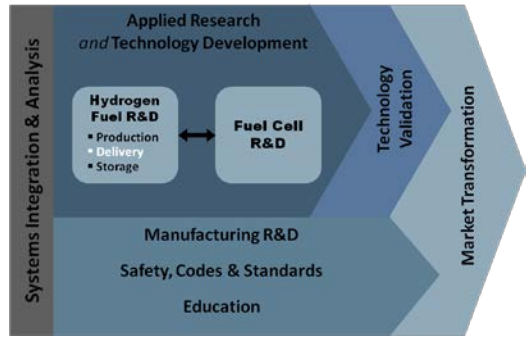
3.2 Hydrogen Delivery



Delivery is an essential component of any future hydrogen infrastructure. It encompasses those processes needed to transport hydrogen from a central or semi-central production facility to the final point of use and those required to load the energy carrier directly onto a given fuel cell system. Successful commercialization of hydrogen-fueled fuel cell systems, including those used in vehicles, backup power sources, and distributed power generators, will likely depend on a hydrogen delivery infrastructure that provides the same level of safety, convenience, and functionality as existing liquid and gaseous fossil fuel-based infrastructures. Because hydrogen can be produced from a variety of domestic resources, its production can take place in large, centralized plants or in a distributed manner, directly at fueling stations and stationary power sites. As such, the hydrogen delivery infrastructure will need to integrate with these various hydrogen production options. For hydrogen to become an economically viable energy carrier for light-duty vehicles, the combined cost of production and delivery must be reduced to <$4.00/gallon of gasoline equivalent[1] (gge) (untaxed).[2] The delivery and dispensing contribution to this cost must be <$2.00/gge. Currently, the high-volume levelized cost of dispensed hydrogen is above this target.

3.2.1 Technical Goal and Objectives

Goal

Develop technologies that reduce the costs of delivering hydrogen to a level at which its use as an energy carrier in fuel cell applications is competitive with alternative transportation and power generation technologies.

Objectives

- By 2020, reduce the cost of hydrogen delivery from the point of central production to the point of use in consumer vehicles to <$2/gge for at least one delivery pathway to meet the production and delivery cost target of <$4/gge by 2020.[3]

- By 2020, reduce the cost of hydrogen compression, storage, and dispensing at on-site production stations to <$2.15/gge to meet the production and delivery cost target of <$4/gge by 2020 (2007 dollars) (untaxed, delivered, dispensed).

3.2.2 Technical Approach

The Hydrogen Delivery sub-program is focused on meeting its objectives through research, development, and demonstration (RD&D) investments made in: (1) innovative technologies and processes to address the

[1] One gge is roughly equivalent on an energy basis to one kg of hydrogen. One gge and one kg of hydrogen are used interchangeably in this document.

[2] DOE Fuel Cell Technologies Office Record #11007, "Hydrogen Threshold Cost Calculation." Mark Ruth and Fred Joseck, March 2011. http://hydrogen.energy.gov/pdfs/11007_h2_threshold_costs.pdf. All costs in this plan are in 2007 dollars to be consistent with EERE planning, which uses the energy costs from the *Annual Energy Outlook 2009*.

[3] This target is for a well-established hydrogen market demand for transportation (e.g., 15% market penetration in an urban area with a population of approximately 1M). The specific scenario examined assumes central production of H_2 that serves a city of moderately large size (population: ~1.2M), that the distance between the plant and city is 100 km (or 62 mi), and that the average fueling station capacity is 1,000 kg/day.

challenges of low-cost, reliable hydrogen delivery and (2) infrastructure modeling, including delivery pathway analysis and optimization. Toward this end, the Hydrogen Delivery sub-program's efforts will be coordinated with other sub-program endeavors in the Fuel Cell Technologies Office (The Office), other U.S. Department of Energy (DOE) programs that have similar objectives, and related activities conducted by the U.S. Department of Transportation (DOT) and U.S. Department of Commerce (DOC). Individual projects will address the barriers outlined in Section 3.2.5, and progress toward meeting sub-program objectives will be measured against the technical targets outlined in Tables 3.2.3 and 3.2.4.

Hydrogen Transport and Fueling Options

The production of hydrogen is a relatively large and growing industry. In the United States alone, over 9 million metric tons of hydrogen are produced annually,[4] mostly for use as an industrial feedstock. The majority is produced at or near petroleum refineries and ammonia plants—the primary users of industrial hydrogen. More than 1,500 miles of hydrogen pipelines[5] serve regions with high concentrations of industrial hydrogen users, along the Gulf coast, near Los Angeles, and near Chicago along the lower portion of Lake Michigan.[6] The comparatively smaller merchant hydrogen market is serviced by cryogenic liquid hydrogen trucks or gaseous hydrogen tube trailers.

With respect to fuel cell use, processes associated with the delivery of hydrogen can be categorized either as transport operations, involving the transmission and distribution of hydrogen from one point to another; or as fueling operations, involving the transfer of hydrogen into the final receiving device (e.g., to an onboard storage tank). Hydrogen delivery from a centralized or semi-centralized production facility requires both transport and fueling operations, while delivery operations associated with distributed production (i.e., on-site production directly at the point of use) typically involve only gaseous fueling operations—see figure 3.2.2 (a) for details. There are three means by which hydrogen is commonly transported, shown schematically in Figures 3.2.1 (a)–(c), as a liquid by cryogenic tank truck or as a compressed gas by tube trailer or by pipeline. Also shown in Figure 3.2.1 (d) is a fourth option, transport in solid or liquid carrier form—an approach that is still in research and development (R&D). While the first three pathways involve the transport of molecular hydrogen, the latter approach employs a material that chemically binds or physisorbs hydrogen. A fifth option that is also in R&D is the transport of hydrogen as a cryogenic gas at temperatures of around 80 K. DOE's component technical targets for these last two options (delivery via solid or liquid carriers and delivery as a cryogenic gas) are currently under development.

[4] DOE Fuel Cell Technologies Office Record #12014, "Current U.S. Hydrogen Production." Fred Joseck, June 2012. http://hydrogen.energy.gov/pdfs/12014_current_us_hydrogen_production.pdf.

[5] Based on correspondence with the Pipeline and Hazardous Materials Safety Administration (PHMSA)'s on the 2013 Gas Transmission and Gathering Annual Data.

[6] By comparison, nearly 300,000 miles of onshore natural gas transmission pipeline exist in the United States. See "Annual Report Mileage for Natural Gas Transmission & Gathering Systems," PHMSA Calendar Year 2013. http://1.usa.gov/1NA9HNu.

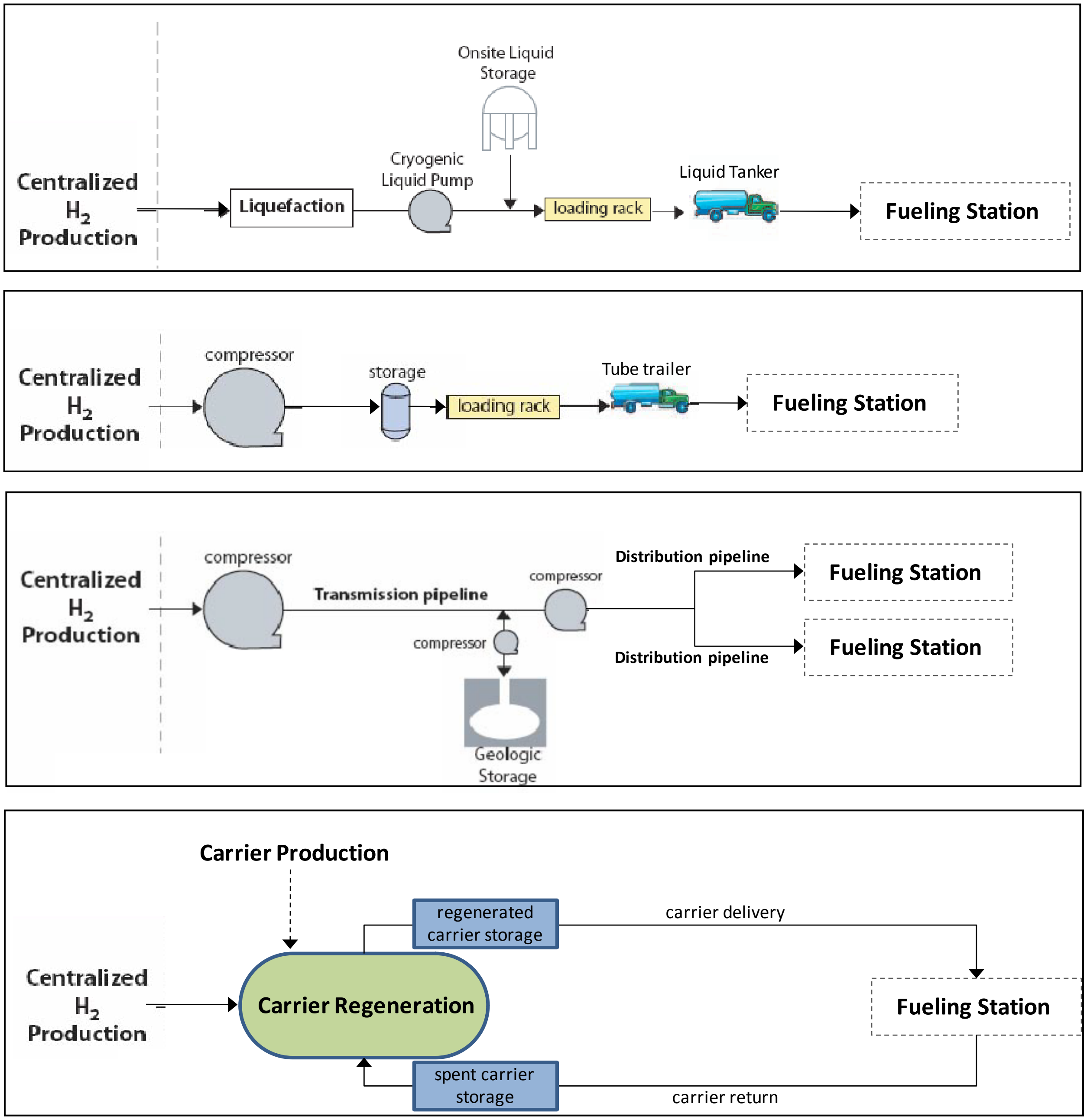


Figure 3.2.1 Basic hydrogen transport pathway options.

Each transport option consists of a series of process operations that in turn are composed of a set of individual process components. Conceivably, alternative pathways could be chosen that combine elements from two or more of these basic approaches. For example, gaseous hydrogen can be transported by pipeline to a terminal where it is liquefied for distribution by cryogenic tank truck (a practice currently employed at several North American facilities) or it could be transformed at the terminal into a carrier for subsequent distribution. To minimize delivery costs, transport logistics are optimized by geographic location, availability of operational resources (e.g., transmission and distribution pipelines, trucks, compressors), market size and type (urban, interstate, or rural), and customer needs. These pathways have evolved over time with the growth of the industrial gas market and will continue to do so as various fuel cell markets emerge and expand and as new delivery technologies are developed and implemented.

