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Updated Cost, Well-to-Wheels Energy Use, and Emissions for the Current Technology Status of Ten Hydrogen Production, Delivery, and Distribution Scenarios

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Technical Report
NREL/TP-6A10-60528
March 2013

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The U.S. Driving Research and Innovation for Vehicle efficiency and Energy sustainability's (U.S. DRIVE's) Fuel Pathway Integration Technical Team identified the need to examine concurrently the cost and well-to-wheels energy use and emissions of various hydrogen production, delivery, and use pathways and to carefully document the key parameters of the analysis. They reviewed the results of the study both for content and for presentation and provided many helpful pointers. In addition, they participated in the gap analysis that identified issues reported in Section 9.0. Current and past members of the team include Matt Watkins and Eric Bunnelle (ExxonMobil Corporation); Laura Verduzco (Chevron Corporation); Garry Gunter (Phillips 66 Company); Herie Soto (Shell Oil Products US); Brian Bonner (Air Products and Chemicals, Inc.), and Fred Joseck (U.S. Department of Energy [DOE]).

Model developers assisted in the use of their models and understanding of underlying assumptions. Neil Popovich (National Renewable Energy Laboratory [NREL]) performed many delivery scenario simulations to identify and explain anomalies. Macro-System Model developers include Victor Diakov (NREL) and Tim Sa and Mike Goldsby (Sandia National Laboratories).

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List of Abbreviations and Acronyms

°C	degrees Celsius
°F	degrees Fahrenheit
atm	atmosphere
Btu	British thermal unit
CCS	carbon capture and sequestration
CO	carbon monoxide
CO_2	carbon dioxide
CO_2-eq.	carbon dioxide-equivalent
CPM	cost-per-mile
CSD	compression, storage, and dispensing
DOE	U.S. Department of Energy
FCEV	fuel cell electric vehicle
FCTO	Fuel Cell Technologies Office
gge	gallon gasoline equivalent
GHG	greenhouse gas
GREET	Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation
H2, H_2	diatomic hydrogen
H2A	Hydrogen Analysis
HDSAM	H2A Delivery Scenario Analysis Model
h	hour
ICE	internal combustion engine
kg	kilogram
kWh	kilowatt-hour
L	liter

lb	pound
LHV	lower heating value
mi	mile
mpgge	miles per gallon gasoline equivalent
MSM	Macro-System Model
MSRP	manufacturer's suggested retail price
NOx	oxides of nitrogen
NREL	National Renewable Energy Laboratory
O&M	operations and maintenance
PM	particulate matter
PSA	pressure swing adsorption
psi	pounds per square inch
psia	pounds per square inch absolute
psig	pounds per square inch gauge
RPE	retail price equivalent
SMR	steam methane reforming
TBW	tire and brake wear
U.S.	United States
VOC	volatile organic compound
WGS	water-gas shift
WTP	well-to-pump
WTW	well-to-wheels

Executive Summary

The United States (U.S.) Department of Energy's (DOE's) Hydrogen and Fuel Cells Program—which is coordinated across the Department and includes activities in the Offices of Energy Efficiency and Renewable Energy (EERE), Science, Nuclear Energy, and Fossil Energy—has identified a need to understand the cost, energy use, and emissions tradeoffs of various hydrogen production, delivery, distribution and use options under consideration for fuel cell vehicles. The Fuel Cell Technologies Office (FCTO) within EERE has been researching and developing hydrogen and fuel cell technologies because they have the potential to reduce U.S. dependence on foreign crude oil, diversify energy sources, decrease greenhouse gas (GHG) emissions, and provide domestic economic growth.

This report describes a life-cycle assessment conducted by the National Renewable Energy Laboratory (NREL) of 10 hydrogen production, delivery, dispensing, and use pathways that were evaluated for cost, energy use, and GHG emissions (see Table ES.1). This evaluation updates and expands on a previous assessment of seven pathways conducted in 2009 (Ruth, Laffen and Timbario 2009). The evaluation takes a life-cycle approach, addressing both the "well-to-wheels" (WTW) transportation fuel cycle and also the portion of the vehicle cycle that considers the manufacturing of a fuel cell electric vehicle (FCEV) and the decommissioning and disposal/recycling of the FCEV. This study summarizes key results, parameters, and sensitivities to those parameters for the 10 hydrogen pathways, reporting on the levelized cost of hydrogen in 2007 U.S. dollars as well as life-cycle energy use and GHG emissions associated with the pathways.[1] The results from this assessment aid in understanding and evaluating technology needs and progress, potential environmental impacts, and the energy-related economic benefits of various hydrogen production, delivery, and dispensing options.

Table ES.1. Ten Hydrogen Production, Delivery, and Distribution Pathways

	Feedstock	Central or Distributed Production	Carbon Capture and Sequestration	Delivery Method	Hydrogen Distribution
1	Natural Gas	Distributed	No	Not applicable	700 bar, gaseous
2[a]	Ethanol	Distributed	No	Not applicable	700 bar, gaseous
3	Grid Electricity	Distributed	No	Not applicable	700 bar, gaseous
4	Biomass	Central	No	Gaseous H_2 in pipelines	700 bar, gaseous
5[a]	Biomass	Central	No	Gaseous H_2 truck	700 bar, gaseous
6	Biomass	Central	No	Liquid H_2 truck	700 bar, gaseous
7[a]	Biomass	Central	No	Liquid H_2 truck	Cryo-compressed
8	Natural Gas	Central	No	Gaseous H_2 in pipelines	700 bar, gaseous
9	Wind Electricity	Central	No	Gaseous H_2 in pipelines	700 bar, gaseous
10	Coal	Central	Yes	Gaseous H_2 in pipelines	700 bar, gaseous

[a] Newly analyzed pathways

[1] This analysis does not attempt to evaluate the selling price of hydrogen, which will depend on market factors. Instead, results are discussed in terms of levelized cost, which is the resulting break-even cost of hydrogen calculated on a net present value basis to cover all capital, operating, and maintenance costs including a set internal rate of return on expenditures.

The pathways evaluated in this study represent currently available hydrogen production, delivery, and dispensing technologies, projected to a commercialized scale. Plausible production scenarios for mature hydrogen transportation-fuel markets combined with market penetration of hydrogen fuel cell vehicles were used in this analysis. This study does not evaluate transition scenarios where equipment may not be fully utilized. The assumptions used in the analysis reflect current technology: technology that has been developed to the bench scale (at a minimum) but has not necessarily been demonstrated at commercial scales. All the technology options have potential for research and development (R&D) improvements.

For the evaluation, FCEVs were assumed to have an on-road fuel economy of 48 miles per gallon gasoline equivalent (mpgge). The 48 mpgge assumption is consistent with NREL's analysis of on-road FCEV fuel economy data from the Hydrogen Fleet and Infrastructure Demonstration and Validation Project (Wipke et al. 2012) and also reflects modeling of FCEV fuel economy by Argonne using its Autonomie model, based on Argonne's modeling assumptions and information from original equipment manufacturers (Rousseau 2012). Because fuel economy is likely to improve with fuel cell research and development advances, a sensitivity analysis was also performed for an assumed fuel economy of 68 mpgge. This higher end fuel economy was chosen as it represents the average fuel economy of a Toyota fuel cell vehicle in on-road testing conducted in California in 2009 (Wipke, Anton and Sprik 2009).

The hydrogen Macro-System Model (MSM) was used to analyze the pathways by linking the H2A Production models, the Hydrogen Delivery Scenario Analysis Model (HDSAM), the Greenhouse Gas, Regulated Emission, and Energy for Transportation (GREET) Model, and the Cost-per-Mile (CPM) Tool.[2] The MSM links those models so they can be executed concurrently, utilizing the capabilities of each and ensuring consistency among them. Also, the MSM is available to the public and enables users to analyze pathways and complete sensitivity analyses that are not reported in this document. Consistent with the standard employed by the H2A Production model and HDSAM, costs are presented in 2007 U.S. dollars.

The analysis has been reviewed by the U.S. DRIVE Partnership's Fuel Pathway Integration Technical Team, which includes members from DOE, national laboratories, and energy companies (Phillips 66, Chevron Corporation, Shell, and ExxonMobil Corporation).

Figure ES.1 depicts the performance of the 10 hydrogen fuel pathways, comparing pathway hydrogen fuel cost on a $/mile basis to fuel-cycle WTW GHG emissions on a gram CO_2-equivalent per mile basis. As seen in the figure, the levelized cost of hydrogen on a per mile basis (assuming a 48 mpgge fuel economy) ranges from $0.10/mile for the distributed natural gas production pathway to $0.18/mile for the distributed ethanol-reforming pathway (compared to gasoline costs of about $0.13/mile for a conventional gasoline vehicle). Figure ES.2 provides more detail on the WTW greenhouse gas emissions, showing total GHG emissions on a gram CO_2-equivalent per mile basis for the 48 to 68 mpgge fuel economy range. The figure illustrates that all of the pathways except for the distributed electrolysis pathway result in GHG emissions

[2] This analysis uses a version of the MSM that incorporates H2A Version 3 (2012), HDSAM Version 2.3 (2012), GREET 1 (2011, rev. 1) and GREET 2 (version 2.7). The versions of H2A, HDSAM, and GREET used were current at the time this life-cycle evaluation began. As of the publication of this report, H2A Version 3 and HDSAM Version 2.3 are still current, but more recent updates of the GREET 1 and GREET 2 models were made available in late 2012.

lower than 400 g/mile, based on a fuel economy of 48 mpgge. When a higher fuel economy of 68 mpgge is considered, all of the pathways except distributed electrolysis result in GHG emissions lower than 250 g/mile.

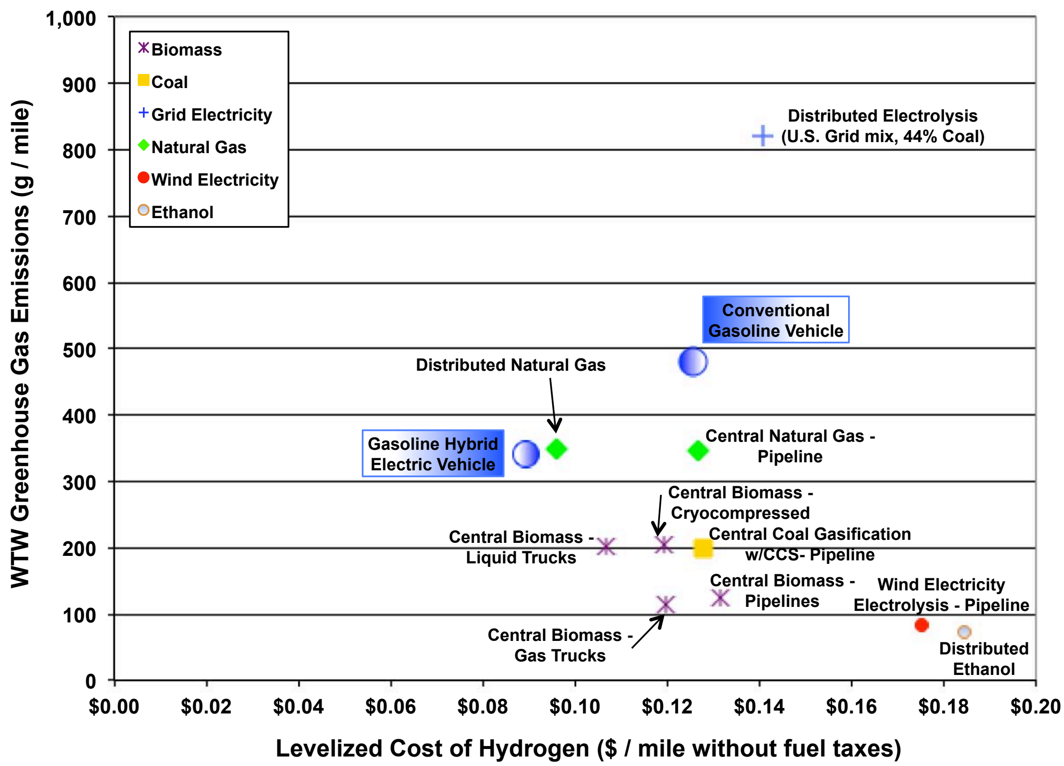

Figure ES.1. Comparison of pathways' levelized costs and GHG emissions

Distributed electrolysis has high GHG emissions when compared to the other hydrogen pathways because of the assumed electricity grid mix (the U.S. average grid mix is assumed, with coal production accounting for 44% of electricity generation). The pathways that use natural gas as a feedstock use little petroleum but have high GHG emissions compared to most of the other pathways due to the GHG emissions associated with producing hydrogen from natural gas. The coal pathway has slightly lower GHG emissions than the natural gas pathways do because of the efficient carbon-sequestration system that is assumed; no other pathways assume the use of a carbon sequestration system. The biomass and ethanol pathways have higher petroleum use than all but the distributed electrolysis pathway because the biomass and ethanol feedstocks are delivered using trucks.

Of the four options for delivering hydrogen from a centralized production plant, pipeline delivery has the lowest GHG emissions and lowest petroleum use. The two liquid truck delivery options have higher GHG emissions because of the high electricity consumption of the liquefaction process (the U.S. average grid mix is assumed). The GHG emissions for hydrogen dispensed as a cryo-compressed liquid are slightly lower than those for hydrogen dispensed as a gas because the liquid pump requires less electricity than the compressor necessary for delivering 700 bar gaseous hydrogen. Hydrogen delivered in a gas truck has low GHG emissions but a high petroleum use because each truckload only carries 520 kg of hydrogen.

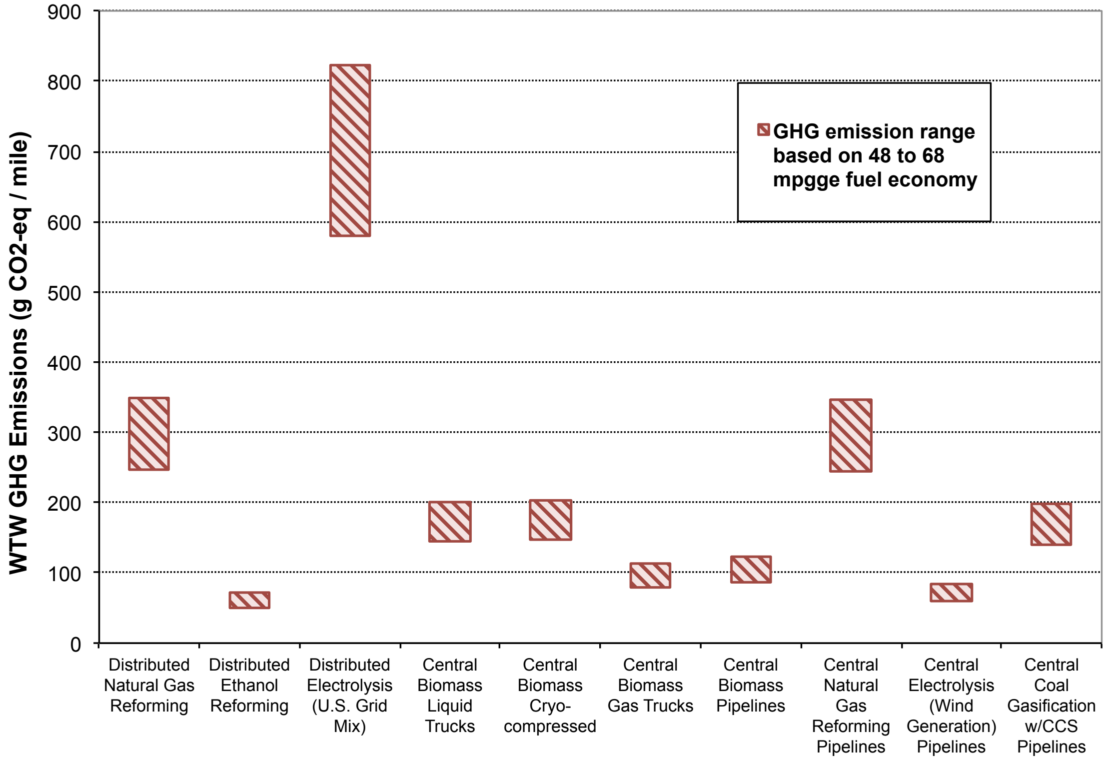

Figure ES.2. WTW GHG emissions for 10 hydrogen pathways

Figure ES.3 shows the levelized cost of hydrogen for the 10 pathways, breaking out hydrogen production costs, delivery costs, dispensing station costs (also known as CSD costs—station compression, storage, and dispensing costs), and the share of hydrogen levelized cost associated with pathway hydrogen losses. As seen in the figure, hydrogen production, delivery, and dispensing costs range from \$4.60/kg H_2 to almost \$9.00/kg H_2. Hydrogen production costs are at or near DOE's \$2.00/kg target for four of the production pathways (representing 7 of the total 10 overall pathways evaluated). Station CSD costs range from about \$1.00/kg to \$2.50/kg, showing the need for R&D advancements to lower the cost of dispensed hydrogen.

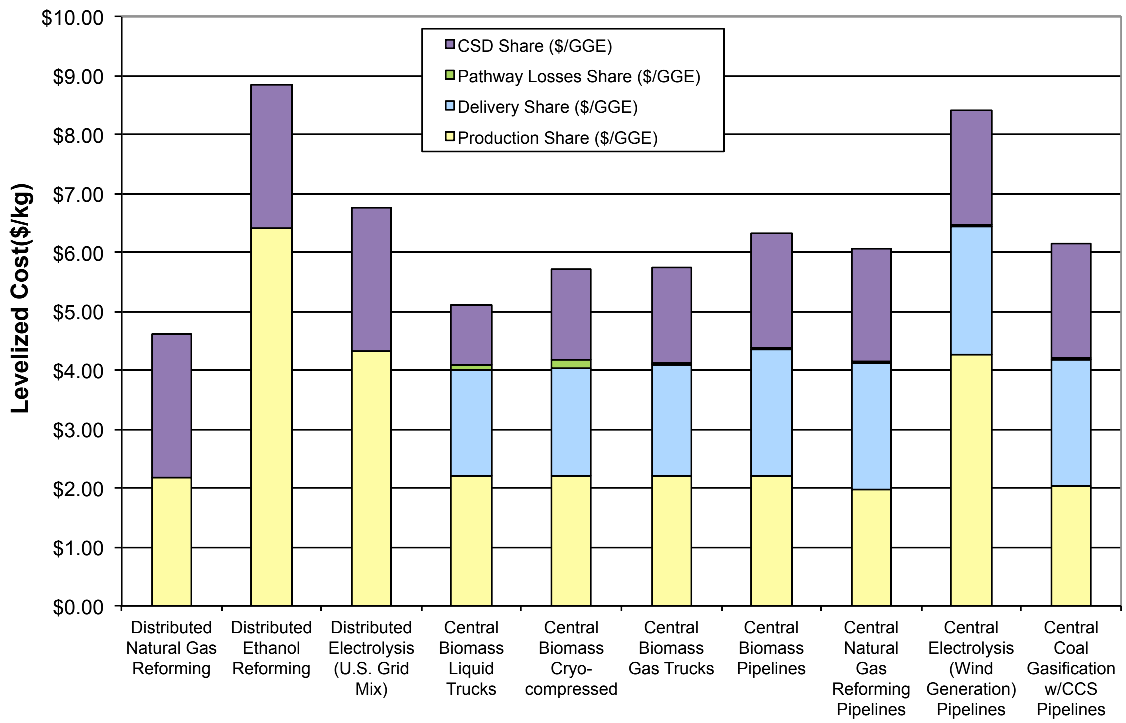

Figure ES.3. Hydrogen production levelized costs for 10 pathways

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1 Introduction

1.1 Document's Intent

The United States (U.S.) Department of Energy (DOE) has identified a need to understand the life-cycle cost, energy use, and emissions tradeoffs of various hydrogen production, delivery, and use pathways under consideration to enable a transition from a hydrocarbon-based economy to a hydrogen-and-electricity-based economy. In 2009 the National Renewable Energy Laboratory (NREL) addressed this need by analyzing and reporting on a life-cycle cost, energy use, and emissions evaluation of seven hydrogen production, delivery, and use pathways (Ruth, Laffen and Timbario 2009). The present analysis updates and expands on the 2009 evaluation, assessing life-cycle costs, energy use, and emissions of a set of hydrogen pathways using updated costs and technology assumptions. This report contains the results of the updated life-cycle evaluation, including the updated cost of delivered hydrogen for the seven hydrogen production, delivery, and use pathways previously studied using the Macro-System Model (MSM), as well as three additional potential hydrogen production, delivery, and use pathways. The report also provides the results of sensitivity evaluations of the cost of delivered hydrogen to varying assumptions regarding feedstock cost, capital cost, plant capacity, and utility cost.

This analysis will aid in understanding and assessing technology needs and progress, potential environmental impacts, and the energy-related economic benefits of various hydrogen supply and demand pathways.

The MSM was used to analyze the pathways by linking the H2A Production Model, the Hydrogen Delivery Scenario Analysis Model (HDSAM), the Greenhouse Gas, Regulated Emission, and Energy for Transportation (GREET) Model, and the Cost-per-Mile (CPM) Tool. The MSM links those models so they can be executed concurrently, utilizing the capabilities of each and ensuring consistency among them. Also, the MSM is available to the public and enables users to analyze pathways and complete sensitivity analyses that are not reported in this document. Consistent with the standard employed by the H2A Production model and HDSAM, costs are presented in 2007 U.S. dollars.

The primary differences between the 2009 report and this report are that the current study:

- Analyzed three additional pathways: distributed ethanol reforming, central biomass reforming with delivery in gaseous hydrogen trucks, and central biomass reforming with delivery in liquid hydrogen trucks with cryo-compressed dispensing.
- Added vehicle costs and vehicle-cycle energy use and emissions to calculate overall ownership costs and fuel-plus-vehicle-cycle energy use and emissions. The vehicle is assumed to be owned for 5 years and be driven 15,000 miles per year and sold in good condition at the end of that period. Energy use and emissions are averaged over a vehicle lifetime of 160,000 miles.

- Used H2A Version 3, HDSAM Version 2.3, GREET 1 2011, GREET 2.7, and the CPM Tool within the MSM.[3] (The central coal with carbon-capture and sequestration [CCS] case still uses H2A Version 2.1.1, which is the most recent H2A version of this case.)
- Updated energy prices from the Energy Information Administration's Annual Energy Outlook 2009.
- Updated cost of delivered hydrogen in 2007 dollars from 2005 dollars (except for the central coal with CCS pathway).
- Reduced vehicle penetration rate from 50% to 15%.
- Increased vehicle fuel economy from 45 to 48 miles per gallon gasoline equivalent (mpgge). Additional sensitivity analyses using 68 mpgge were also performed.
- Increased hydrogen dispensing pressure from 5,000 psi (350 bar) to 10,000 psi (700 bar).

This document reports a greater level of detail than analyses that show only the full pathway results (or maybe have a single break-point in the pathway), but it reports little information at the unit-operation level. Parameters that are expected to have major effects on the results are reported at the unit-operation level.

1.2 Hypothetical Market State and Technology Development Assumptions

The pathways analyzed are intended to be plausible production scenarios for mature technologies with full deployment of a regional hydrogen fueling network. They are not transition scenarios where equipment may not be utilized fully, nor are they technology validation activities where production, delivery, and vehicle costs are higher due to first-of-a-kind plants and low production levels of vehicles. Specifically, today's technical status is extrapolated to a scenario where 15% of the vehicles are fueled by hydrogen in a city with the area (553 mi^2) and population (1,247,364) of Indianapolis, Indiana, and all equipment is fully utilized for its lifetime. Production facilities are not scaled to meet demand; instead, necessary demand from other nearby communities is assumed available so the facilities are kept at the H2A-defined natural scale.

Costs, energy use, and emissions estimates in this study are based on current technologies, and costs are reported in 2007 U.S. dollars (except where noted). In this analysis, "current technology" refers to technology that is available currently at the bench scale—not necessarily technology that has been demonstrated at production scales. Thus, assumptions about larger-scale performance and equipment requirements and costs are necessary.

Designs and costs in this analysis do not include additional requirements of first-of-a-kind or one-of-a-kind technologies. In many cases, first-of-a-kind technologies require safety factors, instrumentation, and contingencies that are not necessary later in the development process. Those additional costs are not included in this analysis because they are difficult to account for and because they are not well understood. Instead, technology designs and costs are based on "nth

[3] The versions of H2A, HDSAM, and GREET used were current at the time this life-cycle evaluation began. As of the publication of this report, H2A Version 3 and HDSAM Version 2.3 are still current, but more recent updates of the GREET 1 and GREET 2 models were made available in late 2012.

plant" techniques (techniques that inherently assume that the technology is mature and do not include additional contingency, capital costs, and yield loss necessary for first-of-a-kind plant cost estimation).

1.3 Analysis Boundaries

The "well-to-wheels" (WTW) energy use and emissions are assessed for each pathway using the GREET 1 fuel-cycle model. Included in the assessment are feedstock recovery, transportation, and storage; fuel production, transportation, storage, and distribution; and vehicle production, maintenance, operation, and disposal. The reported energy use includes both direct and indirect use of raw materials (natural gas, coal, and petroleum). For feedstock recovery, direct use of raw materials involves those used to recover and refine the feedstock, and indirect use of raw materials involves those needed to produce electricity and materials that are used directly. In addition to WTW analyses, life-cycle energy use and emissions are assessed for each pathway by combining the fuel-cycle WTW assessment from GREET 1 with the vehicle-cycle assessment from GREET 2.

Energy used and emissions generated to produce the equipment required to recover the feedstock, produce the fuel, produce the vehicles, and so on, are not included.

1.4 Pathways

The 10 pathways included in this analysis are shown in Table 1.4.1.

Table 1.4.1. Ten Hydrogen Production, Delivery, and Distribution Pathways

	Feedstock	Central or Distributed Production	Carbon Capture and Sequestration	Delivery Method	Hydrogen Distribution
1	Natural Gas	Distributed	No	Not applicable	700 bar, gaseous
2[a]	Ethanol	Distributed	No	Not applicable	700 bar, gaseous
3	Grid Electricity	Distributed	No	Not applicable	700 bar, gaseous
4	Biomass	Central	No	Gaseous H_2 in pipelines	700 bar, gaseous
5[a]	Biomass	Central	No	Gaseous H_2 truck	700 bar, gaseous
6	Biomass	Central	No	Liquid H_2 truck	700 bar, gaseous
7[a]	Biomass	Central	No	Liquid H_2 truck	Cryo-compressed
8	Natural Gas	Central	No	Gaseous H_2 in pipelines	700 bar, gaseous
9	Wind Electricity	Central	No	Gaseous H_2 in pipelines	700 bar, gaseous
10	Coal	Central	Yes	Gaseous H_2 in pipelines	700 bar, gaseous

[a] Newly analyzed pathways

For convenience, the pathways are identified throughout this report using the feedstock and the delivery method; for example: Pathway 1 is referred to as the distributed natural gas pathway, Pathway 2 is referred to as the distributed ethanol pathway, Pathway 3 is the distributed electrolysis pathway, and Pathway 4 is the central biomass with pipeline delivery pathway.

Each pathway description below includes a flowchart showing the major subsystems of the hydrogen production and delivery pathway and the amount of energy required for each. Not included in these flowcharts are the energy requirements to supply the feedstock for hydrogen production; the energy use for feedstock production and delivery is included in the full WTW results presented in Section 6.0.

1.4.1 Pathway 1: Distributed Natural Gas

In the distributed natural gas pathway, hydrogen is produced from natural gas at the hydrogen refueling site using a 1,500 kg H_2/day steam methane reformer (SMR) with water-gas shift (WGS). Pressure swing adsorption (PSA) is used to obtain the required hydrogen purity. The hydrogen is then compressed to 12,687 psi (875 bar) and stored on-site prior to dispensing as a gaseous fuel to the 10,000 psi (700 bar) vehicle fuel tank. The flow diagram in Figure 1.4.1 shows the fuel production and delivery components of the distributed natural gas pathway and the energy balance for the major hydrogen-related subsystems, on a 1-gallon gasoline equivalent (gge) basis. The production and forecourt technologies are detailed in Ruth, Laffen and Timbario (2009).

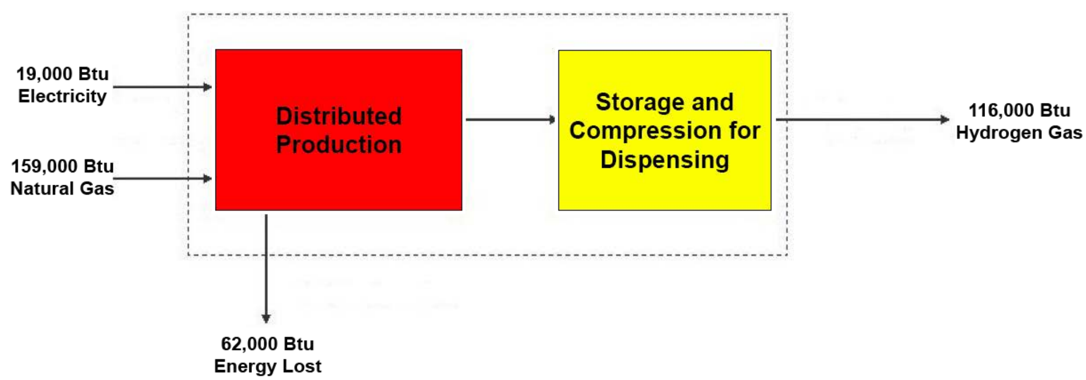


Figure 1.4.1. Flow diagram and energy balance of distributed natural gas pathway

Values may not sum to zero due to rounding.

This pathway is considered among the least costly in the near term to establish early market refueling capability (Greene et al. 2008).

1.4.2 Pathway 2: Distributed Ethanol

In the distributed ethanol pathway, hydrogen is produced from corn stover-based ethanol at the hydrogen refueling site using a 1,500 kg H_2/day steam reformer with a WGS reactor. PSA is used to obtain the required hydrogen purity. The hydrogen is then compressed to 12,687 psi (875 bar) and stored on-site prior to dispensing as a gaseous fuel to the 10,000 psi (700 bar) vehicle fuel tank. The flow diagram in Figure 1.4.2 shows the fuel production and delivery components of the distributed ethanol pathway and the energy balance for the major hydrogen-related subsystems, on a 1-gge basis. The production technologies are detailed in Section 2.2, and the delivery technologies are detailed in Ruth, Laffen and Timbario (2009).

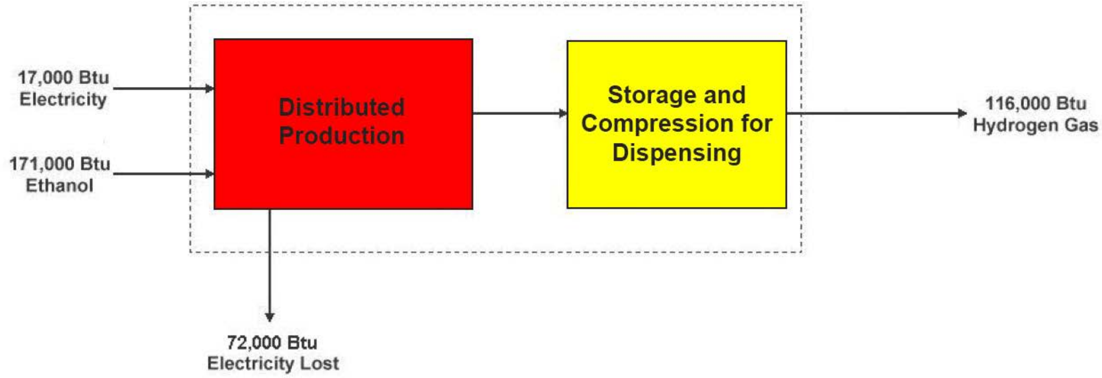


Figure 1.4.2. Flow diagram and energy balance of distributed ethanol pathway

Values may not sum to zero due to rounding.

1.4.3 Pathway 3: Distributed Electricity

In the distributed electricity pathway, hydrogen is produced from water at the hydrogen refueling site using a 1,500 kg H_2/day grid-powered electrolyzer. A scrubber is used to obtain the required hydrogen purity. The hydrogen is then compressed to 12,687 psi (875 bar) and stored on-site prior to dispensing as a gaseous fuel to the 10,000 psi (700 bar) vehicle fuel tank. The flow diagram in Figure 1.4.3 shows the fuel production and delivery components of the distributed electricity pathway and the energy balance for the major hydrogen-related subsystems, on a 1-gge basis. The production and forecourt technologies are detailed in Ruth, Laffen and Timbario (2009).

This pathway offers an alternative to distributed natural gas, particularly in areas where clean, inexpensive electricity is available.

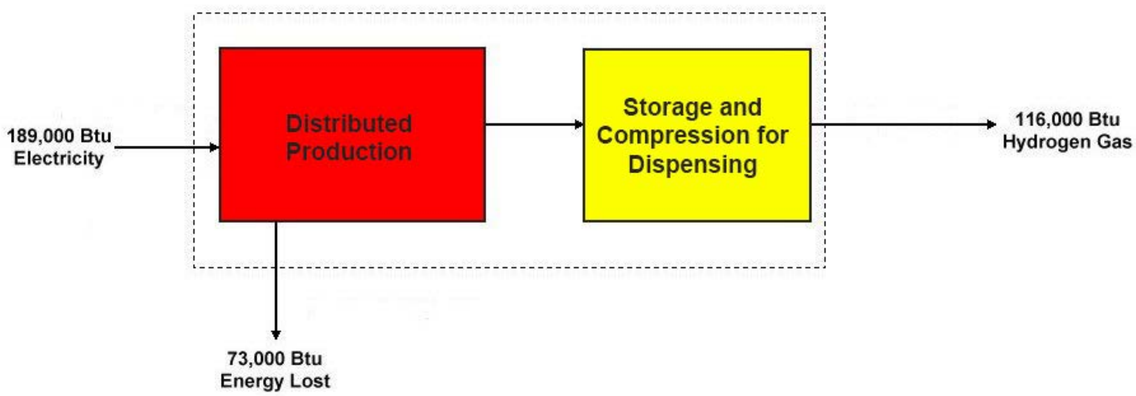


Figure 1.4.3. Flow diagram and energy balance of distributed electricity pathway

Values may not sum to zero due to rounding.

1.4.4 Pathway 4: Central Biomass—Pipeline Delivery

In the central biomass—pipeline delivery pathway, woody biomass (poplar) within a 50-mile radius is transported via truck to a central hydrogen production facility with a design capacity of

2,000 bone dry metric ton/day biomass (~155,000 kg H_2/day). An indirectly heated biomass gasifier converts the biomass to a biogas, which is then converted to hydrogen using a catalytic SMR with WGS. PSA is used to obtain the required hydrogen purity. The hydrogen is compressed to 1,000 psi (69 bar) and injected into a pipeline, through which it is transported to a 1,000 kg/day forecourt hydrogen refueling station. There the hydrogen is compressed to 12,687 psi (875 bar) and dispensed as a gaseous fuel to the 10,000 psi (700 bar) vehicle fuel tank. The flow diagram in Figure 1.4.4 shows the fuel production and delivery components of the central biomass—pipeline delivery pathway and the energy balance for the major hydrogen-related subsystems, on a 1-gge basis. The production, delivery, and forecourt technologies are detailed in Ruth, Laffen and Timbario (2009).

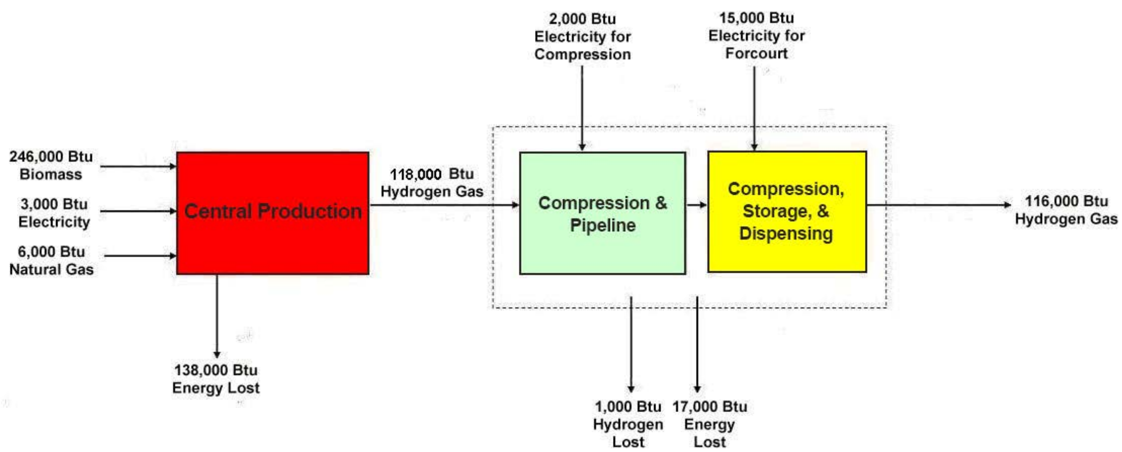


Figure 1.4.4. Flow diagram and energy balance of central biomass—pipeline delivery pathway

Values may not sum to zero due to rounding.

1.4.5 Pathway 5: Central Biomass—Gaseous H_2 Truck Delivery

In the central biomass—gaseous truck delivery pathway, woody biomass (poplar) within a 50-mile radius is transported via truck to a central hydrogen production facility with a design capacity of 2,000 bone dry metric ton/day biomass (~155,000 kg H_2/day). An indirectly heated biomass gasifier converts the biomass to a biogas, which is then converted to hydrogen using a catalytic SMR with WGS. PSA is used to obtain the required hydrogen purity. The hydrogen is then transported via pipeline to a cavern for geologic storage. The cavern is designed to satisfy a surge in demand during the summer period and to provide storage during the annual shutdown of the hydrogen production facility. The usable capacity of the geologic storage is >1.3 million kg H_2. The hydrogen is then transported from the geologic storage facility to a terminal, where it is compressed to 3,777 psi and loaded into tube trailers. The tube trailers are transported via truck to a 800 kg/day forecourt hydrogen refueling station. There the hydrogen is compressed to 12,687 psi (875 bar) and dispensed as a gaseous fuel to the 10,000 psi (700 bar) vehicle fuel tank. The flow diagram in Figure 1.4.5 shows the fuel production and delivery components of the central biomass—gaseous truck delivery pathway and the energy balance for the major hydrogen-related subsystems, on a 1-gge basis. The production and forecourt technologies are detailed in Ruth, Laffen and Timbario (2009).

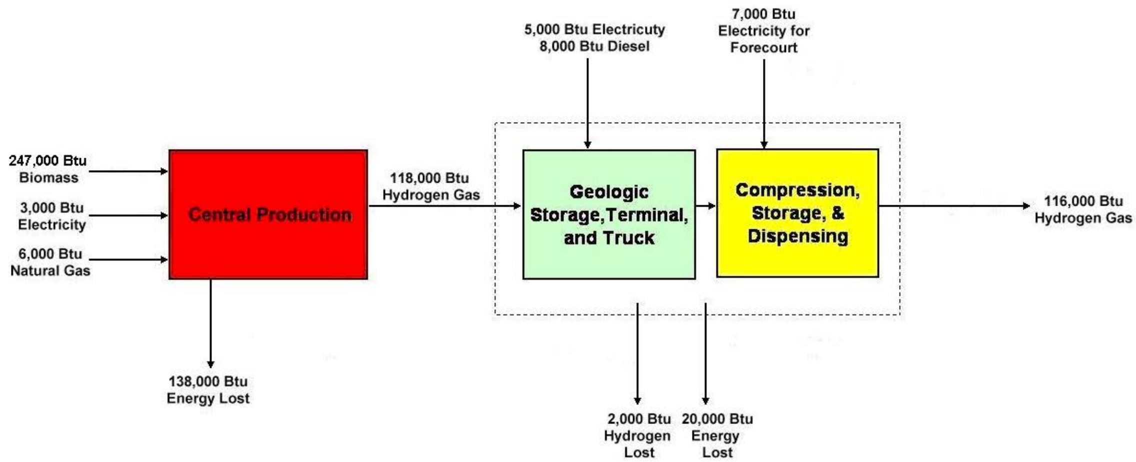


Figure 1.4.5. Flow diagram and energy balance of central biomass—gaseous truck delivery pathway

Values may not sum to zero due to rounding.

1.4.6 Pathway 6: Central Biomass—Liquid Truck Delivery and Gaseous Dispensing

In the central biomass—liquid truck delivery pathway, woody biomass (poplar) within a 50-mile radius is transported via truck to a central hydrogen production facility with a design capacity of 2,000 bone dry metric ton/day biomass (~155,000 kg H_2/day). An indirectly heated biomass gasifier converts the biomass to a biogas, which is then converted to hydrogen using a catalytic SMR with WGS. PSA is used to obtain the required hydrogen purity. The hydrogen is liquefied, stored as necessary, loaded into tube trailers, and delivered via truck to a 1,000 kg/day forecourt hydrogen refueling station, where it is vaporized, compressed to 12,687 psi (875 bar), and dispensed as a gaseous fuel to the 10,000 psi (700 bar) vehicle fuel tank. The flow diagram in Figure 1.4.6 shows the fuel production and delivery components of the central biomass—liquid truck delivery pathway and the energy balance for the major hydrogen-related subsystems, on a 1-gge basis. The production and forecourt technologies are detailed in Ruth, Laffen and Timbario (2009).

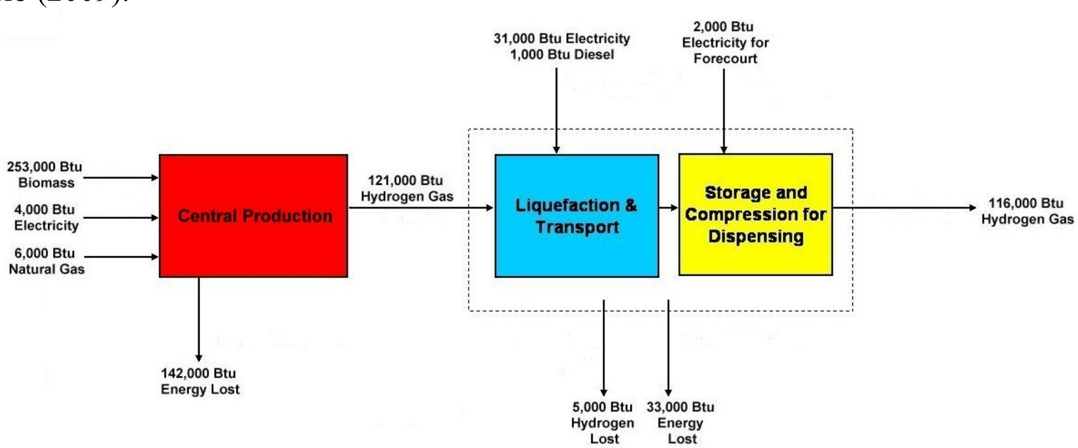


Figure 1.4.6. Flow diagram and energy balance of central biomass—liquid truck delivery pathway

Values may not sum to zero due to rounding.

1.4.7 Pathway 7: Central Biomass—Liquid Truck Delivery and Cryo-Compressed Dispensing

In the central biomass—liquid truck delivery and cryo-compressed dispensing pathway, woody biomass (poplar) within a 50-mile radius is transported via truck to a central hydrogen production facility with a design capacity of 2,000 bone dry metric ton/day biomass (~155,000 kg H_2/day). An indirectly heated biomass gasifier converts the biomass to a biogas, which is then converted to hydrogen using a catalytic SMR with WGS. PSA is used to obtain the required hydrogen purity. The hydrogen is liquefied, stored as necessary, loaded into tube trailers, and delivered via truck to a 1,000 kg/day forecourt hydrogen refueling station, where it is dispensed via a cryogenic pump as a gaseous fuel to the 10,000 psi (700 bar) vehicle fuel tank. The flow diagram in Figure 1.4.7 shows the fuel production and delivery components of the central biomass—liquid truck delivery and cryo-compressed dispensing pathway and the energy balance for the major hydrogen-related subsystems, on a 1-gge basis. The production and delivery technologies are detailed in Ruth, Laffen and Timbario (2009).

The biomass pathways were selected for this study because of their potential to provide hydrogen with low or zero net carbon dioxide (CO_2) emissions and because there are feedstock availability, delivery, and handling issues that are unique to biomass. These pathways are also more dependent on regional resource availability and costs than other pathways are; while sensitivity studies to regionality are outside the scope of this study, they may be conducted as more data become available.

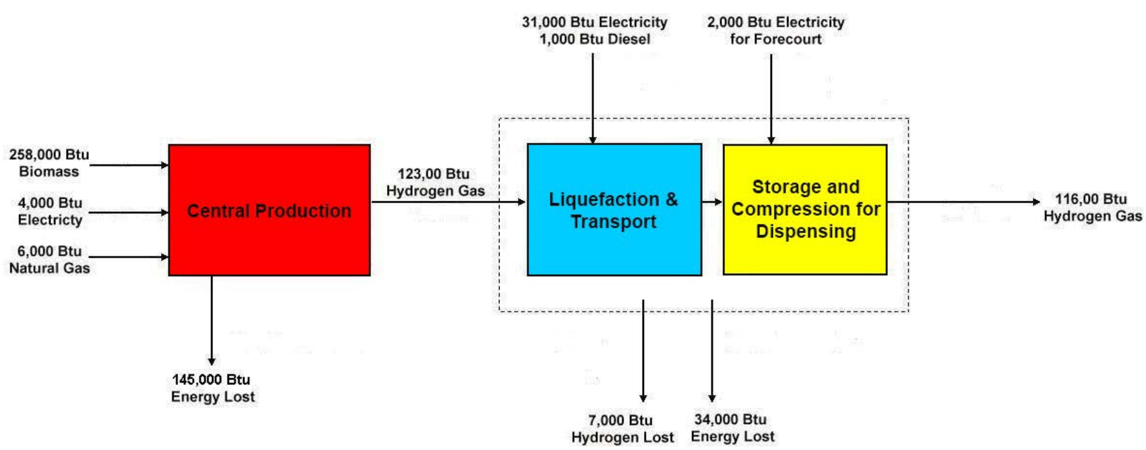


Figure 1.4.7. Flow diagram and energy balance of central biomass—liquid truck delivery and cryo-compressed dispensing pathway

Values may not sum to zero due to rounding.

These are the only pathways studied that utilize liquid hydrogen delivery. Comparison of the liquid hydrogen delivery pathways with the central biomass—pipeline delivery pathway offers insights to the advantages, disadvantages, and issues associated with liquid hydrogen delivery. It also offers the opportunity to examine the sensitivity of delivery options (gaseous or liquid truck and gaseous pipeline) to parameters such as delivery distance and degree of hydrogen penetration in the vehicular fuel market.

1.4.8 Pathway 8: Central Natural Gas—Pipeline Delivery

In the central natural gas—pipeline delivery pathway, natural gas is carried via pipeline to a central hydrogen production facility with a design capacity of ~379,000 kg H_2/day, where an SMR with WGS is used to reform the natural gas to hydrogen. PSA is used to obtain the required hydrogen purity. The hydrogen is compressed to 1,000 psi (69 bar) and injected into a pipeline, through which it is transported to a 1,000 kg/day forecourt hydrogen refueling station. There the hydrogen is compressed to 12,687 psi (875 bar) and dispensed as a gaseous fuel to the 10,000 psi (700 bar) vehicle fuel tank. The flow diagram in Figure 1.4.8 shows the fuel production and delivery components of the central natural gas—pipeline delivery pathway and the energy balance for the major hydrogen-related subsystems, on a 1-gge basis. The production, delivery, and forecourt technologies are detailed in Ruth, Laffen and Timbario (2009).

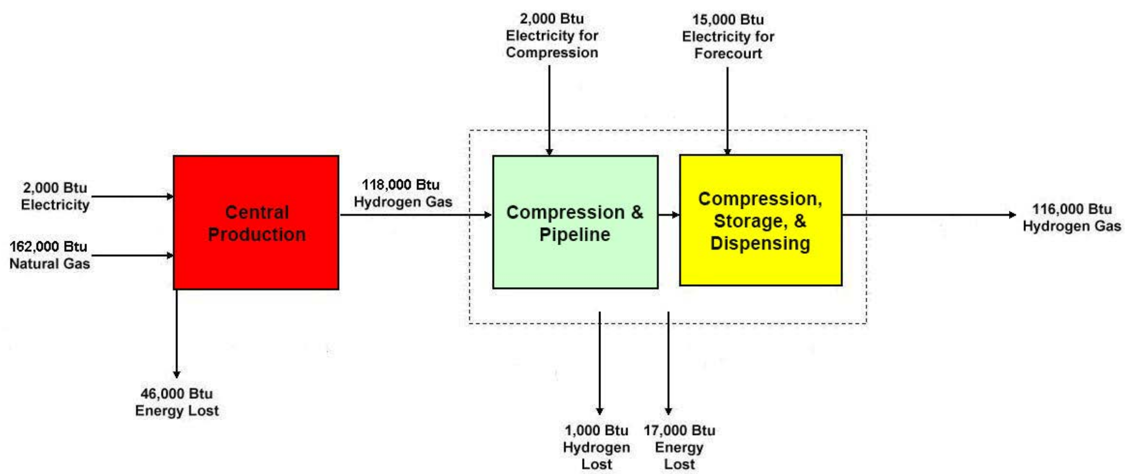


Figure 1.4.8. Flow diagram and energy balance of central natural gas—pipeline delivery pathway

Values may not sum to zero due to rounding.

The central natural gas—pipeline delivery pathway was selected as a benchmark case for this study. Large-scale natural gas reforming is a mature process being used to produce hydrogen for industrial applications such as merchant hydrogen sales, chemical production, and oil refining. It is expected to result in the lowest cost of hydrogen when pipeline delivery is employed.

1.4.9 Pathway 9: Central Wind Electricity—Pipeline Delivery

In the central wind electricity—pipeline delivery pathway, hydrogen is produced from water at a central production facility using a grid-powered electrolyzer with a design capacity of ~52,300 kg H_2/day. It is assumed that the facility buys wind-power credits for all of the electricity purchased. (From an emission perspective, solar photovoltaic or other forms of zero-emission electricity could be assumed, though the costs presented assume the purchase of wind power.) A scrubber is used to obtain the required hydrogen purity. The hydrogen is compressed to 1,000 psi (69 bar) and injected into a pipeline, through which it is transported to a 1,000 kg/day forecourt hydrogen refueling station. There the hydrogen is compressed to 12,687 psi (875 bar) and dispensed as a gaseous fuel to the 10,000 psi (700 bar) vehicle fuel tank. The flow diagram in Figure 1.4.9 shows the fuel production and delivery components of the central wind electricity—pipeline delivery pathway and the energy balance for the major hydrogen-related subsystems, on a 1-gge basis. The production and forecourt technologies are detailed in Ruth, Laffen and Timbario (2009).

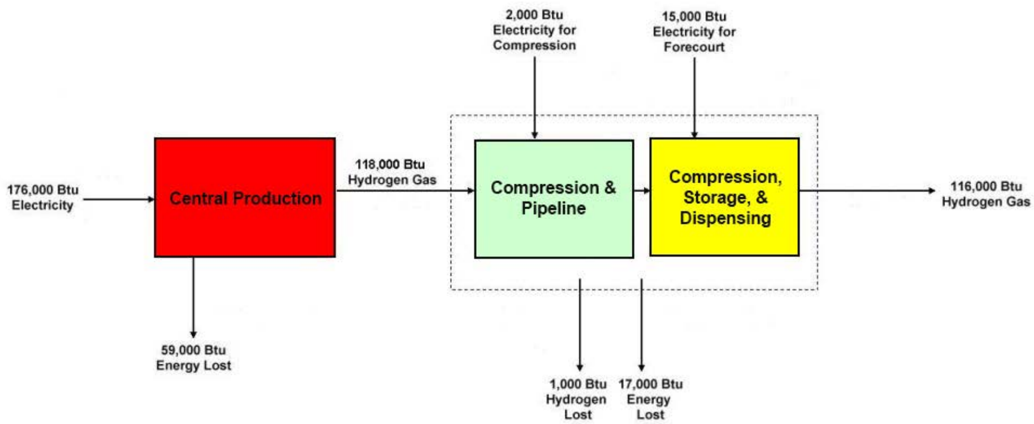


Figure 1.4.9. Flow diagram and energy balance of central wind electricity—pipeline delivery pathway

Values may not sum to zero due to rounding.

The central wind electricity—pipeline delivery pathway represents a low-carbon, renewable energy-based option for providing hydrogen as a transportation fuel. Unlike the biomass pathways, which have potential geographic limitations, the wind electricity pathway can be implemented anywhere that wind-power credits are available for purchase.

1.4.10 Pathway 10: Central Coal with Carbon Capture and Sequestration—Pipeline Delivery

In the central coal with carbon capture and sequestration (CCS)—pipeline delivery pathway, coal is delivered via rail to a central hydrogen production facility with a design capacity of ~308,000 kg H_2/day, where it is gasified. A shift converter is used to convert the syngas to a hydrogen-rich gas, which undergoes acid gas cleanup and removes hydrogen sulfide prior to entering a PSA unit to obtain the required hydrogen purity. Carbon dioxide is captured using a Selexol process and is compressed to 2,200 psi (152 bar) for injection to a pipeline. It is transported via pipeline to a sequestration site. The hydrogen is compressed to 1,000 psi (69 bar) and injected into a pipeline, through which it is transported to a 1,000 kg/day forecourt hydrogen refueling station. There the hydrogen is compressed to 12,687 psi (875 bar) and dispensed as a gaseous fuel to the 10,000 psi (700 bar) vehicle fuel tank. The flow diagram in Figure 1.4.10 shows the fuel production and delivery components of the central coal with CCS—pipeline delivery pathway and the energy balance for the major hydrogen-related subsystems, on a 1-gge basis. The production and forecourt technologies are detailed in Ruth, Laffen and Timbario (2009).

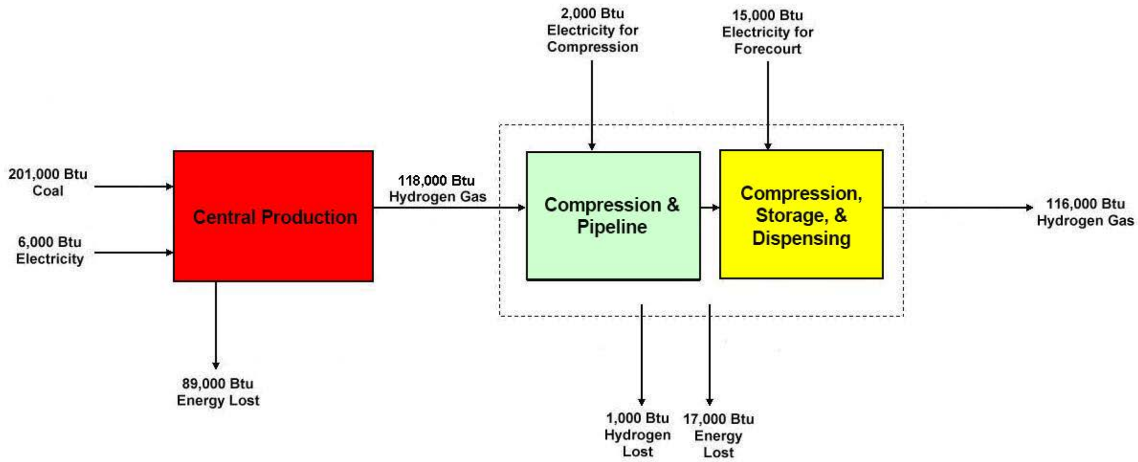


Figure 1.4.10. Flow diagram and energy balance of central coal with CCS—pipeline delivery pathway

Values may not sum to zero due to rounding.

Coal is an abundant fossil fuel in the United States, typically available at a relatively low cost. The central coal with CCS—pipeline delivery pathway was selected for this study to enable comparisons between coal and other fossil and renewable options for providing hydrogen transportation fuel. It is the only pathway studied that includes carbon capture and sequestration, thus offering opportunities for better understanding the effects of CCS on hydrogen costs, energy use, and emissions.

1.5 Models Used in the Pathway Analyses

The H2A Production Model Version 3.0 (Steward, Ramsden and Zuboy 2012) applies a standard discounted cash flow rate of return methodology to determine the minimum hydrogen selling price for central and forecourt hydrogen production technologies, including a specified after-tax internal rate of return. The H2A Production Model performs carbon sequestration calculations for centralized hydrogen production pathways and refueling station compression, storage, and dispensing calculations for distributed hydrogen production pathways.

HDSAM Version 2.3 (Mintz, Elgowainy and Gillette 2010) calculates the cost of hydrogen delivery using an engineering economics approach via a single or mixed mode for transmission and distribution (cryogenic tank truck, compressed gas truck, or pipeline) for a scenario defined by type and size of market, penetration rate, and refueling station capacity. Delivery in Version 2.3 includes all transport, storage, and conditioning activities from the outlets of a centralized hydrogen production facility to and including a fuel station that stores, in some cases further conditions, and dispenses the hydrogen to vehicles; this version does not model distributed production scenarios. Discounted cash flow is used to calculate the cost contribution of each component in the delivery chain.

The GREET models (Argonne National Laboratory, 2012) calculate the full fuel-cycle (GREET 1) and vehicle-cycle (GREET 2) emissions and energy use associated with various transportation fuels for light-duty vehicles. Emissions included are the five criteria pollutants (volatile organic compounds, carbon monoxide, oxides of nitrogen, oxides of sulfur, and particulate matter) and three greenhouse gases (carbon dioxide, methane, and nitrous oxide). Additionally, total fuel-cycle and vehicle-cycle energy consumption, fossil fuel consumption, and petroleum consumption are calculated. More than 100 fuel production pathways and more than 70 vehicle/fuel systems are available in the current version of GREET. For this hydrogen pathways report, the GREET 1 2011 and GREET 2.7 versions were utilized for GREET 1 and GREET 2, respectively.

The CPM Tool (Timbario et al. 2011) calculates the cost of vehicle ownership by estimating acquisition and operating costs for consumers and fleets. Operating costs include fuel, maintenance, tires, and repairs; ownership costs include insurance, registration, taxes and fees, depreciation, financing, and tax credits. The CPM Tool was developed to allow simultaneous comparisons of conventional light-duty internal combustion engine (ICE) vehicles, mild and full hybrid electric vehicles, and fuel cell electric vehicles (FCEVs). The tool assumes that the vehicle is kept for five years and is driven 15,000 miles per year. At the end of the ownership period, the vehicle is assumed to be sold in a clean, reconditioned state. All operating and ownership costs in 2007 dollars for the 5-year period are summed and divided by the annual vehicle miles traveled to obtain the annual cost per mile.

The MSM (Ruth et al. 2011) links the H2A Production Model, HDSAM, GREET, and the CPM Tool to perform WTW analysis of the energy use, emissions, and economics of hydrogen production and delivery pathways from feedstock extraction through end use of hydrogen in vehicles. The primary inputs to the MSM are technology year, city size and hydrogen fuel penetration, production and delivery technology, and vehicle fuel economy. H2A and HDSAM results are used for many of GREET's input parameters in each MSM run. Primary energy source requirements and emissions are analyzed. Outputs of the model include the amount and type of feedstock used to produce hydrogen, efficiency values of different technologies, energy use and emissions of various pathways, hydrogen production capacity to meet demand, and levelized cost of hydrogen at the pump achievable under different scenarios.

The MSM provides a Web-based interface that allows users to perform hydrogen pathway analyses following their own interests. It also allows for extensive single-parameter and multi-parameter sensitivity studies. The MSM will be updated with future versions of the H2A Production Model, HDSAM, GREET, and the CPM Tool as they are made public.[4]

[4] For access to the MSM, please contact Victor Diakov at victor.diakov@nrel.gov.

2 Production Technology Descriptions and Assumptions

The hydrogen production technologies used in each of the 10 pathways examined in this study are summarized below. Full details for each production technology except ethanol reforming can be found in Ruth, Laffen and Timbario (2009). Note that this study assumes that energy used in the production facility for lighting, control systems, and other ancillary systems is small relative to the energy used directly in the production process; these items are therefore not included in the cost, energy use, and emissions calculations.

2.1 Distributed Natural Gas Reforming

The H2A distributed natural gas model (James 2012) determines a baseline delivered cost of hydrogen for the forecourt production of hydrogen from natural gas steam reforming. The natural gas reforming process is based on an ASPEN simulation of a 20-atm conventional SMR process, with an accompanying hydro-desulfurization pretreatment and PSA gas cleanup. The PSA is based on a four-bed Batta cycle achieving 75% hydrogen recovery (single pass). Multiple passes are used to increase recovery. The unit is assumed to be factory built (as opposed to on-site construction) and skid-mounted for easy and rapid installation.

A single 1,500 kg/day unit is assumed. The system is assumed to be air-cooled (and thus requires no cooling water flow). The product hydrogen exits the PSA at 300 psi and is compressed for storage in metal cylinder storage tanks (2,500 psi max pressures). The hydrogen is next compressed to 12,700 psi (maximum) for transfer into a four-bed, high-pressure cascade system to allow rapid filling of 10,000-psi onboard hydrogen vehicular tanks. A process flow diagram is shown in Ruth, Laffen and Timbario (2009).

2.2 Distributed Ethanol Reforming

The H2A distributed ethanol model (James 2012) determines a baseline delivered cost of hydrogen for the forecourt production of hydrogen from ethanol reforming. The ethanol reforming process is based on an ASPEN simulation of a 20-atm conventional tube-in-shell steam reactor with PSA gas cleanup. Precious metal catalyst is assumed. The catalyzed conversion of ethanol to methane occurs rapidly to near-full ethanol conversion in a compact adiabatic pre-reformer. Because methane is the primary component of the pre-reformer effluent, the remainder of the system is nearly identical to that of a natural gas reformer system. Ethanol is the sole feedstock and is also used as a supplemental fuel to the burner. An adiabatic flame temperature of 950°C is assumed for the burner, and the reformer temperature is assumed to be 850°C. Flue gas is exhausted at 110°C. The PSA is based on a four-bed Batta cycle achieving 75% hydrogen recovery. The unit is assumed to be factory built (as opposed to on-site construction) and is skid-mounted for easy and rapid installation.

A single 1,500 kg/day unit is assumed. The system is assumed to be air-cooled (and thus requires no cooling water flow). The product hydrogen exits the PSA at 300 psi and is compressed for storage in metal cylinder storage tanks (2,500 psi max pressures). The hydrogen is next compressed to 12,700 psi (maximum) for transfer into a four-bed high-pressure cascade system to allow rapid filling of 10,000-psi onboard hydrogen vehicular tanks. A process flow diagram is shown in Ruth, Laffen and Timbario (2009).

2.3 Distributed Electrolysis

The system modeled in the H2A distributed electrolysis model (Ruth and Ramsden 2012) is a standalone, grid-powered electrolyzer system with a total hydrogen production capacity of 1,500 kg/day. The system is based on the NEL Hydrogen (formerly Norsk Hydro) bi-polar alkaline electrolyzer system (Atmospheric Type No. 5040–5150 amp direct current). The electrolyzer system modeled is a skid-mounted unit, including the electrolyzer system and necessary auxiliary subsystems. The electrolyzer units use process water for electrolysis and cooling water. Potassium hydroxide is the electrolyte in the system. The system includes the following equipment: transformer, thyristor, electrolyzer unit, lye tank, feed water demineralizer, hydrogen scrubber, gas holder, two compressor units to 30 bar (435 psig), deoxidizer, and twin tower dryer.

As with the distributed natural gas and ethanol reforming pathways, the produced hydrogen is compressed to 12,700 psi to allow rapid filling of 10,000-psi onboard hydrogen vehicular tanks. A process flow chart and a mass balance diagram are shown in Ruth, Laffen and Timbario (2009).

2.4 Central Biomass Gasification

The systems examined in the H2A central biomass gasification model (Mann and Steward 2012) are based on the Battelle/FERCO indirectly heated biomass gasifier, conventional catalytic steam reforming, WGS, and PSA purification. The indirectly heated biomass gasifier uses hot sand circulating between the char combustor and the gasifier to provide the heat necessary for gasification. Steam is used as the fluidizing gas; no oxygen (as pure oxygen or air) is fed to the gasifier. The biomass feedstock is assumed to be a woody biomass, represented as hybrid poplar. A process flow chart is shown in Ruth, Laffen and Timbario (2009).

2.5 Central Natural Gas Reforming

Steam reforming of natural gas continues to be the most efficient, economical, and widely used process for production of hydrogen. The H2A central natural gas reforming model (Rutkowski 2012) assesses the economics of production of hydrogen by steam reforming of natural gas.

A process flow diagram and stream summaries for the central natural gas reforming process are shown in Ruth, Laffen and Timbario (2009). Natural gas is fed to the plant from a pipeline at a pressure of 450 psia. The gas is generally sulfur-free, but mercaptans (odorizers) must be cleaned from the gas to prevent contamination of the reformer catalyst. The desulfurized natural gas feedstock is mixed with process steam to be reacted over a nickel-based catalyst contained inside a system of high alloy steel tubes. The reforming reaction, which converts the methane to a mixture of carbon monoxide (CO) and H_2, is strongly endothermic, and the metallurgy of the tubes usually limits the reaction temperature to 760°–930°C.

The flue gas path of the fired reformer is integrated with additional boiler tubes to produce about 700,000 lb/h steam. Of this, about 450,000 lb/h is superheated to 450 psia and 750°F to be added to the incoming natural gas. Excess steam from the boiler is sent off-site; however, revenue from the steam is not factored into the economic assessment. After the reformer, the process gas mixture of CO and H_2 passes through a heat recovery step and is fed into a WGS reactor to produce additional H_2.

2.6 Central Electrolysis with Renewable Power

The system modeled in the H2A central electrolysis model (Ramsden and Ruth 2011) is a standalone grid-powered electrolyzer system with a total hydrogen production capacity of 52,300 kg/day. The technology is identical to that used for distributed electrolysis even though it is 35 times larger, which provides economies of scale for the auxiliary components. Thus, the process description for distributed electrolysis in Section 2.3 applies to this production process as well.

The H2A central electrolysis model is not based on wind power, so this analysis assumes that a single facility is buying electricity from the grid and wind-power credits for all of the electricity purchased. Because the facility is using grid power, the operating capacity factor is 97%. If the facility were co-located with the wind turbines, it would likely have a lower operating capacity because the turbines would not be generating electricity all of the time. The optimal location and the capacity factor are not studied in this analysis.

2.7 Central Coal with Carbon Capture and Sequestration

The H2A central coal with carbon capture and sequestration model (Rutkowski 2008) uses capital and operating cost data to determine a plant-gate cost for hydrogen produced from coal gasification. The plant design for hydrogen production is based on commercially available process technologies with modifications to meet current permitting regulations for environmental compliance. The coal gasification production plant is designed to capture and sequester CO_2 emissions resulting from the shift conversion process.

The plant utilizes a Wabash River-scale ConocoPhillips (EGas) gasifier, conventional gas cooling, commercial shift conversion and acid gas cleanup, commercial sulfuric acid technology, and commercial PSA. A steam turbine supplies the electricity needed for the process except that required to compress the CO_2. A two-stage Selexol process is used to remove CO_2. Carbon dioxide is compressed to 2,200 psi for sequestration using electricity purchased from the grid (U.S. grid mix). The EGas gasifier is the gasifier of choice for this study because it has been operated on both bituminous and subbituminous coals. H2A simulations of hydrogen from coal in central plants are based on the use of Pittsburgh No. 8 bituminous coal, while GREET simulations are based on generic coal. The properties of Pittsburgh No. 8 coal used in the H2A analysis, a process flow chart, and the energy efficiencies are shown in Ruth, Laffen and Timbario (2009).

3 Delivery and Dispensing Technology Descriptions and Assumptions

The hydrogen delivery and distribution technologies used in each of the 10 pathways examined in this study are summarized below. Full details for each delivery and distribution technology used in the previous study can be found in Ruth, Laffen and Timbario (2009). Note that this study assumes that energy used in the hydrogen refueling station for items such as lighting, cryogenic pumping, and security cameras is small relative to the total delivery and distribution energy use; these items are therefore not included in the cost, energy use, and emissions calculations.

3.1 Gaseous Hydrogen via Pipeline

The pathways with delivery of gaseous hydrogen via pipeline include the following components: central production → compressor → geologic storage for plant outages → transmission and distribution pipeline → and gaseous hydrogen fuel station.

The largest diameter pipe of those in each scenario is the transmission pipeline. It extends from the production facility to the city gate. The diameter of the transmission pipeline is a function of its length, peak hydrogen demand, and the pressure differential between the pipeline inlet at the production end and the pipeline outlet at the city gate. An intermediate diameter pipe (trunk line) creates one or more rings within an area and is used to carry hydrogen from the transmission line to the individual service pipelines that connect to each individual hydrogen fuel station. HDSAM finds the least-cost combination of trunk and service lines and in doing so determines the number of trunk lines and their location, lengths, and diameters. The pipeline system requires a compressor to increase hydrogen pressure from its production level to the pressure at the terminus of the transmission line.

3.1.1 Pipeline

Pipeline diameter is calculated using the Panhandle B pipeline equation (see Ruth, Laffen and Timbario 2009) and is used to simulate compressible flow. HDSAM uses a cost curve to estimate the capital cost of a hydrogen pipeline system. Data from the curve are broken down into four parts: pipeline material cost, labor cost, miscellaneous cost, and right-of-way cost. It is assumed that the cost of a hydrogen pipeline will be 10% higher than that of a natural gas pipeline given that materials and weld-types may be different.

3.1.2 Compressor

Storage for production plant outages and demand surges is provided in geologic formations, which are assumed to be immediately adjacent to the production facility. A compressor is required to charge the hydrogen produced at a central facility into the geologic storage cavern. The same compressor is used to extract hydrogen from the cavern and push it into the pipeline at the operating pressure of the pipeline. HDSAM is designed to calculate the cost of a centralized compressor that can raise the pressure of a defined flow rate from one pressure to another. Spare compressor units are included in the model to ensure a high level of operational availability. It is assumed that there are no pressure drops in the after-cooler or interstage coolers. An electric-powered compressor is assumed.

A cost curve has been developed to estimate the uninstalled capital cost of transmission and terminal compressors. Figure 3.1.1 shows the cost of a compressor (2- and 3-stage) versus motor rating.

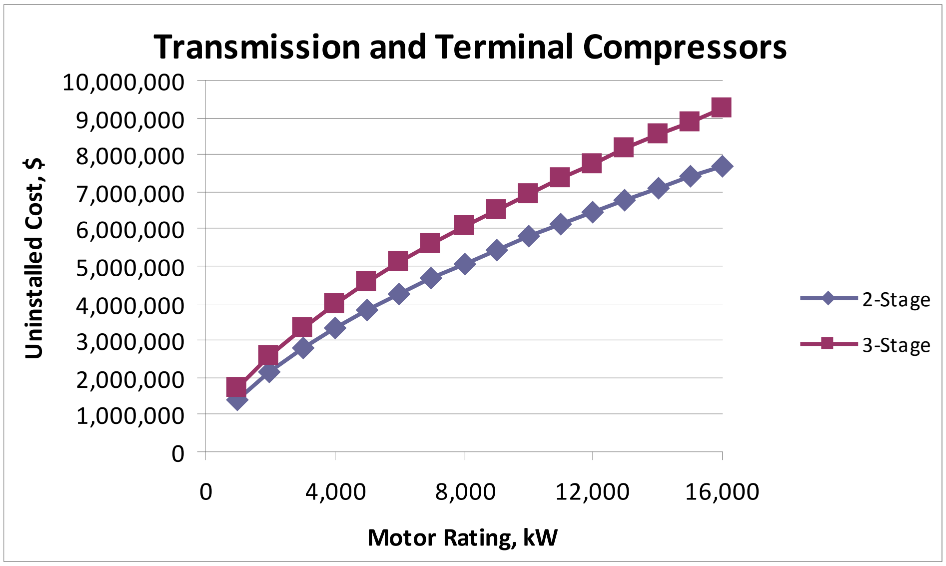


Figure 3.1.1. Compressor cost as a function of motor rating

Source: Elgowainy, Mintz and Gillette 2010 (costs are in 2007$)

The capital cost of the compressor needs to be based on a unit that is capable of processing the peak hydrogen flow rate. During a typical operating year, however, the feed flow rate will fluctuate. Therefore, an average hydrogen flow rate is used as a basis to calculate the annual energy requirement and follows the compressor power equation in Ruth, Laffen and Timbario (2009).

3.2 Gaseous Hydrogen via Trucks

The pathways with delivery of gaseous hydrogen via trucks include the following components: central production → compressor → geologic storage for plant outages → gaseous hydrogen terminal → gaseous hydrogen truck transmission and distribution → and gaseous hydrogen fuel station.

As described above for pathways with gaseous hydrogen delivery via pipeline, storage for production plant outages and demand surges is provided in geologic formations, which are assumed to be immediately adjacent to the production facility. From the geologic storage facility, the hydrogen is transported to a terminal or depot, where it is stored, compressed, and loaded onto trailers for delivery to stations. The terminal's storage requirement is determined by the following factors: peak daily demand, days of summer peak demand, and expected days per year that the production plant is off-line. The amount of required storage determines the number of truck-filling bays required at the terminal, the capacities of storage tanks, and the resulting capital and operating costs associated with the terminal.

For gaseous hydrogen truck transmission and distribution, tube trailers provide the primary on-site storage at the gaseous hydrogen fuel station. Because the compressor and cascade charging system operate at a constant rate, on-site storage is used to accommodate peak demand. Peak demand occurs on Fridays between 4:00 p.m. and 6:00 p.m. (Nexant 2008). Figure 3.2.1 shows the hourly Friday demand profile at a refueling station over 24 hours. The area under the curve above the daily average hourly demand represents the minimum storage requirement to satisfy the station demand during peak hours (approximately 30% of daily demand).

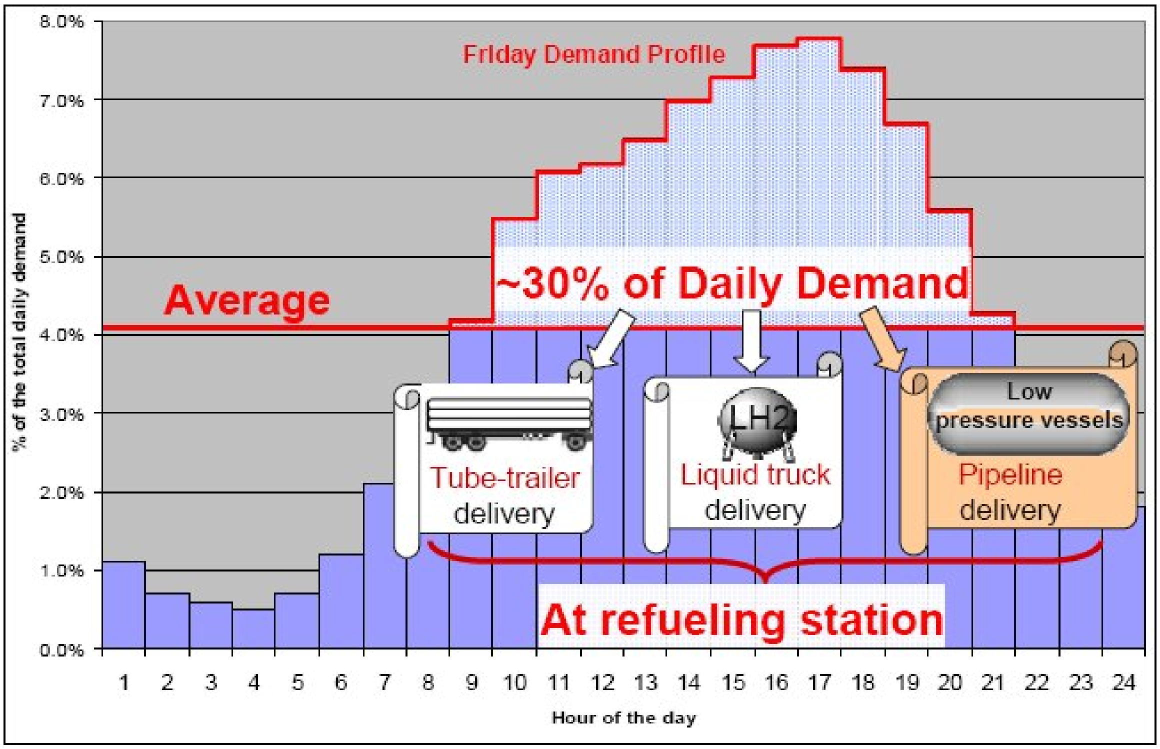


Figure 3.2.1. Hydrogen daily average demand for a peak dispensing day

Source: Nexant 2008

Capital and operating costs for dispensers, ancillary equipment, storage/cascade charging system, and forecourt compressors are calculated in HDSAM. The number of trucks and trailers and the distance traveled are used to calculate the capital and operating costs of delivery trucks as well as the amount of diesel fuel required.

3.2.1 Gaseous Hydrogen Truck

To maximize the usage of each truck, HDSAM assumes that a single tractor can serve multiple forecourt stations. The number of trailers (therefore the number of stations served) is optimized to maximize the use of the tractor. Because a trailer is assumed to be left at the fuel station and used as on-site storage, a single truck can move several trailers to any of the stations that it serves. HDSAM assumes that each trailer is refilled at the same terminal facility. The number of trailers for each tractor is calculated by considering the time required to empty the trailer at the forecourt station and the time required to deliver a full trailer and to return an empty one. The number of trailers required for each truck is typically more than the number of stations served by that truck because there needs to be a full trailer ready to be delivered when the truck returns with an empty trailer.

The capital, labor, fuel, and other operating and maintenance costs for the truck and trailers are calculated and added together.

3.3 Compression, Storage, and Dispensing of Gaseous Hydrogen

Hydrogen distribution requires compression, storage, and dispensing at the fueling station to transfer hydrogen at 12,700 psi to vehicles in the required fill-up time.

Much like gasoline stations, hydrogen stations will experience seasonal demand (see Ruth, Laffen and Timbario 2009). In addition to seasonal demand, demand variation occurs daily during the week as well as hourly during the day as shown in Figure 3.2.1.

Daily and hourly fluctuations in demand are further described in Ruth, Laffen and Timbario (2009).

Refueling stations include a cascade charging system with at least one bank of three pressure vessels operating under different pressures (4,000, 8,000, and 11,000 psi) to satisfy vehicle refueling requirements. Each vessel holds 17 ft^3 of hydrogen at a maximum pressure of 14,200 psi.

The calculation for the number of dispensers is described in Ruth, Laffen and Timbario (2009).

3.4 Liquid Hydrogen via Trucks with Gaseous Hydrogen Dispensing

The pathways with delivery of liquid hydrogen via trucks and dispensing of gaseous hydrogen include the following components: central production → liquefier → liquid hydrogen terminal (including liquid storage for plant outages) → liquid hydrogen truck transmission and distribution → and gaseous hydrogen fuel station.

For liquid hydrogen truck transmission and distribution, HDSAM calculates the number and cost of the trucks and trailers required to deliver the fuel to fueling stations as well as the distances traveled. The capital and operating costs of the delivery trucks, including the amount of diesel fuel required, are computed. Additionally, the costs of appropriately sized liquefiers, terminal storage, liquid pumps, and vaporizers are calculated.

Peak demand is used to determine the design capacity of the terminal or depot where hydrogen is stored and loaded onto trailers for delivery to stations. Cryogenic storage tanks are used to mitigate production outages and demand surges and are assumed to be sited immediately adjacent to the production facility. The terminal's storage requirement is determined by the following factors: peak daily demand, days of summer peak demand, and expected days per year that the production plant is off-line. The amount of required storage determines the number of truck-filling bays required at the terminal, the capacities of storage tanks, and the resulting capital and operating costs associated with the terminal. Liquefier design is also linked to peak demand.

3.4.1 Liquid Hydrogen Truck

HDSAM calculates the amount of hydrogen that is loaded on a trailer when it leaves the terminal as well as the amount of boil-off losses during delivery to a station (see Ruth, Laffen and Timbario 2009).

HDSAM assumes there are only combinations of one tractor and one trailer. Additionally, it assumes that the stations are the same distance from the terminal and that the same amount of hydrogen is delivered to each station.

3.4.2 Liquefier

For the pathways analysis, HDSAM is able to cost a single liquefier unit based on an idealized liquefier power equation and an energy requirement based on literature data. The actual power requirement is calculated using the curve in Figure 3.4.1.

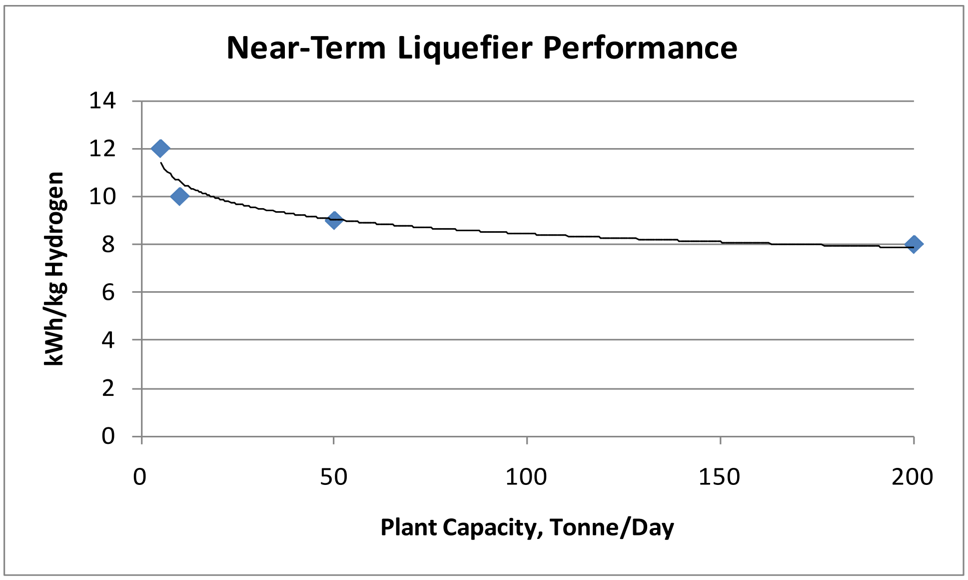


Figure 3.4.1. Liquefier energy requirement versus hydrogen flow rate

Source: Elgowainy, Mintz and Gillette 2010

The liquefier efficiency is calculated by dividing the theoretical power by the actual power requirement as described in Ruth, Laffen and Timbario (2009).

It is assumed that the inlet and outlet pressures for the liquefier are both 1 atm and that the feed to the system is pure hydrogen.

A cost curve has been developed based on several literature sources that estimate the capital cost of a liquefier. Figure 3.4.2 displays the costs for an installed liquefier. For the purposes of this analysis, a conventional liquefier is assumed.

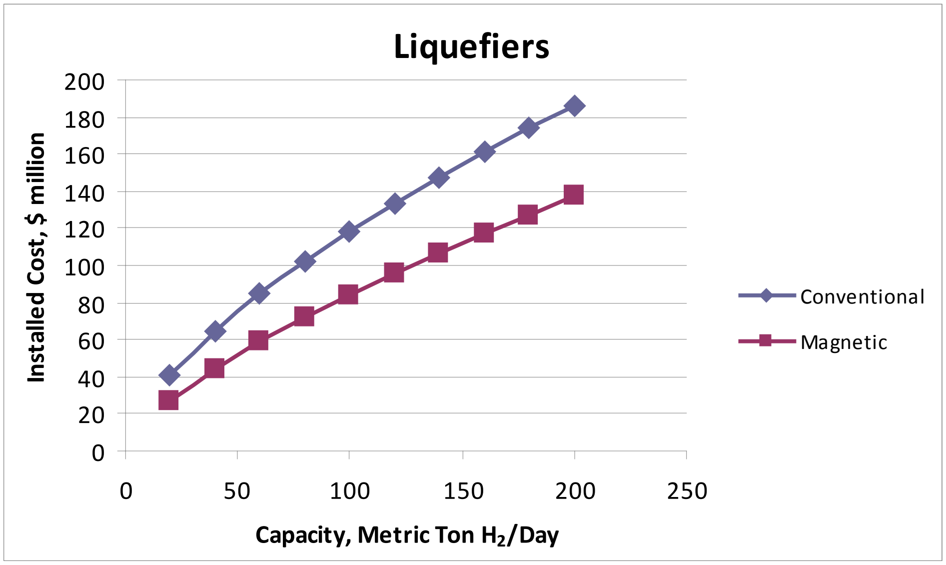


Figure 3.4.2. Liquefier cost versus design capacity

Source: Elgowainy, Mintz and Gillette 2010 (costs are in 2007$)

Refueling station electricity supply costs, assuming 480 V service, are shown in Figure 3.4.3.

