USDRIVE

DRIVING RESEARCH AND INNOVATION FOR
VEHICLE EFFICIENCY AND ENERGY SUSTAINABILITY

Hydrogen Delivery Technical Team Roadmap

June 2013

This roadmap is a document of the U.S. DRIVE Partnership. U.S. DRIVE (United States Driving Research and Innovation for Vehicle efficiency and Energy sustainability) is a voluntary, non-binding, and nonlegal partnership among the U.S. Department of Energy; United States Council for Automotive Research (USCAR), representing Chrysler Group LLC, Ford Motor Company, and General Motors; Tesla Motors; five energy companies — BPAmerica, Chevron Corporation, Phillips 66 Company, ExxonMobil Corporation, and Shell Oil Products US; two utilities — Southern California Edison and DTE Energy; and the Electric Power Research Institute (EPRI).

The Hydrogen Delivery Technical Team is one of 12 U.S. DRIVE technical teams ("tech teams") whose mission is to accelerate the development of pre-competitive and innovative technologies to enable a full range of efficient and clean advanced light-duty vehicles, as well as related energy infrastructure.

For more information about U.S. DRIVE, please see the U.S. DRIVE Partnership Plan, www.vehicles.energy.gov/about/partnerships/usdrive.html or www.uscar.org.

Table of Contents

List of Figures

List of Tables

Acknowledgements

Hydrogen Delivery Technical Team (HDTT) Organization Members

Argonne National Laboratory
BP America
Chevron
U.S. Department of Energy Fuel Cell Technologies Office
U.S. Department of Transportation
ExxonMobil
Oak Ridge National Laboratory
Phillips 66
Praxair
Royal Dutch Shell

Hydrogen Delivery 2013 Roadmap Contributors

Contributor	Affiliation
Tim Barckholtz	ExxonMobil
Al Burgunder	Praxair
Dan Casey	Chevron
Sara Dillich	U.S. Department of Energy Fuel Cell Technologies Office
Amgad Elgowainy	Argonne National Laboratory
Jim Merritt	U.S. Department of Transportation
George Parks	Phillips 66
Steve Pawel	Oak Ridge National Laboratory
Jim Simnick*	BP America
Herie Soto	Royal Dutch Shell
Erika Sutherland*	U.S. Department of Energy Fuel Cell Technologies Office

* HDTT Co-Chair.

Mission

The mission of the Hydrogen Delivery Technical Team (HDTT) is to enable the development of hydrogen delivery technologies, which will allow for fuel cell competitiveness with gasoline and hybrid technologies by achieving an as-produced, delivered, and dispensed hydrogen cost of $2-$4 per gallon of gasoline equivalent of hydrogen.

The HDTT mission supports U.S. DRIVE Partnership (United States Driving Research and Innovation for Vehicle efficiency and Energy sustainability) Goal 2, which is to enable reliable fuel cell electric vehicles (FCEVs) with performance, safety, and costs comparable to or better than advanced conventional vehicle technologies, supported by viable hydrogen storage and the widespread availability of hydrogen fuel.

Scope

The scope of hydrogen delivery is broad. As shown in Figure 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 centralized and moderately sized semi-centralized production facilities as well as compression storage and dispensing of hydrogen produced from small-scale, distributed facilities located at vehicle refueling stations. The scope of the delivery infrastructure does not include technologies for hydrogen production or for hydrogen storage onboard a fuel cell electric vehicle.

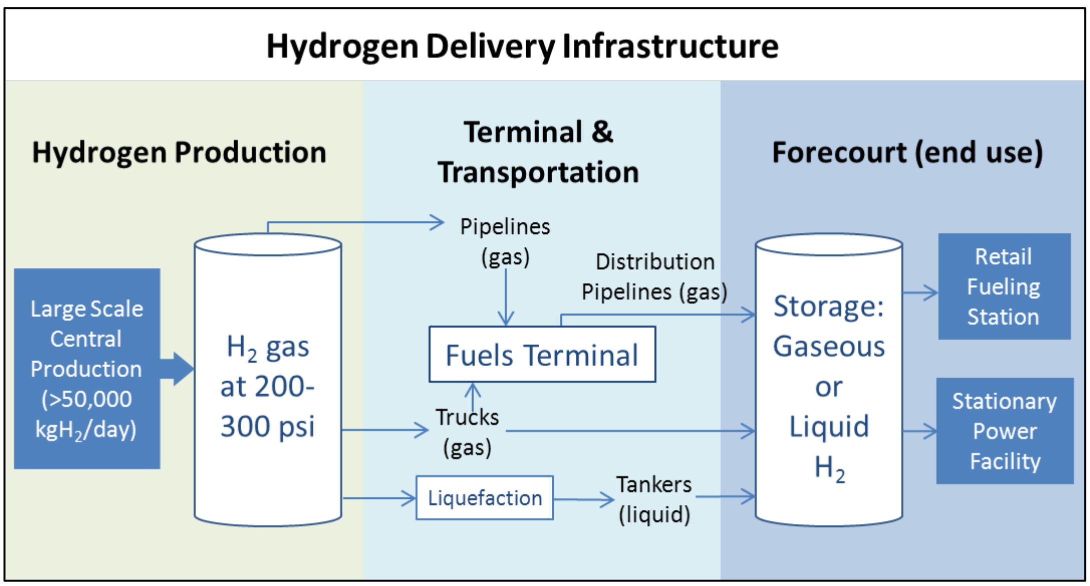


Figure 1. Hydrogen Delivery Scope

Centralized hydrogen production facilities are likely to use the full complement of delivery infrastructure functions, including transport. 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 2)
- Liquid hydrogen delivery (Figure 3)
- Novel solid or liquid hydrogen carriers (Figure 4)

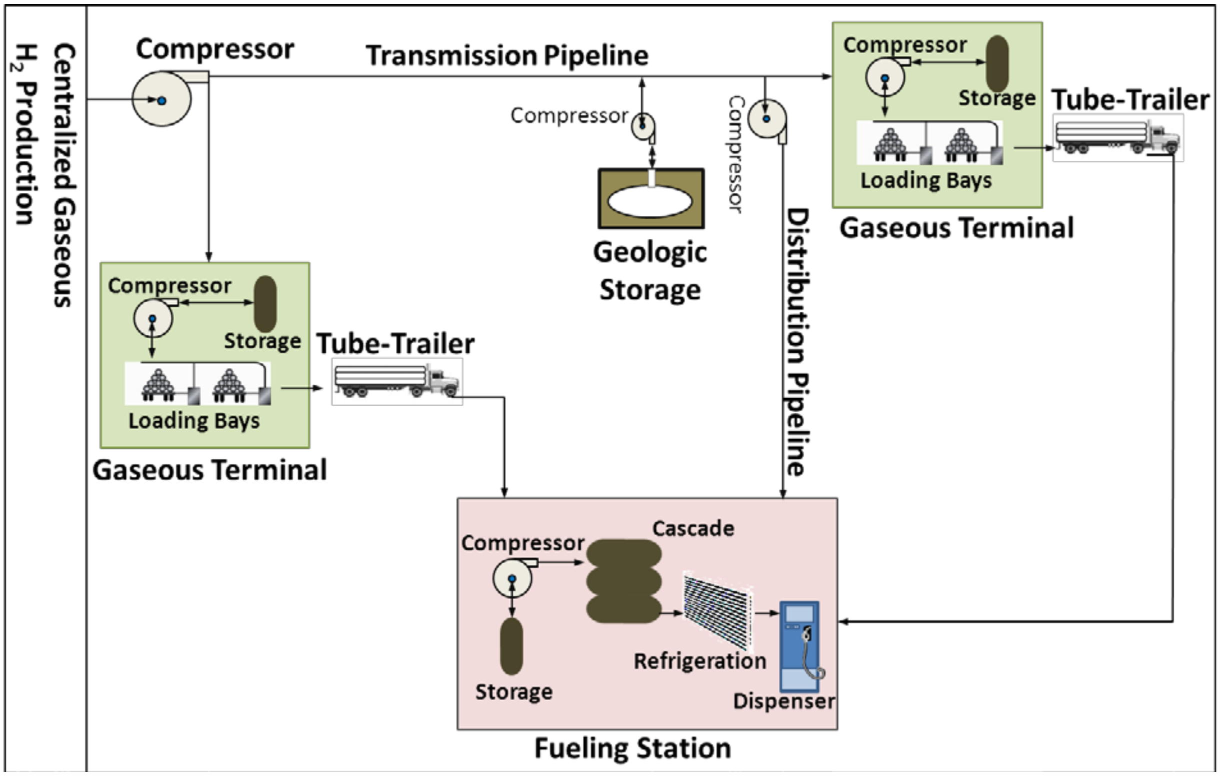


Figure 2. Example of Gaseous Delivery Pathway

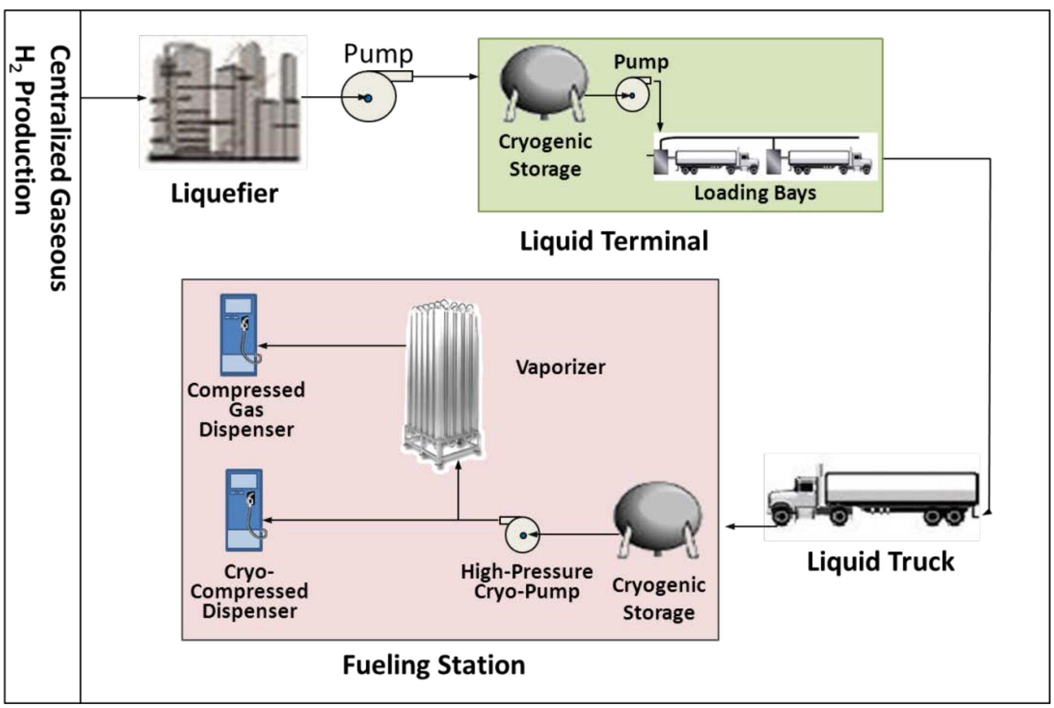


Figure 3. Example of Liquid Delivery Pathway

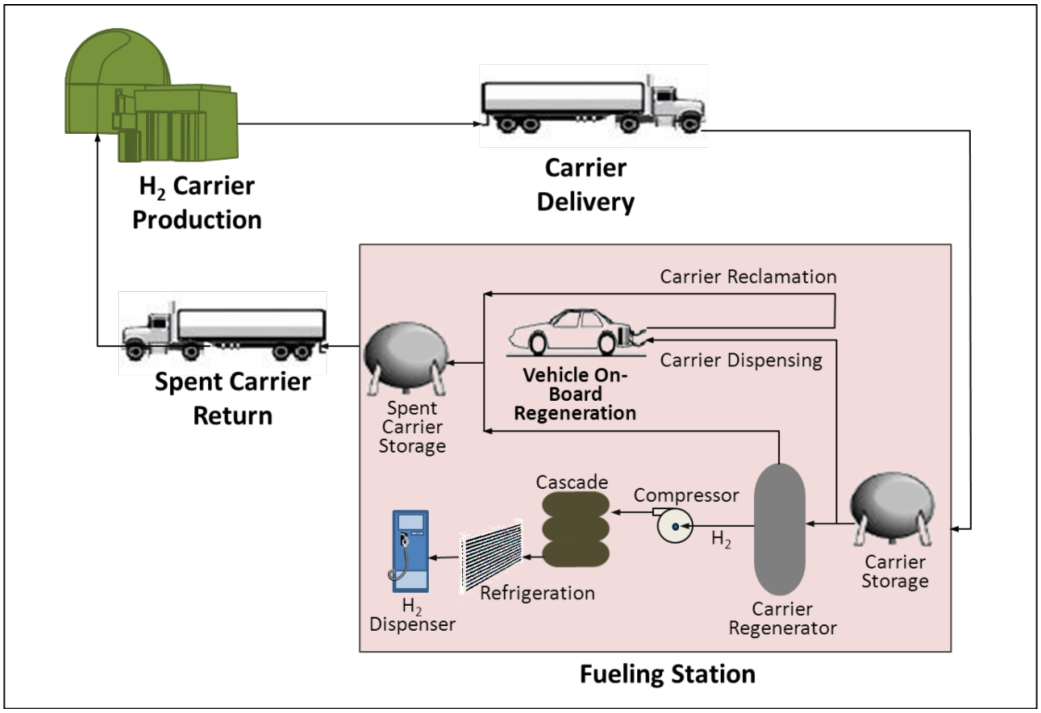


Figure 4. Example of Carrier Delivery Pathway

Roadmap Introduction

Hydrogen, as part of a portfolio of technologies, holds the long-term potential to solve two critical problems within U.S. energy infrastructure: dependence on foreign oil and emission of greenhouse gases (GHGs) and pollutants. The American transportation sector is almost completely reliant on petroleum, 45% of which is currently imported, and tailpipe emissions remain one of the country's key air quality concerns. Fuel cell electric vehicles operating on hydrogen produced from domestically available resources — including renewable resources, natural gas with carbon sequestration, biomass gasification and nuclear energy — would dramatically decrease emissions of GHGs and other pollutants as well as 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, providing additional national energy and environmental benefits.

Successful commercialization of hydrogen fuel cell electric vehicles will depend on the presence of a hydrogen delivery infrastructure that provides the same level of safety and convenience as the existing gasoline delivery infrastructure. In addition, the hydrogen delivery infrastructure will need to support the various production pathways for hydrogen fuel. 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 may play an important role during the transitional phase while hydrogen is gaining public acceptance. Hydrogen delivery systems include not only transport and delivery from centralized production operations, but also the storage, compression, and dispensing operations, which are essential regardless of the production location.

The potential hydrogen delivery pathways are based on the various physical states in which hydrogen can be delivered. These pathways include gaseous hydrogen, liquid hydrogen, and a spectrum of possible solid or liquid hydrogen carriers. Mixed pathways are also possible options. Delivery pathways contain numerous components such as compressors, pipelines, liquefiers, gaseous tube trailers, cryogenic liquid trucks, storage vessels, terminals, and dispensers.