The final point in the delivery chain for fuel cell applications are the fueling sites. At present, there are approximately 10 public fueling stations in the United States that supply hydrogen to over 125 light-duty fuel cell electric vehicles (FCEVs) and 20 fuel cell buses.[7] An additional 41 public hydrogen fueling stations are planned by the end of 2015. While these current stations reside in California, development is expected by 2017 in the northeast region. The cost of dispensed hydrogen at these facilities can vary significantly depending on a number of factors, one of which is station capacity, or the maximum amount of hydrogen that can be dispensed daily at a given site and the utilization of the station. This quantity impacts the upstream method of hydrogen transport. High volume, high utilization stations benefit from liquid delivery, where lower volume and low utilization stations are better suited for gaseous tube trailer delivery to avoid boil off losses. More information on early market and near-term station design is available in the *Hydrogen Fueling Infrastructure Research and Station Technology (H2FIRST) Reference Station Design Task* report.[8] In addition, a growing number of manufacturing facilities and distribution centers in the United States employ fuel cell-powered material handling equipment (MHE), such as forklifts,[9] and are equipped with on-site fueling operations.

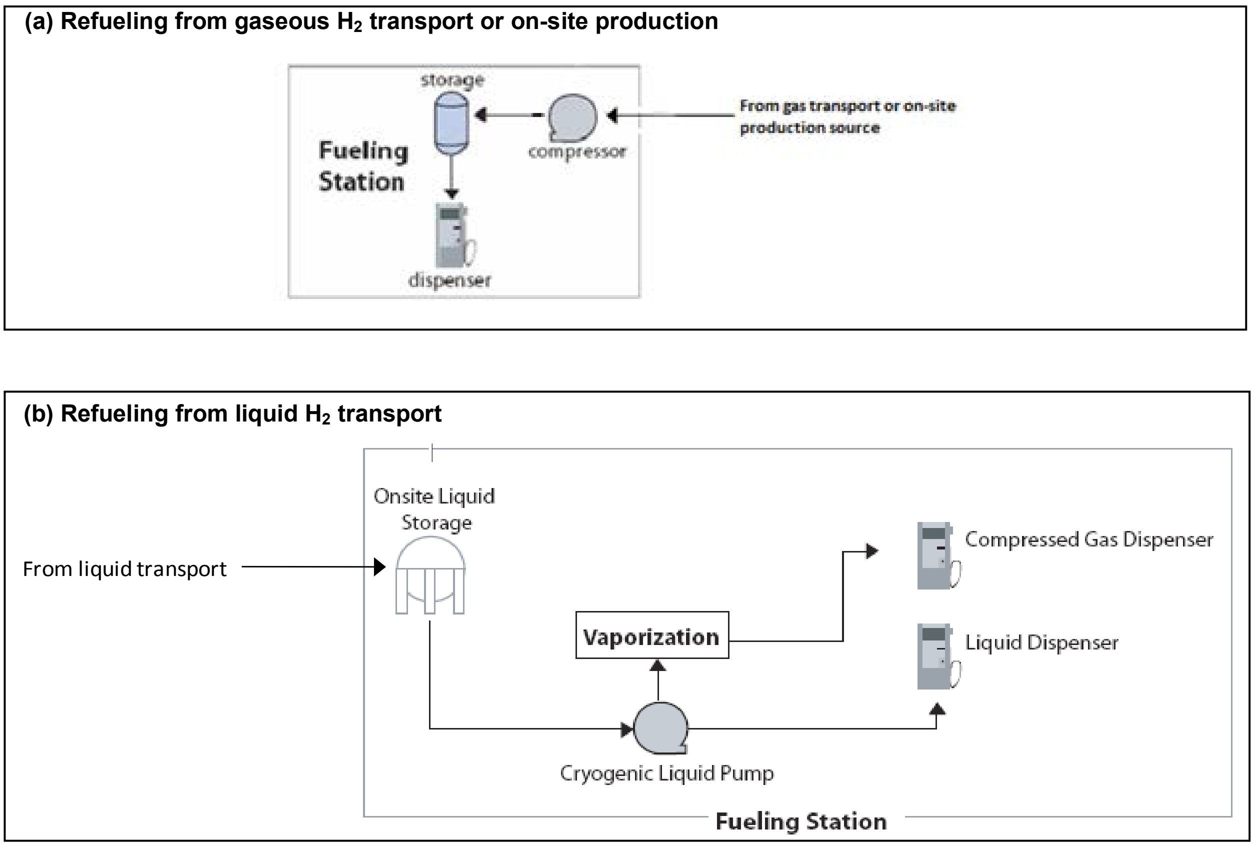


Figure 3.2.2 Typical hydrogen fueling options

[7] *Annual Evaluation of Fuel Cell Electric Vehicle Deployment and Hydrogen Fuel Station Network Development.* California Air Resources Board, June 2014. http://www.arb.ca.gov/msprog/zevprog/ab8/ab8_report_final_june2014.pdf.

[8] See http://www.nrel.gov/docs/fy15osti/64107.pdf.

[9] As of September 2014, fuel cell-powered forklifts had been deployed in at least 47 U.S. facilities.

Shown in Figure 3.2.2 are the key process operations employed at liquid- and gas-based hydrogen fueling stations. Note that the delivery of a hydrogen-bearing carrier would require a different series of fueling operations. In all cases, the costs associated with the fueling station are significant, representing as much as half of the overall delivery cost.

Hydrogen Transport and Fueling Operations and Components

Along many product delivery pathways are regional terminals that receive large volumes of the product and further process, apportion, and/or package it for final distribution to small retail outlets. In the case of hydrogen, the terminal might receive hydrogen (for example, in gaseous form from a pipeline) and further purify, compress, and load it onto tube trailers for distribution to various fueling sites. As shown in the schematic in Figure 3.2.3, there are a number of commonalities between process operations at each stage. As a result, improved technology developed for one stage of hydrogen delivery might also be applied at other points of the infrastructure. For example, improved storage technology could be used at both terminals and fueling stations. There is also the potential for pathway optimization through technology advances to reduce overall delivery cost. An example of this would be the development of high-pressure tube trailers that could deliver hydrogen gas to fueling stations at the desired dispensing pressure, thereby partially offsetting the need for multiple-stage, small-scale compressors at each of these sites using a single set of large-scale compression units at the terminal. Listed in Table 3.2.1 are the individual process components employed for both transport and fueling, along with a brief description of the commercial status of each. As outlined in Section 3.2.5, many of these will require improvement in order to establish a cost-effective hydrogen delivery infrastructure that meets the objectives defined above.

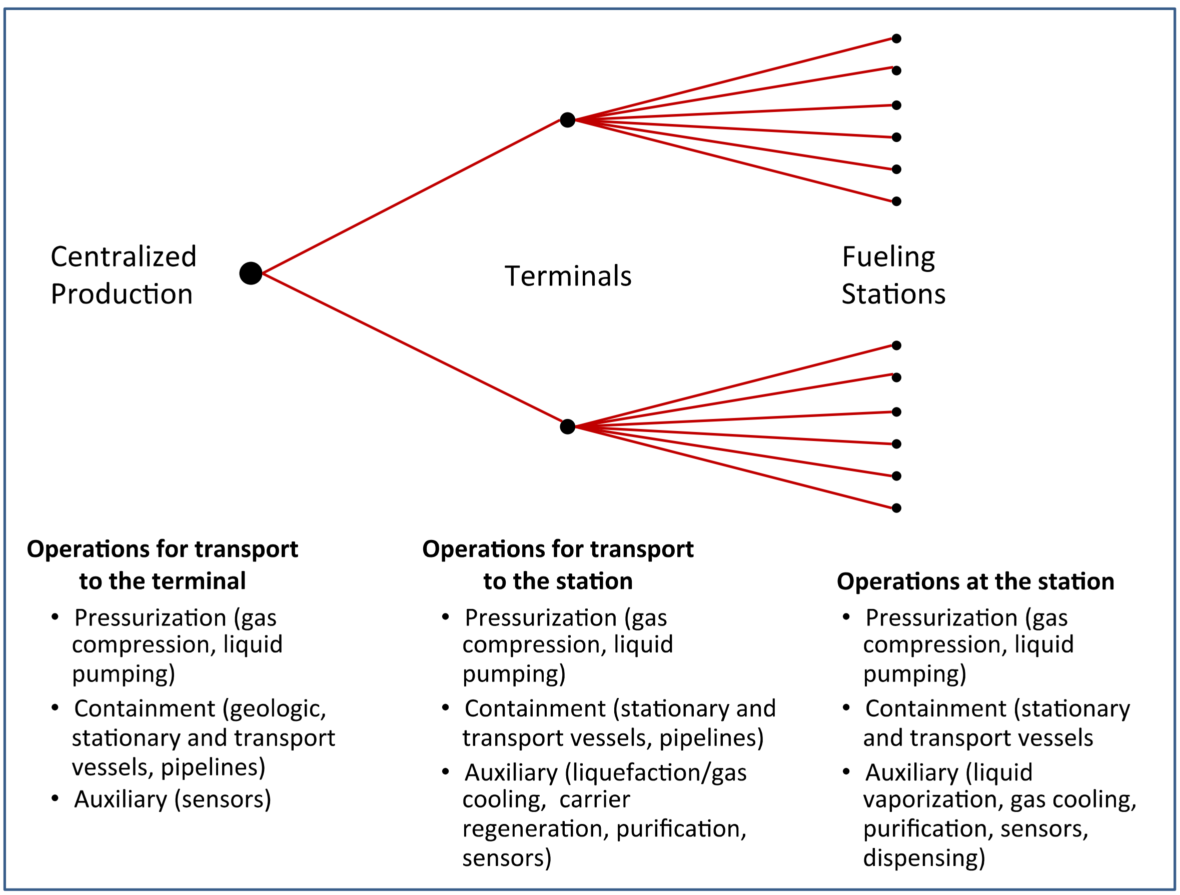


Figure 3.2.3 Commonality of process operations along a generic hydrogen delivery pathway.

Table 3.2.1 Hydrogen Delivery Infrastructure Components		
	Delivery Component	Current Status
Pressurization	Gas compressors	Compression operations can be differentiated based on capacity and pressurization needs. For pipeline transport, high flow rates (thousands of kg/hr) and relatively low pressures (<10 MPa) and compression ratios (10:1) are required. The opposite is true at fueling stations, where compressor flow rates may be 5–100 kg/hr and compression pressures as high as 100 MPa (1,000 bar). Loading operations at terminals generally have intermediate needs. High flow rate reciprocating piston compressors are typically employed for pipeline transport and terminal pressure vessel loading operations and high-pressure diaphragm compressors are used at hydrogen fueling stations (although small reciprocating and intensifier compressors are also used). Ionic liquid compressors are beginning to be commercialized for use in low-to-moderate flow rate and high-pressure gas compression operations.
	Liquid pumps	Liquid H_2 is typically pressurized with specially designed centrifugal pumps. Cryogenic reciprocating pumps have also been employed.
Containment	Pipelines	This is the perceived lowest cost option for large-volume H_2 transport. However, because the capital investment for pipelines is high, there must be a steady, high-volume gas demand to justify the investment cost. Transmission line pressures are typically 3–15 MPa (30–150 bar), while distribution line pressures range from 1–5 MPa (10–50 bar).[a] Materials of construction are mild, low carbon steels. Embrittlement concerns for these materials are far less than for higher strength steels and are further mitigated by proper pipeline design. (There are some concerns with combined fatigue effects due to pressure surging in the lines and with poor welds at pipe joints.) Long pipelines for liquid hydrogen are currently cost prohibitive.
	Gas storage	The most common pressure vessel construction is the Type 1 steel tube. These are capable of storing gaseous H_2 at pressures of 13.5–41 MPa (135–410 bar) and can be interconnected to increase overall storage capacity. Storage pressure is limited for over the road transport based on DOT regulations which depend on vessel construction, vessel size, and transport container design. Current carrying capacity for steel tube trailers is only about 300 kg (at ~18 MPa, or 180 bar). Because of the limited amount of H_2 that can be transported by steel tube trailer, this transport approach is economically constrained to a radius of ~300 km from the point of production. Compressed hydrogen gas can also be delivered by rail, ship, and barge. Composite pressure vessels are also available. Typically these cost more than steel vessels of equivalent size, but generally will store H_2 at higher pressures (and therefore higher capacity), and storage costs on a "per kg of H_2 stored" basis are often lower. The use of composite vessels for tube trailer transport and for on-site storage is being developed.
	Geologic storage	Geologic storage is commonly used in the natural gas delivery infrastructure to store large quantities of gas at modest pressures (~15–20 MPa, or ~150–200 bar). Caverns are typically formed in impermeable salt domes to minimize gas loss. There is one H_2 storage salt cavern site in the United States, at Lake Jackson, Texas, that has been in operation for several decades and two others that have been built recently (also in Texas).
Auxiliary Processing	Liquefaction systems	Over 90% of merchant hydrogen is transported in liquid form, which is currently the most economical means of truck transport for large market demands (>100 kg/day) and for distances greater than ~300 km.[b] There are 10 liquefaction plants in North America, each varying in capacity from 5,400–32,000 kg/day.[c] These plants employ multiple cooling cycles (including pre-cooling with liquid N_2, a Brayton cycle, and a Joule-Thompson cycle) and are energy intensive, consuming energy in amounts corresponding to ~⅓ of the energy in the hydrogen.

