Hydrogen Delivery Technology Roadmap

November 2005

Contents

Figures

Tables

1 Introduction

Hydrogen holds the long-term potential to solve two critical problems related to the energy infrastructure: U.S. dependence on foreign oil and U.S. emissions of greenhouse gases and pollutants. The U.S. transportation sector is almost completely reliant on petroleum, over half of which is currently imported, and tailpipe emissions remain one of the country's key air quality concerns. Fuel cell vehicles operating on hydrogen produced from domestically available resources – including renewable resources, coal with carbon sequestration, or nuclear energy – would dramatically decrease greenhouse gases and other emissions, and would reduce dependence on oil from politically volatile regions of the world. Clean, domestically-produced hydrogen could also be used to generate electricity in stationary fuel cells at power plants, further extending national energy and environmental benefits.

In the 2003 State of the Union address, President Bush announced a $1.2 billion Hydrogen Fuel Initiative to support the development of commercially viable, hydrogen-powered fuel cells. The Initiative recognizes hydrogen's potential to play a major role in America's future energy system and calls for increased federal funding for research and development (R&D). The goal is to enable industry to reach a commercialization decision by 2015 so that Americans will have the opportunity to purchase hydrogen-powered fuel cell vehicles in auto showrooms by 2020. The Initiative features parallel R&D tracks to develop (1) reliable, cost-effective, fuel cell vehicle and stationary power technologies and (2) the supporting *hydrogen production and delivery infrastructure*.

The FreedomCAR and Fuel Partnership is a key organization in this national R&D effort. The partnership is a collaborative effort among the U.S. Department of Energy (DOE), major energy companies (BP America, Chevron Corporation, ConocoPhillips, Exxon Mobil Corporation, and Shell Hydrogen LLC), and automobile manufacturers in the United States Council for Automotive Research or USCAR (DaimlerChrysler Corporation, Ford Motor Company, and General Motors Corporation). The Partnership is an effort to examine and advance the pre-competitive, high-risk research needed to develop the component and infrastructure technologies necessary to enable a full range of affordable cars and light trucks, and the fueling infrastructure for them that will reduce the dependence of the nation's personal transportation system on imported oil and minimize harmful vehicle emissions, without sacrificing freedom of mobility and freedom of vehicle choice. The Partnership strives to provide an historic opportunity to support the development of technologies that could potentially transform the U.S. personal transportation system to one that uses sustainable energy resources and produces minimal criteria or net carbon emissions on a life cycle or well-to-wheel basis. Fuel cell vehicles fueled by hydrogen, especially hydrogen derived from renewables, will make an important contribution toward achieving this vision.

The partners jointly conduct technology roadmapping, determine technical requirements, suggest research and development (R&D) priorities, and monitor the R&D activities necessary to achieve the Partnership's Research Goals. The Research Goals are used as the criteria against which the Partnership will assess specific research directions and the overall progress of its efforts. DOE, or DOE and USCAR, are responsible for determining the methodology and other assumptions that will be input into the methodology from which the Partnership's Research

Goals will be derived. The projected prices of energy feedstock, energy products and other alternative energy sources, used to assess pathways for production of energy carriers such as hydrogen, are not provided by the Partnership but come from DOE and DOE identified third party sources. Furthermore, the original members of the FreedomCAR Partnership determined the following basic assumptions in 2002, prior to the inclusion of energy providers in the expanded FreedomCAR and Fuel Partnership:

1. All new vehicle and fuels options, including hydrogen, have to be cost-competitive with current vehicle and fuels options, including gasoline and diesel.
2. The performance goals determined from the above assumptions have to be pathway independent.

The FreedomCAR and Fuel Partnership has established Technical teams—consisting of scientists and engineers with technology-specific expertise from the USCAR member companies, energy partner companies, national laboratories, and DOE technology development managers as well as other Federal agencies if approved by the appropriate Operating Group/Groups. Technical teams have non-proprietary discussions and are responsible for developing R&D plans and roadmaps, reviewing research results, and evaluating the technical progress toward meeting the Partnership's Research Goals. The technical teams:

- Identify comprehensive technical goals related to improving the energy efficiency and cost of vehicles and/or to establishing a national hydrogen infrastructure;
- Assess overall appropriateness of technical goals on a systems and benchmarking basis;
- Identify data gaps and R&D needs;
- Identify technical expertise to undertake the technical effort;
- Establish technical milestones and timing;
- Monitor progress in the R&D programs; and
- Report progress toward goals at regular intervals to the FreedomCAR and Fuel Operations Groups and to external reviewers.

Successful commercialization of hydrogen fuel cell vehicles will depend upon the presence of a hydrogen delivery infrastructure that provides the same level of safety, convenience, and functionality as the existing gasoline delivery infrastructure. In addition, the hydrogen delivery infrastructure will need to support hydrogen's various production options. Because hydrogen can be produced from a variety of domestic resources, production can take place in large, centralized plants or in a distributed manner—directly at refueling stations and stationary power sites. Due to the higher capital investment required for centralized production, distributed production is expected to play a particularly important role during the transitional phase while hydrogen is gaining public acceptance. Hydrogen delivery systems must include not only transport and delivery from central production operations, but also the storage, compression, and dispensing operations, which are essential no matter where production takes place.

Hydrogen delivery pathways include gaseous hydrogen, cryogenic liquid hydrogen, and a spectrum of possible solid or liquid hydrogen carriers. Mixed pathways are also an option. These pathways contain numerous components such as compressors, pipelines, liquefiers, gaseous tube trailers, cryogenic liquid trucks, storage vessels, terminals, and dispensers.

The FreedomCAR and Fuel Partnership has organized a Hydrogen Delivery Technical (Tech) Team which developed this Hydrogen Delivery Roadmap. This roadmap identifies the technical goals and milestones for hydrogen delivery systems; surveys technologies that could help meet these goals; identifies the barriers to achieving the goals; and suggests research priorites and a strategy for conducting R&D in hydrogen delivery, including critical needs for the near term (*transition period*) versus the longer term (*fully-developed hydrogen economy*).

In order to meet the identified cost, efficiency, and reliability technical goals and milestones, the hydrogen delivery infrastructure will require a variety of improved and new technologies. While some of these advancements represent developmental improvements to existing technology, others will require radical new concepts and major breakthroughs to deliver the required performance and costs. The Delivery Tech Team recognizes that federal funding should be directed and focused on high-risk, breakthrough research efforts while the private sector needs to take on the tasks of developmental technology improvements. This research approach is delineated in the suggested Research Strategy, Section 8.

2 Goal and Objectives

Goal:

Hydrogen delivery technologies that enable the introduction and long-term viability of hydrogen as an energy carrier for transportation and stationary power.

Objectives:[1]

By **2007**, Criteria for a cost-effective and energy-efficient hydrogen delivery infrastructure for the introduction and long-term use of hydrogen for transportation and stationary power.

By **2010**, Cost of hydrogen delivery from central and semi-central production facilities to the gate of refueling stations and other end users ***<$0.90 per kg*** of hydrogen.[2]

By **2010**, Cost of compression, storage, and dispensing at refueling stations and stationary power sites less than ***<$0.80 per kg*** of hydrogen.[1]

By **2015**, Cost of hydrogen delivery from the point of production to the point of use in vehicles or stationary power units ***<$1.00 per kg*** of hydrogen in total.[2]

By **2015,** Cost of hydrogen delivery during the transition to ***<$xx per kg***. [3]

[1] These objectives are derived from the FreedomCAR and Fuels Partnership overall premise that hydrogen fuel cell vehicles have to be cost competitive with current vehicle and fuel options on a cost per mile driven basis. Based on this premise, DOE analysis and methodology was used to arrive at the the ultimate objective for hydrogen delivery to cost <$1.00 per kg of hydrogen. The intermediate timeframe objectives are milestones along the path to this ultimate objective to track progress.

[2] These cost targets assume a well-established hydrogen market demand for transportation, where greater than 50% of light-duty vehicles on the road are hydrogen-fueled. These costs are derived for typical cities of 100,000 to a million or more people.

[3] The transition is arbitrarily defined as the period during which hydrogen vehicles constitute less than 5% of the light-duty vehicles on the road. Target price to be determined.

3 Scope

Delivery is an essential component of any future hydrogen energy infrastructure. As shown in Figure 3-1, the hydrogen delivery infrastructure starts immediately after hydrogen is produced and ends at the point at which it is introduced into the end-use device (e.g., light-duty vehicle). It includes delivery of hydrogen from large central production facilities as well as from small-scale, distributed production facilities (most commonly located at vehicle refueling stations and often referred to as "forecourt" production facilities). The scope of the delivery infrastructure does *not* include technologies for hydrogen production or for hydrogen storage *on board* a fuel cell vehicle.

Centralized hydrogen production facilities are likely to use the full complement of delivery infrastructure functions, including transport. Most distributed production facilities will need only the storage, compression, and dispensing operations. Delivery infrastructure needs at distributed facilities are a subset of the more comprehensive delivery infrastructure needs for centralized facilities.

This roadmap considers three potential delivery paths:

- gaseous hydrogen delivery (Figure 3-2)
- liquid hydrogen delivery (Figure 3-3)
- novel solid or liquid hydrogen carriers (Figure 3-4)

The liquid and gas paths transport pure hydrogen in its molecular form (H_2) via truck, pipeline, rail, or barge. Liquid or gaseous truck and gas pipelines are the primary methods for delivering industrial hydrogen today. The carrier path uses materials that transport hydrogen in a form other than free H_2 molecules, such as liquid hydrocarbons, absorbents, metal hydrides, or other hydrogen-rich compounds. Ideal carrier materials would have simple, inexpensive treatment processes at a fueling station, or on-board a vehicle, to release H_2 for use in fuel cells. For organizational purposes, materials that require more elaborate processing or are commonly used as hydrogen feedstocks today (natural gas, ethanol, methanol, etc.) are not considered "carriers," and fall outside the purview of this roadmap.