The HDTT of the U.S. DRIVE Partnership has developed this Hydrogen Delivery Roadmap to address the technical goals and milestones for hydrogen delivery systems, survey technologies that could help meet these goals, and identify the barriers to achieving these goals. Research priorities and strategies are also suggested for conducting applied research and development (R&D) of hydrogen delivery systems, including critical needs for the near term (transition period) and the longer term (fully developed hydrogen fuel cell technology and infrastructure). 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 novel concepts and major breakthroughs to achieve the required performance and costs. Close collaboration with other U.S. DRIVE technical teams is also critical to success. The HDTT coordinates closely with the Hydrogen Storage, Hydrogen Production, Codes and Standards, and Fuel Pathways Integration Technical Teams. The liquid and gaseous pathways 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 pathway uses materials that transport hydrogen in a form other than free H_2 molecules, such as liquid hydrocarbons, sorbents, metal hydrides, chemical hydrides, or other hydrogen-rich compounds. Ideal carrier materials would have simple, inexpensive treatment processes at a fueling station, or onboard a vehicle, to release molecular hydrogen for use in fuel cells. For organizational purposes, materials that require more elaborate processing or are commonly used as hydrogen feedstocks today (e.g., natural gas, ethanol, and methanol) are not considered “carriers” and fall outside the purview of this roadmap.

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

Table 1. Hydrogen Delivery Infrastructure Components

<table>
<tr><th colspan="6">Delivery Technology Components</th></tr>
<tr><th colspan="2">Production</th><th colspan="2">Terminals & Transmission</th><th colspan="2">Forecourt</th></tr>
<tr><td colspan="2">Storage at Production Site</td><td colspan="2">Pipelines, Transmission & Distribution</td><td colspan="2">Carrier Transfiguration</td></tr>
<tr><td colspan="2">Carrier Production/Regeneration</td><td colspan="2">Tucks, Rail, Barges</td><td colspan="2">Separation/Purification</td></tr>
<tr><td colspan="2"></td><td colspan="2">Compressors & Liquid Pumps</td><td colspan="2">Storage Tanks</td></tr>
<tr><td colspan="2"></td><td colspan="2">Liquid and Gaseous Storage Tanks</td><td colspan="2">Compression/Vaporization</td></tr>
<tr><td colspan="2"></td><td colspan="2">Geologic Storage</td><td colspan="2">Fuel Dispensers</td></tr>
<tr><td colspan="2"></td><td colspan="2">Terminals</td><td colspan="2">Cooling</td></tr>
<tr><td colspan="2"></td><td colspan="2">Liquefiers</td><td colspan="2"></td></tr>
<tr><th colspan="6">Crosscutting</th></tr>
<tr><td colspan="3">Health & Human Safety</td><td colspan="3">Codes & Standards</td></tr>
<tr><td colspan="3">Sensors & Controls</td><td colspan="3">Right-of-Way/Permitting</td></tr>
</table>

This roadmap also addresses the need for delivery system analysis. Current and emerging technologies, systems, and options for hydrogen delivery need to be comprehensively analyzed to ascertain the associated costs, performance, and advantages or disadvantages. Such detailed analyses help researchers evaluate trade-offs among hydrogen delivery methods and build an understanding of how advanced technologies could alter the requirements for transitional and long-term systems. Results of these analyses allow researchers to focus research and design on areas that show the greatest promise for contributing to a commercially viable hydrogen delivery infrastructure.

Full deployment of hydrogen-based transportation technologies and infrastructure 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 delivery technologies mature. This roadmap identifies the research, design, and demonstration needed to support hydrogen delivery during the transition period from laboratory to mature infrastructure technologies ready for large scale deployment. Support for technology development through the transition period will be critical to achieving a successful transition. While the precise makeup of the infrastructure in the long term remains unclear, various combinations or permutations of all three paths (i.e., gaseous, liquid, and carriers) are likely to play a role. The mix of technologies 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 to be utilized. Alternatives that could change delivery technology needs, such as home refueling, are not addressed herein.

Gaseous Hydrogen Pathway

As shown in Figure 2, the gaseous hydrogen delivery pathway 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, more than 2,100 kilometers (km) (1,200 miles) of dedicated hydrogen transmission pipelines serve the United States. In contrast, the natural gas and petroleum pipeline system is quite extensive in the continental United States, as shown in Table 2.

Table 2. Natural Gas and Petroleum Pipelines[1]

Type	Approximate Distance	Typical Material Used	Diameter	Pressure
Natural Gas Transmission	490,000 km (305,000 miles)	steel	0.1-0.8 m (3.9-31.5 in)	40-70 bar (580-1,000 psi)
Natural Gas Distribution	2,000,000 km (1,233,000 miles)	steel/cast Iron/polyethylene	0.05-0.2 m (2.0-8.0 in)	0.03-10 bar (0.5-150 psi)
Crude Oil & Finished Petroleum Products	293,000 km (182,000 miles)	steel	Up to 1.07 m (up to 42 in)	96.53 bar (1,400 psi)

[1] U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration, "Natural Gas Transmission, Gas Distribution, and Hazardous Liquid Pipeline Annual Mileage," July 31, 2012, http://phmsa.dot.gov/portal/site/PHMSA/menuitem.ebdc7a8a7e39f2e55cf2031050248a0c/?vgnextoid=036b52edc3c3e110VgnVCM1000001ecb7898RCRD&vgnextchannel=3b6c03347e4d8210VgnVCM1000001ecb7898RCRD&vgnextfmt=print.

More than 9 million metric tons of gaseous hydrogen are produced in the United States annually, mostly for use as an industrial feedstock.[2] The majority of this hydrogen is produced at or near petroleum refineries and ammonia plants — the main users of industrial hydrogen. The 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 hydrogen is served by onsite hydrogen plants, gaseous hydrogen tube trailers, or cryogenic liquid hydrogen trucks.

Based on extensive delivery system analyses, gaseous hydrogen transmission and distribution 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 (ROW), and other expenses. Several technical barriers, including hydrogen embrittlement, the need for improved seal technology, and techniques to control hydrogen permeation and leakage, also restrict the more widespread use of hydrogen pipelines. In addition, the need for lower-cost, more reliable, and more durable hydrogen central compression technology is vital for pipeline delivery.

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.

Converting existing natural gas or petroleum pipelines to hydrogen use — if and when they became available — is also a possibility. Research into the suitability of these pipelines for hydrogen use relative to hydrogen embrittlement would need to be examined carefully. It might also be possible to develop coatings and in-situ coating technologies to overcome hydrogen embrittlement issues in order to permit utilization of these existing pipelines.

Relatively small amounts of gaseous hydrogen can be transported short distances by high-pressure (250 bar or 3,626 pounds per square inch [psi]) tube trailers. A modern high-pressure tube trailer is capable of transporting approximately 600 kilograms (kg) of hydrogen (in contrast to gasoline tank trucks, which can transport nearly 14 times the equivalent energy). There is the potential to develop higher-pressure tube trailers that would be considerably more economical for hydrogen delivery. More information can be found in the tube trailer section.

Liquid Hydrogen Pathway

The liquid delivery pathway for hydrogen includes a number of well-known and currently practiced elements. As shown in Figure 3, the first step is liquefaction, which is well understood yet costly 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; loaded into liquid delivery trucks; and transported to the "point of use." At distribution sites, the liquid is stored in vacuum-jacketed tanks until it is used, typically as a gas product. For fuel cell applications such as hydrogen vehicles and forklifts, the pressure of hydrogen molecules need to be increased using a pump and then vaporized at the desired pressure before dispensing into the onboard storage vessel. Converting liquid hydrogen to gas is performed by passing the liquid through an ambient

2 MarketsandMarkets, "Global Hydrogen Generation Market by Merchant & Captive Type, Distributed & Centralized Generation, Application & Technology Trends & Forecasts, (2011-2016)," www.marketsandmarkets.com.

air or warm water bath vaporizer (heat exchanger). Ambient vaporizers are sized to achieve the desired flow rates at the worst-case seasonal ambient conditions.

Today, the liquid hydrogen pathway is a well-developed and competitive method of providing hydrogen molecules for high-demand applications that are beyond the reach of hydrogen pipeline supplies. The liquid pathway is more economical than gaseous trucking for high market demands (greater than 300 kg/day) because a liquid tanker truck with a capacity of approximately 4,000 kg can transport more than 10 times the capacity of a typical steel gaseous tube trailer. The nine existing liquefaction plants in North America vary in production size from 5,400-62,000 kg of hydrogen per day.

The energy cost for converting gaseous hydrogen to liquid is high because hydrogen has an extremely low condensing point (-423.2°F at atmospheric pressure). The theoretical thermodynamic energy needed for hydrogen liquefaction represents approximately 10% of the energy in the hydrogen (lower heating value). In addition, the current liquefaction technology is designed for conventional merchant hydrogen markets for which the current energy efficiency of liquefaction is sufficient. An estimate for current liquefaction is that the energy required about 35% of the energy content of the hydrogen.

Today's liquefaction units are relatively small, in keeping with the current demands of the merchant hydrogen market. A large market penetration of fuel cell electric vehicles could justify the construction of large-scale liquefaction units. Breakthrough liquefaction technology such as magnetic or acoustic liquefaction may deliver added future value.

Hydrogen Carrier Pathway

Simply stated, carriers are materials capable of transporting, delivering, or storing hydrogen in any chemical state other than free hydrogen molecules. Potential carriers include sorption materials, liquid hydrocarbons, chemical hydrides, and metal hydrides. The carrier pathway was originally considered because it might be capable of delivering hydrogen to the forecourt (and perhaps to the vehicle itself) in liquid or solid form, thereby cutting delivery costs significantly.

Experimental work and analysis carried out in recent years has shown that most carrier systems are unlikely to meet the technical goals for carrier systems.[3] There is interest in some sorption materials such as metallic organic frameworks (MOF). There is also still some interest in off-board regenerable chemical hydrides for onboard storage — primarily ammonia borane (NH_3BH_3). Even this system has significant problems that need to be addressed, including ammonia formation upon dehydrogenation, material handling issues, high regeneration costs, and significant energy requirements. The delivery sub-program is not currently supporting any work on carriers.

Key Issues and Challenges

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 both gaseous delivery via pipelines and compressed gas tube trailers and liquid delivery via liquid trucks. 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. The key issues and challenges with respect to the delivery pathways and forecourt delivery stations are outlined in Table 3 and presented in more detail in the *Gaps and Technical Barriers* section.

[3] Fuel Cell Technologies Office, *Multi-Year Research, Development and Deployment Plan* (Washington, DC: U.S. Department of Energy, 2012), section 3.3, http://www1.eere.energy.gov/hydrogenandfuelcells/mypp/pdfs/storage.pdf.

Table 3. Key Issues and Challenges by Technology Area

Technology Area	Key Issues and Challenges
Forecourt Compression, Storage, and Dispensing	▪ Compressor cost, reliability, and efficiency ▪ Storage cost and footprint ▪ Dispenser cost and reliability ▪ Cooling equipment for -40^0C precooling ▪ Meter accuracy and cost
Pipelines	▪ Installed capital cost ▪ ROW cost ▪ Hydrogen embrittlement ▪ Pipeline compressor cost and reliability
Compressed Gas Tube Trailers	▪ High capital cost of composite tube trailers ▪ DOT weight limit of 36.3 metric tons
Liquid Tankers	▪ Cost of liquefaction capital ▪ Energy intensity of liquefaction ▪ Boil-off losses
All	▪ Hydrogen quality ▪ Leak detection ▪ Safety and education

Current Status and Technical Targets

1. Analysis

Hydrogen delivery analysis is required to assist the U.S. DRIVE Partnership in understanding the trade-offs and impacts of various hydrogen delivery options on the levelized cost of hydrogen at different market conditions. In addition, the analysis identifies several key barriers to large-scale infrastructure deployment as well as the required R&D efforts to address those barriers. The delivery analysis examines the impacts of primary delivery components on the delivery cost of hydrogen from its point of production to the points of demand at the refueling stations. Delivery scenarios are evaluated at market conditions that are defined by city size and population, vehicle ownership rate and annual vehicle miles travelled, market penetration of hydrogen vehicles, vehicular onboard storage option and fuel economy, refueling station size and utilization, refueling demand profiles, refueling protocol, distance from production site to refueling sites, transmission and distribution modes, and bulk storage type and size.

Delivery analysis begins with specifying hourly demand of hydrogen at any defined market conditions. The next step is sizing the entire infrastructure needed to transport, distribute, store, and dispense hydrogen from its point of production at 300 psi to the point of use at the nozzles of refueling stations. The final step is calculating the delivery cost at the component and pathway levels. The delivery cost is reported in the forms of levelized cost (i.e., in \$/kg H_2), total capital costs, operation and maintenance costs, energy costs, and annual and cumulative cash flow. Other metrics important for the analysis include land area, life cycle energy use and GHG emissions, and total process fuel and electricity use.

To facilitate reliable analysis, accurate cost and performance data are needed for each component along the delivery pathway. These components include pipelines, liquid trucks, tube trailers, compressors, compressed gaseous storage, caverns, liquefiers, pumps, cryogenic storage, refrigeration equipment, vaporizers, dispensers, controls, and utilities.

Current analysis show that pipeline delivery provides the lowest cost option for large market demands (>150 metric tons per day) and large refueling station demand (>1000 kg/day). Liquid delivery represents the lowest cost near-term option for end-use demand >150 kg/day mainly due because the surplus capacity of the liquefaction plants in the US can produce liquid hydrogen at a marginal cost. Compressed gas tube-trailers are suited for smaller end-use demand (<150 kg/day) and short distance deliveries due to their low payload (~300 kg). The contribution of refueling station capital investment contributes approximately half of the total delivery cost. The capital investment at the refueling station is dominated by cost of compression and storage. The investment risk and the underutilization of the refueling station capital investment during the pre-commercialization and the transition to large scale deployment of fuel cell electric vehicles represent the major market barriers to the full commercialization of fuel cell electric vehicles.

2. Gaseous Pipelines

The United States has an extensive pipeline transmission and distribution infrastructure for natural gas, as shown in Table 2. Injecting hydrogen into the existing natural gas infrastructure is a potential early market strategy for cost reduction. Challenges to this strategy include the following:

- The existing infrastructure is already in use at, or very near, capacity; only very limited seasonal volume could be made available for hydrogen.
- An unknown portion of the existing infrastructure has been compromised by corrosion or other physical damage, rendering it unfit for hydrogen service.
- The materials and fabrication techniques used in the construction of the pipelines were not designed for hydrogen compatibility, and post-fabrication inspection techniques used at the time of construction may not be sufficient for hydrogen use.
- The pressure fluctuations used to manage demand loads induce a low-cycle fatigue load on steels for which little is known regarding the influence of hydrogen.
- End-use pressure requirements for hydrogen fuel cells significantly exceed the typical pressures in the natural gas distribution system, requiring additional compression.
- Contaminants associated with natural gas are potentially destructive to fuel cell operation and lifetime. Thus, hydrogen separation and substantial purification would be needed in order to implement a shared infrastructure scenario.
- The energy density of hydrogen per unit volume is approximately one-third that of natural gas. Thus mixing 12% of hydrogen in natural gas by volume translates to only 4% of hydrogen in the mixture by energy.

As a result of the challenges associated with shared infrastructure, the transmission and distribution of hydrogen is generally considered independently and is not part of a shared infrastructure.

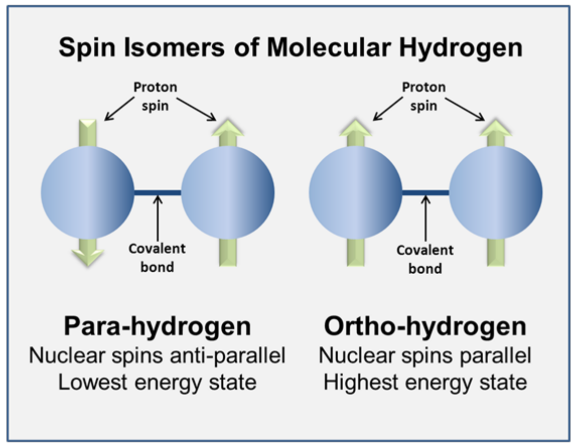
A complete hydrogen pipeline infrastructure would include both transmission and distribution pipelines to minimize overall hydrogen delivery costs. More analysis is needed to better understand the costs and other trade-offs for a hydrogen pipeline infrastructure before a semi-optimized pressure range can be identified based on the transport distance, demand volume, pressure required, compression costs, and safety concerns. The current capital cost estimates range from $765,000/mile for 6 inch pipeline to $4.5M /mile for 40 inch pipeline, including right of way (ROW) cost for hydrogen pipeline transmission infrastructure and from $440,000/mile for 4 inch pipeline to $1,200,000 for 8 inch pipeline including

ROW cost for distribution pipelines.[4] Cost estimates vary widely based on the ROW costs. Ongoing analysis efforts based on the Hydrogen Delivery Scenario Analysis Model (HDSAM) suggest that line sizes nominally similar to natural gas transmission and distribution line sizes with line pressures on the order of 35-150 bar (500-2,200 psi) may minimize cost.