Table 3.2.1 Hydrogen Delivery Infrastructure Components		
	Delivery Component	Current Status
	Gas cooling systems	70-MPa (700-bar) dispensing of gaseous H_2 into Type IV tanks at a fill rate of 1.6 kg/min currently requires pre-cooling of the gas to overcome the heat of compression and the consequent effects on pressure vessel strength.[c]
	Separators/ purifiers	Common practice is to use pressure swing adsorption to remove impurities from gaseous hydrogen for use in fuel cells. This is done at the point of production. Other technologies include membrane and cryogenic separation. Compressor lubricants are removed by filtration.
	Dispensers	Commercial vehicle station gas dispensers often consist of a locking nozzle equipped for communication with the tank to ensure proper pre-programmed fill rates, safety breakaway hoses, electronically controlled delivery valving, and temperature/pressure compensated metering in packaging that resembles a standard gasoline dispenser. Dispenser systems exist that handle either 35- or 70-MPa (350- or 700-bar) gas pressure.
	Sensors	Hydrogen is colorless and odorless, and its flames are virtually invisible in daylight. Commercial hydrogen sensor technology currently can be categorized as one of six basic types: electrochemical, palladium and palladium alloy film, metal oxide, pellistor, thermal conductivity, and optical/acoustic devices.
	Evaporators	Used to generate gas from liquid H_2 at a given pressure, these units are usually composed of a series of finned heat exchangers that can be heated indirectly by air, water, or steam.
Carrier	Carrier systems	Currently not employed for H_2 transport. Preliminary assessments of various potential carriers—including ammonia, liquid hydrocarbons, metal hydrides, adsorbents, and chemical hydrogen storage materials—have not indicated that carrier materials offer a significant economic advantage relative to molecular hydrogen solely for delivery needs. However, R&D efforts continue to be supported through the onboard hydrogen storage efforts, and the potential use of hydrogen carriers may be re-evaluated as additional information or technology improvements become available.

[a] Final Report: Hydrogen Delivery Infrastructure Options Analysis. DE-FG36-05GO15032. Nexant, Inc., Dec. 2008.

[b] "Hydrogen Technologies," HySafe.org. http://www.hysafe.org/download/998/BRHS%20Chap2_Engineering_version%200_9_0.pdf.

[c] DOE Fuel Cell Technologies Office Record #9013, "Energy Requirements for Hydrogen Gas Compression and Liquefaction as Related to Vehicle Storage Needs." Monterey Gardiner, Oct. 2009. http://www.hydrogen.energy.gov/pdfs/9013_energy_requirements_for_hydrogen_gas_compression.pdf.

Research Strategy

Hydrogen can become a key energy carrier in the United States only after critical economic and technical barriers to the development of a more expanded infrastructure are overcome. The needs for RD&D range from incremental improvements to major advances in technology. Research activities can be staged; i.e., it is anticipated that certain needs must be satisfied in the near term to solidify early fuel cell markets, while others do not need to be fully met until there are appropriate signs for more widespread consumer demand. In addition, several factors will impact the strategic choices made for Delivery sub-program RD&D investment, including:

- Emergence of potentially sustainable fuel cell markets—Sub-program support for emerging market applications will be critical in developing commercial acceptance and demand for fuel cell technology as well as establishing low-cost delivery technologies that can serve future markets. Nascent markets, such as the use of fuel cells in backup power sources and MHE, will likely continue to take advantage of the present merchant hydrogen infrastructure. However, for these markets to grow and become sustainable, the levelized, as-dispensed cost of hydrogen must be reduced, including the delivery portion of that cost. Advances in delivery technology and process optimization that commercially entrench these early markets will also make the next set of market applications in the evolutionary chain (e.g., delivery vehicles and larger-scale distributed power generation) more economically attractive and therefore more viable.

- Hydrogen production strategy—The Fuel Cell Technologies Office's target for the untaxed, as-dispensed cost of hydrogen includes the costs of both production and delivery. Under several scenarios, there may be inherent trade-offs between the cost of production and the cost of delivery. Distributed hydrogen production, for example at the fueling site, eliminates costs associated with transporting hydrogen from a centralized or semi-centralized production facility. However, economies of scale associated with centralized or semi-centralized production result in lower production costs than experienced with smaller size, on-site production systems. In addition, it is possible to produce hydrogen at pressures higher than that delivered in current steam methane reforming practice. Again, there is a trade-off in the higher costs incurred with high-pressure production equipment versus the reduction in compression cost downstream at the fueling site.

- Required form of hydrogen for application—Fuel cell-powered forklifts often utilize 350-bar compressed hydrogen gas (CHG), while light-duty FCEVs will initially require 700-bar CHG for full range. The latter requires higher compression capability at FCEV fueling stations and a means of cooling the gas prior to dispensing (to avoid issues associated with hydrogen heating as it is compressed into the vehicle's tank), both of which represent higher fueling cost. In addition, the Storage sub-program is developing next-generation storage technologies that may require the delivery of cryogenic gaseous or liquid hydrogen or liquid delivery of chemical hydrogen storage materials that require off-board regeneration, each of which would require a different set of process operations than those currently used in fueling operations.

- Safety, codes and standards considerations—The implementation of codes and standards by regulating authorities ensures safe equipment/facility design, construction, and operation for every aspect of the hydrogen delivery infrastructure—including truck, rail, and pipeline transport; tank and geologic storage; handling at the terminal; and handling and dispensing at the fueling site. By nature, safety, codes and standards also affect the costs for all of these operations as well as for other factors such as insurance. Possible elimination or mitigation of processes constrained by regulation in favor of those less constrained can potentially reduce overall delivery cost as long as safety is not compromised. The development of safety equipment that facilitates lower cost operation, less land use, lower cost facility design (e.g., fueling station), or reduced insurance costs can have the same effect.

With the above in mind, the Delivery sub-program will be aligned along the following RD&D thrusts:

1) Innovative Technologies and Processes to Address the Challenges of Low-Cost, Reliable Hydrogen Delivery

The largest RD&D activity will concentrate on developing innovative process technologies that can reduce hydrogen transport and fueling costs. Investment decisions for these technologies will be guided by results from process and pathway optimization studies, as outlined for the analysis activity below. Stakeholder input and results from recent analyses indicate for long-term, high market penetration of light-duty FCEVs that advancements in the following delivery components would offer the greatest opportunity toward meeting the Office's cost target for as-dispensed hydrogen:

- Low-cost, high-efficiency pressurization equipment—including gas compressors and cryo-compression liquid pumps.

- Advanced containment technology—including low-cost pipelines and high-pressure gas transport and stationary storage vessels.

- Auxiliary process units and enabling technologies—including novel hydrogen liquefaction or gas cooling systems; low-cost, high-reliability dispensers; and advanced materials and sensors that promote more economic delivery processes.

2) Infrastructure Modeling

a. *Delivery Pathway Analysis*
The publicly available Hydrogen Delivery Scenario Analysis Model (HDSAM)[10] links together various hydrogen delivery component functions and costs to develop capacity/flow parameters for a variety of different potential hydrogen delivery infrastructure options. The model can be used to calculate the full cost of a given hydrogen delivery pathway, define underlying individual cost contributions, and examine the economic effects of new delivery technologies as a function of hydrogen demand, transport distance, and underlying finance factors (e.g., internal rate of return, insurance, land costs). In addition to stakeholder feedback, this modeling tool provides a means of identifying those processes or factors likely to have the greatest impact on delivery cost for future sub-program technology development. Future efforts will include: (1) refining the cost inputs and assumptions made to the model as new data become available, (2) assessing the potential impact of current technology development projects on hydrogen delivery cost as a means of measuring individual project progress towards the targets listed in Tables 3.2.3 and 3.2.4, and (3) evaluating the impact of hydrogen production and onboard storage technologies on delivery pathway options, operations, and costs. Of particular strategic importance to The Office is an investigation of delivery pathway options for emerging markets such as MHE to identify key near-term technical and cost barriers for these.

b. *Delivery Pathway Optimization*
HDSAM also allows one to examine trade-offs between components and process operations along any potential delivery pathway and determine the effects of individual process or equipment optimization in minimizing overall cost, in essence carrying out a “deep-dive” to frame the engineering limits for competing process technologies. While the infrastructure analysis activity described above will identify key cost contributors, this research thrust will investigate how these contributors can be mitigated or eliminated through hypothetical but practical changes in technology. This will afford a more deliberate basis for making invest-ments in new delivery technology. The example of advanced high-pressure tube trailers is one possible technology topic for consideration. Another includes understanding hydrogen temperature effects. For example, a recent preliminary analysis suggests that cooling hydrogen to 70–90 K at a production site or terminal, transporting it in insulated tube trailers, and charging cold gas to the vehicle may offer significant delivery cost advantages as well as achieve a higher volumetric FCEV storage efficiency due to the higher density of the cold hydrogen gas relative to ambient gas. Again, initial efforts will focus on emerging markets to provide immediate value to The Office.

c. *Station Design Optimization*
The Hydrogen Refueling Station Analysis Model (HRSAM) focuses on the analysis and optimization of the near-term hydrogen refueling station. It enables one to examine trade-offs between station

[10] HDSAM V2.3. http://www.hydrogen.energy.gov/h2a_delivery.html.

types, capacities, and peak performance. The model estimates the cost and capability of near-term stations designed to meet the SAE J2601 fueling protocol. The model was developed to support the public private partnership H2USA to enable analysis of near-term stations. The model helps to identify key cost contributors and how these contributors can be mitigated or eliminated through changes in the station design. The model also allows for investigation into the effect of a ramped utilization rate and can identify station sizes that are most optimal for a developing market. The tool was designed to be compatible with the Hydrogen Financial Analysis Tool (H2FAST) developed by the Systems Analysis team.