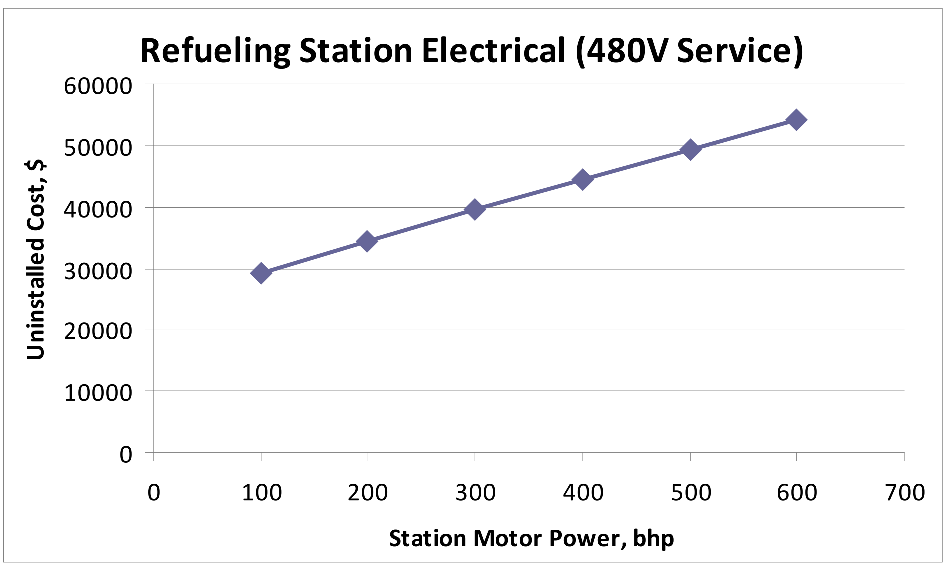


Figure 3.4.3. Refueling station electrical cost versus rated motor power

Source: Elgowainy, Mintz and Gillette 2010 (costs are in 2007$)

3.5 Liquid Hydrogen via Trucks with Dispensing of Cryo-Compressed Liquid Hydrogen

The liquid hydrogen pathway includes the following components: central production → liquefier → liquid hydrogen (including liquid storage for plant outages) → liquid hydrogen truck transmission and distribution → and liquid hydrogen fuel station.

For liquid hydrogen via trucks with dispensing of cryo-compressed liquid hydrogen, HDSAM calculates the number and cost of the trucks and trailers required to deliver the fuel to fueling stations and the distances traveled in the same way that it calculates this information for liquid hydrogen via trucks with gaseous hydrogen dispensing. The only subsystem in this pathway that differs from the liquid hydrogen via trucks with gaseous hydrogen dispensing pathway is the cryo-compressed dispensing, which comprises a cryogenic pump and a cryogenic dispenser.

4 Vehicle Assumptions

4.1 Vehicle Fuel Economy

Vehicle fuel economy is a primary parameter for these analyses because it has an inversely proportional effect on cost per mile as well as energy use and emissions per mile. For this study, the estimated fuel economy for the fuel cell vehicle is 48 mpgge, representing the expected actual on-road fuel economy of the vehicle (not "window sticker" reported fuel economy). As this study investigates current technology, the fuel cell vehicle is presumed to reflect a conventional vehicle, including a fuel cell-based powertrain and regenerative braking, but without significant light-weighting, advanced aerodynamics, low-rolling-resistance tires, or other advanced vehicle platform improvements to improve fuel economy. For this analysis, 48 mpgge is used as the base fuel economy, but a sensitivity analysis of all hydrogen pathways was conducted using 68 mpgge. This higher end fuel economy represents the average fuel economy of a Toyota fuel cell vehicle in on-road testing conducted in California in 2009 (Wipke, Anton and Sprik 2009).

Selection of the 48 mpgge fuel economy parameter is based on a consideration of NREL-analyzed FCEV data as well as modeling results from Argonne National Laboratory. NREL has collected fuel economy data under the Controlled Hydrogen Fleet and Infrastructure Demonstration and Validation Project (Wipke et al. 2012). Final fuel economy results for that project are displayed in Figure 4.1.1, which shows an on-road range of 36–52 mpgge for a second-generation FCEV. This range includes the 48 mppge fuel economy that was used in this analysis. The 48 mpgge value also reflects modeling of FCEV fuel economy by Argonne using its Autonomie model, based on Argonne's modeling assumptions and information from original equipment manufacturers (Rousseau 2012).

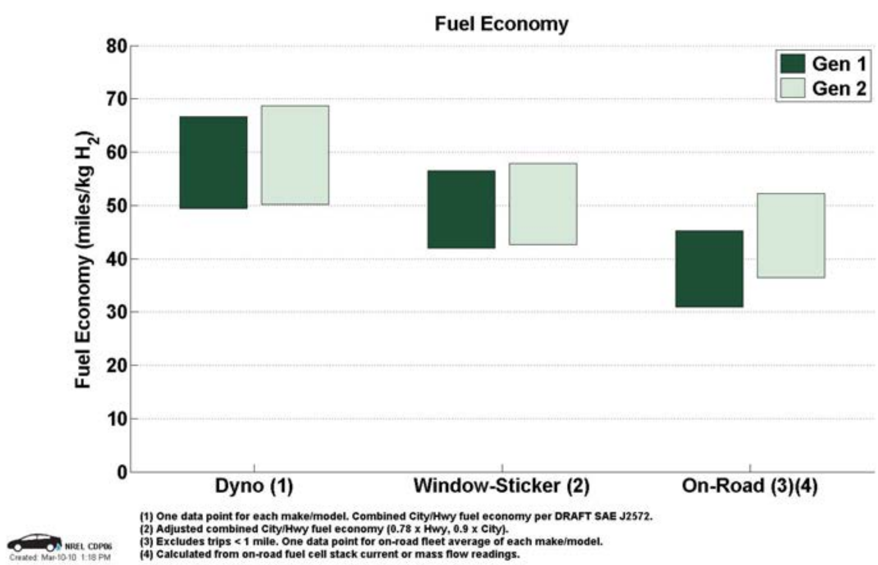


Figure 4.1.1. NREL hydrogen fleet and infrastructure demonstration and validation project fuel economy

Source: Wipke et al. 2012

4.2 Vehicle Criteria Pollutant Emissions

Table 4.2.1 presents the default values of emission change rates used in the GREET model for a hydrogen fuel cell vehicle as compared to the modeled gasoline vehicle. Those values are used for this study.

Hydrogen FCEVs run on hydrogen instead of combustible carbon compounds, so there are no volatile organic carbon compounds (VOC) to either evaporate or be exhausted due to incomplete emissions. Likewise, there are no CO or methane (CH_4) emissions. Because these vehicles run on fuel cells instead of combustion engines, combustion-caused pollutants are also avoided; therefore, there are no PM_{10}, NOx, or N_2O emissions.

Vehicles within the same class (mid-size passenger car), whether powered by a gasoline internal combustion engine or a hydrogen fuel cell, are assumed to have similar tire- and brake-wear (TBW) particulate matter (PM) emissions (Wang, 1999).

Table 4.2.1. Change in Exhaust as Compared to a Gasoline Vehicle

Vehicle	Exhaust VOC	Evap. VOC	CO	NOx	Exhaust PM	CH_4	N_2O	TBW PM
H_2 FCEV	-100%	-100%	-100%	-100%	-100%	-100%	-100%	0%

4.3 Vehicle Cost

Vehicle ownership costs are based on purchasing a new vehicle, driving it 15,000 miles/year over a 5-year period, and selling it in good condition at the end of that timeframe.

To estimate the purchase cost, original equipment manufacturer data beginning with model year 1993 (when available) were obtained for six conventional ICE mid-size-class sedans: the Chevrolet Malibu, Ford Fusion, Honda Accord, Nissan Altima, Saturn Aura, and Toyota Camry. In addition, manufacturer's data for the Ford Taurus (which was discontinued in 2006 and subsequently reintroduced in 2008) were also collected to help fill in early 1990s data because vehicles like the Fusion and Aura are both relatively new models. Manufacturer's suggested retail price (MSRP) data were collected for each of the seven models through model year 2010. MSRP data were then averaged together for each model year. For example, MSRP data for a 2002 Chevrolet Malibu, Honda Accord, Nissan Altima, and Toyota Camry were averaged together to get a generic 2002 mid-size sedan MSRP. Not all seven models were used in the averaging due to class change or vehicle model availability in that model year. The process was repeated for model years 1993–2010. The resulting averaged MSRP was used to define a generic mid-size conventional ICE cost for each model year.

Both MSRP and invoice price, which were provided in current dollars for 1993–2010, were converted to 2007 constant dollars using the Consumer Price Index for All Urban Consumers for New Cars. MSRP and invoice were plotted in 2007 constant dollars and projected using a best-fit curve to obtain future vehicle pricing.

To determine the MSRP of an FCEV, the FCEV subsystem costs were calculated relative to a conventional ICE vehicle. Cost estimates and DOE cost goals were taken from Plotkin et al. (2009). Revised hydrogen storage system costs for 700 bar compressed gas storage were based on cost analyses conducted by Strategic Analysis, Inc. (James 2012). Table 4.3.1 and Table 4.3.2

list those subsystem components and accompanying costs for the model-year 2015 FCEV and conventional ICE vehicles. The conventional ICE vehicle subsystem costs were then subtracted from the FCEV subsystem costs to obtain the incremental subsystem costs of the FCEV. As outlined in Plotkin et al. (2009), the costs in Table 4.3.1 and Table 4.3.2 are manufacturing costs and are not representative of MSRP. Therefore, Plotkin et al. (2009) multiplied these manufacturing costs by 1.5 to obtain the retail price equivalent (RPE). The incremental RPE of the FCEV over the conventional ICE vehicle was obtained by summing the incremental subsystem costs and multiplying by 1.5. This increment was then added to the conventional ICE vehicle MSRP to obtain the FCEV MSRP.

Table 4.3.1. FCEV Subsystem Costs

	2015
Fuel cell system	$4,500
Hydrogen storage	$2,400
Motor	$700
Battery	$1,000
Transmission	$100
Electronics	$500
Exhaust	$0

Table 4.3.2. ICE Vehicle Subsystem Costs

	2015
Engine	$1,800
Hydrogen storage	$0
Motor	$0
Battery	$0
Transmission	$100
Electronics	$0

Maintenance costs for ICEs were estimated by extrapolating the maintenance cost history of four sedans. Those were adjusted by a maintenance cost ratio range used by the National Energy Modeling System to estimate maintenance costs for FCEVs. The ratio's value is 1.08 in 2015 and goes down to 1.04 in 2019.

Tire and repair costs for FCEVs were assumed to be the same as those for ICEs. Expenses for registration, taxes, and fees were estimated using the same tax rate as for ICEs.

Insurance premiums for ICEs were estimated by extrapolating the national averages of combined (collision, liability, and comprehensive) insurance premiums for sedans. Those costs were multiplied by a ratio of 1.11 to estimate insurance premiums for FCEVs. The ratio was set to the premium ratio of a natural gas Honda Civic to a conventional ICE Honda Civic.

Vehicle depreciation was based on NADA resale values for five sedans. The percentage of retained MSRP for each sedan was averaged to develop a common percentage applied to all ICEs in each ownership year. That percentage was then adjusted by the difference between the conventional ICE Honda Civic and the natural gas Honda Civic to estimate the depreciation of the FCEVs.

Standard financing at a loan rate of 7.51% over a 5-year period with 8.23% down was used to calculate financing costs.

4.4 Vehicle-Cycle Energy Use and Emissions

Energy use and emissions for the vehicle cycle are estimated using GREET 2 as described above. They include energy use and emissions for creating vehicle materials, vehicle assembly, vehicle maintenance, and disposal/recycling including all upstream energy and emissions requirements. GREET 2 default values are used for all vehicle parameters.

The GREET 2 default FCEV is defined as a 3,020 lb vehicle with a 70 kW fuel cell stack. The fuel cell stack is estimated to weigh 226 lb and require 546 lb of auxiliary systems. The vehicle is assumed to have a 30 kW nickel-metal hydride (NiMH) battery for hybridization. The battery weighs 110 lb and needs to be replaced twice over the vehicle lifetime.

The component mass of the vehicle (i.e., the mass without batteries or fluids) is estimated at 2,832 lb, and the percentage of mass in each subsystem is shown in Table 4.4.1.

Table 4.4.1. FCEV Subsystem Mass Percentages

Powertrain system	**8.0%**
Transmission system	2.6%
Chassis (without battery)	23.0%
Traction motor	3.8%
Generator	0.0%
Electronic controller	3.4%
Fuel cell auxiliary system	19.3%
Body: including body-in-white, interior, exterior, and glass	39.9%

5 Financial Assumptions

DOE's hydrogen cost analysis models (the H2A Production Model and HDSAM) use a common set of economic assumptions to allow for consistent and comparable results across technology options. Table 5.0.1 provides a set of key economic parameters selected by H2A analysts and discussed with industry collaborators who participated in the H2A effort.

Table 5.0.1. H2A Key Economic Parameters

Parameter	Value
Start-up year	2015
Reference year	2007 dollars
Percentage equity financing	100%
After-tax internal rate of return	10% real
Inflation rate	1.9%
Effective corporate income tax rate	38.9%
Depreciation schedule	Modified Accelerated Cost Recovery System
Economic analysis period:	
Central plant production	40 years
Forecourt production	20 years

In cases where the capital cost component is a large fraction of the levelized cost of producing hydrogen, the assumed after-tax internal rate of return (IRR) strongly affects the results calculated by H2A. As seen in Table 5.0.1, H2A uses an IRR of 10% real, after tax. The 10% real, after-tax value was derived from return on equity statistics (adjusted for inflation) for large company stocks over the period of 1926–2002. Because returns already account for corporate taxes, this value is an after-tax return. The use of a 10% real IRR is intended to reflect a steady-state situation in the future in which hydrogen is a familiar and publicly accepted fuel and in which a significant demand for hydrogen for transportation exists (Pacific Northwest National Laboratory 2004).

This 10% after-tax IRR is linked to the H2A assumption of 100% equity financing. Actual projects would probably be financed with a combination of debt and equity, but H2A analysts have been told that firms typically assume 100% equity financing for paper studies and analyses. When debt financing is used, a higher after-tax IRR can be achieved with the same levelized cost. The increase is dependent upon the fraction of debt financing and the interest rate on that debt. Figure 5.0.1 shows the after-tax IRR for multiple combinations of equity and debt financing at three different interest rates for production of hydrogen from coal in central facilities; delivery costs are not included in the data shown. Technologies with different ratios of capital to operating cost will result in slightly different curves.

Figure 5.0.1 also shows the before-tax IRR for the same combinations of equity and debt financing. Corporate income tax can be considered a reduction in profits, so a pre-tax IRR is always greater than an after-tax IRR. Figure 5.0.1 shows pre-tax and after-tax IRR ranges for different debt interest rates and different percentages of equity financing.

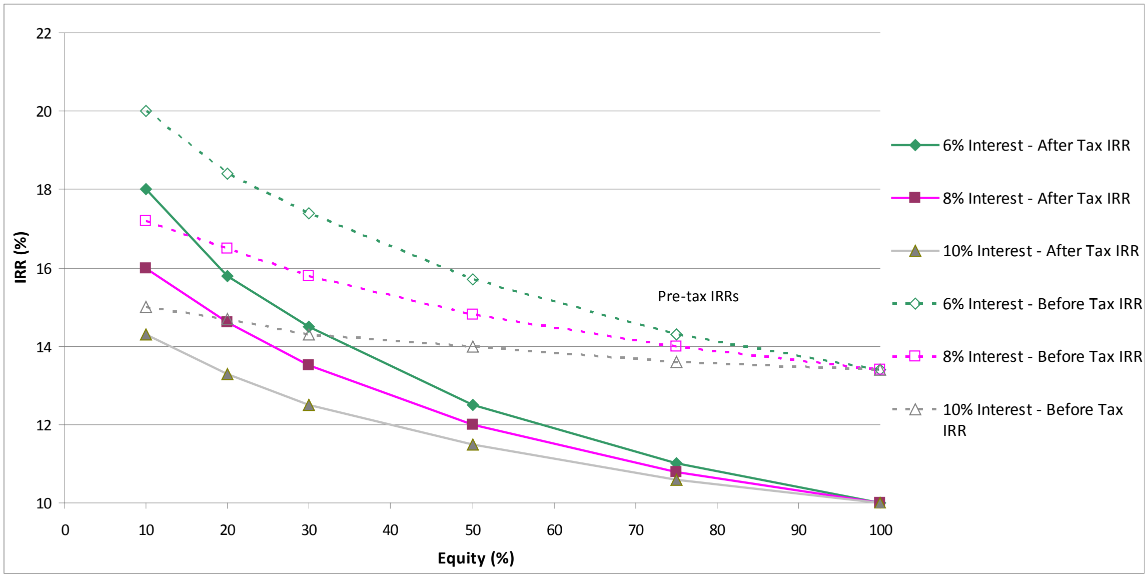


Figure 5.0.1. Post-tax and pre-tax IRRs that result in the same levelized cost for multiple combinations of equity and debt financing (central production of hydrogen from coal with CCS pathway)

6 Pathway Results

This study assessed the life-cycle cost, energy use, and greenhouse gas (GHG) emissions of each of the 10 pathways listed in Table 6.0.1 (see detailed descriptions of each pathway in Section 1.4).

Table 6.0.1. Ten Hydrogen Production, Delivery, and Distribution Pathways

	Feedstock	Central or Distributed Production	Carbon Capture and Sequestration	Delivery Method	Hydrogen Distribution
1	Natural Gas	Distributed	No	Not applicable	700 bar, gaseous
2[a]	Ethanol	Distributed	No	Not applicable	700 bar, gaseous
3	Grid Electricity	Distributed	No	Not applicable	700 bar, gaseous
4	Biomass	Central	No	Gaseous H_2 in pipelines	700 bar, gaseous
5[a]	Biomass	Central	No	Gaseous H_2 truck	700 bar, gaseous
6	Biomass	Central	No	Liquid H_2 truck	700 bar, gaseous
7[a]	Biomass	Central	No	Liquid H_2 truck	Cryo-compressed
8	Natural Gas	Central	No	Gaseous H_2 in pipelines	700 bar, gaseous
9	Wind Electricity	Central	No	Gaseous H_2 in pipelines	700 bar, gaseous
10	Coal	Central	Yes	Gaseous H_2 in pipelines	700 bar, gaseous

[a] Newly analyzed pathways

The hydrogen production technologies are described in Section 2, and the delivery technologies are detailed in Section 3. Fuel cell vehicle assumptions and financial assumptions are discussed in Sections 4 and 5, respectively. This section presents the results of the life-cycle cost, energy use, and GHG emissions analysis for each pathway. As noted above, the base analysis is conducted using a fuel economy of 48 mpgge, with a sensitivity analysis conducted using a fuel economy of 68 mpgge. Results presented are for a fuel economy of 48 mpgge, except where noted.

6.1 Distributed Natural Gas

Figure 6.1.1 shows the major inputs, assumptions, and outputs for each of the subsystems considered in the well-to-tank analysis, including feedstock supply and hydrogen dispensing. (See Appendix A for more details on this pathway.)

The well-to-pump (WTP) and WTW cost of hydrogen, energy use, and emissions for the distributed natural gas pathway are summarized in Table 6.1.1.

6.1.1 Cost Breakdown

Figure 6.1.2 shows the feedstock and energy price inputs and the resulting hydrogen production, delivery, and distribution costs for the distributed natural gas pathway. The financial assumptions used in this analysis are detailed in Section 5.0.

Figure 6.1.3 shows the contributions of hydrogen production, distribution (compression, storage, and dispensing—CSD), and losses to the levelized cost of hydrogen shown in Figure 6.1.2.

Figure 6.1.4 and Table 6.1.2 show the breakdown of levelized costs for the distributed natural gas pathway.

Inputs			Assumptions			Outputs		
						NG Delivery Pressure	Average of gas companies	
			NG Recovery, Processing, & Transport			NG Quality at Delivery	Average of gas companies	
			NG Recovery Efficiency	95.7%				
			NG emitted & combusted during recovery	399	g/MMbtu	NG Cost	$6.09	2007 $ / mmBTU
			NG processing energy efficiency	97.2%		NG Share of H2 Levelized Cost	$1.28	2007$ / kg H2 dispensed
			NG emitted & combusted during processing	33	g/MMbtu			
			NG emitted & combusted during transport	199,400	g/MMbtu	WTG CO2 Emissions	650	g CO2 eq./ 116000 Btu
Coal Input (including upstream)	300	Btu / 116000Btu to Pump	NG transport distance	500	miles	WTG CH4 Emissions	1,750	g CO2 eq./ 116000 Btu
Natural Gas Input (including upstream)	127,200	Btu / 116000Btu to Pump	Compression Req'ts. (stages & efficiency)	Average of gas companies		WTG N2O Emissions	3	g CO2 eq./ 116000 Btu
Petroleum Input (including upstream)	500	Btu / 116000Btu to Pump				WTG GHG Emissions	2,390	g CO2 eq./ 116000 Btu
			Hydrogen Production			Hydrogen Output Pressure	300	psi
Natural gas consumption	0.156	MMBtu/kg H2 produced				Hydrogen Outlet Quality	99.9%	
Electricity consumption	1.11	kWh / kg H2 produced						
Process Water Consumption	5.77	gal / kg H2 produced	Distributed plant design capacity	1,500	kg / day	Total capital investment	$1,150	2007$ / daily kg H2 (effective capacity)
Cooling Water Consumption	0.00	gal / kg H2 produced	Capacity factor	89%		Levelized Cost of Capital	$0.59	2007$ / kg H2 dispensed
			# of Plants Needed to Meet City Demand	92		Fixed O&M Costs	$0.19	2007$ / kg H2 dispensed
Total Capital Investment per station	$1,530,000	2007$	Process energy efficiency	71.4%		Variable O&M Costs	$0.12	2007$ / kg H2 dispensed
			Electricity Mix	US Mix		Total Levelized Cost	$2.17	2007$ / kg H2 dispensed
			After-tax IRR	10%				
Coal Input (including upstream)	5,600	Btu / 116000Btu to Pump	Assumed Plant Life	20		Production CO2 Emissions	10,410	g CO2 eq./ 116000 Btu
Natural Gas Input (including upstream)	49,200	Btu / 116000Btu to Pump				Production CH4 Emissions	690	g CO2 eq./ 116000 Btu
Petroleum Input (including upstream)	400	Btu / 116000Btu to Pump				Production N2O Emissions	8	g CO2 eq./ 116000 Btu
						Production GHG Emissions	11,100	g CO2 eq./ 116000 Btu
Electricity consumption	4.4	kWh / kg H2 produced	**Forecourt Dispensing**			Hydrogen outlet pressure	12,700	psi
						Basis -- Hydrogen Quantity	116,000	Btu (116,000 Btu/gal non-oxygenated conventional unleaded gasoline)
			City Population	1,247,000	people			
Total Capital Investment (per station)	$5,059,000	2007$ / station	Hydrogen Vehicle Penetration	15%				
Total Capital Investment	$465,391,000	2007$ / all stations	City hydrogen use	121,100	kg / day	Total capital investment	$3,810	2007$ / daily kg H2 (effective capacity)
			Average Dispensing Rate per Station	1,330	kg / day	Levelized Cost of Capital	$1.49	2007$ / kg H2 dispensed
			Number of Dispensing Stations	92		Energy & Fuel	$0.40	2007$ / kg H2 dispensed
			Number of Compression Steps	5		Other O&M Costs	$0.54	2007$ / kg H2 dispensed
			Usable Low Pressure Storage per Station	1,450	kg H2	Levelized Cost of Dispensing	$2.43	2007$ / kg H2 dispensed
			Usable Cascade Storage per Station	200	kg H2			
Coal Input (including upstream)	21,900	Btu / 116000Btu to Pump	Site storage	100%	% of design capacity	CSD CO2 Emissions	3,020	g CO2 eq./ 116000 Btu
Natural Gas Input (including upstream)	9,700	Btu / 116000Btu to Pump	# of 2-hose Dispensers per Station	3		CSD CH4 Emissions	190	g CO2 eq./ 116000 Btu
Petroleum Input (including upstream)	800	Btu / 116000Btu to Pump	Hydrogen losses	0.50%		CSD N2O Emissions	12	g CO2 eq./ 116000 Btu
						CSD GHG Emissions	3,220	g CO2 eq./ 116000 Btu
Vehicle Mass	3,020	lb	**Vehicle**			Cost Per Mile	$0.66	2007$ / mi
Fuel cell size	70	kW	Fuel Economy	48.0	mi / GGE	Fuel Share	$0.10	2007$ / mi
Size of hybridization battery	30	kW	Vehicle Miles Traveled	15,000	mi / yr	Maintenance, Tires, Repairs	$0.07	2007$ / mi
			Vehicle Lifetime	160,000	mi	Insurance & Registration	$0.12	2007$ / mi
			Purchase Year	2015		Depreciation	$0.27	2007$ / mi
			Vehicle Purchase Cost	$33,700	2007$	Financing	$0.10	2007$ / mi
			Fuel Cell System Cost	$4,500	2007$			
Coal Input (including upstream)	2,300	Btu / gge fuel consumed	Hydrogen Storage System Cost	$2,400	2007$	Vehicle Cycle CO2 Emissions	1,670	g CO2 eq / gge fuel consumed
Natural Gas Input (including upstream)	12,100	Btu / gge fuel consumed	Tax Credit	$0	2007$	Vehicle Cycle CH4 Emissions	170	g CO2 eq / gge fuel consumed
Petroleum Input (including upstream)	6,900	Btu / gge fuel consumed				Vehicle Cycle N2O Emissions	6	g CO2 eq / gge fuel consumed
						Vehicle Cycle GHG Emissions	1,850	g CO2 eq / gge fuel consumed

Figure 6.1.1. Summary of major inputs, assumptions, and outputs by subsystem for the distributed natural gas pathway

Table 6.1.1. WTP and WTW Results for the Distributed Natural Gas Pathway

	WTP		WTW	
Coal input (including upstream)[a]	27,700	Btu/116,000 Btu	580	Btu/mi
Natural gas input (including upstream)[a]	186,100	Btu/116,000 Btu	3,900	Btu/mi
Petroleum input (including upstream)[a]	1,700	Btu/116,000 Btu	40	Btu/mi
Fossil energy input (including upstream)[a]	215,500	Btu/116,000 Btu	4,500	Btu/mi
WTP CO_2 emissions[b]	14,100	g/116,000 Btu	290	g/mi
WTP CH_4 emissions	100	g/116,000 Btu	2	g/mi
WTP N_2O emissions	20	g/116,000 Btu	0	g/mi
WTP GHG emissions	16,700	g CO_2-eq./ 116,000 Btu	350	g/mi
	Cost per kg		**Cost per mile**	
Levelized cost of hydrogen	$4.60	2007$/kg	$0.10	2007$/mi

[a] Coal, natural gas, and petroleum inputs include those used directly in the hydrogen production and delivery pathway as feedstocks and fuels; those used to produce electricity and other materials used in the pathway; and those used upstream of the pathway to recover, refine, and deliver the feedstock.
[b] Includes the carbon content of CO, CH_4, and volatile organic compound emissions that decompose in the atmosphere to CO_2.

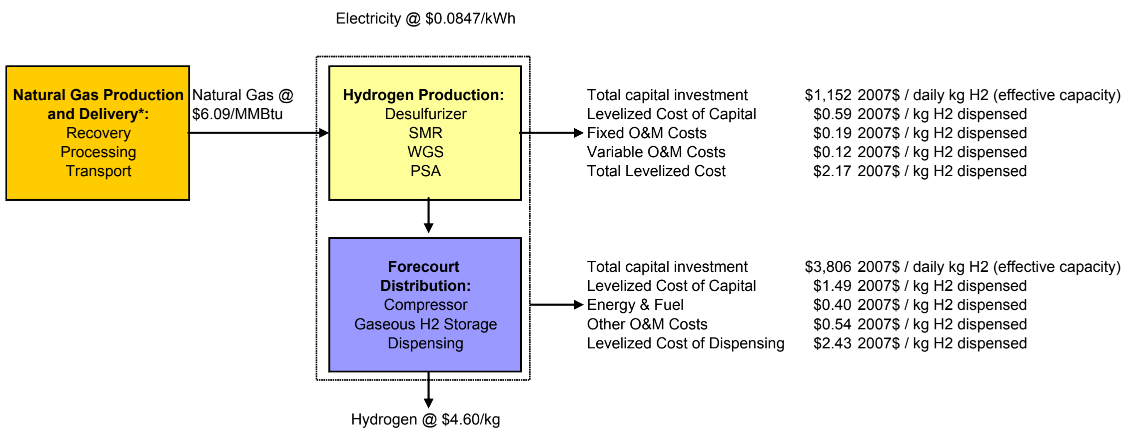


Figure 6.1.2. Cost analysis inputs and high-level results for the distributed natural gas pathway

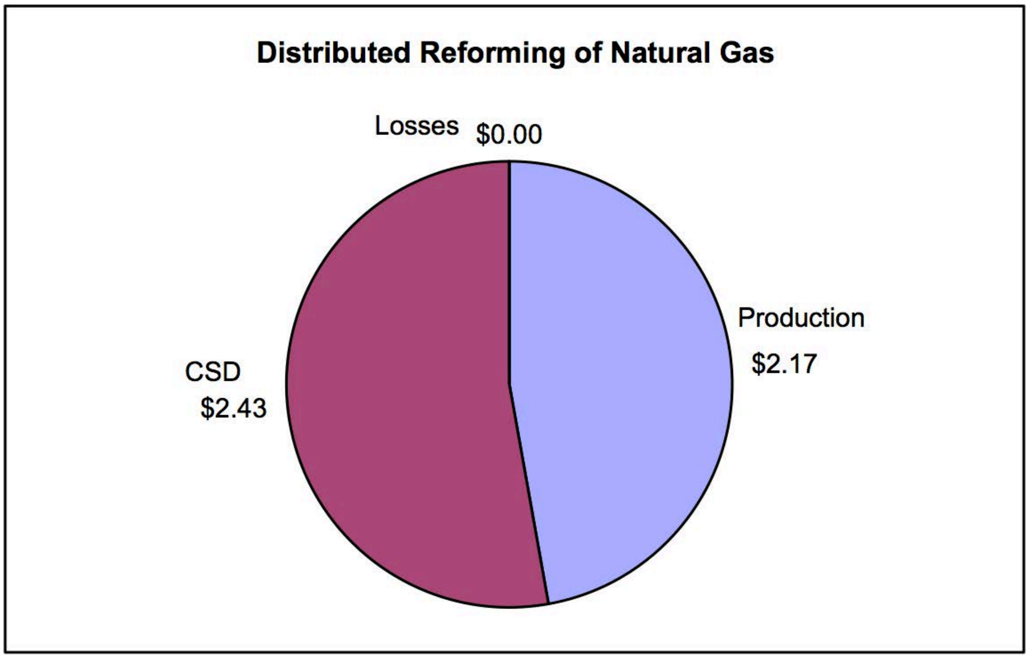


Figure 6.1.3. Contribution of hydrogen production, CSD, and losses to the levelized cost of hydrogen for the distributed natural gas pathway

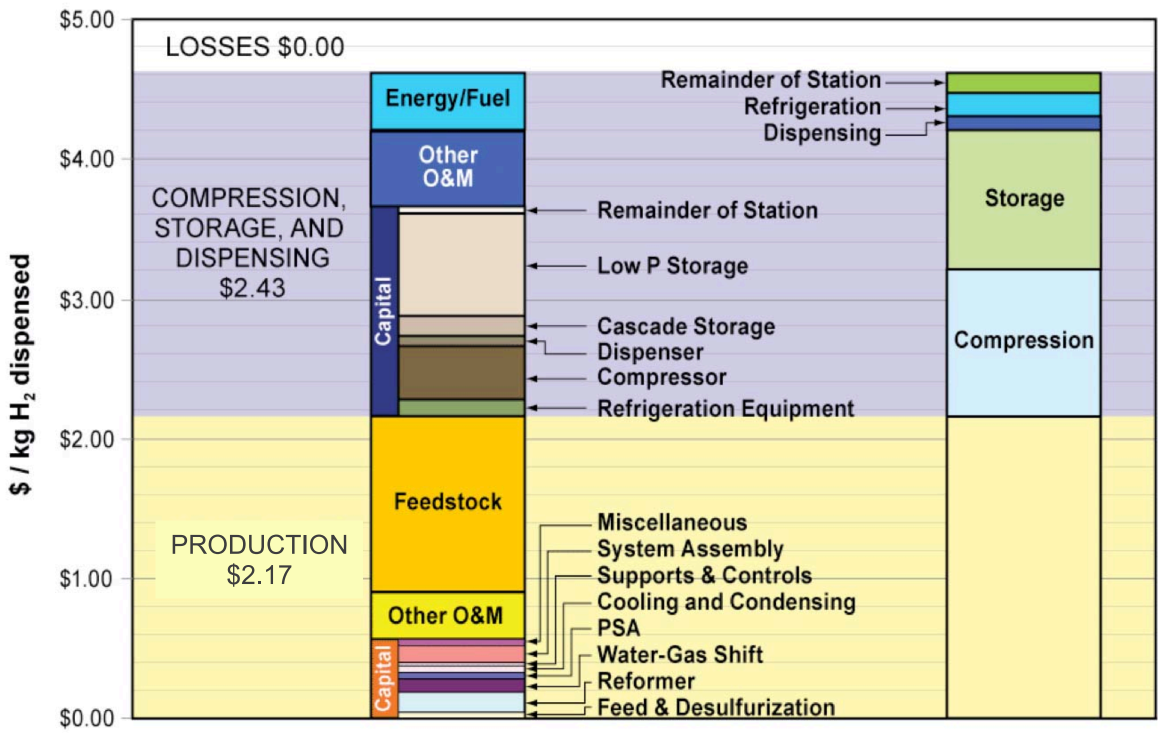


Figure 6.1.4. Breakdown of levelized costs for the distributed natural gas pathway

Table 6.1.2. Contribution of Production and CSD Processes to Levelized Hydrogen Cost for the Distributed Natural Gas Pathway

Cost Component	Capital	Other O&M[a]	Feedstock	Energy/ Fuel	Total
Production	$0.58	$0.32	$1.28		$2.17
Feed and desulfurization	$0.06				
Reformer	$0.13				
WGS	$0.10				
PSA	$0.04				
Cooling and condensing	$0.04				
Supports and controls	$0.03				
System assembly	$0.12				
Miscellaneous	$0.05				
CSD	$1.49	$0.54		$0.40	$2.43
Compressor (levelized)					$1.04
Storage (levelized)					$0.99
Dispenser (levelized)					$0.10
Refrigeration (levelized)					$0.16
Remainder of station (levelized)					$0.14
Losses					$0.00
Total	**$2.07**	**$0.86**	**$1.28**	**$0.40**	**$4.60**

[a] O&M: operations and maintenance

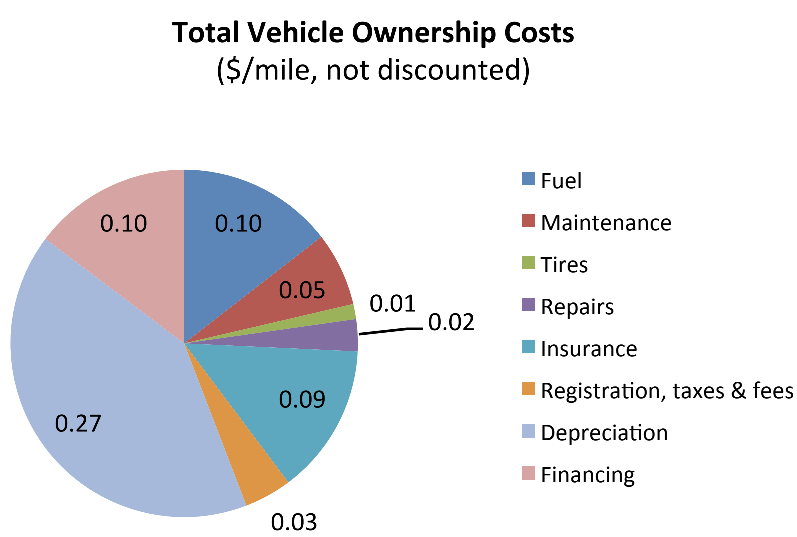


Figure 6.1.5. Breakdown of vehicle ownership costs for the distributed natural gas pathway

Fuel costs are not the only costs of ownership of a vehicle. Vehicle ownership costs including fuel, maintenance, tires, repairs, insurance, registration, and vehicle depreciation and financing are shown in Figure 6.1.5. Note that the costs in the figure are not discounted (i.e., a discount rate was not used to reduce future costs to their net present values). That methodology has the same effect as a discount rate of 0%.

6.1.2 Energy Use and Emissions Breakdown

Figures 6.1.6 and 6.1.7 show the WTW energy inputs and losses for the distributed natural gas pathway. The WTW energy inputs to natural gas production and delivery include those necessary to produce 116,000 Btu of natural gas for reforming. Additional WTW energy inputs for natural gas needed for heating and lost in reforming are reported as inputs to hydrogen production.

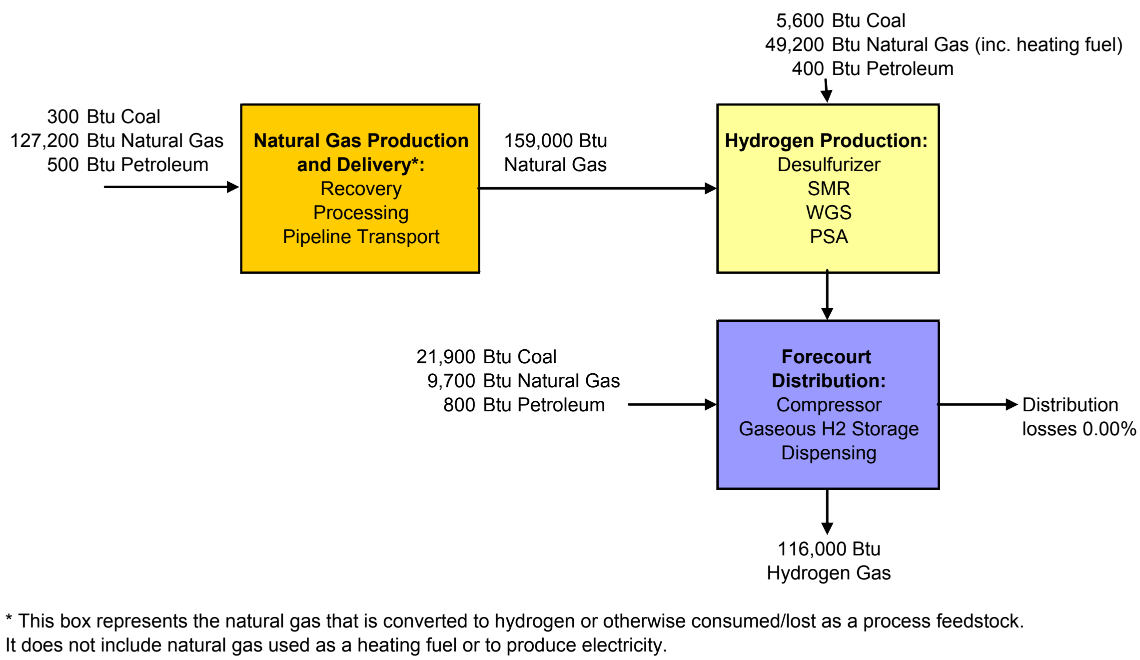


Figure 6.1.6. WTW energy inputs to deliver 116,000 Btu hydrogen to a vehicle using the distributed natural gas pathway

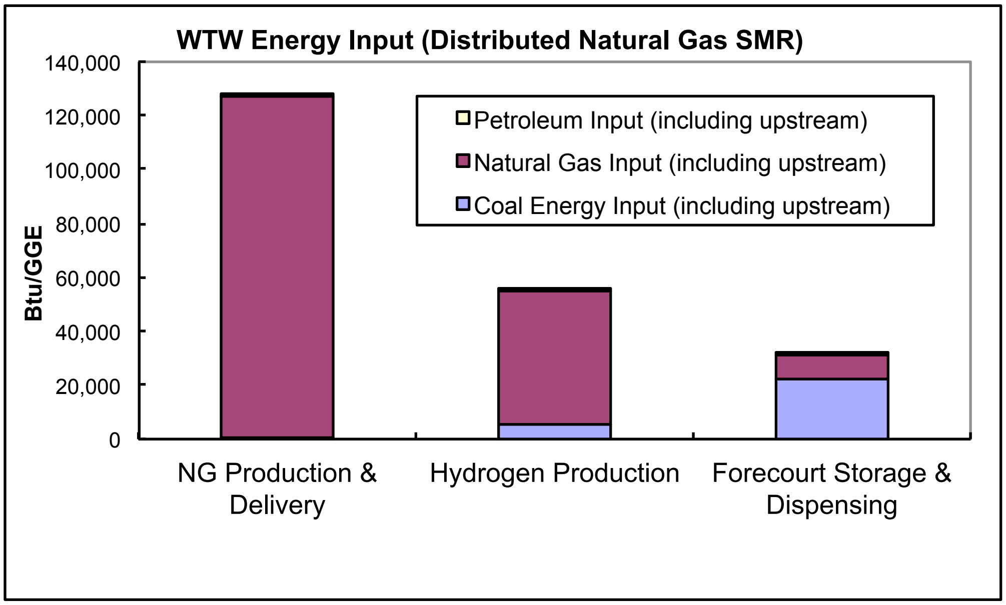
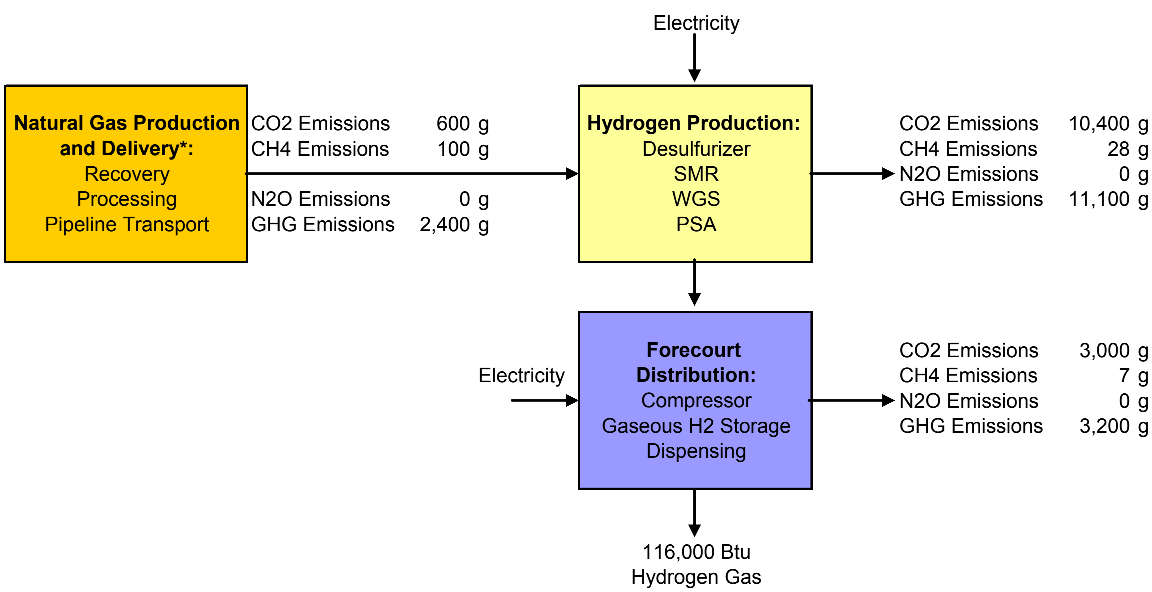


Figure 6.1.7. WTW petroleum, natural gas, and coal inputs to deliver 116,000 Btu hydrogen using the distributed natural gas pathway

Figures 6.1.8 and 6.1.9 show the WTW emissions resulting from the delivery of 116,000 Btu hydrogen to a vehicle fuel tank using the distributed natural gas pathway.



* This box represents the natural gas that is converted to hydrogen or otherwise consumed/lost as a process feedstock. It does not include natural gas used as a heating fuel or to produce electricity.

Figure 6.1.8. WTW emissions resulting from delivery of 116,000 Btu hydrogen using the distributed natural gas pathway

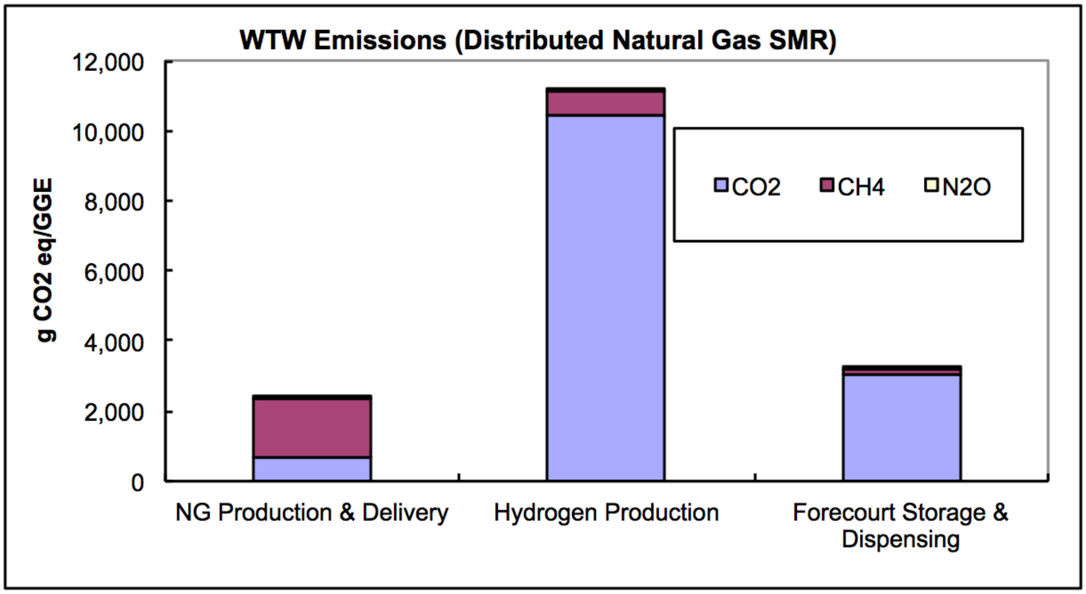


Figure 6.1.9. WTW CO_2, CH_4, and N_2O emissions resulting from delivery of 116,000 Btu hydrogen to a vehicle using the distributed natural gas pathway

Figures 6.1.10 and 6.1.11 show the energy inputs and emissions, respectively, for the vehicle cycles in addition to those for the fuel production cycle. The fuel production cycle values are consistent with those reported in Figures 6.1.7 and 6.1.9.

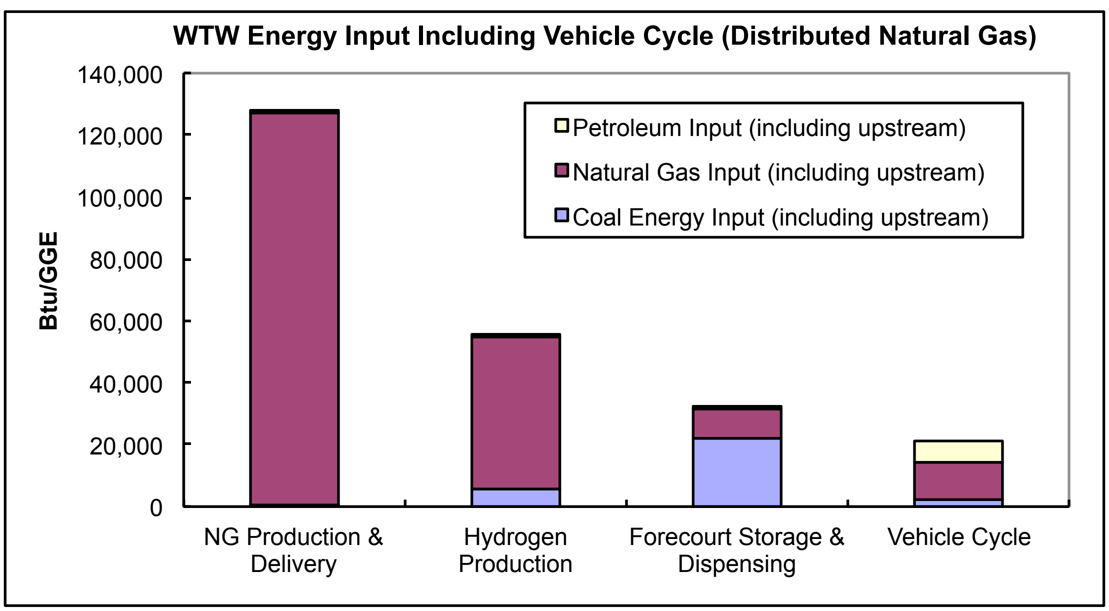


Figure 6.1.10. WTW petroleum, natural gas, and coal inputs for both the distributed natural gas pathway and the vehicle cycle

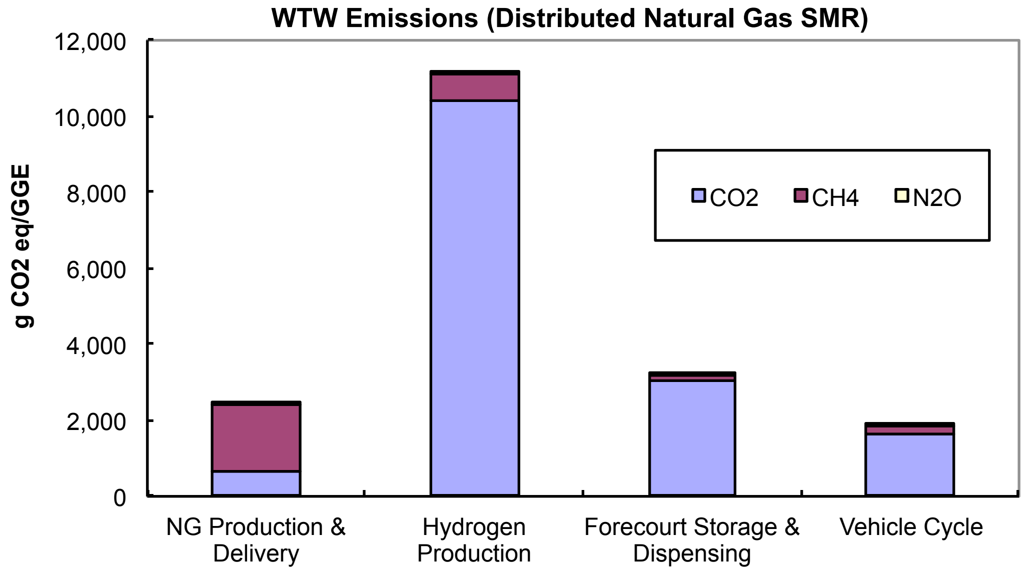


Figure 6.1.11. WTW CO_2, CH_4, and N_2O emissions for both the distributed natural gas pathway and the vehicle cycle

6.1.3 Sensitivities

6.1.3.1 Production Sensitivities

The parameters used for this analysis are not known absolutely, so sensitivity analyses were performed to better understand the potential effects of that lack of knowledge on the final results. Several sensitivities were run on this pathway. They focused primarily on cost factors; however, several sensitivities also affect energy use and emissions. Figure 6.1.12 shows the effects of several production parameters on the pathway's levelized cost, and Table 6.1.3 shows the effect of production energy efficiency on WTW energy use and emissions.

The assumed electrical grid mix also affects the energy use and emissions. Table 6.1.4 shows the differences in energy use and GHG emissions between the U.S. average grid mix (which was used for all other sensitivities) and a hypothetical green grid mix that is 100% renewable energy (solar and wind).

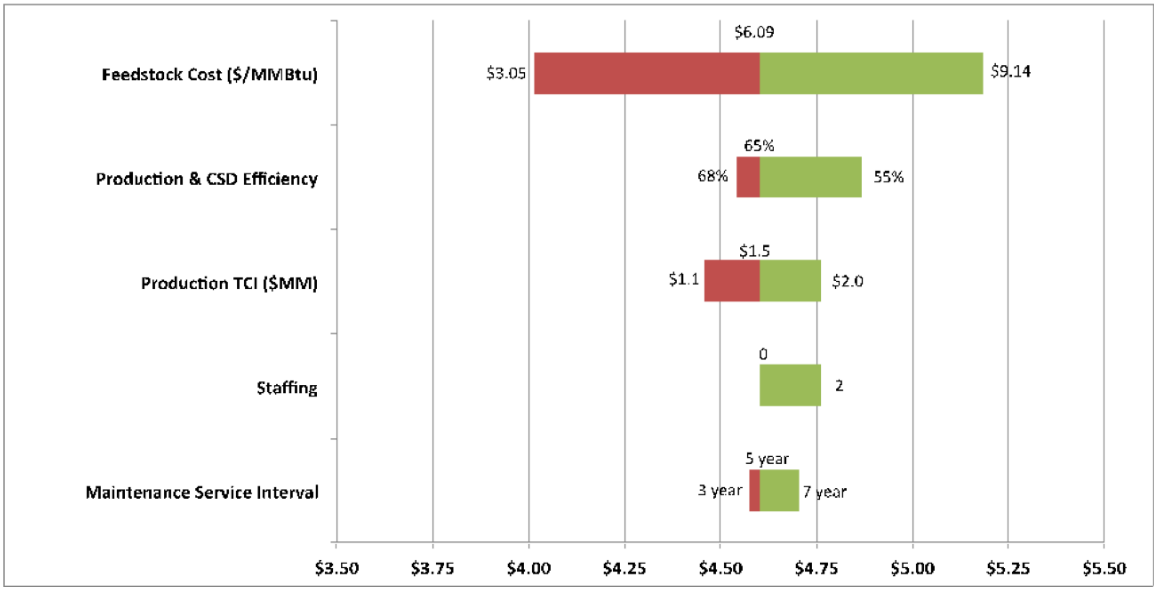


Figure 6.1.12. Production sensitivities for the distributed natural gas pathway

Table 6.1.3. The Effects of Production Energy Efficiency on Primary Energy Use and Emissions from the Distributed Natural Gas Pathway

	60% Efficiency	71% Efficiency	75% Efficiency
WTW GHG emissions (g/mile)	400	350	340
WTW fossil energy (Btu/mile)	5,200	4,500	4,300
WTW petroleum energy (Btu/mile)	40	40	40
WTW total energy (Btu/mile)	5,400	4,700	4,500

Table 6.1.4. The Effects of Fuel Economy and Grid Mix on Use of Primary Energy and Emissions from the Distributed Natural Gas Pathway

	U.S. Average Grid Mix (48 mpgge)	U.S. Average Grid Mix (68 mpgge)	"Green" Grid Mix (48 mpgge)
WTW GHG emissions (g/mile)	350	250	270
WTW fossil energy (Btu/mile)	4,500	3,200	3,600
WTW petroleum energy (Btu/mile)	40	30	10
WTW Total energy (Btu/mile)	4,700	3,300	4,100

6.2 Distributed Ethanol

Figure 6.2.1 shows the major inputs, assumptions, and outputs for each of the subsystems considered in the well-to-tank analysis, including feedstock supply and hydrogen dispensing. (See Appendix B for more details on this pathway.)

The WTP and WTW cost of hydrogen, energy use, and emissions for the distributed ethanol pathway are summarized in Table 6.2.1.

6.2.1 Cost Breakdown

Figure 6.2.2 shows the feedstock and energy price inputs and the resulting hydrogen production, delivery, and distribution costs for the distributed ethanol pathway. The financial assumptions used in this analysis are detailed in Section 5.

Figure 6.2.3 shows the contributions of hydrogen production, distribution (CSD), and losses to the levelized cost of hydrogen shown in Figure 6.2.2.

Figure 6.2.4 and Table 6.2.2 show the breakdown of levelized costs for the distributed ethanol pathway.

Inputs			Assumptions			Outputs		
			Ethanol Production					
			Percent from Corn Stover	100%		Ethanol Cost	$3.04	2007 $ / gal
			Corn Stover Production	2.21	dry ton / acre	Ethanol Share of H2 Cost	$5.29	2007$ / kg H2 dispensed
Coal Input (including upstream)	-21,100	Btu / 116000Btu to Pump	Ethanol Yield from Corn Stover	90.0	gal / dry ton			
Natural Gas Input (including upstream)	400	Btu / 116000Btu to Pump	Elec. Co-Prod. from Corn Stover Conversion	2.28	kWh / gal ethanol	WTG CO2 Emissions	-14,010	g CO2 eq./ 116000 Btu
Petroleum Input (including upstream)	12,700	Btu / 116000Btu to Pump				WTG CH4 Emissions	-20	g CO2 eq./ 116000 Btu
			Displacement method used for estimating effects of co-produced electricity on LCA results			WTG N2O Emissions	1,140	g CO2 eq./ 116000 Btu
Energy use and emissions calcs include electricity displaced by ethanol production						WTG GHG Emissions	-12,900	g CO2 eq./ 116000 Btu
						Hydrogen Output Pressure	300	psi
Ethanol Consumption	2.19	gal / kg H2 produced	**Hydrogen Production**			Hydrogen Outlet Quality	99.9%	
Electricity consumption	0.49	kWh / kg H2 produced						
Process Water Consumption	8.18	gal / kg H2 produced	Distributed plant design capacity	1,500	kg / day	Total capital investment	$1,430	2007$ / daily kg H2 (effective capacity)
Cooling Water Consumption	0.00	gal / kg H2 produced	Capacity factor	89%		Levelized Cost of Capital	$0.83	2007$ / kg H2 dispensed
			# of Plants Needed to Meet City Demand	92		Fixed O&M Costs	$0.24	2007$ / kg H2 dispensed
Total Capital Investment per station	$1,907,000	2007$	Process energy efficiency	67.4%		Variable O&M Costs	$0.07	2007$ / kg H2 dispensed
			Electricity Mix	US Mix		Total Levelized Cost	$6.42	2007$ / kg H2 dispensed
			After-tax IRR	10%				
Coal Input (including upstream)	2,400	Btu / 116000Btu to Pump	Assumed Plant Life	20		SMR CO2 Emissions	13,080	g CO2 eq./ 116000 Btu
Natural Gas Input (including upstream)	1,100	Btu / 116000Btu to Pump				SMR CH4 Emissions	20	g CO2 eq./ 116000 Btu
Petroleum Input (including upstream)	100	Btu / 116000Btu to Pump				SMR N2O Emissions	1	g CO2 eq./ 116000 Btu
						SMR GHG Emissions	14,010	g CO2 eq./ 116000 Btu
Electricity consumption	4.4	kWh / kg H2	**Forecourt Dispensing**			Hydrogen outlet pressure	12,700	psi
						Basis -- Hydrogen Quantity	116,000	Btu (116,000 Btu/gal non-oxygenated conventional unleaded gasoline)
			City Population	1,247,000	people			
Total Capital Investment (per station)	$5,059,000	2007$ / station	Hydrogen Vehicle Penetration	15%		Total capital investment	$3,810	2007$ / daily kg H2 (effective capacity)
Total Capital Investment	$465,390,000	2007$ / all stations	City hydrogen use	121,100	kg / day	Levelized Cost of Capital	$1.49	2007$ / kg H2 dispensed
			Average Dispensing Rate per Station	1,329	kg / day	Energy & Fuel	$0.40	2007$ / kg H2 dispensed
			Number of Dispensing Stations	92		Other O&M Costs	$0.54	2007$ / kg H2 dispensed
			Number of Compression Steps	5		Levelized Cost of Dispensing	$2.43	2007$ / kg H2 dispensed
			Usable Low Pressure Storage per Station	1450	kg H2			
			Usable Cascade Storage per Station	200	kg H2	CSD CO2 Emissions	3,020	g CO2 eq./ 116000 Btu
Coal Input (including upstream)	21,900	Btu / 116000Btu to Pump	Site storage	100%	% of design capacity	CSD CH4 Emissions	190	g CO2 eq./ 116000 Btu
Natural Gas Input (including upstream)	9,700	Btu / 116000Btu to Pump	# of 2-hose Dispensers per Station	3		CSD N2O Emissions	12	g CO2 eq./ 116000 Btu
Petroleum Input (including upstream)	800	Btu / 116000Btu to Pump	Hydrogen losses	0.50%		CSD GHG Emissions	11,320	g CO2 eq./ 116000 Btu
Vehicle Mass	3,020	lb	**Vehicle**			Cost Per Mile	$0.75	2007$ / mi
Fuel cell size	70	kW	Fuel Economy	48.0	mi / GGE	Fuel Share	$0.18	2007$ / mi
Size of hybridization battery	30	kW	Vehicle Miles Traveled	15,000	mi / yr	Maintenance, Tires, Repairs	$0.07	2007$ / mi
			Vehicle Lifetime	160,000	mi	Insurance & Registration	$0.12	2007$ / mi
			Purchase Year	2015		Depreciation	$0.27	2007$ / mi
			Vehicle Purchase Cost	$33,700	2007$	Financing	$0.10	2007$ / mi
			Fuel Cell System Cost	$4,500	2007$			
Coal Input (including upstream)	2,300	Btu / gge fuel consumed	Hydrogen Storage System Cost	$2,400	2007$	Veh. Cycle CO2 Emissions	1,670	g CO2 eq / gge fuel consumed
Natural Gas Input (including upstream)	12,100	Btu / gge fuel consumed	Tax Credit	$0	2007$	Veh. Cycle CH4 Emissions	170	g CO2 eq / gge fuel consumed
Petroleum Input (including upstream)	6,900	Btu / gge fuel consumed				Veh. Cycle N2O Emissions	6	g CO2 eq / gge fuel consumed
						Veh. Cycle GHG Emissions	1,850	g CO2 eq / gge fuel consumed

Figure 6.2.1. Summary of major inputs, assumptions, and outputs by subsystem for the distributed ethanol pathway

Table 6.2.1. WTP and WTW Results for the Distributed Ethanol Pathway

	WTP		WTW	
Coal input (including upstream)[a]	3,200	Btu/116,000 Btu	70	Btu/mi
Natural gas input (including upstream)[a]	11,200	Btu/116,000 Btu	200	Btu/mi
Petroleum input (including upstream)[a]	13,600	Btu/116,000 Btu	300	Btu/mi
Fossil energy input (including upstream)[a]	28,000	Btu/116,000 Btu	600	Btu/mi
WTP CO_2 emissions[b]	2,100	g/116,000 Btu	45	g/mi
WTP CH_4 emissions	7	g/116,000 Btu	0	g/mi
WTP N_2O emissions	4	g/116,000 Btu	0	g/mi
WTP GHG emissions	3,400	g CO_2-eq./ 116,000 Btu	70	g/mi
	Cost per kg		**Cost per mile**	
Levelized cost of hydrogen	$8.84	2007$/kg	$0.18	2007$/mi

[a] Coal, natural gas, and petroleum inputs include those used directly in the hydrogen production and delivery pathway as feedstocks and fuels; those used to produce electricity and other materials used in the pathway; and those used upstream of the pathway to recover, refine, and deliver the feedstock.
[b] Includes the carbon content of CO, CH_4, and volatile organic compound emissions that decompose in the atmosphere to CO_2.

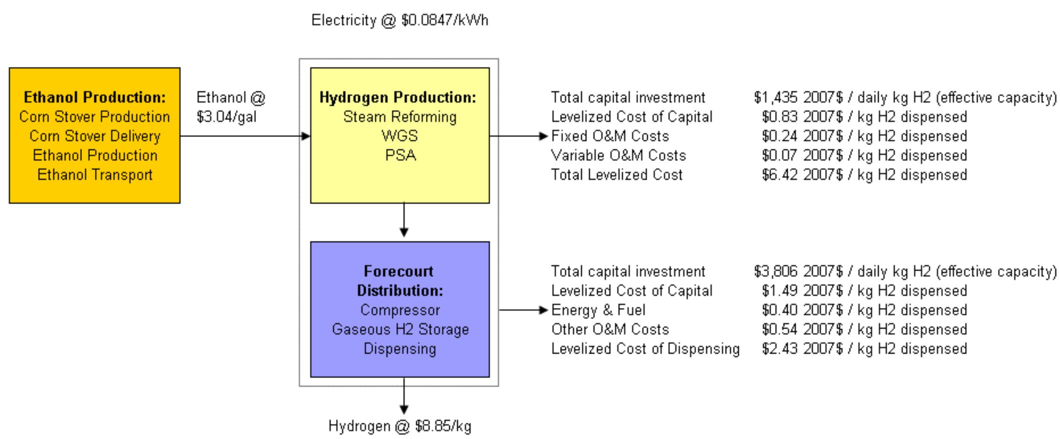


Figure 6.2.2. Cost analysis inputs and high-level results for the distributed ethanol pathway

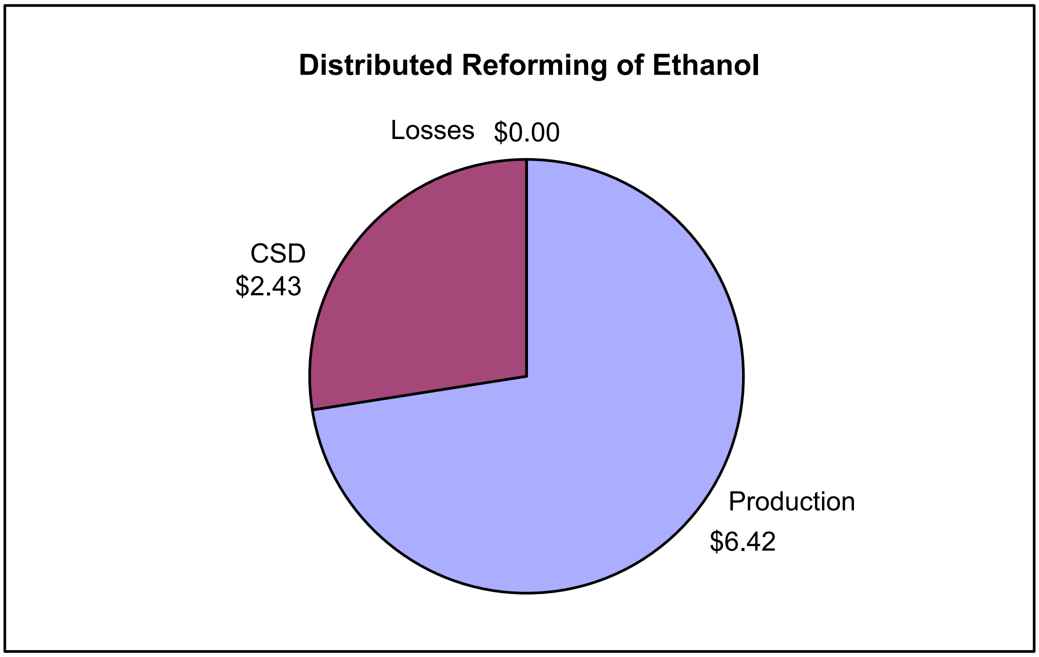


Figure 6.2.3. Contribution of hydrogen production, CSD, and losses to the levelized cost of hydrogen for the distributed ethanol pathway

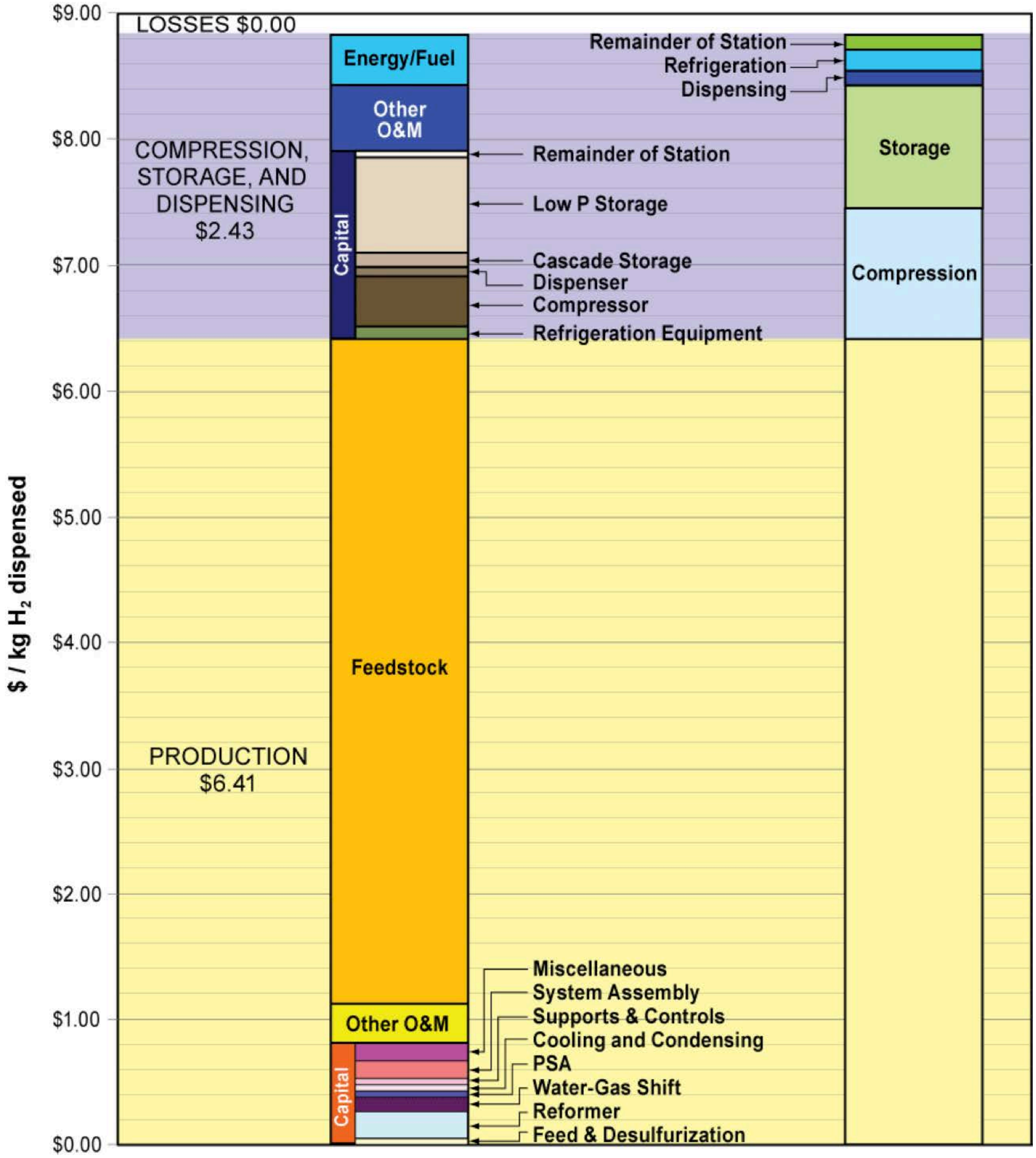


Figure 6.2.4. Breakdown of levelized costs for the distributed ethanol pathway

Table 6.2.2. Contribution of Production and CSD Processes to Levelized Hydrogen Cost for the Distributed Ethanol Pathway

Cost Component	Capital	Other O&M	Feedstock	Energy/ Fuel	Total
Production	$0.82	$0.31	$5.29		$6.42
Feed and desulfurization	$0.06				
Reformer	$0.20				
WGS	$0.13				
PSA	$0.05				
Cooling and condensing	$0.05				
Supports and controls	$0.04				
System assembly	$0.14				
Miscellaneous	$0.16				
CSD	$1.49	$0.54		$0.40	$2.43
Compressor (levelized)					$1.04
Storage (levelized)					$0.99
Dispenser (levelized)					$0.10
Refrigeration (levelized)					$0.16
Remainder of station (levelized)					$0.14
Losses					$0.00
Total	**$2.31**	**$0.86**	**$5.29**	**$0.40**	**$8.85**

6.2.2 Energy Use and Emissions Breakdown

Figures 6.2.5 and 6.2.6 show the WTW energy inputs and losses for the distributed ethanol pathway. The WTW energy inputs to ethanol production and delivery include those necessary to produce 116,000 Btu of ethanol for reforming. Additional WTW energy inputs for natural gas needed for heating and lost in reforming are reported as inputs to hydrogen production.

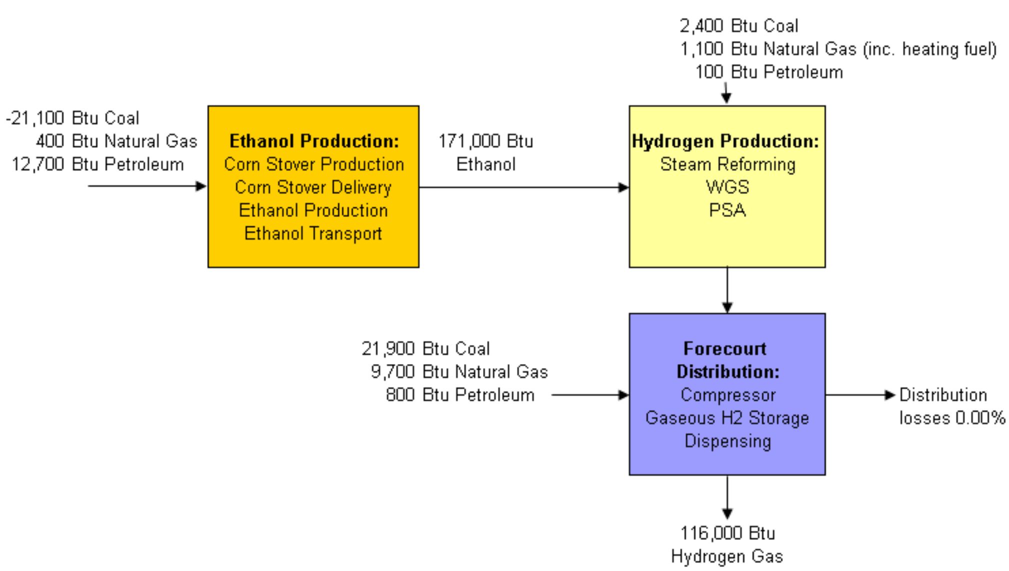


Figure 6.2.5. WTW energy inputs to deliver 116,000 Btu hydrogen to a vehicle using the distributed ethanol pathway

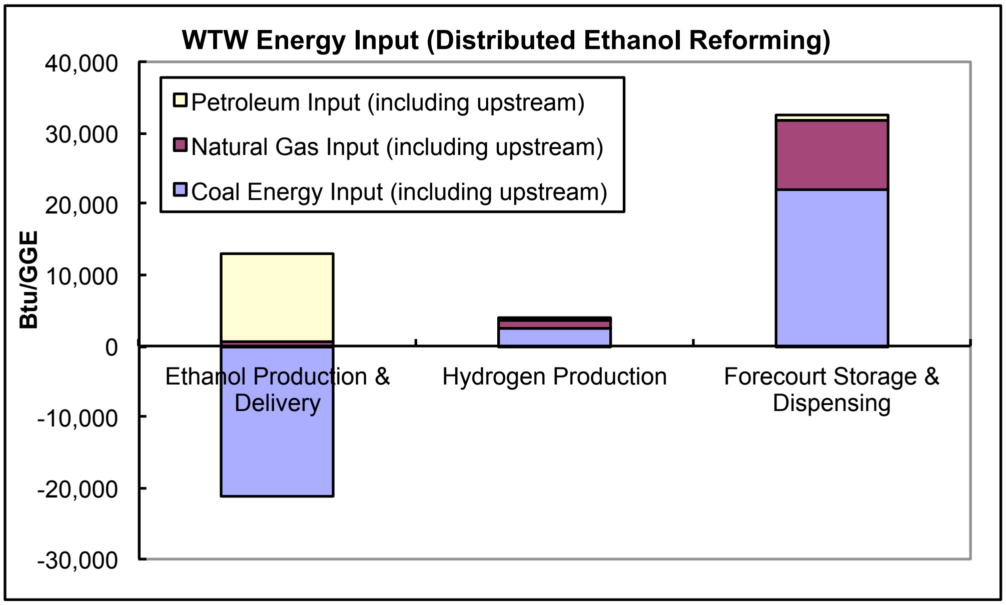


Figure 6.2.6. WTW petroleum, natural gas, and coal inputs to deliver 116,000 Btu hydrogen using the distributed ethanol pathway

Figures 6.2.7 and 6.2.8 show the WTW emissions resulting from the delivery of 116,000 Btu hydrogen to a vehicle fuel tank using the distributed ethanol pathway.

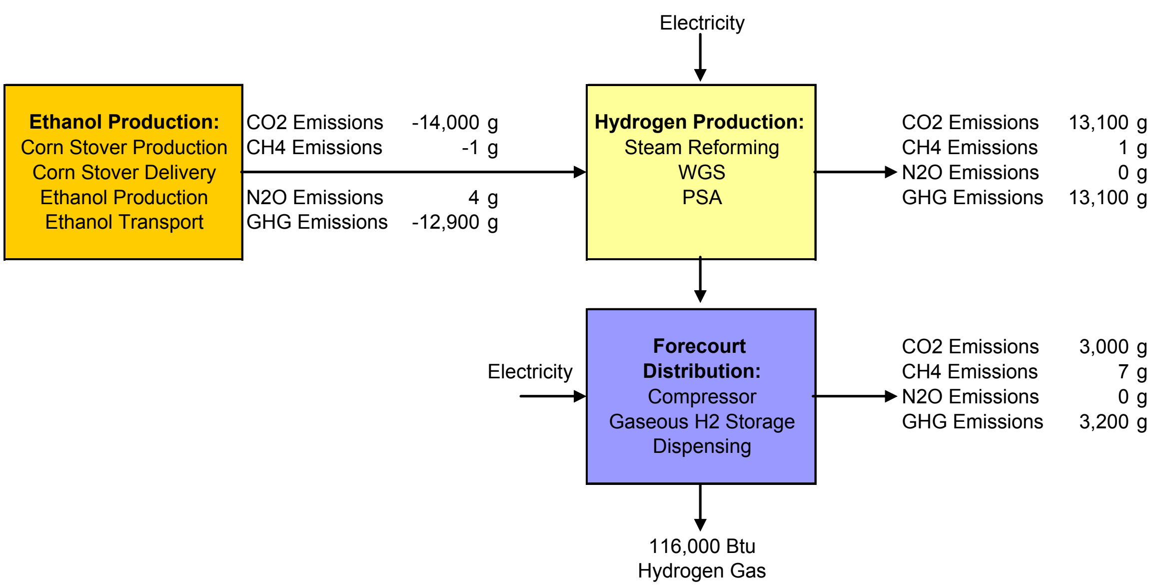


Figure 6.2.7. WTW emissions resulting from delivery of 116,000 Btu hydrogen using the distributed ethanol pathway

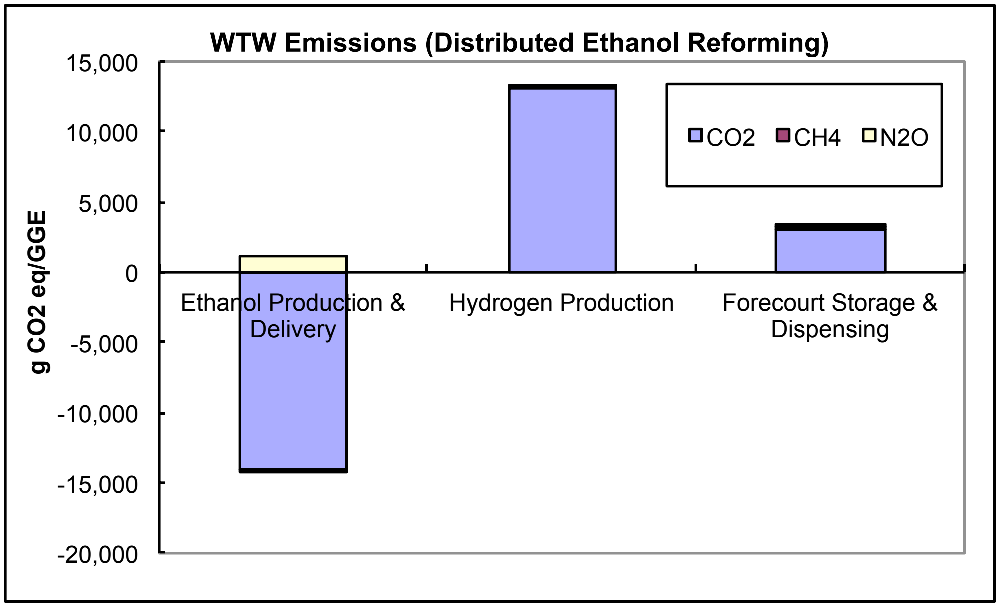


Figure 6.2.8. WTW CO_2, CH_4, and N_2O emissions resulting from delivery of 116,000 Btu hydrogen to a vehicle using the distributed ethanol pathway

6.2.3 Sensitivities

6.2.3.1 Production Sensitivities

The parameters used for this analysis are not known absolutely, so sensitivity analyses were performed to better understand the potential effects of that lack of knowledge on the final results. Several sensitivities were run on this pathway. They focused primarily on cost factors; however, several sensitivities also affect energy use and emissions. Figure 6.2.9 shows the effects of several production parameters on the pathway's levelized cost, and Table 6.2.3 shows the effect of production energy efficiency on WTW energy use and emissions.

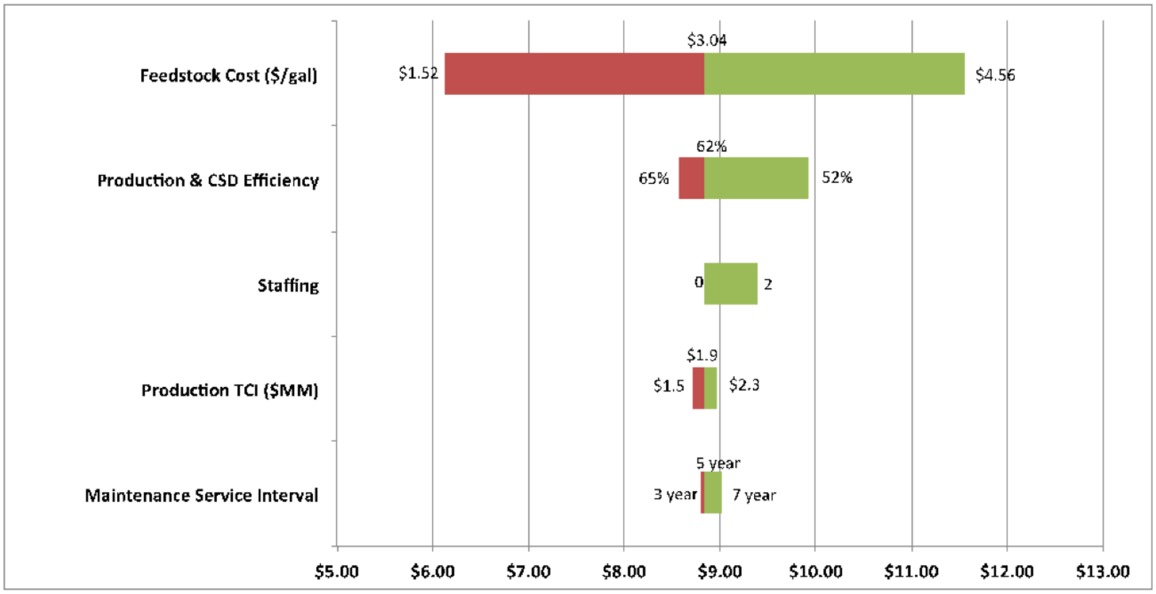


Figure 6.2.9. Production sensitivities for the distributed ethanol pathway

Table 6.2.3. The Effects of Production Energy Efficiency on Primary Energy Use and Emissions from the Distributed Ethanol Pathway

	56% Efficiency	67% Efficiency	70% Efficiency
WTW GHG emissions (g/mile)	70	70	70
WTW fossil energy (Btu/mile)	550	590	590
WTW petroleum energy (Btu/mile)	340	280	270
WTW total energy (Btu/mile)	9,300	7,900	7,500

The assumed electrical grid mix also affects the energy use and emissions. Table 6.2.4 shows the differences in energy use and GHG emissions between the U.S. average grid mix (which was used for all other sensitivities) and a hypothetical green grid mix that is 100% renewable energy (solar and wind).

Table 6.2.4. The Effects of Fuel Economy and Grid Mix on Use of Primary Energy and Emissions from the Distributed Ethanol Pathway

	U.S. Average Grid Mix (48 mpgge)	U.S. Average Grid Mix (68 mpgge)	“Green” Grid Mix (48 mpgge)
WTW GHG emissions (g/mile)	70	50	60
WTW fossil energy (Btu/mile)	590	410	490
WTW petroleum energy (Btu/mile)	280	200	280
WTW total energy (Btu/mile)	7,900	5,600	7,800

6.3 Distributed Electricity

Figure 6.3.1 shows the major inputs, assumptions, and outputs for each of the subsystems considered in the well-to-tank analysis, including feedstock supply and hydrogen dispensing. (See Appendix C for more details on this pathway.)