The feasibility of pipelines in urban areas may be impacted by safety considerations, codes, standards, and regulations that are still in development for hydrogen pipelines. The 2011 edition of ASME B31.12 — Hydrogen Piping and Pipelines Standard does not contain pressure limits on transmission or distribution pipelines. ROW availability or cost in urban areas may also prove to be a limiting factor. Also, current natural gas regulations require the use of an odorant for leak detection in lines servicing non-industrial customers. If odorant technology were to be developed for hydrogen pipelines, it would need to be easily removed or be compatible with vehicle fuel cells. Sensor-based leak detection methods could overcome this problem if proven acceptable to regulators.

The United States currently has more than 2,000 km (1,200 miles) of dedicated steel hydrogen transmission pipeline operating at constant line pressures covering the range of about 30-80 bar (500-1,200 psi). However, significant technical questions must be addressed prior to establishing a very large hydrogen pipeline infrastructure. The chief technical concern is hydrogen embrittlement of metallic pipelines and welds. Welds are particularly susceptible to embrittlement due to the microstructure changes that can occur during the welding process. Special welding techniques enable the reduction of residual stress and thus reduce the risk of embrittlement. Such practices are in use for deep water and sour gas pipelines. Hydrogen embrittlement could also be a concern if the existing natural gas infrastructure was used to transport a mixture of hydrogen and natural gas. Important avenues for improving hydrogen pipeline performance and technology include the following:

- Developing a more comprehensive understanding of hydrogen embrittlement
- Investigating the use of coatings to prevent hydrogen embrittlement
- Improving welding technology
- Replacing steel pipelines with composite pipelines



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*

[4] Tubb, R., "2012 Worldwide Pipeline Construction Report", *Pipeline and Gas Journal*, vol. 239, No 1, January 2012, http://www.pipelineandgasjournal.com/2012-worldwide-pipeline-construction-report.

Recent progress includes an outline of the proposed composite pipeline code submitted to the B31.12 Hydrogen Piping and Pipelines Code Committee. The technical background for Codification of Fiber Reinforced Polymer (FRP) was presented to the ASME B31.12 Committee on March 15, 2012.[5]

3. Liquefaction

Liquefaction is an energy-intensive, multistage process that uses a series of refrigerants and compression/expansion loops to convert hydrogen from the gaseous phase to the liquid phase. Hydrogen has the lowest boiling point of any element except helium, and it transitions from gas to liquid at -253°C (20 K). Liquid hydrogen is odorless, transparent, and only one-fourteenth as dense as water.

Figure 5 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.

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 because 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 employed by several industrial gas companies that produce and market liquefied hydrogen across North America. Currently, small scale liquefaction plants require 12-15 kilowatt hours (kWh) of electricity per kg of liquid hydrogen. Capital recovery for the liquefaction process alone is expected to exceed $1/kg of product and require 8-10 kWh of energy per kilogram of hydrogen for future large scale liquefaction plants.[6] The primary barriers to using liquid hydrogen in vehicle fuel cells is its manufacturing and product conditioning (compression/pumping) for use in vehicles. Potential areas of improvement include the following:

- Increasing the scale of liquid production
- 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)
- Driving down the capital intensity of the liquefaction and conditioning systems
- Developing novel approaches to liquefaction such as magnetic or acoustic liquefaction

[5] Thad Adams, “Fiber Reinforced Composite Pipelines,”(presentation), www.hydrogen.energy.gov/pdfs/review12/pd022_adams_2012_o.pdf.

[6] Fuel Cell Technologies Office, *Multi-Year Research, Development and Deployment Plan* (Washington, DC: U.S. Department of Energy, 2012), section 3.2, http://www1.eere.energy.gov/hydrogenandfuelcells/mypp/pdfs/delivery.pdf.

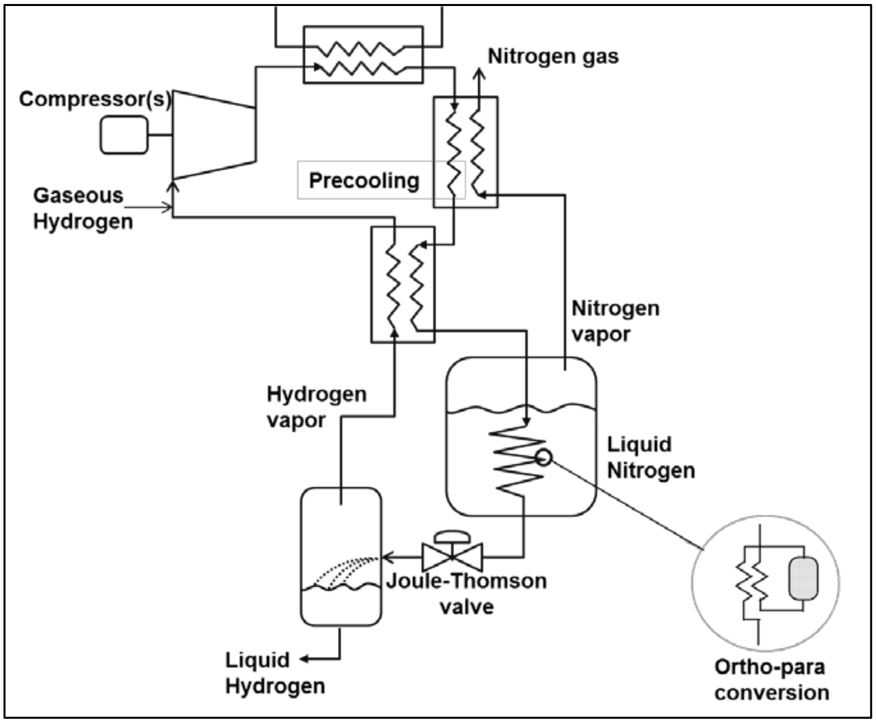


Figure 5. Hydrogen Liquefaction Plant

4. Compression

As seen in Figures 2-4, compression is an integral aspect of hydrogen delivery. Compression needs differ along the delivery pathway and include the following:

- Pipelines: High throughput, medium pressure (70 bar or 1,000 psi), very high reliability
- Terminals: Medium throughput, high pressure (350 bar or 5,000 psi), high reliability
- Forecourts: Moderate throughput, high pressure (900 bar or 14,000 psi), high reliability

Compressors are classified as either positive displacement compressors or centrifugal compressors. Most positive displacement compressors fall into two major categories: reciprocating and rotary. A reciprocating compressor uses a linear drive to move pistons or a diaphragm in a back-and-forth motion to compress the gas, and it contains inlet and outlet check valves. The most common reciprocating compressors operate at high revolutions per minute (rpm). Problems with reciprocating compressors for hydrogen include poor reliability, 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 may address some of these problems.

Positive displacement rotary compressors have rotating pumping elements such as gears, lobes, screws, vanes, or rollers, but they do not contain check valves. Examples of this type of compressor include screws, rotary vanes, scrolls, and trochoidal “Wankel” compressors. Rotary compressors are not commonly used with hydrogen due to the tight tolerances required to compress the extremely small hydrogen molecule without significant leakage.

Centrifugal compressors are routinely used in natural gas service for pipeline transmission and to meet other needs involving high throughput and modest compression ratios. If hydrogen is to be transported via pipeline, similar compressors designed for hydrogen transmission will be needed. Due to hydrogen’s low molecular weight, hydrogen compressors need tip speeds around three times higher than those used for natural gas. These high speed and purity requirements present challenges in seal design, contamination, vibration, material selection, and rotor dynamics. To achieve high hydrogen pressures, these compressors require multiple stages operating at high rotational speeds, as well as special seals and high mechanical tolerances. Centrifugal compressors designed to work with hydrogen are at the prototype stage of development. The cost of these advanced designs and reliability verification testing must be reduced.

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. Multistage compression and intercooling are used to achieve high pressures.

State-of-the-art 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 with increasing focus on evolving compression technologies. Required compression ratios vary at different points in the delivery system. Transmission pipeline compression is a high-throughput application (50,000-2 million kg/day) with a modest compression ratio, typically requiring raising the pressure from about 5 bar to about 70 bar (70 psi to 1,000 psi). Refueling stations require lower compression throughput (5-120 kg/h) but at a much higher compression ratios. Current refueling station compressors are capable of delivering up to 35 kg/h at a pressure ratio of 45 (20-900 bar). High-pressure hydrogen tanks are currently the leading technology for onboard vehicle storage. While early fuel cell electric vehicle designs stored hydrogen at 350 bar (5,000 psi), most current designs use 700-bar (10,000 psi) tanks. With proposed 700-bar onboard storage systems, tanks will need to be filled at pressures as high as 875 bar (a tank filled at 875 bar at 85°C would equilibrate to 700 bar at room temperature). If low-pressure, onboard hydrogen carrier and storage technology is successfully developed, the delivery pressure may be reduced to 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 and for geologic storage).

5. Cryogenic Liquid Hydrogen Pumps

Liquid hydrogen is pressurized with cryogenic pumps in the liquid delivery pathway (see Figure 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 in the pump. The materials used in the pumps must be capable of withstanding these extreme temperatures without becoming brittle. Capital investment in cryogenic pumps can be high, due to the materials and other specialized hardware employed, but can satisfy high throughput (up to 120 kg/h) due to the high liquid density. The need to periodically recharge the pump and purge any frozen or trapped gases results in expensive process downtime.

6. Hydrogen Storage

High-Pressure Vessels

Gaseous pressure vessels (tanks) are currently the most common means of storing hydrogen for buffering against supply-demand mismatch. Storage pressures may range from 135 bar (~2,000 psi) to 1,000 bar (~15,000 psi). 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. Current cost estimates for low (~160 bar), medium (430 bar), and high (860 bar) pressure are $600/kg, $1,100/kg, and $1,450/kg stored, respectively.

High-pressure onboard vehicular tanks represent the state of the art in gaseous hydrogen storage vessels. For onboard 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 4.8 megajoules (MJ)/liter (L) at a pressure of 700 bar (10,000 psi), only 15% of the 31.6 MJ/L contained in gasoline. High-pressure tanks can be characterized by their structural element (wall, shell) and their permeation barrier (liner). According to the European Integrated Hydrogen Project, compressed hydrogen storage vessels are classified according to the categories shown in Table 4.

Table 4. 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 stationary gaseous storage pressure vessels are Type I cylinders and tubes. Typical industrial hydrogen cylinders hold approximately 0.61 kg (1.35 pounds) 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). Cylinders may be used individually or can be joined by a manifold to extend storage volumes.

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 typically available in configurations of 3-18 tubes, holding up to approximately 700 kg of hydrogen at 165 bar (2,400 psi). Higher-pressure Type I or Type II stationary vessels are also available and allow more hydrogen to be stored per unit volume. However, the cost of the vessel is higher due to an increase in the required thickness of the vessel walls. For any particular application there will be an optimum balance of storage pressure, tank volume, footprint, and capital cost. Stationary tubes have individual valves and safety devices, but they are joined by a manifold so that hydrogen can be withdrawn from a single tube or from several tubes simultaneously.

Refueling site hydrogen storage is emerging as one of the major costs in hydrogen delivery infrastructure. Storage in other parts of the delivery infrastructure such as gaseous terminals can also be costly. Type III and Type IV high-pressure hydrogen tanks for onboard vehicles can be utilized for higher-pressure stationary hydrogen storage such as 450-bar and 900-bar buffer storage for 350-bar and 700-bar dispensing into hydrogen vehicles. With further development, it is believed that Type III or Type IV hydrogen vessels could be more cost effective than Type I or Type II vessels by storing hydrogen at higher pressures. This depends on whether costs can be reduced for both carbon or alternative fibers and the manufacturing process used to make these tanks. In the future, some other composite tank technology might also be effective in this area.

There is also a need to better understand the effects of high-pressure charge/discharge cycles and cycle depth as well as environmental effects (heat, moisture, etc.) on tank integrity. These factors could have a significant effect on useful tank lifetime and economics.

Cryo-Compressed Tanks

Researchers are also exploring the use of high-pressure, cryogenic gaseous tanks for onboard storage 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 would have the potential to store hydrogen at temperatures as low as 80 K (-193ºC or -315°F). This approach avoids the need for energy for the ortho-para conversion if the hydrogen is liquefied, but it requires energy to cool the gas and for 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 hydrogen gas (ambient to cryogenic temperatures) or even liquid hydrogen. Alternatively, one could consider using cold hydrogen gas tanks that would require less cooling at the station.. There may be some optimum combination of pressure and temperature over the range of 80-200 K (-193°C to -73°C).

Use of Solid Carriers for Hydrogen Tank Storage

Another concept that might reduce the cost and increase the volumetric efficiency of hydrogen storage is the use of solid carriers within the storage tank. This is identical to some of the approaches being researched for onboard vehicle hydrogen storage. For example, a metal hydride or a novel nanostructured absorbent such as carbon nanotubes might be put inside the vessel to allow for higher-density storage of hydrogen at lower pressures. Stationary off-board storage does not have the same weight and volume restrictions of onboard vehicle storage, and systems that do not meet the goals for onboard storage might be effective for stationary off-board storage vessels. However, such systems require cooling to adsorb the hydrogen for storage as well as heating to regenerate the hydrogen for release from storage.

The optimized future scenario may include some combination of high pressure, cold gas, and a solid carrier in order to achieve a cost-efficient and volumetrically efficient hydrogen stationary gas storage system.

Liquid Hydrogen Tanks

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 storage, which is pumped and vaporized to pressurized gaseous hydrogen for onboard storage. The cryogenic liquid storage tanks at refueling stations are sized to satisfy the station demand for 7-10 days or more in order to limit the number of liquid truck deliveries.

Super-insulated pressure vessels are needed to store liquid hydrogen because 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 pounds per square inch gauge [psig]). No matter how well a liquid vessel is insulated, some hydrogen boil-off will occur, a phenomenon that is especially pronounced in small tanks that have relatively large surface-to-volume ratios. Typical evaporation values are presented in Table 5.

Table 5. 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 million	<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 5,700-95,000 L (1,500-25,000 gallons or 400-6,700 kg) of hydrogen. Currently, the most economical way to store large volumes of liquid hydrogen is a double-wall Horten sphere. The tanks consist of an outer shell of carbon steel, typically an SA516, and an inner shell of stainless steel, typically a Type 304. The spheres have a maximum allowable working pressure of 75 psi (5.2 bar). A 4-inch annular space between the double-wall is filled with perlite.

Large vessels originally developed for the space program represent the state of the art in liquid hydrogen tanks, and the National Aeronautics and Space Administration (NASA) has been using and storing liquid hydrogen for more than 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. For example, underground liquid storage reduces the above-ground footprint and also provides greater storage capacity per unit volume compared with underground 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 and thus can reduce required setback distances. This space-saving feature is particularly advantageous for urban refueling stations where space is at a premium.

Development of a successful cryogenic storage tank design involves a multidisciplinary approach. It will involve materials engineering (high-strength metallic and composite materials) to achieve pressure containment and material integrity at low temperatures, thermal engineering (design and deployment of novel insulation materials), and an accompanying small footprint compressor to handle boil-off gas.