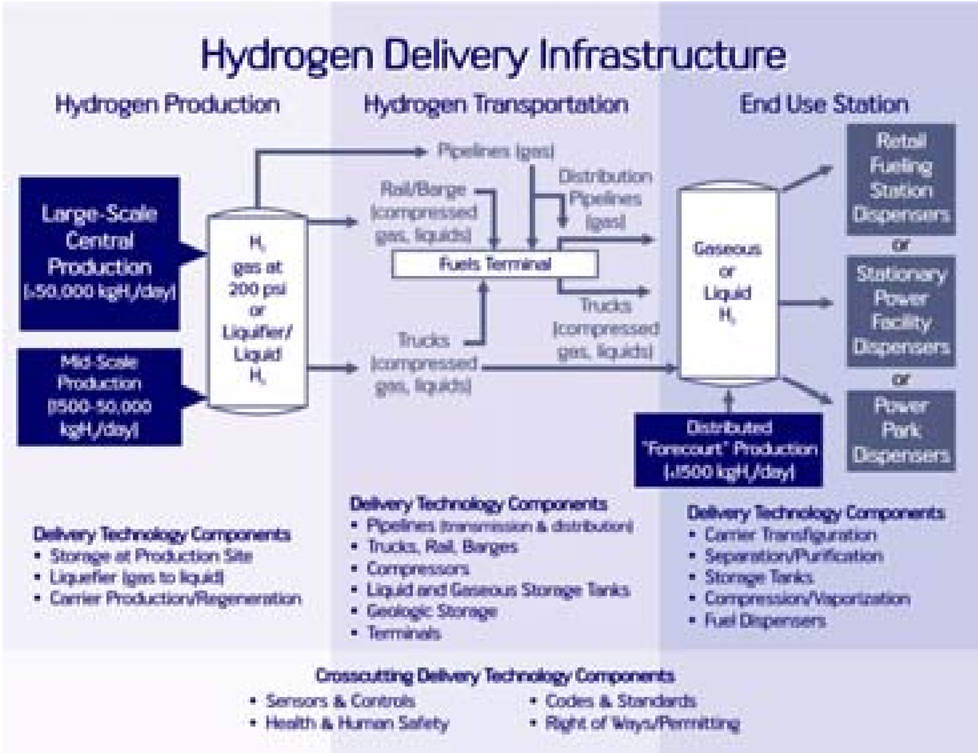


Figure 3-1: Hydrogen Delivery Scope

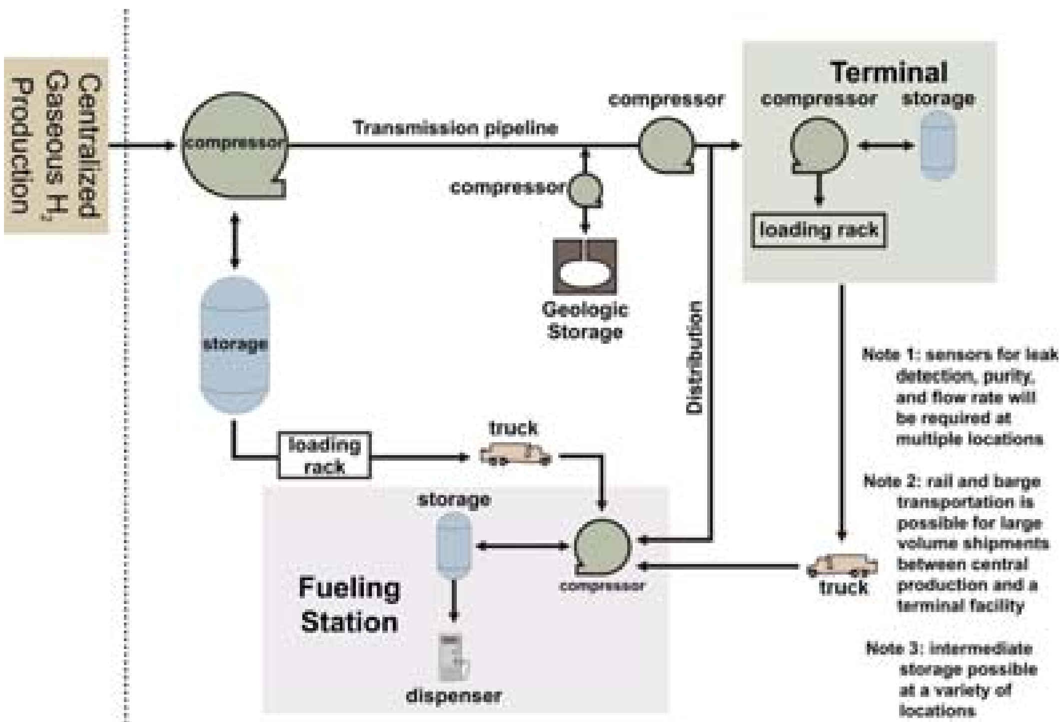


Figure 3-2: Gaseous Delivery Pathway

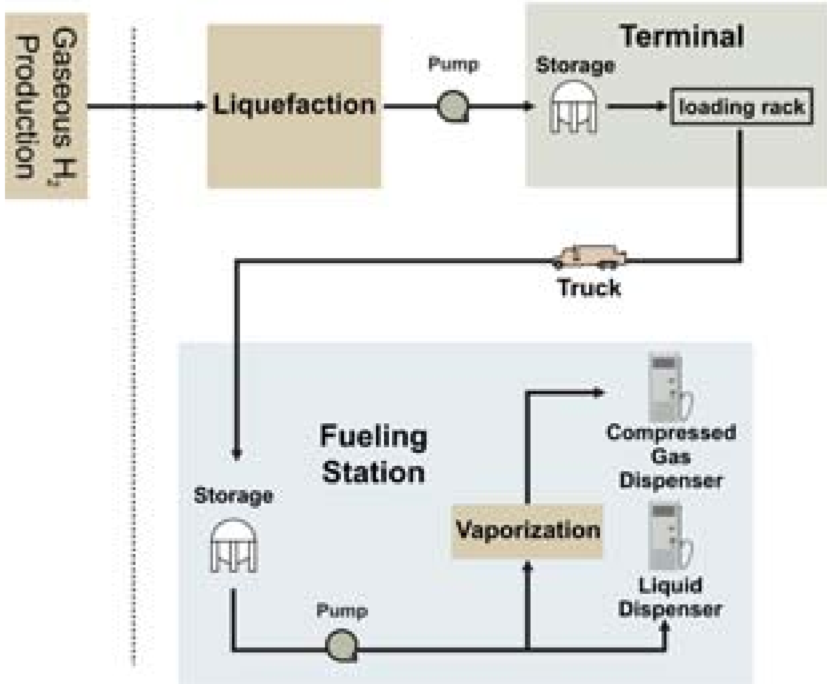


Figure 3-3: Liquid Hydrogen Delivery Pathway

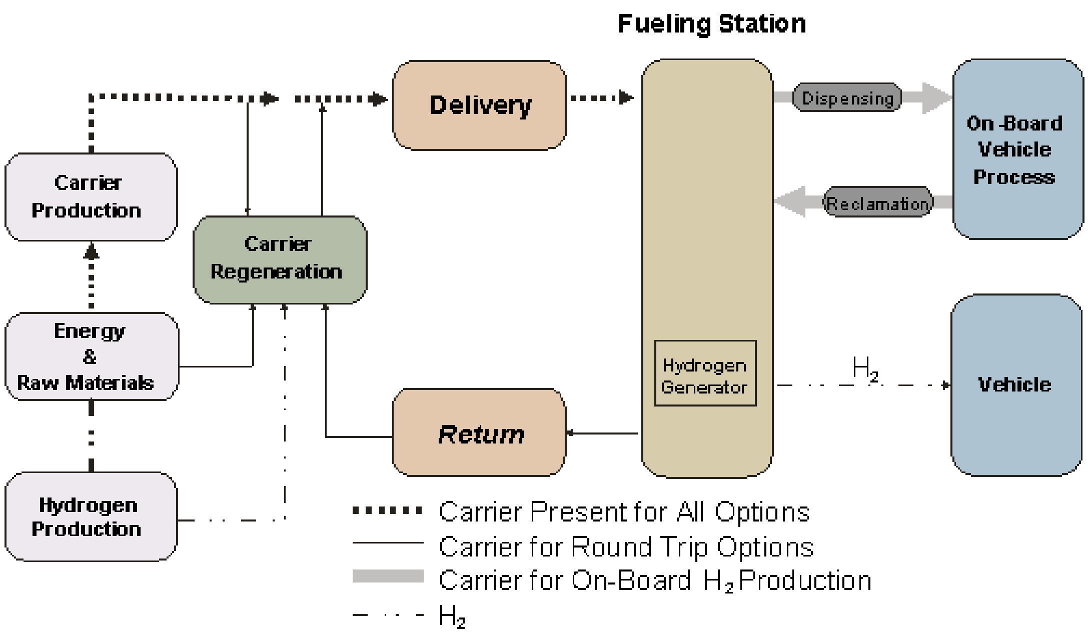


Figure 3-4: Hydrogen Carrier Delivery Pathway

Within the three primary delivery paths, this roadmap addresses the specific technology components listed in Table 3-1.

Table 3-1: Hydrogen Delivery Infrastructure Components

• Pipelines	• Geologic Storage
• Compression	• Separation/Purification
• Liquefaction	• Dispensers
• Tube Trailers, Cryogenic Liquid Trucks, Rails, Barges, and Ships	• Other Forecourt Considerations
• Liquid and Gaseous Tanks	• Carriers and Carrier Charging and Discharging

The roadmap also addresses the needs for delivery system analysis. Current and emerging technologies, systems, and options for hydrogen delivery will need to be comprehensively analyzed to ascertain the associated costs, performance, and advantages or disadvantages. Such detailed analyses will help to evaluate tradeoffs among hydrogen delivery methods and build understanding of how advanced technologies could alter requirements for transitional and long-term systems (e.g., novel hydrogen carriers might eliminate the need for liquefaction). Results of these analyses will focus R&D on areas that show the greatest promise for contributing to a commercially viable hydrogen delivery infrastructure.

Transitioning from a gasoline-based to a hydrogen-based transportation fuel economy will take time. Delivery infrastructure needs and resources will vary by region and type of market (i.e., urban, interstate, or rural), and infrastructure options will also evolve as demand grows and as delivery technologies develop and improve. This roadmap identifies the R&D needed to support hydrogen delivery during the transition period *and* after the hydrogen economy has become fully developed. Support for both of these time periods will be critical to achieving a successful transition and then ensuring that advanced, lower-cost technologies will be available for the future. While the precise makeup of the infrastructure for each time frame remains unclear, various combinations or permutations of all three paths (gaseous, liquid, and novel solid or liquid hydrogen carriers) are likely to play a role. The mix will vary by geographic location and over time as markets expand and new technologies are developed.

This roadmap was developed under the assumption that the current retail model for delivering fuel to customers will continue, although the density of refueling stations may decrease somewhat from current levels. Alternatives that could change delivery technology needs, such as home refueling, are not addressed at this time.

4 Technology Status

4.1 Status of Alternative Delivery Pathways

To support the diverse hydrogen production options, the future hydrogen delivery infrastructure may incorporate multiple delivery pathways capable of handling hydrogen in various forms, including gaseous, liquid, and carrier-based. The technologies required to support these delivery pathways are at various stages of development, but must ultimately meet or exceed the level of safety, convenience, reliability, and energy efficiency provided by the existing gasoline delivery infrastructure.

Gaseous Hydrogen Pathway

As shown earlier, in Figure 3-2, the gaseous hydrogen delivery path includes compression, storage, and transport by pipeline and/or tube trailer. Some operations, such as compression, occur at multiple points between the production facility and the end user.

Today, only about 1,000 km (630 miles) of dedicated hydrogen transmission pipelines serve the United States. In contrast, the natural gas pipeline system is quite extensive in the continental United States, as shown in Table 4-1.

Table 4-1: Natural Gas Pipelines in the Continental United States

Type	Approximate Distance	Typical Material Used	Diameter	Pressure
Transmission	580,000 km (360,000 miles)	steel	0.1-0.8 m (3.9-31.5 in)	40-70 bar (580-1,000 psi)
Distribution	1,600,000 km (1,000,000 miles)	steel/cast iron/ polyethylene	0.05-0.2 m (2.0-8.0 in)	0.03-10 bar (0.5-150 psi)

Ten million metric tons of gaseous hydrogen is produced in the United States annually, mostly for use as an industrial feedstock. The majority of this hydrogen is produced at or near petroleum refineries and ammonia plants—the main users of industrial hydrogen. The 630 miles of existing hydrogen pipelines serve regions with high concentrations of these industrial hydrogen users (primarily along the Gulf coast). The relatively small market for other uses of merchant hydrogen is served by gaseous hydrogen tube trailers or cryogenic liquid hydrogen trucks.

Gaseous hydrogen transmission by pipeline is currently the lowest-cost delivery option for large volumes of hydrogen. The high initial capital cost for this option, however, constitutes a major barrier to the construction of new hydrogen pipelines. These initial costs include materials, labor, right-of-way, and other expenses. Major technical barriers also restrict more widespread use of hydrogen pipelines. The chief concern is the potential for hydrogen to embrittle the steel and welds used to fabricate transmission pipelines. Other potential obstacles include the need for improved seal technology and techniques to control permeation and leakage in general (retrofitting with in-situ coating may be explored). In addition, the need for lower cost, more reliable, and more durable hydrogen compression technology is vital.

Right-of-way (ROW) costs vary greatly by location. In some cases, it may be possible to use an existing ROW; in other cases, ROW costs may be prohibitive, or the ROW may be unattainable. Existing codes and standards for hydrogen pipelines are insufficient and must be further developed to ensure adequate safety and to simplify the process of obtaining permits. Improved leak detection or sensor technology will be essential to ensure safe operation and conformance to standards.

Use of existing natural gas pipelines for the delivery of pure hydrogen or mixtures of up to 20-30% hydrogen is a possibility, particularly in the transitive stages of a hydrogen economy. The existing natural gas pipeline infrastructure is heavily utilized, however, and natural gas consumption continues to grow. Some excess pipeline capacity exists during parts of the calendar year, but the capacity is fully utilized during peak summer and winter periods.

Nonetheless, this option warrants further exploration for the transition period. Some studies suggest that <30% hydrogen mixed with natural gas may pose less of an embrittlement problem than pure hydrogen, but this remains to be verified. If mixtures of hydrogen and natural gas are to be considered, a low-cost technology for hydrogen separation and purification will be needed.

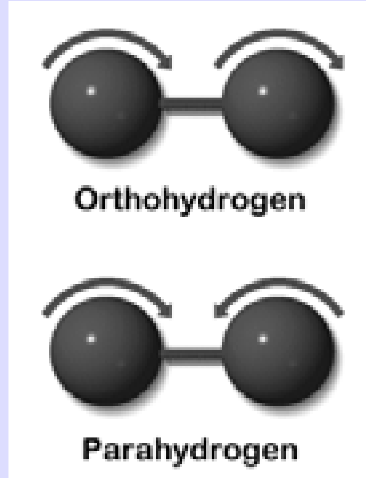
Relatively small amounts of gaseous hydrogen can be transported short distances by high-pressure (182 bar or 2,640 psi) tube trailer. A modern high-pressure tube trailer is capable of transporting approximately 300-400 kg of hydrogen (in contrast to gasoline tank trucks, which can transport nearly 20 times the equivalent energy). Unfortunately, this method of hydrogen delivery is expensive for distributing hydrogen as a transportation fuel.

Liquid Hydrogen Pathway

The liquid delivery path for hydrogen includes a number of well-known and currently practiced elements. As shown in Figure 3-3, the first step is liquefaction, which is a well-understood yet costly operation because of the large energy requirement and relatively low energy efficiencies. The liquefaction process involves cooling gaseous hydrogen to below -253°C (-423°F) using liquid nitrogen and a series of compression and expansion steps. The cryogenic liquid hydrogen is then stored at the liquefaction plant in large, insulated tanks; dispensed to liquid delivery trucks by means of a truck loading rack; and transported over long distances to local distribution sites. At those sites, the liquid is stored and then vaporized to a high-pressure gaseous product for dispensing.

Today, the liquid hydrogen pathway is used almost exclusively by merchant vendors to lower the cost of delivering hydrogen to industrial sites located far from hydrogen pipelines. Over these longer distances, liquid trucking becomes more economical than gaseous trucking, because a liquid tanker truck can transport a tenfold larger mass of hydrogen than a gaseous tube trailer. The ten existing liquefaction plants in North America vary in size from 5,400 to 32,000 kg per day.

The energy cost for converting gaseous hydrogen to liquid is extremely high because it requires low temperatures and the need to change the *ortho* spin of hydrogen to *para* (see inset). The thermodynamic energy needed for hydrogen liquefaction represents 10% of the energy in the hydrogen (lower heating



Orthohydrogen and Parahydrogen

Each of the two hydrogen atoms in a hydrogen molecule contains one proton. These protons can be thought of as spinning in either the same or opposite directions. Molecules in which the protons spin in the same direction are orthohydrogen molecules; when they spin in opposite directions, the molecules are called parahydrogen molecules.

Why Convert Orthohydrogen to Parahydrogen?

At thermodynamic equilibrium, gaseous hydrogen is made up of a mixture of 75% *ortho* and 25% *para* hydrogen. Orthohydrogen is unstable at the low temperatures required for liquid hydrogen and will change to the more stable parahydrogen over time. This process releases heat that vaporizes a portion of the liquid. An ortho-para conversion catalyst is used during the liquefaction process to convert most of ortho to para hydrogen so that the resulting liquid can be stored without excessive vent loss.

Source: C*CHEM, a division of Molecular Products Inc. www.cchem.com/opcat value or LHV). In addition, the current technology is not energy efficient, and the liquefaction step itself consumes one-third or more of the energy in the hydrogen.

Improved economies of scale could help lower the cost of the liquid pathway. Today's liquefaction units are relatively small, in keeping with the minimal demand for liquid hydrogen. Larger markets could justify the construction of larger-scale liquefaction units with better heat integration. New, large-scale liquefaction plants placed adjacent to hydrogen production facilities or power plants could expand opportunities for heat and energy integration between plants, which would further improve system economics.

Hydrogen Carrier Pathway

Simply stated, carriers are a means of transporting, delivering, or storing hydrogen in any chemical state *other than* free hydrogen molecules. Potential carriers include liquid hydrocarbons, metal hydrides, sorbents, and ammonia.

Carriers would avoid many of the problems associated with transporting pure molecular hydrogen. If carriers could be delivered via existing and/or low-cost infrastructures, they could significantly lower hydrogen delivery costs. Reliance on this type of infrastructure suggests that the following characteristics would be desirable in potential carriers:

- Maintain liquid, solid, or slurry phase under favorable temperature and pressure conditions
- Provide high hydrogen capacity with respect to both volumetric and mass energy densities
- Offer simple, low-cost, highly energy-efficient transformation process for discharging hydrogen
- Support simple and low-energy process for recharging with hydrogen (in the case of two-way carriers)
- Are safe and environmentally benign

Materials such as methane and ethanol are not considered carriers because the chemistry required to process them is quite complex and expensive. These types of materials are classified as hydrogen *feedstocks* and are being investigated as potential sources of hydrogen, as discussed in the *Hydrogen Production Roadmap*.