The WTP and WTW cost of hydrogen, energy use, and emissions for the distributed electricity pathway are summarized in Table 6.3.1.

6.3.1 Cost Breakdown

Figure 6.3.2 shows the feedstock and energy price inputs and the resulting hydrogen production, delivery, and distribution costs for the distributed electricity pathway. The financial assumptions used in this analysis are detailed in Section 5.

Figure 6.3.3 shows the contributions of hydrogen production, distribution (CSD), and losses to the levelized cost of hydrogen shown in Figure 6.3.2.

Figure 6.3.4 and Table 6.3.2 show the breakdown of levelized costs for the distributed electricity pathway.

Inputs			Assumptions			Outputs		
			Electricity Generation & Transmission					
			U.S. Grid Mix			Electricity price at H2 production	0.0574	2007$ / kWh
			Biomass Fraction	1%		Electricity Share of H2 Cost	$3.22	2007$ / kg H2 dispensed
			Coal Fraction	44%				
			Natural Gas Fraction	21%		WTG CO2 Emissions	36,930	g CO2 eq./ 116000 Btu
Coal Input (including upstream)	159,600	Btu / 116000Btu to Pump	Nuclear Fraction	21%		WTG CH4 Emissions	2,280	g CO2 eq./ 116000 Btu
Natural Gas Input (including upstream)	70,800	Btu / 116000Btu to Pump	Residual Oil Fraction	1%		WTG N2O Emissions	150	g CO2 eq./ 116000 Btu
Petroleum Input (including upstream)	6,100	Btu / 116000Btu to Pump	Others (Carbon Neutral)	12%		WTG GHG Emissions	39,360	g CO2 eq./ 116000 Btu
						Hydrogen Output Pressure	300	psi
Electricity consumption	50.0	kWh / kg H2 produced	**Hydrogen Production**			Hydrogen Outlet Quality	100.0%	
Process Water Consumption	2.94	gal / kg H2 produced						
Cooling Water Consumption	0.11	gal / kg H2 produced	Distributed plant design capacity	1,500	kg / day	Total capital investment	$1,700	2007$ / daily kg H2 (effective capacity)
			Capacity factor	89%		Levelized Cost of Capital	$0.77	2007$ / kg H2 dispensed
			# of Plants Needed to Meet City Demand	91		Fixed O&M Costs	$0.28	2007$ / kg H2 dispensed
Total Capital Investment per station	$2,258,000	2007$	Process energy efficiency	66.8%		Variable O&M Costs	$0.06	2007$ / kg H2 dispensed
			Electricity Mix	US Mix		Total Levelized Cost	$4.32	2007$ / kg H2 dispensed
			After-tax IRR	10%				
Coal Input (including upstream)	86,400	Btu / 116000Btu to Pump	Assumed Plant Life	20	years	Production CO2 Emissions	0	g CO2 eq./ 116000 Btu
Natural Gas Input (including upstream)	38,300	Btu / 116000Btu to Pump				Production CH4 Emissions	0	g CO2 eq./ 116000 Btu
Petroleum Input (including upstream)	3,300	Btu / 116000Btu to Pump				Production N2O Emissions	0	g CO2 eq./ 116000 Btu
						Production GHG Emissions	0	g CO2 eq./ 116000 Btu
Electricity consumption	4.4	kWh / kg H2	**Forecourt Dispensing**			Hydrogen outlet pressure	12,700	psi
Electricity price	$0.088	2007$ / kWh				Basis -- Hydrogen Quantity	116,000	Btu (116,000 Btu/gal non-oxygenated conventional unleaded gasoline)
			City Population	1,247,000	people			
			Hydrogen Vehicle Penetration	15%				
Total Capital Investment (per station)	$5,059,000	2007$ / station	City hydrogen use	121,100	kg / day	Total capital investment	$3,810	2007$ / daily kg H2 (effective capacity)
Total Capital Investment	$465,391,000	2007$ / all stations	Average Dispensing Rate per Station	1,330	kg / day	Levelized Cost of Capital	$1.49	2007$ / kg H2 dispensed
			Number of Dispensing Stations	92		Energy & Fuel	$0.40	2007$ / kg H2 dispensed
			Number of Compression Steps	0		Other O&M Costs	$0.54	2007$ / kg H2 dispensed
			Usable Low Pressure Storage per Station	1,450	kg H2	Levelized Cost of Dispensing	$2.43	2007$ / kg H2 dispensed
			Usable Cascade Storage per Station	200	kg H2			
Coal Input (including upstream)	21,900	Btu / 116000Btu to Pump	Site storage	100%	% of design capacity	CSD CO2 Emissions	3,020	g CO2 eq./ 116000 Btu
Natural Gas Input (including upstream)	9,700	Btu / 116000Btu to Pump	# of 2-hose Dispensers per Station	3		CSD CH4 Emissions	190	g CO2 eq./ 116000 Btu
Petroleum Input (including upstream)	800	Btu / 116000Btu to Pump	Hydrogen losses	0.50%		CSD N2O Emissions	12	g CO2 eq./ 116000 Btu
						CSD GHG Emissions	3,220	g CO2 eq./ 116000 Btu
Vehicle Mass	3,020	lb	**Vehicle**			Cost Per Mile	$0.71	2007$ / mi
Fuel cell size	70	kW	Fuel Economy	48.0	mi / gge	Fuel Share	$0.14	2007$ / mi
Size of hybridization battery	30	kW	Vehicle Miles Traveled	15,000	mi / yr	Maintenance, Tires, Repairs	$0.07	2007$ / mi
			Vehicle Lifetime	160,000	mi	Insurance & Registration	$0.12	2007$ / mi
			Purchase Year	2015		Depreciation	$0.27	2007$ / mi
			Vehicle Purchase Cost	$33,700	2007$	Financing	$0.10	2007$ / mi
			Fuel Cell System Cost	$4,500	2007$			
Coal Input (including upstream)	2,300	Btu / gge fuel consumed	Hydrogen Storage System Cost	$2,400	2007$	Vehicle Cycle CO2 Emissions	1,670	g CO2 eq / gge fuel consumed
Natural Gas Input (including upstream)	12,100	Btu / gge fuel consumed	Tax Credit	$0	2007$	Vehicle Cycle CH4 Emissions	7	g CO2 eq / gge fuel consumed
Petroleum Input (including upstream)	6,900	Btu / gge fuel consumed				Vehicle Cycle N2O Emissions	0	g CO2 eq / gge fuel consumed
						Vehicle Cycle GHG Emissions	1,850	g CO2 eq / gge fuel consumed

Figure 6.3.1. Summary of major inputs, assumptions, and outputs by subsystem for the distributed grid electricity pathway

Table 6.3.1. WTP and WTW Results for the Distributed Grid Electricity Pathway

	WTP		WTW	
Coal input (including upstream)[a]	267,900	Btu/116,000 Btu	5,590	Btu/mi
Natural gas input (including upstream)[a]	118,800	Btu/116,000 Btu	2,480	Btu/mi
Petroleum input (including upstream)[a]	10,200	Btu/116,000 Btu	210	Btu/mi
Fossil energy input (including upstream)[a]	396,900	Btu/116,000 Btu	8,280	Btu/mi
WTP CO_2 emissions[b]	40,000	g/116,000 Btu	770	g/mi
WTP CH_4 emissions	100	g/116,000 Btu	2	g/mi
WTP N_2O emissions	1	g/116,000 Btu	0	g/mi
WTP GHG emissions	42,600	g CO_2-eq./ 116,000 Btu	820	g/mi
	Cost per kg		**Cost per mile**	
Levelized cost of hydrogen	$6.75	2007$/kg	$0.14	2007$/mi

[a] Coal, natural gas, and petroleum inputs include those used directly in the hydrogen production and delivery pathway as feedstocks and fuels; those used to produce electricity and other materials used in the pathway; and those used upstream of the pathway to recover, refine, and deliver the feedstock.
[b] Includes the carbon content of CO, CH_4, and volatile organic compound emissions that decompose in the atmosphere to CO_2.

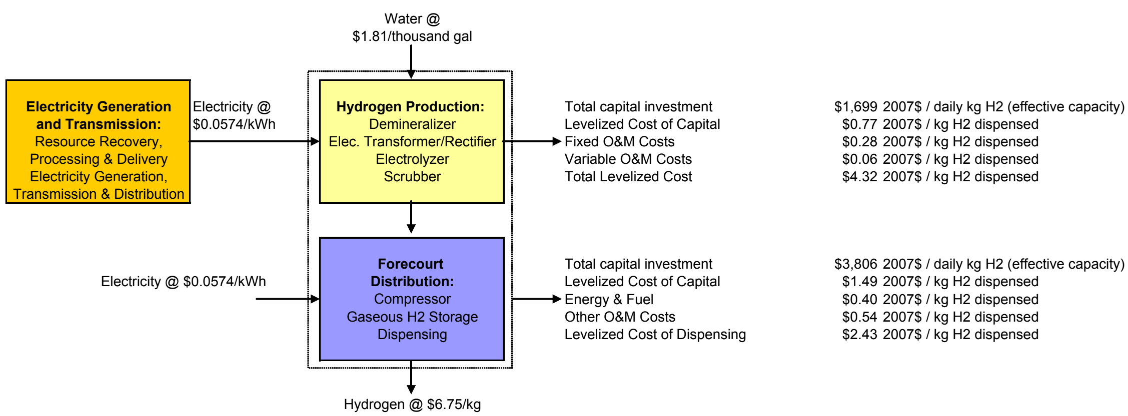


Figure 6.3.2. Cost analysis inputs and high-level results for the distributed grid electricity pathway

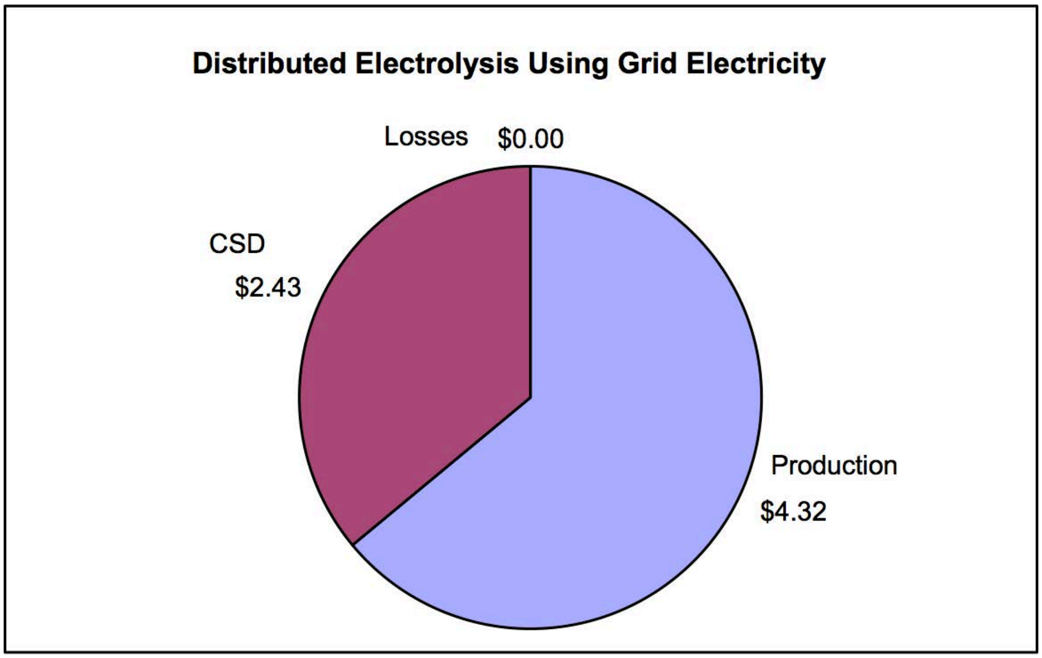


Figure 6.3.3. Contribution of hydrogen production, CSD, and losses to the levelized cost of hydrogen for the distributed grid electricity pathway

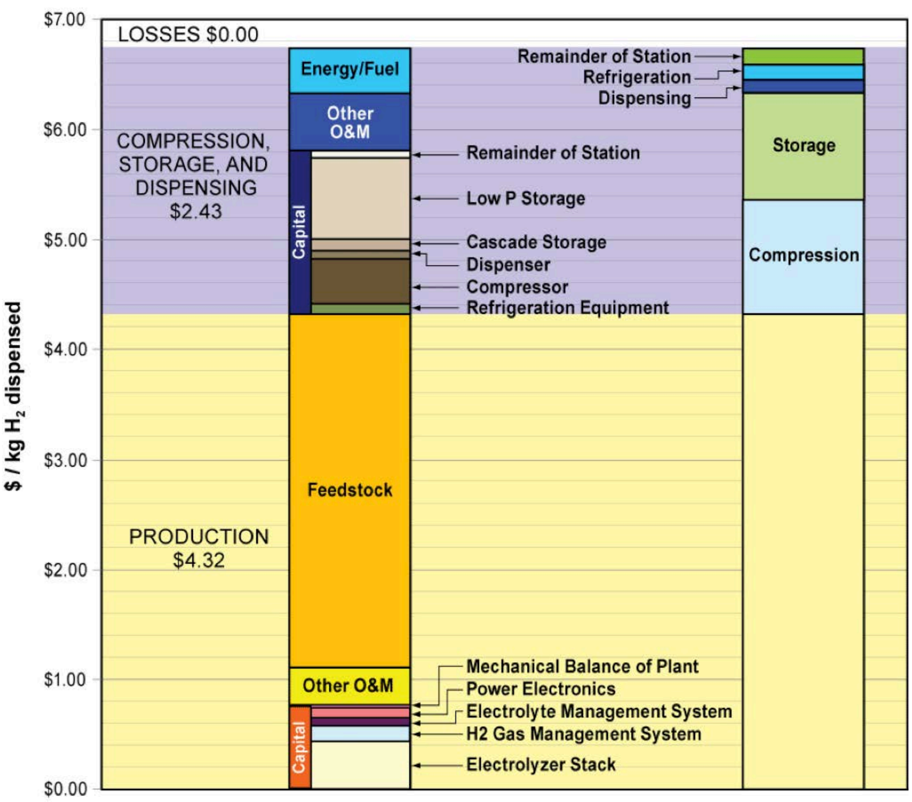


Figure 6.3.4. Breakdown of levelized costs for the distributed grid electricity pathway

Table 6.3.2. Contribution of Production and CSD Processes to Levelized Hydrogen Cost for the Distributed Grid Electricity Pathway

Cost Component	Capital	Other O&M	Feedstock	Energy/ Fuel	Total
Production	$0.76	$0.35	$3.22		$4.23
Electrolyzer stack	$0.42				
H_2 gas management system	$0.14				
Electrolyte management system	$0.09				
Power electronics	$0.09				
Balance of plant	$0.02				
CSD	$1.49	$0.54		$0.40	$2.43
Compressor (levelized)					$1.04
Storage (levelized)					$0.99
Dispenser (levelized)					$0.10
Refrigeration (levelized)					$0.16
Remainder of Station (levelized)					$0.14
Losses					$0.00
Total	**$2.24**	**$0.89**	**$3.22**	**$0.40**	**$6.75**

6.3.2 Energy Use and Emissions Breakdown

Figures 6.3.5 and 6.3.6 show the WTW energy inputs and losses for the distributed electricity pathway.

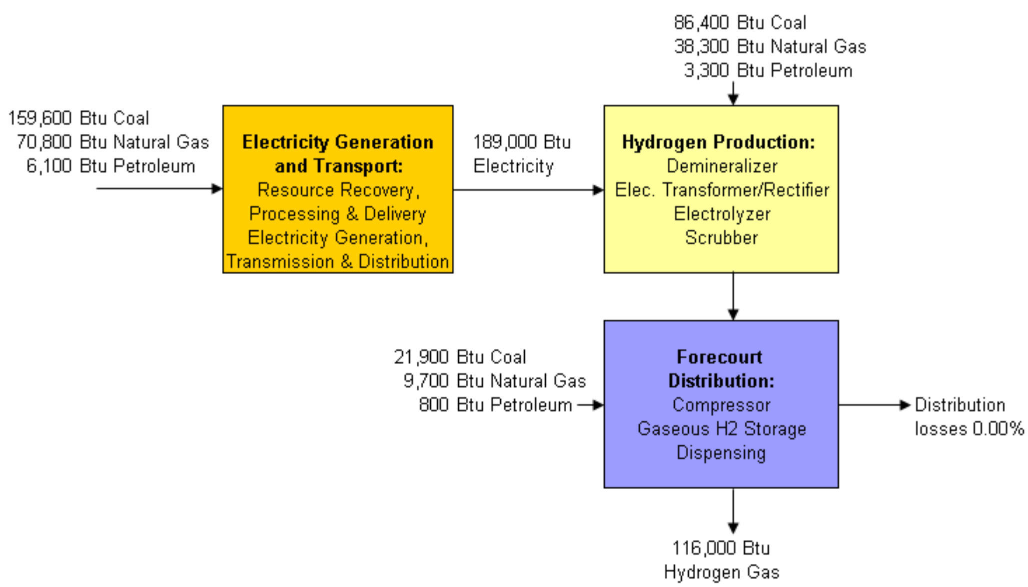


Figure 6.3.5. WTW energy inputs to deliver 116,000 Btu hydrogen to a vehicle using the distributed grid electricity pathway

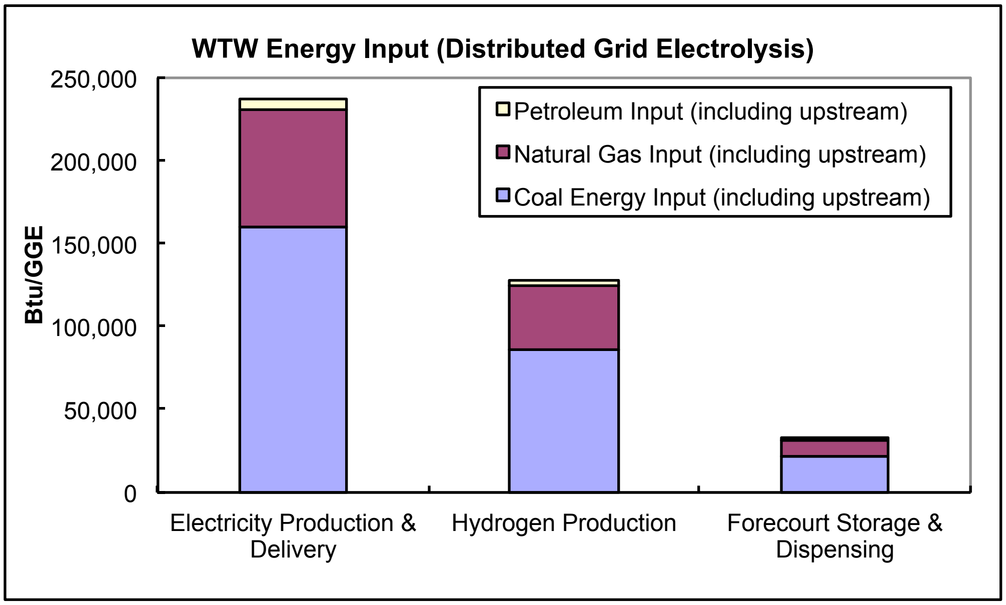


Figure 6.3.6. WTW petroleum, natural gas, and coal inputs to deliver 116,000 Btu hydrogen using the distributed grid electricity pathway

Figures 6.3.7 and 6.3.8 show the WTW emissions resulting from the delivery of 116,000 Btu hydrogen to a vehicle fuel tank using the distributed electricity pathway.

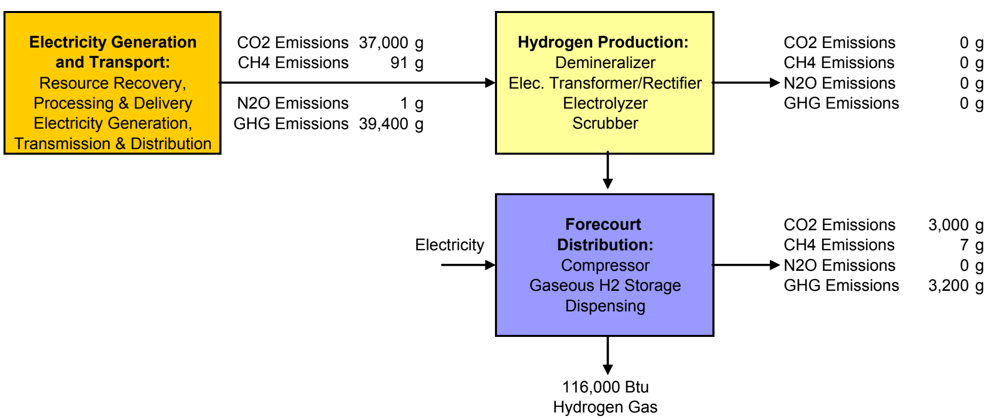


Figure 6.3.7. WTW emissions resulting from delivery of 116,000 Btu hydrogen using the distributed grid electricity pathway

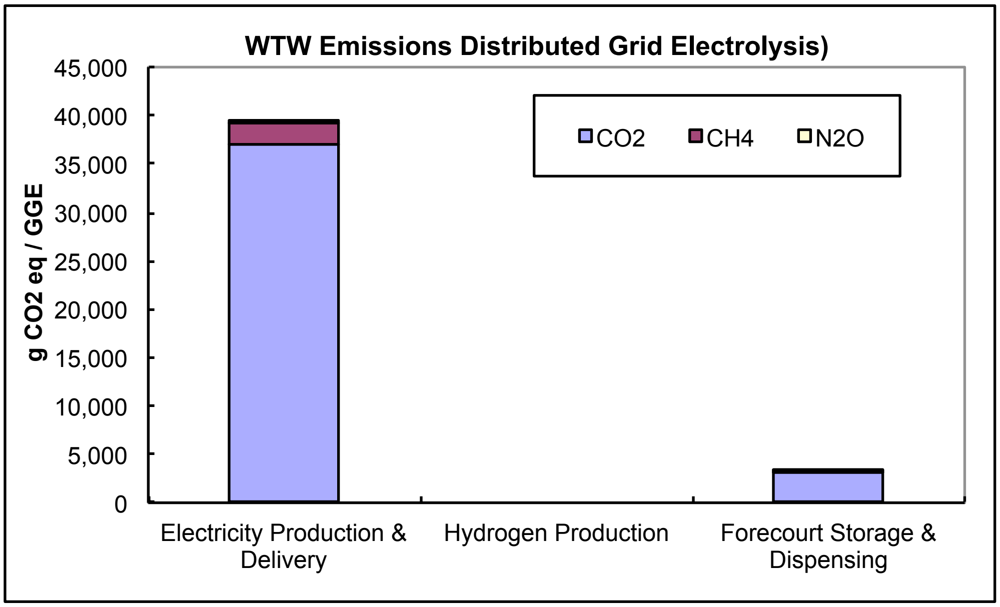


Figure 6.3.8. WTW CO_2, CH_4, and N_2O emissions resulting from delivery of 116,000 Btu hydrogen to a vehicle using the distributed grid electricity pathway

6.3.3 Sensitivities

6.3.3.1 Production Sensitivities

The parameters used for this analysis are not known absolutely, so sensitivity analyses were performed to better understand the potential effects of that lack of knowledge on the final results. Several sensitivities were run on this pathway. They focused primarily on cost factors; however, several sensitivities also affect energy use and emissions. Figure 6.3.9 shows the effects of several production parameters on the pathway's levelized cost, and Table 6.3.3 shows the effect of production energy efficiency on WTW energy use and emissions.

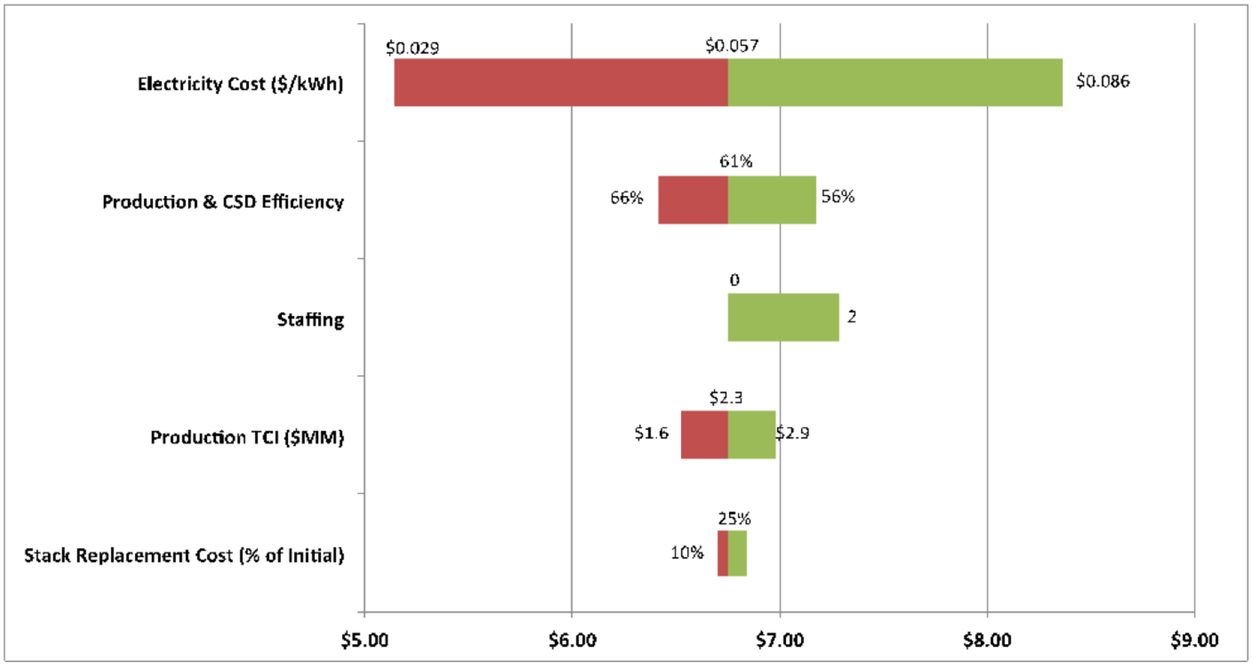


Figure 6.3.9. Production sensitivities for the distributed grid electrolysis pathway

Table 6.3.3. The Effects of Production Energy Efficiency on Primary Energy Use and Emissions from the Distributed Grid Electrolysis Pathway

	61% Efficiency	67% Efficiency	72% Efficiency
WTW GHG Emissions (g/mile)	900	820	760
WTW Fossil Energy (Btu/mile)	9,000	8,300	7,700
WTW Petroleum Energy (Btu/mile)	230	210	200
WTW Total Energy (Btu/mile)	10,700	9,800	9,100

The assumed electrical grid mix also affects the energy use and emissions. If a hypothetical green grid mix that is 100% renewable energy (solar and wind) is used instead of the average grid mix (which was used for all other sensitivities), no fossil energy is used, nor are there any GHG emissions (Table 6.3.4).

Table 6.3.4. The Effects of Fuel Economy and Grid Mix on Use of Primary Energy and Emissions from the Distributed Grid Electrolysis Pathway

	U.S. Average Grid Mix (48 mpgge)	U.S. Average Grid Mix (68 mpgge)	"Green" Grid Mix (48 mpgge)
WTW GHG emissions (g/mile)	820	580	10
WTW fossil energy (Btu/mile)	8,300	5,800	0
WTW petroleum energy (Btu/mile)	210	150	0
WTW total energy (Btu/mile)	9,800	6,800	4,300

6.4 Central Biomass—Pipeline Delivery

Figure 6.4.1 shows the major inputs, assumptions, and outputs for each of the subsystems considered in the well-to-tank analysis, including feedstock supply and hydrogen dispensing. (See Appendix D for more details on this pathway.)

The WTP and WTW cost of hydrogen, energy use, and emissions for the central biomass—pipeline delivery pathway are summarized in Table 6.4.1.

Net GHG emissions include carbon dioxide uptake occurring during growth of the biomass. The analysis assumes that 100% of the carbon in the biomass is provided by atmospheric carbon dioxide. No other carbon uptake is assumed (e.g., carbon utilized to produce roots is assumed to be returned to the atmosphere through decomposition). Likewise, land use change is assumed to have neither positive nor negative effects on emissions.

6.4.1 Cost Breakdown

Figure 6.4.2 shows the feedstock and energy price inputs and the resulting hydrogen production, delivery, and distribution costs for the central biomass—pipeline delivery pathway. The financial assumptions used in this analysis are detailed in Section 5.

Figure 6.4.3 shows the contributions of hydrogen production, delivery, and losses to the levelized cost of hydrogen shown in Figure 6.4.2.

Figure 6.4.4 and Table 6.4.2 show the breakdown of levelized costs for the central biomass—pipeline delivery pathway.

Inputs

Biomass Production & Delivery		
Energy Use for Farming Trees	235,000	Btu / dry ton
Coal Input (including upstream)	200	Btu / 116000Btu to Pump
Natural Gas Input (including upstream)	600	Btu / 116000Btu to Pump
Petroleum Input (including upstream)	2,900	Btu / 116000Btu to Pump
Hydrogen Production		
Biomass consumption	13.5	kg (dry) / kg H2 produced
Natural gas consumption	0.0059	MMBtu / kg H2 produced
Electricity consumption	0.98	kWh / kg H2 produced
Process Water Consumption	1.32	gal / kg H2 produced
Cooling Water Consumption	79.3	gal / kg H2 produced
Total Capital Investment	$181,080,000	2007$
Coal Input (including upstream)	5,100	Btu / 116000Btu to Pump
Natural Gas Input (including upstream)	9,500	Btu / 116000Btu to Pump
Petroleum Input (including upstream)	3,400	Btu / 116000Btu to Pump
Pipelines for Delivery		
Electricity consumption for compressor	0.56	kWh / kg H2 dispensed
Electricity consumption for geo storage	0.01	kWh / kg H2 dispensed
Total electricity consumption	0.57	kWh / kg H2 dispensed
Total Capital Investment	$404,341,000	2007$
Coal Input (including upstream)	2,800	Btu / 116000Btu to Pump
Natural Gas Input (including upstream)	1,300	Btu / 116000Btu to Pump
Petroleum Input (including upstream)	100	Btu / 116000Btu to Pump
Forecourt Dispensing		
Electricity consumption	4.4	kWh / kg H2 dispensed
Total Capital Investment per Station	$2,629,000	2007$ / station
Total Capital Investment	$320,679,000	2007$ / all stations
Inlet pressure of hydrogen at stations	300	psi
Coal Input (including upstream)	24,400	Btu / 116000 Btu to Pump
Natural Gas Input (including upstream)	10,800	Btu / 116000 Btu to Pump
Petroleum Input (including upstream)	900	Btu / 116000 Btu to Pump
Vehicle		
Vehicle Mass	3,020	lb
Fuel cell size	70	kW
Hybridization battery (peak power)	30	kW
Coal Input (including upstream)	2,300	Btu / gge fuel consumed
Natural Gas Input (including upstream)	12,100	Btu / gge fuel consumed
Petroleum Input (including upstream)	6,900	Btu / gge fuel consumed

Assumptions

Biomass Production & Delivery		
Fraction of Woody Biomass	100%	
LUC GHG changes	='Params - U	g / dry ton
Average dist from farm to H2 production	pstream'!E15	miles
Hydrogen Production		
Central plant design capacity	155,200	kg / day
Capacity factor	90%	
Number of production facilities necessary	0.87	
Process energy efficiency	46.0%	
Electricity Mix	US Mix	
After-tax IRR	10%	
Assumed Plant Life	40	
Pipelines for Delivery		
City Population	1,247,000	people
Hydrogen Vehicle Penetration	15%	
City hydrogen use	121,100	kg / day
Distance from City to Production Facility	62	miles
Geologic storage capacity	1,325,000	kg H2
Number of trunk pipelines	3	
Service-line length	1.5	miles / line
Number of service lines	122	
Hydrogen losses	0.80%	
Forecourt Dispensing		
Average Dispensing Rate per Station	1,000	kg/day
Number of Dispensing Stations	122	
Number of Compression Steps	5	
Usable Low Pressure Storage per Station	370	kg H2
Usable Cascade Storage per Station	130	kg H2
Site storage	42%	% of design capacity
# of 2-hose Dispensers per Station	2	
Hydrogen Losses	0.50%	
Vehicle		
Fuel Economy	48.0	mi / gge
Vehicle Miles Traveled	15,000	mi / yr
Vehicle Lifetime	160,000	mi
Purchase Year	2015	
Vehicle Purchase Cost	$33,700	2007$
Fuel Cell System Cost	$4,500	2007$
Hydrogen Storage System Cost	$2,400	2007$
Tax Credit	$0	2007$

Outputs

Biomass Production & Delivery		
Biomass moisture content	25%	
Woody biomass LHV	16,013,200	Btu / dry ton
Biomass price at H2 production	$75	2007 $ / dry ton
Biomass Share of Levelized Cos	$0.97	2007$ / kg H2 dispensed
WTG CO2 Emissions	-24,830	g CO2 eq./ 116000 Btu
WTG CH4 Emissions	13	g CO2 eq./ 116000 Btu
WTG N2O Emissions	35	g CO2 eq./ 116000 Btu
WTG GHG Emissions	-24,780	g CO2 eq./ 116000 Btu
Hydrogen Production		
Hydrogen Output Pressure	300	psi
Hydrogen Outlet Quality	99.9%	
Total capital investment	$1,300	2007$ / daily kg H2 (effective capacity)
Levelized Cost of Capital	$0.64	2007$ / kg H2 dispensed
Fixed O&M Costs	$0.23	2007$ / kg H2 dispensed
Variable O&M Costs	$0.40	2007$ / kg H2 dispensed
Total Levelized Cost	$2.24	2007$ / kg H2 dispensed
Production CO2 Emissions	26,510	g CO2 eq./ 116000 Btu
Production CH4 Emissions	140	g CO2 eq./ 116000 Btu
Production N2O Emissions	43	g CO2 eq./ 116000 Btu
Production GHG Emissions	26,690	g CO2 eq./ 116000 Btu
Pipelines for Delivery		
Total capital investment	$3,300	2007$ / daily kg H2 (effective capacity)
Levelized Cost of Capital	$1.71	2007$ / kg H2 dispensed
Energy & Fuel	$0.04	2007$ / kg H2 dispensed
Other O&M Costs	$0.40	2007$ / kg H2 dispensed
Levelized Cost of Delivery	$2.15	2007$ / kg H2 dispensed
Delivery CO2 Emissions	390	g CO2 eq./ 116000 Btu
Delivery CH4 Emissions	24	g CO2 eq./ 116000 Btu
Delivery N2O Emissions	2	g CO2 eq./ 116000 Btu
Delivery GHG Emissions	420	g CO2 eq./ 116000 Btu
Forecourt Dispensing		
Hydrogen outlet pressure	12,700	psi
Basis -- Hydrogen Quantity	116,000	Btu (116,000 Btu/gal non-oxygenated conventional unleaded gasoline)
Total capital investment	$2,650	2007$ / daily kg H2 (effective capacity)
Levelized Cost of Capital	$1.08	2007$ / kg H2 dispensed
Energy & Fuel	$0.41	2007$ / kg H2 dispensed
Other O&M Costs	$0.43	2007$ / kg H2 dispensed
Levelized Cost of Dispensing	$1.93	2007$ / kg H2 dispensed
CSD CO2 Emissions	3,370	g CO2 eq./ 116000 Btu
CSD CH4 Emissions	210	g CO2 eq./ 116000 Btu
CSD N2O Emissions	14	g CO2 eq./ 116000 Btu
CSD GHG Emissions	3,590	g CO2 eq./ 116000 Btu
Vehicle		
Cost Per Mile	$0.70	2007$ / mi
Fuel Share	$0.13	2007$ / mi
Maintenance, Tires, Repairs	$0.07	2007$ / mi
Insurance & Registration	$0.12	2007$ / mi
Depreciation	$0.27	2007$ / mi
Financing	$0.10	2007$ / mi
Veh. Cycle CO2 Emissions	1,670	g CO2 eq/ gge fuel consumed
Veh. Cycle CH4 Emissions	7	g CO2 eq/ gge fuel consumed
Veh. Cycle N2O Emissions	0	g CO2 eq/ gge fuel consumed
Veh. Cycle GHG Emissions	1,850	g CO2 eq/ gge fuel consumed

Figure 6.4.1. Summary of major inputs, assumptions, and outputs by subsystem for the central biomass—pipeline delivery pathway

Table 6.4.1. WTP and WTW Results for the Central Biomass—Pipeline Delivery Pathway

	WTP		WTW	
Coal input (including upstream)[a]	32,600	Btu/116,000 Btu	680	Btu/mi
Natural gas input (including upstream)[a]	22,600	Btu/116,000 Btu	460	Btu/mi
Petroleum input (including upstream)[a]	7,300	Btu/116,000 Btu	150	Btu/mi
Fossil energy input (including upstream)[a]	62,100	Btu/116,000 Btu	1,300	Btu/mi
WTP CO_2 emissions[b]	5,400	g/116,000 Btu	110	g/mi
WTP CH_4 emissions	15	g/116,000 Btu	0	g/mi
WTP N_2O emissions	0	g/116,000 Btu	0	g/mi
WTP GHG emissions	5,900	g CO_2-eq./ 116,000 Btu	120	g/mi
	Cost per kg		**Cost per mile**	
Levelized cost of hydrogen	$6.32	2007$/kg	$0.13	2007$/mi

[a] Coal, natural gas, and petroleum inputs include those used directly in the hydrogen production and delivery pathway as feedstocks and fuels; those used to produce electricity and other materials used in the pathway; and those used upstream of the pathway to recover, refine, and deliver the feedstock.
[b] Includes the carbon content of CO, CH_4, and volatile organic compound emissions that decompose in the atmosphere to CO_2.

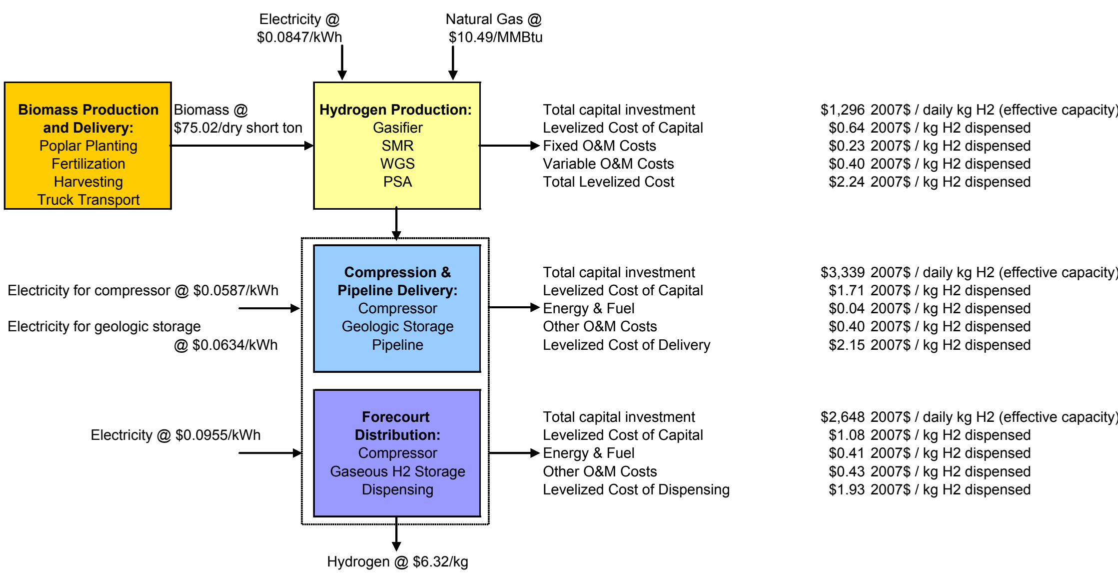


Figure 6.4.2. Cost analysis inputs and high-level results for the central biomass—pipeline delivery pathway

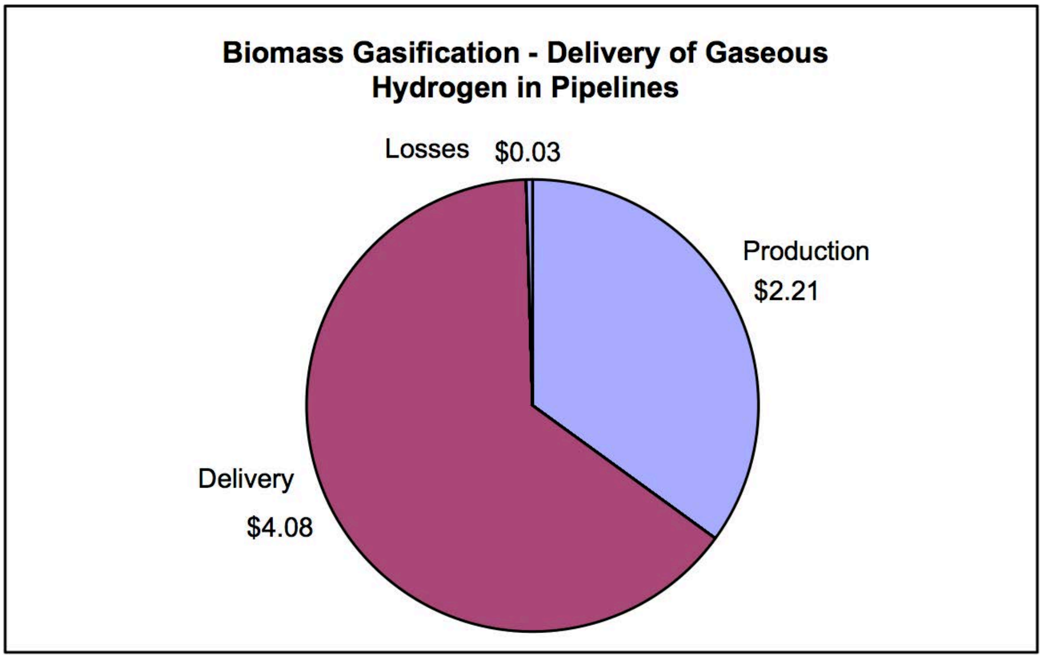


Figure 6.4.3. Contribution of hydrogen production, delivery, and losses to the levelized cost of hydrogen for the central biomass—pipeline delivery pathway

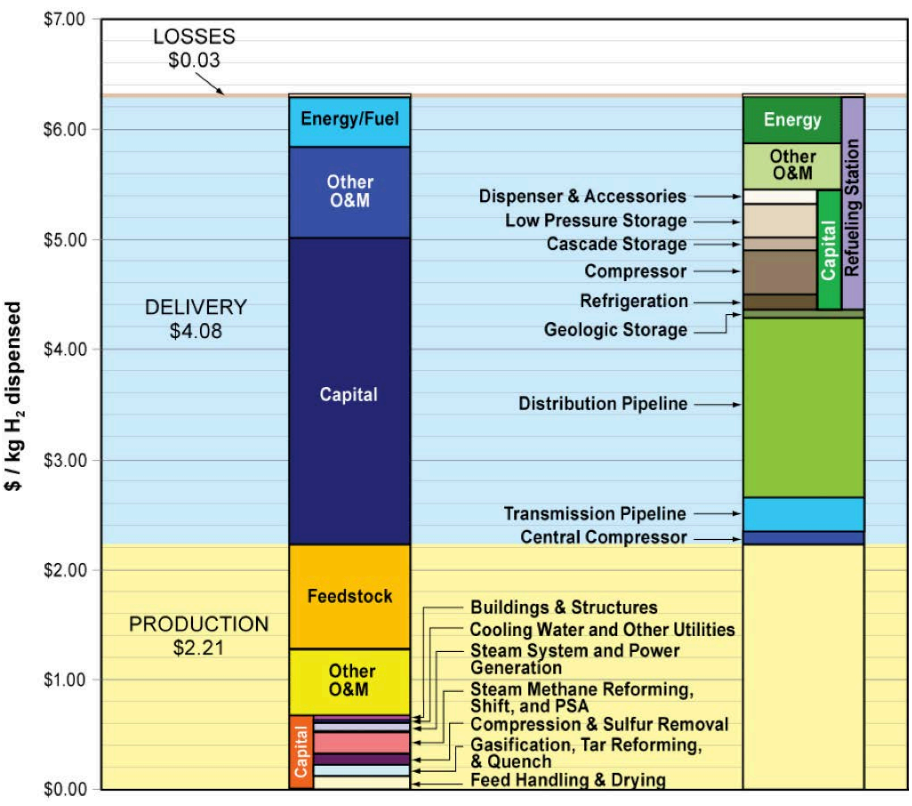


Figure 6.4.4. Breakdown of levelized costs for the central biomass—pipeline delivery pathway

Table 6.4.2. Contribution of Production and Delivery Processes to Levelized Hydrogen Cost for the Central Biomass—Pipeline Delivery Pathway

Cost Component	**Capital**	**Other O&M**	**Feedstock**	**Energy/ Fuel**	**Total**
Production	$0.64	$0.62	$0.96		$2.21
Feed handling and drying	$0.11				
Gasification, tar reforming, and quench	$0.10				
Compression and sulfur removal	$0.09				
SMR, WGS, and PSA	$0.18				
Steam system and power generation	$0.09				
Cooling water and other utilities	$0.02				
Buildings and structures	$0.04				
Delivery	$2.80	$0.83		$0.45	$4.08
Central compressor					$0.12
Transmission pipeline					$0.30
Distribution pipeline					$1.64
Geologic storage					$0.09
Gaseous refueling station	$1.08	$0.43		$0.41	$1.93
Refrigeration	$0.12				
Compressor	$0.41				
Cascade storage	$0.12				
Low pressure storage	$0.30				
Dispenser and accessories	$0.13				
Losses					$0.03
Total	**$3.44**	**$1.45**	**$0.96**	**$0.45**	**$6.32**

6.4.2 Energy Use and Emissions Breakdown

Figures 6.4.5 and 6.4.6 show the WTW energy inputs and losses for the central biomass—pipeline delivery pathway.

Figures 6.4.7 and 6.4.8 show the WTW emissions resulting from the delivery of 116,000 Btu hydrogen to a vehicle fuel tank using the central biomass—pipeline delivery pathway.

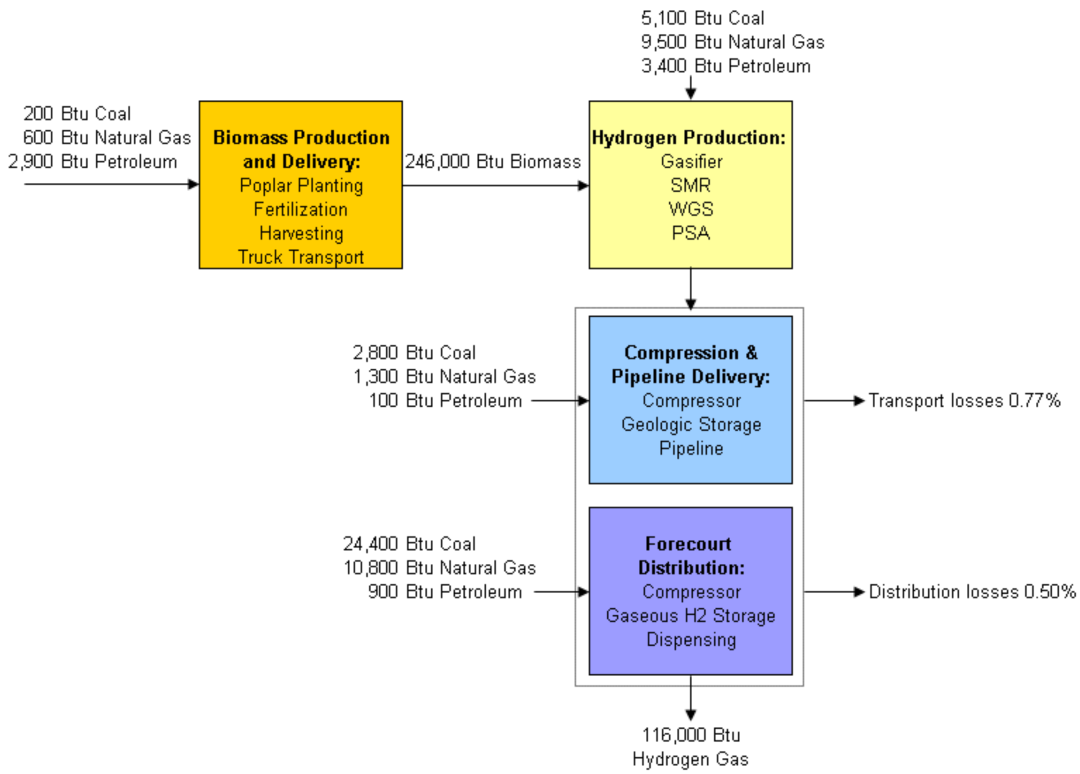


Figure 6.4.5. WTW energy inputs to deliver 116,000 Btu hydrogen to a vehicle using the central biomass—pipeline delivery pathway

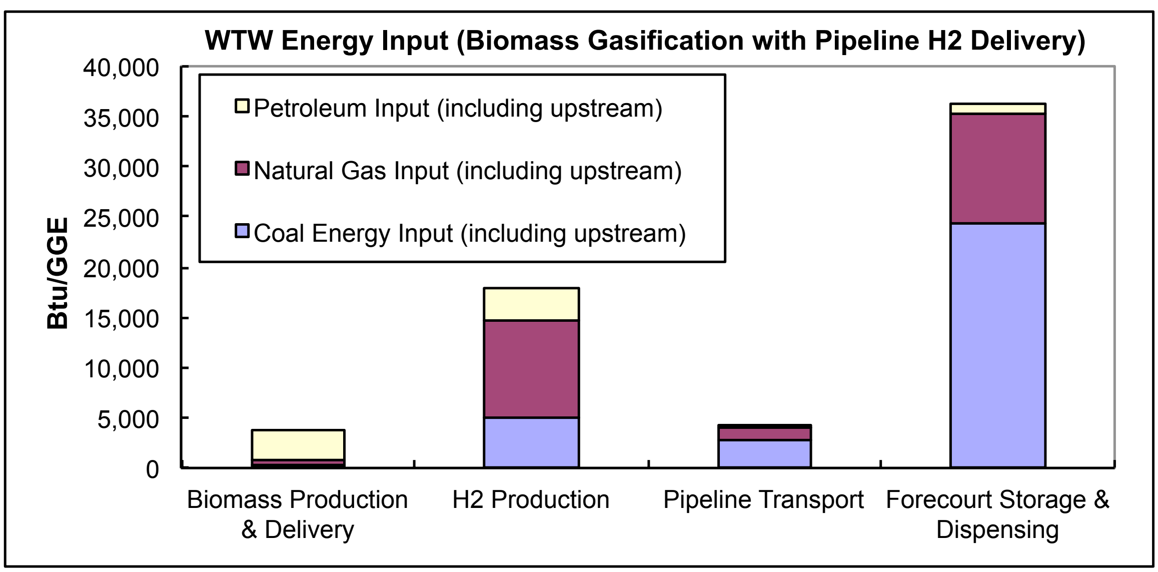


Figure 6.4.6. WTW petroleum, natural gas, and coal inputs to deliver 116,000 Btu hydrogen using the central biomass—pipeline delivery pathway

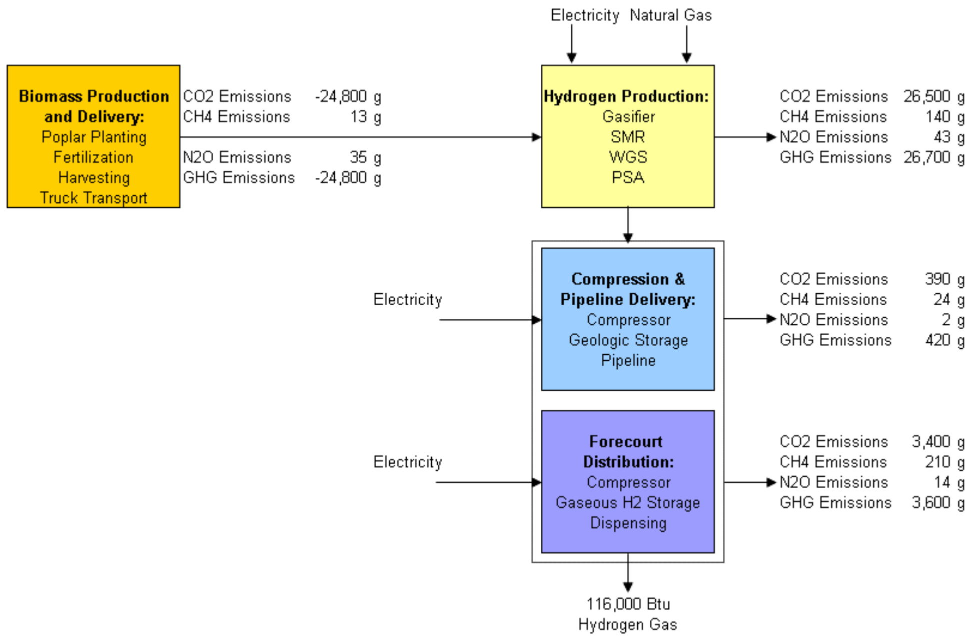


Figure 6.4.7. WTW emissions resulting from delivery of 116,000 Btu hydrogen using the central biomass—pipeline delivery pathway

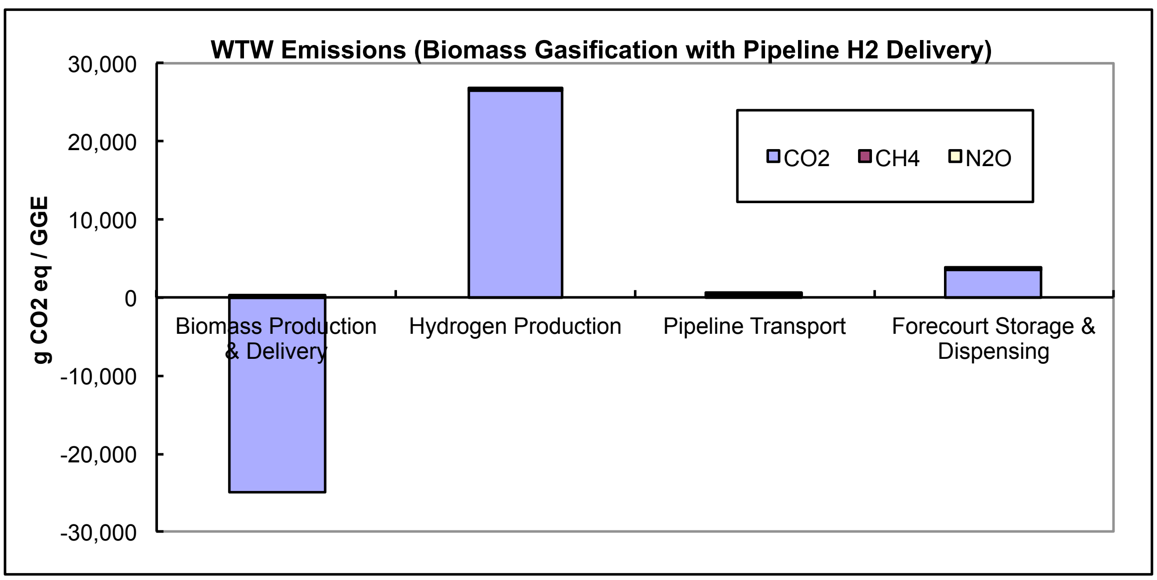


Figure 6.4.8. WTW CO_2, CH_4, and N_2O emissions resulting from delivery of 116,000 Btu hydrogen to a vehicle using the central biomass—pipeline delivery pathway

6.4.3 Sensitivities

6.4.3.1 Production Sensitivities

Several sensitivities were run on the production portion of the central biomass—pipeline delivery pathway. These sensitivities focused primarily on cost factors; however, several sensitivities also affect energy use and emissions. Figure 6.4.9 shows the effects of several production parameters on the pathway's levelized cost, and Table 6.4.3 shows the effects of varying production energy efficiency on WTW energy use and emissions.

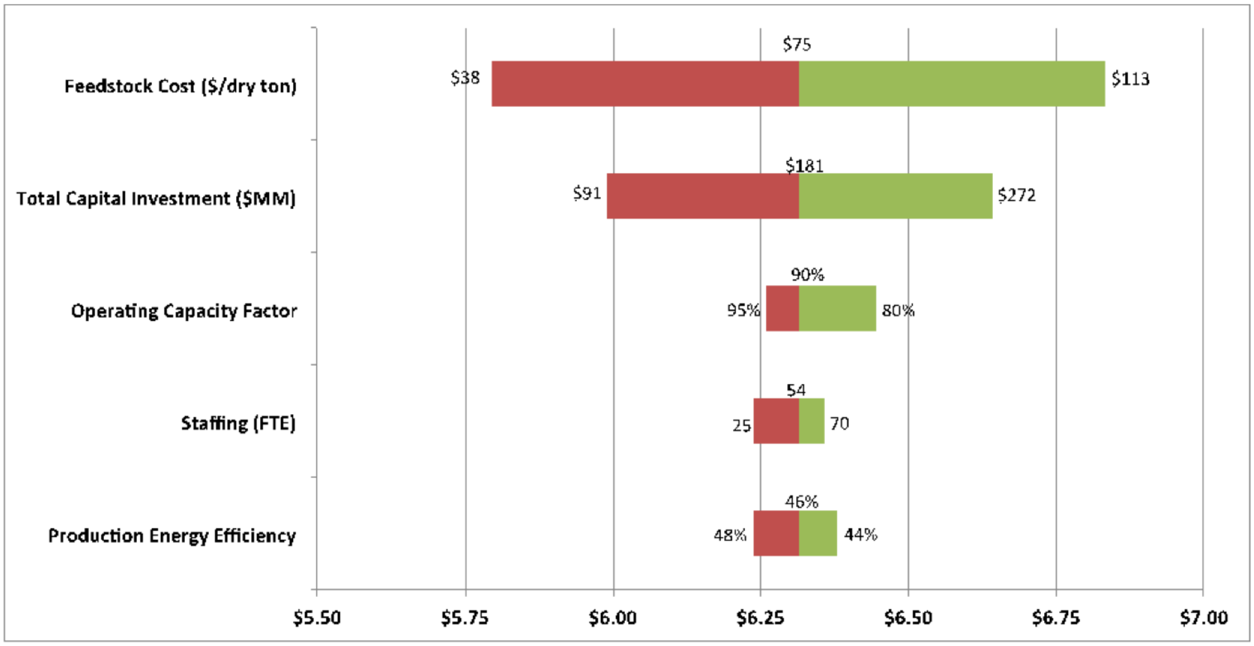


Figure 6.4.9. Production sensitivities for the central biomass—pipeline delivery pathway

Table 6.4.3. The Effects of Production Energy Efficiency on Primary Energy Use and Emissions from the Central Biomass—Pipeline Delivery Pathway

	44% Efficiency	46% Efficiency	48% Efficiency
WTW GHG emissions (g/mile)	120	120	120
WTW fossil energy (Btu/mile)	1,300	1,300	1,300
WTW petroleum energy (Btu/mile)	160	150	150
WTW total energy (Btu/mile)	6,900	6,600	6,300

The assumed electrical grid mix also affects the energy use and emissions. Table 6.4.4 shows the differences in energy use and GHG emissions between the U.S. average grid mix (which was used for all other sensitivities) and a hypothetical green grid mix that is 100% renewable energy (solar and wind).

Table 6.4.4. The Effects of Fuel Economy and Grid Mix on Use of Primary Energy and Emissions from the Central Biomass—Pipeline Delivery Pathway

	U.S. Average Grid Mix (48 mpgge)	U.S. Average Grid Mix (68 mpgge)	"Green" Grid Mix (48 mpgge)
WTW GHG emissions (g/mile)	120	90	20
WTW fossil energy (Btu/mile)	1,300	900	300
WTW petroleum energy (Btu/mile)	150	110	130
WTW total energy (Btu/mile)	6,600	4,700	5,900

6.4.3.2 Delivery Sensitivities

Delivery cost, energy use, and emissions are strongly dependent upon daily consumption of hydrogen within a city and delivery distance from the central facility to the city gate. Sensitivities were run to show some of those effects. Daily consumption was varied by keeping the city size constant and adjusting the penetration of hydrogen vehicles from the base case of 15%. The resulting consumption is shown in Figure 6.4.10.

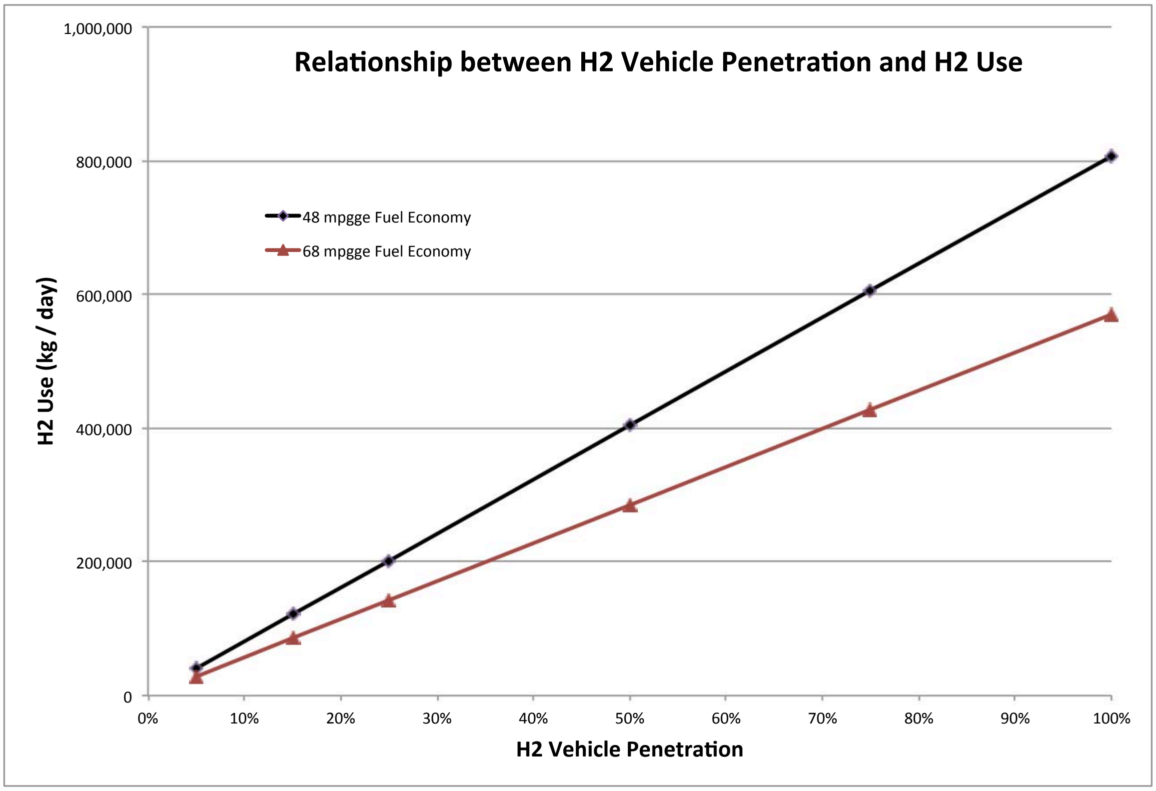


Figure 6.4.10. Daily hydrogen consumption versus hydrogen vehicle penetration for the central biomass—pipeline delivery pathway

As expected there are economies of scale for higher vehicle penetration/hydrogen consumption, and the levelized cost of delivery decreases as the distance from the production plant to the city gate is shortened. Figures 6.4.11 and 6.4.12 show those economic effects (the figures show identical data but are organized differently).

As Figure 6.4.12 shows, the cost increase due to distance from the city is more gradual with higher penetration because the cost of the transmission pipeline is shared more fully with increased demand.

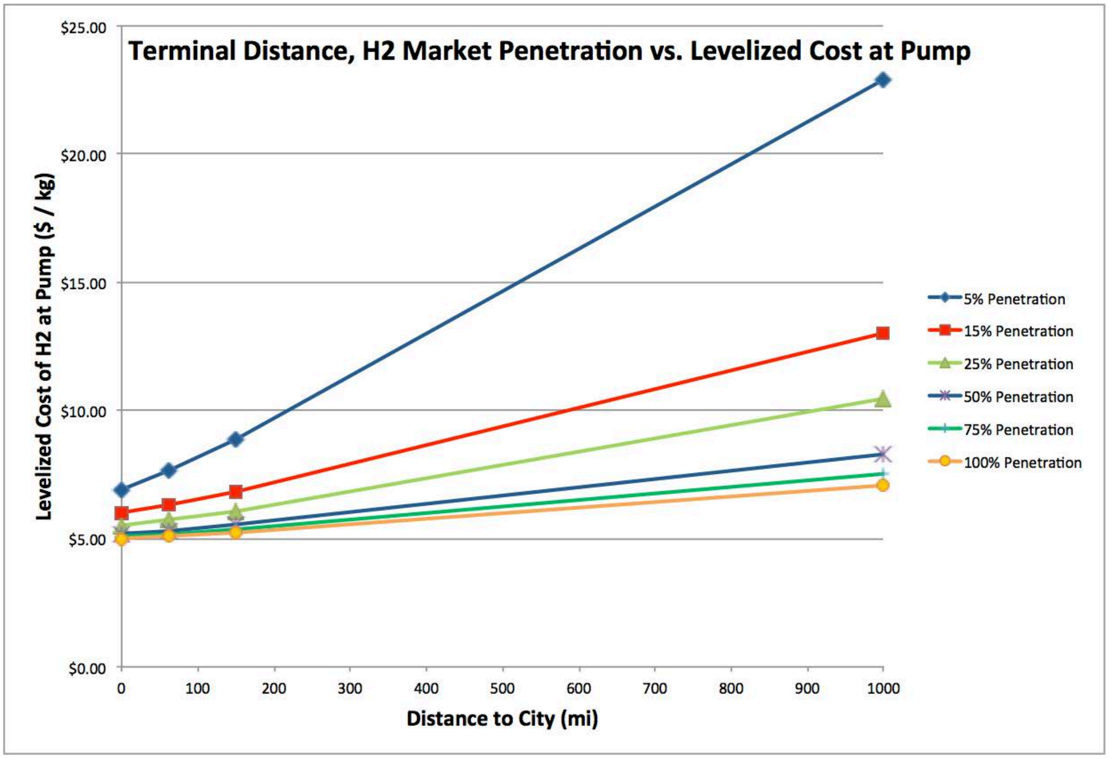


Figure 6.4.11. Levelized cost versus hydrogen vehicle penetration and distance between production facility and city gate for the central biomass—pipeline delivery pathway

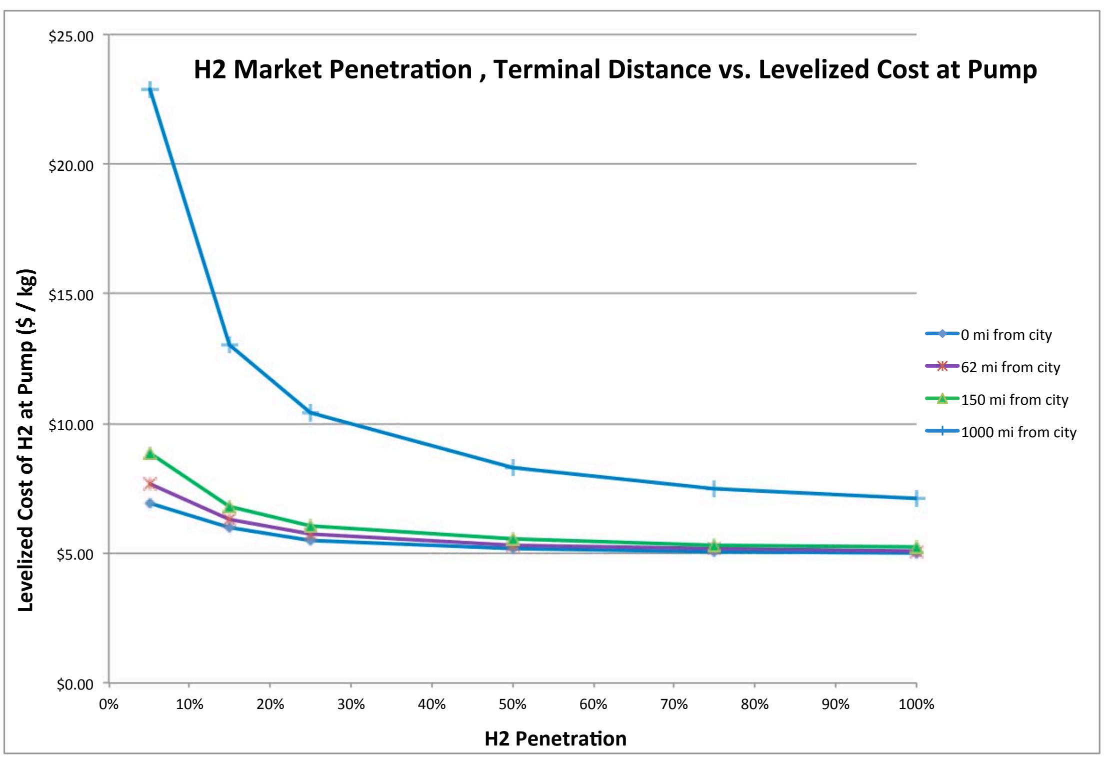


Figure 6.4.12. Levelized cost versus hydrogen vehicle penetration and distance between production facility and city gate for the central biomass—pipeline delivery pathway

The effects of penetration and distance between the production facility and city gate on WTW GHG emissions, WTW petroleum use, and WTW fossil energy use are shown in Figures 6.4.13, 6.4.14, and 6.4.15. The overall emissions change little with penetration because the additional energy required for distance is minimal. That additional electricity requirement is for compression over the distance. The total energy required for compression varies little with increased penetration because the total electricity required to compress each kilogram of hydrogen is nearly constant for all penetrations. That is the case because only a small portion of the total energy is needed for compression for the pipelines (see Figure 6.4.1), and much of the pressure drop is in the service pipelines instead of the transmission or trunk pipelines.

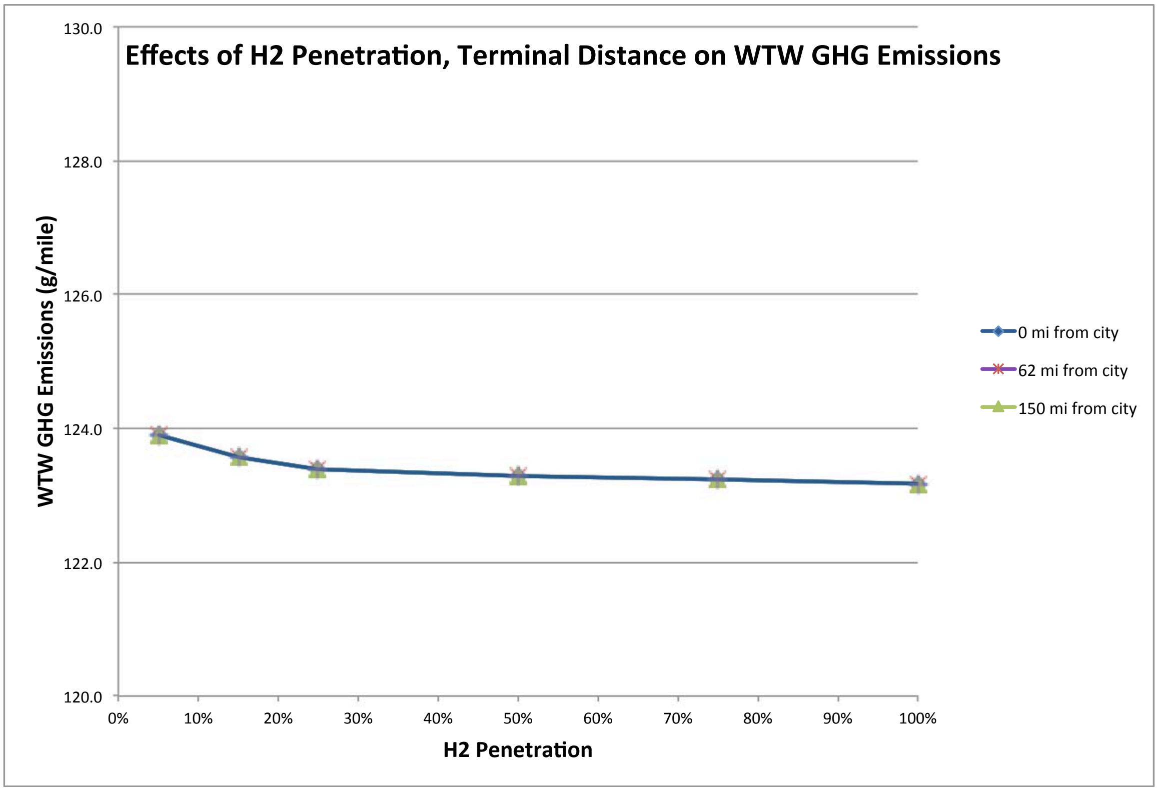


Figure 6.4.13. WTW GHG emissions versus penetration for the central biomass—pipeline delivery pathway

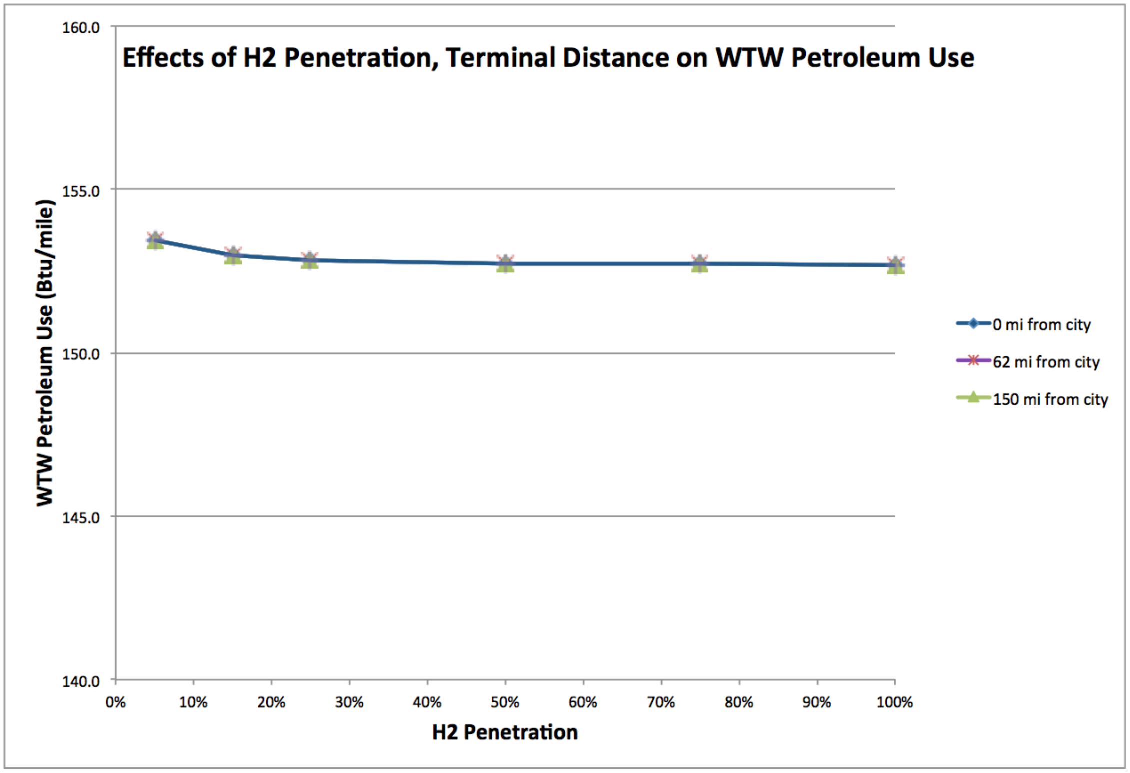


Figure 6.4.14. WTW petroleum use versus penetration for the central biomass—pipeline delivery pathway

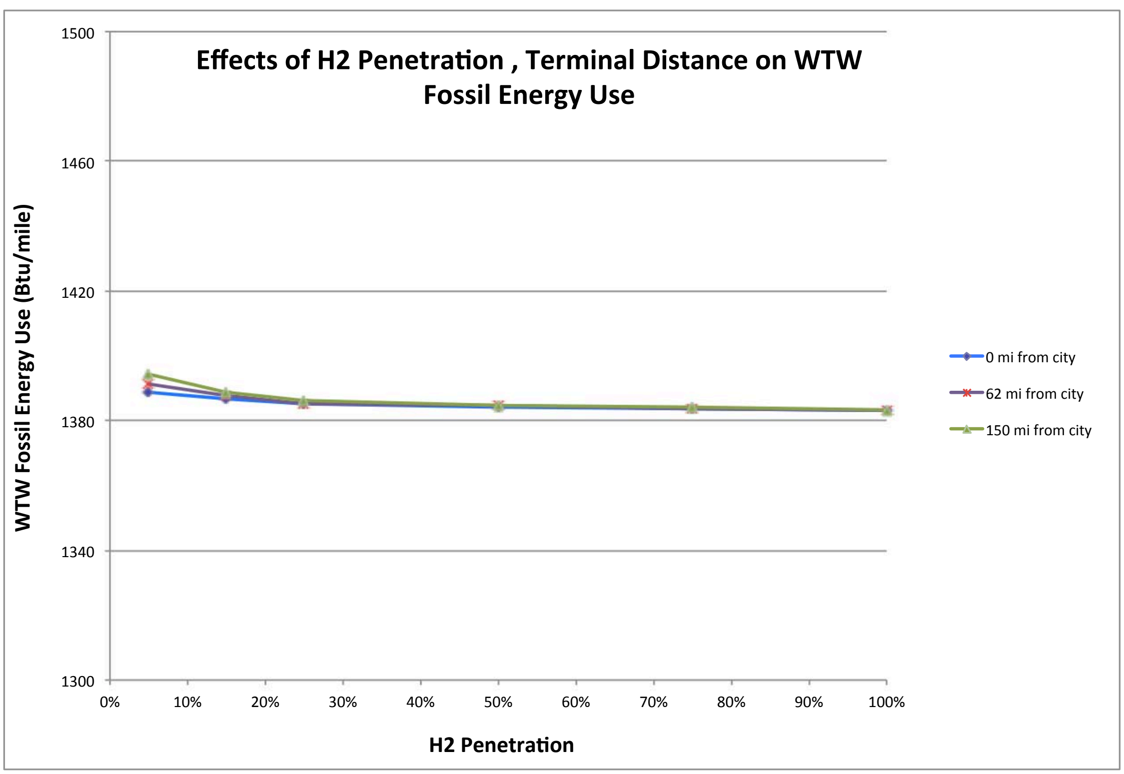


Figure 6.4.15. WTW fossil energy use versus penetration for the central biomass—pipeline delivery pathway

The effects of city population on levelized cost of hydrogen, GHG emissions, and petroleum energy use are shown in Figures 6.4.16, 6.4.17, and 6.4.18. Levelized hydrogen cost, GHG emissions, and petroleum energy use decrease only gradually with population increases for cities with populations of 5,000 or greater. The increase in cost between 500,000 people and 1,250,000 people shown in Figure 6.4.16 is caused by increased installed pipeline costs per kg hydrogen dispensed. In both cases, there are two trunk pipeline rings; however, because population density is essentially constant, the larger population results in a larger city area and thus longer rings in the trunk pipelines. Those longer rings result in higher pipeline capital costs per kg dispensed. Additional people result in HDSAM-calculated optimums with more than two rings, thus reducing the pipeline capital costs per kg dispensed.

Figure 6.4.19 shows the effect of fuel economy on the levelized cost of hydrogen. The hydrogen cost increases with increasing fuel economy, with the greatest increase in hydrogen cost occurring when fuel economy is increased from 40 mpgge to 50 mpgge. Lower demand for hydrogen resulting from higher fuel economy, as shown in Figure 6.4.20, is the reason for the increasing hydrogen costs. HDSAM optimization calculations calculated an optimum of two rings for all fuel economies except 48 mpgge. In that case it calculated three rings, resulting in a large jump in levelized cost between 40 mpgge and 48 mpgge.

Figures 6.4.21 and 6.4.22 show that GHG emissions and petroleum energy use decrease with increasing fuel economy, as one might expect.

Figures 6.4.23, 6.4.24, and 6.4.25 show the effects of forecourt size on levelized cost of hydrogen, GHG emissions, and petroleum energy use for the central biomass—pipeline delivery pathway. Cost, emissions, and petroleum energy use decrease with increasing forecourt size. The apparent inconsistent result at 1,000 kg/day forecourt size in Figure 6.4.23 is due to a step-change in distribution pipeline capital cost. At 750 kg/day, the diameter is 0.75 in. and at 1,000 kg/day the diameter is 1.0 in. Because discrete diameters are chosen, a jump between them is required and the larger pipeline is not as fully utilized as the smaller one is.