3.2.3 Programmatic Status

Projects currently funded by the Delivery sub-program are shown in Table 3.2.2. Activities focused on pressurization technology development include the design of centrifugal compressors for high hydrogen flow rates, an electrochemical means of achieving high compression ratios for fueling applications, and the evaluation of ionic liquid compression of hydrogen gas and reciprocating pumping of hydrogen liquid. Advanced pressurized containment technologies being developed include the design of high-pressure gas vessels for transport and stationary storage, the characterization of hydrogen embrittlement enhanced fatigue in base and weld metal sections of common pipeline steels, and the evaluation of fiber-reinforced polymers as alternative pipeline materials. In addition, magnetic refrigeration is being explored for hydrogen liquefaction. Analysis efforts include the use of HDSAM and other models to benchmark the projected costs of technologies in development against those of technologies currently employed by industry, to evaluate various delivery pathway costs for the MHE market, and to carry out a detailed optimization analysis of gas compression.

Table 3.2.2 Current (2015) Hydrogen Delivery Projects		
Challenge	**Approach**	**Activities**
Analysis		
Identify the cost-effective options for hydrogen delivery	Evaluate pathways and processes for delivering gaseous or liquid hydrogen and novel carriers under various technology market and financial assumptions.	Argonne National Laboratory (ANL) and Pacific Northwest National Laboratory (PNNL): Evaluates delivery options for the light-duty vehicle market, carries out a detailed engineering and economic evaluation of station technologies, and evaluates the trade-offs along the competing delivery pathways.
Pressurization		
Compression: Increase the reliability, reduce the cost, and improve the energy efficiency of gaseous hydrogen compressors. Pumps: Increase the reliability, reduce the cost, and improve the energy efficiency of liquid hydrogen pumps.	Develop improved compression technologies for gaseous hydrogen. Develop improved compression technologies for liquid hydrogen.	Southwest Research Institute: Develops, fabricates, and tests a linear motor reciprocating compressor. The design proposed incorporates several key components that have been demonstrated at TRL 4 or higher with the goal to improve compressor reliability and efficiency.
Containment		
Pipelines: Reduce installed costs and ensure safety, reliability, and durability. Tube trailer and storage vessels: Reduce capital cost on a \$/kg H_2 stored basis while ensuring safety, reliability, and durability.	Resolve concerns about hydrogen embrittlement of steel and evaluate new materials for pipeline delivery of hydrogen. Develop vessels that can store gas under higher pressure and/or reduced temperature.	Sandia National Laboratories (SNL): Tests and models pipeline and weld materials. Savannah River National Laboratory (SRNL): Evaluates low-cost fiber-reinforced polymer (FRP) composite pipelines. Lincoln Composites: Develops a high-pressure, composite tube trailer vessel. Oak Ridge National Laboratory: Develops an in-ground reinforced concrete-based vessel. Wiretough Cylinders: Develops low-cost wire wrapped cylinders for forecourt stationary storage.
Auxiliary		
Liquefaction: Reduce the capital cost and improve the energy efficiency of hydrogen liquefaction.	Explore new approaches to hydrogen liquefaction.	PNNL: Demonstrates at laboratory scale an alternative method of cryogenically cooling H_2 to <20 K via magnetic refrigeration.
Dispensing		
Dispensers: Reduce cost, improve reliability, and metering and dispensing accuracy.	Improve dispensing hose reliability.	NanoSonic Inc.: Develops a safe, reliable, and cost-effective hose for use at hydrogen refueling stations.

3.2.4 Technical Challenges

Cost and Energy Efficiency

The overarching techno-economic challenge for this sub-program is to reduce the cost of hydrogen delivery so that stakeholders can achieve the return on investment required for infrastructure build out. Without cost-competitive hydrogen sourcing, fuel cell technology will not be economically viable for broad market application. To meet the long-term target of <$2.00/gge (i.e., the delivery cost half of the total H_2 cost target),[11] significant improvements in delivery technology are required. For example, if pipeline transport is to be employed at greater scale, the capital cost for pipeline procurement and installation needs to be reduced while maintaining the same level of safety and reliability that has been achieved for the last 50+ years in the industrial gas market experience. If cryogenic liquid transport is to be used in higher volume, the capital cost and energy efficiency associated with liquefaction must be improved dramatically and losses due to vaporization need to be minimized. The use of gaseous tube trailers could be very attractive if their carrying capacities can continue to be increased, perhaps through the use of higher pressure and/or cooled gas or the use of a novel carrier in the tubes. The gas compression technology used at terminals and fueling sites must be more reliable (i.e., reducing the need for backup units), require less/easier maintenance, and be lower cost. In general, the costs at fueling sites need to be brought down to a level that ensures a positive return on investment can be realized far more quickly than is currently projected.

Hydrogen Purity Requirements

Polymer Electrolyte Membrane (PEM) fuel cell stacks require very high-quality hydrogen (see Appendix C). If the hydrogen is produced at the required specifications, then design of the delivery infrastructure must either guard against contamination or provide for a final purification step just prior to dispensing. Alternatively, hydrogen could be produced at lower purity levels and purified to specification further downstream along the delivery pathway prior to dispensing. The optimum purification strategy that will minimize overall costs will depend on the nature of the potential contamination issues and thus the technologies employed across production and delivery. The delivery research plan includes inputs and outputs across Hydrogen Production, Delivery, Storage, Fuel Cells, and Systems Analysis to coordinate this strategy.

Hydrogen Leakage

Diatomic hydrogen is a very light molecule and can diffuse at much higher rates than other fuel or energy carrier gases, such as natural gas. This property introduces unique challenges in designing process equipment and selecting suitable materials of construction that mitigate hydrogen leakage. Currently, significant leakage issues are avoided in the handling and use of large quantities of hydrogen in industrial settings because process operations are highly monitored and equipment is maintained and operated by trained, skilled operators. The establishment of hydrogen as a major energy carrier, where it will be handled in more open settings at times by the general public (e.g., vehicle fueling), will require robust system design and engineering and appropriate safety measures for many of the processes discussed above.

Analysis of Infrastructure Trade-Offs

HDSAM offers a means of identifying key cost contributors for various delivery scenarios. To date, its use for this purpose has specifically focused on long-term fuel cell applications, notably a light-duty FCEV market. However, it is recognized that the infrastructure for long-term markets will likely grow out of that which initially develops around smaller near-term fuel cell applications markets. Analysis of the delivery options and

[11] DOE Fuel Cell Technologies Office Record #12001, "H_2 Production and Delivery Cost Apportionment." Scott Weil, Sara Dillich, Fred Joseck, and Mark Ruth, Dec. 2012. http://www.hydrogen.energy.gov/pdfs/12001_h2_pd_cost_apportionment.pdf.

challenges for these early markets is needed. In addition, a subsequent analysis must be undertaken that focuses on how potentially interdependent process operations (e.g., high-pressure storage and gas compression) can be optimized to reduce overall pathway costs. Other trade-off studies that should be conducted include: (1) an evaluation of the effects of production strategy (e.g., distributed and high-pressure production) on the as-dispensed cost of hydrogen, (2) further investigation of a cold (~80 K) delivery pathway, and (3) an initial delivery operations analysis of alternative storage systems being developed for onboard FCEV storage in the Storage sub-program.

Technical and Cost Targets

The key to achieving the sub-program's goal and objectives is to reduce capital and operating costs and improve performance reliability for major delivery process technologies: pressurized containment (for stationary and transport operations), pressurization (compression and pumping), and liquefaction. The sub-program targets listed in Tables 3.2.4 are designed to meet the Program's cost targets for as-dispensed hydrogen. The Program's goal is for at least one delivery pathway to have an overall cost of \$2.00/gge of hydrogen by 2020, and for all delivery pathways (detailed in Figure 3.2.1) to ultimately cost ≤\$2.00/gge of hydrogen.[12] HDSAM[13] was used to perform the top-down analyses that guided each technology's individual cost targets (based on the Program's overarching cost targets). These individual targets were based on the current status of the technology and the potential for technological advancements in the future. The status of these technologies was determined through consultations with stakeholders and industry as well as analyses of industry data performed at ANL. Current costs were then adjusted for reductions that would be seen in a high-volume, mature market. The assumptions used to perform the top-down analyses that guided these targets are detailed in DOE Fuel Cell Technologies Office Record #13013.[14]

The individual component targets for 2020 have been set such that the tube trailer delivery pathway meets the cost target of \$2.00/gge of hydrogen. The ultimate targets have been set such that the pipeline delivery and liquid hydrogen delivery pathways both achieve a cost of ≤\$2.00/gge. Ultimate targets were not set for the tube trailer pathway because it is expected that gaseous hydrogen will be delivered primarily by pipelines in a mature, high-volume market.

[12] DOE Fuel Cell Technologies Office Record #12001, "H_2 Production and Delivery Cost Apportionment." Scott Weil, Sara Dillich, Fred Joseck, and Mark Ruth, Dec. 2012. http://www.hydrogen.energy.gov/pdfs/12001_h2_pd_cost_apportionment.pdf. .

[13] HDSAM V2.3. http://www.hydrogen.energy.gov/h2a_delivery.html.

[14] DOE Fuel Cell Technologies Office Record #13013, "H_2 Delivery Cost Projections—2013." E. Sutherland, A. Elgowainy, and S. Dillich, Dec. 2013. http://www.hydrogen.energy.gov/pdfs/13013_h2_delivery_cost_central.pdf.

Table 3.2.3 Cost Targets for Hydrogen Delivery[a]				
Category	FY 2011 Status[bb]	FY 2015 Status	FY 2020 Target	Ultimate Target[cc]
Hydrogen Delivery Sub-Program Cost Targets				
Delivery costs associated with distributed H_2 production[aa]				
Aggregate fueling station cost ($/gge)	2.50	2.19	2.15	<1.70
Delivery costs associated with centralized H_2 production[aa]				
Aggregate cost of transport, distribution, and fueling ($/gge)	3.60–4.40	3.35–4.35	2.00	<2.00

Table 3.2.4 Technical Targets for Hydrogen Delivery Components[a]				
Category	FY 2011 Status[bb]	FY 2015 Status	FY 2020 Target	Ultimate Target[cc]
Gaseous Hydrogen Delivery				
Pipelines: Transmission				
Total Capital Investment ($/mile for an 8-in. diameter equivalent pipeline) [excluding right-of-way][b]	765,000	765,000	695,000	520,000
Transmission Pressure[c] (bar)	70	70	100	120
H_2 Leakage (% of hydrogen transported)[d]	–	<0.5%	<0.5%	<0.5%
Lifetime[e] (years)	–	–	50	50
Pipelines: Distribution: Trunk and Service Lines				
Total Capital Investment ($/mile for a 1-in. pipeline) [excluding right-of-way][f]	440,000	355,000	230,000	140,000
Distribution Pressure[g] (bar)	40	100	100	120
H_2 Leakage (% of hydrogen transported)[h]	–	0.02%	0.02%	≤0.02%
Lifetime[e] (years)	–	–	50	50
Pipeline, Terminal, and Geologic Storage Compressors (~ 200,000 kg H_2/day peak flow, 20-bar inlet)				

Table 3.2.4 Technical Targets for Hydrogen Delivery Components[a]				
Category	FY 2011 Status[bb]	FY 2015 Status	FY 2020 Target	Ultimate Target[cc]
Compressor Specific Energy (kWh/kg)[i]	Undefined	0.82	0.82	0.84
Discharge Pressure (bar)	Undefined	100	100	120
Uninstalled Capital Cost ($)[j] (200,000 kg/day)	5.4 million	5.5 million	3.6 million	1.8 million
Losses (% of H_2 throughput)[k]	0.5%	0.5%	0.5%	<0.5%
Availability[l]	Low	85%	90%	90%
Annual Maintenance Cost (% of installed capital cost)[m]	4%	6%	4%	2%
Lifetime (years)[dd]	–	–	15	>15
Tube Trailer Terminal Truck Refueling Compressors (~ 300-kg H_2/hr peak flow, 100-bar Input)[n]				
Compressor Specific Energy (kWh/kg)	–	1.1	1.1	N/A
Discharge Pressure (bar)	–	550	550	N/A
Capacity (kg/hr)	–	40	300	N/A
Uninstalled Capital Cost ($)	–	250,000	450,000	N/A
Losses (% of H_2 throughput)	–	0.5%	0.5%	N/A
Availability	–	90%	90%	N/A
Annual Maintenance Cost (% of installed capital cost)	–	10%	2%	N/A
Lifetime[dd] (years)	–	–	15	>15
Small Compressors: Fueling Sites (~ 100 kg H_2/hr peak flow)				
Availability[o]	Low	70%–90%	85%	≥90%
Compressor Specific Energy (kWh/kg)[p]	2.8	*100-bar pipeline delivery:* 1.6	*100-bar pipeline delivery:* 1.6	*120-bar pipeline delivery:* 1.4

