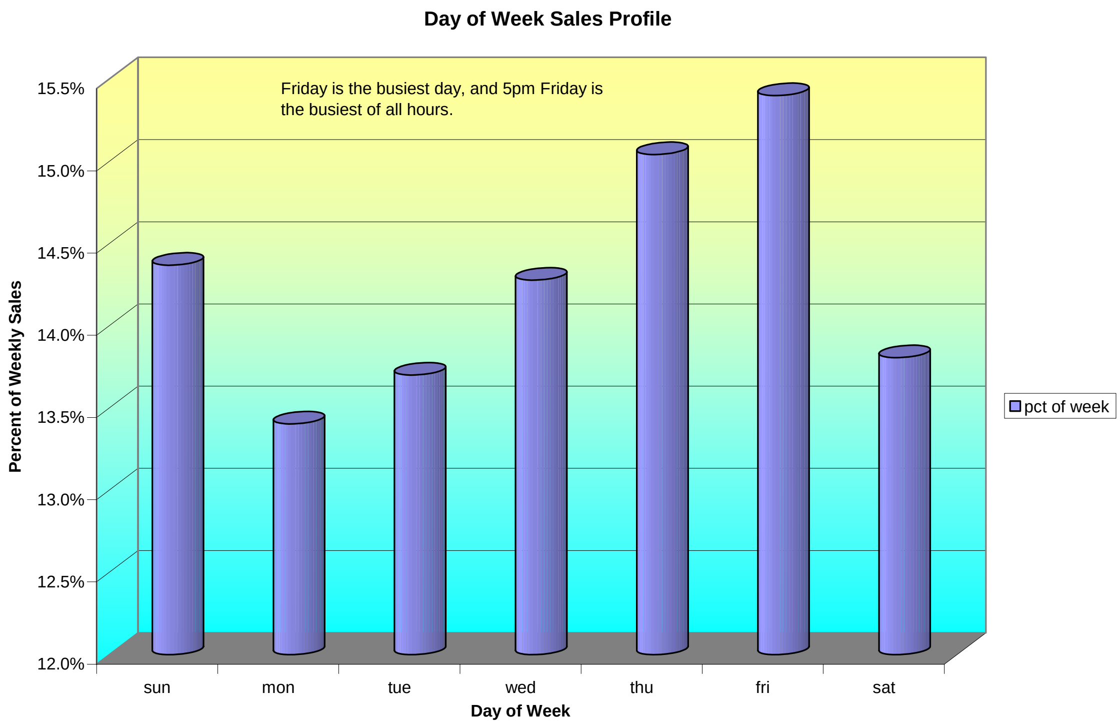



Figure 1-27 Variation in Fuel Demand by Day of the Week

Gasoline powered vehicles typically fill 10 to 12 gallons of fuel at any one time, and have an average fuel tank size of approximately 16 gallons capacity. The typical driver, therefore, fills an average of 62 to 75 percent of the tank volume at any station visit. If a light duty vehicle has an average fuel consumptions of 25 mpg, a full tank represents a range of about 400 miles. Furthermore, if a typical light duty vehicle travels 12,000 miles per year, one fill of 10 gallons would be required every 7.6 days [(25 miles/gallon * 10 gallons * 365 days/year) / (12,000 miles/year)], giving an average consumption of 1.3 gallons per day (10 gallons / 7.6 days).

If a hydrogen powered vehicle were to average 50 miles per kg of hydrogen, then an on-board storage capacity of 8 kg (400 miles / 50 miles/kg) would be required to have a range comparable to that of a gasoline vehicle. Assuming a fill quantity on the same basis as for gasoline vehicles, then 5 to 6 kg of hydrogen would be transferred to the vehicle. This is equivalent to a fuel use of about 0.65 kg per day (5 kg / 7.6 days). If the station dispenses 4,400 gallons per day of gasoline, this would be equivalent to a hydrogen station dispensing 2,200 kg per day of hydrogen (4,400 gallons/day * 0.65 kg/day / 1.3 gallons/day).

### 1.2.4 Fueling Station Characteristics - Hydrogen

The DOE goals for hydrogen dispensing rates are 0.5, 1.5, and 2.0 kg/min in 2005, 2010, and 2015, respectively. Thus, a fuel cell vehicle would, on average, be refueled in 10 minutes today, dropping to 2.5 minutes in 2015. Ten minutes is probably longer than an average motorist spends to refuel a car today, but the time would likely not be viewed as excessive for the early consumers of fuel cell vehicles. However, the 'average' consumer will likely expect refueling times comparable to today's gasoline vehicles, and a time of 2.5 minutes is consistent with today's times.

In terms of providing fueling stations for fuel cell vehicles, simultaneously converting all 170,000 gasoline stations to dispense both gasoline and hydrogen would clearly be infeasible. The minimum number of station conversions required to establish a practical hydrogen infrastructure was estimated by General Motors based on the following criteria:

- To establish a self-sustaining hydrogen vehicle demand, 1 million fuel cell vehicles should be in operation.
- Stations should be located in each of the 100 largest metropolitan areas, with a maximum driving distance to the nearest station of 2 miles. The combined population in these 100 metropolitan areas represents about 70 percent of the total US population.
- Along the 130,000 miles of interstate routes, the stations should be located no further than 25 miles apart.

On this basis, 6500 stations would be required in urban areas, and 5700 stations would be required in rural areas, for a total of 11,700 stations. This number of stations is about 7 percent of the current total for gasoline stations, and should be a practical near term goal. Nonetheless, the estimated capital investment to convert the 11,700 stations is on the order of $12 billion.

## 1.3 GASEOUS HYDROGEN DELIVERY BY PIPELINES

### 1.3.1 Existing hydrogen gas pipelines in the U.S.

<u>Gas flow rates</u>

Hydrogen pipelines in the U.S. are currently operated by the companies which own the hydrogen being transported. Unlike the natural gas industry, there are no common carrier companies. Most pipelines are owned by three industrial gas companies (Air Liquide, Air Products, and Praxair). In addition, several refinery operators have fairly short hydrogen pipelines between their facilities.

Consequently, hydrogen pipelines are generally sized to satisfy specific plant requirements at the time the pipeline was built. There is rarely significant spare capacity, unless a customer or a production plant has closed. In practice, a 10 inch or 12 inch pipeline will carry 100 million standard cubic feet per day of hydrogen, assuming a transmission pressure of at least 600 psig (41.38 bars g) with economically acceptable pressure losses. 100 MSCFD is about the size when economies of scale for hydrogen production plants are fully realized, and it is a common size selected in practice. Consequently, there are few hydrogen pipelines built over 12 inch (30.48 cm) size. There are many smaller pipelines which have been built to service individual customer requirements which may be much less than 100 MSCFD (2.7 Million Nm3/d). As sales volume to specific customers is commercially sensitive information, flow rates in individual pipelines are not available.

<u>Line sizes</u>

Existing hydrogen pipelines mostly service the petrochemical industry, and consequently are in areas (primarily the Gulf Coast) where there are large numbers of existing pipelines, some of which are available for purchase. Probably the majority of H2 pipelines systems have some part, and often a large part of their length, comprised of old pipelines which have been converted to hydrogen service. The available pipeline size may be larger or smaller than would ideally have been selected, but the economic advantage of purchase and conversion is so great that some compromise is usually necessary. Many systems have used sections of 8 inch and 10 inch former crude oil pipeline. These are the most common sizes used among the approximately 600 miles (900 km) of $H_2$ pipelines in service in the U.S. The largest diameter $H_2$ lines are 18 inches or 45.72 cm (1.2 miles or 1.92 km long) and 14 inches or 35.52 cm (30 miles or 48 km long).

Delivery pressures

Hydrogen supplied by pipeline is used by refineries to supplement much larger quantities produced in-house. Consequently, the pipeline operating pressure is a function of the pressure required by the refinery. The refineries use purchased hydrogen for desulphurization and hydrocracking. Both are high pressure processes, typically 3,000 psig (206.9 bars g). They also need $H_2$ for hydrotreating at 500 to 700 psig (34 to 48 bars g). However, purchased hydrogen is frequently connected at the suction of existing refinery compressors, so a wide variety of pressures are specific to the refinery customers. $H_2$ pipeline pressures are in a range between 400 and 2,000 psig (28 and 138 bars g), with the majority operating between 600 and 900 psig (41 and 62 bars g).

Transport distances

The location of hydrogen production plants relative to the customer location is based on economics and logistics. Most pipeline hydrogen is produced for the market in steam methane reformer (SMR) or partial oxidation (POX) plants. Both use natural gas as a feedstock. Other sources are crude hydrogen produced as a by-product of chlor-alkali or other processes. The SMR process is exothermic, and economics dictate that these plants be located close to a market for by-product steam. Frequently, the customer plant has no use for steam, and the SMR must be located elsewhere, requiring a pipeline between the production plant and the user. In terms of logistics, the requirement for high reliability of supply leads to the construction of pipelines linking two or more production plants with one or more customers. In the U.S. all three industrial gas companies have hydrogen networks over 150 miles (240 km) long, largely to improve reliability of supply to customers. In Europe, Air Liquide has a hydrogen network of 650 miles (1040 km) connecting 8 production plants with customers in France, Belgium, and the Netherlands.

Locations of the feed and boost compressors

Hydrogen compressors feeding the pipeline system are usually found at locations where crude hydrogen (purchased from petrochemical plant by-product streams) are cleaned by pressure swing absorbers, and injected into the pipeline. By-product hydrogen is generally available at low pressure, and therefore hydrogen compressors are unavoidable. However, $H_2$ compressors are expensive, high maintenance items, and are not installed if there is an alternative. If the hydrogen is produced from natural gas, the favored alternative is to compress the natural gas, rather than the hydrogen. The hydrogen delivery pressure from a steam methane reformer is typically about 150 psi (10.3 bars) less than the pressure of the natural gas feedstock, because of pressure losses in the process and purification systems. As current hydrogen pipelines are relatively short (up to 150 miles) the pressure at the production plant is usually sufficiently high to avoid the need for intermediate booster stations along the pipeline. Occasionally, flow increase along an existing pipeline will require the addition of a booster compressor to the system, but there are only two or three such installations in the U.S.

Construction materials

Concern about the possibility of failure due to hydrogen induced embrittlement of carbon steel has led to a variety of approaches designed to avoid this phenomenon. The simplest is to specify low strength grades (API 5LX Grades 42 or 52). There is some experimental evidence that high strength carbon steel is more prone to embrittlement, thus should be avoided. Another approach is to specify "clean" steel, in which impurities such as sulfur and manganese are minimized. More recently, companies have specified micro-alloyed steel, in which strength is obtained by the addition of very small quantities of metals such as vanadium, niobium, and titanium. If these measures are not practical, the stress level in the material can be reduced by selecting a greater wall thickness than would otherwise be required by the design codes. This leads to higher material costs, particularly for large pipelines.

Compressed Gas Association G-5.6 contains a number of guidelines for the selection of carbon steel pipe for hydrogen service. The document recommends the use of micro alloyed pipeline steel conforming to API 5LX Grades 42 or 52, with limits on sulfur (<0.01 percent), phosphorus (0.015 percent), and carbon equivalent (0.35). The ferrite grain size is limited to ASTM 8 or finer. There are other limits on hardness, tensile strength, and Charpy impact strength which exceed the standard requirements of API 5LX steel. Another option offered by the CGA document is the use of standard pipe material (ASTM A-106 grade B, or API 5LX grades 42 and 52) without the requirement for additional limits on chemistry. In this case, it is recommended that the operating stress level in the pipe be limited to 30 percent of the specified minimum yield strength, or 20 percent of the specified ultimate tensile strength.

Although hydrogen has a much higher permeability through plastic materials than natural gas, it may be suitable at low pressure (under 100 psig or 6.9 bars g). Research is in progress at Oak Ridge National Laboratory to develop plastic materials with reduced permeability to hydrogen. Plastic materials such as high density polyethylene are widely used for natural gas distribution because of low material and joining costs.

Capital costs

As hydrogen pipelines built to date are relatively small in diameter (compared to natural gas transmission pipelines), the cost of the pipe material is relatively small compared to the fixed costs such as right of way, engineering, and inspection. Consequently, the additional cost of specific metallurgical requirements has been a small part of the final installed cost (no more than 5 percent). The installed cost of hydrogen pipelines varies widely, depending on location. The cost of a 12 inch (30.48 cm) pipeline (including right of way, environmental, permitting, engineering, etc.) varies from $500,000 per mile in rural Texas to $2,000,000 per mile in urban

California.  The cost of hydrogen compressor stations, although very high compared to natural gas, has not been a major concern so far because they are rarely required on current hydrogen systems.  Compressor stations represent a significant part of the operating cost of natural gas transmission pipelines because they are required approximately every 40 miles (64 km) to maintain an operating pressure which maximizes the efficient use of the pipeline.  Existing hydrogen pipelines are rarely more than 150 miles (240 km) long, and there may be two or more hydrogen production plants along the pipeline.  Usually, the only compression required is at the production plant.  Even at production plants, hydrogen compressors are avoided if possible by compressing the natural gas feedstock instead.  If long, large diameter (>30 inches or 76.2 cm)) hydrogen pipelines are built in the future, the capital cost of compressors and hydrogen specific pipeline materials will be much more significant.

<u>Compression energy consumption</u>

The example below compares the energy transported, with the energy used for compression, for a hydrogen and natural gas pipeline of the same size, using a single compressor at the originating plant.

Because of the physical properties of hydrogen (low molecular weight and low specific density), the energy required to compress a given volume of hydrogen is much greater than for natural gas, as illustrated in Table 1-17.

- Compress from $P_{initial}$ = 1 psig (0.07 bars g) to $P_{final}$ =1000 psig (69 bars g)
- 4-stage, inter-cooled compression equipment
- Initial temp = 70 °F (21 °C); inter-stage temp = 90 °F (32 °C)
- Compress the same volumetric quantity of each gas, i.e.  XX million SCF/day:

Table 1-17
Compression Energy Requirements

| | Natural gas | Hydrogen |
|---|---|---|
| Delivered energy consumed during compression | 0.31 percent | 1.33 percent |

However, hydrogen has a much lower viscosity than natural gas, and thus for a given pipeline pressure loss, a greater volume of H2 can be transported.  A representative calculation is shown in Table 1-18:

- 100 miles (160 km) of 20” (50.8 cm) I.D. pipeline
- Gas temp = constant 70 °F (21 °C)
- Initial pressure = 1000 psig (69 bars g)
- Outlet pressure = 800 psig (55 bars g)

Table 1-18
Pipeline Gas Delivery Volumes

| | Natural gas | Hydrogen |
|---|---|---|
| Volume of gas delivered, $10^6$ standard $ft^3$/hr ($10^6$ Nm3/h) | 7.0 (0.19) | 18.4 (0.5) |

Combining the compression energy and hydraulic loss calculations yields the values shown in Table 1-19.

Table 1-19
Pipeline Gas Delivery Volumes

| | Natural gas | Hydrogen |
|---|---|---|
| Volume of gas delivered, $10^6$ standard $ft^3$/hr ($10^6$ Nm3/h) | 7.0 (0.19) | 18.4 (0.5) |
| Lower heating value energy delivered, $10^6$ Btu/hr ($10^6$ KJ/hr) | 6,391 | 5,060 |
| Less compression energy, $10^6$ Btu/hr ($10^6$ KJ/hr) | (20) | (69) |
| Net energy delivered, $10^6$ Btu/hr ($10^6$ KJ/hr) | 6,371 | 4,991 |

The above implies a system de-rating of 20 to 25 percent on a delivered energy basis.

Leakage and losses

As hydrogen has a very small molecule compared to most other gases, leakage from mechanical joints is a more likely, and considerable care in the selection and installation of flanges, compression fittings, etc. is required. In practice, routine leakage surveys using hydrogen detectors rarely detect leakage. Many of the leakage sources common in natural gas systems (venting, relief valves, etc.) are avoided by design in hydrogen systems due to the problem of hydrogen autoignition.

Emissions from the compressor stations

Vents from hydrogen compressor equipment are always connected to a flare system to avoid unexpected ignition of hydrogen released during shutdown and other operations. The only emission to be expected is water vapor.

Maintenance and other operating requirements

Most of the costs associated with hydrogen pipeline maintenance are identical to those of a natural gas or other pipeline. Significant annual costs are clearing of vegetation, cathodic protection readings, cathodic protection maintenance, and valve maintenance. Hydrogen pipelines, like natural gas pipelines, are subject to a mandatory Pipeline Integrity Management Program, which requires periodic testing or inspection of the underground pipeline.

### 1.3.2 Experiences in the construction, operation, and maintenance of hydrogen pipelines in the US and other parts of the world

Pipe joining techniques used to minimize leakage

In general, hydrogen pipeline construction maximizes the use of welded joints to avoid leakage problems. Inevitably, there are some locations where a permanent joint is not possible because of the need for removal of a pipe section for maintenance. For such connections 2 inch or larger, flanged connections are used. The preferred gasket material is spiral wound stainless steel. The stainless spiral is sandwiched between layers of elastomer, which provides a complete seal when the flange bolts are tightened to apply load. This design is preferred because the stainless steel element protects against complete failure of the gasket in case of fire. This is important in the case of hydrogen, as hydrogen leaking from a flange is more readily ignited than natural gas

Conversion of existing gas and oil pipelines to hydrogen service

Several hydrogen pipeline systems in Texas and Louisiana include sections of pipelines converted from previous oil or hydrocarbon service. These converted pipelines are usually quite old, varying from early 40's to mid 70's, and are available because of the decline in production of crude oil and associated products in Texas. In most cases, these pipelines where originally built for crude oil service, but they have often been used for other fluids, such as petroleum products and natural gas. All pipelines in the US are built from material qualified to American Petroleum Institute (API 5L) specifications, although the requirements for material grade or wall thickness may vary between oil and natural gas service due to differences in the design requirements for these fluids. Specifically, Department of Transport regulations require that natural gas and hydrogen pipelines are designed for a lower working stress level in populated areas. This means that pipelines originally designed for liquid service may have a thinner wall than would be required for gas being carried at the same pressure.

## 1.4 GASEOUS AND LIQUID HYDROGEN DELIVERY BY TRUCKS AND RAIL

### 1.4.1 Current gaseous and liquid delivery by trucks and rails from merchant hydrogen plants

The existing delivery network

A substantial truck delivery infrastructure already exists to supply the many industrial users of hydrogen. Applications include metal processing, food industries and power generation. Larger volume customers such as chemical manufacturers and refineries either produce H2 on site, or are supplied by pipeline. Four companies (Air Liquide, Air Products, BOC Gases, and Praxair) supply virtually all the merchant hydrogen market. There are 8 hydrogen liquefaction plants in North America, producing approximately 300 tons per day total output. The industrial gas companies have about 180 liquid hydrogen trailers between them. There are gas hydrogen trailer filling plants in all major industrial states, and about 1500 tube trailers in service.

Typical delivery distances and their practical limits

The physical characteristics of  the delivery trailers determines their patterns of use.  A gas delivery (tube) trailer costs about $165,000, but can only deliver 700 pounds of hydrogen.  The hydrogen cargo represents less than 1 percent of the weight of the trailer, so the fuel and manpower costs per unit of hydrogen transported is very high.  Consequently, gas trailers are typically used to supply relatively small volume customers within a state.  Liquid trailers cost about $625,000, and can carry up to 6,500 pounds of product.  However, the cost of the liquid product is much higher than compressed gas, because of the capital and energy costs associated with the liquefaction plant.  Liquid trailers are used to supply relatively large customers, in order to avoid the high distribution costs of gas trailers.  Because of the very small number of liquid hydrogen plants owned by each company, inter-state liquid deliveries of over 1000 miles are common.  The liquid is sub-cooled at the originating plant (to a temperature significantly below boiling point) in order to avoid venting of hydrogen during transportation.

<u>Types of trailers and their hydrogen holding capacities and pressures</u>

Tube trailers consist of 10 to 36 cluster high-pressure cylinders (tubes) varying in length from 20 feet for small tubes to 38 feet on the jumbo tube trailers.  Each tube may contain gaseous product at as much as 3,000 psig (20.69 bars g).  The most common (and largest volume) arrangement is 9 tubes of 92 cubic feet capacity.  A common delivery practice is to leave the trailer at the customer location, so that it acts as both a delivery and storage vessel.  As the tubes cannot be completely depressurized (depending on the customer application pressure) there will always be a quantity of gas which cannot be used.  Liquid trailers are available in capacities between 1,450 and 6,500 pounds.  The operating temperature is -423 °F.  The delivery pressure is low, but liquid can be used to generate very high pressure gas at a low energy cost, using high pressure cryogenic pumps.  Larger LH2 transport vessels are possible.  Detailed design studies have been carried out by the Europe-Quebec hydrogen export project for 200 ton seagoing containers for liquid hydrogen.  This type of design requires considerable sub-cooling, so that the gas remains in the liquid phase for the entire journey.  For this reason, there has been no attempt to ship LH2 by rail, due to relatively uncertain transit times.

<u>Fuel consumption in the delivery</u>

6 miles per gallon is the average fuel consumption of a diesel fuel tractor operating at a combined city/highway average speed of 30 miles per hour.

<u>Loading/unloading time and associated leakages</u>

It takes about 6 hours to fill a tube trailer at the hydrogen supply terminal.  At the customer location or station, it takes about 1.5 hours for a full tube trailer to be dropped off, and the empty trailer to be hooked up and removed.  Gas losses during these operations are about 3 percent.  For liquid hydrogen trailers, the process of drop off and filling at the terminal typically takes between 4 and 5 hours.  Unloading the trailer at each customer location or station takes 3 to 4 hours.

<u>Boil-off loss during the shipping in case of liquid hydrogen</u>

Losses occur when liquid hydrogen is introduced to warm components, such as transfer hoses and piping. There are significant losses when the trailer is being filled at the liquid hydrogen plant, and again when the trailer is being unloaded at each customer location or station. Depending on the number of drop-offs, losses vary from 6 percent to 10 percent.

<u>Energy consumption and emissions in the liquefaction and hydrogen compression processes</u>

The power requirement for liquefaction is in the range 15 to 17.5 kWh/kg. The compression of hydrogen from 300 psig to 1000 psig (20.69 to 69 bars g) requires 0.3 kWh/lb (0.66 kWh/kg). Vents at hydrogen liquefaction and compression plants are always routed to a flare, so the only emission is water vapor.

<u>Emissions in truck delivery</u>

Liquid hydrogen is sub-cooled before it is loaded into the trailer in order to avoid vapor losses during shipment. Normally, the only emission is the diesel exhaust products from the tractor.

<u>Tank materials, capital costs, travel time, maintenance and other O&M requirements</u> .

The material of trailer tubes is carbon steel with metallurgy specifically adapted for high pressure hydrogen environment. The design is regulated by the Department of Transport, which allows significantly lower wall thickness than would be required for stationary hydrogen vessels designed to the pressure vessel code. However, the DOT regulations also require that vehicle tube trailers have to be re-tested periodically.

### 1.4.2 Issues Related to Compressed and Liquid Hydrogen Delivery by Truck and Rail

The primary issue affecting truck delivery of liquid hydrogen and especially compressed hydrogen is the high ratio of truck fuel consumption energy relative to the delivered hydrogen energy. This ratio is more favorable for delivery by rail, but railroad delivery of hydrogen is impractical for most central plant and distributed station scenarios. On the other hand, liquid hydrogen delivery can provide auxiliary benefits in many situations. These three issues are discussed in more detail in the following.

#### *1.4.2.1 Truck Delivery of Compressed and Liquid Hydrogen*

Truck delivery of gasoline and diesel fuel from refineries or storage terminals to fueling stations is well established. However, the relatively low gravimetric and volumetric energy density of all hydrogen storage modes makes analogous truck delivery of hydrogen problematic.

Saturated liquid hydrogen at 10 psig (0.69 bar g)), which is a representative cryogenic tank truck condition, contains about 25 percent as much energy, on a lower heating value basis, as an equivalent volume of gasoline. A given volume of hydrogen compressed to 2,700 psi (186.2 bars), which is a representative tube trailer condition, contains roughly 6 percent as much energy as the same volume of gasoline.

On a mass basis, trucks, which are limited to 80,000 pounds (36,400 kg) gross weight in the U.S., can deliver substantially less compressed or liquid hydrogen compared to gasoline tank truck deliveries. The substantial weight of steel pressure vessel tubes combined with the low density of compressed hydrogen result in a payload-to-gross-weight ratio of hydrogen tube trailer trucks that is usually less than 1 percent; this compares to 70 percent or more for gasoline tank trucks. However, as discussed below in Section 2.4.3, DOT exemptions permitting composite pressure vessel tubes, and possibly higher pressures, may improve this ratio.

Liquid hydrogen tank trailers are usually affected by volume and center-of-gravity issues so that their gross weight is less than the 80,000 pound limit. Additionally, their double-wall vacuum-jacketed construction makes the empty trailer much heavier than gasoline tank trailers. As a result, their payload-to-gross-weight ratio is usually about 10 percent.

Many additional factors affect the hydrogen payload that can be delivered by trucks to fueling stations. For tube trailers, the minimum pressure to which the tubes can be emptied is an important factor. This usually depends on the pressure ratio capability of the compressor at the station, the selection of which involves an economic tradeoff. Many smaller factors affect the deliverable payload for liquid hydrogen tank trucks. These include the following: 1) the ullage space that must be maintained when filling the trailer tank to ensure the tank does not become 'liquid full' as the saturation pressure increases; 2) the tank pressure rating and pressure-relief setting, which affect the time-to-vent; 3) the tank heat leak characteristics, which affect the evaporation rate during venting as well as the time-to vent; 4) vapor losses when the liquid hydrogen is transferred to the station tank; 5) the need to maintain a small quantity of liquid in the tank to keep it cold during the return trip; and 6) the fact that hydrogen vapor remains in the tank when it is empty of liquid. The last effect is significant, as a liquid hydrogen tank which is completely empty of liquid contains roughly 25 percent as much hydrogen, in the form of saturated vapor, as a full hydrogen tube trailer.

Figure 1-28 shows the ratio of the diesel fuel energy consumption to the delivered hydrogen energy, as a function of delivery distance, for current typical hydrogen tube trailers and cryogenic tank trucks. The key assumptions relative to delivered energy and truck fuel consumption are indicated in the graph. These result from reasonable assumptions regarding all the capacities and factors mentioned in the prior paragraph. These assumptions, and the results shown in Figure 1-28, are very similar to those in the H2A studies and other analyses.[13]

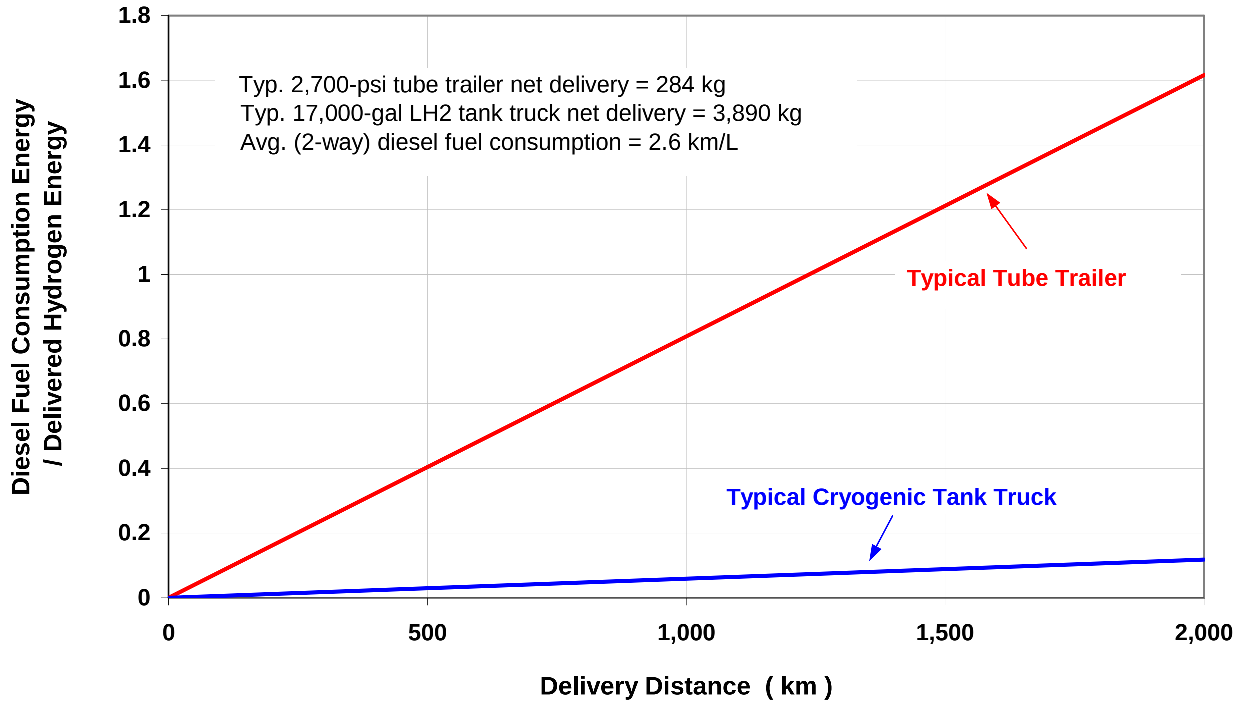



Figure 1-28 Diesel fuel consumption energy relative to delivered hydrogen energy for different tube trailer and cryogenic tank truck delivery distances.

As shown in the figure, more than 20 percent of the hydrogen energy delivered by tube trailers is consumed by a diesel-fueled truck for delivery distances greater than about 185 miles (200 km). The consumed-to-delivered energy ratio is not nearly as high for liquid hydrogen tank trucks, but it is still much higher than for gasoline or diesel fuel tank trucks. If the trucks were hydrogen fuel cell powered, the results would be more favorable, but they would depend on specifics such as the engine efficiency and weight ratios. Future tube trailer and cryogenic tank truck technology improvements and regulatory changes may also increase the quantity of deliverable hydrogen, but it is unlikely that truck delivery of hydrogen will ever be anywhere near as economical as truck delivery of gasoline and diesel fuel.

#### *1.4.2.2 Rail Delivery of Liquid Hydrogen*

The delivered-to-consumed energy ratio is more favorable for liquid hydrogen rail cars than for highway tank trucks, primarily because rail car tank capacity (up to approximately 9,000 kg [14]) is much larger, and railroads are more efficient than highway trucks in terms of payload relative to fuel consumption. However, the primary issue associated with hydrogen delivery by rail is that railroads connecting likely hydrogen production plants with fueling stations do not now exist, and, in nearly all cases, new rail lines would be impractical and uneconomical to install. Secondary issues include venting and vapor loss if current railroad logistics procedures were employed.

#### 1.4.2.3 Auxiliary Benefits of a Liquid Hydrogen Delivery Infrastructure

Liquid hydrogen delivered by truck from central production plants to fueling stations is highly appropriate in one specific situation, and provides certain benefits in more general circumstances. These benefits are summarized below:

- Liquid hydrogen delivery is the appropriate infrastructure strategy for stations that refuel liquid hydrogen vehicles. Liquefaction at fueling stations is certain to be uneconomical unless there is an unforeseen and substantial reduction in the cost of small-capacity hydrogen liquefiers. One manufacturer, BMW, has announced plans to commercialize hydrogen vehicles with liquid hydrogen fuel tanks.[15]
- Liquid hydrogen storage at stations that dispense compressed hydrogen can substantially reduce station capital and operating costs because liquid hydrogen pumps are less expensive, both in terms of initial cost and power consumption, than gas compressors. However, for extremely low-throughput stations (e.g., to support demonstration of a few hydrogen vehicles), stations with liquid storage often use vaporize-compress systems, as opposed to the more efficient pump-vaporize systems, to better manage vapor losses from infrequent station use.
- Use of liquid storage vessels and pumps can eliminate the need for expensive high-pressure vessel cascade systems. It is usually most economical to size the pump to accommodate the peak fueling rate requirement, which allows a small buffer vessel to replace a much larger cascade system. The economic benefits are especially significant for 70 MPa (10,000 psi or roughly 700 bars) refueling. For many stations with very high throughput requirements, CNG experience has shown that it is more practical to use a "direct fast-fill" system, where the compressor is sized to accommodate the peak demand and the storage cascade is replaced by a small buffer.[16] This will also be the case for high-throughput compressed hydrogen fueling stations, and liquid pumps will be even more economical relative to the large-capacity compressors needed for these situations.
- For 70 MPa (10,000 psi or roughly 700 bars) fueling, a test program supporting the SAE J2601 hydrogen fueling protocol has demonstrated that, due to heat-of-compression effects, precooling will be required to achieve full fills unless fueling times are order-of-magnitude longer than gasoline vehicle refueling times, or fuel tank over-pressure and over-temperature limits are increased beyond currently accepted compressed natural gas standards.[17] These tests showed that initial hydrogen temperatures of -20 °C (-4 °F) or less will probably be required, and expensive refrigeration systems will be required. For stations with liquid hydrogen delivery and storage, relatively inexpensive heat exchangers, mixers, or vaporizer controllers will suffice.

### 1.4.3 New Technology for Improving Efficiency, Cost, and Reliability of These Transport Modes

The challenges of economic delivery of gases by truck or rail have been faced by industrial gas companies for many decades. Therefore, it is unlikely there are any overlooked technologies that can abruptly improve the efficiency, cost, or reliability of these transportation modes. However, there is considerable current research, some of which is directed at other applications, that may enable incremental improvements. Also, widespread use of hydrogen as a transportation fuel would substantially increase hydrogen demand, and this new paradigm may make certain technologies more economical or efficient than they would be under current circumstances.

Potential improvements to compressed and liquid hydrogen truck and rail transportation are discussed below. Technologies that might increase hydrogen liquefaction efficiency or decrease costs are also discussed. Fundamentally different hydrogen carrier technologies (e.g., hydrides) that might eventually be adopted to truck or rail transportation are discussed in Section 2.6.

#### *1.4.3.1 Composite Pressure Vessels*

Substantial progress has been made in the last few decades to develop composite pressure vessels, which are significantly lighter than steel vessels with equivalent pressure ratings. Composite vessels consist of a metal or polymer shell ("liner"), overwrapped with high-strength glass or carbon fibers. These vessels are currently used in compressed natural gas and hydrogen vehicle fuel tanks. A number of manufacturers are testing hydrogen vehicle composite fuel tanks rated at 70 MPa (10,000 psi or roughly 700 bars).

Composite containers are available in relatively small sizes for vehicle fuel application, both hydrogen and compressed natural gas. The leading manufacturer is Lincoln Composites, who have built over 55,000 composite tanks to date. These small tanks have been installed on trailers to take advantage of low weight. A composite trailer for hydrogen transportation carries approximately 228 vertically mounted 44 gal. capacity steel composite cylinders. Greater savings in weight would be possible if larger capacity composite vessels become available.

Title 49 of the U.S. Code of Federal Regulations (CFR) requires tube trailer pressure vessels to be fabricated consistent with Department of Transportation (DOT) specifications 3AX or 3AAX, which apply only to steel. However, DOT has granted exemptions that permit the use of non-DOT, fully wrapped, carbon fiber reinforced aluminum cylinders in tube trailers, subject to the limitations defined in the exemption.[18] Composite pressure vessels obviously provide the potential for higher capacity, and/or lighter weight, hydrogen tube trailers. However, this improvement is not anticipated to be adequate for tube trailers to become a cost effective mode for delivering hydrogen.

Composite pressure vessel manufacturers include Lincoln Composites, Dynetek, Harsco SCI Composites, and Quantum.

#### *1.4.3.2 "Cryogas" Tube Trailers*

A technology being developed by Lawrence Livermore National Laboratory (LLNL) with DOE sponsorship involves storing hydrogen at high pressures and low temperatures in insulated pressure vessels. This strategy is to store hydrogen as a cryogenic gas, but not as a liquid, which will be discussed subsequently). LLNL has been developing this "cryogas" technology primarily for on-vehicle hydrogen storage, but they have also conceptualized transporting hydrogen at approximately 25 MPa (3,600 psi or roughly 250 bars) and 80°K (-315 °F) in insulated pressure vessel tube trailers.[19] This obviously results in a density higher than room temperature gas at the same pressure, but the density is not as high as that of a saturated liquid. It remains to be demonstrated if this technology provides economic advantages over conventional hydrogen tube trailers and cryogenic tank trucks.

#### *1.4.3.3 Liquid Hydrogen Tank Truck Trailers and Tank Cars*

As discussed in Section 2.4.1, liquid hydrogen is routinely transported in cryogenic tank truck trailers with capacities up to approximately 15,000 gross gallons (approximately 3,600 kg), depending on the saturation pressure and hullage volume. Cryogenic tank trailer design and manufacturing tradeoffs that involve capacity, weight, hold time, evaporation rate, and cost are well established. Liquid hydrogen tank trailers are typically constructed using stainless steel inner and outer tanks, with multi-layer insulation in the vacuum jacket. Certain design requirements and filling parameters are specified in CFR Title 49 (DOT).[20]

These cryogenic tank trailer design tradeoffs have been fully exploited by manufacturers such as Chart and Russell Engineering Works. There is no combination that will provide significantly lower cost with higher capacity or longer hold time. Costs will be somewhat lower if manufacturing volumes increase substantially, although cryogenic tank trailer costs are highly dependent on the price of steel.

No new design or manufacturing technologies with the potential for substantial liquid hydrogen tank trailer cost reduction or performance improvement have been identified. Exceptions might include different hydrogen storage technologies, such as the previously discussed cryogas strategy, or the absorbed and adsorbed technologies discussed in Section 2.6.

The situation for liquid hydrogen railroad tank cars is similar to that for liquid hydrogen tank truck trailers with respect to cost reductions or performance improvements. Liquid hydrogen railroad tank cars are manufactured in extremely small quantities, and certain of their design and performance requirements are specified in CFR Title 49 (DOT).

#### *1.4.3.4 Hydrogen Liquefaction — Existing Technology*

Available design options can lower the capital cost, or improve the efficiency, of liquefaction plants, but it is unlikely that both goals can be achieved simultaneously using current technology. New liquefier concepts are in the development stage, but this technology will probably not impact liquefaction plant designs in the near term, and the long-term potential of these technologies are uncertain. The following discussion briefly reviews current liquefier technology options and potential improvements using new technologies.

Because of its low boiling temperature and other properties, hydrogen is a very difficult gas to liquefy. To condense ambient temperature and pressure hydrogen gas, approximately 4,300 kJ/kg must be removed, and its temperature must be reduced to 20 °K (-423 °F). Moreover, to avoid abrupt boiling loss in the liquid hydrogen storage tank, ortho hydrogen must be converted to para hydrogen, and this requires an additional 500 kJ/kg. Because the Joule-Thomson (J-T) coefficient is negative above its inversion temperature (about 200 °K, or -100 °F at atmospheric pressure), hydrogen liquefiers require some form of precooling, via heat exchange with colder fluid and/or isentropic expansion, before cooling by simple throttling is possible. Final cooling and liquefaction is almost always accomplished via J-T throttling because most expansion devices (e.g., turboexpanders) are incompatible with two-phase flow.

In spite of these challenges, hydrogen is routinely liquefied using a variety of cycles. Figure 1-29 illustrates a relatively simple precoded J-T cycle. This and other liquefaction cycles are described in detail in cryogenics textbooks.[21] The cycle shown uses a nitrogen refrigerator to precool the compressed hydrogen stream. A fraction of this cooled gas condenses to liquid as it is expanded through the J-T valve. The uncondensed gas is returned to the compressor after it receives heat from, and thereby further cools, the precooled gas flowing to the J-T valve. The compressed and precooled gas is typically processed through ortho-para conversion reactors, one of which is illustrated in the diagram.

More efficient liquefaction cycles typically include more stages of turboexpansion and heat exchange, which minimize thermodynamic irreversibilities. Of course, these more complex cycles are more expensive, and this illustrates the fundamental tradeoff:

| | | |
|---|---|---|
| Low capital cost and low efficiency (i.e., high operating cost) | vs. | High capital cost and high efficiency (i.e., low operating cost) |

The liquefier efficiency is often characterized as the input work required to produce a unit mass of liquid. The resultant units are energy per unit mass, e.g., kJ/kg. The "ideal" work (i.e., zero thermodynamic irreversibilities) required to liquefy hydrogen from ambient conditions, including ortho-to-para conversion, is approximately 14,000 kJ/kg.

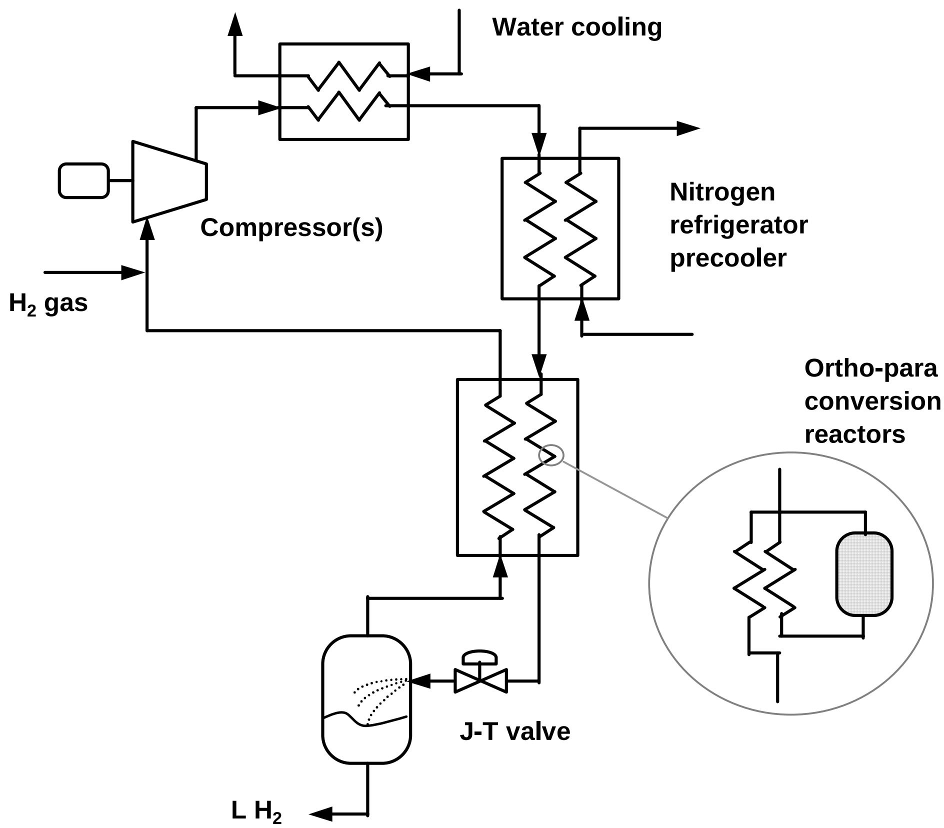



Figure 1-29 Simplified, pre-cooled Joule-Thomson cycle for hydrogen liquefaction

A frequently cited survey estimates that a highly efficient liquefaction plant might have a work requirement as low as about 35,000 kJ/kg, or roughly 2.5 times the ideal work requirement.[22] This is about 29 percent of the lower heating value. Liquefaction is often cited as requiring 35 to 40 percent of the lower heating value, and so this illustrates the magnitude of improvement that might be anticipated using the most efficient current technology.[23]

As previously emphasized, more efficient hydrogen liquefaction plants with lower operating costs have higher capital costs, and visa versa. Economy of scale considerations would suggest that large plants should be designed with more complex cycles to realize the life cycle cost benefits of higher efficiency. However, capital investment risk issues are also important, and so the tradeoff is often biased toward minimizing initial capital cost in spite of higher life cycle costs.

### *1.4.3.5 Hydrogen Liquefaction — Developmental Technologies*

Table 1-20 lists some examples of developmental liquefaction technologies and concepts that have some potential for reducing liquefier capital and/or operating costs. These technologies, all of which are currently in the R&D or conceptual stage, are briefly reviewed here, with emphasis on their prospects for impacting a future hydrogen infrastructure. Cited references provide more technical details regarding the operating principles of each technology.

The DOE-sponsored Gas Equipment Engineering Corporation project, summarized in the first row of Table 1-20, is demonstrating a 200-500 kg/day liquefaction pilot plant that employs a combined reverse Brayton and J-T cycle.[24] This cycle is basically the same as what is generally referred to as the Claude cycle, and therefore it could be regarded as an application of previously discussed current technology. Stages of isentropic expansion eliminate the need for the nitrogen refrigerator precooler, as shown in Figure 1-29. This project will utilize special gas bearing turboexpander-compressor units, which should enhance overall plant efficiency because some of the compression power is provided by the turboexpanders.

Magnetocaloric liquefiers utilize the temperature change associated with isentropic demagnetization of ferromagnetic materials near their Curie point temperatures to provide the needed refrigeration. As indicated in the second row of Table 1-20, DOE is sponsoring a New Concepts Research Corporation and Prometheus Energy Company project to develop a hydrogen liquefier based on this principle.[25] Their concept uses six active magnetic regenerative (AMR) refrigeration stages to cool and liquefy hydrogen, including ortho-para conversion. The design employs a conduction-cooled superconductivity magnet and pressurized helium to transfer heat from the hydrogen to the AMR refrigerators. This project's initial objectives are to build and demonstrate one AMR stage and to design a 10-20 kg/day six-stage AMR hydrogen liquefier. The stated goal is 25 to 35 percent electrical efficiency, which corresponds to approximately 16 to 12 percent of the hydrogen lower heating value.

Table 1-20
Developmental Hydrogen Liquefaction Technologies

| Advanced Hydrogen Liquefaction Concept | Operating Principle Summary | Potential Benefits Summary | Status | Remarks |
|---|---|---|---|---|
| Combined Reverse Brayton J-T Hydrogen Liquefaction Cycle | Cycle employs two (isentropic expansion) turboexpanders prior to (isenthalpic expansion) J-T valve. | Dual turboexpander-compressors reduce compression power requirement. Need for nitrogen refrigerator precooling is eliminated. | DOE HFCIT sponsoring development program (Gas Equip. Engr. Corp., R&D Dynamics, AMCRS)[8]. 200-500 kg/day pilot plant to be demonstrated. | Basically a Claude liquefaction cycle, but uses novel R&D Dynamics gas bearing turboexpander-compressors. |
| Active Magnetic Regenerative (AMR) Hydrogen Liquefier | Applies magneto caloric refrigeration to liquefy hydrogen. $H_2$ gas is cooled through 6 AMR refrigeration stages. | More efficient and less expensive compared with conventional hydrogen liquefaction technologies. | DOE HFCIT sponsoring development program (New Concepts Research Corp. & Prometheus Energy Co.). One-stage AMR refrigerator being demonstrated; 6-stage AMR liquefier being | Complete liquefier will include superconductivity magnet subsystem, different magnetic refrigerant materials for each |

| | | | | |
|---|---|---|---|---|
| | | | designed. | stage, and He heat transfer fluid. |
| Pulse Tube Refrigerator Hydrogen Liquefier | Orifice pulse tube refrigerators (OPTRs) utilize a variation on the Stirling cycle, with a gas mass replacing the displacer and isothermal processes replacing the adiabatic compression and expansion. OPTRs may be powered by conventional compressors ot thermoacoustic drivers (TADs). | High operating efficiency and few or zero (for TAD-OPTR) moving parts. OPTR application for hydrogen liquefaction is theoretically possible. | Pulse tube refrigeration R&D projects are ongoing in many government, university, and company laboratories. A 370-gpd natural gas liquefier TAD-OPTR has been demonstrated. | No large-scale hydrogen liquefier pulse tube refrigerator projects are known. |
| Integration of Hydrogen Production and Liquefaction with LNG Import Terminal | Colocate NG-to-hydrogen SMR and liquefier with LNG import terminal. Integrate hydrogen precooler with LNG vaporizer. | Substantially reduced operating cost and slightly reduced capital cost by using LNG vaporizer for hydrogen precooling. Minimum-cost SMR feedgas (no pipeline transportation). | Proposed concept. | Public popularity of hydrogen economy may benefit unpopular LNG import terminal project proposals. |

Since the pulse tube refrigerator (PTR) was first conceived in the 1960s, considerable research has been carried out at government, university, and private company laboratories to utilize this novel refrigeration principle for practical applications. The PTR cycle is similar to the Stirling cycle, except that a mass of gas (usually helium) replaces the displacer and the compression and expansion processes are more nearly isothermal than adiabatic. Advances to the basic PTR concept include the orifice pulse tube refrigerator (OPTR), which utilizes an orifice-restricted reservoir volume opposite the compressor, and application of a thermoacoustic driver (TAD) to replace the piston compressor. A potential advantage of the OPTR is that it has relatively few moving parts, and a TAD-OPTR can have essentially no moving parts. OPTRs have been studied for relatively large scale gas liquefaction. For example, Praxair, which acquired the rights from Chart Industries, worked with LANL and NIST to develop a 500 gal/day TAD-OPTR natural gas liquefier.[26] This project demonstrated a 370 gal/day production rate, but it was discontinued in 2004. NASA has researched OPTR applications for reliquefying hydrogen in “zero-boiloff” liquid hydrogen tankage systems for aerospace applications. While no large scale OPTR hydrogen liquefier development programs are known, this technology might provide benefits, such as lower operating costs, for a hydrogen infrastructure, and therefore it is listed in the table.

The last row summarizes a concept whereby a natural gas reformer and hydrogen liquefier might be co-located with a liquefied natural gas terminal. The main benefit would be hydrogen precooling for the liquefaction process provided by natural gas vaporization. As such, a substantial fraction of the hydrogen liquefaction energy would be provided “for free”. The principal liability is that it is only applicable to new land-based LNG terminals. This strategy is currently only a proposed concept, and no documented technical feasibility analyses are known.[27]

## 1.5 NATURAL GAS PIPELINES

### 1.5.1 Description of the Natural Gas System

To best assess the feasibility of using the existing natural gas system for hydrogen delivery, it is advantageous to understand how the natural gas system is designed to safely and reliably supply natural gas to customers. Proposed changes that seriously impede the gas companies’ ability to meet customer expectations (quality, quantity, and cost), or that increases safety or reliability risks, are not likely to be adopted. This study will briefly describe how the existing system meets those requirements currently and will highlight possible concerns and potential solutions to challenges related to using these facilities for hydrogen delivery.

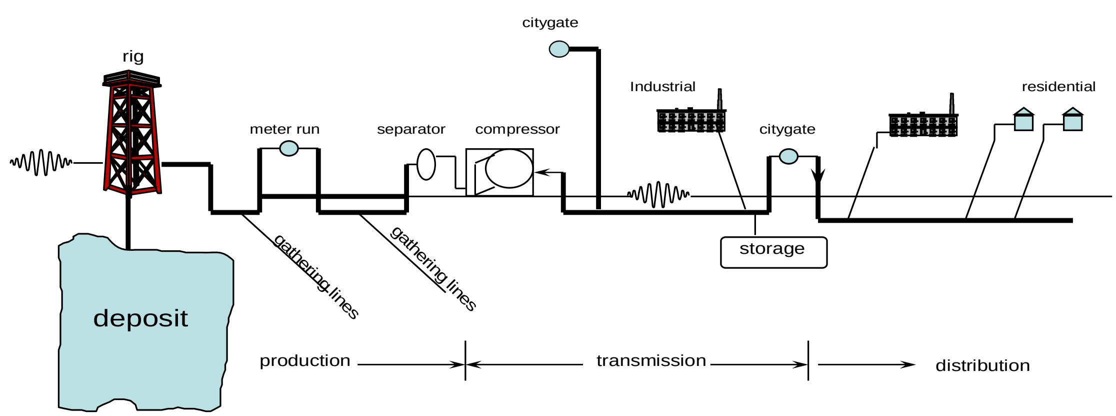



Figure 1-30 Natural Gas System

The existing natural pipeline network consists of five primary piping systems; gathering lines, transmission pipelines, feeder lines, and distribution mains and services. These piping systems are highly regulated and are designed to delivery gas of a relatively consistent quality, safely, reliably, and at a competitive price. Even with a common function, each system has some unique operating practices and regulatory requirements that generally involve a different group of operators (pipeline companies versus distribution utilities) with different skills for managing their respective systems. The distinct delineation between the three primary gas systems, transmission, feeder, and distribution, is "operating pressure". In this study, gathering line issues will not be examined, since the gas gathering system is somewhat removed from the expected site of the $H_2$ production plant. See Figure 1-30 for a graphical illustration and relation connection among the systems.

Transmission pipelines are used for moving large volumes of gas over long distances, and there are about 292,000 miles on-shore of these pipelines. The following table shows sizes of the pipelines in the U.S. These pipelines are owned by both transmission and distribution companies, but meet one of the Federal definitions of a transmission pipeline.

Table 1-21
US Natural Gas Transmission Line Characteristics
(DOT Transmission reports, 2004)

| Pipe diameter | Unknown | 4 in. | 6 to 10 in. | 12 to 20 in. | 21 to 28 in. | Over 28 in. |
|---|---|---|---|---|---|---|
| Length, miles | 93 | 20,726 | 65,292 | 89,242 | 46,674 | 69,686 |
| Percent of total | 0.03 | 7.1 | 22.4 | 30.6 | 16.0 | 23.9 |

Transmission line pressures are mostly between 500 psig (34.5 bars g) and 1,000 psig (69 bars g). All pipelines are made of steel but specifications vary. Many of the older pipes are API Grade B, with a specified minimum yield stress (SMYS) of 35,000 psi (2,415 bars), or API 5L X42 (42,000 psi or 2,897 bar SMYS). Some of the newer pipelines are made of higher strength steels which allow for a reduced wall thickness, which often relates to a lower cost. About 75 percent of all transmission lines have been in operation 30 years or longer. Most transmission lines are owned and operated by pipeline companies, but distribution companies operate about 45,000 miles of transmission pipeline. Most of the distribution-owned pipes are relatively small in diameter and many operate at pressures lower than 500 psig (34.48 bars g). Transmission lines will generally have four types of in-line facilities; compressors to raise gas pressure in order to move the gas, valves to provide a method for isolating sections of the pipe in case of damage or the need for maintenance, interconnects to inject or extract gas, or to blend gases from different pipelines, and launch and receiver fittings for cleaning and inspecting the pipe. Interconnects that supply gas to downstream customers along the pipe, are referred to as "gate stations" or "city gate" stations when feeding a distribution system. Other deliveries are made along the pipeline to industrial customers and even property owners (farm taps). At each commercial gate station, there will be measuring and regulation equipment and possibly other gas conditioning equipment to ensure the gas is delivered at an agreed upon quality and pressure. Gas can also be directed to storage. Pipeline companies do not odorize all gas in the transmission line, but if the pipeline is located in populated Class 3 or 4 locations, an odorant is added. Odorant may also be added at the city gate station.

Once the gas is taken from the transmission pipe, it is transported by "feeder" lines or inter-station pipelines that operate below transmission pressure, but higher than distribution pressure

(150 psig to 300 psig or 10.34 to 20.68 bars g)). These pipelines can often serve as main supply arteries to the distribution system or that loop a large demand area. Feeder lines are steel pipes and sizes are generally between 6 and 12 inches in diameter. These feeder lines can also have a number of delivery points along it. Some of the take points feed large communities or demand centers and are referred to as "district regulator stations". These stations generally have measuring and regulation facilities. If the feeder liner gas in not odorized, then odorant must be added before it goes into the distribution system.

The gas is fed from the feeder line or city gate station to the distribution system. Distribution system pressures can vary significantly, from as low as ¼ psig up to 125 psig (0.02 to 8.65 bars g), but most systems have a maximum allowable operating pressure of 60 psig (4.14 bars g). Pipe materials can vary as well, with most systems having cast iron, steel, and plastic (polyethylene) mains. Service pipes to individual customers are tapped into the mains, so they operate at the same pressure as the mains. Service pipe materials in most systems are steel, cast iron (larger service pipes), and plastic, but older systems could also have copper, and even PVC service pipes. When the distribution operating pressure is above the ¼ psig (0.02 bars g) utilization pressure, then a regulator, with a meter, is installed at the structure to reduce pressure and record the cumulative flow.

The pipes in all of the systems described above, must be designed to meet DOT regulations, and are operated and maintained in accordance with DOT and more stringent state and local codes. Steps are taken to maintain desired pressures in the respective systems, to prevent the unintended release of gas, and to ensure acceptable quality is maintained. With this basic understanding of how the existing natural gas network functions, there can be an assessment of the feasibility of using these pipes for hydrogen delivery without jeopardizing the reliability and safety of service to the public.

## 1.6 NOVEL SOLID AND LIQUID HYDROGEN CARRIER PROCESSES

### 1.6.1 Chemical Hydrides

In addition to storing and transporting hydrogen in a gaseous or liquid state, it is possible to carry hydrogen as part of a larger molecule – a chemical hydride. At the point of use, hydrogen can typically be liberated by reacting the chemical hydride material with water in an exothermic reaction. In general, the chemical hydrides are stored and transported either as a chemical solution or as slurry. Both of these mediums can be transported via truck and will be easy to pump on and off of a vehicle. In addition, hydrogen stored in chemical hydride slurry or solution can exceed the DOE goals for volumetric and gravimetric energy density, depending on their chemical composition, effective hydrogen yield, and mixture with water and carrier liquids..

In the case of widespread chemical hydride usage, chemical hydrides would likely be transported from a central processing plant to the forecourt by truck and then dispensed onto vehicles. Hydrogen would be liberated on-board and the spent slurry or solution would be returned to the forecourt during vehicle fueling. Spent slurry recovered at the forecourt would be returned to the processing facility where it would undergo a chemical reaction to produce the chemical hydride material.

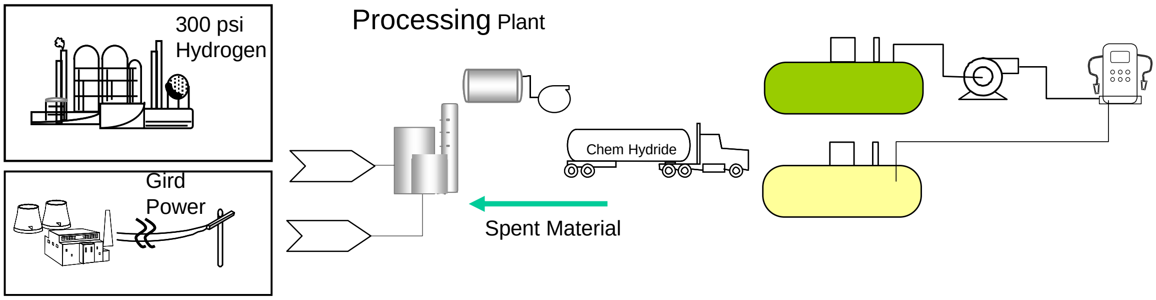



Figure 1-31 Chemical Hydride Processing and Delivery System

### 1.6.1.1 *Chemical Hydride Description*

A chemical hydride material is constructed of molecules containing hydrogen, from which molecular hydrogen can be liberated through a chemical process, typically in an exothermic reaction with water. A typical chemical hydride reaction:

$$ZH_2 + H_2O = ZO + 2H_2 + Heat$$

Electricity

*Where, Z refers to several possible cations or combination of elements.*

The exothermicity of this reaction is particularly beneficial as there isn't an energy requirement on board the vehicle. All of the energy intensive processes are undertaken at a central facility where endothermic reactions can take place more efficiently. Nevertheless, certain chemical hydrides must react over a catalyst at temperatures ranging from 200 to 400°C. These materials are sometimes referred to as irreversible hydrides because they cannot be regenerated on board the vehicle.

Reprocessing can involve a series of operations using a variety of energy inputs including natural gas, coal, hydrogen, or electric power. The simplest approach for reprocessing spent material is by electrolysis, which requires only electric power as an energy input.

The type of chemical hydride material affects the hydrogen yield, energy inputs, and overall storage and delivery cost. Ongoing chemical hydride development is discussed in the following section.

### 1.6.1.2 *Chemical Hydride Developers*

Several organizations are investigating chemical hydrides as materials for hydrogen storage and delivery. A summary of their efforts is included here.

<u>Chemical Hydride Center of Excellence</u>

In 2004 the U.S. Department of Energy created three Centers of Excellence to research methods of hydrogen storage. In the field of chemical hydrides two national labs, Pacific Northwest National Lab (PNNL) and Los Alamos National Lab, were selected to be the DOE Center of Excellence. At present these two labs are focusing on a number of different topics, including the development of tools for evaluating thermodynamic pathways for hydride generation/regeneration, kinetics, and system designs, as well research into kinetics control, catalysis, and promising hydrides such as boranes.[28]

Millennium Cell

Millennium Cell, a publicly held company, has developed a sodium borohydride ($NaBH_4$) system for providing hydrogen on-board the vehicle. This system has been installed on prototype vehicles including Daimler Chrylser's Natrium. They are also working with the Center of Excellence to assess alternative hydride materials as well as developing reprocessing systems for chemical hydrides.

The primary chemical hydride reaction in the Millenium Cell system is shown below:

$$NaBH_4 + 2H_2O = NaBO_2 + 4H_2$$

The reaction occurs over a nickel based catalyst at 400 °C. Once at temperature the reaction is exothermic and will remain at temperature.[29]

Before hydrogen liberation the chemical hydride material, $NaBH_4$, is stored in an aqueous solution. In this form, hydrogen is released over time depending upon the temperature, water content, and pH of the solution. Sodium hydroxide is added to the solution to stabilize the mixture, reducing the rate of hydrogen release during storage.

In addition to the high temperature and catalysts required for reaction, problems can also arise from the tendency of the hydride material and the spent material, $NaBO_2$, to form a solid precipitate. The precipitate can plug the fuel delivery system and prevent pumping of the material. The formation of the precipitate depends on the temperature and water content of the solution, with increased water and temperature suppressing the formation of the precipitate.

This mixture creates a stable solution suitable for storage, except under extreme temperature conditions. In these cases an electric heater could be used to warm the solution to minimize the risk of precipitation.

The regeneration of the chemical hydride is an energy intensive process, dominating the energy inputs that determine the well-to-wheels efficiency of using a sodium borohydride as a hydrogen carrier. A key step in that regeneration process is making elemental sodium that will then be converted to sodium hydride and later sodium borohydride. It has been determined that producing sodium from NaOH instead of NaCl results in significantly lower energy consumption and improved efficiency. The hydrogen assisted electrolysis reaction shown below occurs at 350 °C. According to Millenium Cell, the overall electrolysis reaction is as follows:

$$NaOH + \frac{1}{2} H_2 = Na + H_2O$$

The theoretical minimum energy requirement for this reaction is 1.25 kWh/kg Na. In laboratory tests, Millenium Cell has obtained an overall reaction efficiency of 66 percent and believes that the potential exists to be 80 percent efficient in this process. At present the total electricity consumption required to process enough material to liberate one kilogram of hydrogen is upwards of 18.4 kWh.[30]

In an effort to reduce energy consumption, several reprocessing schemes have been considered for $NaBH_4$.

A detailed description of the sodium borohydride process is included in Millennium Cell's reports to DOE.

Safe Hydrogen

Safe Hydrogen, a private company, is developing a process involving a magnesium-hydride that is transported in an oil slurry. Liberating the hydrogen from the magnesium slurry requires a reaction with water and will be performed using a solid oxide membrane (SOM) process. The SOM approach requires that water be provided in a separate tank or recovered from the fuel cell cathode on the vehicle (which is not considered attractive by automakers).[31] The primary reaction is shown below:

$$MgH_2 + 2H_2O = Mg(OH)_2 + 2H_2$$

The key energy intensive step in the regeneration of Mg from the $Mg(OH)_2$ formed during $MgH_2$ hydrolysis in the hydrogen assisted electrolysis of MgO, as shown in the reaction below:

$$MgO + H_2 = Mg + H_2O$$

Based on laboratory experiments performed at Boston University the total electricity consumption for this reaction is approximately 6.7 kWh/kg Mg. When evaluated in the overall fuel chain, this leads to an electrical consumption of 40 kWh/kg $H_2$. The actual consumption will be greater if the other steps are included.[32]

#### *1.6.1.3 Chemical Hydride Performance Parameters*

The performance of a chemical hydride system will depend on the materials and reaction steps involved. At this time, developers are investigating materials with the goal of reducing the reprocessing energy input and developing a reliable system for on-board storage. A successful chemical hydride system will differ from the approaches that are in use today.

Section 2.6.8, Truck Transport, shows the hydrogen release and storage parameters for chemical hydrides that are under development as well as those for a generic system. The hydrogen bound in the hydride, as well as the hydrogen released (yield) are shown for the different options. The hydrogen yield from the hydride solution corresponds to the mass of hydrogen released from the reaction divided by the hydride/solution mass fraction. The yield of the chemical hydrides in solution is typically less than 10 percent. The hydrogen yield can be used to estimate truck transport as well as fuel storage requirements.

Accounting for the water used in the hydride reaction is an important step in the analysis. In the case of $NaBH_4$, sufficient water for the dehydrogenation reaction is available in the solution. A small amount of water may need to be recovered on board the vehicle to guard against precipitate formation under some load conditions. The requirements for shipping the spent material are about the same as those for the fresh solution.

In the case of $MgH_2$, the solution is transported without water. The water is added on-board the vehicle and the resultant spent material is significantly heavier then the fresh material. Consequently, the supply of water to the forecourt and return of the spent material need to be factored into the delivery analysis for chemical hydride options, which are not transported in water solution.

#### *1.6.1.4 System Requirements*

To keep the analysis more straightforward, the generic chemical hydride is based on reprocessing spent material with 1 kg hydrogen per kg hydrogen yield. Reprocessing is assumed with an electrolysis process. The material is transported in an aqueous solution and spent material is returned with the delivery truck. The forecourt station is configured with 6 dual hose dispensers. The dispenser system includes pumps for fresh and spent material. Tankage at the forecourt has sufficient capacity for both fresh and spent material.

Preliminary capital and operating costs are shown in Table 1-22. It is possible for the total capital cost of the material to differ up to an order of magnitude, depending on the $H_2$ capacity of the material in the slurry/solution and the cost of that material.

The primary operating cost will be the electricity required for the regeneration process. The amount of energy required for these processes is very dependent upon the chemical hydride being used. In the case of the Safe Hydrogen system, 60 kWh of electricity input is required per kg of hydrogen. No other energy inputs are required. For sodium borohydride, various reprocessing schemes have been studied. The electricity input varies from only electric power to 18 kWh of electric power plus one kg of hydrogen required for every kg of hydrogen bound in the sodium borohydride.

The source and cost of the electric power has a significant impact on the cost of the overall system. The cost of electric power depends on the capacity factor of the generation system, feedstock costs, transmission, and other factors. Chemical hydride developers argue that reprocessing plants will require the output of a dedicated power plant. The costs associated with maintaining grid reliability and peak generation capacity would not be a burden to a power plant serving a chemical hydride system. If a large fraction of automobiles in the U.S. were fueled on hydrogen that was based on electrolysis reprocessing many new power plants would need to be built and the resource mix and cost of power would not reflect the average U.S. mix.

The assumption on electric power mix depends on the scenario for chemical hydride based hydrogen. If all vehicles operated on hydrogen with chemical hydride storage, then a new power resource mix would certainly need to be considered. In the near term, the issue of power resources is less certain.

Table 1-22
Cost and Energy Inputs for Chemical Hydride System

| Energy Carrier | Installed Capital Cost ($) | Operating Cost ($/kg) | Energy Consumption |
|---|---|---|---|
| Reprocessing Plant (330 tons/day) | 181,000,000 | | |
| Tanks | 5,000,000 | | |
| Solvent Separation | 11,000,000 | | |
| Heat Transfer Equipment | 40,000,000 | | |
| Hydriding Equipment | 100,000,000 | | |
| Reduction Equipment | 25,000,000 | | |
| Hydrogen (kg,input/kg,liberated) | | | 1 |
| Electricity (kWh/kg) | | | 18 |
| Delivery Truck (80,000lb) GVW | 180,000 | | |
| Tractor | 100,000 | | |
| Trailer | 80,000 | | |
| Fuel Cost ($/kg) | | 0.021 | |
| Diesel Consumption (L/kg) | | | 0.05 |
| Forecourt Station (2000 kg/day) | 568,000 | | |
| Compressor | 50,000 | | |
| Pumps and Dispenser | 80,000 | | |
| Storage tanks | 100,000 | | |
| Site work | 256,000 | | |
| Fuel First Charge | 82,200 | | |
| Utilities ($/kg) | | 0.0 | |
| O&M ($/kg) | | 0.238 | |
| Variable O&M ($/kg) | | 0.0002 | |

Cost information based on initial discussions with chemical hydride developers. Power consumption for a generic formulation that requires 1 kg hydrogen input per kg hydrogen yield. Balance of energy input for reprocessing plant is electric power.

### 1.6.2 Bricks

Hydrogen may be stored and transported in "bricks," which are individual containers storing metal hydride or activated carbon structures. Each brick is sized for the average hydrogen load of a single vehicle. Refueling a vehicle will entail removing a spent brick and replacing it with a charged brick (it is possible to have multiple smaller bricks onboard each vehicle). The spent brick will be returned to the plant for processing. By storing the carrier material in individual containers, transportation and refueling are potentially easier and safer than pumping/moving activated carrier materials between transportation, storage, and vehicle. The bricks will likely be transported via truck between the forecourt and the central plant using specially designed cargo containers that can quickly move large numbers of bricks on and off truck trailers. A schematic of the delivery system is shown in Figure 1-32.

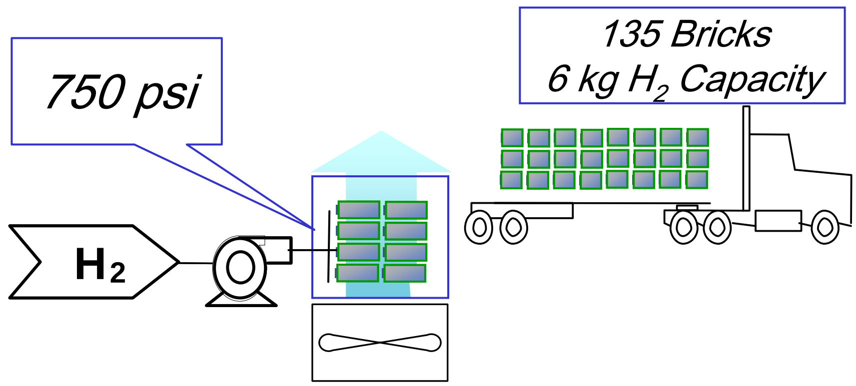



Figure 1-32 Hydrogen Brick Delivery System

#### 1.6.2.1 Description

Storage performance of bricks is based on the amount of hydrogen that can be stored in the material (by way of surface adsorption) and the fraction of that hydrogen that can be released in a timely fashion given pressure/temperature desorption characteristics.

The process of fueling a car with a brick of hydrogen storage material will consist of loading a charged brick and removing a spent brick from the vehicle. It is likely that the mass of the bricks will be close to 100 kg, necessitating the development of a mechanical device that will perform the loading/unloading task.

Complex trailers and forecourt storage tanks will not be necessary when transporting hydrogen in bricks, as the materials will all be sufficiently contained by the individual containers. As shown in Table 1-23, the size of a generic brick is based on a total hydrogen mass of 5.5 kg, a carrier storage capability of 6 percent hydrogen by weight (DOE goal), and an aluminum container with a wall thickness of 0.5 cm.

Once the brick is onboard the vehicle, the hydrogen will have to be removed from the carrier material. Depending on the type of carrier selected, this process will may require increasing the temperature of the carrier material and/or providing some heat of reaction to the system. No matter the material, the design of the container will have to facilitate the process of liberating hydrogen from the carrier material. The design may likely include some type of internal heat exchange mechanism.

While a variety of materials can be used in the manufacture of hydrogen-storing bricks, a generic case is being used to evaluate the potential performance and cost of transporting hydrogen in bricks. The generic case is based on the following parameters:

Table 1-23
Brick Parameters

| | |
|---|---|
| $H_2$ Contained (kg) | 5.5 |
| Carrier Capacity (weight percent) | 6.00 |

| | |
|---|---|
| Density of Carrier Material ($kg/m^3$) | 3,000 |
| Mass of Carrier Material (kg) | 91.7 |
| Volume ($m^3$) | 0.031 |
| Length of Cube (m) | 0.313 |
| Surface Area ($m^2$) | 0.586 |
| Box Thickness (m) | 0.005 |
| Box Material ($m^3$) | 0.003 |
| Mass of Aluminum (kg) | 7.92 |
| Actual Capacity (weight percent) | 5.52 |
| Actual Density ($kg/m^3$) | 2,965 |
| Total Mass (kg) | 99.58 |

#### *1.6.2.2 Materials and Developers*

There are a few different types of hydrogen carrier materials that can be stored in bricks. Certain factors that will be particularly important when determining what type of material will be ideal for use in a brick-type storage system.

- Hydrogen Storage Capacity (weight percent) – This will determine the mass of the carrier material in the brick
- Material Density – This will determine the volume of the carrier material in the brick
- Energy/Reactants Required for H2 Removal – This is a particular concern as all the energy or reactants must be provided onboard the vehicle and large transfers will likely add complexity to the brick container

<u>Metal Hydride</u>

Metal hydrides will adsorb and desorb hydrogen onto the material surface depending on the temperature and pressure of the hydrogen in the system. Metal hydrides are quite dense and do not require significant reprocessing with each cycle, as there is no chemical shift in composition with hydriding/dehydriding. Metal hydrides generally have poor hydrogen capacity (rarely more than 2 percent by weight) and the energy required to desorb the hydrogen can be significant.

The DOE Metal Hydride Center of Excellence is coordinated by Sandia National Laboratories and involves 16 other government, industry, and university partners.

<u>Activated Carbon Structures</u>

Recent efforts have focused on the use of carbon nanostructures to store hydrogen. While it has been reported that hydrogen yields approaching the 6 percent DOE goal have been achieved, these experiments were conducted at cryogenic temperatures and elevated pressure. If progress can be made and the DOE target can be met at conditions that are closer to ambient, the carbon structures may be applicable for brick-type fueling.

The DOE Carbon-Based Hydrogen Storage Center of Excellence is coordinated by National Renewable Energy Laboratory National Laboratories and involves 11 other government, industry, and university partners.

#### *1.6.2.3 Equipment Description*

<u>Bricks</u>

The container for the storage material will likely be the most complex piece of storage or transportation equipment. The containers must be light, non-corrosive, impenetrable to hydrogen, and capable of dealing with the pressures and temperatures associated with the hydriding/ dehydriding processes. It is highly likely that thermal energy will have to be supplied in order to liberate the hydrogen from the storage material. It will be necessary for the system to efficiently and effectively distribute thermal energy throughout the hydride material. For most storage materials, the vapor pressure of the hydrogen will be greater than ambient at most operating conditions, making the container a low-pressure vessel.

<u>Central Plant</u>

The requirements of the central plant will consist of a hydrogen supply, the equipment necessary to move the bricks through the plant, and the equipment necessary to hydride the spent bricks. The hydrogen supply can come from a variety of sources, any of which will be compatible with bricks. Once the bricks have been offloaded from the trailer, they will likely have to be hooked up to a hydrogen supply – which may be pressurized – so that the hydriding process can take place. Since the hydriding process is exothermic for most materials, it may be necessary to actively cool the bricks, as they will not be able to store as much hydrogen at elevated temperatures. It is possible that the cooling system could be as simple as a series of fans if the hydriding process is slow enough. Once the proper amount of hydrogen has been adsorbed to the brick material, it will need to be moved within the plant and reloaded into cargo containers or onto pallets so that they can then be easily loaded onto trucks and delivered to refueling stations.

<u>Transportation</u>

Trucks will likely be the primary method of transport for hydrogen carrying bricks. The equipment required for transportation of bricks is less complex than of many of the other potential hydrogen carriers, as the brick containers provide all of the sophisticated containment capability that is otherwise a part of the trailer. While hydrogen or liquid containment will not be a primary requirement of a brick trailer, it will be necessary to develop a system that will allow a large number of bricks to be quickly transferred on and off of the trailer. This system may resemble the rolling pallets and cargo boxes that are often used to easily and quickly move heavy loads on and off cargo planes.

<u>Forecourt</u>

As with the transportation equipment, it is likely that the forecourt equipment will be less sophisticated, as it is not explicitly charged with hydrogen storage, but is instead required only to move and store containers that themselves perform the task of hydrogen storage. The forecourt storage system will likely have to be developed in conjunction with the transportation system, so that rolling pallets or cargo containers (for example) can be easily maneuvered around both the trailer and the storage area at the forecourt. In addition to a dedicated storage area for bricks (both charged and spent), a mechanical system used to move bricks on and off individual vehicles is necessary.

#### *1.6.2.4 Capital Costs*

Capital costs will be primarily dependent on the cost of the carrier material in the brick. While a large number of expenses are involved in transporting hydrogen via brick, as shown in Table 1-24, the gross mass of the storage material will cause it to dominate the overall cost. The following table indicates that primary capital costs for each sector of the brick delivery process. The costs indicated below are for individual components, not for an entire distribution network. The total cost will depend on the size of the network and the proximity of the central plant to the forecourt.

Table 1-24
Capital Costs for Brick Concept

| Equipment | Description | Cost | Notes |
|---|---|---|---|
| ***Bricks*** | | | |
| Storage Material | Most likely a metal or carbon structure onto which hydrogen can be easily adsorbed and desorbed by varying temperature and pressure. | \$10-15/kg | 50-100 kg/brick |
| Container | The brick container will have to be light, impenetrable to H2, and able to stand the elevated temperature and pressure of hydriding/dehydriding. | \$85 | Total cost assumed to be 5*material cost (aluminum) |
| ***Central Plant*** | | | |
| Brick Transporter | Used to move bricks from the cargo containers to a location where the hydriding process will take place. | \$320,000 | Conveyor belt system ~\$80/ft. Assume 3*\$80/ft for specialized/outdoor system. 1000 ft. http://www.gilmorekramer.com |
| Hydrogen Supply | Hydrogen can be produced using whatever method is most effective at the given time and place. | | Cost will vary significantly based on the generation process utilized. |
| Hydrogen Compressor | This will be unnecessary if the hydrogen supply provides a significantly high hydrogen stream. | \$18,800,000 | H2A compressor: 165,000 kg/day, 5-40 atm. |
| Cooling System | The cooling system will be necessary for those materials that undergo a strongly exothermic process upon hydriding. | | |
| ***Transport*** | | | |
| Tractor | The standard tractor used in a tractor-trailer arrangement to haul heavy cargo over the roadways. | \$100,000 | |

| | | | |
|---|---|---|---|
| Trailer | Similar to a large flatbed or box truck but with the ability to easily load or unload a specific type of cargo container. | $40,000 | |
| Cargo Container/ Pallet | A large number of individual bricks will be stored together and will be able to be easily moved on and off the trailer at the central plant and the forecourt. | $10,000 | Two per truck. |
| ***Forecourt*** | | | |
| Storage | A dedicated area will have to be devoted to storing one or more of the cargo containers that will be delivered by the truck. | | Costs will be dependant on land costs at the given location. |
| Brick Transporter | A mechanical system will be necessary to move the 50-100kg bricks from the cargo containers to the vehicles. | $96,000 | Conveyor belt system ~$80/ft. Assume 4*$80/ft for specialized/outdoor system. 300ft. http://www.gilmorekramer.com |

#### *1.6.2.5 Energy Requirements*

When using bricks as a hydrogen transport mechanism, there will be numerous energy requirements. Within the central plant, energy will be required to move the bricks through the plant. For those materials that are strongly exothermic during hydriding, energy will required to actively cool the bricks, although this may be as simple as a series of fans, requiring minimal energy in relation to other requirements. In the case of materials that require high pressure hydrogen for hydriding, energy will be required to operate the compressor. This piece of the overall energy requirement could be significant. Electricity will be the energy carrier needed to supply these central plant energy requirements.

The source and cost of the electric power has a significant impact on the cost of the overall system. The cost of electric power depends on the capacity factor of the generation system, feedstock costs, transmission, and other factors.

Diesel fuel will likely provide the energy requirements for transportation. The transportation energy requirement will be primarily dependent on the distance between the plant and the fueling stations. It is possible that transportation is a significant part of the overall energy requirement.

Because the fuel has been processed and stored in the bricks at the central plant, there are very few energy requirements at the forecourt. It will be necessary to have an electrically driven mechanism to move the bricks from the storage area to the dispensing area. This is likely to be a very minor fraction of the overall energy use.

Once the brick is onboard the vehicle, in most cases, thermal energy will be required to heat the storage material in order to desorb the hydrogen from the material surface. While this may be a significant fraction of the overall energy requirement it is possible that waste energy from the vehicle power-train will be able to meet this requirement.

Table 1-25
Energy Use and Operating Costs for Brick Concept

| | Energy Use | Energy Cost ($/kg) |
|---|---|---|
| Processing Plant<br>Compressor (kWh/kg) | 0.92 | 0.075 |
| Delivery Truck<br>Fuel (L/kg) | 0.05 | 0.023 |
| Forecourt Station<br>Electricity (kWh/kg)<br>O&M<br>Variable O&M | 0.05 | 0.004<br>0.238<br>0.0002 |

### 1.6.3 Flowable Powders

Hydrogen may be stored and transported while adsorbed to metal hydride or activated carbon in the form a flowable powder. Flowable powders will be processed at a central plant facility and transported by truck and trailer to the forecourt where the powder is stored and loaded onto vehicles.

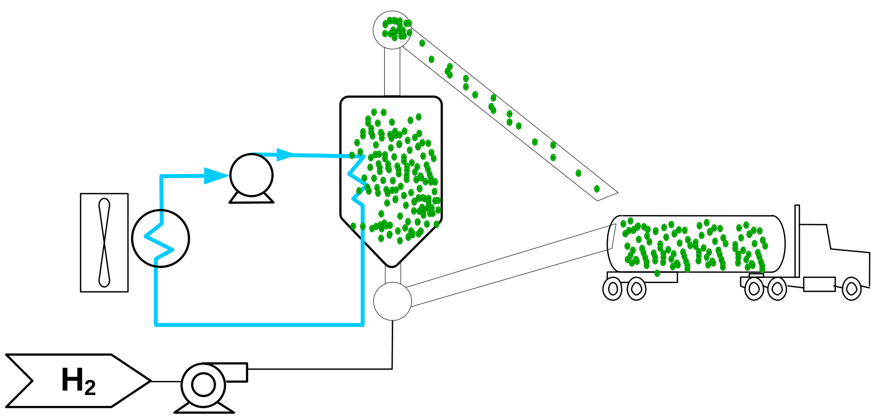



Figure 1-33 Illustration of flowable powder processing, including $H_2$ compression and heat removal

#### *1.6.3.1 Description*

To reduce the volumetric energy density of stored hydrogen, it is possible to adsorb hydrogen to the surface of metals of activated carbon structures. These hydrogen carrying solids can be in the form of a powder which allows for easier pumping and material handling. In the case of a metal hydride, the delivery system is shown in Figure 1-33. Flowable powder will be transported on a truck between a processing facility and the forecourt. In order to adsorb hydrogen to the carrier material's surface it is necessary to pressurize the hydrogen and remove heat from the material being hydrided, as the process is generally exothermic. Once the hydrogen is adsorbed to the surface of the powder, it can be stored or transported to the forecourt.

Storage performance of flowable powder is based on the amount of hydrogen that can be stored in the material (by way of surface adsorption) and the fraction of that hydrogen that can be released in a timely fashion given pressure/temperature desorption characteristics.

The metal hydride or activated carbon material is powdered in order to make the material easier to move between transportation, storage, and vehicle. Fueling a vehicle with a flowable powder consists of removing the spent powder from onboard and replacing that powder with hydrided powder.

There are a number of challenges when using a flowable powder as a storage and transportation medium:

- Reactivity – Some of the storage materials may be reactive in air, or with other substances, necessitating the inerting of the storage and transport environments which could make moving the powder significantly more difficult.
- Solids Transport – Unlike a liquid or a gas, a solid cannot be easily pumped or compressed in order to facilitate mass transfer. A significant mechanical system will be necessary to move the flowable powder.
- Heat Transfer – In order to desorb the hydrogen, it is likely that thermal energy will have to be transferred to the storage material, making the issues of heat transfer and proper distribution of thermal energy within the vehicle storage tank and issue.

#### *1.6.3.2 Materials and Developers*

There are a few different types of hydrogen carrier materials that can be used as flowable powders. Certain factors that will be particularly important when determining what type of material will be ideal for use in flowable powder-type storage system.

- Hydrogen Storage Capacity (weight percent) – This will determine the mass of powder onboard the vehicle.
- Material Density – This will determine the storage volume onboard the vehicle
- Energy/Reactants Required for $H_2$ Removal – This is a particular concern as all the energy or reactants must be provided onboard the vehicle and large transfers will likely add complexity to storage

Metal Hydride

Metal hydrides will adsorb and desorb hydrogen onto the material surface depending on the temperature and pressure of the hydrogen in the system. Metal hydrides are quite dense and do not require significant reprocessing with each cycle, as there is no chemical shift in composition with hydriding/dehydriding. Metal hydrides generally have poor hydrogen capacity (rarely more than 2 percent by weight) and the energy required to desorb the hydrogen can be significant.

The DOE Metal Hydride Center of Excellence is coordinated by Sandia National Laboratories and involves 16 other government, industry, and university partners.

Activated Carbon Structures

Recent efforts have focused on the use of carbon nanostructures to store hydrogen. While it has been reported that hydrogen yields approaching the 6 percent DOE goal have been achieved, these experiments were conducted at cryogenic temperatures and elevated pressure. If progress can be made and the DOE target can be met at conditions that are closer to ambient, the carbon structures may be applicable for flowable powder-type fueling.

The DOE Carbon-Based Hydrogen Storage Center of Excellence is coordinated by National Renewable Energy Laboratory National Laboratories and involves 11 other government, industry, and university partners.

Despite early efforts by research institutions and national labs, it is very had to predict with certainty the hydrogen yield of a well engineered material. As these materials are not easily definable chemical compounds with known molecular structures, it is possible for the hydrogen yield to increase significantly with development. Given that unknown, it is important to develop the tools necessary to evaluate new materials and the processes involved in utilizing those materials to their potential.

#### *1.6.3.3 Equipment Description*

Powder

The powder is simply fine particles of the metal storage material to facilitate easier solids transport.

Central Plant

The requirements of the central plant will consist of a hydrogen supply, the equipment necessary to move the powder through the plant, and the equipment necessary to hydride the powder. The hydrogen supply can come from a variety of sources, any of which will be compatible with flowable powder. Once the powder has been offloaded from the trailer, it will likely need to be moved – via some sort of conveyor system – to the location where the metal will be subjected to the hydriding process. Since the hydriding process is exothermic for most materials, it may be necessary to actively cool the powder, as they it will not store as much hydrogen at elevated temperatures. Once the hydriding process has taken place the powder will be loaded into chemical-type trailers so that it can be brought by truck to the forecourt. It is important to remember that if the material is reactive, these processes will have to all take place within an inert environment.

Transportation

Trucks will likely be the primary method of transport for flowable power. The trailer required for the transportation will have to be non-corrosive, impenetrable to hydrogen, able to provide an inert environment, and capable of withstanding elevated storage pressures, given that the vapor pressure of hydrogen at most operating conditions will be greater than ambient. A mechanical system will be necessary to remove the powder from the trailer.

Forecourt

Forecourt storage will have to deal with the same issues that were addressed when transporting the flowable powder. Potentially complex mechanical systems will necessary in order to move the powder from the storage to the vehicles, as powder cannot be pumped or compressed.

#### *1.6.3.4 Capital Costs*

Capital costs will be primarily dependent on the cost of the powder material. While a large number of expenses are involved in transporting hydrogen via flowable powder, as shown in Table 1-26, the total mass of the storage material will cause it to dominate the overall cost. The following table indicates that primary capital costs for each sector of the delivery process. The costs indicated below are for individual components, not for an entire distribution network. The total cost will depend on the size of the network and the proximity of the central plant to the forecourt.

Table 1-26
Capital Costs for Flowable Powder Concept

| Equipment | Description | Cost | Notes |
|---|---|---|---|
| ***Powder*** | | | |
| Storage Material | Most likely a metal or carbon structure onto which hydrogen can be easily adsorbed and desorbed by varying temperature and pressure. | $10-15/kg | |
| ***Central Plant*** | | | |
| Powder Transporter | Used to move powder from the cargo containers to a location where the hydriding process will take place. | $320,000 | Conveyor belt system ~$80/ft. Assume 3*$80/ft for specialized/outdoor system. 1000 ft. http://www.gilmorekramer.com |
| Hydrogen Supply | Hydrogen can be produced using whatever method is most effective at the given time and place. | | Cost will vary significantly based on the generation process utilized. |
| Hydrogen Compressor | This will be unnecessary if the hydrogen supply provides a significantly high hydrogen stream. | $18,800,000 | H2A compressor: 165,000 kg/day, 5-40 atm. |
| Cooling System | The cooling system will be necessary for those materials that undergo a strongly exothermic process upon hydriding. | | |
| ***Transport*** | | | |

| | | | |
|---|---|---|---|
| | | $100,000 | |
| Tractor | The standard tractor used in a tractor-trailer arrangement to haul heavy cargo over the roadways. | | |
| Trailer | Similar to a common chemical trailer. It will, however, need to have a mechanical system to offload the powder and the capability to maintain an inert environment. | $100,000 | Based on a dry chemical trailer cost of $60,000. ARCO Trailers |
| ***Forecourt*** | | | |
| Storage | Storage tanks must be non-corrosive, impenetrable to hydrogen, able to provide an inert environment, and capable of withstanding elevated storage pressures. | $100,000 | Cost will be highly dependant on the size of the forecourt station. |
| Powder Transporter | A mechanical system will be necessary to move the powder from the storage tanks to the vehicles. | $96,000 | Conveyor belt system ~$80/ft. Assume 4*$80/ft for specialized/outdoor system. 300ft. http://www.gilmorekramer.com |
| Dispenser | | $80,000 | |
| Fuel First Charge | | $250,000 | |
| Site Preparation | Includes control/safety equipment and indirect depreciable capital | $445,000 | |

#### *1.6.3.5 Energy Requirements*

When using flowable powder as a hydrogen transport mechanism, there will be numerous energy requirements. Within the central plant, energy will be required to move the powder through the plant. For those materials that are strongly exothermic during hydriding, energy will be required to actively cool the powder, although this may be as simple as a series of fans or cycling cooling water. In the case of materials that require high pressure hydrogen for hydriding, energy will be required to operate the compressor. This piece of the overall energy requirement could be significant. Electricity will be the energy carrier needed to supply these central plant energy requirements.