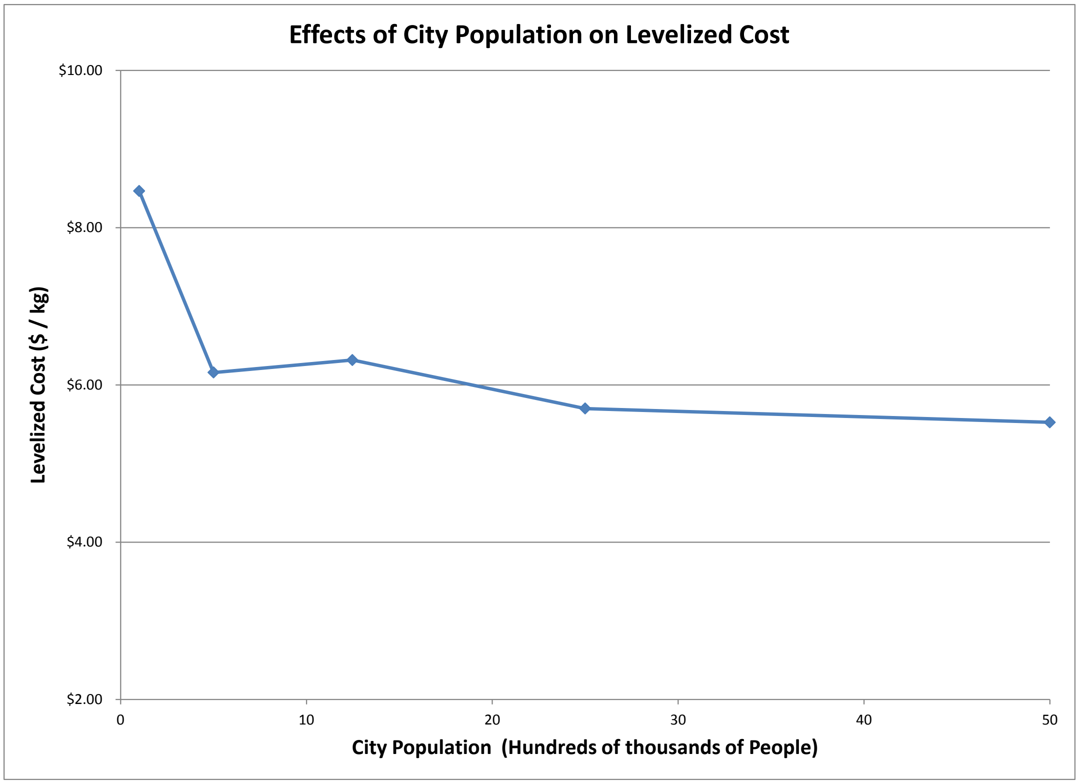


Figure 6.4.16. Levelized cost versus city population for the central biomass—pipeline delivery pathway

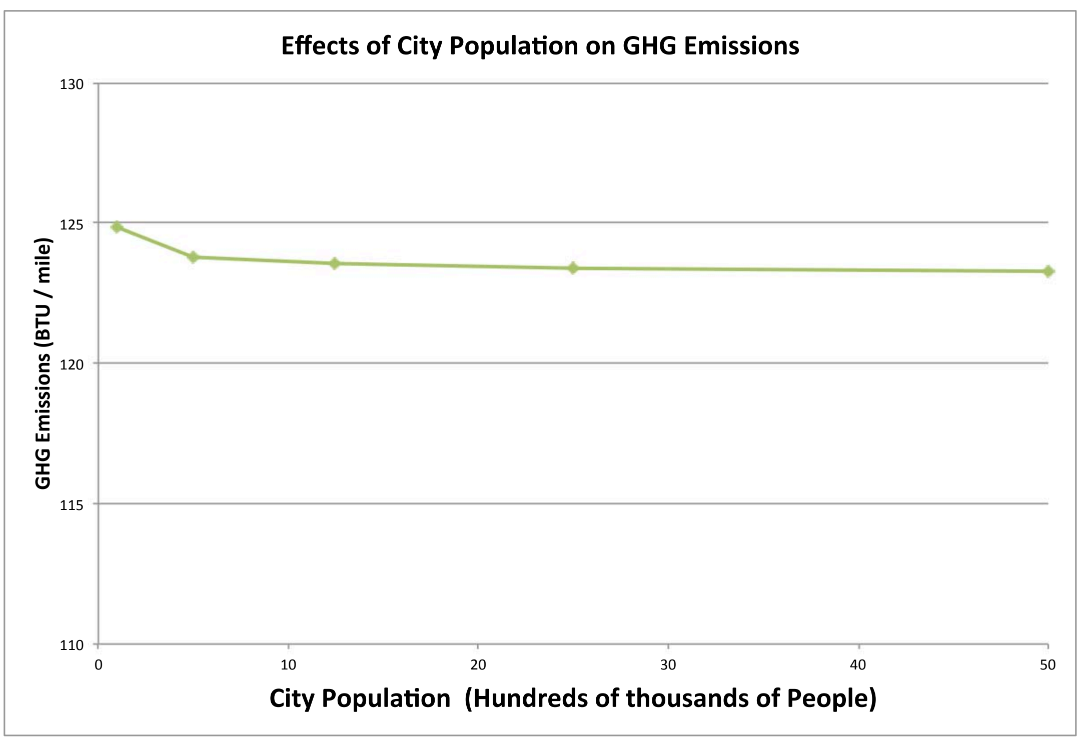


Figure 6.4.17. GHG emissions versus city population for the central biomass—pipeline delivery pathway

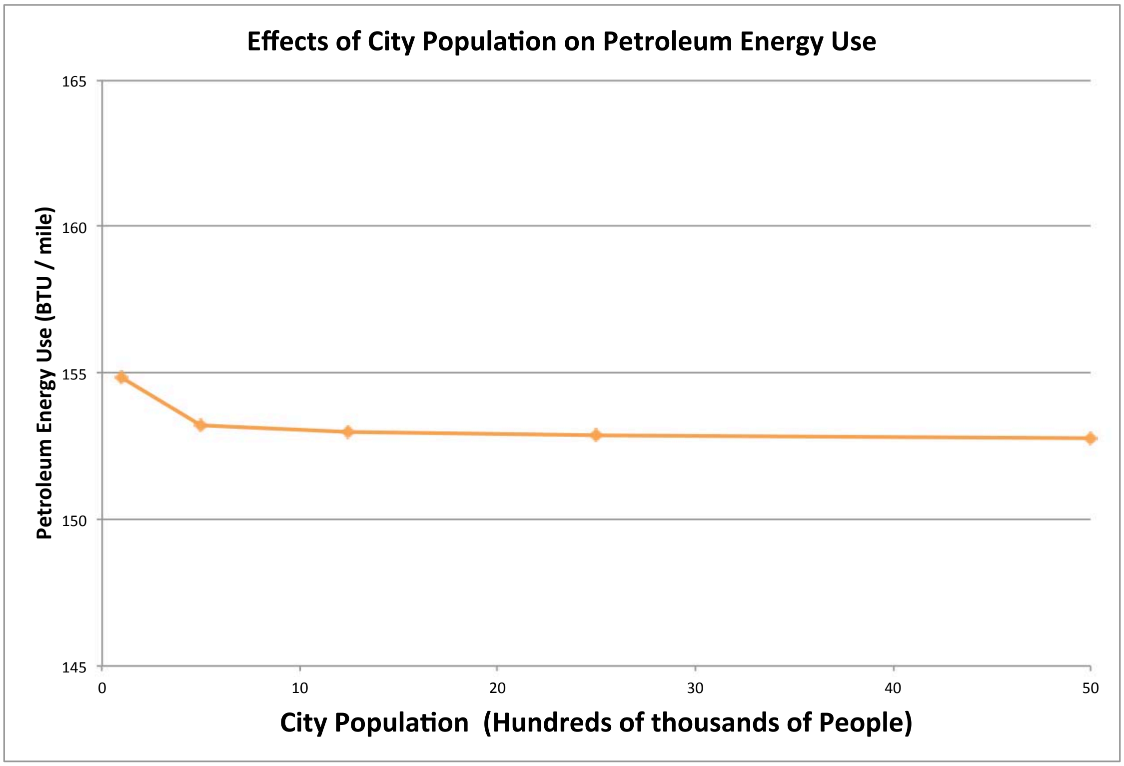


Figure 6.4.18. Petroleum energy use versus city population for the central biomass—pipeline delivery pathway

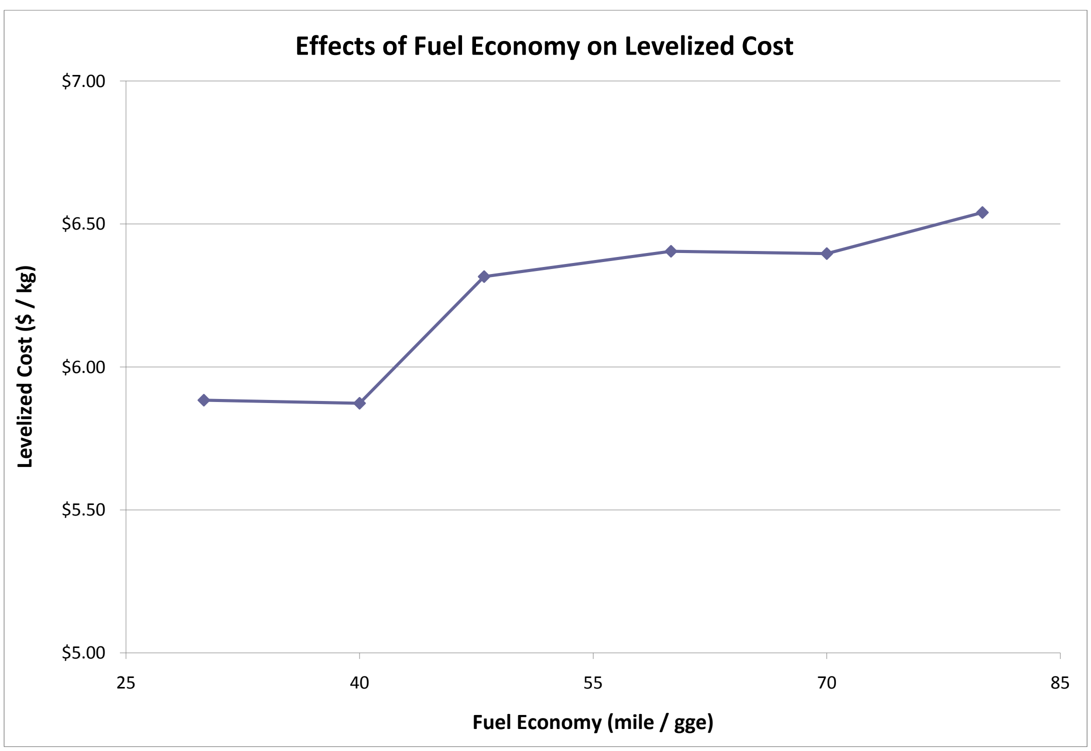


Figure 6.4.19. Levelized cost versus fuel economy for the central biomass—pipeline delivery pathway

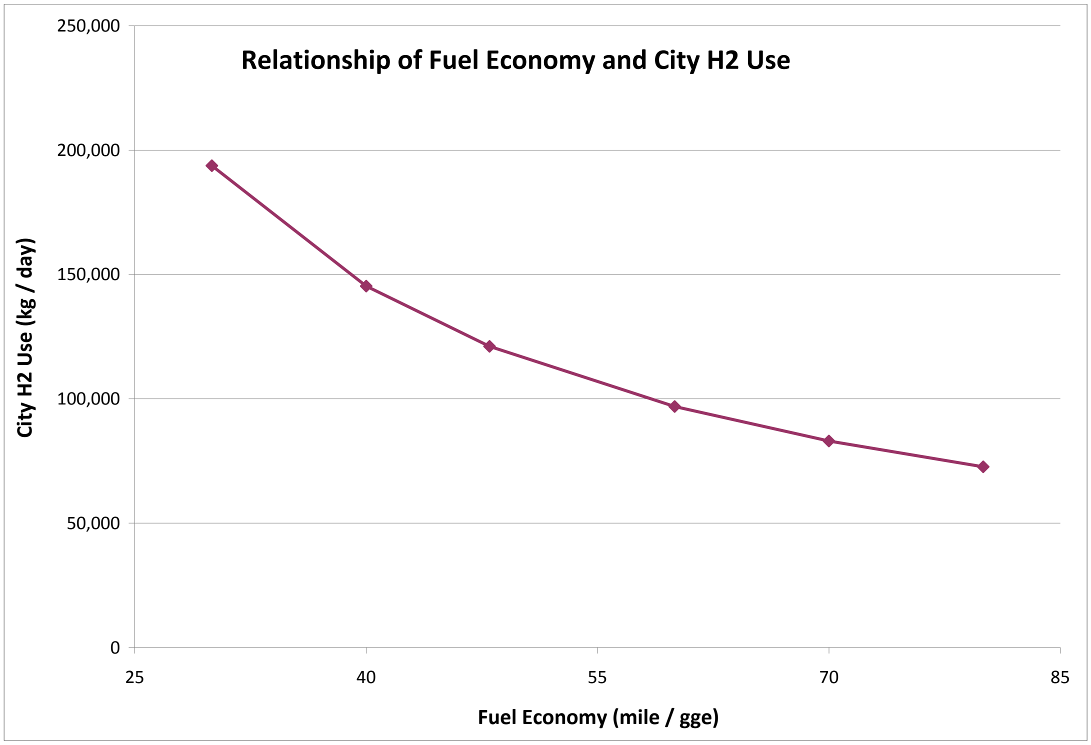


Figure 6.4.20. City hydrogen use versus fuel economy for the central biomass—pipeline delivery pathway

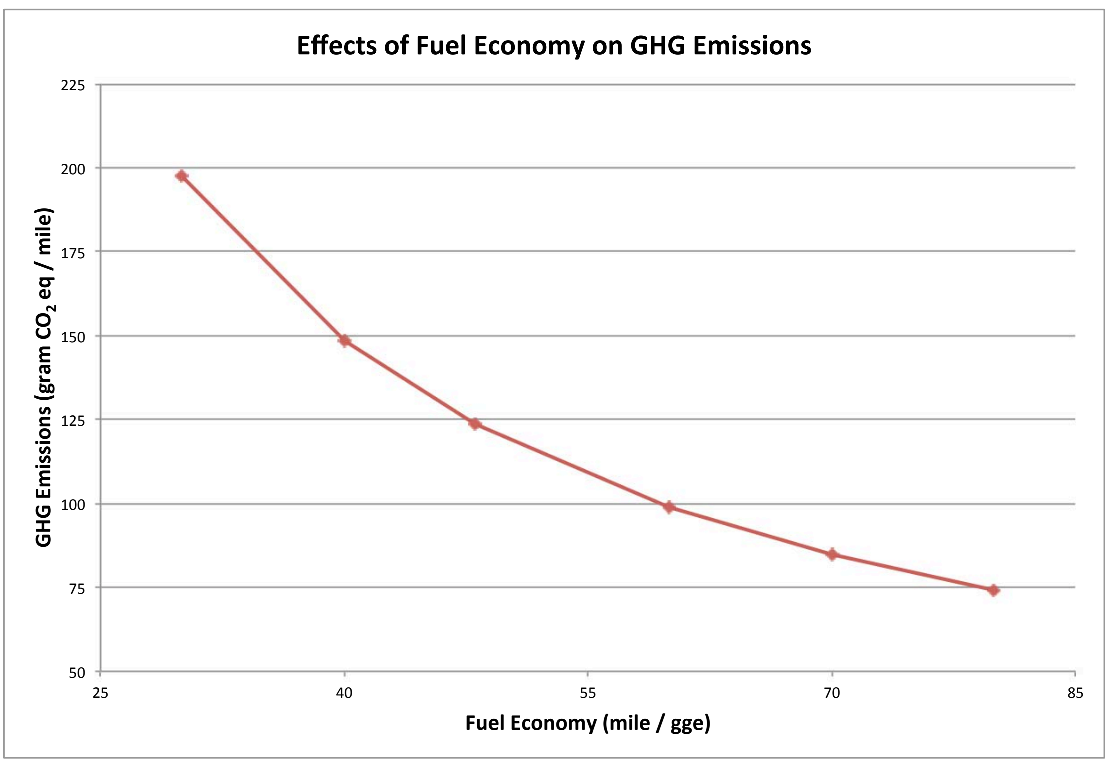


Figure 6.4.21. GHG emissions versus fuel economy for the central biomass—pipeline delivery pathway

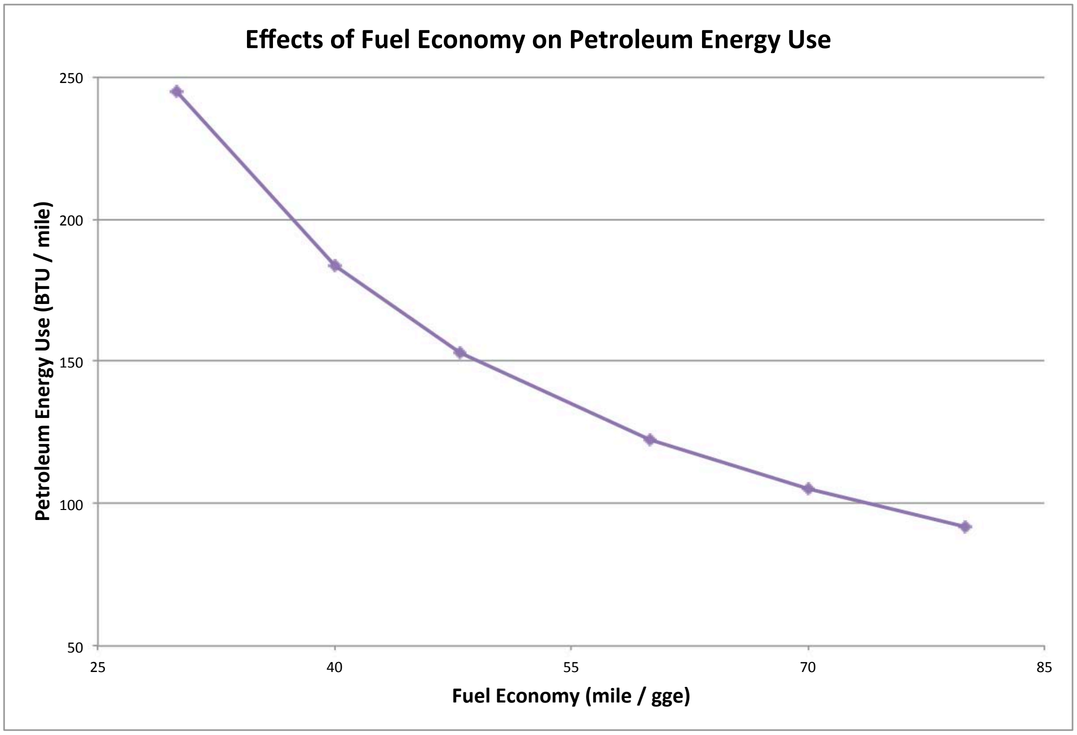


Figure 6.4.22. Petroleum use versus fuel economy for the central biomass—pipeline delivery pathway

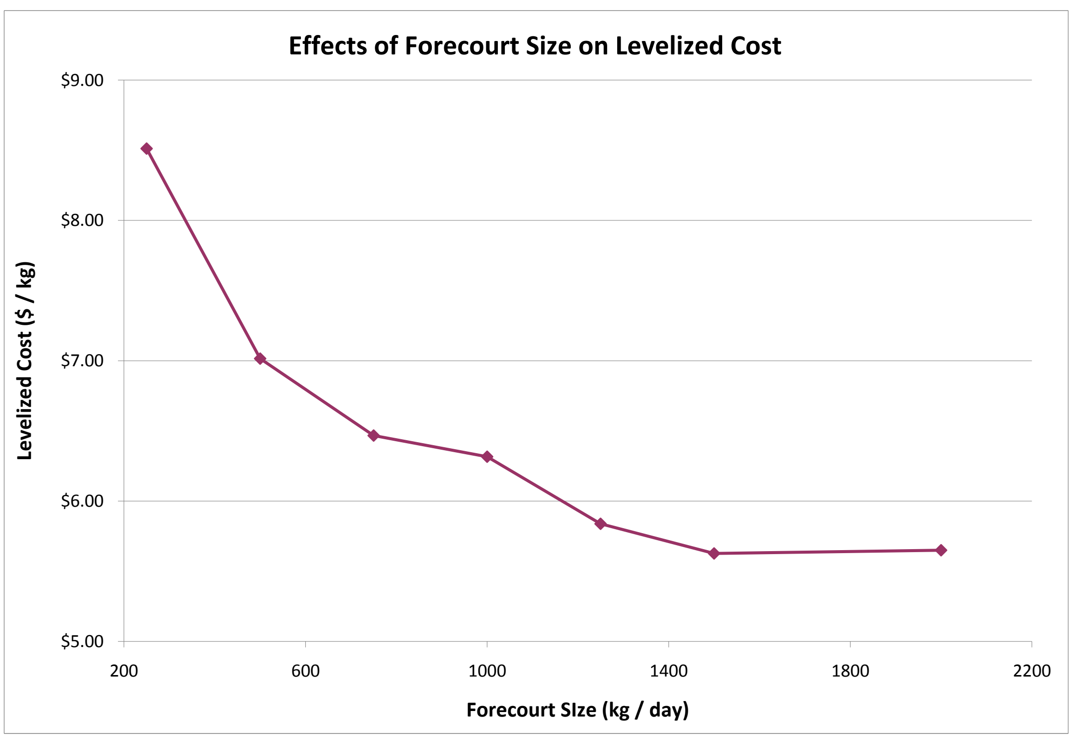


Figure 6.4.23. Levelized cost versus forecourt size for the central biomass—pipeline delivery pathway

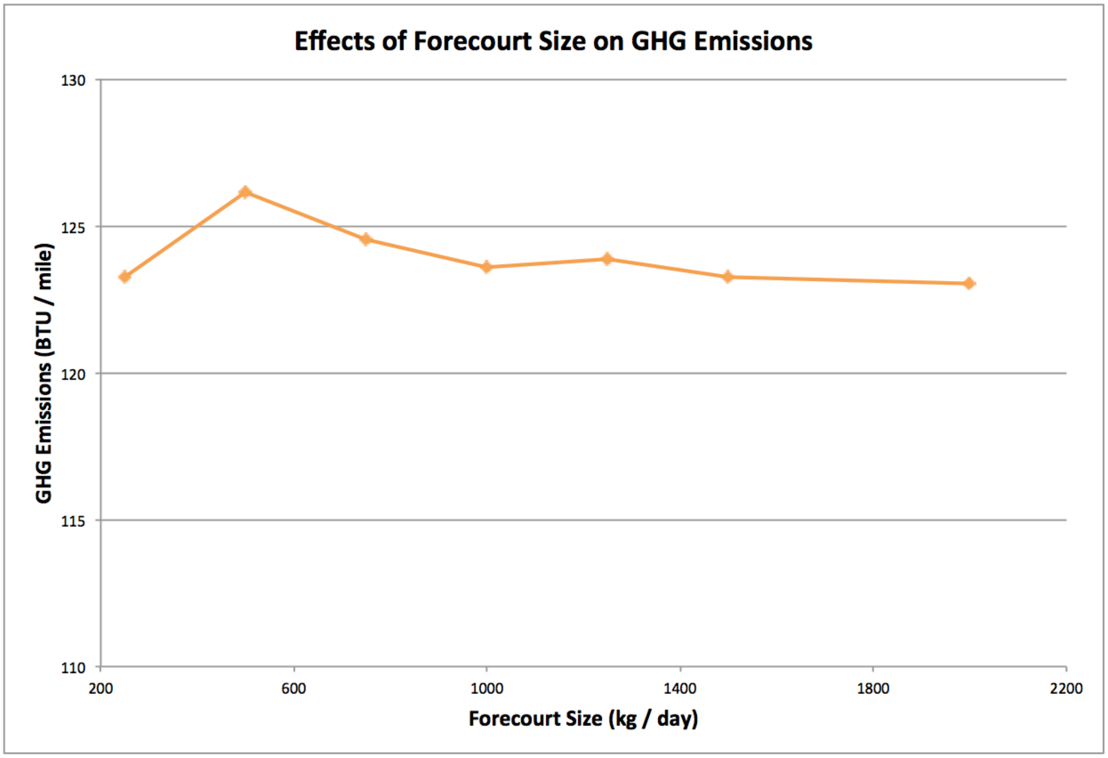


Figure 6.4.24. GHG emissions versus forecourt size for the central biomass—pipeline delivery pathway

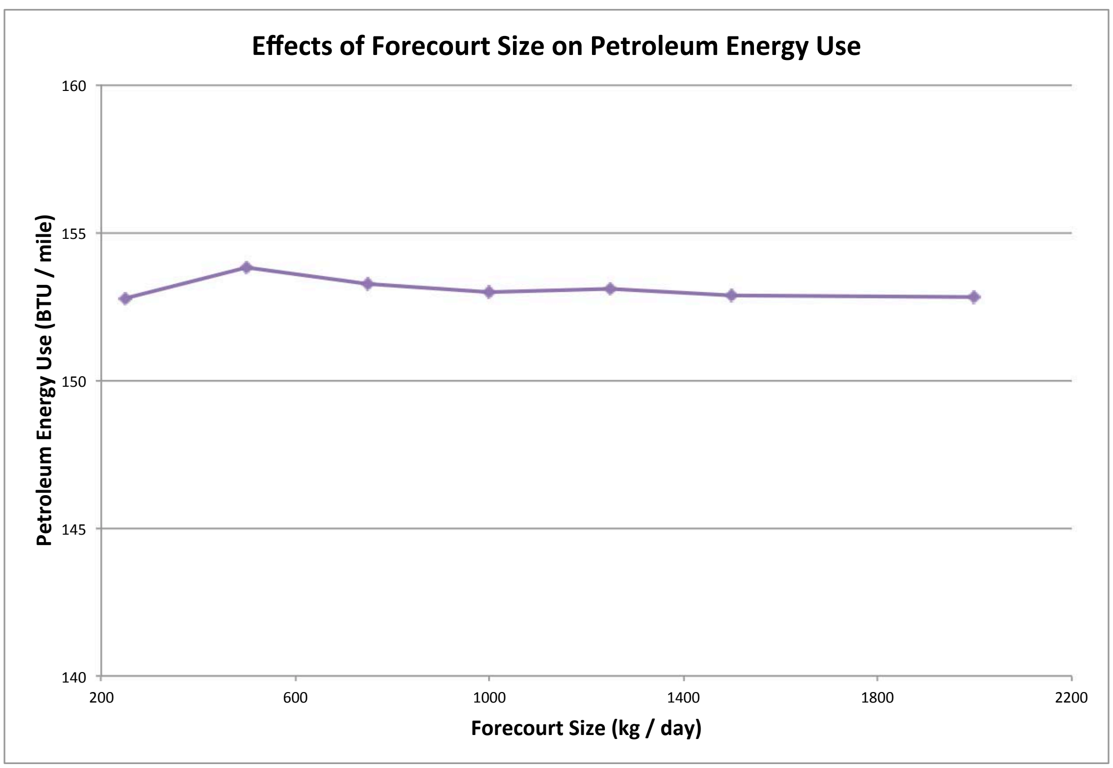


Figure 6.4.25. Petroleum energy use versus forecourt size for the central biomass—pipeline delivery pathway

6.5 Central Biomass—Gaseous H_2 Truck Delivery

Figure 6.5.1 shows the major inputs, assumptions, and outputs for each of the subsystems considered in the well-to-tank analysis, including feedstock supply and hydrogen dispensing. (See Appendix E for more details on this pathway.)

The WTP and WTW cost of hydrogen, energy use, and emissions for the central biomass—gaseous H_2 truck delivery pathway are summarized in Table 6.5.1.

Net GHG emissions include carbon dioxide uptake occurring during growth of the biomass. As noted above, the analysis assumes that 100% of the carbon in the biomass is provided by atmospheric carbon dioxide and that land use change is assumed to have neither positive nor negative effects on emissions.

6.5.1 Cost Breakdown

Figure 6.5.2 shows the feedstock and energy price inputs and the resulting hydrogen production, delivery, and distribution costs for the central biomass—gaseous H_2 truck delivery pathway. The financial assumptions used in this analysis are detailed in Section 5.

Figure 6.5.3 shows the contributions of hydrogen production, delivery, and losses to the levelized cost of hydrogen shown in Figure 6.5.2.

Figure 6.5.4 and Table 6.5.2 show the breakdown of levelized costs for the central biomass—gaseous H_2 truck delivery pathway.

Inputs			Assumptions			Outputs		
						Biomass moisture content	25%	
			Biomass Production & Delivery			Woody biomass LHV	16,013,000	Btu / dry ton
Energy Use for Farming Trees	235,000	Btu / dry ton				Biomass price at H2 production	$75.02	2007 $ / dry ton
			Fraction of Woody Biomass	100%		Biomass Share of Levelized Cos	$0.97	2007$ / kg H2 dispensed
			LUC GHG changes	0	g / dry ton			
Coal Input (including upstream)	300	Btu / 116000Btu to Pump	Average distance from farm to H2 prod.	40	miles	WTG CO2 Emissions	-24,850	g CO2 eq./ 116000 Btu
Natural Gas Input (including upstream)	800	Btu / 116000Btu to Pump				WTG CH4 Emissions	15	g CO2 eq./ 116000 Btu
Petroleum Input (including upstream)	3,200	Btu / 116000Btu to Pump				WTG N2O Emissions	35	g CO2 eq./ 116000 Btu
						WTG GHG Emissions	-24,800	g CO2 eq./ 116000 Btu
						Hydrogen Output Pressure	300	psi
Biomass consumption	13.5	kg (dry) / kg H2 produced	**Hydrogen Production**			Hydrogen Outlet Quality	99.9%	
Natural gas consumption	0.0059	MMBtu / kg H2 produced						
Electricity consumption	0.98	kWh / kg H2 produced	Central plant design capacity	155,200	kg / day	Total capital investment	$1,300	2007$ / daily kg H2 (effective capacity)
Process Water Consumption	1.32	gal / kg H2 produced	Capacity factor	90%		Levelized Cost of Capital	$0.65	2007$ / kg H2 dispensed
Cooling Water Consumption	79.3	gal / kg H2 produced	Number of production facilities necessary	0.87		Fixed O&M Costs	$0.23	2007$ / kg H2 dispensed
			Process energy efficiency	46.0%		Variable O&M Costs	$0.40	2007$ / kg H2 dispensed
Total Capital Investment	$181,080,000	2007$	Electricity Mix	US Mix		Total Levelized Cost	$2.25	2007$ / kg H2 dispensed
			After-tax IRR	10%				
Coal Input (including upstream)	5,200	Btu / 116000Btu to Pump	Assumed Plant Life	40		Production CO2 Emissions	26,620	g CO2 eq./ 116000 Btu
Natural Gas Input (including upstream)	9,700	Btu / 116000Btu to Pump				Production CH4 Emissions	140	g CO2 eq./ 116000 Btu
Petroleum Input (including upstream)	3,700	Btu / 116000Btu to Pump				Production N2O Emissions	43	g CO2 eq./ 116000 Btu
						Production GHG Emissions	26,800	g CO2 eq./ 116000 Btu
						Total capital investment	$2,100	2007$ / daily kg delivered
Electricity consumption at terminal	1.31	kWh / kg H2 dispensed	**Gas Trucks for Delivery (with Terminal and Geologic Storage)**			Levelized Electricity cost	$0.09	2007$ / kg H2 delivered
Electricity consumption for geo storage	0.01	kWh / kg H2 dispensed				Levelized Diesel cost	$0.20	2007$ / kg H2 delivered
Total electricity consumption	1.32	kWh / kg H2 dispensed	City Population	1,247,000	people	Levelized Labor cost	$0.41	2007$ / kg H2 delivered
Diesel consumption	58.9	gal / 1000 kg H2	Hydrogen Vehicle Penetration	15%		Levelized Other operating costs	$0.34	2007$ / kg H2 delivered
			City hydrogen use	121,100	kg / day			
			One-way distance for delivery	62	miles	Levelized Cost of Delivery	$1.88	2007$ / kg H2 delivered
Total Capital Investment	$254,858,000	2007$	Storage capacity (geologic + terminal)	1,470,000	kg H2			
			Number of truck-trips required	79,700	per year	Delivery CO2 Emissions	910	g CO2 eq./ 116000 Btu
Coal Input (including upstream)	400	Btu / 116000Btu to Pump	Truck hydrogen capacity	560	kg / truckload	Delivery CH4 Emissions	32	g CO2 eq./ 116000 Btu
Natural Gas Input (including upstream)	1,400	Btu / 116000Btu to Pump	Efficiency of truck loading compressors	88.0%		Delivery N2O Emissions	7	g CO2 eq./ 116000 Btu
Petroleum Input (including upstream)	9,800	Btu / 116000Btu to Pump	Hydrogen losses	1.0%		Delivery GHG Emissions	950	g CO2 eq./ 116000 Btu
						Hydrogen outlet pressure	12,700	psi
Electricity consumption	2.1	kWh / kg H2	**Forecourt Dispensing**			Basis -- Hydrogen Quantity	116,000	Btu (116,000 Btu/gal non-oxygenated conventional unleaded gasoline)
Electricity price	$0.096	2007$ / kWh						
			Average Dispensing Rate per Station	800	kg / day	Total capital investment	$2,190	2007$ / daily kg
Total Capital Investment per Station	$1,744,000	2007$ / station	Number of Dispensing Stations	152		Levelized Cost of Capital	$0.95	2007$ / kg H2 dispensed
Total Capital Investment	$265,136,000	2007$ / all stations	Number of Compressor Steps	5		Energy & Fuel	$0.20	2007$ / kg H2 dispensed
			Usable Low Pressure Storage per Station	N/A	(storage on trucks)	Other O&M Costs	$0.46	2007$ / kg H2 dispensed
Minimum inlet pressure from tube trailer	220	psi	Usable Cascade Storage per Station	130	kg H2	Levelized Cost of Dispensing	$1.61	2007$ / kg H2 dispensed
Coal Input (including upstream)	16,700	Btu / 116000Btu to Pump	Site storage	14%	% of design capacity	CSD CO2 Emissions	2,310	g CO2 eq./ 116000 Btu
Natural Gas Input (including upstream)	7,400	Btu / 116000Btu to Pump	# of 2-hose Dispensers per Station	2		CSD CH4 Emissions	140	g CO2 eq./ 116000 Btu
Petroleum Input (including upstream)	700	Btu / 116000Btu to Pump	Hydrogen loss factor	0.50%		CSD N2O Emissions	9	g CO2 eq./ 116000 Btu
						CSD GHG Emissions	2,470	g CO2 eq./ 116000 Btu
						Cost Per Mile	$0.69	2007$ / mi
Vehicle Mass	3,020	lb	**Vehicle**			Fuel Share	$0.12	2007$ / mi
Fuel cell size	70	kW	Fuel Economy	48.0	mi / gge	Maintenance, Tires, Repairs	$0.07	2007$ / mi
Hybridization battery (peak power)	30	kW	Vehicle Miles Traveled	15,000	mi / yr	Insurance & Registration	$0.12	2007$ / mi
			Vehicle Lifetime	160,000	mi	Depreciation	$0.27	2007$ / mi
			Purchase Year	2015		Financing	$0.10	2007$ / mi
			Vehicle Purchase Cost	$33,700	2007$			
Coal Input (including upstream)	2,400	Btu / gge fuel consumed	Fuel Cell System Cost	$4,500	2007$	Vehicle Cycle CO2 Emissions	1,750	g CO2 eq/ gge fuel consumed
Natural Gas Input (including upstream)	12,400	Btu / gge fuel consumed	Hydrogen Storage System Cost	$2,400	2007$	Vehicle Cycle CH4 Emissions	170	g CO2 eq/ gge fuel consumed
Petroleum Input (including upstream)	7,700	Btu / gge fuel consumed	Tax Credit	$0	2007$	Vehicle Cycle N2O Emissions	7	g CO2 eq/ gge fuel consumed
						Vehicle Cycle GHG Emissions	1,940	g CO2 eq/ gge fuel consumed

Figure 6.5.1. Summary of major inputs, assumptions, and outputs by subsystem for the central biomass—gaseous H_2 truck delivery pathway

Table 6.5.1. WTP and WTW Results for the Central Biomass—Gaseous H_2 Truck Delivery Pathway

	WTP		WTW	
Coal input (including upstream)[a]	22,700	Btu/116,000 Btu	470	Btu/mi
Natural gas input (including upstream)[a]	15,300	Btu/116,000 Btu	400	Btu/mi
Petroleum input (including upstream)[a]	17,500	Btu/116,000 Btu	360	Btu/mi
Fossil energy input (including upstream)[a]	59,500	Btu/116,000 Btu	1,240	Btu/mi
WTP CO_2 emissions[b]	5,000	g/116,000 Btu	100	g/mi
WTP CH_4 emissions	13	g/116,000 Btu	0	g/mi
WTP N_2O emissions	0	g/116,000 Btu	0	g/mi
WTP GHG emissions	5,400	g CO_2-eq./ 116,000 Btu	110	g/mi
	Cost per kg		**Cost per mile**	
Levelized cost of hydrogen	$5.74	2007$/kg	$0.12	2007$/mi

[a] Coal, natural gas, and petroleum inputs include those used directly in the hydrogen production and delivery pathway as feedstocks and fuels; those used to produce electricity and other materials used in the pathway; and those used upstream of the pathway to recover, refine, and deliver the feedstock.
[b] Includes the carbon content of CO, CH_4, and volatile organic compound emissions that decompose in the atmosphere to CO_2.

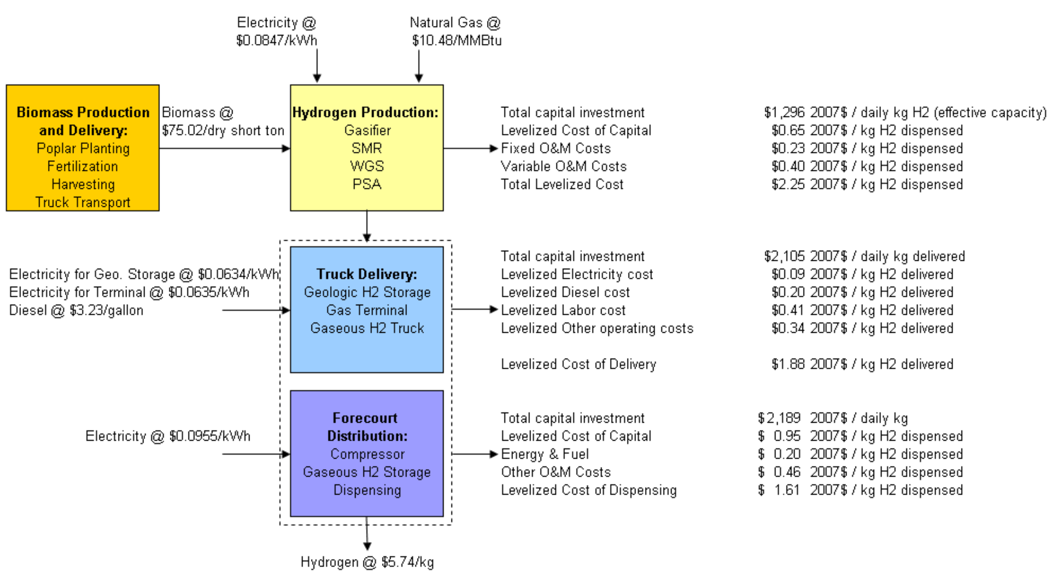


Figure 6.5.2. Cost analysis inputs and high-level results for the central biomass—gaseous H_2 truck delivery pathway

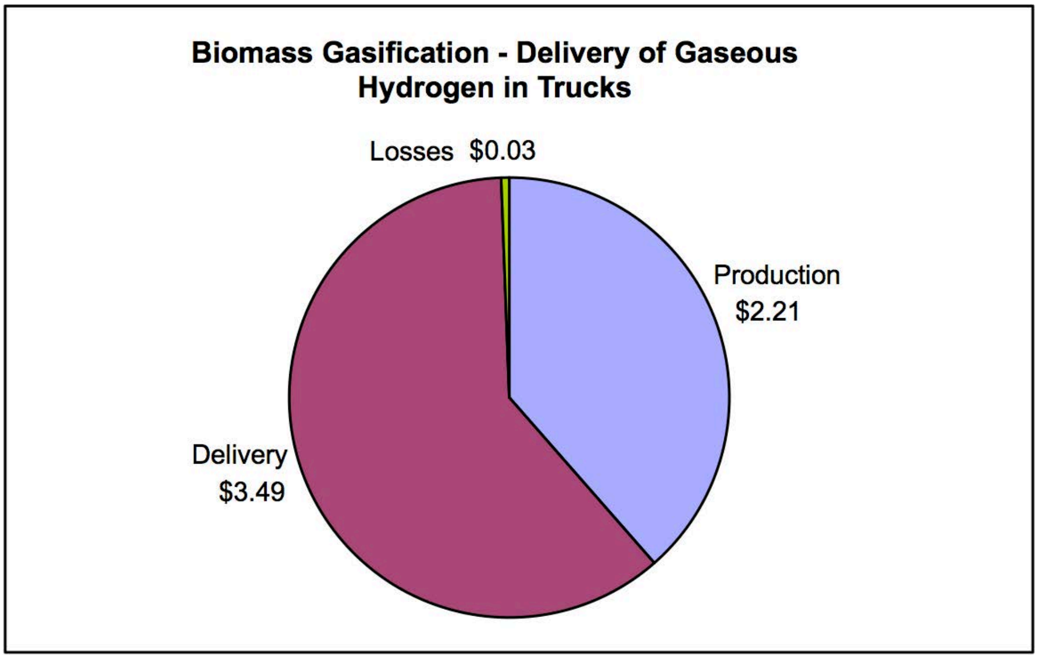


Figure 6.5.3. Contribution of hydrogen production, delivery, and losses to the levelized cost of hydrogen for the central biomass—gaseous H_2 truck delivery pathway

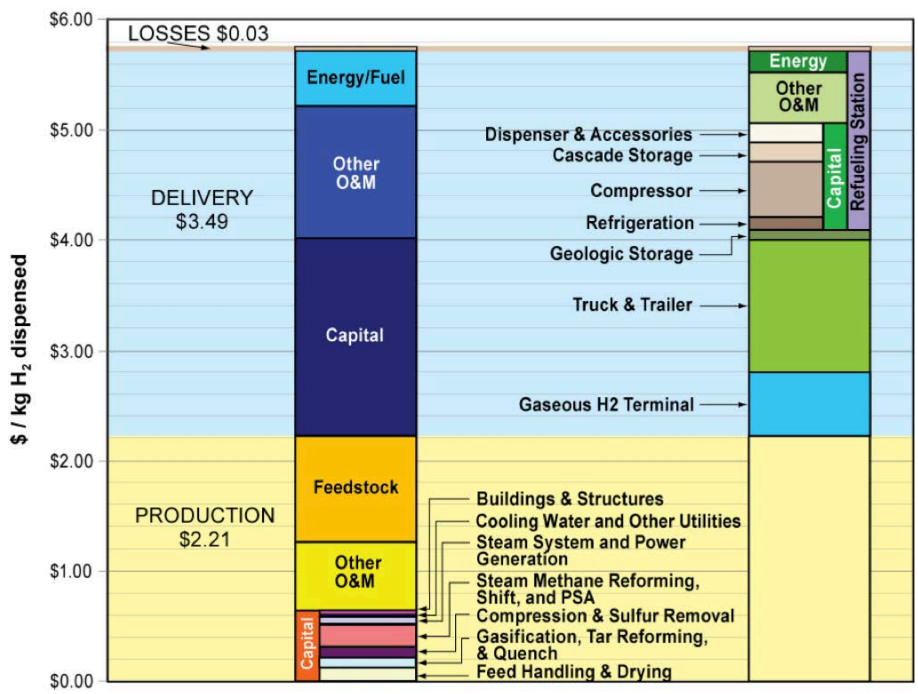


Figure 6.5.4. Breakdown of levelized costs for the central biomass—gaseous H_2 truck delivery pathway

Table 6.5.2. Contribution of Production and Delivery Processes to Levelized Hydrogen Cost for the Central Biomass—Gaseous H_2 Truck Delivery Pathway

Cost Component	**Capital**	**Other O&M**	**Feedstock**	**Energy/ Fuel**	**Total**
Production	\$0.64	\$0.62	\$0.96		\$2.21
Feed handling and drying	\$0.11				
Gasification, tar reforming, and quench	\$0.10				
Compression and sulfur removal	\$0.09				
SMR, WGS, and PSA	\$0.18				
Steam system and power generation	\$0.09				
Cooling water and other utilities	\$0.02				
Buildings and structures	\$0.04				
Delivery	\$1.81	\$1.18		\$0.51	\$3.49
Gaseous H_2 terminal					\$0.59
Truck and trailer					\$1.19
Geologic storage					\$0.11
Gaseous refueling station	\$0.95	\$0.46		\$0.20	\$1.61
Refrigeration	\$0.12				
Compressor	\$0.50				
Cascade storage	\$0.17				
Low pressure storage	\$0.00				
Dispenser and accessories	\$0.17				
Losses					\$0.03
Total	**\$2.45**	**\$1.80**	**\$0.96**	**\$0.51**	**\$5.74**

6.5.2 Energy Use and Emissions Breakdown

Figures 6.5.5 and 6.5.6 show the WTW energy inputs and losses for the central biomass—gaseous H_2 truck delivery pathway.

Figures 6.5.7 and 6.5.8 show the WTW emissions resulting from the delivery of 116,000 Btu hydrogen to a vehicle fuel tank using the central biomass—gaseous H_2 truck delivery pathway.

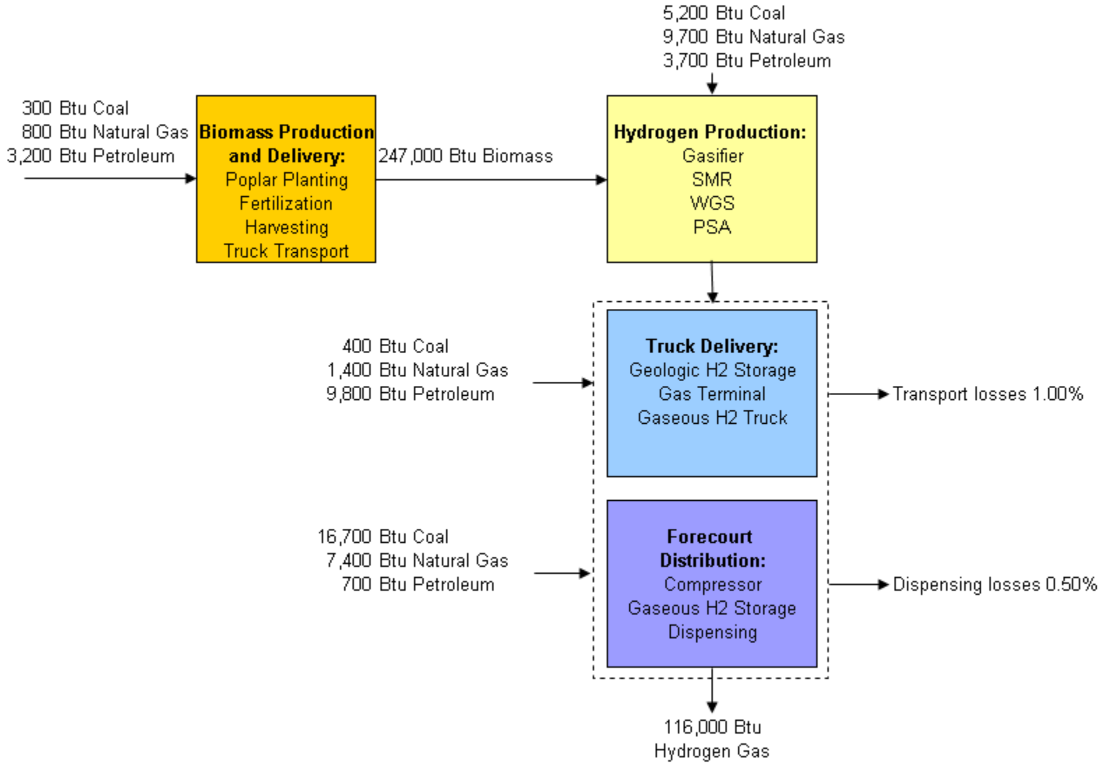


Figure 6.5.5. WTW energy inputs to deliver 116,000 Btu hydrogen to a vehicle using the central biomass—gaseous H_2 truck delivery pathway

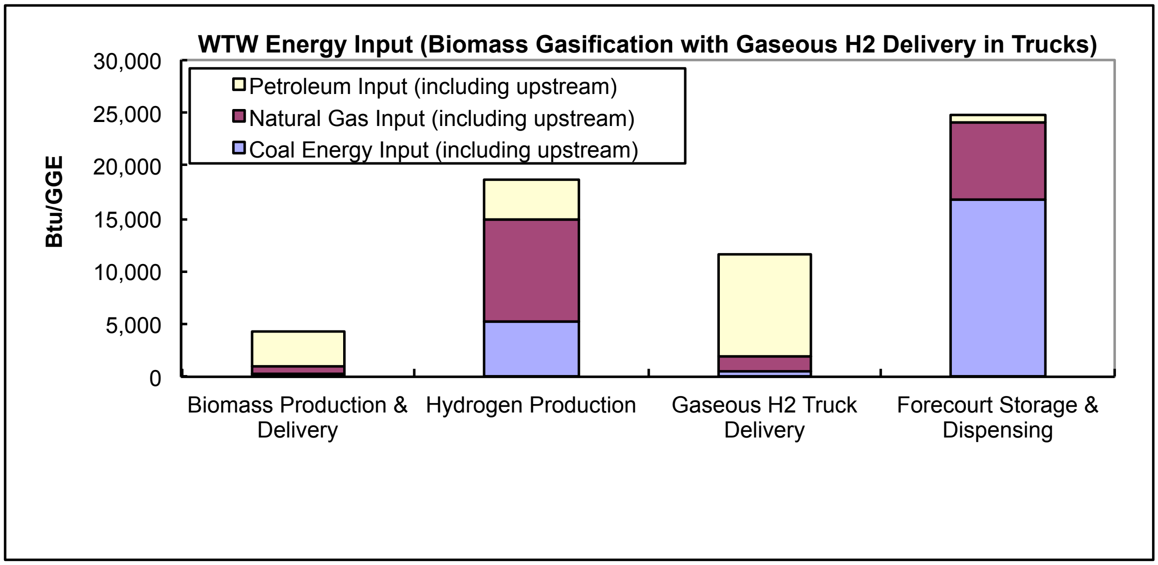


Figure 6.5.6. WTW petroleum, natural gas, and coal inputs to deliver 116,000 Btu hydrogen using the central biomass—gaseous H_2 truck delivery pathway

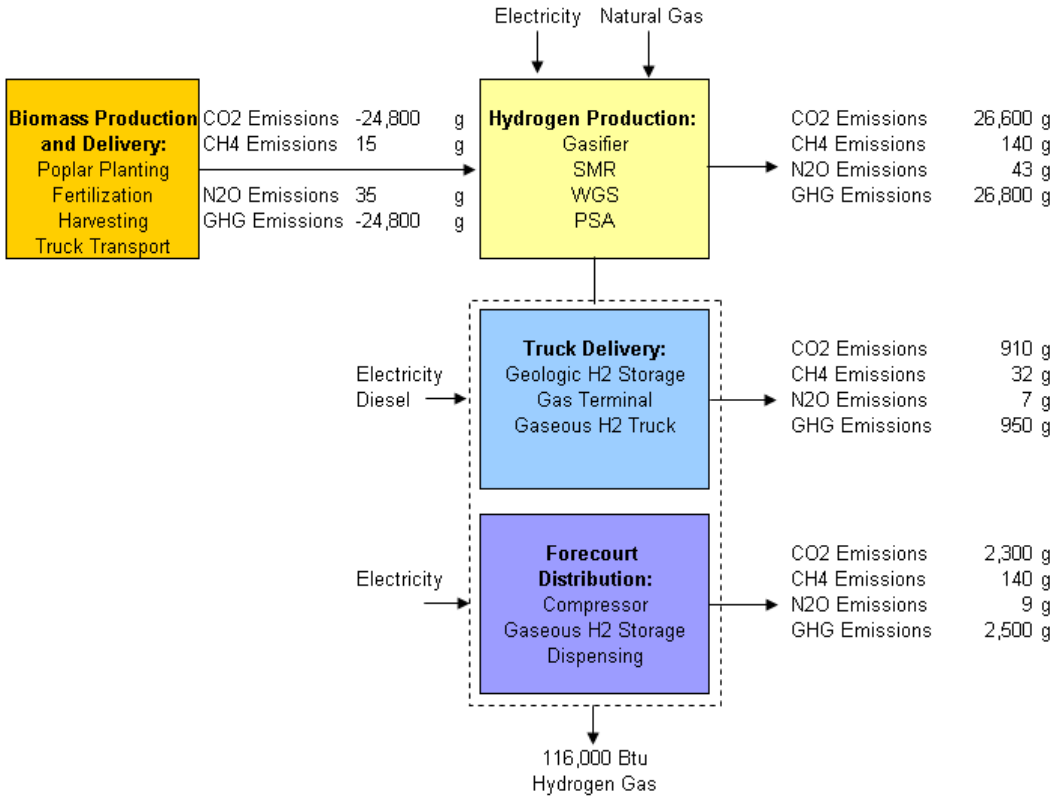


Figure 6.5.7. WTW emissions resulting from delivery of 116,000 Btu hydrogen using the central biomass—gaseous H_2 truck delivery pathway

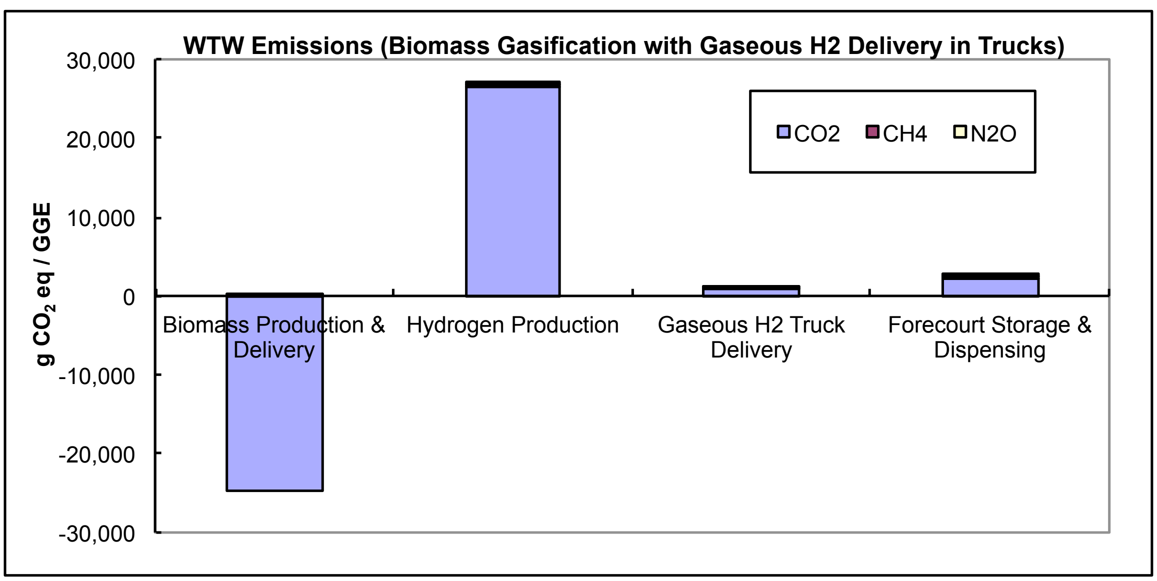


Figure 6.5.8. WTW CO_2, CH_4, and N_2O emissions resulting from delivery of 116,000 Btu hydrogen to a vehicle using the central biomass—gaseous H_2 truck delivery pathway

6.5.3 Sensitivities

6.5.3.1 Production Sensitivities

Several sensitivities were run on the production portion of the central biomass—pipeline delivery pathway. These sensitivities focused primarily on cost factors; however, several sensitivities also affect energy use and emissions. Figure 6.5.9 shows the effects of several production parameters on the pathway's levelized cost, and Table 6.5.3 shows the effects of varying production energy efficiency on WTW energy use and emissions.

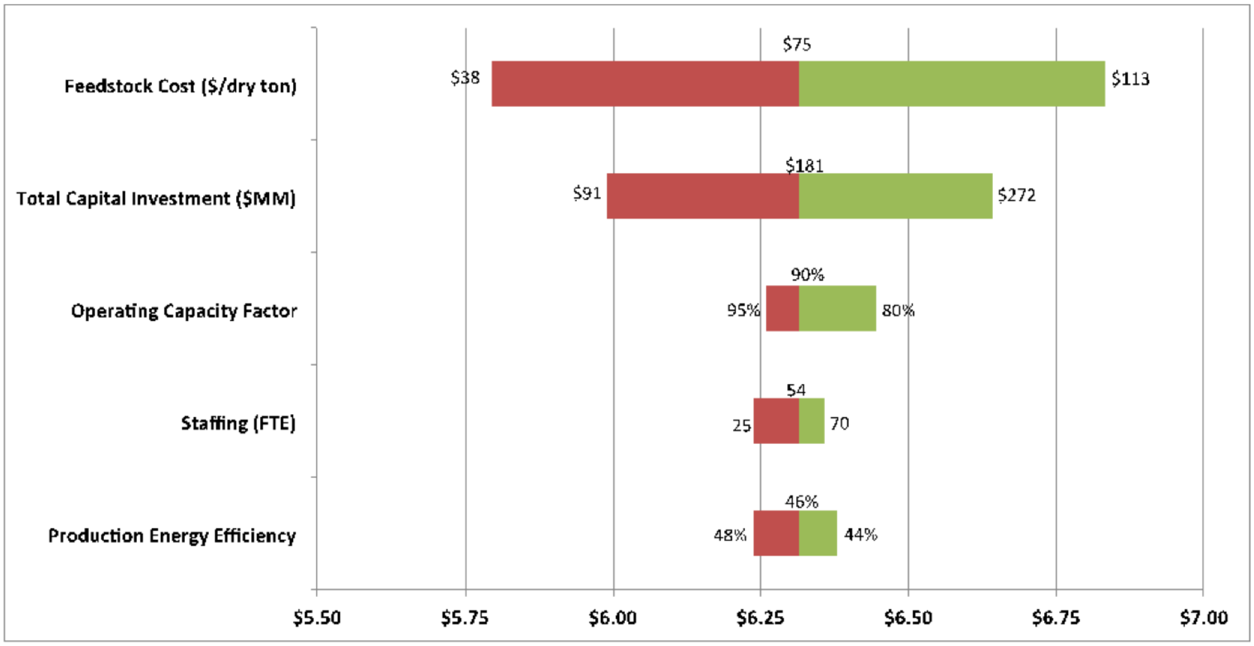


Figure 6.5.9. Production sensitivities for the central biomass—gaseous H_2 truck delivery pathway

Table 6.5.3. The Effects of Production Energy Efficiency on Primary Energy Use and Emissions from the Central Biomass—Gaseous H_2 Truck Delivery Pathway

	44% Efficiency	46% Efficiency	48% Efficiency
WTW GHG emissions (g/mile)	110	110	110
WTW fossil energy (Btu/mile)	1,300	1,200	1,200
WTW petroleum energy (Btu/mile)	370	360	360
WTW total energy (Btu/mile)	6,800	6,500	6,200

The assumed electrical grid mix also affects the energy use and emissions. Table 6.5.4 shows the differences in energy use and GHG emissions between the U.S. average grid mix (which was used for all other sensitivities) and a hypothetical green grid mix that is 100% renewable energy (solar and wind).

Table 6.5.4. The Effects of Fuel Economy and Grid Mix on Use of Primary Energy and Emissions from the Central Biomass—Gaseous H_2 Truck Delivery Pathway

	U.S. Average Grid Mix (48 mpgge)	U.S. Average Grid Mix (68 mpgge)	"Green" Grid Mix (48 mpgge)
WTW GHG emissions (g/mile)	110	80	40
WTW fossil energy (Btu/mile)	1,200	900	500
WTW petroleum energy (Btu/mile)	360	260	340
WTW total energy (Btu/mile)	6,500	4,600	6,000

6.5.3.2 Delivery Sensitivities

Delivery cost, energy use, and emissions are strongly dependent upon the daily consumption of hydrogen within a city and the delivery distance from the central facility to the city gate. Sensitivities were run to show some of those effects. Daily consumption was varied by keeping the city size constant and adjusting the penetration of hydrogen vehicles from the base case of 15%. The resulting consumption is shown in Figure 6.5.10.

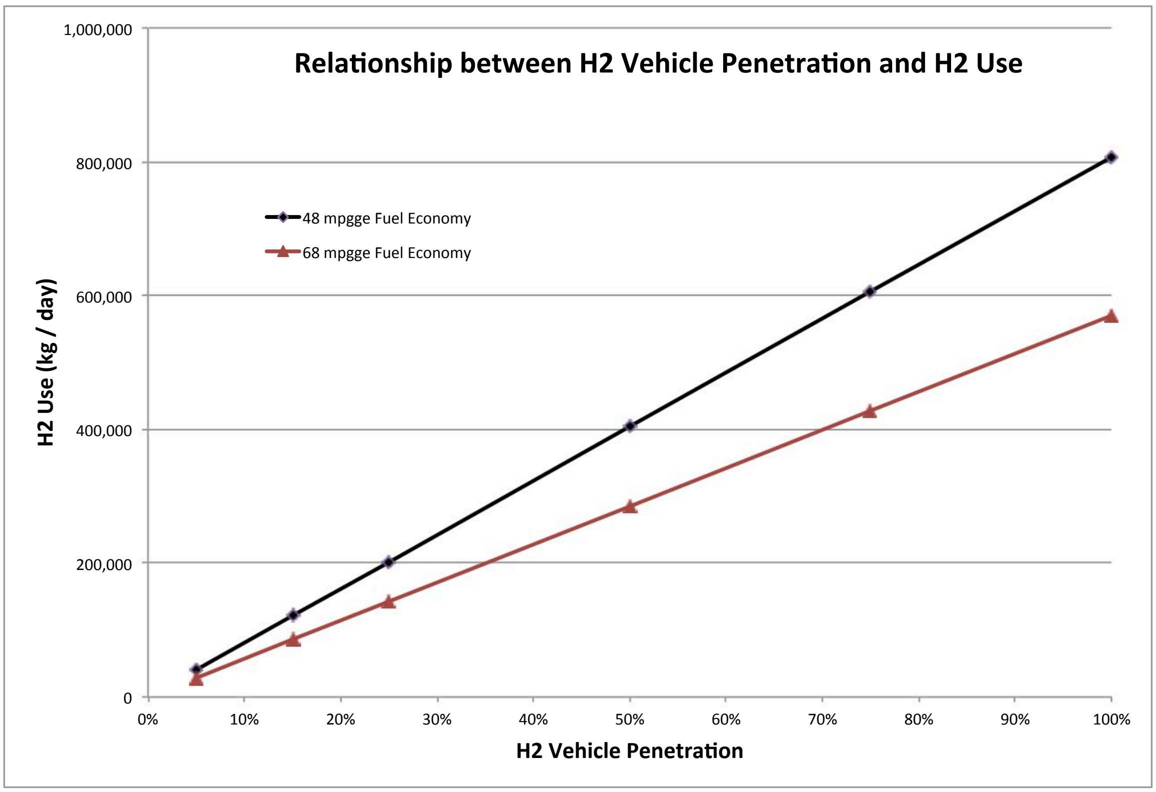


Figure 6.5.10. Daily hydrogen consumption versus hydrogen vehicle penetration for the central biomass—gaseous H_2 truck delivery pathway

As expected there are economies of scale for higher vehicle penetration/hydrogen consumption, and the levelized cost of delivery decreases as the distance from the production plant to the city gate is shortened. Figures 6.5.11 and 6.5.12 show those economic effects (the figures show identical data but are organized differently).

As Figure 6.5.12 shows, there is a $1.17 increase in levelized cost when the production facility is assumed to be 150 miles from the city gate as compared to being at the city gate. There is a much larger levelized-cost increase when the distance is assumed to be 1,000 miles because the levelized cost of trucking increases with added distance due to additional driver time, additional fuel requirements, and an increased number of trucks and trailers required.

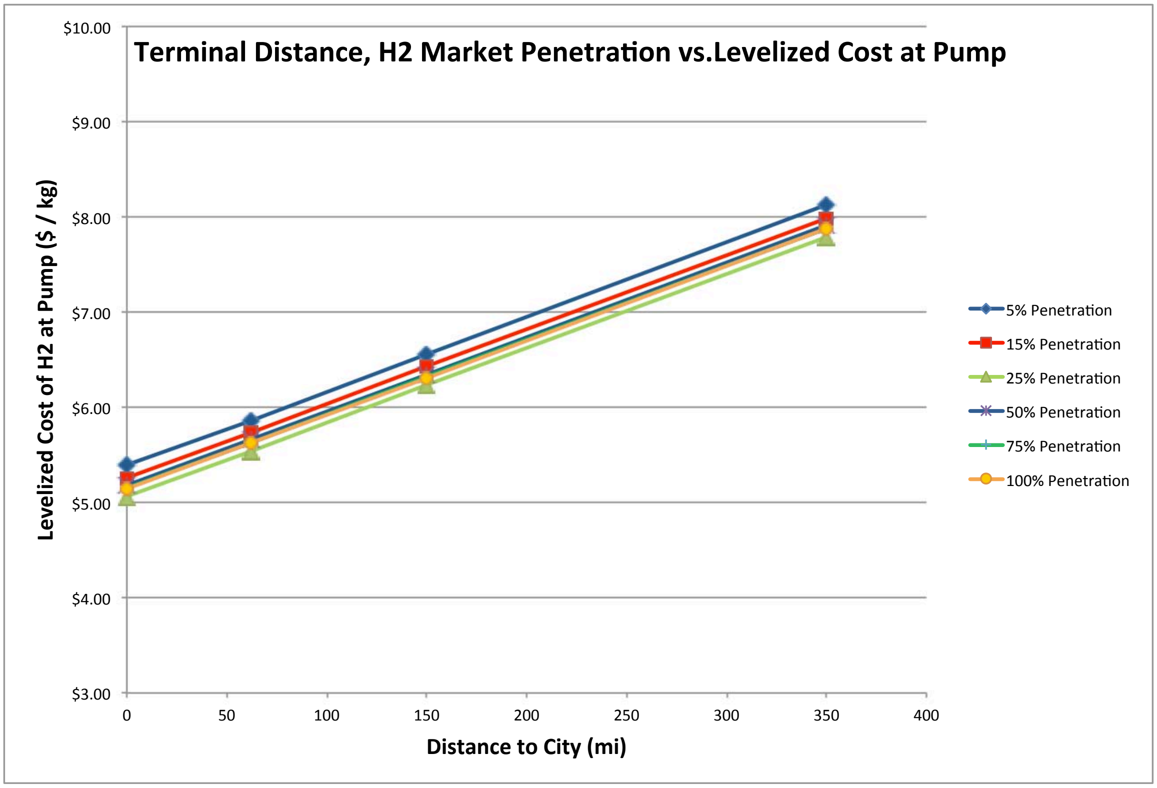


Figure 6.5.11. Levelized cost versus hydrogen vehicle penetration and distance between production facility and city gate for the central biomass—gaseous H_2 truck delivery pathway

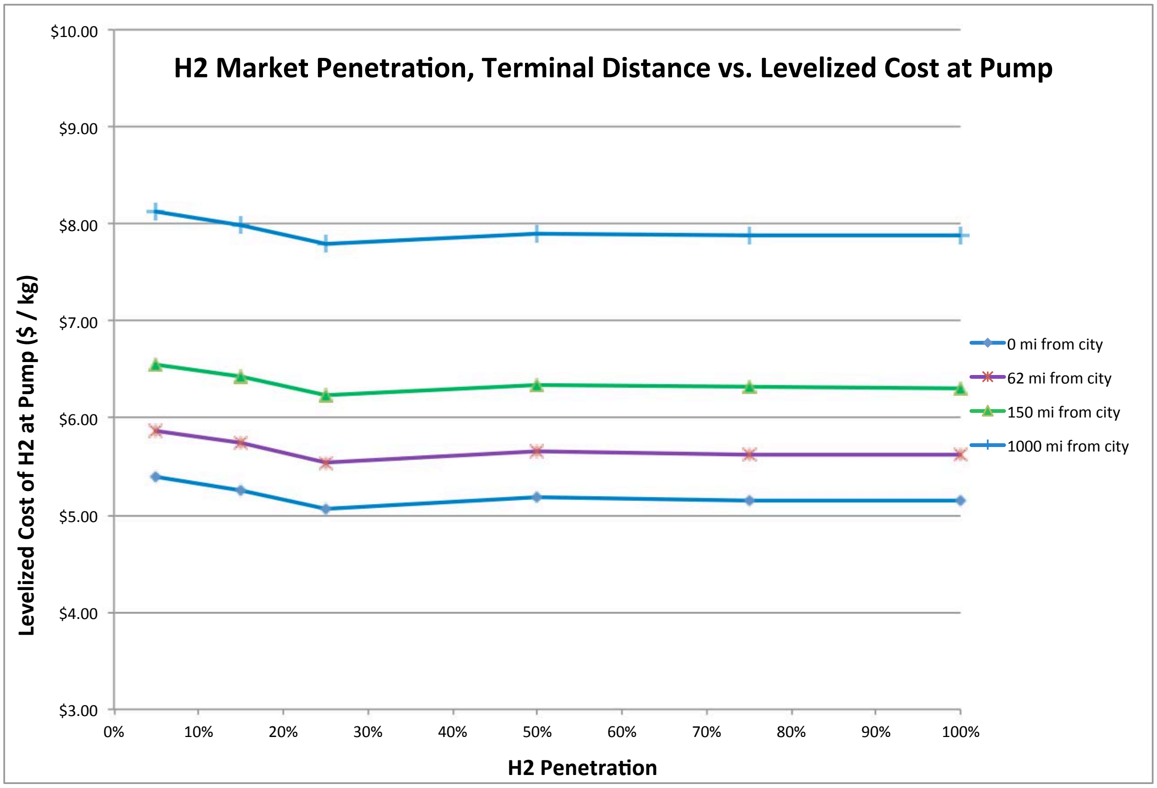


Figure 6.5.12. Levelized cost versus hydrogen vehicle penetration and distance between production facility and city gate for the central biomass—gaseous H_2 truck delivery pathway

The effects of penetration and distance between the production facility and the city gate on WTW GHG emissions, WTW petroleum use, and WTW fossil energy use are shown in Figures 6.5.13, 6.5.14, and 6.5.15, respectively. In each case, the energy use and emissions decrease when the production facility is closer to the city gate because of reduced diesel use for trucking.

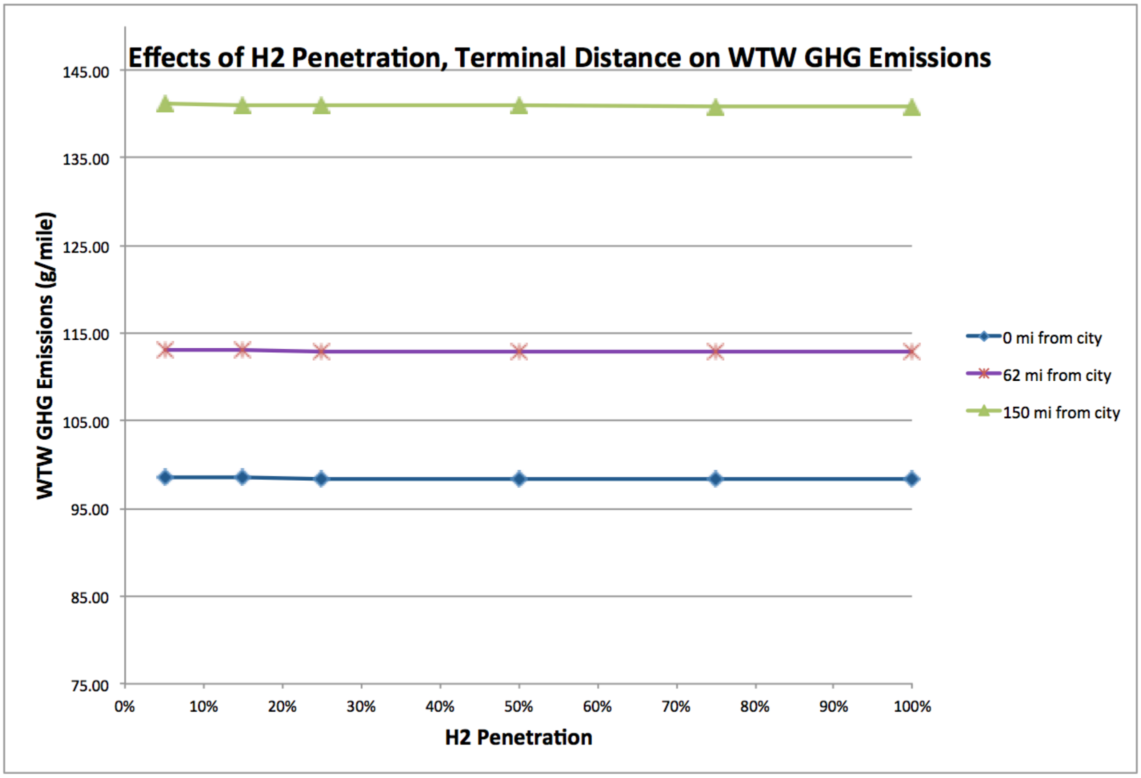


Figure 6.5.13. WTW GHG emissions versus penetration for the central biomass—gaseous H_2 truck delivery pathway

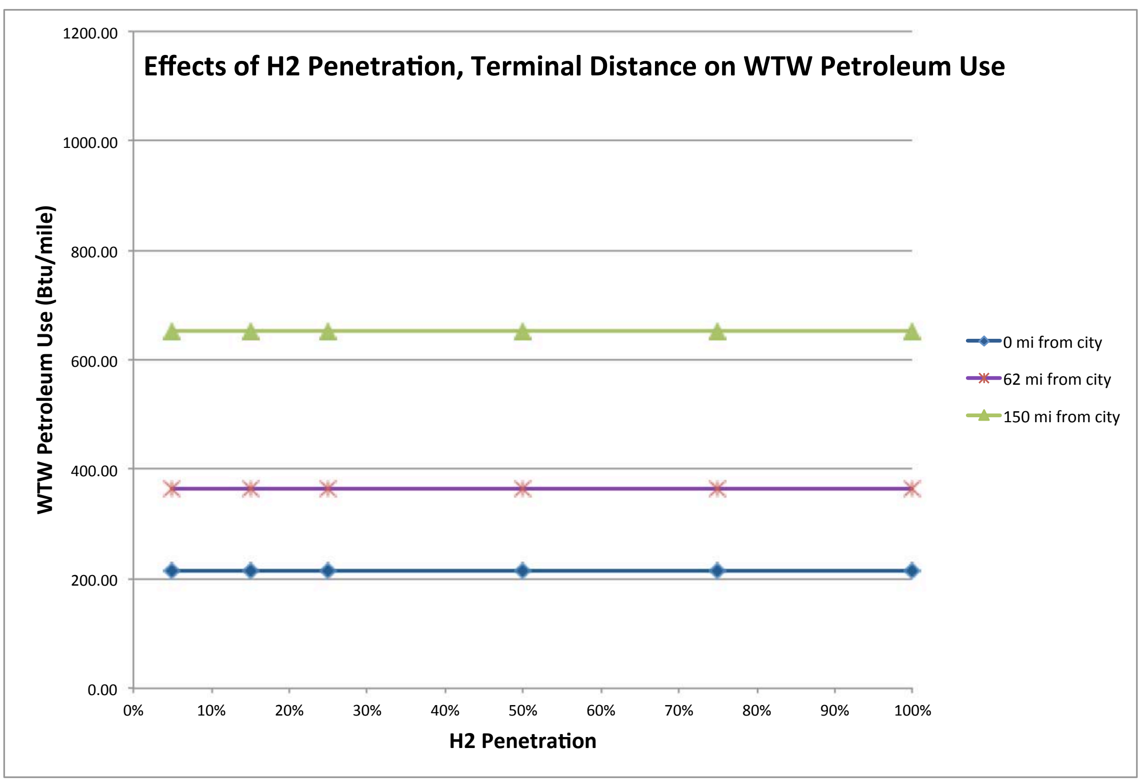


Figure 6.5.14. WTW petroleum use versus penetration for the central biomass—gaseous H_2 truck delivery pathway

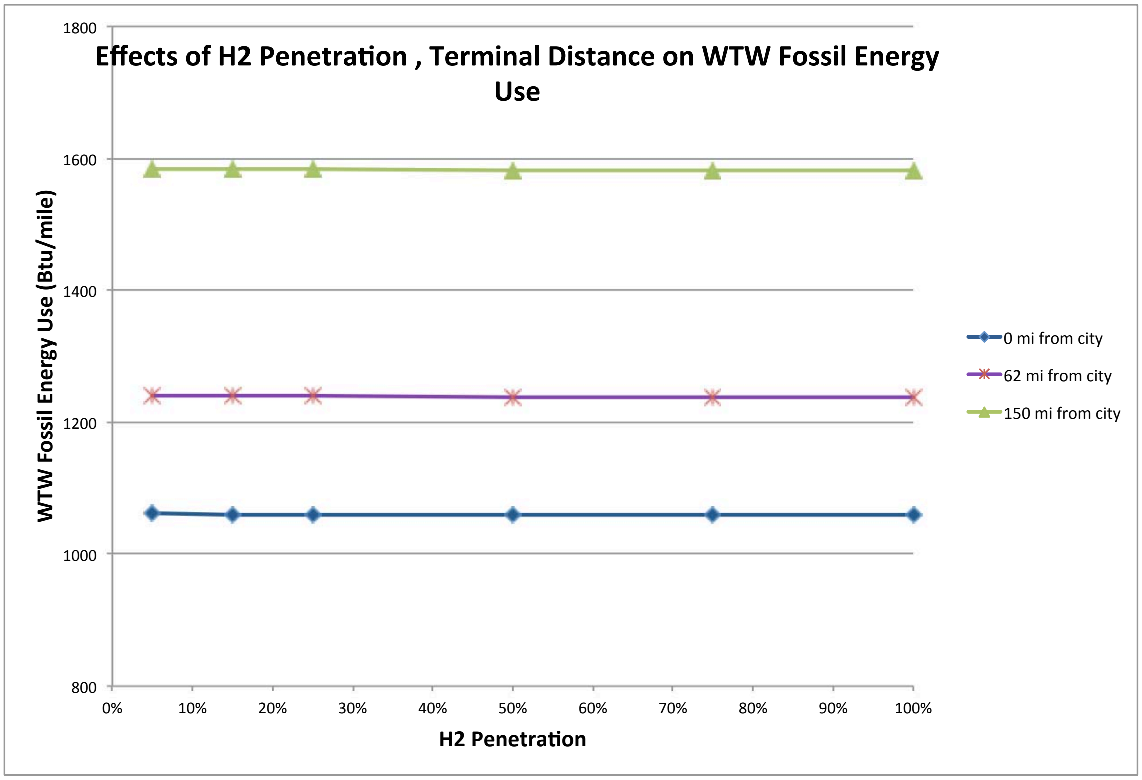


Figure 6.5.15. WTW fossil energy use versus penetration for the central biomass—gaseous H_2 truck delivery pathway

The effects of city population on levelized cost of hydrogen, GHG emissions, and petroleum energy use are shown in Figures 6.5.16, 6.5.17, and 6.5.18. Levelized hydrogen cost remains nearly constant for all city populations studied. GHG emissions and petroleum energy use generally increase with increasing city population. The apparent bounce at 500,000 people in Figure 6.5.16 is caused by a difference between costs for the terminal and for the trucks. The terminal costs are declining through the entire range as population increases due to economies of scale (not shown). The truck costs are increasing through the entire population range due to increased city size increasing truck travel distance (not shown). In most cases, they cancel each other out; however, between 100,000 and 500,000 people the decrease in terminal cost is greater than the increase in truck cost.

Figure 6.5.19 shows the effect of fuel economy on the levelized cost of hydrogen. The relationship between fuel economy and city hydrogen use is shown in Figure 6.5.20.

Figures 6.5.21 and 6.5.22 show that GHG emissions and petroleum energy use decrease with increasing fuel economy, as one might expect.

Figures 6.5.23, 6.5.24, and 6.5.25 show the effects of forecourt size on levelized cost of hydrogen, GHG emissions, and petroleum energy use for the central biomass—gaseous H_2 truck delivery pathway. Cost, emissions, and petroleum energy use decrease with increasing forecourt size up to 800 kg/day.