Most potential carriers are two-way (round-trip) carriers. In a round-trip system, the hydrogen-rich carrier material is transported to the fueling station, dehydrogenated on location (or on a vehicle), and then returned to a central facility for recharging with hydrogen. A one-way carrier is a hydrogen-rich material that is transported to the refueling station and decomposed to yield hydrogen and an environmentally benign, disposable by-product (e.g., nitrogen, in the case of ammonia). One-way carriers offer a distinct advantage in that they do not have to be returned to a central facility for reprocessing. The by-product(s) of a one-way carrier, however, must pose no environmental issues and possess virtually no value.

Sample Hydrogen Carriers

A variety of potential carriers are under consideration for hydrogen delivery. Candidates currently include ammonia, liquid hydrocarbons, hydrates or clathrates, metal hydrides, nanostructures, and bricks or flowable powders.

Ammonia: Ammonia is a common chemical commodity produced from natural gas today. It is a potential one-way carrier that can be easily transported and simply transformed by cracking to nitrogen and hydrogen:

$$NH_3 \rightarrow N_2 + 3H_2$$

Hydrogenation/Dehydrogenation of Liquid Hydrocarbons: A liquid hydrocarbon carrier could be catalytically dehydrogenated at a refueling station or on a vehicle. The "dehydrided" liquid would then be returned to a central plant or terminal for rehydriding:

$$C_nH_{2n} \leftrightarrow C_nH_n + n/2\ H_2$$

Hydrates/Clathrates: A clathrate is a stable structure of water molecules formed around a light molecule (see Figure 4-1). The most common clathrates are methane hydrates, which hold large amounts of natural gas. Clathrates were recently discovered to form around hydrogen molecules, but these materials currently suffer from stability problems. Stable hydrogen clathrates would offer high hydrogen capacities and be easily decomposed into hydrogen and the clathrate components—typically, light hydrocarbons and/or water:

$$(H_2O)_n(CH_4)_m(H_2)_p \rightarrow nH_2O + mCH_4 + pH_2$$

Clathrates would likely be handled as slurries or solids to deliver hydrogen.

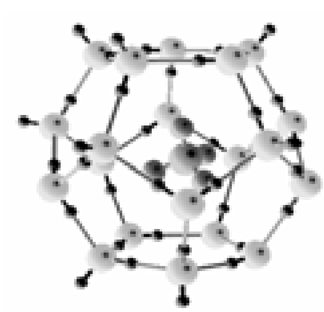


Figure 4-1: Clathrate Molecule

Metal Hydrides: Metal hydrides are well-known hydrogen carriers. They adsorb hydrogen at low pressures and can hold up to 6-7% hydrogen by weight. Generally, hydrides that hold the most hydrogen have high heats of adsorption, so they give off a great deal of heat when "charged" with hydrogen, and they require high temperatures to release the hydrogen.

As hydrogen carriers, metal hydrides work best in situations in which both the delivering and receiving systems are based on the same hydride. In this way, the heat generated by the receiver can be used to release hydrogen from the delivery system.

Nanostructures: Nanostructures, particularly single-walled carbon nanotubes (SWNTs), have attracted considerable attention as candidates for the on-board storage of hydrogen. Although mounting evidence indicates that they lack the adsorption capacity to serve in that role, they may still be useful in the hydrogen delivery infrastructure. They appear to have the ability to adsorb hydrogen and increase the storage capacity of vessels under moderate pressures or low temperatures.

Bricks or Flowable Powders: Although most of the discussion on carriers has focused on liquids, several of the materials mentioned above are solids. Stable, solid carriers might be delivered in many different ways. Slurries have been mentioned, but novel systems such as flowable powders or solid "bricks" might also be considered as potential delivery mechanisms. Such systems could flow one way or involve the exchange of spent material for fresh, "charged" carrier material.

Status

Although hydrogen carriers have not been thoroughly investigated for use in hydrogen delivery, much of the relevant science and technology has been studied in connection with other applications. Hydrogenation and dehydrogenation of hydrocarbons are fairly common industrial operations, but those operations generally require high amounts of energy and high temperatures to release the hydrogen. New materials must be developed to provide greater hydrogen capacity and optimized energetics. Metal hydrides are under intense study for use in storing hydrogen on-board vehicles. They may also be useful as carriers for hydrogen delivery, which imposes substantially different, and perhaps less challenging, performance requirements.

Carrier use will require the development of simple conversion technology and equipment. Dehydriding of the carrier must be straightforward and produce high-purity hydrogen. Although generic methods exist for many potential carriers, innovative technologies may be needed for new carriers, and standard technologies may need to be modified for use at retail sites. Similarly, chemistry and technologies for rehydriding must be adapted for commercial use. Round-trip carriers will entail some additional complexity and costs, including the addition of storage at refueling stations or terminals. Reprocessing of a two-way carrier is an additional operating step, whether it is accomplished at terminals or more central locations. This approach would significantly increase the complexity of terminal operations compared to today's typical gasoline terminals.

Logistics for liquid or gaseous carrier delivery are generally assumed to be similar to those associated with today's liquid and gaseous fuel delivery systems, yet fuel delivery mechanisms may differ radically from those used today. Carriers might be solid slurries, flowable powders, or even solid materials ("bricks"). Unconventional carriers could radically alter the current retail model. For example, easily loadable solid carriers could be marketed on an exchange basis from almost any retail site, much like small propane cylinders are distributed today.

4.2 Status of Technology Components

Gaseous Pipelines

The infrastructure for gaseous hydrogen delivery by pipeline must include both transmission and distribution. In conventional terminology, *transmission* lines generally use relatively large-diameter, high-pressure (35-100 bar or 500-1,500 psi) pipelines for moving large volumes of gas over long distances. In contrast, *distribution* lines typically provide more localized delivery of smaller volumes of gas through smaller-diameter, lower-pressure (0.3-14 bar or 5-200 psi) pipelines. For hydrogen delivery, pressures in distribution lines are likely to be higher (14-28 bar or 200-400 psi) than in natural gas distribution lines due to the need for high pressures at refueling stations and power sites. Other than this potential distinction for hydrogen delivery requirements, the issues mentioned below generally apply to hydrogen pipelines of all types, as well as to existing natural gas pipelines that may be converted to hydrogen duty. Furthermore, with appropriate separations technology included, the issues discussed below apply to pure hydrogen gas as well as to mixtures of natural gas containing a substantial fraction (10-30%) of hydrogen gas.

Although the United States currently has about 1,000 km (630 miles) of dedicated steel hydrogen transmission pipeline, significant technical questions must be addressed prior to establishing a major hydrogen pipeline infrastructure. The chief technical concern is hydrogen embrittlement of metallic pipelines and welds. In the simplest sense, hydrogen embrittlement describes the decrease in ductility or toughness of materials as a result of interaction with atomic hydrogen. Pipeline materials can be exposed to atomic hydrogen in several ways, on both sides of the pipeline. On the inside of the pipeline, some molecular hydrogen under high pressure may dissociate. On the outside, atomic hydrogen may form as a result of natural corrosion processes or from electrochemical systems employed to protect against corrosion (cathodic protection). In the absence of significant stresses, hydrogen embrittlement may lead to blistering or internal cracking. When exposed to aggressive stress states associated with fabrication (e.g., welding) or service (e.g., high pressure and/or cyclic loading), hydrogen-embrittled materials may be susceptible to unstable crack growth leading to sudden, low-ductility failure (i.e., pipeline ruptures). While details of embrittlement depend on specific combinations of material and environment, a key factor in susceptibility is the microstructure of the material, including such properties as composition, crystal structure of the phase(s) present, and strength level. Important avenues for improving hydrogen pipeline performance include the development of techniques to reduce stress/loads or eliminate hydrogen penetration into the material, as well as the development of new, high-strength materials immune to hydrogen embrittlement. Since welds are particularly susceptible to embrittlement, pipeline materials that eliminate the need for welding together pipeline sections (e.g., "spoolable" pipeline materials) may also help solve the embrittlement problem.

No commercial pipelines for liquid hydrogen currently exist. Without breakthrough technologies, liquid hydrogen delivery in pipelines is considered impractical and cost prohibitive. In addition to the high cost and energy inefficiency of current liquefaction technologies, the engineering requirements for constructing of a pipeline with appropriate materials and codes are problematic. This option will not be addressed by this Delivery Roadmap.

Liquefaction

Liquefaction is an energy-intensive, multi-stage process that uses a series of refrigerants and compression/expansion loops to produce the extreme cold necessary to convert hydrogen from the gaseous to the liquid phase. Hydrogen has the lowest boiling point of any element except helium, and shifts from gas to liquid at -253°C (-423°F). Liquid hydrogen is odorless, transparent, and only one-fourteenth as dense as water. Figure 4-2 shows the typical liquefaction sequence of compression, isenthalpic expansion (through a Joule-Thomson valve), expansion cooling through a turbine, and cooling by liquid nitrogen via a brazed aluminum heat exchanger.

As noted earlier, a hydrogen molecule can exist in two electron orbital spin states: *ortho* and *para*. Hydrogen in the liquid state must be close to 100% parahydrogen since orthohydrogen at low temperatures will naturally convert to parahydrogen, releasing heat that causes the liquid hydrogen to vaporize. Ortho/para conversion catalyst beds are used to convert most of the hydrogen to the para form. A significant percentage of the energy required to liquefy hydrogen is consumed in making this ortho-to-para conversion.

Liquefaction technology is currently employed only in small plants by merchant hydrogen vendors. The liquefaction process alone costs more than $1.00/kg and is only

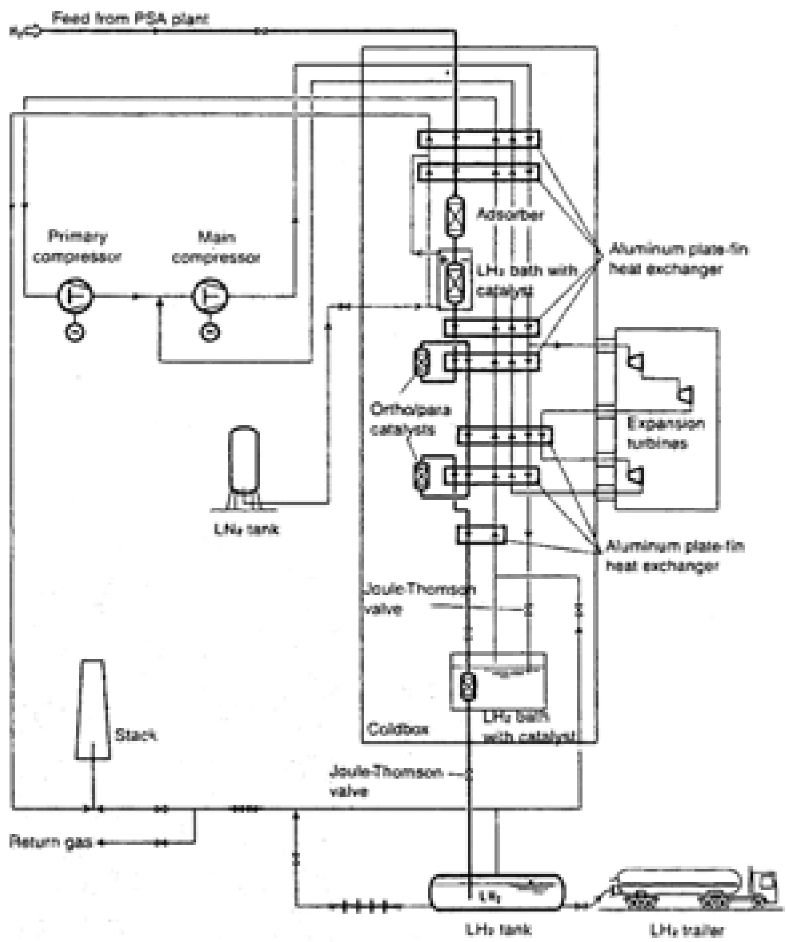


Figure 4-2: Hydrogen Liquefaction Plant

about 65% energy efficient. The primary barriers to using liquid hydrogen for delivery are the high cost and high energy use of liquefaction. Potential areas of improvement include:

- increasing the scale of the operation
- improving the heat and energy integration, (e.g., co-locating the liquefaction with hydrogen production or power production and integrating energy and heat across the operations)
- lowering the cost of heat exchange materials
- developing novel approaches to liquefaction such as magnetic or acoustic liquefaction

Compression and Cryogenic Liquid Hydrogen Pumps

Compression Status

As seen in Figures 3-1 through 3-4, compression is an integral aspect of hydrogen delivery. A compressor is a device that will accept a gas at a certain pressure and add force or energy such that the gas exits the device at a higher pressure. Figure 4-3 plots types of compressors typically used for natural gas service as a function of throughput and pressure. Displacement compressors used to compress hydrogen today are similar to those used for natural gas, but they incorporate different materials and some design changes.

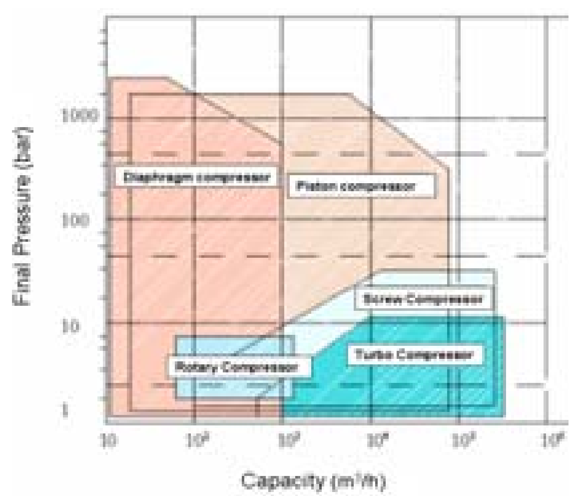


Figure 4-3: Operating Characteristics of Various Compressors

Most displacement compressors fall into two major categories: reciprocating and rotary. A reciprocating compressor uses pistons with a back-and-forth motion to compress the gas, and contains inlet and outlet check valves. The most common reciprocating compressors are piston-type and diaphragm compressors operating at high rpm. Problems with reciprocating compressors for hydrogen include poor reliability (due to many moving parts and other issues), contamination from lubricants, high noise levels, and high capital costs (arising from the need to install spares to improve reliability). Intensifiers, which are piston-type compressors of a different design that operate at low rpm, potentially address some of these problems associated with reciprocating compressors in hydrogen service.

Rotary compressors are displacement compressors that have rotating pumping elements such as gears, lobes, screws, vanes, or rollers, but do not contain check valves. Examples of this type include screws, rotary vanes, scrolls, and trochoidal ''Wankel'' compressors. Rotary compressors have not been used with hydrogen due to the extremely tight tolerances required to compress hydrogen, which is an extremely small molecule.