The source and cost of the electric power has a significant impact on the cost of the overall system. The cost of electric power depends on the capacity factor of the generation system, feedstock costs, transmission, and other factors.

Diesel fuel will likely provide the energy requirements for transportation. The transportation energy requirement will be primarily dependent on the distance between the plant and the fueling stations. It is possible that transportation is a significant part of the overall energy requirement.

Because the fuel has been processed and stored in the powder at the central plant, there are very few energy requirements at the forecourt. It will be necessary to have an electrically driven mechanism to move the powder from the storage area to the dispensing area. This is likely to be a minor fraction of the overall energy use.

Once the powder is onboard the vehicle, in most cases, thermal energy will be required to heat the storage material in order to desorb the hydrogen from the material surface. While this may be a significant fraction of the overall energy requirement it is possible that waste energy from the vehicle power-train will be able to meet this requirement.

Table 1-27
Energy Use and Operating Costs for Flowable Powder Concept

| | Energy Use | Energy Cost ($/kg) |
|---|---|---|
| Processing Plant | | |
| Compressor (kWh/kg) | 0.92 | 0.075 |
| Delivery Truck | | |
| Fuel (L/kg) | 0.05 | 0.023 |
| Forecourt Station | | |
| Electricity (kWh/kg) | 0.05 | 0.004 |
| O&M | | 0.238 |
| Variable O&M | | 0.0002 |

### 1.6.4 Truck Transport

Trucks are presently the primary carrier of vehicle fuel for local delivery. Truck delivery is also the principal mode for several hydrogen delivery pathways using a variety of hydrogen storage options. In comparison to pipeline transport, trucking hydrogen has the benefit of flexibility regarding delivery location and type of carrier. Trucks will be able to quickly supply new fueling stations before pipeline infrastructure can be put in place. In addition, by not supplying fueling stations with pipelines, there is greater ability to utilize and adapt to different types of hydrogen carriers. Despite these advantages, roadway size and weight limitations limit the delivery capacity of trucks and trailers. The amount of hydrogen delivered by trucks is governed by weight and volumetric limits as well as the conversion efficiency from the energy carrier to hydrogen on board the vehicle.

The following section introduces the important topics and issues associated with transporting hydrogen via truck, as well as define many of the cost inputs and energy inputs that will vary for many of the storage mediums that can be transported via truck.

The parameters affecting truck transport are discussed for the following categories of energy carriers.

- Gasoline
- Pure Hydrogen (compressed, liquid)
- Reformed Liquid Fuels (ethanol, methanol, ammonia)

- Chemical Hydrides (liquid solution)
- Alanates
- Flowable Powder (chemical hydride, metal hydride, carbon)
- Bricks (Solid media such as metal hydride or carbon)

All of the original analysis that has been performed uses a standard scenario that involves a 200 km roundtrip delivery distance.

This section includes a review of the available information on truck transport as well as an analytical framework for the analysis of truck delivery. During the development of the analysis, information gaps were identified and discussed.

#### *1.6.4.1 Delivery Truck Description*

As a mode of hydrogen transport, 'truck' or 'trucking' will refer to the combination of a semi-tractor and a cargo trailer. The tractor is assumed to be the standard, diesel-fueled, 10-wheeled tractor truck that is prevalent in the transport of all types of overland cargo. Depending on the type of hydrogen carrier in use, the type of cargo trailer will vary.

The process of delivering hydrogen by truck includes picking up a full trailer at a terminal and driving that trailer to a fueling station. Depending on the type of carrier used, the process of unloading the trailer at the fueling station will either require the operator to detach and leave the trailer at the fueling station (in the case of $cH_2$ tube trailers) or transfer the cargo from the trailer to the storage facility at the fueling station.

When evaluating the cost of transporting hydrogen by truck, there are a number of variables that need to be considered:

- **Capital:** While it is assumed that the cost of the tractor will be constant for different energy carriers, the requirements of the trailer will lead to significant differences in capital costs.
- **Capacity:** The more fuel that can be carried on a single truck, the more efficient the overall transport process will be.
- **Labor:** The overall labor cost includes the time spent loading/unloading the trailer – which will vary for different types of hydrogen carriers – and the time spent driving from the terminal to the fueling stations. Variables that affect this cost include truck speed, transport distance, and labor rate.
- **Fuel:** Fuel costs are dependent on the distance driven and the economy of the tractor-trailer arrangement.
- **O&M:** All of the cost associated with the continuous operation of the tractor-trailer arrangement, including insurance, taxes, licensing, and general maintenance.

When comparing the costs of trucking different types of hydrogen carriers, there are certain variables that will impact the relative cost of transport. The variables that have the greatest effect on relative cost:

- Trailer Capital Cost
- Capacity
- Loading/Unloading Time

Most of the other cost factors will be the same for all types of hydrogen carriers. These cost factors will vary with the scenario – transport distance – but not as a result of the carrier.

#### *1.6.4.2 Transportation Mediums*

There are a number of factors that are important to consider when evaluating the cost and energy impacts of truck delivery options. One of the most important is the delivered mass. Road regulations limit the total weight of truck and cargo (gross vehicle weight) to 80,000 lb. For similar truck/trailer combinations, the maximum cargo mass are set for all carriers. The delivered mass depends on the trailer configuration, and density of the hydrogen storage media. In some instances the trailer will 'cube-out.' This means that the density of the cargo is such that it will reach the maximum volume without reaching the maximum vehicle weight. In these cases the trailers are not holding the maximum mass as a result of low cargo density. Also, each transportation mechanism will have a hydrogen yield – which is defined as the fraction, by mass, of the cargo that can be recovered as useful hydrogen – that will directly affect the delivered mass of hydrogen.

Capital cost and labor input also depend on transportation medium and preliminary estimates are included in the following discussion.

The analysis of the transportation mediums also determined the process energy input. When evaluating the transportation mediums, the process energy input only includes the energy used to move the cargo. In all the following cases, diesel fuel is the carrier of the process energy. Any energy required for reformation is not factored into the process energy input. Therefore it is not a measure of plant-to-forecourt efficiency, as the product being delivered is not always pure hydrogen.

<u>Compressed Gas</u>

Delivering compressed hydrogen to a fueling station provides a refueling option that can be implemented relatively quickly with a low capital cost. Delivered sources of compressed hydrogen include both cylinders delivered by truck and tube trailers. Current practice and the assumed delivery scenarios involve leaving the tube trailer at the forecourt. Hydrogen is not offloaded to ground storage for the baseline scenario.

Hydrogen tube trailer fueling stations are a simple, relatively inexpensive way to provide hydrogen fueling for vehicles. Hydrogen gas is stored in the tube trailer, which feeds a compressor. After compression, the gas is stored in buffer or cascaded storage tanks and then dispensed to the vehicles. The trailer assembly is typically not a permanent fixture since it is refilled off site when empty. Connections to the trailer utilize a flexible hose while permanent tube trailer installations are typically connected with rigid tubing.

A tube trailer consists of a pack of pressurized cylinders connected by a manifold and housed on a trailer. Tube trailers hold roughly 120,000 scf (280 kg) of hydrogen at pressures in the range of

2,400 to 3,100 psi (166 to 214 bars). Typical dimensions for the trailer are 40 to 45 feet long, 10 feet high, and 8 to 9 feet wide. When installed, the trailer is supported by a wheel assembly on one end and landing gear on the other.

Table 1-28 shows the parameters for cost and energy analysis for compressed gas delivery as well as gasoline and liquid hydrogen. The delivered hydrogen is shown for each option. Capital costs, labor and diesel fuel consumption are also estimated. The diesel energy input, in J diesel/ J delivered hydrogen, is also calculated. This value is an input to the well to wheels energy analysis.

Gas storage capacity is limited by the tube packing volume on the trailer as well as the overall trailer weight. As displayed in Table 1-28, the H2A models assign two pressure levels – 2,700 psi and 7,000 psi (186 to 483 bars) – for compressed hydrogen. Several strategies are available for transferring the hydrogen from the tube trailer to the vehicle. These are discussed under the forecourt system.

The assumed unloading time for the tube trailer reflects maneuvering a tube trailer from its parking position to an intermediate location. Providing additional parking for the new and spent tube trailers could reduce transfer time by about an hour.

Liquid Hydrogen

The primary advantage of liquid hydrogen transportation and storage is its relatively high density. The density of liquid hydrogen saturated at 10 psig or 0.69 bars g (which is typical for truck-transported hydrogen) is 4.28 $lb/ft^3$ (68 $kg/m^3$) This is approximately 3.8 and 2.9 times the density of 60 °F (15.5C) hydrogen gas compressed to 3,600 psig and 5,000 psig (248 to 345 Bars g), respectively. Note that the density decreases as saturation pressure and temperature increase. The storage parameters are discussed in a report by the California Energy Commission.[33] The main disadvantages of liquid hydrogen are associated with its very low temperature. Special cryogenic equipment is required to produce, store, and process liquid hydrogen. Even with this cryogenic equipment, some boil-off loss inevitably occurs at various points in the infrastructure chain. This boil-off loss can be negligible for fueling stations with a high throughput, but it can be substantial for low-throughput stations; i.e., where liquid hydrogen deliveries are less frequent than once per week. Additional consideration of boil-off losses is included in subsequent discussions of fueling station design and components.

In the case of liquid hydrogen, boil off and residual hydrogen left in the truck reduce the hydrogen yield from an as-loaded value of 4,142 kg to an as-delivered value of 3,890 kg. Heat entering the hydrogen can result in an increase in pressure. If hydrogen is loaded on board the vehicle at 0 psig (0 bars g), a typical trip would raise the pressure no more than 10 psi (0.69 bars) and not result in boil-off during the trip. Connections to fuel transfer equipment can result in heat entering the liquid hydrogen system and possible boil off. The extremely low temperature lead to trailers that are more complex and costly than gasoline trailers. Table 1-28shows the parameters for liquid hydrogen delivery.

Table 1-28
Standard Energy Carriers

| Energy Carrier | Gasoline | Compressed hydrogen (2,700 psi or 186 bars) | Compressed hydrogen (7,000 psi or 483 bars) | Liquid Hydrogen |
|---|---|---|---|---|
| **Physical Inputs** | | | | |
| Density (kg/m$^3$) | 720 | 14 | 30 | 70 |
| Temperature (°C) | ambient | ambient | ambient | -252 |
| Pressure | ambient | 2,700 psi or 186 bars | 7,000 psi or 483 bars | ambient |
| Cargo Mass (kg) | 27,250 | 313 | 693 | 4,142 |
| Cargo Volume (m$^3$) | 37.9 | 23.4 | 23.0 | 65.0 |
| Product Delivered (gal, kg) | 10,000 | 284 | 665 | 3,890 |
| Delivered Energy (MJ) | 1,220,000 | 34,100 | 79,800 | 467,000 |
| Process Energy Input (MJ,diesel/MJ,hydrogen) | 0.00226 | 0.08080 | 0.03450 | 0.00590 |
| **Financial Inputs** | | | | |
| Truck Capital Cost ($) | 165,000 | 250,000 | 465,000 | 725,000 |
| Diesel Fuel Cost ($/kg $H_2$) | | 0.119 | 0.051 | 0.009 |
| Labor (hr) | 4.0 | 5.5 | 5.5 | 7.5 |

Reformed Liquid Fuels: Methanol, Ethanol, and Ammonia

Several energy carriers can be converted to hydrogen at the fueling station.

Alcohols can be transported in existing gasoline trucks. The trucks have aluminum storage tanks which may be subject to corrosion with long term exposure to alcohols. However, the short contact time for fuel deliveries has not prevented the use of these trucks for alcohol fuel service.

Ammonia can be transported in two forms: anhydrous and aqueous. Anhydrous ammonia is pure ammonia in a liquid state and aqueous ammonia is ammonia dissolved in water at an approximate mass fraction of 30 percent. While anhydrous ammonia has a higher hydrogen yield it is transported as a liquefied gas at 200 psi (138 bars). Ammonia trucks are common in agricultural areas and similar in configuration and cost to LPG trucks.

Anhydrous ammonia is stored at low pressure so the configuration of the truck is similar to a gasoline truck, although the tank material must be stainless steel instead of aluminum to protect against corrosion.

While the transportation of these energy carriers is straightforward, the analysis must consider the hydrogen that is produced from each option as illustrated in Table 1-29. The hydrogen yield is calculated based on the stoichiometry of the reforming process. The basis for the yield is described in the report section for each energy carrier. For methanol and ethanol reforming, process gas from the reformer provides the energy input for conversion to hydrogen. The hydrogen yield reflects the total fuel required to produce a kg of hydrogen, In the case of ammonia, energy inputs are also required for reforming. This energy can be derived from natural gas, product hydrogen, or other energy sources. Natural gas is assumed here, so the energy required to reform ammonia does not affect the hydrogen yield.

The reformation process requires water in the case of anhydrous ammonia, methanol, and ethanol. Water is piped to the forecourt and it does not affect trucking costs. Energy inputs for water transport are less than 0.01 (MJ/kg water) which is much smaller than other energy inputs for delivery. Water purification may be required at the forecourt. The cost of water is included in the forecourt analysis.

Table 1-29
Reformed Liquid Fuels

| Energy Carrier | Anhydrous Ammonia | Aqueous Ammonia | Methanol | Ethanol |
|---|---|---|---|---|
| **Physical Inputs** | | | | |
| Chemical Formula | $NH_3$ | $NH_3$ | $CH_3OH$ | $C_2H_5OH$ |
| Blending Component (mass fraction) | | $H_2O$* (71 percent) | $H_2O$* (52-63 percent) | $H_2O$* (53-70 percent) |
| Density (kg/m$^3$) | 618 | 900 | 791 | 790 |
| Temperature (°C) | ambient | ambient | ambient | ambient |
| Pressure | 200 psi or 13.8 bars | 2.3 psi or 0.16 bars | ambient | ambient |
| Cargo Mass (kg) | 27,250 | 27,250 | 27,250 | 27,250 |
| Cargo Volume (m$^3$) | 44.1 | 30.3 | 34.4 | 34.5 |
| Hydrogen Yield ( percent) | 17.7 percent | 5.1 percent | 18.6 percent | 21.9 percent |
| Product Delivered (kg) | 4,834 | 1,398 | 5,069 | 5,968 |
| Delivered Energy (MJ) | 580,000 | 168,000 | 608,000 | 716,000 |
| Additional Energy Req. (MJ) | 74,000 | 21,500* | | 205,000 |
| Process Energy Input* (MJ,diesel/MJ,hydrogen) | 0.00475 | 0.01640 | 0.00453 | 0.00385 |
| **Financial Inputs** | | | | |
| Capital Cost ($) | 300,000 | 180,000 | 180,000 | 180,000 |
| Fuel Cost ($/kg) | 0.007 | 0.024 | 0.007 | 0.006 |
| Labor (h) | 6 | 4 | 4 | 4 |
| *The Process Energy input does not include the additional energy necessary to reform these liquid fuels | | *Additional energy is required to separate the ammonia and water | * This water can be piped to the station | * This water can be piped to the station |

## Chemical Hydrides: Liquid Solution

Transporting hydrogen is also possible in chemical hydrides that are in aqueous solutions or oil slurries. In this fashion the hydrides can be transported in much the same way as a liquid. This makes the transport and the loading/unloading processes easier and faster. The drawback to transporting the hydride in a liquid solution is that the gravimetric energy density decreases because it is now necessary to ship both the hydride and water. An exothermic reaction releases the hydrogen from the chemical hydride on board the vehicle, so no additional energy inputs are required

Table 1-30 shows the parameters for a generic chemical hydride. A wide range of energy inputs, hydrogen yield, and net hydrogen product delivered are possible for different hydride chemistries. The generic hydride is based on a water solution, so the hydrogen yield is reduced by the water carried on-board the truck. A sensitivity analysis would need to consider both the truck delivery as well as the central reprocessing plant energy inputs.

Another key factor to consider in the transport of chemical hydrides is the return trip for spent material. For some hydride formulations, the spent material may be heaver than the material shipped to the fueling station. In this case the mass of the spent material would affect the strategy for trucking the hydride material. Segregating spent material from fresh hydride material also affects transport and storage strategies. One straightforward approach is to unload a tank truck load of fresh material at the forecourt and then fill the truck with spent material. This option would require additional storage at the forecourt but would simplify the truck transport. The possibility of transporting any combination of fresh and spent material on a truck has also been considered. This approach would require a bladder or other barrier to separate the spent and fresh material. Costs and performance associated with transporting only fresh or spent material are shown in Table 1-30.

Alanates

Alanates, a type of complex metal hydride, are another medium for transporting hydrogen. Alanates have the potential to carry more hydrogen than simple metal hydrides and the hydrogen can be removed from the alanates at relatively modest temperatures (35 °C - 110 °C).

Certain alanates that perform well as hydrogen carriers also react with oxygenated environments, creating a potentially dangerous situation that requires delicate handling of the material. In order to reduce the likelihood of any reaction between the alanate and air, the trailer carrying the material will also serve as the forecourt storage mechanism. The alanate will always be stored in the trailer and the adsorption/desorption process will also take place in the trailer. This minimizes the possibility of exposure to air, but also makes the storage trailer far more costly than a standard dry chemical or liquid trailer. This is the primary additional cost regarding the transportation of alanates.

Flowable Powder

Transporting hydrogen is also possible in either chemical or metal hydrides. Many of these hydrides will be in the form of a granulated solid, a powder. There are a vast number of different hydrides that can be transported as a flowable powder and many of them have different yields that affect the hydrogen delivered and the additional energy requirement. Nevertheless it is important to identify some of the main issues with the transportation of a powder.

One issue involves the packing density of the material. The density of the powder will be approximately 50-60 percent of the density of a solid block. However, the analysis of multiple hydrides transportable as powders indicates that this density shift is generally not significant enough to cause trailers to 'cube-out.' The material density shown in Table 1-30 accounts for the packing density of a powder. Most trailers were able to carry the maximum weight within the volume limitations.

If a hydride with favorable yield, energy requirement, and density can be found transporting it as a powder should feasible from both an energy and cost perspective.

Bricks

It also may be possible to store metal and chemical hydrides as “bricks” in individual containers. By storing the hydride in individual cases it will be possible to have a very simple trailer. The complex chemical containment will be managed by the individual containers. A drawback to transporting the bricks is that the containers take up valuable weight and volume on board the truck. As shown in Table 1-30, this additional weight and volume decrease the gravimetric yield of shipped material from 5.5 percent to 4.7 percent. For the analysis the containers were assumed to be aluminum with walls that were 1cm thick. Each container would contain 6 kg of hydrogen. Using a hydride with a 5 percent yield, the final mass is approximately 15 percent container, and 85 percent hydride.

Table 1-30
Flowable Powder and Bricks

| Energy Carrier | Alanate | Chemical Hydride (liquid solution) | Flowable Powder | Bricks |
|---|---|---|---|---|
| **Physical Inputs** | | | | |
| Chemical Formula | $NaAlH_4$ | Various | Various | Various |
| Blending Component (mass fraction) | | $H_2O$ (50 percent) | | |
| Density (kg/m$^3$) | 1,250 | 1,000 | 750 | 2,929 |
| Temperature (°C) | ambient | ambient | ambient | ambient |
| Pressure | ambient | ambient | ambient | ambient |
| Cargo Mass (kg) | 27,250 | 27,250 | 27,250 | 27,250 |
| Cargo Volume (m$^3$) | 21.8 | 27.3 | 36.3 | 9.3 |
| Hydrogen Yield ( percent) | 5.5 percent | 6.0 percent | 5.5 percent | 4.7 percent |
| Product Delivered (kg) | 1,499 | 1,635 | 1,499 | 1,281 |
| Delivered Energy (MJ) | 180,000 | 389,000 | 180,000 | 164,000 |
| Additional Energy Req. (MJ) | | | Variable* | Variable* |
| Process Energy Input* (MJ,diesel/MJ,hydrogen) | 0.01530 | 0.01339 | 0.01530 | 0.01680 |
| **Financial Inputs** | | | | |
| Capital Cost ($) | 300,000 | 180,000 | 200,000 | 140,000 |
| Fuel Cost ($/kg) | 0.023 | 0.021 | 0.023 | 0.025 |
| Delivery Labor (h) | 6 | 6 | 6 | 6 |
| *The Process Energy input does not include the additional energy necessary to reform these liquid fuels | | | *Depends significantly on the material used, but most will require additional | *Depends significantly on the material used, but most will require additional |

energy. energy.

#### 1.6.4.3 Equipment Description

Tube Trailer

Tube trailers are used to transport compressed hydrogen. A tube trailer typically consists of either one or a number of long steel tubes (H2A assumes nine for a 2700 psi (186 bars) trailer and one for a 700 psi (48.3 bars) trailer) arranged together. Tube trailers are typically left at the fueling station and serve as the primary forecourt storage. Major drawbacks of the tube trailer are the size and weight of the individual tube and the fact that the density of compressed hydrogen is still quite low. Most of what is being transported is the storage mechanism, not the hydrogen. The amount of vehicle fuel delivered on a tube trailer is an order of magnitude less than a large gasoline truck.

Due to the requirements made on high pressure vessels, the cost of the tube trailer is also significantly greater than the standard petroleum trailer.

Liquid Hydrogen Trailer

Liquid hydrogen is transported in cryogenic tanks that are necessary to keep the hydrogen at its boiling point, -253 °C. The cryogenic tank is a two part system consisting of a stainless-steel inner vessel and an outer vessel made of either carbon steel or aluminum. In between the two vessels is fiberglass insulation and a vacuum. The appearance of the cryogenic trailer is similar to that of a standard gasoline truck, however the complexity of managing the cryogenic materials yield an extremely high capital cost – more than six times more than a standard gasoline truck.

While the liquid hydrogen trailer can transport hydrogen at a greater density than the tube trailers, it is still limited by the low density of liquid hydrogen.

Liquid Trailer

Liquid trailers will be used to transport the liquid fuels – aqueous ammonia, ethanol, methanol - that will be reformed to hydrogen at the forecourt or on the vehicle. The liquid trailer is capable of carrying high density fluids and will operate at the maximum weight limit. The hydrogen capacity of the liquid trailer is primarily dependent upon the yield of the liquid being carried. The liquids in the trailer will be at ambient pressure.

Pressurized Liquid

At ambient temperatures anhydrous ammonia will have a vapor pressure that is greater than ambient, necessitating a liquid trailer that is capable of withstanding elevated pressures. This should not significantly affect the size of the vessel or the storage capacity, but the capital cost of this trailer will be greater than that of a standard liquid trailer.

Dry Chemical

Many of the chemical and metal hydrides will be present in a flowable powder. Some of these chemical compounds may not be compatible with an oxygenated environment, necessitating a trailer that can transport dry chemicals in an inert environment. In addition, the trailer will need systems designed to move the powder between the trailer and storage containers. Unlike most of the other carriers, the hydrides will be recycled. This means that there trailers will have to removed spent hydrides and bring them back for processing and hydriding.

Bricks

Because the materials in the bricks will be contained in individual containers, a truck that is moving bricks will be the cheapest and least sophisticated. It will be necessary to develop a system that can quickly and easily move the bricks on and off the trailers. Otherwise, most of the technical containment is performed by the brick containers themselves.

#### *1.6.4.4 Capital Costs*

The capital cost of the tractors is assumed to be the same for all of the delivery mediums and is taken as $100,000, which is the H2A tractor cost.

Trailer costs were based on H2A costs for compressed and liquid hydrogen trailers, as well as quote costs for petroleum trailers, chemical trailers, and flatbed cargo containers. The assumed capital costs are as follows:

Table 1-31
Assumed Trailer Capital Costs

| | |
|---|---:|
| Tube Trailer (2,700 psi or 186 bars) | $165,000 |
| Tube Trailer (7,000 psi or 483 bars) | $350,000 |
| Cryo Trailer | $625,000 |
| High Pressure Liquid | $200,000 |
| Liquid | $80,000 |
| Dry Chemical | $100,000 |
| Hazardous Material (Alanate) | $200,000 |
| Bricks | $40,000 |

#### *1.6.4.5 Loading/Unloading Time*

The time required to unload the cargo from the trailers will also lead to cost differences between the different mediums. The total time includes the process of obtaining the cargo at the terminal and all of the time spent at the forecourt station. Activities at the forecourt can range from switching trailers, unloading liquids, to unloading hydrides and reloading spent material for recycling.

#### *1.6.4.6 Process Energy Requirements*

In terms of truck transportation, the only process energy consumed is the diesel fuel used in the truck. This is a function of the fuel economy of the tractor and the distance traveled. The fuel economy is 2.6 km/L throughout the analysis. This is based on the H2A value and supporting research indicating that the number selected is a good average for tractor fuel economy.

#### *1.6.4.7 Analysis Approach - H2A Models*

The H2A Components Model is a very effective method for determining the costs associated with transporting hydrogen. The trucking component can be used in conjunction with much of the data presented above to calculate the total cost of trucking hydrogen. While there are numerous variables in the H2A models, many are not sensitive to a particular trucking method or have a weak affect on the total cost. In these cases the H2A assumptions can be used.

In order to use the H2A model to determine general cost information only a few inputs are required. The inputs that will have the greatest impact on the overall cost are the following:

- **Capacity**: The total amount of hydrogen that can be transported on a truck is often the single greatest factor in determining the overall cost (note: the cH2 model can be easily modified to calculate costs for other transportation mechanisms).
- **Capital Cost**: The capital cost for the tractor will similar for most transportation mechanisms, but the trailer cost will be highly variable.
- **Delivery Distance**: Delivery distance will have a large impact on the amount of hydrogen that can be delivered during the analysis period.

Other variables such as average vehicle speed, loading time, tractor fuel economy, and fuel cost will also affect the overall cost, but will not vary significantly between methods of transport.

The H2A Component Model is a good tool for determining costs for transportation as it sets a standard for the cost considerations included in an analysis and can be easily modified to provide an analysis for a variety of transportation methods.

## 1.7 HYDROGEN / NATURAL GAS SEPARATION PROCESSES

### 1.7.1 Design Bases

For the purposes of the study, it was agreed to base the hydrogen-natural gas separation process on the following scenario:

- 61 hydrogen refueling stations in a large city are supplied by the pipeline
- 10 percent and 50 percent hydrogen fractions by volume in the pipeline
- 600 psig (41.4 bars g) mixture pressure at inlet to hydrogn-natural gas separation plant
- 300 psig (20,65 bars g) hydrogen pressure at exit from separation plant
- 150 psig (10.33 bars g) natural gas pressure at exit from separation plant
- 64,000 kg/day hydrogen mass flow rate from separation plant.

The latter figure was taken from the ANL Scenario Model for a large city with a 10 percent hydrogen market penetration. A large city could justify the construction of a hydrogen production facility, but the concept of mixing hydrogen with natural gas would likely only apply to low market penetrations; i.e., higher penetrations would justify the construction of a dedicated hydrogen pipeline.

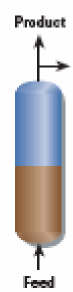
Hydrogen concentrations of both 10 percent and 50 percent were evaluated. The lower concentration value minimizes the institutional issues with mixing hydrogen with natural gas. The higher heating value of the mixture is about 965 Btu/standard $ft^3$ (37.1 million J /$Nm^3$), which is above the typical contractual lower limit of 950 Btu/standard $ft^3$ (36.5 million J /$Nm^3$). In addition, the Wobbe Index of the mixture is about 1313, which is above the minimum value of 1310 for the safe operation of natural gas appliances. As such, the mixture can be used anywhere within the natural gas distribution system. The principal liability of the low concentration is the thermodynamic penalty associated with separating the low concentration component from the high.

Increasing the hydrogen concentration to 50 percent reduces the separation losses. However, transmitting the gas mixture is now limited to those pipelines which have no customers between the mixing point and the separation point. A preliminary analysis by GTI shows this constraint to limit the potential lines to perhaps 5 percent of the existing pipelines.

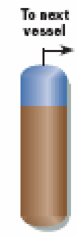
### 1.7.2 Pressure Swing Adsorbtion

#### *1.7.2.1 Principles of Operation*

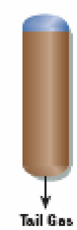
The following is a brief description of how a pressure swing adsorbtion system can separate hydrogn from a hydrogen / natural gas mixed stream. The system consists of 4 to 12 towers filled with activated carbon and zeolite, a granular alumino-silicate material. The granular structure of zeolite is designed to maximize its ability to adsorb gases onto the surface. Each tower goes through a 5 stage cycle, as follows:



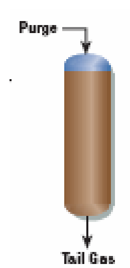

1) Hydrogen Production. The feed hydrogen / natural gas mixture enters the bottom of the vessel at high pressure. The larger natural gas molecules are adsorbed first, and therefore will concentrate in the lower part of the vessel. The smaller hydrogen molecules will pass through to the top of the vessel, and will be collected into a pure hydrogen product manifold. When part of the bed is loaded with natural gas, the vessel is isolated from the pure gas manifold, and another vessel is switched into production. The pressure gradient from the bottom of the vessel to the top of the vessel is typically 5 to 10 psi (0.35-0.7 bars); thus, if pure hydrogen is required at 300 psig (20.69 bars g), the mixed gas inlet pressure need only be about 310 psig (21.4 bars g).



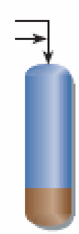

2) <u>Depressurization To Another Vessel</u>.  Pure hydrogen stored in the top of the vessel is recovered by depressurization to another vessel. This process is stopped before the natural gas / hydrogen interface reaches the top of the vessel. A part of this recovered hydrogen is used to purge another vessel undergoing regeneration.




3) <u>Depressurization To Downstream Natural Gas Manifold</u>.  The vessel is almost completely depressurized to release the adsorbed natural gas from the zeolite. Typically, the vessel pressure is dropped to about 5 psig (0.35 bars g); as such, the natural gas passing to the downstream pipeline will have to be recompressed to the nominal pipeline pressure.  Hydrogen co-adsorbed on the bed is also released with this stream.




4) <u>Pure Hydrogen Purge</u>.  Hydrogen from another vessel (see stage 2) is used to purge the balance of the natural gas from the adsorbent. This hydrogen / natural gas mixture passes to the downstream low pressure natural gas manifold. The higher the hydrogen purity requirement, the more hydrogen will be required for the purge.



5) Re-pressurization. To restore the vessel to stage 1 condition, it must be re-pressurized with pure hydrogen to the adsorption pressure. Some of the hydrogen comes from stage 2, and some comes from a pure product slip stream. At the end of re-pressurization, the vessel is ready to repeat stage 1.

#### *1.7.2.2 Evaluation of Hydrogen Separation from a Mixed Stream*

Pressure swing adsorbtion systems are commercial items, with well defined performance and costs. However, for the proposed separation concept, the adsorbtion approach suffers from several disadvantages, as follows:

- The heavier component (natural gas) is released in the low pressure cycle. As it is envisaged that hydrogen will be the minority component in the inlet stream, the larger, natural gas component will need to re-compressed from 5 psig (0.35 bars g) to the operating pressure of the distribution system.
- The adsorbtion process is ideally suited to the separation of $H_2$ from CO, $CO_2$, and $C_nH_n$ molecules when hydrogen is the major component of the feed stream. This is typical of steam methane reformers, and hydrogen purity levels of 99.999 percent have been achieved. However, $CH_4$ is more difficult to separate from $H_2$, and significantly lower purity levels can be expected.
- For low initial concentrations of hydrogen, a significant portion of the hydrogen is used as the purge gas, and thereby lost to the process in the outlet natural gas stream. With an initial hydrogen concentration of 10 percent, the hydrogen recovery is estimated to be in the range of only 40 to 50 percent, and this is likely to be an uneconomic separation approach.

### 1.7.3 Methane Hydrate

Methane, at particular combinations of pressure and temperature, reacts with water to form a solid compound, or hydrate. The water molecules form a rigid lattice, or cage, with most cages containing a molecule of methane. In principle, mixtures of natural gas and hydrogen can be readily separated by removing the natural gas as a hydrate.

Pure methane forms a so-called Structure I hydrate, arranged in a body centered cubic form. A unit cell contains 46 water molecules, effectively storing 164 volumes of methane at standard conditions per unit volume of hydrate. However, natural gas contains other hydrocarbons, such as ethane, propane, and butane. As such, natural gas forms a so-called Structure II hydrate, consisting of a unit cell with 136 water molecules. A photograph of the granular hydrate is shown in Figure 1-34.

Figure 1-34  Methane Hydrate in Powder form

Equilibrium pressure and temperature curves for methane hydrate formation, with and without a promoter, are shown in Figure 1-35.  For example, at room temperature, a methane pressure of about 1,800 psi (124 bars) is required without a promoter.  With a promoter, the equilibrium pressure falls to about 200 psi (13.8 bars).  The promoters lower the interfacial tension between the water and the gas, allowing the gas to more easily penetrate the water cage.  The hydrogen bonding between water molecules is also strengthened; as such, the hydrate will not dissociate as easily at elevated temperatures. When hydrate forms, heat is released from the system (exothermic), and when the hydrate is dissociated, heat must be supplied to the system (endothermic).  When the hydrate is heated, the dissociation step consists of the methane molecule leaving the water cage as a gas, leaving liquid water behind.

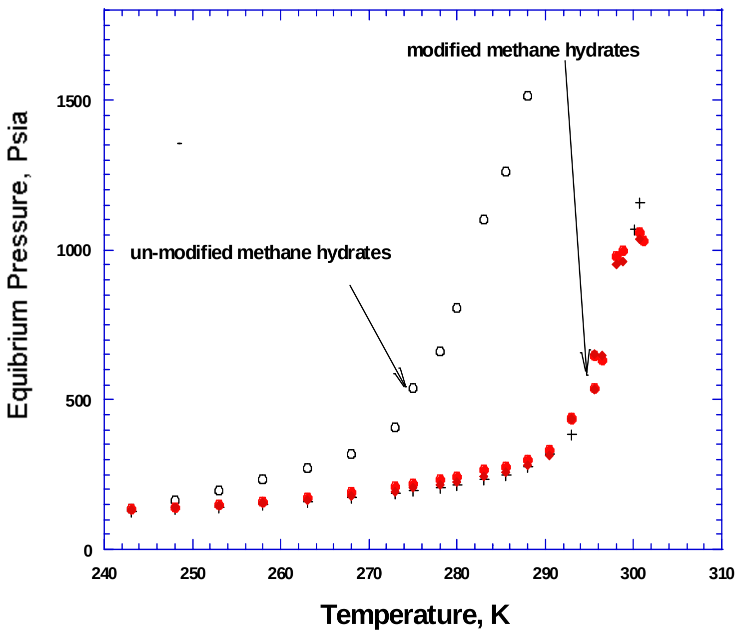



Figure 1-35  Equilibrium Pressure vs. Temperature Curve of Methane Hydrate with New Additive

Hydrogen also forms hydrates, but only at pressures above 25,000 psia (1,724 bars a). As such, only methane hydrates will form at the pressures of interest.

#### *1.7.3.1 Process Flow Diagram*

The following steps can describe the process.

The feed gas blend is mixed with chilled recycled water and a proprietary hydrate promoter, and delivered to the hydrate reactor. With a inlet pressure of 600 psia (41.38 bars a), cooling the mixture to about 10 °C causes methane hydrate to form. The hydrogen exists as both free and as entrained gas in the hydrate slurry.

The hydrate slurry and hydrogen are sent to a separator, where hydrogen is recovered.

The hydrate slurry continues to another vessel where heat is added to dissociate the hydrate into natural gas and water. The recovery methane is sent to a drying tower to meet pipeline water content specifications, and then forwarded to the distribution pipelines after a quality check

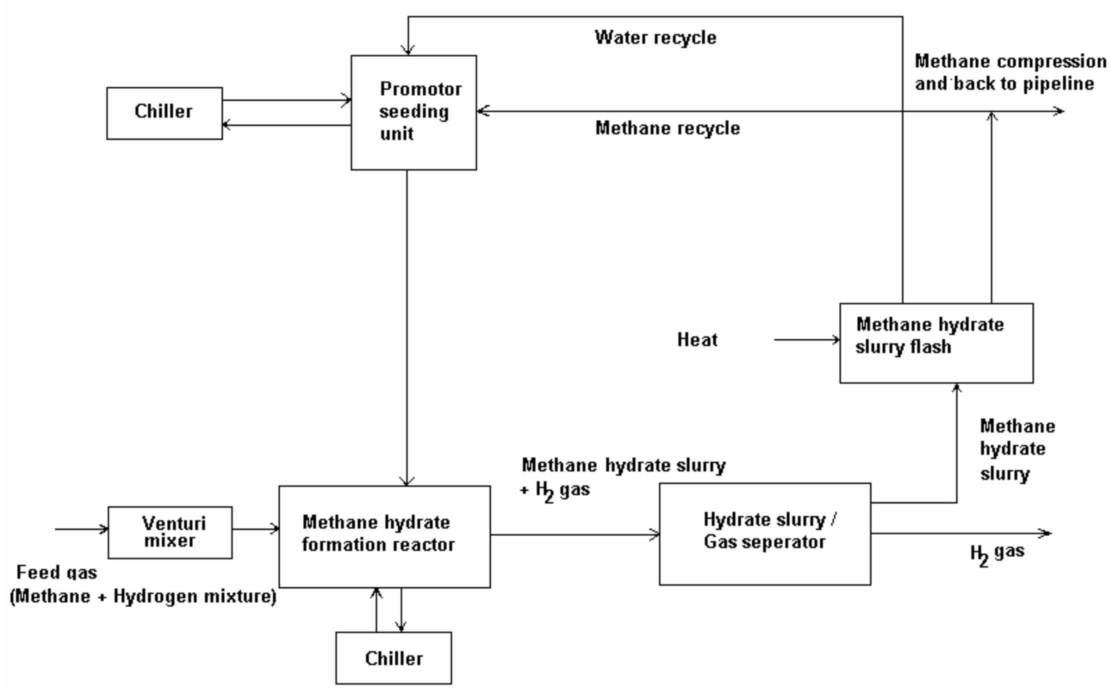



Figure 1-36 Hydrate Separation Process Diagram

The promoter is available commercially, and can be purchased in bulk quantities. Further, the promoter is in liquid form, and is easily mixed with water for injection in the chilled feed gas stream. The promoter is non-corrosive and poses no health hazards.

A portion of the thermal energy required for hydrate dissociation can be supplied by cooling the mixed gas stream entering the hydrate reactor. Similarly, a portion of the net energy released during hydrate formation can be used for the dissociation reaction.

#### *1.7.3.2 Equilibrium Limitations*

A review of the equilibrium data shows a decrease in the methane pressure must be accompanied by a decrease in the hydration temperature. For example, an inlet mixture of 90 percent natural gas and 10 percent hydrogen at 600 psia (41.38 bars a)will have a natural gas partial pressure of 540 psia (37.24 bars a). As such, the required hydrate formation temperature is about 295 °K, or 22 °C. However, as the hydrate is formed, the partial pressure of the methane drops. To have a final hydrogen stream containing no more than 10 percent methane, the final hydrate reaction pressure will need to be about 67 psia (4.62 ars) , consisting of 60 psia (4.14 bars a) hydrogen and 7 psia (0.48 bars a) methane. With an equilibrium pressure of 7 psia (0.48 bars a), the required hydrate temperatures will be at least as low as liquefied natural gas, or about 100 °K. As such, the methane will condense before the hydrate is formed, particularly in the presence of solid water. For these reasons, the methane hydrate concept was dropped from further consideration.

### 1.7.4 Hydrogen Sorbent

Although not commercial, hydrogen separation using sorbents such as metal hydrides has potential to efficiently separate low quality hydrogen streams to high purity hydrogen. A few organizations are investigating sorbents use for hydrogen separation, most notably Savanna River, Japan Metals and Chemicals-University of Kogakuin, and DSM-University of Twente (in The Netherlands). Sorbent separation involves three steps: absorption; purging of other gas constituents; and desorption driven by a pressure or temperature difference. Absorption equilibrium and the quantity of pure hydrogen required for impurities purging impact hydrogen recovery. Barriers to sorbent separation implementation include potentially high material cost ($5 - 25/kg), cycling instabilities, and low impurities tolerance of some sorbents. Metal hydrides, for instance, are extremely sensitive to typical reformate impurities, such as carbon monoxide and water vapor (>10 ppm will damage some metal hydrides). Some of the impurity interactions with metal hydrides and their impact on performance are tabulated in Table 1-32 below.

Table 1-32
Impurity Interactions with Metal Hydrides

| Impurity Interactions | Effect | Compounds |
|---|---|---|
| **Poisoning** | Rapid loss of hydrogen capacity with cycling, caused by impurities strongly or irreversibly adsorbed on the surface active sites | $H_2S$, $CH_3SH$ |
| **Retardation** | Reduction in absorption /desorption kinetics without significant loss in the ultimate capacity, caused by impurities reversibly adsorbed on the surface active sites | CO, $CO_2$, $NH_3$ |
| **Reaction** | Bulk corrosion leading to irreversible capacity loss | $O_2$, $H_2O$ |
| **Innocuous** | Loss in absorption kinetics due to surface blanketing | $N_2$, $CH_4$ |

Metal hydride-based separation concepts were projected to result in over 90 percent hydrogen recovery from both steam and autothermal reformate streams assuming protection from impurities and operating at 10 atm. Using sorbent technology to separate natural gas and hydrogen should not require large quantities of material, but might require large residence times or high pressure to ensure efficient operation. The resulting pure hydrogen can be at high pressure. In fact, the metal hydride could act as a hydrogen compressor if high temperature heat is supplied for desorption. In addition, hydrogen separation and storage can be achieved in the same medium, reducing the additional cost, safety risks, and power requirement of hydrogen compression and storage. Finally, the impurities that poison metal hydrides (e.g., carbon monoxide and water vapor) are present in minute quantities in natural gas / hdyrogen mixtures compared to typical reformate streams. However, a key challenge remains the tendency for metal hydrides to fracture into intractably small particles upon repeated cycling.

#### *1.7.4.1 Available Information on Hydride Separation*

Two approaches to improving the resistance to impurities, and decreasing the friability of a metal hydride particle, are described below.

The first is sol-gel encapsulation, where the metal hydride particles are encapsulated in a glassy matrix, and the second is surface fluorination treatment of the metal hydride.

Drawing on 20 years of experience in the storage of tritium, the Savannah River Technology Center (SRTC) has developed the means to encapsulate small particles of metal hydrides in a porous matrix of a refractory oxide. The pores of the glassy matrix are large enough to admit hydrogen molecules, but small enough to trap the micrometer-sized particles of equilibrated metal hydrides. Figure 1-37 is a schematic of the sol-gel metal hydride and sol-gel membrane process developed by L.K. Heung et al. of SRTC.

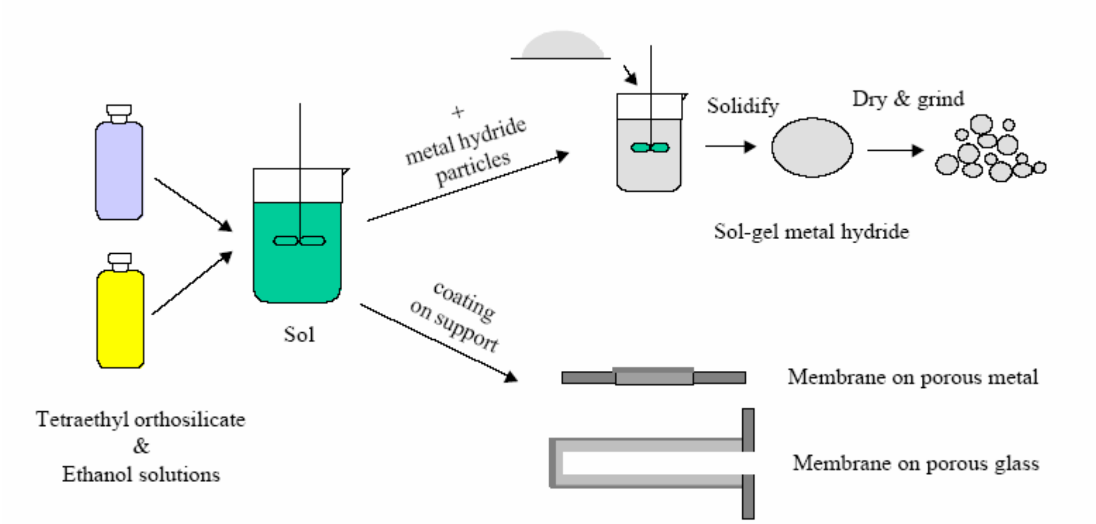



Figure 1-37 Schematic of Sol-Gel Metal Hydride and Sol-Gel Membrane Process

Furthermore, research at Savannah River has demonstrated that the encapsulation technology confers a level of chemical resistance on the metal hydrides. Thus these composite materials may obviate the most severe limitations of traditional metal hydride sorbents, namely their tendency to fracture into intractably small particles and their adverse interaction with other components of the reaction stream. This encapsulation technology appears to solve three problems that have attended the use of metal hydrides for separation of hydrogen from dilute streams:

- The small size of the encapsulated particles speeds up mass transfer and thus the rate of hydrogen sorption and desorption
- The encapsulation facilitates handling of the very small particles of metal hydrides that have been fractured upon repeated cycling (owing to the different lattice constants of hydrided and dehydrided materials)
- The encapsulation also promises to confer resistance to poisoning by impurities in the hydrogen stream, presumably impeding access to the metal hydride for the impurities but not the much smaller molecules of $H_2$.

Fluorination treatment of metal hydrides has been extensively studied by Japanese researchers S. Suda and X. -L. Wang at Kogakuin University, in collaboration with scientists at Japan Metals and Chemicals. They report that a 0.1-1 µm fluorinated surface layer can be formed on a hydriding alloy particle to protect it from molecules of relatively large atomic size. The coating is formed using a weak acidic $F^-$ containing aqueous solution. Suda et al. measured less than a 1% capacity loss and minimal hydriding reaction rate after ten cycles in hydrogen containing 1000 ppm CO at 50 °C. Figure 1-38 shows how the fluoride top-layer may offer the metal hydride improved resistance to impurities.

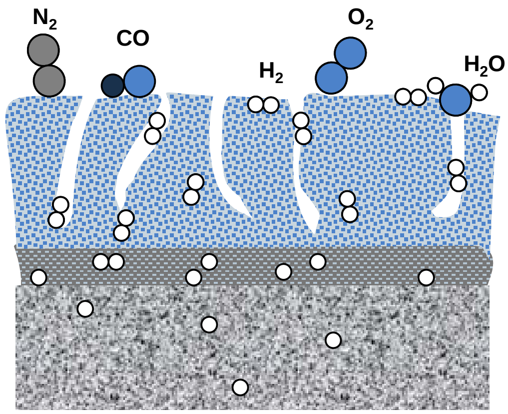



Figure 1-38: Fluorinated Metal Hydrides May Offer Better Impurity Resistance

Researchers at DSM and the University of Twente, Netherlands have conducted demonstrations on hydrogen purification using metal hydride slurries. Ptasinski, van Swaaij, Holstvoogd, Versteeg et al. published several papers between 1980-1994 based on their work on kinetics of $H_2$ absorption/desorption in $LaNi_{5-x}Al_x$ slurries and $H_2$ recovery from lean gas mixtures using metal hydride slurries.

#### *1.7.4.2 Hydride Separation Process Description*

The separation/purification process will be based on a temperature swing cycle, making use of the fact that absorption of hydrogen is exothermic. The process may be carried out in either a batch mode, using a packed column that is alternately cooled and heated, or in a continuous mode, using a moving bed reactor in which the particles of sorbent are circulated in the form of a slurry between cooled and heated sections. In the latter case, the encapsulating shell surrounding the particles may play a role in moderating attrition and in decreasing the minimum fluidization velocity. Figure 1-39 shows a schematic representation of metal hydride based hydrogen purification or separation.

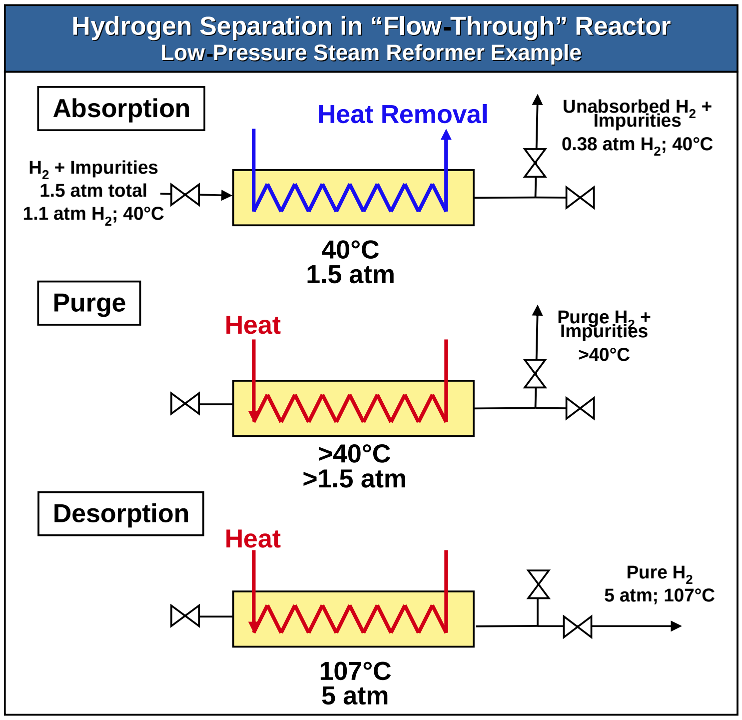



Figure 1-39: Schematic Representation of Metal Hydride Based Hydrogen Purification

A typical low-temperature metal hydride is assumed in order to determine physical properties such as density, heat of reaction and slurry viscosity. These properties will affect the subsequent design of equipment such as absorber and desorber columns (heat exchangers), slurry pumps, and agitated storage tanks. Table 1-33 shows the physical properties of relevance for $TiFe_{0.85}Mn_{0.15}$ slurried with *n*-octane.

Table 1-33
Physical Properties of $TiFe_{0.85}Mn_{0.15}$ / *n*-octane slurry

| **Characteristic** | **Units** | **Value** |
|---|---|---|
| Metal hydride | - | $TiFe_{.85}Mn_{.15}$ |
| Metal hydride density | $kg/m^3$ | 6,500 |
| Liquid carrier | - | *n*-octane |
| Liquid carrier density | $kg/m^3$ | 703 |
| Liquid carrier viscosity | Pa-sec | 4.81e-4 |
| Solids loading in slurry | wt. % | 50 |
| Slurry density | $kg/m^3$ | 1,270 |
| Slurry viscosity | Pa-sec | 5.10e-3 |
| Metal hydride heat of desorption | kJ/mol $H_2$ | 29.5 |
| Specific heat of liquid carrier | kJ/kg-K | 1.77 |
| Desorption energy required for slurry | kJ/kg $H_2$ | 19,000 |
| Desorption energy required for slurry | kJ/kg slurry | 143 |

#### 1.7.4.3 *Equipment Description*

The major components of a hydride-based hydrogen separation plant are:

- Absorber
- Stripping column
- Desorber
- Storage vessels
- Pump and compressor

Figure 1-40 below shows dry metal hydride-based hydrogen separation from low-pressure steam reformer reformate stream.

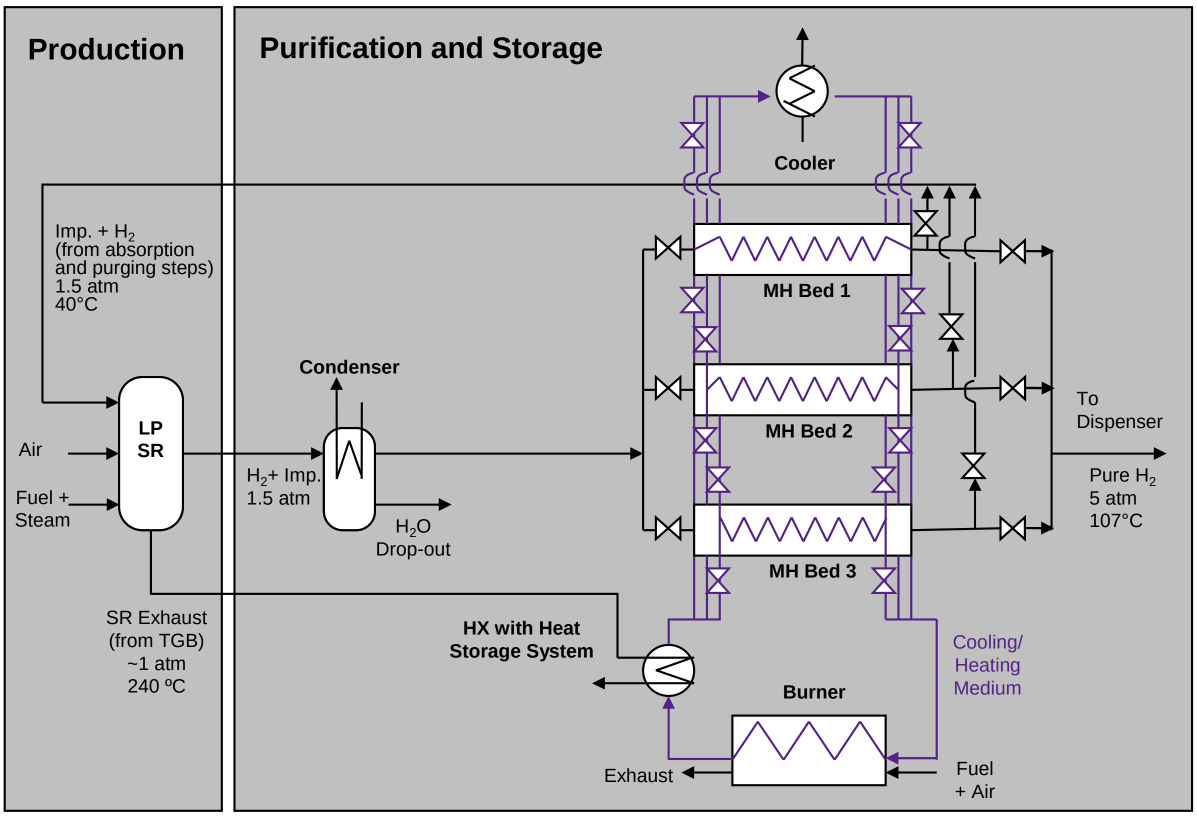



Figure 1-40 Dry Metal Hydride Based Hydrogen Separation from Reformate Stream

Figure 1-41 shows metal hydride slurry-based hydrogen separation from low-pressure steam reformer reformate stream.

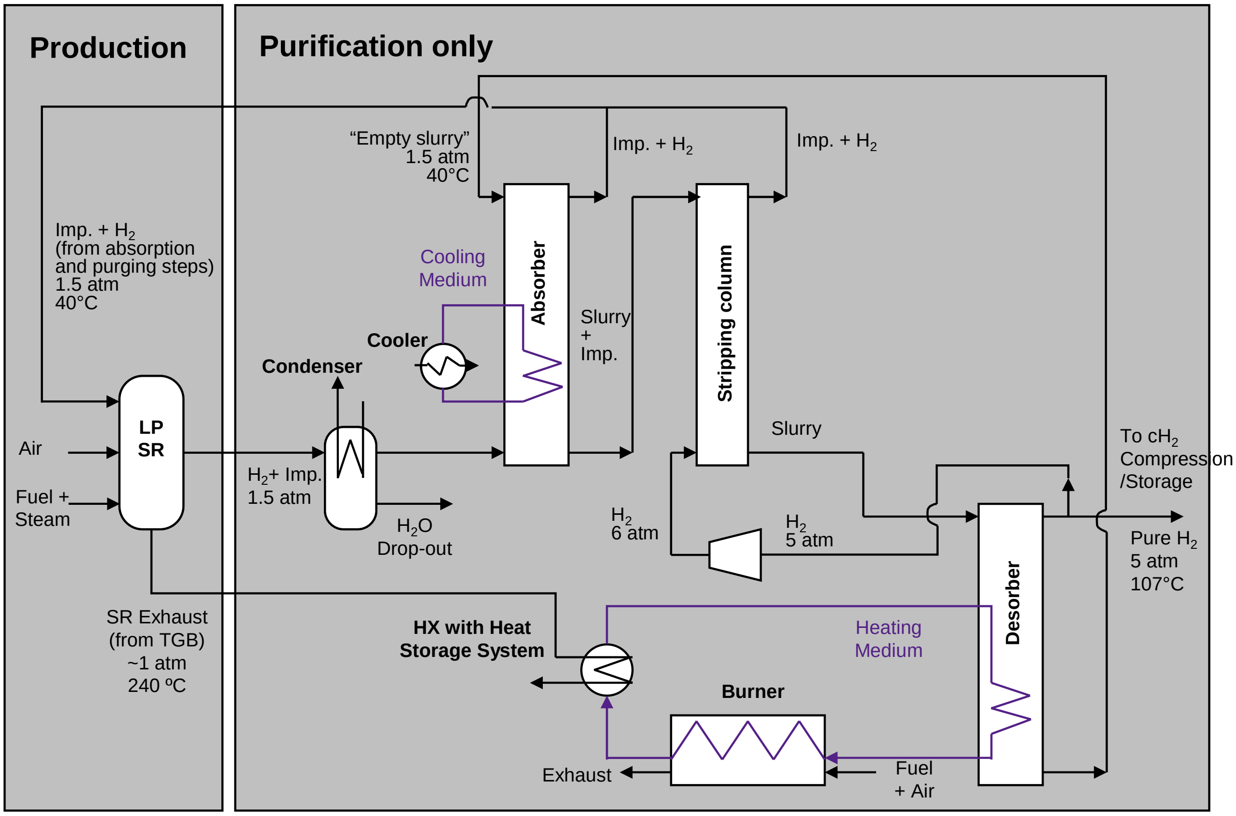



Figure 1-41 Metal Hydride Slurry Based Hydrogen Separation from Reformate Stream

### *1.7.4.4 Energy Inputs*

Figure 1-42 shows the primary energy requirement for hydrogen separation from high-pressure steam reformer reformate streams. Although the PSA has the lowest energy requirement, the metal hydride slurry based separation has the potential to have the least energy requirement if waste heat can be used for de-hydrogenation.

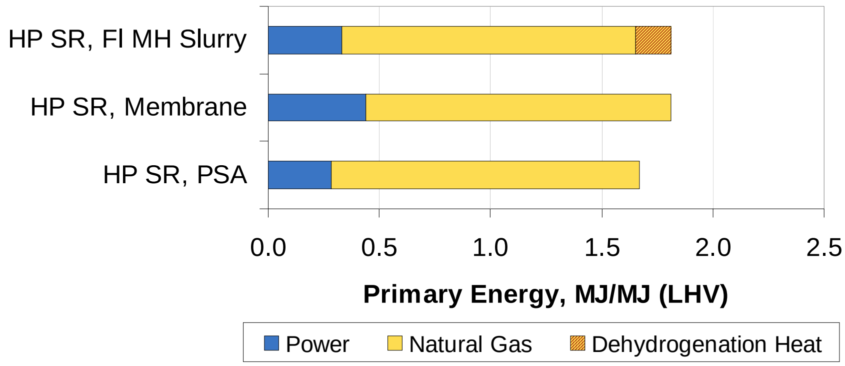



Figure 1-42 Primary Energy Requirement for $H_2$ Separation from HP SR Reformate Streams

### *1.7.4.5 Cost*

In a previous DOE assessment, TIAX performed a capital cost analysis for a 300 vehicle per day compressed hydrogen fueling station using metal hydride slurry $H_2$ purification. Table 1-34 summarizes the major component and material costs for the hydrogen purification system.

Table 1-34
Capital Cost for 300 Vehicle/Day Compressed Hydrogen Fueling Station using Metal Hydride Slurry Hydrogen Purification

| MH Slurry System for 300veh/day Station | Units | Purification and Storage | | | | Purification | |
|---|---|---|---|---|---|---|---|
| | | HP SR | HP ATR | LP SR | LP ATR | HP SR | LP SR |
| **Operating Pressure** | atm | 10 | 10 | 1.5 | 3 | 10 | 1.5 |
| **MH Price** | $/kg | $18 | | | | | |
| **Liquid Phase Price** | $/kg | $2 | | | | | |
| **Total MH Slurry Cost** | $ | $413,900 | $414,300 | $413,100 | $412,600 | $5,200 | $5,400 |
| **Absorber** | $ | $8,400 | $9,900 | $12,100 | $14,500 | $8,400 | $12,100 |
| **Stripping Column** | $ | $2,800 | $2,800 | $2,800 | $2,800 | $2,800 | $2,800 |
| **Desorber** | $ | $12,600 | $12,600 | $12,600 | $12,600 | $8,100 | $8,100 |
| **Storage Vessels Cost** | $ | $5,100 | $5,100 | $5,100 | $5,100 | $0 | $0 |
| **Pump and Compressor** | $ | $1,800 | $1,800 | $1,800 | $1,800 | $1,800 | $1,800 |
| **Total Cost** | **$** | **$444,600** | **$446,500** | **$447,500** | **$449,400** | **$26,300** | **$30,200** |

Figure 1-43 compares the capital cost of a central high-pressure steam reformer plant, with compressed hydrogen storage and dispensing, and three options for hydrogen purification, i.e. PSA, membrane and fluorinated metal hydride slurry.

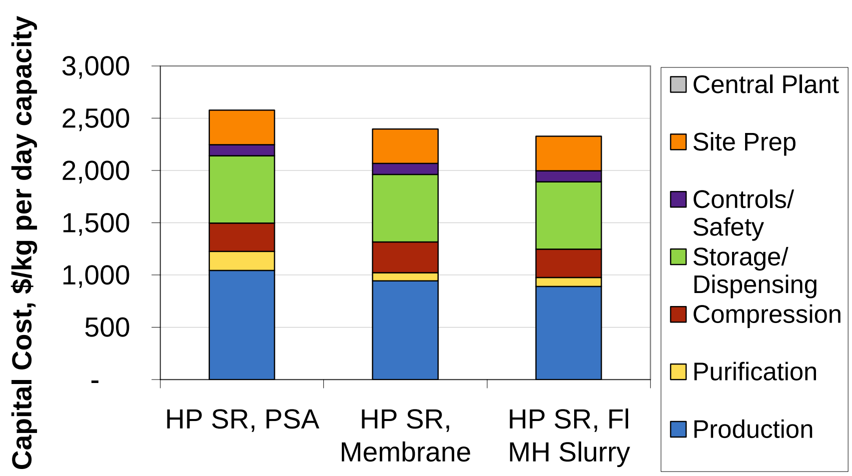


Figure 1-43  Capital Cost for Steam Reformer Central Plant with Hydrogen Purification

Figure 1-44 shows that fluorinated metal hydride slurry with low-pressure steam reforming rivals central plant options for lowest overall capital cost input for compressed hydrogen fueling stations.  Note that the purification category includes the reformate compressor costs for the low-pressure reformer with PSA or membrane purification.

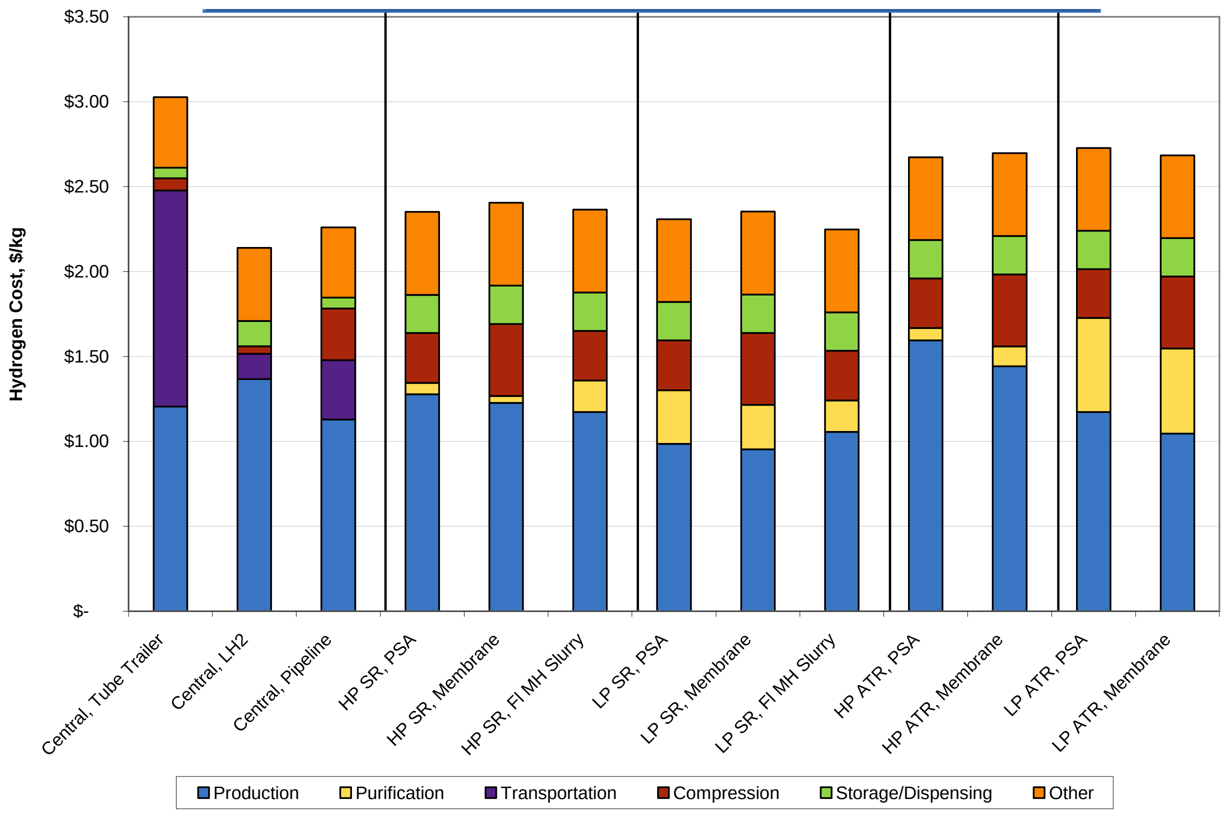



Figure 1-44  Capital Cost for Compressed Hydrogen Vehicle Fueling Station (300 vehicle/day)

### 1.7.5 Membrane Separation

Membranes have been considered recently for separating reformate steams especially for smaller scale processes.  Membranes work on the principle of selective gas permeation.  "Fast" gases such as hydrogen, permeate through the membrane and leave "slow" gases such as nitrogen and hydrocarbons behind.  The driving force of the process is hydrogen partial pressure difference. The feed stream is pressurized and the fast gases permeate through the membrane to the lower pressure side. Membrane separation has been limited by materials strength, low selectivity, and inherent reactivity.  Impurities of concern are CO, $H_2S$, and heavy hydrocarbons.

Metallic membranes are a special class that is only permeable (i.e., 100 percent selective) to hydrogen.  Conventional metallic membrane technology operating at 16 atm gives 85 percent hydrogen recovery from typical steam reformate streams but only 75 percent recovery from typical autothermal reformate steams and the systems cost significantly more. Using membranes to separate natural gas and hydrogen would require a very high pressure differential or large surface area. High inlet pressure (60 – 80 atm) may be attainable with the natural gas / hydrogen pipeline, but most conventional membranes cannot withstand pressure differentials greater than about 20 atm. Therefore, large surface area would likely be required resulting in high cost. In addition, the need to repressurize the hydrogen after it passes through the membrane presents a large parasitic loss.

Zirconium based membranes are potentially a lower cost alternative to palladium supported membranes

- Palladium price exceeded $1,000 per troy ounce in 2000 due to its strategic use in the autocatalyst industry. Current price is $361 per troy ounce.
- DOE funds many palladium-supported membrane technologies and refractory metals materials research (Mo, W, Ta, Re, Nb)
- Japanese researchers have promising results from non-palladium, amorphous alloy (mainly zirconium-nickel) membranes that have not received DOE funding
- Non-palladium alloys may be two orders of magnitude cheaper than palladium-based alloys on a weight basis (Hara 2000)

## 1.8 HYDROGEN STORAGE NEEDS FOR DELIVERY INFRASTRUCTURE

In this subtask, Nexant surveyed and reviewed applicable technologies, existing or in development, for the required storage of hydrogen and/or carriers within the delivery infrastructure as input to conduct Tasks 5 and 6. The technologies surveyed include:

- High pressure gas and liquid hydrogen storage at terminals and refueling sites
- Geologic hydrogen gas storage
- Storage for carriers within the delivery infrastructure

Hydrogen can be stored as a compressed gas, a liquid, or may be combined with a metal hydride. Geological storage is also an option, especially if hydrogen is to serve large and geographically diverse market such as that now served by natural gas. Also, while geological storage technology is a general commercial gas storage, it may have new applications when examined in connection with potential hydrogen storage and $CO_2$ sequestration. Both operations will require similar geological formations, and procedures for measuring and monitoring the stored material. Significant public education work will be required for underground storage of both hydrogen and $CO_2$.

### 1.8.1 Hydrogen Storage Properties

Hydrogen molecules exist in para- and ortho- forms, depending on the electron configurations in the two atoms in the molecule. At hydrogen's boiling point of -423 °F, the equilibrium concentration is primarily para-hydrogen; however, at room temperature and above, the equilibrium concentration is about 25 percent para- and 75 percent ortho-hydrogen. The conversion of ortho- to para-hydrogen is very slow in the absence of a catalyst to promote the reaction. If the hydrogen is liquefied without first catalytically converting the ortho- to the para-form, the ortho-hydrogen will slowly convert to para-hydrogen in an exothermic reaction releasing about 230 Btu/$lb_m$ of energy.

### 1.8.2 Liquid, Compressed Gas, and Geological Storage

#### *1.8.2.1 Liquid Hydrogen Storage*

The heat of transformation from the ortho- to para-hydrogen conversion can cause the evaporation of as much as 50 percent of the liquid hydrogen over a 10 day period. Thus, long-term storage of hydrogen will require the conversion to minimize boil-off losses. Conversion catalysts include activated carbon, ferric oxide, rare earth metals, uranium compounds, chromic oxide, and some nickel compounds. The heat released during conversion is usually removed by cooling with liquid nitrogen, then further cooling with liquid hydrogen.

Even after conversion of the ortho- to the para- form, boil-off is still a major concern for liquid storage. The critical pressure and temperature of hydrogen are only 13 bar and 33 °K, respectively. As such, hydrogen cannot exist as a liquid within the range of the more common storage temperature; i.e., 100 °K for liquid nitrogen up to 298 °K at ambient conditions. Thus, the liquid must be stored as a cryogenic fluid at its boiling point, and any heat transfer to the liquid causes some of the hydrogen to evaporate. Typical heat sources include ortho- to para-conversion, mixing or pumping equipment, or heat transer through the storage vessel. Cryogenic containers minimize conductive, convective, and radiant heat transfer by using double-wall construction with a vacuum in the space between the walls. Layers of reflective, low-emittance heat shielding are used between the inner and outer walls to minimize radiant heat transfer. Some large storage vessels have an additional outer wall, with the space filled by liquid nitrogen.

Most liquid hydrogen tanks are spherical, which minimizes the heat transfer surface area per unit of storage volume. Storing hydrogen as a liquid is a mature technology, as illustrated by the large 850,000 gallon storage at the NASA Kennedy Space Center in Figure 1-45. The energy required for hydrogen liquefaction is equal to about 30 percent of the heating value of hydrogen being liquefied. Evaporation losses further increase the effective liquefaction energy by requiring any gas to be captured and re-liquefied.

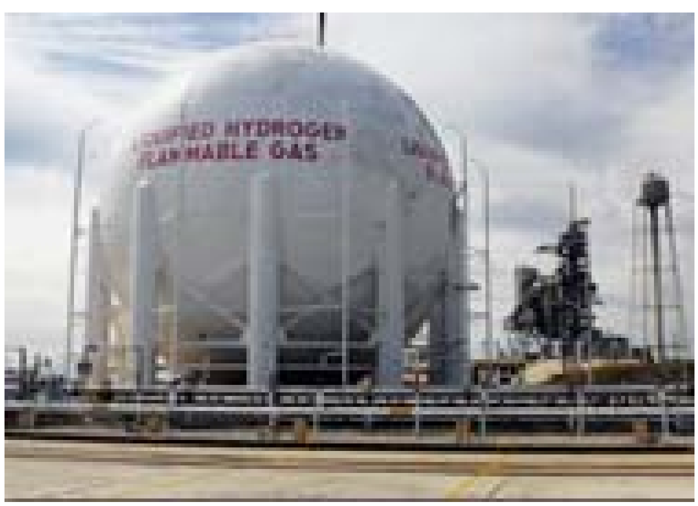


Figure 1-45 Liquid Hydrogen Storage at NASA Kennedy Space Center (NASA Photo)

For transporting liquid hydrogen, the volume to surface area advantage of spherical tanks is often sacrificed, and more economical and transportable cylindrical tanks are used. Figure 1-46 shows a liquid hydrogen truck and trailer. The units, which typically have capacities of 12,000 to 17,000 gallons, use many of the design features as stationary tanks, but must also meet Department of Transportation regulations.


Figure 1-46 Liquid Hydrogen Transport Tanker

#### *1.8.2.2 Compressed Gas Storage*

Compressed gas storage of hydrogen is perhaps the simplest storage solution. The main problem with compressed gas storage is the low energy density. While the energy density can be increased by higher pressures, capital and operating costs must be evaluated as a tradeoff with the increased storage capability. Low pressure spherical tanks typically operate at 1,700 to 2,300 psig (117 to 158 bars g), while high pressure cylindrical vessels have operating pressures of 2,900 to perhaps 12,000 psig (200 to perhaps 828 bars g).

It can be noted that the hydrogen delivered to a forecourt by a truck transporter is lower than might be expected, for two reasons:

1) All gases, including hydrogen, exhibit non-ideal gas behavior at high pressures. As such, the mass of hydrogen transported by the truck is less than that predicted by the familiar expression PV = mRT.

2) The storage tanks on the transport trucks are designed for a maximum pressure of about 3,600 psig (248 bars g), while the forecourt storage tanks operate at pressures in the range of 6,000 psig (414 bars g) to perhaps 12,000 psig (828 bars g). As a result, the transfer of the hydrogen from the truck to the forecourt will require a compressor. However, compressors are designed for reasonable efficiencies only over a limited pressure ratio range, and drawing the truck tank pressures to values much below 400 psig (27.6 bars g) will likely be inefficient.

Storage tanks for truck transport and stationary use are typically fabricated from steel. However, considerable effort has been devoted to the design and analysis of composite storage tanks for light duty vehicle use. Current tank designs are typically filament wound, with either a polyethylene or an aluminum liner, as illustrated in Figure 1-47 [38].

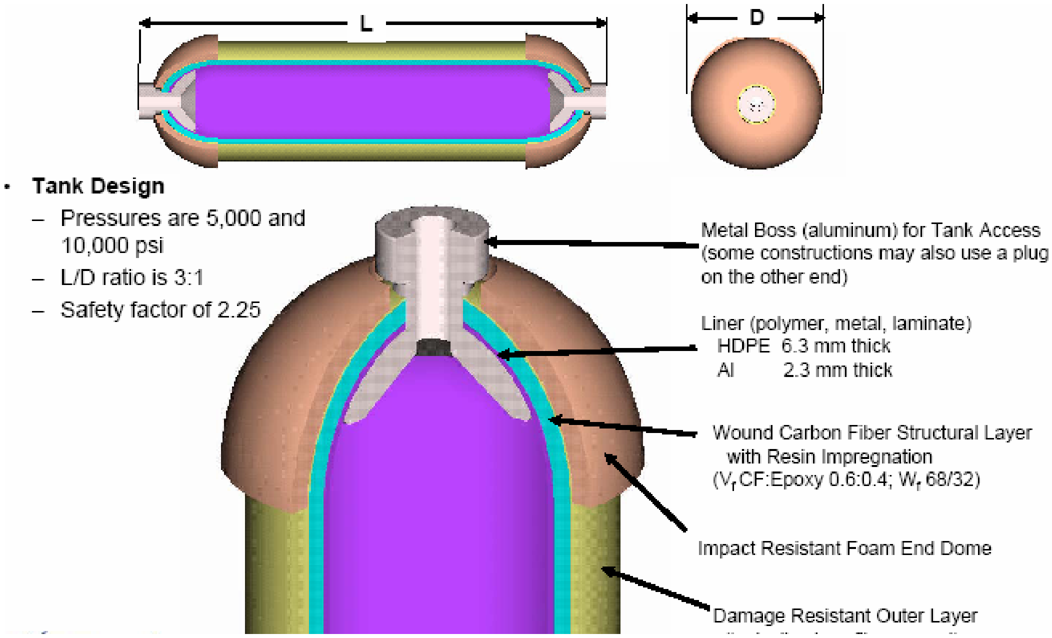



Figure 1-47 Compressed Hydrogen Composite Tank Design

The DOE has set a series of performance and cost criteria for current and future compressed gas storage tanks. These criteria, together with the results from an analysis of a state-of-the-art composite tank, are summarized in Table 1-35. Although current tank designs, even with operating pressures as high as 10,000 psig (690 bars g), do not meet the near term DOE targets for energy density and cost, similar tank designs might find application in future truck transport or forecourt storage designs.

Table 1-35
Performance and Costs of Compressed Hydrogen Storage Tanks for Light Duty Vehicles

| | DOE Targets | | | Model Results | |
|---|---|---|---|---|---|
| System Metric | 2005 | 2010 | 2015 | 5,000 psi | 10,000 psi |
| Cost ($/kWh) | 6 | 4 | 2 | 10 - 16 | 14 - 24 |
| Specific Energy (Wt%) | 4.5 | 6 | 9 | 6.7 | 6.3 |
| Energy Density (kWh/liter) | 1.2 | 1.5 | 2.7 | 0.6* | 0.9* |

* Tank volume only

#### 1.8.2.3 Underground Storage

If the properties of a geological formation are suitable, underground storage of hydrogen gas is a potential alternative. Underground storage of natural gas is widespread in connection with natural gas pipeline systems. The storage caverns may be natural formations or man-made structures. Porous formations are also used for gas storage in areas of existing or depleted oil/gas fields.

The principal geological requirement is an impermeable cap rock to prevent leakage of the gas to the surface. Also, a very careful geological survey will be required to locate any faults, abandoned drill holes, or other features that could allow the gas to escape from the planned storage area. In January 2001, a natural gas explosion killed 2 people in Hutchinson, Kansas; the gas leaked from geological storage site, and migrated some 7 miles to the town via a combination of abandoned brine wells and geological formations.

### 1.8.3 Research and Development in Hydrogen Storage Technologies

The three generic mechanisms for storing hydrogen in materials are as noted below:

- Absorption. Hydrogen is absorbed directly into the bulk of the material. In simple crystalline metal hydrides, the atomic hydrogen is incorporated into interstitial sites in the crystallographic lattice structure.
- Adsorption. There are two mechanisms, physisorption and chemisorption, based on the energetics of the adsorption mechanism.
- Physisorbed hydrogen is weakly energetically bound to the material. One of the more promising concepts is that under development by Air Products, which uses perhydro-N-ethyl carbazole as the adsorpter. The storage capacity is about 6 weight percent hydrogen. The hydrogenation process occurs at a temperature and pressure of 170 °C and 1,000 psi (69 bars), respectively, while the dehydrogenation temperature is a favorable 190 °C. Research is underway with similar fluids to increase the hydrogen capacity, and to reduce the dehydrogenation temperature to the 80 - 90 °C operating temperatures characteristic of PEM fuel cells.
- Sorptive processes typically require highly porous materials to maximize the surface area for easy uptake and release of the hydrogen.
- Chemical reaction. The hydrogen storage involves displacive chemical reactions for both hydrogen generation and hydrogen storage. For reactions that may be reversible on-board a vehicle, hydrogen generation and hydrogen storage take place by a simple reversal of the chemical reaction as a result of modest changes in the temperature and pressure. Sodium alanate-based complex metal hydrides are an example. In many cases, the hydrogen generation reaction is not reversible under modest temperature/pressure changes. Therefore, although hydrogen can be generated on-board the vehicle, getting hydrogen back into the starting material must be done off-board. Sodium borohydride is an example.

The following programs are being lead by the US DOE and others:

- Research and development in complex metal hydrides targets advanced materials, including light-weight complex hydrides, destabilized binary hydrides, intermetallic hydrides, modified lithium amides, and other on-board reversible hydrides.
- Chemical hydrogen storage research and development is focusing on low cost, energy efficent regeneration systems for these irreversible storage systems. Currently, borohydride-water systems, magnesium-hydride slurries, and innovation beyond boron are under investigation.
- Carbon-based materials for hydrogen storage use high surface area sorbents such as hybrid carbon nanotubes, aerogels, and nanofibers, as well as metal-organic frameworks and conducting polymers. A coordinated experimental and theoretical effort is underway to characterize the materials, to understand the mechanism and extent of hydrogen absorption/adsorption, and to improve the reproducibility of the measured performance.

Idaho National Energy Laboratory and others are investigating the use of graphite nano-fibers ("carbon whiskers") and other similar concepts. The fibers are typically 5 to 100 microns long, with a diameter of 5 to 100 nanometers, and are made up of stacks of platelets. The graphite substrate serves as an adsorbent to store hydrogen at low to moderate pressure. Pressurizing the tank during filling causes the substrate to adsorb the hydrogen molecules, and depressurization causes the hydrogen to be released. So far, results of tests using such substrates have been inconclusive, and the mass of hydrogen projected to be stored is not especially impressive. However, the Laboratory is pursuing a collaborative effort with an industrial partner on a technology that promises to greatly improve the storage effectiveness. The technology uses metal ions to intercalate graphite fibers to increase the adsorption area. Additional details about this promising technology are proprietary at this time.

## 1.9 ETHANOL / METHANOL / AMMONIA TRANSPORT AND CONVERSION TO $H_2$

Ethanol, methanol, and ammonia are all mechanisms for transporting hydrogen in a liquid form. Once delivered to the forecourt, the ethanol can be reformed with steam to produce hydrogen and carbon dioxide. The hydrogen is separated from the carbon dioxide, and compressed for delivery to the fuel cell vehicle. In a somewhat different process, the methanol can be dissociated at moderate temperatures to form a mixture of carbon monoxide and hydrogen. The carbon monoxide is then further reacted with steam, in the familiar water-gas shift reaction, to form additional hydrogen.

In a similar process, ammonia can be dissociated at high temperatures to form a mixture of hydrogen and nitrogen gases. The hydrogen is separated from the nitrogen, and the hydrogen compressed for delivery.

Of the three carriers, ethanol is perhaps of the highest long term interest. The ethanol is derived from renewable resources, such as corn or switchgrass, and is non-toxic. However, ethanol is considerably more difficult to reform than methanol, as high molar ratios of water to ethanol must be used to prevent carbon deposition. In contrast, methanol is readily dissociated / reformed to produce hydrogen. However, methanol is toxic, and is normally derived from non-renewable resources, such as natural gas. Similarly, ammonia is both toxic and is produced from natural gas. In addition, following dissociation, the separation of hydrogen from unreacted ammonia is likely to be energy intensive, as fuel cells are generally intolerant of ammonia.

The practicalities of producing ethanol, methanol, and ammonia on the large scales required for a hydrogen economy are outlined below.

### 1.9.1 Ethanol

#### *1.9.1.1 Production*

At its most basic, ethanol is grain alcohol. The majority of the ethanol in the U.S. is made from corn, but it can also be produced from other feedstocks such as grain sorghum, wheat, barley, potatoes, switchgrass, or dedicated energy crops. Brazil, the world's largest ethanol producer, makes the fuel from sugarcane.

Most of the ethanol in the U.S. is made using the dry mill method, in which the starch portion of the corn is fermented into sugar, then fermented into alcohol. The major steps in the dry milling process are as follows:

1. **Milling** - The feedstock passes through a hammer mill, which grinds it into a fine powder called meal.

2. **Liquefaction** - The meal is mixed with water and alpha-amylase, then passed through cookers where the starch is liquefied.

3. **Saccharification -** The mash from the cookers is cooled and the secondary enzyme, gluco-amylase, is added to convert the liquefied starch to a fermentable sugar, dextrose.

4. **Fermentation** - Yeast is added to the mash to ferment the sugars to ethanol and carbon dioxide.

5. **Distillation** - The fermented mash contains about 10 percent alcohol, plus all the non-fermentable solids from the corn and yeast cells. The mash is pumped to the continuous flow, multi-column distillation system, where the alcohol is removed from the solids and the water. The alcohol leaves the top of the final column at about 96 percent strength, and the residue mash is transferred to the co-product processing area.

6. **Dehydration**. The alcohol from the top of the column passes through a molecular sieve dehydration system, where the remaining water is removed. The alcohol product at this stage is called anhydrous ethanol (pure, without water) and is approximately 200 proof.

7. **Denaturing**. Ethanol that will be used for fuel must be denatured, or made unfit for human consumption, by the addition of 2 to 5 percent gasoline.

8. **Co-Products**. There are two main co-products created in the production of ethanol: distillers grain; and carbon dioxide. Distillers grain, used wet or dry, is a livestock feed. Carbon dioxide, in many ethanol plants, is collected, compressed, and sold for use in other industries.

The production rate of ethanol, in millions of gallons per year, from 1980 through 2003 is illustrated in Figure 1-48, and the principal geographic regions of ethanol production are shown in Figure 1-49. The principal interest in ethanol began in the 1970s, when oil supply disruptions in the Middle East became a national security issue, and America began to phase out tetraethyl lead as an octane booster from gasoline. Several major oil companies began to market ethanol as a gasoline volume extender and as an octane booster. In 1978, Congress approved the National Energy Act, which included a Federal tax exemption for gasoline containing 10 percent alcohol; the subsidy reduced the cost of ethanol to around the wholesale price of gasoline, making it economically viable as a gasoline blending component. The growth of ethanol was enhanced substantially by State tax incentives to ethanol producers. The combination of Federal and State tax incentives made ethanol economically attractive in the Midwest, but the difficulty and high cost of transporting ethanol precludes consumption in other markets.

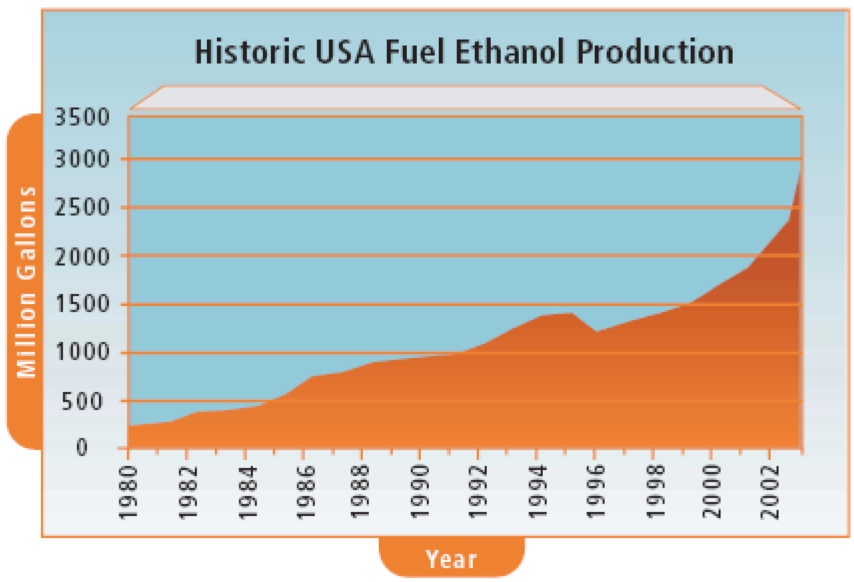



Figure 1-48 Historic Annual US Ethanol Production
Million Gallons Per Year - 1980 to 2003

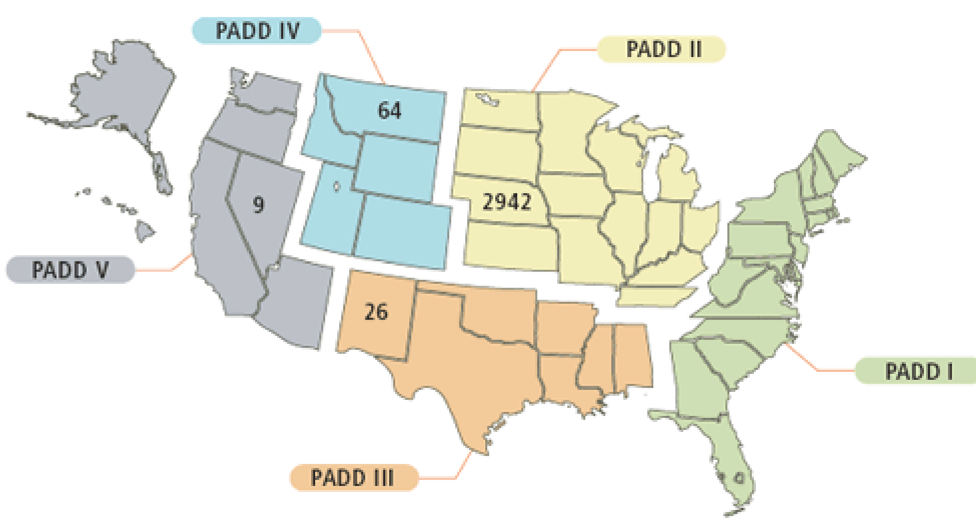


Figure 1-49 Ethanol Production Capacity by PADD
(Petroleum Administration for Defense District) - Millions of Gallons per Year

Since 1980, ethanol has enjoyed considerable success. The ethanol program received a boost from Congress in 1990 with the passage of the Clean Air Act Amendments, which mandated the use of oxygenated fuels in specific regions during the winter months to reduce carbon monoxide. The two most common methods to increase the oxygen level are blending with either methyl tertiary butyl ether (MTBE) or ethanol. Unfortunately, ethanol's high volatility, measured by Reid vapor pressure, limits its use in hot weather, where evaporative emissions can contribute to ozone formation. However, in consideration of the environmental benefits to the use of ethanol, amendements to the Clean Air Act were enacted in 2001 allowing an increase of 1 psi (0.069 bars) in the Reid vapor pressure for gasoline containing 10 percent ethanol.. As a result, ethanol's expanded role as a clean-air additive has allowed it to penetrate markets outside the Midwest.

The projected rates of ethanol production for 2004 through 2012 are presented in Figure 1-50, and the distribution of ethanol for direct blending (10 percent ethanol) or E85 production (85 percent ethanol) are summarized in Table 1-36.