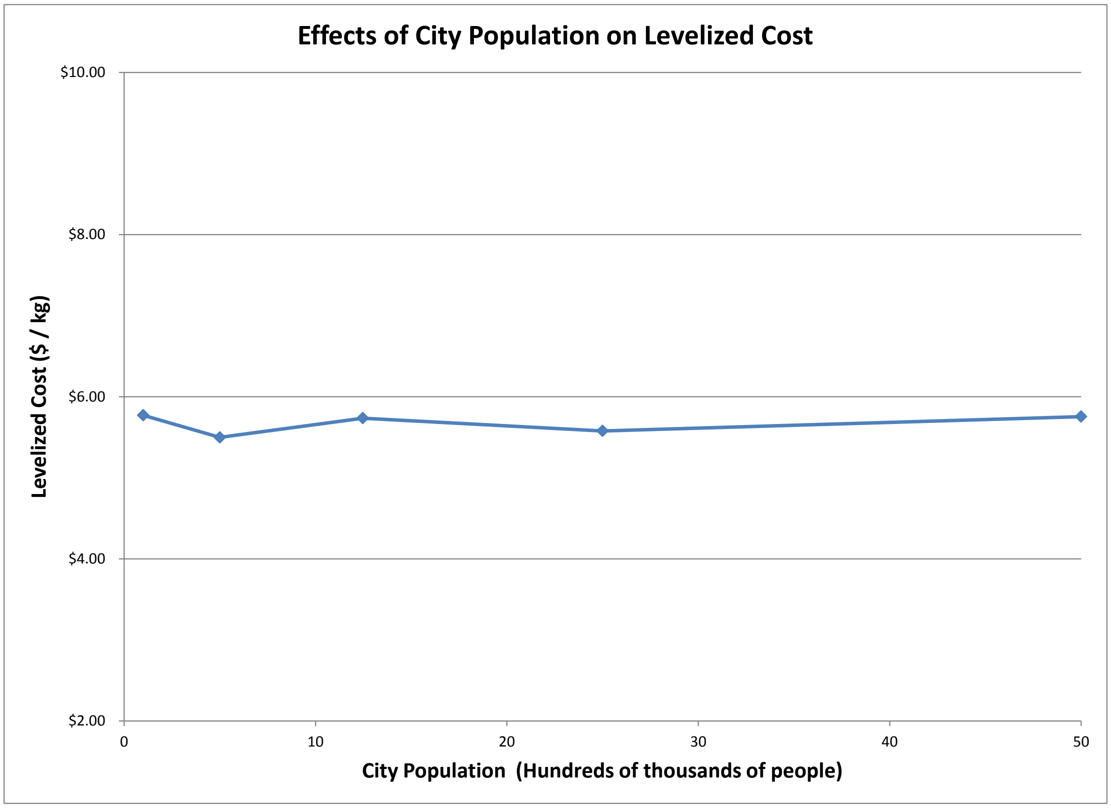


Figure 6.5.16. Levelized cost versus city population for the central biomass—gaseous H_2 truck delivery pathway

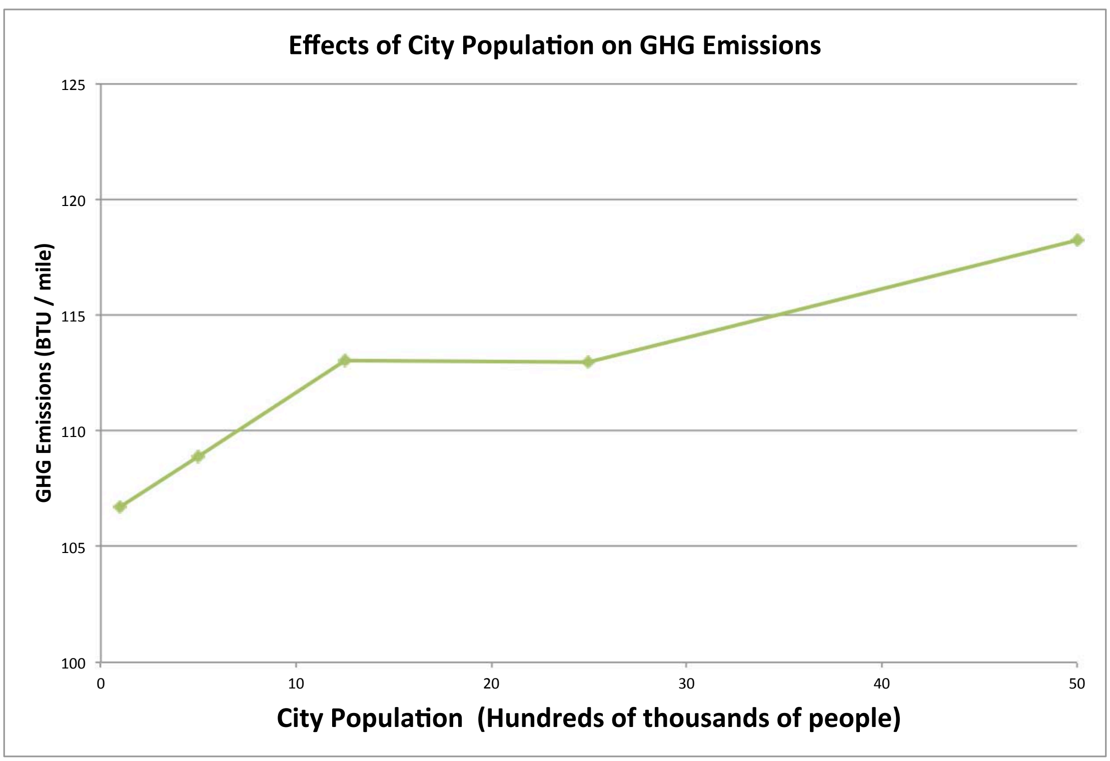


Figure 6.5.17. GHG emissions versus city population for the central biomass—gaseous H_2 truck delivery pathway

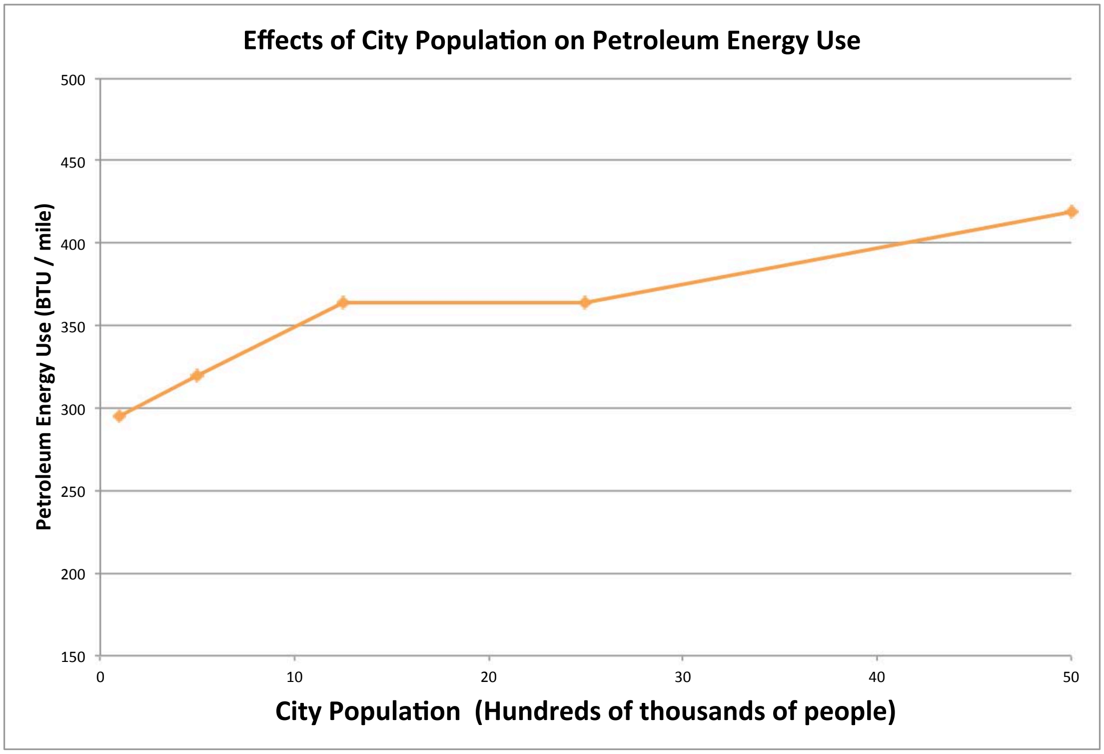


Figure 6.5.18. Petroleum energy use versus city population for the central biomass—gaseous H_2 truck delivery pathway

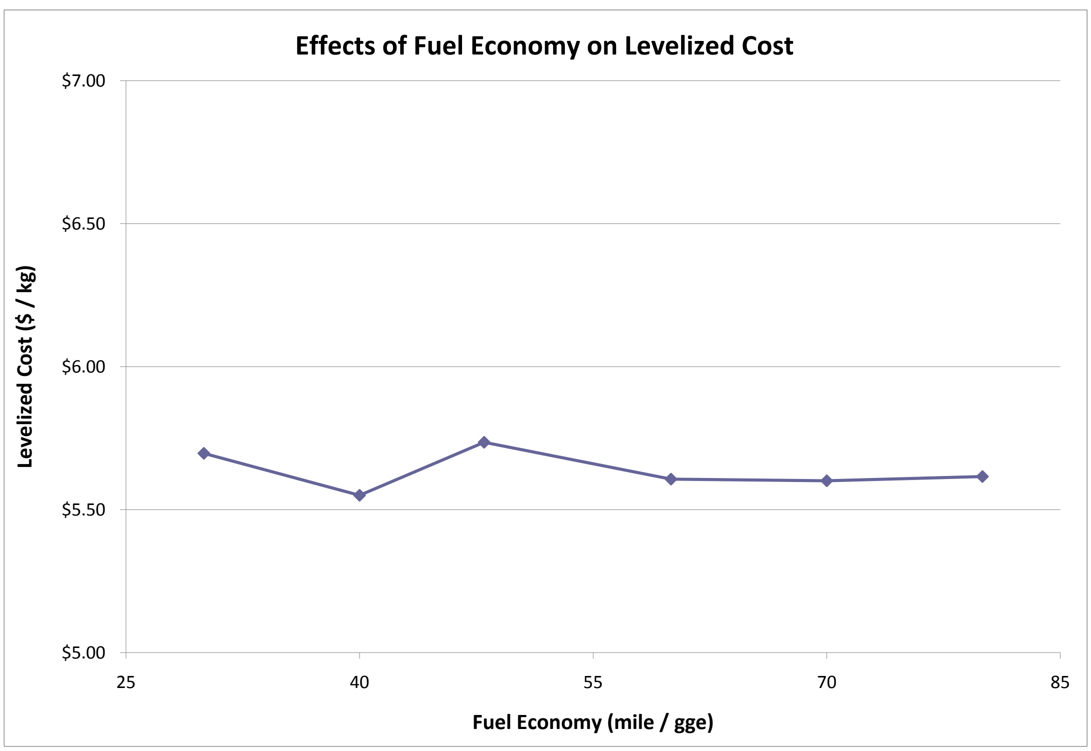


Figure 6.5.19. Levelized cost versus fuel economy for the central biomass—gaseous H_2 truck delivery pathway

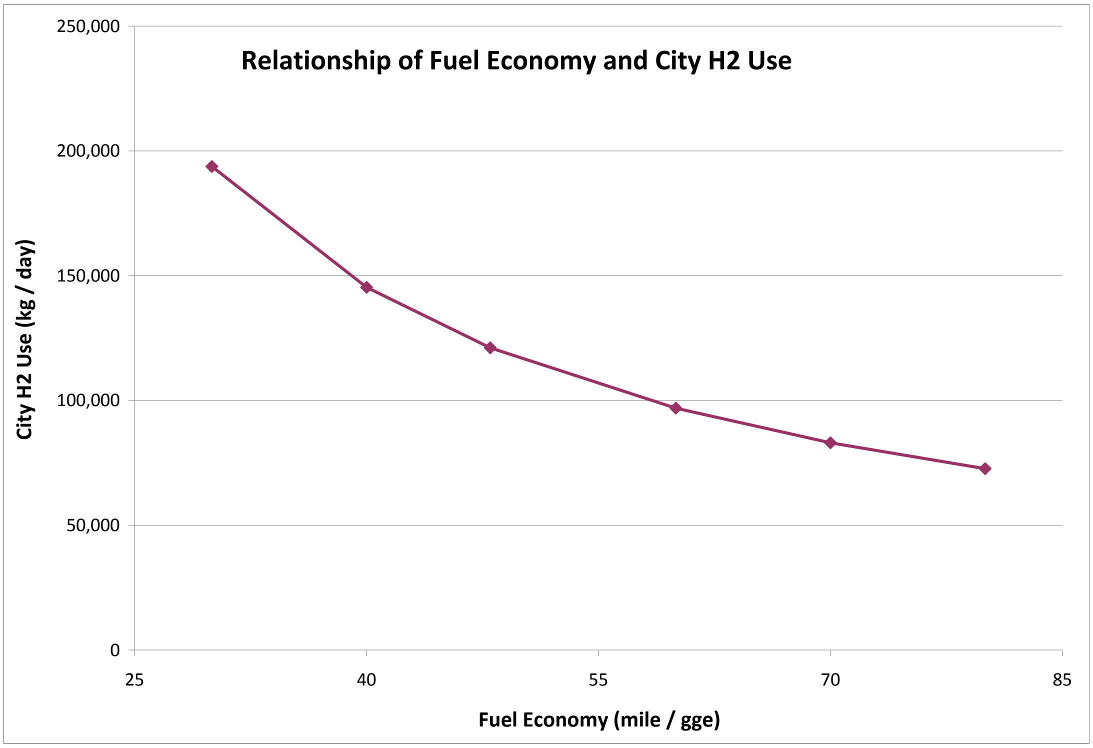


Figure 6.5.20. City hydrogen use versus fuel economy for the central biomass—gaseous H_2 truck delivery pathway

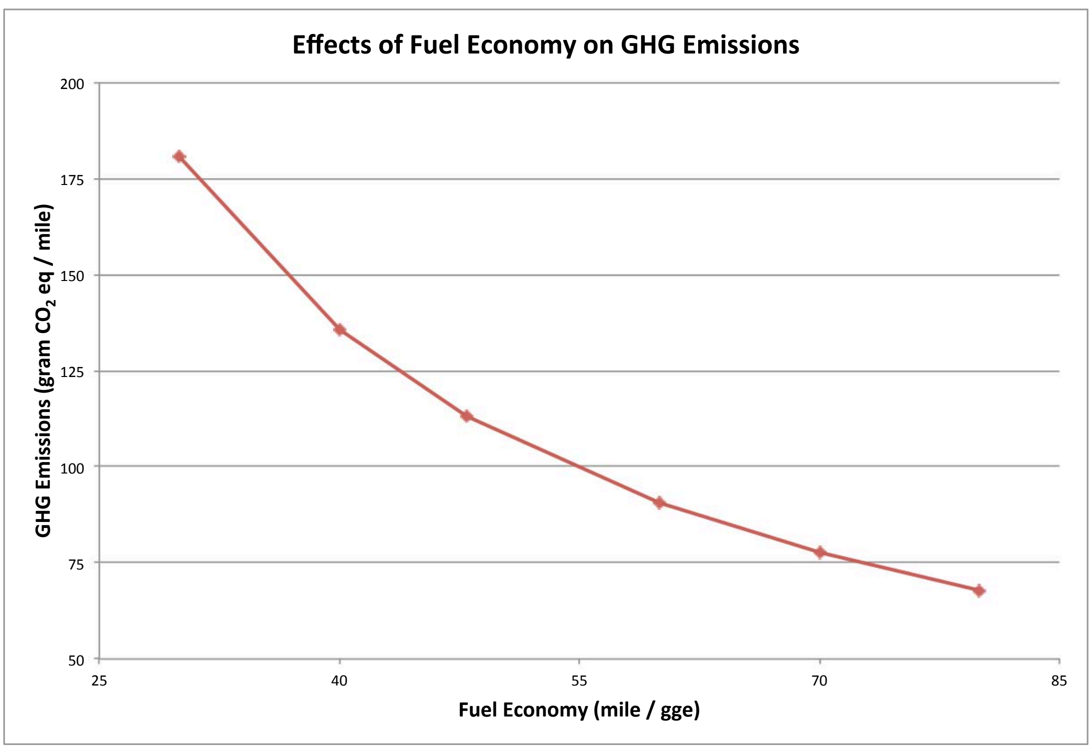


Figure 6.5.21. GHG emissions versus fuel economy for the central biomass—gaseous H_2 truck delivery pathway

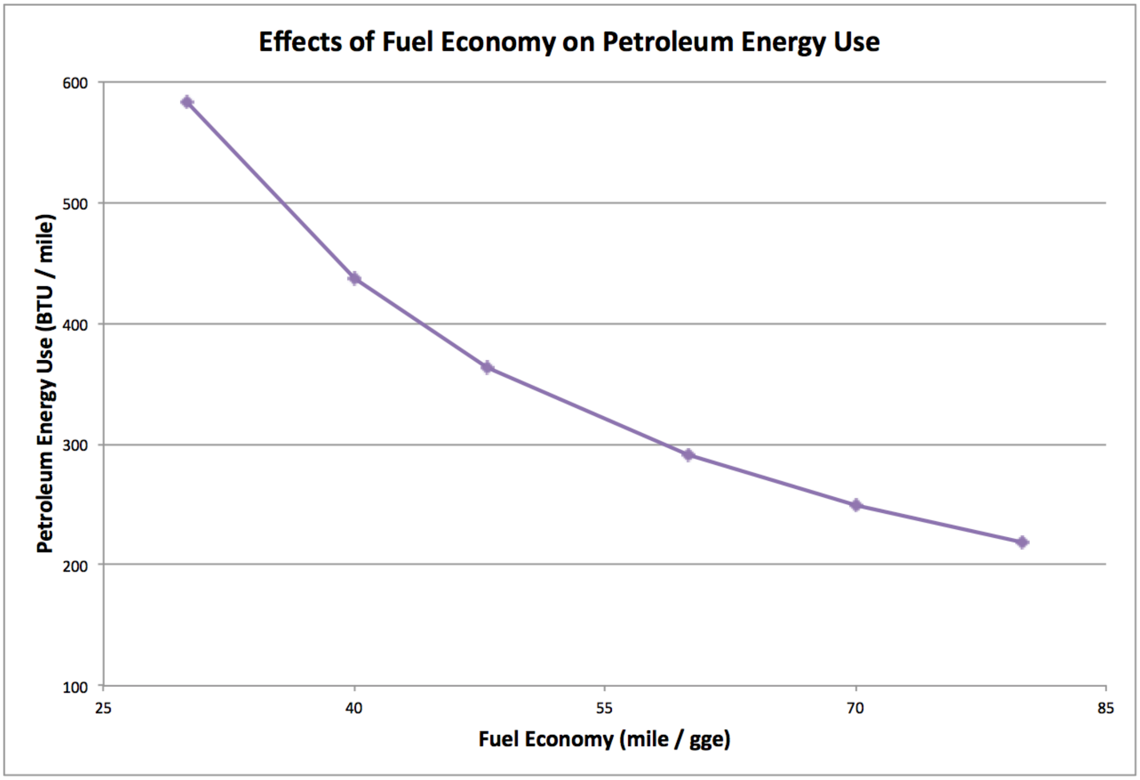


Figure 6.5.22. Petroleum use versus fuel economy for the central biomass—gaseous H_2 truck delivery pathway

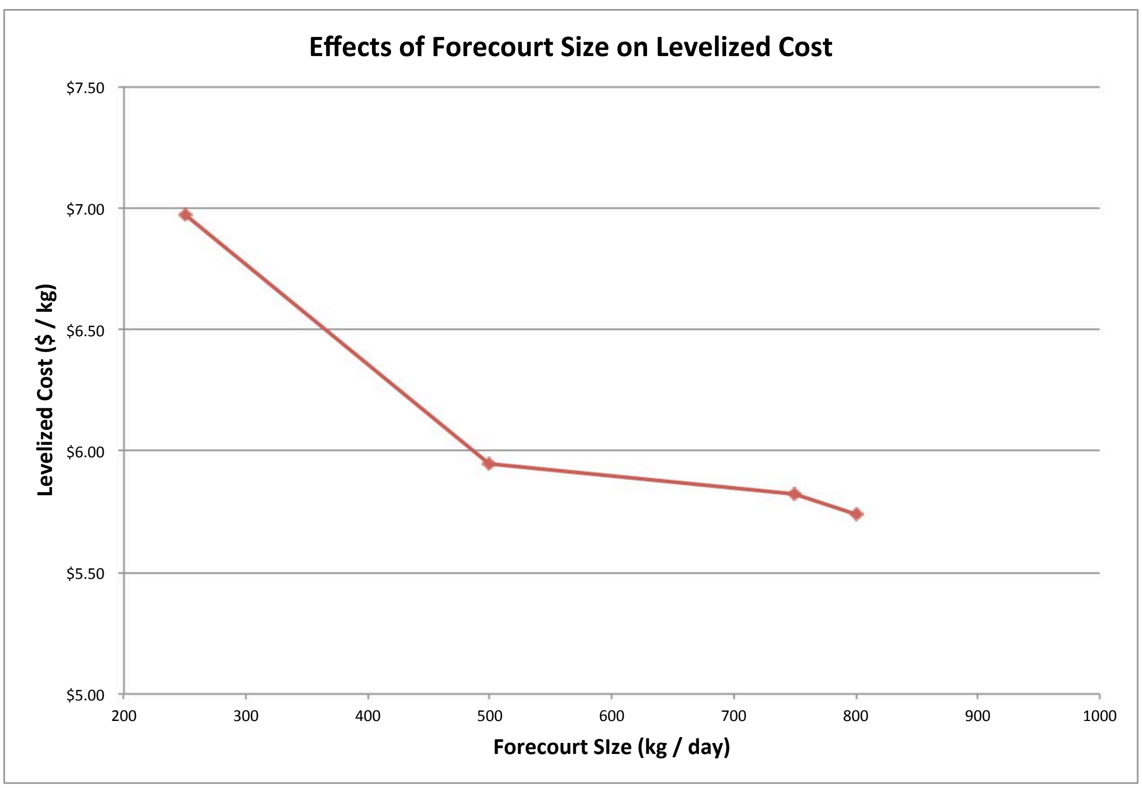


Figure 6.5.23. Levelized cost versus forecourt size for the central biomass—gaseous H_2 truck delivery pathway

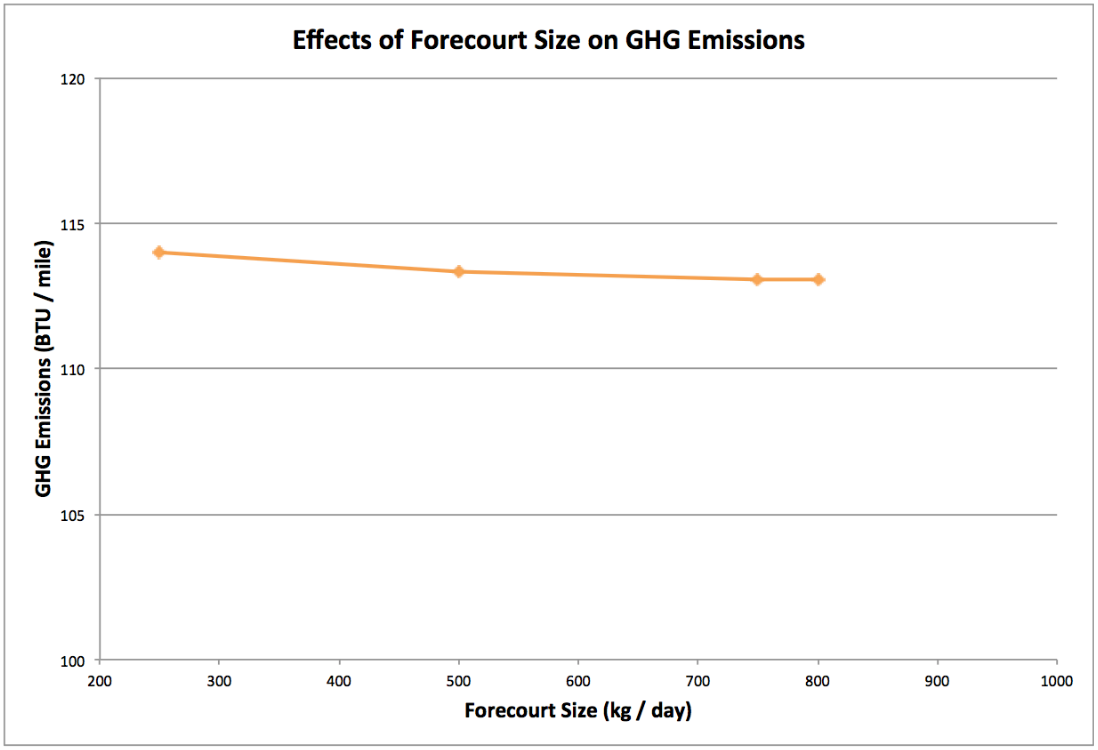


Figure 6.5.24. GHG emissions versus forecourt size for the central biomass—gaseous H_2 truck delivery pathway

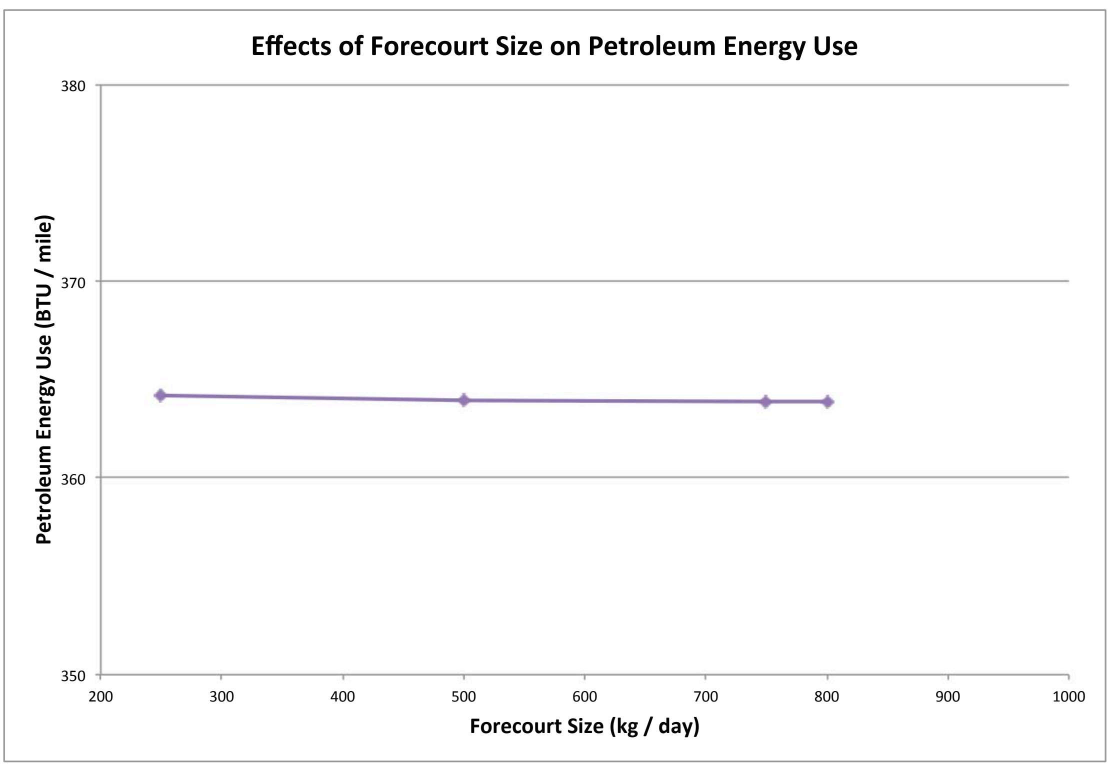


Figure 6.5.25. Petroleum energy use versus forecourt size for the central biomass—gaseous H_2 truck delivery pathway

6.6 Central Biomass—Liquid Truck Delivery and Gaseous Dispensing

Figure 6.6.1 shows the major inputs, assumptions, and outputs for each of the subsystems considered in the well-to-tank analysis, including feedstock supply and hydrogen dispensing. (See Appendix F for more details on this pathway.)

The WTP and WTW cost of hydrogen, energy use, and emissions for the central biomass—liquid truck delivery and gaseous dispensing pathway are summarized in Table 6.6.1.

Net GHG emissions include carbon dioxide uptake occurring during growth of the biomass. As noted above, the analysis assumes that 100% of the carbon in the biomass is provided by atmospheric carbon dioxide and that land use change is assumed to have neither positive nor negative effects on emissions.

6.6.1 Cost Breakdown

Figure 6.6.2 shows the feedstock and energy price inputs and the resulting hydrogen production, delivery, and distribution costs for the central biomass—liquid truck delivery and gaseous dispensing pathway. The financial assumptions used in this analysis are detailed in Section 5.0.

Inputs			Assumptions			Outputs		
			Biomass Production & Delivery			Biomass moisture content	25%	
Energy Use for Farming Trees	235,000	Btu / dry ton				Woody biomass LHV	16,013,000	Btu / dry ton
						Biomass price at H2 production	$75	2007 $ / dry ton
			Fraction of Woody Biomass	='Params - Upstream'!D3		Biomass Share of Levelized Cost	$1.00	2007$ / kg H2 dispensed
			LUC GHG changes	='Params - U	g / dry ton			
Coal Input (including upstream)	200	Btu / 116000Btu to Pump	Average distance from farm to H2 prod.	='Params - U	miles	WTG CO2 Emissions	-25,540	g CO2 eq./ 116000 Btu
Natural Gas Input (including upstream)	600	Btu / 116000Btu to Pump				WTG CH4 Emissions	13	g CO2 eq./ 116000 Btu
Petroleum Input (including upstream)	2,800	Btu / 116000Btu to Pump				WTG N2O Emissions	36	g CO2 eq./ 116000 Btu
						WTG GHG Emissions	-25,490	g CO2 eq./ 116000 Btu
						Hydrogen Output Pressure	300	psi
Biomass consumption	13.5	kg (dry) / kg H2 produced	**Hydrogen Production**			Hydrogen Outlet Quality	99.9%	
Natural gas consumption	0.0059	MMBtu / kg H2 produced						
Electricity consumption	0.98	kWh / kg H2 produced	Central plant design capacity	155,200	kg / day	Total capital investment	$1,300	2007$ / daily kg H2 (effective capacity)
Process Water Consumption	1.32	gal / kg H2 produced	Capacity factor	90%		Levelized Cost of Capital	$0.66	2007$ / kg H2 dispensed
Cooling Water Consumption	79.3	gal / kg H2 produced	Number of production facilities necessary	0.87		Fixed O&M Costs	$0.23	2007$ / kg H2 dispensed
			Process energy efficiency	46.0%		Variable O&M Costs	$0.41	2007$ / kg H2 dispensed
Total Capital Investment	$181,080,000	2007$	Electricity Mix	US Mix		Total Levelized Cost	$2.30	2007$ / kg H2 dispensed
			After-tax IRR	10%				
Coal Input (including upstream)	5,300	Btu / 116000Btu to Pump	Assumed Plant Life	40		Production CO2 Emissions	27,230	g CO2 eq./ 116000 Btu
Natural Gas Input (including upstream)	9,700	Btu / 116000Btu to Pump				Production CH4 Emissions	140	g CO2 eq./ 116000 Btu
Petroleum Input (including upstream)	3,300	Btu / 116000Btu to Pump				Production N2O Emissions	44	g CO2 eq./ 116000 Btu
						Production GHG Emissions	27,410	g CO2 eq./ 116000 Btu
						Total capital investment	$1,980	2007$ / daily kg H2 (effective capacity)
Liquefaction electricity consumption	8.5	kWh / kg H2 dispensed	**Liquefaction and Truck-Delivery**			Levelized Electricity cost	$0.58	2007$ / kg H2 dispensed
Terminal electricity consumption	0.03	kWh / kg H2 dispensed				Levelized Diesel cost	$0.03	2007$ / kg H2 dispensed
Total electricity consumption	8.57	kWh / kg H2 dispensed	City Population	1,247,000	people	Levelized Labor cost	$0.09	2007$ / kg H2 dispensed
Diesel consumption	7.6	gal / 1000 kg H2 dispensed	Hydrogen Vehicle Penetration	15%		Levelized Other operating costs	$0.24	2007$ / kg H2 dispensed
			City hydrogen use	121,100	kg / day			
Total Capital Investment	$239,448,000	2007$	One-way distance for delivery	98	miles	Levelized Cost of Delivery	$1.80	2007$ / kg H2 delivered
			Terminal Design Capacity	1,103,000	kg H2			
			Number of truck-trips required per year	10,200				
Coal Input (including upstream)	51,700	Btu / 116000Btu to Pump	Truck hydrogen capacity	4,400	kg / truckload	Delivery CO2 Emissions	7,220	g CO2 eq./ 116000 Btu
Natural Gas Input (including upstream)	23,000	Btu / 116000Btu to Pump	Liquefaction energy efficiency	79.3%		Delivery CH4 Emissions	440	g CO2 eq./ 116000 Btu
Petroleum Input (including upstream)	3,000	Btu / 116000Btu to Pump	Hydrogen losses	2.8%		Delivery N2O Emissions	30	g CO2 eq./ 116000 Btu
						Delivery GHG Emissions	7,690	g CO2 eq./ 116000 Btu
						Onboard Storage Pressure	12,700	psi
Electricity consumption	0.51	kWh / kg H2 dispensed	**Forecourt Dispensing**			Basis -- Hydrogen Quantity	116,000	Btu (116,000 Btu/gal non-oxygenated conventional unleaded gasoline)
			Average Dispensing Rate per Station	1,000	kg / day	Total capital investment	$1,330	2007$ / daily kg H2 (effective capacity)
Total Capital Investment per Station	$1,315,000	2007$ / station	Number of Dispensing Stations	122		Levelized Cost of Capital	$0.49	2007$ / kg H2 dispensed
Total Capital Investment	$160,485,000	2007$ / all stations	Number of Cascade Pumps	1		Energy & Fuel	$0.05	2007$ / kg H2 dispensed
			Liquid H2 storage capacity per Station	4,600	kg H2	Other O&M Costs	$0.48	2007$ / kg H2 dispensed
			Usable Cascade Storage per Station	70	kg H2	Levelized Cost of Dispensing	$1.02	2007$ / kg H2 dispensed
Coal Input (including upstream)	Included in Delivery Section		Site storage	400%	% of design capacity	CSD CO2 Emissions	Included in Delivery Section	
Natural Gas Input (including upstream)	Included in Delivery Section		# of 2-hose Dispensers per Station	2		CSD CH4 Emissions	Included in Delivery Section	
Petroleum Input (including upstream)	Included in Delivery Section		Hydrogen Losses	1.1%		CSD N2O Emissions	Included in Delivery Section	
						CSD GHG Emissions	Included in Delivery Section	
						Cost Per Mile	$0.67	2007$ / mi
Vehicle Mass	3,020	lb	**Vehicle**			Fuel Share	$0.11	2007$ / mi
Fuel cell size	70	kW	Fuel Economy	48.0	mi / gge	Maintenance, Tires, Repairs	$0.07	2007$ / mi
Hybridization battery (peak power)	30	kW	Vehicle Miles Traveled	15,000	mi / yr	Insurance & Registration	$0.12	2007$ / mi
			Vehicle Lifetime	160,000	mi	Depreciation	$0.27	2007$ / mi
			Purchase Year	2015		Financing	$0.10	2007$ / mi
			Vehicle Purchase Cost	$33,700	2007$			
Coal Input (including upstream)	2,300	Btu / gge fuel consumed	Fuel Cell System Cost	$4,500	2007$	Veh. Cycle CO2 Emissions	1,670	g CO2 eq/ gge fuel consumed
Natural Gas Input (including upstream)	12,100	Btu / gge fuel consumed	Hydrogen Storage System Cost	$2,400	2007$	Veh. Cycle CH4 Emissions	170	g CO2 eq/ gge fuel consumed
Petroleum Input (including upstream)	6,900	Btu / gge fuel consumed	Tax Credit	$0	2007$	Veh. Cycle N2O Emissions	6	g CO2 eq/ gge fuel consumed
						Veh. Cycle GHG Emissions	1,850	g CO2 eq/ gge fuel consumed

Figure 6.6.1. Summary of major inputs, assumptions, and outputs by subsystem for the central biomass—liquid truck delivery and gaseous dispensing pathway

Table 6.6.1. WTP and WTW Results for the Central Biomass—Liquid Truck Delivery and Gaseous Dispensing Pathway

	WTP		WTW	
Coal input (including upstream)[a]	57,200	Btu/116,000 Btu	1,190	Btu/mi
Natural gas input (including upstream)[a]	33,400	Btu/116,000 Btu	700	Btu/mi
Petroleum input (including upstream)[a]	9,100	Btu/116,000 Btu	190	Btu/mi
Fossil energy input (including upstream)[a]	367,400	Btu/116,000 Btu	2,080	Btu/mi
WTP CO_2 emissions[b]	8,900	g/116,000 Btu	190	g/mi
WTP CH_4 emissions	24	g/116,000 Btu	0	g/mi
WTP N_2O emissions	0	g/116,000 Btu	0	g/mi
WTP GHG emissions	9,600	g CO_2-eq./ 116,000 Btu	200	g/mi
	Cost per kg		**Cost per mile**	
Levelized cost of hydrogen	$5.12	2007$/kg	$0.11	2007$/mi

[a] Coal, natural gas, and petroleum inputs include those used directly in the hydrogen production and delivery pathway as feedstocks and fuels; those used to produce electricity and other materials used in the pathway; and those used upstream of the pathway to recover, refine, and deliver the feedstock.
[b] Includes the carbon content of CO, CH_4, and volatile organic compound emissions that decompose in the atmosphere to CO_2.

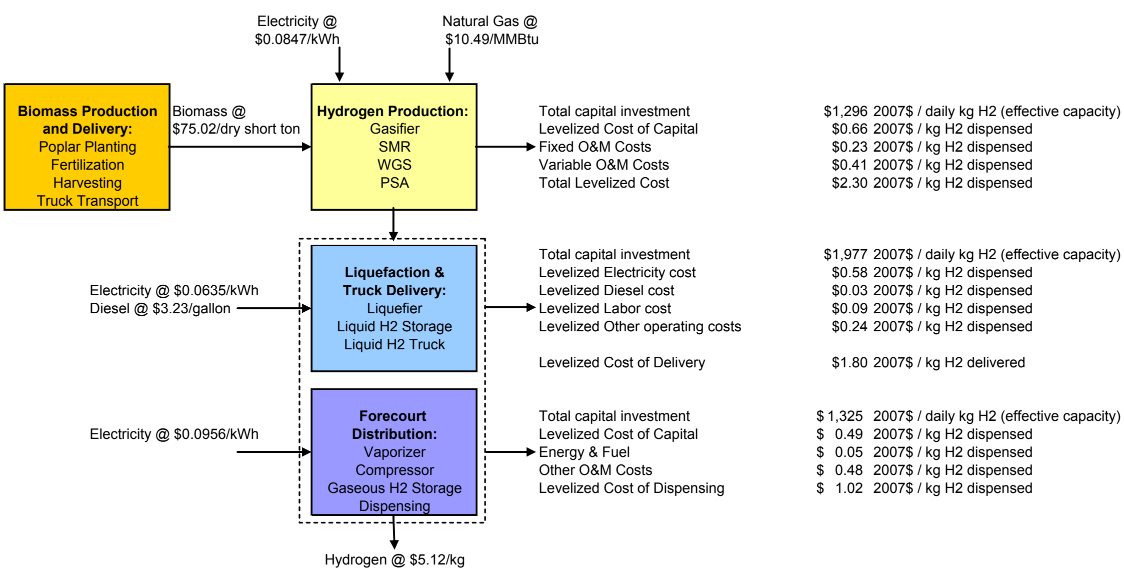


Figure 6.6.2. Cost analysis inputs and high-level results for the central biomass—liquid truck delivery and gaseous dispensing pathway

Figure 6.6.3 shows the contributions of hydrogen production, delivery, and losses to the levelized cost of hydrogen shown in Figure 6.6.2.

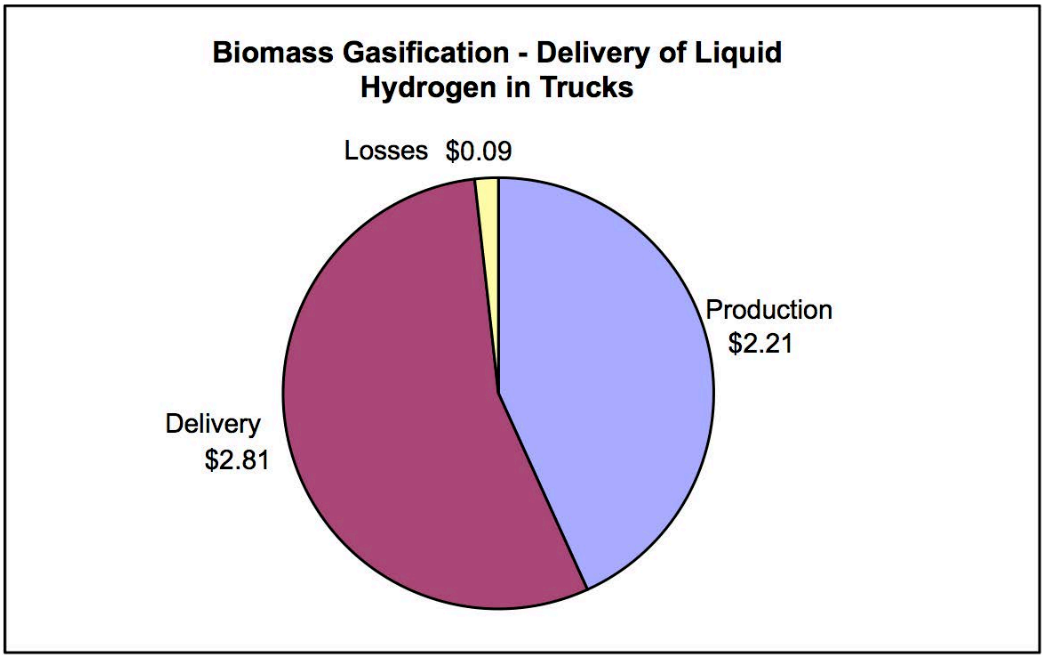


Figure 6.6.3. Contribution of hydrogen production, delivery, and losses to the levelized cost of hydrogen for the central biomass—liquid truck delivery and gaseous dispensing pathway

Figure 6.6.4 and Table 6.6.2 show the breakdown of levelized costs for the central biomass—liquid truck delivery and gaseous dispensing pathway.

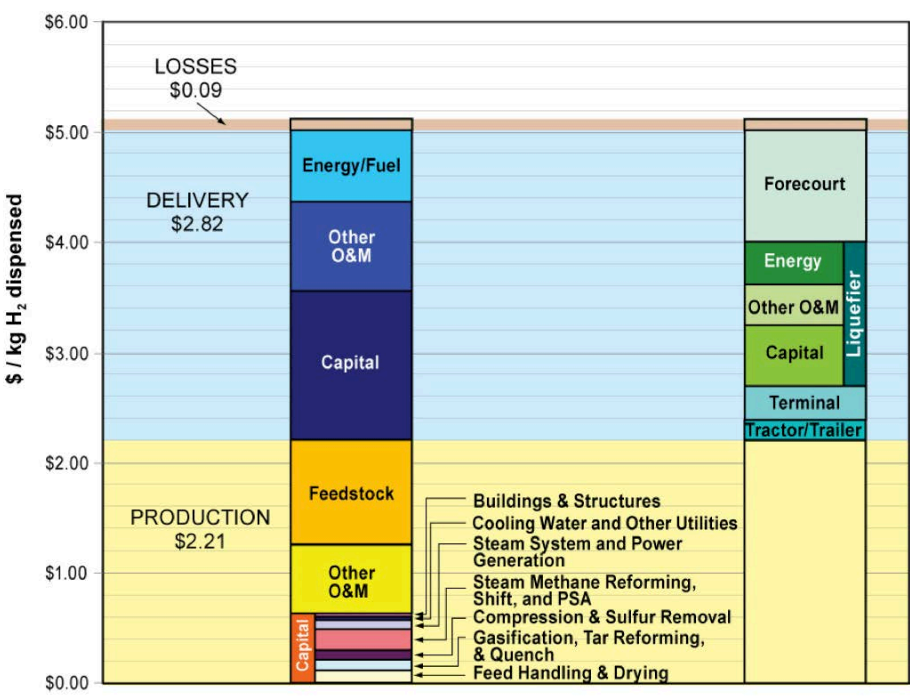


Figure 6.6.4. Breakdown of levelized costs for the central biomass—liquid truck delivery and gaseous dispensing pathway

Table 6.6.2. Contribution of Production and Delivery Processes to Levelized Hydrogen Cost for the Central Biomass—Liquid Truck Delivery and Gaseous Dispensing Pathway

Cost Component	Capital	Other O&M	Feedstock	Energy/ Fuel	Total
Production	$0.64	$0.62	$0.96		$2.21
Feed handling and drying	$0.11				
Gasification, tar reforming, and quench	$0.10				
Compression and sulfur removal	$0.09				
SMR, WGS, and PSA	$0.18				
Steam system and power generation	$0.09				
Cooling water and other utilities	$0.02				
Buildings and structures	$0.04				
Delivery	$1.35	$0.81		$0.65	$2.81
Tractor/trailer					$0.18
Terminal					$0.30
Liquefier	$0.57	$0.16		$0.58	$1.31
Forecourt	$0.49	$0.48		$0.05	$1.02
Losses					$0.09
Total	**$1.99**	**$1.43**	**$0.96**	**$0.65**	**$5.12**

6.6.2 Energy Use and Emissions Breakdown

Figures 6.6.5 and 6.6.6 show the WTW energy inputs and losses for the central biomass—liquid truck delivery and gaseous dispensing pathway.

Figures 6.6.7 and 6.6.8 show the WTW emissions resulting from the delivery of 116,000 Btu hydrogen to a vehicle fuel tank using the central biomass—liquid truck delivery and gaseous dispensing pathway.

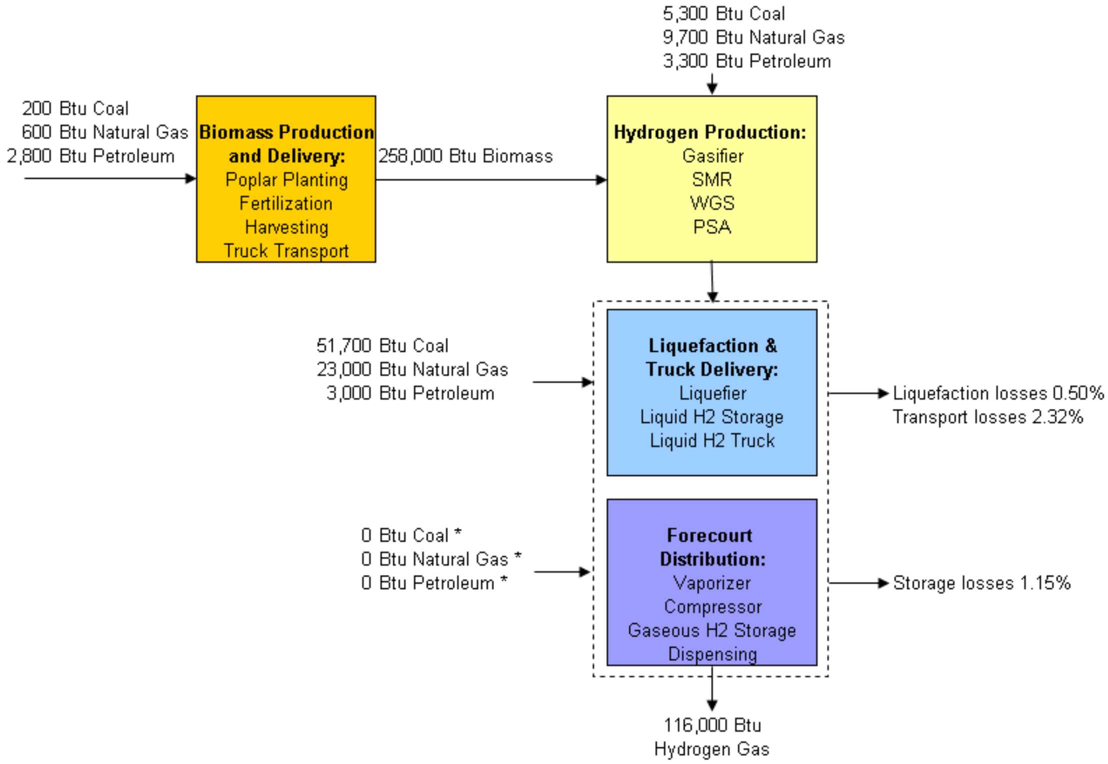


Figure 6.6.5. WTW energy inputs to deliver 116,000 Btu hydrogen to a vehicle using the central biomass—liquid truck delivery and gaseous dispensing pathway

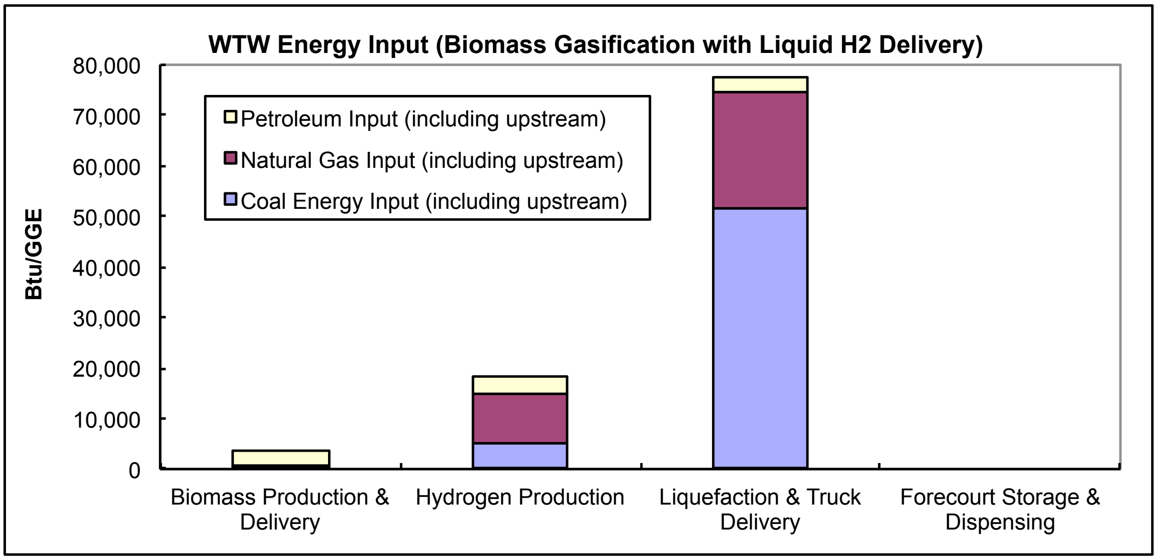


Figure 6.6.6. WTW petroleum, natural gas, and coal inputs to deliver 116,000 Btu hydrogen using the central biomass—liquid truck delivery and gaseous dispensing pathway

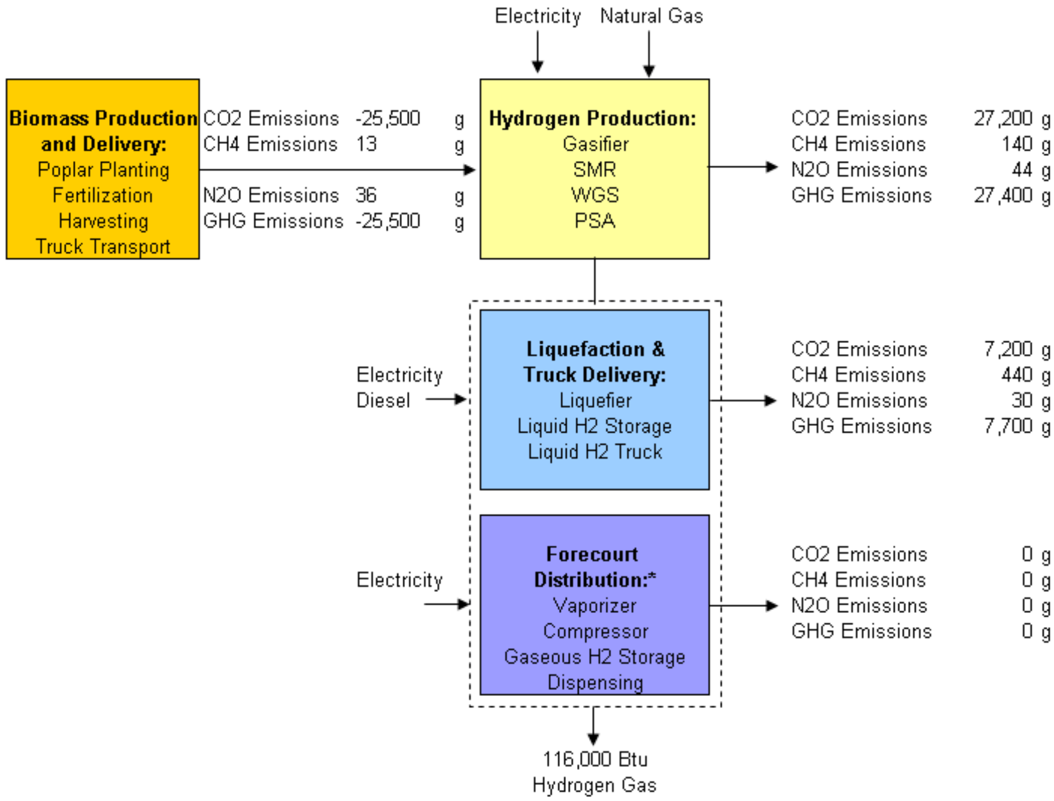


Figure 6.6.7. WTW emissions resulting from delivery of 116,000 Btu hydrogen using the central biomass—liquid truck delivery and gaseous dispensing pathway

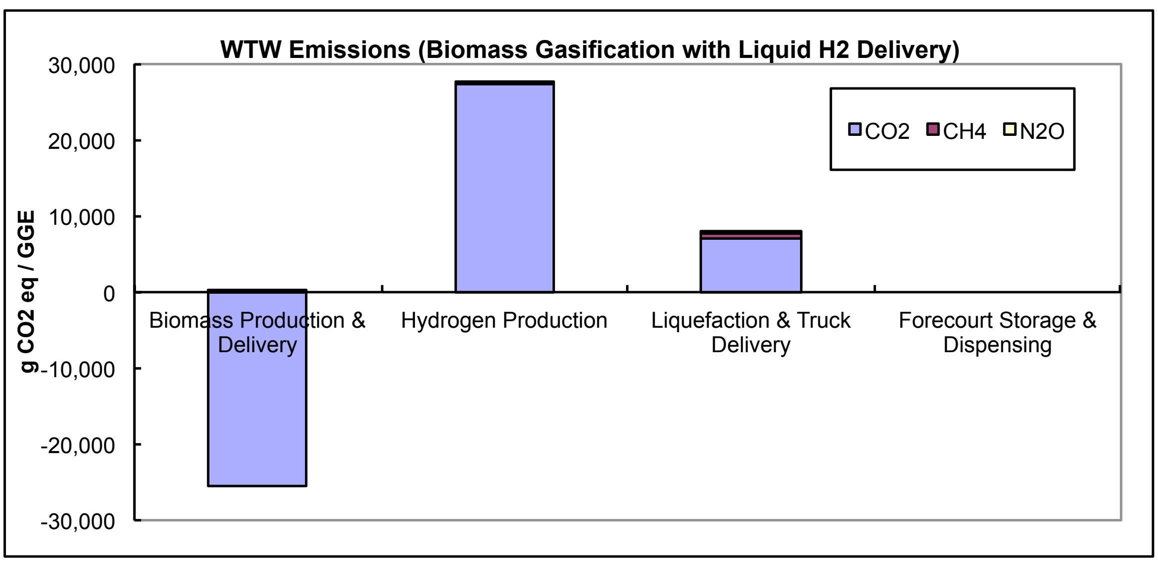


Figure 6.6.8. WTW CO_2, CH_4, and N_2O emissions resulting from delivery of 116,000 Btu hydrogen to a vehicle using the central biomass—liquid truck delivery and gaseous dispensing pathway

6.6.3 Sensitivities

6.6.3.1 Production Sensitivities

Several sensitivities were run on the production portion of the central biomass—liquid truck delivery and gaseous dispensing pathway. These sensitivities focused primarily on cost factors; however, several sensitivities also affect energy use and emissions. Figure 6.6.9 shows the effects of several production parameters on the pathway's levelized cost, and Table 6.6.3 shows the effects of varying production energy efficiency on WTW energy use and emissions.

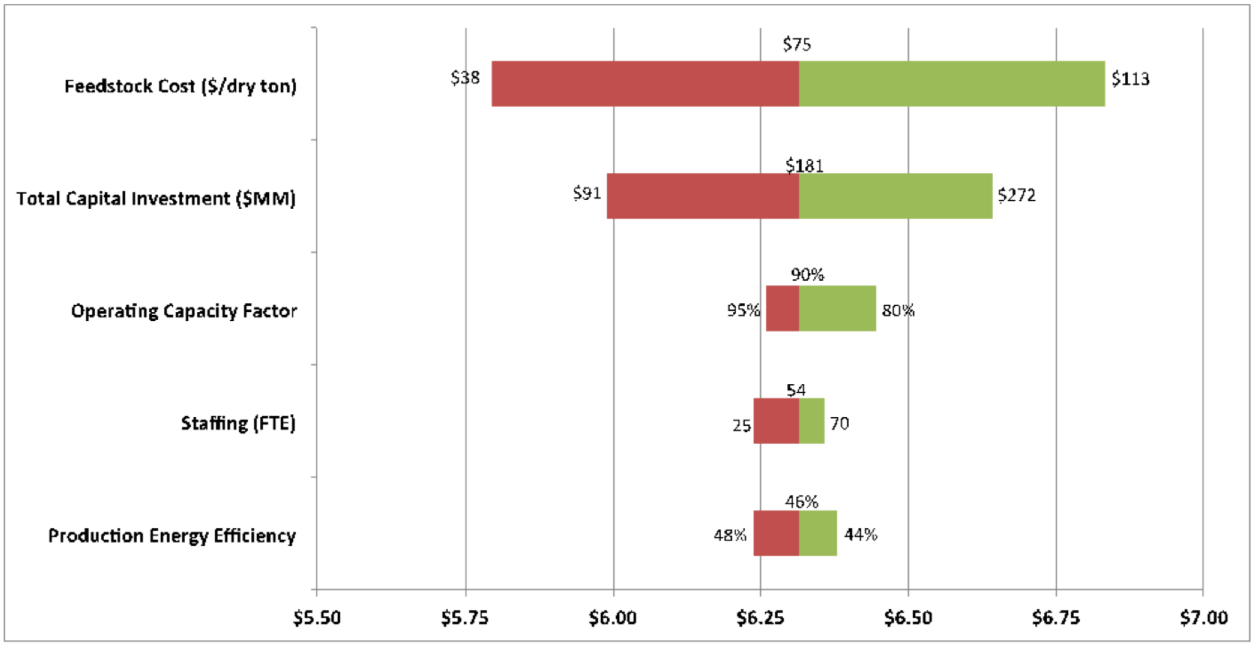


Figure 6.6.9. Production sensitivities for the central biomass—liquid truck delivery and gaseous dispensing pathway

Table 6.6.3. The Effects of Production Energy Efficiency on Primary Energy Use and Emissions from the Central Biomass—Liquid Truck Delivery and Gaseous Dispensing Pathway

	44% Efficiency	46% Efficiency	48% Efficiency
WTW GHG emissions (g/mile)	200	200	200
WTW fossil energy (Btu/mile)	2,100	2,100	2,100
WTW petroleum energy (Btu/mile)	200	190	180
WTW total energy (Btu/mile)	8,000	7,700	7,400

The assumed electrical grid mix also affects the energy use and emissions. Table 6.6.4 shows the differences in energy use and GHG emissions between the U.S. average grid mix (which was used for all other sensitivities) and a hypothetical green grid mix that is 100% renewable energy (solar and wind).

Table 6.6.4. The Effects of Fuel Economy and Grid Mix on Use of Primary Energy and Emissions from the Central Biomass—Liquid Truck Delivery and Gaseous Dispensing Pathway

	U.S. Average Grid Mix (48 mpgge)	U.S. Average Grid Mix (68 mpgge)	"Green" Grid Mix (48 mpgge)
WTW GHG emissions (g/mile)	200	150	30
WTW fossil energy (Btu/mile)	2,100	1,500	300
WTW petroleum energy (Btu/mile)	190	130	140
WTW total energy (Btu/mile)	7,700	5,500	6,500

6.6.3.2 Delivery Sensitivities

Delivery cost, energy use, and emissions are strongly dependent upon the daily consumption of hydrogen within a city and the delivery distance from the central facility to the city gate. Sensitivities were run to show some of those effects. Daily consumption was varied by keeping the city size constant and adjusting the penetration of hydrogen vehicles from the base case of 15%. The resulting consumption is shown in Figure 6.6.10.

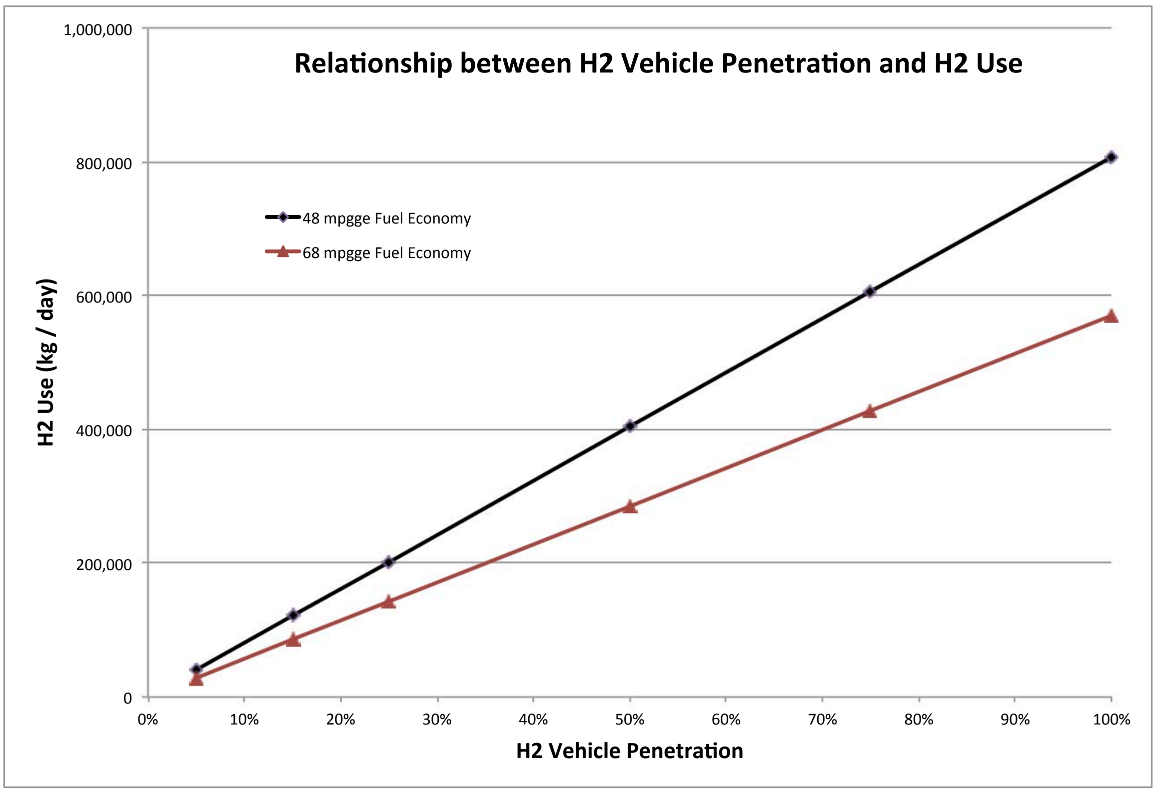


Figure 6.6.10. Daily hydrogen consumption versus hydrogen vehicle penetration for the central biomass—liquid truck delivery and gaseous dispensing pathway

As expected there are economies of scale for higher vehicle penetration/hydrogen consumption, and the levelized cost of delivery decreases as the distance from the production plant to the city gate is shortened. Figures 6.6.11 and 6.6.12 show those economic effects (the figures show identical data but are organized differently). In cases where the hydrogen vehicle penetration is 5% or 15%, only one liquefier is necessary. Two liquefiers are needed for the 25% penetration case because of size limitations, resulting in increased levelized cost due to increased levelized liquefier capital costs. Levelized liquefier capital costs are higher because each of the two liquefiers is smaller than the one in the 15% penetration case.

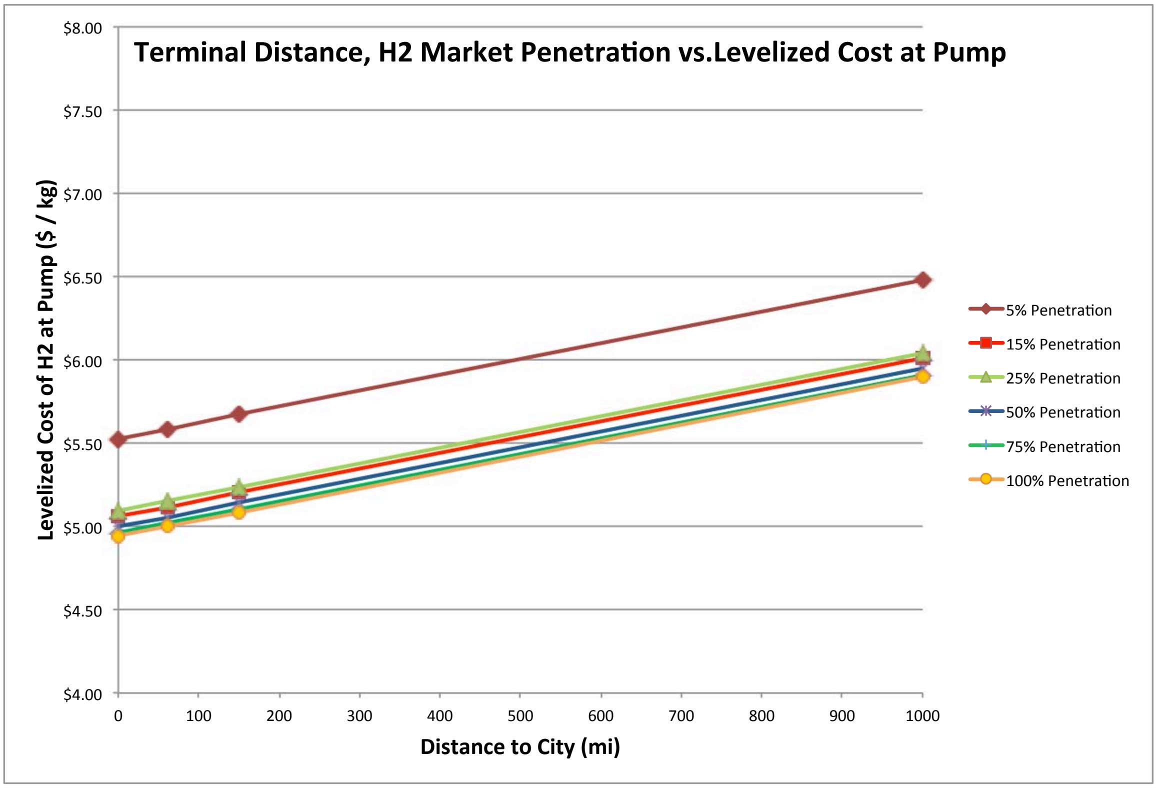


Figure 6.6.11. Levelized cost versus hydrogen vehicle penetration and distance between production facility and city gate for the central biomass—liquid truck delivery and gaseous dispensing pathway

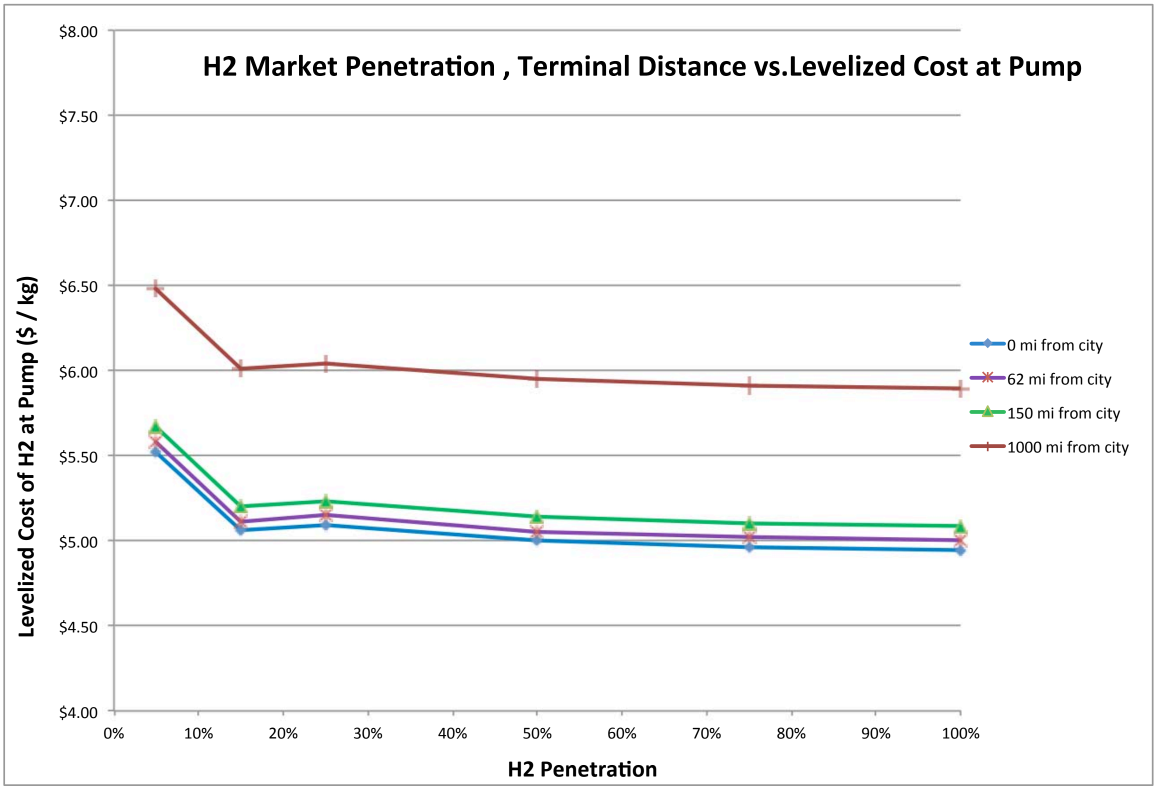


Figure 6.6.12. Levelized cost versus hydrogen vehicle penetration and distance between production facility and city gate for the central biomass—liquid truck delivery and gaseous dispensing pathway

As Figure 6.6.12 shows, there is a $0.14 increase in levelized cost when the production facility is assumed to be 150 miles from the city gate as compared to being at the city gate. There is a much larger levelized-cost increase when the distance is assumed to be 1,000 miles because the levelized cost of trucking increases with added distance due to additional driver time, additional fuel requirements, and an increased number of trucks and trailers required. Figure 6.6.13 shows the liquid truck portion of the levelized cost; note that the base case distance is 62 miles and that the truck's levelized cost is $0.18 for all penetration levels at that distance. Because the city size is constant and the assumed station size is sufficient to utilize a full truckload at each station, each delivery has the same travel distance and takes the same amount of time within the city regardless of penetration level; therefore, the levelized cost within the city gate is constant for all penetration levels.

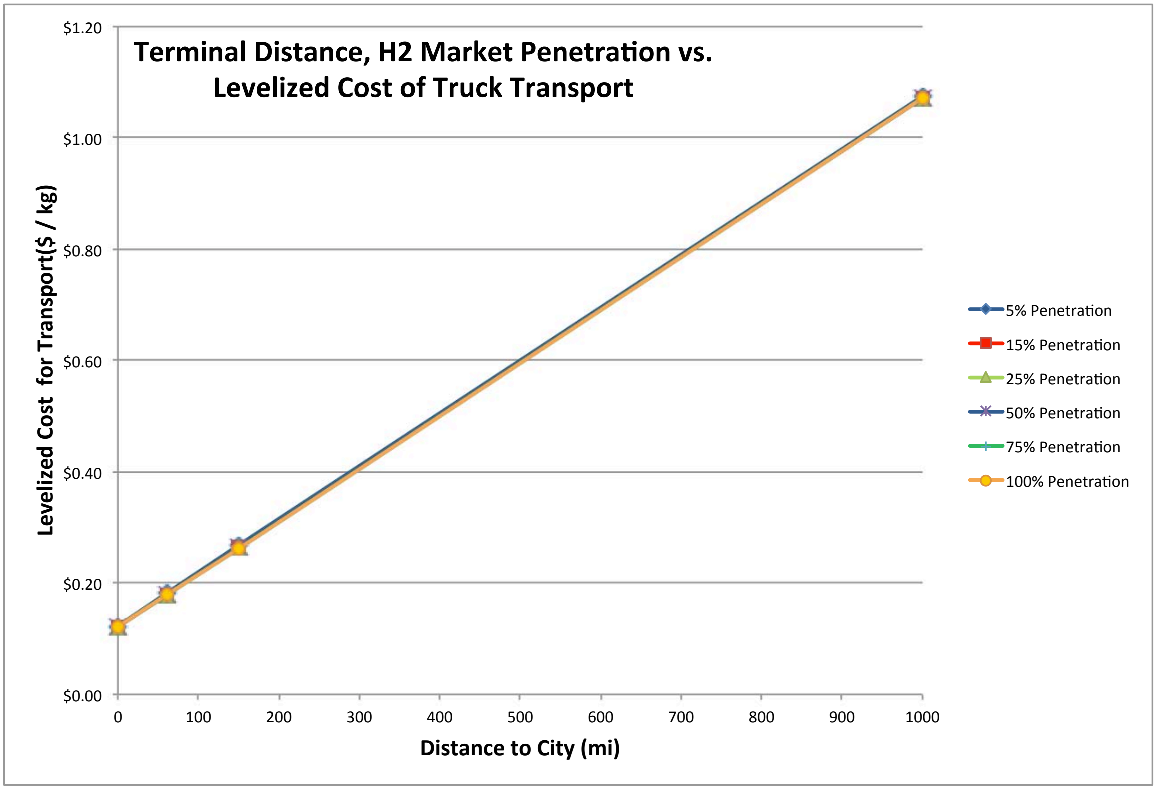


Figure 6.6.13. Truck levelized cost versus distance between production facility and city gate for the central biomass—liquid truck delivery and gaseous dispensing pathway

The most notable feature in Figure 6.6.13 is the insensitivity of transport levelized cost to changes in FCEV penetration. The significant drop in the levelized cost of hydrogen as FCEV penetration increases to 15% (shown in Figure 6.6.11) is due to the reduced cost of liquefaction, which is shown in Figure 6.6.14 (liquefier cost is constant when penetration levels are kept constant no matter how far the liquefiers are from the city). When the penetration is increased to 25% from 15%, two smaller liquefiers are needed due to scale limitations; thus, the capital cost per annual kilogram increases, resulting in increased levelized cost.

The majority of the liquefaction system's cost driver is capital (Table 6.6.2 shows that the capital accounts for \$0.57/kg H_2 of the \$1.31/kg H_2 total liquefaction cost). As shown in Figure 6.6.15, capital-cost reduction drives the cost decrease as penetration increases.

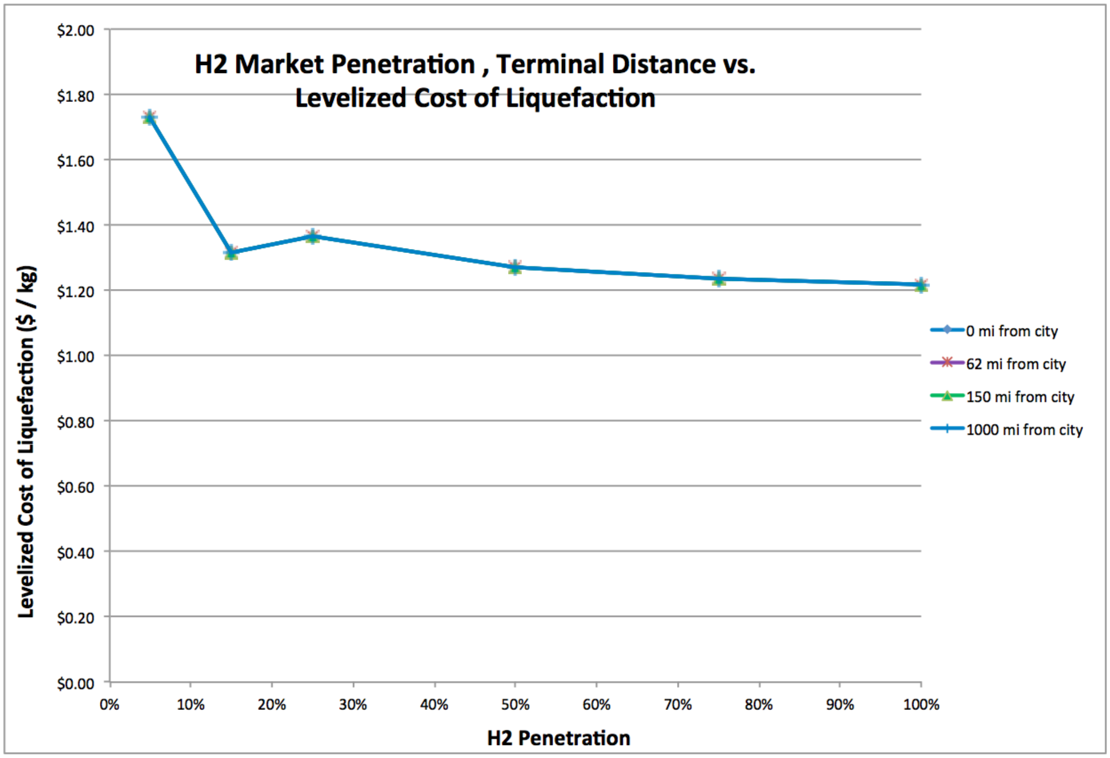


Figure 6.6.14. Liquefaction system levelized cost versus penetration for the central biomass—liquid truck delivery and gaseous dispensing pathway

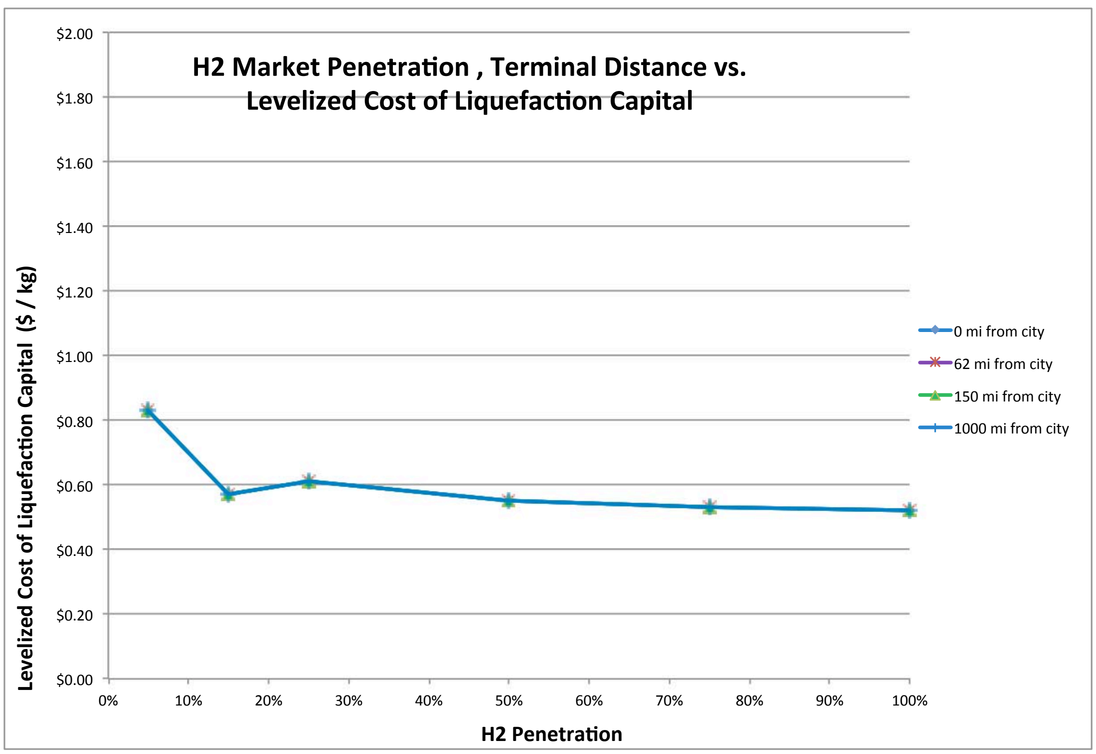


Figure 6.6.15. Liquefaction system capital cost (levelized) versus penetration for the central biomass—liquid truck delivery and gaseous dispensing pathway

The additional cost variable for the levelized cost of the liquefaction system is the system efficiency, because increased efficiency reduces the energy required for liquefaction. Figure 6.6.16 shows the effect of penetration (directly affecting liquefaction system size) on efficiency. Note that one liquefier is needed for 5% and 15% penetration, two for 25%, three for 50%, four for 75%, and five for 100% penetration, and that larger liquefaction systems result in higher efficiencies. More efficient liquefaction systems result in lower GHG emissions and fossil energy use.

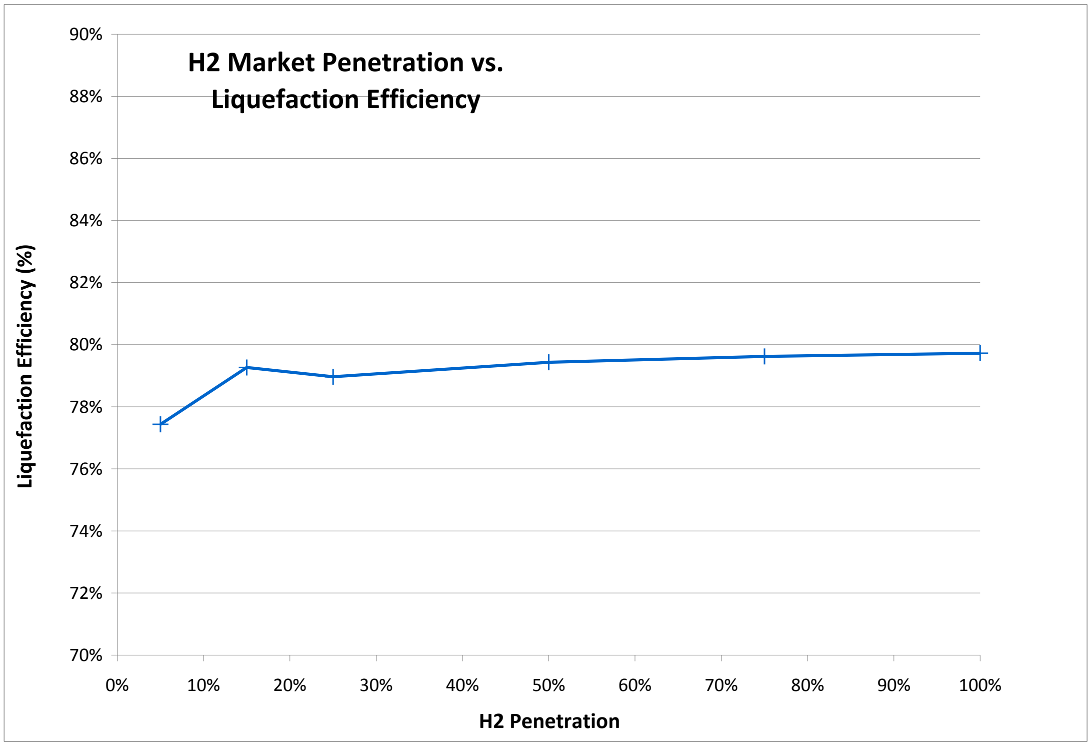


Figure 6.6.16. Liquefaction system efficiency versus penetration for the central biomass—liquid truck delivery and gaseous dispensing pathway

The effects of penetration and distance between the production facility and the city gate on WTW GHG emissions, WTW petroleum use, and WTW fossil energy use are shown in Figures 6.6.17, 6.6.18, and 6.6.19, respectively. In each case, the energy use and emissions decrease as liquefaction system efficiency increases with penetration and then plateaus as discussed above. Energy use and emissions are also reduced when the production facility is closer to the city gate because of reduced diesel use for trucking.

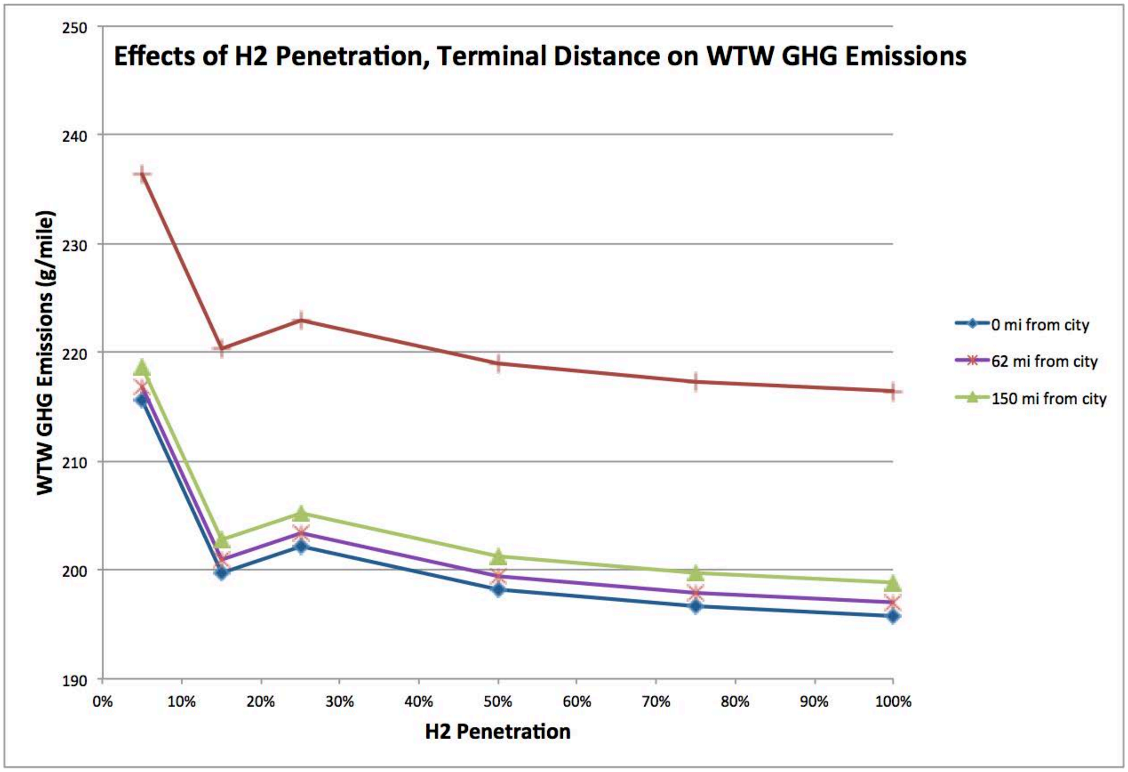


Figure 6.6.17. WTW GHG emissions versus penetration for the central biomass—liquid truck delivery and gaseous dispensing pathway

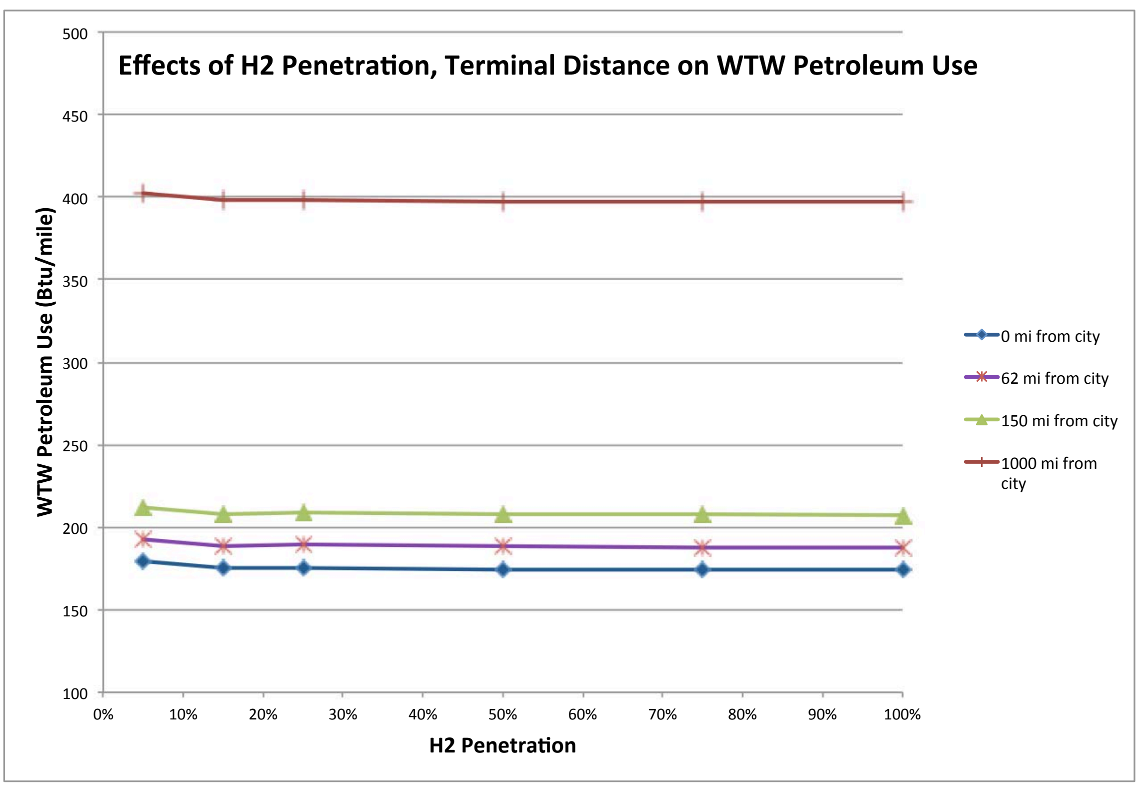


Figure 6.6.18. WTW petroleum use versus penetration for the central biomass—liquid truck delivery and gaseous dispensing pathway

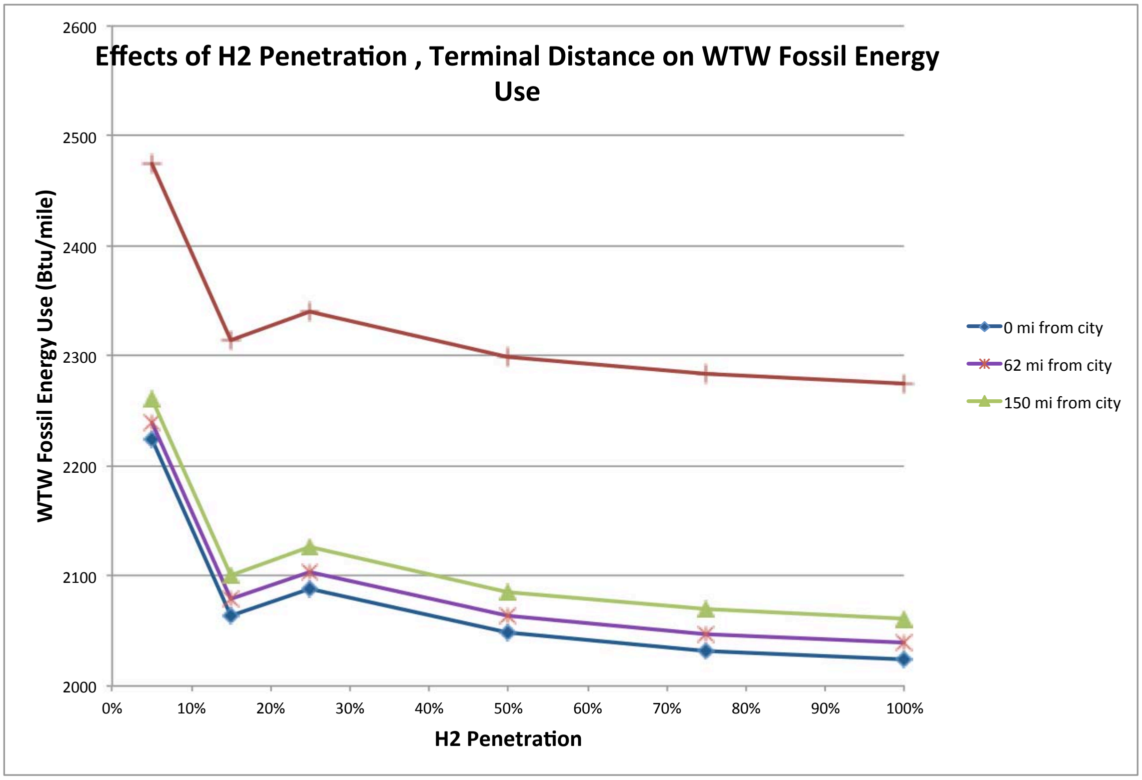


Figure 6.6.19. WTW fossil energy use versus penetration for the central biomass—liquid truck delivery and gaseous dispensing pathway

The effects of city population on levelized cost of hydrogen, GHG emissions, and petroleum energy use are shown in Figures 6.6.20, 6.6.21, and 6.6.22. Levelized hydrogen cost decreases slightly with increasing city population. GHG emissions also generally decrease with increasing city population, while petroleum energy use increases with increasing city population above a population of 500,000 due to increased city area with increased population.