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

The majority of today’s transportation fuels are transported to local terminals over a network of pipelines and then distributed locally to the points of use via tanker trucks. Barge, rail, and truck transport are also used, as shown in Figure 6.

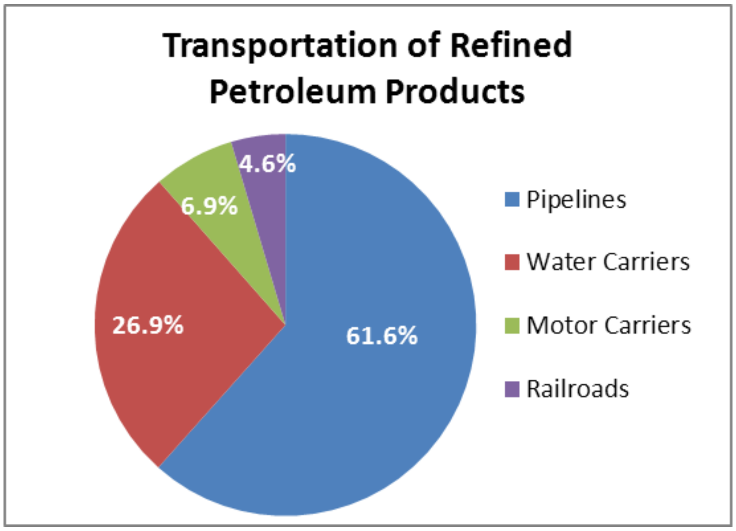


Figure 6. Transportation of Refined Petroleum Products by Method[7]

Similarly, hydrogen fuel is transported today by three modes: regional pipeline networks, on commercial roadways using cryogenic liquid cargo trailers, and on commercial roadways using high-pressure gaseous tube trailers. Rail, barge, and ship travel are also potential transport modes, but they are not in commercial use today.

High-pressure cylinders and tube trailers at 182 bar (2,640 psi) are commonly used to distribute gaseous hydrogen within 320 km (200 miles) of the source. Higher-pressure, 250-bar composite tube trailers have recently received U.S. Department of Transportation (DOT) certification and can carry 560 kg of hydrogen onboard. Hydrogen can be economically distributed within 600 miles of the source using liquid hydrogen tanker trucks that have capacities of 3,000-4,000 kg of hydrogen.

Successful widespread use of hydrogen 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 larger pipeline network similar to that used for natural gas, other modes of transport may be more efficient for outlying areas or dense urban settings. Rail and barge transport offer higher load-carrying capacities and higher weight limits than over-the-road trailers. Trucks, railways, and barges may 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 a high-efficiency liquid storage container similar in size to over-the-road trailers. In the future, it is conceivable that liquid hydrogen tanker ships (similar to liquefied natural gas [LNG] tankers) may be used to transport large volumes of hydrogen between U.S. ports and overseas.

Tube Trailers

Tube trailers are currently limited by DOT regulations to pressures of less than 250 bar. Further development and testing of Types II, III, or IV higher-pressure composite vessels for hydrogen, along

[7] Bureau of Transportations Statistics, "Table 1-61: Crude Oil and Petroleum Products Transported in the United States by Mode," accessed January 2013, www.rita.dot.gov/bts/sites/rita.dot.gov.bts/files/publications/national_transportation_statistics/2011/html/table_01_61.html.

with the development of appropriate codes and standards, will eventually allow the use of higher-pressure hydrogen tube trailers that also comply with federal truck weight limitations. Other approaches being researched for more cost-effective stationary gaseous hydrogen storage may also be applicable for transportation. This includes the use of cryo or cold gas and possibly the use of solid carriers in the tube vessels. With sufficient technology development to minimize capital cost, high pressure composite tube trailers could dramatically decrease the cost of hydrogen transport via tube trailer by significantly increasing the carrying capacity.

Hydrogen leak detection, in the absence of odorizers, is a challenge. Currently, commercially available leak detection equipment is handheld. Ideally, an online leak detector (direct or indirect measurement) would be a desirable addition to a tube trailer. Improved monitoring and assessment of the structural integrity of tubes and appurtenances may be called for in the presence of higher containment pressures. Some examples of potentially novel methods include in-situ strain monitoring and acoustic emission monitoring. Codes and standards will need to address integrity management for the operating envelope.

Liquid Hydrogen Trailers

Cryogenic liquid hydrogen trailers can carry up to 4,000 kg of hydrogen and operate at near atmospheric pressure. Some hydrogen boil-off can occur during transport despite the super-insulated design of these tankers, potentially on the order of 0.5% per day. Hydrogen boil-off of up to 5% also occurs when unloading the liquid hydrogen on delivery. If cost effective, a system could be installed to compress and recover the hydrogen boil-off during unloading if warranted. Based on the economics of off-loading liquid hydrogen into a customer's tank (distance from source, driver hours, losses), most organizations plan deliveries to serve up to three customer sites.

It is estimated that merchant liquid hydrogen suppliers possess more than 140 liquid hydrogen trailers. Current markets include food processing; refineries; chemical processes; oil hydrogenation; and glass, electronics, and metals manufacturing.

8. Geologic Storage

Underground storage in natural and mined formations, known as geologic storage, is routinely used to provide seasonal and surge capacity for natural gas. Large-scale hydrogen infrastructure would require similar bulk storage space. There are currently four locations that use geologic storage for hydrogen — three in Texas and one in Teeside, England.

Four types of geologic storage are being considered for use with hydrogen: salt caverns, aquifers, depleted oil or gas reservoirs, and hard rock caverns. Most geologic gas storage sites can handle pressures of 80-160 bar (1,200-2,300 psi). The four hydrogen storage sites in use today are all salt caverns, hollow cavities inside a large underground salt layer formed by drilling a hole into the salt structure and creating a geologic void by gradually dissolving the salt with freshwater or seawater. Salt caverns provide secure containment for materials that do not dissolve salt (such as hydrogen). All four facilities have operated without any known hydrogen leakage problems.

Depleted oil or gas reservoirs are an attractive future option due to the existing transport infrastructure in place around them. Aquifers — naturally occurring porous geological formations — are also attractive, due to their natural occurrence, availability, and low setup capital. Many aquifers have a water-saturated top layer caprock that serves to seal the structure and make it impermeable to vertical seepage, thus reducing hydrogen losses. A more expensive option is the engineering- and construction-intensive lined hard rock caverns. These caverns require both intensive mining operations and the construction of an impermeable layer to prevent gas losses at the higher pressures that are needed to increase the storage capacities of these facilities. Due to the high construction costs, hard rock caverns would only be developed where other options are not geographically present or the capacity of the other options has been exceeded.

The initial cost estimates of each geologic storage option in dollars per kilogram are shown in Figure 7.[8]

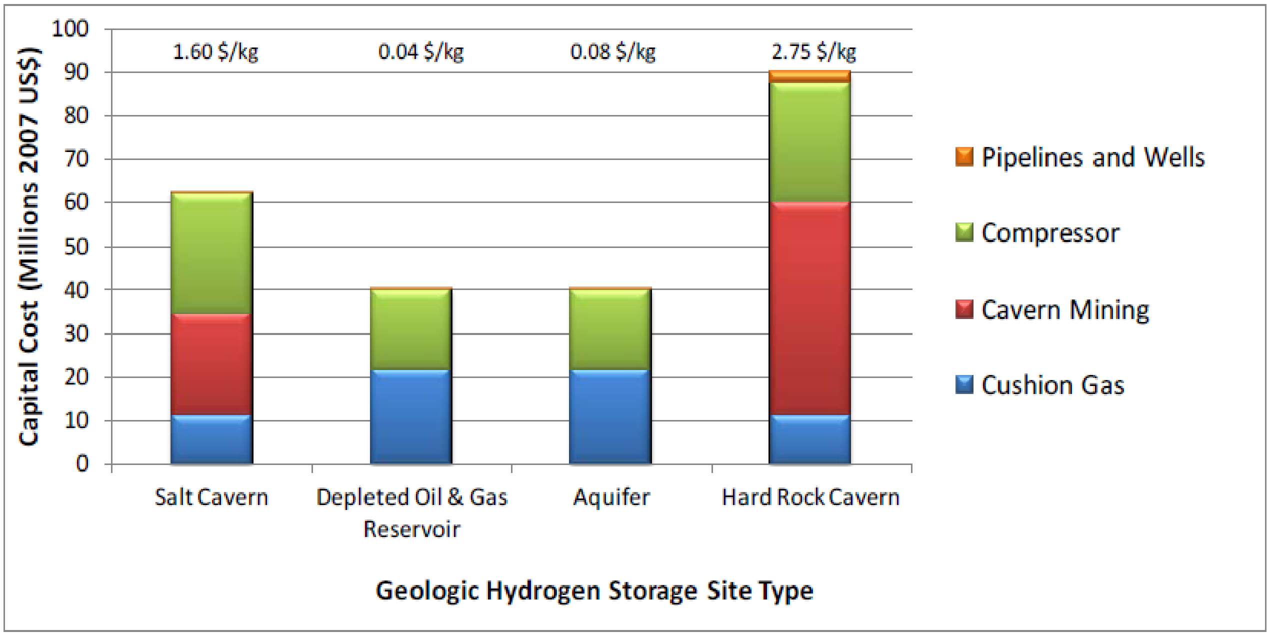


Figure 7. Cost Comparison of Geologic Storage Methods

9. Hydrogen Quality

Hydrogen purity requirements are determined by the needs of the application. For example, refining processes such as hydrotreating for sulfur removal from liquid fuels can utilize purities between 80% and 90%, while compressed gas companies provide hydrogen to the electronics and chip manufacturing industries with "six nines" purity, i.e., 99.9999%, unlike standard "pipeline grade" hydrogen purity of 99.95%. As purity demands increase, so does the cost of the hydrogen, including extra costs associated with the storage, transport and testing necessary to maintain and monitor that grade of purity.

Current Fuel Cell Hydrogen Guidelines and Specification Efforts

There has been good progress on developing a hydrogen fuel specification through the cooperation of several U.S. DRIVE Partnership technical teams, in particular the Hydrogen Delivery, Codes and Standards, and Fuel Cell Technical Teams. For fuel cell electric vehicles, the information currently available indicates that very high purity hydrogen — on the order of 99.97% or better — will be required.[9] As part of the former FreedomCAR and Fuel Partnership (now the U.S. DRIVE Partnership), universities and national laboratories completed significant work to understand the influence of the type and level of contaminants in hydrogen on single proton electrolyte membrane (PEM) fuel cell

---

[8] A.S. Lord, P.H. Kobos, G.T. Klise, and D.J. Borns, *A Life Cycle Cost Analysis Framework for Geologic Storage of Hydrogen: A User's Tool*, SAND2011-6221 (Albuquerque, NM and Livermore, CA: Sandia National Laboratories, September 2011), http://prod.sandia.gov/techlib/access-control.cgi/2011/116221.pdf.

[9] Appendix C, Fuel Cell Technologies Office, *Multi-Year Research, Development and Deployment Plan* (Washington, DC: U.S. Department of Energy, 2012), section 3.3, http://www1.eere.energy.gov/hydrogenandfuelcells/mypp/pdfs/storage.pdf.

performance.[10] Final purity specifications will be dependent on fuel cell stack durability efforts that are now under development. This purity requirement will be better understood once information from actual operating cycles of FCEVs is available. The research to date indicates that single fuel cells are susceptible to even low levels of sulfur compounds, carbon monoxide, and ammonia.

The U.S. Department of Energy (DOE) and partner demonstration fleet and refueling projects showed that hydrogen could be produced either on-site or delivered at purity levels to sustain vehicle operations with no fuel cell degradation due to contaminants. It remains to be studied how multiple contaminants in mixtures simultaneously affect fuel cell stack operation, how a stack performs in a vehicle with starts and stops that can possibly offer purging of contaminants, and other factors important in day-to-day FCEV operation. For example, water purging may affect fuel cell stack durability.

In September 2011, SAE International published the standard "Fuel Quality Guideline for Fuel Cell Vehicles" (SAE J2719) as the specification for fuel-cell-grade hydrogen. The state of California adopted the SAE standard as its legal requirement for sale of hydrogen for FCEVs to consumers. The ASTM International Committee D03 on Gaseous Fuels has developed and published key sampling and testing methods for determination of contaminants in hydrogen for fuel cell electric vehicles. Good cooperation and coordination between U.S. DRIVE technical teams and ASTM D03 made this progress possible. ASTM standards are the most utilized fuel standards for current fuels in the United States.

A comprehensive assessment of hydrogen purity capability by the most popular technique used today for compressed hydrogen purification, pressure swing absorption (PSA), was developed and published by researchers at Argonne National Laboratory for the U.S. DRIVE Partnership.[11] This assessment indicates that modern PSA systems can remove most contaminants to safe levels at a reasonable cost. Very high purity hydrogen is achieved if the hydrogen is liquefied. In the long term, additional studies are needed to determine the effects on hydrogen purity of large-scale distribution of hydrogen in tube trailers and pipelines, storage in caverns, and other distribution systems; particularly, to see if contamination will occur and what, if any, polishing technology is needed to deliver a pure product as described in the next section.

Purification of Hydrogen

Hydrogen purification is normally part of the production process, yet the need for purification may also arise during the hydrogen delivery process. FCEVs' very stringent hydrogen quality requirements dictate that either great care must be taken so that no contamination occurs in the delivery infrastructure or there may be a need for final purification just prior to dispensing at the refueling station and/or on the vehicle.

Current commercial technologies for high-purity hydrogen gas include cryogenic liquefaction and sorption — typically PSA. If the hydrogen is liquefied, the hydrogen gas from that liquid hydrogen is absolutely pure, barring secondary contamination. 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.

Particular purification needs relevant to hydrogen delivery include:

[10] The *Codes and Standards Technical Team Roadmap* is available through the EERE Website: http://www.eere.energy.gov/vehiclesandfuels/about/partnerships/roadmaps-other_docs.html.

[11] D. Papadias, S. Ahmed, R. Kumar, and F. Joseck, "Hydrogen Quality for Fuel Cell Vehicles — A Modeling Study of the Sensitivity of Impurity Content in Hydrogen to the Process Variables in the SMR-PSA Pathway," *International Journal of Hydrogen Energy*, 34 (2009) 6021-6035.

- Removal of small amounts of impurities introduced between the production site and retail, known as polishing. The main concerns in this area are compressor lubricants (if lubricated compressors are used), contamination from geologic storage, and particulates. Ionic contaminants such as sodium or other cationic salts can arise from electrolytic production of hydrogen.
- Separation of hydrogen from natural gas in a hydrogen and natural gas mixture shipped together in a pipeline for hydrogen delivery is typically done using PSA.
- Separation of impurities formed during production of hydrogen from a carrier is dependent on the carrier and the extent to which it can contaminate the hydrogen.

Polishing entails removing 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 a drop in the pressure level, and the purified hydrogen may need to be recompressed at additional cost. Similarly, cryogenic liquefaction of 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. Polishing particulate filters may also be needed. In each of these scenarios, polishing purification would add to the hydrogen cost.

Separation of hydrogen and 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 of <20%, 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. Cost effective niche applications such as hydrogen recycling for steel plants have begun demonstration projects with electrochemical separation and repressurization using stacks developed by H2 Pump.

The requirements for purifying hydrogen after delivery via carrier will depend on which carrier system is used. For a carrier such as ammonia, hydrogen would have to be separated from nitrogen and the un-reacted ammonia would need to be 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.

Analytical Methodology and Sampling

Since 2003, researchers have made great progress in developing more sensitive sampling and testing methods for the determination of hydrogen purity and contaminants. Researchers have completed work and published standards on better gas chromatography, mass spectrometers, and other methods to detect trace levels of contaminants. ASTM Committee D03 is continuing to develop and publish these methods.