Figure 1-50 Projected Annual US Ethanol Production
Million Gallons Per Year - 2004 to 2012

Table 1-36
Projected Uses of Ethanol (Thousands Barrels per Day)

| Ethanol Use | 1998 | 2005 | 2010 | 2020 |
|---|---|---|---|---|
| Direct Blending | 90 | 106 | 107 | 131 |

| | | | | |
|---|---|---|---|---|
| E85 | 0 | 20 | 35 | 49 |
| Total | 90 | 126 | 142 | 180 |
| Sources: 1998: Energy Information Administration (EIA), *Petroleum Supply Annual 1998*, DOE/EIA-0340(98/1) (Washington, DC, June 1999). Projections: EIA, AEO2000 National Energy Modeling System run AEO2K.D100199A. | | | | |

### *1.9.1.2 Current Ethanol Prices*

In mid-2005, the rack price for ethanol, at the point of rail shipment, ranged from $1.55 to $1.66 per gallon. However, by May 2006, the rack prices in the mid-West ranged from $2.63 to $2.87 per gallon. The increase in price likely follows from a combination of increases in the price of crude oil during this period, and the mandated replacement of methyl tertiary butyl ether with ethanol as the oxygenate in reformulated gasoline in several states.

### *1.9.1.3 Current Tax Credits*

Ethanol currently enjoys a Volumetric Ethanol Excise Tax Credit. The credit is assessed at a rate of 51 cents per gallon of ethanol, and the entire excise tax is assessed on the finished gasoline. The credit applies to any blend of ethanol and gasoline, and it also applies to ethyl tertiary butyl ether (ETBE), a gasoline blending component made from ethanol. The excise tax exemption does not apply to blends containing less than 5.7 percent, or more than 10 percent, ethanol, such as E85. The credit is effective through 2010. However, the tax credits are assumed to remain in force indefinitely, given that historically they have been extended when they expired.

The lower heating value for ethanol is approximately two-thirds that of gasoline. Thus, an average wholesale price of $2.75 per gallon of ethanol, before the application of the tax credit, is equivalent, before taxes, to a price of $4.15 per gallon of gasoline.

Similarly, the net cost of ethanol, after application of the tax credit, is about $2.25 per gallon, which is equivalent, before taxes, to approximately $3.35 per gallon of gasoline.

### *1.9.1.4 Ethanol Potential in the United States*

In 2004, the ethanol industry processed 1.26 billion bushels of corn, producing about 3.5 billion gallons of ethanol. The total US corn production capacity is currently 11.8 billion bushels.[34] If all of domestic corn production were converted to ethanol, the production capacity would be about 33 billion gallons per year. Converting this volume of ethanol to hydrogen by means of auto thermal reforming would yield approximately 17 million kg of hydrogen each year. Assuming 1 kg of hydrogen in a fuel cell vehicle is equivalent to 2 gallons of gasoline to today's cars, hydrogen from biomass ethanol could offset about 25 percent of the current domestic gasoline consumption

### *1.9.1.5 Energy Use in the Production of Ethanol*

The energy required to produce a gallon of ethanol is strongly influenced by the allocation of energies to 1) ethanol, and 2) the byproducts of ethanol production.[35],[36] The current preferred method for ethanol production is dry milling, and the principal byproduct is distillers dried grain with solubles (DDGS). DDGS is sold as a feed supplement for cattle, pigs, and chickens.

A comprehensive 2004 study by the US Department of Agriculture shows the fossil energy content to produce a gallon of ethanol as 69,600 Btu/gallon if all of the energy in producing the ethanol is ascribed to the ethanol. The energy requirements include corn seed production, fertilizer production, corn harvesting, corn transportation, ethanol conversion, and ethanol distribution. Assuming a lower heating value of 76,000 Btu/gal for ethanol results in an energy out / energy in ratio of only 1.09.

Nonetheless, many references to the efficiency of ethanol production, including the above USDA study, cite an energy out / energy in ratio of about 1.65. The higher value relies on the following approach: Corn is 60 to 66 percent starch, and if the energy used to produce the ethanol is proportioned by the starch content, not by the total corn content, then the energy out / energy in ratio improves to 1.65. Implied in this calculation is an unstated assumption that the energy used to convert the fiber, gluten, and oil in the corn to DDGS provides just as useful a product as the ethanol.

One can take the above analysis one step further by proportioning the energy inputs based on the relative economic values of the ethanol and the DDGS. For example, each bushel, or 56 pounds, of corn yields 2.8 gallons of ethanol and 17 pounds of DDGS. The ethanol is worth about $1.60/gallon, but the DDGS sells for only $75/ton. Further, average shipping costs for DDGS from the ethanol plants to dairy farmers, which are the largest consumers, average about $49/ton. Thus, the net value of DDGS is on the order of $124/ton. Thus, a bushel of corn yields $4.50 in ethanol, but only $1.00 in DDGS. If the energy used to produce a gallon of ethanol is apportioned based on the value of the product, as opposed to the starch content, the ratio of energy out / energy in is a more modest 1.34.Certainly, if the corn ethanol industry is to make a significant reduction in US gasoline consumption, the subject of the Federal subsidy will need to be revisited. A corn farmer purchases 69,600 Btu of fossil energy, and sells a gasoline distributor 76,000 Btu of ethanol energy. For the added 6,400 Btu, the government provides the farmer with a subsidy of $0.50. This is, in effect, the taxpayer purchasing energy from the agricultural industry at $80 per million Btu. Today, with ethanol meeting 2 percent of the gasoline demand, the subsidy does not attract national attention. However, as the ethanol industry grows in the coming years, a subsidy of $0.50/gallon can probably be neither politically nor economically supported. Market prices for biomass will, in the long run, need to determine the true ethanol pricing.

#### *1.9.1.6 Cellulosic Production of Ethanol*

There are numerous approaches to expanding the domestic production of ethanol beyond that which can be supported by the corn industry. In general, ethanol can be produced more efficiently using cellulose from switchgrass, rather than starch from corn and sugarcane. Several studies, and at least one demonstration project, are underway in methods for pretreating switchgrass or other agricultural waste to separate the sugars for fermentation. They all involve separating the cellulose and hemicellulose from the lignin, and then fracturing the cellulose and hemicellulose structure to allow enzymes access to the sugars. The lignin cannot be converted to ethanol, but it can be burned, and this is the principal source of thermal energy for the ethanol production steps. It is also the principal reason that ethanol from switchgrass is so much more efficient than ethanol from corn; the cellulose feedstock supplies its' own process heat, while the corn feedstock relies on external fossil fuels for its' process heat.

A likely upper limit on the domestic ethanol production is given in a study conducted by the National Resources Defense Council. The capacity limit is based on the following assumptions:

- Switchgrass yields can be increased from 5 dry tons per acre to 12.4 using agricultural methods similar to those used in hybrid corn production today.
- Ethanol production can be increased from 50 gallons per ton to 117 gallons per ton. For comparison, corn currently yields 100 gallons per ton of corn kernels.
- 114 million acres can be placed under cultivation without disrupting current food production methods. This is an area 425 miles by 425 miles, which would be a large portion of the Midwest.

Under these conditions, 165 billion gallons per year of ethanol could be produced, which is equivalent to 108 billion gallons of gasoline. This gasoline equivalent represents 85 percent of the current gasoline consumption, but only 35 percent of the projected gasoline consumption of 290 billion gallons per year in 2050. In essence, fuel economy would need to improve to 50 miles per gallon if the US were to supply all of its gasoline, as ethanol, in 2050.

Battelle has assembled a parallel report on the potential for biomass energy supplies in the US. The report addresses both the amount of land, which can be dedicated to ethanol production without adversely affecting current agriculture, and the price of the biomass as it relates to ethanol production. The report's most conservative assumption is to 1) use the branches, leaves, and stalks of food plants which would otherwise be plowed back into the soil, plus 2) plant switchgrass on the land set aside for the Conservation Reserve Program. The latter represents about 8 percent of US cropland. Under these conditions, 35 billion gallons of gasoline equivalent could be produced.

At the other end of the scale, to match the current US gasoline consumption of 135 billion gallons per year, something on the order of 75 percent of the US cropland would have to be dedicated to switchgrass. Clearly, this is unlikely to occur, and one might postulate the long term potential for ethanol production to be something on the order of 50 billion gallons of gasoline equivalent per year. This would correspond to 75 billion gallons per year of ethanol, which would be an increase of about 20 over the current ethanol capacity.

#### *1.9.1.7 Ethanol Reforming*

The preferred approach for ethanol reforming is steam reforming over a metal catalyst [41,42]. However, relatively large quantities of steam must be provided to suppress the formation of ethylene by the following dissociation reaction:

$$C_2H_5OH \rightarrow C_2H_4 + H_2O$$

Ethylene is deficient in hydrogen, and if it were to form, the ethylene would dissociate, depositing solid carbon onto the catlyst surfaces.
Small experimental evaluations in ethanol reforming have demonstrated the following:

- A typical catalyst is nickel, with a metal oxide substrate such as $CeO_2$, $Al_2O_3$, $Y_2O_3$, or $La_2O_3$
- Reformer temperatures are in the range of 600 to 1,100 °F, depending on the catalyst
- Ethanol conversions of 95 to 99 percent, with hydrogen selectivities of 50 to 60 percent, have been achieved
- Hydrogen yields are in the range of 80 to 85 percent of the stoichiometric value of 6 moles $H_2$ per mole ethanol.

Since the reformer steam-to-carbon ratio must be high to suppress the formation of ethylene, the thermal demand for the latent heat of water vaporatization is likely to be substantial. However, much of this latent heat can be recycled within the reformer by means of a recuperative heat exchanger.

On a point related to ethanol reforming, aqueous phase reforming concepts for hydrogen generation are under active development. However, aqueous systems are more appropriate for certain sugar alcohols, such as sorbitol and glycerol, rather than ethanol [43].

### 1.9.2 Methanol

#### *1.9.2.1 Production*

Methanol is produced in a number of different ways, but the primary route is through the synthesis of natural gas in the following reactions:

$$CH_4 + H_2O \rightarrow CO + 3H_2$$
$$CO + 2H_2 \rightarrow CH_3OH$$

Typically, natural gas is the major cost component of methanol production.

North America is the largest methanol consuming region in the world. In 2001, the US consumption exceeded 2,600 million gallons.[37]

Until the late 1990's, the US had 18 methanol plants, with production capability of about 2,600 million gallons. The following table details the domestic production facilities:

Table 1-37
Methanol Plants in the United States

| Company | Location | PADD [1] | Capacity, $10^6$ Gal/Yr | Built |
|---|---|---|---|---|
| Motiva | Delaware City, DE (closed) | 1 | 100 | 1978 |
| Air Products | Pace, FL | 1 | 60 | 1969 |
| Tennessee Eastman | Kingsport, TN | 2 | 65 | 1987 |
| Terra | Woodward, OK | 2 | 40 | 1994 |
| Ashland | Plaquemine, LA (closed) | 3 | 160 | 1983 |
| Borden | Geismar, LA (closed) | 3 | 330 | 1965 |
| BP/Sterling | Texas City, TX (closed) | 3 | 150 | 1975 |
| Enron | Pasadena, TX (closed) | 3 | 125 | 1970 |

| | | | | |
|---|---|---|---|---|
| Lyondell | Channelview, TX | 3 | 260 | 1983 |
| Fortier | Fortier, LA (closed) | 3 | 190 | 1994 |
| Georgia Gulf | Plaquemine, LA (closed) | 3 | 160 | 1981 |
| Celanese | Bishop, TX | 3 | 167 | 1968 |
| Celanese/Valero | Clear Lake, TX | 3 | 200 | 1966 |
| Liquid Carbonics | Geismar, LA | 3 | 30 | 1979 |
| Millennium | Deer Park, TX | 3 | 200 | 1968 |
| Terra/BMC | Beaumont, TX | 3 | 283 | 1977 |
| Coastal | Cheyenne, WY | 4 | 27 | 1989 |
| Sand Creek | Commerce City, CO (closed) | 4 | 33 | 1969 |

Note: PADD: Petroleum Administration for Defense Districts
1 East Coast; 2 Midwest; 3 Gulf Coast; 4 Rocky Mountain; 5 West Coast

Of the 18 domestic plants, 10 plants are currently in operation, producing about 1,332 million gallons per year. The remaining 8 plants were closed in the late 1990's and the early 2000's for a variety of economic reasons. In particular, several new methanol production facilities were built in regions with relatively cheap natural gas feedstock. At the same time, US natural gas feedstock prices were climbing to historically high levels. As a result, some of the older US plants found it difficult to compete with the new larger, and more efficient, plants.

Today, the United States produces about 1,250 million gallons per year, varying by operating rates. Approximately 40 percent of the domestic production is sold on the open market, with the balance delivered to a captive market, using the methanol internally as a feedstock for other products. The balance of methanol demand is covered in the global merchant market through imports.

In 2001, the United States imported approximately 1,800 million gallons of methanol, with the majority of the imports from the Caribbean. The United States occasionally exports relatively small volumes of methanol to Mexico, the Caribbean, and South America. The following table shows methanol import volumes into the United States from the major exporters.

Table 1-38
2001 Methanol Imports to the United States from Major Suppliers

| | |
|---|---|
| Chile | 963,000 metric tons |
| Trinidad | 1,649,000 metric tons |
| Venezuela | 832,000 metric tons |
| Equatorial Guinea | 407,000 metric tons |
| Canada | 361,000 metric tons |

#### *1.9.2.2 Demand*

Methanol is an important chemical building block used for many organic intermediates and downstream processes including esterification, ammoniation, methylation, and polymerization. The primary chemical intermediates include formaldehyde, acetic acid, methylamines, methyl methacrylate (MMA), dimethyl terephthalate (DMT), and methyl tertiary butyl ether (MTBE).

In the 1990's, MTBE production capacity grew in the United States from about 4,000 barrels per day to more than 250,000 bpd. Markets for MTBE have been largely driven by the legislative mandates of the federal Clean Air Act Amendments of 1990, which required the use of oxygenated gasoline in areas of the country, which failed to meet air quality standards. However, US demand is expected to fall sharply over the next few years, as several states have imposed a ban on MTBE due to contamination of groundwater from leaking gasoline storage tanks.

#### *1.9.2.3 Transportation*

The largest US methanol plants are concentrated on the Texas Gulf Coast between Houston and Beaumont, and are in close proximity to the major methanol derivative plants. Some of the methanol plants in this region are connected by pipeline to the major derivative plants.

Barge movements of methanol are seen between the Texas and Louisiana Gulf Coasts, as well as up the Mississippi River from terminals near New Orleans to discharge points throughout the Midwest. Typical methanol barges are 418,000 gallons.

Typical inland movements involve railcars and tanker trucks. Railway transportation is the most economic option for distances over 250 miles. Rail cars are typically 30,000 gallons, while the capacity of a tanker truck is about 8,000 gallons. Rail freight costs between the US Gulf Coast and the upper Midwest generally vay between 11 and 15 cents per gallon.

Methanol imports enter the United States at a number of regional ports, including New Orleans, Wilmington (South Carolina), New York, Seattle, San Francisco, and Los Angeles, although almost 80 percent enters the Texas and Louisiana Gulf Coasts. While methanol is consumed all across North America, the bulk of the consumption is on the US Gulf Coast between Texas and Louisiana. Imports into Louisiana are re-loaded onto smaller barges for movement up the Mississippi River to the Midwest.

Of approximately 2,600 million gallons of methanol sold each year in the US, about 2,100 million gallons is covered by the merchant market through contracts or spot sales. The remaining 500 million gallons per year is transferred between sellers and buyers across the United States.

#### *1.9.2.4 Bulk Storage*

Methanol can be stored in mild steel tanks, which are commonly used throughout the United States. Dedicated methanol storage tanks are already in service throughout the United States, and most major ports and terminal locations have ample room for expansion of existing facilities. The for-hire storage of bulk petrochemicals began about 40 years ago, and operates as a step in the delivery cycle. The primary functions of bulk storage include matching production rates with demand rates, and to accumulate product in an upwardly mobile market and to take advantage of higher prices at a later date. (what is the storage requirement and cost at forecourt??)

#### *1.9.2.5 Methanol Reforming*

Methanol is readily reformed through the following decomposition and shift reactions:

$$CH_3OH \rightarrow CO + 2H_2$$
$$CO + H_2O \rightarrow CO_2 + H_2$$

The overall reaction is endothermic, and some of the product hydrogen is normally burned to provide the required thermal energy.

For a forecourt station delivering 1,500 kg per day of hydrogen to fuel cell vehicles, the following materials and utilities are required: 11,085 kg of methanol; 7.70 kWht of thermal energy; and 1,056 kWhe of electric energy. Included in the analysis are an efficiency of 85 percent for the hydrogen burner, and 81 percent for the pressure swing absorption hydrogen purification system.[38]

The stoichiometric demand for methanol in the reforming process is 5.30 kg of methanol per kg of hydrogen. However, when the internal requirements for thermal energy and purification are included, the methanol demand increases to 7.39 kg, which implies a nominal reformer efficiency of 72 percent.

The current domestic consumption of methanol is about 2,600 million gallons per year. If this flow could be diverted to hydrogen production, approximately 1.0 billion kg of hydrogen would be generated. Assuming 1 kg of hydrogen in a fuel cell vehicle is equivalent to 2 gallons of gasoline in today's cars, the hydrogen from methanol would displace about 1.5 percent of the current gasoline demand.

### 1.9.3 Ammonia

#### *1.9.3.1 Production*

Ammonia is produced commercially by reforming natural gas with steam to form carbon dioxide and hydrogen, and then reacting the hydrogen with nitrogen to form ammonia. The basic chemical reactions are as follows:

$$CH_4 + 2\,H_2O \rightarrow CO_2 + 4\,H_2$$
$$N_2 + 3\,H_2 \rightarrow 2\,NH_3$$

The commercial ammonia production facilities in the United States are listed in Table 1-39. The bulk of the production capacity is adjacent to the principal natural gas distribution lines; i.e., in Louisiana and in the Midwest. As with methanol production, the price of natural gas has a strong influence on the required selling price for the ammonia.

Table 1-39
Domestic Ammonia Plants, Capacities, and Locations

| Company | Number of plants | Total capacity, 1,000 tonnes/year | States |
|---|---|---|---|
| Agrium US Inc. | 2 | 1,775 | Texas and Alaska |
| CF Industries, Inc. | 4 | 2,041 | Louisiana |
| Coffeyville Resources LLC | 1 | 350 | Kansas |
| Dakota Gasification Co. | 1 | 362 | North Dakota |
| Dyno Nobel, Inc. | 2 | 275 | Wyoming and |

| | | | |
|---|---|---|---|
| | | | Oregon |
| El Dorado Chemical Co. | 1 | 175 | Alabama |
| Green Valley Chemical Corp. | 1 | 32 | Iowa |
| Honeywell Nylon, Inc. | 1 | 530 | Virginia |
| IMC Phosphates Co. | 1 | 508 | Louisiana |
| Koch Industries Co. | 5 | 2,934 | Kansas, Oklahoma, Iowa, Nebraska and Louisiana |
| MissChem Nitrogen, LLC | 2 | 607 | Mississippi |
| Nitromite Fertilizer | 1 | 127 | Texas |
| PCS Nitrogen Fertilizer, LP | 4 | 2,084 | Georgia, Louisiana, Ohio, and Tennessee |
| Royster-Clark, Inc. | 1 | 278 | Illinois |
| Terra Industries, Inc. | 4 | 1,919 | Texas, Iowa, and Oklahoma |
| Triad Nitrogen, LLC | 1 | 522 | Louisiana |

#### *1.9.3.2 Transportation*

Anhydrous ammonia is typically transported in pressurized rail cars, each with a nominal capacity of 30,000 gallons. The saturation pressure of ammonia ranges from 14.7 psia (1.01 bars a) at -28 °F to 378 psia (26 bars a) at 140 °F (60 °C), so the rail car tanks always operate at pressures above atmospheric.

There are also about 2,000 miles (3,200 km) of ammonia pipelines running north from Louisiana, supplying anhydrous ammonia for fertilizer to the Midwest. The pipe is carbon steel, with diameters ranging from 6 in. (15.24 cm) to 10 in (25.4 cm).

#### *1.9.3.3 Dissociation*

Ammonia dissociators are available on a commercial basis, and are typically used to provide reducing atmospheres at metal heat treating plants. Two types of dissociators are available: high temperature units, which operate at 1,000 °C and use a nickel/iron oxide catalysts; and low temperature units, which operate at 700 °C and use a precious metal catalyst, such as ruthenium. The high temperature designs drive the dissociation reaction further, with residual ammonia concentrations of 50 to 60 ppm at 1,000 °C, and about 250 ppm at 700 °C.[39]

The dissociation reaction is endothermic, with a theoretical efficiency of 87 percent. Small commercial dissociators have an overall efficiency of 55 to 65 percent; i.e., 63 to 75 percent of the theoretical efficiency. To provide the energy for the dissociation reaction, and to maintain the catalyst at the dissociation temperature, approximately 25 percent of the product hydrogen must be burned.

### 1.9.3.4 Hydrogen Purification

Ammonia dissociator vendors typically guarantee a residual ammonia concentration of 50 ppm, but measured concentration is usually on the order of 5 ppm. However, the hydrogen purity specification for the project calls for a maximum concentration of 0.1 ppm. In principle, a pressure swing absorption unit could be used to remove the residual ammonia, but the discharge hydrogen must have a purity of at least 99.99999 percent. The efficiency of a absorption unit under this requirement will likely be too low for practial application.. An alternate approach is to absorb the ammonia in a zeolite bed. Zeolites are naturally occuring minerals, with a typical composition of $M_{x/n}[(AlO_2)_x(SiO_2)_y]_{w.}H_2O$. With a nominal carrying capacity of 6 mg of ammonia per gram of zeolite, approximately 12 kg of zeolite would need to be replaced each day for a forecourt dispensing 1,500 kg of hydrogen. Fortunately, the zeolites are inexpensive, and the daily material cost would be on the order of $2.

### 1.9.3.5 Ammonia Handling

Ammonia is a toxic substance, and its handling often requires special procedures. For example, a combined cycle power plant at the UC Medical Center in San Francisco uses a selective catalytic reduction system for control of nitrogen oxide emissions. The reagent for the catalytic process is ammonia. For safety reasons, the ammonia is transferred from the delivery truck to the plant's holding tanks inside a sealed building; further, the operator must wear a hazardous materials suit with a respirator.

Whether such involved procedures would be required for ammonia delivery to the dissociator at a forecourt station is something of an open issue.

### 1.9.3.6 Ammonia Potential

The current domestic ammonia production capacity is 14,500,000 metric tons per year. If this flow could be diverted to hydrogen production with an overall dissociation efficiency of 70 percent, approximately 1.8 billion kg of hydrogen would be generated. Assuming 1 kg of hydrogen in a fuel cell vehicle is equivalent to 2 gallons of gasoline in today's cars, the hydrogen from ammonia would displace about 2.5 percent of the current gasoline demand.

## 1.10 POWER TRANSMISSION AND DELIVERY SYSTEMS IN US

The electric transmission system within the US, both the equipment and the cooperating organizations, is a very complex undertaking. Some principal features of the system, including capacity constraints on the existing lines, are discussed below.

### 1.10.1 North American Electric Reliability Council (NERC)

The stated mission for NERC is to ensure the bulk electric system in North America is reliable, adequate, and secure. NERC is the primary link for the several regional reliability councils shown on Figure 1-51.


Figure 1-51 Regional Reliability Councils

| | | | |
|---|---|---|---|
| ECAR: | East Central Area Reliability Coordination Agreement | MRO: | Midwest Reliability Organization |
| ERCOT: | Electric Reliability Council of Texas | NPCC: | Northeast Power Coordinating Council |
| FRCC: | Florida Reliability Coordinating Committee | SERC: | Southeastern Electric Reliability Council |
| MAAC: | Mid-Atlantic Area Council | SPP: | Southwest Power Pool |
| MAIN: | Mid-America Interconnected Network | WECC: | Western Electric Coordinating Council |

The interconnections between regions are illustrated in Figure 1-52. NERC previously published transmission and distribution data, but except for limited maps no longer provides the information. One of the remaining maps on the NERC web page shows the regional interconnections and is reported as Figure 1-53.

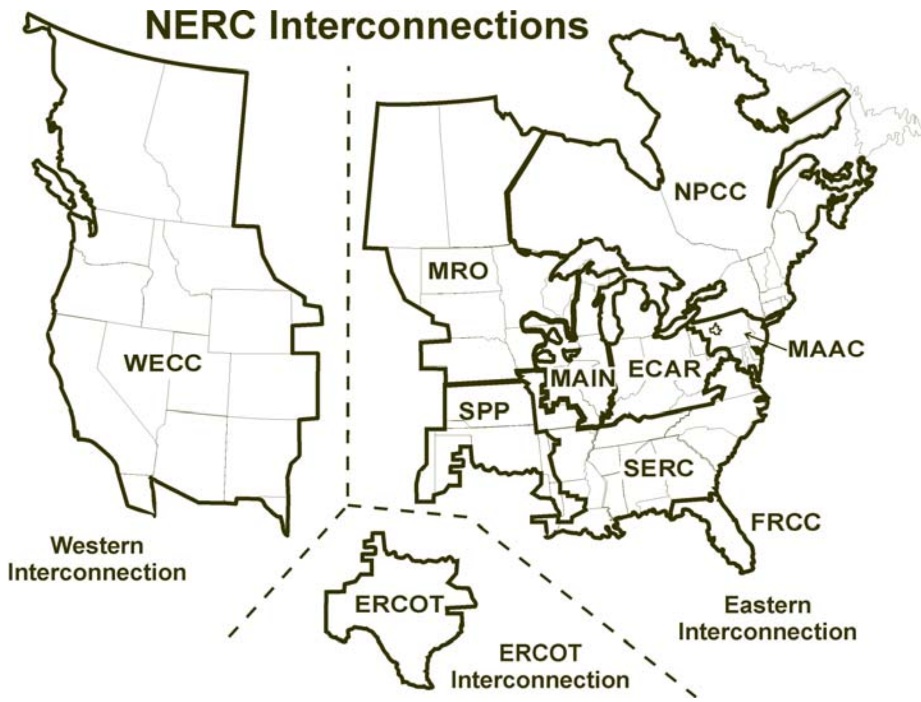


Figure 1-52 NERC Interconnections

Since its formation in 1968, NERC has operated as a voluntary organization, relying on reciprocity, peer pressure, and the mutual self-interest of all those involved. The changes taking place in the electric industry have altered many of the traditional mechanisms, incentives, and responsibilities for maintaining reliability to the point that the voluntary system of compliance with reliability standards is no longer adequate. In response to these changes, NERC has promoted the development of a new mandatory system of reliability standards and compliance that would be backstopped in the United States by the Federal Energy Regulatory Commission (FERC).

On August 8, 2005, the Energy Policy Act of 2005 was signed into law, which authorizes the creation of an electric reliability organization (ERO) with the statutory authority to enforce compliance with reliability standards among all market participants. The goal of NERC is to become certified, and then begin operation as, the electric reliability organization in the United States and Canada.

### 1.10.2 Federal Electric Regulatory Commission (FERC)

FERC is primarily concerned with price and other regulatory issues for the energy industry. FERC is an independent agency that regulates the interstate transmission of electricity, natural gas, and oil. FERC also reviews proposals to build liquefied natural gas terminals and interstate natural gas pipelines, and issues licenses to hydroelectric projects.

FERC's data include an illustration (Figure 1-53) of the current and proposed independent system operators (ISO) and regional transmission operators (RTO), which will be responsible for much of the transmission and distribution systems in North America. Several organizations forming these groups are in different stages of development.

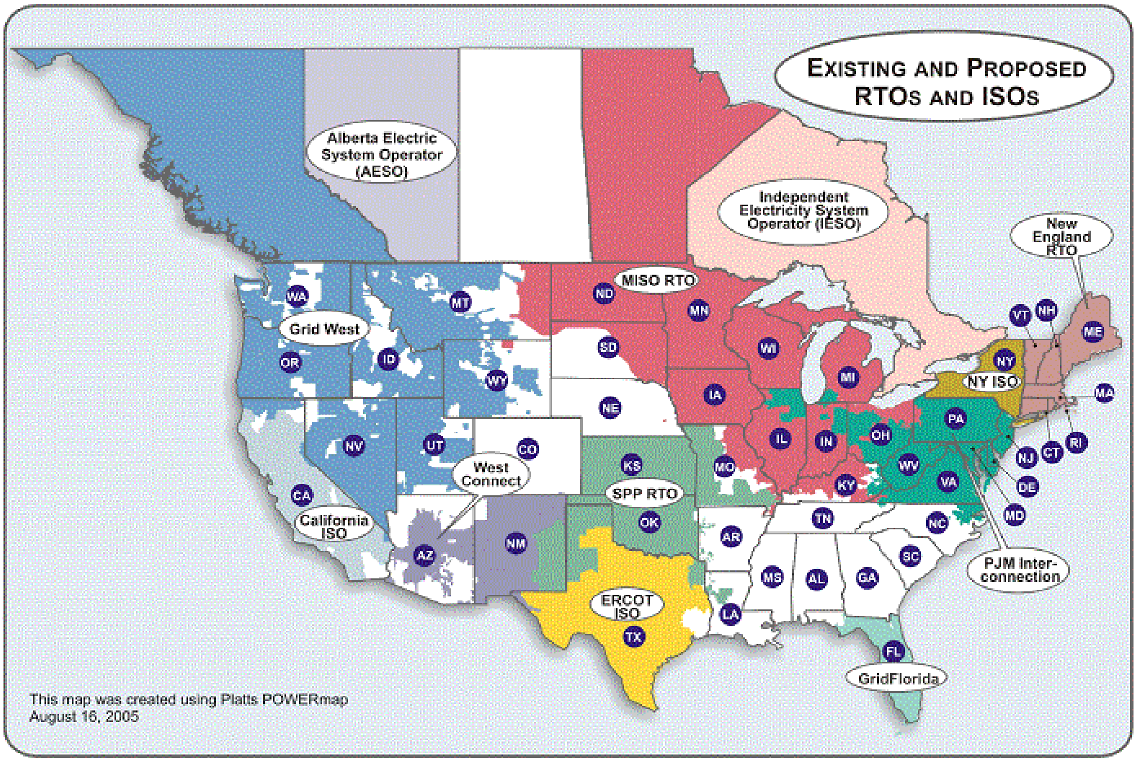



Figure 1-53 Federal Energy Regulatory Commission Map of Regional Transmission Operators and Independent System Operators

### 1.10.3 State Public Utilities Commissions

The States also have commissions for regulating and monitoring electric and other energy utilities.

Relevant to this study are state plans for the both the expansion of renewable energy generation resources, and the associated additions to the transmission system to transmit the energy from often-remote sites to the population centers. An example of such a plan is that prepared by the California Public Utilities Commission; it is available at http://www.cpuc.ca.gov/Published/Report/32197.htm.

Some of the details to the plan are shown in Table 1-40, which lists a possible scenario for the California utilities to meet a mandate goal for 20 percent renewable energy by 2017. A scenario for additions to a portion of the transmission grid east of Los Angeles is illustrated in Figure 1-54.

### 1.10.4 National Transmission Grid Study

The US DOE published the National Transmission Grid Study in May 2002.[40] The study was performed to examine transmission constraints in the system, and to evaluate the benefits of establishing a national grid. The full report is available at http://www.eh.doe.gov/ntgs/ reports.html#reports. A DOE model, the Policy Office Electricity Modeling System (POEMS), was used to investigate the constraints.

In addition to the extensive background information and assessments, the report illustrates the principal constraints for several regions of the country. Regional examples are presented here in Figure 1-55 and Figure 1-56, and details within the California system are shown in Figure 1-57.

Table 1-40
Possible Sources of New Renewable Generation in California
Source: CEC Table 13 Renewable Resource Assessment September 30, 2003

| Location Statewide | County / Resource | Added 2005 (MW) | Added 2008 (MW) | Added 2017 (MW) |
|---|---|---|---|---|
| **PG&E Service Area** | Modoc / geothermal | | | 105 |
| | Siskiyou / geothermal | | 100 | 90 |
| | Solano / wind | 215 | 100 | 85 |
| | Alameda / wind | 50 | 110 | 50 |
| | **Location total** | **265** | **310** | **330** |
| | Other biomass | 20 | 45 | 55 |
| | **Other total** | **20** | **45** | **55** |
| **Area Totals** | | **285** | **355** | **385** |
| **SCE and IID Service Area** | Imperial / geothermal | 120 | 60 | 190 |
| | Imperial / biomass | | | 80 |
| | Kern / wind | 285 | 1,410 | 2,365 |
| | Mono / geothermal | | 50 | 300 |
| | Riverside / wind | 200 | 190 | 140 |
| | San Bernardino / wind | 50 | 40 | 310 |
| | San Bernardino / solar | | | 180 |
| | Los Angeles / biomass | 15 | 65 | |
| | Los Angeles / wind | 100 | | 315 |
| | **Location total** | **770** | **1,815** | **3,880** |
| | Other wind | | | 30 |
| | Other biomass | 15 | 17 | 5 |
| | **Other total** | **15** | **17** | **35** |
| **Area Totals** | | **785** | **1,832** | **3,915** |
| **SDG&E Service Area** | San Diego / wind | | 200 | 200 |
| | San Diego / biomass | 20 | 10 | |
| **Area Totals** | | **20** | **210** | **200** |
| **Statewide Totals** | | **1,090** | **2,397** | **4,500** |
| **Cumulative Totals** | | **1,090** | **3,487** | **7,987** |

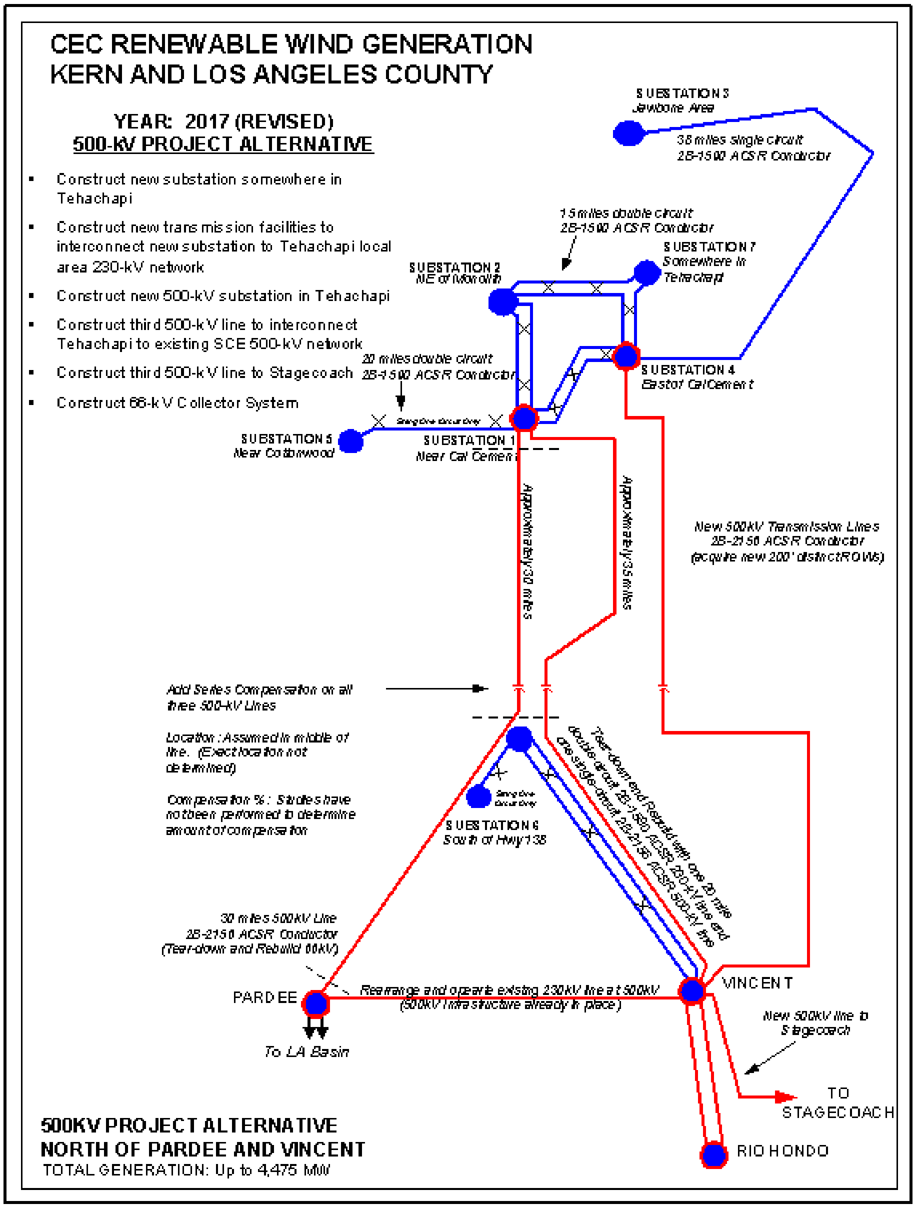



Figure 1-54 Possible Expansion Scenario for One Segment of the California Transmission System

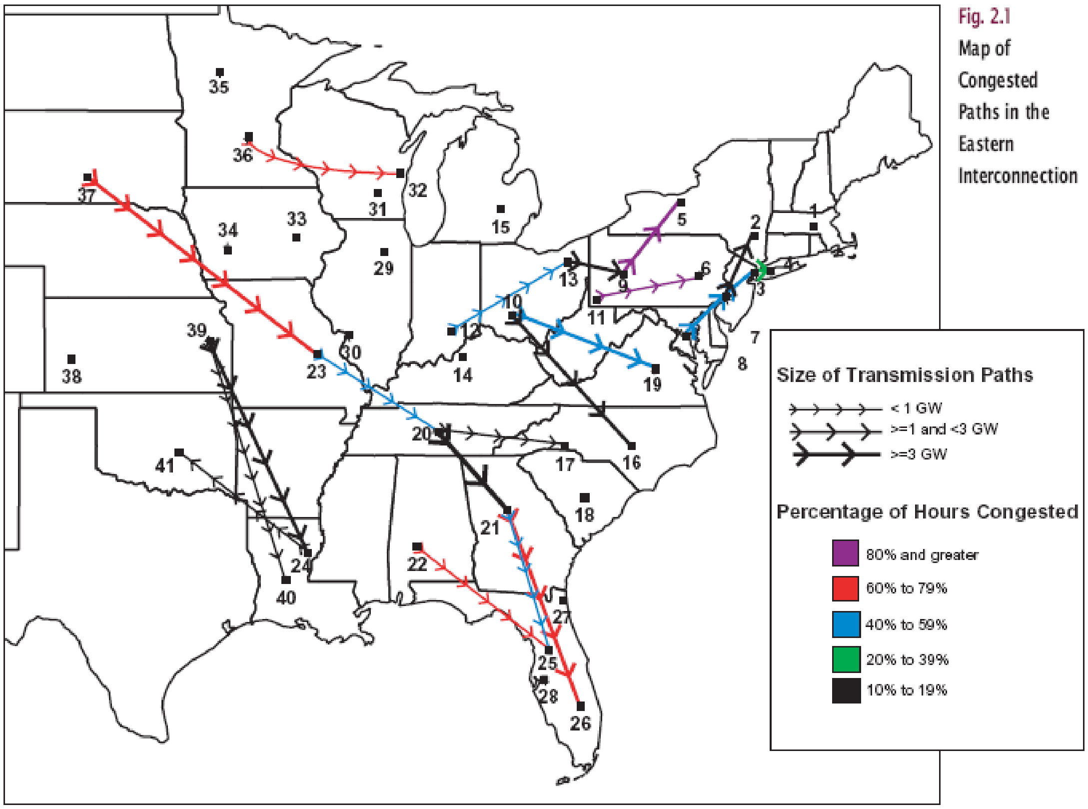



Figure 1-55 Constraint Example from the US DOE Transmission Grid Study

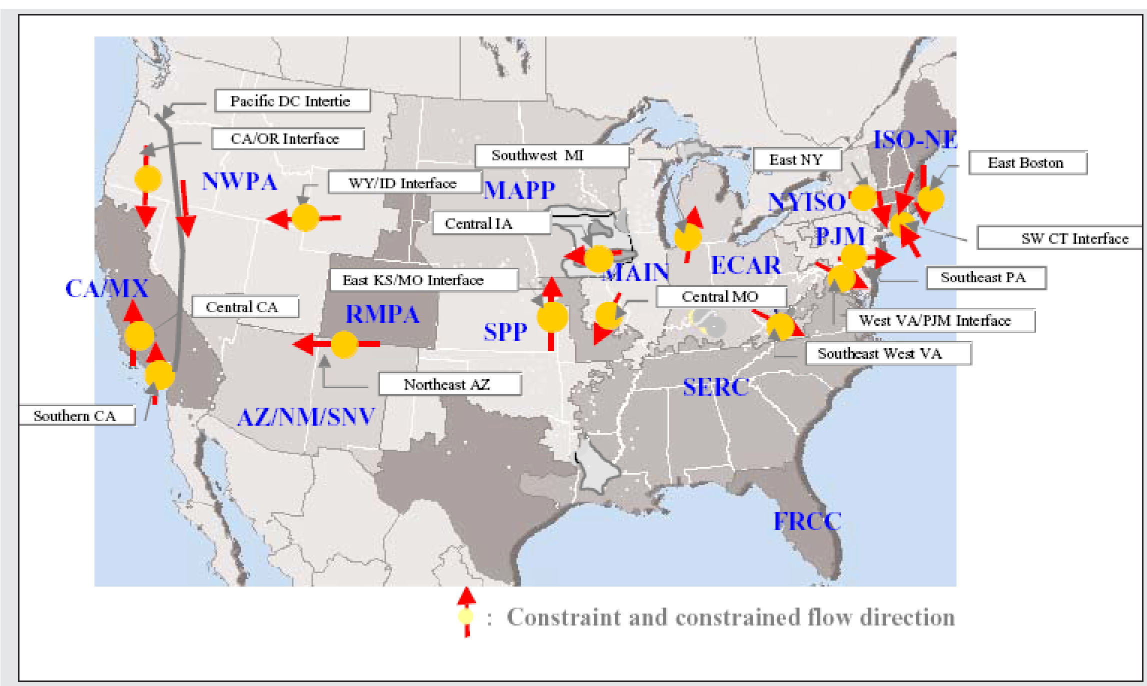



Figure 1-56 Overview of Transmission Constraints in the US

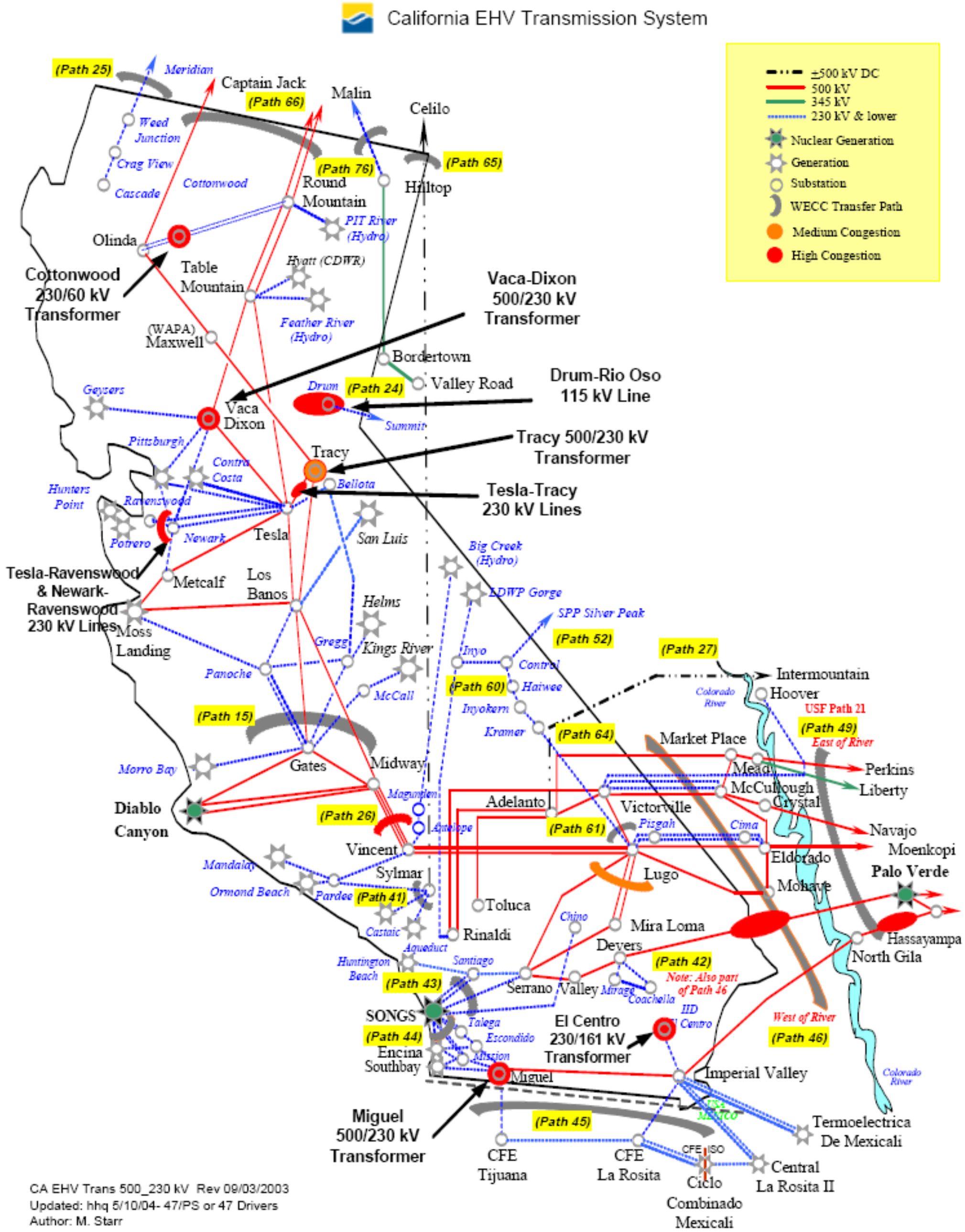



Figure 1-57 Transmission System and Constraints in California

From the information presented in Figure 1-55 through Figure 1-57, it is clear that assessments of the transmission grid for carrying energy from new or existing renewable sources to new hydrogen production facilities must be conducted at the local level. Further, the assessments are likely to be valid only for a specific period; i.e., 2005 through 2009. It is also apparent that conclusions reached at the local level will not translate well into general conclusions for the country as a whole.

The transmission system is exceedingly complex, and some corridors are already congested. Thus, developing a plan for integrating renewable energy supplies with the current, and the future, transmission system for the large scale production of hydrogen production on a national level will be a significant undertaking.

On a point related to the expansion of the transmission grid, a recent study by the National Council on Electric Policy lists typical costs for new, medium- and high-voltage transmission lines. The costs are listed in Table 1-41.

Table 1-41
Reported Transmission Line Cost Data

| Transmission Facility | Typical Capital Cost |
|---|---|
| New 345 kilovolt (kV) single circuit line | $915,000 per mile |
| New 345 kV double circuit line | $1.71 million per mile |
| New 138 kV single circuit line | $390,000 per mile |
| New 138 kV double circuit line | $540,000 per mile |
| New 69 kV single circuit line | $285,000 per mile |
| New 69 kV double circuit line | $380,000 per mile |
| Single circuit underground lines | Approximately four times the cost of above-ground single circuit lines. |
| Rebuild/Upgrade 69 kV line to 138 kV line | $400,000 per mile |
| Source: American Transmission Company, *10-Year Transmission Assessment*, September 2003. | |

## 1.11 PREVIOUS SYSTEM ANALYSES AND MODELING WORK BY DOE AND OTHERS

### 1.11.1 Geographical Information Systems

Several of the maps shown in the preceding sections, such as natural gas transmission lines, show features of the energy infrastructure on very large scales. However, analyses of the progression of the hydrogen distribution infrastructure will need to analyze existing systems on a local scale. Here, information from commercial Geographical Information Systems (GIS) sources will prove valuable.

One example is the Virtual Hydropower Prospector GIS developed by Idaho National Laboratories. The INL database shows hydroelectric plants, together with towns, roads, electrical distribution lines, and so on. Figure 1-58 shows a typical map selected from the GIS with the hydroelectric power plants shown; details of the plants from the GIS database are listed in Table 1-42. More highly detailed maps are also readily available, with resolutions on the order of 1 meter.

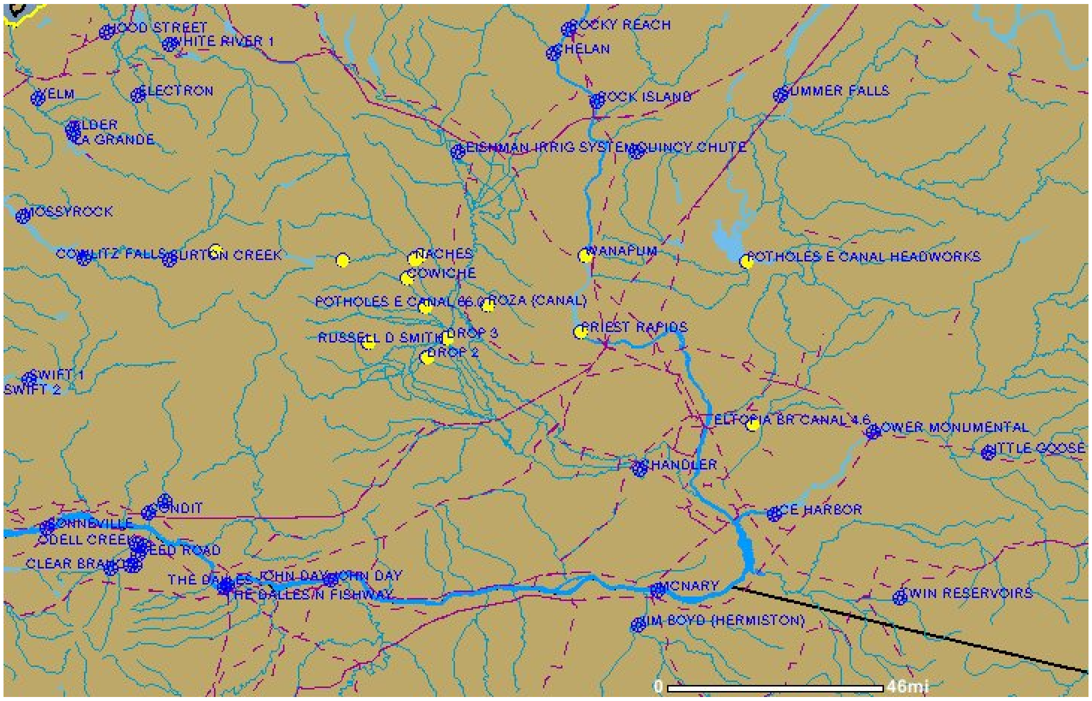



Figure 1-58 Example of Idaho National Laboratories GIS Map of Hydroelectric Power Plants

Table 1-42
Summary of GIS Data for Hydroelectric Plants in Figure 1-50

| Record | Name | Operator | Cap (MW) |
|---|---|---|---|
| 1 | Drop 3 | Bureau of Indian Affairs | 1.8 |
| 2 | Cowiche | Yakima-Tieton Irrigation District | 1.47 |
| 3 | Orchard Avenue | Yakima-Tieton Irrigation District | 1.441 |
| 4 | Naches | PacifiCorp | 6.37 |
| 5 | Naches Drop | PacifiCorp | 1.4 |
| 6 | Roza (Canal) | Bureau of Reclamation | 12.937 |
| 7 | Priest Rapids | Grant Company Public Utility District 2 | 834.9 |
| 8 | Potholes East Canal Headworks | South Columbia Basin Irrigation District | 6.5 |
| 9 | Russel D. Smith | South Columbia Basin Irrigation District | 6.1 |
| 10 | Potholes East Canal 66.0 | South Columbia Basin Irrigation District | 2.4 |
| 11 | Eltopia Bride Canal 4.6 | South Columbia Basin Irrigation District | 2.2 |
| 12 | Wanapum | Grant Company Public Utility District 2 | 900 |
| 13 | Drop 2 | Bureau of Indian Affairs | 2.5 |

As might be expected, GIS data are available for a broad range of specific subjects. A few examples are listed below:

The NREL GIS group has developed maps for various resources and for specific projects. If you are interested in having your own maps created, contact the GIS Webmaster.

Renewable Energy Atlas of the West

Interactive maps with zoom-in capability that highlight the wind, biomass, geothermal, and solar resources in the 11 western states.

- Federal Energy Management Program Maps
  Maps showing the market potential for various technologies at federal facilities throughout the country.
- Maps of Indian Lands
  Created in support of the report, Energy Consumption and Renewable Energy Development Potential on Indian Lands by the Energy Information Administration, U.S. Department of Energy.
- Solar Maps
  Maps of solar radiation resources available for several photovoltaic collector orientations in the U.S.
- Transportation Technologies
  Interactive geographical map of the Clean Cities coalitions boundaries and the Alternative Fuel Station Locator mapping application.
- Wind Maps
  Maps of gridded wind resource potential are based on wind power density.

### 1.11.2 H2A Models

DOE's $H_2A$ Analysis group is developing 2 modeling tools, each built on a common basis, for analyzing hydrogen delivery concepts at the component, technology, and system levels, in terms of performance, cost, benefits, and risks.

#### *1.11.2.1 Component Model*

The Component Model, compiled by the National Renewable Energy Laboratory, allows the user to access authoritative information on hydrogen delivery component costs and performance. The model is in an Excel format, with a separate spreadsheet for each principal component. Representative performance and efficiency values are provided for each component. The components currently under development include:

- Truck transporting compressed gas cylinders or liquid hydrogen
- Hydrogen pipeline
- Medium pressure hydrogen compressors for pipeline service, and high pressure hydrogen compressors for forecourt service
- Hydrogen liquefaction
- Gaseous hydrogen storage cylinders, and liquid hydrogen storage tanks
- Truck terminals for transferring compressed gas or liquid hydrogen Geologic storage of compressed gas

Each of the component spread sheets also includes estimates of the following items: 1) installed capital cost as a function of size; 2) annual operation and maintenance costs, for items such as fuel, electric energy, labor, spare parts, property taxes, and insurance; and 3) equipment lifetimes, including periodic replacements. From these data, estimates for the levelized price for hydrogen are calculated based on standard set of financial parameters. The latter includes a required internal rate of return, federal and state tax rates, depreciation, and escalation.

### 1.11.2.2 Scenario Model

The Scenario Model, compiled by Argonne National Laboratories, allows the user to estimate delivery prices for hydrogen for a wide range of markets. The user first specifies the market scenario. The model develops a delivery and dispensing infrastructure, develops capital and operating cost estimates for the infrastructure, and then calculates a levelized cost for delivering the hydrogen. The model is in an Excel format, and uses as its estimate bases the NREL Component Model. The Scenario Model also incorporates a number of Visual Basic macros for assembling the delivery infrastructure.

The user specifies three principal inputs, with several options available under each input as follows:

- Geographic, with options for Small City, Large City, Rural Interstate 160 km, and Rural Interstate 320 km
- $H_2$ Penetration, with options for 1, 10, 30, and 70 percent
- Delivery Mode, with options for Compressed Hydrogen Truck Transport, Liquid Hydrogen Truck Transport, and Gas Pipeline.

Once the inputs have been selected, the model assembles the required infrastructure and develops the necessary cost estimates. For example, the user might specify the following scenario: Hydrogen is delivered to a small city by a pipeline, and hydrogen has reached a market penetration of 30 percent in the light duty vehicle fuel demand. The outputs calculated by the model are summarized in Table 1-43.

Table 1-43
Hydrogen Scenario Model Outputs

| | |
|---|---|
| Population, each | 100,000 |
| Vehicles per person, each | 1.16 |
| Refueling station capacity, kg/day | 1,500 |
| Distance from $H_2$ production plant to city, km | 100 |
| Fuel economy, equivalent miles per gallon | 57.5 |
| Annual distance traveled, miles | 14,950 |
| Hydrogen vehicles in city, each | 34,800 |
| Refueling stations in city, each | 24 |
| City hydrogen use, kg/day | 24,954 |
| Pipeline distances, km | |
| - Service | 40 |
| - Trunk | 161 |
| - Transmission | 100 |
| Delivery cost for hydrogen, $/kg | 1.51 |

The user can also run parametric studies on various inputs to determine the lowest cost method for hydrogen delivery. For example, low market penetrations may favor delivery by liquid hydrogen transporters, while higher market penetrations may show pipelines to offer the lowest cost.

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# Task Report

# Task 2: Evaluate Current and Future Efficiencies and Costs of Hydrogen Delivery Options

**Nexant, Inc., Air Liquide, Argonne National Laboratory, Chevron Technology Venture, Gas Technology Institute, National Renewable Energy Laboratory, Pacific Northwest National Laboratory, and TIAX LLC**

**May 2008**

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# Executive Summary

Nexant, Inc., in conjunction with Air Liquide, Argonne National Laboratory, Chevron Technology Venture, Gas Technology Institute, National Renewable Energy Laboratory, Pacific Northwest National Laboratory, and TIAX LLC, conducted an in-depth comparative analysis of various promising infrastructure options for hydrogen delivery and distribution to refueling stations from central, semi-central, and distributed production facilities. The major objectives are to provide improved hydrogen delivery modeling capability and meaningful recommendations to DOE on the research strategy that will lead to cost effective and energy efficient hydrogen delivery infrastructure to meet the DOE delivery goals, which in turn will help enable the use of hydrogen as a major energy carrier for fuel cell vehicles and stationary power generation.

The results of this project have been appropriately incorporated in Version 2 of the DOE H2A Delivery Models: the Components Model V2 and the Hydrogen Delivery Scenario Model (HDSAM V2).

## DELIVERY OPTIONS

The project evaluated and analyzed the following six hydrogen delivery options:

- Option 1: Dedicated pipelines for gaseous hydrogen delivery
- Option 2: Use of existing natural gas or oil pipelines for gaseous hydrogen delivery
- Option 3: Use of existing natural gas pipelines by blending in gaseous hydrogen with the separation of hydrogen from natural gas at the point of use
- Option 4: Truck delivery of gaseous hydrogen with tube trailers
- Option 5: Truck delivery of liquid hydrogen
- Option 6: Use of novel solid or liquid hydrogen carriers, in slurry or solvent form, transported by pipeline, rail, or trucks

## EVALUATION OF OPTIONS 2 AND 3

Under Option 2, Use of Existing Natural Gas or Oil Pipelines for Gaseous Hydrogen Delivery, the following activities were conducted: a survey of the existing pipeline infrastructure; an analysis of the ability of existing pipeline materials to withstand hydrogen embrittlement; and estimates of the pipeline de-rating associated with switching from a hydrocarbon to hydrogen. The analysis concluded the existing system could accommodate only a small fraction of the long term hydrogen delivery requirements, and only then in a limited portion (i.e., south central) portion of the country.

Under Option 3, Use of Existing Natural Gas Pipelines by Blending and Separating Natural Gas and Hydrogen, several gas separation techniques were evaluated. However, the delivery approach was found to be impractical. The hydrogen fraction must be kept in the range of only a few percent to maintain the energy content, in Btu/ft$^3$, of the mixed gas within the contractual limits imposed on the distribution companies. As such, the high capital cost of the gas separation system, together with the large electric energy requirements for gas compression, resulted in delivered hydrogen costs well above program targets.

A complete discussion of these options and results will be included in the final report of the Nexant project.

### EVALUATION OF OPTION 6

Option 6 is a futuristic hydrogen delivery option with a high degree of technical uncertainties. The carriers can be divided into the following four types:

| Material Type | Example Material | Storage State | $H_2$ Discharge |
|---|---|---|---|
| Metal Hydrides | Sodium Alanate | Packed Powder | Endothermic Desorption |
| Chemical Hydrides | Sodium Borohydride | Aqueous Solution | Catalyzed Exothermic Hydrolysis |
| Liquid-Phase Hydrogen Carrier | N-Ethylcarbazole | Liquid | Endothermic Dehydrogenation |
| High Surface Area Carbon Sorbents | AX-21 | Low-Temp Solid Powder | Endothermic desorption |

Most of the cost data presented for these four types, presented in a topical report of this project entitled “HYDROGEN DELIVERY USING ALTERNATIVE HYDROGEN CARRIERS: ANALYSIS AND RESULTS” are mix of experience from other field and current development results. Option 6 is excluded from the current H2A model. The analysis provided on the Option 6 is intended to be used as the preliminary basis to expend the H2A model to include Option 6.

### UPDATED PERFORMANCE AND COST DATA

Updated performance, capital cost, and operating cost data were compiled for the following delivery infrastructure components:

- Refueling station compressors
- Transmission pipeline and gas terminal compressors
- Low pressure (~2,500 psi or 172.4 bar) gas storage
- Cascade gas charging system (6,250 psi or 431 bars)
- Liquefaction plants
- Liquid storage vessels, pumps, and vaporizers
- Hydrogen distribution pipelines within a city
- 480 and 4,160 Volt electric power supply for refueling stations
- Refueling station and distribution terminal land areas

The revised data have been incorporated in the H2A Delivery Components Model and the Hydrogen Delivery Scenario Model (HDSAM) as V2 of these models.

## INFRASTRUCTURE STORAGE

One of the principal activities in the project was to incorporate hydrogen storage in the delivery system to accommodate the unavoidable mismatches between production and demand. There are two storage requirements: a short term capacity for the hourly variation in refueling station demand; and a long term capacity for the seasonal variation in refueling station demand and production plant outages.

A representative hourly variation in refueling station demand is illustrated in Figure 0-1, and an illustration of the seasonal variation in demand, together with an annual production plant outage for scheduled maintenance, is shown in Figure 0-2. The seasonal demand variation is a product of annual driving profiles; i.e., miles driven in the summer are normally higher than miles driven in the winter.

A series of optimization studies concluded the following for gaseous hydrogen pipeline delivery pathways: 1) long term storage is most economically provided by compressed gas storage in geologic formations, if geologic storage is available, and in liquid storage, if geologic storage is not available; and 2) for hydrogen delivery by pipeline, short term storage is most economically provided by low pressure (~2,500 psi or 172.4 bars) compressed gas storage at the refueling station. For the demand profile shown in Figure 1, the nominal storage capacity is about 30 percent of the daily hydrogen dispensed. However, the user is free to use any demand profile, and the H2A Delivery Models V2 will optimize the refueling station storage capacity.

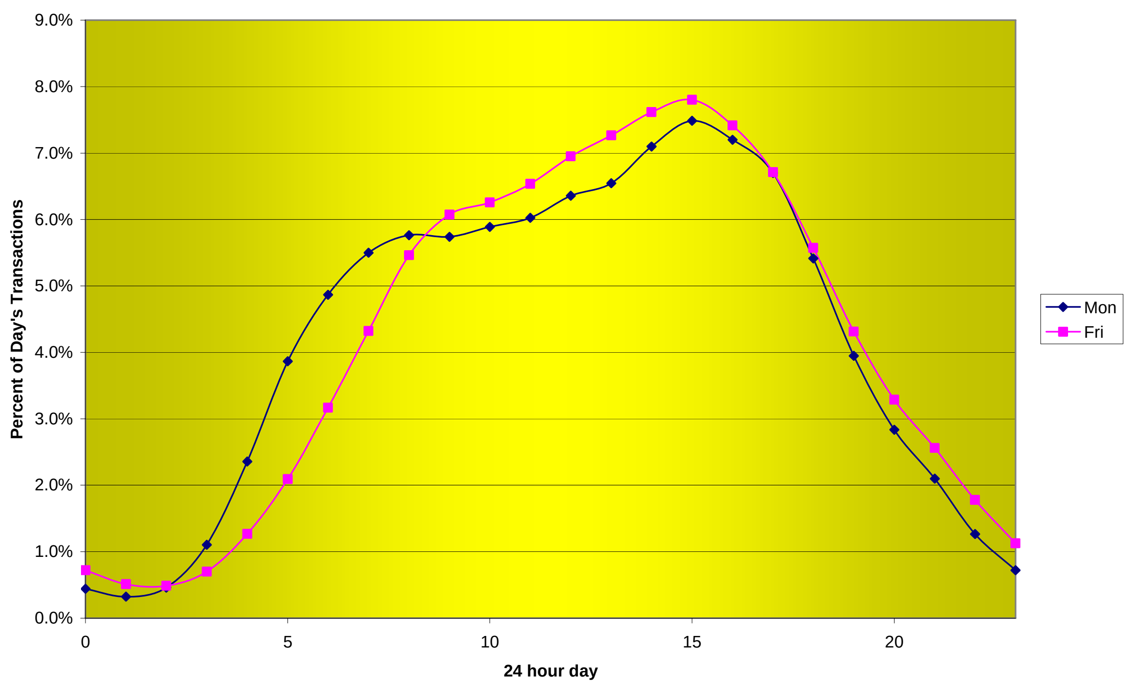


Figure 0-1 Hourly Variation in Refueling Station Demand[1]

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[1] Refueling station demand profiles supplied by Chevron based on over 400 of their stations.

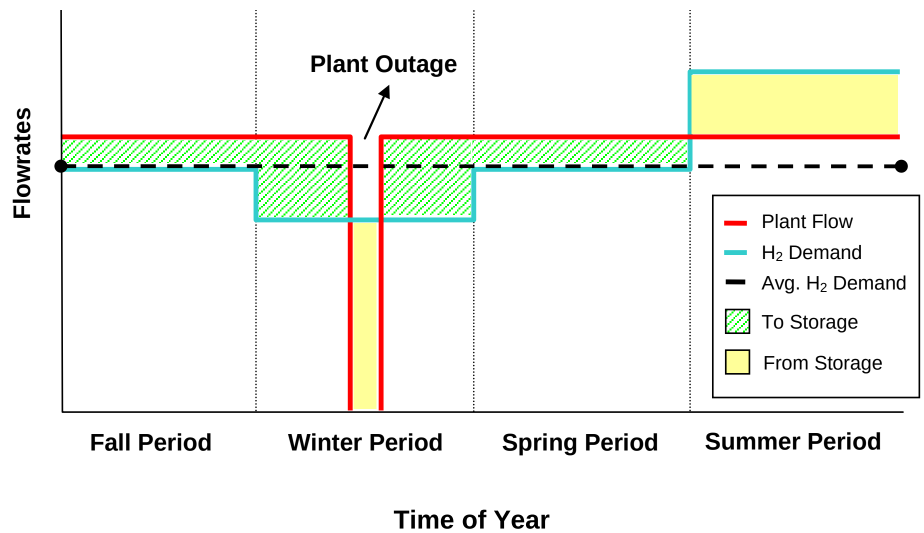


Figure 0-2 Seasonal Variation in Production Plant and Storage Operation

For gaseous hydrogen tube trailer delivery, the tube trailer is dropped off at the refueling site and used to meet the hourly storage needs. Long term storage is provided by compressed gas geologic storage or liquid hydrogen storage. The V2 Models also include several hours of low pressure gas storage at the terminals used to fill the tube trailers to ensure smooth loading operations.

For liquefaction and cryogenic liquid delivery of hydrogen, hydrogen storage is not as much of a cost factor due the much higher density of liquid hydrogen compared to gaseous hydrogen and because the high cost of liquefaction dominates the hydrogen delivery cost. The refueling site hourly storage needs are met by a liquid storage tank capable of holding the capacity of two liquid truck deliveries. The V2 Models also include liquid storage at the terminals sufficient to handle plant outages, the summer peak demand, as well to ensure smooth truck loading operations.

## DELIVERY PATHWAYS

Within the H2A Delivery Scenario Model V2 (HDSAM V2), a total of nine delivery pathways are available for selection by the user. Three liquid delivery pathways are illustrated in Figures 0-3, 0-4, and 0-5. Four tube trailer pathways are shown in Figures 0-6, 0-7, 0-8, and 0-9, and two pipeline delivery pathways are illustrated in Figures 0-10 and 0-11. There is a tenth pathway that uses an oversize pipeline to provide the required short term storage capacity (hours), in conjunction with either geologic or liquid storage to meet the longer term storage requirements (days). This is discussed in this report but has not been explicitly included in the HDSAM V2.

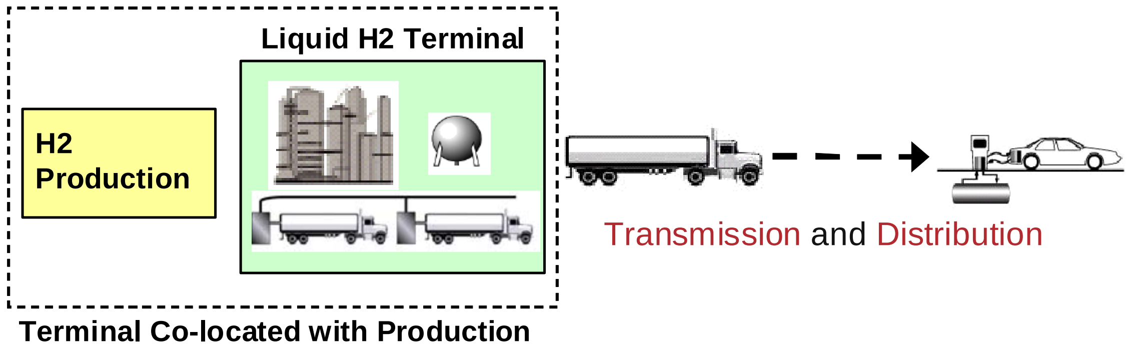


Figure 0-3  Pathway 1: Liquid Delivery Pathway with Liquid Long Term Storage

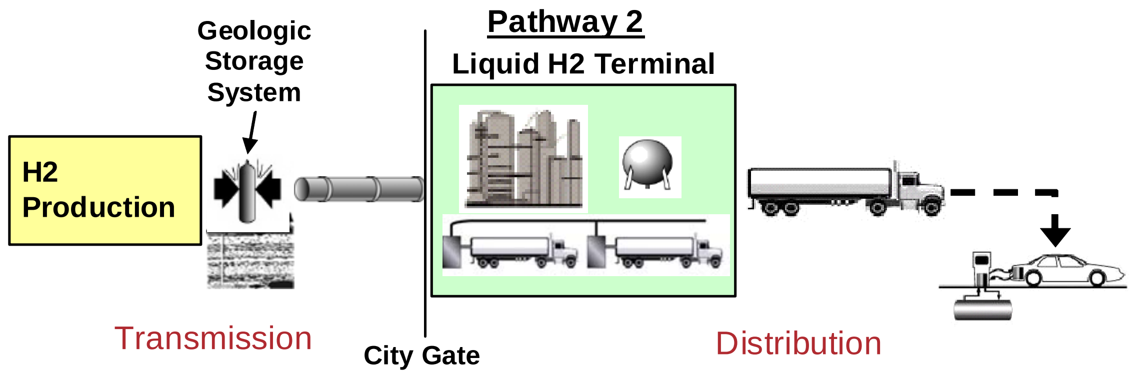


Figure 0-4  Pathway 2: Mixed Mode Liquid Delivery Pathway with Long Term Geologic Storage

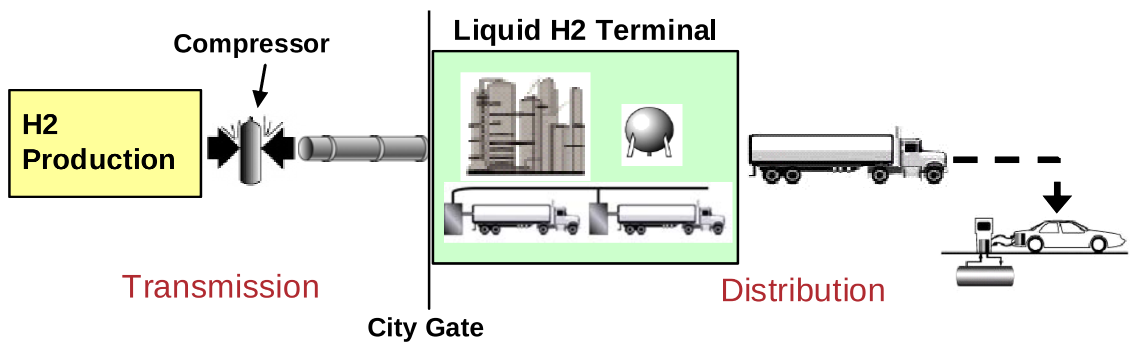


Figure 0-5  Pathway 3: Mixed Mode Liquid Delivery Pathway with Liquid Long Term Storage

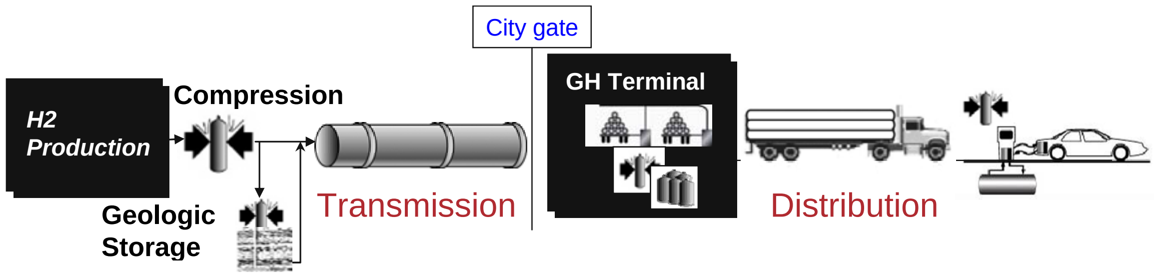


Figure 0-6 Pathway 4: Mixed Mode Tube Trailer Delivery Pathway with Long Term Geologic Storage

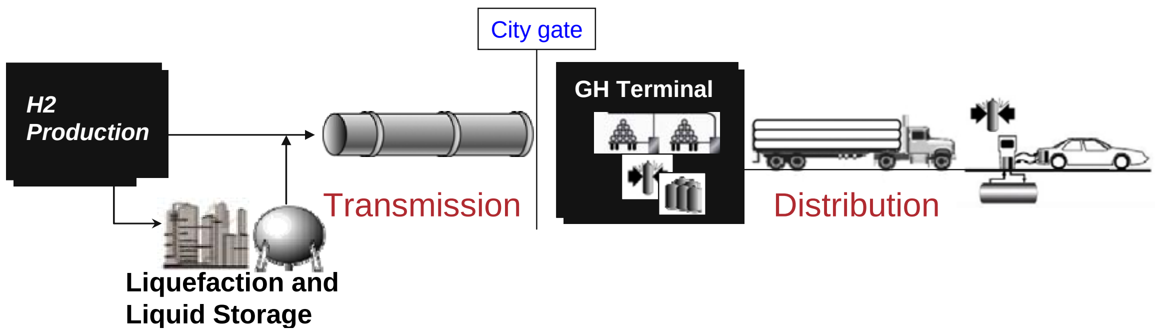


Figure 0-7 Pathway 5: Mixed Mode Tube Trailer Delivery Pathway with Liquid Long Term Storage

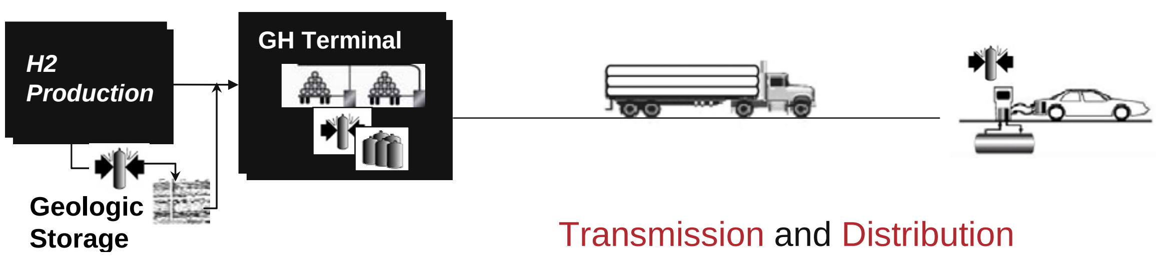


Figure 0-8 Pathway 6: Tube Trailer Delivery Pathway with Long Term Geologic Storage

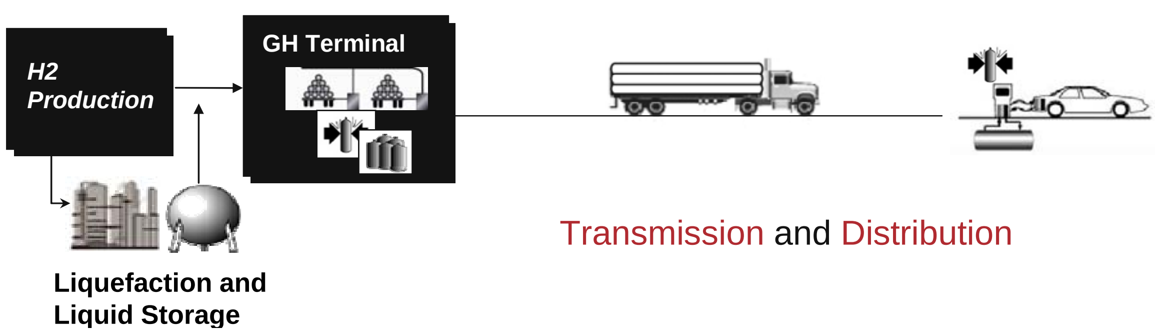


Figure 0-9 Pathway 7: Tube Trailer Delivery Pathway with Long Term Liquid Storage

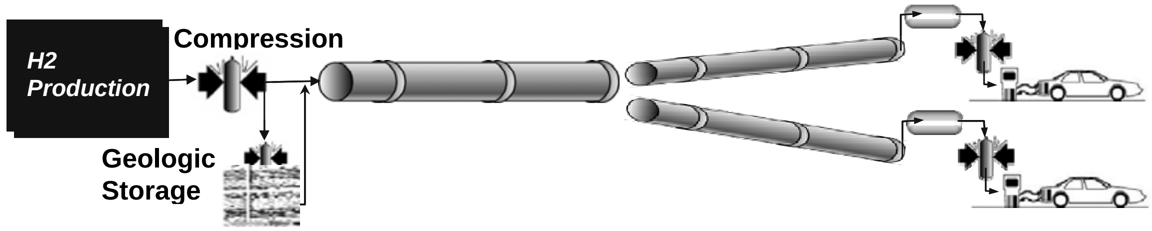


Figure 0-10  Pathway 8: Pipeline Delivery Pathway with Long Term Geologic Storage

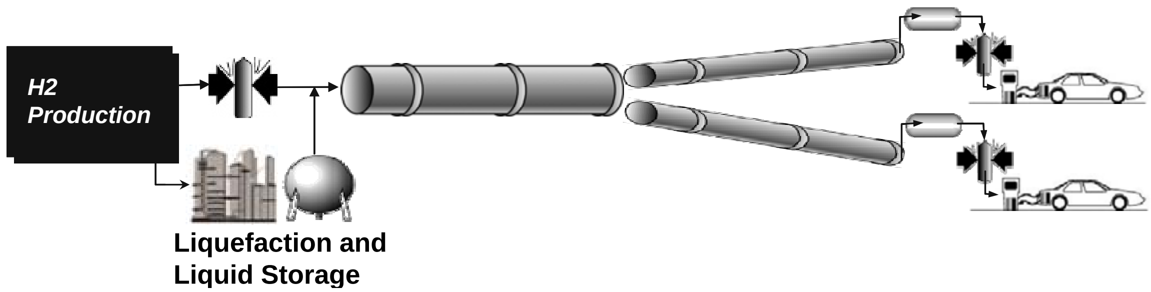


Figure 0-11  Pathway 9: Pipeline Delivery Pathway with Long Term Liquid Storage

## H2A DELIVERY MODELS

There are two H2A Delivery Models; the Components Model and the Hydrogen Delivery Scenario Model (HDSAM). The models and users guides are available at www.hydrogen.energy.gov/h2a_delivery.html.

The Components Model allows the user to examine the costs, energy efficiency and greenhouse gas (GHG) emissions of individual components (e.g. compressors, pipelines, liquefiers, terminals, etc.).

HDSAM V2 allows the user to select specific geographically based scenarios (e.g. a particular city, rural/interstate fueling, or combined city and rural interstate) and examine delivery costs as a function of hydrogen fuel cell vehicle market penetration. To run the HDSAM V2 model for a city, the user selects the following: city; market penetration; delivery pathway; and type of long term storage (geologic or liquid). HDSAM then calculates the following: infrastructure system capacities; short term storage capacities (for pipeline delivery pathways); long term storage capacities; delivery system capital cost; delivery system operating costs; levelized cost of hydrogen dispensed, energy efficiencies and GHG emissions. The basic inputs and summary results of a representative calculation are shown in Figure 0-12. In this example the calculations are performed for Los Angeles, California, with a market penetration of 20 percent. Hydrogen is delivered by pipeline, the average refueling station capacity is 1,500 kg/day, and long term storage is in the form of liquid hydrogen. For this set of parameters, the levelized cost to deliver hydrogen is $2.68 per kg.

In addition to using the H2A Delivery Models with their default values for current hydrogen delivery technologies, the models can be used to:

- Understand the key delivery cost drivers and the best delivery pathway for various markets and market penetrations.

- Quantify the overall delivery cost reduction possible based on replacing specific default values with lower costs or improved performance of one or more of the component technologies.

This ability can help guide the most effective R&D approach to reduce hydrogen delivery costs.

H2 Market
- Urban
- Rural Interstate
- Combined

Market Penetration

H2 Vehicle Market 20 %

Transmission Mode
- Compressed H2 Truck
- Liquid H2 Truck
- Pipeline

Distribution Mode
- Compressed H2 Truck
- Liquid H2 Truck
- Pipeline

Refueling Station Size

Desired Dispensing Rate [kg/day] 1500

City Selection

Los Angeles--Long Beach--Santa Ana, CA

Population 11,789,487

Click Here To Calculate

Component for Plant Outage and Summer Peak
- Geologic Storage
- Liquefier and Liquid Storage

**Delivery Costs**

| | |
|---|---|
| Total Cost [$/kg] | 2.68 |

**Key Delivery Inputs and Assumptions**

| | |
|---|---|
| City population | 11,789,487 |
| City area (mi2) | 1668 |
| Population density (people/mi2) | 7,068 |
| Vehicles/person | 0.65 |
| Miles driven per year/ vehicle | 12,823 |
| Distance from production to city (mi) | 62 |
| Utilization of H2 stations full capacity (% of total number of H2 stations) | 100% |
| Number of Days for Scheduled Production Plant Outage | 10 |
| Summer Surge: % above the System Average Daily Demand | 10.0% |
| Number of Days for Surges (Above Average Demand) | 120 |
| Friday Peak: % above Daily Average Demand | 8.0% |
| H2 Vehicles fuel economy equivalent (mi/gge) | 67.30 |

**Demand Calculations**

| | |
|---|---|
| H2 use per LDV per year (kg/y) | 194 |
| H2 use per LDV kg H2/day (ave) | 0.53 |
| Number of H2 vehicles in city | 1,528,894 |
| City H2 daily use (kg/d) | 814,680 |
| Number of H2 refueling stations in city | 544 |
| Adjusted (actual) average H2 station daily dispensing rate (kg/day) | 1498 |
| Number of H2 stations/Number of gasoline stations | 14% |
| Average distance between stations (mi) | 1.75 |

**Delivery Mode Calculations**

| | |
|---|---|
| Number of trunk rings | 4 |
| Pipeline ring1 (trunk) peak flow rate [kg/day] | 625,421 |
| Pipeline ring2 (trunk) peak flow rate [kg/day] | 454,026 |
| Pipeline ring3 (trunk) peak flow rate [kg/day] | 458,629 |
| Pipeline ring4 (trunk) peak flow rate [kg/day] | 397,641 |
| Pipeline transmission length (mi) | 62 |
| Pipeline ring1 (trunk) length (mi) | 29 |
| Pipeline ring2 (trunk) length (mi) | 69 |
| Pipeline ring3 (trunk) length (mi) | 111 |
| Pipeline ring4 (trunk) length (mi) | 153 |
| Pipeline service total length (mi) | 1003 |
| Pipeline ring1 (trunk) radius (mi) | 4 |
| Pipeline ring2 (trunk) radius (mi) | 9 |
| Pipeline ring3 (trunk) radius (mi) | 14 |
| Pipeline ring4 (trunk) radius (mi) | 19 |
| Transmission pipe diameter (in) | 15.50 |
| Ring1 (trunk) pipe diameter (in) | 12.00 |
| Ring2 (trunk) pipe diameter (in) | 14.75 |
| Ring3 (trunk) pipe diameter (in) | 16.75 |
| Ring4 (trunk) pipe diameter (in) | 17.00 |
| Pipeline service diameter (in) | 1.00 |

Figure 0-12 Summary Page from Example Calculation of H2A Delivery Model

## SUMMARY OF RESULTS AND RECOMMENDATIONS

The results of numerous HDSAM V2 model runs, over a wide range of market conditions, show the following general conclusions for currently available hydrogen delivery technologies:

- At low market demands (<10% market penetration)with a central plant 62 or greater miles from the city, the delivery cost of hydrogen to refueling stations is high for all delivery modes ($5-$10/kg of hydrogen or even higher), suggesting that distributed production of hydrogen at refueling stations may serve the early markets for hydrogen vehicles. Alternatively a small semi-central plant located at the city gate may provide sufficiently low delivery cost by tube trailers.
- If the city size is small (<400,000 people), if the market penetration is low (<10%), if the refueling station capacity is small (<400 kg/day), and if the distance to the production plant is modest (<62 miles or <99 km), then hydrogen delivery by tube trailer is the lowest cost option. For early market conditions, delivery costs of $5 to $12/kg are anticipated.
- If one or two market conditions move from the 'small' to the 'large' category, hydrogen delivery by liquid truck may be the lowest cost approach. However the energy consumed is 80% the energy in the hydrogen delivered due to the energy intensity of hydrogen liquefaction.
- For a maturing hydrogen fuel cell vehicle market (>20% market penetration), hydrogen delivery by pipeline is almost universally preferred, with expected delivery costs in the range of $2 to $4/kg of hydrogen depending on the size of the city and market penetration level.
- If the hydrogen production plants are located less than 62 miles from the "city gate" and if tube trailers are developed that could deliver about 1,000 kg of hydrogen, the cost of tube trailer delivery drops significantly and approaches the cost of pipeline delivery. This approach could avoid the required cost, time, disruption, and potential safety concerns of building hydrogen pipeline distribution systems in urban areas.
- The energy use in the delivery of hydrogen can be significant. For pipeline delivery, tube trailer delivery and liquid hydrogen delivery the Well to Vehicle Tank energy use is about 30%, 35% and 80% of the energy in the hydrogen delivered respectively.
- Greenhouse gas emissions are the lowest with pipeline delivery, moderately higher with tube trailer delivery, but essentially double with liquid delivery.
- The cost of hydrogen delivery is a function of the market demand in terms of kg of hydrogen per square mile (determined by the population density, vehicle ownership rate, and % transportation vehicle market penetration) and the distance between the central manufacturing plant and the market. Thus delivery costs to the vast majority of the U.S.(>75% of the land area) can be reasonably modeled in HDSAM V2 by drawing large enough circles (markets) around each major city and defining the population density as a function of distance from the center of the circle.
- There would be sufficient hydrogen demand to justify a central hydrogen production plant (50,000 to 350,000 kg/day of hydrogen production) located near any significant

urban area (>300,000 people) even at modest transportation vehicle market penetration (>25%). Large urban areas will require multiple large hydrogen production plants to supply them. As a result of this and the relatively high cost of hydrogen transport, it would be expected to have the production plant(s) located as close to the city as permitted. This is likely to be less than 62 miles (99.2 km) from the "city gate" and quite possibly at the city's edge.

Tube trailers, liquid truck delivery, and pipelines are each the optimum delivery method at different points in the maturation of the hydrogen infrastructure. As such, efforts to reduce the energy requirements and the capital cost of each method can reduce the overall costs of hydrogen delivery in the transition to and widespread use of hydrogen fuel cell vehicles. Possible research efforts include the following:

- Lower cost composite based high pressure storage vessels for hydrogen storage and cascade charging systems at the refueling station. These storage vessels are a major cost for all delivery pathways.
- Composite based high pressure (7,000 psi or 482.76 bars) tube trailers or other approaches to a tube trailer with a capacity of 1000 kg of hydrogen.
- FRP transmission and or distribution pipelines to reduce pipeline capital and thus pipeline delivery costs. The distribution lines are the larger portion of the pipeline costs.
- Magnetic or other novel methods for hydrogen liquefaction.

Finally possible enhancements to HDSAM V2 include:

- Adding an option for 10,000 psi (or roughly 700 bars) vehicle fills
- Including, as required, the equipment to pre-cool the hydrogen gas prior to dispensing for 10,000 psi (or roughly 700 bars) fills and vehicle hydride and sorbent storage approaches.
- Adding novel hydrogen carriers to the delivery pathways. Potential carriers include metal hydrides/alanates, chemical hydrides, liquid phase hydrogen carriers, and high surface area sorbents. Preliminary studies indicate the latter two approaches hold some promise for hydrogen delivery.
- Adding novel hydrogen carriers to the delivery pathways. Potential carriers include metal hydrides/alanates, chemical hydrides, liquid phase hydrogen carriers, and high surface area sorbents. Preliminary studies indicate the latter two approaches hold some promise for hydrogen delivery
- Examining the use of cold (-50$^{o}$C to -150$^{o}$C) hydrogen compressed gas for delivery and vehicle storage.

In this project, the Nexant team has conducted an in-depth comparative analysis of various promising infrastructure options for hydrogen delivery and distribution to refueling stations from central, semi-central and distributed production facilities. The major objectives are to provide improved hydrogen delivery modeling capability and meaningful recommendations to DOE on the research strategy that will lead to cost effective and energy efficient hydrogen delivery infrastructure to meet the DOE delivery goals, which in turn will help enable the use of hydrogen as a major energy carrier for fuel cell vehicles and stationary power generation.

The project focuses on hydrogen supply for light-duty fuel cell vehicles but the results can be utilized for other hydrogen markets.