Centrifugal compressors are routinely used in natural gas service for pipeline transmission and to meet other needs involving high throughput and modest compression ratios. Unfortunately, centrifugal compressors do not currently work for hydrogen. Hydrogen's low molecular weight causes seal design problems including contamination, vibration, and rotor dynamics issues. To achieve high pressures, these compressors would require many stages operating at high rotational speeds, as well as special seals and tolerance standards. Improved materials and designs are needed.

The energy required to compress a gas is a logarithmic function of the pressure ratio. The incremental energy input becomes smaller as higher pressures are reached. Multi-stage compression and intercooling are used to achieve high pressures.
The state-of-the-art in gaseous hydrogen compression involves the use of reciprocating pistons for high-volume applications and pistons or diaphragms for small-volume applications. Advances have centered on the optimization of subsystems rather than the development of new approaches. Required compression ratios vary at different points in the delivery system. Transmission pipeline compression is a high-throughput application (500,000-2,000,000 kg/day) with a modest compression ratio, typically requiring raising the pressure from about 5 to about 70 bar (100 to 1,000 psi). Refueling stations have lower flow rates (100-3,000 kg/day) but much higher compression ratios. If high-pressure hydrogen tanks are used for on-board vehicle storage, the delivered hydrogen pressure requirements may be 350 to 700 bar (5,000-10,000 psi). If low-pressure on-board hydrogen carrier and storage technology is successfully developed, the delivery pressure may be only 7-100 bar (100-1,500 psi). Other throughput and compression ratios will be needed at other points in the delivery infrastructure (e.g., at terminals, for geologic storage, etc.).

Cryogenic Liquid Hydrogen Pumps
Liquid hydrogen is pressurized with cryogenic pumps, which are employed more than once during the liquid delivery pathway (see Figure 3-3). Cryogenic pumps can achieve high pumping speeds and operate at relatively high discharge pressures. These pumps must operate under extremely cold temperatures to maintain the hydrogen in a liquid state at all times—any vaporization will cause damaging cavitation. The materials used in the pumps must be capable of withstanding these extreme temperatures without becoming brittle. The need to periodically recharge the pump and purge any frozen or trapped gases results in expensive process downtime, which can only be avoided by adding more pumping stages.

Tube Trailers, Cryogenic Liquid Trucks, Rail, Barges, and Ships

Gaseous tube trailers and cryogenic liquid tank trucks are used to deliver hydrogen to end users not served by the limited hydrogen pipeline system that has been established for industrial users. Rail, barge, and ship are also potential transport modes, but are not typically used today.

High-pressure cylinders and tube trailers at 182 bar (2,640 psi) are used for gaseous hydrogen distribution over distances of 160-320 km (100-200 miles). For distances up to 1,600 km (1,000 miles), hydrogen is usually transported as a liquid in super-insulated, cryogenic, over-the-road trucks, and then vaporized for use at the customer site. High-pressure gaseous tube trailers can hold 300-400 kg of hydrogen, whereas cryogenic liquid trucks have a capacity of 3,000-4,000 kg of hydrogen.

The majority (66%) of today's transportation fuels are transported to local terminals over a network of pipelines and then distributed locally to the points of use over the road. The remainder of the long-distance fuel transportation is handled by trucking (4%), barges (28%), with the rest (2%) carried by rail.

Success in making hydrogen the "transportation fuel of the future" will require a delivery infrastructure that accommodates diverse means of distribution. Although the most economical means of transporting hydrogen in the future may be by a pipeline network similar to that used for today's transportation fuels, other modes of transport will be needed in outlying areas. Over-the-road tankers, rail, and barge may be the only options for some remote areas of the country. Rail and barge offer higher load-carrying capacities and higher weight limits than over-the-road trailers. Trucks, rail, and barge will also play a key role during the transition phase, when hydrogen demand is low and economic incentives for building hydrogen pipelines are not yet in place.

Hydrogen is currently shipped overseas using tube skids or high-efficiency liquid storage skids in limited volumes. In the future, large-volume liquid hydrogen tankers (similar to LNG tankers) may be used to ship large volumes of hydrogen overseas.

Liquid and Gaseous Storage Tanks

Pressure vessels (tanks) are currently the most common means of storing hydrogen. The practice of storing hydrogen under pressure has been in use for many years, and the procedure is similar to that for storing natural gas.

High pressure on-board vehicular tanks represent the state-of-the-art in gaseous hydrogen storage vessels. For on-board applications, high-pressure tanks rated at 700 bar (10,000 psi) have been demonstrated using carbon-fiber composites to ensure strength and durability, and work continues on reducing cost and optimizing material properties. Even at these high pressures, the energy density is low compared to an equivalent volume of gasoline; the hydrogen vessel contains 4.4 MJ/L at a pressure of 700 bar (10,000 psi), which is only 14% of the 31.6 MJ/L contained in gasoline. These tanks can be characterized by their structural element (wall, shell) and their permeation barrier (liner). According to the European Integrated Hydrogen Project (EIHP), compressed hydrogen storage vessels are classified according to the categories shown in Table 4-2.

Table 4-2: Classification of Hydrogen Storage Vessels

Type I	All-metal cylinder
Type II	Load-bearing metal liner hoop wrapped with resin-impregnated continuous filament
Type III	Non-load-bearing metal liner axial and hoop wrapped with resin-impregnated continuous filament
Type IV	Non-load-bearing, non-metal liner axial and hoop wrapped with resin impregnated continuous filament

The most common off-board gaseous storage pressure vessels are cylinders and tubes. Typical industrial hydrogen cylinders hold approximately 0.61 kg (1.35 lbs) of hydrogen at a pressure of 156 bar (2,265 psi) at 21°C (70°F), and have a volume of 54 L (1.9 ft^3) (1.3 m x 0.23 m dimensions or 51" x 9"). These are intended to be secured and stored upright. Cylinders may be used individually or can be joined by a manifold to extend storage volumes.

Tube trailers are available in capacities of up to 300-400 kg of hydrogen utilizing nine tubes, each with a volume of 2.6 cubic meters (93 ft^3) at pressures of 182 bar (2,640 psi). Stationary tube modules can be used to store larger quantities of hydrogen. The amount of hydrogen contained in each tube depends on its diameter, length, and pressure rating. Modules are available in configurations of 3 to 18 tubes holding up to approximately 700 kg of hydrogen (150,000 scf) at 165 bar (2,400 psi). Mobile and stationary tubes have individual valves and safety devices, but are joined by a manifold so that hydrogen can be withdrawn from a single tube or from several tubes simultaneously.

Researchers are exploring use of high-pressure, cryogenic gaseous tanks to increase the amount of hydrogen that can be stored per unit volume and avoid the energy penalties associated with hydrogen liquefaction at 20 K (-253°C or -423°F). Compressed hydrogen gas at cryogenic temperatures is much denser than in regular compressed tanks at ambient temperatures. These new tanks have the potential to store hydrogen at 80 K (-193ºC or -315°F), which eliminates the need for the ortho-para conversion step in liquefaction. This approach does require energy to cool the gas, however, and also requires proper vessel insulation to keep the gas cool. These high-pressure cryogenic tanks are currently capable of maintaining pressure at 200-400 bar (2,900-5,800 psi) and could be filled with either compressed (ambient to cryogenic temperatures) or liquid hydrogen.

Cryogenic liquid hydrogen tanks are currently the most common way to store larger quantities of hydrogen because they provide a higher volumetric density than gas storage. Most current demonstration projects use liquid hydrogen, which is then converted to pressurized gaseous hydrogen for on-board storage.

Super-insulated pressure vessels are needed to store liquid hydrogen since temperatures close to 20 K (-253° C or -423° F) are required to maintain hydrogen as a liquid at typical vessel pressures (<5 bar or 73 psig). No matter how well-insulated, some hydrogen boil-off will occur, a phenomenon that is especially pronounced in small tanks with large surface-to-volume ratios. Typical evaporation values are presented in Table 4-3.

Table 4-3: Evaporation Rates from Cryogenic Liquid Hydrogen Storage Tanks

Evaporation Rates from Cryogenic Liquid Hydrogen Storage Tanks		
Tank Volume (m^3)	Tank Volume (gal)	Evaporation Rate per day
50	13,000	0.4%
100	26,000	0.2%
20,000	5,000,000	0.06%

Liquid hydrogen tanks can be spherical or cylindrical. Larger tanks are usually spherical to reduce the surface area and thus decrease evaporative losses. Capacities range from 5,700 L to 95,000 L (1,500-25,000 gallons or 400-6,650 kg) of hydrogen. Liquid hydrogen is transported to these tanks by liquid tanker semi-trailers with capacities of 45,000 L to 64,000 L (12,000-17,000 gal or 3,150-4,480 kg) of hydrogen. These tankers are basically of the same design as the stationary tanks, but must also meet the requirements of the Department of Transportation (DOT).

Large vessels originally developed for the space program represent the state-of-the-art in liquid hydrogen tanks. NASA has been using and storing liquid hydrogen for over 30 years. At Cape Canaveral, NASA has a spherical tank with an outer diameter of 20 m (66 ft) and a storage volume of about 3,800 m^3 (1 million gallons) with a storage period of several years (evaporation rate is under 0.03% per day).

While underground liquid hydrogen storage would likely cost more than a traditional above-ground pressurized hydrogen system, the underground approach offers several advantages. Underground liquid storage reduces the above-ground footprint and also provides greater storage capacity per unit volume compared with gas storage. In addition, if the underground tank can maintain both high pressures and cryogenic temperatures, it provides the flexibility to store hydrogen in any of three different forms: liquid hydrogen, cryo-compressed hydrogen, and compressed hydrogen. A refueling station that uses an underground storage tank is also inherently safer. In addition—as is common at today's gasoline stations—portions of the area above the underground tanks could be used for business. This space-saving feature is particularly advantageous at urban refueling stations, where space is at a premium.

Geologic Storage

Depending on the geology of the area in question, geologic storage could develop into a relatively inexpensive method for the large-scale storage of hydrogen. Geologic storage is routinely used to provide seasonal and surge capacity for natural gas (see Table 4-5 on page 26), and hydrogen will eventually require similar bulk storage space.

Town gas, which contains 20-60% hydrogen, has been successfully stored in caverns in France and Germany for many years. In Teeside, England, Imperial Chemical Industries (ICI) has stored hydrogen in a brine salt cavern for years. These facilities have operated without any known hydrogen leakage problems.

Many geological sites have the potential to store hydrogen, including salt caverns, mined caverns, natural caves, and aquifer structures. Salt caverns are hollow cavities inside a large underground salt layer. Most commonly, they are formed by drilling a hole into the salt structure and gradually dissolving the salt with fresh water or seawater, thus creating a geological void. Salt caverns provide secure containment for materials that do not dissolve salt (such as hydrogen). The suitability of mined and natural caverns for hydrogen storage will depend on their location and geological characteristics. Aquifers are porous geological formations, and many have a water-saturated top layer that creates a caprock. For underground storage, a good caprock serves to seal the structure and make it impermeable to the surroundings.

Most geological sites can handle pressures of 80 to 160 bar (1,200-2,300 psi). As with any large storage vessel, the cushion gas that remains in a geologic storage site represents a major issue in discharging hydrogen. Experience with natural gas suggests that cushion gas would amount to about 15% of the storage capacity. The amount needed is not well understood, however, and is highly dependent on characteristics of the specific structure.

Specially engineered rock caverns, referred to as lined rock caverns (LRC), present another storage option. The concept relies on the rock mass (primarily crystalline rock) as the structural element. Creating this artificial geological pressure vessel involves excavating a vertically cylindrical cavity 20-50 m (60-160 ft) in diameter and 50-115 m (160-380 ft) in length, building a 1 m (3 ft) thick reinforced concrete outer shell, and lining the cavity with 12 to 15 mm (0.5-0.6 in) of carbon steel. These latter two engineering elements serve two purposes: the first is to distribute the forces (stresses) from the engineered shell structure to the rock mass surrounding it, and the second is to provide an impermeable barrier to the gas being held. This geological pressure vessel, while containing natural gas, can sustain pressures in the range of 150-250 bar (2,200-3,600 psi). Technical studies and field tests of the technology, which has been under development in Sweden since 1987, indicate that the idea is technically sound and economically practical. In the United States, LRC technology has focused on two projects for storing natural gas: one near Atlanta, Georgia, with 148 million cubic meters (5.2 billion cubic feet (bcf)) of working gas capacity, and another near Boston, Massachusetts, with a capacity of 74 million m^3 (2.6 bcf).

One way to lower the construction and mining costs of an LRC is to refrigerate the geological pressure vessel. Refrigerated storage reduces the physical space required to store a given quantity and provides multiple, high-capacity peaking cycles per year (as compared to liquefied natural gas). Work is ongoing to evaluate the technical specifications and economics of a 140 million-cubic-meter (5 bcf) refrigerated natural gas mined cavern in the Baltimore/Washington metropolitan area. The design calls for a mined cavern of approximately 1 million cubic meters (0.037 bcf) at a depth of 900 meters (3,000 ft) with a temperature of -29° C (-20° F) and a maximum pressure of 86 bar (1,250 psig). The facility is estimated to cost about $173 million, or approximately $34.5 per million standard cubic feet of gas stored.

Separation and Purification

Hydrogen purification is normally part of the production process, yet the need for purification may also arise during the hydrogen delivery process. Current commercial technologies for hydrogen purification include sorption—typically pressure swing adsorption (PSA) – and cryogenic purification. PSA is the most commonly deployed commercial technology and is used for all large-scale commercial production. Refining and chemical operations commonly use metallic and nonmetallic membrane separation technologies to purify dilute hydrogen streams, and improved membrane separation is being investigated as a potentially lower-cost alternative to PSA.

Further information on these separation and purification technologies can be found in the Hydrogen Production Roadmap. This document explores only the particular purification needs relevant to hydrogen delivery:

- Removal of small amounts of impurities introduced between the production site and retail site (“polishing”)
- Separation of hydrogen from natural gas in a hydrogen-natural gas mixture exiting a pipeline or storage facility
- Separation of impurities produced upon production of hydrogen from a carrier

Polishing entails the removal of small amounts of impurities or fuel cell poisons from hydrogen prior to final delivery. In this application, PSA may offer advantages over membrane and cryogenic technologies in terms of speed, cost, and efficiency. Use of polymer and ceramic membranes, for example, causes some level of pressure drop, and the purified hydrogen may need to be recompressed at additional cost. Similarly, cooling all the hydrogen to remove trace impurities would be extremely costly. Although a sorption-based scheme appears most cost-effective at present, membrane technologies are constantly improving. In an effective sorption-based scheme, the sorbent should be selective for the impurities so that hydrogen can flow through without any significant interactions. Any energy required to clean up the sorbent would be proportional to the concentration of impurities.

Separation of hydrogen-natural gas mixtures poses a different problem: large volumes of gas must be treated at very low cost. Hydrogen is likely to be present in concentrations 2-30%, with methane accounting for the majority of the balance. PSA units, membrane separators, or other novel approaches could all potentially be useful in this separation process.