Table 3.2.4 Technical Targets for Hydrogen Delivery Components[a]				
Category	FY 2011 Status[bb]	FY 2015 Status	FY 2020 Target	Ultimate Target[cc]
		250-bar tube trailer delivery: 1.5	500-bar tube trailer delivery: 1.4	
Losses (% of H_2 throughput)[k]	0.5%	0.5%	0.5%	<0.5%
Uninstalled Capital Cost ($) (based on 750 kg/day station, [~100 kg H_2/hr peak compressor flow][q]	675,000 (Three compressors at $225,000 each. two at 50% throughput each, and one backup)	*100-bar pipeline delivery:* 275,000 (Three compressors, no backup) *250-bar tube trailer delivery:* 250,000 (One compressor, one backup)	*100-bar pipeline delivery:* 275,000 *500-bar tube trailer delivery:* 90,000 (One compressor, no backup)	*120-bar pipeline delivery:* 170,000 (One compressor, no backup)
Annual Maintenance[r] (% of installed capital cost)	4%	8%	4%	2%
Outlet Pressure Capability (bar)[s]	860	950	950	950
Lifetime (years)[ee]	–	–	10	>10
Stationary Gaseous Hydrogen Storage Tanks[t]				
Low Pressure (160 bar) Purchased Capital Cost ($/kg of H_2 stored) Corresponding Tank Size (kg)	1,000 –	850 25	500 710	450 400
Moderate Pressure (430 bar) Purchased Capital Cost ($/kg of H_2 stored) Corresponding Tank Size (kg)	1,100 –	1,100 22	600 65	600 65
High Pressure (925 bar) Purchased Capital Cost ($/kg of H_2 stored)[ll] Corresponding Tank Size (kg)	1,450 –	2,000 16	600 65	600 65

Table 3.2.4 Technical Targets for Hydrogen Delivery Components[a]				
Category	FY 2011 Status[bb]	FY 2015 Status	FY 2020 Target	Ultimate Target[cc]
Lifetime of High Pressure Vessels[ff] (years)	–	30	30	>30
Gaseous Tube Trailers[u]				
Payload (kg of H_2)	560	720	1,100	N/A
Operating Pressure Capability (bar)	250	250	500	N/A
Purchased Capital Cost ($/kg of payload)	930	720	600	N/A
Lifetime[gg] (years)	–	30	30	>30
Geologic Storage[v]				
Installed Capital Cost [w] ($)	equal to natural gas caverns	16 million	8 million	5 million
Liquid Hydrogen Delivery				
Small-Scale Liquefaction (30,000 kg H_2/day)[x]				
Installed Capital Cost ($)[y]	54 million	70 million	70 million	–
Energy Required (kWh/kg of H_2)[z]	10	15	12	–
Large-Scale Liquefaction (300,000 kg H_2/day)[x]				
Installed Capital Cost ($)[y]	186 million	560 million	560 million	142 million
Energy Required (kWh/kg of H_2)[z]	8	12	11	6.0
Liquid Hydrogen Storage Tank (3,500 m^3 Tank)				
Uninstalled Capital Cost ($)	–	6.6 million	6.6 million	3.3 million
Liquid Hydrogen Tank Trailers[hh]				
Payload (kg hydrogen)	–	4,554	4,554	5,250
Purchased Capital Cost ($/kg of payload)	–	190	190	70
Lifetime (years)[ii]	–	30	30	>30
Liquid H_2 Pumps (Terminals and Fueling)[jj]				

Table 3.2.4 Technical Targets for Hydrogen Delivery Components[a]				
Category	FY 2011 Status[bb]	FY 2015 Status	FY 2020 Target	Ultimate Target[cc]
Uninstalled Capital Cost ($) (<5 bar, 1,720 kg/h)	–	80,000	70,000	57,000
Uninstalled Capital Cost ($) (430 bar, 100 kg/h)	100,000	75,000	75,000	65,000
Uninstalled Capital Cost ($) (900 bar, 100 kg/h)	–	650,000	650,000	200,000
Specific Energy (kWh/kg), (900 bar, 100 kg/h)	–	0.6	0.5	0.5
Lifetime (years)	–	10	10	>10
Gas Dispenser				
Uninstalled cost/dispenser ($) (1 hose per dispenser)	50,000 (700-bar refueling)	65,000 (700-bar refueling)	60,000 (700-bar refueling)	40,000 (700-bar refueling)
Refrigeration Equipment (10–15 tons/day)[kk]				
Uninstalled Capital Cost ($)	–	140,000	100,000	70,000

[a] All costs in table are in 2007 dollars to be consistent with EERE planning, which uses the energy costs from the *Annual Energy Outlook 2009*. These costs also assume a high-volume market.

[b] Pipeline Capital Costs: The 2011 and 2015 costs are from HDSAM V2.3. (For more details on the HDSAM, see www.hydrogen.energy.gov.) The model assumes that a hydrogen pipeline costs 10% more to construct than a natural gas pipeline of the same diameter and length. The costs of natural gas pipelines are determined from analyses of historical construction costs published by Brown et al. ("National Lab Uses OGJ Data to Develop Cost Equations," *Oil & Gas Journal*, D. Brown, J. Cabe, and T. Stout, Jan. 3, 2011). It is important to note that construction costs do vary widely throughout the entire country, and the Brown et al. publication does have region-specific cost analyses. HDSAM V2.3 and the pipeline capital cost target in the Multi-Year Research, Development, and Demonstration (MYRD&D) plan are based on the analyses that corresponded to the entire country (rather than any particular region), however, and were vetted with industry consultation. The assumption of a 10% premium for hydrogen lines was based on discussions with industrial gas companies that build and operate the current system of hydrogen pipelines in the United States. Right-of-way costs have been excluded from the target, because they vary widely and are not a technical characteristic of the technology. They are, however, included in the top-down analysis that drives targets for the pipeline pathway.

[c] The 2015 status of transmission pressure is based on the maximum operating pressure of hydrogen pipelines as of March 2015. For more information, see: http://energy.gov/sites/prod/files/2014/03/f9/nexant_h2a.pdf. The 2020 target is set to lower compression requirements at the forecourt.

[d] Hydrogen leakage is hydrogen that permeates or leaks from fittings, etc., as a percent of the amount of hydrogen carried by the pipeline. The 2015 status and future targets are based on industry consultation, along with the assumption that leak rates from hydrogen pipelines will be no higher than those from current natural gas pipeline infrastructure. Leak rates for the natural gas pipeline infrastructure were taken from ANL's GREET model. (See https://greet.es.anl.gov/greet/index.htm.) The values in GREET are based primarily on the Environmental Protection Agency's 2013 Inventory of Greenhouse Gas Emissions and Sinks, and are detailed at https://greet.es.anl.gov/publication-ch4-updates-13.

[e] Pipeline lifetime refers to the minimum time period that the pipeline must remain in service to justify the capital cost of its installation. The 2020 and ultimate targets are intended to be at least equivalent to that of natural gas pipeline infrastructure. The actual life of a pipeline can exceed its design life.

[f] The 2011 status for distribution pipelines was based on the lines being built out of steel and their construction costs being 10% higher than those of natural gas pipelines. The costs of natural gas pipelines were taken from HDSAM V2.3 and are detailed further

in Footnote b. The 2015 status and future targets are based on distribution pipelines being built out of fiber-reinforced composite material. Industry consultations were used to derive the cost of FRP pipelines in 2015.

[g] The 2015 distribution pressure is based on the current rating of fiber-reinforced composite pipe. The ultimate target has been set to enable the pipeline delivery pathway to meet its ultimate cost target.

[h] The leak rate refers to hydrogen losses through the pipeline material and/or fittings. The 2011 status was based on the use of steel for pipeline construction, while the current status and future targets are based on the use of fiber-reinforced composite piping (FRP). The values of permeation rates through FRP liners and joints were derived from experimentation conducted on FRP at SRNL in 2009. Some of these results can be seen in their 2009 Annual Merit Review presentation: http://www.hydrogen.energy.gov/pdfs/review09/pd_42_adams.pdf.

[i] Compressor Specific Energy: In the 2012 version of the MYRD&D plan, the energy consumption of compressors was characterized by their isentropic efficiency, which was about 88% for large reciprocating compressors used for hydrogen. In 2015, this metric was changed to represent energy consumption for every unit of hydrogen compressed (kWh/kg) at the specified inlet pressures, discharge pressures, and capacities. The current metric characterizes the isentropic efficiency, losses, motor efficiency, and motor size of a large compressor. The 2015 status is based on the expected performance of a centrifugal compression technology funded by DOE from 2008–2014.

[j] Large Compressor Capital Cost: The 2011 cost status was based on HDSAM V2.3. HDSAM V2.3 contains algorithms that can estimate a compressor's cost as a function of its motor size. These algorithms were derived from cost data supplied by various vendors for two- and three-stage reciprocating compressors. The 2015 status is based on the projected capital cost of centrifugal compression technology funded by DOE from 2008–2014. The 2011 cost status is lower than the 2015 cost status because it was a projection for a hypothetical technology, and because it assumed reciprocating compression rather than centrifugal compression. HDSAM V2.3 had been used to estimate the motor power that a reciprocating compressor of the specified size (200,000 kg/day from 20 bar to 100 bar) would require, and to then estimate the compressor cost corresponding to that power; the 2011 cost status was not based on a commercially available compressor. The 2015 status is instead based on cost projections for an existing centrifugal design, which is likely to be preferable to reciprocating compression because of better reliability. The 2020 and ultimate targets are based on cost reductions that would be necessary to achieve overall delivery cost objectives.

[k] Losses: Hydrogen can leak through compressor seals. The 2015 status of leak rate was based on typical ratings of hydrogen compressor seals. Future targets are set to ensure leak rates do not exceed the current status.

[l] Large Compressor Reliability: The 2011 status was based on the use of redundant reciprocating compression, which faces reliability issues due to the large number of moving parts. It was assumed that three compressors, each rated at 50% of the system flow, would be necessary to ensure reliable pipeline operation. The 2015 status is based on a reliability analysis that was completed by Concepts NREC for a novel centrifugal compression technology they designed and tested with DOE funding between 2008 and 2014. The analysis estimated their compressor's availability based on typical failure rates of its components. The 2020 and Ultimate targets are based on reliability remaining high enough that each compressor requires only one redundancy.

[m] Annual Maintenance: The 2015 maintenance cost status was derived from a reliability analysis completed by Concepts NREC for the 240,000 kg/day centrifugal compressor they designed with DOE funding from 2008–2014. The study indicated that the Concepts compressor has a maintenance cost of about $0.005/kWh (as indicated in their 2014 Annual Merit Review presentation: http://www.hydrogen.energy.gov/pdfs/review14/pd017_dibella_2014_o.pdf). HDSAM V2.3 was used to determine the kWh the compressor would consume in a year. In the past, DOE also set targets for the contamination potential of compressors. It is now assumed that any compressor that meets DOE targets will not add contaminants to the hydrogen fuel.