The project evaluates and analyzes the following six hydrogen delivery options:

- Option 1: Dedicated pipelines for gaseous hydrogen delivery
- Option 2: Use of existing natural gas or oil pipelines for gaseous hydrogen delivery
- Option 3: Use of existing natural gas pipelines by blending in gaseous hydrogen with the separation of hydrogen from natural gas at the point of use
- Option 4: Truck delivery of gaseous hydrogen
- Option 5: Truck delivery of liquid hydrogen
- Option 6: Use of novel solid or liquid $H_2$ carriers in slurry/solvent form transported by pipeline/rail/trucks

The Nexant team conducted the project in six technical tasks:

- Task 1: Collect and Compile Data and Knowledge Base
- Task 2: Evaluate Current and Future Efficiencies and Costs of Hydrogen Delivery Options
- Task 3: Evaluate Existing Infrastructure Capability for Hydrogen Delivery
- Task 4: Assess GHG and Pollutant Emissions in Hydrogen Delivery
- Task 5: Compare and Rank Delivery Options
- Task 6: Recommend Hydrogen Delivery Strategies

The project team assembled to conduct this work consists of seven members. Air Liquide, GTI, and Nexant have the real world experience of building infrastructure projects and owning and operating hydrogen pipelines and other types of hydrogen delivery facilities. This real word experience can lead to meaningful and credible design and cost estimate for the various hydrogen delivery options and address the practical issues in the design. TIAX, Argonne National Lab (ANL), Pacific Northwest National Lab (PNNL), and the National Renewable Energy Lab (NREL) have the technology forward looking which can contribute to a successful identification and assessment of some promising delivery options currently still in the development, as well as the strong expertise and capability in delivery modeling. Chevron Technology Venture is the ultimate user of the hydrogen delivered and can provide their valuable perspectives on the path for building the hydrogen economy.

This interim report will focus on Options 1, 4, and 5, which have been incorporated into the H2A Delivery Components Model and Hydrogen Delivery Scenario Model (H2A Delivery Models) as Version (V2) of these models. The other pathways and final recommendations will be presented in the Final Nexant project report.

## 2.1 MODEL DESIGN PARAMETERS

Most of the effort on this project, as well as in H2A delivery modeling in general, focuses on currently available hydrogen delivery technologies. Thus, all of the components modeled in the default/base case (e.g. compressors, steel tanks, liquefaction units, steel pipelines, etc.) can be purchased and utilized now. Although hydrogen fuel cell vehicles are not generally available, these too are modeled as current technologies. Model inputs are based largely on analyses of cost data bases and vendor quotes, supplemented by industry review. All information sources are referenced in this report and/or in the models themselves.

### 2.1.1 Current Technology Characterization versus Future Projections

To a large extent, the characteristics of current hydrogen delivery technology determine how the infrastructure can be modeled and optimized, and how well new technologies can be modeled. For example, the relationship between capital cost and pressure determines the optimum design and cost of conventional steel storage tanks. This relationship is explained in Sections 2.2.3 and 2.2.4. Although composite gas storage vessels are now being developed for off-board hydrogen storage, these cannot be modeled in the current H2A Delivery Models without extreme care because the capital cost vs. pressure relationship for these vessels differs from that of steel vessels, resulting in potentially different optima for storage pressure and cost. This, in turn, is likely to alter the optimum hydrogen delivery infrastructure storage scheme from that described in this report and utilized in the H2A Delivery Models.

Similarly, most current gaseous hydrogen vehicle refueling is to a 5,000 psi (or roughly 350 bars) end-state fill pressure. Although research and development of 10,000 psi (or roughly 700 bars) vehicle refueling is underway, components modeled in the H2A Delivery Models V2 can accommodate only 5,000 psi (or roughly 350 bars) vehicle fills. Additional data on equipment costs and characteristics are needed to model 10,000 psi (or roughly 700 bars) fills accurately.

On the other hand, the H2A Delivery Models are designed to accommodate a range of alternative assumptions, thereby providing considerable flexibility to the users. Many default inputs can be changed to examine various cases of interest. Some of these changes define alternative scenarios that would still utilize existing hydrogen delivery technology. Simple examples of this include varying the size of refueling stations, hours of storage at a terminal, or the frequency of truck deliveries. All these choices/inputs can be entered on the appropriate Excel spreadsheets in the H2A Delivery Models.

The H2A Delivery Models also allow the user to modify default values that characterize individual delivery components (e.g., capital cost of compressors or liquefaction plants, compressor efficiency, truck fuel economy, etc.). Users might choose to change any of these inputs to better reflect their own experience or to examine the impact of a potential change on the results or perhaps to reflect advances in technology. Care needs to be taken when making such changes, however, as they could impact the basic relationships and optimizations incorporated in the models. This report and the H2A Delivery Model Users Guides[2] contain the information needed by a skilled delivery analyst to avoid pitfalls when making such changes. A Help Desk is also available for specific questions.[3]

### 2.1.2 Fuel Cell Vehicle Operating Characteristics

Within the H2A Delivery Models, the operating characteristics of fuel cell vehicles reflect the objectives of the US Department of Energy's *Multiyear Research, Development and Demonstration Plan* for hydrogen and fuel cell vehicles. Those objectives are to develop a 60 percent peak-efficient, durable, direct hydrogen fuel cell power system at a cost of $45/kW by 2010 and $30/kW by 2015.[4] As compared with a conventional spark-ignition (SI) gasoline-fueled vehicle, this translates into an average fuel economy for hydrogen FCVs of approximately 58 miles per gasoline-gallon-equivalent (mpgge).[5] The characteristics of the hydrogen FCV are taken from DOE's ongoing Multipath Study,[6] for which the PSAT model was run to generate estimates of conventional SI and FCV fuel economy for model year (MY) 2007 mid-sized automobiles.[7] Both conventional and hydrogen LDVs are modeled as "average" vehicles (i.e., mid-sized automobiles). For modeling purposes, the conventional vehicle is assumed to be a MY 2007 vehicle that achieves a "rated" fuel economy of 29 mpg.[8] The comparable 2007 MY FCV achieves a "rated" fuel economy of 58 mpgge.

Both gasoline and hydrogen LDVs are assumed to have a driving range of approximately 300 miles (480 km) and to refuel at comparable intervals. Approximately 6 kg of hydrogen is assumed to be stored on board the vehicle (of which 5.6 kg or 95% is recoverable) [9] and to be supplied via a hydrogen production and delivery infrastructure. Note that the level of fuel efficiency assumed for hydrogen fuel cell vehicles is not appreciably greater that that obtained in current laboratory and field trials. The challenge is to achieve this efficiency while improving durability to a level comparable to conventional internal-combustion engines and also reducing the amount of precious metal catalysts and other expensive materials in the fuel-cell stack or replacing them with less expensive options.

In terms of other operating parameters, fuel cell vehicles are assumed to be driven the same number of annual miles as conventional vehicles, under the same road and climactic conditions, and with comparable vehicle loads. However, as with other defaults, the user can change fuel-cell vehicle fuel economy and annual utilization to reflect a desired scenario by making appropriate adjustments to model inputs.

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2 US Department of Energy, Office of Hydrogen Fuel Cells and Infrastructure Technologies, accessed Oct. 2007 at http://www.hydrogen.energy.gov/h2a_delivery/html.

3 Ibid.

4 US Department of Energy, Office of Hydrogen Fuel Cells and Infrastructure Technologies, *Multiyear Research, Development and Demonstration Plan*, April 2007 accessed Oct. 2007 at http://www1.eere.energy.gov/hydrogenandfuelcells/mypp.

5 A gasoline gallon-equivalent (gge) is the amount of hydrogen that has the same energy content (on a lower heating value basis) as a gallon of gasoline. A gallon of gasoline contains approximately 116,000 Btu, roughly equivalent to the energy content of 1 kilogram of hydrogen.

6 S. Plotkin, Argonne National Laboratory, personal communication, Nov. 21, 2007.

7 A. Rousseau, Argonne National Laboratory, personal communication, Nov. 20, 2007. For further information on PSAT (Powertrain Systems Analysis Toolkit) see http://www.anl.gov/Media_Center/News/2006/news061219.html.

8 "Rated" or test fuel economy is estimated over a driving cycle which simulates a combination of urban and suburban driving. Actual fuel economy typically is considerably less for conventional IC vehicles. For FCVs there are no data to estimate actual fuel economy. In 2005 the entire fleet of gasoline-fueled LDVs achieved approximately 20.2 mpg.

9 Personal communication, R. Ahluwalia,Argonne National Laboratory, Oct. 2007.

### 2.1.3 Refueling Station Characteristics

In the delivery infrastructure bringing hydrogen motor fuel from centralized production facilities to hydrogen-fueled vehicles, hydrogen refueling stations will serve much the same function as today's gasoline stations. They will dispense hydrogen, gasoline and perhaps other fuels, and will sell various convenience items. Aside from restrictions governing setback and separation distances, their footprint will be comparable to that of conventional gasoline stations. And they will serve similar numbers of vehicles with similar demand profiles. Modeling hydrogen refueling thus requires an understanding of gasoline refueling both at the macro and micro level.

Gasoline retailing has evolved in the past several years. The number of retail outlets declined from over 210,000 in 1993 to 167,476 in 2005, a drop of nearly 20% (see Figure 2-1), while productivity (measured in terms of average sales per outlet) grew over 60%. No single factor has been identified for productivity gains, but as the DOE's Energy Information Administration stated in a recent report, "there are many reasons for the increased intensity in the use of retail outlets … Introduction of higher-cost Phase I diesel and motor gasoline in the early 1990's (required by the 1990 Clean Air Act Amendments) tended to increase the costs to retailers. Additionally, underground storage tank requirements that generally became effective at the end of 1998 elevated the costs of those remaining in the industry. These factors tended to squeeze marginal operators, some of whom probably exited the industry. Increases in some retailing costs elicited efforts by retailers to reduce other costs, including using the fixed assets (e.g., the retail outlet and its location) more intensely by shoehorning more goods and services into the outlet and expanding operating hours."[10]

While new environmental regulations raised costs, revenue streams from traditional automotive service and repair were eroded by the increased dependability and complexity of motor vehicles and the rise of "quick lubes", tire warehouses and other specialty retailers. Refueling stations sought replacement revenue to augment essentially flat motor gasoline and lubricant revenues – first from the sale of convenience items and more recently from the sale of branded fast food and ATM transactions. Today, refueling stations that include convenience stores account for an estimated 75% of motor fuel sales.[11] It should be noted, however, that while motor fuel represents more than two-thirds of the sales dollars at refueling stations that include convenience stores, it accounts for only a third of their profits.[12]

10 US DOE, Energy Information Administration, Restructuring: The Changing Face of Motor Gasoline Marketing, accessed Nov. 2007 at http://www.eia.doe.gov/emeu/finance/sptopics/downstrm00/index.html.

11 Convenience Store Industry Sales Hit New Highs in 2005, National Association of Convenience Stores, accessed Nov. 2007 at http://www.nacsonline.com/NACS/News/Press_Releases/2006/pr040506.htm.

12 Ibid.

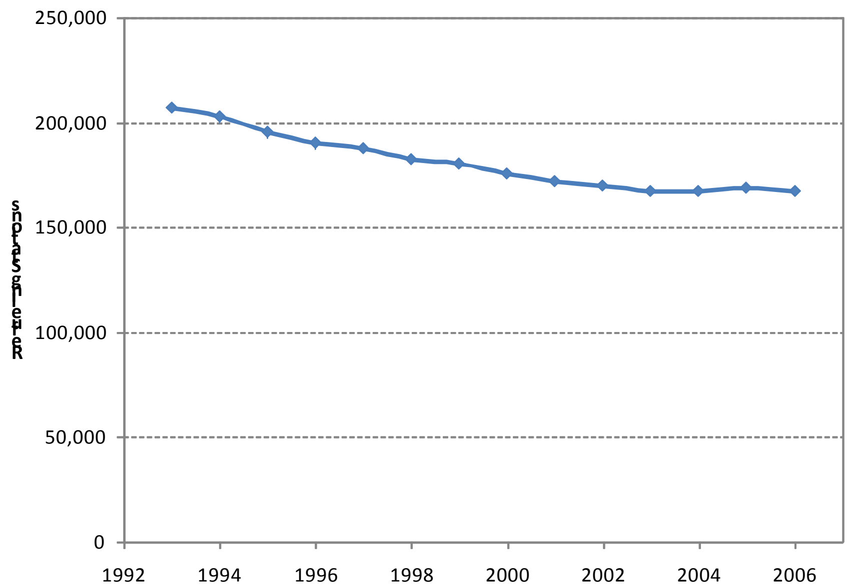


Figure 2-1 Refueling Stations in the U.S., 1993-2006

Although gross margins have remained steady at approximately $0.12 /gal in the past decade, motor fuel margins have dropped on a percentage basis (from well over 9% to 7.2% in 2005). Declining margins are due to a combination of consumer shifts from higher margin premium- and mid-grade fuels to regular-grade fuel, and increased credit card expenses which rise with fuel price. [13]

Nationally, refueling stations now dispense an average of more than 89,000 gallons of motor fuel per month, approximately 75% of which (67,000 gals) is gasoline (see Figure 2-2).[14] As with any average, however, there is considerable variability in station size. Small stations, particularly those in rural areas or where the business includes significant service and repair revenue streams, may dispense less than 30,000 gals per month while large urban stations, particularly "hyperstations" like those affiliated with Wal-Mart or Costco, may dispense 10-15 or more times that amount.[15,16] Stations on rural interstate highways may dispense only half as much fuel as large urban stations, whereas busy truck stops, which would normally include a larger proportion of diesel fuel sales, may dispense 150 percent of the average.

Among branded outlets, average station size may differ due to regional characteristics, the mix of stations in urban versus rural markets, and the age distribution of company-owned stations. For these reasons, it is very difficult to characterize the features of an "average" station. It is also

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13 Ibid.

14 In 2005, an estimated 179.1 billion gals of motor fuel (140 billion gals of gasoline and gasohol and 39.1 billion gals of diesel and other fuels) were consumed by vehicles on and off highways, and dispensed at 168,987 retail outlets. (Davis, S.C. and S. W. Diegel, *Transportation Energy Data Book*, Oak Ridge National Laboratory, ORNL-6978, 26th Edition, 2007, pp. 2-13 and 4-17; accessed Oct. 2007 at http://cta.ornl.gov/data/tedb26/Edition26_Full_Doc.pdf.

15 Melaina, M. and J. Bremson, *Regularities in Early Hydrogen Station Size Distributions*, 26th North American Conference, Intl. Assn. of Energy Economists, Ann Arbor, Sept. 24-27, 2006.

16 A Look at the New Competitors: Motor Fuel Retailing at Hypermarkets, MPSI, Inc. for National Association of Convenience Stores, accessed Nov. 2007 at http://www.nacsonline.com/NACS/Resource/MotorFuels/hypermart_exsumm.htm. Supermarkets, grocery stores, warehouse clubs and mass merchandisers that market gasoline are generically referred to as "hypermarkets".

difficult to obtain what are often internal data on the operations of company-owned stations. Fortunately, the Nexant team included Chevron, whose staff provided the team with typical operating characteristics of Chevron refueling stations located primarily in Florida, California and Washington State.[17] Based on these data, it is clear that Chevron's average station is larger than the national average, typically dispensing 135,000 gals of gasoline per month from six multi-fuel pumping dispensers (12 hoses). Newer Chevron stations are even larger, designed to dispense up to 300,000 gals per month from six dispensers.

In addition to capacity increases, stations are also becoming more capital intensive. According to the Energy Information Administration, US majors' retail outlets rose from an average of $500,000 net investment in place per outlet in 1990 to $771,000 in 1999.[18] Although some of the increase undoubtedly came from the divestiture of marginal (generally smaller) outlets, capital investment in retailing outlets rose over the decade, suggesting real increases.

As with the quantity of fuel dispensed, stations may serve a market consisting of a few hundred vehicles in an area with a radius of 1 to 2 miles, or thousands of vehicles in an area with a radius of 6.5 to 8 miles. The former is typical of the average convenience store; the latter occurs at Costco or other "hypermarket" locations. On a national level, dividing the number of LDVs on the road by the number of refueling stations yields a national estimate of average LDVs per station.[19] As shown in Figure 2-2 this average has been climbing steadily, from about 900 vehicles in 1993 to over 1400 in 2005.[20] For gasoline LDVs the trend is comparable, rising to approximately 1300 in 2005. Over time, the average refueling station may be expected to approach the capacity of Chevron's average station and the average population served may be expected to reach 2000 or more LDVs served per station.

Table 2-1 contrasts Chevron stations with US stations, as well as with comparable hydrogen refueling stations as represented in the H2A Delivery Models. Assuming a typical "fill" of 10 to 12 gallons per vehicle,[21] the average US station serves 180 to 220 gasoline vehicles per day. Given the higher relative fuel efficiency of fuel cell vehicles, the average hydrogen refueling station may be expected to serve a similar number of vehicles per day, assuming that the average "fill" is 75% of tank capacity, or approximately 4.6 kg per vehicle. Much as new Chevron-owned stations serve more than three times as many vehicles as today's average station, large hydrogen refueling stations might serve very large numbers of vehicles.

[17] Personal communication, Chevron, Inc., Aug. 2006.

[18] US DOE, Energy Information Administration, *Restructuring: The Changing Face of Motor Gasoline Marketing*, accessed Nov. 2007 at http://www.eia.doe.gov/emeu/finance/sptopics/downstrm00/index.html.

[19] LDVs per station has no time dimension. Assuming the average LDV refuels once a week, daily station fills could be estimated as this value divided by 7.

[20] Data from National Petroleum News, accessed Nov. 2007 at http://www.npnweb.com/uploads/researchdata/2006/USAnnualStationCount/06-stationcount.pdf.

[21] Ibid.

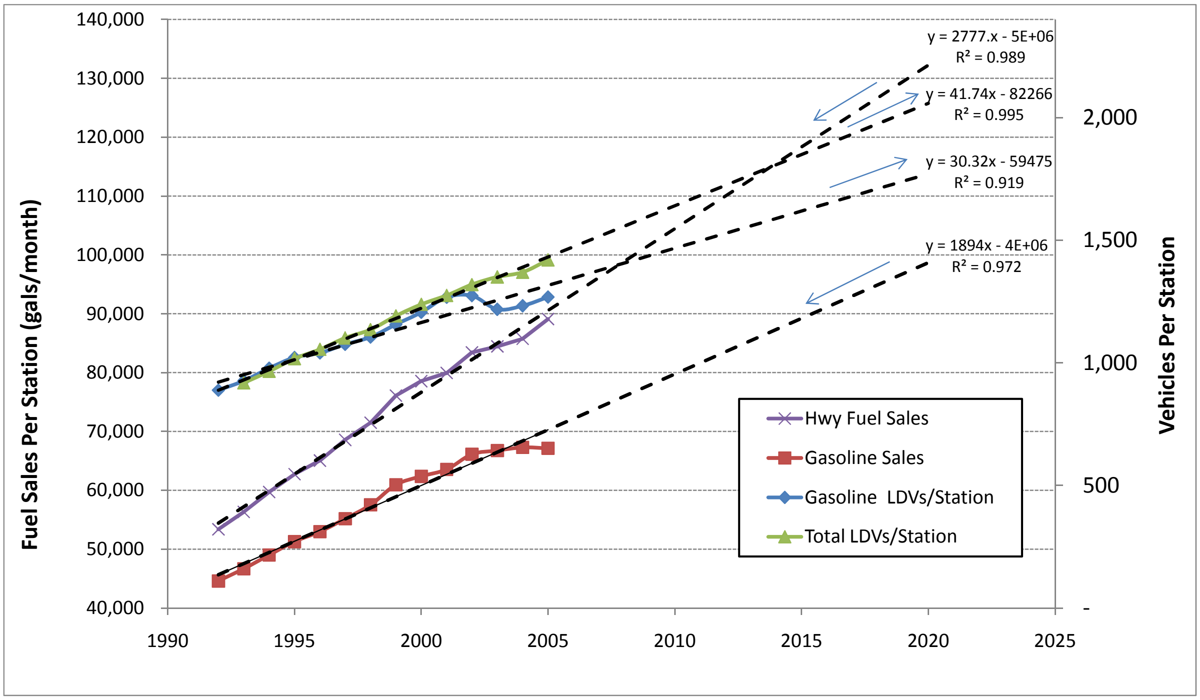


Figure 2-2 Trend in Size of Average Refueling Station and Vehicle Population Served

Table 2-1 Average Size of Current Gasoline Stations as Compared with Hydrogen Refueling Stations in the H2A Delivery Models

| Refueling Stations | Average Gasoline Gals (kg) Dispensed Per Month | Average Gasoline Gals (kg) Dispensed Per Day | Vehicle Fills Per Day |
|---|---|---|---|
| All US gasoline stations<br>Hydrogen station | 67,000<br>(26,000) | 2,200<br>(900) | 180 -220 |
| All Chevron-owned gas stations<br>Hydrogen station | 135,000<br>(52,000) | 4,500<br>(1,700) | 375-450 |
| New Chevron-owned gas stations<br>Hydrogen station | 300,000<br>(115,000 ) | 10,000<br>(3,800 ) | 830 -1,000 |
| Smallest hydrogen station | (1,500) | (50) | 11 [a] |
| Largest hydrogen station | (180,000) | (6,000) | 1360[a] |

Sources: US: Davis, S.C. and S. W. Diegel, *Transportation Energy Data Book*, Oak Ridge National Laboratory, ORNL-6978, 26th Edition, 2007, pp. 2-13 and 4-17; accessed Oct. 2007 at http://cta.ornl.gov/data/tedb26/Edition26_Full_Doc.pdf.
Chevron: Personal communication, Chevron, Inc., Aug. 2006.
[a]Hydrogen dispensed and daily fills computed from average fuel economy of hydrogen midsized car (58 mpge vs. gasoline (22 mpg) LDVs, assuming an average fill of 4.6 kg.

### 2.1.4 Fueling Profiles

In addition to providing estimates of station dispensing volumes, Chevron also supplied the project team with refueling profiles for 387 of their company-owned outlets. Based on credit card sales, transactions were plotted by time of day to produce hourly distributions of refueling events. These distributions vary by day of the week and station location, the latter reflecting the influence of commuter patterns on fueling, mainly on the way to and from work. Stations located on Interstate and major highways in or near urban areas exhibit refueling patterns that are similar to local urban stations. However, weekend patterns are significantly different from weekday patterns, showing a later morning fueling peak. Examples of these patterns are shown in Figure 2-3 through Figure 2-5 for mid-week, Monday and Friday, and weekends, respectively. Figure 2-6 displays daily transactions (or "fills") expressed as a percentage of total weekly transactions.

From these data it is clear that peak refueling demand occurs on Friday evening, with a secondary peak on Sunday afternoon. It may be that people top off their vehicle tanks on a Sunday to be ready for the work week, reducing demand on Mondays and Tuesdays, and that people going away for a weekend refuel on Fridays. This pattern may be more or less visible depending on the location of a given station and the proportion of commuter traffic it serves.

The within-day profile shows demand generally picking up before 6 AM, building throughout the day and then reaching a maximum around 5 PM. Again, stations that serve many commuters might show a more pronounced pattern of morning and evening peaks.

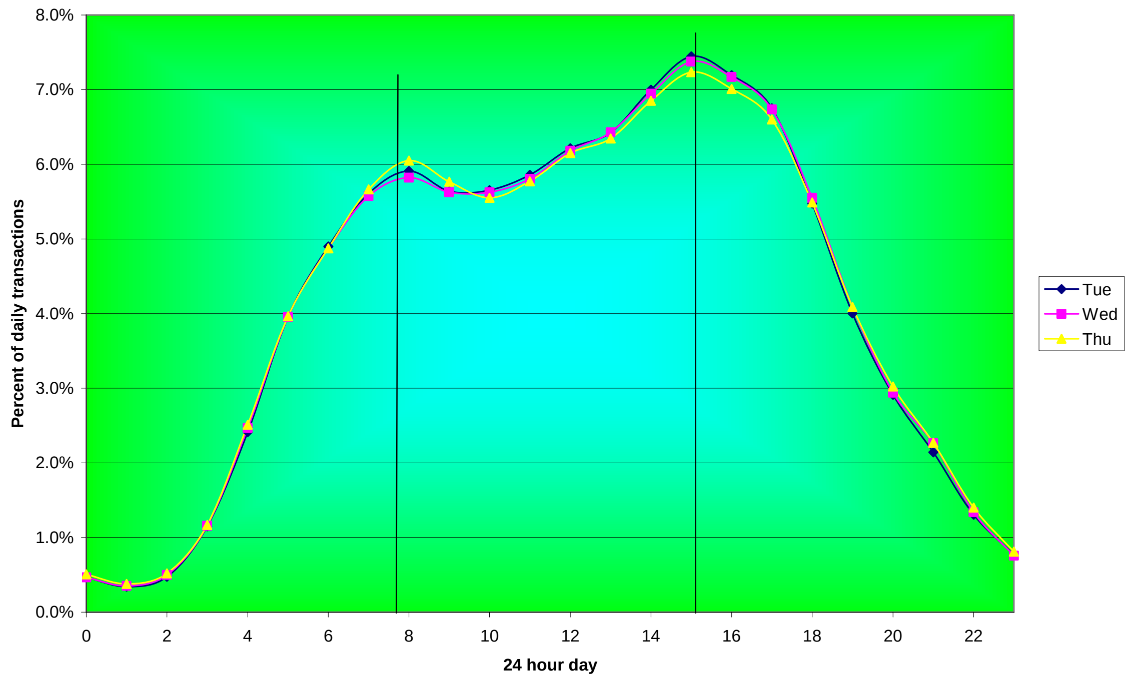


Figure 2-3 Gasoline Station Hourly Refueling Profile for Tuesday, Wednesday and Thursday

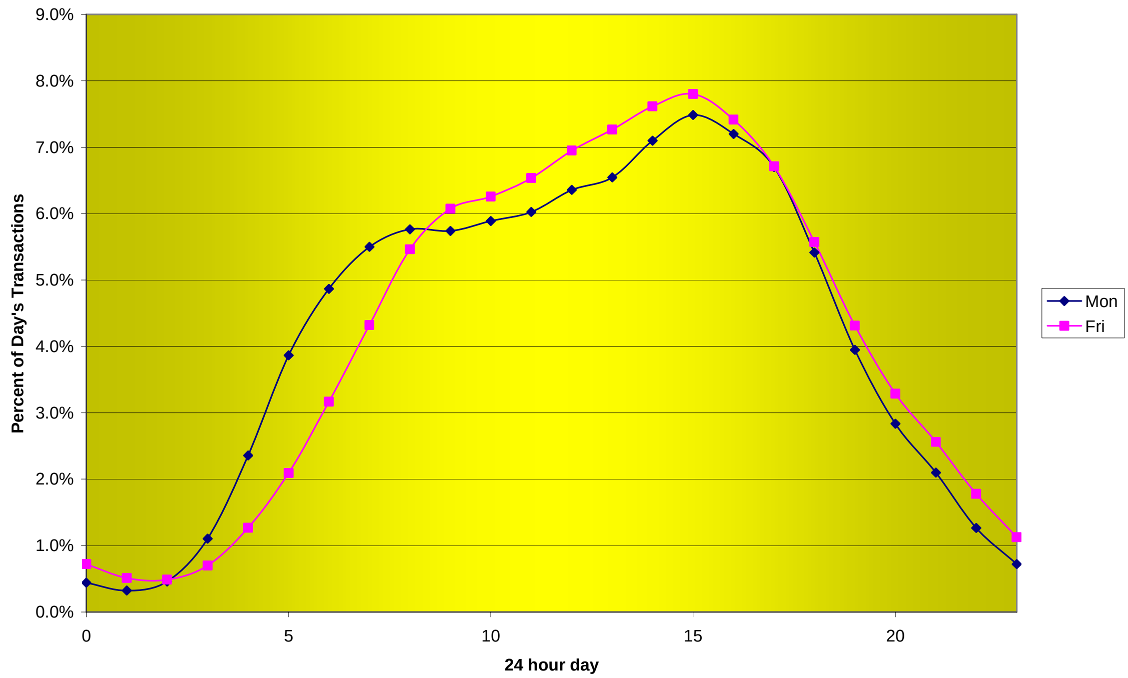


Figure 2-4  Gasoline Station Hourly Refueling Profile for Friday and Monday

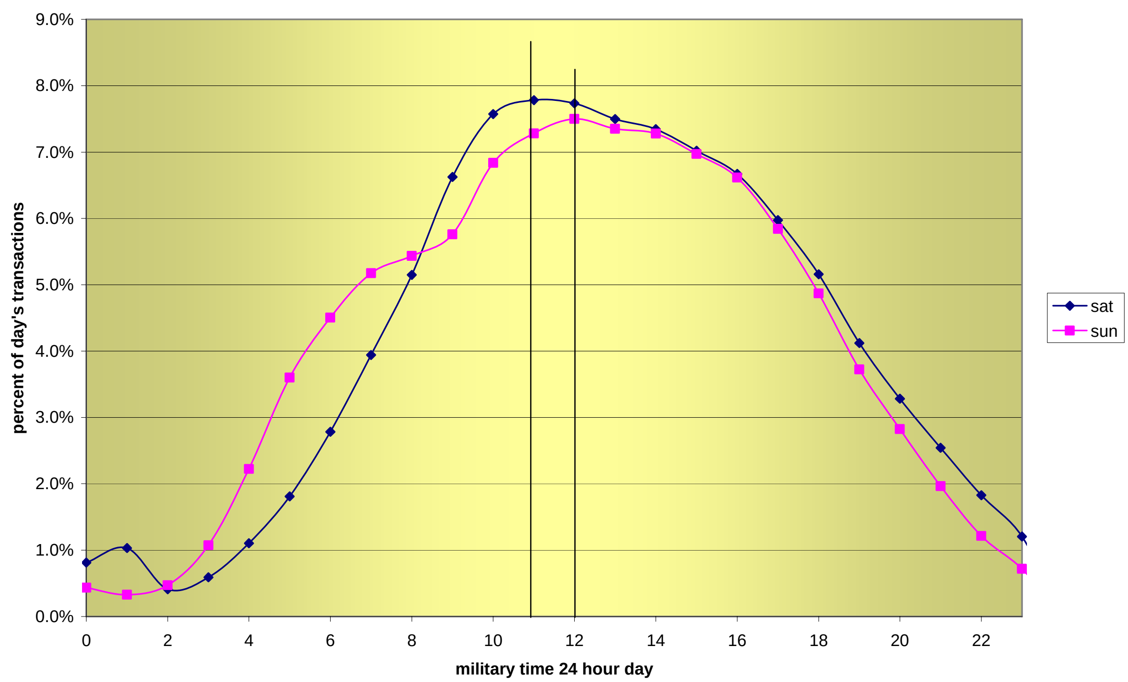


Figure 2-5  Gasoline Station Hourly Refueling Profile for Saturday and Sunday

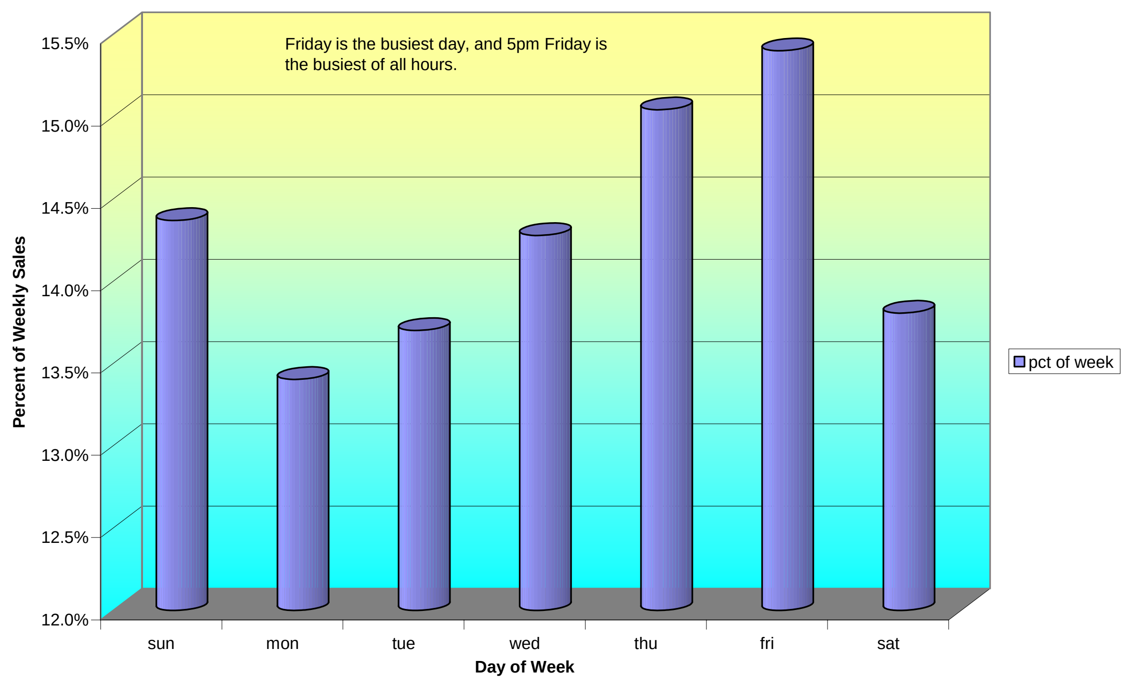


Figure 2-6 Weekly Distribution of Fuel Transactions or "Fills"

Gasoline-fueled vehicles typically purchase 10 to 12 gallons per "fill", and have an average fuel tank capacity of 16 gallons. Thus, a typical "fill" is 62 to 75 percent of tank volume. Assuming a typical gasoline LDV fuel economy of 22 mpg,[22] a gasoline LDV can travel approximately 265 miles (424 km) on a 75% fill. For the purposes of the H2A Delivery Models, it is assumed that a hydrogen fuel cell vehicle will typically purchase 4.6 kg of hydrogen which is about 75% of a 6 kg capacity storage tank on the vehicle. If a hydrogen vehicle averages 58 miles (92.8 km) per kg of hydrogen, it has the same range between refueling as a gasoline vehicle (265 miles or 424 km).

If a typical light-duty vehicle travels 12,000 miles (19,200 km) per year, one fill of 11 gallons is required every 7.4 days (22 mpg * 11 gallons * 365 days/year/12,000 miles/year), giving an average daily consumption of 1.5 gallons (11 gallons/7.4 days). This is equivalent to 0.6 kg per day for a hydrogen vehicle obtaining 2.6 times the fuel economy of a comparable gasoline vehicle.

In addition to the hourly and daily variations discussed above, refueling demand is also subject to seasonal fluctuations. The summer driving season, roughly from June through September, typically sees an increase in travel and fuel use.[23] This increase tends to be larger in the northern part of the country where winter driving is depressed by weather and associated road

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22 This is the average for MY 2000 midsized cars (27.0 mpg EPA "rated" and 22.0 mpg adjusted) on a standard driving cycle. US Environmental Protection Agency, *Light-Duty Automotive Technology and Fuel Economy Trends: 1975 through 2007*, accessed Nov. 2007 at http://www.epa.gov/otaq/fetrends.htm.

23 Ibid.

conditions.[24, 25] In the H2A delivery models an increase of 10 percent above annual average demand is assumed during the 120-day summer driving season, with a corresponding decline in demand during the remaining months. This seasonal demand fluctuation is handled upstream of the forecourt by employing either geologic storage or liquid hydrogen storage to supplement production. This buffer storage is described later in sections 2.1.9 and 2.3.1 of this report.

### 2.1.5 Refueling Station Design Parameters

For the purposes of the H2A models, the following design parameters were adopted for refueling stations:

Station average daily dispensing rates can range from 50 to 6,000 kg/day. The lower limit represents a demonstration-scale station visited infrequently by experimental fuel cell vehicles, while the upper limit represents the largest commercial station one might imagine. The station size is specified by its average daily dispensing rate. (Note: There is no capacity factor concept used. This differs from the H2A Forecourt Production V1[26] approach. For example, an H2A Forecourt Production Model 1,500 kg/day forecourt has a 70 percent capacity factor and thus an average daily dispensing rate of 1,050 kg/day. This is called a 1,050 kg/day refueling site in the H2A Delivery Models Version 2. The stations are assumed to operate 18 hours each day from 6:00 am to 12:00 am.

The vehicle's refueling fill pressure is taken to be 5,000 psi (or roughly 350 bars) after equilibration to standard temperature. As such, the maximum cascade charging system pressure is assumed to be 6,250 psi (431 bars), which allows the vehicle to refuel within the desired time of 3 minutes and allows for some over-pressure to compensate for some temperature rise during refueling.

The refueling station includes a dispenser, a cascade charging system unit, a compressor (for gas delivery), a pump/evaporator unit (for liquid delivery), and a fuel storage unit.

#### *2.1.5.1 Refueling Station Cascade Charging System*

The cascade charging system is comprised of three pressure vessels, each with a 21.3 kg holding capacity, and a maximum pressure of 6,250 psi (431 bars). There may be more than one bank of 3 cascade charging vessels depending on the size of the refueling station. To satisfy the vehicle filling dynamics, each of the vessels operates under a different minimum pressure; specifically, 6,000, 4,350, and 2,000 psi (414, 300, and 138 bars).

#### *2.1.5.2 Refueling Station Compressor*

For pipeline distribution, the compressor operates in one of two following modes:

During periods of low station demand, the compressor takes suction from the distribution pipeline at 300 psi (20.69 bars), and delivers intermediate pressure gas to a fuel storage unit at 2,500 psi (172.4 bars).

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[24] Ibid.

[25] Personal communication, Chevron, Inc., Aug. 2006.

[26] US Department of Energy: www.hydrogen.energy.gov under Systems Analysis-H2A

During periods of high station demand, the compressor takes suction from both the distribution pipeline and the fuel storage unit, and delivers high pressure gas to the cascade charging system.

For compressed gas tube trailer truck distribution, the compressor takes suction from the tube trailer, and delivers high pressure gas to the cascade charging system.

##### *2.1.5.3 Refueling Station Liquid, Storage Pump and Evaporator*

While the gaseous refueling stations employ a compressor to charge the cascade system, the liquid refueling stations employ a pump and an evaporator to achieve the same goal. The pump takes suction from the liquid storage tank pressure, and raises the pressure to the cascade charging system pressure. The high pressure liquid is then gasified in the evaporator, and heated to the cascade operating temperature. The cryogenic liquid storage tanks at the refueling station are sized to satisfy the station average daily demand, and to limit the number of liquid truck deliveries to a maximum of three stations per trip.

##### *2.1.5.4 Refueling Station Hydrogen Storage Unit*

The hydrogen storage consists of one of the following: pressurized tube trailers in the case of compressed gas truck distribution; cryogenic liquid tanks in the case of liquid truck distribution; and low pressure gas storage tanks for pipeline distribution.

Low pressure storage tanks are needed for pipeline distribution systems to absorb the difference between the (constant) flow rate from a production plant and the large hourly variation in refueling demand. As discussed in Section 2.2.3, the optimum operating pressure and holding capacity were found to be 2,500 psi (172.4 bars) and 91 kg, respectively.

### 2.1.6 Transmission and Distribution Pipeline Pressures

There are three stages of pipeline included in the H2A models for urban deliveries: transmission, distribution trunk; and distribution service lines. The arrangement is similar to that for natural gas transmission and distribution.

Hydrogen gas is moved from the production plant to the city gate through large, high pressure transmission lines. At the city gate, the pressure is reduced, and the gas is moved through trunk pipelines for the distribution system. In the distribution service pipelines, the pressure is once more reduced, and the gas is distributed to the refueling stations. In all cases, the hydrogen pressure is reduced through a combination of pressure drop through the pipeline, and a pressure reduction valve and/or system. A flow diagram of the system is shown in Figure 2-7

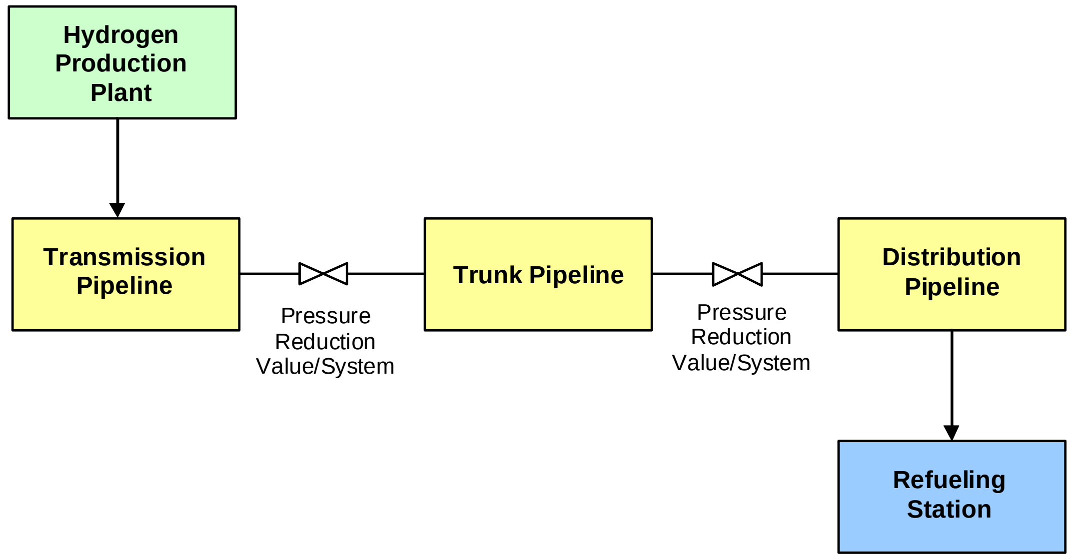


Figure 2-7 Transmission and Distribution Pipeline Arrangement

It is assumed the hydrogen production plant generates hydrogen at a pressure of 300 psi (20.69 bars). Prior to entering the transmission pipeline, the pressure is increased to 1,000 psi (69 bars) with a compressor. The following parameters are assumed for the H2A models:

Transmission System

Inlet Pressure – 1,000 psi (69 bars)

Outlet Pressure – 700 psi (48.3 bars)

Distribution -Trunk System

Inlet Pressure – 600 psi (41.38 bars)

Outlet Pressure – 450 psi (31 bars)

Distribution-Service System

Inlet Pressure – 400 psi (27.6 bars)

Outlet Pressure – 300 psi (20.7 bars).

The current natural gas pipeline system operates with transmission line pressures in the range of 500 to 1,200 psi (34.48 to 82.76 bars). The current very limited hydrogen transmission pipelines operate in this range as well. Higher transmission pipeline pressures may be feasible and desirable in the future. The hydrogen distribution trunk line pressures used are similar to, or higher than, those currently used for natural gas. The hydrogen distribution service line pressures are much higher than those for non-industrial natural gas service lines which are run at less than 125 psi (8.62 bars), or typically much lower. It is advantageous to keep the hydrogen pipeline pressure as high as deemed practical and safe since vehicle refueling is expected to be at high pressure.

### 2.1.7 Gaseous Tube Trailer Delivery Parameters

A tube trailer incorporates nine tubes, each with a volume of 91.8 $ft^3$. The holding capacity of the trailer is 344 kg with a tube pressure of 2,650 psi (182.76 bars). The tube trailer can not be completely discharged. The H2A Delivery models assume a final discharge pressure of 220 psig (15.17 bars g) and thus a delivered capacity of 280 kg. The models also allow the user to change the tube trailer inputs to model a 5,000 psi (344.83 bars) trailer that would have a holding capacity of 650 kg. Such technology is under development.

The loading time is assumed to be 6 hours and 10 hours for tube pressures of 2,650 psi (182.76 bars) and 5,000 psi (344.83 bar), respectively. The pick-up and drop-off times at the terminal and the refueling stations, including connection and disconnection times, are assumed to be 1 hour and ½ hour, respectively.

The truck is assumed to be powered by a Diesel engine with a fuel economy of 5 mpg. The truck average speed is assumed to be 43 mph on the highway, and 25 mph in the city. The truck operates 18 hours per day, consistent with the refueling stations operational hours. The yearly truck availability is assumed to be 98 percent.

### 2.1.8 Liquid Truck Delivery Parameters

The liquid truck tank volume is assumed to be approximately 17,000 gallon, with a nominal holding capacity of 4,600 kg. A heel of liquid hydrogen must be left in the truck so its delivered capacity is 4,110 kg.

The truck fill time is assumed to be 2 hours, to which is added 1 hour for connection, disconnection, and parking at the terminal. It is assumed the truck can make a maximum of three stops at refueling stations per trip. The unloading times are assumed to be 3.5, 2.5, and 2.0 hours for 1, 2, and 3 stops, respectively.

The operating parameters for the liquid delivery truck, such as average speed on the highway, are assumed to be the same as for the tube trailer truck.

### 2.1.9 Infrastructure Supply and Demand Variations and Storage Requirements

With a fully commercial hydrogen infrastructure, a network of transmission lines or truck delivery will likely connect a group of production plants with various local cities. As such, a maintenance outage on a particular plant is not likely to cause a severe disruption of hydrogen delivery, as the other plants in the network might accommodate the deficit. However, in the early phases of the infrastructure development, only one production plant may supply a city, and some form of long term storage will be necessary to accommodate production plant outages such as for annual maintenance. In addition, as discussed in Section 2.1.3, there is a seasonal variation in gasoline demand. Specifically, the summer demand is approximately 10 percent higher than the annual average, and the winter demand is 10 percent lower. Thus, the long term storage system must store the excess production in the winter, and deliver the stored hydrogen to supplement the production supply in the summer.

For the purposes of the H2A models, an annual schedule of production and demand was developed, as illustrated in Figure 2-8.

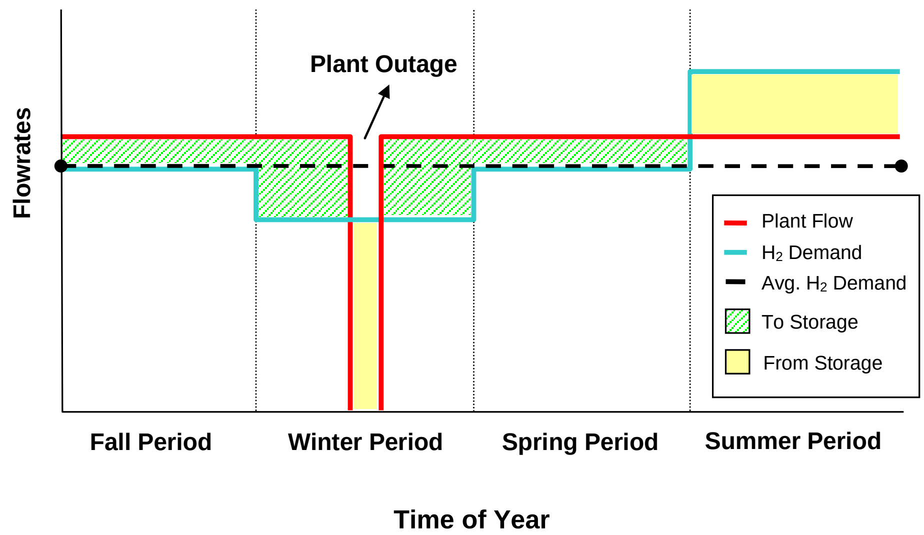


Figure 2-8 Operation of the Storage System During the Year

The dashed black line represents an average hydrogen demand throughout the year, while the blue line shows an assumed seasonal demand profile. The red line represents the hydrogen supplied by the production plant, which includes a production plant outage during the low demand period of the winter for annual scheduled maintenance.

During the fall, and in the spring, the seasonal demand is assumed to be the same as the average demand, and the blue and black lines overlap. During the winter, the demand is assumed to be 10 percent below the average demand, and the blue line lies below the black. During the summer, the demand is 10 percent higher than the average, and the blue line is above the black.

The green hatched sections correspond to the periods in which the production plant flow rate exceeds the demand, and the difference is directed to the storage system. The yellow shaded areas represent periods when the hydrogen flows from the storage system into the distribution system to replace or supplement the production supply. The model is designed such that the green shaded area in the fall and the first part of the winter is equal to the yellow shaded area during the plant outage period and the green shaded area in the second part of the winter and the spring is equal to the yellow shaded area in the summer. The H2A Delivery Models appropriately size the storage capacity to handle the maximum of the two green shaded areas in addition to handling any losses that may occur during the storage period.

The daily design flow rate for the production plant is determined by calculating the annual hydrogen demand (the area under the black or blue lines), adding all of the annual losses in the delivery pathway, and then dividing the resulting amount by the number of annual days in operation (365 days minus scheduled production outage days).

The storage capacity is based on values specified by the user for the following: the plant outage period; the increase in summer daily demand (above the annual average daily demand), as a percentage of the annual average daily demand; the length of the summer peak period; and the length of the winter period. The default assumptions for the parameters involved in the storage capacity calculations within the H2A delivery models are shown in Table 2-2 below. Finally, the drop in winter daily demand, as a percentage of the annual average demand is calculated by equating the green and yellow shaded areas.

Table 2-2 Default Assumptions for Storage Capacity Calculations

| Parameter | Default Assumption |
|---|---|
| Production Plant Outage Period | 10 days |
| Increase in Daily Demand during Summer | 10 percent of the annual average daily demand |
| Drop in Daily Demand during Winter | 10 percent of the annual average daily demand |
| Length of Summer Period | 120 days |

Although the production plant scheduled outage is assumed to occur for 10 days, such duration can be modified to investigate the effect of this parameter on the hydrogen delivery cost for various scenarios. Also, the percentage increase in summer demand and the duration of such increase can be modified to investigate the effect of these parameters on the hydrogen delivery cost. As shown in detail later in this report, the lowest cost multi-day hydrogen storage is geologic storage if it is available, followed by liquefaction and liquid storage. Geologic storage would be located near the production plant site or somewhere between the production plant and the city gate the plant serves. Liquefaction and liquid storage would be located at the plant site except for the mixed-mode liquid hydrogen delivery (i.e., gaseous delivery by pipeline to city gate and liquid hydrogen distribution to refueling stations in the city), in which case the liquefier and the liquid storage vessels are located at a terminal near the city gate.

Variation in hydrogen demand occurs daily during any given week as well as hourly during any given day as shown in Figure 2-9 and Figure 2-10. The peak demand is assumed to occur on a Friday at 3:00 PM, according to refueling profiles provided by Chevron. The Friday peak is assumed to be 8% above the weekly average daily demand, while the hourly peak is assumed to be 87% above the daily average hourly demand.

Intuitively, the best location for hydrogen storage to handle the daily and hourly fluctuations in demand is at the point of use, i.e., at the refueling site. This was proven quantitatively by examining other possible options such as at the terminals or central production plant sites. This avoids having to increase the size of upstream infrastructure to follow the peak demands at the refueling sites.

The refueling site storage is in the form of low pressure storage (2,500 psi or 172.41 bars) in the case of pipeline delivery, tube-trailers in the case of compressed hydrogen gas delivery via tube-trailers, or liquid cryogenic storage tanks in the case of liquid hydrogen truck delivery. The low pressure storage requirement at the refueling station is approximately 30% of the average daily demand for the Chevron demand profile of Figure 2-10, as discussed later in Section 2.3.1.

Storage upstream of the refueling station for hour and daily demand variations should be considered as an option only if locating such storage at the refueling sites is not possible for pipeline deliveries due to footprint limitations. Another storage alternative could be the pipeline internal volume. Such alternative is plausible if the required amount of storage and the length of the pipeline are such that a modest increase in pipe diameter can accommodate the daily and hourly variations in demand. Section 2.2.13 explains the pipeline storage alternative in detail.

To ensure adequate sizing of the refueling station components, a worst case scenario is assumed such that a refueling station could experience a spike in demand for the first period (approximately 3 minutes) of each hour with all the dispensing hoses simultaneously fueling vehicles during that period. Since increase in demand for such a short-duration is relatively small compared to the entire peak hour demand, this spike in demand is optimally handled by a corresponding increase in the size of the cascade charging system, as described later in Section 2.3.2.

In addition to the infrastructure storage described above, a small amount of low pressure (2,500 psi or 172.41 bars) storage (1/4 of a day is the default value in the H2A Delivery Models) is provided at the tube trailer loading terminals to ensure smooth loading operations. Similarly 1 day of liquid hydrogen storage (default value in the H2A Delivery Models) is provided at a liquid terminal to ensure smooth loading of liquid hydrogen trucks.

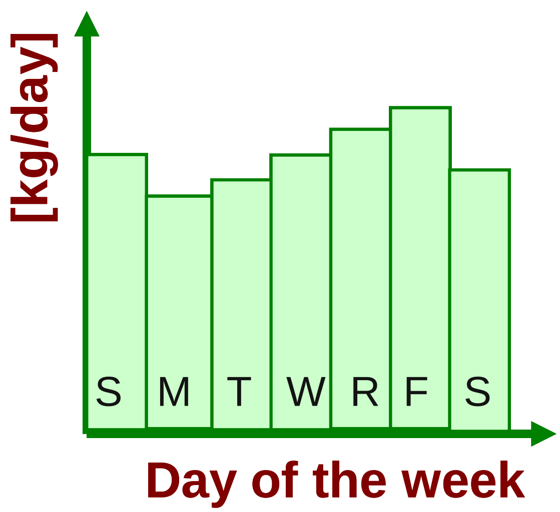


Figure 2-9 Hydrogen Weekly Average Daily Demand Variation

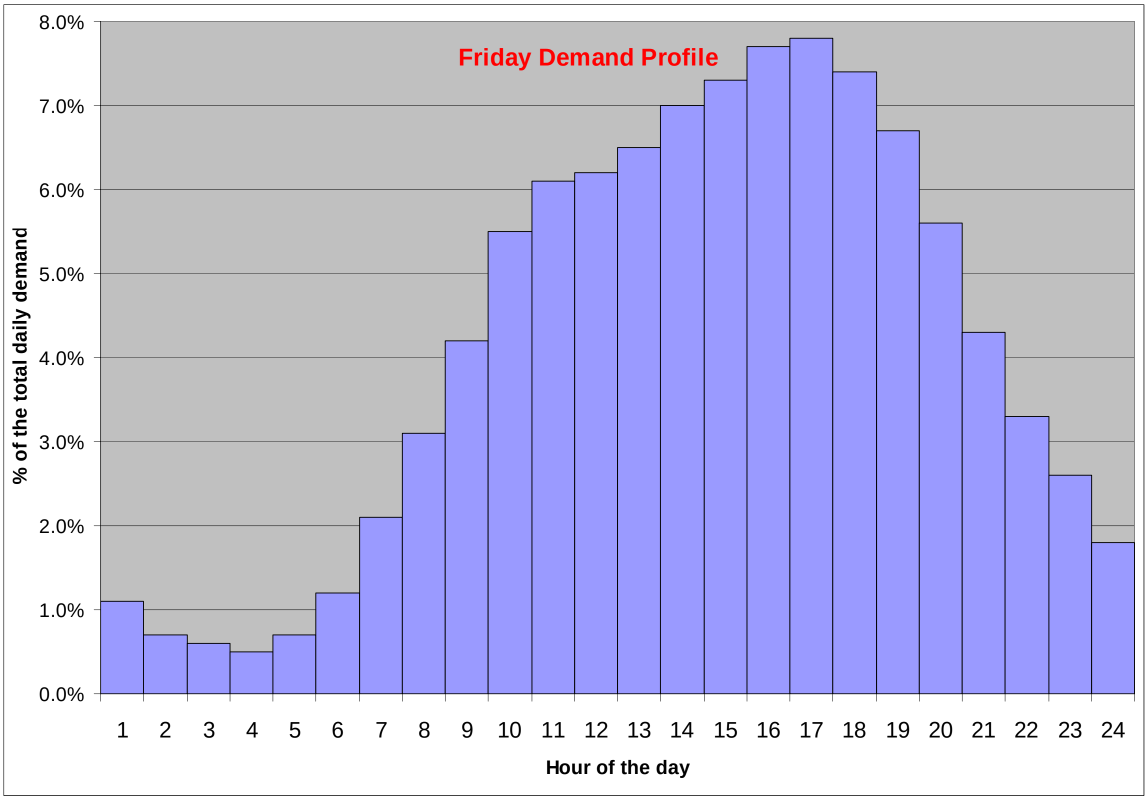


Figure 2-10 Hydrogen Daily Average Hourly Demand Variation

## 2.2 MODEL DATA BASE

### 2.2.1 Installation, Indirect, and Operation and Maintenance Cost Factors

For each delivery component, the total capital investment is calculated using the following formula:

$$TCI = C_{cap}(F_{install})(F_{dir/ind})$$

where $TCI$ = total capital investment
$C_{cap}$ = purchased equipment capital cost
$F_{install}$ = installation factor (if applicable)
$F_{dir/ind}$ = direct and indirect capital cost factor

Annual operating and maintenance costs are also required in the calculation of delivered hydrogen; the annual costs include insurance, property taxes, labor, labor overhead, and utility costs, to name a few.

#### *2.2.1.1 Installation Factor and Indirect Costs*

The total capital investment calculation requires an installation factor and an estimate of indirect costs.

For those cost relationships in the H2A Delivery Models which do not directly include an installation factor an installation factor is required. Table 2-3 shows the installation factors used for each component.

Table 2-3 Installation Factors

| Component | Installation Factor |
|---|---|
| Compressors up to 250 kg/hr design capacity (refueling station and terminal) | 1.2 |
| Refueling station cascade storage system | 1.3 |
| Refueling station low pressure compressed gas storage | 1.3 |
| Refueling station dispenser | 1.2 |
| Refueling station electrical upgrading | 2.24 for 480V service<br>1.85 for 4,160V service |
| Refueling station overall control and safety equipment | 1.2 |
| Refueling station LH2 pump | 1.2 |
| Refueling station LH2 storage | 1.2 |
| Refueling station LH2 evaporator | 1.2 |
| Trucks – GH2 | No installation factor |
| Trucks – LH2 | No installation factor |
| Terminal LH2 pump | 1.3 |
| Terminal LH2 storage | 1.3 |
| Terminal LH2 evaporator | 1.3 |
| H2 Pipelines | Installation included in cost curves |
| Liquefier | Installation factor included in cost curve |
| Terminal buildings and structures | Installation factor included in cost estimate |
| Large compressors greater than 250 kg/hr capacity | 2.0 |
| Geologic storage cavern and associated equipment (except charging/discharging compressor) | Installation included in cost curves |

Indirect capital cost factors for non-refueling station components are shown in Table 2-4, and the indirect factors for refueling station components are shown in Table 2-5.

Table 2-4 Indirect Cost Percentages for Non-Refueling Station Components
Percent of Initial Capital Investment

| Item | In Model | Notes |
|---|---|---|
| Site Preparation | 4% | |
| Engineering and Design | 10% | |
| Project Contingency | 10% | |
| One-time Licensing Fees | 0% | |
| Up-Front Permitting Costs | 3% | |
| Overall indirect factor on installed cost | 1.27 | |
| Owner's Cost | 12% | Owner's engineering and lender due diligence added for the following components: large compressor, compressed gas terminal, liquid hydrogen terminal and liquefier |

Table 2-5 Indirect Cost Percentages for Refueling Station Components
Percent of Initial Capital Investment

| Item | In Model |
|---|---|
| Site Preparation | 5% |
| Engineering and Design | 10% |
| Project Contingency | 5% |
| One-time Licensing Fees | 0% |
| Up-Front Permitting Costs | 3% |
| Overall indirect factor on installation cost | 1.23 |

For the majority of the components in the H2A Delivery Models, the total capital investment is generally small enough that the project financing is in the form of equity. However, for large investments, such as a liquefaction plant, an owner's cost factor is applied, which provides the funds necessary for additional owner's engineering, potential construction debt origination and closure fees, and due diligence studies.

#### *2.2.1.2 Operation and Maintenance Cost Factors*

Most of the delivery components incur annual expenses for operation and maintenance. The principal expenses include insurance, property taxes, licenses, permits, labor, utility costs and repairs.

Labor costs are calculated based on the annual hours of operation, and assumed labor type. Unburdened labor rates are derived from the Bureau of Labor and Statistics for the assumed labor type. The unburdened rates are then multiplied by the Overhead and G&A rate noted below to derive the burdened labor cost.

The operation and maintenance cost factors for non-refueling station components are shown in Table 2-6, and the factors for refueling station components are shown in Table 2-7.

Table 2-6 Operation and Maintenance Cost Factors: Non-Refueling Station Components

| Item | In Model | Notes |
|---|---|---|
| Insurance | 1% | Of Total Capital Investment |
| Property Taxes | 1.5% | Of Total Capital Investment |
| Licensing and Permits | 1% | Of Total Capital Investment |
| Operating, Maintenance and Repairs | See comment | Compressors: 4% of Total Installed Capital<br>Other: 0.5% of Total Installed Capital |
| Overhead and G&A | 50% | Of Total Unburdened Labor Cost |

Table 2-7 Operation and Maintenance Cost Factors: Refueling Station Components

| Item | In Model | Notes |
|---|---|---|
| Insurance | 1% | Of Total Capital Investment |
| Property Taxes | 0.75% | Of Total Capital Investment |
| Licensing and Permits | 0.1% | Of Total Capital Investment |
| Operating, Maintenance and Repairs | See note | Compressor: 4% of Total Installed Capital<br>Storage: 1% of Total Installed Capital<br>Dispensers: $800/dispenser |
| Overhead and G&A | 20% | Of Total Unburdened Labor Cost |

#### *2.2.1.3 Labor Costs in the H2A Models*

*Refueling Station*

The following assumptions apply as the baseline for determining the refueling station labor cost, for either gaseous or liquid hydrogen delivery:

- Refueling station capacity: 1,050 kg/day (average daily dispensed)
- Hours of Operation: 6:00 am to Midnight (18 hours)
- Average number of people in the snack store: 1.5
- Percentage of snack store labor associated with fuel dispensing: 33%
- Annual days of operation: 365

The annual labor hours allocated to fuel dispensing are 3,252 hrs per year (i.e., 18 hrs * 365 days * 1.5 * 0.33). For station capacities other than 1,050 kg/day, the labor hours are assumed to scale linearly as a function of station size. The labor rate used is $10/hr plus 20% for Overhead and G&A.

*Components Other Than Refueling Stations*

The development of labor costs for components other than those at a refueling station are presented in Table 2-8.

In contrast to the refueling station labor requirements, labor for the items in Table 2-8 are not assumed to scale linearly with capacity. Representative data from Plant Design and Economics for Chemical Engineers by M. Peters, K. Timmerhaus and R. West on labor costs vs. capacity for the chemical process industry were used to determine a characteristic scaling factor. A plot of the data, shown in Figure 2-11, suggests a characteristic scaling factor to be 0.25, and this value was adopted for the H2A Delivery Models.

Table 2-8 Development of Labor Costs for Components Other Than Refueling Stations

| Tab | Basis for hours/year | Wage | Wage basis |
|---|---|---|---|
| Compressed Gas/ Liquid Trucks | Calculated based on the number of trips per year and time per trip | $40/hour plus 20% overhead/G&A | Personal communication from an Industrial Gas Company |
| Compressed Gas Terminal | 2 operators, 24 hours per day, and 365 days per year; base capacity is 100,000 kg/day | $24.20/hour plus 50% overhead/G&A | Bureau of Labor Statistics – Petroleum Plant Operators |
| Liquid Terminal | 2 operators, 24 hours per day, and 365 days per year; base capacity is 100,000 kg/day | $24.20/hour plus 50% overhead/G&A | Bureau of Labor Statistics – Petroleum Plant Operators |
| Liquefier | 2 operators, 24 hours per day, and 365 days per year; base capacity is 100,000 kg/day | $24.20/hour plus 50% overhead/G&A | Bureau of Labor Statistics – Petroleum Plant Operators |
| Compressor | 288 hours per year (approximately 3 days per month); base capacity is 100,000 kg/day | $24.20/hour plus 50% overhead/G&A | Bureau of Labor Statistics – Petroleum Plant Operators |
| Pipeline | 4 FTE's (1 FTE = 2,080 hours/year); base capacity is 100,000 kg/day | $15.05/hour plus 50% overhead/G&A | Bureau of Labor Statistics – General Maintenance and Repairs Person |
| Geologic Storage | 1 person, 24 hours/day, 365 days/year; base capacity is 100,000 kg/day | $24.20/hour plus 50% overhead/G&A | Bureau of Labor Statistics – Petroleum Plant Operators |

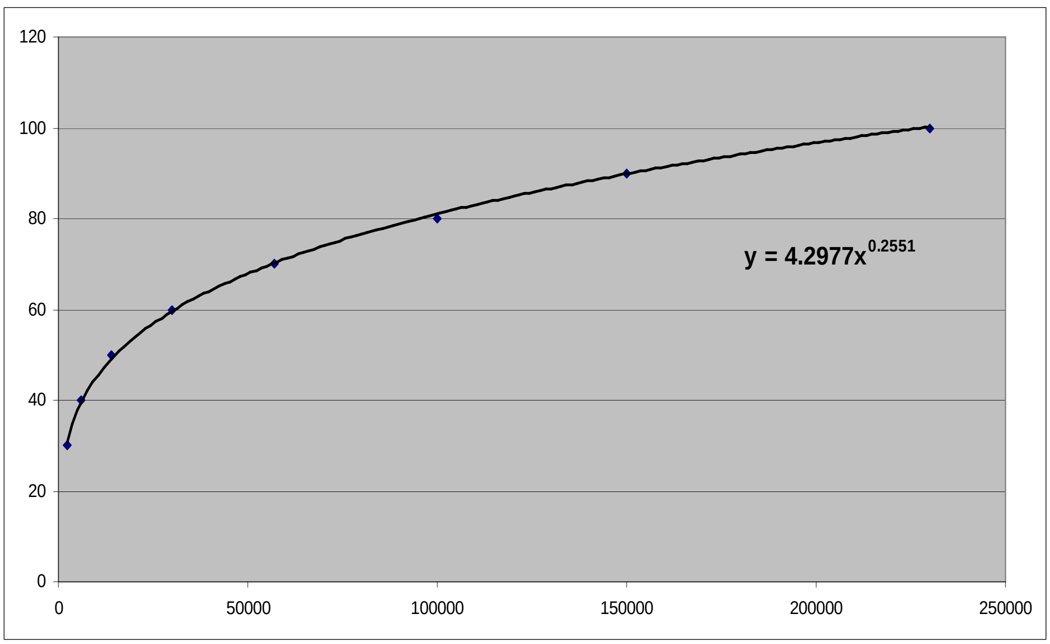


Figure 2-11 Labor Cost as a Function of Capacity (vertical axis: relative labor cost; horizontal axis: system capacity in kg/hour) [27]

[27] Peters, M.,Timmerhaus, K., and West, R. "Plant Design and Economics for Chemical Engineers, 5th Edition". McGraw Hill. New York: 2003. pg. 265.

### 2.2.2 Hydrogen Pipeline Costs

#### *2.2.2.1 Transmission Pipeline Costs*

Equations for estimating transmission pipeline costs were developed from historical cost data for natural gas transmission lines. Nathan Parker, a graduate student at the University of California at Davis, completed a regression analysis of 13 years of natural gas pipeline data from the Oil and Gas Journal. The equations from Mr. Parker's report, which are used in the delivery models, are shown below[28]:

- Pipeline materials: (330.5 * (Diameter, in.)$^2$ + 687 * (Diameter, in.) + 26,960)) * (Length, miles) + 35,000
- Miscellaneous costs: (8,417 * (Diameter, in.) + 7,324) * (Length, miles) + 95,000
- Labor costs: (343 * (Diameter, in.)$^2$ + 2,074 * (Diameter, in.) + 170,013)) * (Length, miles) + 185,000
- Right of way: (577 * (Diameter, in.) + 29,788)) * (Length, miles) + 40,000

In the models, each of the equations listed above are multiplied by a factor of 1.1. This factor adjusts the natural gas pipeline costs for higher costs anticipated in a hydrogen pipeline. The increased costs are due to 1) more stringent inspections of the welds, and 2) leak-free seals on the isolation and control valves. This is based on discussions with Industrial Gas companies who build and operate the existing hydrogen pipelines in the U.S. The above equations are also multiplied by 110.5/100 (ratio of GDP indices for 2005 and 2000) in the models to adjust the price year of the original equations (2000) to a price year of 2005.

The pipeline diameter is calculated from the 'Panhandle B' equation, which uses a series of parameters to simulate turbulent compressible gas flow in long pipelines[29].

#### *2.2.2.2 Distribution Pipeline Costs*

In the H2A Delivery Component and the Scenario Models V1, unit costs for distribution pipelines within a city were estimated using natural gas pipeline cost equations derived by Nathan Parker at the University of California as explained in Section 2.2.2.1. However, a refinement to this cost approach is desirable. The Oil and Gas natural gas pipeline data are dominated by more rural and larger pipeline diameters and operating pressures higher than are typically used for urban distribution.

During the course of the study, cost information on natural gas distribution line costs were obtained from 4 disparate sources as discussed below. In support of revised cost equations for the H2A Delivery Models, unit distribution pipelines costs for urban and downtown installations were assembled, and plotted as functions of the pipe diameter. Polynomial curve fits were then developed for use in the H2A Delivery Models. For the purposes of the model, the distribution pipelines were assumed to be steel, rather than plastic pipe, as would be appropriate for hydrogen pipelines. As a result, the cost analyses were based exclusively on steel pipeline data.

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[28] Parker, Nathan. "Using Natural Gas Transmission Pipeline Costs to Estimate Hydrogen Pipeline Costs," Technical Report No. UCD-ITS-RR-04-3, Institute of Transportation Studies, University of California, Davis, January 2005.

[29] Gas Processors Supplier Association, Engineering Data Book, 11th Edition, 1998, http://gpsa.gasprocessors.com

Implicit in the approach is the assumption that historical natural gas distribution line costs are representative of future hydrogen distribution line costs. As discussed in Section 2.2.2.1, the limited amount of hydrogen transmission pipeline is estimated to cost at most 1.1 times the cost of natural gas transmission pipeline. However, this assumption has yet to be tested for distribution pipeline, as no intra-city hydrogen distribution system yet exists. In particular, there is a host of regulatory issues which must be resolved before such a system can be built, including whether or not odorants or other leak detection approach will be required, allowable operating pressures, pipeline materials issues, and distances from occupied buildings. These factors may result in hydrogen distribution systems which are more expensive than natural gas systems. However, an attempt to estimate a cost factor to be applied to hydrogen distribution systems would currently be little more than a guess, and for the purposes of the H2A Delivery Models, the factor is presently assumed to be the same as that used for transmission pipelines; i.e., 1.1.

Plastic pipe[30] is now the predominant material for natural gas distribution service line purposes operating at low pressures. In most circumstances, plastic pipe is less expensive, easier to handle, and less costly to install than other types of pipe. Plastic pipe also does not require active corrosion control methods, such as cathodic protection, and is generally less expensive to maintain. Plastic pipe has proven to be highly reliable in most circumstances.

Steel pipe remains the most common material for natural gas distribution trunk lines/mains, and is the second most common material for natural gas services. Steel can be specified for almost any set of pressure, temperature and environmental conditions. However, steel tends to be more difficult and costly to install, and more expensive to maintain, than plastic pipe for most low and medium pressure applications. Cathode protected coated steel remains the pipe material of choice for most high pressure applications.

Natural gas distribution mains vary widely in diameter, from less than 2 inches (5.08 cm) in diameter for distribution mains serving a small number of residential or commercial customers, up to high-volume distribution mains of more than 12 inches (30.48 cm) in diameter serving major industrial or power generation customers. Nationally, more than 84 percent of the total distribution mains have a diameter of 4 inches (10.16 cm) or less, and 58 percent of the total has a diameter of 2 inches (5.08 cm) or less.

Statistical data on unit costs from a sample of 180 domestic gas distribution companies are presented in Table 2-9 for steel pipe, and in

Table 2-10 for plastic pipe.

Table 2-9 Installed Cost for Gas Distribution Piping Using Steel, $/linear foot

| Location | 8 inch (20.32 cm) | 12 inch (30.48 cm) | 16 inch (40.64 cm) | 20 inch (50.8 cm) |
|---|---|---|---|---|
| Rural | 59 | 89 | 118 | 148 |
| Suburban | 70 | 104 | 139 | 174 |

30 Hazelden, G., (Gas Technology Institute, Des Moines, Illinois), "Pipeline Topical Report Update", October 2006

| | | | | |
|---|---|---|---|---|
| Urban | 125 | 187 | 250 | 312 |
| Downtown | 400 | 600 | 800 | 1,000 |

Table 2-10 Installed Cost for Gas Distribution Piping Using Plastic, $/linear foot

| Location | 2 inch (5.08 cm) | 4 inch (10.16 cm) | 6 inch (15.24 cm) | 8 inch (20.32 cm) |
|---|---|---|---|---|
| Rural | 10 | 14 | 17 | 20 |
| Suburban | 12 | 16 | 20 | 24 |
| Urban | 22 | 29 | 36 | 43 |
| Downtown | 125 | 165 | 205 | 245 |

The Gas Technology Institute[31] recently completed an informal review of projected natural gas pipeline installation costs. A summary of the survey showed the following:

- Unit costs for 2 inch and 4 inch pipelines, operating at 1,000 psi (69 bars), in a combined urban/suburban environment, ranged from $100 to $180 per foot
- Reducing the operating pressure to 200 psi (13.79 bars) reduced the unit costs to values in the range of $60 to $140 per foot ($197 to $459 per meter)
- For some regulatory jurisdictions, securing approval for distribution lines operating at pressure as high as 1,000 psi (69 bars) could be problematic. Comprehensive public hearings, restrictions on distances from buildings, and other mandates will likely be required.

In a separate survey, Gas Technology Institute[32] conducted a limited survey on the estimated costs for installing distribution piping for hydrogen delivery. Surveys were sent to 20 gas distribution companies involved in pipeline construction. The respondents were asked to provide the cost per foot of installing pipe in urban, suburban, and rural environments. Pressures were limited to 450 psi (31 bars), and pipe sizes were limited to 4, 6, and 8 inch (10.16, 15.24, and 20.32 cm) diameter. In addition, any available information on 1 and 2 inch (2.54 and 5.08 cm) distribution lines was also requested.

Information was obtained from 7 companies, and the installed materials were limited to steel pipe only. The responses are summarized in

[31] Hazelden, G., (Gas Technology Institute, Des Moines, Illinois), “Pipeline Topical Report”, July 2006

[32] Hazelden, G., (Gas Technology Institute, Des Moines, Illinois), “Pipeline Topical Report”, July 2006

Table 2-11. The cost information was consistent with other surveys, with the exception of the rural costs from the gas company in Utah, which seemed somewhat low.

Table 2-11 Estimated Unit Costs for Hydrogen Steel Pipelines, $/foot

| | | Pipeline Size | | |
|---|---|---|---|---|
| Geographic area | Location | 4 inch (10.16 cm) | 6 inch (15.24 cm) | 8 inch (20.32 cm) |
| Gas company in Utah | Urban | 50-100 | 80-150 | 100-165 |
| | Suburban | 20-45 | 65-100 | 80-120 |
| | Rural | 15-35 | 25-40 | 35-60 |
| | 1in. | Similar to 4in. | | |
| Gas company in Northwest | Average for all zones | 65-125 | | |
| Gas company in Northeast | Suburban | | | 65 |
| | Suburban (1 in.) | 30 | | |
| Gas company in New England | | 180 | 200 | 220 |
| Gas company in Northeast | Urban | 75 | 95 | 115 |
| | Suburban | 60 | 78 | 95 |
| | Rural | 50 | 65 | 80 |
| | 1in. | 45-50 | | |
| Gas company in Northeast | Average for all zones | 100-180 | | |

Nexant contacted Pacific Gas & Electric Company[33], the local utility in San Francisco, for information on natural gas distribution systems within the city. The following information was obtained:

- San Francisco has a mix of cast iron, steel, and plastic distribution lines. The cast iron was installed in the 1930s. Subsequent lines were steel, but the current choice is high density polyethylene.
- Gas distribution pressures are restricted to 60 psi (4.14 bars) to limit both the potential and the chemical energy stored in the lines. In some cities, distribution pressures may be as high as 100 psi (6.89 bars), but PG&E has no immediate plans to increase pressures above 60 psi (4.14 bars).
- PG&E does not own the rights-of-way for the distribution lines. The rights-of-way are leased from the city under a franchise arrangement, in which PG&E pays an annual fee to the city. The franchise fees are approximately 2 to 3 percent of the gross revenues for the pipeline.
- The utilities common to PG&E can share trenches; i.e., PG&E will often run an electric line directly below a gas line. Locating multiple gas lines in a common trench is also done. If PG&E was to enter the hydrogen distribution business, the utility could, in principle, locate a hydrogen line next to a natural gas line. However, if a company separate from PG&E were to distribute hydrogen, PG&E is under no obligation to share a trench or the associated right-of-way. Further, a minimum 5 foot (1.52 m) separation is required between utility trenches. As such, the installation costs for a company separate from PG&E are likely to be much higher than those for PG&E.

[33] Telephone conversations with Todd Hogenson [(925) 974-4144] and Mark Heckman [(415) 973-1840], Pacific Gas & Electric Company, San Francisco, California, August 23, 2005

- Typical installation costs are \$100/linear foot (\$328/linear meter) in residential areas, increasing to \$300/linear foot (\$984/linear meter) in congested urban areas. The unit cost is dominated by the labor component, and the total installed cost is essentially immune to the pipe size and material. Part of the high costs are due to city-imposed limits on hours for installation (9:00 am to 3:00 pm), a requirement to return the street to traffic access at the end of every day, and prohibitions on storing construction materials at the site overnight. The street must also be returned to its original condition at the completion of the pipeline installation.

*Recommended Inputs to the Component and HDSAM Models*

The unit cost data for steel pipelines from the four references discussed above are plotted as functions of the location (urban or downtown) and the pipe size in Figure 2-12. The variations in unit costs can, in some cases, be fairly significant due to differences in geographic locations from which the data were derived, operating pressures, and allocations to the 'urban' or 'downtown' classification. Nonetheless, for the purposes of the study, the trend lines through the data are assumed to yield representative unit steel pipe costs, and are estimated as follows:

Urban locations:

- Unit cost, \$/mile = 1.1 * (836 * (Diameter, in.)$^2$ + 50,441 * (Diameter, in.) + 291,948)

Downtown locations, for diameters in the range of 1 to 6 in. (2.54 to 15.24 cm):

- Unit cost, \$/ mile = 1.1 * (30,048 * (Diameter, in.)$^2$ - 82,986 * (Diameter, in.) + 345,389)

Downtown locations, for diameters in the range of 6 to 20 in. (15.24 to 50.8 cm):

- Unit cost, \$/ mile = 1.1 * (-4,243 * (Diameter, in.)$^2$ + 414,377 * (Diameter, in.) - 1,272,104)

The factor of 1.1 reflects the estimated cost premium for a hydrogen pipeline compared to a natural gas pipeline. The premium is associated with all welded construction and additional quality control on welding and examinations.

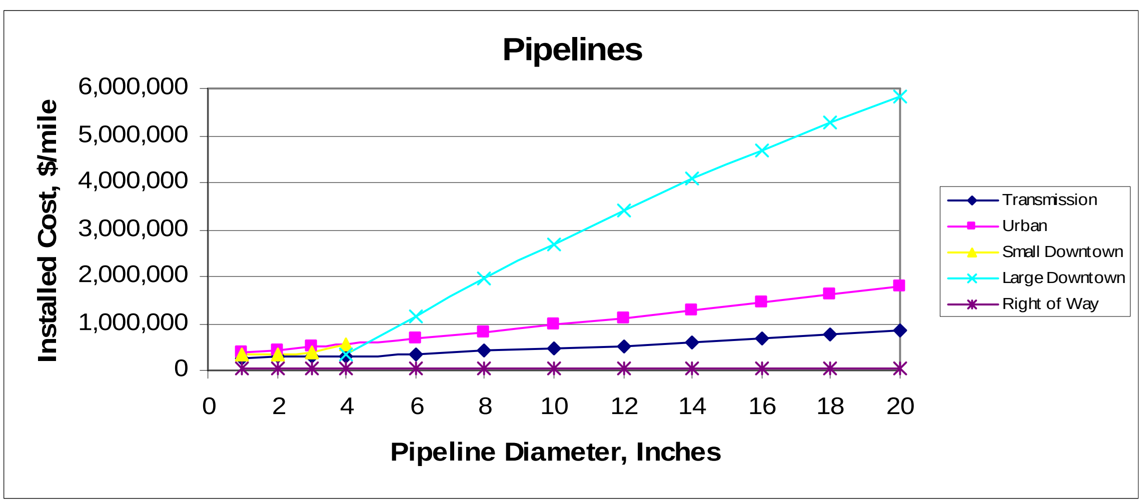



Figure 2-12 Compilation of Steel Pipeline Unit Cost Data

As a point of reference, the costs used from the Oil and Gas Journal for hydrogen transmission lines and right-of-way (see Section 2.2.2.1) are also shown in Figure 2-12 (for the year 2000). The right-of-way costs derived from the Oil and Gas Journal (see Section 2.2.2.1) are added to both the transmission and distribution pipeline costs as a rough estimate of this additional cost factor in the H2A Delivery Models V2.

Using these equations, projected installed piping costs, in $/mile and including Right of Way costs, are listed in Table 2-12.

Table 2-12 Unit Steel Distribution Pipeline Costs, Including Right of Way Costs, Using Trend Line Equations

| | Unit Cost, $/mile | |
|---|---|---|
| Diameter, in. (cm) | Urban | Downtown |
| 1 (2.54( | $410,000 | $360,000 |
| 2 (5.08) | $470,000 | $370,000 |
| 4 (10.16) | $600,000 | $580,000 |
| 6 (15.24) | $730,000 | $1,200,000 |
| 8 (20.32) | $870,000 | $2,000,000 |
| 12 (30.48) | $1,200,000 | $3,400,000 |
| 16 (40.64) | $1,500,000 | $4,700,000 |
| 20 (50.8) | $1,800,000 | $5,900,000 |

For the purposes of the H2A Delivery Models, downtown costs are used for the inner most distribution main ring and its service lines of the pipeline distribution system for cities. The urban costs are used for the rest of the city. In the H2A HDSAM model, the pipeline distribution system consists of a series of 1-4 circular distribution mains, depending on the size of the city, with appropriate distribution service lines to the refueling stations.[34]

### 2.2.3 Low Pressure Storage

As discussed in Section 2.1.9, low pressure gas storage (~2,500 psi or 172 bars) is used in the delivery infrastructure to fulfill two requirements: 1) for pipeline delivery pathways, to accommodate the hourly variation in refueling station demand; and 2) for tube trailer terminals, to accommodate the short term differences between the constant output from the production plant output and the embarkation/disembarkation schedules of the tube trucks. Both of these cases satisfy short term storage requirements; i.e., a nominal 0.3 days for the refueling stations, and 0.25 days for the tube trailer terminals. For long term storage demands, which last days or weeks, geologic or liquid storage is the preferred lower cost option.

Early in the study, optimization studies were conducted on compressed gas storage options for both short term and long term requirements. The pathway included a production plant, a compressed gas terminal adjacent to the production plant, a transmission pipeline to a city gate, and a system of distribution pipelines to the refueling stations. The purpose of the gas terminal was to accommodate either 1) the short term variation between the constant output from the production plant and the hourly demand at the fueling stations, or 2) the long term storage

34 www.hydrogen.energy.gov/h2a_delivery/html

requirements for production plant outages, and the seasonal variation between peak summer demand and minimum winter demand.

Outlined below is a discussion of the optimization process for short term and long term compressed gas storage at a terminal. However, as the study progressed, it was found that geologic or liquid storage was much more economical than compressed gas storage to accommodate production plant outages and seasonal demand variation. It was also found that the most economical location to place low pressure storage vessels to meet the hourly variation in refueling station demand was at the refueling stations. As such, the results of the early low pressure storage optimization studies for gas terminals were not implemented in the Version 2 of the H2A Delivery Models. Nonetheless, the results of the earlier optimization studies are included here for the following reasons: completeness in the discussion; the preferred vessel operating pressure of 2,500 psi (172.4 bars) was found to be broadly applicable to the low pressure storage requirements in Version 2 of the H2A Delivery Models; and a compressed gas terminal adjacent to a production plant may have a use in the delivery infrastructure in which land constraints at the refueling stations preclude the addition of low pressure storage vessels to the mandatory cascade system.

#### *2.2.3.1 Background to Earlier Delivery Pathway*

The hydrogen demand within a city is primarily determined by the number of vehicles refueling at a particular time. In contrast, the hydrogen supply to the city is generally provided by a local production plant, which operates most efficiently at a constant output. For hydrogen pipeline delivery, the preferred method for accommodating the difference between the hourly supply and the hourly demand is to locate compressed gas storage at the refueling site. Alternately, one could locate compressed gas storage at a terminal adjacent to the production plant. During the evening, when the city demand is low, hydrogen from the production plant is compressed and stored in the pressure vessels. During the day, when the city demand is high, compressed gas from the storage vessel is added to the flow from the production plant.

There were two types of gaseous terminals evaluated in the study, but which, for reasons discussed above, were not selected for eventual use in the H2A Delivery Models. The first was co-located with a production facility, and it served two purposes: 1) provided storage for plant outages, seasonal variation in demand, and daily variation in demand (pipeline delivery cases); and 2) compressed the hydrogen for transfer either to a transmission pipelines or tube trailers. The second was located at the end of a transmission pipeline at the city gate, and it served two purposes: 1) provided storage for plant outages, seasonal variation in demand, and daily variation in demand (pipeline delivery cases); and 2) compressed the hydrogen for transfer to tube trailers.

A generic flow diagram of a gaseous terminal co-located with a production plant is shown in Figure 2-13.

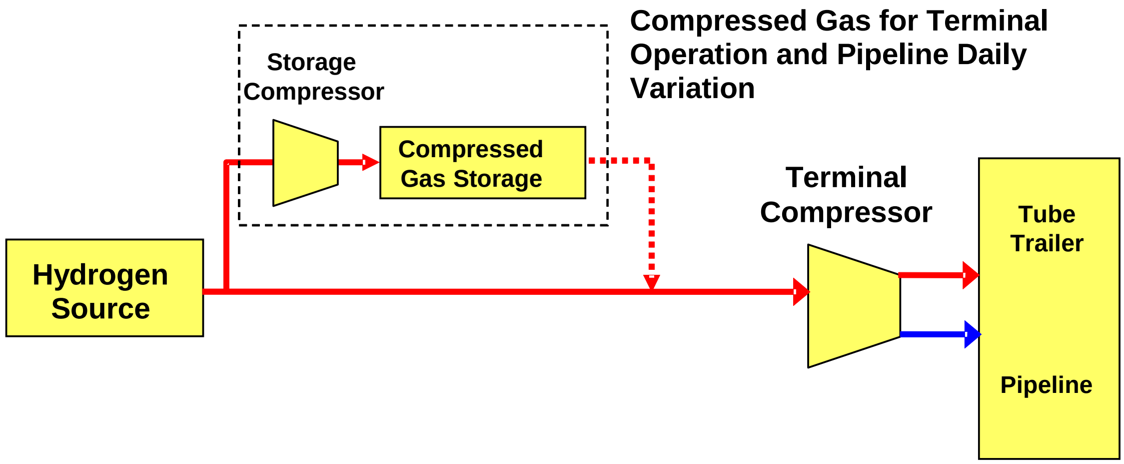



Figure 2-13 Flow Diagram for Gaseous Terminal Co-Located with Production Plant

The storage requirements for the seasonal plant outage and seasonal demand variation are described in Section 2.1.9. The design parameters to accommodate the hourly variation in demand are discussed below. The analysis below develops a preferred operating pressure for the gas storage vessels, and recommends a unit cost, in $/kg of hydrogen, for the storage vessels. The resulting operating pressure and unit costs generally apply to vessels for hourly storage needs regardless of their location in the delivery infrastructure and are as such used in the H2A Delivery Models Version 2.

#### *2.2.3.2 Pressure Vessel Types and Fabrication Costs*

For given storage vessel dimensions, the tank weight, and by inference, its cost, are inversely proportional to the allowable material stresses. For a vessel designed under Section VIII, Rules for Construction of Pressure Vessels, of the ASME Boiler and Pressure Vessel Code, the allowable stress is one-quarter of the tensile stress under the Division 1 requirements, and one-third of the tensile stress under Division 2. The inspection requirements are more thorough under Division 2, which leads to the higher allowable stresses.

For many tank and pressure vessel applications, a common fabrication material is ASTM (American Society for Testing and Materials) SA516 Grade 70 carbon steel. The '70' refers to the tensile stress in 1000 psi (69 bars), so the allowable stress at moderate temperatures is 17,500 psi (1,207 bars). The material is fabricated in standard plate dimensions of 8 ft x 10 feet (2.44 m x 3.05 m), and thicknesses up to 2.5 inches (6.35 cm). The vessel shells are formed by rolling the plates, and then welding on a longitudinal seam. The heads are formed by forging, and then welding to the shell. The optimum storage pressure, discussed below, is in the range of 2,000 to 2,500 psi (138-172 bars). For a vessel 48 inches (122 cm) in diameter operating at 2,000 psi (138 bars), the required shell thickness is 2.5 inches (6.35 cm). Further assuming a length of 24 feet (7.3 m) yields a vessel mass of 36,900 pounds (16,773 kg). The fabrication cost for the vessel, estimated by the AspenTech Icarus cost estimating program, is $70,600 (1st Quarter 2006 dollars). This is equivalent to a unit material price of $1.91 per pound of steel, and a unit hydrogen storage price of $980 per kilogram of hydrogen.

A potentially lower cost alternate to SA516 is ASTM SA36, which has an allowable stress of about 14,000 psi (965.5 bars). For a vessel 48 inches in diameter operating at 2,000 psi (138 bars), the required shell thickness would be 3.25 inches (8.255 cm). Further assuming a length of 24 feet (7.3 m) yields a vessel mass of 46,300 pounds (21,045 kg). With this design, the estimated cost using the Icarus program is $82,500. This is equivalent to a unit material price of $1.78 per pound of steel, which is a savings of 7 percent compared to SA516. However, the thicker wall thickness reduces the inside diameter, which leads to an increase in the unit hydrogen storage price to $1,223 per kg.

In the South Coast Air Quality Management District report "Status Report for Hydrogen Study Team", CP Industries provided a quote on 3 of their ASME vessels[35]. The vessels start as seamless pipe, and the heads are formed by heating and forging each end of the pipe; there is no longitudinal or circumferential welding involved. The material is ASTM SA372, Grade J, Class 70, with a tensile stress of 120,000 psi (8,276 bars). For Division 2 fabrication, the allowable stress is 40,000 psi (2,759 bars), or 130 percent higher than SA516. The SCAQMD design is based on the following: 5,500 psi (379 bars); 20 inches (50.8 cm) outside diameter; and 22 feet (6.71 m) vessel length. Using their quoted FOB price of $56,200 (1st Quarter 2006 dollars) yields a unit material price of $2.75 per pound of steel, and a unit hydrogen storage price of $718 per kilogram of hydrogen.