Requirements for purifying hydrogen after delivery via carrier will depend on which carrier system is used. For a carrier like ammonia, hydrogen would have to be separated from nitrogen and the unreacted ammonia removed. In the case of a hydrocarbon carrier, hydrocarbon vapors and secondary reaction products would need to be removed. In view of this high dependence on the carrier, research on post-carrier separations will be pursued only after the most promising carriers have been identified.

Hydrogen Dispensers

Dispensing both gaseous and liquid hydrogen to vehicles is still in the early stages of development, and only a few demonstration projects are under way. Europe and other parts of the world are examining the use of liquid hydrogen on board the vehicle, while the United States is focusing on gaseous hydrogen delivery. This roadmap addresses only gaseous dispensing. Issues to be addressed include costs, safety, nozzles, pressures, expansion, materials of construction, metering, units of sale, and carrier exchange.

Few vendors currently offer the sophisticated technology for compressed hydrogen dispensers, and costs are high compared to gasoline dispensers. Expanded demonstration and pilot programs sponsored by the DOE in partnership with industry should spur efficiency improvements in the technology and help lower costs associated with hydrogen gas/liquid delivery via dispensers. The long-term target is for self-refueling, which will require a high level of safety and incorporate engineering controls and education of the public.

A single hydrogen nozzle currently costs about $4,000. In contrast, a gasoline dispensing nozzle costs $40 to $110. A complete gasoline dispenser unit currently costs less than $15,000, while a hydrogen dispenser costs many times more. The high capital costs associated with dispensing hydrogen to vehicles is a major barrier to widespread development of hydrogen refueling stations, particularly during the transition phase when demand is low. As the technology matures and more manufacturers enter the market, however, these costs are likely to decrease.

Hydrogen, particularly high-pressure hydrogen, presents safety concerns that differ from those of gasoline and must be addressed by engineering controls to assure safe delivery. These controls involve fail-safe, leak-proof connectors between the dispenser nozzle and vehicle fill port. The ease with which hydrogen can ignite mandates zero leakage from the equipment.

The few sites that now deliver compressed hydrogen have experienced persistent problems with nozzle leakage. Analysis of the problem points to corrosion of components from moisture and abrasion of the high-pressure seals by external dirt particulates. Leakage of hydrogen involves significant safety issues, particularly for untrained refuelers at the forecourt. An engineering solution is also needed to prevent inadvertent discharge of the nozzle when it is not coupled to the vehicle. Inadvertent discharge has resulted in a high-pressure hydrogen release or "pop" that could startle a customer.

The pressure of delivered hydrogen will generally be dictated by the available on-board storage system and the desired mileage of the vehicle between fill-ups. Current mileage targets are for a minimum of 500 km (300 miles) to match consumer expectations based on mileage with gasoline. Some current designs for bulk storage at refueling sites assume a pressure of 350-700 bar (5,000-10,000 psi). Tradeoffs will be required to balance higher pressure with thicker-walled (and heavier) on- and off-board storage containers. Successful development of low-pressure, on-board storage systems would substantially alleviate this potential problem. The DOE target for on-board storage is a system that could operate at 100 bar (1,500 psi) or less.

Development of dispenser technology will also require stakeholders to reach a consensus on the style of vehicle and dispenser connectors. To avoid over- or under-filling the vehicle hydrogen tank, it must somehow "communicate" with the dispenser. While a vehicle is being refueled with compressed hydrogen, a heating effect that occurs during dispensing can waste fill tank volume with expanded hydrogen. If a vehicle's hydrogen tank was allowed to cool over several minutes, more hydrogen could be delivered during that refueling session. A solution may involve more sophisticated dispenser technology that would allow re-circulation of cooler hydrogen from the site storage.

Equipment for handling both liquid and high-pressure hydrogen involves expensive, robust materials of construction. Development of low-cost, reliable materials of construction for hydrogen dispensing equipment is a key challenge.

Reliable and accurate metering of the dispensed hydrogen is another important technology needed for retail vehicle refueling with hydrogen. Metering of cryogenic hydrogen involves electronic or mechanical mechanisms that work under conditions of extreme cold. Likewise, metering of high-pressure hydrogen will require mechanisms that perform under extreme pressure conditions.

Finally, the hydrogen refueling industry and federal and state governments need to decide upon the unit of sale for refueling vehicles with hydrogen. Options include using the energy equivalent to gasoline, or absolute units such as dollars per liter, per pound, or per kilo.

As mentioned, one alternative to compressed hydrogen is a novel hydrogen "carrier." Carriers might enable novel refueling paradigms, such as a hydrogen-containing "brick" or granular solid absorbent that can be exchanged at the refueling site. Technology would then be needed to support the quick, convenient exchange of "spent" bricks/absorbent for "full" bricks/absorbent. Design of this exchange equipment at the refueling site depends heavily on the characteristics of the chosen carrier.

Mobile Fuelers

Status

Mobile fuelers are an option being explored for hydrogen delivery during the very early part of the transition. Mobile fuelers combine hydrogen storage with a dispenser in a portable unit that can fuel vehicles directly. A mobile fueler has less capacity than tube trailers, but typically provides a higher delivery pressure. While tube trailers are capable of hauling 300-400 kg of hydrogen at 182 bar (2,460 psi), mobile fuelers have a capacity of 110 kg at 350 bar (5,000 psi). Just as tubes are carried on a trailer, the mobile fueler is transported using a separate vehicle. A smaller size can also be towed using a pickup truck instead of a tractor trailer. This smaller unit can supply 60 kg (130 lb) at 350 bar (5,000 psi). No utility requirements pertain to a mobile fueling site, but the site is required to meet the NFPA 50A Standard for Gaseous Hydrogen Systems at Consumer Sites and local codes.

Terminals

Status

Petroleum

The United States has approximately 132 operating refineries and 1,300 petroleum product terminals. These facilities supply petroleum products to more than 167,000 retail service stations, truck stops, and marinas. Not counted in these statistics are the distributor bulk storage and non-retail fleet locations, such as rental companies and schools. As shown in Figure 4-4, the number of retail stations has dropped by 19% in the last 12 years, and the number of refineries and terminals has also declined significantly. In addition, ownership of retail stations and terminals has shifted significantly from major oil companies toward third parties.

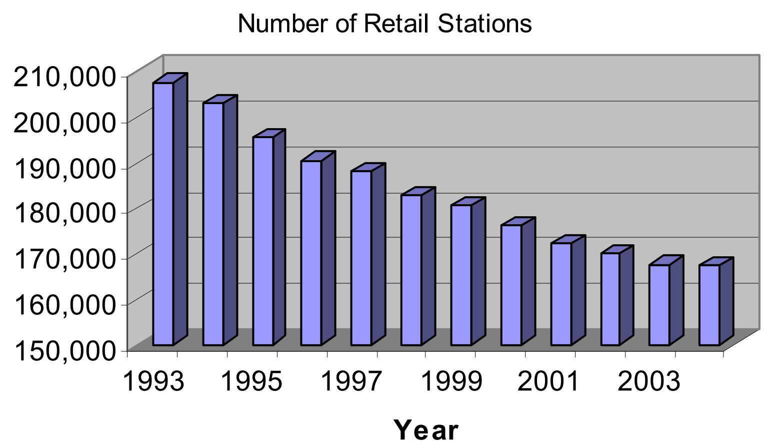


Figure 4-4: Number of Retail Stations Over Time

Terminaling costs can range from 10-25% of the transportation cost of gasoline, about 0.1 to 0.3 cents per liter (0.4-1.2 cents/gal) from the refinery to the retail station. Since 68% of domestic petroleum shipments are delivered via pipeline and 27% by water, the majority of the terminals are connected to pipelines and many have docks or both. As shown on the following page in Table 4-4, terminals range widely in size, depending on the retail network they serve.

Logistical hubs serve as gateways for regional supply and play an important role in balancing supply and demand. A logistical hub is characterized by interconnections of many pipelines to each other, and often to other modes of transport such as tankers, barges, and rail. These interconnections allow supply to move from system to system across counties, states, and regions in a hub-to-hub progression. These hubs, such as Pasadena, Texas, and New York Harbor, are also characterized by their substantial storage capacity. The storage and transportation options enhance supply opportunities and increase supply flexibility, both of which are essential for an efficient and cost-competitive market. Storage and transportation options at hubs also allow market participants to adjust their supply and demand between hubs to restore balance.

Table 4-4: Terminal Statistics

Number of Tanks	2-25
Tank Sizes	<1,000 - 150,000 bbls (barrels) <160 - 24,000 m^3
Typical Tank Sizes	20,000 - 60,000 bbls 3,200 - 10,000 m^3
Number of Products	1-12
Number of Personnel	2-20

Natural Gas

Post-production natural gas is most commonly stored in one of three types of pressurized underground facilities: 1) depleted reservoirs in oil and/or gas fields, 2) aquifers, or 3) salt caverns. Abandoned mines have also been used in the past, and hard-rock caverns are undergoing evaluation for commercial storage. As of 2003, approximately 407 storage facilities were located in the lower 48 states. The approximately 38 aquifers were primarily in the Illinois/Indiana/Iowa area, while the 29 salt cavern facilities were along the Gulf Coast. The 340 depleted reservoirs were spread across several states, but were concentrated in the western Pennsylvania/Ohio/West Virginia/New York areas. Many areas, such as New England, the south Atlantic, the Dakotas, and Arizona/Nevada, have no storage at all. The suitability of a location is dependent on its physical characteristics (porosity, permeability) and economics (site costs, deliverability rate, cycling capability). Capacities are shown in Table 4-5 (from the EIA).

Table 4-5: Current Natural Gas Storage Sites

Type of Storage	Number	Total Capacity	Average Capacity
Salt Caverns	29	6.4×10^9 m^3 (226 bcf)	0.22×10^9 m^3 (7.8 bcf)
Aquifers	38	35×10^9 m^3 (1,234 bcf)	0.92×10^9 m^3 (32.5 bcf)
Depleted Fields	340	219×10^9 m^3 (7,747 bcf)	0.56×10^9 m^3 (19.8 bcf)
Total	407	260×10^9 m^3 (9,207 bcf)	0.57×10^9 m^3 (20.2 bcf)

Hydrogen

The United States currently has 40 gaseous hydrogen distribution terminals, and there are nine liquid hydrogen production facilities in North America. The United States also has 118 captive hydrogen producers. In addition to serving the industrial sector, all of these facilities could (and some do) distribute gaseous hydrogen.

Today's typical, bulk, gaseous hydrogen distribution terminals obtain their hydrogen supply through the vaporization of liquid hydrogen. Liquid-to-gas system terminals are more complex than their petroleum counterparts since they incorporate additional steps for vaporization and compression and must address issues of higher-pressure and lower-temperature storage. In the case of hydrogen carriers, terminals may perform carrier recharging and handling of spent carriers. Future gaseous hydrogen distribution terminals may be supplied by a pipeline or on-site generation systems. Quality control, which is getting more stringent at petroleum terminals, will be extremely important in monitoring and maintaining the high-purity specification required for hydrogen.

Despite these special considerations, hydrogen terminals will also bear many similarities to petroleum terminals. The terminals will have storage and loading racks (stanchions) and will be staffed with personnel that have the required skill sets to ensure safe and reliable operations. The terminal will be responsible for receipts, deliveries, and monitoring inventory to prevent stock-outs. The logistics of loading multiple trucks for multiple customers will be similar, along with the back-office business of custody transfers, truck tickets, and other paperwork.

Other Forecourt Issues

Safety is paramount for public acceptance of hydrogen, and forecourt engineering must employ the safest design. For compressed hydrogen, liquefied hydrogen, or a hydrogen carrier, key safety issues remain to be addressed. Hydrogen has a wide range of flammability in air and a low ignition energy threshold; therefore, forecourt hydrogen handling equipment must be leak-proof. The FreedomCAR and Fuel Partnership Codes and Standards Technical Team is exploring design and storage issues. The forecourt must incorporate engineering controls that meet the final codes and standards. Such items as hydrogen leak sensors, infrared fire/flame detectors, remote monitoring, and fail-safe designs may be considered to meet the eventual standards.

As the level and sophistication of safety controls increases, so does the cost for hydrogen refueling sites. Safety controls are essential, but they must be cost-effective. Since this equipment will be in frequent use as more hydrogen-powered vehicles get on the road, the equipment will also require regular maintenance to prevent failures and protect the public and retail site employees.

Storage of intermediate and high-pressure hydrogen at the retail site poses other challenges. Some designs provide for intermediate storage at 350-500 bar (5,000-7,000 psi), with compression and storage in a smaller, high-pressure delivery tank at 700 bar (10,000 psi). Locations under consideration for these tanks include placement in the forecourt behind protective barriers, underground, or even above ground in a supported canopy. Each design offers advantages and drawbacks.

Bulk hydrogen off-loading into storage at the retail site will require delivery trucks to be on-site for the period of time needed to replenish the hydrogen inventory. This unloading of hydrogen gas or liquid involves hazards that must be addressed, and the refueling trucks must be kept out of the way of retail traffic. Tankers also must have adequate room for maneuvering. Depending upon tanker size and retail site footprint, refueling truck access could pose special challenges for site design.

Unlike bulk petroleum liquid off-loading, compressed gas or liquefied hydrogen bulk off-loading from a truck must incorporate engineering controls to assure that the process is performed safely without overfilling storage capacity. These technologies are relatively well-known in the compressed gas and liquefied gas industry, but new to the fuels industry.

To meet the goal of letting customers refuel their own vehicles, consumer education is essential. Demonstrations on how to use this new technology can be delivered via on-site attendants, pamphlets, brochures, and even advertising. Education to raise awareness and instill confidence in consumers is critical to widespread acceptance of this new fuel and vehicle technology.

5 Key Technical Barriers

Analysis

Lack of Comprehensive Delivery Infrastructure Analyses. The options and trade-offs involved in various approaches to hydrogen delivery are not well understood. In-depth comparative analyses are required to examine the most promising options for delivering and distributing hydrogen from both large (>50,000 kg/day) and small (1,500-10,000 kg/day) production facilities to refueling stations and stationary power facilities. Such analyses would provide critical information for defining a cost-effective, energy-efficient, and safe hydrogen delivery infrastructure to support both the introductory phase and the long-term use of hydrogen for transportation and stationary power.

Pipelines

Installed Capital Cost. The cost of new pipeline construction is high. Materials and labor comprise approximately 70% of new pipeline construction costs, so technology is needed to fabricate pipelines that use less expensive materials and require a minimum of sophisticated joining and inspections.