Figure 6.6.23 shows the effect of fuel economy on the levelized cost of hydrogen. The cost of hydrogen increases with increasing fuel economy above 40 mpgge. The relationship between fuel economy and city hydrogen use is shown in Figure 6.6.24. As with FCEV penetration, the number and scale of the liquefiers affects the levelized cost. At 30 mpgge, two smaller liquefiers are necessary and result in higher costs than the single liquefier needed for the higher fuel economies does. Because the hydrogen demand is reduced as fuel economies increase, liquefaction of reduced amounts of hydrogen results in higher levelized costs.

Figures 6.6.25 and 6.6.26 show that GHG emissions and petroleum energy use decrease with increasing fuel economy, as one might expect.

Figures 6.6.27, 6.6.28, and 6.6.29 show the effects of forecourt size on levelized cost of hydrogen, GHG emissions, and petroleum energy use for the central biomass—liquid truck delivery and gaseous dispensing pathway.

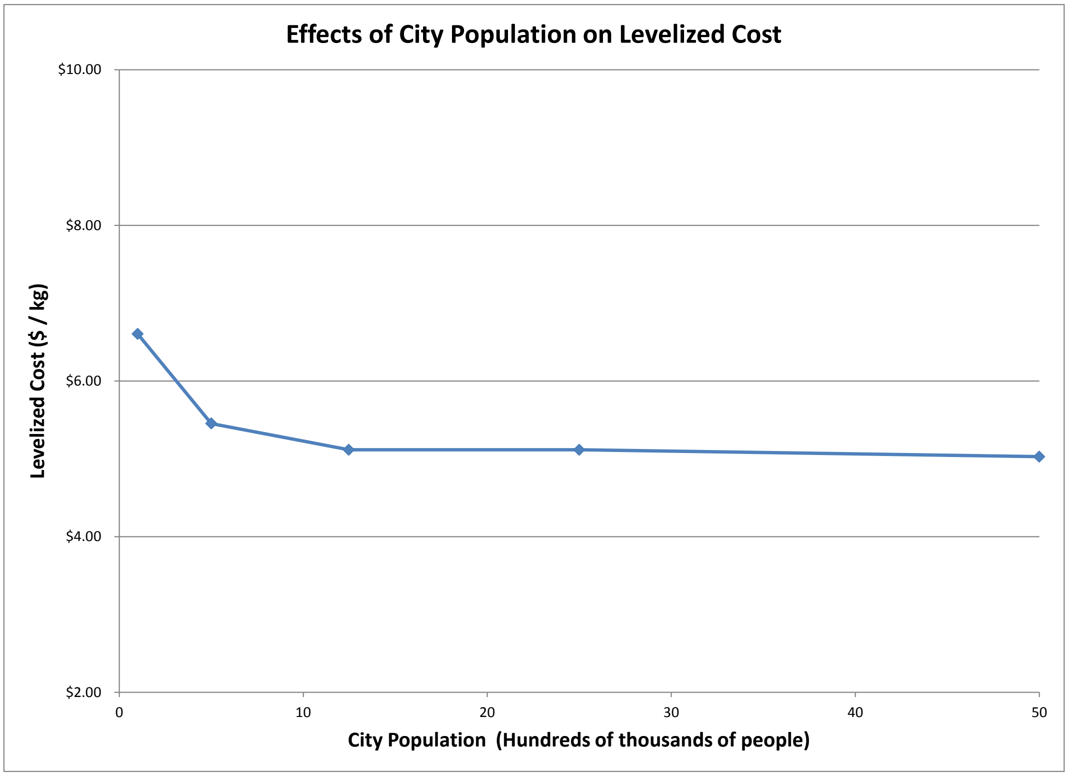


Figure 6.6.20. Levelized cost versus city population for the central biomass—liquid truck delivery and gaseous dispensing pathway

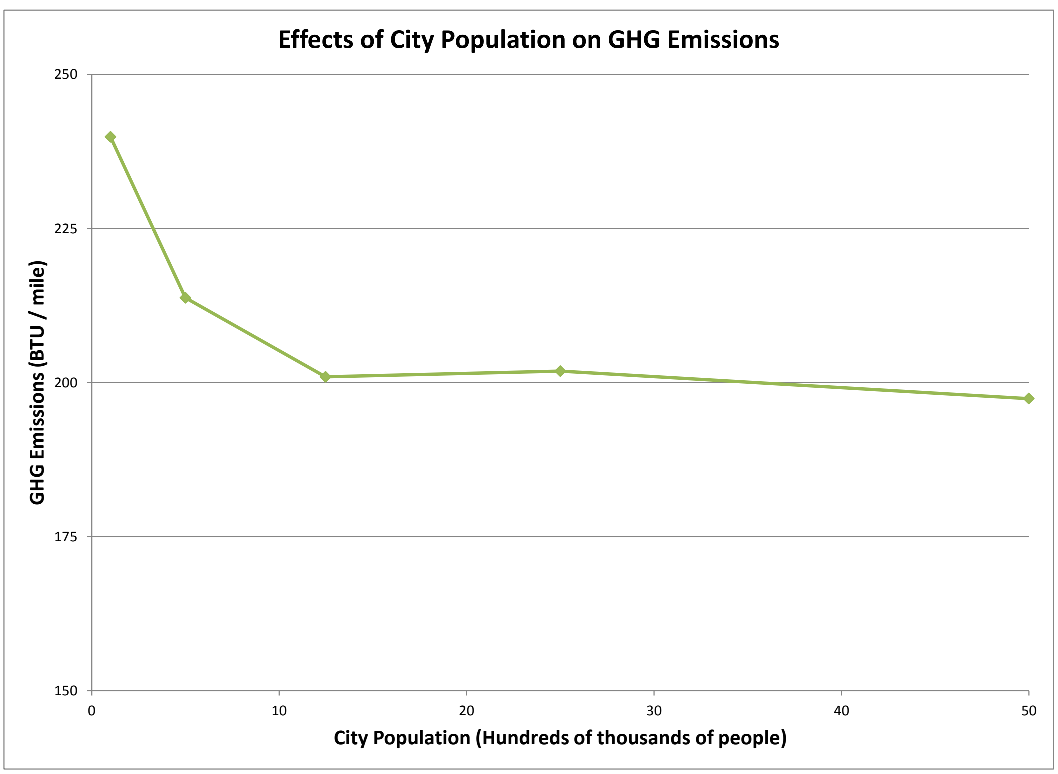


Figure 6.6.21. GHG emissions versus city population for the central biomass—liquid truck delivery and gaseous dispensing pathway

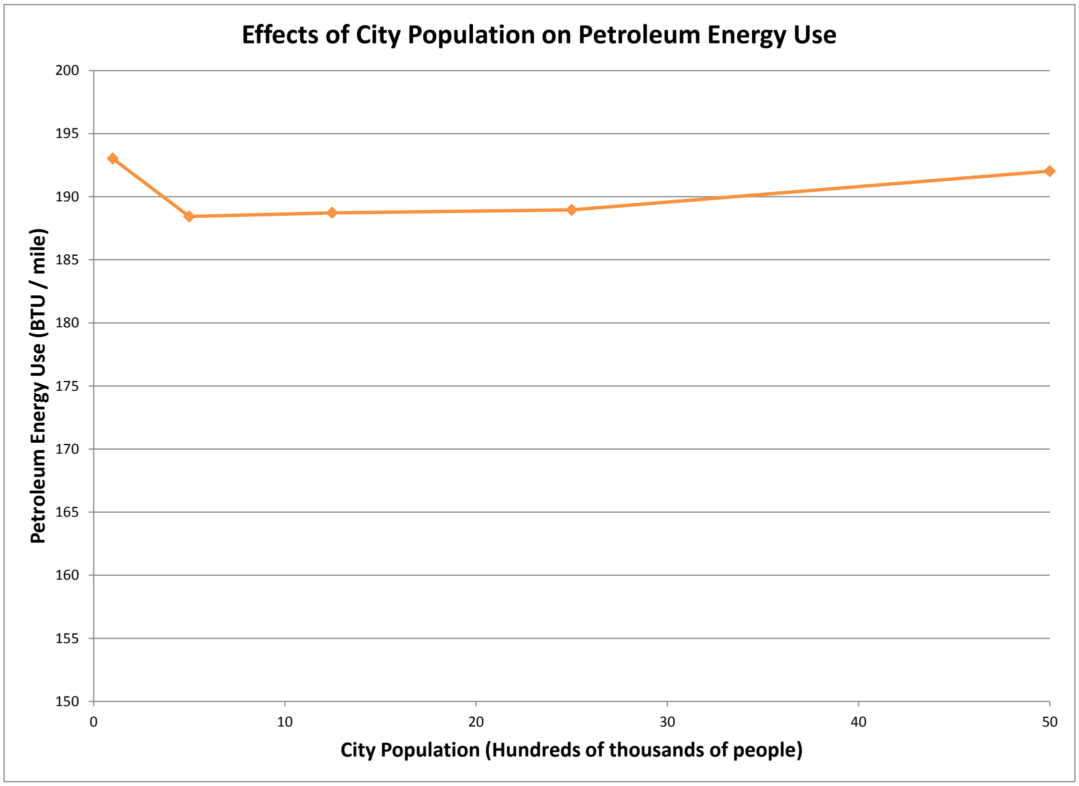


Figure 6.6.22. Petroleum energy versus city population for the central biomass—liquid truck delivery and gaseous dispensing pathway

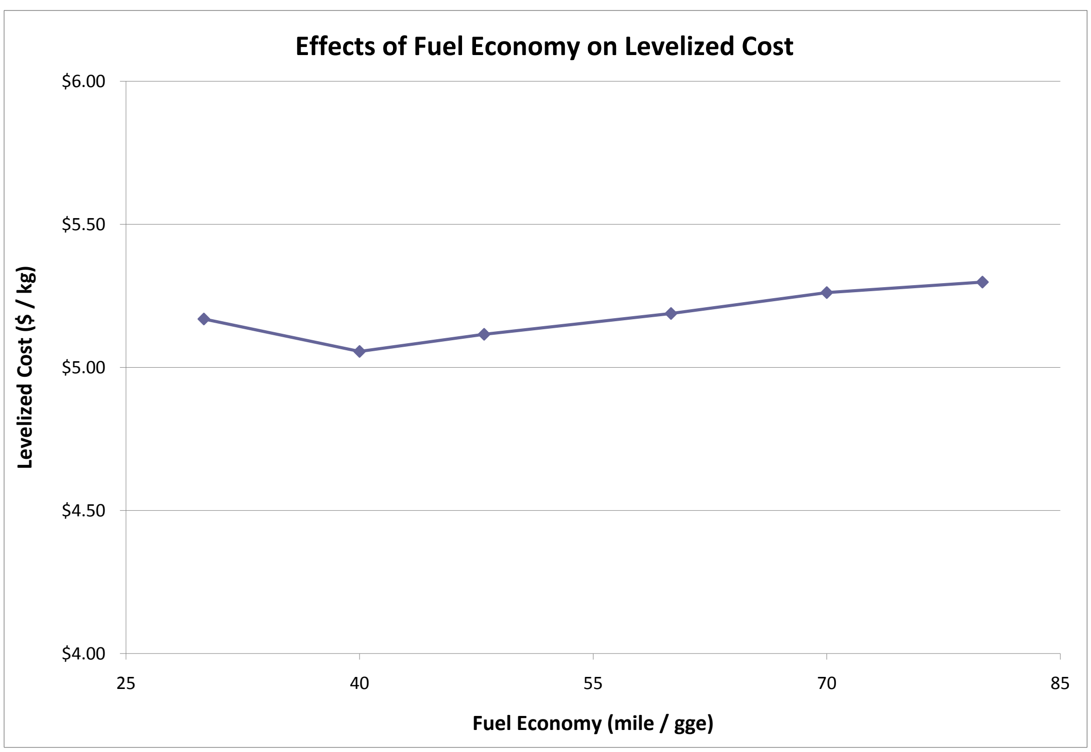


Figure 6.6.23. Levelized cost versus fuel economy for the central biomass—liquid truck delivery and gaseous dispensing pathway

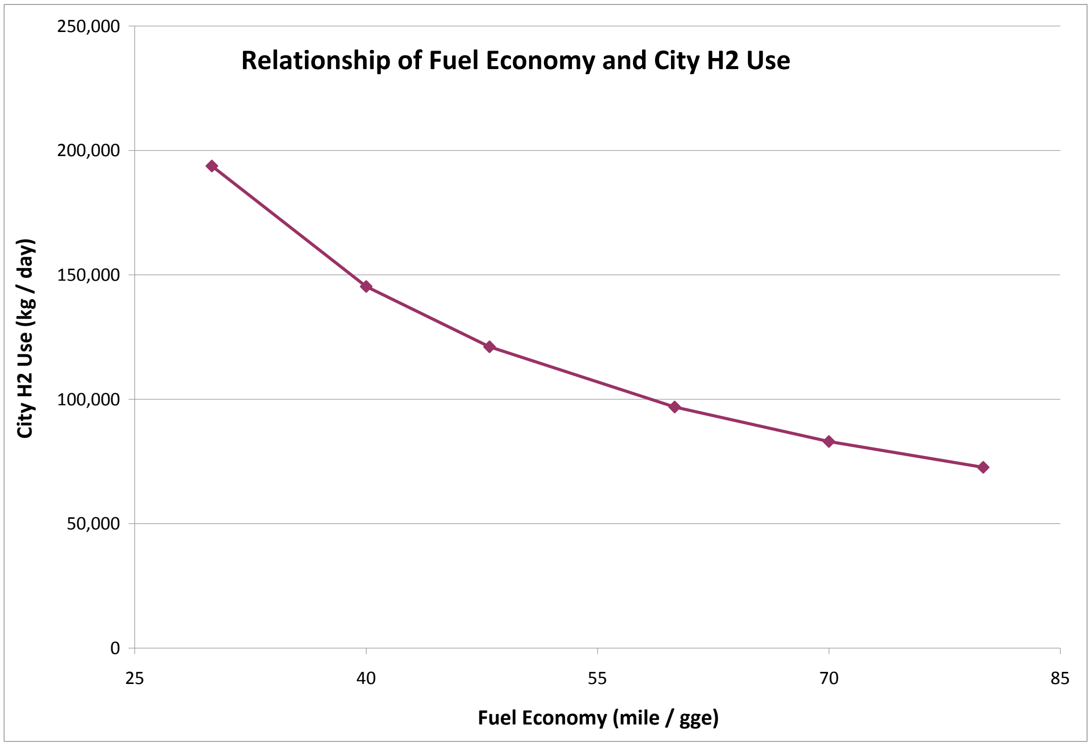


Figure 6.6.24. City hydrogen use versus fuel economy for the central biomass—liquid truck delivery and gaseous dispensing pathway

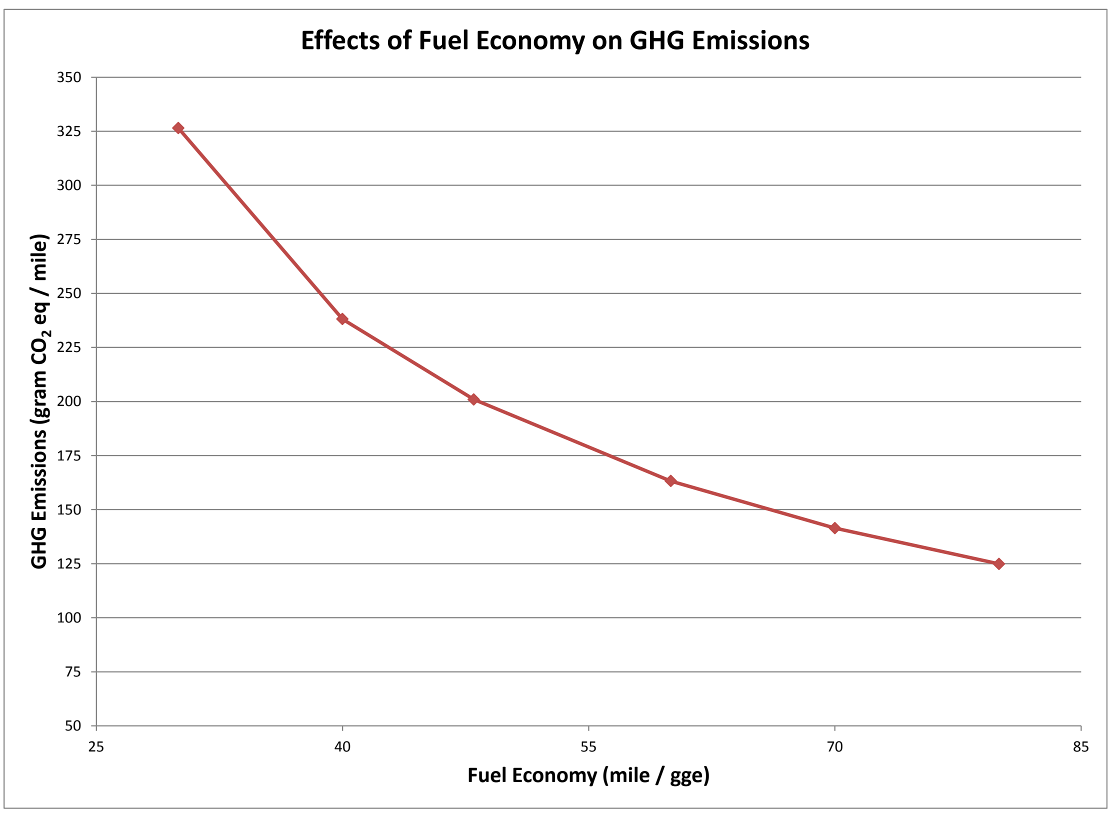


Figure 6.6.25. GHG emissions versus fuel economy for the central biomass—liquid truck delivery and gaseous dispensing pathway

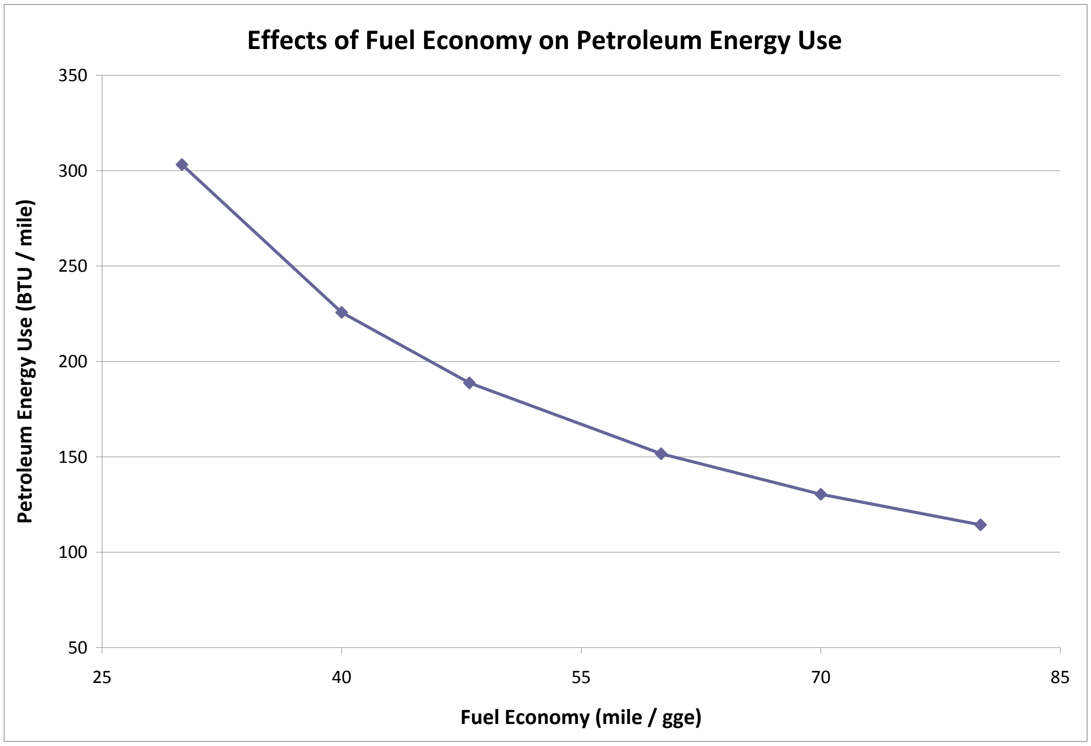


Figure 6.6.26. Petroleum energy use versus fuel economy for the central biomass—liquid truck delivery and gaseous dispensing pathway

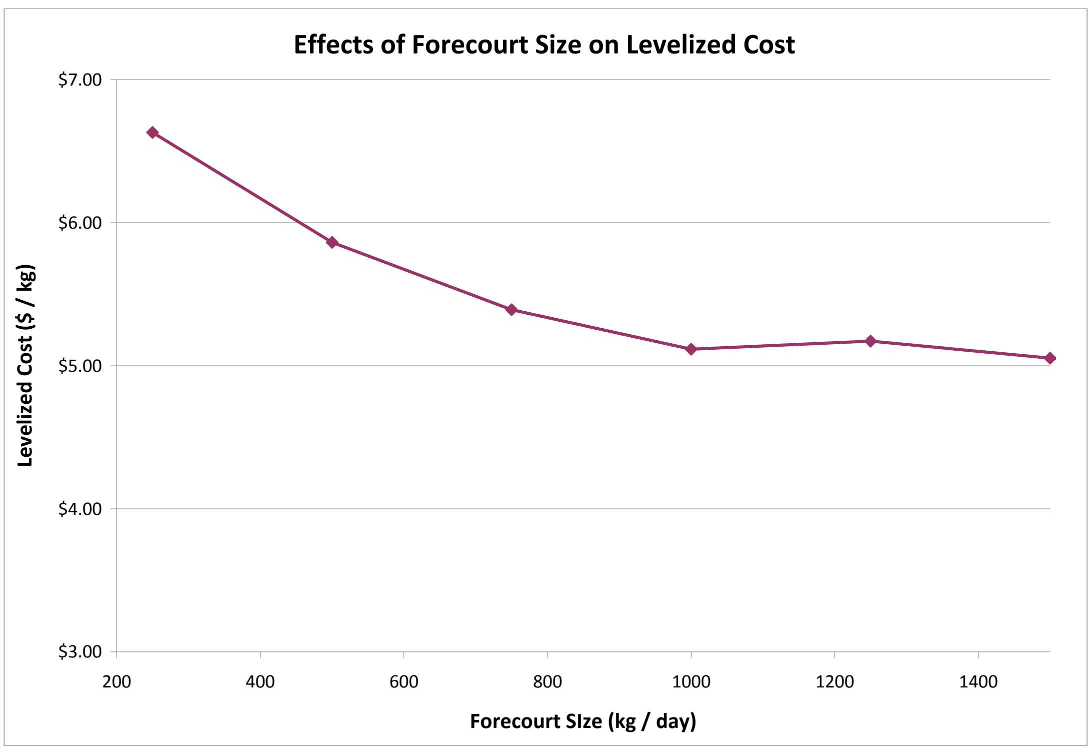


Figure 6.6.27. Levelized cost versus forecourt size for the central biomass—liquid truck delivery and gaseous dispensing pathway

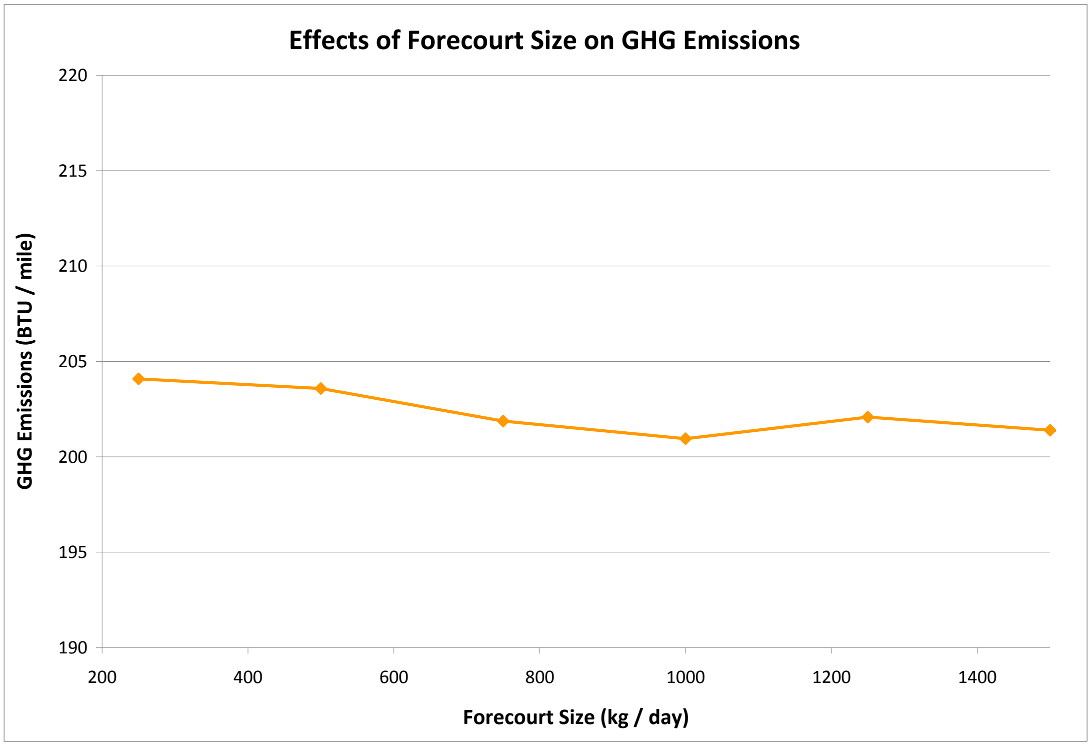


Figure 6.6.28. GHG emissions versus forecourt size for the central biomass—liquid truck delivery and gaseous dispensing pathway

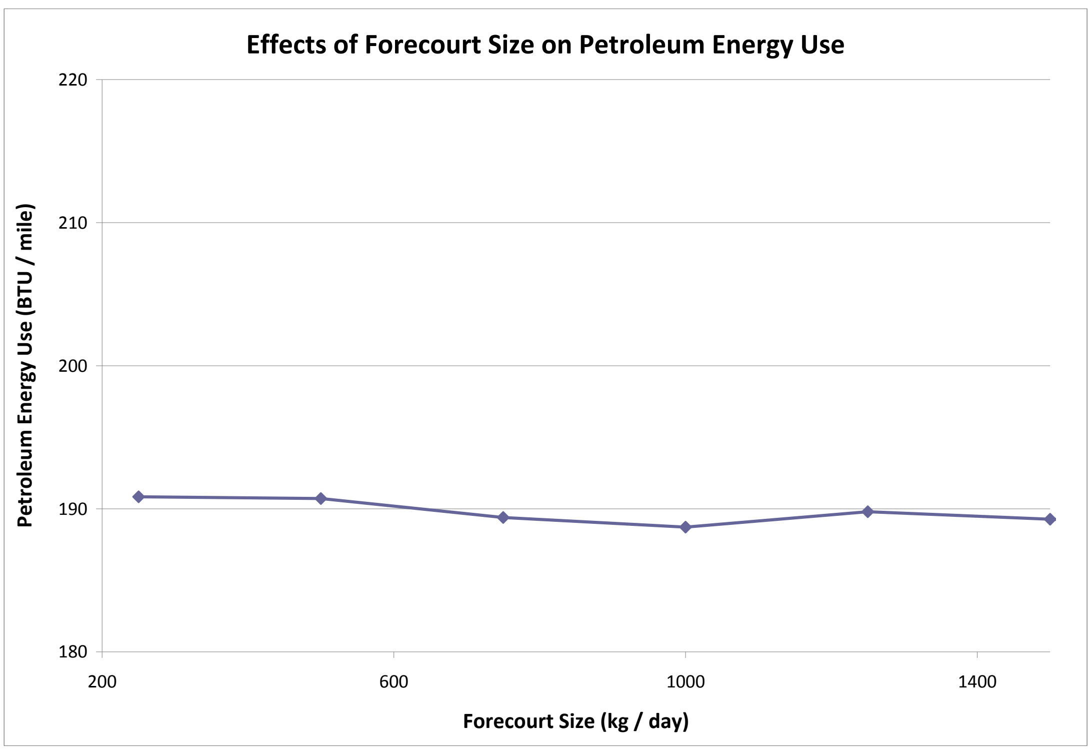


Figure 6.6.29. Petroleum energy use versus forecourt size for the central biomass—liquid truck delivery and gaseous dispensing pathway

6.7 Central Biomass—Liquid Truck Delivery and Cryo-Compressed Dispensing

Figure 6.7.1 shows the major inputs, assumptions, and outputs for each of the subsystems considered in the well-to-tank analysis, including feedstock supply and hydrogen dispensing. (See Appendix G for more details on this pathway.)

The WTP and WTW cost of hydrogen, energy use, and emissions for the central biomass—liquid truck delivery and cryo-compressed dispensing pathway are summarized in Table 6.7.1.

Net GHG emissions include carbon dioxide uptake occurring during growth of the biomass. As noted above, the analysis assumes that 100% of the carbon in the biomass is provided by atmospheric carbon dioxide and that land use change is assumed to have neither positive nor negative effects on emissions.

6.7.1 Cost Breakdown

Figure 6.7.2 shows the feedstock and energy price inputs and the resulting hydrogen production, delivery, and distribution costs for the central biomass—liquid truck delivery and cryo-compressed dispensing pathway. The financial assumptions used in this analysis are detailed in Section 5.

Inputs			Assumptions			Outputs		
						Biomass moisture content	25%	
			Biomass Production & Delivery			Woody biomass LHV	16,013,000	Btu / dry ton
Energy Use for Farming Trees	235,000	Btu / dry ton				Biomass price at H2 production	$75	2007 $ / dry ton
			Fraction of Woody Biomass	100%		Biomass Share of Levelized Cos	$1.02	2007$ / kg H2 dispensed
			LUC GHG changes	0	g / dry ton			
Coal Input (including upstream)	200	Btu / 116000Btu to Pump	Average distance from farm to H2 prod.	40	miles	WTG CO2 Emissions	-26,040	g CO2 eq./ 116000 Btu
Natural Gas Input (including upstream)	600	Btu / 116000Btu to Pump				WTG CH4 Emissions	13	g CO2 eq./ 116000 Btu
Petroleum Input (including upstream)	2,800	Btu / 116000Btu to Pump				WTG N2O Emissions	36	g CO2 eq./ 116000 Btu
						WTG GHG Emissions	-25,990	g CO2 eq./ 116000 Btu
						Hydrogen Output Pressure	300	psi
Biomass consumption	13.5	kg (dry) / kg H2 produced	**Hydrogen Production**			Hydrogen Outlet Quality	99.9%	
Natural gas consumption	0.0059	MMBtu / kg H2 produced						
Electricity consumption	0.98	kWh / kg H2	Central plant design capacity	155,200	kg / day	Total capital investment	$1,300	2007$ / daily kg H2 (effective capacity)
Process Water Consumption	1.32	gal / kg H2 produced	Capacity factor	90%		Levelized Cost of Capital	$0.67	2007$ / kg H2 dispensed
Cooling Water Consumption	79.3	gal / kg H2 produced	Number of production facilities	0.87		Fixed O&M Costs	$0.24	2007$ / kg H2 dispensed
			Process energy efficiency	46.0%		Variable O&M Costs	$0.42	2007$ / kg H2 dispensed
Total Capital Investment	$181,080,000	2007$	Electricity Mix	US Mix		Total Levelized Cost	$2.35	2007$ / kg H2 dispensed
			After-tax IRR	10%				
Coal Input (including upstream)	5,400	Btu / 116000Btu to Pump	Assumed Plant Life	40		Production CO2 Emissions	27,800	g CO2 eq./ 116000 Btu
Natural Gas Input (including upstream)	9,900	Btu / 116000Btu to Pump				Production CH4 Emissions	140	g CO2 eq./ 116000 Btu
Petroleum Input (including upstream)	3,300	Btu / 116000Btu to Pump				Production N2O Emissions	45	g CO2 eq./ 116000 Btu
						Production GHG Emissions	28,000	g CO2 eq./ 116000 Btu
Liquefaction electricity consumption	8.5	kWh / kg H2	**Liquefaction and Truck-Delivery**			Total capital investment	$2,000	2007$ / daily kg delivered
Terminal electricity consumption	0.02	kWh / kg H3				Levelized Electricity cost	$0.59	2007$ / kg H2 delivered
Total electricity consumption	8.5	kWh / kg H4	City Population	1,247,000	people	Levelized Diesel cost	$0.03	2007$ / kg H2 delivered
Diesel consumption	7.7	gal / 1000 kg H2	Hydrogen Vehicle Penetration	15%		Levelized Labor cost	$0.09	2007$ / kg H2 delivered
			City hydrogen use	121,100	kg / day	Levelized Other operating costs	$0.24	2007$ / kg H2 delivered
Total Capital Investment	$242,361,000	2007$	One-way distance for delivery	98	miles			
			Terminal Design Capacity	1,124,000	kg H2	Levelized Cost of Delivery	$1.82	2007$ / kg H2 delivered
			Number of truck-trips required	10,400				
Coal Input (including upstream)	52,400	Btu / 116000Btu to Pump	Truck hydrogen capacity	4,400	kg / truckload	Delivery CO2 Emissions	7,320	g CO2 eq./ 116000 Btu
Natural Gas Input (including upstream)	23,400	Btu / 116000Btu to Pump	Liquefaction energy efficiency	79.3%		Delivery CH4 Emissions	450	g CO2 eq./ 116000 Btu
Petroleum Input (including upstream)	3,000	Btu / 116000Btu to Pump	Hydrogen losses	2.8%		Delivery N2O Emissions	30	g CO2 eq./ 116000 Btu
						Delivery GHG Emissions	7,800	g CO2 eq./ 116000 Btu
						Hydrogen outlet pressure	12,700	psi
Electricity consumption	0.49	kWh / kg H2	**Cryo-Compressed Dispensing**			Basis -- Hydrogen Quantity	116,000	Btu (116,000 Btu/gal non-oxygenated conventional unleaded gasoline)
			Total Hydrogen Dispensed	1,000	kg / day	Total capital investment	$2,120	2007$ / daily kg
Total Capital Investment per Station	$2,100,000	2007$ / station	Number of Dispensing Stations	122		Levelized Cost of Capital	$0.90	2007$ / kg H2 dispensed
Total Capital Investment	$256,147,000	2007$ / all stations	Number of Cascade Pumps	1		Energy & Fuel	$0.05	2007$ / kg H2 dispensed
			Liquid H2 storage capacity per Station	4,600	kg H2	Other O&M Costs	$0.61	2007$ / kg H2 dispensed
			Usable Cascade Storage per Station	0	kg H2	Levelized Cost of Dispensing	$3.38	2007$ / kg H2 dispensed
Coal Input (including upstream)	Included in Delivery Section		Site storage	390%	% of design capacity	CSD CO2 Emissions	Included in Delivery Section	
Natural Gas Input (including upstream)	Included in Delivery Section		# of 2-hose Dispensers per Station	2		CSD CH4 Emissions	Included in Delivery Section	
Petroleum Input (including upstream)	Included in Delivery Section		Hydrogen losses	3.1%		CSD N2O Emissions	Included in Delivery Section	
						CSD GHG Emissions	Included in Delivery Section	
						Cost Per Mile	$0.69	2007$ / mi
Vehicle Mass	3,020	lb	**Vehicle**			Fuel Share	$0.12	2007$ / mi
Fuel cell size	70	kW	Fuel Economy	48.0	mi / gge	Maintenance, Tires, Repairs	$0.07	2007$ / mi
Hybridization battery (peak power)	30	kW	Vehicle Miles Traveled	15,000	mi / yr	Insurance & Registration	$0.12	2007$ / mi
			Vehicle Lifetime	160,000	mi	Depreciation	$0.27	2007$ / mi
			Purchase Year	2015		Financing	$0.10	2007$ / mi
			Vehicle Purchase Cost	$33,700	2007$			
Coal Input (including upstream)	2,300	Btu / gge fuel consumed	Fuel Cell System Cost	$4,500	2007$	Veh. Cycle CO2 Emissions	1,670	g / gge fuel consumed
Natural Gas Input (including upstream)	12,100	Btu / gge fuel consumed	Storage System Cost (assume 700Bar	$2,400	2007$	Veh. Cycle CH4 Emissions	170	g / gge fuel consumed
Petroleum Input (including upstream)	6,900	Btu / gge fuel consumed	Tax Credit	$0	2007$	Veh. Cycle N2O Emissions	6	g / gge fuel consumed
						Veh. Cycle GHG Emissions	1,850	g / gge fuel consumed

Figure 6.7.1. Summary of major inputs, assumptions, and outputs by subsystem for the central biomass—liquid truck delivery and cryo-compressed dispensing pathway

Table 6.7.1. WTP and WTW Results for the Central Biomass—Liquid Truck Delivery and Cryo-Compressed Dispensing Pathway

	WTP		WTW	
Coal input (including upstream)[a]	58,000	Btu/116,000 Btu	1,210	Btu/mi
Natural gas input (including upstream)[a]	33,900	Btu/116,000 Btu	710	Btu/mi
Petroleum input (including upstream)[a]	9,200	Btu/116,000 Btu	190	Btu/mi
Fossil energy input (including upstream)[a]	374,100	Btu/116,000 Btu	2,110	Btu/mi
WTP CO_2 emissions[b]	9,000	g/116,000 Btu	190	g/mi
WTP CH_4 emissions	24	g/116,000 Btu	1	g/mi
WTP N_2O emissions	0	g/116,000 Btu	0	g/mi
WTP GHG emissions	9,800	g CO_2-eq./ 116,000 Btu	200	g/mi
	Cost per kg		**Cost per mile**	
Levelized cost of hydrogen	$5.73	2007$/kg	$0.12	2007$/mi

[a] Coal, natural gas, and petroleum inputs include those used directly in the hydrogen production and delivery pathway as feedstocks and fuels; those used to produce electricity and other materials used in the pathway; and those used upstream of the pathway to recover, refine, and deliver the feedstock.
[b] Includes the carbon content of CO, CH_4, and volatile organic compound emissions that decompose in the atmosphere to CO_2.

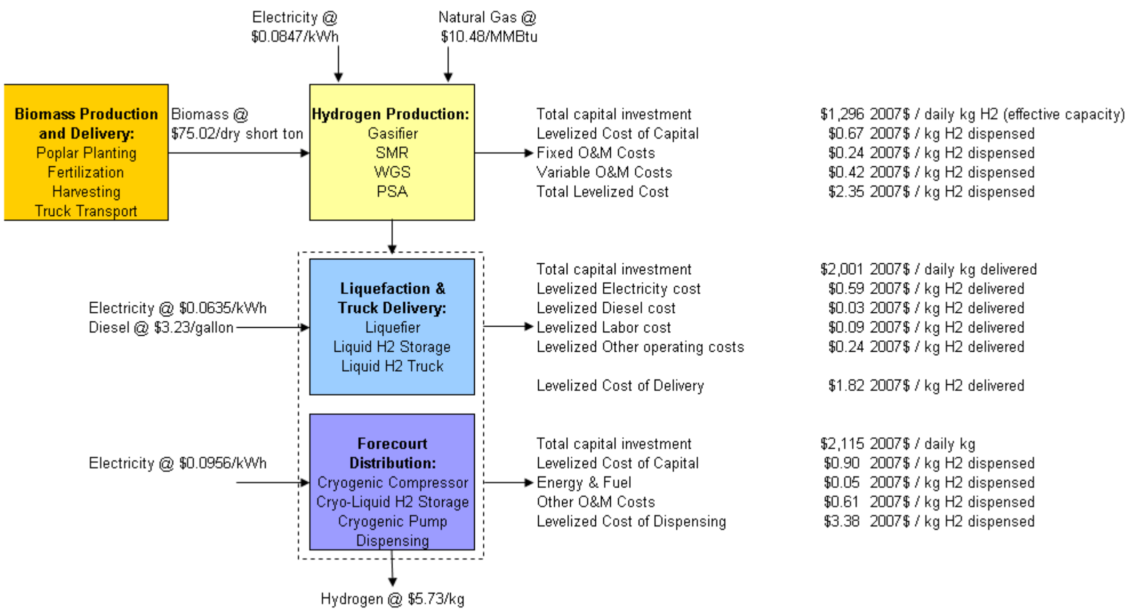


Figure 6.7.2. Cost analysis inputs and high-level results for the central biomass—liquid truck delivery and cryo-compressed dispensing pathway

Figure 6.7.3 shows the contributions of hydrogen production, delivery, and losses to the levelized cost of hydrogen shown in Figure 6.7.2.

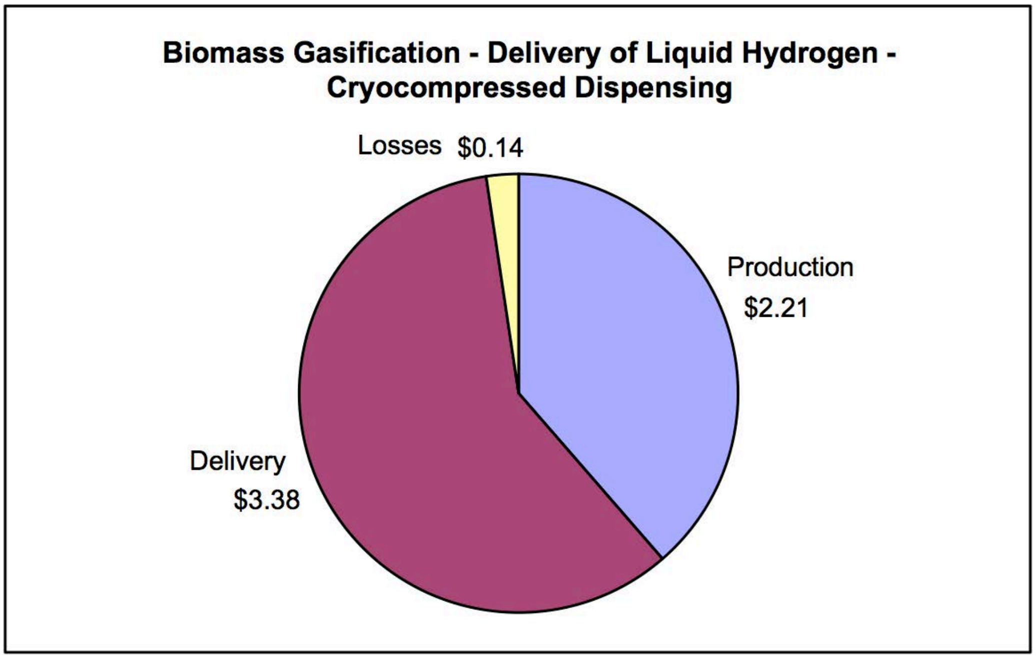


Figure 6.7.3. Contribution of hydrogen production, delivery, and losses to the levelized cost of hydrogen for the central biomass—liquid truck delivery and cryo-compressed dispensing pathway

Figure 6.7.4 and Table 6.7.2 show the breakdown of levelized costs for the central biomass—liquid truck delivery and cryo-compressed dispensing pathway.

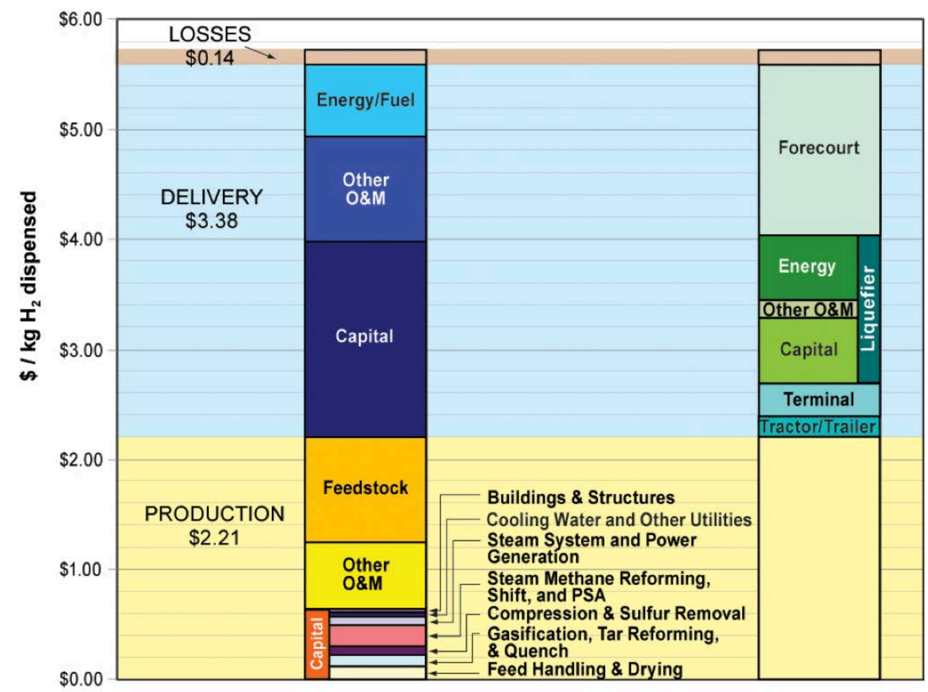


Figure 6.7.4. Breakdown of levelized costs for the central biomass—liquid truck delivery and cryo-compressed dispensing pathway

Table 6.7.2. Contribution of Production and Delivery Processes to Levelized Hydrogen Cost for the Central Biomass—Liquid Truck Delivery and Cryo-Compressed Dispensing Pathway

Cost Component	Capital	Other O&M	Feedstock	Energy/ Fuel	Total
Production	$0.64	$0.62	$0.96		$2.21
Feed handling and drying	$0.11				
Gasification, tar reforming, and quench	$0.10				
Compression and sulfur removal	$0.09				
SMR, WGS, and PSA	$0.18				
Steam system and power generation	$0.09				
Cooling water and other utilities	$0.02				
Buildings and structures	$0.04				
Delivery	$1.77	$0.94		$0.66	$3.38
Tractor/trailer					$0.18
Terminal					$0.31
Liquefier	$0.58	$0.17		$0.59	$1.33
Forecourt	$0.90	$0.61		$0.05	$1.56
Losses					$0.14
Total	**$2.41**	**$1.56**	**$0.96**	**$0.66**	**$5.73**

6.7.2 Energy Use and Emissions Breakdown

Figures 6.7.5 and 6.7.6 show the WTW energy inputs and losses for the central biomass—liquid truck delivery and cryo-compressed dispensing pathway.

Figures 6.7.7 and 6.7.8 show the WTW emissions resulting from the delivery of 116,000 Btu hydrogen to a vehicle fuel tank using the central biomass—liquid truck delivery and cryo-compressed dispensing pathway.

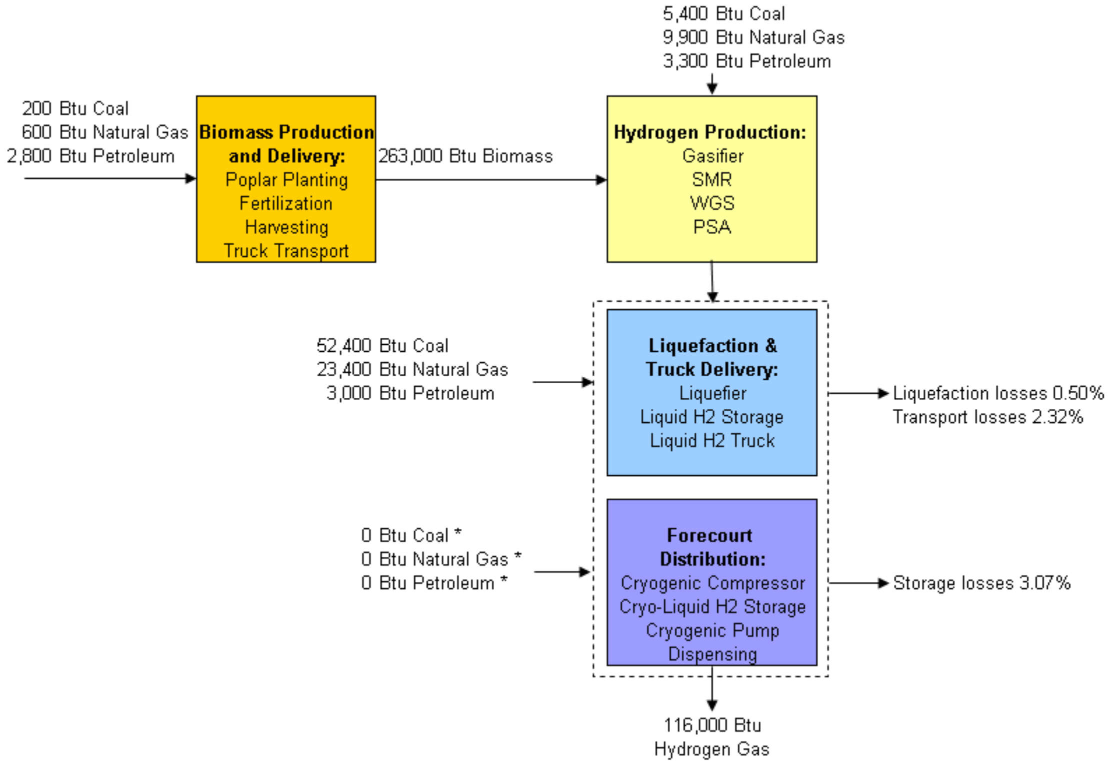


Figure 6.7.5. WTW energy inputs to deliver 116,000 Btu hydrogen to a vehicle using the central biomass—liquid truck delivery and cryo-compressed dispensing pathway

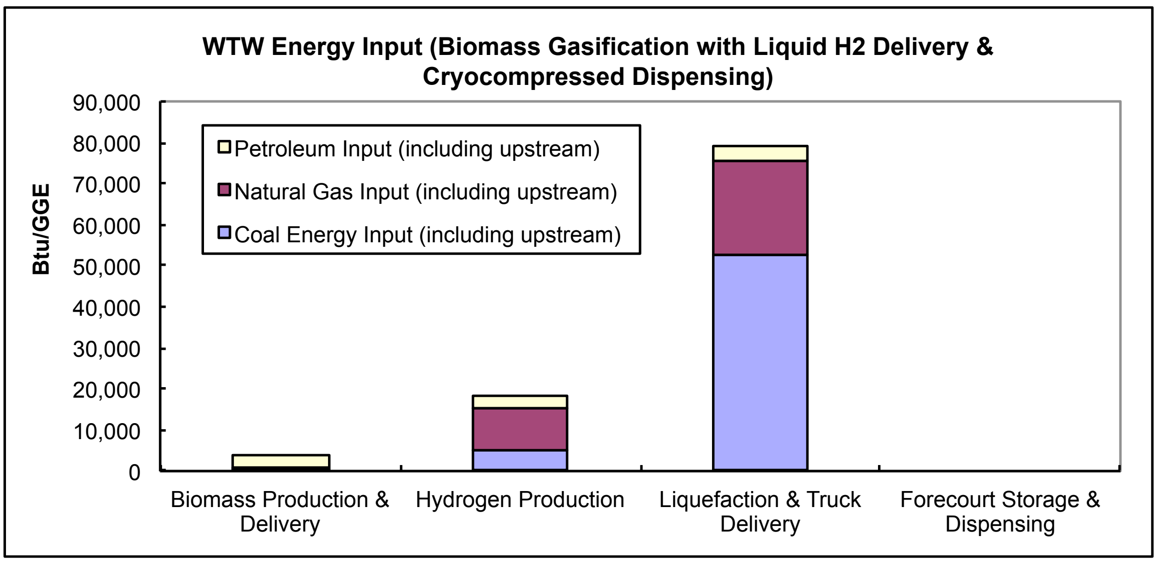


Figure 6.7.6. WTW petroleum, natural gas, and coal inputs to deliver 116,000 Btu hydrogen using the central biomass—liquid truck delivery and cryo-compressed dispensing pathway

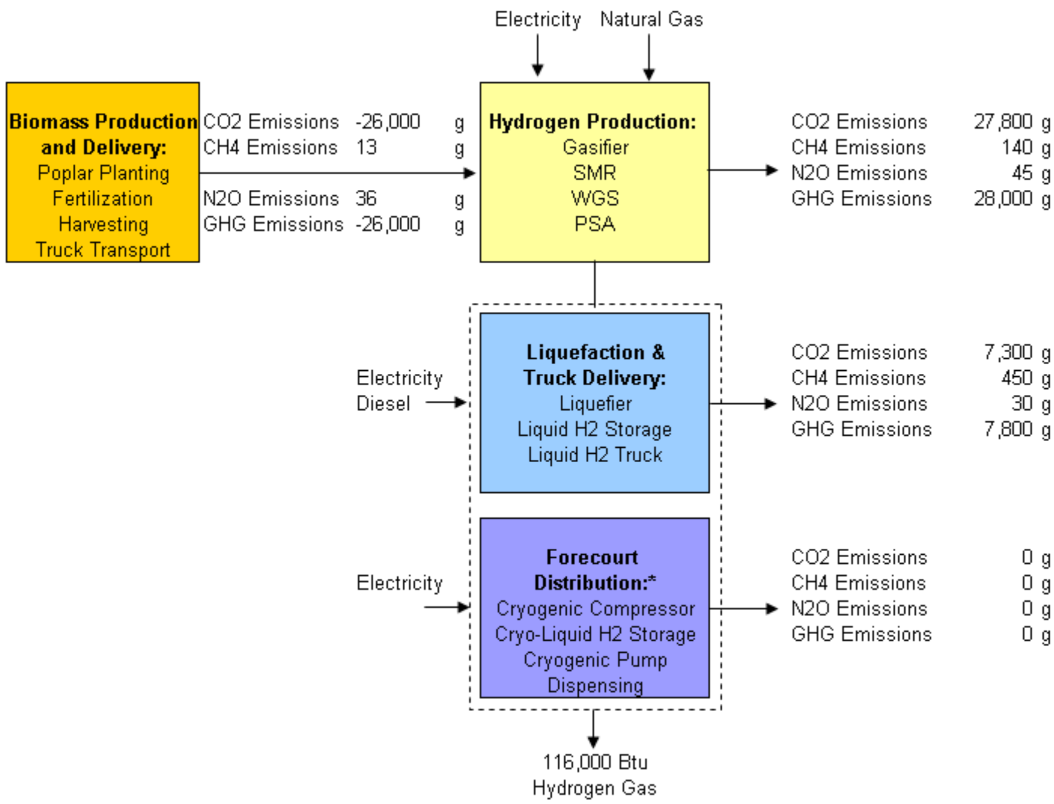


Figure 6.7.7. WTW emissions resulting from delivery of 116,000 Btu hydrogen using the central biomass—liquid truck delivery and cryo-compressed dispensing pathway

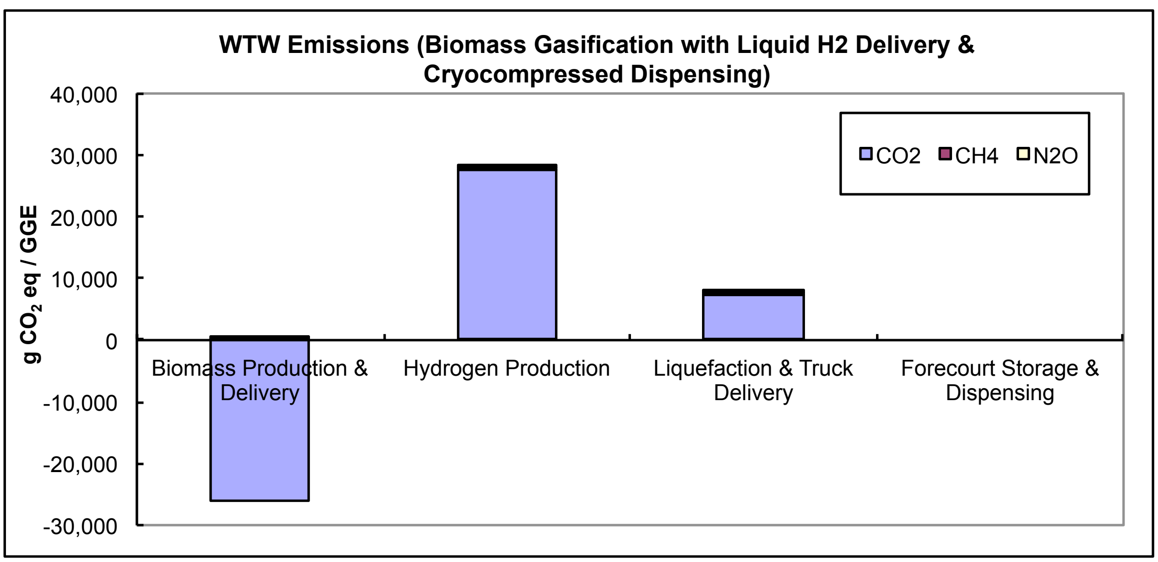


Figure 6.7.8. WTW CO_2, CH_4, and N_2O emissions resulting from delivery of 116,000 Btu hydrogen to a vehicle using the central biomass—liquid truck delivery and cryo-compressed dispensing pathway

6.7.3 Sensitivities

6.7.3.1 Production Sensitivities

Several sensitivities were run on the production portion of the central biomass—liquid truck delivery and cryo-compressed dispensing pathway. These sensitivities focused primarily on cost factors; however, several sensitivities also affect energy use and emissions. Figure 6.7.9 shows the effects of several production parameters on the pathway's levelized cost, and Table 6.7.3 shows the effects of varying production energy efficiency on WTW energy use and emissions.

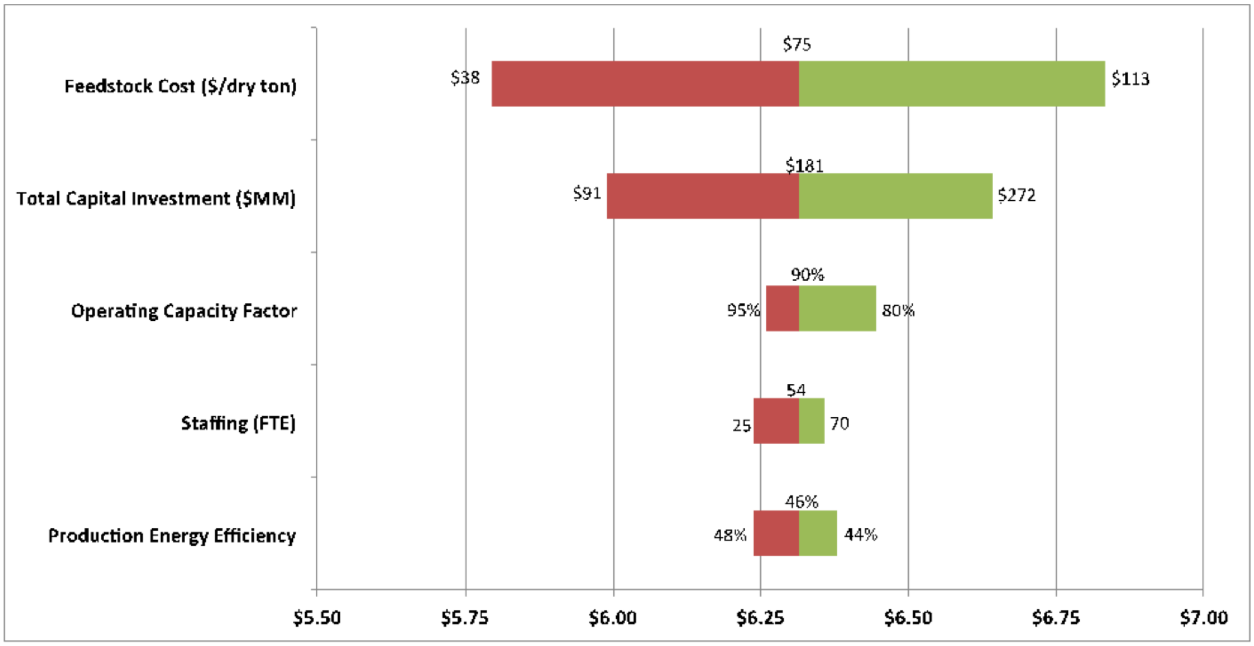


Figure 6.7.9. Production sensitivities for the central biomass—liquid truck delivery and cryo-compressed dispensing pathway

Table 6.7.3. The Effects of Production Energy Efficiency on Primary Energy Use and Emissions from the Central Biomass—Liquid Truck Delivery and Cryo-Compressed Dispensing Pathway

	44% Efficiency	46% Efficiency	48% Efficiency
WTW GHG emissions (g/mile)	200	200	200
WTW fossil energy (Btu/mile)	2,100	2,100	2,100
WTW petroleum energy (Btu/mile)	200	190	190
WTW total energy (Btu/mile)	8,100	7,800	7,600

The assumed electrical grid mix also affects the energy use and emissions. Table 6.7.4 shows the differences in energy use and GHG emissions between the U.S. average grid mix (which was used for all other sensitivities) and a hypothetical green grid mix that is 100% renewable energy (solar and wind).

Table 6.7.4. The Effects of Fuel Economy and Grid Mix on Use of Primary Energy and Emissions from the Central Biomass—Liquid Truck Delivery and Cryo-Compressed Dispensing Pathway

	U.S. Average Grid Mix (48 mpgge)	U.S. Average Grid Mix (68 mpgge)	"Green" Grid Mix (48 mpgge)
WTW GHG emissions (g/mile)	200	150	30
WTW fossil energy (Btu/mile)	2,100	1,500	300
WTW petroleum energy (Btu/mile)	190	140	150
WTW total energy (Btu/mile)	7,800	5,600	6,600

6.7.3.2 Delivery Sensitivities

Delivery cost, energy use, and emissions are strongly dependent upon the daily consumption of hydrogen within a city and the delivery distance from the central facility to the city gate. Sensitivities were run to show some of those effects. Daily consumption was varied by keeping the city size constant and adjusting the penetration of hydrogen vehicles from the base case of 15%. The resulting consumption is shown in Figure 6.7.10.

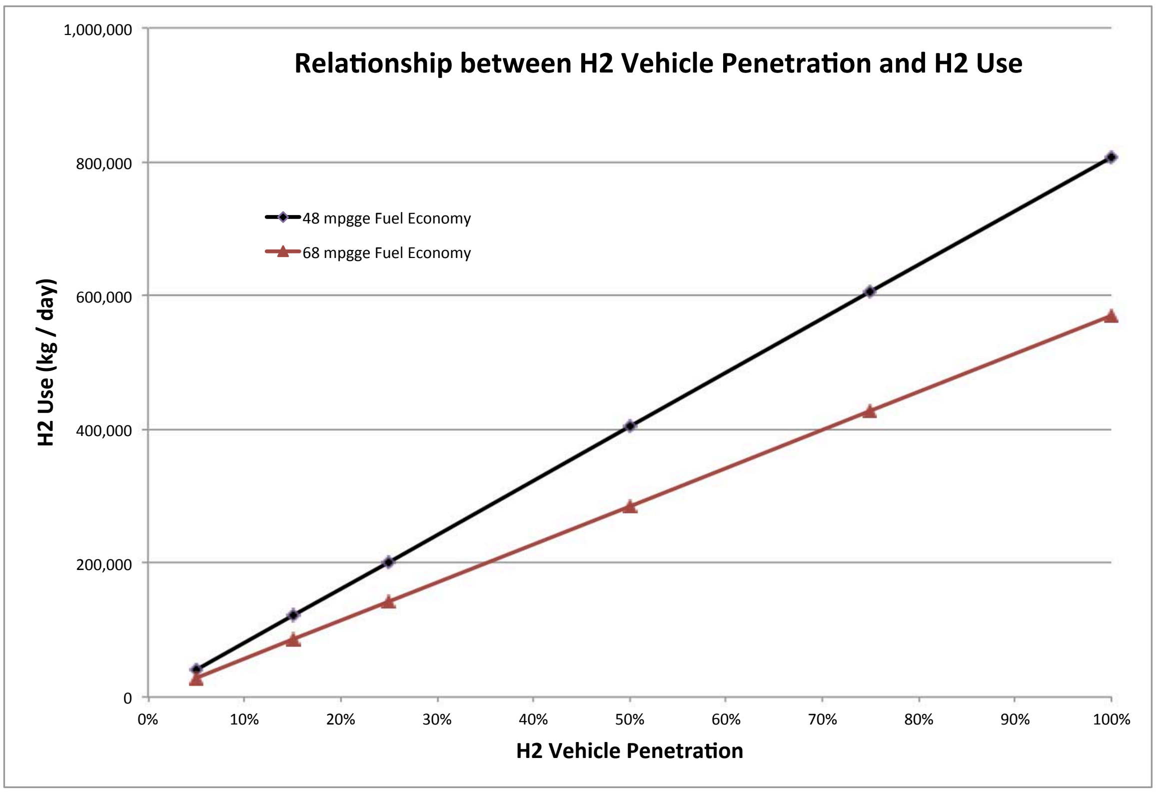


Figure 6.7.10. Daily hydrogen consumption versus hydrogen vehicle penetration for the central biomass—liquid truck delivery and cryo-compressed dispensing pathway

As expected, there are economies of scale for higher vehicle penetration/hydrogen consumption, and the levelized cost of delivery decreases as the distance from the production plant to the city gate is shortened. Figures 6.7.11 and 6.7.12 show those economic effects (the figures show identical data but are organized differently).

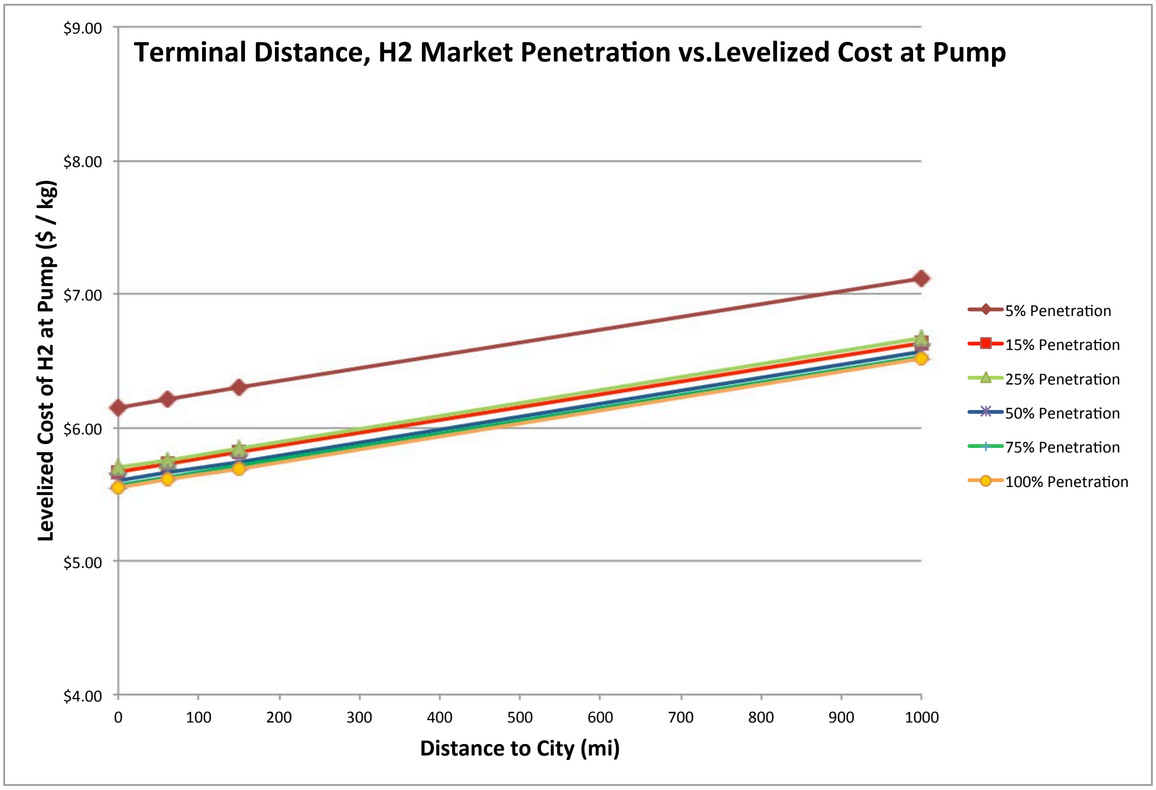


Figure 6.7.11. Levelized cost versus hydrogen vehicle penetration and distance between production facility and city gate for the central biomass—liquid truck delivery and cryo-compressed dispensing pathway

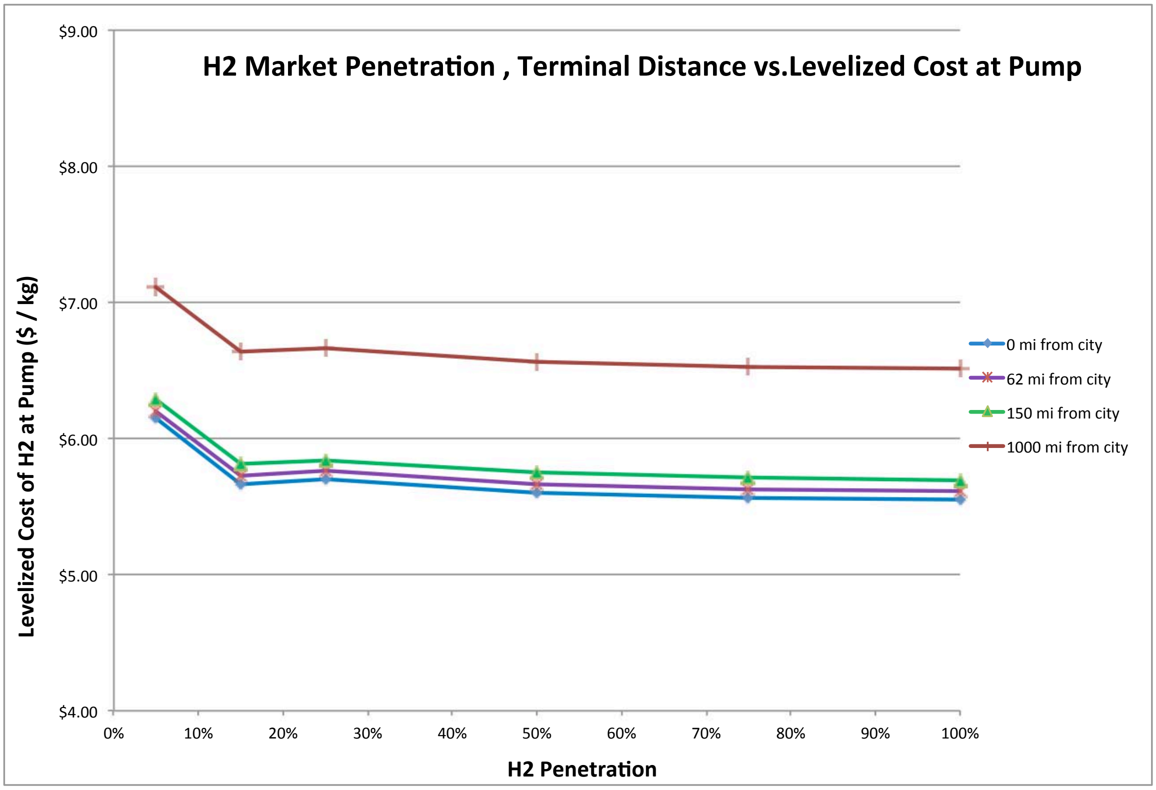


Figure 6.7.12. Levelized cost versus hydrogen vehicle penetration and distance between production facility and city gate for the central biomass—liquid truck delivery and cryo-compressed dispensing pathway

As Figure 6.7.12 shows, there is a $0.14 increase in levelized cost when the production facility is assumed to be 150 miles from the city gate as compared to being at the city gate. There is a much larger levelized-cost increase when the distance is assumed to be 1,000 miles because the levelized cost of trucking increases with added distance due to additional driver time, additional fuel requirements, and an increased number of trucks and trailers required. Figure 6.7.13 shows the liquid truck portion of the levelized cost; note that the base case distance is 62 miles and that the truck's levelized cost is $0.18 for all penetration levels at that distance. Because the city size is constant and the assumed station size is sufficient to utilize a full truckload at each station, each delivery has the same travel distance and takes the same amount of time within the city regardless of penetration level; therefore, the levelized cost within the city gate is constant for all penetration levels.

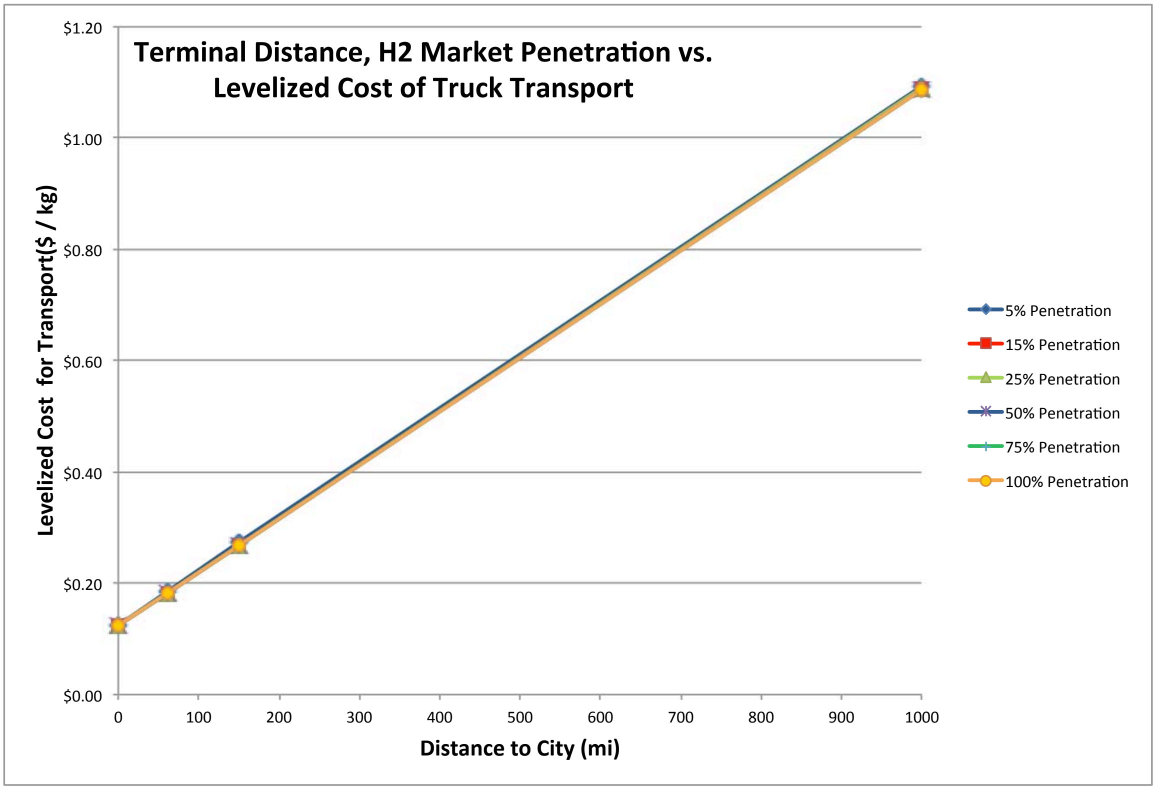


Figure 6.7.13. Truck levelized cost versus distance between production facility and city gate for the central biomass—liquid truck delivery and cryo-compressed dispensing pathway

The most notable feature in Figure 6.7.13 is the insensitivity of transport levelized cost to changes in FCEV penetration. The significant drop in the levelized cost of hydrogen as FCEV penetration increases to 15% (shown in Figure 6.7.11) is due to the reduced cost of liquefaction, which is shown in Figure 6.7.14 (liquefier cost is constant for all distances from the city). Note that one liquefier is needed for 5% and 15% penetration, two for 25%, three for 50%, four for 75%, and five for 100% penetration. The two liquefiers at 25% penetration are smaller than the one at 15% penetration, thus their capital cost when normalized to annual throughput is higher. The higher capital cost results in higher levelized costs.

The majority of the liquefaction system's cost driver is capital (Table 6.7.2 shows that the capital accounts for \$0.58/kg H_2 of the \$1.33/kg H_2 total liquefaction cost). As shown in Figure 6.7.15, capital-cost reduction drives the cost decrease as penetration increases.

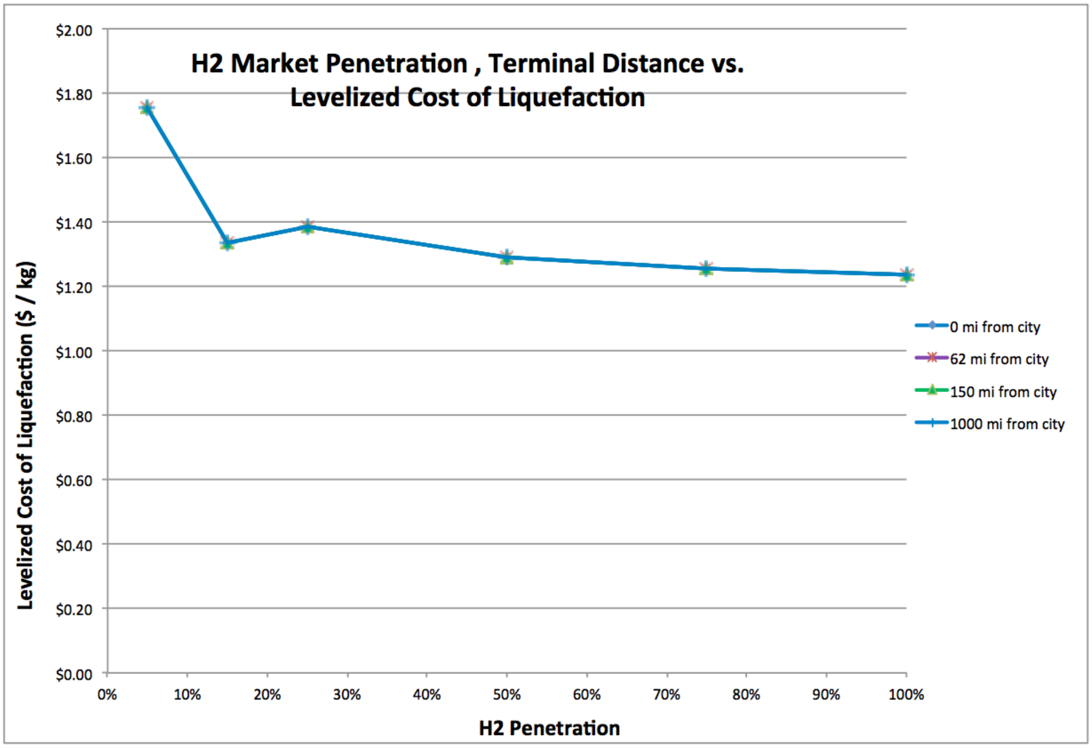


Figure 6.7.14. Liquefaction system levelized cost versus penetration for the central biomass—liquid truck delivery and cryo-compressed dispensing pathway

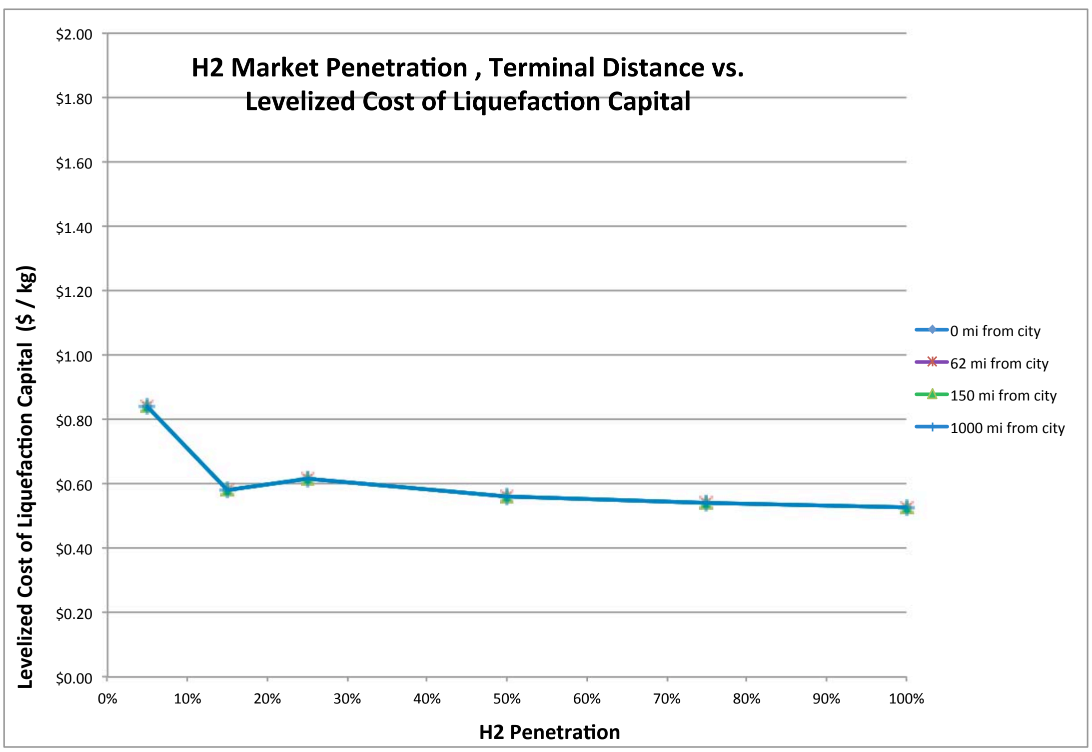


Figure 6.7.15. Liquefaction system capital cost (levelized) versus penetration for the central biomass—liquid truck delivery and cryo-compressed dispensing pathway

The additional cost variable for the liquefaction system levelized cost is the system efficiency because increased efficiency reduces the energy required for liquefaction. Figure 6.7.16 shows the effect of penetration (directly affecting liquefaction system size) on efficiency. As in the previous figures, smaller liquefaction systems result in lower efficiencies.