If the CP Industries approach to vessel fabrication is applied to the requirements of a gas storage vessel, their standard vessel which comes closest in design parameters would be as follows: 2,800 psi (193.1 bars) design pressure; 24 inch (61 cm) outside diameter; and 25 foot (7.62 m) vessel length. Assuming a unit material price of $2.75 per pound of steel results in a unit hydrogen storage price of $596 per kilogram.

Some observations can be made from the above figures:

1) The incremental costs of the high strength steels, in $/lb, compared to the more common carbon steels are small enough that the high strength steels are likely the economic choice for a pressure vessel.

2) Lower storage pressures are preferred. The pressure vessel wall thickness is proportional to the design pressure; however, the stored mass is proportional to the design pressure times the inverse of the compressibility factor. In effect, the inverse of the compressibility factor is equivalent to a storage efficiency, in pounds of gas stored per psi of design pressure. The effect is plotted in Figure 2-14.

[35] "Status Report for Hydrogen Study Team, Attachment A, Hydrogen Compatibility Study Team Report and Supporting Documents", South Coast Air Quality Management District, August 2001

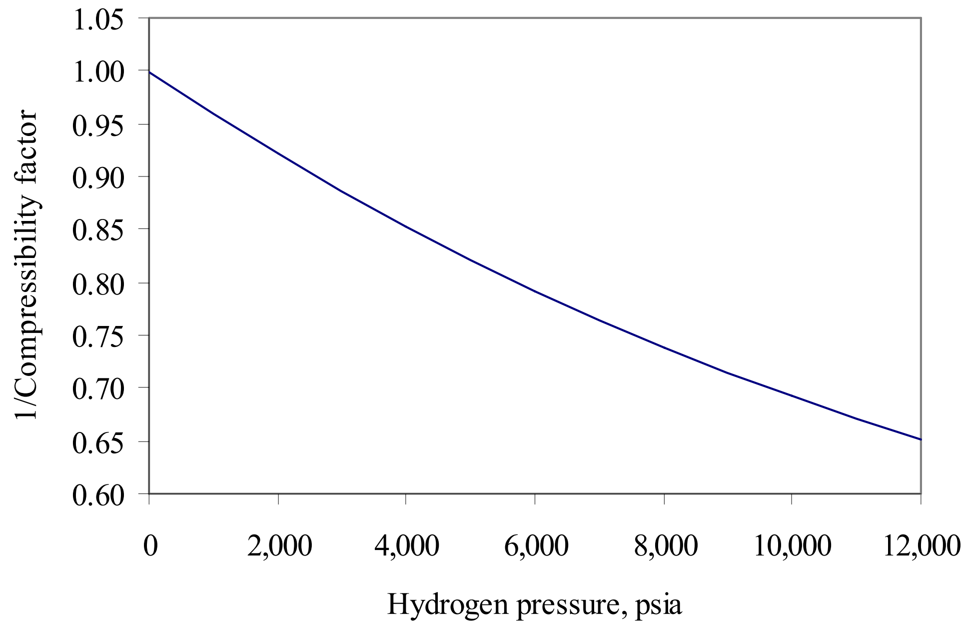



Figure 2-14 Inverse of Hydrogen Compressibility Factor as a Function of Pressure

3) The vessel fabrication approach adopted by CP Industries is limited to a maximum vessel diameter of 24 inches (61 cm). 24 inch (61 cm) pipe is available in wall thicknesses up to Schedule 160 (2.344 inches or 5.95 cm wall thickness), which implies a maximum design pressure on the order of 8,600 psi (593.1 bars). However, for pipe diameters of 26 inches (66 cm) and above, the standard wall thicknesses are in the range of 0.5 to 0.75 inches (1.27 to 1.91 cm), which effectively limits design pressures to the range of 1,500 to 1,800 psi (103 to 124 bars).

#### *2.2.3.3 Preferred Gas Storage Vessel Operating Pressure*

The preferred operating pressure for the gas storage at a terminal should be the one which minimizes the sum of the capital cost of the pressure vessel, the capital cost of the compressor, and the equivalent capital cost for the energy supplied to the compressor. The example chosen to examine to quantify these relationships was with the gas storage located at a terminal adjacent to the production plant. To help define the preferred pressure, an Excel spreadsheet model was developed, which calculated each of the above costs over the following ranges of design conditions:

- Production plant capacities of 1,000 kg/day, 10,000 kg/day, 325,000 kg/day, 500,000 kg/day, and 800,000 kg/day
- Gas storage operating pressures of 1,265 psi to 4,015 psi (87 to 277 bars), in increments of 250 psi (17.24 bars).

The pressure vessel dimensions and costs were developed as follows:

- The hourly gas flows to, and from, the gas terminal were defined by the difference between the uniform gas delivery from the production plant and the variable demand on the transmission pipeline; the latter was defined by the Chevron gas station fueling profile (see Section 2.1.4). An example of the operating profile for the gas terminal is shown in

Table 2-13. Positive compression rates represent gas flows from the production plant into storage, and negative compression rates represent gas flows from storage into the transmission pipeline.

- Pressure vessel dimensions, wall thicknesses, and weights were calculated using standard formulas, subject to the following constraints: a length-to-diameter ratio not to exceed 6; and a wall thickness not to exceed 2.5 inches (6.35 cm).
- Unit vessel costs were estimated to be $2.90 per pound, including fabrication, delivery, and sales tax. To this unit price was added 20 percent for the following: steel support frame; concrete foundations; pressure relief valves; inter-vessel piping; isolation valves; installation; and hydraulic test of completed assembly.

Gas terminal compressor capacities and costs were developed as follows:

- The design power demand was defined by the following: the highest hourly flow rate to storage from the calculations of the pressure vessel capacities; a 3-stage reciprocating compressor with inter-cooling; and an isentropic compressor efficiency of 88 percent. The maximum compressor capacity was fixed at 16,000 kWe; for higher power levels, multiple compressors were used.
- Compressor capital costs were calculated using the cost information presented in Section 2.2.5.
- The power to drive the compressor was assumed to be proportional to the hourly hydrogen flow rate into storage; i.e., the compressors were driven by variable speed electric motors, and the efficiency was independent of the compressor speed. The hourly compressor power demands are shown in the last column of

Table 2-13.

- The annual electric energy cost for the compressors was calculated as follows: (Daily energy demand, kWhe) x (365 days per year) x ($0.065/kWhe for commercial electric energy). The annual energy cost was converted to an equivalent capital cost by dividing the energy cost by a fixed charge rate of 0.15.

The sums of the cost elements are plotted as a function of the storage pressure and the production plant capacity, as shown in Figure 2-15.

## Table 2-13 Hourly Operating Profile for Gas Terminal

325,000 kg/day City Demand
2,500 psi (172.4 bars) Storage Pressure

| Time, hours | Fraction design flow | Transmission rate, $lb_m$/hr | Active storage, $lb_m$ | Compression rate, $lb_m$/hr | Compression power, kWe |
|---|---|---|---|---|---|
| 12:00 AM | 0.07 | 3,575 | 83,395 | 24,134 | 10,447 |
| 1:00 AM | 0.06 | 2,860 | 109,674 | 26,279 | 11,376 |
| 2:00 AM | 0.07 | 3,575 | 136,668 | 26,994 | 11,685 |
| 3:00 AM | 0.17 | 8,581 | 162,947 | 26,279 | 11,376 |
| 4:00 AM | 0.34 | 17,877 | 184,220 | 21,273 | 9,209 |
| 5:00 AM | 0.55 | 28,603 | 196,198 | 11,977 | 5,185 |
| 6:00 AM | 0.68 | 35,038 | 197,449 | 1,251 | 542 |
| 7:00 AM | 0.79 | 40,759 | 192,265 | -5,184 | 0 |
| 8:00 AM | 0.81 | 42,189 | 181,360 | -10,905 | 0 |
| 9:00 AM | 0.79 | 40,759 | 169,025 | -12,335 | 0 |
| 10:00 AM | 0.77 | 40,044 | 158,120 | -10,905 | 0 |
| 11:00 AM | 0.80 | 41,474 | 147,930 | -10,190 | 0 |
| 12:00 PM | 0.86 | 44,334 | 136,310 | -11,620 | 0 |
| 1:00 PM | 0.88 | 45,407 | 121,830 | -14,480 | 0 |
| 2:00 PM | 0.97 | 50,055 | 106,277 | -15,553 | 0 |
| 3:00 PM | 1.00 | 51,843 | 86,077 | -20,201 | 0 |
| 4:00 PM | 0.98 | 50,770 | 64,088 | -21,988 | 0 |
| 5:00 PM | 0.94 | 48,625 | 43,172 | -20,916 | 0 |
| 6:00 PM | 0.76 | 39,329 | 24,402 | -18,771 | 0 |
| 7:00 PM | 0.55 | 28,603 | 14,927 | -9,475 | 0 |
| 8:00 PM | 0.41 | 21,452 | 16,178 | 1,251 | 542 |
| 9:00 PM | 0.30 | 15,732 | 24,580 | 8,402 | 3,637 |
| 10:00 PM | 0.18 | 9,296 | 38,703 | 14,123 | 6,114 |
| 11:00 PM | 0.11 | 5,721 | 59,261 | 20,558 | 8,900 |
| | | ---------- | | ---------- | -------- |
| | | 716,502 | | 0 | 79,012 |

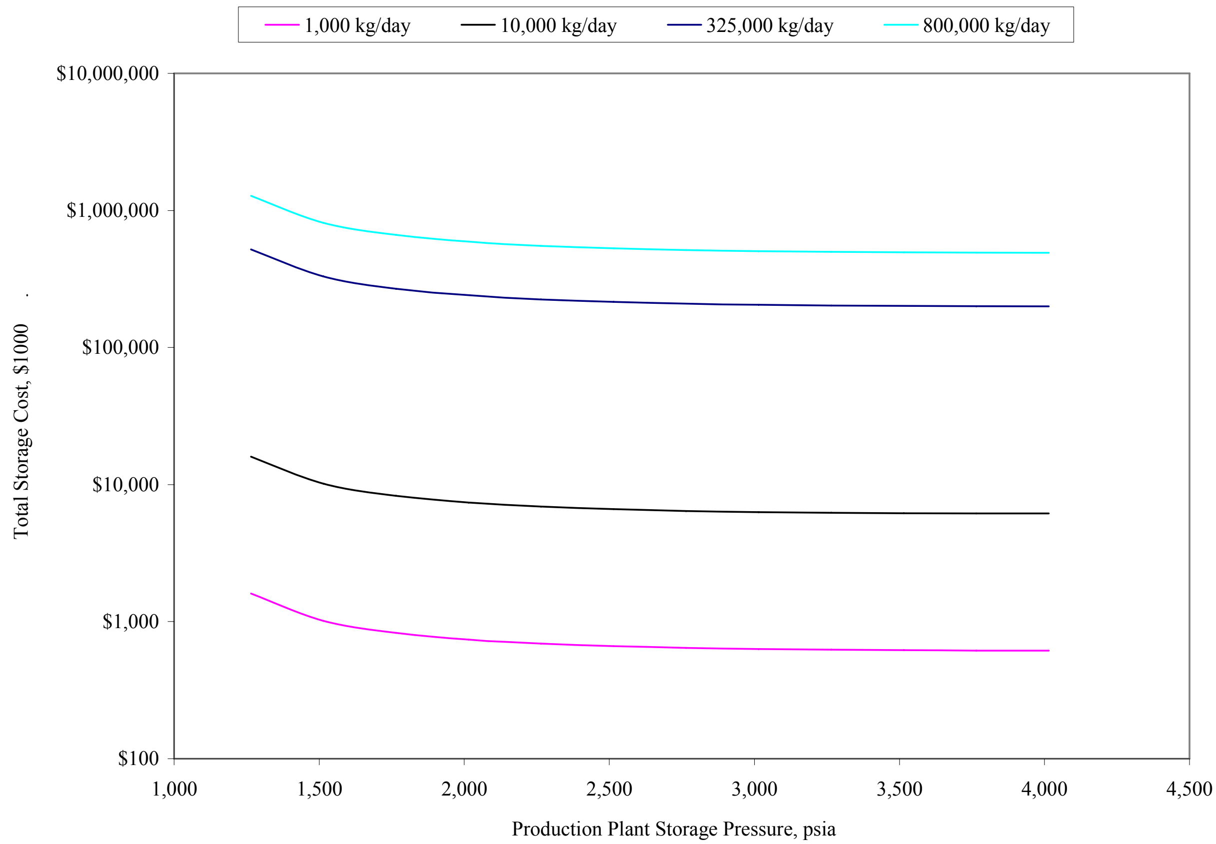



Figure 2-15 Gas Terminal Storage Cost as a Function of Production Plant Capacity and Storage Pressure

Storage system costs decrease for pressures up to about 2,500 psi (172.4 bars), after which the costs reach asymptotic values only slightly below those at 2,500 psi (172.4 bars). For the purposes of the study, the preferred pressure was selected to be 2,500 psi (172.4 bars).

On a serendipitous note, the preferred storage pressure is essentially independent of the production plant capacity. The effect can be traced to two elements, as follows:

- For a pressure vessel operating at 2,500 psi (172.4 bars), and subject to the length-to-diameter and wall thickness constraints noted above, the vessel is 4.1 feet in diameter, 24.9 feet (7.59 m) long, and stores 91 kg of hydrogen. Thus, for all but the smallest production plants, multiple storage vessels are required. As a result, the capital cost for the vessels is directly proportional to the production plant capacity.
- For the purposes of the study, the efficiency of the compressor was assumed to be both constant and independent of the compressor power demand. Thus, the energy consumption and the corresponding equivalent capital cost were directly proportional to the production plant capacity.

In principle, the optimum pressure for a gas terminal may be somewhat different than the optimum pressure for a refueling station due to the relative costs among the following items: pressure vessels; compressors (large versus small); and the equivalent capital cost for the compressor energy (88 percent isentropic efficiency for large units, versus 65 percent for small). To this end, a series of pressure optimization calculations were developed as above, but substituting refueling station compressor characteristics for gas terminal compressor characteristics. The results showed an optimum pressure of 1,750 psi (120.7 bars); however, the total cost for a 2,500 psi (172.4 bars) design was only 2.5 percent higher than for the 1,750 psi (120.7 bars) design. For the purposes of the H2A Delivery Models, an optimum low pressure storage pressure of 2,500 psi (172.4 bars) was selected for all storage requirements, and the associated infrastructure system costs should be nominally representative of a fully optimized design.

#### *2.2.3.4 Design Parameters for Daily Storage*

As noted in the above, the preferred pressure for low pressure storage is 2,500 psi (172.4 bars). However, the calculations did not specify the preferred gas terminal capacity as a function of the city demand, the gas terminal compressor capacity, or the gas terminal compressor annual energy demands for this particular pathway approach. As such, this section addresses the following:

- Chevron gas station profile of hourly fuel demand
- Gas terminal storage model
- Modifications to the Chevron profile due to refueling station equipment capacities
- Preferred capacities for the gas terminal, the refueling station compressor, the refueling station cascade charging system.

*Chevron Profile*

Chevron provided the project with fuel dispensing data from gas stations. The data include the following:

- Chevron average gasoline station dispenses approximately 4,400 gallons per day, or about 135,000 gallons per month. Assuming a typical fill of 10 to 12 gallons per vehicle, 365 to 440 vehicles visit the gas station on an average day.
- The profile of sales by the hour of day reflects the influence of commuter patterns of fueling, mainly on the way to and from work. Figure 2-16 shows the hourly variation in sales on Monday, which has the lowest demand during the week, and Friday, which has the highest. The daily profile shows demand generally increasing around 5:00 am, building through the day, and reaching a maximum in the middle of the afternoon.

For the delivery infrastructure study, the principal demand for hydrogen within a city is assumed to be fuel cell vehicle refueling. Thus, the Chevron demand profile, in essence, defines the hourly demand for hydrogen from the gas terminal.

The ratio of peak flow rate to average flow rate in the Chevron data is 1.74:1.

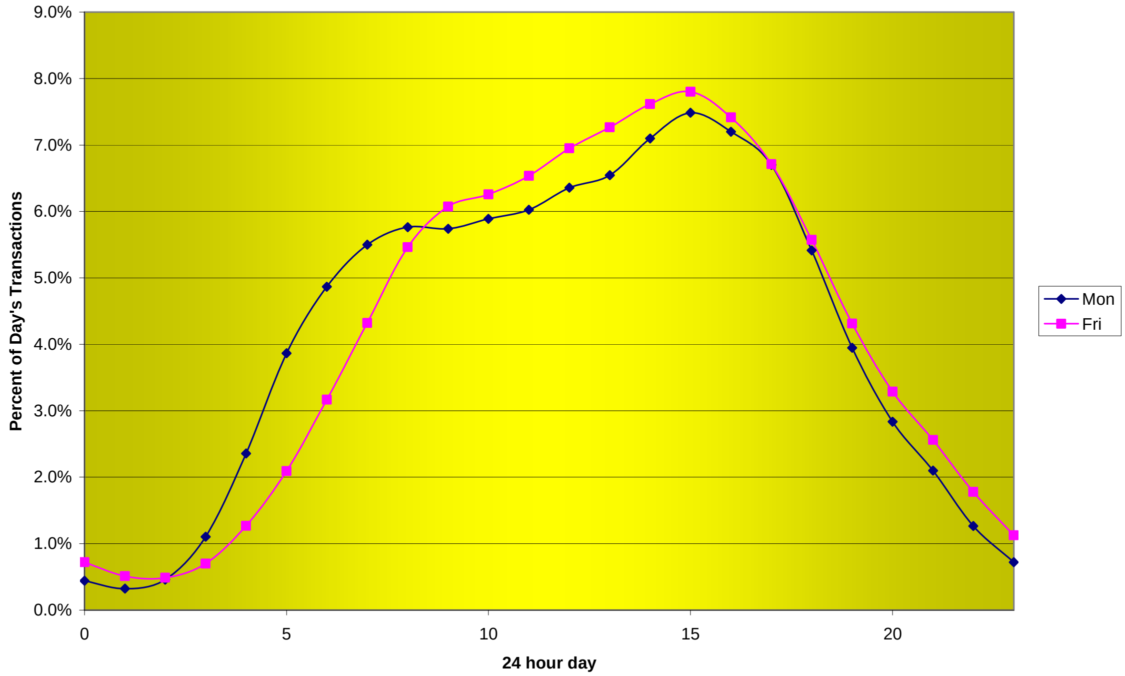



Figure 2-16 Fueling Profile for a Typical Chevron Gas Station

*Gas Terminal Spreadsheet Model - Chevron Profile*

The gas terminal spreadsheet model used to examine this particular pathway initially selects an arbitrary storage capacity, say 30,000 kg. The model then adds to, or subtracts from, the storage mass based on the 24 hour Chevron profile. During the early morning hours, there is a net accumulation in storage as the city demand is low. During the afternoon, the situation is reversed, and there is a net decrease in the stored mass due to high refueling demand. The model calculates the minimum stored mass during the day, and then increases, or decreases, the initial storage capacity until the daily minimum value represents 0.5 hours of the peak demand flow rate. An example of the calculations is shown in Table 2-14 for the following conditions: 1,000,000 city population; 70 percent market penetration; 286,500 kg/day hydrogen delivery; 300 psi (20.69 bars)production plant discharge pressure; 1,000 (69 bars) transmission line inlet pressure, and 2,500 psi (172.4 bars) gas terminal design pressure. The required gas terminal storage capacity is 78,949 kg (174,053 lb).

*Gas Terminal Spreadsheet Model - Modified Chevron Profile*

TIAX has a MATLAB model, which calculates, on a second-by-second basis, the refueling station compressor delivery and cascade vessel pressures during a vehicle fill. The MATLAB model is used in conjunction with the Chevron profile of hourly gasoline dispensed to calculate the refueling station hydrogen demand from the gas terminal over the course of a day. (See Section 2.3 for more information.) The vehicle filling criteria used included the following: a dispensing period of 2.7 minutes; a total vehicle time at the station of 5.7 minutes; and the assumption the station operates at peak demand (all hoses occupied) for the first 5 minutes of every hour. The remaining demand is spread over the balance of the hour. The spreadsheet model used the Friday deliveries that are 108 percent of the average daily capacity based on the Chevron fueling profiles.

## Table 2-14 Gas Terminal Model with Chevron Profile

| | |
|---|---|
| 286,491 | kg/day production rate |
| 315 | $lb_f/in^2$ production pressure |
| 1,015 | $lb_f/in^2$ tranmission pressure |
| 2,515 | $lb_f/in^2$ storage pressure |
| 0.50 | hr minimum stored capacity |

Converge single

| Time, hours | Fraction design flow | Transmission rate, $lb_m$/hr | Active storage, $lb_m$ | Compression rate, $lb_m$/hr | Compression power, kWe |
|---|---|---|---|---|---|
| 12:00 AM | 0.07 | 3,152 | 73,513 | 21,274 | 6,180 |
| 1:00 AM | 0.06 | 2,521 | 96,678 | 23,165 | 6,730 |
| 2:00 AM | 0.07 | 3,152 | 120,474 | 23,795 | 6,913 |
| 3:00 AM | 0.17 | 7,564 | 143,639 | 23,165 | 6,730 |
| 4:00 AM | 0.34 | 15,759 | 162,391 | 18,753 | 5,448 |
| 5:00 AM | 0.55 | 25,214 | 172,950 | 10,558 | 3,067 |
| 6:00 AM | 0.68 | 30,887 | 174,053 | 1,103 | 320 |
| 7:00 AM | 0.79 | 35,930 | 169,483 | -4,570 | 0 |
| 8:00 AM | 0.81 | 37,190 | 159,870 | -9,613 | 0 |
| 9:00 AM | 0.79 | 35,930 | 148,997 | -10,873 | 0 |
| 10:00 AM | 0.77 | 35,299 | 139,384 | -9,613 | 0 |
| 11:00 AM | 0.80 | 36,560 | 130,401 | -8,982 | 0 |
| 12:00 PM | 0.86 | 39,081 | 120,158 | -10,243 | 0 |
| 1:00 PM | 0.88 | 40,027 | 107,394 | -12,764 | 0 |
| 2:00 PM | 0.97 | 44,124 | 93,684 | -13,710 | 0 |
| 3:00 PM | 1.00 | 45,700 | 75,877 | -17,807 | 0 |
| 4:00 PM | 0.98 | 44,754 | 56,494 | -19,383 | 0 |
| 5:00 PM | 0.94 | 42,863 | 38,056 | -18,438 | 0 |
| 6:00 PM | 0.76 | 34,669 | 21,510 | -16,547 | 0 |
| 7:00 PM | 0.55 | 25,214 | 13,158 | -8,352 | 0 |
| 8:00 PM | 0.41 | 18,910 | 14,261 | 1,103 | 320 |
| 9:00 PM | 0.30 | 13,868 | 21,667 | 7,407 | 2,152 |
| 10:00 PM | 0.18 | 8,194 | 34,117 | 12,449 | 3,617 |
| 11:00 PM | 0.11 | 5,043 | 52,239 | 18,122 | 5,265 |
| | | ---------- | | ---------- | -------- |
| | | 631,604 | | 0 | 46,741 |

| | |
|---|---|
| 1.737 | peak-to-average flow factor |
| 631,604 | $lb_m$/day production rate |
| 766.4 | ft-$lb_f/lb_m$-R gas constant |
| 13,158 | $lb_m$ minimum active stored capacity |
| 13,158 | $lb_m$ minimum capacity in 'E' |
| | |
| 0.812 | $lb_m/ft^3$ maximum storage density |
| 0.348 | $lb_m/ft^3$ minimum storage density |
| 0.464 | $lb_m/ft^3$ storage density range |
| | |
| 6.610 | $lb_m$/sec design compressor flow rate |
| 315 | $lb_f/in^2$ inlet pressure |
| 2,515 | $lb_f/in^2$ discharge pressure |
| 8.0 | overall compressor pressure ratio |
| | |
| 2.00 | first stage compression ratio |
| 75 | F first stage inlet temperature |
| 1,155.6 | Btu/$lb_m$ first stage inlet internal energy |
| 193 | F first stage isentropic outlet temperature |
| 1,437.1 | Btu/$lb_m$ first stage outlet internal energy |
| 0.85 | isentropic efficiency |
| 2,310 | kWe first stage compressor power |
| | |
| 2.00 | second stage compression ratio |
| 100 | F first stage intercooler outlet temperature |
| 1,209.3 | Btu/$lb_m$ second stage inlet internal energy |
| 223 | F second stage isentropic outlet temperature |
| 1,497.6 | Btu/$lb_m$ second stage outlet internal energy |
| 0.85 | isentropic efficiency |
| 2,365 | kWe second stage compressor power |
| | |
| 2.00 | third stage compression ratio |
| 100 | F third stage intercooler outlet temperature |
| 1,195.2 | Btu/$lb_m$ third stage inlet internal energy |
| 223 | F third stage isentropic outlet temperature |
| 1,468.0 | Btu/$lb_m$ third stage outlet internal energy |
| 0.85 | isentropic efficiency |
| 2,238 | kWe third stage compressor power |
| | |
| 6,913 | kWe total compressor power |

The original Chevron, and the modified TIAX, demand profiles are shown in Figure 2-17 for the following refueling station design: 1,000 kg/day dispensed; 116 kg/hr compressor capacity; and 43.0 kg cascade system storage capacity. Compared with the Chevron profile, the TIAX profile is much more variable, for three reasons. First, the TIAX profile assumes most of the refueling occurs at the beginning of the hour as a very conservative approach. Second, the TIAX model operates the refueling station compressor on an as-needed basis. Third, the Chevron data are hourly averages. The average dispensing rate is 41.7 kg/hr (i.e., 1000 kg/day / 24 hrs/day); thus, the peak-to-average ratio for the refueling station compressor is 2.78. Before 7:00 am, and after 9:00 pm, the compressor operates at either at partial load, or is off. Between 7:00 am and 9:00 pm, the compressor operates either at partial load or at full load.

Interpretation of the model results show the compressor capacity must be at least large enough to accommodate the hour in which the hydrogen demand is the highest. If the compressor cannot meet this demand, the capacity and cost of the cascade storage system increase rapidly. (See Section 2.3.)

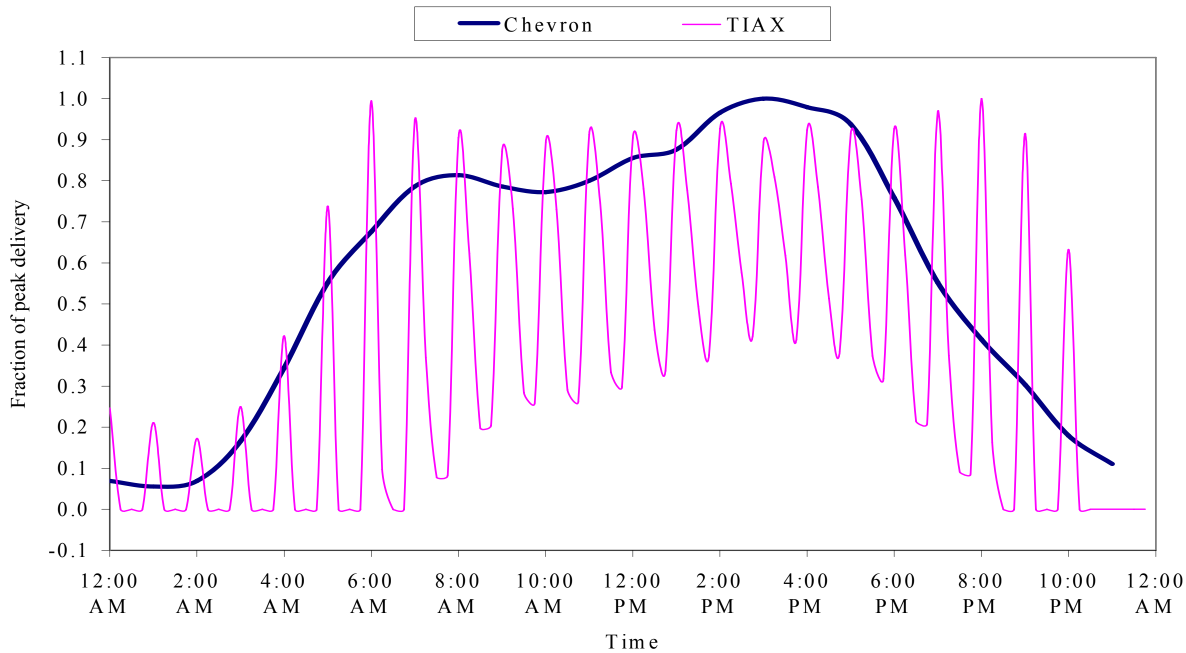



Figure 2-17 Chevron and Modified TIAX Refueling Station Demand Profile (Refueling Station Compressor Peak-to-Average Flow Ratio of 2.8)

The TIAX profile is a result of the relative capacities of the refueling station compressor and the cascade charging system. This profile, in essence, becomes the demand profile for the gas terminal, and the terminal capacity must be selected to satisfy this demand.

The gas terminal spreadsheet model was modified slightly to accept the TIAX profile, as shown in

Table 2-15; only the first 12 hours of the day are shown. For a city demand of 286,500 kg/day, and a refueling station peak-to-average flow demand ratio of 1.5, the required gas terminal storage capacity is 85,434 kg (187,992 lb). Even though the TIAX profile is highly variable, the effect on the terminal capacity is moderate.

The costs associated with an 85,434 kg gas terminal storage capacity, a refueling station compressor capacity of 63 kg/hr, and a cascade charging system capacity of 117.6 kg represent one combination for the delivery infrastructure. To determine the combination which offers the lowest infrastructure cost, TIAX developed demand profiles for the combinations of refueling station compressor and cascade charging system capacities shown in

Table 2-16.  The associated gas terminal capacities to satisfy the profiles are also shown in the table.  In all cases, the required gas terminal compressor power rating is 7,640 kWe.

# Table 2-15 Gas Terminal Model for TIAX Demand Profile

## 286,500 kg/day City Demand, 1.5 Peak-to-Average Demand Ratio
## 63 kg/hr Refueling station Compressor Capacity, 117.6 kg Cascade Storage Capacity

| | |
|---|---|
| 286,491 | kg/day production rate |
| 315 | $lb_f/in^2$ production pressure |
| 1,015 | $lb_f/in^2$ tranmission pressure |
| 2,515 | $lb_f/in^2$ storage pressure |
| 0.50 | hr minimum stored capacity |

| | |
|---|---|
| 1.529 | peak-to-average flow factor |
| 631,604 | $lb_m$/day production rate |
| 766.4 | ft-$lb_f/lb_m$-R gas constant |
| 13,158 | $lb_m$ minimum active stored capacity |
| 13,158 | $lb_m$ minimum capacity in 'E' |
| 0.812 | $lb_m/ft^3$ maximum storage density |
| 0.348 | $lb_m/ft^3$ minimum storage density |
| 0.464 | $lb_m/ft^3$ storage density range |
| 7.308 | $lb_m$/sec design compressor flow rate |
| 315 | $lb_f/in^2$ inlet pressure |
| 2,515 | $lb_f/in^2$ discharge pressure |
| 0.85 | compressor isentropic efficiency |
| 8.0 | overall compressor pressure ratio |
| 2.10 | allowable pressure ratio per state |
| 2.8 | theoretical number of stages |
| 3 | actual number of stages |
| 2.00 | actual stage pressure ratio |
| 7,639 | kWe compressor power demand |
| | First stage |
| 315 | $lb_f/in^2$ inlet pressure |
| 75 | F inlet temperature |
| 1,155.6 | Btu/$lb_m$ inlet internal energy |
| 2.00 | compression ratio |
| 630 | $lb_f/in^2$ outlet pressure |
| 193 | F isentropic outlet temperature |
| 1,436.9 | Btu/$lb_m$ outlet internal energy |
| 281.4 | Btu/$lb_m$ compression work |
| 0.85 | compressor efficiency |
| 2,553 | kWe stage power demand |
| 100 | F intercooler outlet temperature |
| | Second stage |
| 630 | $lb_f/in^2$ inlet pressure |
| 100 | F inlet temperature |
| 1,209.3 | Btu/$lb_m$ inlet internal energy |
| 2.00 | compression ratio |
| 1,258 | $lb_f/in^2$ outlet pressure |
| 223 | F isentropic outlet temperature |
| 1,497.4 | Btu/$lb_m$ outlet internal energy |
| 288.1 | Btu/$lb_m$ compression work |
| 0.85 | compressor efficiency |
| 2,613 | kWe stage power demand |
| 100 | F intercooler outlet temperature |
| | Third stage |
| 1,258 | $lb_f/in^2$ inlet pressure |
| 100 | F inlet temperature |
| 1,195.2 | Btu/$lb_m$ inlet internal energy |
| 2.00 | compression ratio |
| 2,515 | $lb_f/in^2$ outlet pressure |
| 223 | F isentropic outlet temperature |
| 1,467.8 | Btu/$lb_m$ outlet internal energy |
| 272.6 | Btu/$lb_m$ compression work |
| 0.85 | compressor efficiency |
| 2,473 | kWe stage power demand |
| 100 | F intercooler outlet temperature |

| Time, hours | Fraction design flow | Transmission to city rate, $lb_m$/hr | Active storage, $lb_m$ | Compression rate, $lb_m$/hr | Compression power, kWe |
|---|---|---|---|---|---|
| 12:00 AM | 0.4200 | 4,225 | 60,926 | -114,430 | 0 |
| 12:15 AM | 0.0003 | 3 | 63,280 | 9,416 | 2,734 |
| 12:30 AM | 0.0003 | 3 | 69,856 | 26,304 | 7,637 |
| 12:45 AM | 0.0003 | 3 | 76,432 | 26,304 | 7,637 |
| 1:00 AM | 0.3947 | 3,970 | 83,008 | 26,304 | 7,637 |
| 1:15 AM | 0.0003 | 3 | 85,617 | 10,436 | 3,030 |
| 1:30 AM | 0.0003 | 3 | 92,193 | 26,304 | 7,637 |
| 1:45 AM | 0.0003 | 3 | 98,769 | 26,304 | 7,637 |
| 2:00 AM | 0.3000 | 3,018 | 105,345 | 26,304 | 7,637 |
| 2:15 AM | 0.0003 | 3 | 108,907 | 14,245 | 4,136 |
| 2:30 AM | 0.0003 | 3 | 115,483 | 26,304 | 7,637 |
| 2:45 AM | 0.0003 | 3 | 122,059 | 26,304 | 7,637 |
| 3:00 AM | 0.4566 | 4,593 | 128,635 | 26,304 | 7,637 |
| 3:15 AM | 0.0003 | 3 | 130,621 | 7,943 | 2,306 |
| 3:30 AM | 0.0003 | 3 | 137,197 | 26,304 | 7,637 |
| 3:45 AM | 0.0003 | 3 | 143,773 | 26,304 | 7,637 |
| 4:00 AM | 0.7719 | 7,765 | 150,349 | 26,304 | 7,637 |
| 4:15 AM | 0.0003 | 3 | 149,163 | -4,743 | 0 |
| 4:30 AM | 0.0003 | 3 | 155,739 | 26,304 | 7,637 |
| 4:45 AM | 0.0003 | 3 | 162,315 | 26,304 | 7,637 |
| 5:00 AM | 0.9791 | 9,849 | 168,891 | 26,304 | 7,637 |
| 5:15 AM | 0.3400 | 3,420 | 165,621 | -13,080 | 0 |
| 5:30 AM | 0.0003 | 3 | 168,780 | 12,636 | 3,669 |
| 5:45 AM | 0.0003 | 3 | 175,356 | 26,304 | 7,637 |
| 6:00 AM | 0.9796 | 9,854 | 181,932 | 26,304 | 7,637 |
| 6:15 AM | 0.9979 | 10,039 | 178,657 | -13,101 | 0 |
| 6:30 AM | 0.0003 | 3 | 175,197 | -13,840 | 0 |
| 6:45 AM | 0.0003 | 3 | 181,773 | 26,304 | 7,637 |
| 7:00 AM | 0.9730 | 9,788 | 188,349 | 26,304 | 7,637 |
| 7:15 AM | 0.9799 | 9,858 | 185,140 | -12,835 | 0 |
| 7:30 AM | 0.5750 | 5,785 | 181,862 | -13,114 | 0 |
| 7:45 AM | 0.1236 | 1,244 | 182,656 | 3,178 | 923 |
| 8:00 AM | 0.9645 | 9,702 | 187,992 | 21,342 | 6,197 |
| 8:15 AM | 0.9612 | 9,669 | 184,869 | -12,492 | 0 |
| 8:30 AM | 0.9612 | 9,669 | 181,779 | -12,360 | 0 |
| 8:45 AM | 0.6133 | 6,170 | 178,689 | -12,360 | 0 |
| 9:00 AM | 0.9677 | 9,734 | 179,098 | 1,638 | 476 |
| 9:15 AM | 0.9675 | 9,733 | 175,943 | -12,621 | 0 |
| 9:30 AM | 0.9635 | 9,692 | 172,789 | -12,615 | 0 |
| 9:45 AM | 0.9675 | 9,733 | 169,676 | -12,452 | 0 |
| 10:00 AM | 0.9885 | 9,944 | 166,523 | -12,615 | 0 |
| 10:15 AM | 0.9723 | 9,781 | 163,158 | -13,458 | 0 |
| 10:30 AM | 0.9723 | 9,781 | 159,957 | -12,806 | 0 |
| 10:45 AM | 0.9688 | 9,746 | 156,755 | -12,806 | 0 |
| 11:00 AM | 0.9862 | 9,921 | 153,589 | -12,666 | 0 |
| 11:15 AM | 0.9526 | 9,583 | 150,247 | -13,368 | 0 |
| 11:30 AM | 0.9526 | 9,583 | 147,243 | -12,013 | 0 |
| 11:45 AM | 0.9526 | 9,583 | 144,240 | -12,013 | 0 |
| 12:00 PM | 0.9935 | 9,994 | 141,237 | -12,013 | 0 |
| 12:15 PM | 0.9772 | 9,831 | 137,822 | -13,661 | 0 |

Table 2-16 Refueling station Compressor, Cascade Storage, and Gas Terminal Capacity Combinations (286,500 kg/day City Demand)

| Peak-to-average ratio | Refueling station compressor (capacity, kg/hr) | Refueling station cascade system (capacity, kg) | Terminal storage (capacity, kg) | Daily terminal compressor (energy, kWhe) |
|---|---|---|---|---|
| 1.5 | 63 | 117.6 | 85,434 | 55,058 |
| 2.0 | 83 | 66.0 | 93,744 | 68,855 |
| 2.5 | 104 | 45.9 | 93,663 | 74,509 |
| 2.8 | 116 | 43.0 | 94,392 | 76,534 |
| 3.0 | 125 | 40.2 | 95,010 | 78,654 |
| 3.5 | 146 | 37.3 | 95,712 | 80,456 |

The peak-to-average ratio has a moderate effect on the terminal capacity, but a more pronounced effect on the daily energy requirement of the terminal compressor. The effect is illustrated in Figure 2-18. With a peak-to-average flow ratio of 1.5 for the refueling station compressor, the capacity of the refueling station cascade charging system is high relative to the capacity of the refueling station compressor. As such, the refueling station compressor must operate almost continuously between the hours of 9:00 am and 9:00 pm; correspondingly, the gas flows and the terminal compressor flows into and out of the gas terminal are very small.

The situation is reversed with a peak-to-average flow ratio of 3.5 for the refueling station compressor. Here, the refueling station compressor capacity is high relative to the cascade storage capacity. The large refueling station compressor capacity not only places a high demand on the distribution system, it also allows the rapid refilling of the cascade storage tanks. Thus, the highly variable, short term refueling station demands requires equally rapid changes on the flows into, and out of, the gas terminal vessels.

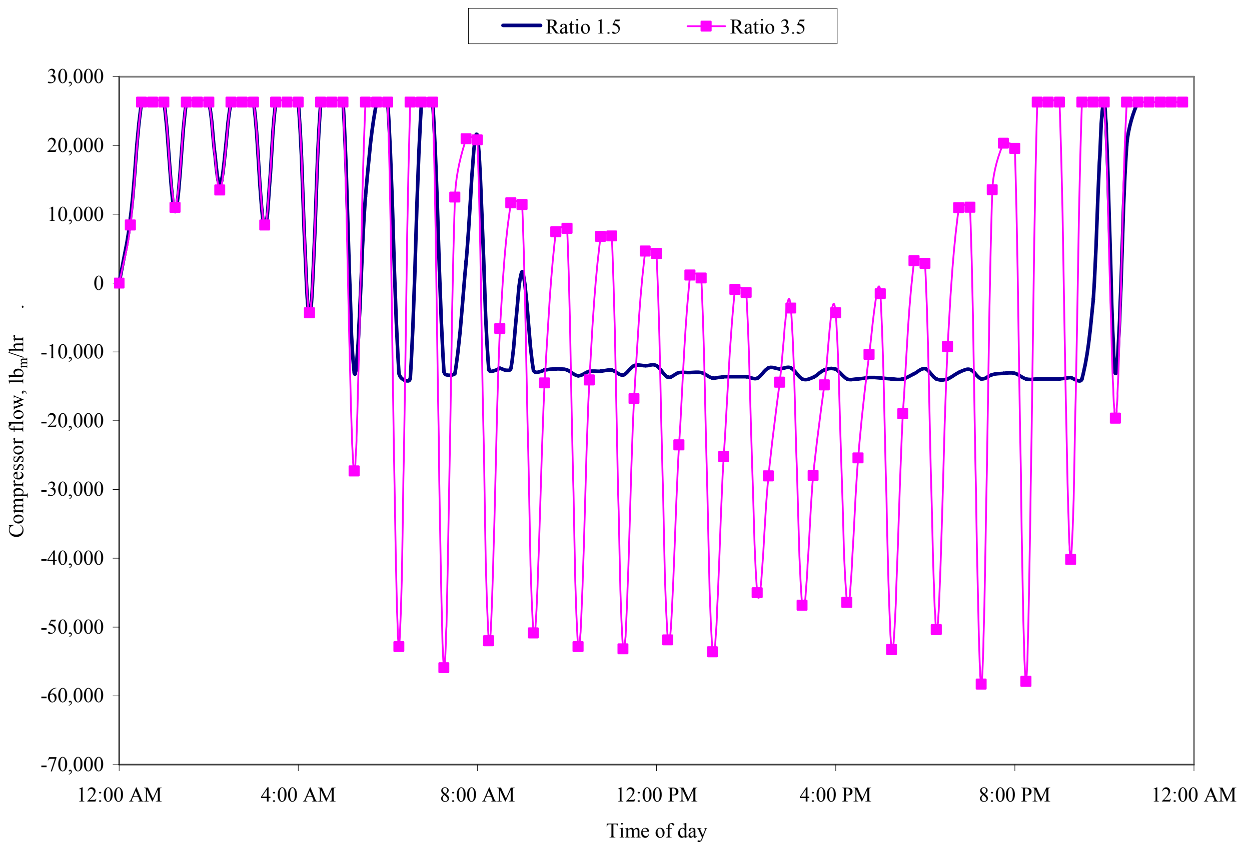



Figure 2-18 Gas Terminal Compressor Flow Demand
(Peak-to-Average Flow Ratios of 1.5 and 3.5)

### *2.2.3.5 Capital and Operating Cost Estimate Costs*

For each of the design combinations listed in

Table 2-16, capital and operating costs were assembled from the following sources:

- For a city demand of 286,500 kg/day, some 287 refueling stations are required, each dispensing an average of 1,000 kg/day
- Refueling station compressor costs were estimated as discussed in Section 2.2.5.
- Refueling station cascade charging system costs were estimated as discussed in Section 2.2.4.
- Low pressure storage costs were estimated as discussed above.
- Terminal compressor costs were estimated as described in Section 2.2.5
- Terminal compressor annual energy costs were estimated using the cost for commercial energy in the H2A Models. The annual cost was converted to an equivalent capital cost using a fixed charge rate of 12.5 percent.

The results of the cost calculations are shown in Figure 2-19. The lowest infrastructure costs occur with the smallest peak-to-average ratios for the refueling station compressor. However, the total infrastructure costs show only a small variation over the range of 1.5 to 2.5.

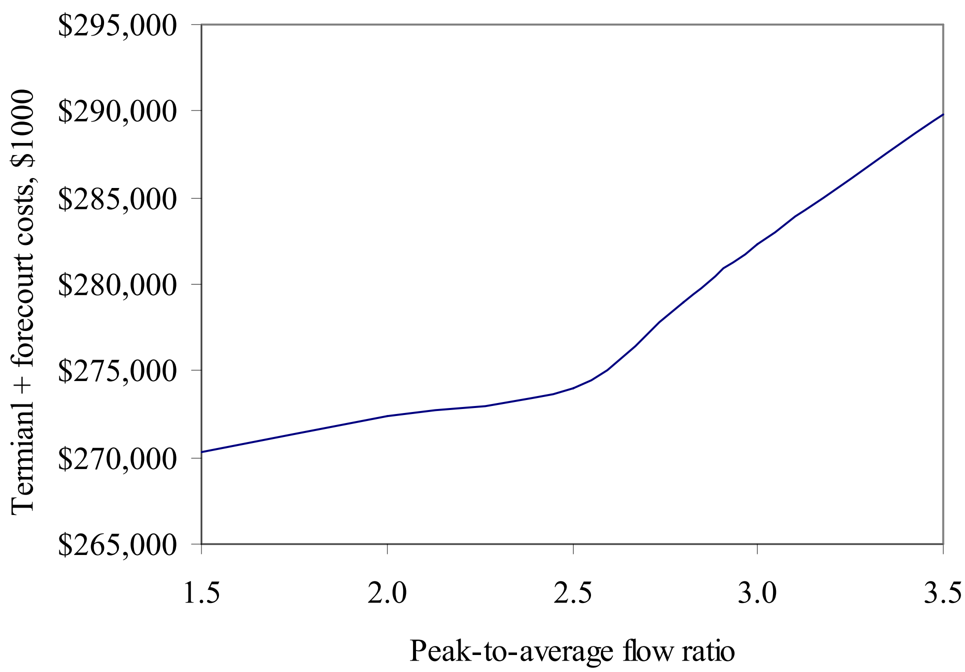



Figure 2-19 Gas Terminal and Refueling Station Cost Estimates
(286,500 kg/day City Demand)

#### *2.2.3.6 Recommended Inputs to the H2A Model*

For the purposes of the study, the following approach was used in the development of the low pressure storage costs and capacities:

- System reliability and availability should be improved by selecting the fewest number of vessels as possible. The availability of the vessels will be essentially 100 percent.

However, the associated isolation and pressure relief valves are likely to be more problematic, and the highest availability should result from the fewest components. As a result, larger vessels should be preferred.

- The largest vessels analyzed above are those based on the use of SA516 Grade 70 carbon steel; i.e., 2.5 inch (6.35 cm) wall thickness, 4.1 feet (1.25 m) in diameter, 24.9 feet (7.59 m) long, and storing 91 kilograms of hydrogen. The approximate weight of each vessel is 32,200 pounds (14,636 kg).
- The unit cost to fabricate a vessel using SA516 carbon steel is $1.91 per pound of steel, as estimated by the Icarus program. The unit fabrication cost for a chromium-molybdenum steel vessel from CP Industries is approximately $2.62 per pound of steel. For the purposes of this study, a unit fabrication cost equal to the average of the above costs, or $2.30 per pound of steel, has been assumed. Although the gas terminal vessels will be fabricated from carbon steel, there will likely need to be fairly strict controls on the steel chemistry, together with limits on the maximum grain size, to provide the desired resistance to hydrogen embrittlement in cyclic pressure service. The estimated FOB price for the fabricated vessel is then $74,000, or $816 per kilogram of hydrogen.
- With a vessel weight of 16 tons, a commercial truck is limited to transporting 2 vessels. Assuming a shipping distance of 1,500 miles (2,400 km) from the fabrication plant to the gas terminal, and a unit truck expense of $2.50 per mile, the delivered price of the vessel is $75,900, or $837 per kilogram of hydrogen.
- Assuming a sales tax rate of 7.5 percent, the total delivered (uninstalled) price for a vessel would be $81,600, or $900 per kilogram of hydrogen.
- Based on the analysis in Section 2.2.4 for the cost of installing gaseous hydrogen storage vessels, an installation factor of 1.3 is recommended and used for these low pressure gaseous hydrogen storage vessels in the H2A Delivery Models Version 2.

Although the analysis above was done specifically for gas storage located at a terminal, the primary conclusions and approach are applicable and are used for gas storage located at the refueling site on the H2A Delivery Models Version 2. (See Section 2.1.9 that explains the advantages to gas storage at the refueling site compared to at a terminal in a hydrogen pipeline delivery infrastructure to handle the hourly refueling site demand profile.)

### 2.2.4 Cascade Charging System Vessels

Hydrogen refueling station designs will likely use a combination of compressor capacity and cascade storage system capacity for filling fuel cell vehicles. The sections below describe the development of a unit capital cost for refueling station cascade vessels, in $ per kilogram of hydrogen, for use in the H2A Delivery Component and HDSAM Models.

#### *2.2.4.1 Pressure Vessel Fabrication Costs*

The basic refueling station storage module is assumed to consist of 3 pressure vessels, a support structure, and associated valves and plumbing. A potential module arrangement is shown in Figure 2-20. Although the vessels shown in the figure are composite vessels under development, steel vessel arrangements look very similar. The peak pressure of these vessels can be 6,250 psi (431 bars) but each may have different minimum pressures. (See Section 2.1.5).

Figure 2-20 Cascade Storage Vessel Arrangement

The steel vessel designs are assumed to be similar to the commercial designs currently offered by CP Industries in Pennsylvania. The vessel shell starts as a seamless pipe section. The heads are then formed by heating and forging each end of the pipe; thus, there are no longitudinal or circumferential welds on the shell or the heads. The material is ASTM SA372, Grade J, Class 70, with a tensile stress of 120,000 psi (8,276 bars). For a vessel designed under Division 2 of Section VIII, Rules for Construction of Pressure Vessels, of the ASME Boiler and Pressure Vessel Code, the allowable stress is one-third of the tensile stress, or 40,000 psi (2,759 bars). In the South Coast Air Quality Management District report "Status Report for Hydrogen Study Team"[36], CP Industries provided a quote for the following equipment: 3 vessels; 20 inch (50.8 cm) outside diameter; 22 foot (6.7 m) length; 5,500 psi (379 bars) design pressure; and FOB price of $56,200 (1st Quarter 2006 dollars). Using the quoted values yields a unit material price of $2.75 per pound of steel, and a unit hydrogen storage price of $718 per kilogram of hydrogen. Recently, Nexant obtained a budgetary price from CP Industries for the following vessel: 16 inch (15.24 cm) outside diameter; 27 foot (8.23 m) length; 1.648 inch (4.19 cm) nominal wall thickness; 7,770 psi (536 bars) design pressure; and FOB price of $18,000 (3rd Quarter 2006 dollars). Using the quoted values yields a unit material price of $2.64 per pound ($5.59 per kg) of steel, and a unit hydrogen storage price of $843 per kilogram of hydrogen.

For the purposes of the study, the following design assumptions have been made:

[36] "Status Report for Hydrogen Study Team, Attachment A, Hydrogen Compatibility Study Team Report and Supporting Documents", South Coast Air Quality Management District, August 2001

- All three cascade system vessels are 16 inches in diameter and 30 feet (9.144 m) long capable of holding 21.3 kilograms of hydrogen at 6,250 psi (431bars).
- A unit storage price of $843 per kilogram of hydrogen applied to the high, the intermediate, and the low pressure vessels. With an assumed sales tax rate of 7.5 percent, the purchased vessel price is $906 per kilogram of hydrogen.

The bare vessels are shipped an average distance of 1,500 miles (2,400 km) to an assembly facility, where the 3 vessels are mounted in the support frame. Nine bare vessels, with a combined weight of 50,000 pounds (22,727 kg), can be shipped on a flat bed truck. Assuming a shipping cost of $2.50 per mile ($1.56 per km), the delivered (uninstalled) vessel price is then $926 per kilogram of hydrogen.

#### *2.2.4.2 Pressure Vessel Auxiliaries and Installation Costs*

At the assembly facility, the 3 vessels are mounted in a support frame, and the requisite valves and plumbing are added. The 3-vessel assemblies are then shipped 250 miles (400 km) to a refueling station, lifted from the truck with a crane, and bolted to a set of concrete anchor bolts. Plumbing connections between the vessel assemblies and the dispensers completes the storage installation. The estimated cost for the vessel supports, valves, plumbing, leak tests, shipping, and installation is $18,102 as shown in Table 2-17.

- The shop fabrication labor rate of $85/hr and the field installation rate of $65/hr are recommended values from the Bechtel cost engineering group. The rates include all overhead expenses, together with various miscellaneous expenses, such as preparation of shop drawings and the documentation of ASME tests.
- Prices for the auxiliary equipment, such as valves, tubing, and fittings, were obtained from the McMaster-Carr web site. One might argue that purchasing the items directly from the equipment suppliers would result in lower prices. However, McMaster-Carr has a substantial sales volume, and the premium for ordering through McMaster-Carr is likely well within the accuracy of the estimate.
- A commercial source for compression fittings, valves, and high pressure tubing is Swagelok. A review of the Swagelok equipment catalog shows pressure rating of 6,000 psi (414 bars) for tubing and valves to be reasonably common for tubing diameters up, and including, ½ inch. Moving to ¾ inch (1.905 cm) fittings and valves typically results in a pressure rating of only 5,000 psi (345 bars). Thus, for the purposes of the cost study, a tube and valve size of ½ inch (1.27 cm) has been assumed. A quick check on the flow coefficients for ½ inch (1.27 cm) ball valves shows the pressure losses to be very modest.
- Flows to and from the vessels are modulated by the 'vessel pressure maintenance valves', and as such, a programmable logic controller will not be required at the refueling station to control the operation of the compressor or the charging/discharging of the storage vessels.
- The operation of the compressor is assumed to be controlled by a pressure switch on the high pressure cylinder. For pressures below 6,000 psi (414 bars), the switch energizes a relay, which closes a contactor supplying electric power to the motor. When the pressure reaches 6,250 psi (431 bars), the switch opens, and the compressor stops.
- All Valves are manual; there are no pneumatically or electrically operated valves.

The 3-vessel combination stores a total of 65 kilogram of hydrogen, yielding a unit cost of $278 per kilogram for the vessel supports and auxiliaries.

Table 2-17 Storage Vessel Auxiliary Items and Costs

| Item | Cost basis | Cost |
|---|---|---|
| Receiving and handling pressure vessels | 2 hours; $85/hr | $170 |
| Structural steel (light) | $2,500 per ton | $950 |
| Fabrication, welding, and assembly | 6 hours; $85/hr | $510 |
| Painting | 2 hours; $85/hr | $170 |
| Vessel pressure relief valves | 1/4 in., ASME certification, 3 each, McMaster-Carr | $1,950 |
| Vessel isolation valves | 1/2 in., ball, stainless steel, 3 each, McMaster-Carr | $750 |
| Vessel pressure maintenance valves | 1/2 in., stainless steel, 3 each, assume relief valve cost | $1,950 |
| Header tubing | 1/2 in., stainless steel, 50 ft., $20/ft, McMaster-Carr | $1,000 |
| Compression fittings | 1/2 in., stainless steel, 12 each, $50 each, McMaster-Carr | $600 |
| Vessel drain valves | 1/4 in., ball, stainless steel, 3 each, McMaster-Carr | $450 |
| Pressure transmitter | 0-10,000 psi, 4-20 mA output, McMaster-Carr | $350 |
| Conduit and wiring for pressure transmitter | 1/2 in., thin wall steel, 50 ft., $5/ft, McMaster-Carr | $250 |
| Install valves, transmitter, and tubing | 6 hours; $85/hr | $510 |
| Hydraulic pressure test of assembly | 4 hours; $85/hr | $340 |
| Helium leak test of assembly | 2 hours; $85/hr | $170 |
| Drying, nitrogen fill, and preparation for shipping | 3 hours; $85/hr | $255 |
| Shipping | 3 assemblies per truck; 250 miles; $2.50/mile | $210 |
| Sales tax on above materials | 7.5 percent | $619 |
| Contractor profit on completed assembly | 25 percent | $2,801 |
| Setting foundation anchors at forecourt | 4 hours; $65/hr | $260 |
| Crane rental at forecourt | $1,000/day; 4 assemblies per day | $250 |
| Unloading and installation at forecourt | 6 hours; $65/hr | $390 |
| Contractor profit on forecourt installation | 20 percent | $180 |
| Contingency | 20 percent on all above costs | $3,017 |
| | | --------- |
| | | $18,102 |

#### *2.2.4.3 Recommended Inputs to the Components and HDSAM Models*

A total price of $926 per kilogram for the vessels, including tax and shipping (uninstalled), plus $278 per kilogram for the supports and auxiliaries yields a total installed price of $1,204 per kilogram.

There are likely some modest economies of scale in storage system costs, which will lead to installed unit prices somewhat above $1,204 per kilogram at small refueling stations, and prices slightly below $1,204 per kilogram at large refueling stations. However, the effects of the cost assumptions in the above analyses, plus short term variations in commodity prices such as steel, are likely to be at least the same order of magnitude as the potential economies of scale. For the purposes of the H2A Delivery Models, the use of a uniform unit storage cost should not unduly influence the results of refueling station or infrastructure optimization studies. For the purposes of the Models, one fixed size, three vessel cascade charging system with a total capacity of 65 kg of hydrogen is used. Depending on the size of the refueling station, multiple units are used as necessary.

### 2.2.5 Transmission, Terminal, and Refueling Station Compressors

#### *2.2.5.1 Transmission and Terminal Compressors*

For medium to large cities, with significant market penetrations for fuel cell vehicles, compressors with power ratings from 1 to several MWe will be required for pipeline delivery pathways and gaseous hydrogen terminal and tube trailer operations. This report outlines recommended approaches for estimating the power requirements and the installed capital costs for large compressors.

Current technology for large hydrogen compressors suitable for transmission line compressors are reciprocating compressors, as opposed to centrifugal machines used for natural gas. A centrifugal compressor increases the pressure in a gas by accelerating the gas in the rotating section, and then converting the kinetic energy to static pressure in the stationary section. Since the kinetic energy is proportional to density x velocity$^2$, the change in pressure is proportional to the gas density. Further, the density varies linearly with the molecular weight, and there are strong Mach number limits on allowable gas velocities within the compressor. As a result, for a given pressure ratio, the number of stages for a hydrogen centrifugal compressor will be 8 times the number of stages for existing natural gas compressor technology, and 14 times the number of stages for an air compressor. Since the cost of a compressor is, to a first order, proportional to the number of stages, the cost for a centrifugal unit would be impractically high for the pressure ratios required in a transmission line compressor. New concepts for hydrogen centrifugal compressors that could be very cost effective are being researched. Reciprocating compressors are used in the H2A Delivery Models for large hydrogen compression flows to represent currently available technology.

For the purposes of the analysis, the suction pressure for the transmission line compressor is assumed to be 300 psi (20.69 bars) from the central hydrogen production plant. The maximum allowable gas temperature during compression is taken to be 275°F (135 °C), based on the requirements of American Petroleum Institute Standard 618, Reciprocating Compressors for Petroleum, Chemical, and Gas Industry Service. For the thermodynamic properties of hydrogen, and with the isentropic efficiencies described below, the allowable pressure ratio per stage of compression used is 2.1.

*Reciprocating Compressor Types*

With transmission line pressures in the range of 1,000 psi (69 bars), gas storage in the range of 2,500 psi (172.4 bars) at tube trailer terminals, and compressor inlet pressures in the range of 300 to 1,000 psi (69 bars), the overall pressure ratio for the large compressors will be in the range of 3 to 7. Assuming an allowable pressure ratio of 2.1 per stage, the compressors will require 2 to 4 stages.

Reciprocating compressors fall into two broad categories: lubricated; and non-lubricated. In a lubricated design, the iron pistons and rings are lubricated by a thin film of oil, which adheres to the cylinder walls. As such, a small quantity of oil is normally carried with the gas as it leaves the cylinder.

In a non-lubricated design, the pistons and rings are a plastic, such as Teflon, and no oil lubrication is required.

In general, lubricated designs require less maintenance, and are more efficient, than non-lubricated designs. Lubricated designs can typically operate 3 years before an inspection and overhaul, while non-lubricated designs must be inspected every 12 to 18 months. In addition, the plastic piston rings in a non-lubricated design do not seal as well as the iron rings in a lubricated compressor. As such, the design capacity of a non-lubricated compressor must be about 5 percent higher than a lubricated compressor.

For lubricated compressors, hydrocarbon levels in the discharge gas can be reduced to values in the range of 1 to 2 parts per billion by means of a two-stage coalescing filter followed by an activated carbon bed. However, considering the stringent hydrogen quality concerns for fuel cell vehicles, this contamination source could still be a concern.

The power demand of a compressor can be reduced by maintaining the gas temperatures as low as possible. Thus, large compressors normally cool the gas leaving each stage by means of either a hydrogen-to-air or a hydrogen-to-water heat exchanger (intercooler). For compressors adjacent to a production plant, cooling water from a wet cooling tower is likely to be available. As such, the gas temperature leaving the intercooler can reasonably be assumed to be equal to the dry bulb temperature. However, the compressor power demand is not a strong function of the intercooler outlet temperature, and water-cooled intercoolers are not considered mandatory. Gas temperatures at the exit of the intercooler in the range of 70 to 100 °F (21.1 to 37.8 °C) are considered typical.

*Capacities*

Performance data and budgetary cost information was obtained from three reciprocating compressor vendors for the following hydrogen service: 100 million standard ft$^3$/day; 265 psi (18.28 bars) suction pressure; and 1,215 psi (83.8 bars) discharge pressure. A summary of the principal performance data is shown in Table 2-18.

Table 2-18 Vendor Information on Large Reciprocating Compressors

| Vendor | Neuman &Esser | Burckhardt Compression | Ariel Compressors | Dresser-Rand |
|---|---|---|---|---|
| Capacity, $10^6$ standard ft$^3$/day | 60.5 | 49.7 | 35.0 | 200.0 |
| ($10^6$ Nm3/d) | (1.635) | (1.343) | (0.946) | (5.405) |
| Number of stages | 2 | 2 | 3 | 2 |
| Lubricated option | | | | |
| - Motor rating, bhp | 6,600 | 5,600 | 3,500 | 22,000 |
| - Motor speed, rpm | 360 | 450 | 594 | 327 |
| Non-lubricated option | | | | |
| - Motor rating, bhp | 7,200 | Not supplied | 4,000 | Not supplied |
| - Motor speed, rpm | 450 | Not supplied | 594 | Not supplied |

The capacities shown are the largest offered by the vendors.

Each of these compressors are driven directly by a synchronous motor. No gearbox is required between the motor and the compressor, and the compressor is intended for constant speed operation.

*Power Calculations and Efficiencies*

The power required in each stage of the compression process can be calculated as follows:

$$\text{Power} = \frac{\text{Power}_{\text{isentropic}}}{\text{Isentropic efficiency}}$$

where the isentropic power is defined by the following expression:

Power $_{\text{isentropic}}$, Btu/sec = (Mass flow rate, $lb_m$/sec)(H $_{\text{outlet}}$ - H $_{\text{inlet}}$, Btu/$lb_m$)

with the enthalpies evaluated at the gas inlet temperature, and at the isentropic outlet temperature for each stage, per the following equation:

$$T_{\text{outlet}} = T_{\text{inlet}} \left( \frac{P_{\text{outlet}}}{P_{\text{inlet}}} \right)^{\frac{k-1}{k}}$$

where k is the ratio of specific heats. For large reciprocating compressors, isentropic efficiencies in the range of 86 to 92 percent are considered typical.

In principle, the best accuracy in the calculation of the compressor power should be reached by 1) using an expression for the enthalpy which is a function of the temperature, 2) including pressure losses into, and out of, each stage, 3) using an assumed intercooler effectiveness to estimate the gas temperature entering each stage, and 4) calculating the performance of each stage, and summing over the number of stages. An example of the approach is shown in

Table 2-19. The pressure losses at each stage were derived from a quote supplied by Neuman & Esser, as noted above. The isentropic efficiency was selected manually to match the calculated power with the quoted power. The stage enthalpies were calculated using the Shomate equation from the NIST Webbook, as detailed in Table 2-20.

### Table 2-19 Estimated Performance of a 60.5 Million Standard Ft$^3$/Day Reciprocating Compressor: Calculations Based on Gas Enthalpies

| | |
|---|---|
| 3.2302 | $lb_m$/sec design compressor flow rate |
| 265 | $lb_f/in^2$ inlet pressure |
| 1,227 | $lb_f/in^2$ discharge pressure |
| 0.893 | compressor isentropic efficiency |
| 4.6 | overall compressor pressure ratio |
| 2.10 | allowable pressure ratio per state |
| 2.1 | theoretical number of stages |
| 2 | actual number of stages |
| 2.15 | actual stage pressure ratio |
| 3,627 | kWe compressor power demand |
| | First stage |
| 264 | $lb_f/in^2$ inlet pressure |
| 100 | F inlet temperature |
| 1,774.7 | Btu/$lb_m$ inlet enthalpy |
| 2.15 | compression ratio |
| 567.4 | $lb_f/in^2$ outlet pressure |
| 238 | F isentropic outlet temperature |
| 2,250.1 | Btu/$lb_m$ outlet enthalpy |
| 475.4 | Btu/$lb_m$ compression work |
| 0.893 | compressor efficiency |
| 1,814 | kWe stage power demand |
| 100 | F intercooler outlet temperature |
| 1,210.7 | Btu/$lb_m$ intercooler outlet internal energy |
| 1,039.4 | Btu/$lb_m$ intercooler heat transfer |
| | Second stage |
| 565 | $lb_f/in^2$ inlet pressure |
| 100 | F inlet temperature |
| 1,774.7 | Btu/$lb_m$ inlet enthalpy |
| 2.15 | compression ratio |
| 1,215.0 | $lb_f/in^2$ outlet pressure |
| 238 | F isentropic outlet temperature |
| 2,250.1 | Btu/$lb_m$ outlet enthalpy |
| 475.4 | Btu/$lb_m$ compression work |
| 0.893 | compressor efficiency |
| 1,814 | kWe stage power demand |
| 100 | F intercooler outlet temperature |
| 1,196.2 | Btu/$lb_m$ intercooler outlet internal energy |
| 1,053.9 | Btu/$lb_m$ intercooler heat transfer |

Stage layout

Table 2-20 Excel Function for Hydrogen Enthalpy Calculations Using the Shomate Equation

```
Function H2H(T) '  Hydrogen enthalpy, Btu/lbm; T in F
Dim A, B, C, D, E, F, G, H
            '  Gas Phase Heat Capacity (Shomate Equation from NIST Webbook)
            '  Cp° = A + B * T + c * t2 + D * t3 + E / t2
            '  H°-H°298.15= A*t + B*t^2/2 + C*t^3/3 + D*t^4/4 - E/t + F - H
            '      Cp = heat capacity (J/mol*K)
            '      H° = standard enthalpy (kJ/mol)
            '      T = Temperature(K) / 1000
            '  Temperature range of 298 to 1000 K
A = 33.066178
B = -11.363417
C = 11.432816
D = -2.772874
E = -0.158558
F = -9.980797
G = 172.707974
H = 0#
T = (T + 459.63) / (1.8 * 1000)   'Convert T to K, then K/1000
H2H = A * T + 1 / 2 * B * T ^ 2 + 1 / 3 * C * T ^ 3 + 1 / 4 * D * T ^ 4 - E / T + F - H
H2H = H2H * 1000 / (2.01594 * 1055.1) * (1000 / 2.20462) + 1696.1
            '  2.10584 is molecular weight for hydrogen, gm/gm-mole
            '  1055.1 is J/Btu
            '  1696.1 is arbitrary constant to set Shomate enthalpy = NIST enthalpy
End Function
```

In practice, the allowable pressure ratios and stage outlet temperatures are low enough that perfect gas relationships should provide a reasonable comparison with the more rigorous calculations. The perfect gas relationships are currently used in the H2A Delivery Models to calculate the compressor power demand, as follows:

$$\text{Power, kJ/sec} = (Z)(\dot{\text{m}})(R)(\text{T})(\text{n})\left(\frac{1}{\eta}\right)\left(\frac{\text{k}}{\text{k}-1}\right)\left[\left(\frac{\text{P}_{\text{outlet}}}{\text{P}_{\text{inlet}}}\right)^{\left(\frac{\text{k}-1}{\text{nk}}\right)}-1\right]$$

where $Z$ is the mean compressibility factor,
m is the mass flow rate, kg-mole/sec
$R$ is the universal gas constant, kJ/kg-mole-°K
T is the inlet gas temperature, °K
n is the number of stages,
η is the isentropic efficiency,
k is the ratio of specific heats,
$P_{outlet}$ is the compressor discharge pressure, bar or psi
$P_{inlet}$ is the compressor inlet pressure, bar or psi

The equation assumes the intercooler outlet temperatures are equal to the ambient temperature.

An example of the H2A calculation is shown in Table 2-21 for the same compressor requirements as in

Table 2-19. The less complex H2A equation yields a power requirement of 3,811 kWe, which is within 5 percent of the more rigorous vendor calculation of 3,627 kWe. For the purposes of the H2A Delivery Models, the H2A equation is judged to be suitably accurate.

Table 2-21 Estimated Performance of a 60.5 Million Standard $Ft^3$/Day Reciprocating Compressor: Calculations Based on Perfect Gas Relationships

| | |
|---:|---|
| 1.03198 | mean compressibility factor |
| 126,593 | kg/day hydrogen flow rate |
| 8.3144 | kJ/kg-mole K universal gas constant |
| 37.8 | C suction and interstage gas temperature |
| 2 | number of stages |
| 1.41 | ratio of specific heats |
| 1,265 | $lb_f/in^2$ discharge pressure |
| 265 | $lb_f/in^2$ inlet pressure |
| 0.893 | compressor efficiency |
| 3,811 | kWe H2A compressor work equation |

*Uninstalled and Total Installed Costs*

Capital cost estimates for large 2- and 3-stage reciprocating compressors were assembled from data supplied by Air Liquide, Neuman & Esser, Burckhardt Compression, Ariel Compressors, and Dresser-Rand.

The cost data from Air Liquide were total installed costs. The cost information from the other three compressor vendors was direct material costs only, and typically included the following: compressor; electric drive motor; drive coupling; lubrication system; pulsation suppression equipment; cooling water piping; instrumentation; and control panel. To the basic material costs, one must add estimates for the following: sales tax; shipping; foundations; intercoolers; bulk piping and electric materials; insulation; site installation and assembly; and commissioning.

Based on discussions with two cost engineers from Bechtel, total installed costs for large compressors have historically been in the range of 1.8 to 3.4 times the basic material cost. The former value applies to refineries, while the latter value applies to remote compression stations along a transmission line. For the H2A Delivery Model, the large pipeline compressors will be located adjacent to the production plant. Other large compressors may exist at terminals. It is assumed these installations will be more typical of a refinery than a remote pipeline compressor station. As such, an installation factor of 2.0 was adopted, and applied to the vendor cost information.

The total uninstalled costs, as a function of the motor rating, for 2-stage compressors is illustrated in Figure 2-21. The motor ratings are nominally 10 percent higher than the calculated power demand. For a given power demand, Air Liquide estimates the cost of a 3-stage compressor to be 20 percent higher than a 2-stage design.

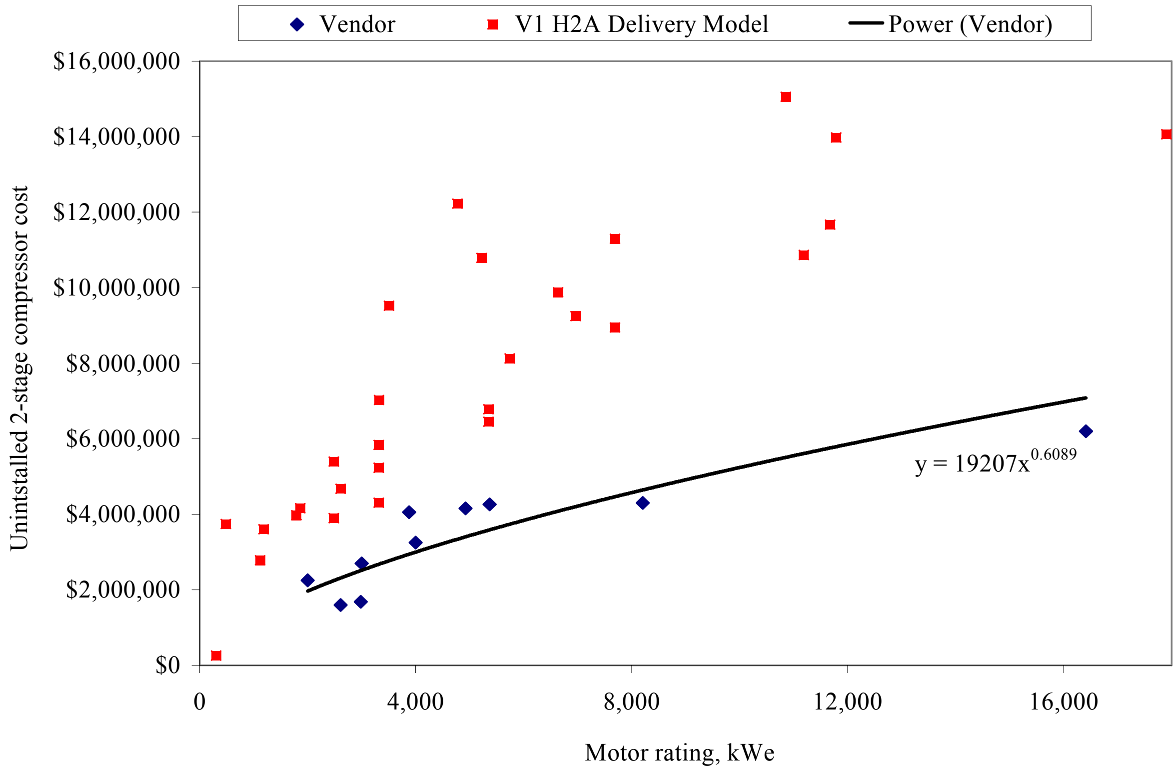



Figure 2-21  Uninstalled Costs for 2-Stage Reciprocating Compressor as a Function of Motor Rating

*Recommended Inputs to the Components and HDSAM Models*

For the purposes of the H2A Delivery Models, the annual energy demand and installed cost for large compressors can be estimated as follows:

- The electric power demand can be calculated using the current H2A Delivery Models equation, with an assumed compressor isentropic efficiency of 88 percent. Any potential errors introduced by the use of perfect gas relationships in the calculation of the power demand are certainly of the same order of magnitude as the assumption for the isentropic efficiency. In addition, the motor efficiency is calculated via the following equation, where x = ln shaft kW:

$$\text{Efficiency} = 8\text{E-}05x^4 - 0.0015x^3 + 0.0061x^2 + 0.0311x + 0.7617$$ [37]

- The motor rating is estimated to be 110 percent of the electric power demand
- The largest commercial motor rating is assumed to be 16,000 kWe. For calculated power rating above 16,000 kWe, multiple compressors are required
- The total uninstalled cost for a 2-stage lubricated compressor can be estimated as follows:

[37] This equation, derived from data presented in A Guide to Chemical Engineering Process Design and Economics by G. D. Ulrich, is used in the Component and HDSAM models for all motors.

Cost = 19,207 * (Motor rating, kWe) $^{0.6089}$

- The total installed cost for a 3-stage lubricated compressor is estimated to be 120 percent of the total installed cost of a 2-stage compressor at the same motor rating
- If a non-lubricated compressor is considered mandatory, the motor rating is estimated to be 110 percent of the lubricated compressor motor rating. With this motor rating, the above equations are applied to calculate the total installed cost. (Note: The H2A Delivery Models V2 assumes lubricated compressors are used.)
- Due the generally poor reliability of large hydrogen compressors in service today, industrial practice is to have installed spare compressors. The H2A Delivery Models install 3 compressors each with a capacity of 50% of the required duty with 2 operating to reflect current industry practice.

#### *2.2.5.2 Refueling Station Compressors*

Refueling station compressors fall into 3 basic types: reciprocating; diaphragm; and hydraulic intensifier.

A reciprocating compressor uses a piston inside a cylinder to compress the gas. A cross section view of a typical three-stage compressor is shown in Figure 2-22. The discharge from the first stage cylinder cascades to the second stage cylinder, with the gas cooled by a water- or air-cooled heat exchanger between the stages. The final pressure is reached at the discharge from the third stage.

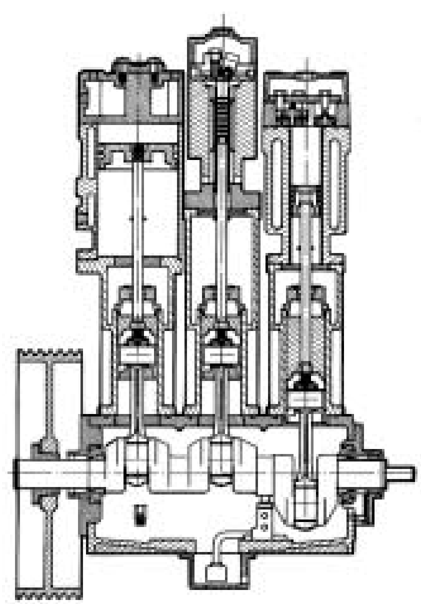


Figure 2-22 Cross Section of Reciprocating Compressor

A diaphragm compressor uses a flexible metal diaphragm, sandwiched between two metal plates, to compress the gas. A cross section view of a typical diaphragm compressor is shown in Figure

2-23. The motion of the diaphragm is controlled by pressurized oil, which moves in to, and out of, the space below the diaphragm. Diaphragm compressors typically involve only a single stage of compression. The gas temperature rise, even for very large compression ratios, tends to be moderate, due to heat transfer through the diaphragm and into the oil below.

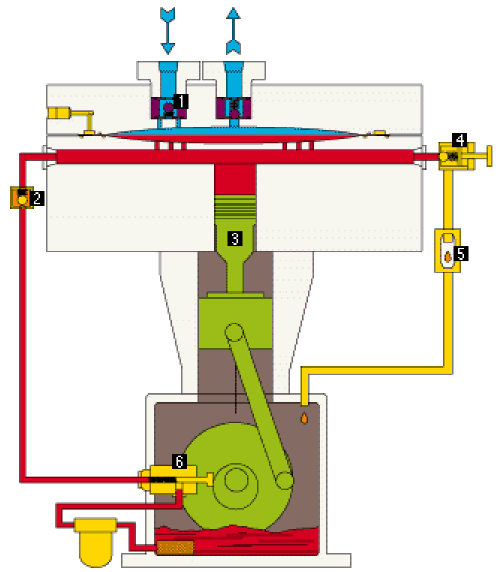



Figure 2-23 Cross Section of Diaphragm Compressor

A hydraulic intensifier combines various elements of a reciprocating and a diaphragm compressor. A cross section view of a typical design is shown in Figure 2-24. The gas is compressed by a moving piston, as in a reciprocating design, but the motion of the compression piston is controlled by hydraulic fluid moving back and forth across a motive piston. Hydraulic fluid pressures can be less than the final gas discharge pressure by the selection of different diameters for the motive and compression pistons. The hydraulic intensifier operates a very low RPM compared to a standard reciprocating compressor.

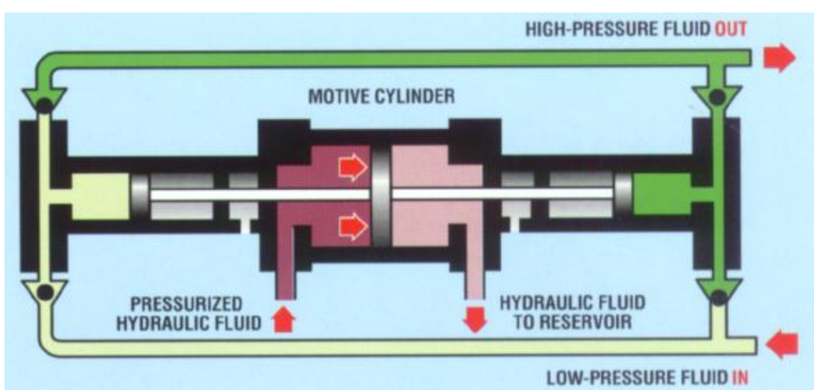



Figure 2-24 Cross Section of a Hydraulic Intensifier

*Manufacturer Survey*

A survey was conducted of possible compressor suppliers to determine the range of designs available, and estimated purchase prices. The results are shown in Table 2-22.In general, the three types of compressors can meet the pressure requirements for a refueling station; specifically, an inlet pressure as low as 300 psi (20.69 bars) and a discharge pressure of 6,250 psi (431 bars). However, as discussed in Section 2.1.3, refueling station capacities span the range of 50 kg/day to 6,000 kg/day in the H2A Delivery Models. Further, as discussed in Section 2.3, the optimum peak-to-average capacity ratio for the compressor is nominally 2.0. As such, the required range of compressor capacities is 8 kg/hr to 500 kg/hr. The largest compressor capacity identified in the survey was 250 kg/hr, which implies multiple compressors will be required for the larger refueling stations.

Compressor efficiencies were, in general, not supplied by the vendors. Further, calculating efficiency from the motor horsepower ratings can often lead to low calculated values. For the purposes of the H2A Delivery Models, a universal efficiency of 65 percent has been assumed for all refueling station compressor types and capacities.

Table 2-22, an allowance of 3 to 7 percent of the purchase price was added to the reciprocating compressors costs for an oil removal system following the last stage.

In general, the three types of compressors can meet the pressure requirements for a refueling station; specifically, an inlet pressure as low as 300 psi (20.69 bars) and a discharge pressure of 6,250 psi (431 bars). However, as discussed in Section 2.1.3, refueling station capacities span the range of 50 kg/day to 6,000 kg/day in the H2A Delivery Models. Further, as discussed in Section 2.3, the optimum peak-to-average capacity ratio for the compressor is nominally 2.0. As such, the required range of compressor capacities is 8 kg/hr to 500 kg/hr. The largest compressor capacity identified in the survey was 250 kg/hr, which implies multiple compressors will be required for the larger refueling stations.

Compressor efficiencies were, in general, not supplied by the vendors. Further, calculating efficiency from the motor horsepower ratings can often lead to low calculated values. For the purposes of the H2A Delivery Models, a universal efficiency of 65 percent has been assumed for all refueling station compressor types and capacities.

Table 2-22 Results from Survey of Potential Refueling Station Compressors

| Manufacturer | Type | Stages | Capacity (kg/hr) | Inlet Pressure (psig) | Outlet Pressure (psig) | Motor (HP) | Power (kW) | Comp. Cost ($K) | Filter Costs** ($K) | Uninstalled Costs ($K) |
|---|---|---|---|---|---|---|---|---|---|---|
| RIX* | Recip | | 8.5 | 40 | 5500 | | | 81 | 2 | 83 |
| Knox-Western* | Recip | | 28 | | | | | 144 | 6 | 150 |
| RIX* | Recip | | 42 | 40 | 4500 | | | 184 | 8 | 192 |
| Greenfield* | Recip | | 42 | 35 | 4500 | | | 207 | 8 | 215 |
| Greenfield | Recip | 3 | 87 | 300 | 6000 | 250 | | 265 | 17 | 282 |
| Greenfield | Recip | 4 | 93 | 300 | 6000 | 250 | | 265 | 19 | 284 |
| RIX | Recip | | 171 | 300 | 6500 | | | 1000 | 34 | 1034 |
| Knox-Western | Recip | | 251 | 300 | 6500 | | | 900 | 50 | 950 |
| PDC Machines | Diaphragm | 2 | 50 | 300 | 6000 | | | 180 | 0 | 180 |
| PDC Machines | Diaphragm | 2 | 100 | 300 | 6000 | | | 385 | 0 | 385 |
| PDC Machines | Diaphragm | 2 | 164 | 300 | 6000 | | | 790 | 0 | 790 |
| Fluitron | Diaphragm | 2 | 50 | 300 | 6000 | 100 | 43 | 155 | 0 | 155 |
| PPI | Diaphragm | 2 | 33 | 300 | 6500 | | | 170 | 0 | 170 |
| Hofer*** (Neuman-Esser in U.S.) | Diaphragm | 2 | 50 | 300 | 6000 | 125 | | 350 | 0 | 350 |
| Hydro-Pac | Intensifier | 2 | 9.2 | 300 | 6000 | 60 | 35 | 73 | 29 | 102 |
| Hydro-Pac**** | Intensifier | 1 | 30 | 6250 | 12500 | 40 | | 70 | 7 | 77 |

* The costs here are 15% greater than quoted costs to reflect the difference in the inlet/outlet pressure per recommendation of David Savidge, RIX

** Additional filtration (10% of compressor cost) is added to reciprocating compressors

*** This data point not considered as it appears to be a statistical outlier and comes from and unofficial quote.

**** This Hydro-Pac compressor was not considered in the cost estimation as it is significantly outside the pressure range required in the forecourt

### *Recommended Inputs to the H2A Delivery Models*

A plot of the uninstalled compressor costs, as a function of the capacity, is shown in Figure 2-25 for reciprocating compressors. Interestingly, the data in Table 2-22 for the diaphragm compressor costs follow very closely the trend line for the reciprocating units. For the purposes of the H2A Delivery Models, the uninstalled cost for a refueling station compressor is given as follows:

Uninstalled cost, $ = 4,2058 * (Capacity, kg/hr) + 18,975

The estimate is independent of the type of compressor. The H2A Models assume an installation factor of 1.2.

Due the generally poor reliability of hydrogen compressors in service today, industrial practice is to have installed spare compressors. The H2A Delivery Models installs 3 compressors at refueling sites each with a capacity of 50% of the required duty with 2 operating.

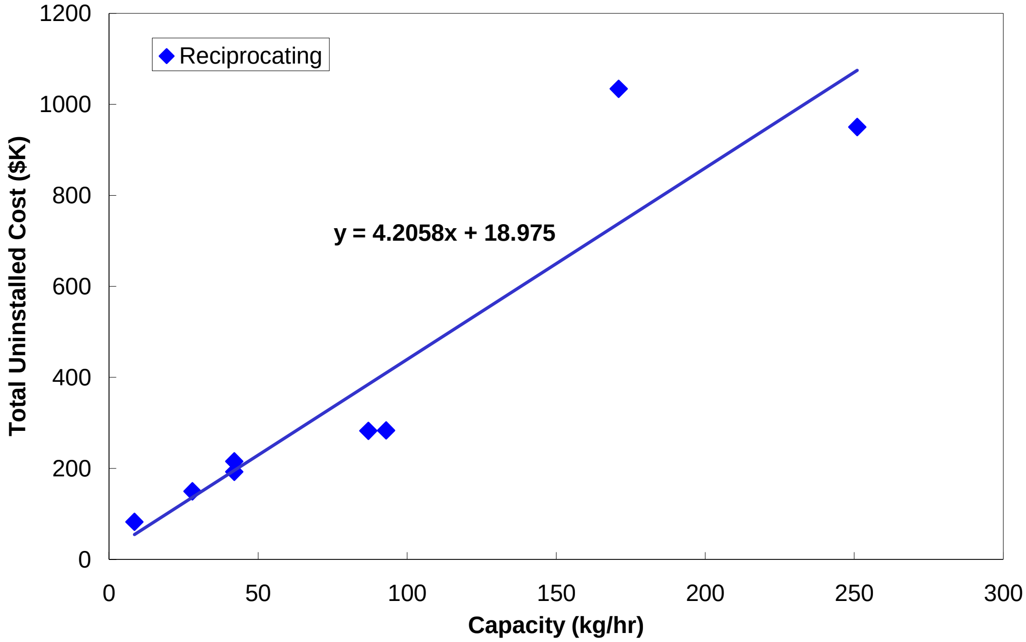



Figure 2-25 Refueling Station Compressor Costs as a Function of Capacity

### 2.2.6 Refueling Station Electric Power Supply

The electric power requirements of refueling stations will be much higher than a conventional gasoline station due to the demands of the compressor. As a result, the cost of the electric distribution equipment within the refueling station, such as the wiring and switchgear, is also expected to be higher than in a gasoline station.

Capital cost estimates were developed for a range of refueling station capacities. The estimates included the main circuit breaker, a motor control center, motor disconnect switches, electric power wiring, junction boxes, terminations, conduit, grounding provisions, instrument wiring for the motor control center, installation labor, and testing.

The common distribution voltages for large commercial systems are 480 Volts and 4,160 Volts. For 480 Volt systems, the largest motor available is 800 bhp (600 kWe); for higher power requirements, the voltage must be increased to 4,160 Volts. There are also differences in distribution system costs, with 480 Volt systems classified as ‘low voltage’, and 4,160 Volt systems classified as ‘medium voltage’. As a result, electric supply costs were developed for both 480 Volt and 4,160 V refueling stations. The low voltage system uninstalled costs are shown in Figure 2-26 for station demands between 0 and 800 bhp, and the medium voltage system uninstalled costs are illustrated in Figure 2-27 for station demands between 1,200 and 2,400 bhp. Based on the detailed analysis that went into these capital cost estimates, installation factors of 2.24 and 1.85 are used for the 480V and 4160V systems respectively in the H2A Delivery Models.