Lack of Understanding of Material Science Issues. There is insufficient understanding of hydrogen embrittlement, fracture toughness, crack propagation, and permeation issues for steel pipeline materials under aggressive hydrogen service conditions. For example, materials need to be investigated under higher pressures than previously studied and under pressure cycling, or for performance with mixtures of hydrogen and natural gas.

Innovative, Low-Cost Materials and Construction Techniques. Current pipeline materials are costly, expensive to weld and join, and potentially susceptible to hydrogen embrittlement, permeation, and leakage. New metallic materials, alternative materials such as plastics or composites, or surface treatments (coatings) need to be developed. Non-metallics might require much simpler (and thus lower-cost) joining technologies and could potentially be fabricated in significantly longer sections than the metallic materials currently used for pipelines.

Seals, Valves, and Related Equipment. Improved seals, valves, and other components for pipelines will be required to enable safe, efficient, and leak-free transport of hydrogen gas in pipelines.

Right-of-Way Issues. Obtaining the right-of-way (ROW) to construct a pipeline through public or private property can be costly and administratively challenging. In some cases, ROW costs may be prohibitively high; in others, the ROW may simply be unattainable.

Liquefaction

High Capital Cost. Current liquefaction technology adds more than $1.00 per kg to the cost of hydrogen. The plants are capital-intensive, and this problem is exacerbated by the lack of low-cost materials that can withstand the conditions. As in the LNG industry, economies of scale can help reduce the cost of liquefaction by allowing for standard plant designs and improved thermal management.

Low Energy Efficiency and Losses. Liquefaction processes currently used by hydrogen vendors require high energy inputs, equating to about 35% of the energy contained in the hydrogen that is liquefied. Roughly 10% of this energy is thermodynamically required to cool the hydrogen and to achieve the ortho/para transition. Better technology could offer opportunities to improve energy efficiency, including aluminum heat exchangers, improved gas compressors, and turbo expanders used in the process. Improvements must also be made in reducing the amount of hydrogen that is lost due to boil-off during storage and transportation.

Lack of Novel Technology and Approaches. Achieving breakthroughs in liquefaction costs and energy efficiency will require substantial research to increase the scale of operations, improve heat/energy integration (perhaps by co-locating the liquefaction with hydrogen production or power production and integrating energy and heat across the operations), lower the costs of heat exchange materials, and improve the catalysts for the ortho/para transition. Development of a novel, next-generation technology, such as acoustic or magnetic liquefaction, could potentially provide a breakthrough and a more effective process.

Carriers

Insufficient Knowledge/Experience. Research has been limited on the use of carriers for hydrogen delivery. As yet, no material has been identified with the right combination of high hydrogen capacity and optimal energetics. Considerable uncertainty exists regarding how a carrier-based delivery infrastructure might look and operate. In addition, carrier development suffers from a lack of standardized computational methods and protocols for calculating the thermodynamics and kinetics for the hydrogenation and dehydrogenation of potential carrier materials. Lack of these tools creates large scientific and economic uncertainties around carrier-based delivery.

Energy Efficiency. Many potential carriers with high hydrogen capacities require too much energy for dehydriding or rehydriding. This problem adversely affects their overall suitability as carriers.

Inadequate Transformation Processes. Simple dehydriding processes that produce clean hydrogen ready for compression are essential for any potential carrier. Many current processes are complex, inefficient, or produce hydrogen with impurities.

Round-Trip Issues. Round-trip carriers, which require a return trip for re-hydriding, increase transportation costs, require station storage space, and introduce additional complexity at terminals, which are traditionally “low-tech” operations.

Compression

Low Reliability. Reciprocating compressors exhibit low reliability, requiring redundant systems to assure acceptable performance. Current centrifugal compression technology is not suitable for hydrogen.

Lubrication Contaminants. Lubricating oil in compression can contaminate the hydrogen being compressed. If this oil is not properly removed, it could have a detrimental effect on fuel cell performance. Non-lubricated designs or zero-lubrication leakage/contamination are needed.

High Capital and Maintenance Cost. Compressors require expensive materials to prevent hydrogen embrittlement and the associated risk of part failures during use. The large number of moving parts in reciprocating compressors also tends to increase maintenance issues and costs. Research needs include better materials and alternative compressor designs.

Low Energy Efficiency. The low efficiency of the electrical drives and the mechanical losses present in compressors result in some level of energy inefficiency. High energy efficiency designs are needed.

Cryogenic Liquid Pumps

Cost. Cryogenic liquid pumps have high capital cost per-unit pumping capacity.

High Maintenance, Poor Reliability, and Excessive Downtime. Cryogenic pumps work under extremely cold temperatures. The hydrogen entering the pump must be in the liquid state at all times as any vaporization will cause cavitation (excessive pressure drop) that will damage the pump. In addition, periodic recharging of the pump is required to purge any frozen or trapped gases. This requirement results in expensive downtime for the pumping process.

Tube Trailers

High Capital and Labor Cost. The low hydrogen-carrying capacity of current gaseous trucks results in high delivery costs. Research needs include the investigation of higher-pressure, composite tubes to increase the carrying capacity of tube trailers. High-pressure tube trailers would require new regulations through the Department of Transportation (DOT).

Rail, Barge, and Ship Carriers

Poor Availability and Delivery Schedule. Hydrogen rail delivery is currently economically feasible only for cryogenic liquid hydrogen. At present, however, almost no hydrogen is transported by rail. Reasons include the lack of timely scheduling and transport to avoid excessive hydrogen boil-off and the lack of rail cars capable of handling cryogenic liquid hydrogen. Needed improvements include scheduling to eliminate delays or storage methods that would allow for delays in delivery without excessive hydrogen boil-off. Hydrogen transport by barge faces similar issues in that few vessels are designed to handle the transport of hydrogen over inland waterways. Storage methods and terminal technologies must also be developed to support the economical transport of hydrogen over rail or water.

Lack of Terminal Infrastructure. Due to the lack of hydrogen distribution by barge and rail systems, no terminal infrastructure currently exists for these delivery options.

Gaseous and Liquid Tanks

Cost. Gaseous and liquid storage tanks add significant cost to the hydrogen delivery infrastructure—especially at refueling and stationary power sites where the hydrogen throughput is low compared to the required capital investment. Technology for lower-cost systems is needed. This technology could include new, lower-cost materials, design for high-throughput manufacturing of identical units, and higher hydrogen capacity per unit volume through the use of higher-pressure gaseous storage or carriers.

Footprint. Real estate at refueling stations is costly. The footprint of hydrogen storage needs to be minimized.

Hydrogen Losses. Liquid storage tanks lose hydrogen by boil-off. The boil-off of liquid hydrogen requires venting and results in a cost and energy penalty.

Materials Requirements. The materials used to make both gaseous and liquid storage tanks must be resistant to hydrogen embrittlement and maintain structural integrity under high-pressure cycling environments.

Underground Liquid Storage Issues. Concerns unique to underground liquid storage present major research challenges. For instance, the effects of soil pressure on the tank, and tank leakage on the surroundings, are unknown. Ground freezing must be avoided, and corrosion issues must be resolved. In addition, seismic (earthquake) effects on the underground tank need to be determined.

Geologic Storage

Cost. Potential cost barriers to geologic storage include the high costs of storage field development, compression, and hydrogen losses (due to leakage).

Identification of Suitable Locations. Candidate sites for geologic storage must have promising permeability characteristics and good caprock formation. Currently, researchers lack adequate tools for modeling potential sites for hydrogen containment and for collecting site-specific geophysical information.

Inadequate Understanding of Hydrogen Behavior in Rock Formations. Potential barriers include the risk that hydrogen gas will escape through unknown conduits in the geologic formation or if there are unexpected variations in storage geometry and material composition. In addition, the chemistry between hydrogen and minerals in underground formations is unknown, and unexpected reactions may compromise the integrity of the storage unit or consume large amounts of hydrogen on initial use. Finally, the rock mass used may not be a continuous medium, and pressure cycling may cause unexpected behavior.

Hydrogen Losses/Leakage During Operation. As with all storage mechanisms, geologic storage may suffer from hydrogen leakage. The amount likely to be lost to the surroundings is currently not known and will depend greatly on the particular geologic formation. Also, when a geologic storage site is first used, the area must be "flushed" of contaminants, and the volume of gas needed to accomplish this for hydrogen is unknown.

Separation and Purification

Polishing Barriers. The nature and amount of the contaminants to be removed will depend on the hydrogen production process, the level of purification employed at a particular stage, and the amount of contamination that occurs in the delivery infrastructure. As a result, specifications for the polishing purification step will unfold over time as these technologies are developed. Several different polishing technologies may be required, depending on the production and delivery technologies employed. The cost and energy use of any polishing step must be minimized, and hydrogen losses must be decreased. Pressure drops will need to be lowered to avoid additional compression costs.

Hydrogen-Natural Gas Mixture Separation. The cost and energy use for this process must be reduced. Options to be explored include membranes and PSA technologies.

Dispensers

High Cost. The high cost of components and the low number of manufacturers are the major factors behind the current expense of hydrogen dispensers.

Materials Requirements. Special materials are required to withstand the high pressures of compressed hydrogen or the low temperatures of cryogenic hydrogen.

Accurate Metering. Current technology makes it difficult to accurately meter hydrogen, whether compressed or cryogenic, and to dispense it at a rate that ensures an acceptable fill-time duration.

Other Forecourt Issues

Fueling Station Design Requirements. Design of the fueling station must solve a variety of forecourt issues. The location of hydrogen storage tanks at the retail site must be optimized for safety and convenience, and the location for bulk off-loading of hydrogen from tanker trucks must allow safe and efficient replenishment of on-site hydrogen while avoiding interference with retail traffic. Due to the high cost of real estate, the footprint for storage and other operations must also be minimized.

Safety, Codes and Standards

Lack of a Comprehensive System of Codes and Standards. Codes and standards governing safety and equipment compatibility must be established for every aspect of the hydrogen delivery infrastructure—including truck, rail, and pipeline transport; tank and geologic storage; handling at the terminal; and handling and dispensing in the forecourt. Some components of the delivery system are so new that the appropriate governing codes and standards simply do not exist. For codes and standards that do exist, the key barrier is communication and education—making the appropriate officials aware of and confident in administering the codes and standards.

Cost-Effective, Reliable, Safety Technology. A variety of safety challenges arise as a result of hydrogen's diffusivity and volatility, the pressures and temperatures at which it must be stored, and the goal of refueling by the public. Monitoring and control technologies (e.g., hydrogen leak sensors, infrared fire/flame detectors, remote monitoring, and fail-safe designs) are needed to meet codes and standards in a cost-effective manner. The need includes methods for low-cost maintenance of hydrogen delivery equipment, especially in the forecourt.

Permitting. The lack of sufficient codes and standards for some technologies makes securing permits especially challenging. The "Not In My Back Yard" (NIMBY) syndrome also acts as a major barrier to permitting needed facilities, including storage sites, pipelines, terminals, and fueling stations.

Education. Education and training programs will be needed to achieve public acceptance and ensure safe handling of hydrogen. Fueling station operators and truck drivers must be trained to handle hydrogen safely. Also, the consumer must be instructed on how to use the refueling equipment safely.

Leak Detection

Hydrogen Leak Detection Technology. The potential for hydrogen leakage exists at every step of the delivery system, and leak detection is crucial to maintaining safe handling. Odorizing hydrogen gas (as is done with natural gas) is particularly challenging since the extremely small and light hydrogen molecule diffuses faster than any known odorant. Odorants may also interfere with the use of hydrogen in fuel cells. Alternative, cost-effective methods for leak detection will likely be needed.

6 Pros and Cons of Hydrogen Delivery Pathways

The three hydrogen delivery pathways have advantages and disadvantages, as described below and summarized in Table 6-1.

Gaseous Pathway. Although gaseous pipelines are the lowest cost-known delivery option at high market penetration, the large fixed capital investments for pipelines make it unacceptably expensive at low penetrations. Truck delivery of gas is very inefficient. Today's 36,000 kg (80,000 lb) gaseous hydrogen truck/trailer combination delivers 300-400 kg of useable hydrogen – enough hydrogen to fuel only 30-50 vehicles. Advances in materials could solve some of these problems by enabling the cost-effective transition from steel to composite tubes. Composite tubes would be both lighter in weight and potentially capable of holding hydrogen at pressures up to 10,000 psi (compared with about 2,600 psi for today's steel tube trailer cylinders). This could increase carrying capacity to over 1,000 kg of hydrogen.

Liquid Pathway. Although liquefaction consumes a significant portion of the hydrogen's energy content, it appears to be the best currently known option for delivery of centrally-produced hydrogen at low market penetration. Liquid trucks can deliver around 7 times more hydrogen than today's gaseous tube trailer. This increased delivery capacity makes up for the high cost of liquefaction when compared with gaseous hydrogen delivery for distances more than 100-200 miles. Although it is cheaper than gaseous delivery, liquid delivery is still costly and very energy-intensive. Breakthroughs in liquefaction or economies of scale could reduce the cost and increase the energy efficiency, making liquid delivery more attractive.

Carriers. Carriers are the "wild card" in the delivery portfolio. A carrier with high energy density and simple transformation (both hydriding and dehydriding) could deliver hydrogen using existing infrastructure and be a key enabler for a hydrogen economy. Novel carriers—solids, liquids, powders, or other novel forms—have the potential to radically alter the distribution system. Carriers are, however, not well understood, and extensive engineering and economic analysis is needed with experimental development of promising materials.

Mixed Pathways. Although the above pathways are distinct, it is highly likely that no single pathway will ever serve as the exclusive mode of distribution. In reality, a mixture of pathways will be needed during the transition to a hydrogen economy. Even when the transition is complete, economics will dictate the preferred delivery pathway for a given locality so that all of the pathways are expected to play a role in hydrogen delivery for the foreseeable future. For example, gaseous distribution pipelines in urban areas are likely to be more difficult and costly to construct than transmission pipelines located in more rural areas. This may create a feasible delivery scenario involving pipeline transmission from a central/semi-central production facility to a terminal where the gas is distributed by tube trailer or liquefied and distributed via tanker trucks, or incorporated into a carrier that is delivered by truck to refueling stations. Mixed pathways might also be used to supplement onsite production.