Location of Testing

Sampling and purity conformance should be demonstrated at the point of hydrogen manufacture and custody transfer. Frequent testing for hydrogen purity at the point of use at refueling sites could be cost prohibitive unless very fast, simple, and low-cost sampling and test methodology is developed. Particulate sampling is especially challenging. Ideally, retail site testing for hydrogen would be performed for a quality survey on an infrequent basis, as the hydrogen production plant is the primary site for delivering hydrogen purity to meet specifications. More frequent quality monitoring of hydrogen purity at the retail site will be needed until the pathways and extent of contamination are well understood. Then, occasional monitoring by the hydrogen supplier, and/or the state weights and measures authority for fuel quality, will check for hydrogen purity.

10. Hydrogen Sensors

A robust and safe hydrogen delivery infrastructure will likely require a means to detect hydrogen leaks. This will be important from both safety and economic perspectives. Odorants are required by regulation in today's urban natural gas distribution pipelines for commercial and residential use. Odorants may be problematic for hydrogen because they would most likely need to be removed due to the stringent quality requirements for fuel cells, unless one could be found that did not interfere with fuel cell performance. Hydrogen pipeline infrastructure, stationary storage, refueling sites, and any enclosed areas where hydrogen may be stored are all candidates for hydrogen detection sensors. Several different companies either have or are developing sensors for hydrogen detection.

Mechanical Integrity Sensors

A relatively new area of technology development is sensors that monitor the mechanical integrity of structures such as pipelines and pressure vessels. Fiber optic sensors and other devices have been developed that can monitor time-dependent defects. Some of these defects include internal corrosion; external corrosion; stress corrosion cracking; pipe movement; pipe stress; and buckling strains due to pipeline slope instability, ground settling, and currents acting on exposed pipelines in river and stream crossings. This technology is particularly well adapted to composite structures, but it can also be applied to steel pipelines or vessels. Such technology might prove very valuable for the hydrogen delivery infrastructure and could complement leak detection. It might also prove valuable as an early detection approach that could avoid mechanical failures and significant hydrogen leakage.

Generally, the biggest problem for natural gas pipelines over the years has been third-party damage as a result of digging up the pipeline ROW to lay new pipeline or for other purposes. This can result in very serious consequences. Mechanical integrity sensors could immediately detect the occurrence of such damage.

Sensors could also be used to monitor hydrogen purity. For example, if an on-site reformer is used to generate hydrogen for a refueling site, then a purification and monitoring system is necessary to protect consumers' FCEVs. A sensor to detect carbon monoxide breakthrough from a PSA purifications system could warn the dealer that the hydrogen is contaminated and should not be used for refueling.

11. Hydrogen Dispensers

Dispensing of both gaseous and liquid hydrogen to vehicles is in development, and demonstration projects are underway. This roadmap deals primarily with gaseous dispensing as the majority of OEMs have chosen gaseous onboard storage. The issues that need to be addressed include costs, safety, nozzles, pressures, expansion, materials of construction, metering, units of sale, and carrier exchange.

The pressure of the delivered hydrogen will be dictated by the available onboard storage system and the desired mileage of the vehicle between fill-ups. Currently, gaseous hydrogen is being dispensed to vehicles with a final fill pressure at ambient temperature of either 350 bar (5,000 psi) or 700 bar (10,000 psi). Protocols for both filling pressures are being defined through SAE J2601.

Few vendors currently offer the sophisticated technology for compressed hydrogen dispensers, and costs are high compared to gasoline dispensers. 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. Expanded demonstration and pilot programs sponsored by DOE in partnership with industry should spur materials and 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.

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. A single hydrogen nozzle currently costs about $7,000. In contrast, a gasoline dispensing nozzle costs $40-$110. A complete gasoline dispenser unit currently costs around $15,000, while a hydrogen dispenser costs between $50,000 and $100,000. As the technology matures and more manufacturers enter the market, however, these costs are likely to decrease.

High-pressure hydrogen presents safety concerns that differ from those of gasoline and must be addressed by engineering controls to ensure safe delivery. These controls involve fail-safe, leak-proof connectors between the dispenser nozzle and vehicle fill port. Advances have been made in hydrogen nozzle design for leak-free fueling. DOE’s Controlled Hydrogen Fleet and Infrastructure Validation and Demonstration Project conducted more than 20,000 fueling events during its seven years of operation. There were no safety reports of leaks in the last two years of the program and only two leaks detected during fueling the two years prior.

Development of dispenser technology will also require stakeholders to reach a consensus on the style of vehicle and dispenser connectors. To avoid under-filling, the vehicle hydrogen tank must communicate with the dispenser. While a vehicle is being refueled with compressed hydrogen, the existing gas in the tank is compressed, raising the temperature in the vehicle hydrogen storage tank. The higher the filling pressure and dispensing rate, the more severe this problem becomes, increasing the need for communication to ensure proper vehicle refueling and perhaps necessitating heat removal protocols and/or cooling of the hydrogen prior to dispensing. This is currently being addressed by the SAE J2601 committee.

The hydrogen refueling industry and federal and state governments need to reach consensus on a 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 kilogram. Once decided reliable and accurate metering of the dispensed hydrogen is needed for retail vehicle refueling with hydrogen. Metering of cryogenic liquid 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 and high gas flow rates.

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.

12. Mobile Fuelers

Mobile fuelers have been used for early market hydrogen delivery. They combine hydrogen storage with a dispenser in a portable unit that can fuel vehicles directly. Mobile fuelers have less capacity than tube trailers but typically provide a higher delivery pressure. While tube trailers are capable of hauling 300-400 kg of hydrogen at 182 bar (2,460 psi), current mobile fuelers have a typical capacity of 110 kg at 350 bar (5,000 psi) using steel tubes. Just as tubes are carried on a trailer, the mobile fueler is transported using a separate vehicle. The use of Type III or Type IV composite cylinders can increase the capacity of mobile fuelers. No utility requirements pertain to a mobile fueling site, but the site is required to meet the National Fire Protection Association (NFPA) 2: Hydrogen Technologies Code and local codes.

Recent additions to mobile fueling options include combinations of a dispenser with gaseous or liquid hydrogen supply, the use of onboard mobile compression, and the use of mobile dispensers that connect to stationary hydrogen supply. Liquid hydrogen supply mobile fuelers combine a liquid cryogenic pump and heat exchanger/vaporizer to produce high-pressure gaseous hydrogen for fueling.

13. Terminals

Petroleum

The United States has approximately 134 operating refineries and 1,300 petroleum product terminals.[12,13] These facilities supply petroleum products to more than 156,000 retail service stations, truck stops, and marinas.[14] These statistics do not include distributor bulk storage and non-retail fleet locations, such as rental companies and schools. As shown in Figure 8, 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.

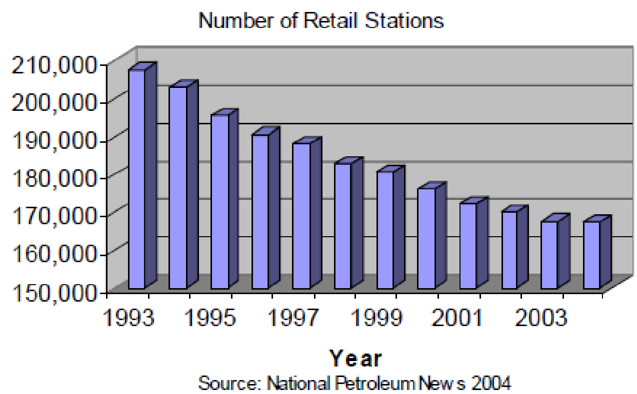


Figure 8. Number of Retail Stations over Time

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/gallon) from the refinery to the retail station. Sixty-two percent of domestic petroleum shipments are delivered via pipeline and 27% are delivered by water, meaning that the majority of terminals are connected to a pipeline, many have a dock, and some have both a pipeline and a dock. As shown in Table 6, terminals range widely in size depending on the retail network they serve.

[12] EIA, "Number and Capacity of Petroleum Refineries," January 2012, http://www.eia.gov/dnav/pet/pet_pnp_cap1_dcu_nus_a.htm.

[13] IRS. "Approved Terminals 3-31-13," http://www.irs.gov/pub/irs-utl/tcn_db.pdf.

[14] National Petroleum News' "MarketFacts 2012."

Table 6. Terminal Statistics

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

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.

Hydrogen

The United States currently has 40 gaseous hydrogen distribution terminals and nine liquid hydrogen production facilities in North America. The United States also has 118 captive hydrogen producers.[15] 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 because they incorporate additional steps for vaporization and compression and must address issues of higher-pressure and lower-temperature storage. Future gaseous hydrogen distribution terminals may also be supplied by liquid hydrogen delivery, pipelines, or on-site generation systems. They may be required to deliver liquid hydrogen or gaseous hydrogen at pressures ranging from 250-350 bar (3,600-5,000 psi). If hydrogen carriers were to be used for hydrogen distribution, terminals may perform carrier regeneration/recharging and handling of spent carriers. Quality control 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.

[15] Suresh, B., et al., "Hydrogen," *Chemical Economics Handbook*. July 2010, http://chemical.ihs.com/CEH/Public/Reports/743.5000.

14. Other Forecourt Issues

Footprint

Current stations are located at R&D facilities, universities, and other locations where space is not at a premium. In future urban settings where real estate will be at a premium, footprint will become very important.

There are many factors to keep in mind when considering station footprint. Bulk hydrogen off-loading at retail sites requires delivery trucks to be on-site. With cryogenic liquid hydrogen, the hydrogen is off-loaded to storage at the refueling site. Truck delivery of gaseous storage may include off-loading of high-capacity tube trailers, or the tube trailers may be left at the site and utilized as the site storage. 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 on tanker size and retail site footprint, refueling truck access could pose special challenges for site design.

There are multiple designs for retail site storage. Some designs provide for intermediate storage at 160-500 bar (2,000-7,000 psi), with compression and storage in smaller, high-pressure tanks at 400-900 bar (6,000-14,000 psi). On-site storage tank placement includes locations in the forecourt behind protective barriers, underground, or even above ground in a supported canopy. Each design offers advantages and drawbacks. Codes and standards vary by location and often require set-back distances or other protective barriers.

Refueling Rate and Cooling Equipment

As discussed in the Dispenser section, while a vehicle is being refueled with compressed hydrogen, rapid buildup of energy raises the temperature in the vehicle hydrogen storage tank. The higher the filling pressure and the faster the fill, the more severe this problem becomes. For 350 bar fills, the vehicle tank is filled to pressures greater than 350 bar so that when the hydrogen in the vehicle tank cools down, the pressure settles at approximately 350 bar. In order to maintain the tank temperature below 85°C during a fast fill at 700 bar, refrigeration is required at the refueling station to chill the hydrogen and limit the rapid increase in temperature. According to the SAE J2601 refueling protocol that is currently under review, precooling is required at -40°C for fast fills (5 kg in 3 minutes), but current 700 bar stations are precooling to approximately -20°C to -30°C. This precooling adds cost at the refueling site. Refrigeration cost increases and the coefficient of performance drops with a decrease in required cooling temperature. An efficient and cost-effective chiller technology needs to be developed for 700 bar dispensing. Furthermore, at such high pressure and low temperatures, fittings and control equipment require special materials and become more costly.

Safety

Safety is paramount for public acceptance of hydrogen, and forecourt engineering must employ the safest cost-effective design. For compressed hydrogen, liquefied hydrogen, or a hydrogen carrier, some 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 forecourt must incorporate engineering controls that meet safety codes and standards. Hazard reviews, failure mode and effective analysis reviews, emergency response plans, catastrophic release plans, and training for retail site and bulk delivery staff are some of the safety practices that are being employed today.

Unlike bulk petroleum liquid off-loading, compressed gas or liquefied hydrogen bulk off-loading from a truck must incorporate gaseous or cryogenic liquid engineering controls to ensure that the process is performed safely without exceeding storage operational pressure and temperature limits. These technologies are relatively well known in the compressed gas and liquefied gas industry, but they are new to the refueling industry. Attention must also be given to the electrostatic properties of delivering hydrogen, a flammable but non-conducting gas. The prevention of electrostatic discharge by proper grounding and other engineering measures must be considered in forecourt equipment, including the dispenser and nozzle.

Gaps and Technical Barriers

1. Analysis

More comprehensive delivery infrastructure analyses need to be developed and the options and trade-offs involved in various approaches to hydrogen delivery should be more fully understood. Additional in-depth comparative analyses are required to examine the most promising options for delivering and distributing hydrogen from large centralized production (>50,000 kg/day), semi-centralized/city-gate production (5,000-50,000 kg/day), and forecourt compression storage and dispensing for distributed production (<1,500 kg/day) at refueling sites for both the transition and longer term. 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.

A major barrier to reliable analysis is the availability of cost and performance data as a function of throughput and manufacturing volume of components. Often such data are not available, because many of the delivery technologies have not been developed at commercial scale. In such cases, analysis relies on estimates based on surveys of manufacturers and experts in the field. Another barrier to reliable analysis is the consistency of cost estimates among alternative technologies that are at different maturity levels. While the cost of mature and reliable technology can be made with a high degree of certainty, cost estimates of emerging technologies in their proof of concept phase or at the demonstration scale are highly uncertain. Such uncertainties should be accounted for in the analysis of various delivery pathway options.

2. Gaseous Pipelines

Installed Capital Cost

The cost of new pipeline construction is high. Of these costs, labor comprises approximately 50% and materials comprise approximately 20%. There is a need for pipeline fabrication technology that eliminates or requires a minimum of sophisticated joining and inspections and other labor-intensive aspects of pipeline construction.

Lack of Understanding of Material Science Issues

There is incomplete 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. Research should encompass the compatibility of hydrogen with improved metallic and nonmetallic materials of construction. If older infrastructures are converted to handling hydrogen, compatibility issues must be well understood as well.

Innovative, Low-Cost Materials and Construction Techniques
Current steel pipeline materials are expensive to weld and join; and potentially susceptible to hydrogen embrittlement, permeation, and leakage, as well as corrosion from external sources. New metallic materials, alternative materials such as plastics or composites, or surface treatments (coatings) need to be explored. Nonmetallics 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. There is a need to evaluate novel materials (i.e., composite materials and alternate metal alloys) as well as newer and automatic joining techniques with the objective of reducing the pipeline construction unit cost.

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.

ROW Issues
Obtaining the 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. Many ROW issues cannot be addressed directly with R&D activities. However, improving materials, developing codes and standards, and educating stakeholders will improve public acceptance and thus indirectly reduce some ROW issues, such as the "not-in-my-backyard" philosophy often prevalent in the face of new technologies. Safety precautions including pipeline design and other measures will be needed for regulators to permit extensive hydrogen distribution pipeline infrastructure in urban areas. The cost and availability of ROW in urban areas can also be problematic.

Acceptability, Cost, and High-Pressure Operation of Hydrogen Distribution Pipelines in Urban Areas
Because the preferred use and storage pressure for hydrogen as an energy carrier is relatively high (100-800 bar), it is desirable for hydrogen distribution lines to be operated at relatively high pressures (20-100 bar). This is similar to current natural gas transmission lines and is significantly higher than the typical pressures of the natural gas distribution pipeline infrastructure which ranges from (0.02-0.2 bar). Non-industrial natural gas distribution in urban areas also includes the use of an odorant for leak detection. A suitable odorant may need to be developed for hydrogen that could either be easily removed or be non-harmful to vehicle fuel cells. Sensor-based leak detection methods might overcome this problem if proven acceptable to regulators.

3. Liquefaction

High Capital Cost
Current liquefaction technology contributes more than $1.00 per kilogram 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 cryogenic 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 liquefied hydrogen. Roughly 10% of the energy in the hydrogen is thermodynamically required to cool the hydrogen and to achieve the ortho/para transition. Opportunities to improve energy efficiency could be achieved through the use of better technology, for example aluminum heat exchangers, heat exchanger technology and engineering, improved gas compressors, and turbo expanders. 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, 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.