The 2011 maintenance status was based on a review of delivery technologies completed by Nexant, Inc., in conjunction with several national laboratories, industrial gas companies, and technology research companies and assumed reciprocating compression rather than centrifugal compression. While the 2015 maintenance cost status is greater than that for 2011, it is believed to be more accurate because it is based on a detailed review of a specific technology.

[n] Tube trailer terminals large enough to serve a mature FCEV market (~ 70,000 kg/day) do not presently exist. Such terminals would likely be located near production plants and require storage capacity (at about 100 bar) to buffer differences between production rates and rates of trailer filling. Compressors in 2015 do not have sufficient capacity to meet the needs of a terminal in a mature market. The 2020 target is based on the capacity that would be necessary to satisfy the truck refueling needs of a terminal in a mature market with about 20 compressors in parallel and 5 redundant compressors.

[o] Fueling Compressor Reliability: The primary compressors being demonstrated for refueling station service are reciprocating, diaphragm, and ionic liquid technologies. The reliability of compression depends on the technology used. Diaphragm compressors typically have better availability than reciprocating compressors but lower capacity. Because three compressors have been assumed to be necessary in 2015 to meet the flow requirements of a 1,000 kg/day station supplied by pipeline, it is assumed that these compressors will also enable redundancy; a station would be able to operate at reduced capacity if one of its compressors failed. In the tube trailer pathway, only one compressor is necessary to satisfy flow requirements, and it is therefore assumed that a redundant compressor will be necessary. The future targets are based on reliability improving enough that redundant compression is not necessary.

[p] Compressor Specific Energy: In the 2012 version of the MYRD&D plan, the energy consumption of compressors was characterized by the isentropic efficiency, which was about 65% for hydrogen refueling station compressors. In 2015, this metric was changed to represent energy consumption for every unit of hydrogen compressed (kWh/kg). The current metric characterizes the isentropic efficiencies, losses, motor efficiencies, and motor sizes of the compressor(s) being employed to meet the specified throughput (100 kg/hour) at the specified suction and discharge pressures. The efficiencies differ depending on the delivery mode (pipeline or tube trailer) because the mode determines the compressor's suction pressure. It is assumed that a tube trailer's minimum delivery pressure (before it is returned to the tube trailer terminal) is 15 bar, and that the tube trailer consolidation strategy (http://www.hydrogen.energy.gov/pdfs/review14/pd014_elgowainy_2014_o.pdf) is implemented in the case of tube

trailer delivery. Implementation of the consolidation strategy lowers the size of the compressor (in terms of throughput) necessary at the station.

[q] Fueling Compressor Capital Cost: The 2011 and 2015 capital costs are modeled using correlations between motor size and compressor cost derived at ANL. The costs vary depending on the mode of delivery (pipeline or tube trailer) because the delivery mode determines the compressor's suction pressure, which determines the size of compressor necessary to meet the station's demand; the motor power requirement and throughput are both impacted by suction pressure. It is assumed that a tube trailer's minimum delivery pressure (before it is returned to the tube trailer terminal) is 15 bar, and that the tube trailer consolidation strategy (http://www.hydrogen.energy.gov/pdfs/review14/pd014_elgowainy_2014_o.pdf) is implemented in the case of tube trailer delivery. Implementation of the consolidation strategy lowers the size of the compressor (in terms of throughput) necessary at the station.

[r] Annual Maintenance: This target refers to the cost of parts and labor associated with annual maintenance activities, including inspection and parts replacement. The 2011 maintenance status was based on a review of delivery technologies completed by Nexant, Inc., in conjunction with several national laboratories, industrial gas companies, and technology research companies. The 2015 maintenance status was based on more recent consultation with industrial experts on reciprocating hydrogen compression. The reason for the increase in estimated maintenance cost between 2011 and 2015 is an improved understanding of compression technologies. Additionally, the current version of the MYRD&D assumes that any compressor that meets DOE targets will not add contaminants to the hydrogen fuel; in the past, DOE also set targets for the contamination potential of compressors.

[s] Fueling Hydrogen Fill Pressure: Light-duty FCEVs rolled out by original equipment manufacturers in the 2015 time frame will require 700-bar fills for full vehicle range, which in turn requires station compression capability of 950 bar. This is already being demonstrated at some fueling sites. The long-term goal of DOE 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 psi). DOE has set targets that include 700-bar fills to allow for the introduction of hydrogen FCEVs with high-pressure vehicle gas storage technology prior to achieving commercialization of the ultimate goal of lower pressure vehicle storage technology.

[t] Stationary Gaseous Storage Tank Capital Costs: Several different pressures are likely for stationary storage purposes in a hydrogen delivery infrastructure. Low-pressure storage will be necessary at terminals and fueling stations supplied by pipelines. Moderate pressure storage will be necessary at 350-bar refueling stations, and high-pressure storage will be necessary at 700-bar refueling stations. The 2015 and 2011 statuses represent the packaged cost of standard steel and composite tanks, including the costs of paint, cleaning, and mounting necessary to transport the tanks; this cost does not, however, include installation at the final destination. Because the cost of storage is highly dependent on the tank size, each of the costs in the Target Table corresponds to a specific tank size. The ultimate target for tank size is smaller in order to create a more aggressive target on a $/kg stored basis.

[u] Gaseous Tube Trailers: The 2015 status of gaseous tube trailer characteristics and costs are based on tube trailers that were developed with Office funding from 2008–2014. The key targets are hydrogen capacity and tube trailer capital cost; while higher pressure tube trailers are available on the market, it is unknown whether they have higher capacities or lower costs than those described. 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. The costs provided only characterize the storage vessels themselves, and not the chassis, truck, or any other ancillary equipment used to transport the vessels.

[v] Geologic Storage: 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 currently operating geologic storage sites for hydrogen in the world (in Texas and one in Teeside, England). Greater knowledge needs to be developed on the availability of hydrogen geologic storage sites. Technology development may also be required to ensure suitability for hydrogen.

[w] Geologic Cavern Capital Cost: The current cost corresponds to a salt cavern with about 1,110 tonnes of working gas, the capacity required to meet the long-term storage needs of a city with a population of about 1 million, and about 15% market penetration of FCEVs; HDSAM V2.3 was used to determine the capacity required. The current cost was extrapolated from a study of geologic storage of gaseous hydrogen published by SNL in 2014. While salt caverns are in use for both natural gas and hydrogen storage, their use is limited to regions of the country with salt deposits. Salt deposits in the United States are located primarily in the central region of the country. Lined hard rock caverns also have the potential to meet long-term storage requirements, and also allow for multiple cycles per year while minimizing the risk of leakage or contamination. They do, however, require a capital investment estimated to be about two to four times greater than that of salt caverns. Geologies along the U.S. East Coast would allow for the development of hard rock caverns, but their potential in California has not yet been assessed. The only commercial lined hard rock cavern in existence is in Sweden. For more details, see "Geologic Storage of Hydrogen: Scaling up to Meet City Transportation Demands," *International Journal of Hydrogen Energy* 39 (2014), A.S. Lord, P.H. Kobos, G.T. Klise, and D.J. Borns, pp. 15,570–15,582, and http://www.netl.doe.gov/File%20Library/Research/Oil-Gas/Natural%20Gas/other/34348_final.pdf.

[x] The terms "small-scale" and "large-scale" characterize the capacities that would be necessary to serve small and large FCEV markets. A 30,000 kg/day liquefier would satisfy a market penetration of about 3%, while a 300,000 kg/day liquefier would satisfy a market penetration of about 30% in a city with a population of about 1 million.

[y] Liquefaction Installed Capital: The 2011 status cost is 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 2015 and 2020 values are based on more recent consultations with industry. These costs only characterize liquefaction equipment (compressors, heat exchangers, expanders, etc.), and not any associated storage.

[z] Liquefaction Energy Use: The 2011status energy requirements 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 2015 and 2020 values are based on more recent consultations with industry. The ultimate target is based on an innovative liquefaction design created as part of the European Union's IDEALHY project from 2011–2013. The design assumes a feed pressure of 80 bar. More details can be found at http://www.idealhy.eu/.

[aa] Costs associated with distributed production refer to an apportionment of the costs required to capitalize, build, and operate a fueling station that are directly attributable to non-production operations, namely gas compression, on-site gas storage (to account for daily and weekly variations in demand), and gas dispensing. Costs associated with centralized production account for the above station costs as well as those required in transmitting the hydrogen from the production facility to the fueling station. Note that station costs associated with distributed production are somewhat higher than those for centralized production. This is because the former requires a higher level of on-site storage to account for seasonal variations in fueling demand. Seasonal variations for the latter are accounted for via geologic and/or terminal storage. The apportionment between the fuelling station cost and the transport and delivery cost is presented in Program records 12001 H2A was used to determine the cost of distributed production in 2015, assuming the fueling station is designed for dispensing of 1,000 kg/day and is fully utilized. (See http://www.hydrogen.energy.gov/h2a_production.html.)

[bb] "2011 Status" numbers were retained in the 2015 update to this MYRD&D section to show the differences between 2011 and 2015.

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

[dd] The compressor lifetime assumes that routine maintenance is performed, such as replacement of seals and valves. The lifetime for pipeline compressors also assumes relatively continuous operation, with few starts and stops during a year. The 2015 statuses are unknown because few compressors are currently in operation in high-volume pipeline or tube trailer filling applications. The 2020 and ultimate targets have been set based on the lifetimes that are expected to be achievable given the technology currently available as well as the replacement frequencies that would enable hydrogen delivery and dispensing by pipeline to meet DOE's ultimate cost target.

[ee] The compressor lifetime assumes that routine maintenance is performed on the compressor, such as replacement of seals and valves, at the service intervals specified by the manufacturer. The 2015 status is unknown because fueling station compressors have not yet been in operation for a substantial amount of time, and operators are still learning how to properly maintain this equipment; achievement of the compressor's design life is highly dependent on proper operation and maintenance. The 2020 and ultimate targets are based on the lifetimes that are expected to be achievable given compressors currently used at natural gas stations as well as the replacement frequencies that would enable hydrogen delivery and dispensing to meet DOE's ultimate cost targets.

[ff] The lifetime status and targets are based on Type II vessels used for high-pressure (925-bar) storage, assuming routine maintenance is conducted. Storage at lower pressures (160 bar and 430 bar) can utilize Type I vessels, which are expected to last at least as long as Type II vessels. However, the impact of fatigue cycles seen at hydrogen stations on the lifetimes of storage vessels is still being assessed.

[gg] The lifetime corresponds to the maximum life that Type IV transportation vessels are currently permitted for by the DOT in CNG service. This service life corresponds to the number of deep cycles these vessels can withstand prior to leaking and/or bursting. Additional research is currently underway regarding the impact of deep fatigue cycles on Type IV vessels in hydrogen storage.

[hh] Liquid Hydrogen Tank Trailers: The cost targets for this category refer only to the cost of the liquid hydrogen storage aboard a tank trailer, not the associated chassis or truck. The design of these tanks is similar to that of stationary storage but must additionally comply with DOT regulations. The 2015 status is based on consultation with industrial gas manufacturers.

[ii] The trailer lifetime assumes that they undergo inspections approximately every 5 years and refurbishing every 10 years.

[jj] Liquid Hydrogen Pumps: The 2011 and 2015 statuses are 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 with the aid of a cascade charging vessel system. The pump costs are based on information from developers that currently manufacture this technology.