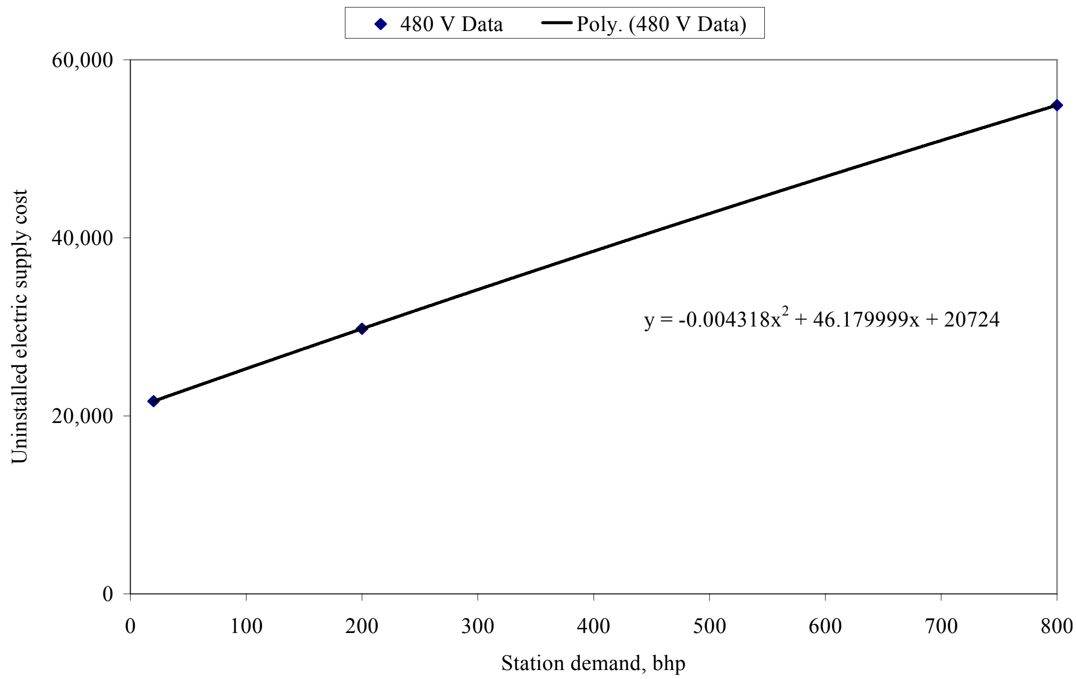



Figure 2-26 Refueling Station Electric Supply Costs - 480 Volts

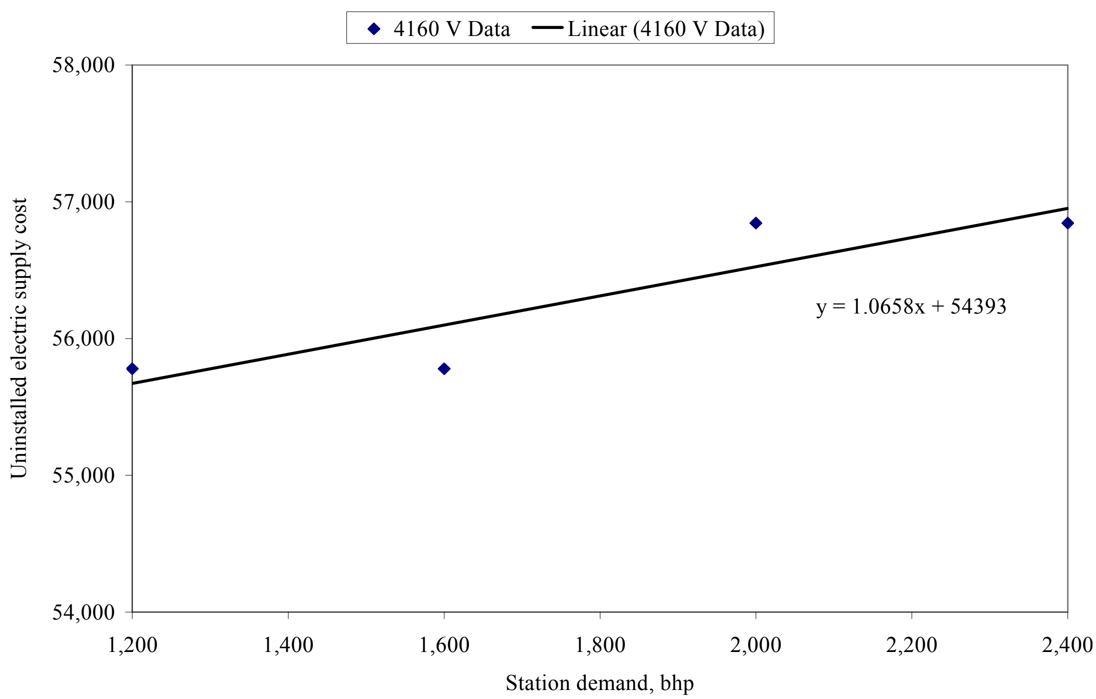



Figure 2-27 Refueling Station Electric Supply Costs - 4160 Volts

A further requirement was imposed on the 4,160 Volt systems. Specifically, the common distribution within a city is 480 Volts, with the medium- and high-voltage equipment normally confined to local substations. For the purposes of the H2A Delivery Models, it was assumed a 4,160 Volt refueling station would need to be supplied by a new, medium voltage cable directly from the substation. Further, the distance from the substation to the refueling station was assumed to be 1 mile, and the cost to install the new electric transmission line was estimated to be $1,000,000. Figure 2-28 shows a comparison between V1 and V2 of the H2A Delivery Models with respect to the refueling station compressor and electrical upgrade costs.

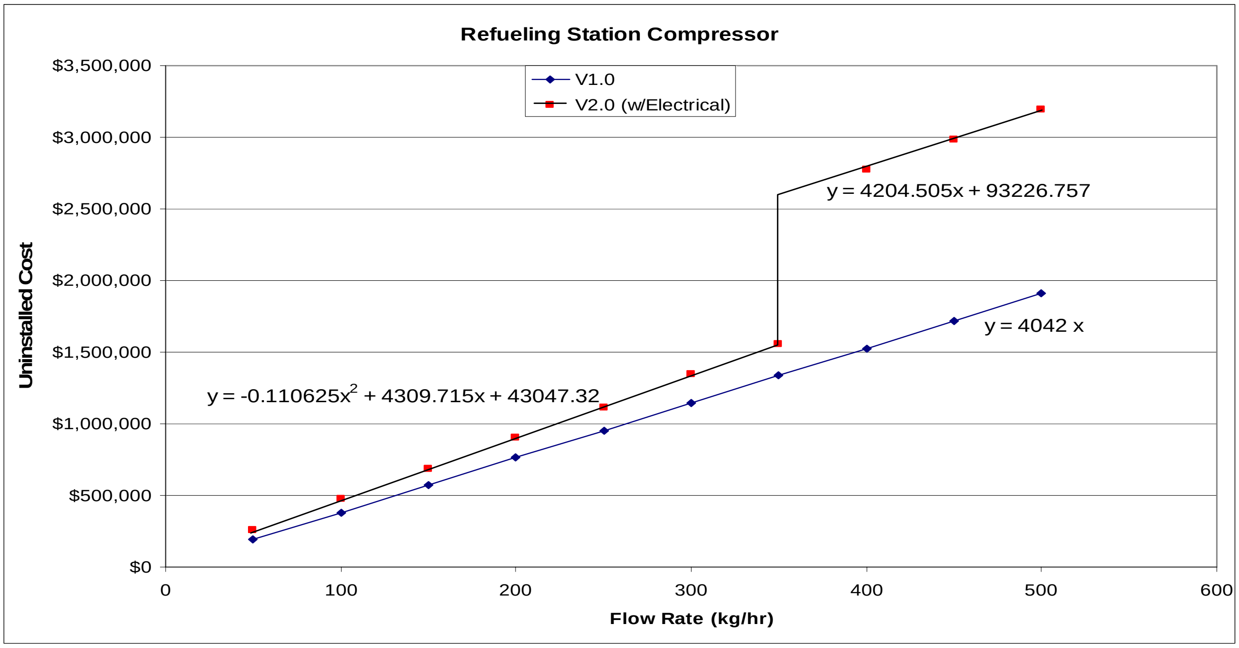



Figure 2-28 Refueling Station Compressor and Electric Supply Costs, Version 1 and 2 of the H2A Delivery Models

### 2.2.7 Liquefaction Plants

#### *2.2.7.1 Introduction*

In a mature hydrogen economy, liquid hydrogen may be required for the following activities:

- Medium to large cities will be supplied with hydrogen from one or more dedicated production plants. During scheduled, or unscheduled, plant outages, hydrogen will need to be supplied from a storage system at or near the production plant. For commercial quantities, compressed gas storage in pressurized vessels will be prohibitively expensive. Geologic storage is the low cost option for this purpose. If it is not available, liquefaction and liquid storage is the next best alternative, (See Section 2.1.8).
- During the transition to the use of hydrogen as a major energy carrier and for small cities or rural communities, construction of a transmission pipeline from the production plant to the city may be economically infeasible. The remaining delivery options include compressed gas tube trailers and liquid hydrogen, and for some combinations of city size and delivery distance, the latter approach may be preferred.

This report discusses the range of commercial liquefaction plant capacities, the energy required for liquefaction, liquefaction plant costs, and liquid storage tank costs.

### *2.2.7.2 Hydrogen Liquefaction*

Hydrogen is liquefied by exploiting the thermodynamic characteristics of the gas; specifically, reducing the pressure, while holding the enthalpy constant, results in a change in temperature. The effect, known as the Joule-Thompson effect, is the change in the temperature as the gas is throttled across a valve; i.e., $(\delta T / \delta P)_{\text{Constant h}}$. The coefficient for hydrogen is negative for temperatures above 200 °K (i.e., the gas temperature rises during throttling), but is positive for temperatures below 200 °K. The 200 °K temperature is known as the inversion temperature. The liquefaction process involves gas compression, cooling with water, and then pre-cooling with liquid nitrogen to drop the hydrogen below the inversion temperature. Final cooling and liquefaction is usually accomplished by throttling, as most expansion turbines are incompatible with two-phase flow. A simplified flow diagram of the current hydrogen liquefaction process is illustrated in Figure 2-29.

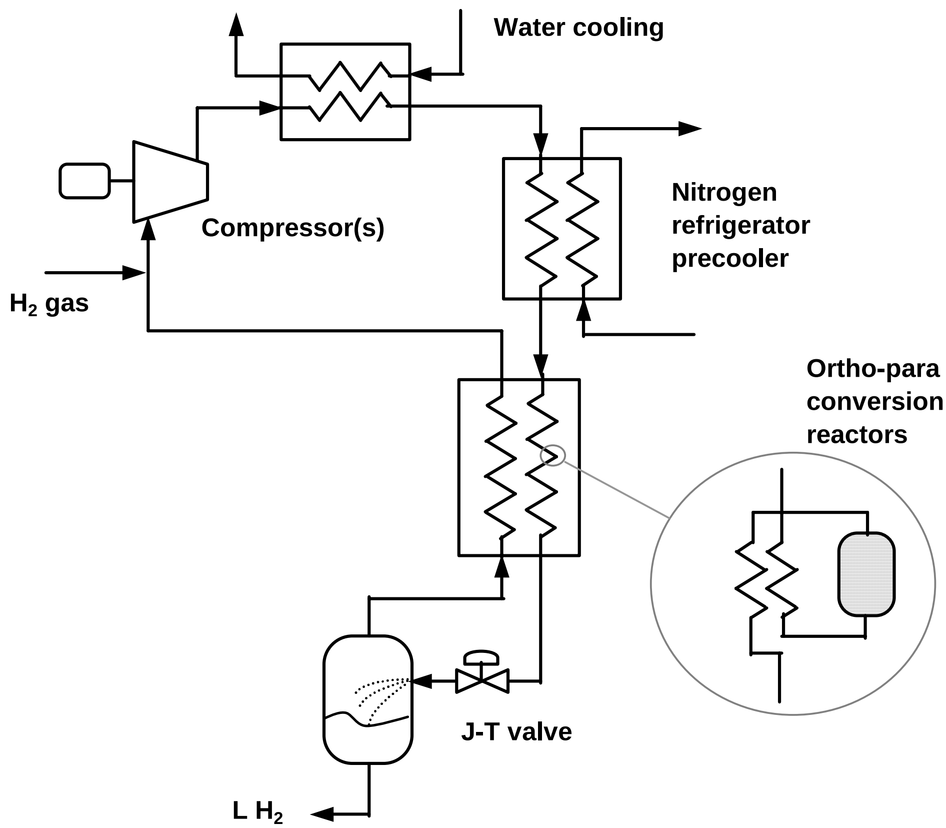



Figure 2-29 Simplified Flow Diagram for Hydrogen Liquefaction Plant

Hydrogen molecules exist in para- and ortho- forms, depending on the electron configurations in the two atoms in the molecule. At hydrogen's boiling point of -253 °C, the equilibrium concentration is primarily para-hydrogen; however, at room temperature and above, the equilibrium concentration is about 25 percent para- and 75 percent ortho-hydrogen. If the hydrogen is liquefied without first catalytically converting the ortho- to the para- form, the ortho-hydrogen will slowly convert to para-hydrogen in an exothermic reaction releasing about 0.15 kWh/kg of energy. The heat of transformation can cause the evaporation of as much as

50 percent of the liquid hydrogen over a 10 day period. The ortho-to-para conversion is performed during liquefaction by means of a catalyst, with the heat released during conversion removed by cooling with liquid nitrogen, then further cooling with liquid hydrogen. Hydrogen liquefaction plants have been built at commercial scale since the mid 1950's to support the space program and to support other uses of hydrogen such as in the specialty chemical industries and in the electronics industry. A large plant was built in Florida with a capacity of 30 metric tons/day, and other large plants followed in the 1960's to support the Apollo program. There are currently 10 plants in the US with capacities ranging from 5.4 to 32 metric tons per day. However, activity in new plant construction has been quiet in the last few years. Recent plants built in Japan and Europe are in the 5 metric ton per day range.

Discussions were held with Andres Kundig of Linde Kryotechnik AG in Switzerland regarding existing, and planned, liquefaction plants. The largest single train plant built by Linde is a 13.5 metric ton per day unit in Magog, Canada. The current limitations on train size are the aluminum plate fin exchangers, the cold box diameter, and the desire to shop fabricate, as opposed to field fabricate the equipment. The current largest size of the cold box is around 15 metric tons per day. A 50 metric ton per day plant has been planned, which would use 3 cold boxes. For a 50 metric ton per day plant, there are 4 expansion turbines in the nitrogen loop, and 6 expansion turbines in the hydrogen loop.

In the future, if there is a demand for a large, single-train plant, Mr. Kundig could foresee new manufacturing techniques that would increase the largest capacity which can be shop fabricated; alternately, larger units would need to be field fabricated. He believes a 250 to 300 metric ton per day plant could be built, but no one has studied this in detail. Other industrial gas hydrogen suppliers have suggested that 100 metric tons per day might be the largest practical size. We have elected to limit the maximum size in the H2A Delivery Models V2 to 200 metric tons/day. Multiple units are used if demand exceeds this.

The hydrogen supplied to a liquefaction plant is typically 99.999 percent hydrogen. Due to the high purity of the feed stream, Linde states the liquefaction plant should be available for at least 360 days each year (98.6 percent availability).

#### *2.2.7.3 Liquefaction Plant Energy Consumption*

The liquefier efficiency is often characterized as the input work required for producing a unit mass of liquid. The ideal work, with zero thermodynamic irreversibility, is a two-step process, involving isothermal compression, followed by isentropic expansion to the liquid state. The theoretical work to liquefy hydrogen from ambient conditions, including the ortho-to-para conversion, is approximately 3.9 kWh/kg.

Currently, Linde has two plants which produce 4.4 and 13.5 metric tons per day in Ingolstadt, Germany, and Magog, Canada, respectively. The smaller plant has an electric consumption of 13 kWh/kg of hydrogen, and the larger one, 12 kWh/kg. Both plants were built in the early 1990's. Linde feels that with the best current compressor technology, a new 10 metric ton per day plant could have an energy requirement of 10 kWh/kg, and a 50 metric ton per day plant, 9 kWh/kg. In the future, Linde predicts the energy demand could be reduced to 8 kWh/kg. These values assume the hydrogen is supplied from a plant at a pressure of 18 bars.

Air Liquide operates a 10 metric ton per day liquefaction plant, which has a unit energy demand of approximately 18 kWh/kg. However, the plant has been in operation for many years, and a current design would have a lower energy consumption. Air Liquide believes the lower limit on the liquefaction energy to be one-half of that in their present plant.

A plot of the Linde and the Air Liquide unit energy estimates is shown in Figure 2-30, with the assumption the lowest energy consumption is reached at a plant capacity of 200 metric tons per day. The curve and equation shown in this figure obtained from the recent discussions with the vendors is used in the H2A Delivery Model Version 2.

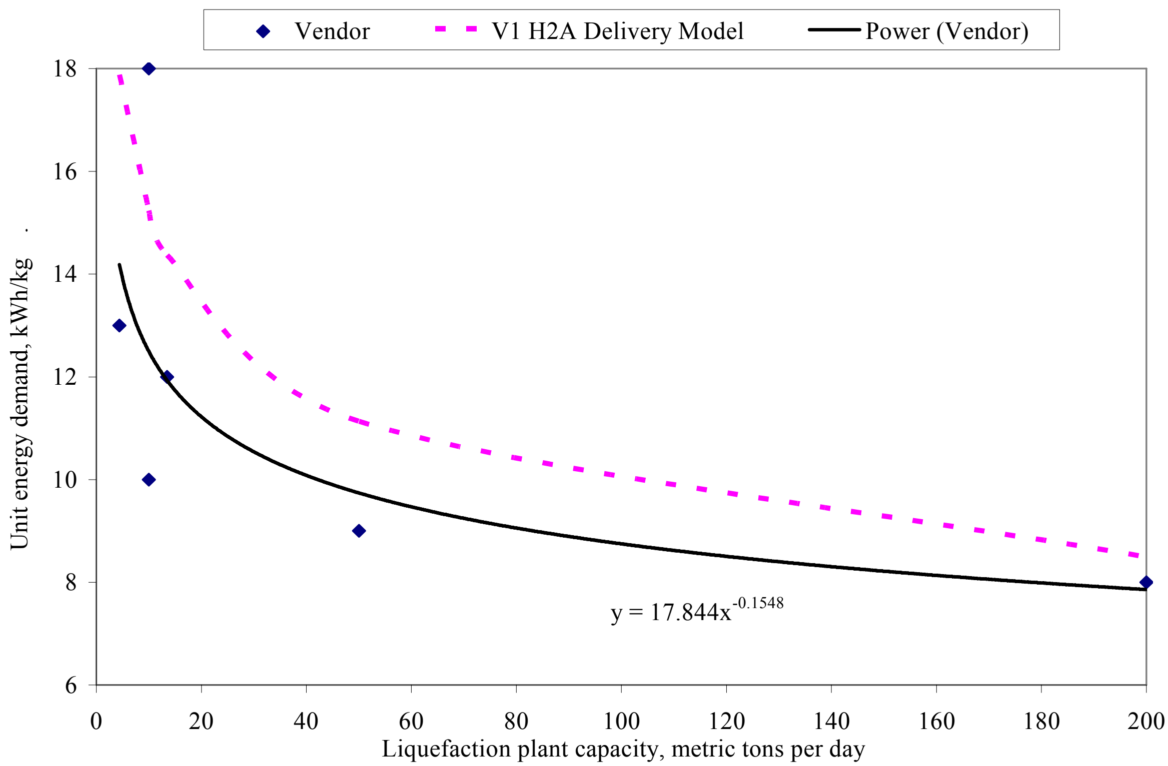



Figure 2-30 Unit Liquefaction Energy Requirements

#### *2.2.7.4 Liquefaction Plant Costs*

Linde Kryotechnik is currently building a 5.1 metric ton per day plant in Leuna, Germany. Construction was completed in mid 2007. The cost is reported to be €20+ million ($26+ million), or approximately $5.1 million per metric ton per day.

Linde was also asked about estimated costs for larger plants. They quoted a 50 metric ton per day plant at CHF 90,000,000, or $75 million, with an accuracy of ±25 percent. The estimate includes the cold boxes, the compressors, the expansion turbines, and the associated piping. The price was equipment only, and did not include shipping, taxes and installation. The taxes and freight would depend on the plant location, and Linde would not speculate on the total installed cost. For the purposes of this study and report, the installation factor for converting direct material price to a total installed cost in this case is estimated to be 2.0 for a plant in the United

States.  This results in a total installed cost of $150 million, or $3.0 million per metric ton per day.

Liquefaction plant costs were also discussed with Praxair.  However, Praxair has not built a plant in 7 to 8 years.  Further, no customers have initiated serious inquiries regarding a new hydrogen plant, and as such, Praxair had no solid cost information.  Praxair commented that a 25 metric ton per day plant might cost $30 million; however, this value seems low.

A plot of the Linde cost data, plus an additional datum point from DOE for a 30 metric ton per day plant, is shown in Figure 2-31 including installation.  A (significant) extrapolation of the cost data to a plant capacity of 200 metric tons per day is also shown.

Figure 2-31 also shows a curve fit of the vendor cost data, plus a plot of the estimated plant costs using the H2A Delivery Models V1 equation for capacities up to 50 metric tons per day.  Note that the trend line (H2A V2) equation is based on the vendor data, even though it matches the H2A V1 cost data very closely.

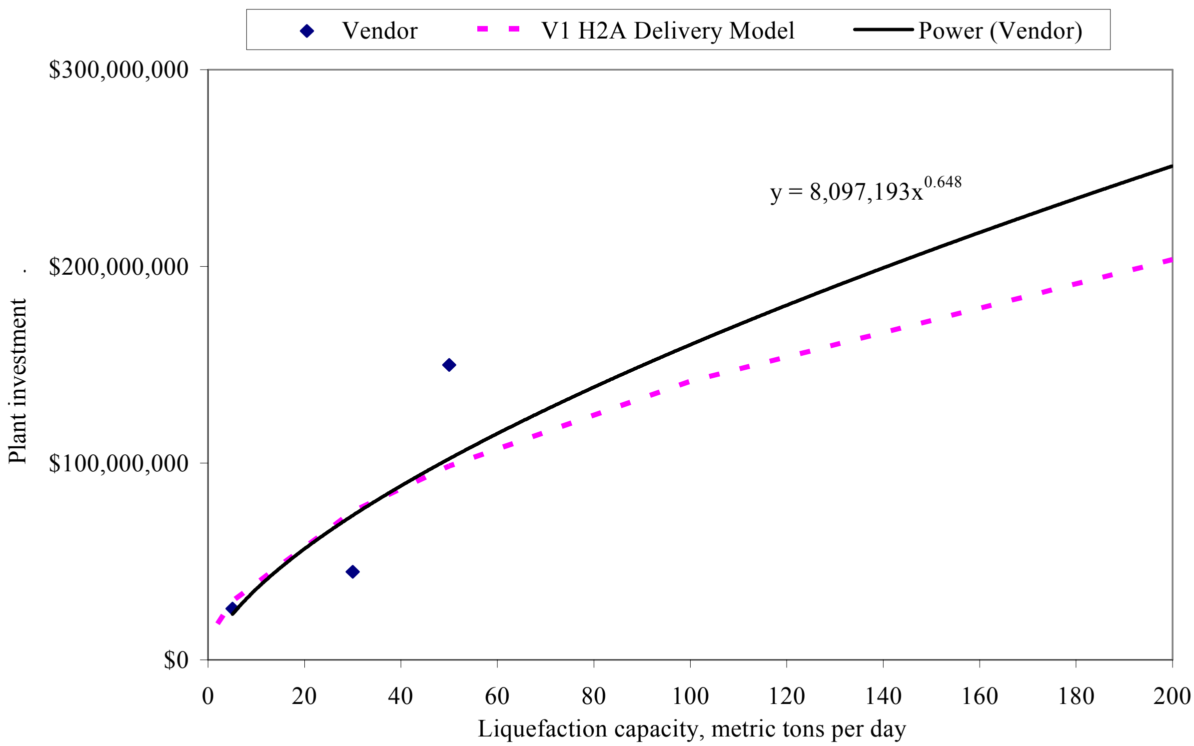



Figure 2-31  Liquefaction Plant Cost as a Function of Capacity

#### *2.2.7.5 Recommended Inputs to the H2A Models*

For the purposes of the H2A model, the following inputs regarding hydrogen liquefaction are recommended:

- Allowable plant sizes should be restricted to values in the range of 0 to 200 metric tons per day. For liquefaction requirements greater than 200 metric tons per day, multiple trains should be used.
- Annual plant availabilities are estimated to be 98.5 percent
- Unit liquefaction energy requirements, in kWh/kg, are estimated as:

  17.844 * (Plant capacity, metric tons per day) $^{-0.1548}$
  with a minimum value of 8 kWh/kg

- The total installed cost in a liquefaction plant is estimated as:

  8,097,000 * (Plant capacity, metric tons per day) $^{0.648}$

### 2.2.8 Terminal and Refueling Station Liquid Pumps and Vaporizers

For liquid hydrogen delivery, pumps are needed to load and unload the cryogenic tractor-trailer vessels. Hydrogen vaporizers are used when the liquid hydrogen is withdrawn from storage and the superheated gas is transferred either to a transmission pipeline at a terminal, or to a cascade charging system at a refueling station.

A series of communications with vendors and other liquid hydrogen experts led to the development of cost curves for pumps and vaporizers. These data are shown in Figure 2-32, Figure 2-33, and Figure 2-34.

Because the required vaporizer capacities and types for terminals and refueling stations differ, separate cost curves have been developed for these applications. Unfortunately only two data points were obtained for each application.

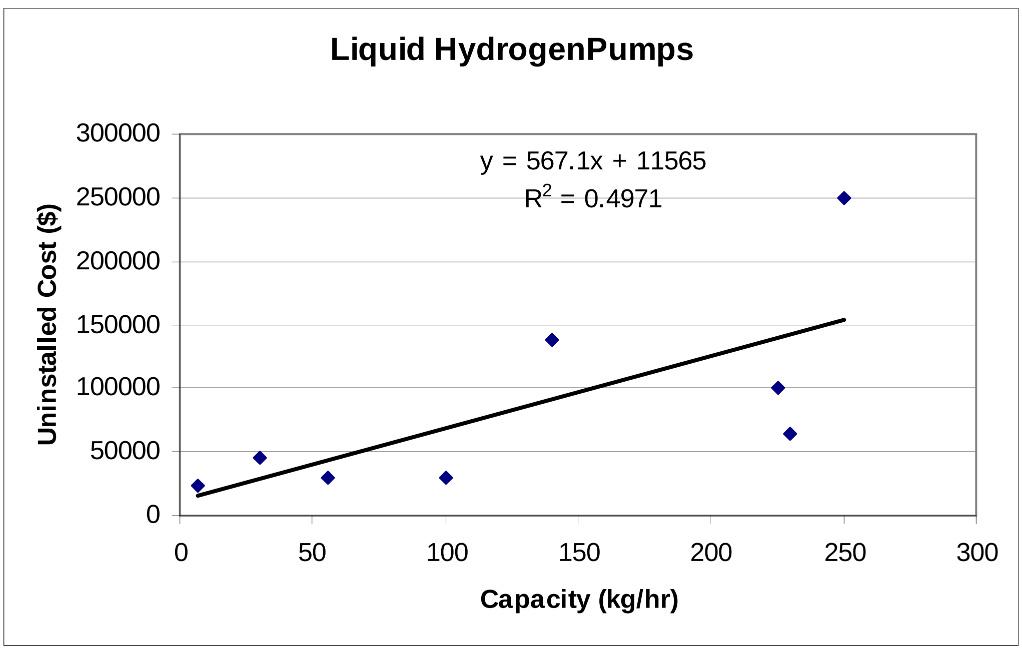



Figure 2-32 Uninstalled Costs for Liquid Hydrogen Pumps

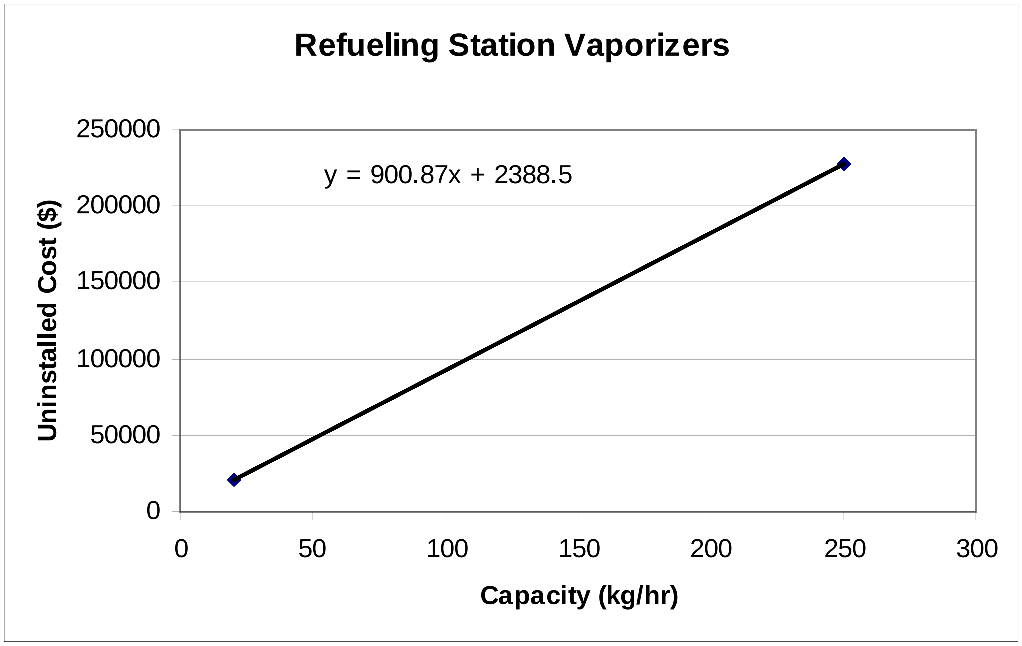



Figure 2-33 Uninstalled Costs for Refueling Station Hydrogen Vaporizers

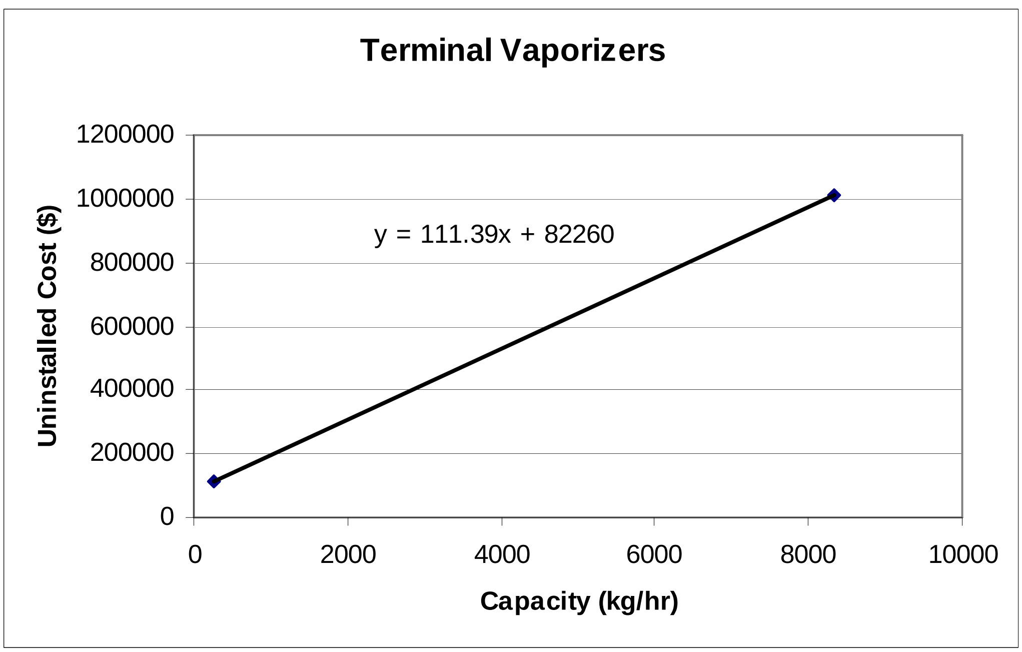



Figure 2-34 Uninstalled Costs for Terminal Hydrogen Vaporizers

The H2A Delivery Models set an upper limit for cryogenic liquid hydrogen pump capacity at 250 kg/hour (6 metric tons/day) since that is the largest pump capacity available at the current time that could be located. If the total required capacity is greater than this value, multiple pumps are used in estimating costs. This same capacity limit is used for vaporizer capacity at refueling stations. For liquid hydrogen terminals, the pump is assumed to have a 250 kg/hour maximum, while there is no limit on vaporizer sizing.

While the vaporizer cost information presented above is used throughout the H2A models, it is recognized the design details associated with the specific vaporizer technology considered in developing these costs may have limited applications. For example, the cost data in Figure 2-33 are based on the use of aluminum tubes with ambient air as the heat exchange medium. While this design is appropriate in many applications, it is uncertain whether it will meet hydrogen refueling requirements for immediate and multiple startups that will be realized at refueling stations.

Costs for the terminal vaporizers (Figure 2-34) are based on a design that incorporates liquid circulating systems with combustion of natural gas to prevent the heat exchanger tubes from frosting up. In addition, the vaporizer models do not include the cost of electricity used to operate them. Due to the wide variation in geographic and climatic conditions in which terminal vaporizers may be located, it is difficult to estimate the cost of natural gas consumption required to heat the heat exchanger tubes so these costs are neglected in the model. Electricity and natural gas costs are anticipated to be quite low in comparison to other costs so that their omission is not expected to be a significant factor in estimating the overall cost of hydrogen delivery. These issues may be examined further as part of the development of future versions of the Delivery Models.

The costs noted in these figures are uninstalled costs. Based on information from industry experts and using the collective engineering judgment of the people involved with this study, the following installation factors are used in the H2A Delivery Models Version 2 to estimate the installed cost of this equipment.

- Liquid hydrogen pumps at a refueling station: 1.2
- Liquid hydrogen pumps at a terminal: 1.3
- Liquid hydrogen vaporizer at a refueling station: 1.2
- Liquid hydrogen vaporizer at a terminal: 1.3

### 2.2.9 Liquid and Gas Terminals

#### *2.2.9.1 Liquid Hydrogen Terminals*

There are two types of liquid hydrogen terminals in the H2A Delivery Models. The first type is co-located with a production facility or located at the city gate and liquefies all of the hydrogen received from the production plant or transmission pipeline, stores it, and loads it into cryogenic liquid trailers for delivery as liquid hydrogen to a refueling station. This is for Pathways 1, 2, and 3 as described in Section 2.4. The storage quantity is large enough to handle the summer peak demand as well as the winter plant outage for maintenance for Pathways 1 and 3. For Pathway 2, gaseous geologic storage is used for the summer peak demand and winter plant outage. In this case the terminal storage has a default value of 1 day to ensure smooth truck loading operations. These terminals serve two purposes: 1) provide storage for plant outages and seasonal variation in demand; and 2) transfers liquid hydrogen to trailers for delivery. A generic flow diagram of the liquid terminals for use with liquid delivery is shown in Figure 2-35. (Note: For the purposes of the H2A Delivery Models the liquefaction unit is treated as separate from the liquid terminal but in effect is part of it.)

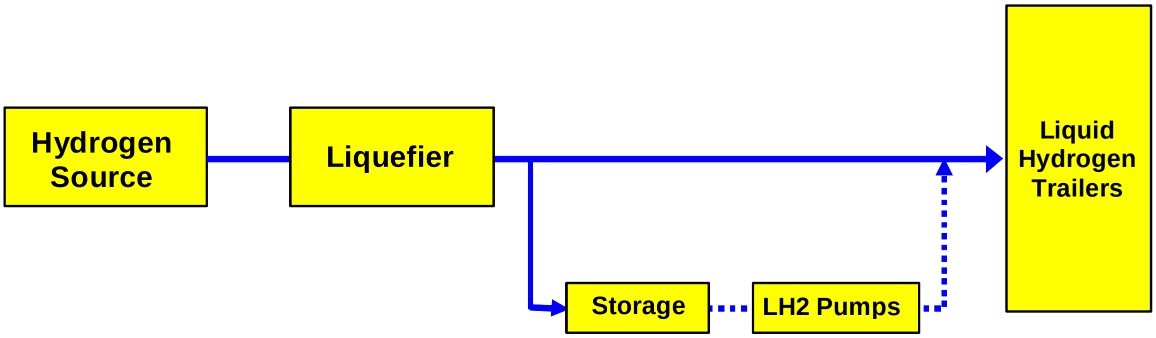



Figure 2-35 Liquid Terminal for Use with Gas Delivery

The second type of liquid terminals is used for gaseous hydrogen delivery if gaseous geologic storage is not available and has two functions; 1) liquefies a portion of the gas flow from the production plant, storing liquid for production plant outages and the summer peak demand; and 2) evaporates the stored liquid as needed and charges it either to a pipeline or a small gas storage system for charging to compressed gas tube trailers for delivery to a refueling station. This is for Pathways 5, 7, 9, and 10 as described in Section 2.4. A generic flow diagram of a liquid terminal for use with gas delivery is shown in Figure 2-36.

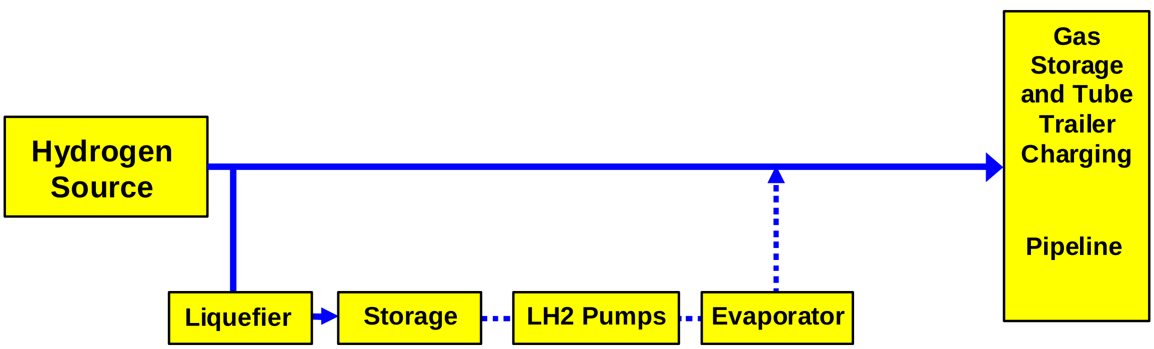



Figure 2-36 Liquid Terminal for Use with Gas Delivery

#### *2.2.9.2 Gaseous Hydrogen Terminals*

The gaseous terminals in the H2A Delivery Models are used to charge gaseous tube trailers with hydrogen. They can be co-located at the hydrogen production plant and receive the hydrogen from the plant or they could be located at the city gate and receive hydrogen from a pipeline. In both cases they have a small amount of low pressure (2,500 psi or 172.4 bars) hydrogen storage (1/4 of a day) to ensure smooth tube trailer charging operations, a compressor, and bays for the tube trailer loading.

### 2.2.10 Gas and Liquid Terminal and Refueling Station Land Areas

The land requirements for the terminals and refueling station facilities are estimated in the H2A Delivery Models and costs are then associated with this land. While the land costs are not believed to be a large contributor to the total cost of delivered hydrogen, the land requirements may be important factors in site selection for either or both of these facilities.

#### *2.2.10.1 Gaseous Hydrogen Terminals*

The gas terminals will consist of truck bays where the hydrogen is loaded into the compressed-gas tube trailers, a main compressor building, an office and maintenance building(s), driving and turnaround areas for the trucks, and some amount of gaseous storage for operational continuity. Various "set-back" distances will also be included around the perimeter of the facility and for various components within the facility.

Figure 2-37 shows a schematic of a gaseous terminal. One of the inherent assumptions in the H2A Delivery Models is that there will be two rows of terminal bays separated by a single driving area. This arrangement allows trucks to back into the loading bays from the corresponding driving area on either side of the drive area. The length of these rows of bays is calculated within the H2A Delivery Models using information on the physical dimensions of an individual bay and the number of bays required to meet the hydrogen demand. This latter parameter is calculated based on demand, distance from the terminal to the demand site, truck speed, loading and unloading times, and other scenario characteristics. The total length of each row of bays plus the appropriate set-back distances on either end determines the overall width of the terminal.

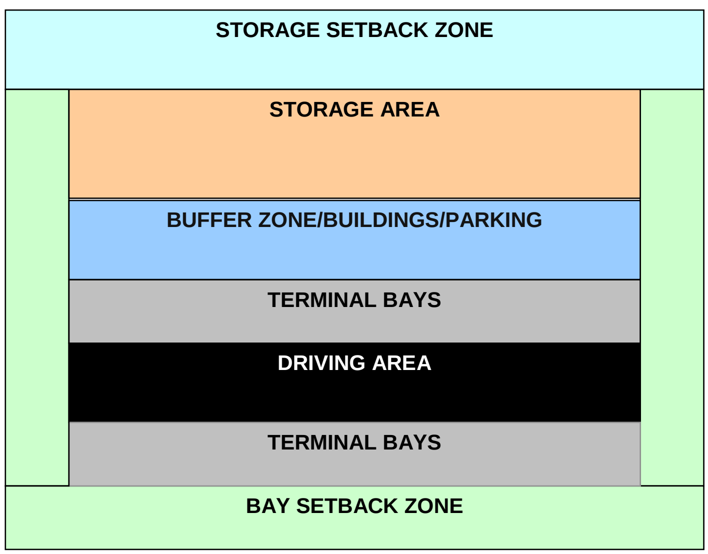



Figure 2-37 Schematic of Gaseous Hydrogen Terminal

The H2A Delivery Models allow the user to specify the quantity of gaseous hydrogen that is to be stored at the terminal. As noted above, this storage allows operational stability within the terminal by assuring the necessary quantities of hydrogen are available at the necessary pressures during loading operations. The user defines the storage quantity in terms of days of average daily hydrogen demand (The Models are pre-loaded with the default assumption of ¼ of a day.). Space requirements for storage are then determined through the use of the dimensions of the individual storage vessels (assumed to be a closed cylinder-shaped vessels), e.g., its length and diameter, and the pressure at which the hydrogen is stored. There is also a defined distance between individual storage vessels. An option to stack individual vessels vertically is also provided. The current default value is that the individual vessels are stacked six high. The storage vessels are assumed to be stacked in a horizontal row in the same direction as the terminal bays. If more than one row of storage vessels is needed, additional rows are placed with a specified distance between the rows. H2A default assumptions for the parameters described above are listed in Table 2-23.

Table 2-23 H2A Default Values for Terminal Area

| Parameter | Gaseous H2 Terminal | Liquid H2 Terminal |
|---|---|---|
| Storage Quantity | 0.25 Days of Average Demand | 1.0 Day of Storage (unless used for summer peak demand and winter plant outages) |
| Storage Vessel Diameter | 1.25 m (Cylinder) | Sphere Diameter calculated |
| Storage Vessel Length | 7.59 m (Cylinder) | |
| Front Clearance of Storage | 3.7 m | Spheres Spaced 15.0 meters apart in all directions |
| Back Clearance of Storage | 0.6 m | |
| Side Clearance of Storage | 0.3 m | |
| Cylinder Stacking | 6 | NA |
| Bay Width | 5.0 m | 5.0 m |
| Bay Depth | 22.0 m | 22.0 m |
| Drive Depth | 15.0 m | 15.0 m |
| Distance from Storage to Compressor (or Pump) House | 15.0 m | 15.0 m |
| Distance from Compressor (or Pump) House to Fill Header | 15.0 m | 15.0 m |
| Bay Perimeter Setback | 15.0 m | 15.0 m |
| Storage Perimeter Setback | 23.0 m | 23.0 m |
| Land Cost at City Gate | \$400,000/acre (\$98.84/$m^2$) | \$400,000/acre (\$98.84/$m^2$) |
| Land Cost near production site | \$50,000/acre (12.35/$m^2$) | \$50,000/acre (12.35/$m^2$) |

The overall depth of the terminal area thus becomes the sum of the bay set-back distance, twice the depth (length) of an individual bay, the width of the driving area, the distance between the compressor house and the bays (this area could also include office buildings, maintenance facilities, and/or employee parking), the distance between the nearest row of storage vessels and the compressor house, the total depth of the storage area, and the storage set-back distance. The total terminal area is then the width times the depth.

For scenarios in which the user has selected liquid storage for “Plant Outage and Summer Peak” combined with “Compressed H2 Truck” delivery, Version 2.0 of HDSAM calculates the required liquid storage area and then separately calculates the gaseous terminal area as described above. These two area requirements are then summed to get the total terminal land requirements. This process may somewhat over-estimate the total land requirements for this scenario.

#### 2.2.10.2 Liquid hydrogen Terminal

Area requirements for a liquid terminal for the liquid delivery pathways using cryogenic liquid trucks are estimated in much the same way as for gaseous hydrogen terminals. As before, the width of the terminal is estimated as the length of a row of bays (plus set-back distances) containing half the total number of bays needed. The depth of the storage area is also determined in a manner similar to that for gaseous hydrogen storage except that it is assumed that each cryogenic storage vessel is a sphere capable of holding up to 3,500 cubic meters of liquid hydrogen. This size storage vessel is the largest for which information was available. The H2A Delivery Models determine the number of such storage vessels needed and locates them in a manner similar to that for the gaseous storage vessels. There is little available information regarding the physical dimensions of liquid hydrogen pumps and vaporizers of the scale needed for large-scale, long term storage. Therefore, Version 2.0 of the H2A Delivery Models does not estimate the land requirements for this equipment. Subsequent versions of the model will include such estimates. Default values used in the H2A Delivery Models for liquid terminals are also shown in Table 2-20A.

The second type of liquid terminal arises when the H2A Delivery Models user elects either the gaseous hydrogen truck or pipeline delivery pathway and also elects to provide long term storage in liquid hydrogen form. Such storage would be used to meet peak summer demand as well to meet hydrogen demand during the annually scheduled production-plant maintenance shutdown. Under this option a small quantity of the production stream is bled off, liquefied and stored in cryogenic, spherical tanks. This bleed stream is to provide sufficient hydrogen to meet the extra, summer demand as well as to meet the demand during the winter period when the production facility is shut down for maintenance (a default value of 10 days plant outage is used). The terminal equipment required when using liquid hydrogen storage in a gaseous hydrogen delivery pathway includes a liquefier, cryogenic storage vessels, liquid hydrogen pumps, and a hydrogen vaporizer.

Area requirements for this type of liquid hydrogen terminal are estimated in a manner similar to that for first type of liquid hydrogen terminal. A major difference however, is that no bays are required. Therefore the model defines the space requirements for the spherical cryogenic storage vessel(s) and assumes that these storage vessels are placed in a single row with the required set-back distances on either end and in front and back of the storage vessels. While this configuration is not likely to be exactly followed in an actual application, the estimation of the land requirement is believed to be representative of configurations that might be used in real applications.

One important difference in the land requirements for liquid terminal compared to gaseous terminals is that a liquid terminal requires a liquefier to be located with the terminal and land requirements for liquefiers are significant. The H2A Delivery Models estimates the liquefier land requirements by scaling to a 0.6 power a reference case value that a 30 metric ton/day hydrogen liquefier will occupy 25,000 square meters.

#### 2.2.10.3 Refueling Station Land Areas

In order to properly define the characteristics and costs of hydrogen delivery it is necessary to determine the land area required for a hydrogen fueling station. In order to determine the area required for a fueling station, it is necessary to consider the area needed for fuel dispensers, on-site hydrogen storage, delivery access, and sufficient setback distances as specified by the National Fire Protection Association (NFPA) Guidelines. In addition, hydrogen fueling stations may include gasoline dispensers and a small on-site convenience store. The H2A Delivery Models methodology for determining the fueling station land area uses the hydrogen demand to determine the number of dispensers and proper size of hydrogen equipment (primarily compressors and storage). Given these metrics, the methodology specifies the required dimensions of the overall fueling station, as well as the amount of the land allocated to hydrogen delivery.

*General Assumptions*

In order to create a simple and useful tool to calculate fueling station land area, a number of simplifying assumptions have been made. Hydrogen fueling stations can be arranged in numerous configurations. In practice the capacity and orientation of a fueling station will be determined by the available property. The methodology, however, assumes a basic architecture based on the conventional gasoline station shown in Figure 2-38.

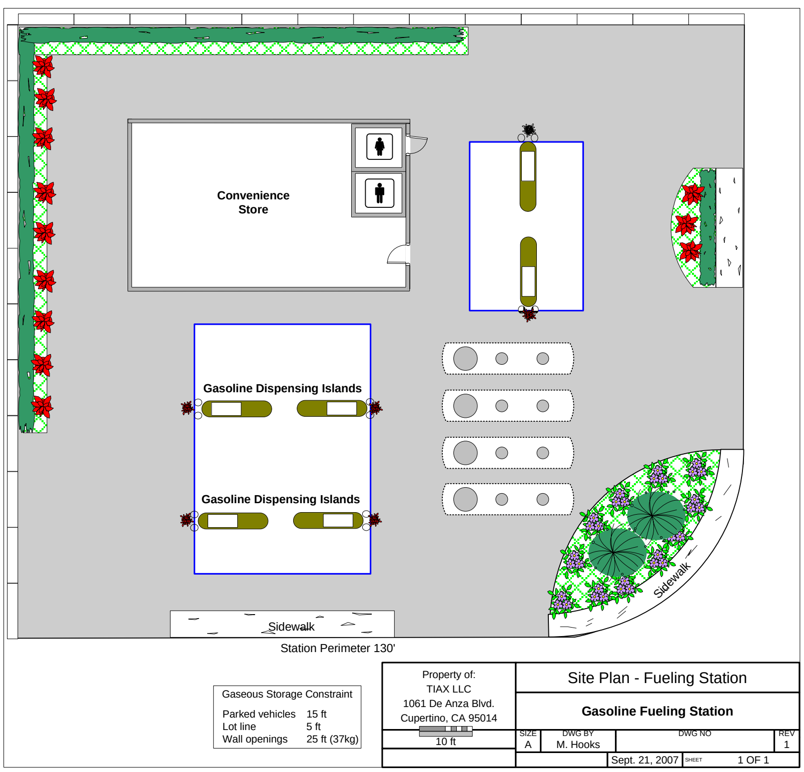



Figure 2-38  Baseline Gasoline Station Site Plan

The baseline configuration of the hydrogen fueling station is partially defined by characteristics of the baseline gasoline station. These characteristics include having a minimum of six dispensers, having a rectangular footprint, being orientated on a street corner, and including a convenience store on the property.

The number of hydrogen dispensers at the fueling station is directly proportional to the hydrogen demand at the fueling station. This calculation is outlined in Section 2.3.2. Fueling stations that do not require six dispensers (an individual dispenser has two hoses and can fuel two vehicles simultaneously) to sufficiently meet the hydrogen demand, will have gasoline dispensers in addition to hydrogen dispensers. At these stations it is assumed that there are a total of six dispensers (hydrogen and gasoline). Additionally, it is assumed that if the hydrogen demand at the fueling station necessitates six or more dispensers, than the station will not have gasoline dispensers. The largest station considered consists of ten dispensers and is capable of dispensing 6,000 kg/day of hydrogen.

The land area allocated to hydrogen delivery is determined by the area required for the hydrogen equipment and the relative number of hydrogen and gasoline dispensers. The area occupied by the convenience store is not allocated to either gasoline or hydrogen delivery, as it will generally generate its own financial returns. If the land area required for the fueling station is in excess of the baseline gasoline station, the incremental station area is assigned to hydrogen. The baseline area (excluding the convenience store) is divided between hydrogen and gasoline delivery based on the proportion of dispensers that distribute each fuel. If the fueling station only contains hydrogen dispensers, all the land area except the convenience store will be allocated to hydrogen delivery.

### Primary Variables

A few primary variables determine the land area required for a hydrogen fueling station.

- Daily Average Fuel Demand
  - The daily average fuel demand is used to calculate the required number of dispensers and storage capacity. (These calculations are detailed in Sections 2.3.1 and 2.3.2 in this report).
  - Average fuel demand is specified by the user in the Models setting the size of the refueling station.
- Setback Distances
  - Setback distances in this analysis are specified by the NFPA and apply to the location of hydrogen storage in relation to a variety of exposures.
  - Setback distances are entered into the model as default values.
- Delivery Method
  - The options for delivery are: gaseous tube trailers, gaseous pipeline delivery, or liquid truck delivery. Each option has unique space requirements.
  - The delivery method is specified by the user in the Models.

#### *Setback Distances*

A major factor in determining the overall land area required for hydrogen fueling stations is the required setback distances from hydrogen storage. These distances are specified by the NFPA (Section 55, Chapter 10). The NFPA setback distances only dictate the relative location of hydrogen storage and do not make any specifications as to the location of other hydrogen equipment or dispensers.

The regulations governing fueling stations are presently under review. Following this review, updated regulations may be released within the next two years. These changes will be released in NFPA 2. The updated regulations may change the basic assumptions and default values used in the H2A Delivery Models. It is unclear at this point how much effect the new regulations will have on the overall land area of the fueling station. Given new regulations, it is also unclear whether the fueling station area requirements will be able to be calculated simply by modifying input parameters. A thorough review of the new NFPA codes will be required upon their release.

It is also important to note that local authorities (generally fire departments) have final jurisdiction over setback distances. This authority allows local officials to make educated adjustments to the NFPA requirements. For example, it is possible for engineered systems (such as fire retardant walls) to be used in order to reduce the setbacks distances specified in NFPA 55 in situations where standard compliance with the standard regulations is challenging or impossible. The H2A Delivery Models do not take advantage of any engineered systems and uses all of the setback distances specified by NFPA 55. Specific setback distances can be found in Table 2-24.

Setback distances specify the distance required between hydrogen storage and specific points on the property, such as wall openings or lot lines. The area between these two points does not have to be vacant. For example, hydrogen storage can be next to the convenience store provided that the walls are sufficiently sprinkled and non-combustible, and that there are no wall openings within the setback distance specified by NFPA. In fact, the H2A Delivery Models now estimate the land area of the fueling station situating storage as close to the convenience store as possible while still maintaining the appropriate distance from wall openings (all doors are assumed to be on the opposite side of the structure). In addition, the other hydrogen components, such as vaporizers and compressors, can be situated within the setback distances surrounding the hydrogen storage. It is unnecessary to provide greater setbacks around those components. This is particularly evident as stations that are supplied with liquid hydrogen, as the vaporizer – a very large component, can be located within the setback around the liquid hydrogen tank.

The NFPA guidelines specify setbacks from flammable liquid storage (i.e. gasoline storage) and the associated components (vents and fills). These setback distances are also specified in Table 2-24. These setback distances were not explicitly included in the H2A Delivery Models given the assumption that they can more easily be located on the site outside the required setback distances.

Based on discussions with representatives from Air Products and Chemicals, there are no specific restrictions regarding the placement of hydrogen dispensers or regarding the relative placement of hydrogen and gasoline dispensers.

Relevant assumptions used to calculate the overall land area required for hydrogen delivery can be found below in Table 2-24.

*Tube Trailer Supplied Fueling Station*

Current tube trailers only have a delivered hydrogen capacity of 280 kg of hydrogen. Limiting the number of deliveries per day to two to avoid site congestion, the maximum refueling station size for this mode of delivery would be about 500 kg/day. However since there is on-going research to try to increase the capacity of tube trailers up as much as 1,000 kg, tube trailer stations as large as 2000 kg/day can be modeled in the H2A Delivery Models. In addition to the standard setback distances required for hydrogen storage the tube trailer supplied station will need to have two parking spots for tube trailers. Having two spots for trailers allows for a simple pick-up/delivery process. Fifteen feet is the assumed width of the trailer spots.

A representative site plan for tube trailer supplied stations is shown in Figure 2-39.

Table 2-24 Hydrogen Fueling Station Design Assumptions

| | **Fueling Station Hydrogen Supply** | | |
|---|---|---|---|
| **Parameter** | **Tube Trailer** | **Pipeline** | **Liquid H2 Truck** |
| | | | |
| Daily Capacity Range | 0 - 2,000 kg/day | 0 - 6,000 kg/day | 0 - 6,000 kg/day |
| Output/Dispenser | ~500 - 600 kg/day | ~500 - 600 kg/day | ~500 - 600 kg/day |
| Hoses/Dispenser | 2 | 2 | 2 |
| Cascade Charging System | 18 % of demand | 18 % of demand | 18 % of demand |
| Low-Pressure Vessel Diameter | | 4 ft. | |
| Low-Pressure Vessel Length | | 25 ft. | |
| High-Pressure Vessel Diameter | 16 in. | 16 in. | 16 in. |
| High-Pressure Vessel Length | 30 ft. | 30 ft. | 30 ft. |
| High-Pressure Vessels per Stack | 6 vessels | 6 vessels | 6 vessels |
| Liquid Storage Vessel Spherical Diameter | | | 21.5 - 23.3 ft. |
| Tube Trailer Parking | 2 | | |
| Tube Trailer Spot Width | 15 ft. | 15 ft. | 15 ft. |
| Setback: Wall Opening | 25 ft | 25 ft | 75 ft. |
| Setback: Lot Line | 5 ft. | 5 ft. | 75 ft. |
| Baseline Station Length | 130 | 130 | 130 |
| Baseline Station Width | 110 | 110 | 110 |
| Baseline Dispensers | 6 | 6 | 6 |
| Convenience Store Length | 50 ft. | 50 ft. | 50 ft. |
| Convenience Store Width | 30 ft. | 30 ft. | 30 ft. |

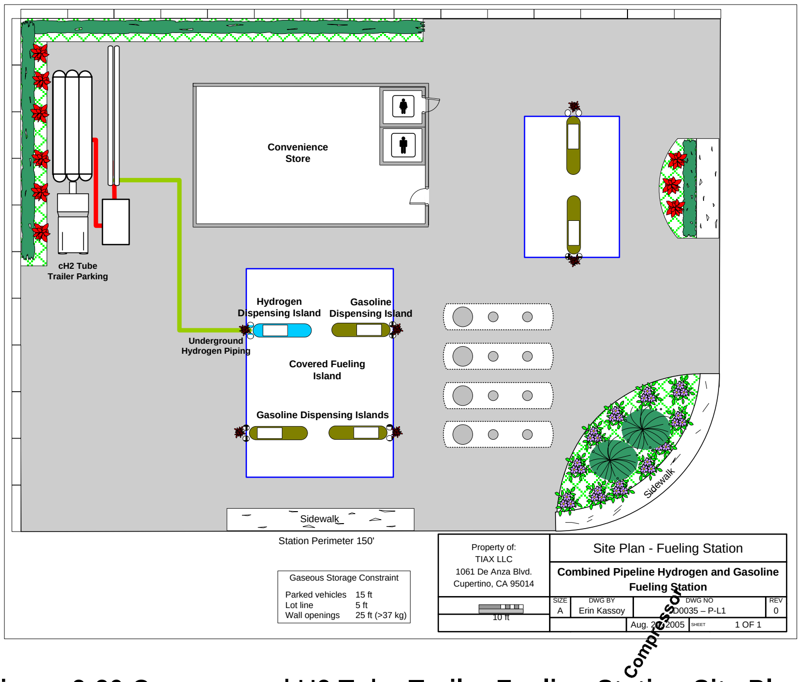



Figure 2-39 Compressed H2 Tube Trailer Fueling Station Site Plan

The fueling station shown in Figure 2-39 has one hydrogen dispenser (~300-500 kg/day) and five gasoline dispensers that are serviced by underground gasoline storage. The tube trailer is shown on the left side of the cascade storage tanks and compressor, but could also be on the right side and still meet the required setback distances for compressed hydrogen storage. For all types of hydrogen delivery there will be a cascade charging system used to fuel vehicles. The vessels (as described in Section 2.2.4) are assumed to be 30 feet (9.144 m) in length and 16 inches (40.64 cm) in diameter. In addition, it is assumed that no more than six vessels can be stacked on top of each other. Cascade storage vessels will be added in groups of three, as three vessels are required to charge hydrogen at the three pressure levels in the cascade system. Given the stated assumptions, the cascade storage has a set length and height for all fueling station configurations. The width will vary between approximately 1.0-4.5 meters for stations between 1,000 – 6,000 kg/day.

*Pipeline Supplied Fueling Station*

Pipeline supplied fueling stations are similar in layout to tube trailer supplied stations with the exception that they substitute tube trailer parking with low-pressure hydrogen storage tanks. Given the essentially unlimited ability of the pipeline to supply hydrogen, the pipeline supplied stations can supply the largest station in the H2A Delivery Models (6,000 kg/day of hydrogen). However, despite the ability to supply high daily demands, the pipeline system cannot instantaneously supply all stations during peak demand periods. In fact, the pipeline system benefits from operating at the steady-state operating conditions that reduce the need for transient response elsewhere in the upstream production and distribution system. In order to ensure this steady-state operating condition, low-pressure storage is included at the fueling station. Hydrogen is supplied to the low-pressure storage tanks at a steady rate, but is removed only when the cascade charging system requires hydrogen to maintain peak pressure. Low-pressure hydrogen storage tanks are assumed to be 25 feet (7.62 m) in length and 4 feet (1.219 m) in diameter (See Section 2.2.3). Additionally, it is assumed that only two low-pressure storage tanks can be stacked on top of each other. Figure 2-40 shows the site plan for a combined gasoline/hydrogen station with four hydrogen dispensers (~2,000-2,500 kg/day) and two gasoline dispensers.

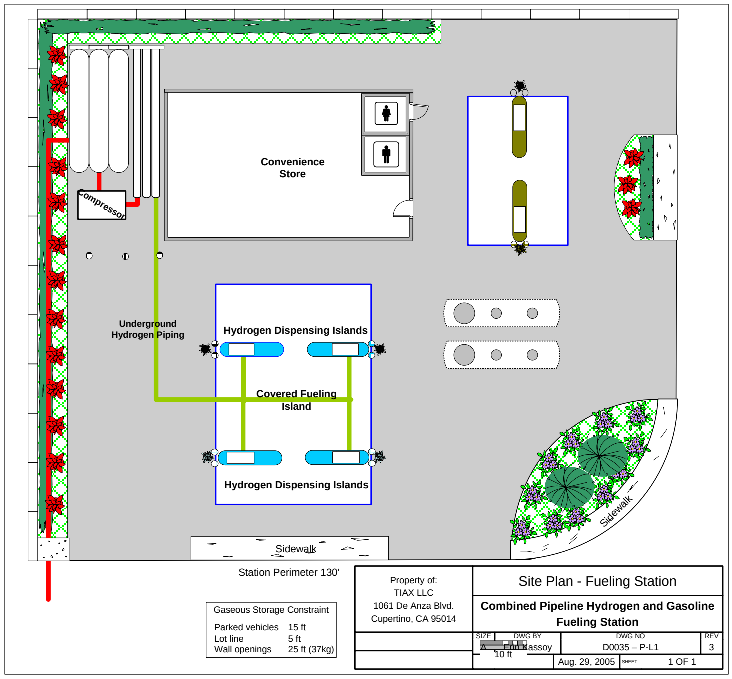



Figure 2-40 Pipeline Supplied Fueling Station Site Plan

If the hydrogen demand is between 4,000 and 6,000 kg/day the station will require more than 6 dispensers to appropriately meet that demand. In that case the overall width of the station is increased and a set of dispensers is added such that each canopy will have two or more rows of dispensers. As stated earlier, stations with six or more hydrogen dispensers will not distribute gasoline.

*Liquid Hydrogen Supplied Fueling Station*

The liquid fueling stations have drastically different characteristics than either pipeline or tube trailer supplied stations as a result of the significantly larger setback distances required by the NFPA. Liquid trucks can deliver 4,110 kg to a refueling site. Since two truck deliveries are allowed per day, liquid hydrogen stations can be as large as the maximum size of 6,000 kg/day dispensing.

Unlike tube trailer supplied stations, liquid hydrogen at the fueling stations is pumped from the delivery truck to onsite liquid storage tanks. Trailers do not remain on-site between deliveries. Therefore it is not necessary to have designated parking spots for the trailers as it is assumed that they can easily maneuver within the large setback distances around the liquid storage tanks. Fueling stations still require high-pressure cascade storage as the hydrogen is still being supplied to the vehicles in a gaseous state. In place of a compressor, the liquid stations have liquid pumps and vaporizers. While they are large pieces of equipment, it is assumed that these components can fit within the significant setback distances surrounding the liquid hydrogen storage. All liquid hydrogen storage tanks are spherical and sized based on the demand of the station. The size of these liquid hydrogen storage tanks depend on how often the liquid hydrogen will be delivered to the station and how much hydrogen is delivered during each delivery (which depends on the number of stops that the truck makes during each delivery). If the station requires at least one delivery every day, the tank is sized to hold twice the capacity of the liquid delivery truck. The larger tank allows for irregular deliveries to be handled by the station. If the delivery frequency is less than once per day, the tank is oversized by a factor of 1.5, which is smaller because it is less likely that two truck deliveries will come back-to-back, as they might when daily deliveries are required. Figure 2-41 shows a liquid supplied station with four hydrogen dispensers (~2,000-2,500 kg/day).

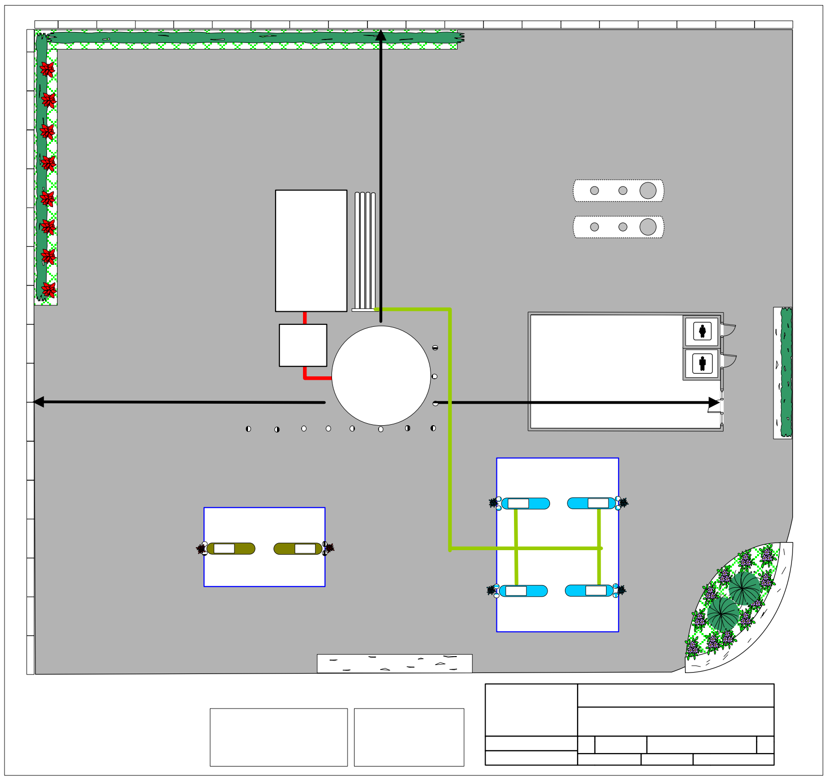



Figure 2-41 Liquid Hydrogen Supplied Fueling Site Plan

Figure 2-41 clearly illustrates the significant effect of the larger setback distances. This significantly increased area requirement may make the use of liquid hydrogen delivery difficult in already-crowded urban areas.

*Results*

The results of the model are shown below in two different formats, showing the area allocation as a function of both average daily demand and number of dispensers.

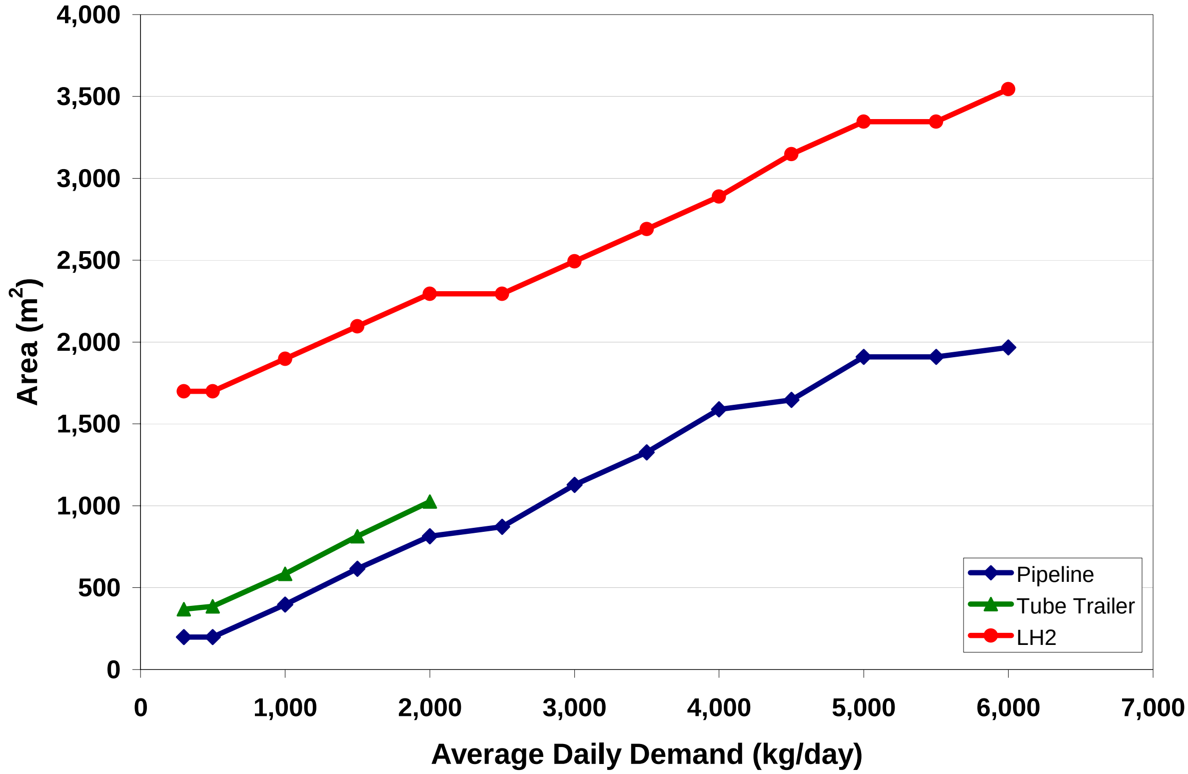



Figure 2-42 Fueling Station Area for Hydrogen Delivery (vs. Demand)

As illustrated in Figure 2-42, the pipeline supplied stations are the most efficient method – from a land-use perspective – for delivering hydrogen. The pipeline scenario is differentiated from the tube trailer scenario because it does not require parking area for two trailers and differentiated from the liquid scenario due to the different setback distances. Figure 2-42 also illustrates the significant difference between the size of gaseous and liquid stations. The relatively flat sections in the projections are a result of incremental demand level changes that do not necessitate an additional dispenser. This is better illustrated in Figure 2-43.

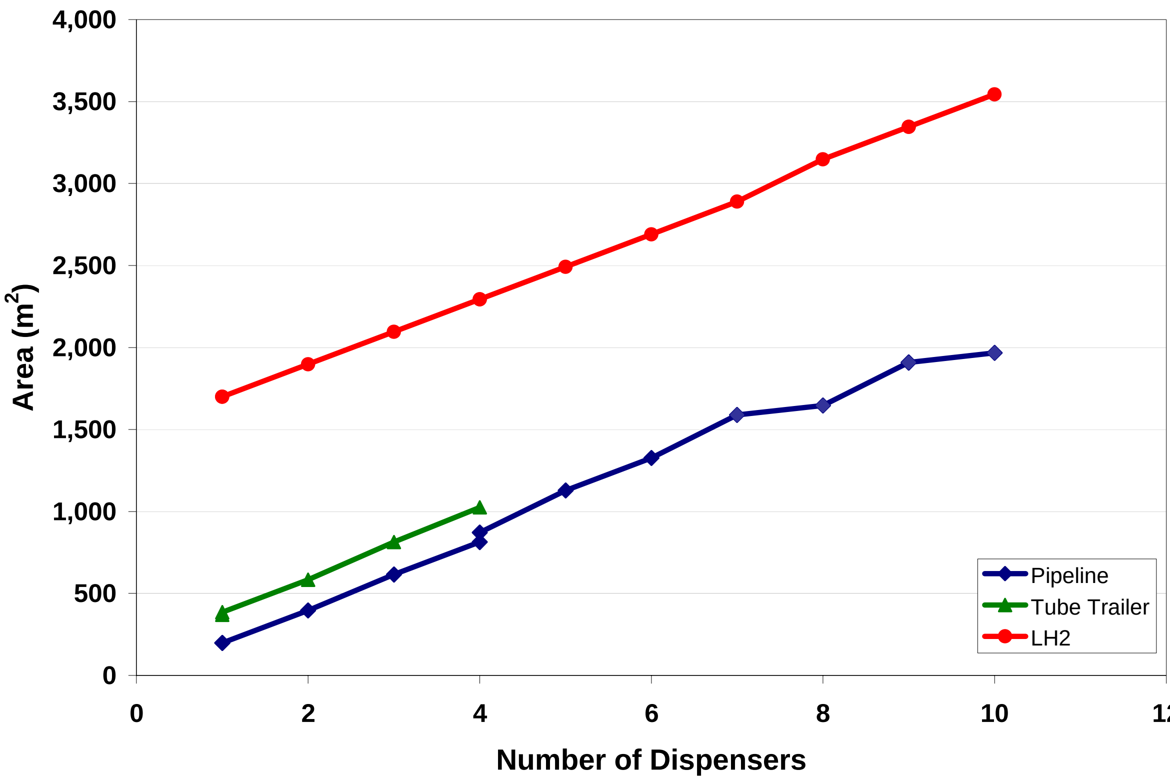



Figure 2-43 Fueling Station Area for Hydrogen Delivery (vs. Dispensers)

As illustrated in Figure 2-43, the overall area requirement tracks more consistently with the number of dispensers than with fuel demand. In the case of the pipeline, the step function at high volumes results from adding additional dispensers.

These results have been included in the H2A Delivery Models in order to give the user a better approximation of the land requirements necessary for hydrogen delivery.

### 2.2.11 Terminal and Refueling Station Liquid Storage

#### *2.2.11.1 Terminal Liquid Storage*

Currently, the most economic way to store large volumes of liquid hydrogen is a double-wall Horten sphere. The tanks consist of an outer shell of carbon steel, typically an SA516, and an inner shell of stainless steel, typically a Type 304. The spheres have a maximum allowable working pressure of 75 psi (5.17 bars). There is a 4- inch annular space between spheres that is filled with perlite.

Budgetary prices were obtained from CB&I for two Horten tank sizes: a single 3,500 $m^3$ tank; and two 1,800 $m^3$ tanks. The costs were $7.65 million for the former, and $4.975 million each for the latter. The estimates are subcontract prices, and include the foundations. For a complete installation, tank instrumentation and connections to the plant utilities will be required; for the purposes of the analysis, an allowance of 5 percent has been added for these items. A graph of

Horten tank costs, as a function of storage volume, is shown as the last two points in Figure 2-44. The subcontract prices have been converted to uninstalled prices by using an installation factor of 1.3; i.e., the uninstalled cost for the 1,800 $m^3$ tank is calculated as follows: $4,975,000 x 1.05 / 1.3 = $4,018,000. Also shown in the figure are estimated uninstalled liquid tank costs from the H2A Delivery Models Version 1 for storage volumes between 100 and 800 $m^3$. The tank costs follow a very consistent trend.

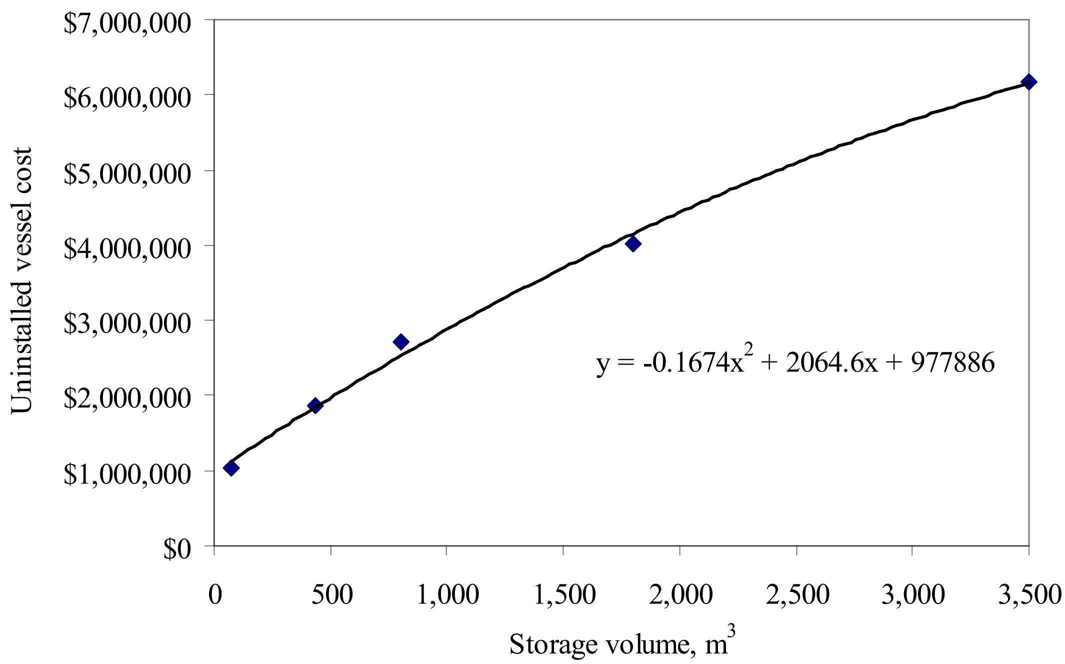



Figure 2-44 Uninstalled Liquid Tank Costs as a Function of Volume

#### *2.2.11.2 Refueling Station Liquid Storage*

As noted in Section 2.2.10, liquid hydrogen refueling stations are assumed to have liquid hydrogen storage facilities. As mentioned previously, the size of these liquid hydrogen storage tanks depend on how often the liquid hydrogen will be delivered to the station and how much hydrogen is delivered during each delivery (which depends on the number of stops that the truck makes during each delivery). If the station requires at least one delivery every day, the tank is sized to hold twice the capacity of the liquid delivery truck. The larger tank allows for irregular deliveries to be handled by the station. If the delivery frequency is less than once per day, the tank is oversized by a factor of 1.5, which is smaller because it is less likely that two truck deliveries will come back-to-back, as they might when daily deliveries are required. These storage vessels are similar to those at liquid hydrogen terminals in that they are spherical in shape but they are much smaller than those at terminals. Typical liquid hydrogen volumes at refueling stations are of the order of tens of cubic meters while those at terminals are typically in the range of hundreds to thousands of cubic meters. Liquid hydrogen refueling stations will also have small scale cryogenic pumps and vaporizers to allow the liquid hydrogen to be removed from storage, vaporized and sent to the cascade system for ultimate dispensing in gaseous form.

For liquid storage at refueling stations, a value for uninstalled cost of $70/kg of hydrogen stored is used in the H2A Delivery Models. This value comes from discussions with vendors when the H2A Delivery Models Version 1 was first generated. When an installation factor of 1.2 is applied, this value represents an installed cost of $84/kg.

### 2.2.12 Geologic Storage

One of the options available in the H2A Delivery Models is the selection of gaseous geologic storage to meet the peak summer demand and to meet the total demand during the winter annually-scheduled shutdown of the hydrogen production plant. The summer demand peak is entered in the model as a percent of the average daily demand along with the duration. The default values are 10% above the average for 120 days (4 months). The winter plant outage default is 10 days. The geologic storage is sized to meet the larger storage need of these two situations.

H2A Delivery Models Version 2.0 is based on the use of salt caverns for underground storage of hydrogen. Other geologic storage technologies are not yet in the model. This technology was chosen for four reasons. First, there are two existing hydrogen salt caverns in the U.S. in Texas. We are not aware of any other types of geologic storage in use for hydrogen. Second, salt caverns are known for their capability to be cycled much more rapidly than other types of underground storage. The daily release from salt caverns can be as high as 11 percent of the working gas capacity (a 10 percent default value is used in the model) whereas 2 to 3 percent is typical for other underground storage options. As one of the objectives of geologic storage is to fully meet the hydrogen demand during times of production plant shutdown, the capacity of other geologic storage options would have to be 3 to 5 times greater than for a salt cavern. Third, the amount of base or cushion gas required in salt caverns appears to be lower than for the other options. Values as low as 20 percent of the working capacity have been reported, whereas requirements for other underground options appear to be in the 40 to 50 percent range. Thus the capital requirement for cushion gas in salt caverns is considerably less than for other options. Fourth, although the data are scattered and not always consistent, H2A Delivery Models developers were able to find more usable cost information for salt caverns than for other options. The initial phase of the Saltville natural gas storage facility in southwest Virginia served as the reference point for the costs in the model. These costs are in line with some cost information obtained from ConocoPhillips who are utilizing one of the two existing hydrogen geologic salt caverns in the U.S. located in Texas.

It is assumed that the geologic facility is located at or near to the hydrogen production facility. The delivery infrastructure costs would not be significantly affected as long as the geologic storage is located close to the production site, along the gaseous pipeline or near a city gate terminal in a mixed mode delivery pathway. If the pipeline delivery pathway has been selected, the cavern is filled by drawing from hydrogen at a pressure equal to the maximum pipeline pressure and discharges hydrogen at this same pressure. If the gaseous-hydrogen truck delivery pathway has been selected, the cavern withdraws hydrogen at a pressure equal to the hydrogen pressure at the gaseous terminal and ultimately discharges at approximately this same pressure. These pressures are consistent with the basic assumption that both the geologic storage facility and the gaseous-hydrogen terminal (if appropriate) are located at or adjacent to the hydrogen production facility.

Input to the geologic storage facility in the H2A Delivery Models includes the summer surge percentage (expressed as the percent above the annual average daily demand), the number of days that the surge continues, the number of days that the winter demand lasts, the number of days of scheduled production- plant outage, the maximum and minimum cavern pressures (i.e., full and with only the base or cushion gas), the hydrogen pressure from which the cavern is fed and the pressure to which the hydrogen is fed upon withdrawal from the cavern, the maximum allowable discharge rate, and the maximum allowable rate at which the cavern can be filled.

The H2A Delivery Models use the input parameters to determine the quantity of hydrogen that must be placed in geologic storage. This quantity is the greater of the quantity needed to meet the summer surge or the quantity needed to meet demand during the production-plant shutdown. In other words, the model determines this quantity under the assumption that the production-plant shutdown will be during the winter months of lowest demand. Another assumption in determining this quantity of hydrogen is that the amount of hydrogen consumed during the summer surge is equal to the difference between the amount of hydrogen actually consumed during the winter period (the lowest demand time of the year) and the amount that would be consumed if the annual-average daily demand were to exist over the same period. Based on the maximum and minimum pressures (i.e., full and empty except for cushion gas) the model determines the actual design capacity of the cavern.

The H2A Delivery Models then do an internal check to assure that the required hydrogen withdrawal rate is not greater than the input value. Should this occur, the model re-calculates the cavern volume so that this limitation is not exceeded.

Using the above calculated information along with user supplied values for numbers of compressors to be used, compression ratios, and compressor efficiencies, the H2A Delivery Models conduct several internal checks on hydrogen volumes and flow rates and estimate energy requirements for the compressors. The compressors are sized based on the greater of the following two pressure ratios: Maximum cavern pressure/inlet (fill) pressure or Outlet (discharge)/Minimum cavern pressure. Compressors are designed to handle one-half the total hydrogen throughput and an equally sized installed spare unit is also available for reliability purposes. In Version 2.0, the cavern must be completely filled, and then completely discharged, i.e., intermediate filling is not allowed.

Based on the physical parameters as input by the user and calculation as described above, the H2A Delivery Models then determines the capital and operating cost for the geologic storage facility. Many of the capital cost components are scaled from information available from the Saltville natural gas storage facility in southwest Virginia. These cost equations are presented below. Other costs, e.g., compressors, are calculated in a manner consistent with costs for equivalent equipment in other parts of the H2A Delivery Models.

- Installed Cavern Cost = 3,738,563 * (cavern $Nm^3$/19,000,000)$^{0.7}$
- Installed Miscellaneous Equipment Cost = 1,906,484 * (cavern $Nm^3$/19,000,000)$^{0.7}$

### 2.2.13 Oversize Transmission Pipeline as Storage

As discussed in this report, in the standard pipeline delivery pathways modeled in the H2A Delivery Models, low pressure gas storage is used to handle the hourly demand variations at the refueling site (see Section 2.1.9 for Pathways 8 and 9). Pipeline Delivery Pathway 10 (see Section 2.4) consists of the following components: a hydrogen production plant; geologic storage; an oversize transmission pipeline to the city gate; distribution pipelines to the refueling stations; and refueling stations, which include a compressor and a cascade charging system. In this case, the oversized transmission pipeline is used for sufficient storage to handle the hourly refueling site demand variations. If the transmission pipeline is of sufficient length, this can be the most cost effective delivery infrastructure option.

As discussed for Pathways 8 and 9, the low pressure storage vessels at the refueling station accommodate the difference between the constant flow rate from the distribution pipeline and the hour-by-hour variation in the refueling demand (see Section 2.1.9). In principle, an oversize transmission pipeline can provide the same function as the low pressure storage vessels. Therefore, if the pipeline infrastructure is extensive enough, oversized pipeline storage might be the lowest cost option for storage to handle the hour to hour variation in demand at refueling stations over the course of each day. Calculations show that only in cases of long (>100 miles or 160 km) and large (>6 inches or 15.24 cm) diameter transmission is there sufficient potential storage volume in the pipeline infrastructure without requiring such a large increase in diameter to negate the potential cost advantage.

An oversize pipeline is defined as one in which the diameter is larger than that required to transmit the design flow rate at the design pressure loss. For example, a 300 km pipeline, transmitting 286,000 kg/day at an inlet pressure of 1,000 psi (69 bars) and an outlet pressure of 700 psi (48.3 bars), requires a diameter of 17 inches. However, if the diameter is increased to, say, 22 inches, the inlet pressure can be as low as 790 psi (54.48 bars) and still achieve an outlet pressure of 700 psi (48.3 bars)at the design flow rate. Thus, by varying the inlet pressure to values in the range of 790 psi to 1,000 psi (54.48 bars to 69 bars), the corresponding changes in the gas density allows the pipeline to function as an elongated storage vessel.

The principal motivation for an oversize pipeline is economics. In particular, the unit price for steel in a pipeline, in $/lb, is lower than in a pressure vessel. In addition, the expensive heads on a pressure vessel are not required on a pipeline, and the inspection and certification costs for a pipeline are much lower than for a pressure vessel.

To determine the required sizes and economic benefits of an oversize pipeline, an Excel spreadsheet model was developed, which modeled the transient performance of the pipeline over a 24 hour period. The spread sheet model included the following components:

- Uniform flow model
- Refueling station demand profile
- Transmission pipeline transient model.

#### *2.2.13.1 Uniform Flow Model*

The uniform flow model determines the minimum pipeline diameter required to transmit the daily city demand at the specified pipeline inlet and outlet pressures. An example calculation for a 300 km (186 mile) pipeline, with inlet and outlet pressure of 1,000 psi (69 bars) and 700 psi (48.3 bars), respectively, is shown in Table 2-25. The model divides the pipeline into 20 equal length segments, and selects a baseline diameter of 60 inches. For the first segment, the model calculates the gas density, velocity, Reynolds number, friction factor, pressure losses, and section outlet pressure. The outlet pressure from the first segment becomes the inlet pressure for the second, and the calculations are repeated for the balance of the segments. The model then iterates on the diameter to achieve the desired outlet pressure of 700 psi (48.3 bars).

Table 2-25 Uniform Flow Transmission Pipeline Model

| Distance, miles | Section inlet pressure, $lb_f/in^2$ | Density, $lb_m/ft^3$ | Velocity, ft/sec | Reynolds number | Friction factor | Pressure loss, ft | Pressure loss, $lb_f/in^2$ | Section outlet pressure, $lb_f/in^2$ | Density, $lb_m/ft^3$ | Mass in segment, $lb_m$ |
|---|---|---|---|---|---|---|---|---|---|---|
| 0 | 999 | 0.347 | 26.8 | 2,195,167 | 0.013 | 5,023 | 12.1 | 987 | 0.343 | 13,172 |
| 9 | 987 | 0.343 | 27.1 | 2,195,167 | 0.013 | 5,142 | 12.2 | 975 | 0.339 | 26,035 |
| 19 | 975 | 0.339 | 27.4 | 2,195,167 | 0.013 | 5,266 | 12.4 | 963 | 0.335 | 25,721 |
| 28 | 963 | 0.335 | 27.8 | 2,195,167 | 0.013 | 5,397 | 12.5 | 950 | 0.331 | 25,403 |
| 37 | 950 | 0.331 | 28.1 | 2,195,167 | 0.013 | 5,535 | 12.7 | 937 | 0.326 | 25,081 |
| 47 | 937 | 0.326 | 28.5 | 2,195,167 | 0.013 | 5,680 | 12.9 | 924 | 0.322 | 24,754 |
| 56 | 924 | 0.322 | 28.9 | 2,195,167 | 0.013 | 5,833 | 13.0 | 911 | 0.318 | 24,422 |
| 65 | 911 | 0.318 | 29.3 | 2,195,167 | 0.013 | 5,995 | 13.2 | 898 | 0.313 | 24,086 |
| 75 | 898 | 0.313 | 29.7 | 2,195,167 | 0.013 | 6,166 | 13.4 | 885 | 0.309 | 23,744 |
| 84 | 885 | 0.309 | 30.1 | 2,195,167 | 0.013 | 6,347 | 13.6 | 871 | 0.304 | 23,398 |
| 93 | 871 | 0.304 | 30.6 | 2,195,167 | 0.013 | 6,540 | 13.8 | 857 | 0.300 | 23,045 |
| 103 | 857 | 0.300 | 31.0 | 2,195,167 | 0.013 | 6,745 | 14.0 | 843 | 0.295 | 22,687 |
| 112 | 843 | 0.295 | 31.5 | 2,195,167 | 0.013 | 6,963 | 14.3 | 829 | 0.290 | 22,323 |
| 121 | 829 | 0.290 | 32.1 | 2,195,167 | 0.013 | 7,196 | 14.5 | 815 | 0.285 | 21,953 |
| 130 | 815 | 0.285 | 32.6 | 2,195,167 | 0.013 | 7,445 | 14.7 | 800 | 0.280 | 21,575 |
| 140 | 800 | 0.280 | 33.2 | 2,195,167 | 0.013 | 7,712 | 15.0 | 785 | 0.275 | 21,191 |
| 149 | 785 | 0.275 | 33.8 | 2,195,167 | 0.013 | 8,000 | 15.3 | 770 | 0.270 | 20,799 |
| 158 | 770 | 0.270 | 34.5 | 2,195,167 | 0.013 | 8,310 | 15.6 | 754 | 0.265 | 20,399 |
| 168 | 754 | 0.265 | 35.2 | 2,195,167 | 0.013 | 8,646 | 15.9 | 738 | 0.259 | 19,991 |
| 177 | 738 | 0.259 | 35.9 | 2,195,167 | 0.013 | 9,010 | 16.2 | 722 | 0.254 | 19,574 |
| 186 | 722 | 0.254 | 36.7 | 2,195,167 | 0.013 | 9,407 | 16.6 | 705 | 0.248 | 9,574 |
| | | | | | | | | | | --------- |
| | | | | | | | | | | 458,929 |

### 2.2.13.2 Refueling Station Demand Profile

Evaluating the refueling profile over the course of the day is important due to the inter-hour effects of the demand curve on storage and compression requirements. Designing the system to meet only an hourly demand can adversely affect the performance in subsequent hours, especially during peak periods. For example, if 75 kg/hr of compressor capacity and 25 kg of useful storage is used to meet an hourly demand of 100 kg, the storage will be empty at the end of the hour, and the system will be unable to meet any demand greater than 75 kg in the following hour.