4. Compression

Low Reliability
Forecourt compressors exhibit low reliability, requiring redundant systems to ensure acceptable availability. Polymer seals experience degradation and need frequent replacement at the high temperatures and pressures they are exposed to in 700 bar hydrogen delivery applications. Traditional centrifugal compression technology for pipelines is not suitable for hydrogen due to the lubricants used. New oil-free centrifugal compression technology, such as that being developed my Mohawk Innovative Technologies Inc. and Concepts NREC, could overcome these issues.

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 and 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. High-volume manufacturing of one type of compressor for forecourts could significantly reduce the capital cost of these compressors.

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

5. Liquid Hydrogen Pumps

The thermal inertia of the liquid pump and the associated boil off needs to be addressed to reduce the cost of liquid pumps.

6. Hydrogen Storage

Cost
Gaseous and liquid storage tanks add significantly to the cost of hydrogen delivery — especially at refueling and stationary power sites where the hydrogen throughput is low compared to the required capital investment. Technology for lower-cost storage systems is needed. This technology could include new, higher-strength and/or lower-cost materials and designs; design for high-throughput manufacturing of identical units; and higher hydrogen capacity per unit volume through the use of higher-pressure gaseous storage, cold hydrogen gas storage, or carriers. Relative costs of steel and composite tanks as a function of size and pressure are needed to choose optimal stationary storage systems designs.

Footprint

Real estate at refueling stations is costly. The footprint of hydrogen storage needs to be minimized, while also maintaining all public safety requirements.

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 fatigue and maintain structural integrity under high-pressure cycling environments and/or cryogenic temperatures. Use of novel materials of construction, both metallic and nonmetallic, must be considered.

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 the effects of tank leakage on the surroundings are unknown. Ground freezing must be avoided, and corrosion issues must be resolved. In addition, seismic (earthquake) effects on underground tanks need to be determined.

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

Tube Trailers

High Capital and Labor Cost

The limited hydrogen-carrying capacity of current gaseous trucks results in high delivery costs. Research needs include the investigation of transporting hydrogen at pressures greater than 250 bar, the use of cold hydrogen, and the possible use of solid carriers to increase the carrying capacity of tube trailers. Further analysis is required to determine the optimal hydrogen storage pressure onboard tube trailers. R&D efforts to reduce the cost of carbon fiber tanks are also needed to reduce the capital cost of the tube trailers.

Rail, Barge, and Ship Carriers

Poor Availability and Delivery Schedule

Hydrogen rail delivery is currently economically more attractive than truck or tanker delivery at distance greater than 1500km and only for cryogenic liquid hydrogen.[16] 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.

[16] Sozinova, O., 2010 FCTO Annual Merit Review Presentation entitled "H2A Delivery Analysis and H2A Delivery Components Model, http://www.hydrogen.energy.gov/pdfs/review10/pd015_sozinova_2010_o_web.pdf.

8. Geologic Storage

Development Cost

The most significant barrier to the use of geologic storage for hydrogen is the high cost of field development and compression. While geologic storage becomes more economically attractive at high volumes, there are still costs inherent in the potential for hydrogen losses due to leakage.

Cushion Gas Requirement

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.

Contamination Concerns

Little is known about the nature and extent of contamination introduced to hydrogen in geologic storage. It is not necessary to purify cavern-stored hydrogen today as it is used for petroleum hydrotreating. However, fuel cell applications demand hydrogen at a much higher purity; therefore, contamination needs to be quantified and purification strategies must be developed for all potential geologic storage media.

Leakage

Hydrogen losses and leakage during operation could also lead to significant cost. As with all storage mechanisms, geologic storage may suffer from hydrogen leakage through permeation. 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.

Effects of Pressure Cycling

There is an inadequate understanding of hydrogen storage in rock formations. The rock mass used may not be a continuous medium, and pressure cycling may cause unexpected behavior or cause hydrogen to react with specific materials in the cavern walls.

Geographical Limitations

Hydrogen geologic storage is further limited by geography, and the suitability of mined and natural caverns will depend on their size and proximity to hydrogen demand. Figure 9 shows potential geologic storage locations in the United States.

While lined rock caverns (LRCs) can be constructed where other storage options are unavailable, cost is a prohibitive factor because gaseous hydrogen storage is economical only with the availability of very large volumes pressurized above 70 bar or 1,000 psig. Further research is needed in the application of these geologic storage methods for hydrogen.

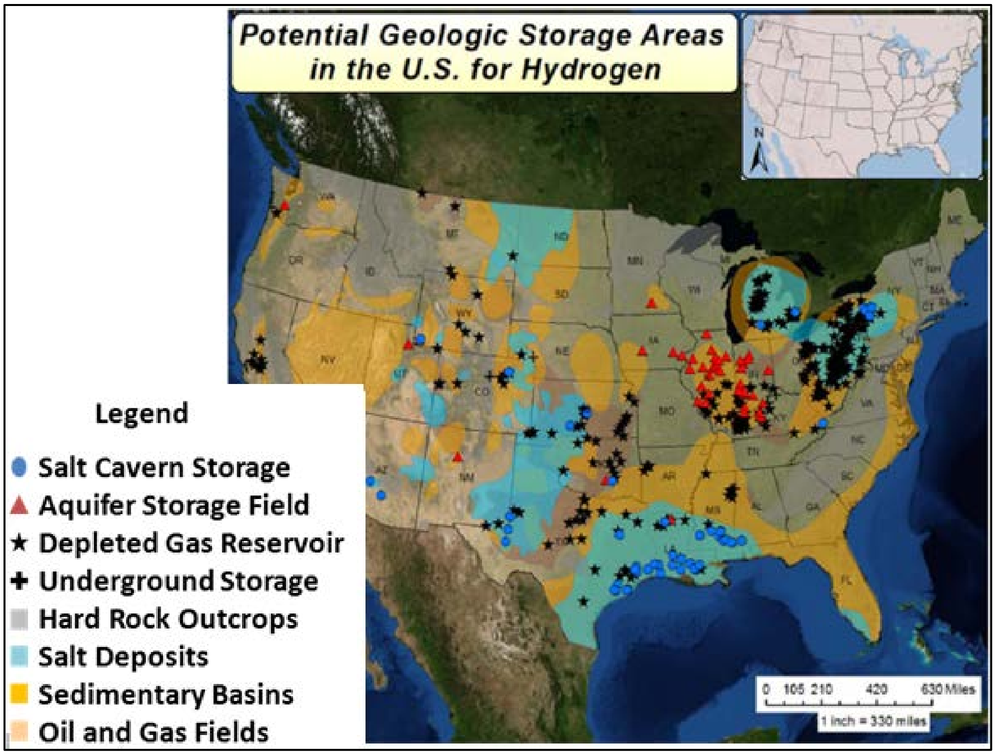


Figure 9. Potential Geologic Storage Sites for Hydrogen in the United States[17]

9. Hydrogen Quality

Hydrogen Quality Requirements

Hydrogen fuel cells require very high quality hydrogen. The final specifications for fuel cell electric vehicles will depend on future fuel cell development efforts. Some cost will likely be incurred within the delivery infrastructure to maintain the high purity required and/or to re-purify the hydrogen as a result of potential contamination from compressors, geologic storage, particulates, or carriers, depending on the development of these technologies.

Refueling Site Polishing Purification

The nature and amount of the contaminants to be removed will depend on the final fuel cell electric vehicle hydrogen quality specifications and the amount of contamination that occurs in the delivery infrastructure. As a result, the requirements for the polishing purification step will unfold over time as these technologies are developed. The cost and energy use of any polishing step must be minimized, and hydrogen losses must be negligible. Pressure drops will need to be low to avoid additional compression costs.

Hydrogen and Natural Gas Mixture Separation

The cost and energy use for this process must be reduced. Options to be explored include membranes, electrochemical separation and PSA technologies.

---

[17] A.S. Lord, P.H. Kobos, G.T. Klise, and D.J. Borns, *A Life Cycle Cost Analysis Framework for Geologic Storage of Hydrogen: A User's Tool,* SAND2011-6221 (Albuquerque, NM, and Livermore, CA: Sandia National Laboratories, September 2011), http://prod.sandia.gov/techlib/access-control.cgi/2011/116221.pdf.

Analytical Methodology and Sampling
Improved methodologies and sampling approaches need to be developed to permit low-level detection of some of the particular contaminants being considered and to minimize the cost of appropriate testing to ensure the quality of hydrogen dispensed meets the standards requirements.

10. Hydrogen Sensors

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 because 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. Suitable odorant technology might need to be developed. Alternatively, cost-effective sensors for leak detection will likely be needed.

Mechanical Integrity Sensors
Development and utilization of mechanical integrity sensor technology for hydrogen pipelines, vessels, and other elements within the hydrogen delivery infrastructure would be very beneficial to maintain a high level of system safety and integrity.

11. Hydrogen Dispensers

High Cost
The high cost of components for 700 bar delivery, in particular the nozzle and controls, and the low number of manufacturers are the major factors behind the high current expense of hydrogen dispensers.

Materials and Design Requirements
Special materials and designs are required to withstand the high pressures of compressed hydrogen, the low temperatures of cryogenic hydrogen, and corrosion issues. In particular, the requirement of flexible dispenser hoses for delivery of high-pressure hydrogen is challenging.

Accurate Metering
Current technology does not allow accurate metering of high-pressure (700 bar) hydrogen at a rate that ensures an acceptable fill-time duration specified by SAE J2601.

12. Mobile Fuelers
Mobile fuelers are a short-term bridge technology and are not being investigated for further development by this technical team.

13. Terminals
Steel tank and sensor technologies required for terminals are reasonably mature. High throughput compressors for loading high pressure tube trailers are needed. Cost reductions and reliability improvements are needed to improve terminal economics. Also, cost-effective analytical techniques to verify hydrogen quality must be developed.

14. Other Forecourt Issues

Emerging Market Challenges
One of the difficulties of encouraging market entry of hydrogen vehicles is the high cost of low-volume hydrogen production and refueling. The cost of delivered hydrogen in dollars per kilogram decreases as the volume of hydrogen produced increases and as stations' dispensing capacities increase. Initial station

sizes in pre-commercial vehicle markets are expected to be around 100-300 kg/day. As market penetration increases, the station size is expected to increase to 1,000 kg/day or greater in order to serve the same number of vehicles currently served by typical gasoline stations. Thus the stations that enter the market first will have the disadvantage of producing hydrogen at a higher cost due to their smaller size. This does not encourage potential early adopters to enter the market, because they will need to make costly upgrades to their stations in order to remain competitive as the market expands. A roll-out plan that addresses this investment risk for early adopters is needed.

Fueling Station Design Requirements — Footprint and Safety

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 aesthetics, 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. There will be additional space requirements for compression, cooling, and other equipment. Due to the high cost of real estate in urban environments, the footprint for storage and other operations must be minimized. Conversion of existing gasoline refueling station to hydrogen stations may present severe space limitations.

Cooling Requirements

Fast filling of hydrogen at high pressures requires precooling of the hydrogen to -20:-40°C. Low-cost, energy-efficient, and compact hydrogen cooling technology will need to be developed if fast filling of high-pressure hydrogen is required.

Codes and Standards

The Codes and Standards Technical Team (CSTT) of the U.S. DRIVE Partnership is working to close the remaining gaps in the codes and standards surrounding the various hydrogen infrastructure components. For more information, please see the CSTT Roadmap available through the U.S. DRIVE Partnership.[18] A remaining key barrier is communication and education — making the appropriate officials aware of and confident in administering the codes and standards.

Cost-Effective and 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 handled, and pursuing the goal of public refueling. 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. These needs include methods for low-cost maintenance of such equipment, especially in the forecourt.

As the level and sophistication of safety controls increase, so does the cost for hydrogen refueling sites. Safety controls are essential, but they must be cost effective. Because 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. As the pressure of refueling vehicle storage tanks increases, so should the maintenance and inspection schedule. Inspection and maintenance of dispenser nozzles during delivery of 700-bar hydrogen will be critical.

Education

To meet the goal of letting customers refuel their own vehicles, consumer education and community awareness are essential. Demonstrations on how to use this new technology can be delivered via on-site

[18] The *Codes and Standards Technical Team Roadmap* is available through the EERE Website: http://www.eere.energy.gov/vehiclesandfuels/about/partnerships/roadmaps-other_docs.html.

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.

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, consumers must be instructed on how to use the refueling equipment safely.

Strategy

Gaseous Pathway

Although gaseous pipelines are the cheapest known delivery option at high market penetration of fuel cell electric vehicles, the large fixed capital investments for pipelines make them unacceptably expensive at low penetrations. Concerns related to safety as well as ROW costs and availability may make pipeline distribution of hydrogen in urban areas problematic. Truck delivery of gas is the lowest-cost gaseous delivery option at lower market penetrations. Advances in materials and structure configurations have solved some of these problems by enabling the cost-effective transition from steel to composite structures; however, further capital cost decreases through materials and manufacturing innovations are needed. Composite pipelines could have much lower capital costs. They could be constructed in much longer segments and spooled, significantly reducing the labor needed for joining and trenching. Composite storage vessels could be more cost-effectively used for higher-pressure stationary storage as well as for higher-pressure tube trailers. Use of cold hydrogen and/or carriers could further increase the hydrogen-carrying capacity of vessels for stationary storage and tube trailers.

Liquid Pathway

Although liquefaction consumes a significant portion of hydrogen's energy content, it appears to be the best currently known option for delivery of hydrogen at centralized plants for long distances at low market penetration. Liquid trucks can deliver around 5-6 times more hydrogen than today's gaseous 250-bar composite tube trailers. This increased delivery capacity makes up for the high cost of liquefaction when compared with gaseous hydrogen delivery over longer distances. Although it is cheaper than gaseous delivery, liquid delivery is still costly and very energy intensive resulting in high GHG emissions for the pathway when modeled using the US grid mix, however such plants are often located near hydro or other green power sources. 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 trucks and be a key enabler for hydrogen infrastructure in the long term. Novel carriers — solids, liquids, powders, or other novel forms — have the potential to radically alter the distribution system. Carriers are, however, still in the early R&D stages, 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 serve as the exclusive mode of hydrogen delivery. It is likely that a mixture of pathways will be needed during the transition to a hydrogen infrastructure. Even when the transition is complete, economics will dictate the preferred delivery pathway for a given locality, meaning 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 centralized/semi-centralized production facility to a terminal where the gas is distributed by tube trailer or liquefied and distributed via tanker trucks. This expectation that all pathways will play a role leads to the distribution of R&D funds to encourage advancements in all pathways.

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. A critical early R&D need is for additional analysis of all of 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 longer 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:

- A study of the trade-offs between higher-pressure hydrogen delivery and onboard storage in terms of compression cost and energy versus the value of the extended range.
- The trade-offs among various configurations and options for storage and compression at refueling sites, and how those options may affect capacity utilization of at a site.
- The trade-offs among options involving 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.
- The optimization of station roll-out plans to consider the locations, initial station size, and costs associated with station upgrading as the market expands.

Getting through the transition period is vital. Costs per unit of hydrogen will be high due to the relatively low level of demand. The first priority should be pursuing 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; low-cost, smaller-footprint storage; and high-efficiency chillers for the -40°C precooling associated with 700-bar dispensing.
- ***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.
- ***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-centralized, centralized, or terminal sites.
- ***Pipeline Technologies:*** Hydrogen embrittlement research should be continued to understand the effects of introducing hydrogen to existing pipelines and FRP pipeline technology should continue to be developed to reduce the installed capital cost of pipelines for high-volume distribution.