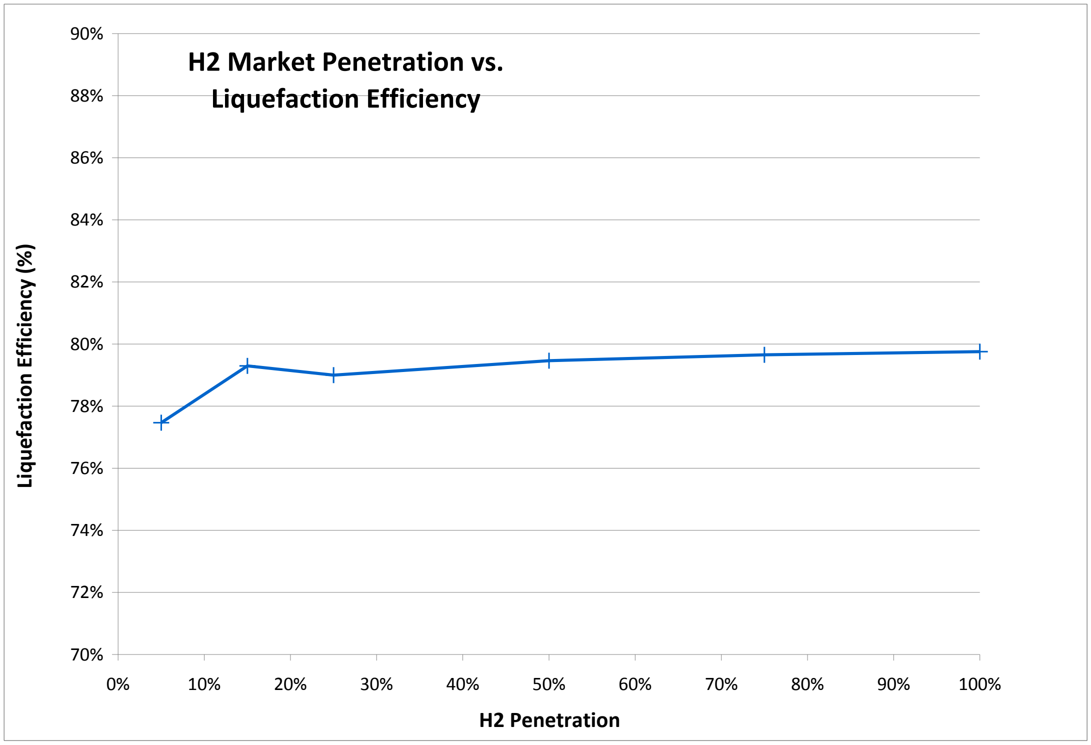


Figure 6.7.16. Liquefaction system efficiency versus penetration for the central biomass—liquid truck delivery and cryo-compressed dispensing pathway

The effects of penetration and distance between the production facility and the city-gate on WTW GHG emissions, WTW petroleum use, and WTW fossil energy use are shown in Figures 6.7.17, 6.7.18, and 6.7.19, respectively. In each case, the energy use and emissions decrease as liquefaction system efficiency increases with penetration and then plateaus as discussed above. Energy use and emissions are also reduced when the production facility is closer to the city gate because of reduced diesel use for trucking.

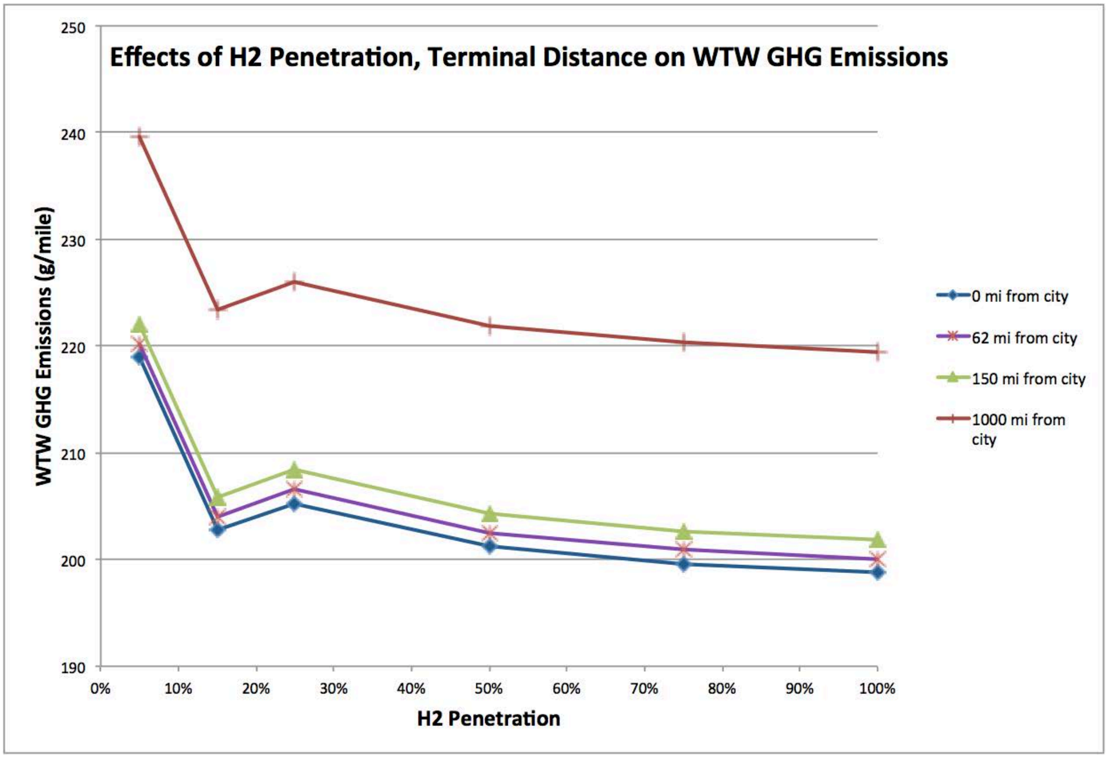


Figure 6.7.17. WTW greenhouse gas emissions versus penetration for the central biomass—liquid truck delivery and cryo-compressed dispensing pathway

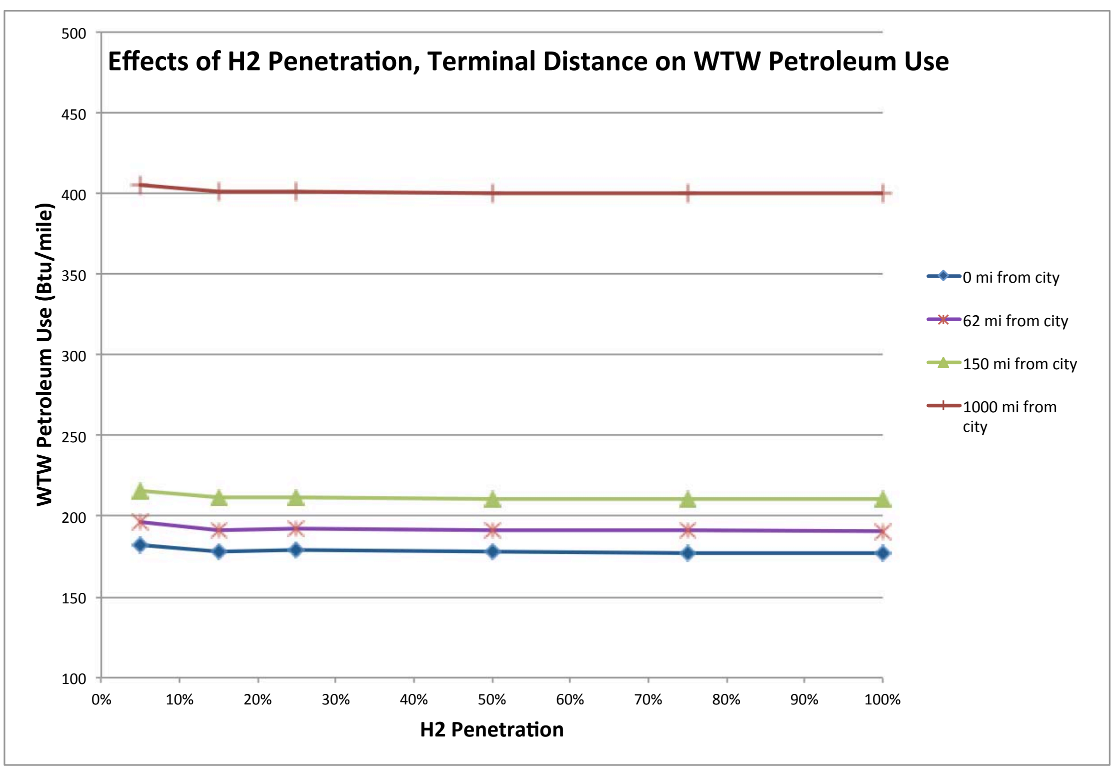


Figure 6.7.18. WTW petroleum use versus penetration for the central biomass—liquid truck delivery and cryo-compressed dispensing pathway

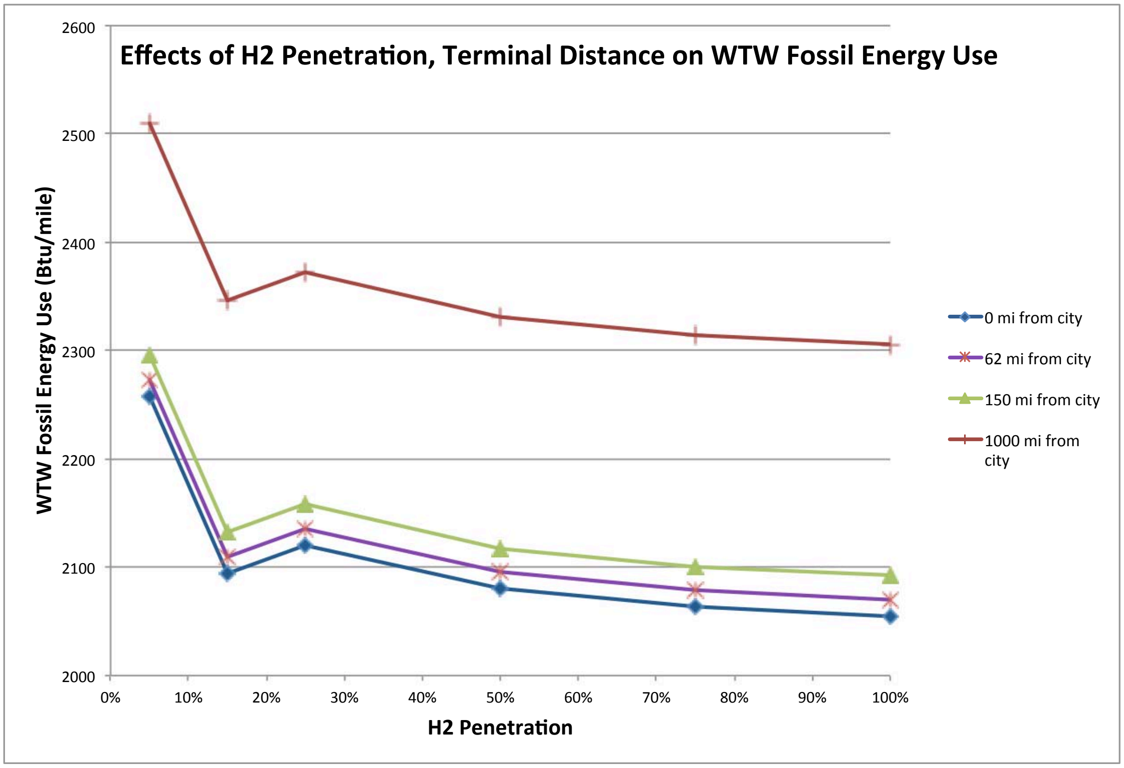


Figure 6.7.19. WTW fossil energy use versus penetration for the central biomass—liquid truck delivery and cryo-compressed dispensing pathway

The effects of city population on levelized cost of hydrogen, GHG emissions, and petroleum energy use are shown in Figures 6.7.20, 6.7.21, and 6.7.22. Levelized hydrogen cost decreases slightly with increasing city population. GHG emissions also generally decrease with increasing city population, while petroleum energy use increases with increasing city population above a population of 5,000.

Figure 6.7.23 shows the effect of fuel economy on the levelized cost of hydrogen. As with FCEV penetration, the number and scale of the liquefiers affects the levelized cost. At 30 mpgge, two smaller liquefiers are necessary and result in higher costs than the single liquefier needed for the higher fuel economies does. Because the hydrogen demand is reduced as fuel economies increase, liquefaction of reduced amounts of hydrogen results in higher levelized costs. The relationship between fuel economy and city hydrogen use is shown in Figure 6.7.24.

Figures 6.7.25 and 6.7.26 show that GHG emissions and petroleum energy use decrease with increasing fuel economy, as one might expect.

Figures 6.7.27, 6.7.28, and 6.7.29 show the effects of forecourt size on levelized cost of hydrogen, GHG emissions, and petroleum energy use for the central biomass—liquid truck delivery and cryo-compressed dispensing pathway.

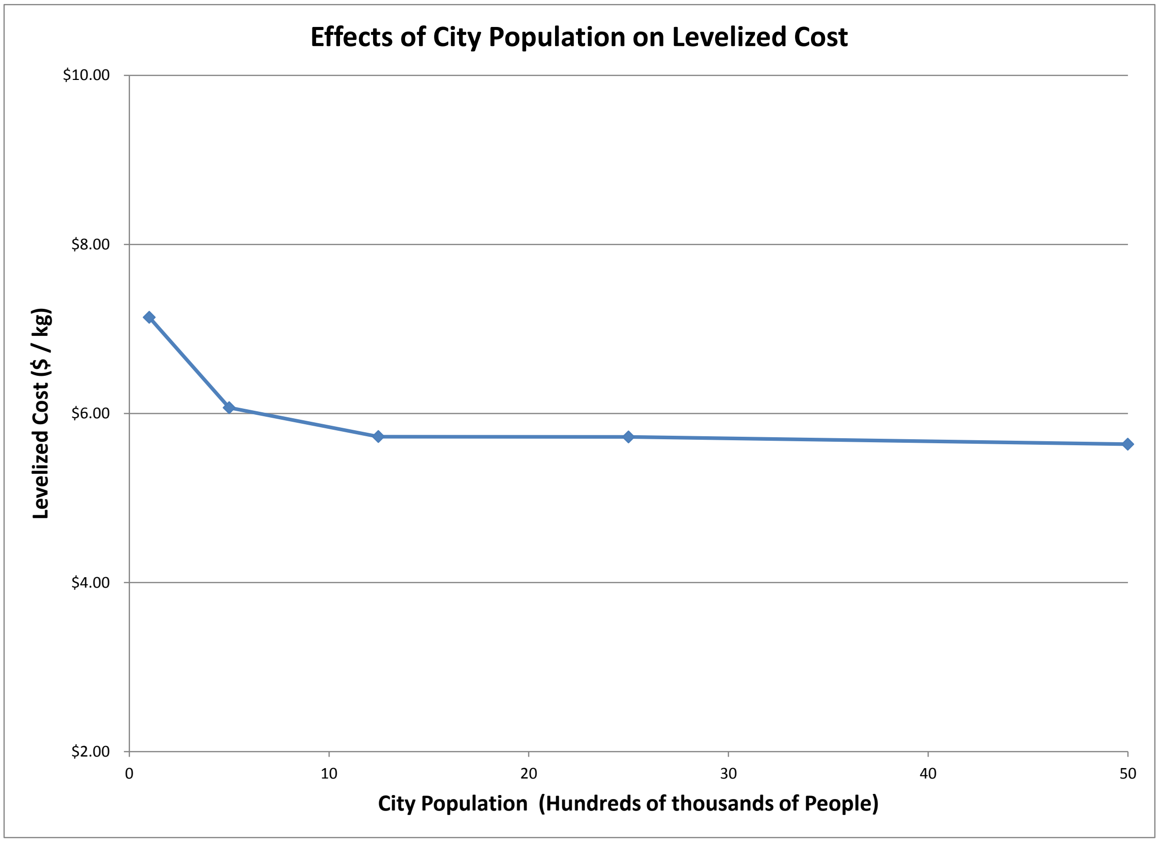


Figure 6.7.20. Levelized cost versus city population for the central biomass—liquid truck delivery and cryo-compressed dispensing pathway

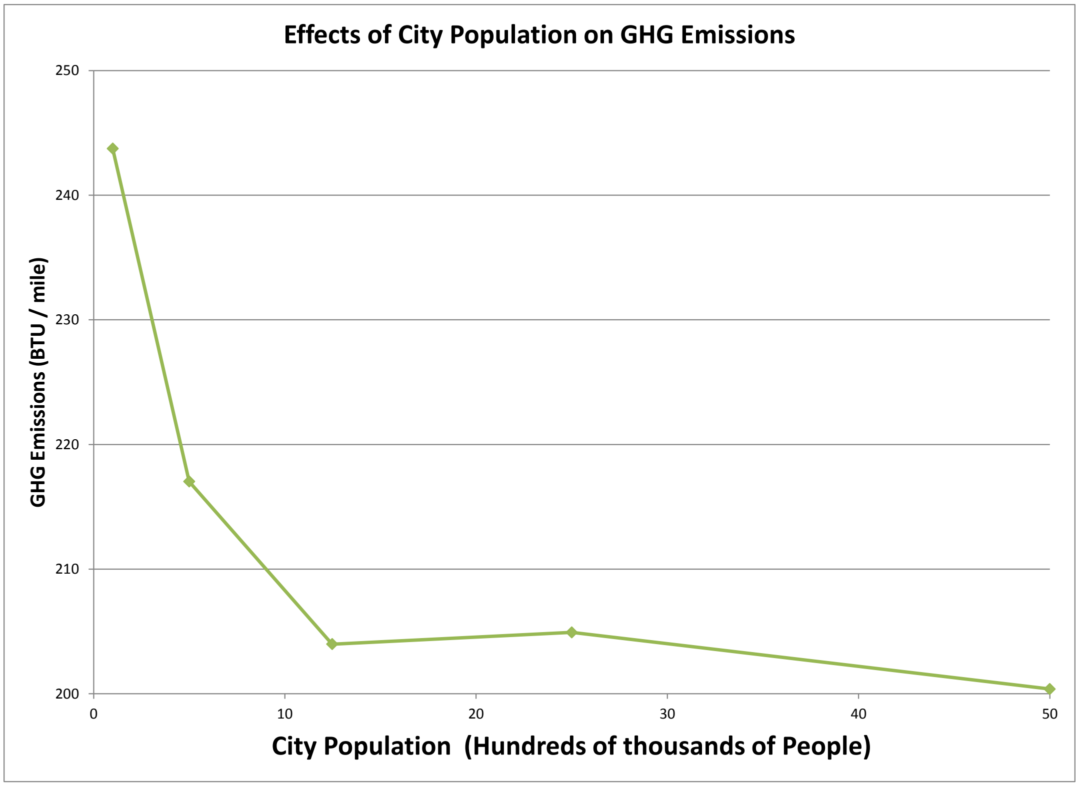


Figure 6.7.21. GHG emissions versus city population for the central biomass—liquid truck delivery and cryo-compressed dispensing pathway

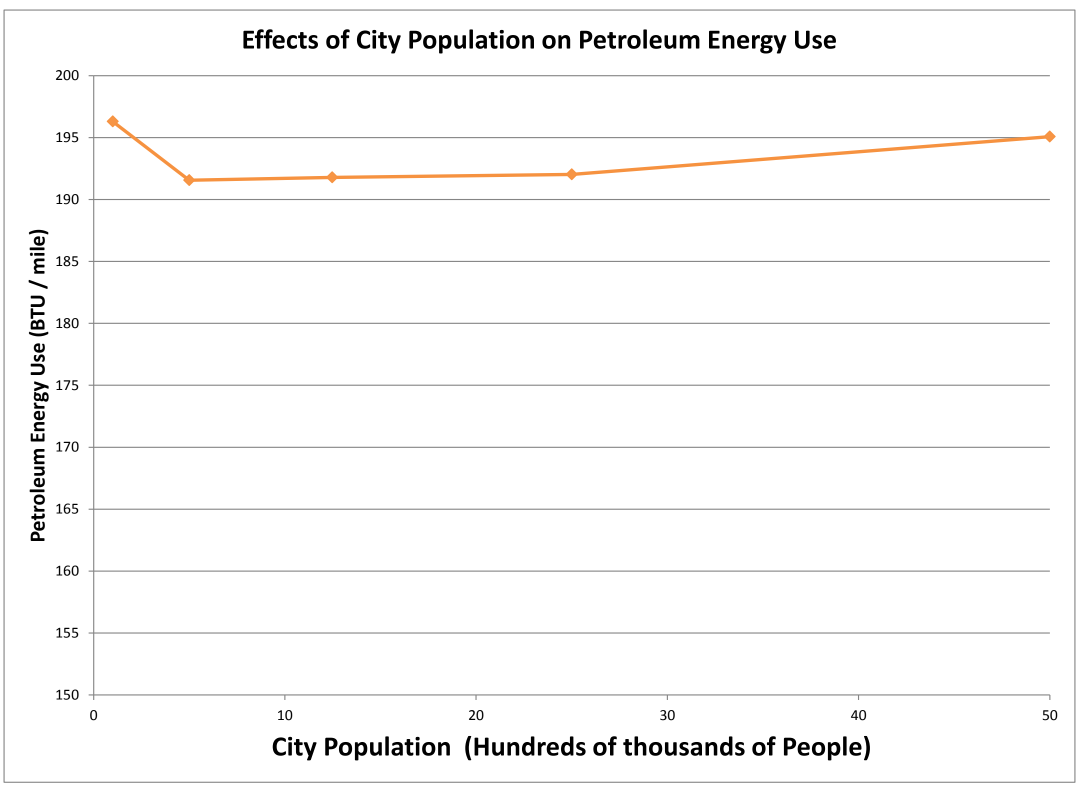


Figure 6.7.22. Petroleum use versus city population for the central biomass—liquid truck delivery and cryo-compressed dispensing pathway

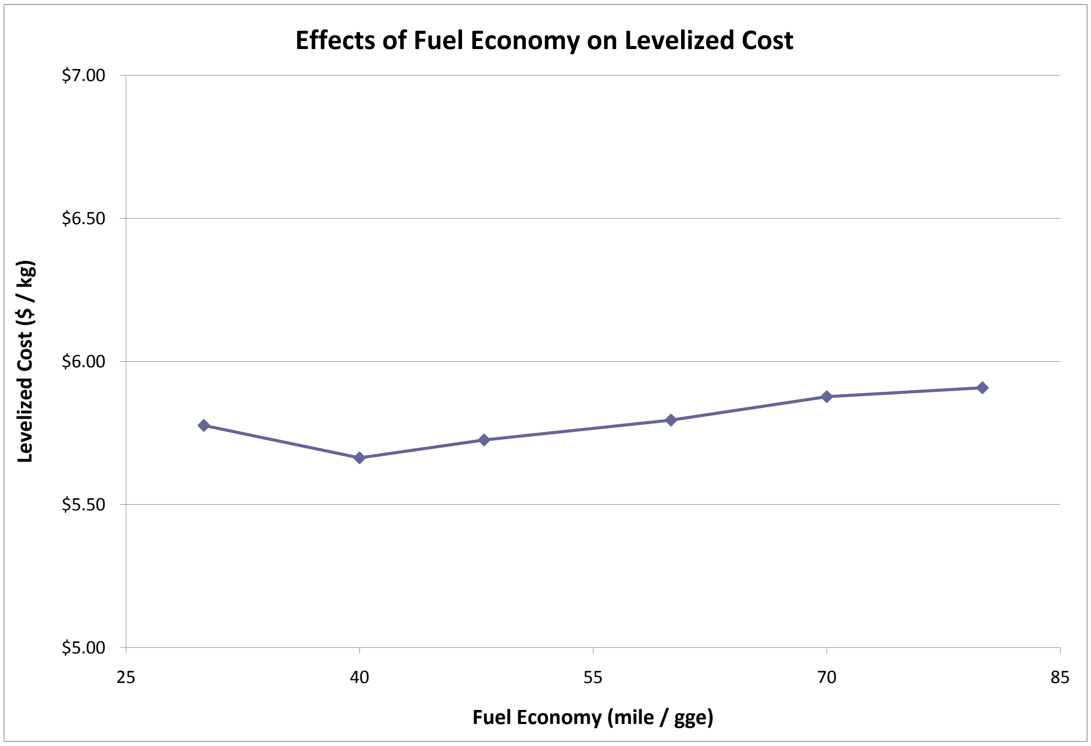


Figure 6.7.23. Levelized cost versus fuel economy for the central biomass—liquid truck delivery and cryo-compressed dispensing pathway

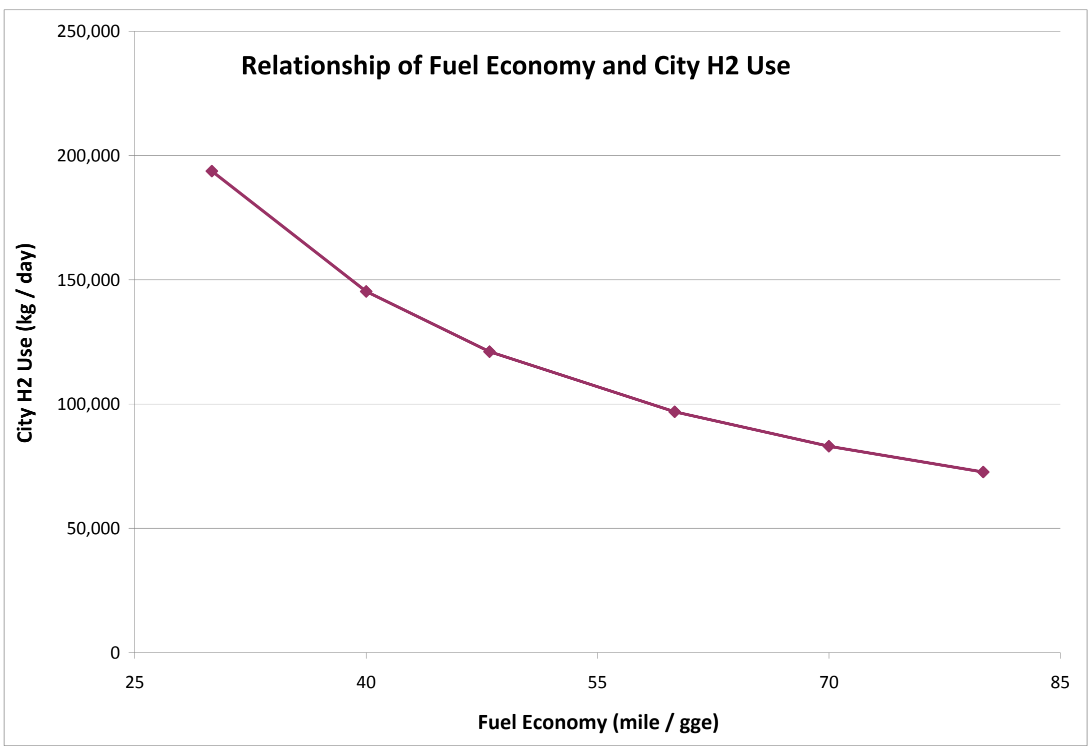


Figure 6.7.24. City hydrogen use versus fuel economy for the central biomass—liquid truck delivery and cryo-compressed dispensing pathway

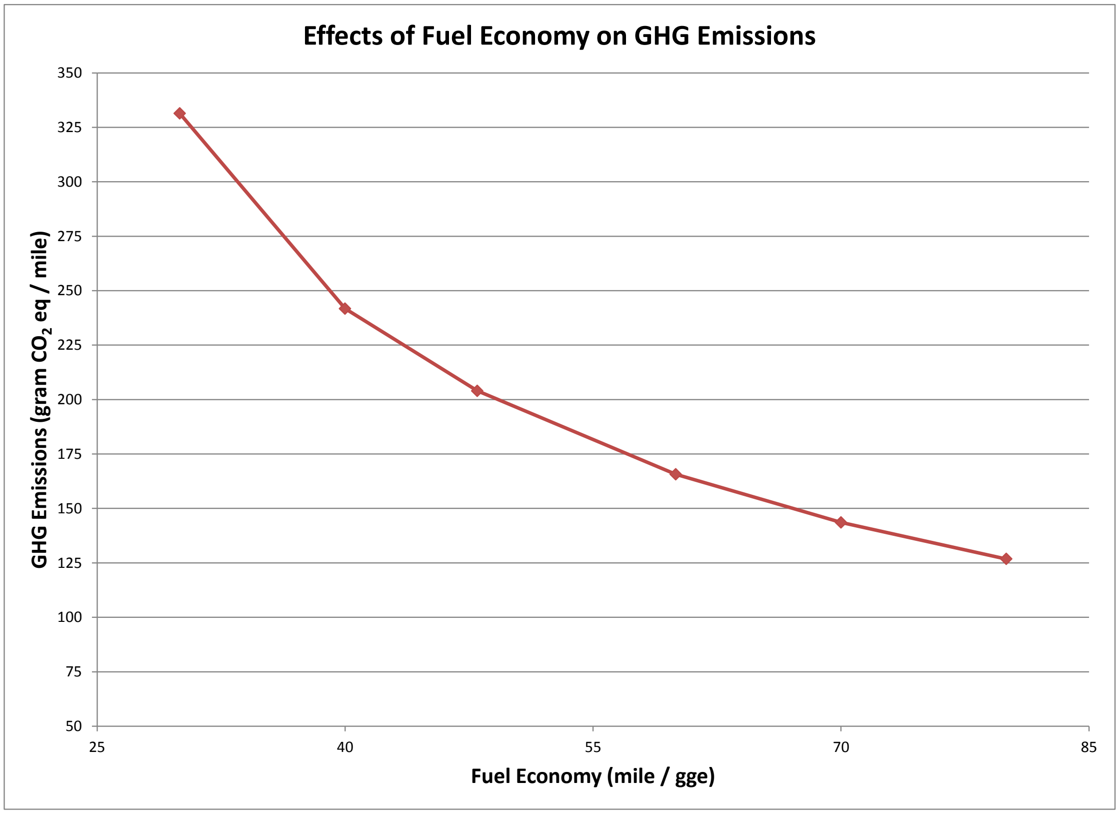


Figure 6.7.25. GHG emissions versus fuel economy for the central biomass—liquid truck delivery and cryo-compressed dispensing pathway

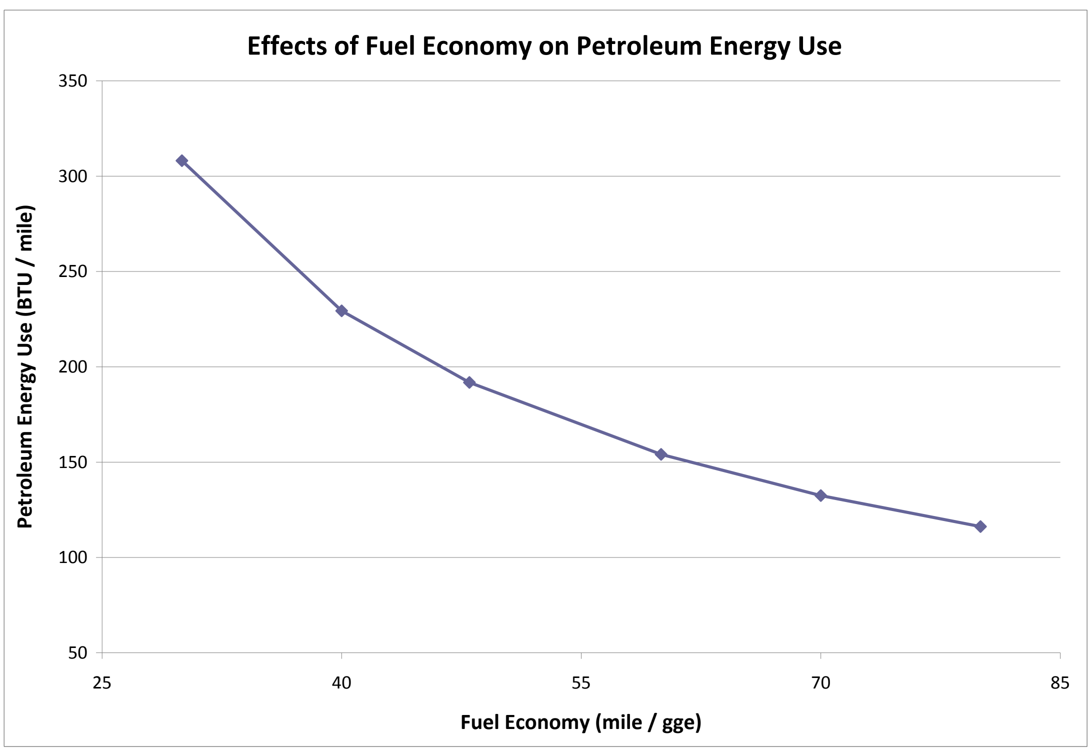


Figure 6.7.26. Petroleum use versus fuel economy for the central biomass—liquid truck delivery and cryo-compressed dispensing pathway

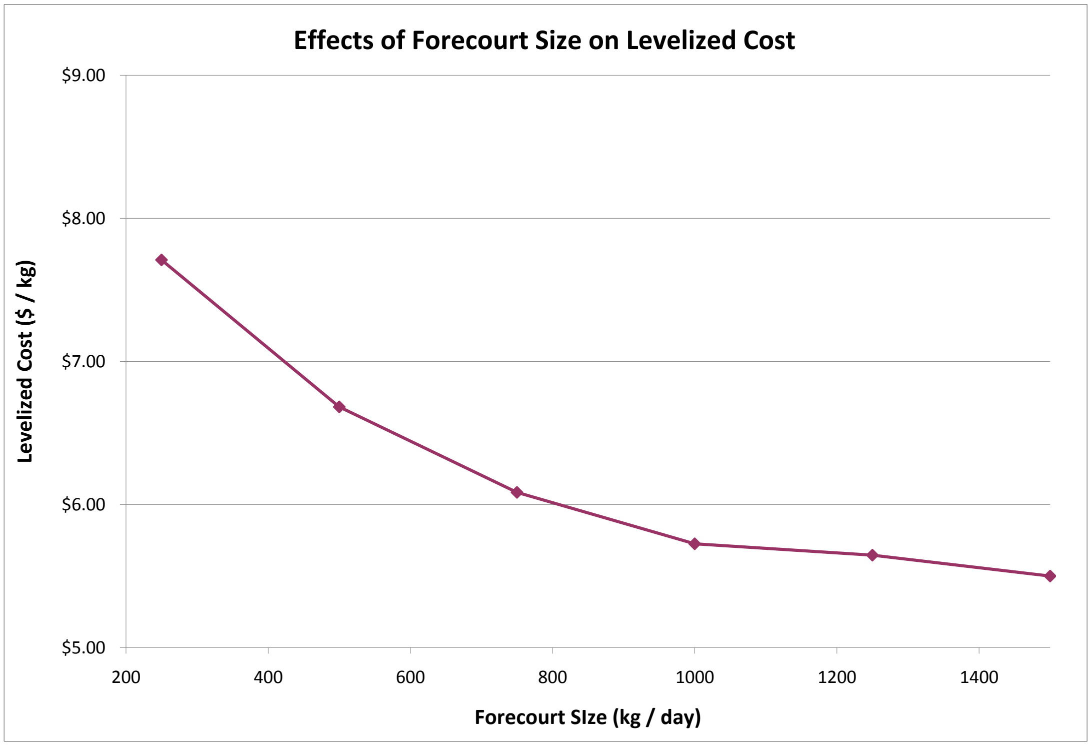


Figure 6.7.27. Levelized cost versus forecourt size for the central biomass—liquid truck delivery and cryo-compressed dispensing pathway

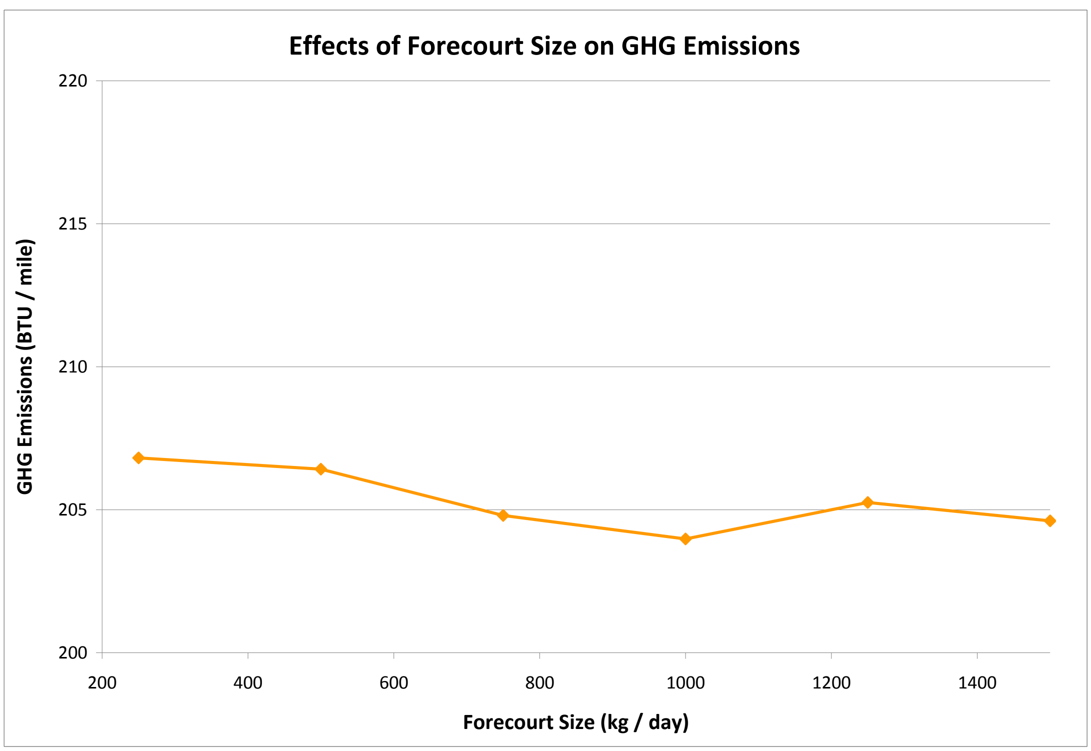


Figure 6.7.28. GHG emission versus forecourt size for the central biomass—liquid truck delivery and cryo-compressed dispensing pathway

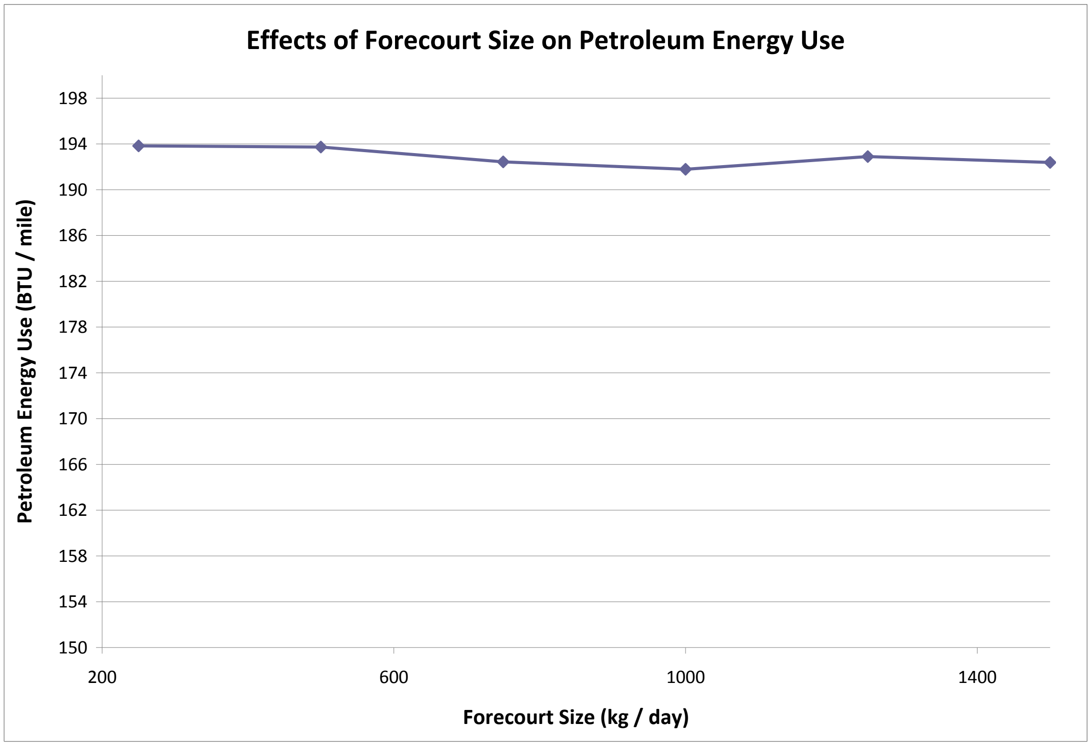


Figure 6.7.29. Petroleum use versus forecourt size for the central biomass—liquid truck delivery and cryo-compressed dispensing pathway

6.8 Central Natural Gas—Pipeline Delivery

Figure 6.8.1 shows the major inputs, assumptions, and outputs for each of the subsystems considered in the well-to-tank analysis, including feedstock supply and hydrogen dispensing. (See Appendix H for more details on this pathway.)

The WTP and WTW cost of hydrogen, energy use, and emissions for the central natural gas—pipeline delivery pathway are summarized in Table 6.8.1.

6.8.1 Cost Breakdown

Figure 6.8.2 shows the feedstock and energy price inputs and the resulting hydrogen production, delivery, and distribution costs for the central natural gas—pipeline delivery pathway. The financial assumptions used in this analysis are detailed in Section 5.

Figure 6.8.3 shows the contributions of hydrogen production, delivery, and losses to the levelized cost of hydrogen shown in Figure 6.8.2.

Figure 6.8.4 and Table 6.8.2 show the breakdown of levelized costs for the central natural gas—pipeline delivery pathway.

Inputs			Assumptions			Outputs		
						NG Delivery Pressure	Average of gas companies	
			NG Recovery, Processing, & Transport			NG Quality at Delivery	Average of gas companies	
			NG Recovery Efficiency	95.7%		NG Cost in 2015	$6.09	2007 $ / mmBTU
			NG emitted during recovery	400	g / MMbtu NG	NG Share of Levelized Cost	$1.52	2007$ / kg H2 dispensed
			NG processing energy efficiency	97.2%				
Coal Input (including upstream)	200	Btu / 116000Btu to Pump	NG emitted during processing	30	g / MMbtu NG	WTG CO2 Emissions	600	g CO2 eq./ 116000 Btu
Natural Gas Input (including upstream)	125,600	Btu / 116000Btu to Pump	NG emitted during transport	199,400	g / MMbtu NG	WTG CH4 Emissions	1,260	g CO2 eq./ 116000 Btu
Petroleum Input (including upstream)	500	Btu / 116000Btu to Pump	NG transport distance	500	miles	WTG N2O Emissions	3	g CO2 eq./ 116000 Btu
						WTG GHG Emissions	1,870	g CO2 eq./ 116000 Btu
						Hydrogen Output Pressure	300	psi
Natural gas consumption	0.1564	MMBtu/kg H2 produced	**Hydrogen Production**			Hydrogen Outlet Quality	99.9%	
Electricity consumption	0.57	kWh / kg H2						
Process Water Consumption	3.36	gal / kg H2	Central plant design capacity	379,400	kg / day	Total capital investment	$632	2007$ / daily kg H2 (effective capacity)
Cooling Water Consumption	1.50	gal / kg H2	Capacity factor	90%		Levelized Cost of Capital	$0.34	2007$ / kg H2 dispensed
			necessary	0.35		Fixed O&M Costs	$0.06	2007$ / kg H2 dispensed
Total Capital Investment	$215,844,000	2007$	Process energy efficiency	71.9%		Variable O&M Costs	$0.08	2007$ / kg H2 dispensed
			Electricity Mix	US Mix		Total Levelized Cost	$2.00	2007$ / kg H2 dispensed
			After-tax IRR	10%				
Coal Input (including upstream)	2,900	Btu / 116000Btu to Pump	Assumed Plant Life	40		SMR CO2 Emissions	10,200	g CO2 eq./ 116000 Btu
Natural Gas Input (including upstream)	48,800	Btu / 116000Btu to Pump				SMR CH4 Emissions	500	g CO2 eq./ 116000 Btu
Petroleum Input (including upstream)	300	Btu / 116000Btu to Pump				SMR N2O Emissions	12	g CO2 eq./ 116000 Btu
						SMR GHG Emissions	10,700	g CO2 eq./ 116000 Btu
Electricity consumption for compressor	0.56	kWh / kg H2 produced	**Pipelines for Delivery**			Total capital investment	$3,340	2007$ / daily kg H2 (effective capacity)
Electricity consumption for geo storage	0.01	kWh / kg H2 produced						
Total electricity consumption	0.57	kWh / kg H2 produced	City Population	1,247,000	people	Levelized Cost of Capital	$1.71	2007$ / kg H2 dispensed
			Hydrogen Vehicle Penetration	15%		Energy & Fuel	$0.04	2007$ / kg H2 dispensed
			City hydrogen use	121,100	kg / day	Other O&M Costs	$0.40	2007$ / kg H2 dispensed
Total Capital Investment	$404,341,000	2007$	Distance from City to Production Facility	62	miles	Levelized Cost of Delivery	$2.15	2007$ / kg H2 dispensed
			Geologic storage capacity	1,324,700	kg H2			
			Number of trunk pipelines	3		Delivery CO2 Emissions	390	g CO2 eq./ 116000 Btu
Coal Input (including upstream)	2,800	Btu / 116000Btu to Pump	Service-line length	1.5	miles / line	Delivery CH4 Emissions	24	g CO2 eq./ 116000 Btu
Natural Gas Input (including upstream)	2,200	Btu / 116000Btu to Pump	Number of service lines	122		Delivery N2O Emissions	2	g CO2 eq./ 116000 Btu
Petroleum Input (including upstream)	100	Btu / 116000Btu to Pump	Hydrogen losses	0.80%		Delivery GHG Emissions	420	g CO2 eq./ 116000 Btu
						Hydrogen outlet pressure	12,700	psi
Electricity consumption	4.4	kWh / kg H2 produced	**Forecourt Dispensing**			Basis -- Hydrogen Quantity	116,000	Btu (116,000 Btu/gal non-oxygenated conventional unleaded gasoline)
Total Capital Investment per Station	$2,629,000	2007$ / station	Average Dispensing Rate per Station	1,000	kg / day	Total capital investment	$2,650	2007$ / daily kg H2 (effective capacity)
Total Capital Investment	$320,679,000	2007$ / all stations	Number of Dispensing Stations	122		Levelized Cost of Capital	$1.08	2007$ / kg H2 dispensed
			Number of Compression Steps	5		Energy & Fuel	$0.41	2007$ / kg H2 dispensed
Inlet pressure of hydrogen at stations	300	psi	Usable Low Pressure Storage per Station	370	kg H2	Other O&M Costs	$0.43	2007$ / kg H2 dispensed
			Usable Cascade Storage per Station	130	kg H2	Levelized Cost of Dispensing	$1.93	2007$ / kg H2 dispensed
Coal Input (including upstream)	24,400	Btu / 116000Btu to Pump	Site storage	42%	% of design capacity	CSD CO2 Emissions	3,370	g CO2 eq./ 116000 Btu
Natural Gas Input (including upstream)	10,800	Btu / 116000Btu to Pump	# 2-hose Dispensers per Station	2		CSD CH4 Emissions	210	g CO2 eq./ 116000 Btu
Petroleum Input (including upstream)	900	Btu / 116000Btu to Pump	Hydrogen Losses	0.50%		CSD N2O Emissions	14	g CO2 eq./ 116000 Btu
						CSD GHG Emissions	3,590	g CO2 eq./ 116000 Btu
						Cost Per Mile	$0.69	2007$ / mi
Vehicle Mass	3,020	lb	**Vehicle**			Fuel Share	$0.13	2007$ / mi
Fuel cell size	70	kW	Fuel Economy	48.0	mi / gge	Maintenance, Tires, Repairs	$0.07	2007$ / mi
Hybridization battery (peak power)	30	kW	Vehicle Miles Traveled	15,000	mi / yr	Insurance & Registration	$0.12	2007$ / mi
			Vehicle Lifetime	160,000	mi	Depreciation	$0.27	2007$ / mi
			Purchase Year	2015		Financing	$0.10	2007$ / mi
			Vehicle Purchase Cost	$33,700	2007$			
Coal Input (including upstream)	2,300	Btu / gge fuel consumed	Fuel Cell System Cost	$4,500	2007$	Veh. Cycle CO2 Emissions	1,670	g CO2 eq / gge fuel consumed
Natural Gas Input (including upstream)	12,100	Btu / gge fuel consumed	Hydrogen Storage System Cost	$2,400	2007$	Veh. Cycle CH4 Emissions	170	g CO2 eq / gge fuel consumed
Petroleum Input (including upstream)	6,900	Btu / gge fuel consumed	Tax Credit	$0	2007$	Veh. Cycle N2O Emissions	6	g CO2 eq / gge fuel consumed
						Veh. Cycle GHG Emissions	1,850	g CO2 eq / gge fuel consumed

Figure 6.8.1. Summary of major inputs, assumptions, and outputs by subsystem for the central natural gas—pipeline delivery pathway

Table 6.8.1. WTP and WTW Results for the Central Natural Gas—Pipeline Delivery Pathway

	WTP		WTW	
Coal input (including upstream)[a]	30,400	Btu/116,000 Btu	630	Btu/mi
Natural gas input (including upstream)[a]	187,400	Btu/116,000 Btu	3,910	Btu/mi
Petroleum input (including upstream)[a]	1,800	Btu/116,000 Btu	40	Btu/mi
Fossil energy input (including upstream)[a]	219,600	Btu/116,000 Btu	4,580	Btu/mi
WTP CO_2 emissions[b]	14,600	g/116,000 Btu	300	g/mi
WTP CH_4 emissions	80	g/116,000 Btu	2	g/mi
WTP N_2O emissions	0	g/116,000 Btu	0	g/mi
WTP GHG emissions	16,600	g CO_2-eq./ 116,000 Btu	350	g/mi
	Cost per kg		**Cost per mile**	
Levelized cost of hydrogen	$6.07	2007$/kg	$0.13	2007$/mi

[a] Coal, natural gas, and petroleum inputs include those used directly in the hydrogen production and delivery pathway as feedstocks and fuels; those used to produce electricity and other materials used in the pathway; and those used upstream of the pathway to recover, refine, and deliver the feedstock.
[b] Includes the carbon content of CO, CH_4, and volatile organic compound emissions that decompose in the atmosphere to CO_2.

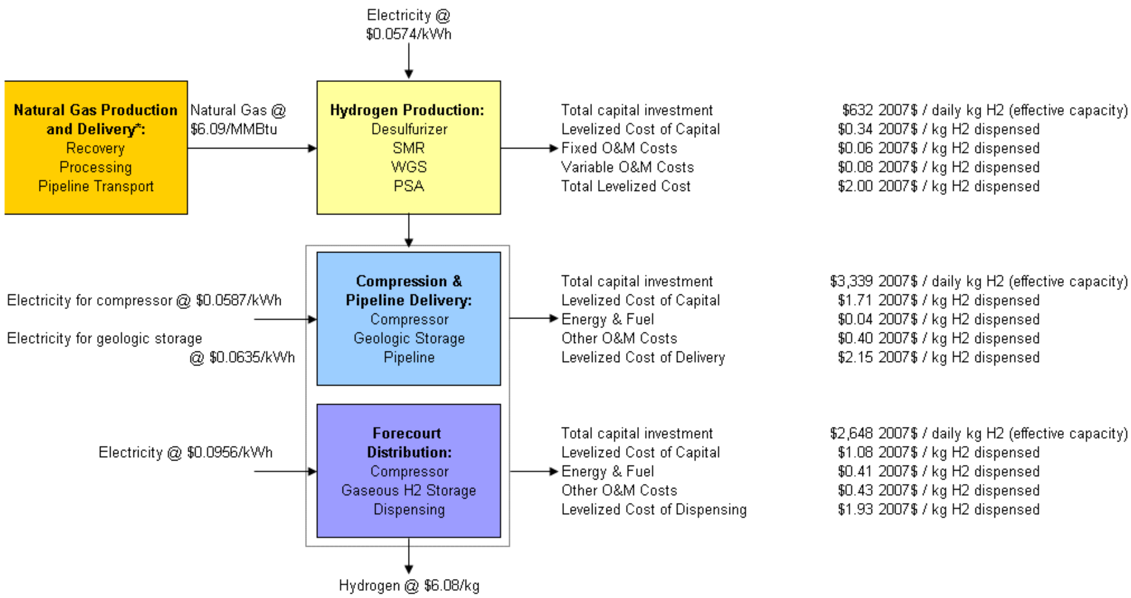


Figure 6.8.2. Cost analysis inputs and high-level results for the central natural gas—pipeline delivery pathway

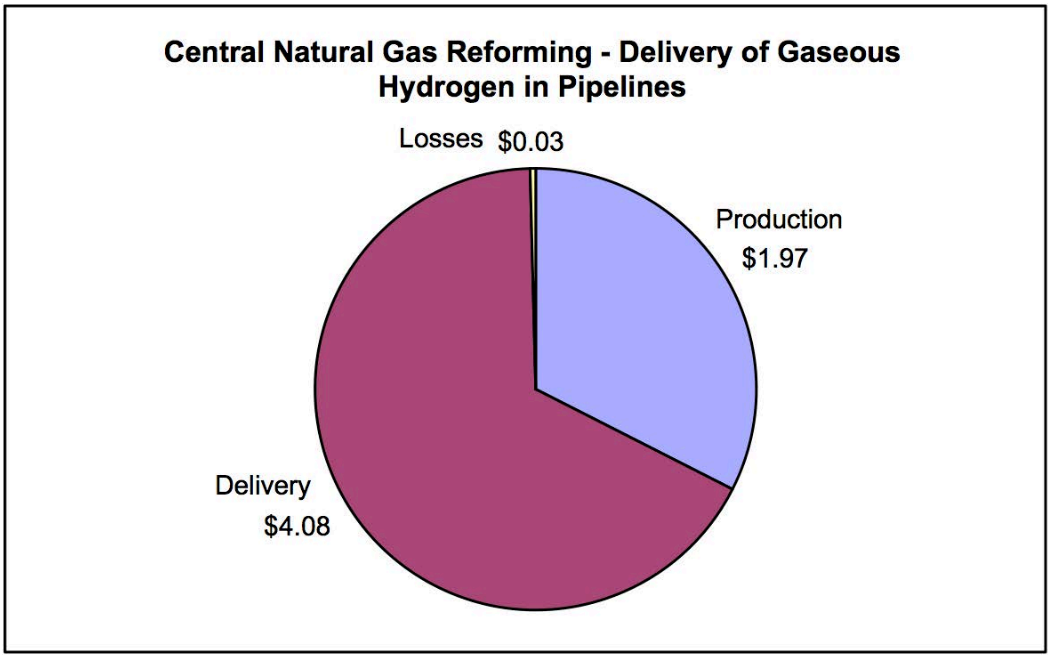


Figure 6.8.3. Contribution of hydrogen production, delivery, and losses to the levelized cost of hydrogen from the central natural gas—pipeline delivery pathway

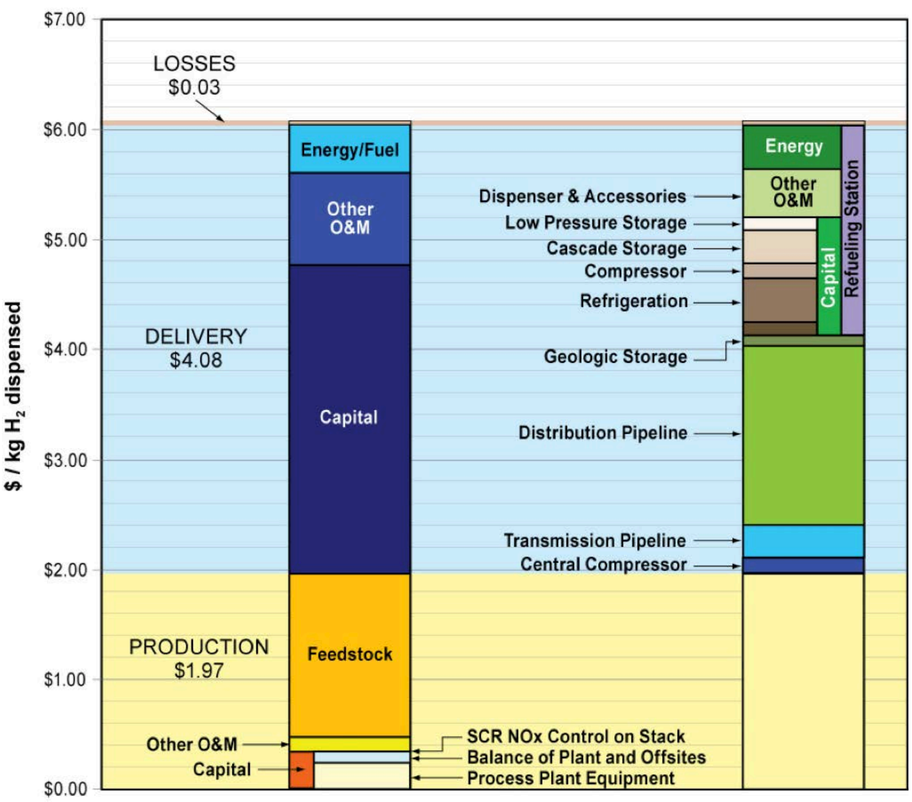


Figure 6.8.4. Breakdown of levelized costs for the central natural gas—pipeline delivery pathway

Table 6.8.2. Contribution of Production and Delivery Processes to Levelized Hydrogen Cost for the Central Natural Gas—Pipeline Delivery Pathway

Cost Component	Capital	Other O&M	Feedstock	Energy/ Fuel	Total
Production	$0.33	$0.14	$1.50		$1.97
Process plant equipment	$0.24				
Balance of plant and offsites	$0.09				
SCR NOx control on stack	$0.00				
Delivery	$2.80	$0.83		$0.45	$4.08
Central compressor					$0.12
Transmission pipeline					$0.30
Distribution pipeline					$1.64
Geologic storage					$0.09
Gaseous refueling station	$1.08	$0.43		$0.41	$1.93
Refrigeration	$0.12				
Compressor	$0.41				
Cascade storage	$0.12				
Low pressure storage	$0.30				
Dispenser and accessories	$0.13				
Losses					$0.03
Total	**$3.13**	**$0.97**	**$1.50**	**$0.45**	**$6.08**

6.8.2 Energy Use and Emissions Breakdown

Figures 6.8.5 and 6.8.6 show the WTW energy inputs and losses for the central natural gas—pipeline delivery pathway.

Figures 6.8.7 and 6.8.8 show the WTW emissions resulting from the delivery of 116,000 Btu hydrogen to a vehicle fuel tank using the central natural gas—pipeline delivery pathway.

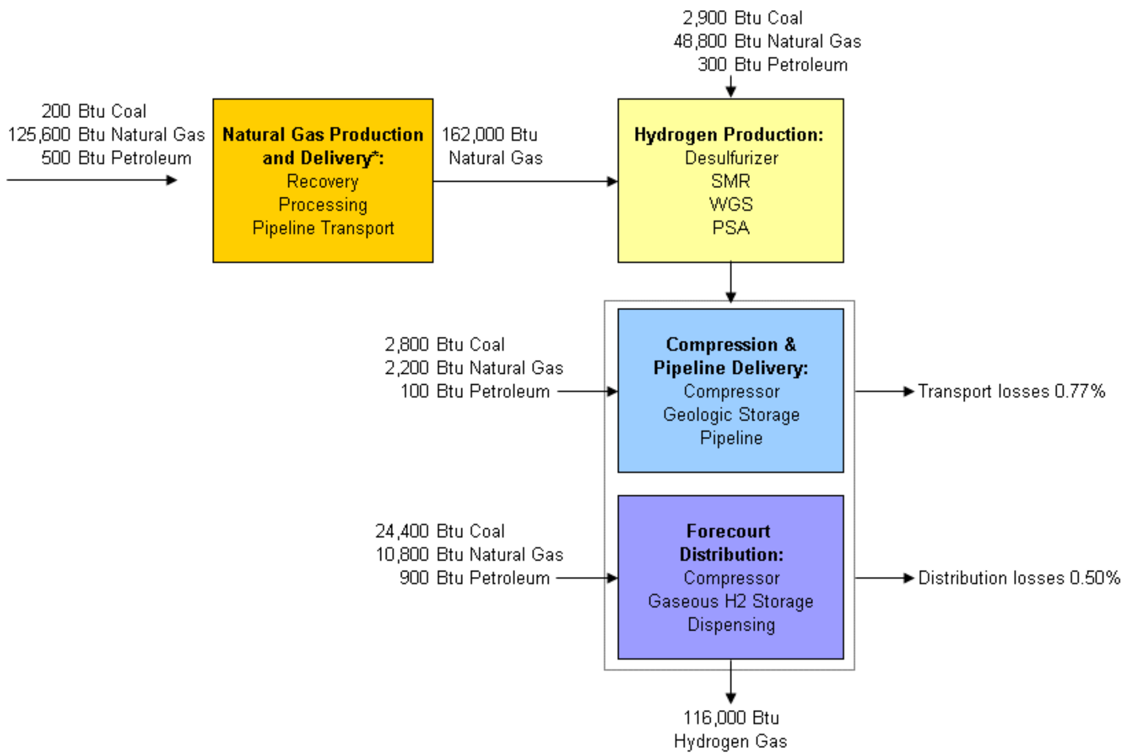


Figure 6.8.5. WTW energy inputs to deliver 116,000 Btu hydrogen to a vehicle using the central natural gas—pipeline delivery pathway

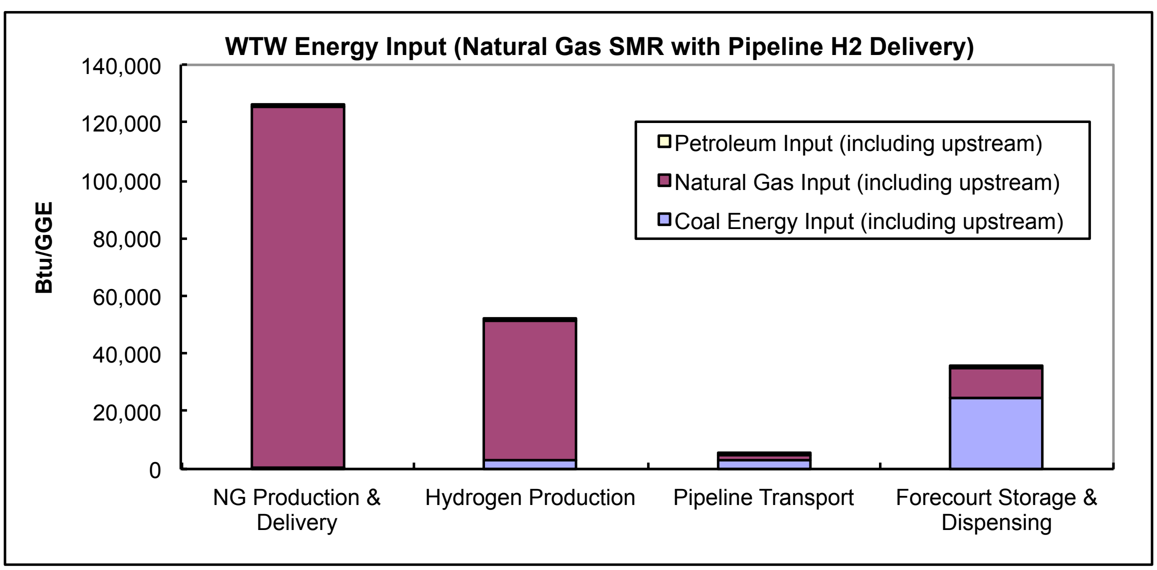


Figure 6.8.6. WTW petroleum, natural gas, and coal inputs to deliver 116,000 Btu hydrogen using the central natural gas—pipeline delivery pathway

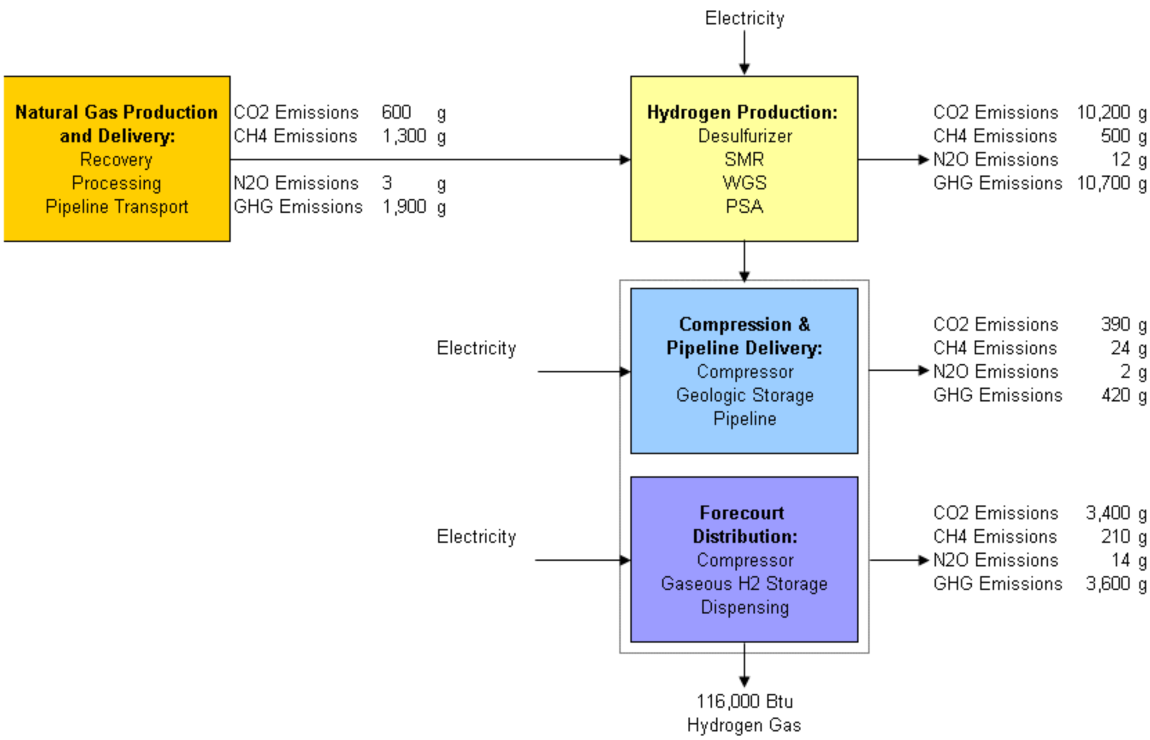


Figure 6.8.7. WTW emissions resulting from delivery of 116,000 Btu hydrogen using the central natural gas—pipeline delivery pathway

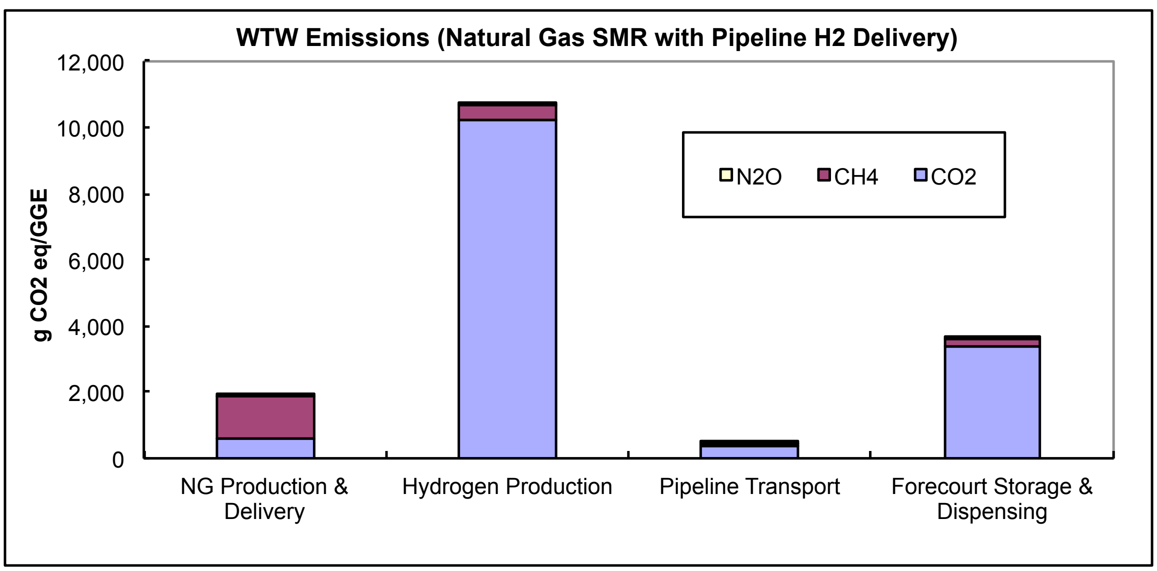


Figure 6.8.8. WTW CO_2, CH_4, and N_2O emissions resulting from delivery of 116,000 Btu hydrogen to a vehicle using the central natural gas—pipeline delivery pathway

6.8.3 Sensitivities

6.8.3.1 Production Sensitivities

Several sensitivities were run on the production portion of the central natural gas—pipeline delivery pathway. These sensitivities focused primarily on cost factors; however, several sensitivities also affect energy use and emissions. Figure 6.8.9 shows the effects of several production parameters on the pathway's levelized cost.

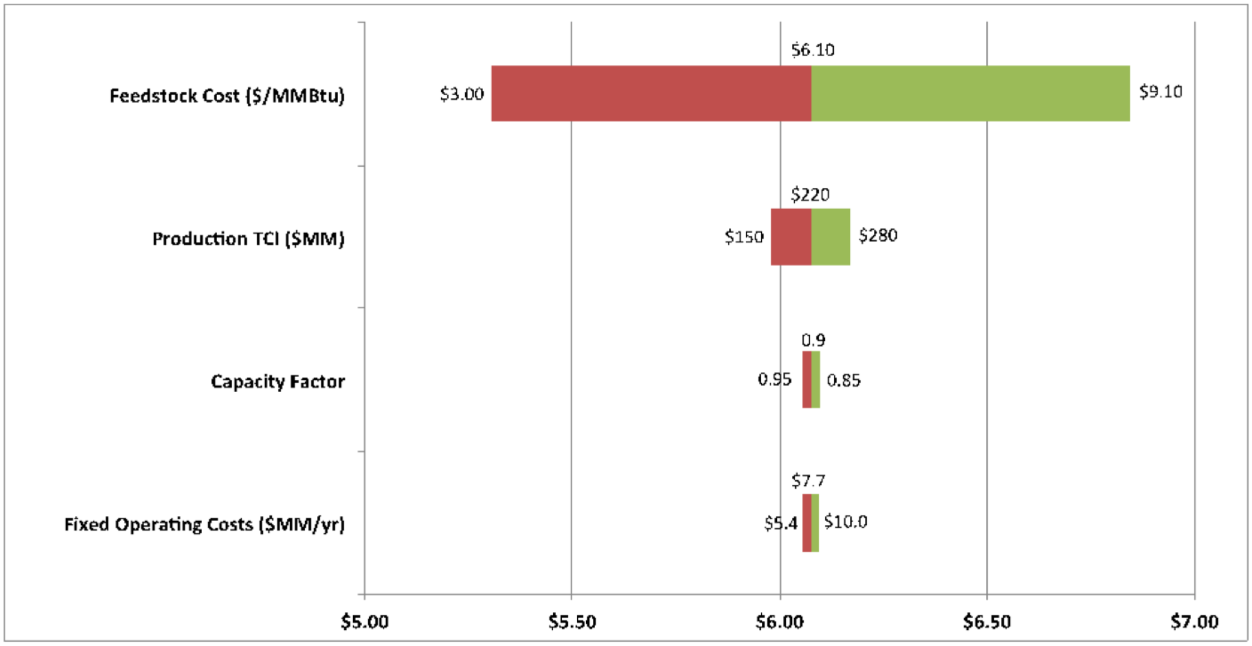


Figure 6.8.9. Production sensitivities for central natural gas–pipeline delivery pathway

The assumed electrical grid mix also affects the energy use and emissions. Table 6.8.3 shows the differences in energy use and GHG emissions between the U.S. average grid mix (which was used for all other sensitivities) and a hypothetical green grid mix that is 100% renewable energy (solar and wind).

Table 6.8.3. The Effects of Fuel Economy and Grid Mix on Use of Primary Energy and Emissions from the Central Natural Gas—Pipeline Delivery Pathway

	U.S. Average Grid Mix (48 mpgge)	U.S. Average Grid Mix (68 mpgge)	"Green" Grid Mix (48 mpgge)
WTW GHG emissions (g/mile)	350	240	250
WTW fossil energy (Btu/mile)	4,600	3,200	3,600
WTW petroleum energy (Btu/mile)	40	30	10
WTW total energy (Btu/mile)	4,800	3,400	4,100

6.8.3.2 Delivery Sensitivities

Pipeline delivery sensitivities are reported for the biomass production scenario in Section 6.4.3. The effects of the sensitivities will be the same for all pipeline delivery scenarios.

6.9 Central Wind Electricity—Pipeline Delivery

Figure 6.9.1 shows the major inputs, assumptions, and outputs for each of the subsystems considered in the well-to-tank analysis, including feedstock supply and hydrogen dispensing. (See Appendix I for more details on this pathway.)

The WTP and WTW cost of hydrogen, energy use, and emissions for the central wind electricity—pipeline delivery pathway are summarized in Table 6.9.1.

6.9.1 Cost Breakdown

Figure 6.9.2 shows the feedstock and energy price inputs and the resulting hydrogen production, delivery, and distribution costs for the central wind electricity—pipeline delivery pathway. The financial assumptions used in this analysis are detailed in Section 5.

Figure 6.9.3 shows the contributions of hydrogen production, delivery, and losses to the levelized cost of hydrogen shown in Figure 6.9.2.

Figure 6.9.4 and Table 6.9.2 show the breakdown of levelized costs for the central wind electricity—pipeline delivery pathway.

Inputs			Assumptions			Outputs		
						NG Delivery Pressure	Average of gas companies	
			NG Recovery, Processing, & Transport			NG Quality at Delivery	Average of gas companies	
			NG Recovery Efficiency	95.7%		NG Cost in 2015	$6.09	2007 $ / mmBTU
			NG emitted during recovery	400	g / MMbtu NG	NG Share of Levelized Cost	$1.52	2007$ / kg H2 dispensed
			NG processing energy efficiency	97.2%				
Coal Input (including upstream)	200	Btu / 116000Btu to Pump	NG emitted during processing	30	g / MMbtu NG	WTG CO2 Emissions	600	g CO2 eq./ 116000 Btu
Natural Gas Input (including upstream)	125,600	Btu / 116000Btu to Pump	NG emitted during transport	199,400	g / MMbtu NG	WTG CH4 Emissions	1,260	g CO2 eq./ 116000 Btu
Petroleum Input (including upstream)	500	Btu / 116000Btu to Pump	NG transport distance	500	miles	WTG N2O Emissions	3	g CO2 eq./ 116000 Btu
						WTG GHG Emissions	1,870	g CO2 eq./ 116000 Btu
						Hydrogen Output Pressure	300	psi
Natural gas consumption	0.1564	MMBtu/kg H2 produced	**Hydrogen Production**			Hydrogen Outlet Quality	99.9%	
Electricity consumption	0.57	kWh / kg H2						
Process Water Consumption	3.36	gal / kg H2	Central plant design capacity	379,400	kg / day	Total capital investment	$632	2007$ / daily kg H2 (effective capacity)
Cooling Water Consumption	1.50	gal / kg H2	Capacity factor	90%		Levelized Cost of Capital	$0.34	2007$ / kg H2 dispensed
			necessary	0.35		Fixed O&M Costs	$0.06	2007$ / kg H2 dispensed
Total Capital Investment	$215,844,000	2007$	Process energy efficiency	71.9%		Variable O&M Costs	$0.08	2007$ / kg H2 dispensed
			Electricity Mix	US Mix		Total Levelized Cost	$2.00	2007$ / kg H2 dispensed
			After-tax IRR	10%				
Coal Input (including upstream)	2,900	Btu / 116000Btu to Pump	Assumed Plant Life	40		SMR CO2 Emissions	10,200	g CO2 eq./ 116000 Btu
Natural Gas Input (including upstream)	48,800	Btu / 116000Btu to Pump				SMR CH4 Emissions	500	g CO2 eq./ 116000 Btu
Petroleum Input (including upstream)	300	Btu / 116000Btu to Pump				SMR N2O Emissions	12	g CO2 eq./ 116000 Btu
						SMR GHG Emissions	10,700	g CO2 eq./ 116000 Btu
Electricity consumption for compressor	0.56	kWh / kg H2 produced	**Pipelines for Delivery**			Total capital investment	$3,340	2007$ / daily kg H2 (effective capacity)
Electricity consumption for geo storage	0.01	kWh / kg H2 produced						
Total electricity consumption	0.57	kWh / kg H2 produced	City Population	1,247,000	people	Levelized Cost of Capital	$1.71	2007$ / kg H2 dispensed
			Hydrogen Vehicle Penetration	15%		Energy & Fuel	$0.04	2007$ / kg H2 dispensed
			City hydrogen use	121,100	kg / day	Other O&M Costs	$0.40	2007$ / kg H2 dispensed
Total Capital Investment	$404,341,000	2007$	Distance from City to Production Facility	62	miles	Levelized Cost of Delivery	$2.15	2007$ / kg H2 dispensed
			Geologic storage capacity	1,324,700	kg H2			
			Number of trunk pipelines	3		Delivery CO2 Emissions	390	g CO2 eq./ 116000 Btu
Coal Input (including upstream)	2,800	Btu / 116000Btu to Pump	Service-line length	1.5	miles / line	Delivery CH4 Emissions	24	g CO2 eq./ 116000 Btu
Natural Gas Input (including upstream)	2,200	Btu / 116000Btu to Pump	Number of service lines	122		Delivery N2O Emissions	2	g CO2 eq./ 116000 Btu
Petroleum Input (including upstream)	100	Btu / 116000Btu to Pump	Hydrogen losses	0.80%		Delivery GHG Emissions	420	g CO2 eq./ 116000 Btu
						Hydrogen outlet pressure	12,700	psi
Electricity consumption	4.4	kWh / kg H2 produced	**Forecourt Dispensing**			Basis -- Hydrogen Quantity	116,000	Btu (116,000 Btu/gal non-oxygenated conventional unleaded gasoline)
Total Capital Investment per Station	$2,629,000	2007$ / station	Average Dispensing Rate per Station	1,000	kg / day	Total capital investment	$2,650	2007$ / daily kg H2 (effective capacity)
Total Capital Investment	$320,679,000	2007$ / all stations	Number of Dispensing Stations	122		Levelized Cost of Capital	$1.08	2007$ / kg H2 dispensed
			Number of Compression Steps	5		Energy & Fuel	$0.41	2007$ / kg H2 dispensed
Inlet pressure of hydrogen at stations	300	psi	Usable Low Pressure Storage per Station	370	kg H2	Other O&M Costs	$0.43	2007$ / kg H2 dispensed
			Usable Cascade Storage per Station	130	kg H2	Levelized Cost of Dispensing	$1.93	2007$ / kg H2 dispensed
Coal Input (including upstream)	24,400	Btu / 116000Btu to Pump	Site storage	42%	% of design capacity	CSD CO2 Emissions	3,370	g CO2 eq./ 116000 Btu
Natural Gas Input (including upstream)	10,800	Btu / 116000Btu to Pump	# 2-hose Dispensers per Station	2		CSD CH4 Emissions	210	g CO2 eq./ 116000 Btu
Petroleum Input (including upstream)	900	Btu / 116000Btu to Pump	Hydrogen Losses	0.50%		CSD N2O Emissions	14	g CO2 eq./ 116000 Btu
						CSD GHG Emissions	3,590	g CO2 eq./ 116000 Btu
						Cost Per Mile	$0.69	2007$ / mi
Vehicle Mass	3,020	lb	**Vehicle**			Fuel Share	$0.13	2007$ / mi
Fuel cell size	70	kW	Fuel Economy	48.0	mi / gge	Maintenance, Tires, Repairs	$0.07	2007$ / mi
Hybridization battery (peak power)	30	kW	Vehicle Miles Traveled	15,000	mi / yr	Insurance & Registration	$0.12	2007$ / mi
			Vehicle Lifetime	160,000	mi	Depreciation	$0.27	2007$ / mi
			Purchase Year	2015		Financing	$0.10	2007$ / mi
			Vehicle Purchase Cost	$33,700	2007$			
Coal Input (including upstream)	2,300	Btu / gge fuel consumed	Fuel Cell System Cost	$4,500	2007$	Veh. Cycle CO2 Emissions	1,670	g CO2 eq / gge fuel consumed
Natural Gas Input (including upstream)	12,100	Btu / gge fuel consumed	Hydrogen Storage System Cost	$2,400	2007$	Veh. Cycle CH4 Emissions	170	g CO2 eq / gge fuel consumed
Petroleum Input (including upstream)	6,900	Btu / gge fuel consumed	Tax Credit	$0	2007$	Veh. Cycle N2O Emissions	6	g CO2 eq / gge fuel consumed
						Veh. Cycle GHG Emissions	1,850	g CO2 eq / gge fuel consumed

Figure 6.9.1. Summary of major inputs, assumptions, and outputs by subsystem for the central wind electricity—pipeline delivery pathway

Table 6.9.1. WTP and WTW Results for the Central Wind Electricity—Pipeline Delivery Pathway

	WTP		WTW	
Coal input (including upstream)[a]	27,300	Btu/116,000 Btu	570	Btu/mi
Natural gas input (including upstream)[a]	12,100	Btu/116,000 Btu	250	Btu/mi
Petroleum input (including upstream)[a]	1,000	Btu/116,000 Btu	20	Btu/mi
Fossil energy input (including upstream)[a]	40,400	Btu/116,000 Btu	840	Btu/mi
WTP CO_2 emissions[b]	3,800	g/116,000 Btu	80	g/mi
WTP CH_4 emissions	10	g/116,000 Btu	0	g/mi
WTP N_2O emissions	0	g/116,000 Btu	0	g/mi
WTP GHG emissions	4,000	g CO_2-eq./ 116,000 Btu	80	g/mi
	Cost per kg		**Cost per mile**	
Levelized cost of hydrogen ($/kg)	$8.41	2007$/kg	$0.18	2007$/mi

[a] Coal, natural gas, and petroleum inputs include those used directly in the hydrogen production and delivery pathway as feedstocks and fuels; those used to produce electricity and other materials used in the pathway; and those used upstream of the pathway to recover, refine, and deliver the feedstock.
[b] Includes the carbon content of CO, CH_4, and volatile organic compound emissions that decompose in the atmosphere to CO_2.