The Chevron gasoline station refueling profile, discussed in Section 2.1.4, indicates demand on an hour-by-hour basis. However, to accurately model the state of the charging system in a refueling station, a series of assumptions were made regarding the demand within the hour. A constant flow rate is the simplest method for allocating demand. However, the approach cannot evaluate the station at full fueling capacity; i.e., all hoses in operation simultaneously. To simulate a system which is sufficiently robust to accommodate most situations, a demand profile was developed in which the station operates at full fueling capacity for the first 5 minutes of the hour. The balance of the hourly demand is distributed evenly among the remaining 55 minutes. During hours of low demand, the first 5 minutes of peak flow often fulfills the entire hourly demand. However, this is not the case during peak demand. As shown in Figure 2-45, the 5 minute/55 minute delivery profile yields periods of high demand, separated by longer periods of low or zero demand.

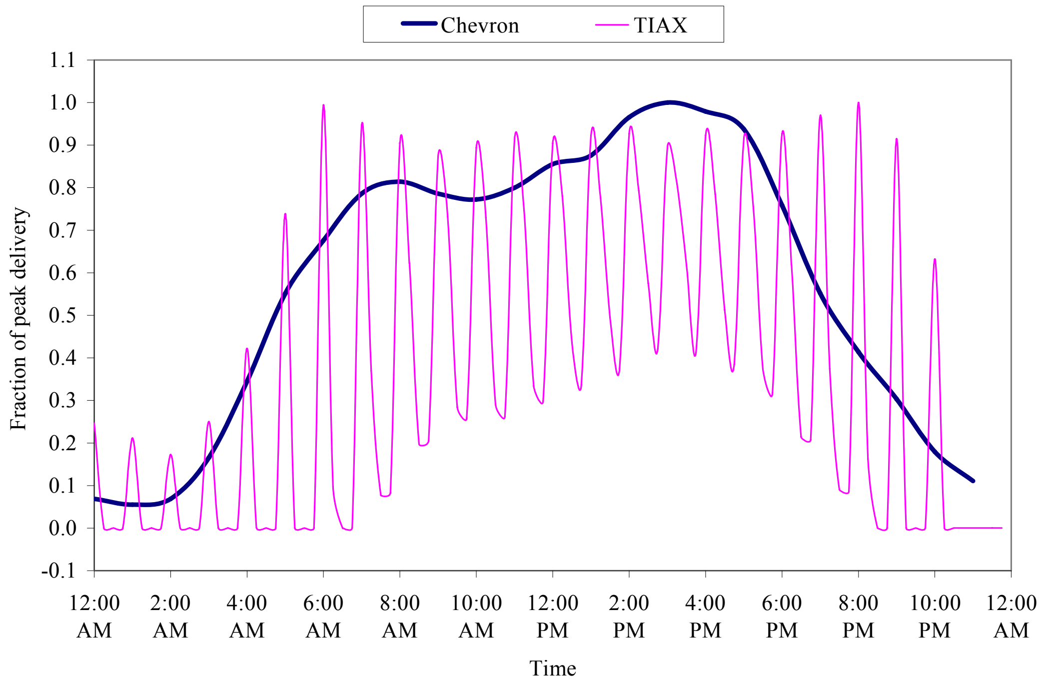



Figure 2-45 Refueling Station Demand Over a 24 Hour Period

#### *2.2.13.3 Transmission Pipeline Transient Model*

An Excel model was developed, which calculated the transient pressure and flow distribution in the transmission pipeline. The model divided a 24 hour period into 96 15-minute periods. The (constant) flow rate into the pipeline is defined by the production plant output, and the flow rate from the pipeline is defined by the varying demand, as illustrated in Figure 2-45. A trial inlet pressure at 12:00 am, and a trial pipeline diameter are selected, from which the pipeline outlet pressures are calculated over the course of the day. If the outlet pressure anytime during the day is less than 700 psi (48.3 bars), then either the starting pressure at 12:00 am, or the pipeline diameter, is too low. Similarly, if the outlet pressure anytime during the day is greater than 700 psi (48.3 bars), then either the starting pressure at 12:00 am, or the pipeline diameter, is too high. An iterative process is required to select the starting pressure and the pipeline diameter which provides the smallest pipeline consistent with the outlet pressure requirements.

An example of the final pressure distribution in a 300 km pipeline is shown in Figure 2-46.

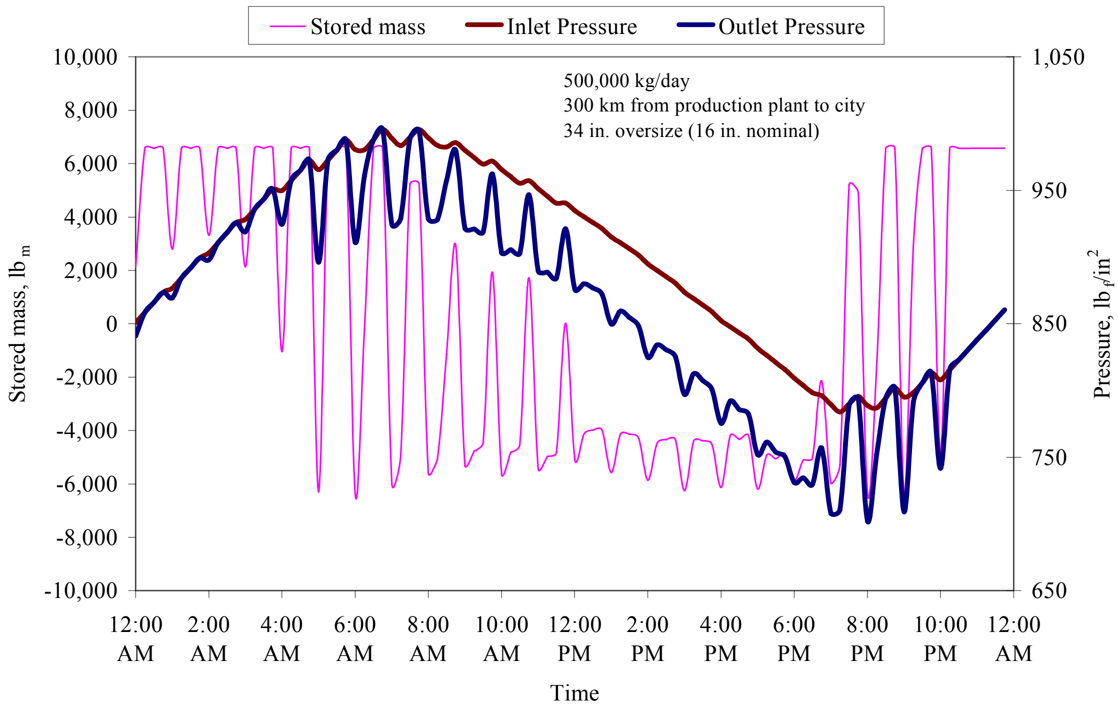



Figure 2-46 Pressure Distribution in Oversize Transmission Pipeline

As discussed in Section 2.3.2, there are various combinations of refueling station compressor and cascade charging system capacities that satisfy the minute-by-minute refueling demand. To determine the combination of transmission pipeline size, refueling station compressor capacity, and cascade system capacity which results in the lowest capital cost, parametric capital cost estimates were developed for the following items:

- Transmission pipeline: The pipeline diameter is a function of the refueling station compressor capacity. Pipeline costs were developed using the H2A Delivery Model cost equations.
- Transmission pipeline compressor: The compressor power requirements are a function of the design flow rate and the inlet pressure. Compressor costs were developed from the equations presented in Section 2.2.5.
- Transmission pipeline compressor energy: Compressor power requirements are calculated for each of the 96 15-minute periods each day, based on the flow rate and the inlet pressure for the period. The energies are summed over the course of both the day and the year, and the annual energy is converted to an equivalent capital cost using the commercial electric energy rates in the H2A Delivery Models and a representative fixed charge rate of 12.5 percent.
- Refueling station compressor and cascade charging system. The allowable combinations of compressor and cascade system capacities, and the corresponding capital costs, are derived from the curves presented in Section 2.3.2.

The results of the parametric cost calculations for a city located 300 km from the production plant and containing 286 refueling stations, each with a daily capacity of 1,000 kg, are shown in Figure 2-47. The peak to average delivery ratio, shown in the figure abscissa, is the refueling station compressor capacity divided by the average hydrogen dispensed in a 24 hour period. The delivery + refueling station costs, shown in the figure ordinate, is the sum of the following: transmission pipeline cost; pipeline compressor cost; equivalent capital cost for the energy to operate the pipeline compressor; refueling station compressor cost; and cascade charging system cost.

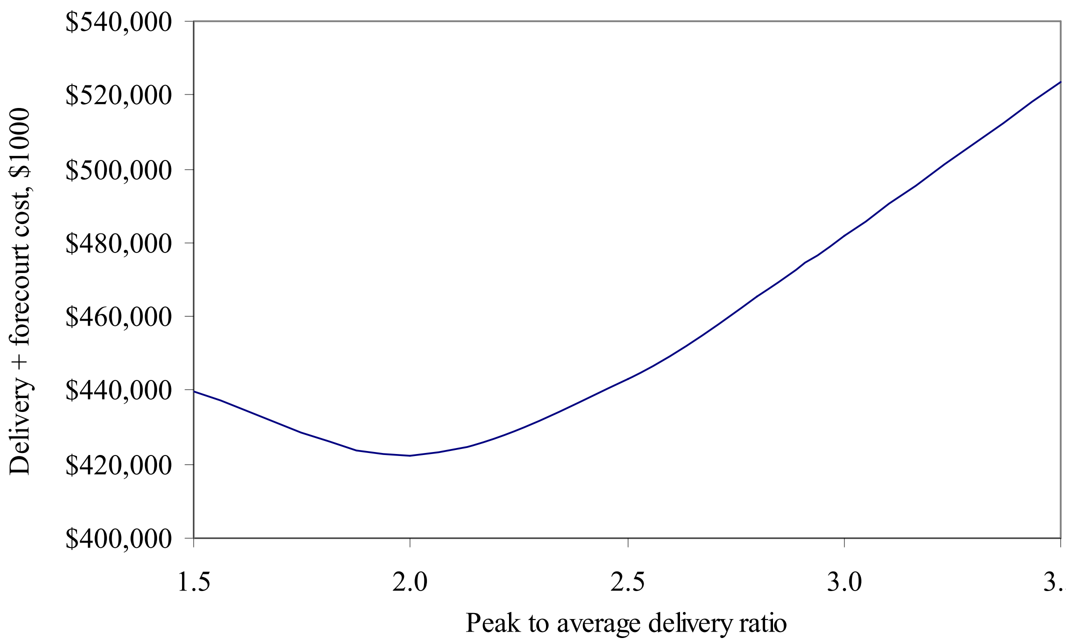



Figure 2-47 Pathway 3 Delivery System Optimization

For the combination of design parameters; the optimum delivery pathway consists of the following items:

- 22 inch (55.88 cm) diameter transmission pipeline
- 4,250 kWe pipeline compressor
- 83 kg/hr refueling station compressor
- 198 kg cascade charging system.

### 2.2.14 Hydrogen Losses

Each component within the delivery infrastructure may include hydrogen losses. For example, liquid hydrogen stored in a well-insulated storage vessel may boil-off, and be lost through a pressure relief valve. These losses become important variables when calculating the hydrogen required by each component in a pathway, and for calculating the design flow rate for each component.

The Nexant team consulted with a variety of industry suppliers to determine the anticipated losses for a range of components. The values shown in Table 2-26 are those used in the H2A Delivery Models Version 2.

Table 2-26 Hydrogen Losses in Transmission and Distribution

| Tab | Loss | Loss Basis |
|---|---|---|
| Refueling Station – GH2 | 0.5% | Compressor throughput |
| Refueling Station – LH2 | 0.25%/day for boil-off | Total capacity of storage tank |
| Truck Tube Trailer – GH2 Delivery | No losses | |
| Compressed Gas Terminal | 0.5% | Truck loading compressor throughput |
| Truck-LH2 Delivery | 0.5% (recovered)* | Hydrogen loading operation |
| | 6% | Hydrogen unloading operation at refueling stations |
| Truck-LH2 Delivery | 0% during transit | This is a regulation |
| Liquid Terminal | 0.25%/day for boil-off | Total capacity of storage tank |
| Liquefier | 0.5% | Liquefier throughput |
| Compressor | 0.5% | Compressor throughput |
| Pipeline: Transmission | 778 kg of $H_2$/ mile/yr | Pipeline transmission line |
| Pipeline: Distribution | 156 kg of $H_2$/ mile/yr | Pipeline distribution |
| Geologic Storage | 0.5% | Compressor throughput |

* *The truck-liquid delivery loading losses are recovered and recycled to the terminal liquefier.*

The primary source of losses in the gaseous-based components is compressor related. As the hydrogen is processed through the compressor, it leaks past the seals or is absorbed in the compressor lubrication oil.

The hydrogen losses in the pipeline infrastructure are estimated from natural gas losses in the current natural gas infrastructure. The basis for the natural gas losses is a detailed study by the Gas Research Institute done for the EPA in 1996 and which is updated by EPA yearly.[38] The latest information available is for 2004. It estimates methane leakage from the natural gas transmission and distribution line infrastructure to be 1,827 million grams, and 1,291 million grams respectively. The natural gas transmission pipeline infrastructure has approximately 300,000 miles (480,000 km) of pipeline. The distribution infrastructure has approximately 1,000,000 miles (1,600,000 km) of pipelines. Converting these natural gas mass leakage rates to volume and then converting this volume to kg of hydrogen, one gets the values shown in Table 2-23 above. This assumes that hydrogen gas leakage will be similar to natural gas leakage in pipeline infrastructure and is only a rough approximation. Most of the leakage of gases in pipeline infrastructure is from valves, fittings, etc, rather than from the pipeline steel itself.

For the liquid components, there are two types of losses: component related (i.e. liquefier losses); and boil-off related. Therefore, at the liquid dispensing station and the liquid terminal, the existence of liquid hydrogen storage tanks means that boil-off losses will occur.

At the liquid hydrogen refueling stations, approximately 6 percent of the truck tanker size is lost when the hydrogen is unloaded from the truck. This loss occurs because of the difficulty in initially maintaining a low enough temperature in the transfer system, leading to a significant loss. There could be an option in the liquid hydrogen refueling station to use a compressor to recover the hydrogen losses, but this option was found to be cost prohibitive. No hydrogen is lost during the filling of the liquid hydrogen delivery truck because the loading terminal is assumed to be co-located with a liquefier, and any losses are simply recycled to the inlet of the liquefier.

[38] Estimate of Methane Emissions from the U.S. Natural Gas Industry, Gas Research Institute and updated information; wwww.epa.gov

## 2.3 DELIVERY SYSTEM STORAGE AND REFUELING SITE DESIGN AND OPTIMIZATION

### 2.3.1 Hydrogen Demand and Supply Variations and Impact on Infrastructure Storage

Figure 2-48 shows the average daily variation in hydrogen supply and demand as modeled in the H2A Delivery Models. The production is assumed to experience a scheduled outage during the lower demand winter season. The scheduled outage is assumed to occur for 10 days (default value); however, such duration can be modified to study the effect of this parameter on the hydrogen delivery cost for various scenarios. The hydrogen daily demand is assumed to experience a seasonal variation with a 10% increase in demand above the yearly average daily demand for 120 days during the summer season, with a corresponding decrease in demand in the winter season (default values). The percentage increase and the duration of such increase can be modified to investigate the effect of these parameters on the hydrogen delivery cost.

In order to avoid the interruption in hydrogen supply and the high cost associated with scaling the delivery components to meet the increase in demand during the summer time, storage infrastructure is sized to absorb the impact of such variation in daily supply and demand. The storage infrastructure can be in the form of geologic storage, which is located near the production site, or in the form of liquid storage in large cryogenic vessels. The liquid hydrogen storage and the associated liquefier are located near the production site except for the mixed-mode liquid hydrogen delivery (i.e., gaseous delivery by pipeline to city gate and LH2 distribution to refueling stations in the city, Pathway 3) in which the liquefier and the liquid storage vessels are located near the city gate (see Section 2.4).

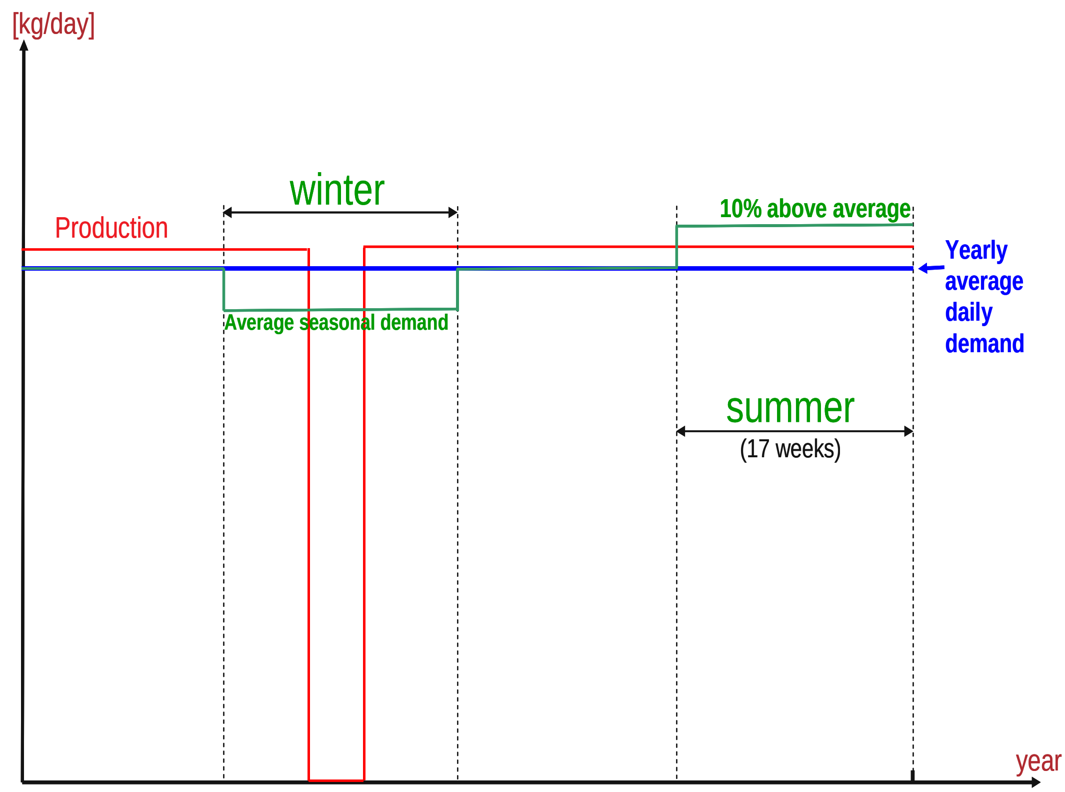


Figure 2-48  Hydrogen Supply and Demand Average Daily Variations

Variation in hydrogen demand occurs daily during any given week as well as hourly during any given day as shown in Figure 2-49 and Figure 2-50. The peak demand occurs on a Friday between 4:00-6:0 PM, according to refueling profiles provided by Chevron. The Friday peak is assumed to be 8% above the weekly average daily demand, while the hourly peak is assumed to be 87% above the daily average hourly demand. The daily and hourly variations are most economically handled by storage at the refueling station site. Such storage is in the form of low pressure storage in the case of pipeline delivery, tube-trailers in the case of compressed hydrogen gas delivery via tube-trailers, or liquid cryogenic storage tanks in the case of liquid hydrogen truck deliveries.  This arrangement eliminates the need for and the cost associated with scaling up the upstream components to handle the daily and hourly variation in demand if the storage were to be located upstream of the refueling station, e.g., at a gaseous terminal. Storage upstream of the refueling station should be considered as an option only if locating such storage at the refueling sites is not possible due to space limitations.

Figure 2-50 shows the Friday hourly demand profile at the refueling station over the 24 hours of that day. The area under the curve above the daily average hourly demand (during the peak demand hours) represents the minimum storage requirement to satisfy the station demand during peak hours. For the Chevron profile shown in the figure, such storage requirement is approximately 30% of the total daily demand. For pipeline deliveries, the low-pressure storage at the refueling station is sized at 30% of the total daily demand based on such analysis. However, for truck deliveries via compressed gas tube-trailers or liquid trucks, the tube-trailer holding capacity or the refueling station liquid storage tank would satisfy such increase in demand during peak hours without a need for additional storage, since truck deliveries to refueling stations do not exceed two deliveries per any given day in the delivery models, and thus refueling stations which are served by truck deliveries would at least carry ½ of the total daily demand in tube-trailers or liquid storage tanks, in excess of the 30% minimum storage requirement shown in Figure 2-50.

A conservative assumption of occupying all the dispensing hoses at the first period of each hour is made in the model to ensure adequate sizing of the refueling station components in such an extreme possibility. Since the relative increase in demand in such a short-duration spike at the first period of each hour is typically small, this spike in demand is typically handled at a minimum cost by a corresponding increase in the size of the cascade charging system as described later in Section 2.3.2.

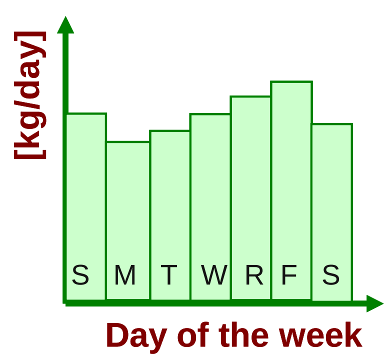



Figure 2-49  Hydrogen Weekly Average Daily Demand Variation

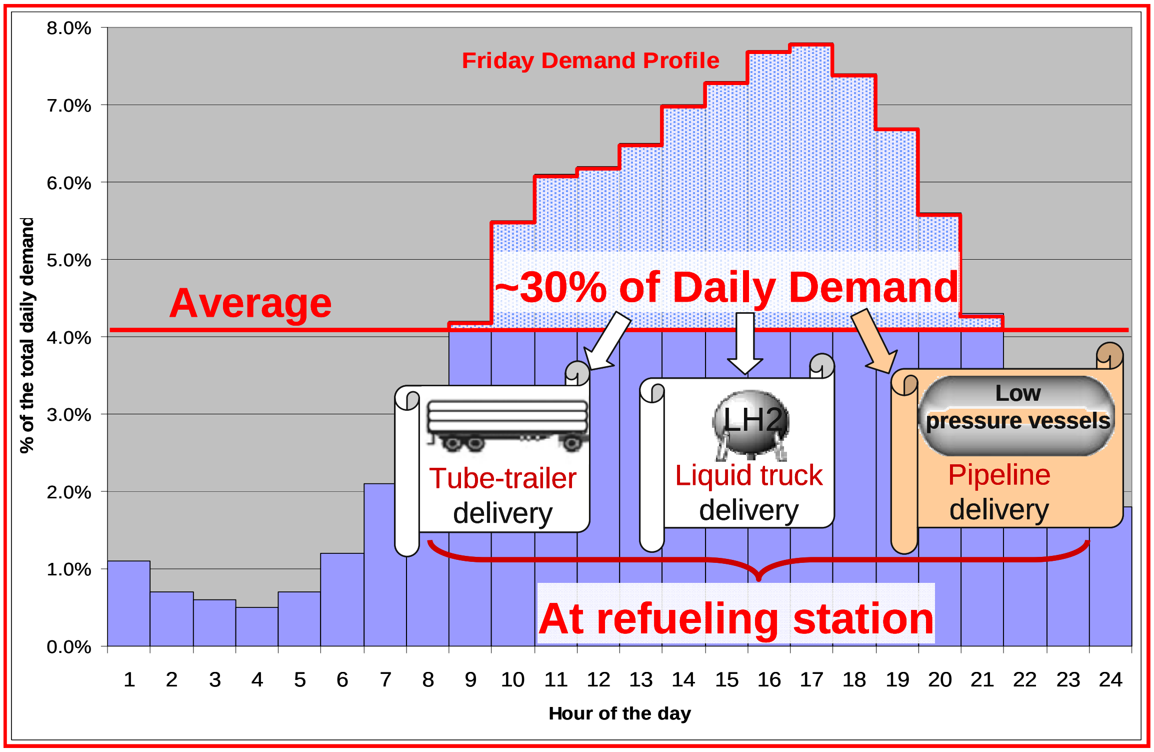



Figure 2-50 Hydrogen Daily Average Hourly Demand Variation

### 2.3.2 Refueling Station Design Requirements

#### *2.3.2.1 Introduction*

This section details the methodology for determining the optimum configuration of the refueling station. The principal elements addressed include:

- Dispenser configuration
- Demand profile
- Cascade Charging System
- Cost optimization

#### *2.3.2.2 Dispenser Configuration*

To determine the number of dispensers required for a refueling station, certain performance metrics were equated with those of standard gasoline stations. The metric deemed most important was the 'hose occupied fraction' (HOF). HOF is the fraction of time, on average, that each hose is occupied during the peak hour of a peak day. By determining the HOF of a gasoline station, the number of hoses/dispensers in a hydrogen refueling station can be selected such that the HOF is approximately equal to that of a gasoline station. For the purposes of the spreadsheet model, it is assumed each dispenser has two hoses, and can service two vehicles simultaneously.

The first step is to determine the HOF of a modern gasoline station. Data for a representative gasoline station, provided by Chevron, are shown in Table 2-27. The station, which dispenses a peak of 300,000 gallons per month, has 6 dispensers, and a total of 12 hoses. Assuming the peak quantity dispensed is 110 percent of that in an average month, based in the summer peak demand surge discussed in Section 2.1.4, the average monthly supplied is 273,000 gallons. The average month is used because the dispensers are not sized to meet the absolute peak demand within the year. Chevron data illustrating weekly and daily demand, described in Section 2.1.4, indicate the peak hour is generally Friday afternoon, between 4 and 5 pm. Assuming an average per-car consumption of 11 gallons, 70 cars are fueled during this hour.

To determine the HOF, the period each vehicle spends occupying a hose at the station must be estimated. Two factors determine this period: the first is the time required to pump the fuel, which depends on the fuel flow rate and the amount of fuel dispensed; and the second is the "linger time", which is the time a vehicle occupies the pump while not actively pumping fuel. Using data from OPW, a manufacturer of gasoline dispensing equipment, the hose flow rate is assumed to be 5 gallons per minute. Three minutes of linger time are assumed for the spreadsheet model calculations. As a result, each vehicle occupies the hose for an average of 5.2 minutes. Over the course of an hour at a station with 6 dispensers, the anticipated 70 vehicles will occupy the hoses for approximately 50 percent of the time. An example of the HOF calculations is presented in Table 2-27.

Table 2-27 Calculation of Hose Occupied Fraction for a Gasoline Station

| Fuel | Gasoline |
|---|---|
| Peak Monthly Supply gge/month | 300,000 |
| Monthly Peak Factor | 1.10 |
| Friday Peak Factor | 1.08 |
| Avg. Monthly Supply* gge/month | 272,727 |
| Avg. Daily Supply gge/day | 9,091 |
| Peak Daily Supply gge/day | 9,818 |
| Peak Hourly Fraction | 7.80% |
| Peak Hour Supply gge/hour | 766 |
| Avg. Fill Amount gal/fill | 11 |
| Peak Vehicle Fills fill/hr | 70 |
| Hose Flow Rate gal/min | 5 |
| Time Required for Fill min | 2.20 |
| Linger Time** min | 3 |
| Total Time at Pump min/fill | 5.20 |
| Total Occupied Hose Time*** min/hr | 362 |
| Available Hoses | 12 |
| Available Hose Time min/hr | 720 |
| **Hose Occupied Fraction** | **50.3%** |

*It is assumed that the interseasonal variations will be adsorbed by the system.

**TIAX Assumption: Linger time is the time that the vehicle is occupying the hose without actively filling the vehicle.

***For all hoses

With the necessary metrics determined, the number of dispensers required for a range of refueling station capacities were calculated, as shown in Table 2-28. The refueling parameters, such as the average quantity dispensed per fuel cell vehicle, are reasonably consistent with the information presented in Sections 2.1.2.

The data in Table 2-28 are plotted in Figure 2-51, which shows the number of dispensers for a range of refueling station capacities. The figure also shows the deviation from the ideal HOF of 50% becomes less pronounced at the larger station sizes. This may have cost benefits, as fewer dispensers may result in lower maximum flow rates, and therefore lower compressor and cascade charging costs.

Despite the scatter in the plot, the following equation can be used to calculate the required dispensers, based on the daily capacity of the refueling station:

$$\text{Dispensers} = \text{Daily Capacity} / (305.85 * \text{Daily Capacity}^{0.0763})$$

Knowing the number of dispensers for a refueling station capacity, it is possible to calculate the maximum possible flow rate. The maximum rate is crucial to calculating the required size of the refueling station compressor and cascade charging system.

## Table 2-28 Refueling Station Dispenser Calculations

| Daily Average Demand (kg/day) | Demand Multiplier | Daily Demand (kg/day) | H2 per Fill (kg) | Daily Cars | Fill Hoses | Dispensers | Mult. | Hose Flow Rate (kg/min) | Fill Time (min) | Linger Time | Occupied Time (min) | Peak Hour Fraction | Peak Flow (kg/hr) | Peak Fills (fills/hr) | Occupied Fraction | Predicted Dispensers |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 300 | 1.19 | 357 | 4.5 | 79 | 2 | 1 | 300 | 1.67 | 2.7 | 3.0 | 5.7 | 7.80% | 27.8 | 6.2 | 29.4% | 1 |
| 400 | 1.19 | 476 | 4.5 | 106 | 2 | 1 | 400 | 1.67 | 2.7 | 3.0 | 5.7 | 7.80% | 37.1 | 8.3 | 39.2% | 1 |
| 600 | 1.19 | 714 | 4.5 | 159 | 2 | 1 | 600 | 1.67 | 2.7 | 3.0 | 5.7 | 7.80% | 55.7 | 12.4 | 58.7% | 1 |
| 800 | 1.19 | 952 | 4.5 | 212 | 4 | 2 | 400 | 1.67 | 2.7 | 3.0 | 5.7 | 7.80% | 74.3 | 16.5 | 39.2% | 2 |
| 1000 | 1.19 | 1190 | 4.5 | 264 | 4 | 2 | 500 | 1.67 | 2.7 | 3.0 | 5.7 | 7.80% | 92.8 | 20.6 | 48.9% | 2 |
| 1200 | 1.19 | 1428 | 4.5 | 317 | 4 | 2 | 600 | 1.67 | 2.7 | 3.0 | 5.7 | 7.80% | 111.4 | 24.8 | 58.7% | 2 |
| 1400 | 1.19 | 1666 | 4.5 | 370 | 6 | 3 | 467 | 1.67 | 2.7 | 3.0 | 5.7 | 7.80% | 129.9 | 28.9 | 45.7% | 3 |
| 1600 | 1.19 | 1904 | 4.5 | 423 | 6 | 3 | 533 | 1.67 | 2.7 | 3.0 | 5.7 | 7.80% | 148.5 | 33.0 | 52.2% | 3 |
| 1800 | 1.19 | 2142 | 4.5 | 476 | 6 | 3 | 600 | 1.67 | 2.7 | 3.0 | 5.7 | 7.80% | 167.1 | 37.1 | 58.7% | 3 |
| 2000 | 1.19 | 2380 | 4.5 | 529 | 8 | 4 | 500 | 1.67 | 2.7 | 3.0 | 5.7 | 7.80% | 185.6 | 41.3 | 48.9% | 4 |
| 2200 | 1.19 | 2618 | 4.5 | 582 | 8 | 4 | 550 | 1.67 | 2.7 | 3.0 | 5.7 | 7.80% | 204.2 | 45.4 | 53.8% | 4 |
| 2400 | 1.19 | 2856 | 4.5 | 635 | 8 | 4 | 600 | 1.67 | 2.7 | 3.0 | 5.7 | 7.80% | 222.8 | 49.5 | 58.7% | 4 |
| 2600 | 1.19 | 3094 | 4.5 | 688 | 10 | 5 | 520 | 1.67 | 2.7 | 3.0 | 5.7 | 7.80% | 241.3 | 53.6 | 50.9% | 5 |
| 2800 | 1.19 | 3332 | 4.5 | 740 | 10 | 5 | 560 | 1.67 | 2.7 | 3.0 | 5.7 | 7.80% | 259.9 | 57.8 | 54.8% | 5 |
| 3000 | 1.19 | 3570 | 4.5 | 793 | 10 | 5 | 600 | 1.67 | 2.7 | 3.0 | 5.7 | 7.80% | 278.5 | 61.9 | 58.7% | 5 |
| 3200 | 1.19 | 3808 | 4.5 | 846 | 12 | 6 | 533 | 1.67 | 2.7 | 3.0 | 5.7 | 7.80% | 297.0 | 66.0 | 52.2% | 6 |
| 3400 | 1.19 | 4046 | 4.5 | 899 | 12 | 6 | 567 | 1.67 | 2.7 | 3.0 | 5.7 | 7.80% | 315.6 | 70.1 | 55.5% | 6 |
| 3600 | 1.19 | 4284 | 4.5 | 952 | 12 | 6 | 600 | 1.67 | 2.7 | 3.0 | 5.7 | 7.80% | 334.2 | 74.3 | 58.7% | 6 |
| 3800 | 1.19 | 4522 | 4.5 | 1005 | 14 | 7 | 543 | 1.67 | 2.7 | 3.0 | 5.7 | 7.80% | 352.7 | 78.4 | 53.1% | 7 |
| 4000 | 1.19 | 4760 | 4.5 | 1058 | 14 | 7 | 571 | 1.67 | 2.7 | 3.0 | 5.7 | 7.80% | 371.3 | 82.5 | 55.9% | 7 |
| 4200 | 1.19 | 4998 | 4.5 | 1111 | 14 | 7 | 600 | 1.67 | 2.7 | 3.0 | 5.7 | 7.80% | 389.8 | 86.6 | 58.7% | 7 |
| 4400 | 1.19 | 5236 | 4.5 | 1164 | 16 | 8 | 550 | 1.67 | 2.7 | 3.0 | 5.7 | 7.80% | 408.4 | 90.8 | 53.8% | 8 |
| 4600 | 1.19 | 5474 | 4.5 | 1216 | 16 | 8 | 575 | 1.67 | 2.7 | 3.0 | 5.7 | 7.80% | 427.0 | 94.9 | 56.3% | 8 |
| 4800 | 1.19 | 5712 | 4.5 | 1269 | 16 | 8 | 600 | 1.67 | 2.7 | 3.0 | 5.7 | 7.80% | 445.5 | 99.0 | 58.7% | 8 |

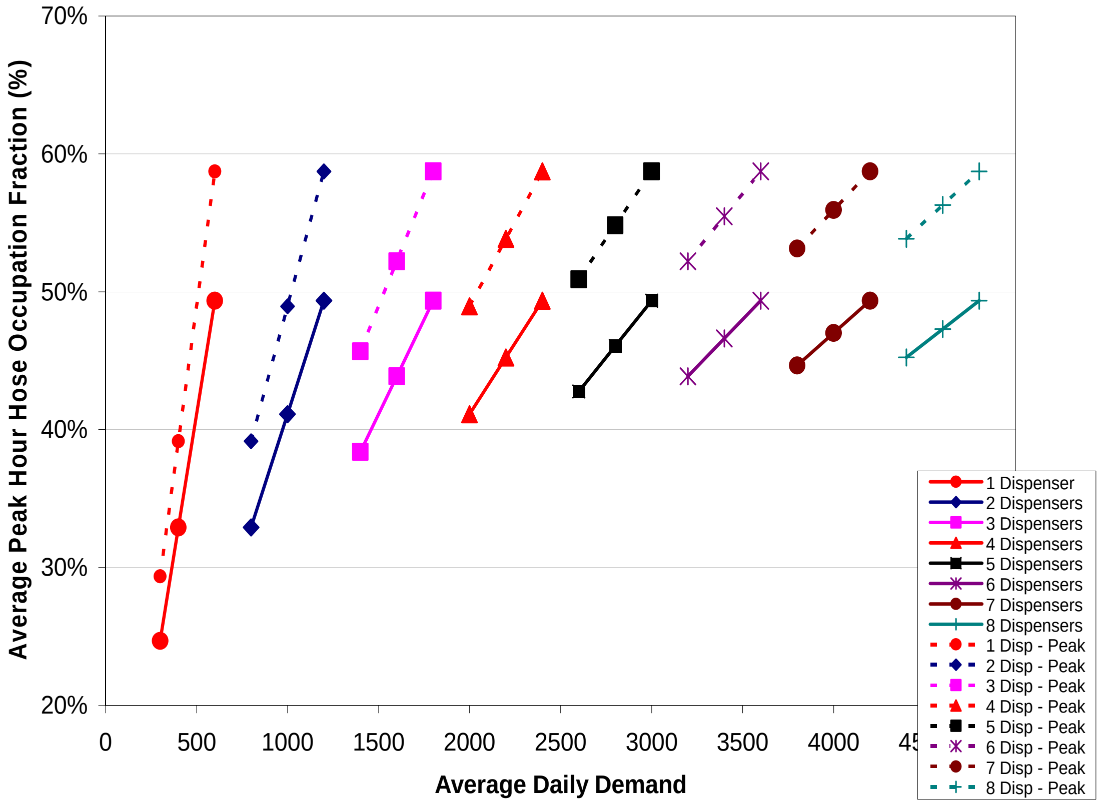
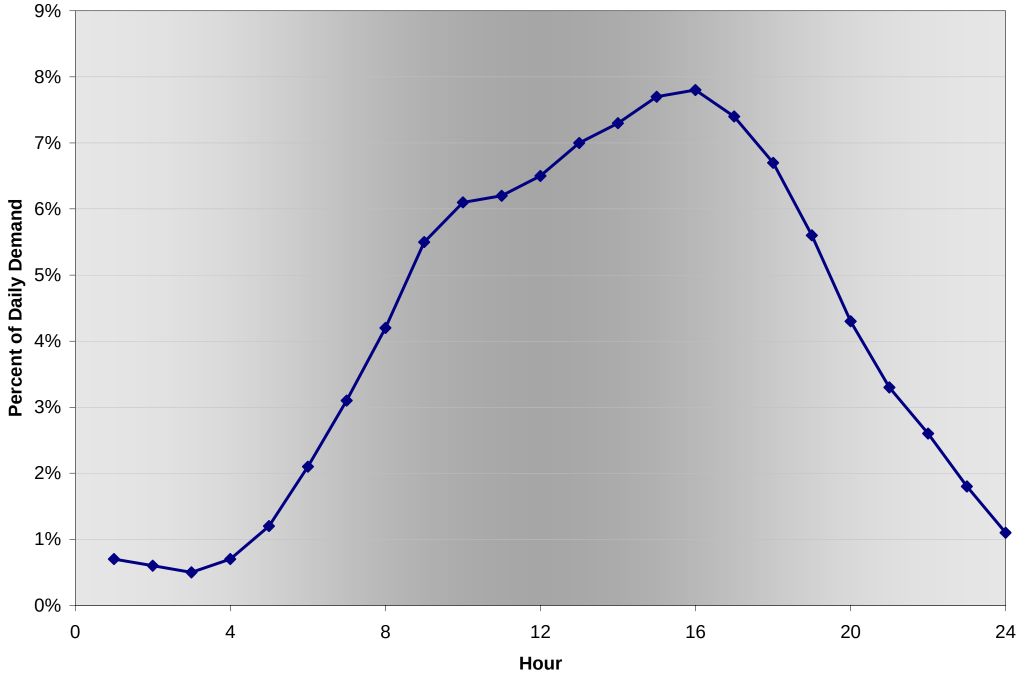



Figure 2-51 Recommended Number of Refueling Station Dispensers

The station demand and dispenser configuration ultimately determine the size of the compressor and cascade charging system. In general, the average daily fuel demand determines the dispenser configuration, with station capacities in the range of 300 to 4,800 kg/day requiring 1 to 8 dispensers. The number of dispensers, and the dispensing hose flow rate, set the maximum flow rate for the station.



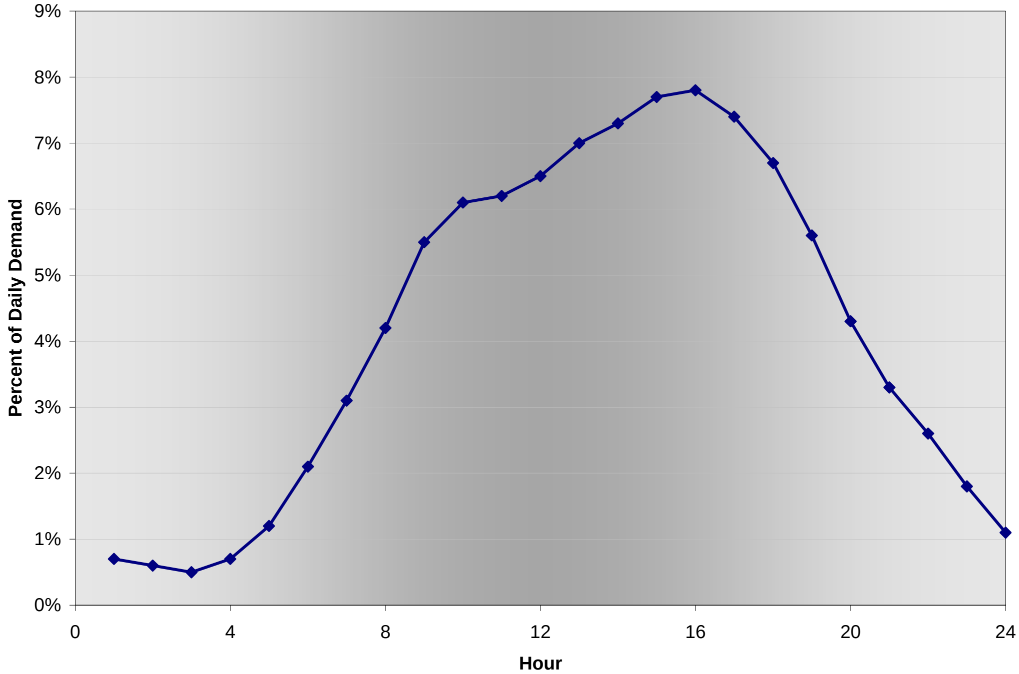

lists the 10 scenarios analyzed in the parametric studies below (Section 2.3.2.4) to determine the method for sizing the compressor/ cascade charging system.

Table 2-29 Refueling Station Dispenser Parameters

| Scenario | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
|---|---|---|---|---|---|---|---|---|---|---|
| Average Demand (kg/day) | 1,400 | 1,800 | 2,142 | 2,000 | 2,200 | 2,400 | 2,856 | 3,400 | 3,600 | 4,284 |
| Dispensers | 3 | 3 | 3 | 4 | 4 | 4 | 4 | 6 | 6 | 6 |
| Average Vehicles (cars/day) | 311 | 400 | 476 | 444 | 489 | 533 | 635 | 756 | 800 | 952 |
| Hose Flow Rate (kg/min) | 1.67 | 1.67 | 1.67 | 1.67 | 1.67 | 1.67 | 1.67 | 1.67 | 1.67 | 1.67 |
| HOF | 38% | 49% | 59% | 41% | 45% | 49% | 59% | 47% | 49% | 59% |
| Peak Flow Rate (kg/hr) | 300 | 300 | 300 | 400 | 400 | 400 | 400 | 600 | 600 | 600 |

### 2.3.2.3 Demand Profile

In addition to the dispenser configuration and the average capacity, the daily demand profile significantly affects the requirements for compression and the cascade charging system. Identifying the demand profile over an entire day is important, due to the inter-hour effects on the cascade charging system and compression requirements. Designing the system to simply meet an hourly demand can adversely affect the performance in subsequent hours. For example, if 75 kg/hr of compressor capacity and 25 kg of useful cascade charging system capacity are needed to meet an hourly demand of 100 kg, the cascade charging storage will be empty, and the system will be unable to meet, any hourly demand greater than 75 kg in the following hour. This is of particular concern during periods of high demand, when limited time is available to replenish empty vessels. As with the dispenser calculations, the station calculations were based on the daily demand for Friday, as data from Chevron indicate the highest demand occurs on this day. The profile, shown in Figure 2-52, is normalized and scaled to the capacities shown in

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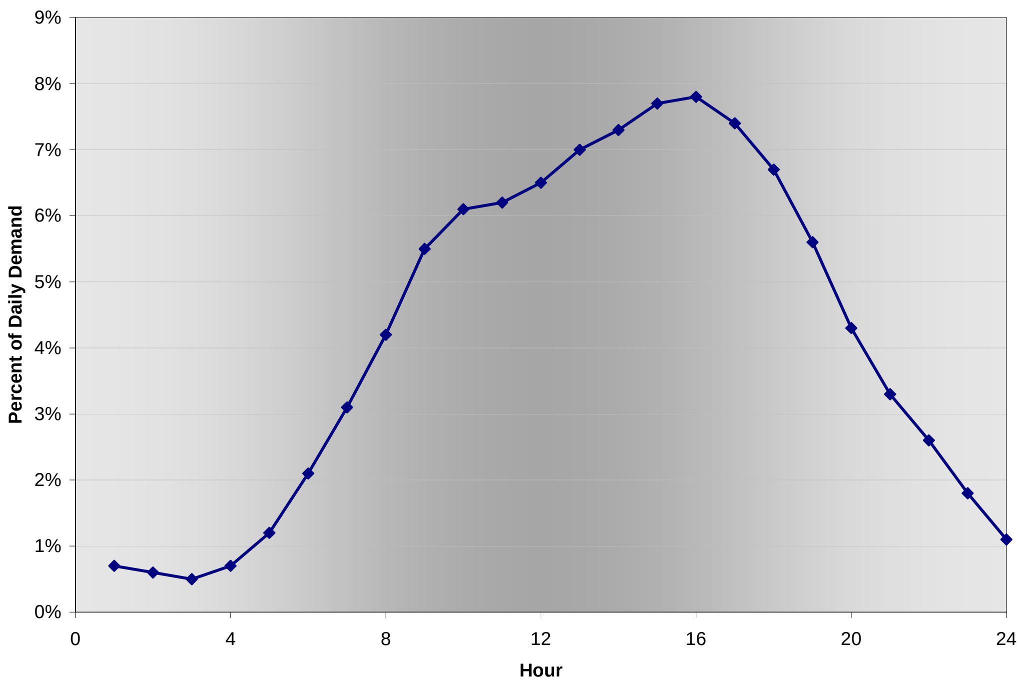


Figure 2-52 Refueling Demand Curve for Friday

The profile specifies the daily demand on an hour-by-hour basis. To accurately model the state of the cascade charging system, various assumptions were made regarding the demand within an hour. A constant flow rate is the simplest method for allocating demand; however, the constant rate never evaluates the station at full capacity, with all dispensers operating simultaneously. To provide for a certain period at full capacity, a profile was created which has the station operating at full capacity for the first 3 minutes of each hour. The balance of the demand for the hour, if any, is spread evenly among the remaining 57 minutes. The profile is intended to be sufficiently aggressive to accommodate most situations that might arise at a commercial station.

The allocation method is illustrated in Figure 2-53. The allocation method yields short periods of high demand, separated by longer periods of low demand. During those hours in which the overall demand is low, the first 3 minutes of peak flow often fulfills the entire demand for the hour.

Again, the purpose of the allocation profile is to fully exercise the range of possible conditions so a refueling station can accommodate the anomalies of real world demand profiles. It is thus a very conservative design approach.

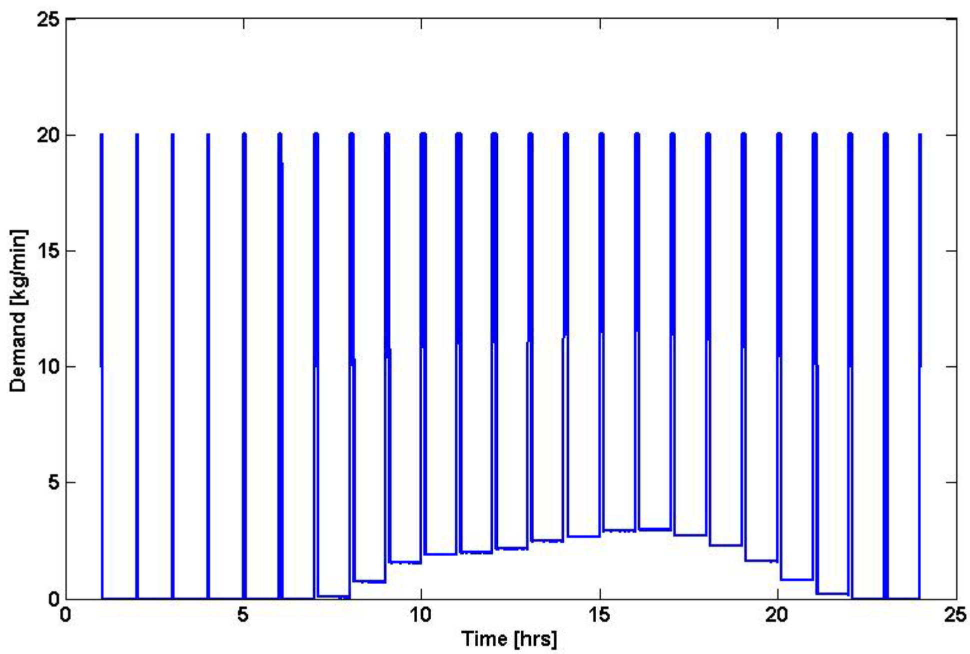



Figure 2-53 Refueling Station Dispensing Profile

#### *2.3.2.4 Cascade Charging System*

After defining the station configuration and the demand profile, the state of the cascade charging system is modeled to determine the necessary combination of compressor and storage capacities. The storage system is a three-tier cascade system replenished by the compressor. Each vessel can operate at the design pressure of 6,500 psi (448.3 bars); however, 2 of the 3 vessels normally operate at lower pressures to reduce the daily energy demand of the compressor. For example, the low pressure vessel supplies hydrogen when the vehicle tank pressure is less than 2,000 psi (138 bars), the mid pressure vessel supplies hydrogen when the tank pressure is between 2,000 and 4,400 psi (138 and 303.5 bars), and the high pressure vessel supplies the vehicle from 4,400 to 6,000 psi (303.5 to 413.8 bars).

Despite consistent demand at each pressure level, the high pressure vessel requires the most frequent replenishment, as only a small mass can be transferred from the vessel before the pressure falls below 6,000 psi (413.8 bars). If that occurs, the cascade system cannot fill the vehicle to the design pressure of 5,000 psi or 344.8 bars (after return to ambient conditions).

TIAX developed a MATLAB model to calculate the required compression and cascade dharging system capacities. To calculate the required cascade charging system capacity, an initial mass is assigned to each of the storage vessels, and the pressures are tracked through the demand cycle. The pressure is calculated with the Soave-Redlich-Kwong (SRK) equation of state, as opposed to the ideal gas law. Figure 2-54 illustrates the variation in calculated density between the SRK equation and the ideal gas law.

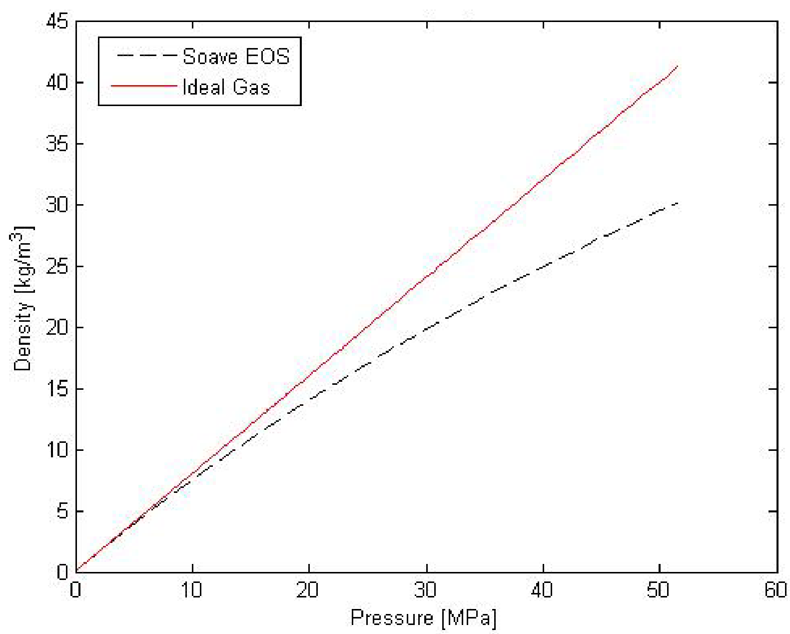



Figure 2-54 Deviation of Hydrogen Density from Ideal Gas Law

As the model progresses through the demand cycle, a logic system determines which vessels are in need of replenishment from the compressor. When the pressure in a vessel falls below the threshold, the compressor begins to charge that vessel. If no vessels are below the threshold, the compressor charges all of the vessels to the design pressure, with priority going to the high pressure vessel. The compressor can feed any and all of the vessels simultaneously, if needed.

If, at any point in the demand cycle, the pressure in a vessel falls below its minimum value, the storage vessels are too small. The model increases the vessel size, and re-evaluates the demand cycle. If the model evaluates the entire demand cycle without a low pressure error, sufficient storage is present for the given demand and compressor capacity.

An example of the pressure calculations during a full demand cycle are shown in Figure 2-55 for a refueling station with a capacity of 3,400 kg/day.

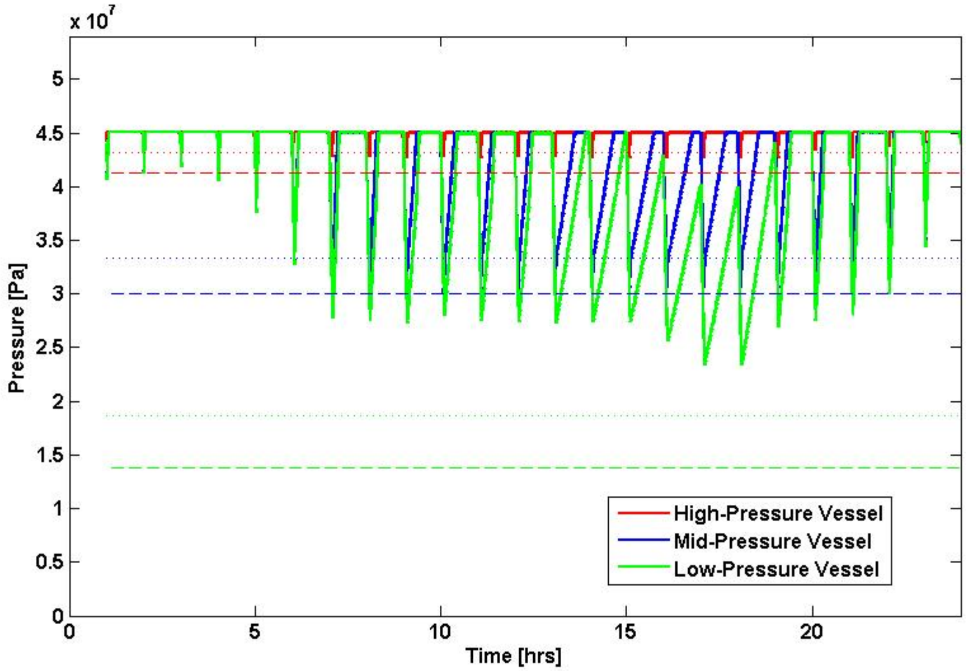


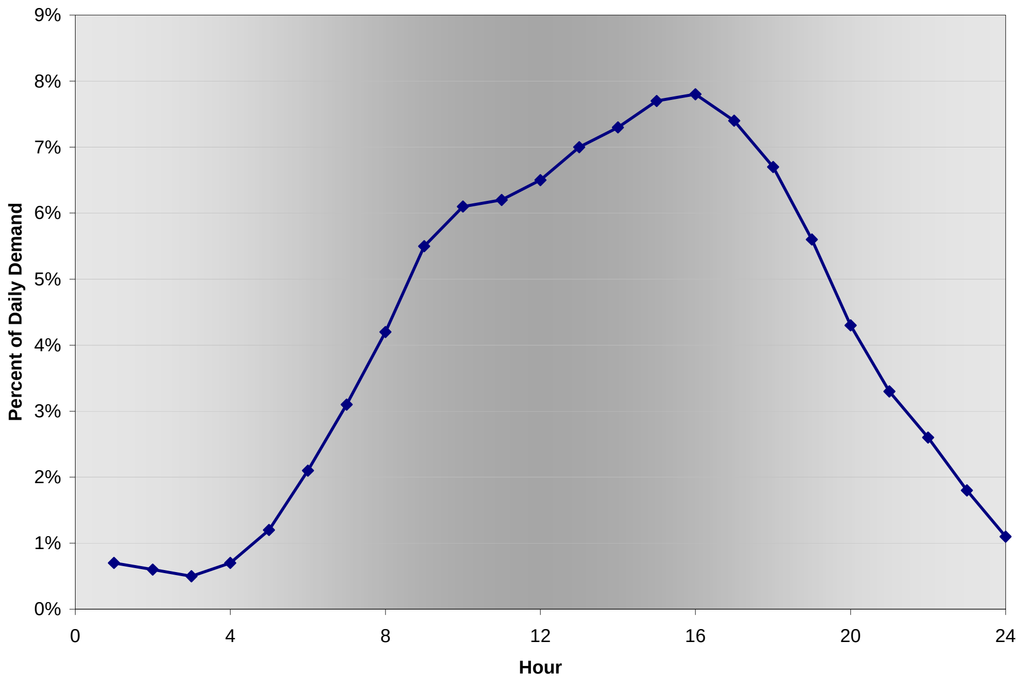

Figure 2-55 Fluctuations in Cascade Charging System Pressure During a Demand Cycle

Figure 2-55 illustrates there is insufficient compressor capacity to recharge the low pressure vessel to 4,500 psi (310.3 bars) during the peak demand hours of 4:00 pm to 6:00 pm. The figure also shows the mid pressure vessel routinely approaches its minimum operating value of 3,000 psi or 206.8 bars (the blue dashed line). In effect, the compressor can maintain the charge in the high and mid pressure vessels, but only at the expense of the low pressure vessel during peak demand periods.

Calculations were developed for a range of refueling station capacities. From these data, 2 non-dimensional metrics were developed, as follows:

- The compressor size is normalized, using the minimum compressor size (Cm) to create the non-dimensional parameter C/Cm. The minimum compressor size is the daily station capacity, in kg/day, divided by 24 hours/day.
- The storage size (St) is normalized using the station daily capacity in kilograms (Cap) to create the non-dimensional parameter, St/Cap.

Results from the ten refueling stations scenarios listed in




are shown in Figure 2-56. The non-dimensional parameters clearly indicate a relationship between cascade charging and compressor capacities over a range of refueling station sizes. It should be noted here that the role of the compressor in gaseous refueling stations is the same as that of a liquid pump/vaporizer combination in liquid refueling stations, i.e., to deliver compressed gaseous hydrogen to the cascade system at the required rate. Therefore, the same relationship between the cascade charging system capacity and compression for gaseous refueling stations shown in Figure 2-56 applies to the relationship between cascade capacity and pump/vaporizer for liquid refueling stations.

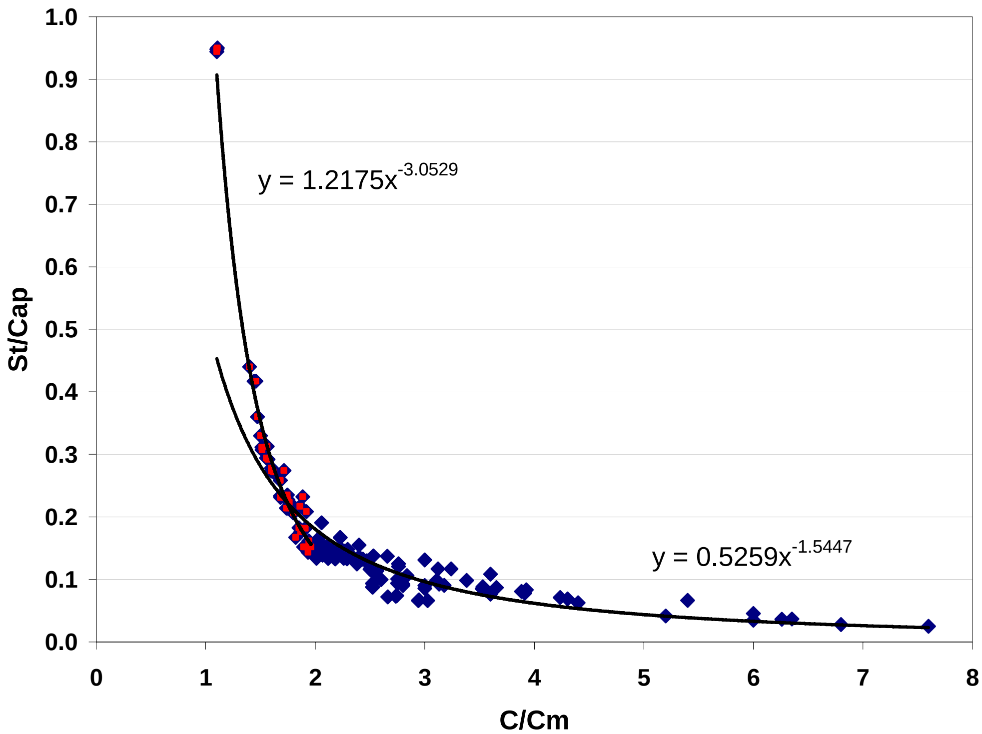



Figure 2-56 Non-dimensional Relationship between Compressor and Cascade Charging Capacities

### *2.3.2.5 Cost Optimization*

To define the lowest cost combination of compressor and cascade charging system capacities, capital and installation costs were assembled from the cascade charging system cost data in Sections 2.2.4, the compressor cost data in Section 2.2.5, and electric power supply cost data in Section 2.2.6. For the purposes of the calculations, the following assumptions were made:

- The unit cost for the cascade charging system, in $/kg, remains constant over the range of refueling station capacities
- For compression demands larger than 250 kg/hr, multiple compressors are installed
- For compressor design capacities greater than 360 kg/hr, the electric power supply voltage for the compressor was increased from 480 Volts to 4160 Volts. For the 4160 Volts systems, it was assumed a new electric power line would need to be installed from the local substation to the refueling station, and the cost for the new line was $1,000,000.

The installed cost data, as a function of C/Cm, for a range of refueling station capacities is shown in Figure 2-57. In the figure, 'C' is the compressor capacity, in kg/hr, and 'Cm' is the minimum compressor capacity, which is equal to the station capacity, in kg/day, divided by 24.

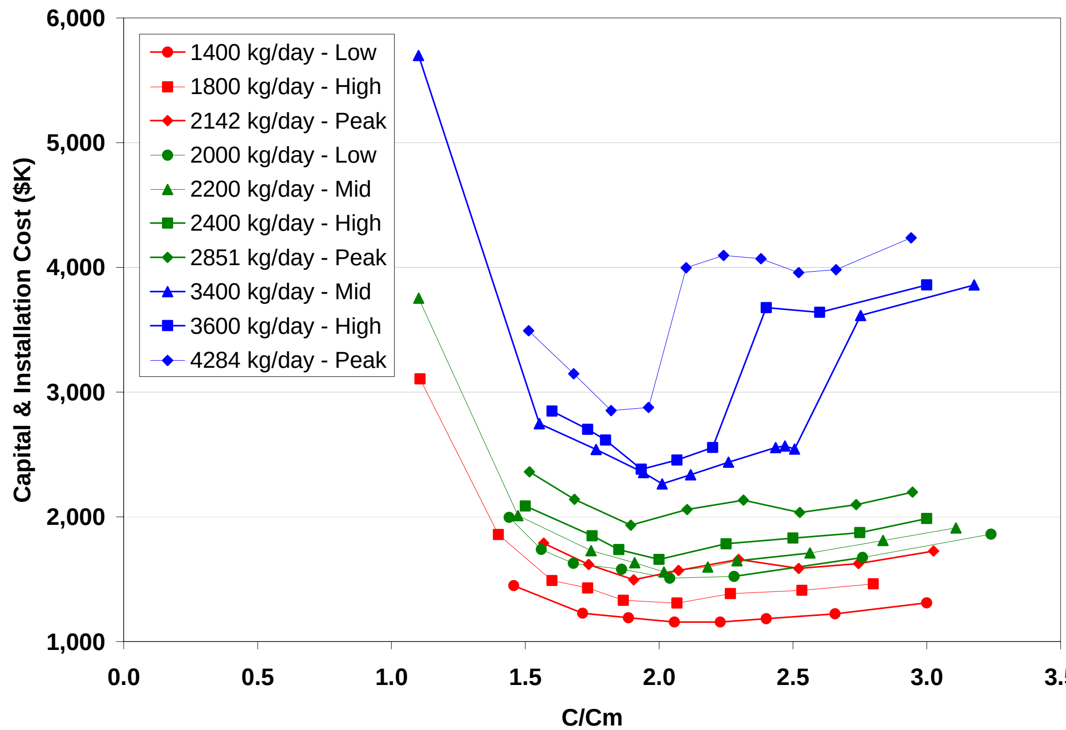



Figure 2-57 Refueling Station Compressor and Cascade Charging System Optimization

For small compressor capacities (C/Cm < 1.5), the cascade charging system capacity increases rapidly, which accounts for the high station costs near C/Cm = 1.0. For refueling station capacities greater than 3,400 kg/day, the compressors operate at 4160 Volts, and the incremental electric supply cost of $1,000,000 produces the step changes in the station costs.

The cost data shown in Figure 2-57 indicate a minimum values exists at C/Cm values in the range of 1.8 to 2.3. Unfortunately, not all of the minimums occur at the same C/Cm value. However, this is to be expected, as the compressor and the cascade charging system costs are not linear functions of capacity.

It should be noted here that while the cascade charging system capacity-compression relationship is essentially the same as that for cascade charging system capacity-liquid pump/vaporizer, the optimum cascade storage-pump/vaporizer sizes could be different from those shown above for cascade-compressor sizes since the cost of compression is different in these two cases.

It should be also noted that the H2A Delivery Models now incorporate a complete cost optimization for the refueling stations that incorporate the principles discussed here and take them a step further as explained in Section 2.3.3.

### *2.3.3 Refueling Station Optimization in the H2A Delivery Models*

The optimum refueling station parameters presented in section 2.3.2.5 are unique to the inputs and assumptions made to arrive at their values. Specifically, the optimum parameter values are restricted to the following inputs and assumptions, which were used in the optimization:

- The Chevron daily and hourly demand profiles
- The conservative assumed spike in demand at the beginning of each hour
- The cost of the compressor, cascade, and electrical upgrades
- The minimum and maximum pressures in each of the cascade vessels
- The vehicle filling dynamics (tank capacity, fill time, linger time, etc.)
- The number of compressors at the refueling station including installed spares
- The number of dispensers and the average hose occupied fraction during the peak hour

A calculation methodology has been developed in the H2A Delivery Models V2 to facilitate the analysis of the impact of such inputs on the optimum parameters. The methodology is based on a simple logic, through which the amount of hydrogen and the pressures in each of the cascade vessels are tracked at the critical points of the demand profile, and a decision is made regarding the size of the compressor and cascade system to satisfy such demand with minimum cost. The selected design parameters are those which satisfy the demand profile at all of its critical points.

It should be noted that the calculation methodology in the H2A Delivery Models V2 optimizes the refueling station components by minimizing the total cost contribution of the refueling station to the hydrogen delivery infrastructure rather than minimizing only the compressor and cascade storage system capital costs as adopted in section 2.3.2.5 above. In the H2A Delivery models the cost optimization includes the cost of low pressure storage for (pipeline delivery), power costs for compressors as well as all capital costs. This facilitates the investigation of the demand profile effect on the cost of refueling station storage, the impact of refueling station storage on its land cost, and the effect of possible underutilization of refueling stations in the early market transition period. Furthermore, the methodology is equally applicable to liquid refueling stations in which the cost of liquid pumps and evaporators are considered in place of their compressors counterpart in the gaseous refueling station. Of particular interest to the analysis of the refueling station are the ability to scale or modify the Chevron profile, the ability to scale the demand spike at the first period of each hour by specifying the occupied fraction of hoses during that period, and the ability to specify the number of underutilized stations as a percentage of the number of fully utilized stations in a given market.

A few other particulars of the H2A Delivery Models V2 should also be noted. Although most of the discussions and examples in this report utilize the Chevron 24 hr station fueling profiles, the Models are based on the refueling stations being open 18 hrs (6 AM-Midnight). The 24 hr Chevron fueling profiles are used in the Models neglecting the small discrepancy in that a very small fraction of fueling occurs between midnight and 6 AM. This results in a negligible design inaccuracy of the fueling sites. Also the final fueling time and linger time chosen for use as the defaults in the Models are 2.76 min. and 2.24 min. respectively. It results in the average fill of 4.6 kg of hydrogen (see Section 2.1.2) in 5 minutes of hose occupation time while also satisfying the DOE Hydrogen Program Target of 5 kg filled in 3 minutes.

## 2.4 H2A DELIVERY SCENARIO MODEL V2 DELIVERY PATHWAYS

### 2.4.1 Liquid Pathways

Truck delivery of liquid hydrogen from central production to refueling stations in urban areas assumes the city area to be of square boundary and that the refueling stations are uniformly distributed within the city. The distance traveled by the truck within the city boundary to the refueling station is assumed to be 1.5 times the linear dimension of the city. The average roundtrip distance and time can then be calculated based on the distance between the production plant and city gate, the average truck speed on highways and within the city boundary, and the time required to connect, unload, and disconnect at the station. The number of possible truck roundtrips per day can then be calculated from the number of refueling station operating hours per day and the average roundtrip time. Knowing the truck full load capacity and the city peak daily demand, the number of trucks is calculated and scaled.

Process flow diagrams of the three different liquid distribution scenarios modeled are shown in Figure 2-58.

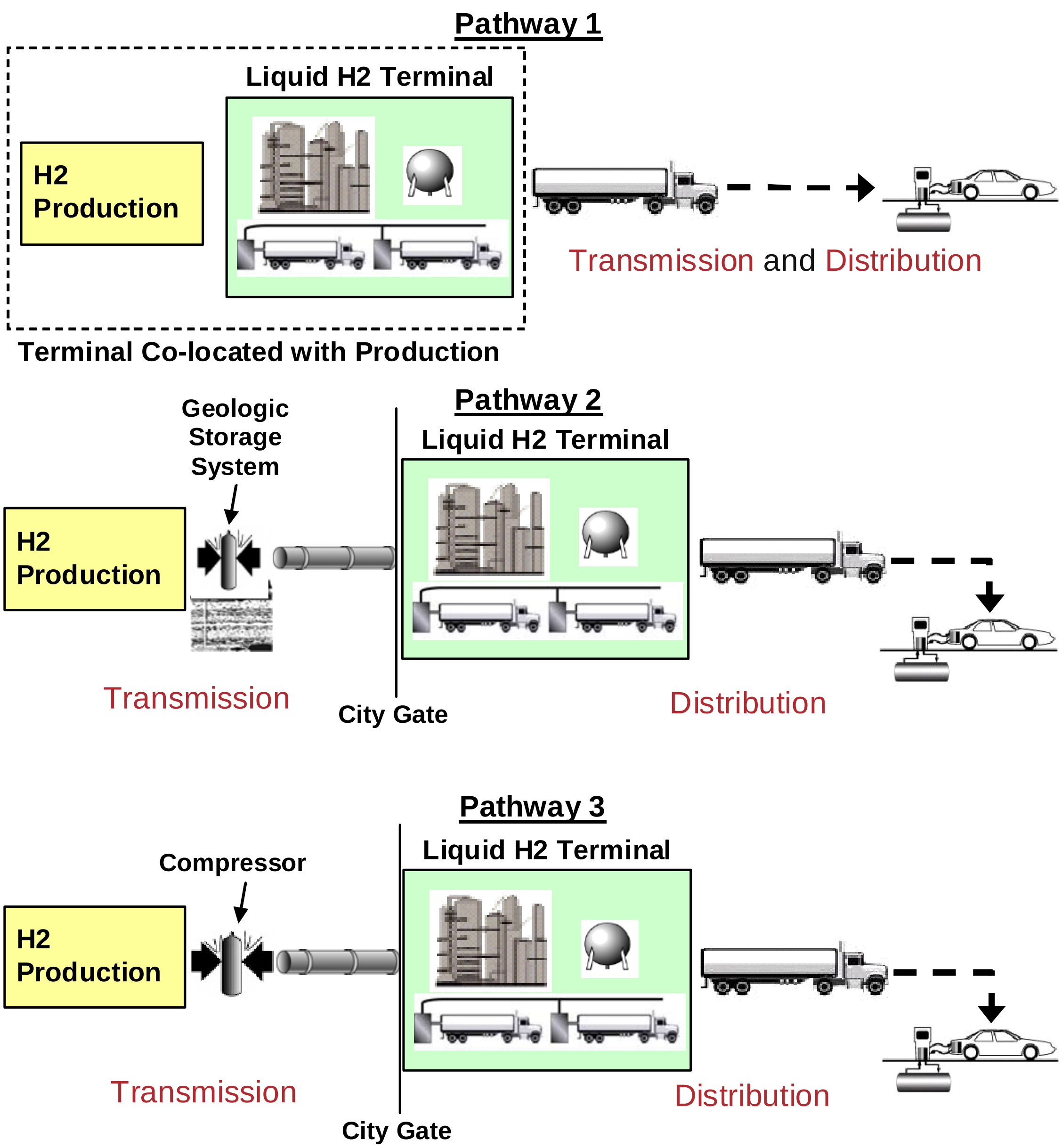



Figure 2-58 Liquid Distribution Scenarios

#### *2.4.1.1 Pathway 1*

This liquid distribution scenario models the situation where a liquid terminal would be co-located with a production plant. The gaseous hydrogen produced by the plant will be sent directly to a liquefier, and then pumped onto a liquid trailer truck for transmission and delivery to the refueling station for loading onto a fuel cell vehicle.

The terminal includes the following components:

- Liquefier – a large liquefier processes the entire flow rate from the plant.

- Storage – Liquid storage is present, in vacuum-jacketed spherical vessels, to hold hydrogen that might be required for a production plant outage or a summer demand surge.
- Loading bays – Bays to load the liquid hydrogen onto the liquid delivery trucks are included. These bays contain all equipment, both safety and process, to get the liquid hydrogen onto the trucks.

From the terminal, the hydrogen is transported to the refueling stations using the liquid delivery trucks. These trucks can make up to three stops during their journey, dropping an equivalent amount of hydrogen to each station. For example, if the truck makes three stops during its trip, it will deliver approximately 1/3 of its hydrogen load to each station (losses will reduce the amount of hydrogen delivered to slightly less than 1/3 of its original hydrogen charge).

Once at the refueling station, the trucks will offload the liquid hydrogen into storage spheres. This transfer process will cause approximately 6 percent of the total hydrogen trailer capacity to be lost. Once the trailer has completed its transfer, the truck goes either to another station, or returns to the plant/terminal for another load of liquid hydrogen.

The liquid refueling station contains all the components necessary to vaporize the liquid hydrogen for loading onto fuel cell cars. From the liquid storage spheres, the hydrogen is pumped to the car delivery pressure, and then evaporated using cryo-evaporators. The gaseous hydrogen is fed to one of three stages of a cascade system, and is loaded directly onto the car from these vessels.

#### *2.4.1.2 Pathway 2*

The second liquid distribution is considered to be "mixed mode". The gaseous hydrogen produced at the plant is compressed, and then fed through a pipeline to the liquid terminal which may be located at any point along the pipeline, but is more likely and assumed to be located at the city gate. The pipeline system, in this scenario, includes the option of using geologic storage to supply hydrogen during a plant outage or during the summer surge. This geologic storage system is designed using a compressor to charge and discharge the cavern.

At the terminal, the process is similar to what occurs in Scenario 1. The gaseous hydrogen delivered by the pipeline is sent directly to a liquefier, and then pumped onto a liquid trailer truck for transmission and delivery to the refueling station for loading onto a fuel cell vehicle.

The terminal includes the following components:

- Liquefier – a large liquefier processes the entire flow rate from the plant.
- Storage – Liquid storage is present, in vacuum-jacketed spherical vessels. A default value of 1 day of storage is used. This ensures smooth truck loading operations and liquid storage is relatively inexpensive.
- Loading bays – Bays to load the liquid hydrogen onto the liquid delivery trucks are included. These bays contain all equipment, both safety and process, to get the liquid hydrogen onto the trucks.

From the terminal, the hydrogen is transported to the refueling stations using the liquid delivery trucks. These trucks can make up to three stops during their journey, dropping an equivalent amount of hydrogen to each station. For example, if the truck makes three stops during its trip, it will deliver approximately 1/3 of its hydrogen load to each station (losses will reduce the amount of hydrogen delivered to slightly less than 1/3 of its original hydrogen charge).

Once at the refueling station, the trucks will offload the liquid hydrogen into storage spheres. This transfer process will cause approximately 6 percent of the total hydrogen trailer capacity to be lost. Once the trailer has completed its transfer, the truck goes either to another station, or returns to the plant/terminal for another load of liquid hydrogen.

The liquid refueling station contains all the components necessary to vaporize the liquid hydrogen for loading onto fuel cell cars. From the liquid storage spheres, the hydrogen is pumped to the car delivery pressure, and then evaporated using cryo-evaporators. The gaseous hydrogen is fed to one of three stages of a cascade system, and is loaded directly onto the car from these vessels.

#### *2.4.1.3 Pathway 3*

The third liquid delivery pathway is also considered to be "mixed mode". The gaseous hydrogen produced at the plant is compressed, and then fed through a pipeline to the liquid terminal which may be located at any point along the pipeline, but is more likely and assumed to be located at the city gate. Unlike Scenario 2, no geologic storage system is included in this scenario.

At the terminal, the gaseous hydrogen delivered by the pipeline is sent directly to a liquefier, and then pumped onto a liquid trailer truck for transmission and delivery to the refueling station for loading onto a fuel cell vehicle. The primary difference is that storage for the summer surge and for a plant outage is included at the terminal as vacuum-insulated spherical vessels.

The terminal includes the following components:

- Liquefier – a large liquefier processes the entire flow rate from the plant.
- Storage – Liquid storage is present, in vacuum-jacketed spherical vessels, to hold hydrogen required to cover a production plant outage and a summer demand surge.
- Loading bays – Bays to load the liquid hydrogen onto the liquid delivery trucks are included. These bays contain all equipment, both safety and process, to get the liquid hydrogen onto the trucks.

From the terminal, the hydrogen is transported to the refueling stations using the liquid delivery trucks. These trucks can make up to three stops during their journey, dropping an equivalent amount of hydrogen to each station. For example, if the truck makes three stops during its trip, it will deliver approximately 1/3 of its hydrogen load to each station (losses will reduce the amount of hydrogen delivered to slightly less than 1/3 of its original hydrogen charge).

Once at the refueling station, the trucks will offload the liquid hydrogen into storage spheres. This transfer process will cause approximately 6 percent of the total hydrogen trailer capacity to be lost. Once the trailer has completed its transfer, the truck goes either to another station, or returns to the plant/terminal for another load of liquid hydrogen.

The liquid refueling station contains all the components necessary to vaporize the liquid hydrogen for loading onto fuel cell cars. From the liquid storage spheres, the hydrogen is pumped to the car delivery pressure, and then evaporated using cryo-evaporators. The gaseous hydrogen is fed to one of three stages of a cascade system, and is loaded directly onto the car from these vessels.

### 2.4.2 Compressed Gas Delivery in Tube Trailers Pathways

Truck delivery of compressed gaseous hydrogen from central production to refueling stations in urban areas assumes the city area to be of square boundary and that the refueling stations are uniformly distributed within the city. The distance traveled by the truck within the city boundary to the refueling station is assumed to be 1.5 times the linear dimension of the city. The average roundtrip distance and time can then be calculated based on the distance between the production plant and city gate, the average truck speed on highways and within the city boundary, and the time required to connect, unload, and disconnect at the station. The number of possible truck roundtrips per day can then be calculated from the number of refueling station operating hours per day and the average roundtrip time. Knowing the truck full load capacity and the city peak daily demand, the number of trucks is calculated and scaled.

Two scenarios are postulated for truck delivery, as follows: 1) hydrogen is delivered to the city gate by pipeline, where it is further compressed at a terminal and loaded onto tube trailers for distribution by trucks; and 2) the hydrogen is compressed and loaded onto the tube trailer at the production plant, and then delivered by trucks to the refueling stations. For each of the scenarios, geologic storage, or a liquefier plus liquid storage, would be employed to satisfy the demand during production plant outages and the increased demand during the summer months. As a result, there are a total of four possible pathways for this distribution mode, as illustrated in Figure 2-59,

Figure 2-60, Figure 2-61, and

Figure 2-62.

In each of these pathways the refueling station s are equipped with a cascade charging system and compression. The tube trailer is dropped off at the refueling station and is used as storage to cover the hour to hour variations in demand over the course of each day.

The gas terminals are equipped with one quarter of a day of low pressure (2500 psi or 172.4 bars) storage and appropriate compression and bays for charging the tube trailers.

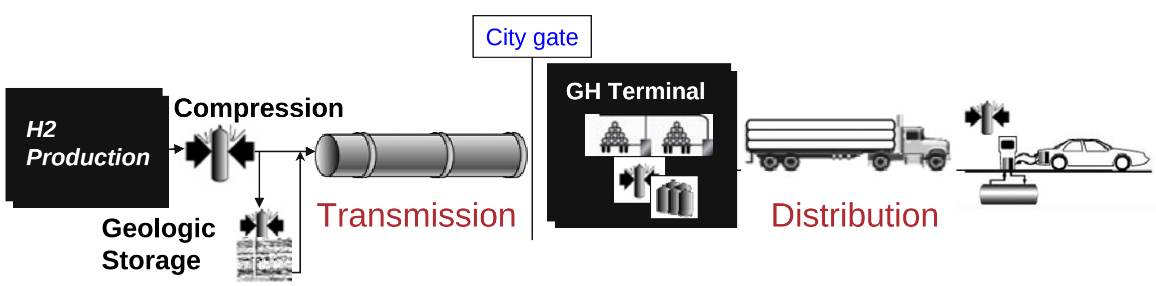


Figure 2-59 Pathway 4: Geologic Storage, Transmission by Pipeline, and Distribution by Tube Trailer

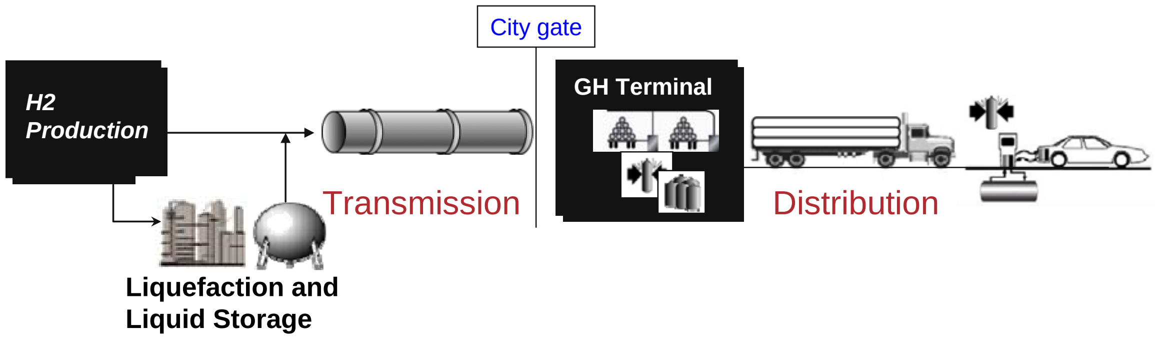



Figure 2-60 Pathway 5: Liquid Storage, Transmission by Pipeline, and Distribution by Tube Trailer

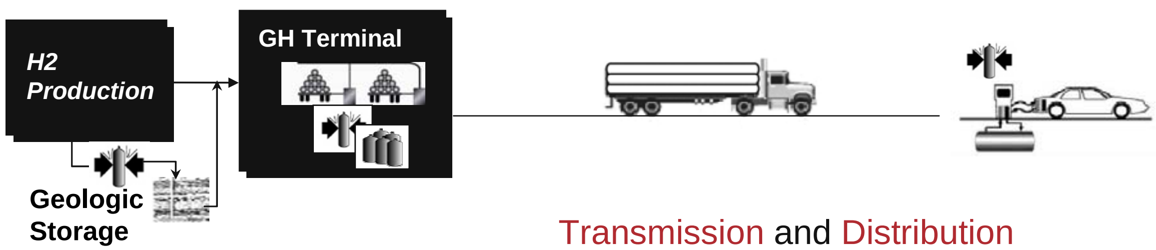



Figure 2-61 Pathway 6: Geologic Storage, and Transmission and Distribution by Tube Trailer

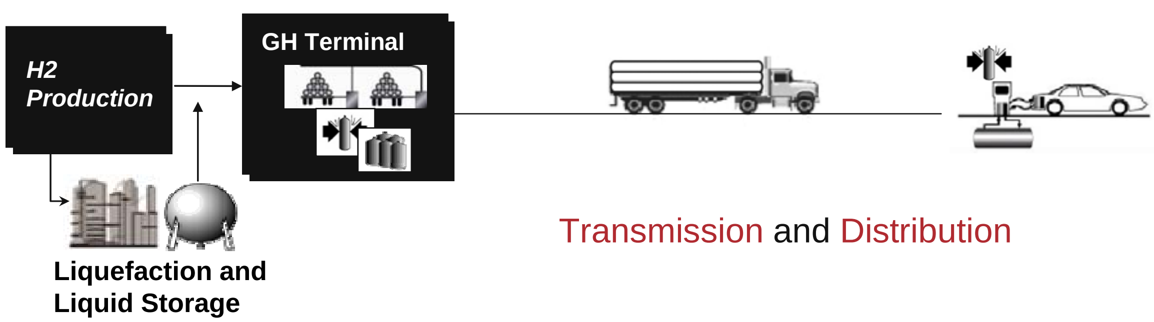



Figure 2-62 Pathway 7: Liquid Storage, and Transmission and Distribution by Tube Trailer

### 2.4.3 Pipeline Delivery

Pipeline delivery of compressed gaseous hydrogen from central production to refueling stations in urban areas is assumed to require a series of components. High pressure transmission lines bring hydrogen from a centralized production facility to the periphery of an urban area. Distribution mainlines (trunk lines in the form of one or more concentric rings) distribute hydrogen from the transmission line throughout the metropolitan area. Service lines connect refueling stations to the hydrogen trunk distribution system. The diameter of any pipeline is a function of its length, peak hydrogen flow, and the pressure differential between the pipeline inlet at the production end and the pipeline outlet. The installed cost of a pipeline distribution system is a function of local geography, the physical size (or land area) of the urban area, the daily demand at refueling stations, and the number and distribution of refueling stations within an urban area. In order to estimate cost for a hypothetical metropolitan area of specified population at specific market penetration, a simple regional geometry is assumed (i.e., no unique geographic features that would cause asymmetry), population density and vehicle ownership are specified empirically, and refueling stations that reflect refueling regional demands are distributed uniformly within specific regions. The resulting model estimates costs for a distribution pipeline for an urban area of specified population and hydrogen vehicle market penetration.

The methodology can be described in terms of the following steps:

1. A population density profile and the total population are used to estimate land area for the total urban region and for four sub-regions, which extend radially from the urban core and are characterized by decreasing population density.

2. For each density region, the total number of light duty vehicles to be served is calculated based on population density and empirical vehicle ownership rates. These ownership rates are a function of population density.

3. A service population is estimated based on an assumed hydrogen-fueled vehicle share.

4. The number of refueling stations required to service the vehicle population in each density region is estimated based on national averages for vehicles served.

5. A heuristic algorithm is used to locate service stations such that distribution and service pipeline requirements are minimized.

6. Pipeline requirements are translated into capital costs based on unit cost estimates, e.g., $/mile/in diameter.

The pipeline model includes up to four trunk lines within a given metropolitan area with service lines extending from the trunk lines to the refueling stations. The model iterates on the number and location of trunk lines within a given metropolitan area until an optimum distribution configuration is obtained at a minimum cost.

#### *2.4.3.1 Pathway 8*

Delivery Pathway 8 consists of the following components: geologic storage; a transmission pipeline to the city gate; distribution pipelines lines to the refueling stations; and refueling stations, which include a compressor, a cascade charging system, and low pressure storage. The pathway is shown schematically in Figure 2-63.

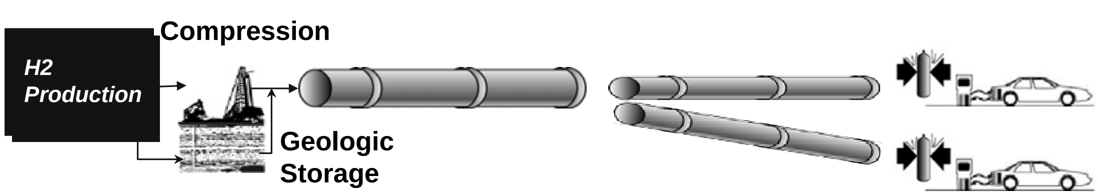


Figure 2-63 Pathway 8: Geologic Storage, and Transmission and Distribution by Pipeline

#### *2.4.3.2 Pathway 9*

Delivery Pathway 9 consists of the following components: a liquefaction plant with liquid storage; liquid pump and evaporator; a transmission pipeline to the city gate; distribution pipelines lines to the refueling stations; and refueling stations, which include a compressor, a cascade charging system, and low pressure storage. In this pathway the liquefaction plant and liquid storage liquefy and store sufficient hydrogen to cover the peak summer demand and winter planned maintenance outage. The pathway is illustrated in

Figure 2-64.