Because forecourt compression, storage and dispensing are required for all delivery pathways they are key areas of focus in the near term. A breakthrough in gaseous tube trailer carrying capacity, hydrogen liquefaction, or carriers could substantially reduce the costs and energy use involved in transporting hydrogen from existing or new semi-centralized or centralized production sites. Developments in carrier technology or lower-cost, high-pressure tank technology could also reduce forecourt storage and/or hydrogen transport costs.

Hydrogen carrier technology could result in a paradigm shift for hydrogen delivery. This approach could reduce costs and substantially reduce the amount of capital investment required for a 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 onboard vehicle hydrogen storage should be leveraged and expanded as warranted for hydrogen delivery applications when viable technologies are proven.

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 U.S. DRIVE Technical Team (CSTT). The HDTT will continue to collaborate with the CSTT in these areas.

Early Market Applications

Background

The successful commercialization of hydrogen fuel cell electric vehicles will depend on 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, it was noted that the hydrogen delivery infrastructure will need to support hydrogen's various production options and that the overall fuel cell electric vehicle pathway needs to be cost competitive with gasoline and diesel vehicle options.

The roadmap considered three potential delivery paths: gaseous hydrogen, liquid hydrogen, and novel solid or liquid hydrogen carriers. Since 2007, research has progressed on all three of these pathways as reported at the May 2012 Hydrogen Production and Delivery session of the DOE Annual Merit Review.[19]

Currently, hydrogen used in industrial applications is produced primarily by reforming fossil fuels, predominantly natural gas, and either used at the point of manufacture or transmitted by pipeline for large users. Two main issues limit efforts to utilize this approach to provide hydrogen in large scale for fuel cell electric vehicle stations:

- Adding a large capacity for generating hydrogen for public fuel cell electric vehicle stations from fossil fuels potentially adds the costly requirement of using carbon dioxide capture and sequestration (CCS) to manage GHG emissions.
- Although gaseous hydrogen transmission by pipeline is the lowest-cost delivery option for large volumes of hydrogen, the high initial capital cost constitutes a major barrier to the construction of new pipelines. Today, only about 1,300 miles of dedicated hydrogen transmission pipelines serve the United States. In contrast, the U.S. natural gas pipeline distribution system covers above 1 million miles.

It was noted in the 2007 report and earlier in this report that use of existing natural gas pipelines for the delivery of pure hydrogen or mixtures of up to 20% hydrogen is a possibility, particularly in the transitive stages of a hydrogen economy.

Recent Developments

There have been two recent initiatives that involve injecting hydrogen into existing natural gas pipelines and co-mixing with methane-based gases for transport. Both have a strategy for increasing use of renewable feed sources for hydrogen production, avoiding the need for CCS. One is an analysis study in Hawaii under DOE sponsorship, the other is in Germany under government sponsorship. Public information on each of these follow:

- According to General Motors, as stated in 2010, "In Hawaii we want to address the proverbial chicken or egg dilemma. There has always been a looming issue over how to ensure that the vehicles and the necessary hydrogen refueling infrastructure are delivered to the market at the same time. Our efforts in Hawaii will help us meet that challenge."[20] It was announced that through the Hawaii

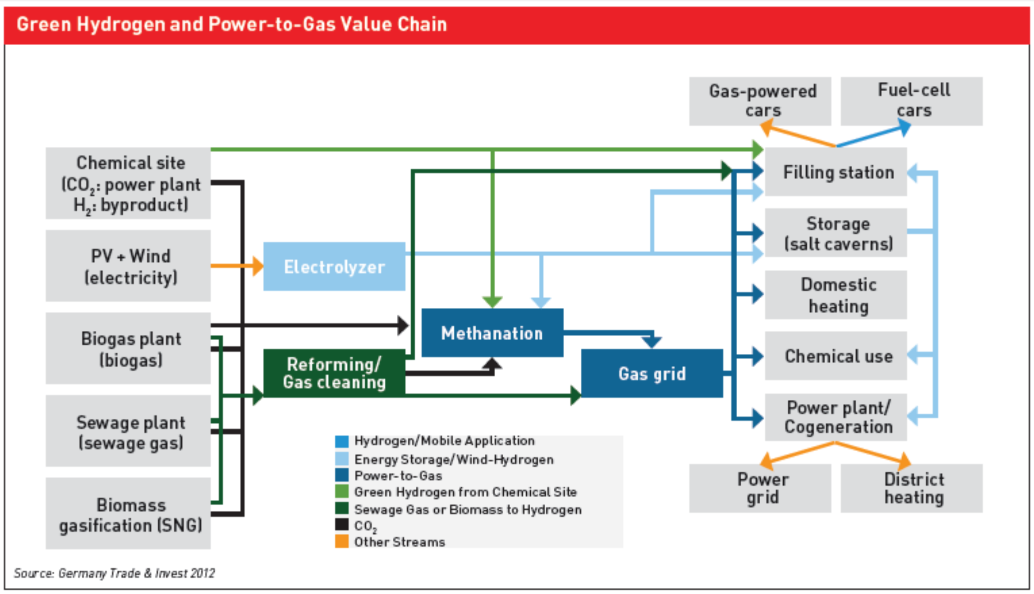
[19] Hydrogen and Fuel Cells Program, "2012 Annual Merit Review Proceedings Hydrogen Production and Delivery," U.S. Department of Energy, http://www.hydrogen.energy.gov/annual_review12_production.html.

[20] C. Freese, Executive Director of General Motors Fuel Cell Activities.

Hydrogen Initiative (H2I), DOE plans to support testing and validation of hydrogen infrastructure technologies, including this approach of injecting hydrogen into existing natural gas pipelines.[21]

- The Hawaii Gas Company (TGC) is one of the partners in this endeavor. TGC currently produces hydrogen and synthetic natural gas and supplies a mixture with 10% hydrogen through a 1,100-mile pipeline network to nearly 30,000 commercial and residential utility customers. As part of H2I, TGC plans to use a proprietary separation process to tap into its pipeline network at strategic locations and separate the hydrogen for use by local fueling stations for fuel cell electric vehicles. The TGC plant feedstock is currently 97.4% petroleum-based, with 2.4% coming from bio-based renewables. In 2011, TGC commissioned a pilot plant to study the conversion of renewable and recyclable feeds to methane, hydrogen, propane, and diesel. This effort will contribute to the state's goal of having 40% of its energy come from local renewable sources by 2030.

- A recent analysis performed by NREL also found that hydrogen could be injected into natural gas pipelines at 5-15% concentrations without resulting in a significant risk.[22]
- The German initiative is called "Green Hydrogen and Power to Gas Value Chain." The overall concept is described in Figure 10.



Power-to-Gas – Mass Energy Storage Solution
"Power-to-gas" is the name given to an energy process and storage technology which allows electricity to be held in reserve in the megawatt range. Existing network infrastructure can be utilized by linking existing power and natural gas grids. This allows seasonally adjusted storage of significant amounts of power and the provision of CO_2-neutral fuels in the form of the resulting renewable energy source gas.

The hydrogen or SNG produced can be fed into the existing natural gas network for further use and replace natural gas on a like-for-like basis. Gas storage is not subject to the same limitations associated with extant energy storage technologies. Moreover, power-to-gas creates investment potential along the entire supply chain: from storage, production and trading to electrolyzer production, gas compression, and smart gas metering amongst other things.

Figure 10. Power-to-Gas Energy Storage Solution[23]

[21] Hawaii Hydrogen Initiative homepage, http://www.hydrogen2hawaii.com.

[22] M.W. Melaina, O. Antonia, and M. Penev, "Blending Hydrogen into Natural Gas Pipeline Networks: A Review of Key Issues," National Renewable Energy Laboratory Technical Report NREL/TP-5600-51995, March 2013, http://www.nrel.gov/docs/fy13osti/51995.pdf.

[23] R. Goldstein, and W. MacDougall, "Green Hydrogen and Power-to-Gas Technology: Mass Energy Storage for the Future Energy Market" (Berlin: Germany Trade and Invest, May 2012),

As previously indicated, this approach is key to converting renewable electricity into hydrogen so that it can be stored and injected into the natural gas network. Renewable and recyclable sources for synthetic natural gas are incorporated into the system and the mixed gas is distributed to multiple services. On the vehicle side, Figure 10 shows both hydrogen fuel cell electric vehicles and compressed natural gas (CNG). For the past few years, India has been developing technology which allows common CNG vehicles to run on blends of hydrogen and natural gas.

Component Technical Targets and Objectives

The technical targets are derived from the U.S. DRIVE Partnership's overall premise that hydrogen fuel cell electric vehicles need 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 an overall threshold cost goal for hydrogen delivery of <$2.00 per kilogram by 2020.[24]

The individual component technical targets were derived from publicly available information and models for hydrogen delivery systems as necessary to achieve the overall delivery cost target of <$2.00 per kilogram. The intermediate time frame technical targets are milestones along the path to track progress.

HDSAM is the foundation for the status and targets found in Table 7. The 2011 status column is based on analysis of publicly available information that has been incorporated into the HDSAM V2.31.[25] Based on this model, the targets listed are necessary but not sufficient to meet the overall delivery cost target of <$2.00 per kilogram. Additional analysis and infrastructure architecture and options are being studied that will provide more insight into delivery infrastructure and all the pertinent cost factors.

The delivery component targets have been set in order to achieve the overall delivery objectives as described in the Current Status and Technical Targets section. DOE has funded the development of the HDSAM to better understand the overall cost and energy use of hydrogen delivery infrastructure options and the contributions of the delivery components to these costs. This model was used to help establish the Component Technical Targets published in the Fuel Cell Technologies Office Multi-Year Research, Development and Deployment Plan (MYRD&D), which are provided in Table 7.

Table 7. Hydrogen Delivery Technical Targets from DOE's MYRD&D[a]

Category	2005 Status[y]	FY 2011 Status	FY 2015 Target	FY 2020[z] Target
Gaseous Hydrogen Delivery				
Pipelines: Transmission				
Total Capital Investment ($/mile for an 8-in. equivalent pipeline, excluding ROW)[b]	765,000	765,000	735,000	710,000

http://www.gtai.de/GTAI/Content/EN/Invest/_SharedDocs/Downloads/GTAI/Fact-sheets/Energy-environmental/fact-sheet-green-hydrogen-mass-energy-storage-for-future.pdf.

24 K. Weil, S. Dillich, F. Joseck, and M. Ruth, "H_2 Production and Delivery Cost Apportionment," Program Record 12001 (Washington, DC: U.S. Department of Energy, December 14, 2012), http://www.hydrogen.energy.gov/pdfs/12001_h2_pd_cost_apportionment.pdf.

25 HDSAM, V2.31, is available at http://www.hydrogen.energy.gov/h2a_delivery.html.

Table 8. (Cont.)

Category	2005 Status[y]	FY 2011 Status	FY 2015 Target	FY 2020[z] Target
Pipelines: Distribution: Trunk and Service Lines				
Total Capital Investment ($/mile for a 1-in. pipeline, excluding ROW)[b]	440,000	440,000	375,000	250,000
Pipelines: Transmission and Distribution				
Reliability/Integrity (including third-party damage issues)[c]	Acceptable for current service	Acceptable for current service	Acceptable for current service	Acceptable for current service
H_2 Leakage (kg-H_2/mile-yr)[d]	Unknown	Undefined	Undefined	<780 (Transmission) <160 (Distribution)
Large Compressors: Transmission Pipelines, Terminals, and Geological Storage				
Reliability[e]	Low	Low	Improved	Improved
Compressor Efficiency (Isentropic)[f]	88%	88%	>88%	>88%
Losses (% of H_2 throughput)	0.5%	0.5%	0.5%	<0.5%
Uninstalled Capital Cost ($) (based on 3,000 kW motor rating)[g]	2.7M	2.7M	2.3M	1.9M
Maintenance (% of Installed Capital Cost)	4%	4%	3%	2%
Contamination[h]	Varies by design	Varies by design	Varies by design	None
Small Compressors: Fueling Sites				
Reliability[i]	Low	Improved	Improved	High
Compressor Efficiency (Isentropic)[j]	65%	65%	73%	80%
Losses (% of H_2 throughput)	0.5%	0.5%	0.5%	<0.5%

Table 9. (Cont.)

Category	2005 Status[y]	FY 2011 Status	FY 2015 Target	FY 2020[z] Target
Uninstalled Capital Cost ($) (based on 1,000 kg/day station, ~100 kg of H_2/h peak compressor flow)[k]	530,000 (two compressors @50% throughput each), plus one backup	675,000 (two compressors @50% throughput each), plus one backup	400,000 (two compressors @50% throughput each), no backup, or $360,000 for one compressor, no backup	240,000 (one compressor), no backup
Maintenance (% of Installed Capital Cost)	4%	4%	2.5%	2%
Outlet Pressure Capability (bar)[l]	430	860	860	860
Compression Power (kW)	200 (20 bar at inlet)	300 (20 bar at inlet)	260 (20 bar at inlet)	240 (20 bar at inlet)
Contamination[m]	Varies by design	Varies by design	Varies by design	None
Stationary Gaseous Hydrogen Storage Tanks (for fueling sites, terminals, or other non-transport storage needs)[n]				
Low Pressure (160 bar) Purchased Capital Cost ($/kg of H_2 stored)	1,000	1,000	850	700
Moderate Pressure (430 bar) Purchased Capital Cost ($/kg of H_2 stored)	1,100	1,100	900	750
High Pressure (860 bar) Purchased Capital Cost ($/kg of H_2 stored)	N/A	1,450	1,200	1,000
Tube Trailers[o]				
Delivery Capacity (kg of H_2)	280	560	700	940
Operating Pressure Capability (bar)	180	250	400	520
Purchased Capital Cost ($)	260,000	470,000	510,000	540,000

Table 10. (Cont.)

Category	2005 Status[y]	FY 2011 Status	FY 2015 Target	FY 2020[z] Target
Geologic Storage[p]				
Installed Capital Cost[q]	Assumed equal to natural gas caverns	Assumed equal to natural gas caverns	Assumed equal to natural gas caverns	Assumed equal to natural gas caverns
Liquid Hydrogen Delivery				
Small-Scale Liquefaction (30,000 kg of H_2/day)				
Installed Capital Cost ($)[r]	54M	54M	42M	29M
Energy Required (kWh/kg of H_2)[s]	10	10	8.0	6.5
Large-Scale Liquefaction (300,000 kg H_2/day)				
Installed Capital Cost ($)[r]	186M	186M	150M	110M
Energy Required (kWh/kg of H_2)[s]	8	8	7.0	5.4
Liquid H_2 Pumps (Fueling)[t]				
Uninstalled Capital Cost ($) (430-bar pressure capability, 100 kg/h)	100,000	100,000	85,000	70,000
Uninstalled Capital Cost ($) (870-bar pressure capability, 100 kg/h)	N/A	N/A	150,000	150,000
Cold Gas Delivery[u]				
Cold Gas Fueling Compressors (same requirements as fueling compressors above except the following)[v]				
Uninstalled Capital Cost ($K) (based on a 1,000 kg/day refueling station, 75 kW [50 kg of H_2/h peak compressor flow])	Undefined	97,000	85,000	75,000
Outlet Pressure Capability (bar)	Undefined	350	350	350
Temperature Capability (K)	Undefined	90	90	70-90
Cold Gas Delivery (Off-Board Storage)[w]				
Low-Pressure Storage Vessel Cost ($) (160 bar; $/kg-$H_2$)	Undefined	Undefined	Undefined	750
High-Pressure Storage Vessel Cost ($) (430 bar; $/kg-$H_2$)	Undefined	Undefined	Undefined	800

Table 11. (Cont.)