[kk] The refrigeration equipment constitutes a chiller and a heat exchanger that bring the temperature of hydrogen to -40˚C before it reaches the dispenser. It is assumed that one chiller and one heat exchanger will be necessary for each dispenser. The capacity of the refrigeration equipment (10–15 tons/day) describes the amount of heat the unit can remove in a day, not the tons of hydrogen it can cool in one day. The heat-removal capabilities of refrigeration units are commonly described in "tonnes," where the tonnage refers to the mass of ice the unit can freeze in a day.

[ll] Cost increased from 2011 to2015 due to an improved understanding of the pressure vessel market. The 2011 cost status was based on analysis of the pressure vessel manufacturing process and components. Cost estimates were made through consultation with suppliers of pressure vessel manufacturers. The 2015 cost status is instead based on quotations from manufacturers themselves.

3.2.5 Technical Barriers

A. Lack of Hydrogen/Carrier and Infrastructure Options Analysis

While options and trade-offs for hydrogen/carrier delivery from central and semi-central production to the point of use are generally well described for long-term market scenarios, this is not true for early markets. Possible means of *optimizing* delivery for either a long-term or short-term market scenario are not well established. The distributed production of hydrogen is another option to be considered in greater detail.

Additional analysis is needed to better understand the advantages and disadvantages of the various possible approaches and technology advancements as well as potential site-specific and regional issues. In all cases, upstream delivery pathway inputs are tied to production outputs and downstream delivery outputs must meet the needs of the onboard storage system. This interdependency between hydrogen production, delivery, and onboard storage needs to be evaluated in order to understand the possible scenarios for minimizing overall life cycle cost, energy use, and environmental impact.

B. Reliability and Costs of Gaseous Hydrogen Compression

Current compression technology used for hydrogen requires frequent maintenance, which results in the need for redundant compressors to minimize downtime and leads to high cost. Centrifugal compression is the lowest cost approach for pipeline compression needs (for example, in natural gas transmission), but the current technology does not work with hydrogen and new concepts have yet to be demonstrated. Lubricants used in normal compression applications can result in unacceptable levels of contamination for PEM fuel cell use. Refueling station compression currently has a high capital cost per unit throughput. The need for high-pressure (70-MPa), onboard storage in first-generation light-duty FCEVs adds to the challenge. More reliable, lower-cost, and higher efficiency gas compression technologies are needed for pipelines, terminals, and fueling sites.

C. Reliability and Costs of Liquid Hydrogen Pumping

Cryogenic liquid pumps currently have lower capital cost per unit pumping capacity compared to gaseous compressors. However, the hydrogen entering the pump must be in the liquid state at all times. Any vaporization will cause cavitation that in turn can damage the pump. Boil-off associated with frequent cooling and heating of the pump requires the installation of recovery compression/ storage system which adds to the overall fueling cost. In addition, periodic recharging of the pump is required to purge any frozen or trapped gases, which results in expensive downtime for the pumping process. Technologies that overcome these challenges are needed to ensure a reliable liquid hydrogen transport option.

D. High As-Installed Cost of Pipelines

Existing hydrogen pipelines are very limited in extent and location and are not adequate to broadly distribute hydrogen. Labor, materials, and other associated costs result in a large capital investment for new pipelines. Land acquisition or right-of-way can also be very costly. Hydrogen embrittlement of steel is not completely understood, in particular the effects on low cycle fatigue. Current joining technology for steel pipes is a major part of the labor costs and impacts the steel microstructure in a manner that can exacerbate hydrogen embrittlement issues. The use of FRP composite pipelines recently introduced for natural gas for gathering at well heads has the potential to reduce capital cost and is being investigated. However, additional effort is needed to understand the reliability, durability, and safety considerations (e.g., third-party damage) of this alternative transport option. Also needed is the development of innovative materials and technologies, such as seals, components, sensors, and safety and control systems.

E. Gaseous Hydrogen Storage and Tube Trailer Delivery Costs

Gaseous hydrogen storage at various points of use (such as production facilities, fueling stations, and terminals) and for tube trailer transport and pipeline system surge capacity adds cost to the delivery infrastructure. Understanding and optimizing for these storage needs, while adjusting for daily and seasonal hydrogen demand cycles, will be important in minimizing cost. Technologies that satisfy these storage requirements at a lower capital cost per kg of hydrogen stored will also reduce overall delivery costs. Possible approaches to technology improvement include maximizing storage pressure per unit of dollar of capital cost, utilizing cold hydrogen gas, and/or utilizing a solid carrier material in the storage vessel. Advancements of this type for transport via tube trailer will likely require additional considerations to ensure DOT approval. In addition, there are specific materials issues associated with gaseous storage. Like pipelines, steel tanks can be impacted by hydrogen embrittlement exacerbated by material fatigue due to pressure cycling, as discussed in

Barrier D. Research into new materials, coatings, and fiber or other composite structures is needed. Costs might also be reduced through the use of Design for Manufacture and Assembly (DFMA) and improved manufacturing technology for high-volume production of identical storage units.

F. Geologic Storage

The feasibility of extensive geologic hydrogen storage needs to be addressed. There are currently only a few hydrogen geologic storage sites in the world. Identification of geologic structures with particularly promising permeability characteristics may be needed. Potential hydrogen contamination and environmental impacts need to be further investigated.

G. Low-Cost, High-Capacity Solid and Liquid Hydrogen Carrier Systems

Novel solid or liquid carriers that can release hydrogen without significant processing operations are possible options for hydrogen transport or for use in stationary bulk storage. Current solid and liquid hydrogen carrier technologies have high costs, insufficient energy density, and/or poor hydrogen release and regeneration characteristics. Substantial improvements in current technologies or new technologies are needed. Materials-based storage approaches are currently the focus of significant R&D activity supported through the Hydrogen Storage sub-program; refer to the Hydrogen Storage MYRD&D section.

H. High-Cost and Low Energy Efficiency of Hydrogen Liquefaction

Cryogenic liquid hydrogen has a much higher energy density than gaseous hydrogen. As a result, in the absence of an extensive hydrogen pipeline infrastructure, transporting liquid hydrogen by cryogenic tank truck is significantly less costly than transporting compressed hydrogen by gaseous tube trailer. However, liquefaction is very energy intensive and inefficient (see Table 3.2.4, Liquid Hydrogen Delivery—Liquefaction), and the cost of this process step represents nearly half of the overall liquid hydrogen delivery cost. Improvements in liquefaction technology are needed to reduce the cost of this delivery pathway. Possibilities include increasing the scale of these operations and improving efficiencies of compressors and expanders; integrating these operations with hydrogen production, power production, or other operations that improve energy efficiency; and developing completely new liquefaction technologies such as magnetic or acoustic liquefaction or other approaches. In addition, hydrogen boil-off from cryogenic liquid storage tanks needs to be addressed and minimized for improved cost and energy efficiency.

I. Other Fueling Site/Terminal Operations

Other potential operations at refueling sites and terminals need to be low cost (capital and operating). Rugged, reliable dispensers are needed to transfer hydrogen in required form to the onboard fuel cell storage system. Hydrogen cooling may be required for cold stationary or onboard vehicle storage, for high-pressure vehicle fills (70 MPa, or 700 bar), or for thermal management during the charging of material-based onboard storage systems. Final purification may be required at refueling sites. Other systems may be needed for handling particular two-way carrier technologies being explored for onboard vehicle storage (refer to the Storage section of the MYRD&D).

J. Hydrogen Leakage and Sensors

The hydrogen molecule is light and diffuses more rapidly than other gases. This makes it more challenging to design equipment, seals, valves, and fittings to avoid hydrogen leakage. Current industrial hydrogen processes are monitored and maintained by trained, skilled operators. A delivery infrastructure designed specifically for hydrogen's use as a major energy carrier will need to rely heavily on sensors and robust designs and engineering. Low-cost hydrogen leak detector sensors are needed. Suitable odorant technology for hydrogen leak detection may also be needed for hydrogen distribution pipelines. The odorant would need to be completely miscible with hydrogen gas and be easily removed or non-damaging to onboard storage systems and fuel cells. The development and use of mechanical integrity sensors that can be built into pipelines and vessels could provide additional protection against mechanical failures that might be caused by third-party damage or other potential mechanical failures. Additionally, purity sensors will be required to verify fuel quality prior to or during dispensing for fuel cell applications.

K. Safety, Codes and Standards, Permitting

Appropriate codes and standards are needed to ensure a reliable and safe hydrogen delivery infrastructure. Some of the hydrogen delivery elements such as tube trailers and cryogenic liquid hydrogen trucks are commercially available, while others are not. Applicable codes and standards are needed for stationary storage at fueling sites and upstream in the hydrogen supply chain. Siting and permitting hurdles need to be overcome. The plan to address these issues is in the Safety, Codes and Standards section of the MYRD&D.

3.2.6 Technical Task Descriptions

The technical task descriptions are presented in Table 3.2.5. Concerns regarding safety and environmental effects will be addressed within each task in coordination with the appropriate sub-program.