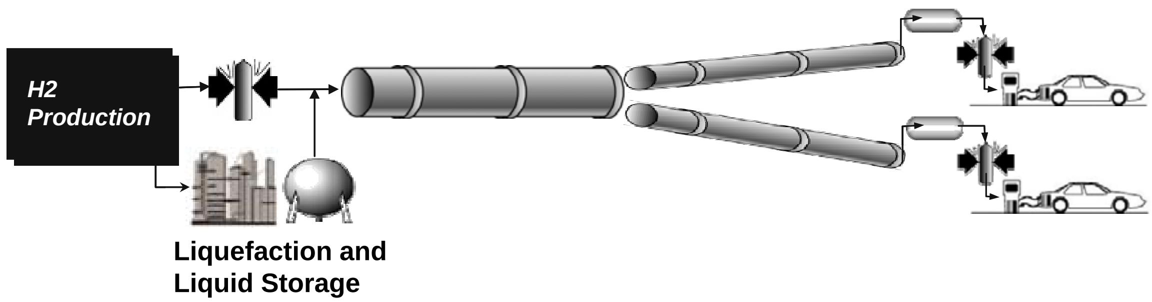



Figure 2-64 Pathway 9: Liquid Storage, and Transmission and Distribution by Pipeline

#### 2.4.3.3 Pathway 10

Delivery Pathway 10 consists of the following components: a hydrogen production plant; a liquefaction plant with liquid storage; liquid pump and evaporator; an oversize transmission pipeline to the city gate; distribution pipelines lines to the refueling stations; and refueling stations, which include a compressor, and a cascade charging system. The liquefaction plant and liquid storage liquefy and store sufficient hydrogen to cover the peak summer demand and winter planned maintenance outage. The oversize transmission pipeline performs the same function as low pressure storage at a refueling station. A discussion of the pipeline storage design process is presented in Section 2.2.13. The pathway is illustrated in Figure 2-57.

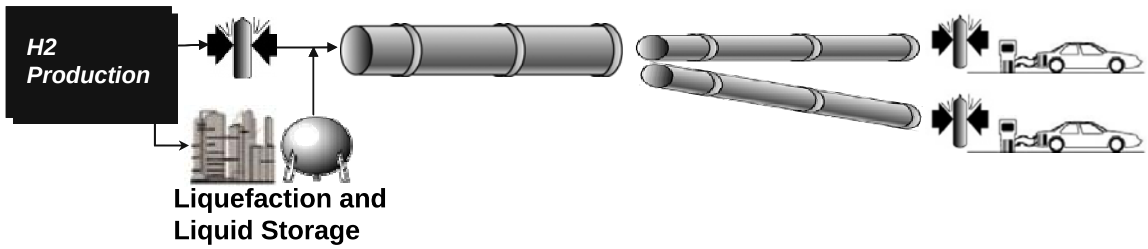



Figure 2-65 Pathway 10: Liquid Storage, and Transmission and Distribution by Pipeline

### 2.4.5 Rural and Rural/Urban Pathways

The H2A Hydrogen Delivery Scenario Model V2 (HDSAM V2) simulates three delivery pathways to rural markets and nine delivery pathways to combined rural/urban markets. Figure 2-66 shows a description of rural delivery pathways. It is assumed that a central production plant is located at the intersection of highways, thus capable of supplying hydrogen to all four market segments of the intersecting highways. Rural refueling stations are located equidistant from each other along the highway segment. The model allows the number of segments to be varied but each segment is assumed to be identical in demand. For practical considerations, the model restricts the length of each highway segment to a maximum of 300 miles for truck deliveries and a maximum of 1000 miles for pipeline deliveries. Delivering hydrogen to this type of market can take place by one of three modes, tube-trailers, liquid trucks, or pipeline. It should be noted that mixed-mode deliveries are not modeled for this market since the refueling stations are assumed to be located near to the interstate highways, thus rendering mixed-mode deliveries not to be economically viable.

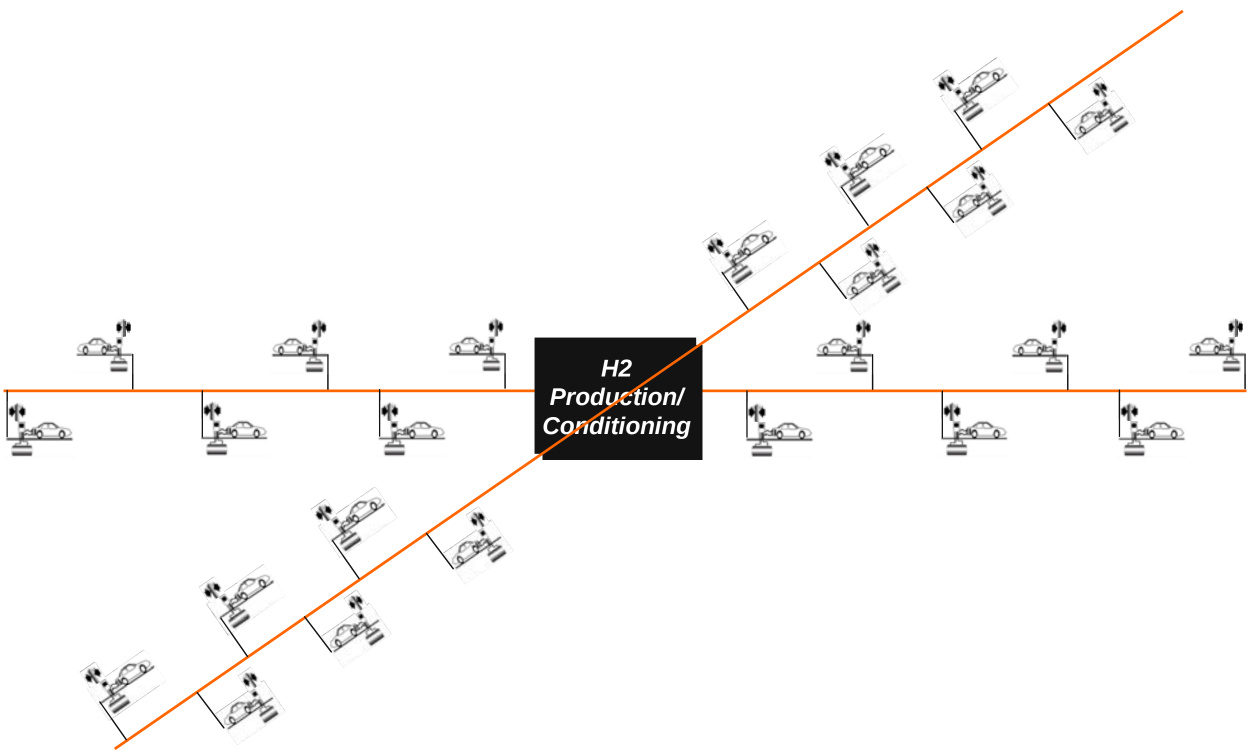



Figure 2-66 Description of Delivery Pathways for Rural Markets

HDSAM 2.0 is also capable of simulating a combined urban/rural market, in which the central production plant is located in a rural area near a highway at a specified distance from an urban market such that the production plant supplies hydrogen to the urban market as well as the refueling stations that are distributed along the interstate segment connecting the production plant to the urban market. In such scenario, all of the refueling stations which are served by the production plant are assumed to have the same demand profile, and thus the design capacities of the delivery components and the infrastructure storage are calculated based on the combined urban/rural market demand. The description of such a combined market is shown in Figure 2-67. The nine possible delivery pathways for this combined market are similar to pathways 1-9 described above in sections 2.4.1-2.4.3 for urban deliveries.

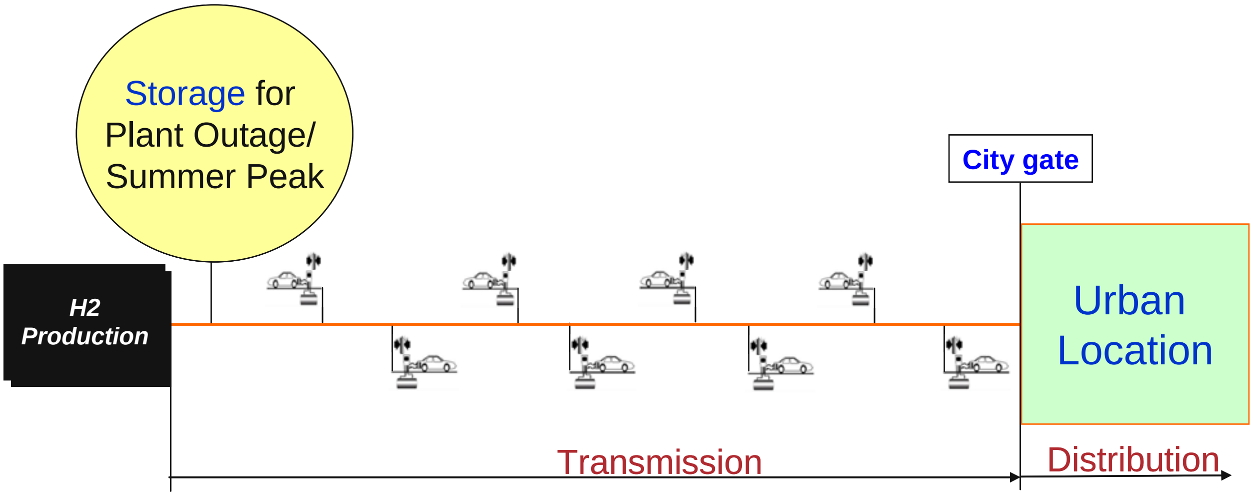



Figure 2-67  Description of Delivery Pathways for Combined Urban/Rural Markets

The H2A Hydrogen Delivery Scenario Model V2 (HDSAM V2) was utilized to perform a parametric analysis to investigate the effect of key delivery parameters on the delivery cost of hydrogen from its point of supply in central plants to the points of demand at refueling stations. In particular, the studied parameters included the market size and penetration of hydrogen vehicles in urban markets, the refueling station size in a given market, the transmission distance of hydrogen from its production site to the city boundaries, and the delivery mode through which hydrogen is delivered from its production site to refueling stations within the city boundary. All other parameters, such as those characterizing the duration of plant outage as well as the seasonal and daily demand profiles in any given market, were kept constant at their default values in this analysis. The default values for the delivery parameters are provided in Section 2 of this report. It should be noted that the results provided in this section of the report are produced for single-mode deliveries to urban markets, although the model is capable of simulating mixed-mode deliveries, rural markets, and combined urban/rural markets.

To highlight the major enhancements made to the characterization hydrogen delivery pathways, the levelized costs of hydrogen delivery produced by V1.0 and V2.0 of HDSAM were compared. Figure 3-1 compares the delivery cost of hydrogen to Indianapolis from a central plant located 62 miles (100 km) away from the city via pipeline delivery and using geologic storage to handle the summer peak demand and planned winter plant outage for maintenance. In this comparison, the refueling stations were sized to supply an annual average daily demand of 1050 kg/day.

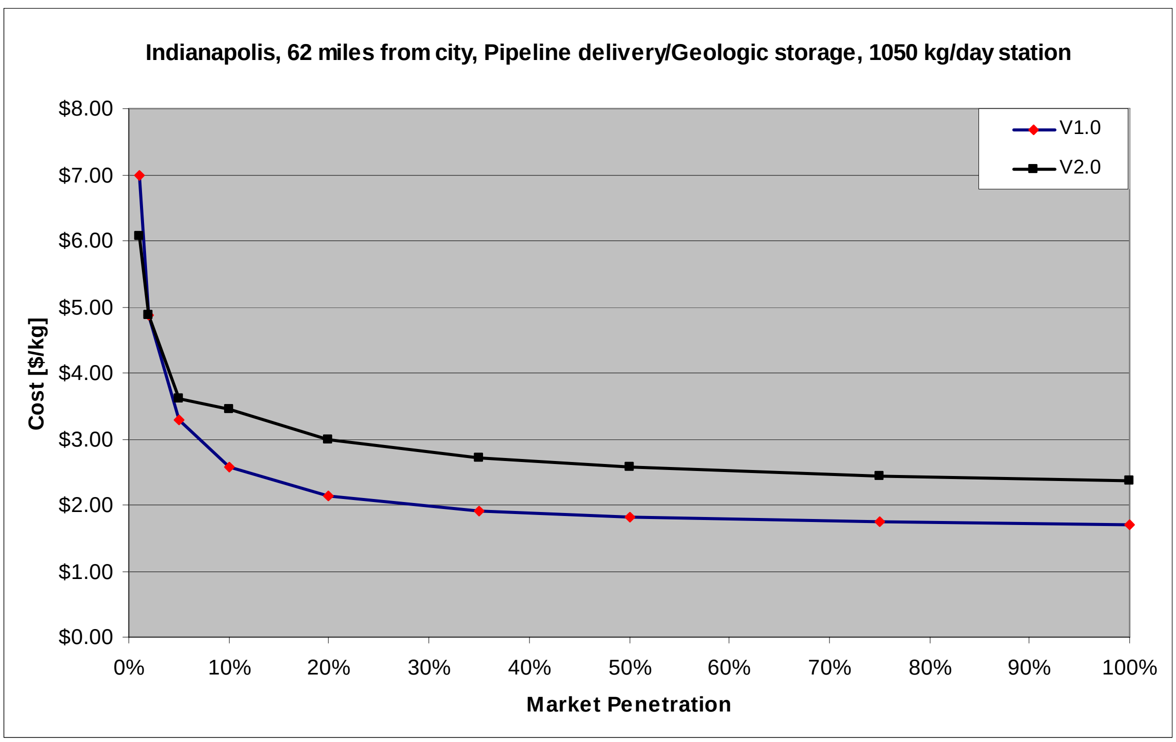



Figure 3-1 Comparison of Pipeline Delivery Cost Predictions by V1.0 and V2.0 of HDSAM

As shown in Figure 3-1, HDSAM V2.0 predicts a higher deliver cost than that of V1.0 by approximately $0.8 at market penetrations above 5%. For this scenario, almost all of the difference could be attributed to the increase in refueling station contribution to the delivery cost in V2.0 compared to that of V1.0 of the model. This is not surprising since in HDSAM 2.0, the refueling station design and optimization were carefully developed based on improved accounting for supply and demand variation profiles, current refueling stations performance data, components' costs, storage needs, and the dynamics of dispensing hydrogen into vehicles' tanks. HDSAM V1.0 was not based on a detailed hourly demand profile, did not account for storage needs or electrical upgrades at the station, and assumed lower cost of components than those adopted in V2.0.

Figure 3-2 shows a comparison of components' cost predictions between V1.0 and V2.0 of HDSAM for the delivery scenario shown of Figure 3-1. It is clear from the figure that the refueling station contribution to the total delivery cost is the highest among all components in both versions of the model for the pipeline delivery pathway, and that the refueling station cost is responsible for most of the increase in the total delivery cost of V2.0 over that of V1.0 of the model. The slight increase in distribution pipeline cost prediction of V2.0 over V1.0 is almost negated by a corresponding decrease in the central compressor cost prediction. The transmission pipeline and the geologic storage cost contributions are essentially unchanged between the two versions of the model.

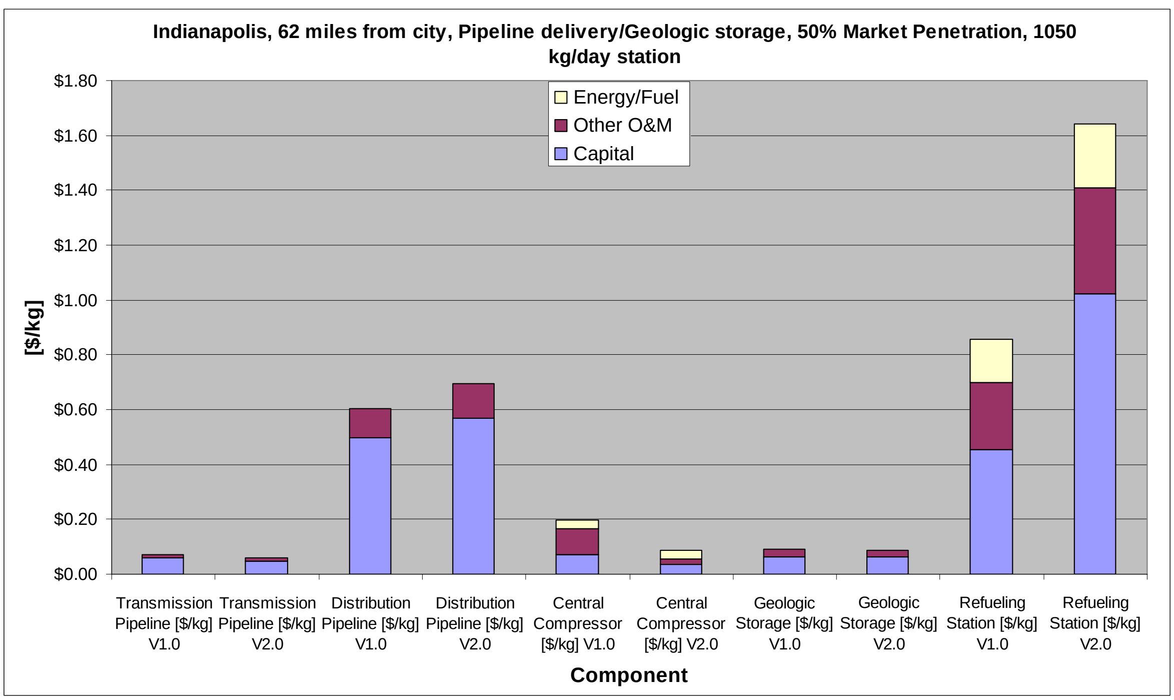



Figure 3-2 Comparison of Components' Cost Contributions in V1.0 and V2.0 of HDSAM for Pipeline Delivery Pathway

Another useful comparison is shown in Figure 3-3, which highlights the relative contribution of compression, storage (geologic storage, and station storage and cascade systems), and transport (pipeline cost) to the total delivery cost. For the above delivery scenario, Figure 3-3 shows that in V1.0 and V2.0 of the model, compression has the highest contribution to the total delivery cost, followed by transport and storage. It should be noted that the refueling station cost in Figure 3-3 does not include the cost of refueling station compression or storage, since they are already included in the compression and storage cost, respectively.

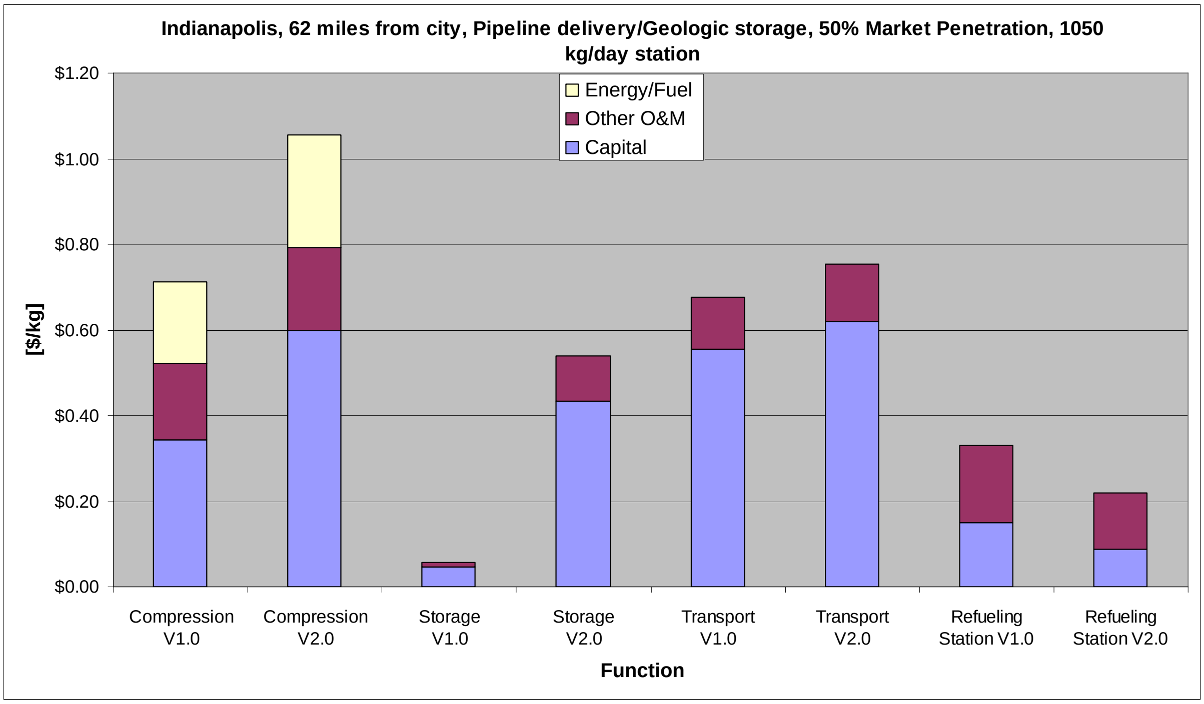



Figure 3-3 Comparison of Cost Contributions by Function in V1.0 and V2.0 of HDSAM for Pipeline Delivery Pathway

It is clear from Figure 3-3 that the compression and storage requirements have increased dramatically in V2.0 of HDSAM compared to those estimated in V1.0 of the model. Furthermore the transport (pipeline) cost has also increased due to the revised cost of pipeline in urban and downtown areas. Finally, the remainder of the refueling station cost has deceased in V2.0 compared to V1.0 of the model due to the lower estimates of direct/indirect costs in V2.0 of the model.

The following list summarizes the revisions and enhancements made to V2.0 of HDSAM that resulted in significant difference in the predicted delivery cost relative to that of V1.0 of the model.

- The installed capital costs have significantly increased for all compressors and storage tanks and vessels except for the central (large) compressor cost, which was revised in V2.0 to be lower than that of V1.0 of the model.
- A production plant outage period has been incorporated in V2.0 of the model, which resulted in large infrastructure storage requirement.
- A more realistic hourly refueling stations demand profile has been incorporated in V2.0 of the model, which resulted in larger compression and storage requirement at the refueling station.

- Most of the components' sizes have been calculated in V2.0 to be lower than those in V1.0 due to the replacement of the universal capacity factor, which was applied across all components of the delivery pathway in V1.0, with a more precise sizing of components in V2.0 through the implementation of appropriate infrastructure storage.
- The direct/indirect costs (as percentages of the installed capital cost) have been revised in V2.0 to be lower than those in V1.0 of the model based on the most recent available data for these costs.

Figure 3-4 compares the delivery cost of hydrogen to Indianapolis from a central plant located 62 miles away from the city via liquid trucks using liquid storage to handle the summer peak demand and planned winter plant outage for maintenance. In this comparison, the refueling station was sized to supply an annual average daily demand of 1,050 kg/day. As shown in Figure 3-4, HDSAM V2.0 predicts higher delivery costs than V1.0 by less than \$0.5 at market penetrations below 20%. The difference increases to approximately \$1.0 at full market penetration. For this scenario, most of the difference could be attributed to the increase in the liquefaction and refueling station contributions to the delivery cost in V2.0 compared to those of V1.0 of the model as shown in Figure 3-5. It should be noted that the increase in the liquefaction cost is attributed to the additional burden of the 10-day scheduled outage of the production plant (compared to 3-day storage capacity in V1.0) since the liquefaction cost for a given liquefier size is almost the same in the two versions of the model. The increase in the refueling station cost shown in Figure 3-5 for V2.0 is attributed to the increase in the estimated cost of the liquid storage tank, evaporator, controls, and cascade vessels.

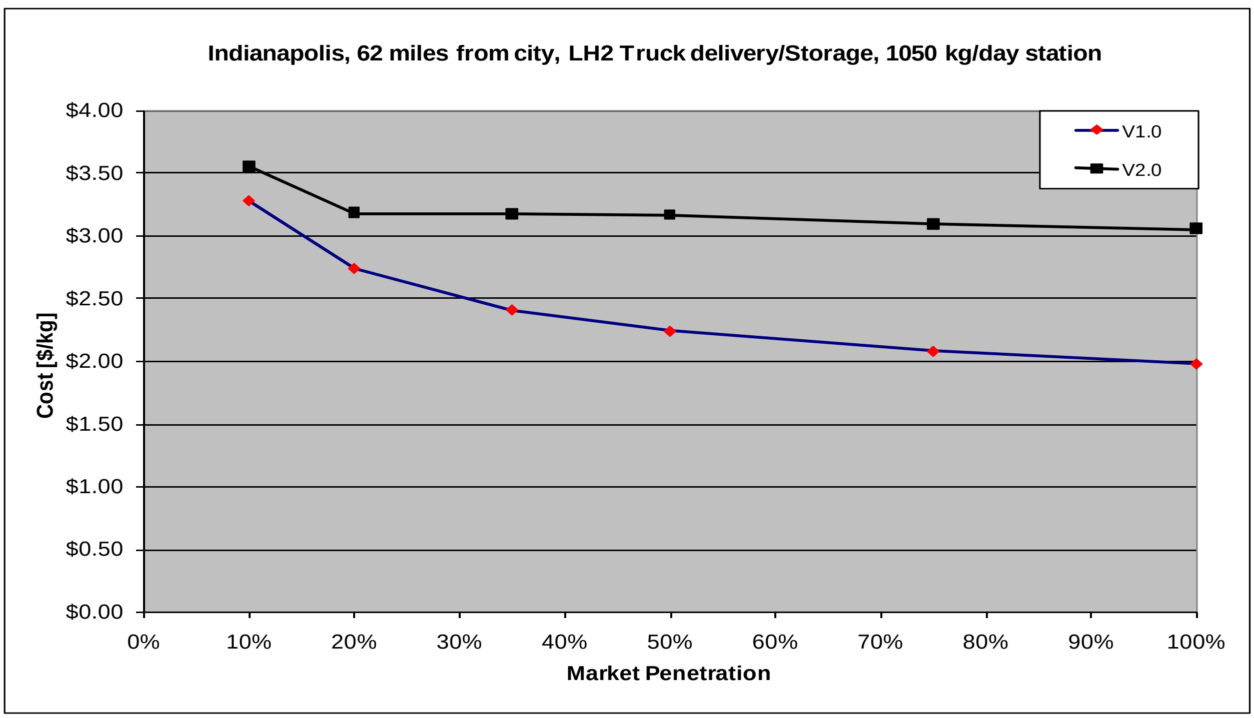



Figure 3-4 Comparison of Liquid Truck Cost Predictions by V1.0 and V2.0 of HDSAM

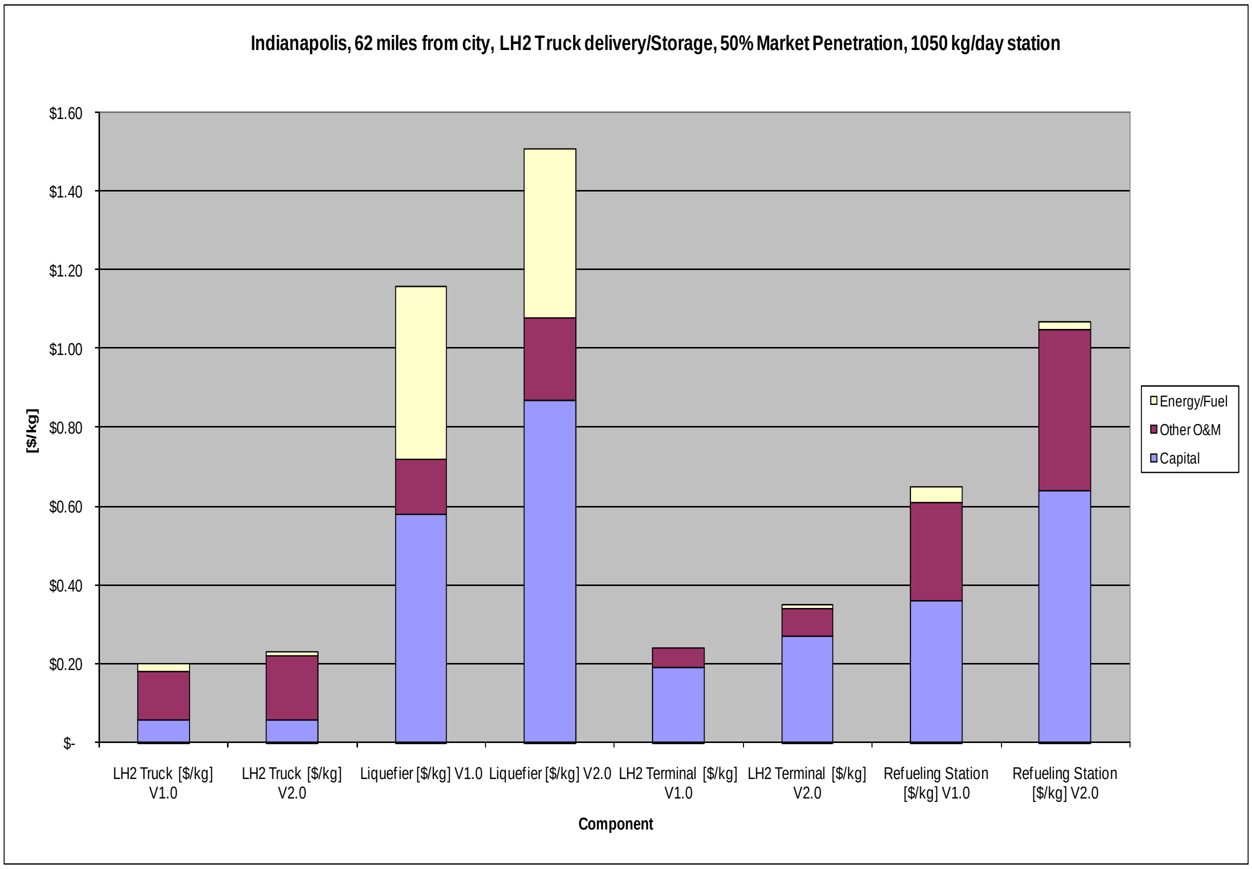



Figure 3-5 Comparison of Components' Cost Contributions in V1.0 and V2.0 of HDSAM for Liquid Truck Delivery Pathway

Figure 3-6 compares the delivery cost of hydrogen to Indianapolis from a central plant located 62 miles away from the city via tube-trailers using geologic storage to handle the summer peak demand and planned winter plant outage for maintenance. In this comparison, the refueling station was sized to supply an annual average daily demand of 100 kg/day. A smaller size station is used because tube trailer stations are restricted to less than 500 kg/day due to a maximum of two truck deliveries per day and the hydrogen capacity of the tube trailer. As shown in Figure 3-6, HDSAM V2.0 predicts higher deliver cost than that of V1.0 by more than $1.0 at low market penetrations by more than $2.0 at higher market penetrations. For this scenario, almost all of the difference could be attributed to the increase in the refueling station contributions to the delivery cost in V2.0 compared to that of V1.0 of the model as shown in Figure 3-7. This is not surprising since in HDSAM 2.0, the refueling station design and optimization were carefully developed based on improved accounting for supply and demand variation profiles, current refueling stations performance data, components' costs, storage needs, and the dynamics of dispensing hydrogen into vehicles' tanks. Figure 3-7 also shows that the tube-trailer cost contribution was revised upward in HDSAM V2.0 due to the assumption of 18 hours of daily operation at the refueling station compared with the 24 hours daily operation previously assumed in V1.0 of the model.

It should be noted that handling the storage requirement for the production plant outage and summer peak demand has been moved from the gaseous terminal in V1.0 to a geologic storage in V2.0 of HDSAM, and thus a corresponding decrease in the gaseous terminal cost contribution is noticed in Figure 3-7.

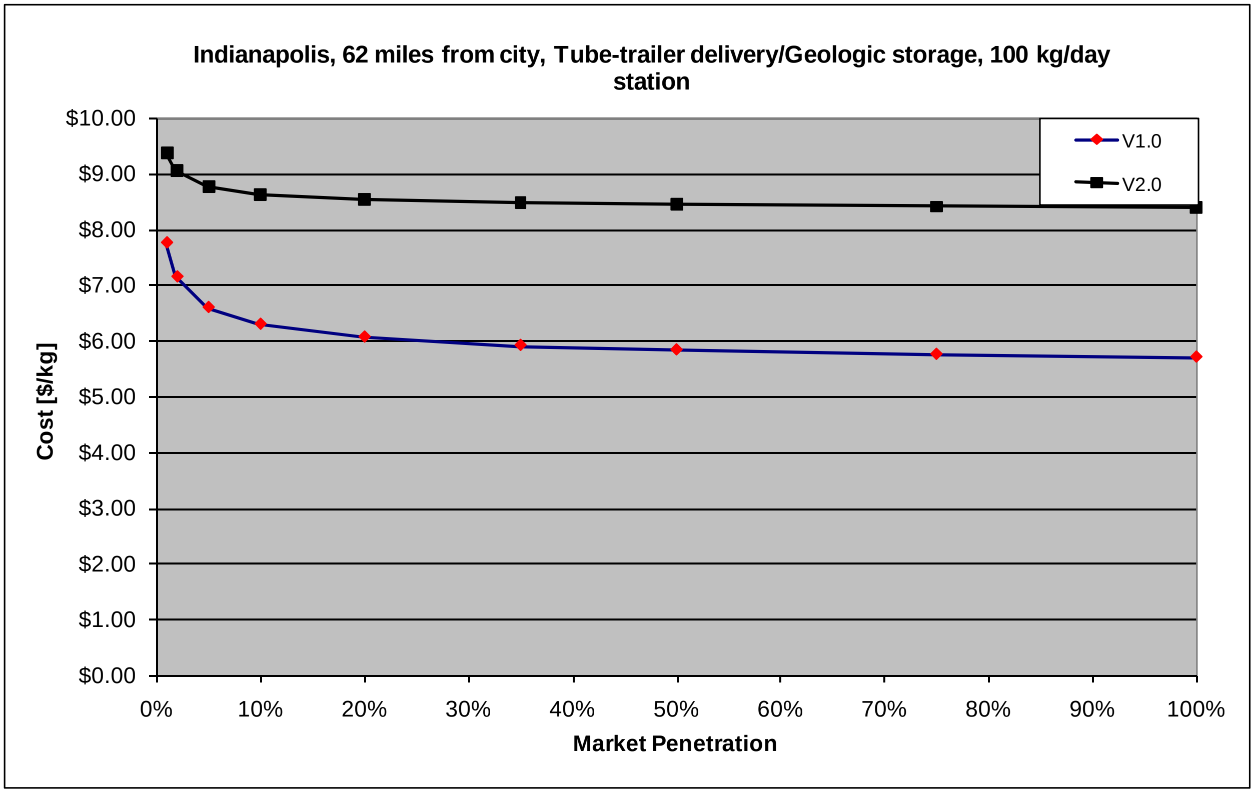



Figure 3-6 Comparison of Tube Trailer Delivery Cost Predictions by V1.0 and V2.0 of HDSAM

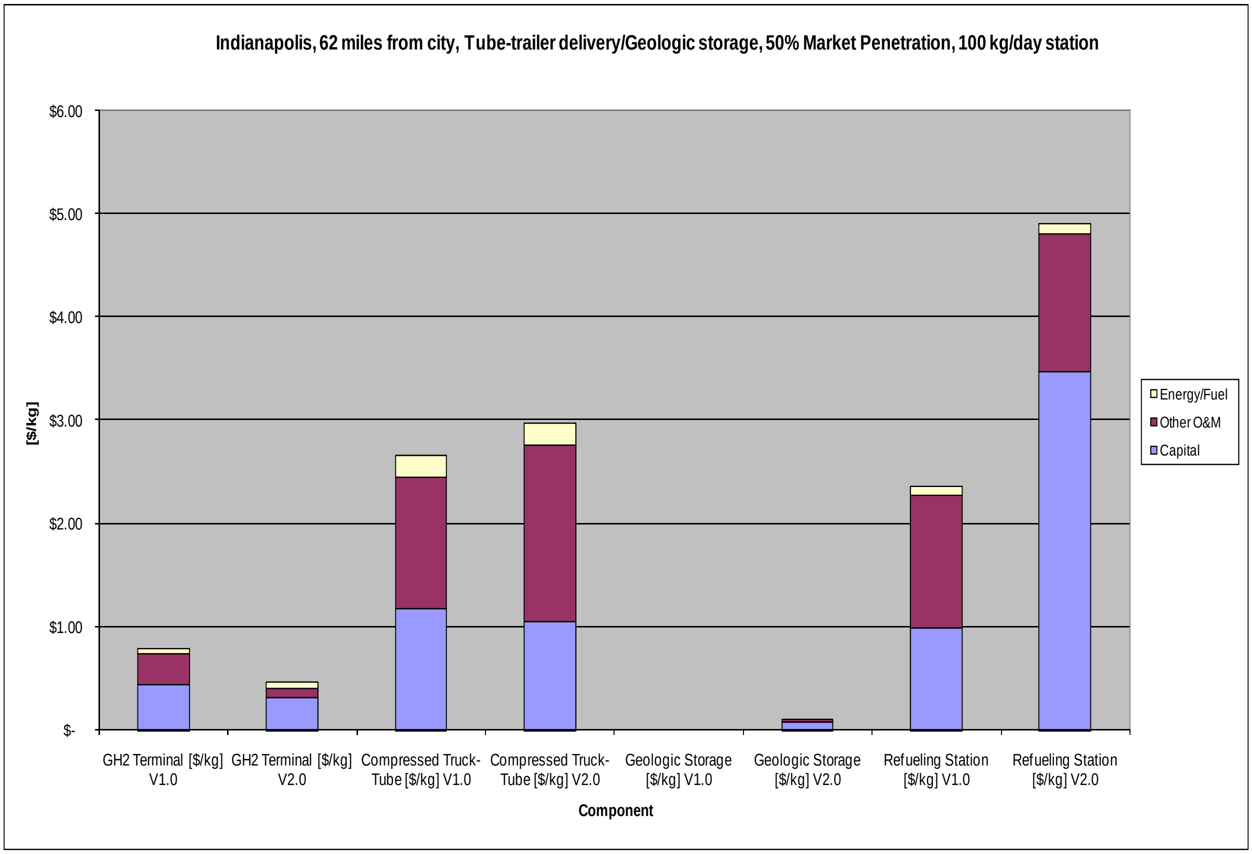



Figure 3-7 Comparison of Components' Contributions in V1.0 and V2.0 of HDSAM for Tube Trailer Delivery Pathway

To study the effect of station size on the cost of delivery for different delivery modes, **Error! Reference source not found.**8 was generated for a small station of 100 kg/day average dispensing capacity in the Los Angeles market for all market penetrations. For such small station size, which is probable at early market transition, the figure indicates that compressed-gas tube-trailer delivery is the most economical mode of delivery compared to the cost of delivery by liquid truck and pipeline modes. It should be noted that such delivery mode would not be practical at high market penetrations, especially in large markets, due to the very large number of refueling stations that would be required. In such case, liquid truck delivery would be a viable choice for delivery since the deliverable capacity of a liquid truck is much higher than that of a tube-trailer, which results in significantly fewer truck deliveries to refueling stations at any market penetration.

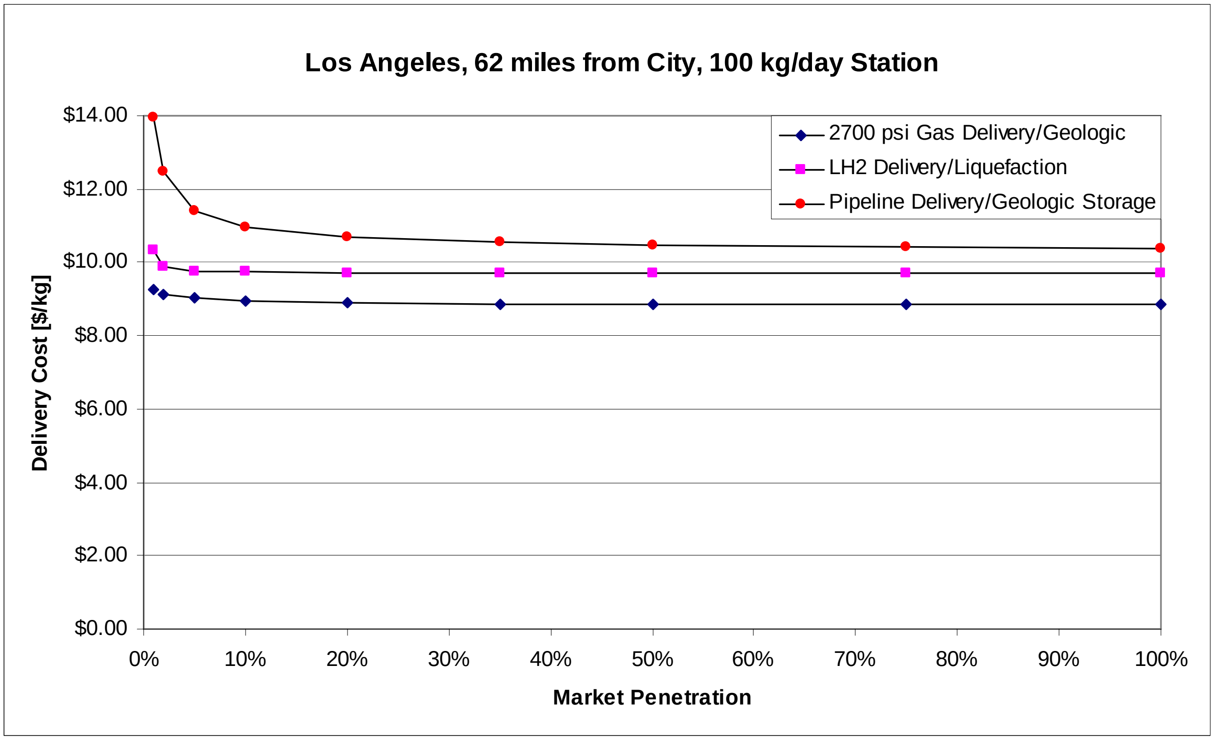



Figure 3-8 Comparison of Tube Trailer Delivery Modes for 100 kg/day Stations

Increasing the station size to a 300 kg/day average dispensing capacity would result in different choices of delivery modes from those indicated in **Error! Reference source not found.**8 for the 100 kg/day station capacity. For a 300 kg/day stations in the Los Angeles market, **Error! Reference source not found.**9 shows that liquid truck deliveries provide the least delivery cost at market penetrations below 10%, while pipeline delivery is the mode of choice for market penetrations above 10%. For all penetrations, tube-trailer deliveries are of higher cost than those of liquid truck or pipeline deliveries, in addition to the potential logistics problem associated with the requirement of two tube-trailer deliveries per day for such station size. It should be noted that higher pressure tube deliveries (e.g., 5,000 psi or 344.8 bars), would require fewer deliveries per day and lower delivery cost for this station size, and could potentially address some of the aforementioned logistics problems, especially at lower market penetrations. It is also expected from the trend implied in **Error! Reference source not found.**8 and **Error! Reference source not found.**9 that station sizes larger than 300 kg/day would expand the advantage of lower pipeline delivery cost to market penetrations below 10% for the Los Angeles market.

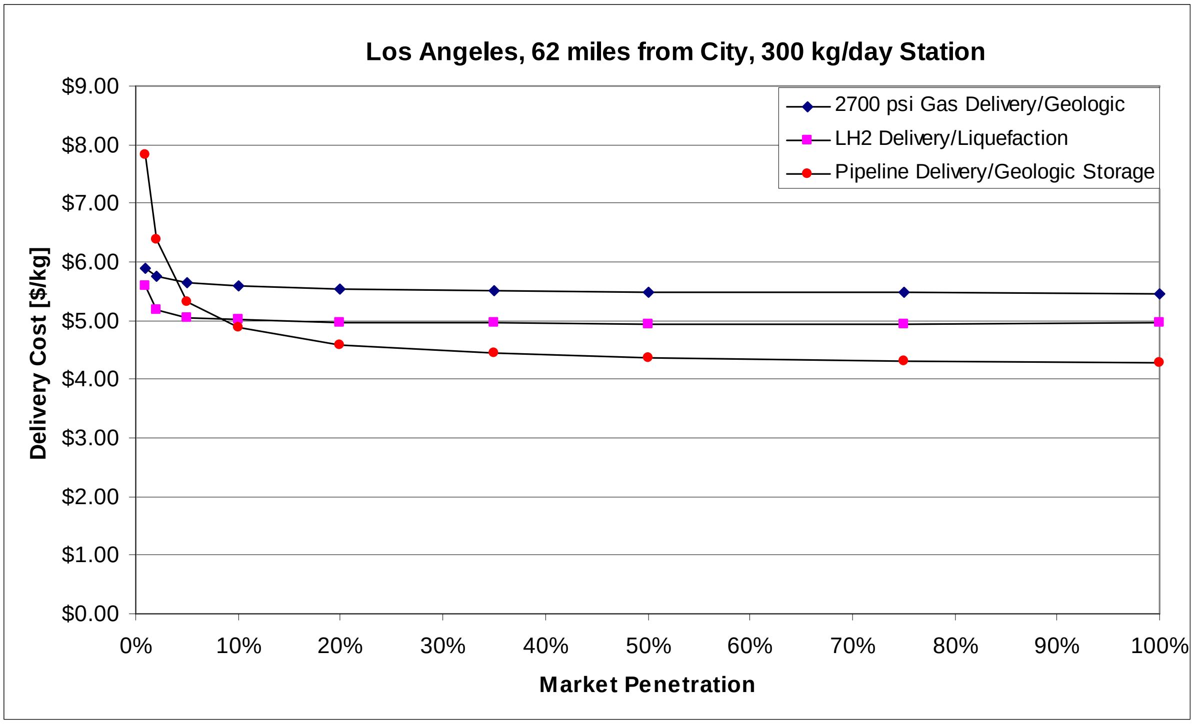



Figure 3-9 Comparison of Delivery Modes for 300 kg/day Stations

The location of the production plant with respect to any given urban market is an important parameter that could significantly affect the delivery cost. **Error! Reference source not found.**10 shows the delivery cost as a function of the distance from production plant to the city boundary of Indianapolis at 10% market penetration and for a station size of 200 kg/day. For such low market penetration, the figure indicates that tube-trailer deliveries are more economical than the two other delivery modes for distances less than approximately 80 miles simply because of the small station size assumed for that market. For production distances greater than 80 miles, the pipeline delivery mode becomes more economical than the tube-trailer delivery due to the rapid increase in the required number of tube-trailers as the production location becomes farther away from the city. It should be noted that, among all shown delivery modes, the liquid truck delivery exhibits the lowest rate of increase in delivery cost as the distance increases from the production site to the city gate. This is attributed to the high capacity of the liquid trucks and its low cost compared to the liquefaction and liquid storage cost in this delivery pathway. This gives the liquid truck delivery a cost advantage over the two other delivery modes at distances longer than 300 miles at this low market penetration and for such small station size.

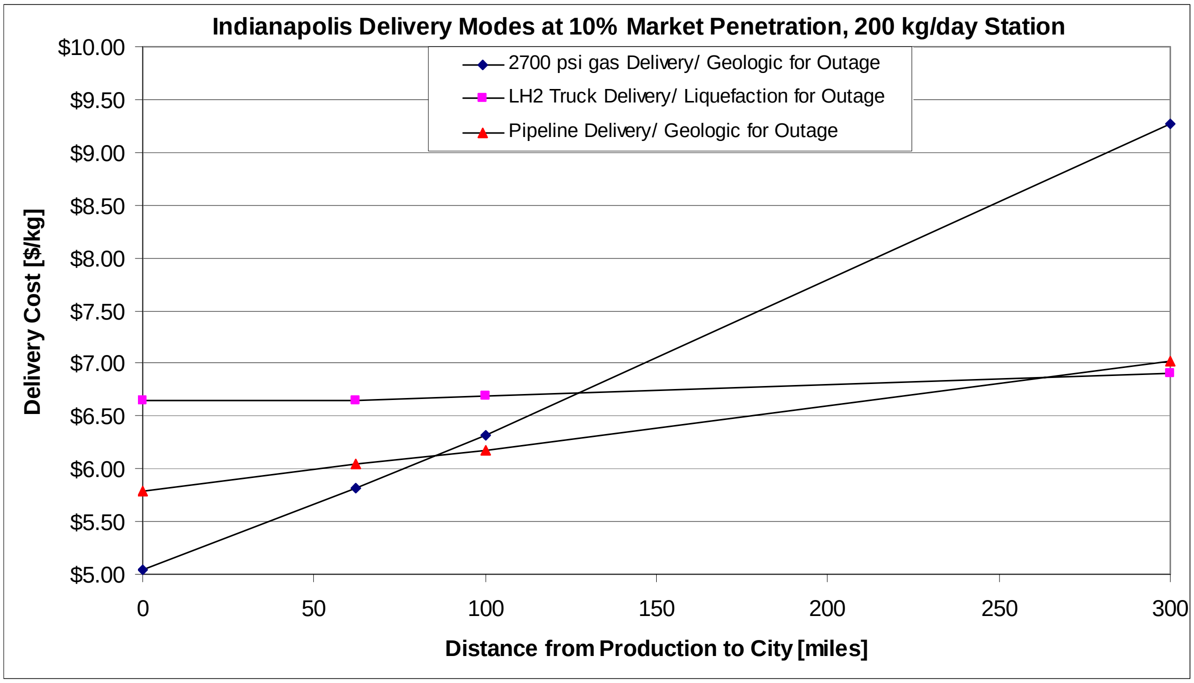



Figure 3-10 Comparison of Delivery Modes at 10% Market Penetration and 200 kg/day Stations

As the market penetration and the station size increase, pipeline delivery becomes more economical than the other modes of delivery regardless of the distance from production site to city gate as shown in **Error! Reference source not found.**11 for Indianapolis at 20% market penetration and 400 kg/size station. This is because the cost contribution of the service lines greatly decreases as the size of the stations increase, and the transmission line cost contribution benefits from the economies of scale at higher market penetrations.

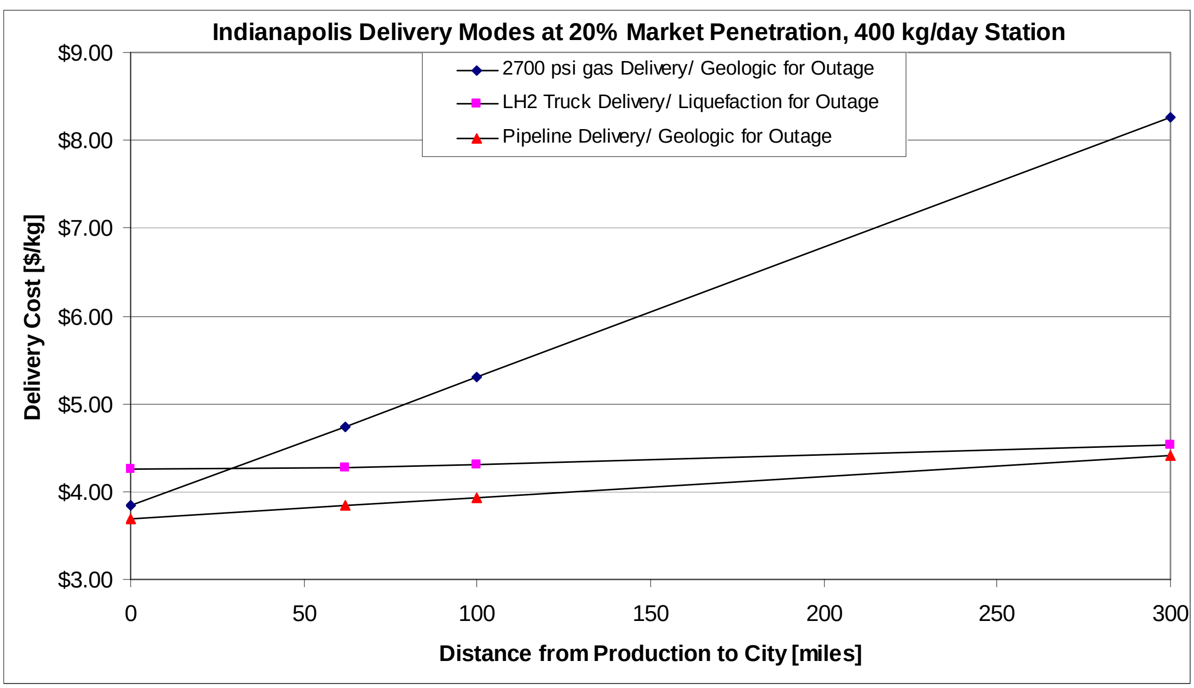



Figure 3-11 Comparison of Delivery Modes at 20% Market Penetration and 400 kg/day Stations

Figure 3-12 shows the effect of the tube-trailer capacity on the hydrogen delivery cost to 400 kg/day refueling stations in the Indianapolis market, located at 62 miles from the production plant. The figure includes the current 2650 psi (182.8 bars) 280 kg tube-trailer deliverable capacity, the 5000 psi (344.8 bars), 500kg tube-trailer deliverable capacity currently in demonstration, and a conceptual 1000 kg capacity tube-trailer. The loading time and tube-trailer cost assumptions are 6 hours and $225k, 10 hours and $350k, and 12 hours and $450k for the 2650 psi (182.76 bars), 5000 psi (344.8 bars), and 1000 kg technologies, respectively. Figure 3-12 shows a drop of about $1.0 in delivery cost from the 2650 psi (182.8 bars) to the 5000 psi (344.8 bars), tube-trailers, and an additional drop of $0.5 if the conceptual 1000 kg tube-trailer could be materialized. It should be noted that the results are based on the assumptions that the refueling stations daily operation is 18 hours and that the maximum number of deliveries to any refueling station is limited to two per day. The later assumption has been questioned by some logistic experts who suggested that the maximum number of daily deliveries should be limited to one delivery per day.

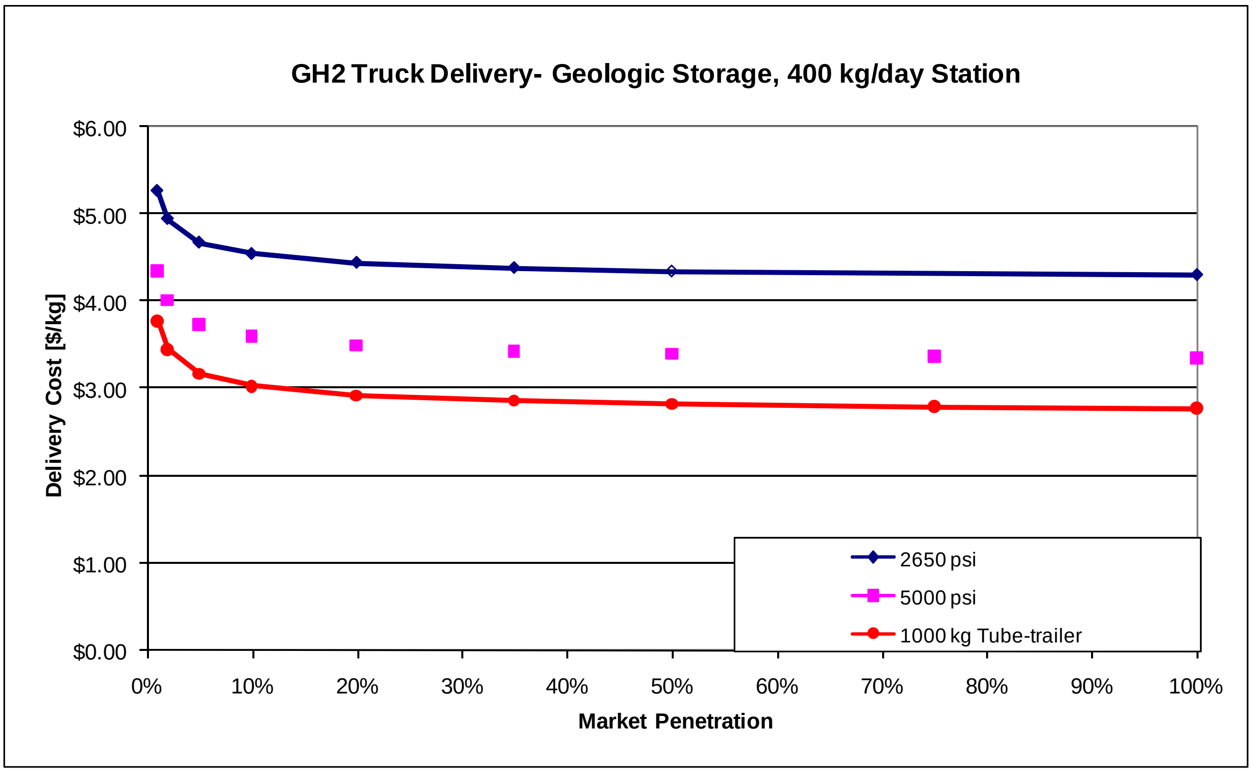



Figure 3-12 Comparison of Hydrogen Delivery Costs by Tube Trailer with Different Capacities to the Indianapolis Market with the Production Plant 62 Miles Away

Figure 3-13 shows a comparison of cost of hydrogen delivery to the Indianapolis market, located at 62 miles from the production facility, via 2700 psi (186.2 bars), tube trailers for three different station capacities of 100, 200, and 400 kg/day. It should be noted that as the station capacity increases in a given market, the corresponding number of stations would proportionally decrease to satisfy the same demand of that market. The figure shows a significant drop in the delivery cost by distributing the hydrogen to fewer stations with larger capacities in the Indianapolis market for all market penetrations. The figure suggests a drop of about $2.5 by delivering to 200 kg/day stations when compared with the delivery cost to 100 kg/day stations, and a further drop of about $1.5 by delivering to 400 kg/day stations. The drop in delivery cost with increasing station capacity is attributed to the station economies of scale associated with the cost-per-kg of the electrical upgrade, controls and safety equipment as well as the compressors and cascade charging system. A smaller portion of the drop in delivery cost for larger stations is associated with the drop in the number of tube-trailers required for hydrogen delivery as the number of stations decreases with increasing the station capacity. It should be mentioned that the decrease in the number of stations in a given market due to the increase in the station capacity would affect the accessibility of refueling stations to hydrogen vehicles in that market.

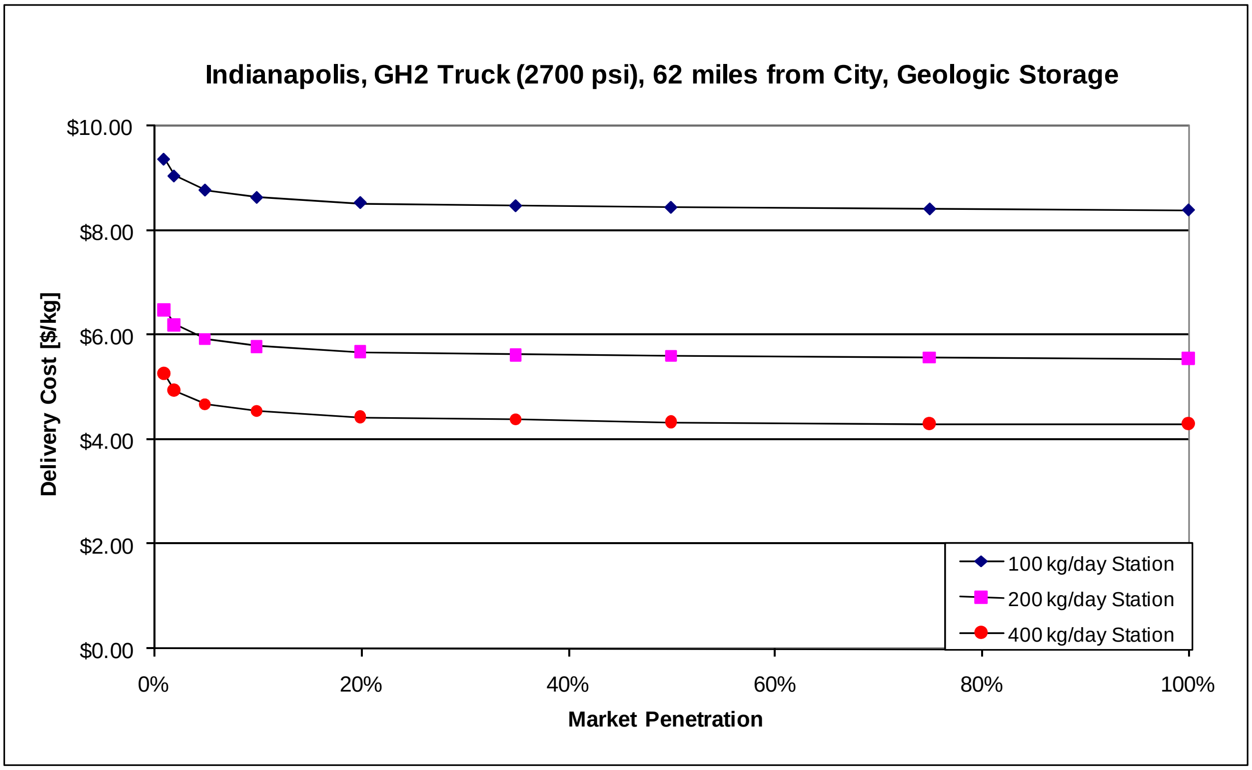



Figure 3-13 Comparison of Hydrogen Delivery Cost by Tube Trailers to the Indianapolis Market with the Production Plant 62 Miles Away to Refueling Stations with Different Design Capacities

Figure 3-14 shows a comparison of cost of hydrogen delivery to the Indianapolis market, located at 62 miles from the production facility, via liquid trucks for three different station capacities of 300, 1000, and 4000 kg/day. It should be noted that as the station capacity increases in a given market, the corresponding number of stations would proportionally decrease to satisfy the same demand of that market. Also, it should be noted that the decrease in the number of stations in a given market due to the increase in the station capacity would affect the accessibility of refueling stations to hydrogen vehicles in that market. The figure shows a significant drop in the delivery cost by about $2.0 for 1000 kg/day stations when compared to the delivery cost for 300 kg/day stations in that market. The drop in delivery cost becomes insignificant as the station capacity increases from 1000 kg/day to 4000 kg/day. The drop in delivery cost with increasing the station capacity from 300 kg/day to 1000 kg/day is attributed to the limitation on the number of unloads per trip (to minimize the large unloading losses), which results in a large storage requirement per refueling station relative to the station size for smaller size stations. HDSAM 2.0 limits that the number of unloads to three drops per trip.

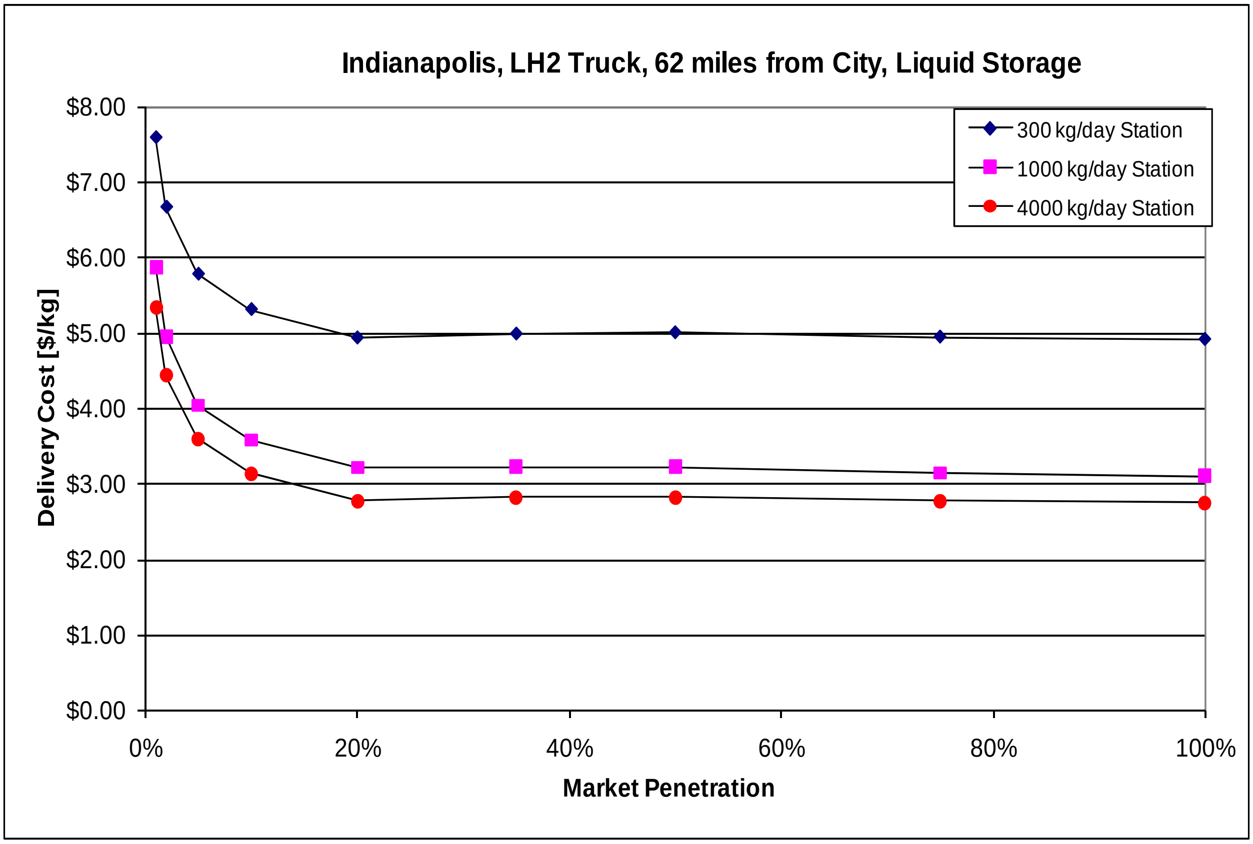



Figure 3-14 Comparison of Hydrogen Delivery by Tube Trailer with Different Design Capacities to the Indianapolis Market with the Production Plant 62 Miles Away

Figure 3-15 shows a comparison of cost of hydrogen delivery to the Indianapolis market, located at 62 miles from the production facility, via pipelines for three different station capacities of 300, 1000, and 4000 kg/day. It should be noted that as the station capacity increases in a given market, the corresponding number of stations would proportionally decrease to satisfy the same demand of that market. Also, It should be noted that the decrease in the number of stations in a given market due to the increase in the station capacity would affect the accessibility of refueling stations to hydrogen vehicles in that market. The figure shows a significant drop in the delivery cost by about $1.5 for 1000 kg/day stations when compared to the delivery cost for 300 kg/day stations in that market.  The drop in delivery cost becomes less significant as the station capacity increases from 1000 kg/day to 4000 kg/day. The drop in delivery cost with increasing the station capacity is attributed to the station economies of scale associated with the cost-per-kg of the electrical upgrade, the controls and safety equipment, and the compressors and cascade charging system. A smaller portion of the drop in delivery cost for larger stations is associated with the drop in the number and cost of distribution pipelines as the number of stations decreases with increasing the station capacity.

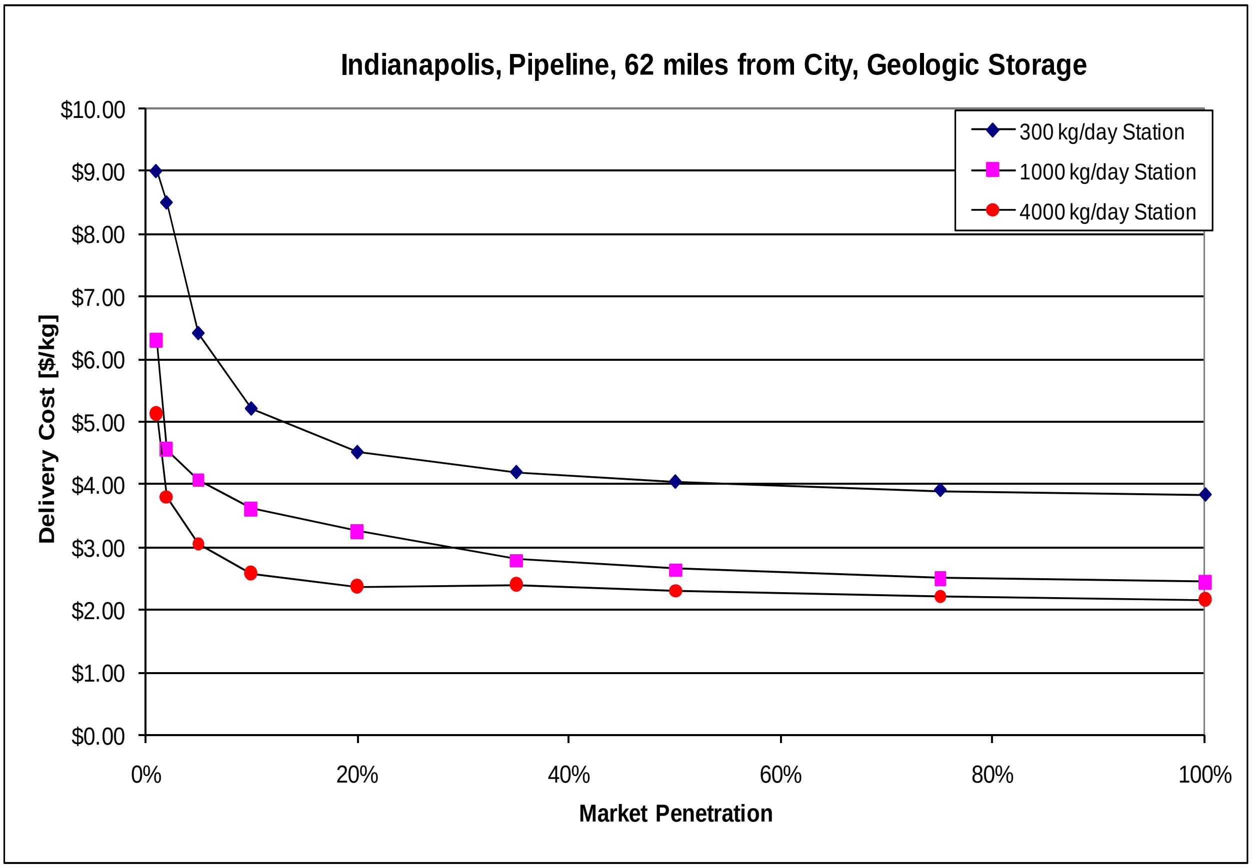



Figure 3-15 Comparison of Hydrogen Delivery by Pipeline with the Production Plant 62 Miles Away to Refueling Stations with Different Design Capacities

Figure 3-16 shows the delivery cost difference associated with the selection of different components for handling the variation of hydrogen supply due to the schedule plant outage and the variation of demand due to the increase in hydrogen demand during the summer season. HDSAM V2.0 assumes the plant outage to be scheduled in the winter for 10 days and the summer demand to increase by 10% over the yearly average demand for a period of 120 days. The two options for handling such large variations in supply and demand in HDSAM are geologic storage or liquefaction/liquid storage. Figure 3-16 shows that the liquefaction/liquid storage option costs about $0.8 more than the geologic storage option. Using the default assumptions in HDSAM, the geologic storage option cost contribution is in the order of $0.1-$0.3/kg compared to $0.8-1.8/kg for the liquefaction/liquid storage option, with the higher cost numbers associated with the low average daily demand of hydrogen. It should be noted that the geologic storage option may not be available along the delivery pathway to certain markets, in which case the liquefaction/liquid storage would be the only available option for these markets.

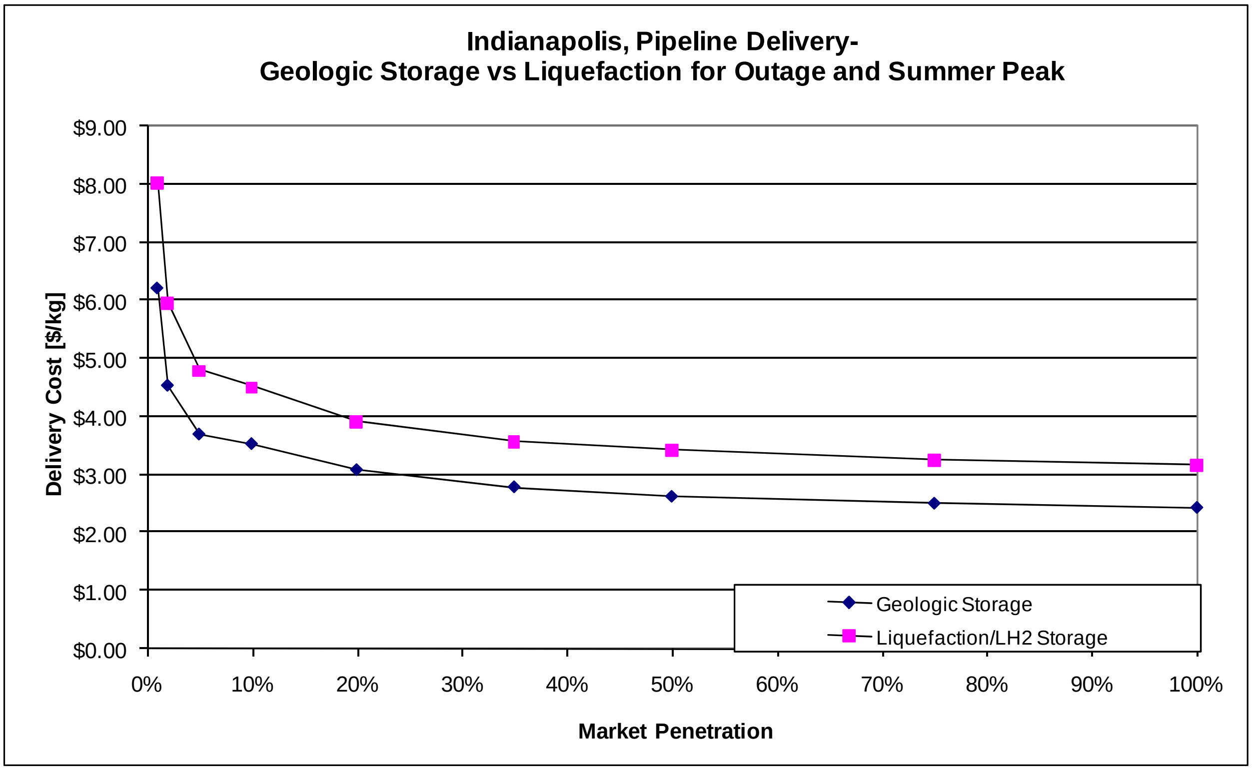



Figure 3-16 Comparison of Delivery Cost with Different Component Selections to Handle Summer Peak Demand and Winter Plant Maintenance Outage

One important aspect of hydrogen delivery is the energy use and greenhouse gases (GHGs) emissions associated with the hydrogen transmission and distribution from production plants to refueling stations by different delivery modes. **Error! Reference source not found.**17 shows the on-site energy use and the upstream energy consumption (associated with producing and supplying the on-site energy source) for the Indianapolis market at a distance of 62 miles from the production plant by the three main delivery modes at 20% market penetration and 400 kg/day station. The figure indicates that compression energy is significant for compressed gas deliveries via tube-trailers or pipeline, which approximately equals 40% of the energy content (lower heating value) of the delivered hydrogen. The distribution of energy consumption varies between these two gas-delivery modes. While the storage compression takes place at the gaseous (GH2) terminal for the tube-trailer delivery, such compression takes place at the refueling station for the pipeline delivery. Such difference in the location of storage compression results in lower energy consumption at the refueling station for tube-trailer delivery compared to that for pipeline delivery. The liquid truck delivery consumes significantly higher energy than that of compressed gas deliveries, primarily due to the high energy consumption in the liquefaction process. Liquid truck delivery consumes 80% of the energy in the hydrogen as shown in **Error! Reference source not found.**17.

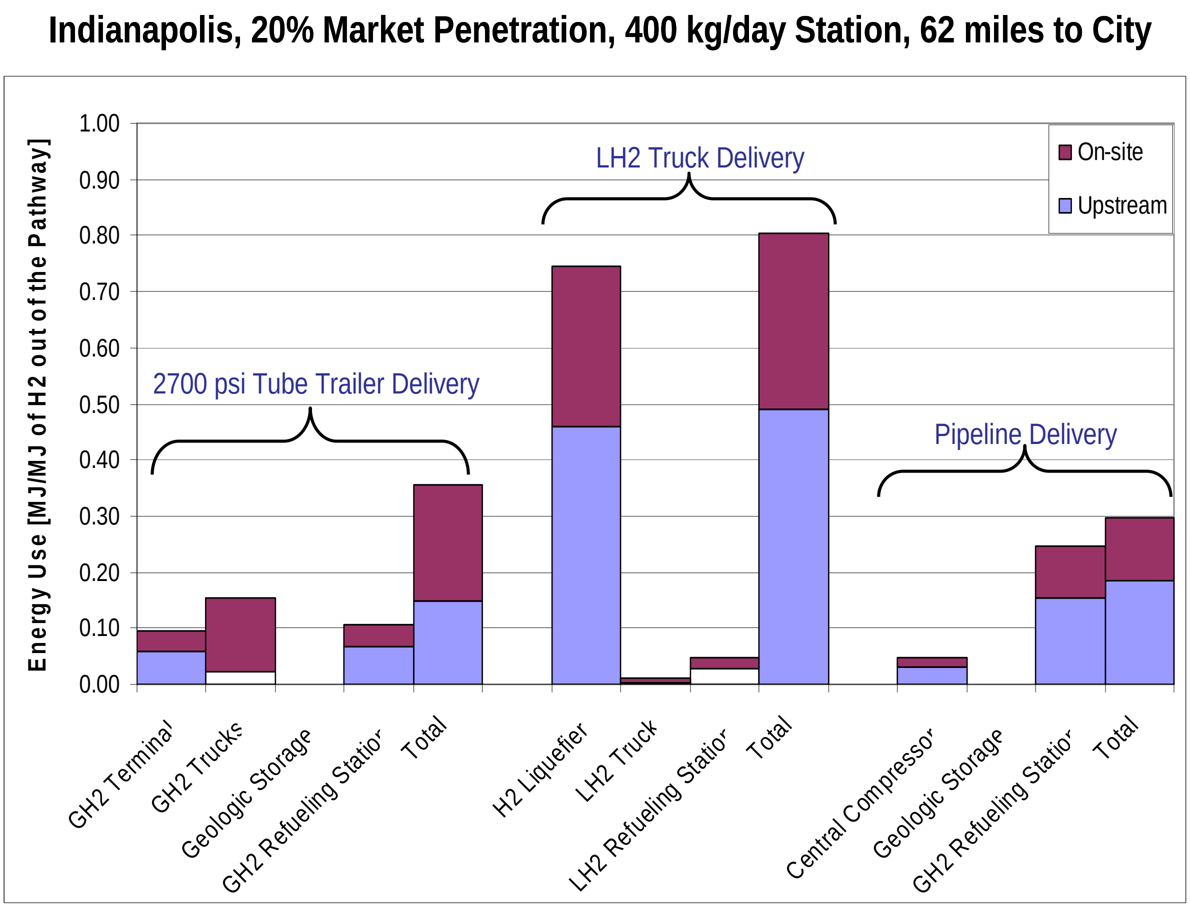



Figure 3-17 Comparison of Energy Use by Delivery Mode to the Indianapolis Market

**Error! Reference source not found.**18 shows the GHGs emissions associated with the energy use by each of the three delivery modes. The GHGs emissions by each component in any of the delivery pathways are proportional to the energy use by such component. The only difference is that the ratios of the on-site to the upstream emissions do not necessarily correspond with the ratio of the on-site to the upstream energy use of **Error! Reference source not found.**17. This is mainly the case with the on-site use of electricity, which involves no emissions since all the emissions have occurred upstream in the processes of generating electricity at the power plants. Other GHGs emissions shown in **Error! Reference source not found.**18, such as those emitted by compressed-gas and liquid trucks, occur mainly onsite with a smaller fraction occurring upstream in the process of recovering and processing the fuel from its petroleum source. As can be seen in the figure, the liquefier is the single most emitting component of GHGs among all components in the three delivery pathways by a large margin.

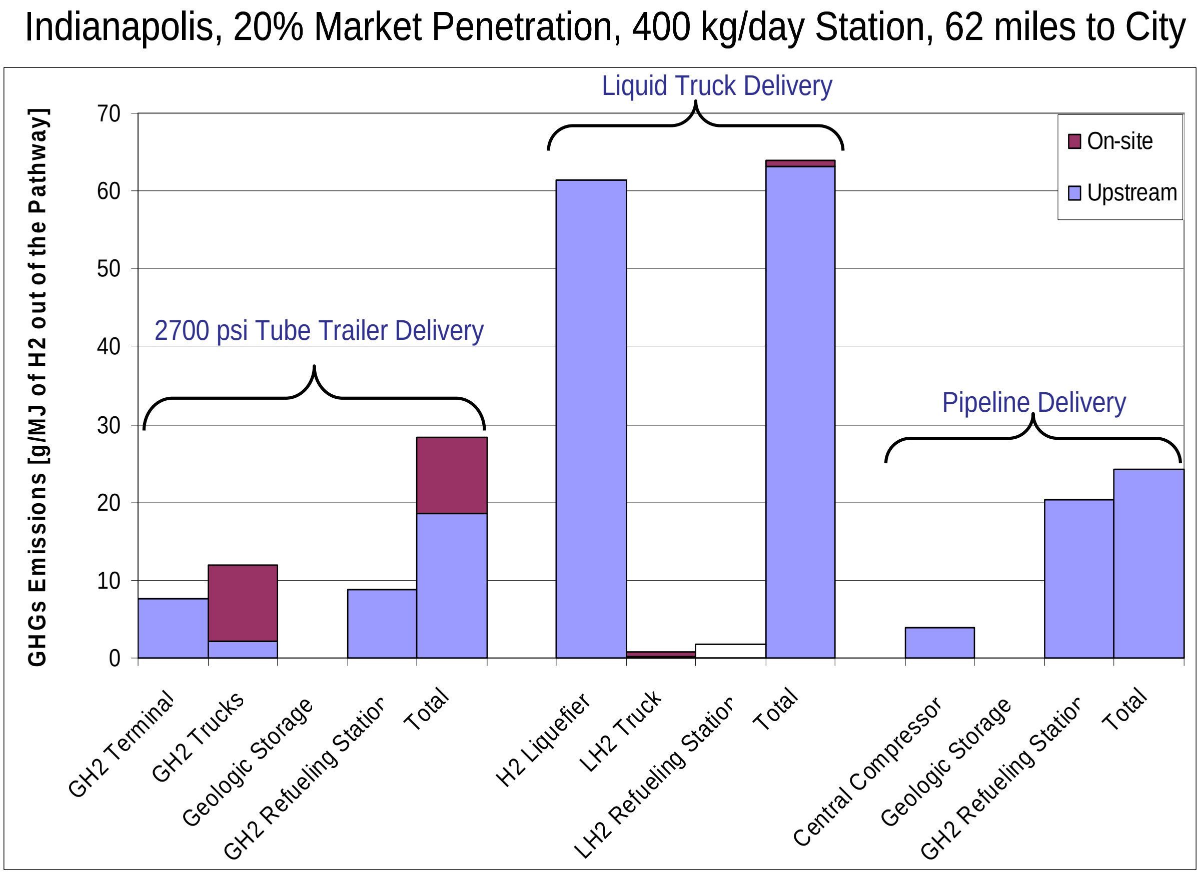



Figure 3-18 Comparison of GHG Emissions by Delivery Mode to the Indianapolis Market

The H2A Delivery Scenario Model V2 (HDSAM V2) estimates the delivery cost of hydrogen using current costs of available technologies. The model's purpose is to identify components with the largest impact on delivery cost and to guide the direction of research for possible delivery cost reductions. The model allows the user to evaluate a broad range of variables in the calculation of hydrogen delivery cost, including:

- Urban, rural, or mixed markets
- City (or city population)
- Hydrogen market penetration
- Refueling station capacity
- Distance from production plant to the hydrogen market
- Delivery method (tube trailer, liquid truck, or gas pipeline)
- Storage method for summer peak demand and production plant outages (geologic or liquid)
- Refueling station hourly demand profiles.

The results of numerous model runs, over a wide range of market conditions, show the following general conclusions for currently available hydrogen delivery technologies:

- At low market demands (<10% market penetration)with a central plant 62 or greater miles from the city, the delivery cost of hydrogen to refueling stations is high for all delivery modes ($5-$10/kg of hydrogen or even higher), suggesting that distributed production of hydrogen at refueling stations may serve the early markets for hydrogen vehicles. Alternatively a small semi-central plant located at the city gate may provide sufficiently low delivery cost by tube trailers.
- If the city size is small (<500,000 people), if the market penetration is low (<10%), if the refueling station capacity is small (<400 kg/day), and if the distance to the production plant is modest (<62 miles or 99 km), then hydrogen delivery by tube trailer is the lowest cost option. For early market conditions, delivery costs of $5 to $12/kg are anticipated.
- If one or two market conditions move from the 'small' to the 'large' category, hydrogen delivery by liquid truck may be the lowest cost approach. However the energy consumed is 80% the energy in the hydrogen delivered due to the energy intensity of hydrogen liquefaction.
- For a maturing hydrogen fuel cell vehicle market (>20% market penetration), hydrogen delivery by pipeline is almost universally preferred, with expected delivery costs in the range of $2 to $4/kg of hydrogen depending on the size of the city and market penetration level.
- If the hydrogen production plants are located less than 62 miles from the "city gate" and if tube trailers are developed that could deliver about 1,000 kg of hydrogen, the

cost of tube trailer delivery drops significantly and approaches the cost of pipeline delivery. This approach could avoid the required cost, time, disruption, and potential safety concerns of building hydrogen pipeline distribution systems in urban areas.

- The energy use in the delivery of hydrogen can be significant. For pipeline delivery, tube trailer delivery and liquid hydrogen delivery the Well to Vehicle Tank energy use is about 30%, 35% and 80% of the energy in the hydrogen delivered respectively.
- Greenhouse gas emissions are the lowest with pipeline delivery, moderately higher with tube trailer delivery, but essentially double with liquid delivery.
- The cost of hydrogen delivery is a function of the market demand in terms of kg of hydrogen per square mile (determined by the population density, vehicle ownership rate, and % transportation vehicle market penetration) and the distance between the central manufacturing plant and the market. Thus delivery costs to the vast majority of the U.S.(>75% of the land area) can be reasonably modeled in HDSAM V2 by drawing large enough circles (markets) around each major city and defining the population density as a function of distance from the center of the circle.
- There would be sufficient hydrogen demand to justify a central hydrogen production plant (50,000 to 350,000 kg/day of hydrogen production) located near any significant urban area (>300,000 people) even at modest transportation vehicle market penetration (>25%). Large urban areas will require multiple large hydrogen production plants to supply them. As a result of this and the relatively high cost of hydrogen transport, it would be expected to have the production plant(s) located as close the city as permitted. This is likely to be less than 62 miles (99 km) from the "city gate" and quite possibly at the city's edge.
- For pipeline delivery, low pressure (~2,500 psi or 172.4 bars) compressed gas storage is required at the refueling station to accommodate the large difference between day and evening refueling demands. The low pressure storage is an adjunct to the nominal 6200 psi (427.6 bars), cascade system, which is required to fill the vehicles to 5,000 psi (344.8 bars),.
- For tube trailer delivery, the adjunct storage capacity to the cascade system is provided by the tube trailer, which remains at the refueling station. For liquid delivery, the adjunct storage capacity is provided by the liquid tank, in conjunction with a liquid pump and vaporizer.
- Refueling station capacities significantly impact the delivery cost of hydrogen for all delivery modes. Increasing refueling station capacity up to 1000 kg/day results in significant delivery cost reduction. Further increase in station capacity results in modest to negligible reduction in cost of delivery. However, it should be noted that as the station capacity increases, the corresponding number of stations would proportionally decrease to satisfy the same demand of a given market, thus affecting the accessibility of refueling stations to hydrogen vehicles in that market if the total market demand is not high enough (e.g. < 20% of the vehicle market during the transition to widespread use of hydrogen fuel cell vehicles). (Note: a 1000 kg/day hydrogen refueling station is about a third the size of the new gasoline stations being built in urban areas.)

- To accommodate production plant outages or the variation in seasonal demand, compressed gas storage in a geologic formation is clearly the preferred approach. However, if such formations are not available along the delivery pathway, liquid storage is the next lowest cost option, followed a distant third by compressed gas storage in steel pressure vessels.
- The HDSAM V2 model provides the capital cost and the greenhouse gas emission data to develop recommendations on the preferred delivery infrastructure as the hydrogen economy matures.

Tube trailers, liquid truck delivery, and pipelines are each the optimum delivery method at different points in the maturation of the hydrogen infrastructure. As such, efforts to reduce the energy requirements and the capital cost of each method can reduce the overall cost of delivery in the transition to and widespread use of hydrogen fuel cell vehicles. Possible research efforts include the following:

- Lower cost composite based high pressure storage vessels for hydrogen storage and cascade charging systems at the refueling station. These storage vessels are a major cost for all delivery pathways.
- Composite based high pressure (7,000 psi or 482.76 bars) tube trailers or other approaches to a tube trailer with a capacity of 1000 kg of hydrogen.
- FRP transmission and or distribution pipelines to reduce pipeline capital and thus pipeline delivery costs. The distribution lines are the larger portion of the pipeline costs.
- Magnetic or other novel, methods for hydrogen liquefaction.

Finally, possible uses and enhancements to HDSAM V2 include:

- Examining and improving the research targets for delivery components.
- Improving the optimization procedures for calculating the size and location of hydrogen distribution lines within a city.
- Adding novel hydrogen carriers to the delivery pathways. Potential carriers include metal hydrides/alanates, chemical hydrides, liquid phase hydrogen carriers, and high surface area sorbents. Preliminary studies indicate the latter two approaches hold some promise for hydrogen delivery.
- Adding an option for 10,000 psi (roughly 700 bars),vehicle fills
- Including, as required, the equipment to pre-cool the hydrogen gas prior to dispensing for 10,000 psi (roughly 700 bars) fills and vehicle hydride and sorbent storage approaches.
- Combining the H2A Central and the Distributed Production Models with the HDSAM delivery model.
- Examining the use of cold (-50$^{o}$C to -150$^{o}$C) hydrogen compressed gas for delivery and vehicle storage.

- Adding regional effects to the model, such as local labor rates, or the difference between the North and the South in the seasonal variation in fuel demand (i.e., winter demand in the North is 70 percent of the summer demand, while winter demand in the South is 90 percent of the summer demand)
- Incorporating performance and cost data on all hydrogen delivery technologies as they are advanced to lower cost and more efficient systems.