Category	2005 Status[y]	FY 2011 Status	FY 2015 Target	FY 2020[z] Target
Temperature Capability (K)	Undefined	Undefined	Undefined	40 K-ambient
Cold Gas Delivery (Tube Trailer Transport)[w]				
Temperature Capability (K)	Undefined	Undefined	Undefined	60 K-ambient
Delivery Capacity at 90 K (kg of H_2)	Undefined	Undefined	Undefined	1,500
Operating Pressure Capability (bar)	Undefined	Undefined	Undefined	340
Purchased Capital Cost ($)	Undefined	Undefined	Undefined	<600,000
Liquid-Carrier-Based Hydrogen Delivery[x]				
Carrier H_2 Content (kg of H_2/m^3)	Undefined	Undefined	Undefined	>70
Cost to regenerate ($/kg of H_2)	Undefined	Undefined	Undefined	<$1.00/kg of H_2
Carrier System Energy Efficiency (from the point of H_2 production through dispensing at the fueling station) (%)	Undefined	Undefined	Undefined	≥70
Gas Dispenser				
Uninstalled cost/dispenser ($ at the design pressure specified, two hoses per dispenser)	30,000 (430bar)	50,000 (860bar)	40,000 (860bar)	35,000 (860bar)

[a] All costs in Table 7 are in 2007 dollars to be consistent with DOE Office of Energy Efficiency and Renewable Energy planning, which uses energy costs from the *2009 Annual Energy Outlook*.

[b] Pipeline Capital Costs: The 2005 and 2011 costs are from HDSAM, V2.3. (For more details on the HDSAM, see www.hydrogen.energy.gov.) The model uses historical costs published in the article "Lab Uses OGJ Data to Develop Cost Equations," by D. Brown, J. Cabe, and T. Stout in the January 3, 2011, edition of the *Oil & Gas Journal* for natural gas steel pipelines as a function of pipeline diameter. It is assumed that hydrogen steel pipeline costs are 10% higher than natural gas pipelines based on discussions with industrial gas companies that build and operate the current system of hydrogen pipelines in the United States. The costs are broken down into materials, labor, and miscellaneous costs in HDSAM. Because they vary widely based on the location of the pipeline installation, ROW costs have been excluded in the analysis. However, they can account for a significant fraction of installation costs, particularly in urban areas. The 2020 target costs are based on projected potential costs for spoolable FRP pipelines of less than 6" in diameter, similar to those used for natural gas gathering lines. (Note: An 8" transmission line service could use two 6" FRP pipelines for equivalent service.) Transmission line pressures are assumed to be as high as 150 bar, trunk lines as high as 50 bar, and service lines as high as 30 bar.

[c] Pipeline reliability refers to maintaining the integrity of the pipeline relative to potential hydrogen embrittlement, third-party damage, or other issues causing cracks or failures. The 2020 target is intended to be at least equivalent to that of today's natural gas pipeline infrastructure.

[d] Hydrogen leakage is hydrogen that permeates or leaks from fittings or other parts of the pipeline as a percent of the amount of hydrogen put through the pipeline. The 2020 target is based on being equivalent to today's natural gas pipeline infrastructure, based on the article "Estimate of Methane Emissions from the U.S. Natural Gas Industry," by David A. Kirchgessner in volume 35, number 6 of *Chemosphere*, published in 1997.

[e] Large Compressor Reliability: Currently, the only hydrogen compressor technology available for pipeline transmission service and other high-throughput, modest-pressure boost service (e.g., a compression ratio of 1.5 to

10) is reciprocating compression. Due to the large number of moving parts and other challenges with hydrogen purity, this technology has low reliability. This means that multiple compressors must be installed to ensure high availability. The "Low" statuses (2005, 2011) are modeled in HDSAM, V2.3, as installing three compressors, each rated at 50% of the system peak flow. The 2020 target of "Improved" reliability assumes two compressors, each rated at 50% of the peak flow for pipeline transmission and truck loading service, and one compressor for hydrogen storage service. Reciprocating compression technology will need significant improvement, or new technology (e.g., centrifugal compression applicable to hydrogen) may be needed to achieve these levels of reliability.

[f] Large Compressor Efficiency: The current status (2011) of 88% isentropic energy efficiency for the compressor itself is typical for large reciprocating compressors used for hydrogen. Isentropic efficiency of compressors is defined as "the increase in the enthalpy of hydrogen due to compression" divided by "the total mechanical energy used by the compressor" under isentropic conditions of compression. The difference between these two is dissipated as waste heat in the compression operation. The 2020 target is set to at least maintain this efficiency.

[g] Large Compressor Capital Cost: These 2005 and 2011 cost statuses are based on HDSAM, V2.3. The model uses capital cost estimates for large two- and three-stage reciprocating compressors based on data supplied by various vendors. For more details on the large compressor capital cost data, see *Hydrogen Delivery Infrastructure Options Analysis, Final Report* (DE-FG36-05GO15032), published by Nexant Inc. in December 2008. The 2020 target cost is set at 70% of the 2011 cost to achieve overall delivery cost objectives.

[h] Large Compressor Contamination: Some reciprocating gas compressor designs require oil lubrication that results in some oil contamination of the compressed gas. Due to the stringent hydrogen quality specifications for PEM fuel cells, the 2020 target is to ensure that there is no possibility of lubricant contamination of the hydrogen from compression. As an alternative, it may be possible to remove such contamination at refueling sites just prior to charging the hydrogen to vehicles if it is not cost prohibitive.

[i] Fueling Compressor Reliability: Currently, several compressor technologies are being demonstrated for refueling station service. The most commonly used technology is the diaphragm technology, but piston technology and intensifiers are also being used. There are concerns about reliability for this service, leading to multiple compressors potentially being installed to ensure high availability. The 2005 status of "Low" is modeled in the HDSAM, V2.3, as installing three compressors, each rated at 50% of the station peak hourly flow. The 2011 status of "Improved" represents some improvement in this area and is modeled as two compressors each rated at 50% of peak station flow. The 2020 Target of "High" assumes only one compressor is needed at the station and that it can handle 100% of the peak station flow. This is deemed necessary to achieve the overall hydrogen delivery cost targets.

[j] Fueling Compression Efficiency: The 2005 and 2011 statuses of 65% isentropic energy efficiency for the compressor itself are typical for the size of the hydrogen refueling station compressors. Isentropic efficiency of compressors is defined as "the percentage of mechanical energy that ends up utilized as compression energy" divided by "the total energy used by the compressor" under isentropic conditions of compression. The difference between these two is dissipated as waste heat in the compression operation. The 2020 target represents new or improved technology to increase the compressor's isentropic energy efficiency to 80%.

[k] Fueling Compressor Capital Cost: The 2005 cost is based on compression for 350-bar hydrogen dispensing. The 2011 cost is based compression to 860 bar for 700-bar dispensing. Both costs are modeled using HDSAM, V2.3. The model uses a cost correlation as a function of motor kilowatts required, based on information obtained from a number of hydrogen compressor vendors. The 2020 target cost is set at 35% of the 2011 cost to achieve the overall delivery cost objectives.

[l] Fueling Hydrogen Fill Pressure: Light-duty fuel cell electric vehicles planned for roll out by original equipment manufacturers in the 2015 time frame will require 700-bar fills for full vehicle range, which in turn requires a station compression capability of 860 bar. This is already being demonstrated at some fueling sites. DOE's long-term goal is to develop solid or liquid carrier or other systems for vehicle storage tanks that allow for at least 300 miles of driving between refueling with more modest pressure storage (<500 bar). DOE has set targets that include 700-bar fills in 2020 to allow for the introduction of hydrogen fuel cell electric vehicles with high-pressure vehicle gas storage technology prior to achieving commercialization of the ultimate goal of lower-pressure vehicle storage technology.

[m] Fueling Compressor Contamination: Some gas compressor designs with dynamic seals require oil lubrication that results in some oil contamination of the compressed gas. Due to the stringent hydrogen quality specifications for PEM fuel cells, the 2020 target is to ensure that there is no possibility of lubricant contamination of the hydrogen from fueling station compression.

[n] Stationary Gaseous Storage Tank Capital Costs: Several different pressures are likely for stationary storage purposes in hydrogen delivery infrastructure — low-pressure storage at terminals and fueling stations where storage is needed but cost dictates lower pressures, moderate pressures for 350-bar refueling, and high pressures for 700-bar refueling. The 2005 and 2011 statuses represent the cost of standard steel and composite tanks. The 2020 target is set at 65% of the 2011 cost to achieve the overall delivery cost objectives.

[o] Tube Trailers: The 2005 and 2011 statuses of tube trailer characteristics and costs are based on HDSAM, V2.3, which uses available information on tube trailers from vendors. The 2020 cost targets are set to achieve the overall delivery cost objectives. There are several possible technology approaches to achieve these 2020 targets. It may be possible to develop more cost-effective composite structures to increase the working pressure of gaseous tube trailers. The pressures in the Target Table are based on the pressure required to achieve the targeted hydrogen capacity. Another approach would be to utilize solid carrier technology and/or to employ low-temperature hydrogen gas. It may also be possible to utilize some combination of these approaches. The key targets are hydrogen capacity and tube trailer capital cost.

[p] Geologic Cavern Capacity Availability: Transportation vehicle fuel demand is significantly higher in the summer than in the winter. To handle this demand surge in the summer without building prohibitively expensive excess production capacity, there will need to be significant hydrogen storage capacity within the hydrogen delivery system. Geologic storage is a very cost-effective storage method for these types of demand swings and is used very effectively for similar demand swings for natural gas. There are only a few geologic storage sites for hydrogen currently operating in the world (three in Texas and one in Teeside, England). Greater knowledge needs to be developed on the availability and suitability of hydrogen geologic storage sites. Technology development may also be required to ensure suitability for hydrogen.

[q] Geologic Cavern Capital Cost: This is based on HDSAM, V2.3, which uses information from a U.S. hydrogen geologic storage site in Texas and assumes that hydrogen geologic caverns have the same capital cost as natural gas caverns. However, this is very limited information and is for a salt dome cavern only. This capital cost target is simply stating that hydrogen geologic storage capital costs need to be about the same as current natural gas geologic storage to make geologic storage of hydrogen cost effective and to enable the possibility of achieving the overall delivery cost objectives. For more details, see *A Lifecycle Cost Analysis Framework for Geologic Storage of Hydrogen: A User's Tool* (SAND2011-6221), by A.S. Lord, P.H. Kobos, G.T. Klise, and D.J. Borns, published by Sandia National Laboratories in September 2011.

[r] Liquefaction Installed Capital: The 2005 and 2011 cost statuses are based on HDSAM, V2.3, which uses a correlation as a function of capacity derived from information obtained from industrial gas companies and other sources. The 2020 target cost is set to achieve the overall delivery cost objectives.

[s] Liquefaction Energy Use: The 2005 and 2011 energy requirement statuses are based on HDSAM, V2.3, which uses a correlation as a function of capacity derived from information obtained from industrial gas companies and other sources. The 2020 target is set to achieve the overall energy efficiency objectives as well as information based on magnetic liquefaction technology that is being developed.

[t] Liquid Hydrogen Pumps: The 2005 status is based on delivery of liquid hydrogen to refueling stations where it is stored in a cryogenic tank, pumped to an evaporator, and then charged to vehicles as a gas for 350-bar refueling with the aid of a cascade charging vessel system. The pump cost correlation is based on information from vendors on hydrogen liquid pumps available in 2005. The 2011 status is based on a technology similar to the technology that was available in 2005, except that the pump charges liquid hydrogen to 700 bar prior to passing the evaporator. The pump costs are based on information from developers that are currently beginning to demonstrate this technology with low hydrogen leakage rates, and a maximum pumping capacity of 100 kg per hour is assumed. This is all modeled in HDSAM, V2.3. The 2020 target is set to achieve the overall delivery cost objectives.

[u] Cold Gas Delivery is now being considered to reduce the cost of delivery and improve vehicle storage volumetric efficiency. The statuses and targets are derived based on one promising scenario. At the terminal, hydrogen is cooled to about 90 K using liquid nitrogen. The hydrogen is transported to the refueling station in super-insulated tube trailers capable of a 340-bar operating pressure. The tube trailer is dropped off at the station where it is used for storage. A compressor and insulated cascade storage vessel system is used to charge the cold hydrogen to a vehicle at 350 bar. The final temperature of the hydrogen on the vehicle would be about 200 K, assuming the vehicle came to the station with a tank one-quarter full at about 50 K, which might be typical. The targets for the Cold Gas Delivery scenario are very preliminary and can only be refined when a more detailed analysis of this delivery pathway is completed. Preliminary statuses and targets are provided for key components based on this scenario.

[v] Cold Gas Fueling Compressor: The 2011 capital costs are based on information from vendors that are starting to offer compressors for cold hydrogen gas. The 2020 target is based on achieving overall hydrogen delivery cost objectives. The pressure and temperature capability targets are based on the Cold Gas scenario used (see note u).

[w] Cold Gas Storage Vessels and Tube Trailers: These targets are based on the Cold Gas scenario (see note u) and achieving the overall delivery cost objectives. The values include consideration of their ambient temperature component counterpart targets and inclusion of expected costs for insulation.

[x] Liquid-Carrier-Based Hydrogen Delivery: Hydrogen liquid carriers are being researched for onboard vehicle storage. In this case, the hydrogen is chemically bound and released on the vehicle for use by the fuel cell. Liquid carriers might meet the volumetric storage efficiency targeted for vehicle storage; however, the spent liquid carrier must be returned to fairly large, semi-centralized facilities to be chemically processed and "recharged" with hydrogen (carrier regeneration). If the liquid carrier has a high enough hydrogen content, as indicated in the Target Table, its delivery costs could be quite low, based on preliminary analysis. This might allow for sufficient regeneration costs and still meet the overall cost objectives for hydrogen delivery. The targets in the Target Table are very preliminary and can only be refined when the cost of regeneration is known and a more detailed analysis of this delivery pathway is completed. The target for carrier hydrogen content is based on achieving delivery capacity of about 1,500 kg of hydrogen in a standard 8,800-gallon gasoline type tanker. These tankers are DOT-weight-limited when delivering gasoline. Delivery modeling of truck delivery shows a very low cost for this delivery pathway if the truck has sufficient hydrogen delivery capacity.

[y] "2005 Status" numbers were retained in the 2011 update to this MYRD&D section to show the differences between 2005 and 2011.

[z] 2020 targets are based on a well-established hydrogen market demand for transportation (15% market penetration). The specific scenario examined assumes centralized production of H_2 that serves a city of moderately large size (population: of about one million), and that the fueling station average dispensing rate is 1,000 kg/day.

Appendix A: Acronyms and Abbreviations

CCS	carbon dioxide capture and sequestration
CSTT	Codes and Standards Technical Team
DOE	U.S. Department of Energy
DOT	U.S. Department of Transportation
EPRI	Electric Power Research Institute
FCEV	fuel cell electric vehicle
FRP	fiber reinforced polymer
ft	feet
FY	fiscal year
gal	gallon
GHG	greenhouse gas
h	hour
H_2	molecular hydrogen
H2I	Hawaii Hydrogen Initiative
HDSAM	Hydrogen Delivery Scenario Analysis Model
HDTT	Hydrogen Delivery Technical Team
ISO	International Organization for Standardization
kg	kilogram
km	kilometer
kW	kilowatt
kWh	kilowatt hour
L	liter
LNG	liquefied natural gas
LRC	lined rock cavern
m	meter
MJ	megajoule
MYRD&D	Fuel Cell Technologies Office Multi-Year Research, Development and Deployment Plan
NASA	National Aeronautics and Space Administration
NFPA	National Fire Protection Association
NH_3BH_3	ammonia borane
PEM	proton exchange membrane
PSA	pressure swing absorption
psi	pounds per square inch
psig	pounds per square inch gauge
R&D	research and development
ROW	right-of-way
rpm	revolutions per minute
TGC	Hawaii Gas Company
USCAR	United States Council for Automotive Research
U.S. DRIVE Partnership	United States Driving Research and Innovation for Vehicle efficiency and Energy sustainability
yr	year