Table 6-1: Pros and Cons of Pathways

Pathway	Pros	Cons
Gaseous	• Pipelines are currently the most cost-effective option for high volumes of hydrogen • No thermodynamic limitations to low costs • Pipeline delivery is highly energy efficient • Minimizes over-the-road transportation (environment and safety benefits) • Tube trailer delivery feasible for small amounts of hydrogen in the transition	• High capital investment • Low cost when full, very costly when marginally used • Permitting difficult and costly • ROW may be costly and difficult to obtain, especially in urban areas • Likely to require geologic or other low-cost bulk storage • Tube trailer delivery is very costly
Liquid	• High energy density • Small volumetric footprint • Liquid tankers are relatively cheap and efficient • Potential option for the transition • Minimizes need for compression in the forecourt	• Thermodynamics limit energy efficiency • High energy consumption and high costs • Not a likely low-cost long-term solution • Potential for stranded capital with liquefaction plants • Complexity of handling cryogenic liquids
Carriers	• Potential to change the economic paradigm (could be the lowest cost option) • Might use existing infrastructure (or at least known infrastructure technology) • Could provide modest (<2,000psi) pressure, modest temperature (+/- 200°C from room temperature) delivery system • Could reduce off-board storage costs	• Little is known; much fundamental R&D is required • Requirements for production, transformation and rehydriding will impact energy efficiency and add costs • May introduce contaminants that could poison the fuel cell • Transformations to release hydrogen will increase forecourt complexity • Two-way carriers will require two-way transport • Unknown safety and environmental issues

7 Transition Issues

As suggested elsewhere in this roadmap, transition to a hydrogen-based transportation system will take time and will face severe economic challenges. The emerging hydrogen delivery infrastructure is likely to face the classic “chicken-and-egg” scenario, a dilemma that traditionally hinders new infrastructure development. Businesses are often reluctant to make the necessary initial investments based on concerns over low volumes, low returns, or stranded assets.

Until demand for hydrogen grows, hydrogen delivery, storage, and dispensing costs may be quite high—especially relative to costs for conventional liquid fuels delivery, storage, and dispensing. As hydrogen markets increase, however, newer technologies and methods for delivering, dispensing, and storing hydrogen are likely to offer economic advantages, putting the early technology adopters at risk of stranding their assets. Those who invest in liquefaction and truck transport of hydrogen during the initial stages, for example, may find their equipment obsolete with the subsequent introduction of more efficient and economic pipelines. Without those early investors, however, demand may never grow enough to support the more economic delivery pathways.

A number of technical or business approaches may help to ease this transition process. One possibility is to initially deliver and dispense hydrogen from larger, more centralized refueling stations instead of from a relatively large number of conveniently-located small refueling stations. This business model might reduce the early economic burden on individual retail sites, giving each a larger market area; the drawback is decreased convenience for end users. Other business strategies could include home refueling or refueling at the workplace.

As a strategy to initiate the transition, it may be more economically attractive to launch hydrogen on a local or regional scale. This approach would reduce initial infrastructure costs—but may cause problems for automakers, whose economic models may depend on the largest potential number of buyers. Since the cost of the infrastructure per unit of hydrogen consumed is likely to be higher in rural areas than in urban areas, these markets may develop at different rates, with urban areas leading the growth in demand.

All of the above-mentioned alternatives need to be studied during the next several years. Technical and business analyses are required to determine which models offer the lowest business risk. Clearly, incentives by automakers or local or national government may be necessary to make any of the early business propositions viable.

8 Research Strategy

Hydrogen can become a major energy carrier only after research has solved many issues that currently hinder development of a full hydrogen-delivery infrastructure. Many infrastructure components face economic and technical barriers, and the R&D needs range from incremental improvements to major breakthroughs in technology. Some of the infrastructure research needs must be met in the near term for use during the transition period, while others do not need to be solved until later, when a full delivery infrastructure is needed to handle the hydrogen demand.

Federal support is necessary for the high-risk, breakthrough research that can achieve the major cost reductions and efficiency improvements needed to meet delivery targets. The private sector can support the lower-risk development work needed as the hydrogen economy begins to develop.

A critical early R&D need is for additional **analysis** of all the options and trade-offs involved in the various delivery pathways and configurations. Such an analysis will help to identify the more efficient and cost-effective approaches for delivery during the transition period and for the long term. This improved understanding is needed to focus research on the most critical areas with the highest impact. At a minimum, this analysis should focus on the following:

- The trade-offs among various configurations and options for storage and compression at refueling sites, and how those options affect capacity utilization of the distributed production at a site

- The trade-offs involved in moving sooner rather than later toward use of transmission pipelines for long-distance hydrogen transport instead of relying on liquefaction and liquid transport

- A better understanding of the role that hydrogen carriers could play in transport and storage

- The trade-offs among options for where and how to purify hydrogen to meet stringent PEM fuel cell specifications and avoid any contamination of the hydrogen downstream of the final purification step

Getting through the **transition** period is vital. Prices per unit of hydrogen will be high due to the relatively low demand level. First priority should be placed on the research needed to reduce delivery costs during this early period. Based on current knowledge, the federal government should emphasize research in the following areas:

- **Forecourt Storage and Compression Technology:** Development of reliable, low-cost compression and low-cost, smaller-footprint storage

- **Liquefaction**: Breakthrough liquefaction technology that could dramatically reduce costs, increase energy efficiency, and minimize the cost of hydrogen transport from current hydrogen production sites or new, semi-central, central, or terminal sites

- **Lower-Cost, Higher-Pressure Tanks for Storage and Tube Trailers**: This research could be applied to reduce the costs of forecourt storage and tube trailer transport

- **Low-Cost Carrier Technology**: This research could improve forecourt storage and/or result in a cost breakthrough for hydrogen transport from current hydrogen production sites or new, semi-central, central, or terminal sites

Since distributed production at the forecourt is likely to play a major role during the transition period, the most immediate need is for lower-cost forecourt compression and storage. A breakthrough in hydrogen liquefaction and/or carriers could substantially reduce the costs and energy use involved in transporting hydrogen from existing or new, semi-central or central production sites. Carrier technology or lower-cost, high-pressure tank technology could also reduce forecourt storage and/or hydrogen transport costs.

Pipeline delivery currently represents the lowest-cost known option for hydrogen delivery when demand is high enough to substantially utilize the pipeline capacity. This cost advantage is particularly strong for long-distance transmission. Research is needed to resolve the hydrogen embrittlement issues of steels and/or to develop alternative pipeline materials. If the associated capital costs could be substantially reduced, hydrogen pipeline transmission could be used sooner rather than later. Researchers also need to explore use of the existing natural gas pipeline infrastructure for hydrogen, or natural gas and hydrogen mixtures. If some capacity is available and the technical issues can be resolved, this method of hydrogen delivery could be used during the transition. Pipeline research requires a concerted and focused effort, including fundamental materials science. It will require strong government support.

Compression technology for pipeline transmission and research on hydrogen **geologic storage** are needed to support pipeline delivery. Geologic storage is heavily relied on for the natural gas pipeline delivery infrastructure and will likely be important for a hydrogen pipeline infrastructure. New, more reliable compression technology is necessary for pipeline transmission applications and to meet geologic storage requirements.

Hydrogen **carrier technology** could result in a paradigm shift for hydrogen delivery. This approach could not only reduce costs but might substantially reduce the amount of capital investment required for the hydrogen delivery infrastructure. It could also change the nature and cost of hydrogen storage. The federal government's current investment in the development of carrier materials for on-board vehicle hydrogen storage should be leveraged and expanded as warranted for hydrogen delivery applications.

Finally, **codes and standards, permitting issues, and sensors** for hydrogen leak detection are all vital to the development of a hydrogen delivery infrastructure. This area has its own FreedomCAR and Fuel Partnership Tech Team. The Delivery Tech Team will collaborate with the Codes & Standards Tech Team in these areas.

All of the other delivery infrastructure components and pathways, barriers, and needs discussed in this roadmap can be adequately addressed by the private sector through their own efforts and by applying the technology funded and developed through government-supported efforts. For example, a gaseous hydrogen terminal would use the advances achieved in high-pressure or carrier storage technology and compression technology.

9 Technical Targets

These technical targets are derived from the FreedomCAR and Fuels Partnership overall premise that hydrogen fuel cell vehicles have to be cost competitive with current vehicle and fuel options on a cost per mile driven basis. Based on this premise, DOE analysis and methodology was used to arrive at the the overall objective for hydrogen delivery to cost <\$1.00 per kg of hydrogen by 2015. (See Section 2.) The individual component technical targets were derived from publically available information and models for hydrogen delivery systems as necessary to achieve the overall delivery cost target of <\$1.00 per kg. The intermediate timeframe technical targets are milestones along the path to track progress. .

Table 9-1: Hydrogen Delivery Targets

Category	FY2003	FY2005	FY2010	FY2015
Pipelines: Transmission				
Total Capital Cost (\$M/mile)[b]	\$1.20	\$1.20	\$1.00	\$0.80
Pipelines: Distribution				
Total Capital Cost (\$M/mile)[b]	\$0.30	\$0.30	\$0.25	\$0.20
Pipelines: Transmission and Distribution				
Reliability (relative to H_2 embrittlement concerns, and integrity)[c]	Undefined	Undefined	Understood	High (Metrics TBD)
H_2 Leakage[d]	Undefined	Undefined	<2%	<0.5%
Compression: Transmission				
Reliability[e]	92%	92%	95%	>99%
Hydrogen Energy Efficiency (%)[f]	99%	99%	99%	99%
Capital Cost (\$M/compressor)[g]	\$18	\$18	\$15	\$12
Compression: At Refueling Sites				
Reliability[e]	Unknown	Unknown	90%	99%
Hydrogen Energy Efficiency (%)[f]	94%	94%	95%	96%
Contamination[h]	Varies by Design	Varies by Design	Reduced	None
Cost Contribution (\$/kg of H_2)[i,j]	\$0.60	\$0.60	\$0.40	\$0.25
Liquefaction				
Small-Scale (30,000 kg H_2/day) Cost Contribution (\$/kg of H_2)[k]	\$1.80	\$1.80	\$1.60	\$1.50
Large-Scale (300,000 kg H_2/day) Cost Contribution (\$/kg of H_2)[k]	\$0.75	\$0.75	\$0.65	\$0.55
Small-Scale (30,000 kg H_2/day) Electrical Energy Efficiency (%)[k, l]	25%	25%	30%	35%
Large-Scale (300,000 kg H_2/day) Electrical Energy Efficiency (%)[k,l]	40%	40%	45%	50%
Carriers				
H_2 Content (% by weight)[m]	3%	3%	6.6%	13.2%
H_2 Content (kg H_2/liter)			0.013	0.027
H_2 Energy Efficiency (From the point of H_2 production through dispensing at the refueling site)[f]	Undefined	Undefined	70%	85%
Total Cost Contribution (From the point of H_2 Production through dispensing at the refueling site) (\$/kg of H_2)	Undefined	Undefined	\$1.70	\$1.00
Storage				
Refueling Site Storage Cost	\$0.70	\$0.70	\$0.30	\$0.20

Category	FY2003	FY2005	FY2010	FY2015
Contribution ($/kg of H_2)[j, n]				
Geologic Storage	Feasibility Unknown	Feasibility Unknown	Verify Feasibility for H2	Capital and operating cost <1.5X that for natural gas on a per kg basis
Hydrogen Purity[o]	>98% (dry basis)			

Footnotes:

a. All dollar values are in 2003 U.S. dollars

b. The 2003 status is based on data from True, W.R.,"Special Report: Pipeline Economics," *Oil and Gas Journal*, Sept. 16, 2002, pp 52-57. This article reports data on the cost of natural gas pipelines as a function of pipe diameter. It breaks the costs down by materials, labor, misc., and right-of-way. It is based on a U.S. average cost. A 15" pipe diameter was used for transmission and 2.5" for distribution. It was assumed that hydrogen pipelines will cost 30% more than natural gas pipelines based on advice from energy and industrial gas companies and organizations. The targeted cost reductions for 2010 and 2015 assume the right-of-way costs do not change.

c. Pipeline reliability used here refers to maintaining integrity of the pipeline relative to potential hydrogen embrittlement or other issues causing cracks or failures. The 2015 target is intended to be at least equivalent to that of today's natural gas pipeline infrastructure.

d. Hydrogen leakage based on the hydrogen that permeates or leaks from the pipeline as a percent of the amount of hydrogen put through the pipeline. The 2015 target is based on being equivalent to today's natural gas pipeline infrastructure based on the article: David A. Kirchgessner, et al, "Estimate of Methane Emissions from the U.S. Natural Gas Industry," *Chemososphere,* Vol.35, No 6, pp1365-1390, 1997.

e. Compression reliability is defined as the percent of time that the compressor can be reliably counted on as being fully operational. The 2003 value for transmission compressors is based on information from energy companies that use these types and sizes of compressors on hydrogen in their own operations.

f. Hydrogen energy efficiency is defined as the hydrogen energy (LHV) out divided by the sum of the hydrogen energy in (LHV) plus all other energy needed for the operation of the process.

g. The 2003 value is based on data from "Special Report: Pipeline Economics*," Oil and Gas Journal*, Sept. 4, 2000, p 78. The compressor capital cost data was plotted vs. the power required for the compressor using the natural gas transmission compressor data provided. The capital cost was increased by 30% as an assumption for higher costs for hydrogen compressors. The power required was calculated assuming 1,000,000 kg/day of hydrogen flow with an inlet pressure of 700 psi and an outlet pressure of 1,000 psi.

h. Some gas compressor designs require oil lubrication that results in some oil contamination of the gas compressed. Due to the stringent hydrogen purity specifications for PEM fuel cells, the 2015 target is to ensure no possibility of lubricant contamination of the hydrogen from the compression needed at refueling stations or stationary power sites since this compression is just prior to use on a vehicle or stationary power fuel cell.

i. The 2003 value is based on utilizing the H2A Forecourt (refueling station) Model spreadsheet tool for a 1500 kg/day distributed natural gas hydrogen production case (www.eere.energy.gov/hydrogenandfuelcells). The standard H2A financial input assumptions were used. It was assumed that two compressors would be needed due to the currently unknown reliability of forecourt compressors, at a total installed capital cost of $600K. The electricity required assumed an isentropic energy efficiency of 70% and an electricity price of $.07/kWhr. The compression operation was assumed to have a fractional share of the forecourt fixed costs based proportional to its capital and the total capital cost of the forecourt.

j. For 2003 and 2005, it is assumed that the hydrogen delivery pressure to the vehicle is 5000 psi. For 2010 and 2015, it is assumed that the hydrogen delivery pressure to the vehicle is 1,500 psi or less based on the on-board vehicle storage program (Section 3.3) being successful in meeting its targets.

k. The 2003 cost contribution and electrical energy efficiency was determined using the H2A Delivery Component Model spreadsheet using standard H2A financial input assumptions and the liquefaction spreadsheet tab (www.eere.energy.doe/hydrogenandfuelcells). The H2A spreadsheet information is based on data from other references sited in the H2A Delivery Component Model. References and a plot of liquefier capital cost as a function of capacity and a plot of actual energy used as a function of liquefier capacity are provided in the H2A Delivery Component model.

l. Electrical energy efficiency is defined as the theoretical energy needed to liquefy the hydrogen divided by the energy actually needed in a hydrogen liquefaction plant. The theoretical energy is that energy needed to cool the gas to the liquefaction temperature and the energy needed for the ortho/para transition. The H2A Delivery Component Model (www.eere.energy.doe/hydrogenandfuelcells) provides the references and a plot of actual energy needed for current hydrogen liquefiers as a function of capacity.

m. The 2010 hydrogen content targets are based on transporting 1,500 kg of hydrogen in a truck. Although regulations vary to some degree by state, a typical truck is limited to carrying 25,000 kg of load and/or 113,000 liters of volume. The minimum hydrogen content (% by weight and kg H_2/liter) to achieve 1,500 kg of hydrogen on the truck is determined by these maximum loads allowable. Trucking costs with this hydrogen payload are such that this transport option would seem attractive relative to the delivery cost objectives. A typical refueling station of 1,500 kg/day of hydrogen servicing hydrogen fuel cell vehicles would service the same number of vehicles as typical gasoline stations serve today. This delivery option would require one truck delivery per day which is also typical of today's gasoline stations. The 2015 targets are calculated in the same way but assuming 3,000 kg per truck load so that the one truck could service two refueling stations. The total cost and attractiveness of this delivery option would depend on the cost of the total carrier delivery system including the cost of discharging the hydrogen at the refueling station and any carrier regeneration costs.

n. The 2003 value is based on utilizing the H2A Forecourt (refueling station) Model spreadsheet tool for a 1,500 kg/day distributed natural gas case (www.eere.energy.gov/hydrogenandfuelcells). The standard H2A financial input assumptions were used. It was assumed that the hydrogen storage installed capital cost is $1.1M based on current technology and 1,100 kg of hydrogen storage. The storage operation was assumed to have a fractional share of the forecourt fixed costs based proportional to its capital and the total capital cost of the forecourt.

o. Based on current available PEM fuel cell information, the tentative contaminant targets are: <10ppb sulfur, <1 ppm carbon monoxide, <100 ppm carbon dioxide, < 1 ppm ammonia, < 100 ppm non-methane hydrocarbons on a C-1 basis, oxygen, nitrogen and argon can not exceed 2% in total, particulate levels must meet ISO standard 14787. Future information on contaminant limits for on-board storage may add additional constraints.