Table 3.2.5 Technical Task Descriptions

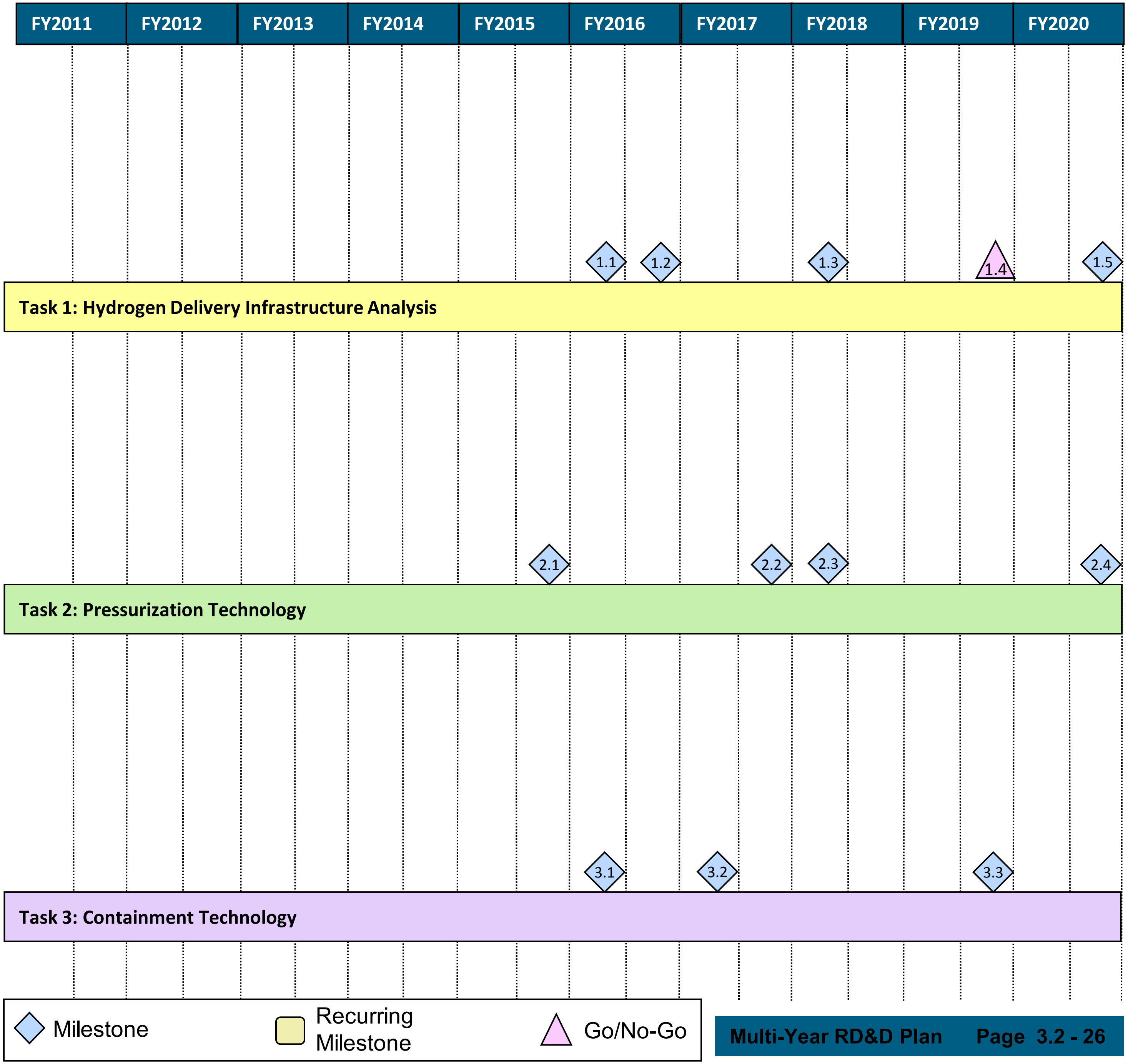
Task	Description	Barriers
1	Delivery Infrastructure Analysis • Characterize the cost and energy efficiency of current and possible future delivery components and pathways and identify the key improvements needed. • Characterize the delivery costs for candidate liquid hydrogen carriers. • Examine the effects of centralized and distributed production output conditions and onboard storage needs (for various markets) on delivery pathway options and cost. • Perform optimization analyses to evaluate the trade-offs between various process operations that can minimize overall delivery cost for near-term markets. • Perform optimization analyses to evaluate the trade-offs between various process operations that can minimize overall delivery cost for mid-and long-term markets.	A, B, C, D, E, F, G, H, I, J
2	Reliable, Energy-Efficient, and Lower Cost Pressurization Technology • Research gas compression and liquid pumping technologies that can improve reliability, eliminate contamination, and reduce cost. • Develop reliable, low-cost, energy-efficient gas compression technology for hydrogen pipeline transport service and terminal needs. • Develop reliable, low-cost, energy-efficient gas compression technology for hydrogen fueling needs. • Develop reliable, low-cost, energy-efficient cryogenic liquid pumping technology for transport and fueling needs	B, C, I, K
3	Safe, Lower Cost Containment Technologies • Research and develop technologies for steel pipeline materials that resolve potential embrittlement concerns. • Research and develop alternative materials for H_2 pipelines that could reduce installed cost while providing safe and reliable operation. • Research and develop more cost-effective gaseous H_2 bulk storage and tube trailer technology, including higher pressure and/or cryogenic vessels, novel solid carriers, vessel materials and architecture, and the use of DFMA and high-throughput production methods. • Develop improved and lower cost valves, fittings, and seals to reduce hydrogen leakage. • Develop mechanical integrity monitoring and leak detection technology. • Research the feasibility of geologic and pipeline storage as a low-cost, high-volume storage option.	D, E, F, G, I, J, K

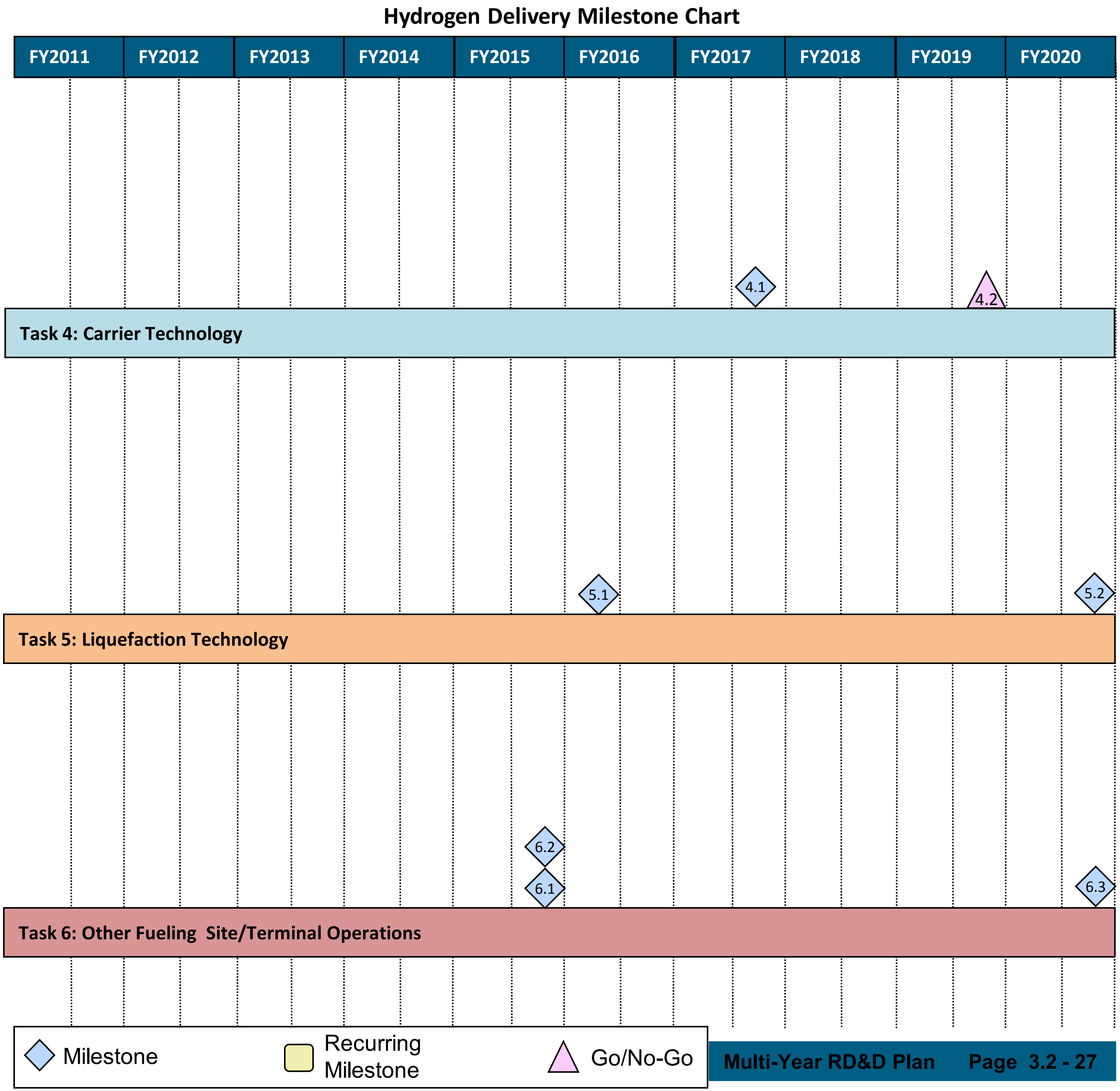
Table 3.2.5 Technical Task Descriptions		
Task	**Description**	**Barriers**
4	**Low-Cost Carrier Technologies (In collaboration with the Hydrogen Onboard Storage Sub-Program)** • Develop novel liquid hydrogen carrier technologies for high-volumetric energy density, low-cost hydrogen transport. • Develop novel solid carrier technology for hydrogen bulk stationary storage. • Develop technologies for transport/off-board regeneration of chemical hydrides.	B, C, E, G, I, J, K
5	**Lower Cost, Energy-Efficient Hydrogen Liquefaction Technology** • Investigate cost and energy efficiency gains for larger scale operations, achieving additional energy integration, and improving refrigeration schemes. • Explore new, potential breakthrough technologies, such as magneto-caloric liquefaction.	H
6	**Other Fueling Site/Terminal Operations** • Identify and define other potential operational needs for fueling sites and terminals that may include gas cooling, final purification, thermal management during vehicle refueling, robust dispensers, and systems for two-way onboard vehicle storage technologies. • Develop low-cost, energy-efficient, and safe technology as appropriate for these operations.	E, I, J, K

3.2.7 Milestones

The following chart shows the interrelationship of milestones and tasks for the Hydrogen Delivery sub-program from FY 2015 through FY 2020. The Hydrogen Delivery sub-program inputs/outputs are summarized in Appendix B.

Hydrogen Delivery Milestone Chart




Hydrogen Delivery Milestone Chart
FY2011
FY2012
FY2013
FY2014
FY2015
FY2016
FY2017
FY2018
FY2019
FY2020
4.1
4.2
Task 4: Carrier Technology
5.1
5.2
Task 5: Liquefaction Technology
6.2
6.1
6.3
Task 6: Other Fueling Site/Terminal Operations
Milestone
Recurring Milestone
Go/No-Go

Task 1: Delivery Infrastructure Analysis	
1.1	Complete deep-dive analysis of potential liquefaction technology. (2Q, 2016)
1.2	Evaluate the projected costs for the transport/off-board regeneration of chemical hydrides. (4Q, 2016)
1.3	Complete deep-dive analysis of potential hydrogen carrier technology. (2Q, 2018)
1.4	Go/No-Go on the use of liquid hydrogen carriers as an effective means of hydrogen delivery. (4Q, 2019)
1.5	Coordinating with the H_2 Production and Storage sub-programs, identify optimized delivery pathways that meet a H_2 delivery and dispensing cost of <$2/gge for use in consumer vehicles. (4Q, 2020)

Task 2: Pressurization Technology	
2.1	By 2015, reduce the cost of hydrogen delivery from the point of production to the point of use for emerging regional consumer and fleet vehicle markets to <$4/gge. (4Q, 2015)
2.2	Downselect two to three H_2 pressurization and/or containment technologies that minimize delivery pathway cost for long-term markets. (4Q, 2017)
2.3	Verify 2020 targeted cost and performance for H_2 pressurization and/or containment technologies that minimize delivery pathway cost for long-term markets. (2Q, 2018)
2.4	By 2020, reduce the cost of hydrogen delivery from the point of production to the point of use in consumer vehicles to <$2/gge. (4Q, 2020)

Task 3: Containment Technology	
3.1	Complete verification of the steel-concrete vessel technology (Q2, 2016)
3.2	Complete performance and cost evaluation of stationary wire wrapped vessel technology. (2Q, 2017)
3.3	Develop a technology for system mechanical integrity monitoring and leak detection of FRP pipeline. (4Q, 2019)

Task 4: Carrier Technology	
4.1	Initial downselect of potential liquid carrier systems for hydrogen delivery and bulk storage based on Go/No-Go decision. (3Q, 2017)
4.2	Go/No-Go on the economic viability of liquid hydrogen carriers for minimizing hydrogen delivery cost. (4Q, 2019)

Task 5: Liquefaction Technology	
5.1	Demonstrate the feasibility of magnetic liquefaction technology in the laboratory. (Q2, 2016)
5.2	Verify 2020 targeted cost and performance for hydrogen liquefaction. (4Q, 2020)

Task 6: Other Fueling Site/Terminal Operations	
6.1	Define potential RD&D activities for other long-term market fueling/terminal needs. (4Q, 2015)
6.2	By 2015, reduce the cost of hydrogen delivery from the point of production to the point of use for emerging regional consumer and fleet vehicle markets to <$4/gge. (4Q, 2015)
6.3	By 2020, reduce the cost of hydrogen delivery from the point of production to the point of use in consumer vehicles to <$2/gge of hydrogen for the gaseous delivery pathway. (4Q, 2020)