10 Conceptual R&D Paths

Table 10-1: Analysis Conceptual R&D Path

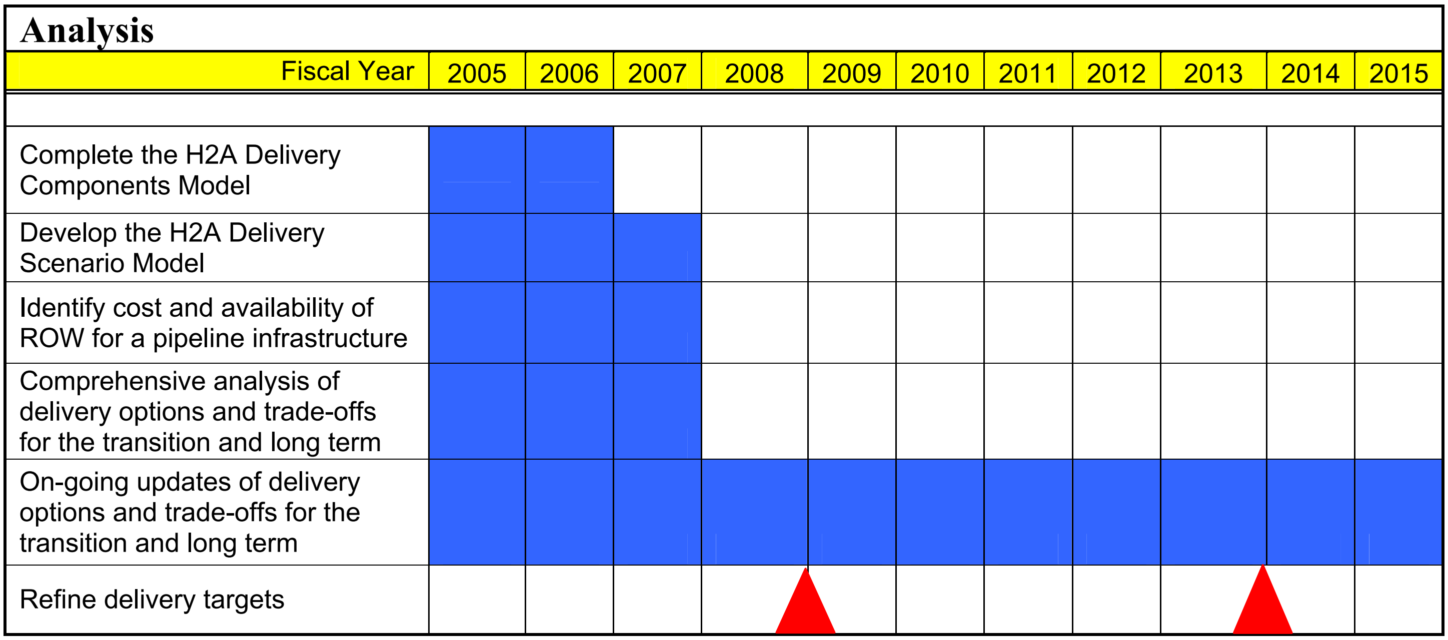


Table 10-2: Pipeline Conceptual R&D Path

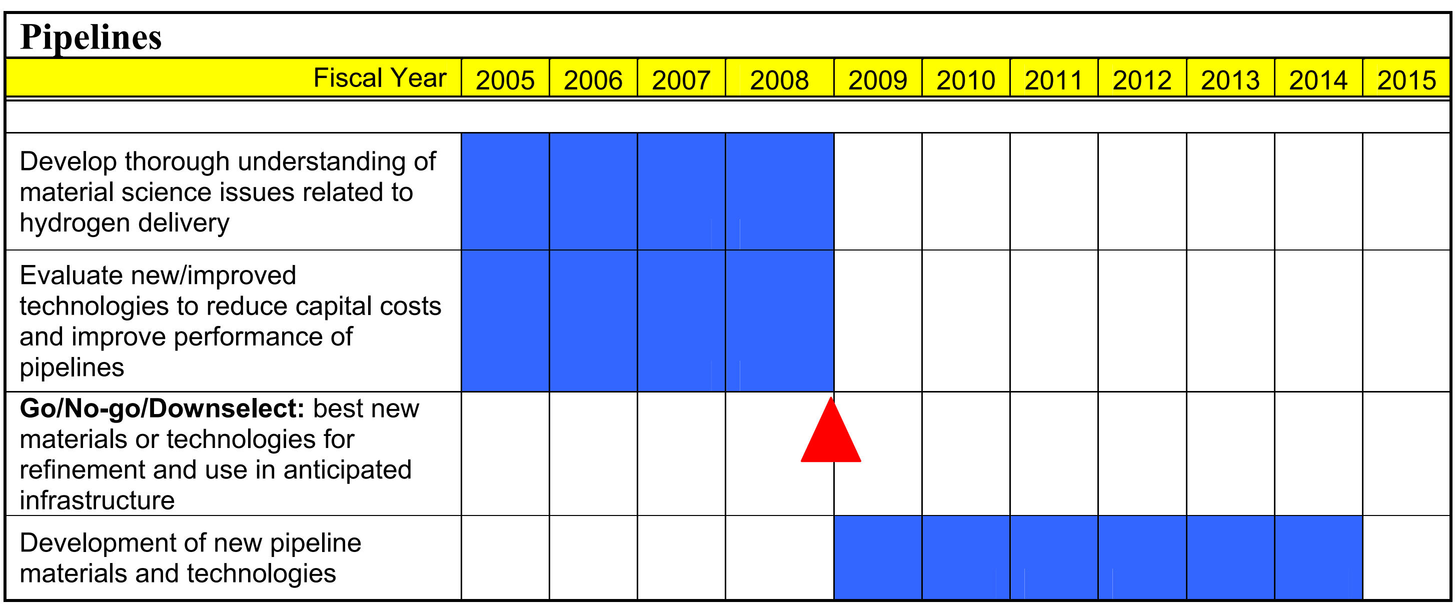


Table 10-3: Liquefaction Conceptual R&D Path

Liquefaction											
Fiscal Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Evaluate opportunities for improvements in liquefaction											
Evaluate novel technologies and their potential for improvements											
Go/No-go/Downselect: best novel technologies											
Conduct focused research on best novel technology(ies)											
Decide on value of developmental improvements in conventional liquefaction technologies											
Research on technologies that could improve efficiency or reduce cost of conventional technology: examples are improved ortho/para conversion catalysts; heat exchange equipment; integration with H2 production, power production, or other operation(s)											

Table 10-4: Carrier Conceptual R&D Path

Carriers											
Fiscal Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Review of carrier targets and options											
Theoretical carrier assessment											
Two-way hydrocarbon carrier research											
Go/No-Go/Downselect: Two-way hydrocarbon carrier											
Two-way hydrocarbon carrier development											
Two-way non-hydrocarbon carrier research											
Go/No-Go/Downselect: Two-way non-hydrocarbon carrier											
Two-way non-hydrocarbon carrier development											
One-way carrier evaluation											
Go/No-Go/Downselect: One-way carrier											
One-way carrier development											
Final carrier evaluations and recommendations											
Final carrier decision											

Table 10-5: Compression Conceptual R&D Path

Compression

Fiscal Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Identify opportunities for improvements in compression											
Evaluate novel technologies and concepts for forecourt applications											
Downselect: best novel compression technologies for forecourt applications											
Conduct research on best novel technology for forecourt applications											
Evaluate novel compression technologies and concepts for transmission applications											
Downselect: best novel compression technologies for transmission applications											
Conduct research on best novel compression technology for transmission applications											

Table 10-6: High-Pressure Gaseous Storage Tanks and Tube Trailers Conceptual R&D Path

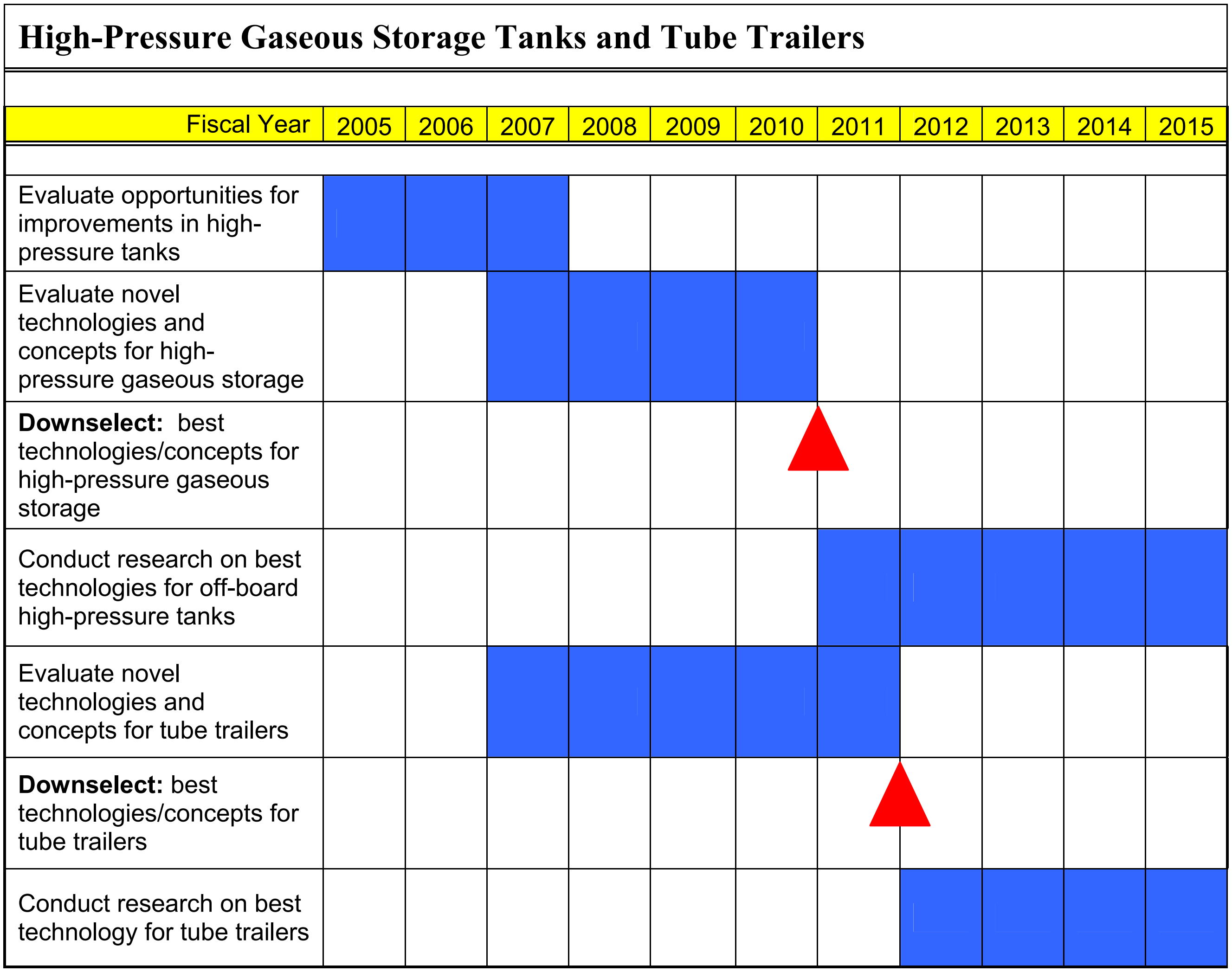


Table 10-7: Geologic Storage Conceptual R&D Path

Geologic Storage											
Fiscal Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Evaluate the possibility of storing hydrogen in geologic structures											
Conduct research on understanding the behavior of hydrogen in rock formations											
Go/No-Go: Geologic storage											
Conduct research to develop criteria for identification of suitable geological sites and develop appropriate modeling tools											
Evaluate and research promising concepts with respect to permeability issues											

11 Appendix: Conversion Factors

Hydrogen/Gasoline
1 kg of hydrogen = 113,571 Btu (LHV) ~ 1 gallon of gasoline

Energy
1 Joule = 0.0009478 Btu
1 Btu = 1055 J

Weight
1 kilogram = 2.2 pounds
1 lb = 0.45 kg
1 metric ton = 1.1023 short tons
1 short ton = 0.9072 metric tons

Volume
1 Liter = 0.035 cubic feet
1 ft^3= 28.32 L = 0.0283 m^3
1 cubic meter = 6.29 barrels
1 bbl = 0.159 m^3

Pressure
1 bar = 14.5 pounds per square inch
1 psi = 0.069 bar

Distance
1 km = 0.62 miles
1 mile = 1.61 km