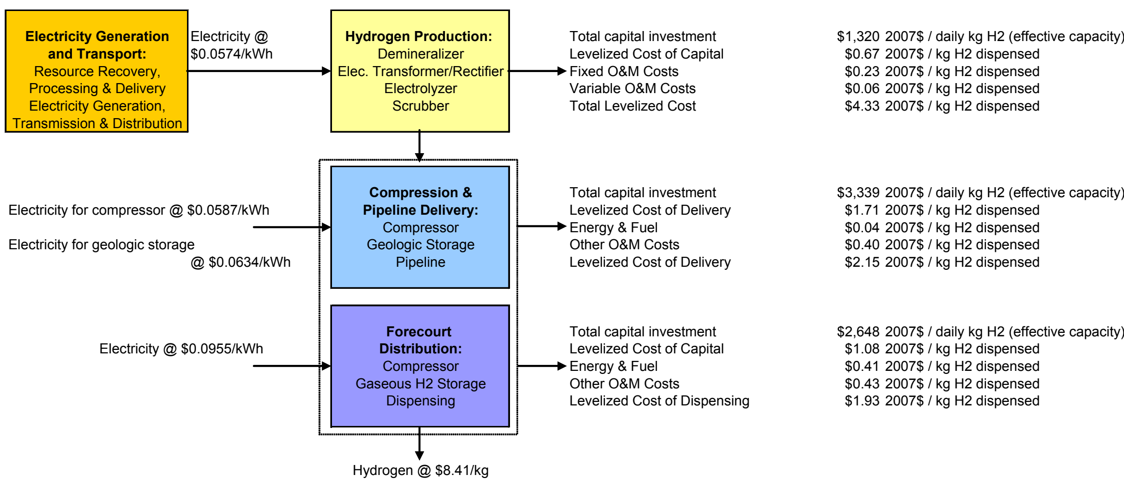


Figure 6.9.2. Cost analysis inputs and high-level results for the central wind electricity—pipeline delivery pathway

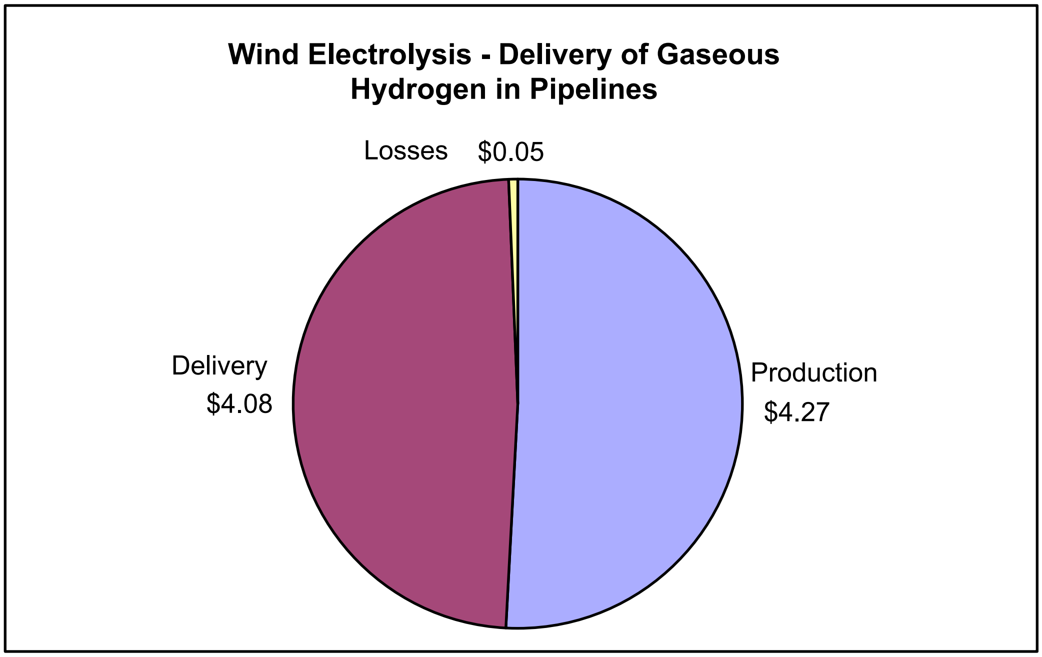


Figure 6.9.3. Contribution of hydrogen production, delivery, and losses to the levelized cost of hydrogen from the central wind electricity—pipeline delivery pathway

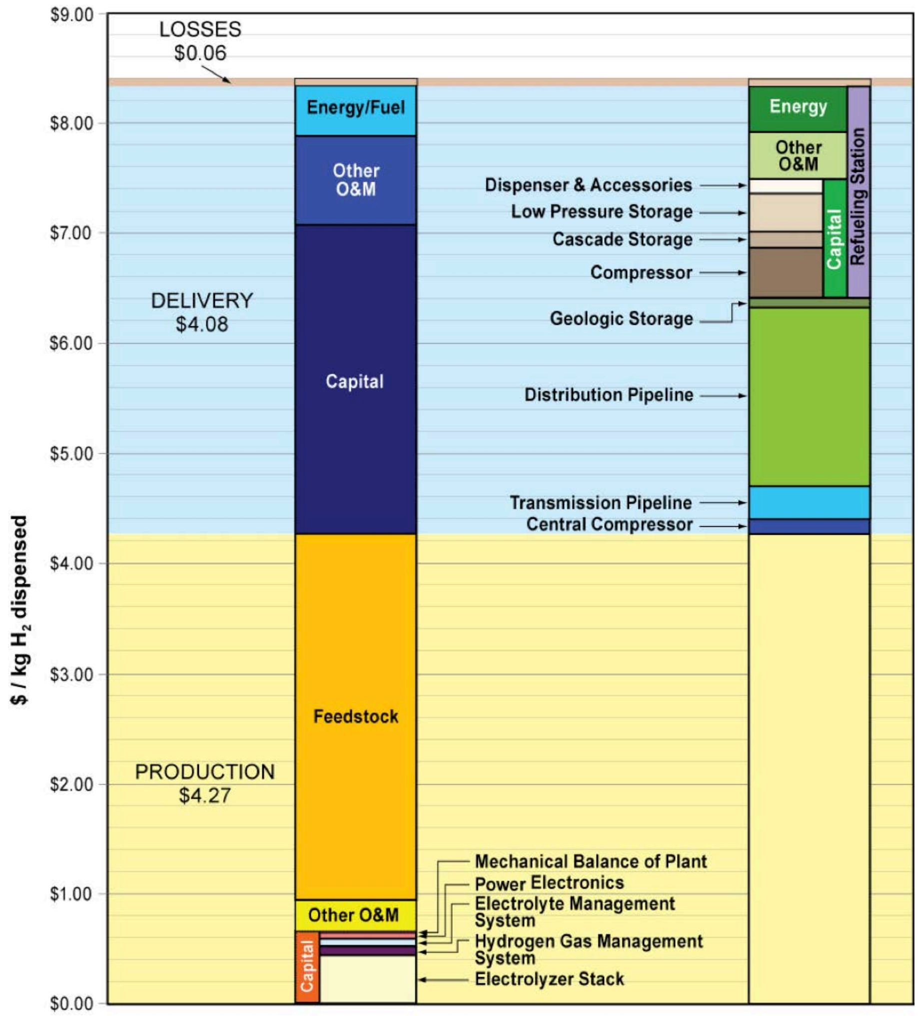


Figure 6.9.4. Breakdown of levelized costs for the central wind electricity—pipeline delivery pathway

Fuel costs are not the only costs of ownership of a vehicle. Vehicle ownership costs including fuel, maintenance, tires, repairs, insurance, registration, and vehicle depreciation and financing are shown in figure 6.9.5. Note that the costs in the figure are not discounted (i.e., a discount rate was not used to reduce future costs to their net present values). That methodology has the same effect as a discount rate of 0%.

Table 6.9.2. Contribution of Production and Delivery Processes to Levelized Hydrogen Cost from the Central Wind Electricity—Pipeline Delivery Pathway

Cost Component	Capital	Other O&M	Feedstock	Energy/ Fuel	Total
Production	$0.66	$0.29	$3.33		$4.27
Electrolyzer stack	$0.43				
Hydrogen gas management system	$0.10				
Electrolyte management system	$0.06				
Power electronics	$0.06				
Mechanical balance of plant	$0.01				
Delivery	$2.80	$0.83		$0.45	$4.08
Central compressor					$0.12
Transmission pipeline					$0.30
Distribution pipeline					$1.64
Geologic storage					$0.09
Gaseous refueling station	$1.08	$0.43		$0.41	$1.93
Compressor	$0.46				
Cascade storage	$0.14				
Low Pressure storage	$0.34				
Dispenser and accessories	$0.14				
Losses					$0.05
Total	**$3.46**	**$1.12**	**$3.33**	**$0.45**	**$8.41**

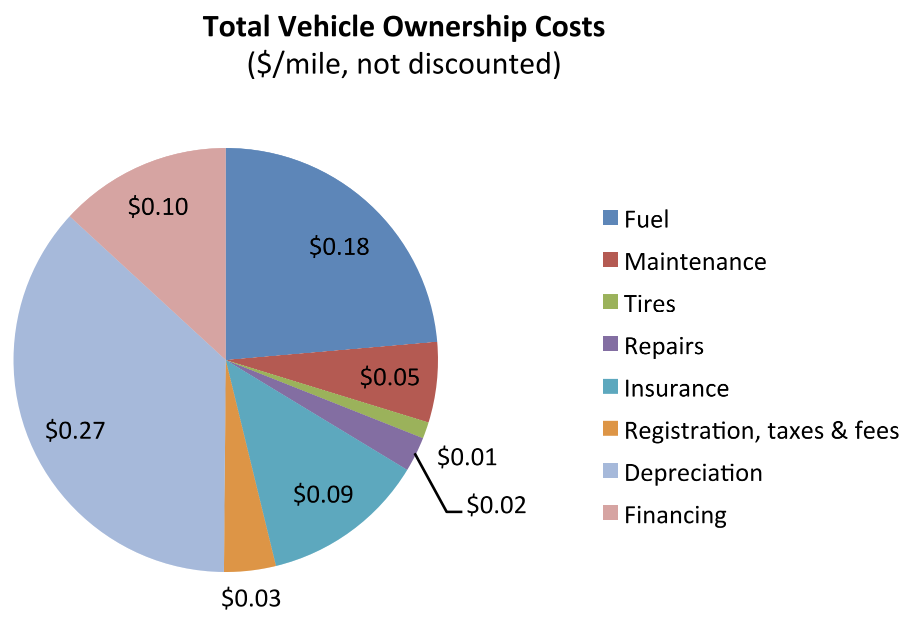


Figure 6.9.5. Breakdown of vehicle ownership costs for the central wind electricity—pipeline delivery pathway

6.9.2 Energy Use and Emissions Breakdown

Figures 6.9.6 and 6.9.7 show the WTW energy inputs and losses for the central wind electricity—pipeline delivery pathway.

Figures 6.9.8 and 6.9.9 show the WTW emissions resulting from the delivery of 116,000 Btu hydrogen to a vehicle fuel tank using the central wind electricity—pipeline delivery pathway.

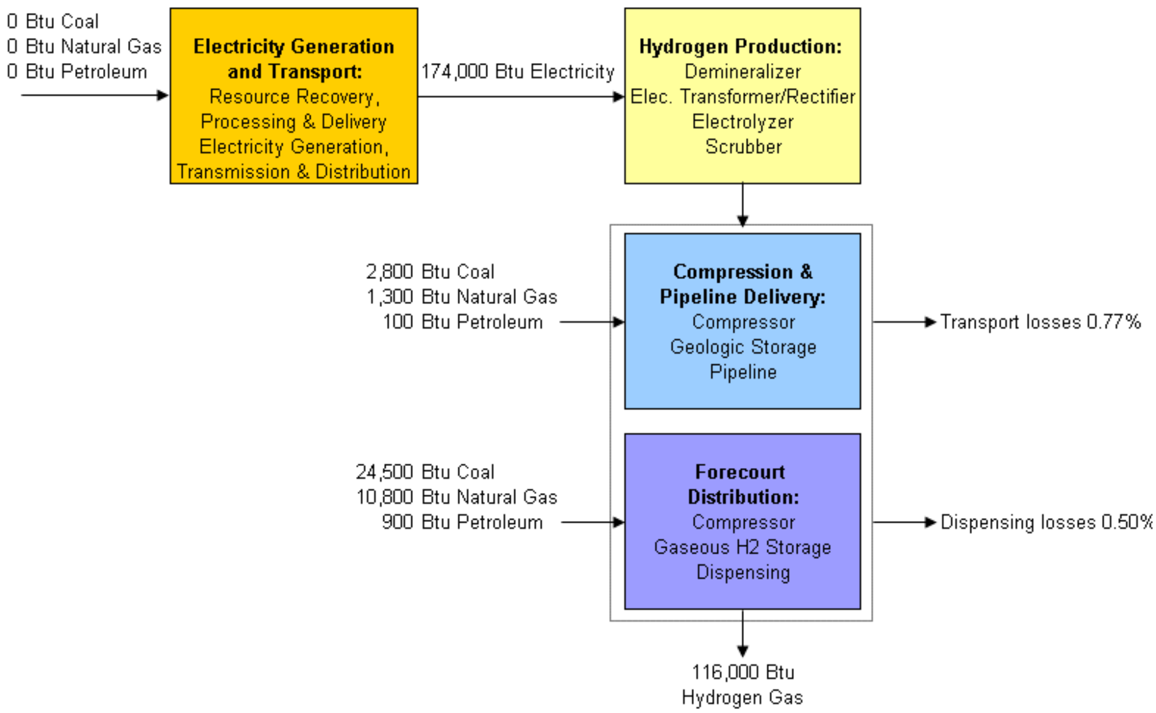


Figure 6.9.6. WTW energy inputs to deliver 116,000 Btu hydrogen to a vehicle using the central wind electricity—pipeline delivery pathway

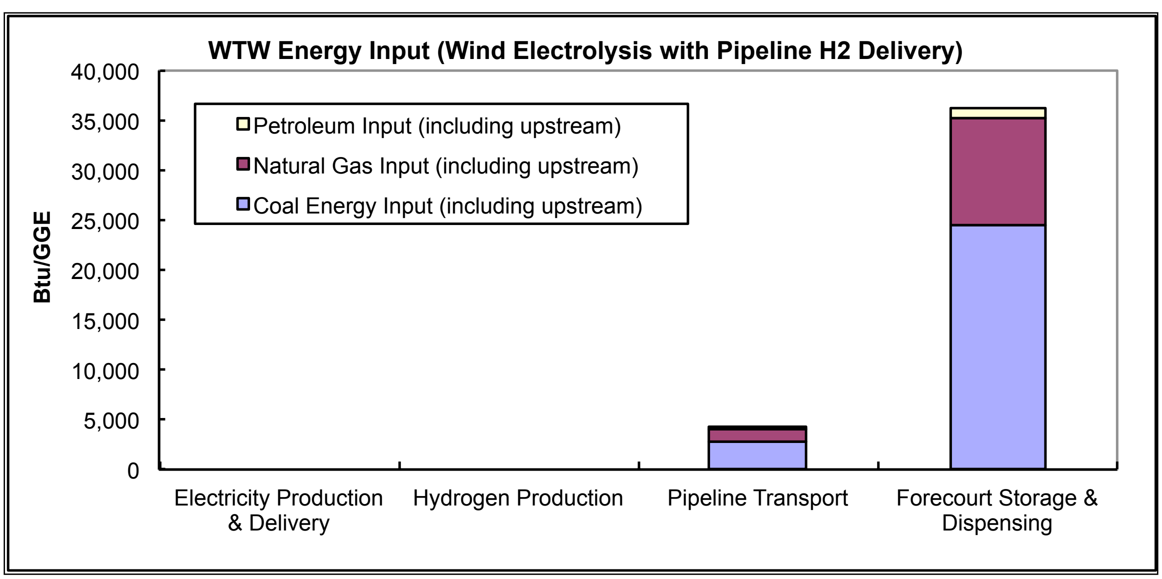


Figure 6.9.7. WTW petroleum, natural gas, and coal inputs to deliver 116,000 Btu hydrogen using the central wind electricity—pipeline delivery pathway

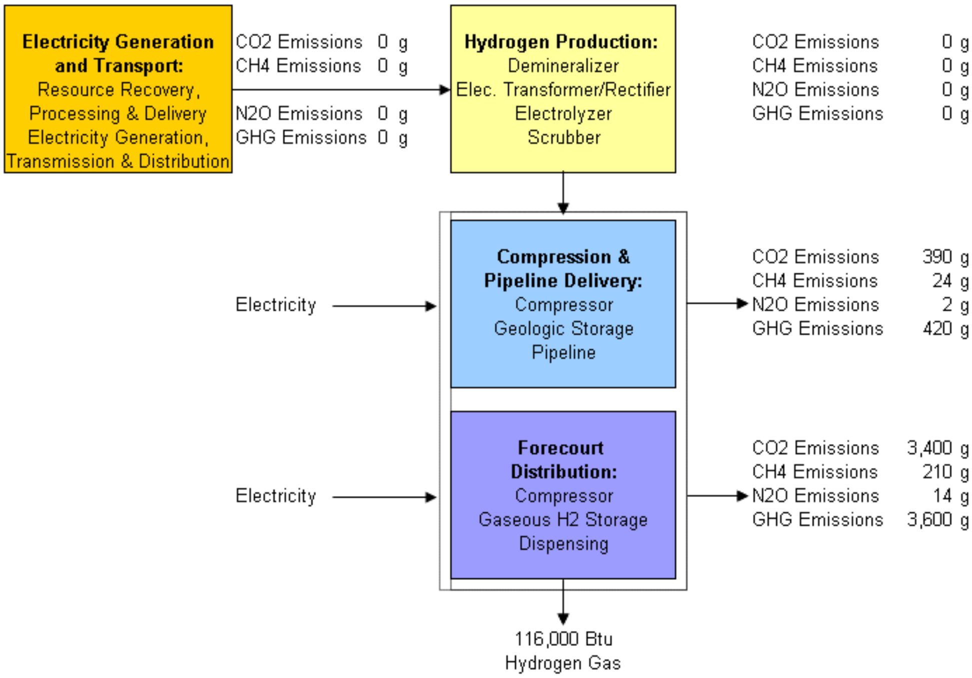


Figure 6.9.8. WTW emissions resulting from delivery of 116,000 Btu hydrogen using the central wind electricity—pipeline delivery pathway

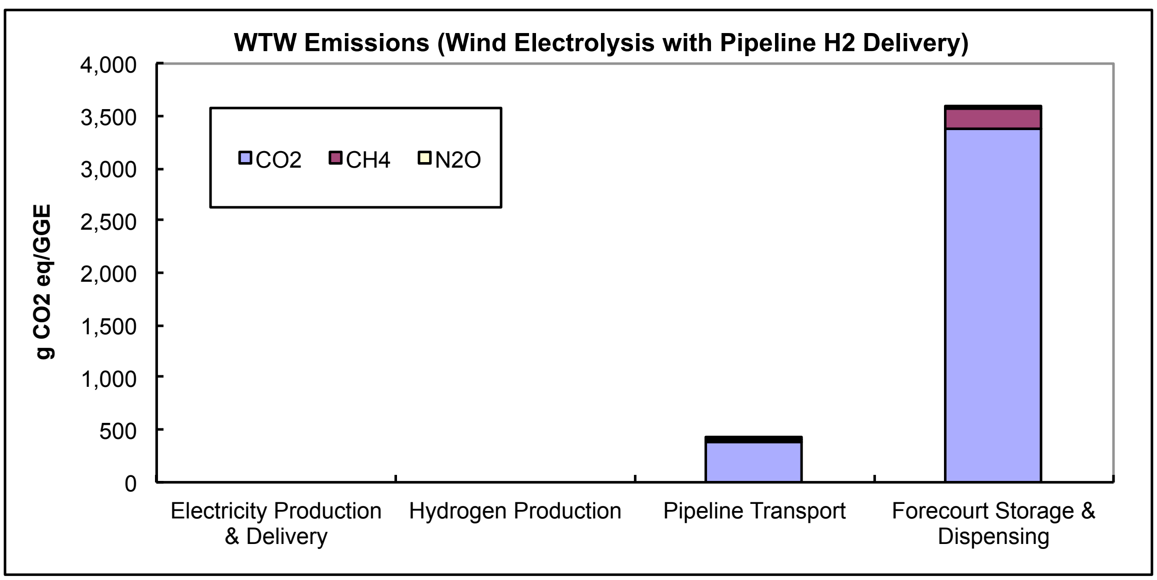


Figure 6.9.9. WTW CO_2, CH_4, and N_2O emissions resulting from delivery of 116,000 Btu hydrogen to a vehicle using the central wind electricity—pipeline delivery pathway

Figures 6.9.10 and 6.9.11 show the energy inputs and emissions, respectively, for the vehicle cycles in addition to those for the fuel production cycle. The fuel production cycle values are consistent with those reported in Figures 6.9.7 and 6.9.9.

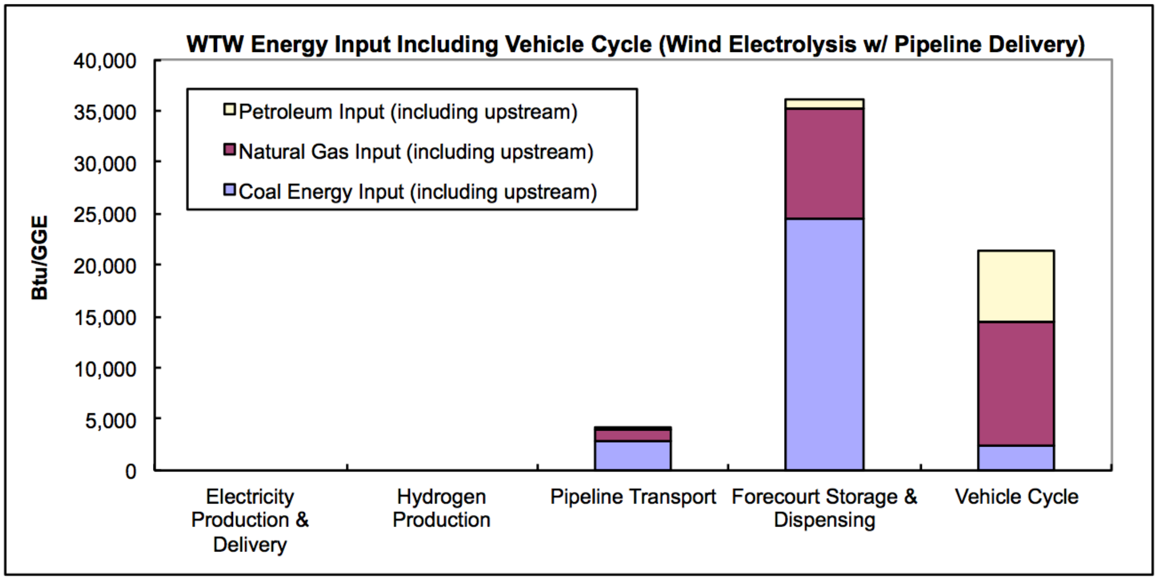


Figure 6.9.10. Life-cycle petroleum, natural gas, and coal inputs for both the central wind electricity—pipeline delivery pathway and the vehicle cycle

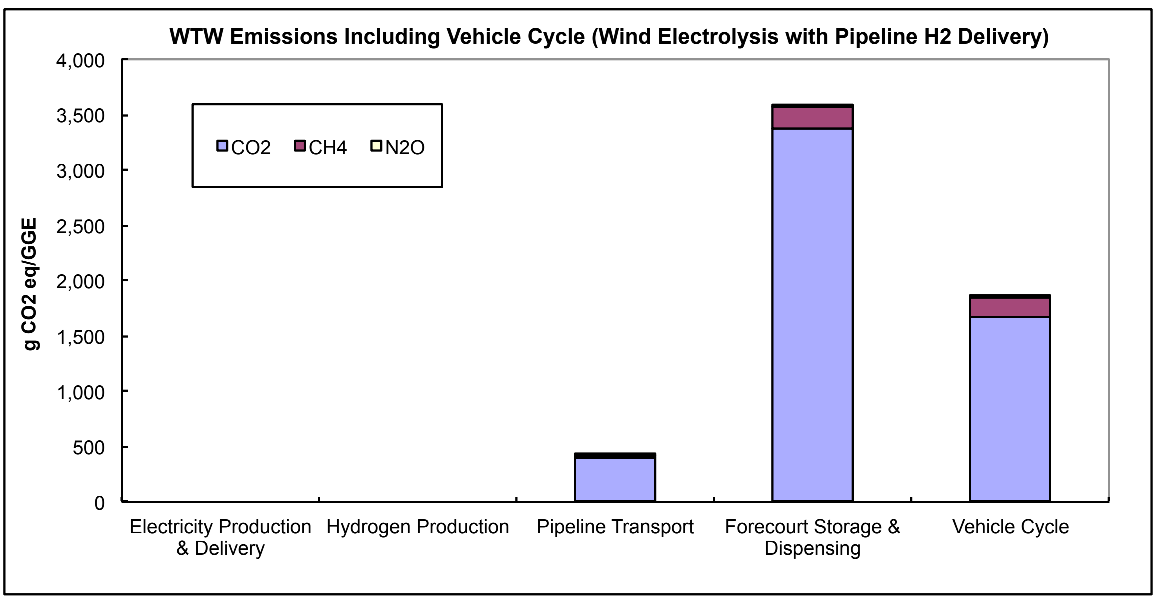


Figure 6.9.11. Life-cycle CO_2, CH_4, and N_2O emissions for both the central wind electricity—pipeline delivery pathway and the vehicle cycle

6.9.3 Sensitivities

6.9.3.1 Production Sensitivities

Several sensitivities were run on the production portion of the central wind electricity—pipeline delivery pathway. These sensitivities focused primarily on cost factors. Figure 6.9.12 shows the effects of several production parameters on the pathway's levelized cost.

Note that the electricity cost is the sensitivity with the greatest potential effect on the levelized cost. The baseline electricity cost is the industrial electricity price and may be too low for wind electricity.

Effects of the sensitivities on WTW energy use and emissions are not shown because, due to the assumption that the electricity feedstock is wind-generated, the production fossil energy use and emissions are zero at all efficiencies.

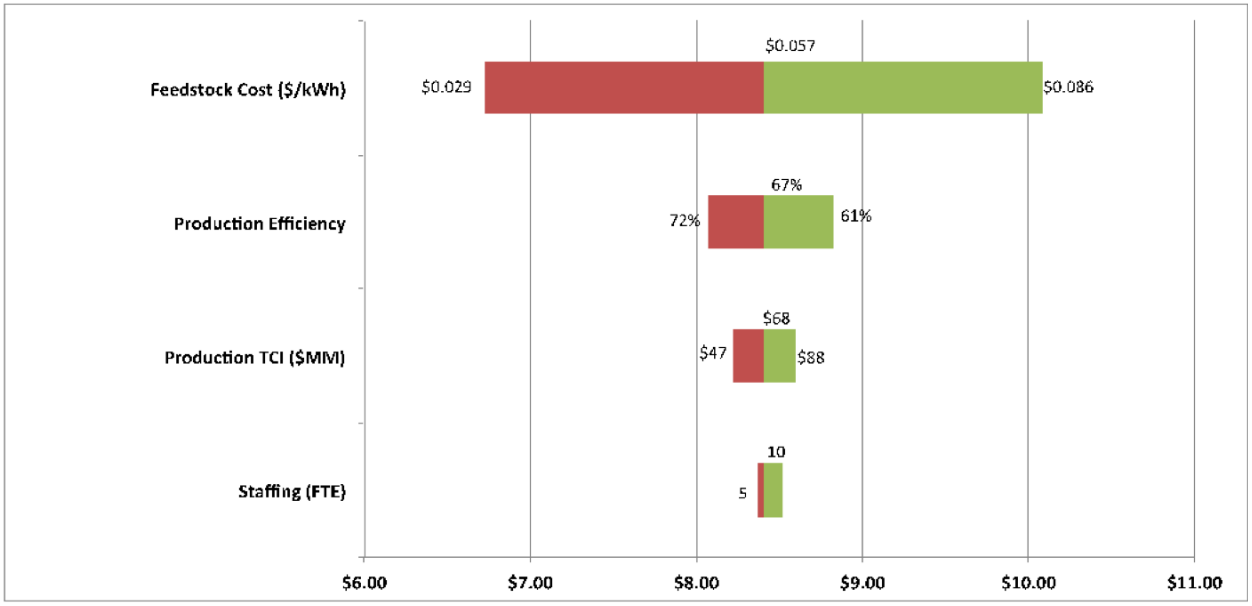


Figure 6.9.12. Production sensitivities for the central wind electricity—pipeline delivery pathway

6.9.3.2 Delivery Sensitivities

Pipeline delivery sensitivities are reported for the biomass production scenario in Section 6.4.3. The effects of the sensitivities will be the same for all pipeline delivery scenarios.

6.10 Central Coal with Carbon Capture and Storage—Pipeline Delivery

Figure 6.10.1 shows the major inputs, assumptions, and outputs for each of the subsystems considered in the well-to-tank analysis, including feedstock supply and hydrogen dispensing. (See Appendix J for more details on this pathway.)

The WTP and WTW cost of hydrogen, energy use, and emissions for the central coal with CCS—pipeline delivery pathway are summarized in Table 6.10.1.

6.10.1 Cost Breakdown

Figure 6.10.2 shows the feedstock and energy price inputs and the resulting hydrogen production, delivery, and distribution costs for the central coal with CCS—pipeline delivery pathway. The financial assumptions used in this analysis are detailed in Section 5.

Figure 6.10.3 shows the contributions of hydrogen production, delivery, and losses to the levelized cost of hydrogen shown in Figure 6.10.2.

Figure 6.10.4 and Table 6.10.2 show the breakdown of levelized costs for the central coal with CCS—pipeline delivery pathway.

Inputs		
Coal Input (including upstream)	116,400	Btu / 116000Btu to Pump
Natural Gas Input (including upstream)	200	Btu / 116000Btu to Pump
Petroleum Input (including upstream)	700	Btu / 116000Btu to Pump
Coal consumption	7.8	kg (dry) / kg H2 produced
Natural gas consumption	0.0	MMBtu/kg H2 produced
Electricity consumption	1.72	kWh / kg H2
Process Water Consumption	2.91	gal / kg H2 produced
Cooling Water Consumption	0.00	gal / kg H2 produced
Total Capital Investment	$691,378,000	2005$
Coal Input (including upstream)	99,400	Btu / 116000Btu to Pump
Natural Gas Input (including upstream)	7,200	Btu / 116000Btu to Pump
Petroleum Input (including upstream)	1,100	Btu / 116000Btu to Pump
Electricity consumption for compressor	0.56	kWh / kg H2 dispensed
Electricity consumption for geo storage	0.01	kWh / kg H2 dispensed
Total electricity consumption	0.57	kWh / kg H2 dispensed
Total Capital Investment	$404,341,000	2007$
Coal Input (including upstream)	3,700	Btu / 116000Btu to Pump
Natural Gas Input (including upstream)	1,300	Btu / 116000Btu to Pump
Petroleum Input (including upstream)	100	Btu / 116000Btu to Pump
Electricity consumption	4.4	kWh / kg H2
Total Capital Investment per Station	$2,629,000	2007$ / station
Total Capital Investment	$320,679,000	2007$ / all stations
Inlet pressure of hydrogen at stations	300	psi
Coal Input (including upstream)	24,400	Btu / 116000Btu to Pump
Natural Gas Input (including upstream)	10,800	Btu / 116000Btu to Pump
Petroleum Input (including upstream)	900	Btu / 116000Btu to Pump
Vehicle Mass	3,020	lb
Fuel cell size	70	kW
Size of hybridization battery	30	kW
Coal Input (including upstream)	2,300	Btu / gge fuel consumed
Natural Gas Input (including upstream)	12,100	Btu / gge fuel consumed
Petroleum Input (including upstream)	6,900	Btu / gge fuel consumed

Assumptions		
Coal Production & Delivery		
Energy Recovery	99.3%	
Average distance from coal mine to H2 prod.	65	miles
Hydrogen Production & Carbon Capture and Sequestration (CCS)		
Central plant design capacity	307,700	kg / day
Capacity factor	90%	
Number of production facilities necessary	0.44	
Process energy efficiency	56.8%	
Electricity Mix	US Mix	
After-tax IRR	10%	
Assumed Plant Life	40	
CO2 Captured for Sequestration	90%	
CO2 Captured for Sequestration	4,925,000	kg CO2 / day
Pipelines for Delivery		
City Population	1,247,000	people
Hydrogen Vehicle Penetration	15%	
City hydrogen use	121,100	kg / day
Distance from City to Production Facility	62	miles
Geologic storage capacity	1,325,000	kg H2
Number of trunk pipelines	3	
Service-line length	1.5	miles / line
Number of service lines	122	
Hydrogen losses	0.76%	
Forecourt Dispensing		
Average Dispensing Rate per Station	1,000	kg/day
Number of Dispensing Stations	122	
Number of Compression Steps	5	
Usable Low Pressure Storage per Station	370	kg H2
Usable Cascade Storage per Station	130	kg H2
Site storage	42%	% of design capacity
# of 2-hose Dispensers per Station	2	
Hydrogen Losses	0.50%	
Vehicle		
Fuel Economy	48.0	mi / gge
Vehicle Miles Traveled	15,000	mi / yr
Vehicle Lifetime	160,000	mi
Purchase Year	2015	
Vehicle Purchase Cost	$33,700	2007$
Fuel Cell System Cost	$4,500	2007$
Hydrogen Storage System Cost	$2,400	2007$
Tax Credit	$0	2007$

Outputs		
Coal price at H2 production	$34	2007 $ / ton
Coal Share of Levelized Cost	$0.30	2007$ / kg H2 dispensed
WTG CO2 Emissions	110	g CO2 eq./ 116000 Btu
WTG CH4 Emissions	430	g CO2 eq./ 116000 Btu
WTG N2O Emissions	1	g CO2 eq./ 116000 Btu
WTG GHG Emissions	540	g CO2 eq./ 116000 Btu
Hydrogen Output Pressure	300	psi
Hydrogen Outlet Quality	99.9%	
Total capital investment	$2,500	2005$ / daily kg H2 (effective capacity)
Levelized Cost of Capital	$1.29	2005$ / kg H2 dispensed
Fixed O&M Costs	$0.30	2005$ / kg H2 dispensed
Variable O&M Costs	$0.18	2005$ / kg H2 dispensed
Total Levelized Cost	$2.06	2005$ / kg H2 dispensed
Production CO2 Emissions	4,510	g CO2 eq./ 116000 Btu
Production CH4 Emissions	440	g CO2 eq./ 116000 Btu
ProductionN2O Emissions	9	g CO2 eq./ 116000 Btu
Production GHG Emissions	4,960	g CO2 eq./ 116000 Btu
Total capital investment	$3,340	2007$ / daily kg dispensed
Levelized Cost of Capital	$1.71	2007$ / kg H2 dispensed
Energy & Fuel	$0.04	2007$ / kg H2 dispensed
Other O&M Costs	$0.40	2007$ / kg H2 dispensed
Levelized Cost of Delivery	$2.15	2007$ / kg H2 dispensed
Delivery CO2 Emissions	390	g CO2 eq./ 116000 Btu
Delivery CH4 Emissions	24	g CO2 eq./ 116000 Btu
Delivery N2O Emissions	2	g CO2 eq./ 116000 Btu
Delivery GHG Emissions	420	g CO2 eq./ 116000 Btu
Hydrogen outlet pressure	12,700	psi
Basis -- Hydrogen Quantity	116,000	Btu (116,000 Btu/gal non-oxygenated conventional unleaded gasoline)
Total capital investment	$2,650	2007$ / daily kg H2 (effective capacity)
Levelized Cost of Capital	$1.08	2007$ / kg H2 dispensed
Energy & Fuel	$0.41	2007$ / kg H2 dispensed
Other O&M Costs	$0.43	2007$ / kg H2 dispensed
Levelized Cost of Dispensing	$1.93	2007$ / kg H2 dispensed
CSD CO2 Emissions	3,370	g CO2 eq./ 116000 Btu
CSD CH4 Emissions	210	g CO2 eq./ 116000 Btu
CSD N2O Emissions	14	g CO2 eq./ 116000 Btu
CSD GHG Emissions	3,590	g CO2 eq./ 116000 Btu
Cost Per Mile	$0.69	2007$ / mi
Fuel Share	$0.13	2007$ / mi
Maintenance, Tires, Repairs	$0.07	2007$ / mi
Insurance & Registration	$0.12	2007$ / mi
Depreciation	$0.27	2007$ / mi
Financing	$0.10	2007$ / mi
Vehicle Cycle CO2 Emissions	1,670	g CO2 eq / gge fuel consumed
Vehicle Cycle CH4 Emissions	170	g CO2 eq / gge fuel consumed
Vehicle Cycle N2O Emissions	6	g CO2 eq / gge fuel consumed
Vehicle Cycle GHG Emissions	1,850	g CO2 eq / gge fuel consumed

Figure 6.10.1. Summary of major inputs, assumptions, and outputs by subsystem for the central coal with CCS—pipeline delivery pathway

Table 6.10.1. WTP and WTW Results for the Central Coal with CCS—Pipeline Delivery Pathway

	WTP		WTW	
Coal input (including upstream)[a]	128,000	Btu/116,000 Btu	5,100	Btu/mi
Natural gas input (including upstream)[a]	19,500	Btu/116,000 Btu	410	Btu/mi
Petroleum input (including upstream)[a]	2,800	Btu/116,000 Btu	60	Btu/mi
Fossil energy input (including upstream)[a]	150,300	Btu/116,000 Btu	5,560	Btu/mi
WTP CO_2 emissions[b]	8,400	g/116,000 Btu	180	g/mi
WTP CH_4 emissions	40	g/116,000 Btu	1	g/mi
WTP N_2O emissions	0	g/116,000 Btu	0	g/mi
WTP GHG emissions	9,500	g CO_2-eq./ 116,000 Btu	200	g/mi
	Cost per kg		**Cost per mile**	
Levelized cost of hydrogen	$6.14	2007 $/kg	$0.13	2007 $/mi

[a] Coal, natural gas, and petroleum inputs include those used directly in the hydrogen production and delivery pathway as feedstocks and fuels; those used to produce electricity and other materials used in the pathway; and those used upstream of the pathway to recover, refine, and deliver the feedstock.
[b] Includes the carbon content of CO, CH_4, and volatile organic compound emissions that decompose in the atmosphere to CO_2.

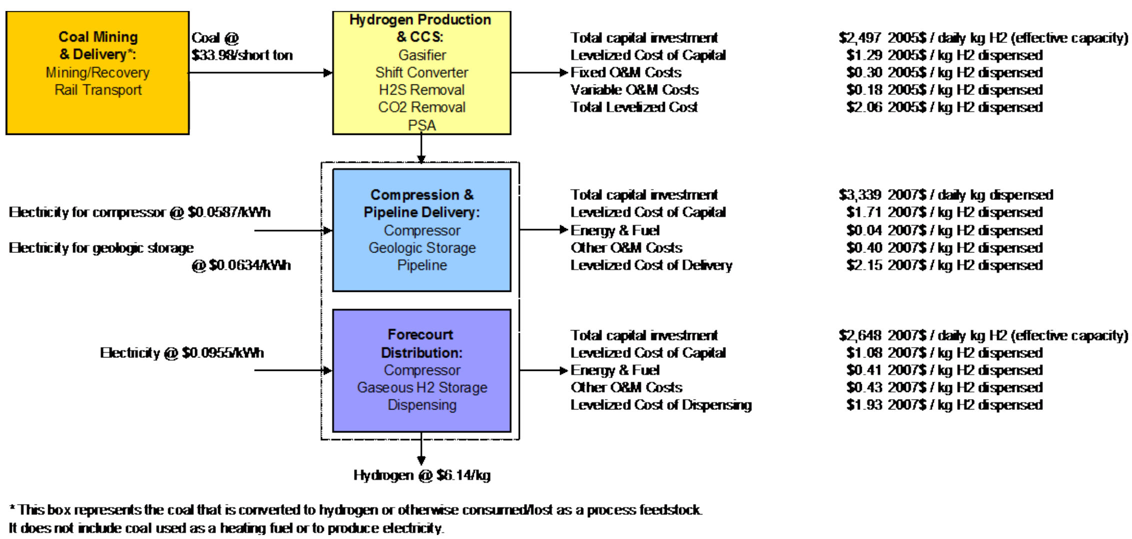


Figure 6.10.2. Cost analysis inputs and high-level results for the central coal with CCS—pipeline delivery pathway

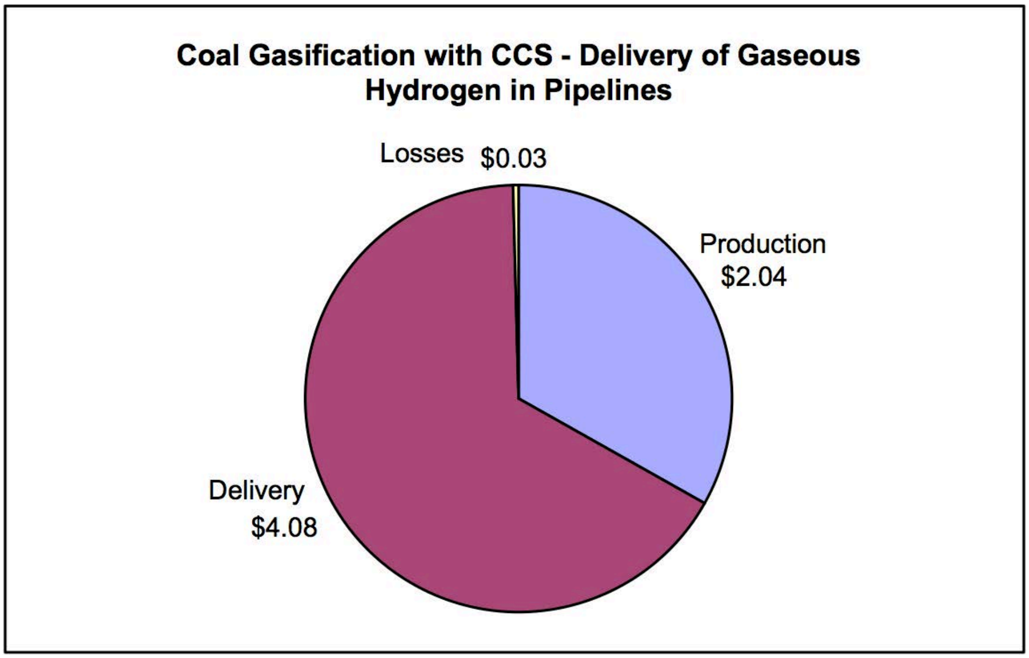


Figure 6.10.3. Contribution of hydrogen production, delivery, and losses to the levelized cost of hydrogen for the central coal with CCS—pipeline delivery pathway

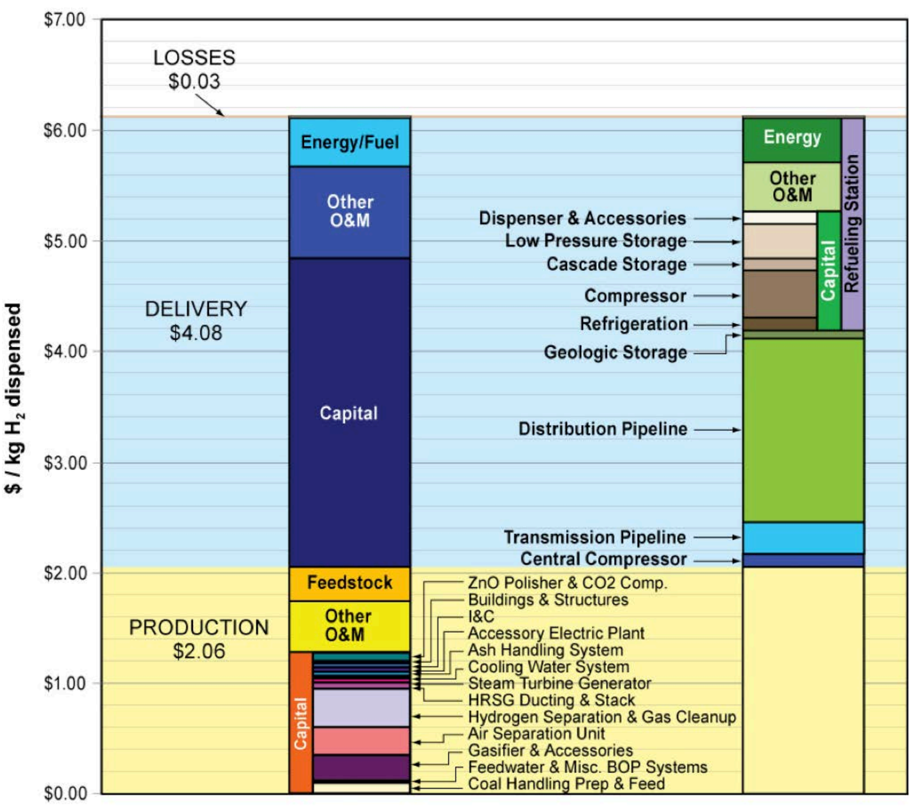


Figure 6.10.4. Breakdown of levelized costs for the central coal with CCS—pipeline delivery pathway

Table 6.10.2. Contribution of Production and Delivery Processes to Levelized Hydrogen Cost from the Central Coal with CCS—Pipeline Delivery Pathway

Cost Component	Capital	Other O&M	Feedstock	Energy/ Fuel	Total
Production	$1.27	$0.48	$0.29		$2.04
Coal handling prep and feed	$0.10				
Feedwater and misc. BOP systems	$0.02				
Gasifier and accessories	$0.23				
Air separation unit	$0.25				
Hydrogen separation and gas cleanup	$0.34				
Heat-recovery steam generator ducting and stack	$0.06				
Steam turbine generator	$0.04				
Cooling water system	$0.02				
Ash handling system	$0.03				
Accessory electric plant	$0.04				
Instrumentation and control	$0.03				
Buildings and structures	$0.02				
ZnO polisher and CO_2 comp.	$0.08				
Delivery	$2.80	$0.83		$0.45	$4.08
Central compressor					$0.12
Transmission pipeline					$0.30
Distribution pipeline					$1.64
Geologic storage					$0.09
Gaseous refueling station	$1.08	$0.43		$0.41	$1.93
Refrigeration	$0.12				
Compressor	$0.41				
Cascade storage	$0.12				
Low pressure storage	$0.30				
Dispenser and accessories	$0.13				
Losses					$0.03
Total	**$4.07**	**$1.31**	**$0.29**	**$0.45**	**$6.14**

6.10.2 Energy Use and Emissions Breakdown

Figures 6.10.5 and 6.10.6 show the WTW energy inputs and losses for the central coal with CCS—pipeline delivery pathway. The WTW energy inputs to coal mining and delivery include those necessary to produce 116,000 Btu of coal for gasification. Additional WTW energy inputs for coal needed for heating, electricity, and process inefficiency are reported as inputs to hydrogen production.

Figures 6.10.7 and 6.10.8 show the WTW emissions resulting from the delivery of 116,000 Btu hydrogen to a vehicle fuel tank using the central coal with CCS—pipeline delivery pathway.

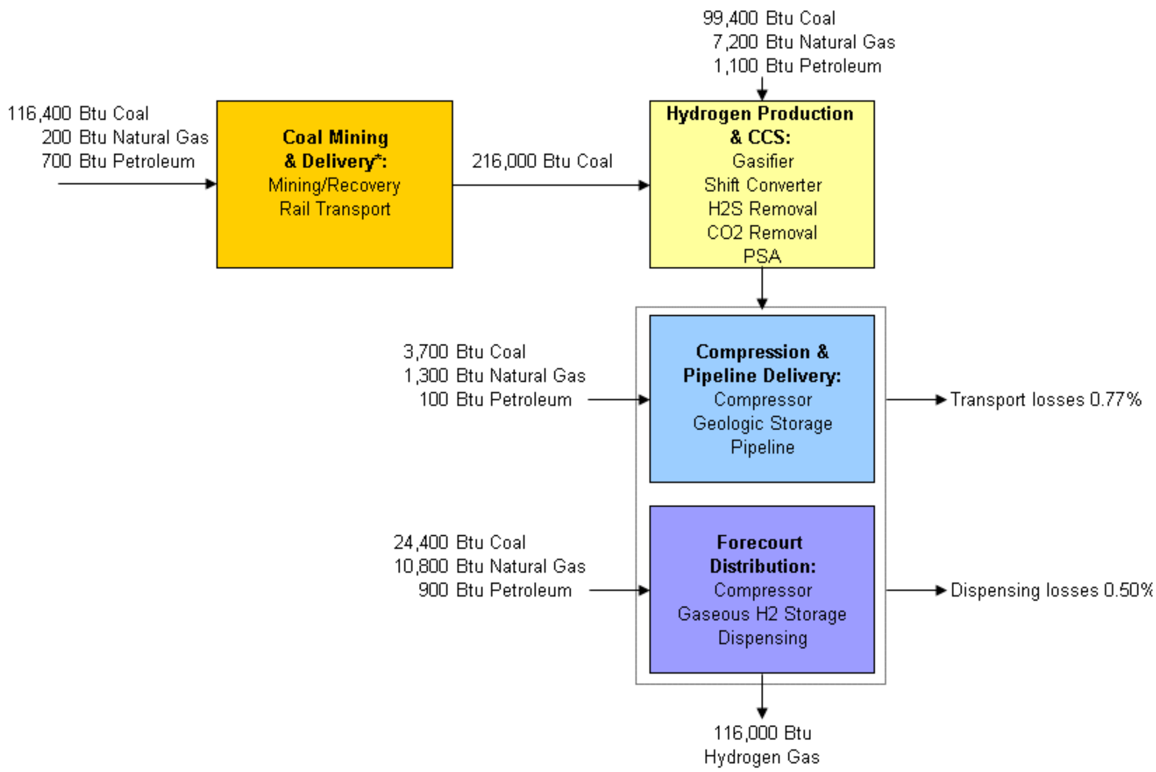


Figure 6.10.5. WTW energy inputs to deliver 116,000 Btu hydrogen to a vehicle using the central coal with CCS—pipeline delivery pathway

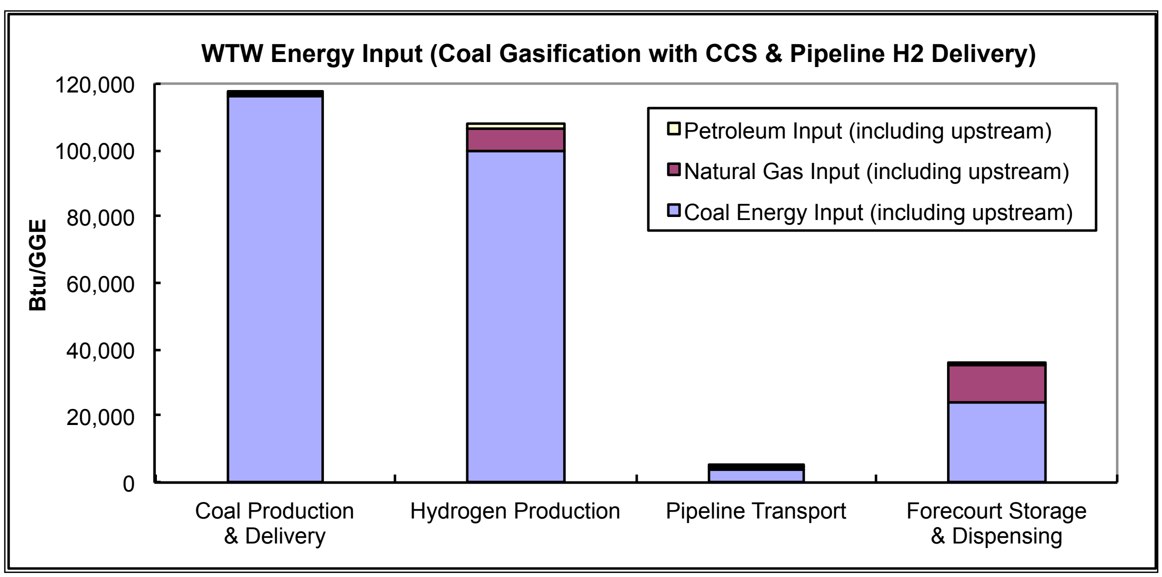


Figure 6.10.6. WTW petroleum, natural gas, and coal inputs to deliver 116,000 Btu hydrogen using the central coal with CCS—pipeline delivery pathway

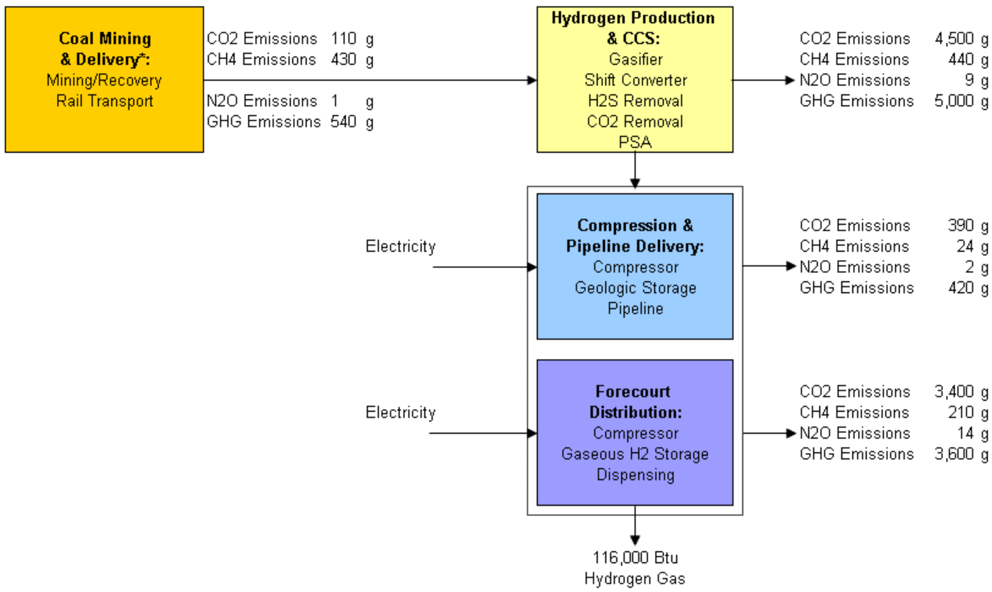


Figure 6.10.7. WTW emissions resulting from delivery of 116,000 Btu hydrogen using the central coal with CCS—pipeline delivery pathway

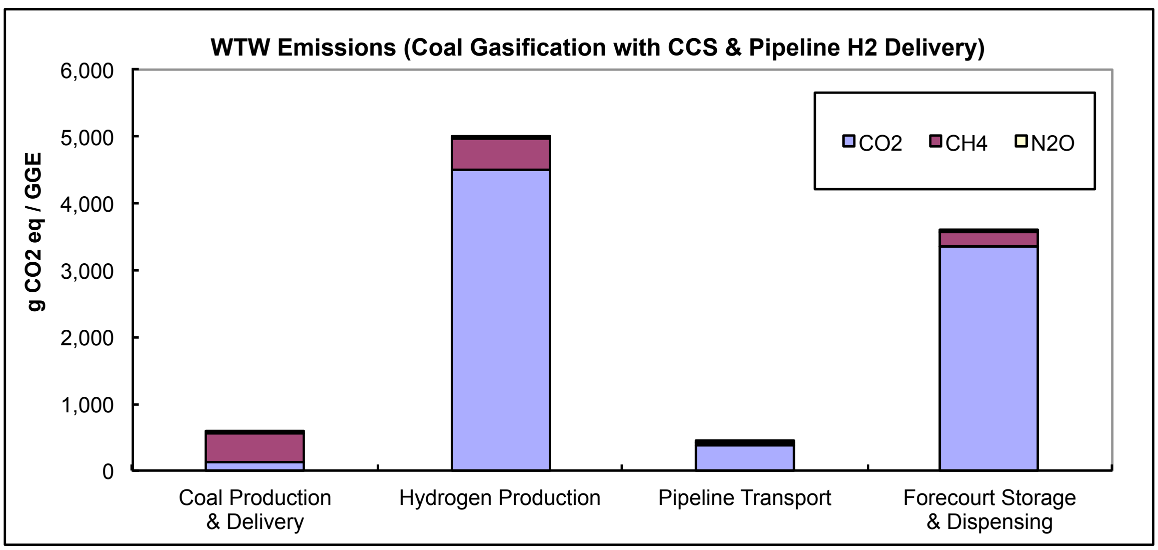


Figure 6.10.8. WTW CO_2, CH_4, and N_2O emissions resulting from delivery of 116,000 Btu hydrogen to a vehicle using the central coal with CCS—pipeline delivery pathway

6.10.3 Sensitivities

6.10.3.1 Production Sensitivities

Several sensitivities were run on the production portion of the central coal with CCS—pipeline delivery pathway. These sensitivities focused primarily on cost factors; however, several sensitivities also affect energy use and emissions. Figure 6.10.9 shows the effects of several production parameters on the pathway's levelized cost, and Table 6.10.3 shows the effect of varying production efficiency on the WTW results.

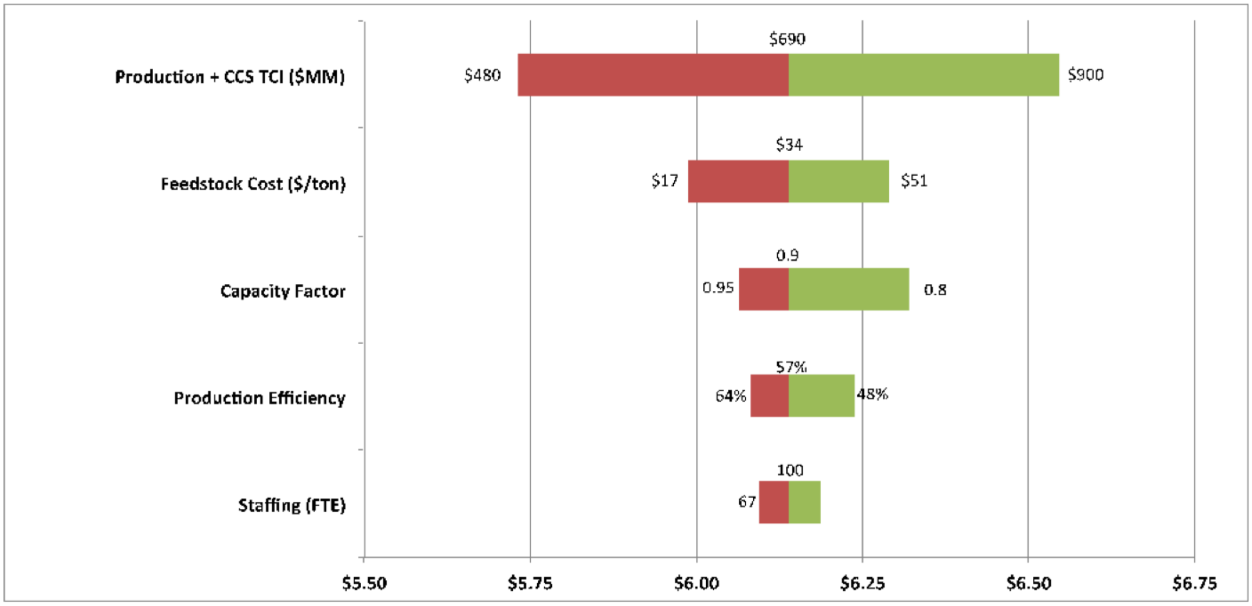


Figure 6.10.9. Production sensitivities for the central coal with CCS—pipeline delivery pathway

Table 6.10.3. The Effects of Production Energy Efficiency on Primary Energy Use and Emissions from the Central Coal with CCS—Pipeline Delivery Pathway

	48% Efficiency	57% Efficiency	64% Efficiency
WTW GHG emissions (g/mile)	220	200	190
WTW fossil energy (Btu/mile)	6,500	5,600	5,100
WTW petroleum energy (Btu/mile)	70	60	60
WTW total energy (Btu/mile)	6,700	5,800	5,300

The assumed electrical grid mix also affects the energy use and emissions because grid electricity is needed for delivery and distribution. Electricity for the production facility is generated internally and can be considered a parasitic loss. Table 6.10.4 shows the differences in energy use and GHG emissions between the U.S. average grid mix (which was used for all other sensitivities) and a hypothetical green grid mix that is 100% renewable energy (solar and wind).

Table 6.10.4. The Effects of Grid Mix on Use of Primary Energy and Emissions from the Central Coal with CCS—Pipeline Delivery Pathway

	U.S. Average Grid Mix (48 mpgge)	U.S. Average Grid Mix (68 mpgge)	"Green" Grid Mix (48 mpgge)
WTW GHG emissions (g/mile)	200	140	70
WTW fossil energy (Btu/mile)	5,600	3,900	4,200
WTW petroleum energy (Btu/mile)	60	40	20
WTW total energy (Btu/mile)	5,800	4,100	4,900

6.10.3.2 Delivery Sensitivities

Pipeline delivery sensitivities are reported for the biomass production scenario in Section 6.4.3. The effects of the sensitivities will be the same for all pipeline delivery scenarios.

7 Pathway Results Comparison

In this section, results from the individual pathways are compared. Each pathway's current estimated levelized hydrogen cost, WTW petroleum use, and WTW GHG emissions are shown in comparison to the other pathways. Key parameters are shown in Table 7.0.1.

Table 7.0.1. Key Analysis Parameters

Parameter	Value and Section with Description
Technology status	Current technology (Section 1.2). Technology is described in Sections 2.0 and 3.0, and parameters are shown in the appendices.
City size	553 mi^2 and 1,247,000 people (equivalent to Indianapolis, IN) (Section 1.2)
Market penetration	15% of hydrogen vehicles (Section 1.2)
Fuel cell vehicle fuel economy	Base case of 48 mpgge analyzed, with a sensitivity case of 68 mpgge
Analysis boundaries	Includes feedstock recovery, transportation, and storage; fuel production, transportation, storage, and distribution; and vehicle operation (Section 1.3)
Monetary value	2007 dollars—except coal with CCS production option, which is in 2005 dollars (Section 5.0)
Equity financing	100% (Section 5.0)
After tax internal rate of return	10% (Section 5.0)
Effective total tax rate	38.9%
Carbon capture efficiency in coal with CCS case	90% (Section 6.10)

Figure 7.0.1 shows the levelized cost of hydrogen for all 10 hydrogen pathways with the parameters described in Section 6.0, based on an assumed FCEV fuel economy of 48 mpgge. (More details on the 10 hydrogen pathways analyzed can be found in Appendices A–J.) Some of the most important pathway parameters are shown in Table 7.0.1, and additional parameters are in Sections 1–6. Sensitivities on parameters in each hydrogen pathway are reported in Section 6. The base case analysis of the hydrogen pathways assumes a 48 mpgge fuel economy. A sensitivity analysis using a fuel economy of 68 mpgge was also conducted. Figure 7.0.2 shows the levelized hydrogen cost results for all 10 pathways for both the 48 mpgge and 68 mpgge fuel economies.

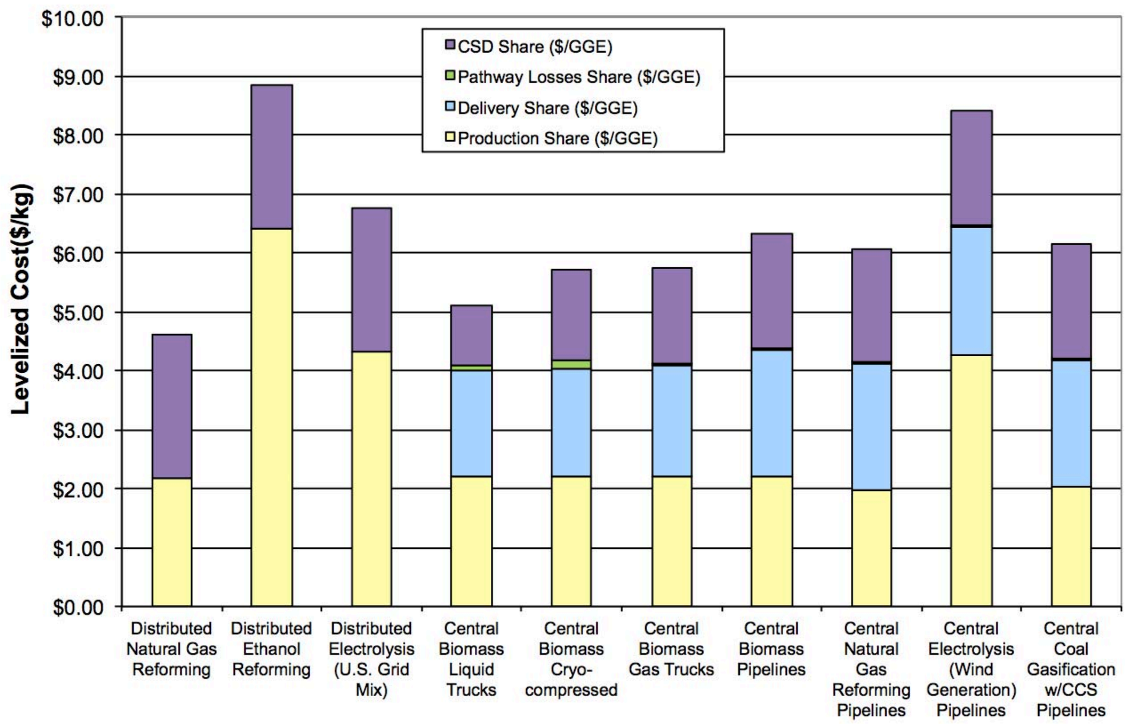


Figure 7.0.1. Levelized cost of hydrogen for all pathways, based on 48 mpgge fuel economy

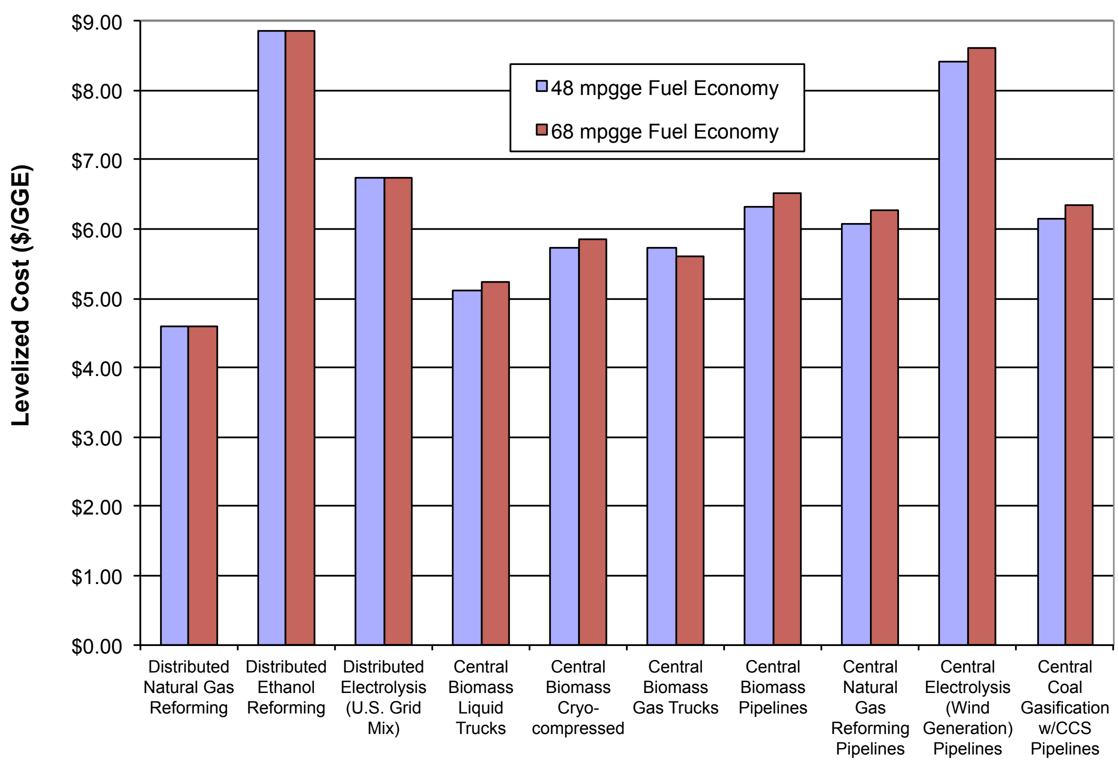


Figure 7.0.2. Levelized cost of hydrogen for all pathways for both 48 and 68 mpgge fuel economy

The levelized cost of hydrogen is calculated directly in the H2A model for the distributed hydrogen production cases and includes both production and CSD costs. For central production cases, the levelized cost of hydrogen is the sum of levelized production cost, levelized delivery cost, the cost of excess production due to losses during delivery, and the cost of CSD.

DOE's Fuel Cells Technologies Office has set a hydrogen threshold cost of \$2.00–\$4.00/gge delivered at the pump (Ruth and Joseck 2011). The comparison in Figure 7.0.1 shows that the hydrogen cost target is close to being met by distributed natural gas reforming. Niche opportunities with low-cost feed or capital costs, different financing options, or higher capacities may help other technologies meet the target. Likewise, delivery costs may be reduced for pipeline delivery if the fuel cell vehicle penetration were greater than 15%, giving those technologies a greater opportunity to meet the target. Otherwise, additional research is necessary to meet targets. Other analysts have used different parameters and reached slightly different levelized costs of hydrogen in their studies. Fletcher and Callaghan (2006) is one example of an analysis that showed that the previous \$2.00–\$3.00/gge levelized cost target (Hydrogen, Fuel Cells and Infrastructure Technology Program 2007) had been met for the distributed natural gas reforming pathway. The primary differences between their analysis and this one are the cost-year dollars (they worked in 2005\$ and this analysis is in 2007\$) and a lower cost for CSD (they estimated \$0.88/kg, and the estimate in this study is \$2.43/kg).

Production costs range from 32% to 73% of the pathway levelized costs. Figure 7.0.3 shows a breakdown of those production costs into capital, feedstock, and other O&M costs. Most technologies are feedstock driven (i.e., feedstock costs make up the majority of the levelized cost); however, the biomass and coal technologies have relatively low feedstock costs and are evenly balanced and capital driven, respectively.

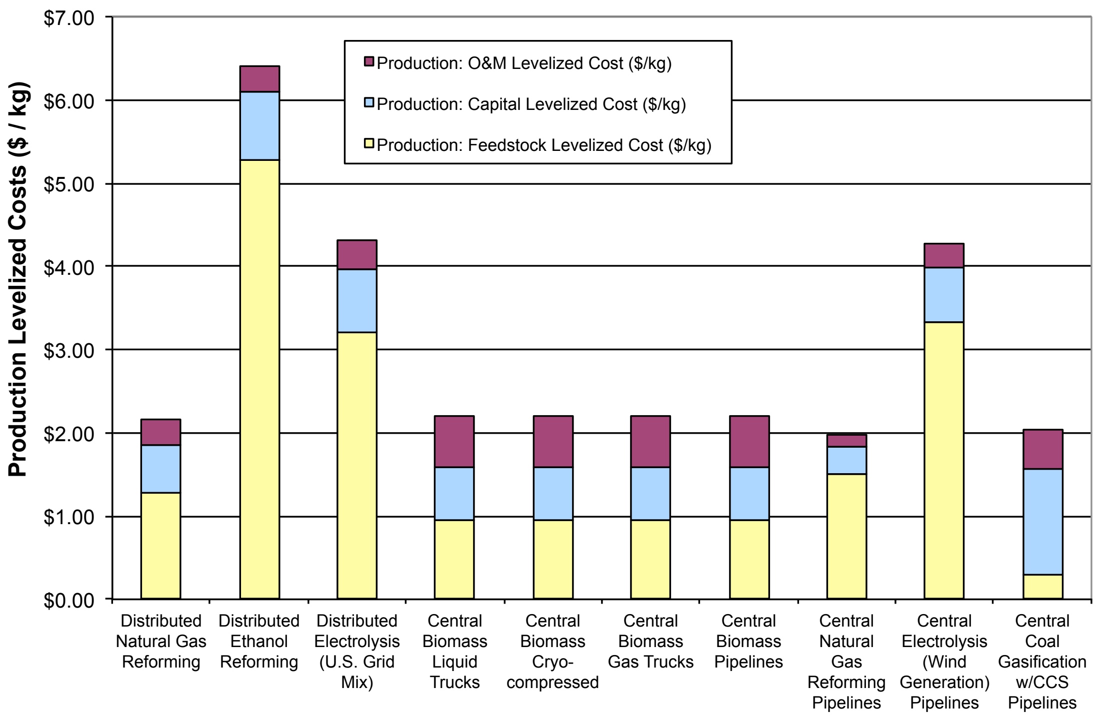


Figure 7.0.3. Production levelized costs for 10 pathways

Levelized cost is not the only cost of concern. Capital costs are also important because a capital investment with the expectation of a payback and profit is necessary for the technologies to be developed. Figure 7.0.4 shows the capital costs for each pathway normalized to a daily dispensing basis. They are also broken into production, delivery, and dispensing shares. The non-pipeline technologies (distributed production and other delivery technologies) require less capital per daily kg of hydrogen than the pipeline technologies do. That status indicates the benefit of distributed and flexible infrastructure at lower penetrations, such as the 15% penetration considered in this report. At higher penetrations, one can expect that the normalized delivery capital cost will drop for pipeline pathways due to economies of scale.

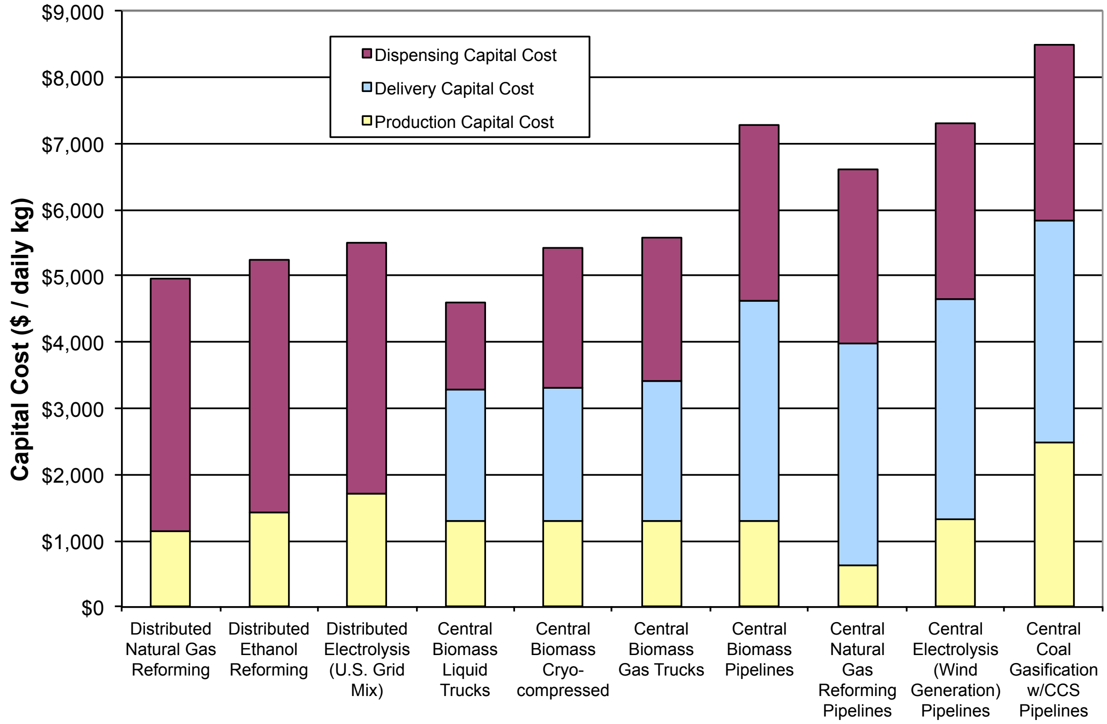


Figure 7.0.4. Normalized capital costs for 10 pathways

Figure 7.0.5 shows a comparison of direct energy use between pathways. Direct energy includes only the energy used directly by the pathway (i.e., feedstock, electricity, and fuel used to run the equipment). It differs from the WTW energy in that WTW energy includes upstream energy requirements as well as energy used directly by the pathway. For example, while electricity is reported as a pathway energy source, the primary energy sources used to generate the electricity (e.g., coal, natural gas) are included in the WTW calculations. As expected, the dominant pathway energy source is the one named in the title of each pathway.

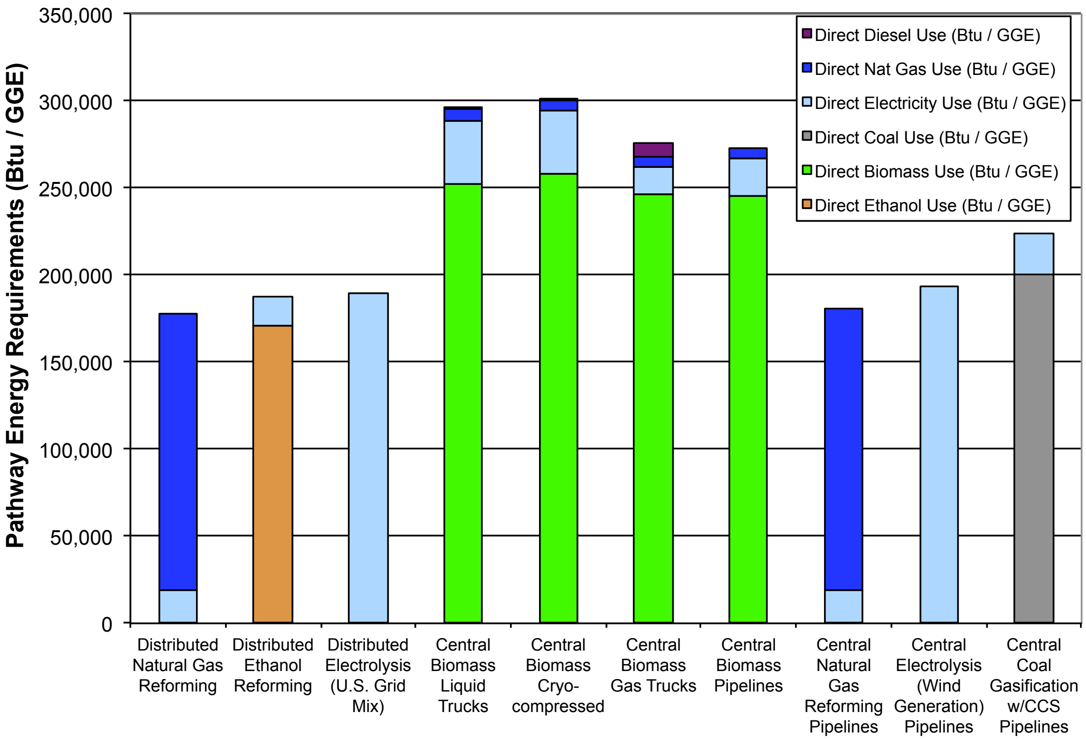


Figure 7.0.5. Pathway energy use for 10 pathways

The pathway efficiency can be considered the inverse of the energy use; Figure 7.0.6 shows those efficiencies. The yellow bars show the production efficiencies that are calculated as the lower heating value (LHV) of the hydrogen produced divided by the LHV of all the production inputs reported in Section 6.0. The blue bars show the pathway efficiencies that are calculated as the LHV of the hydrogen delivered divided by the LHV of all the pathway inputs, which are shown in Figure 7.0.5. The red bars show the WTP efficiencies that are calculated as the LHV of the hydrogen delivered divided by the LHV of all the primary energy inputs (coal, natural gas, crude oil, and biomass) that are used directly or indirectly by the pathway.

As an example, Figure 7.0.6 shows that the production efficiency of the distributed natural gas reforming pathway is 71% (i.e., 71% of all of the energy delivered to the hydrogen production plant is contained in the hydrogen product). Because the pathway includes both the production plant and CSD, the pathway efficiency must account for hydrogen lost and energy required for compression; thus, the pathway efficiency is somewhat lower at 65% for the distributed natural gas reforming pathway. Some additional energy is required to produce and deliver the natural gas and electricity to the facility, so the WTP efficiency is lower yet at 52% for the distributed natural gas reforming pathway.

The pathways with the highest efficiency are the natural gas and ethanol pathways, followed by electrolysis and coal, and those with the lowest efficiency are the biomass pathways. One of the primary reasons the pathway efficiency is lower than reported in 2009 is that the onboard storage pressure is 700 bar instead of 350 bar (as was used in 2009). The increased pressure requires additional electricity for compression and the WTP efficiency of electricity production is low.

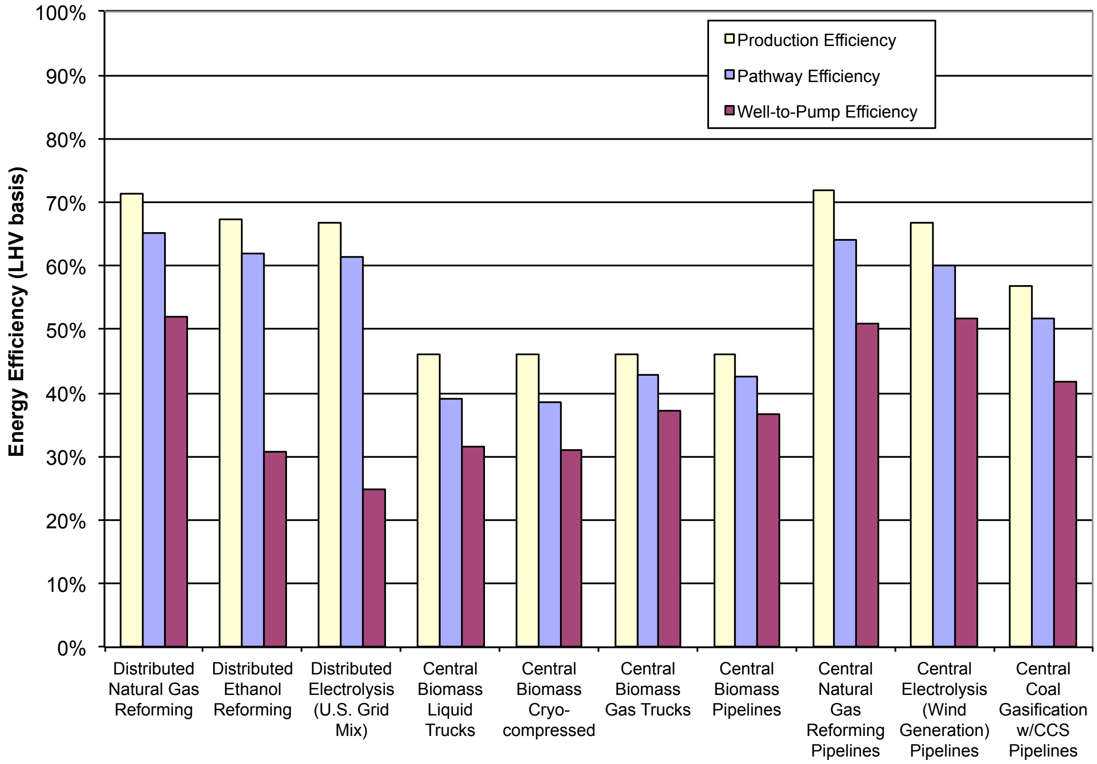


Figure 7.0.6. WTW, pathway, and production efficiencies for 10 hydrogen pathways

Figure 7.0.7 shows the WTW petroleum use for the 10 hydrogen pathways. As vehicle fuel economy has a direct impact on per-mile WTW energy use and emissions, petroleum use for both the 48 mpgge fuel economy base case and the 68 mpgge sensitivity case are shown. In the pathways with truck delivery (biomass—liquid trucks, biomass—cryo-compressed, and biomass—gas trucks), most of the petroleum is used for hydrogen delivery. In technologies where biomass is used as a feedstock (central biomass gasification and distributed ethanol reforming), petroleum is used for farming and for biomass delivery to either the hydrogen or ethanol facility. Petroleum is also required for grid electricity production (0.9% of the grid mix is electricity generated from residual oil), so technologies requiring large amounts of electricity also utilize large amounts of petroleum.

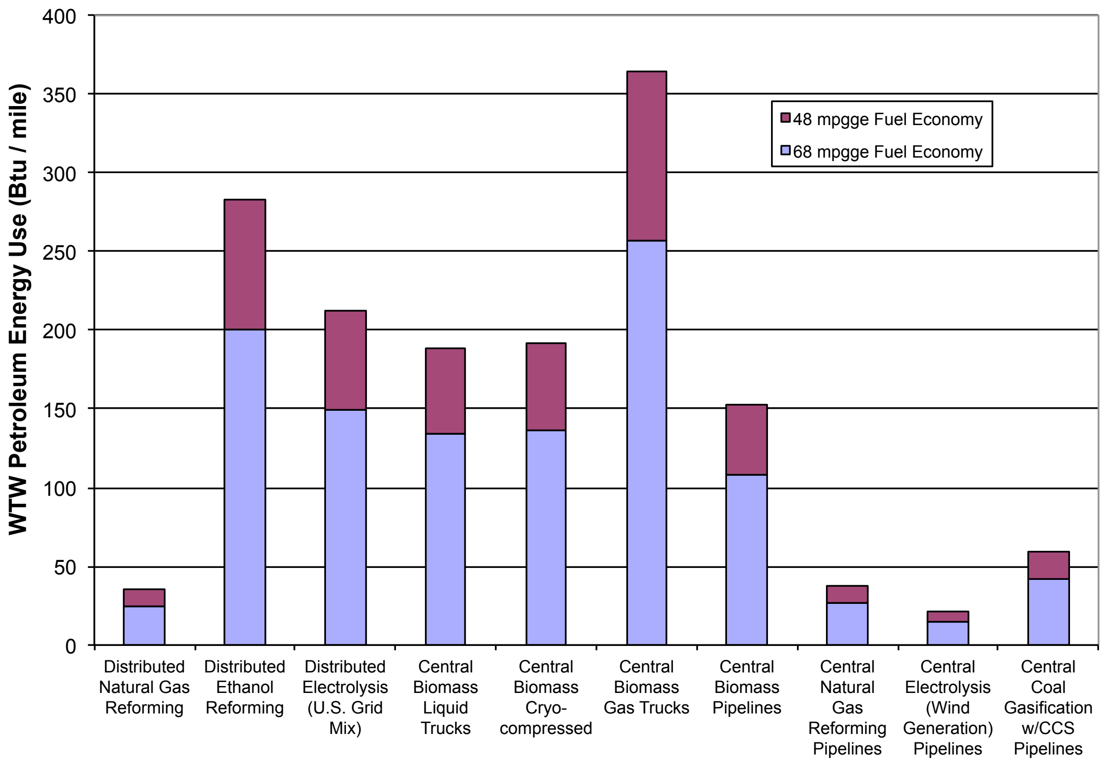


Figure 7.0.7. WTW petroleum energy use for 10 hydrogen pathways

Figure 7.0.8 shows the WTW natural gas use for the 10 hydrogen pathways, again showing the results for both the 48 mpgge and 68 mpgge cases. As expected, the pathways where natural gas is the primary energy source require the most natural gas. Natural gas is required for grid electricity production (21.5% of the grid mix is electricity generated from natural gas). Because distributed electrolysis and liquid truck delivery technologies require large amounts of grid electricity, they also utilize large amounts of natural gas. Finally, natural gas is also utilized in petroleum refining, so technologies with truck delivery require more natural gas than those without (e.g., delivery of hydrogen in a truck requires more natural gas on a WTW basis than delivery via pipeline).

Figure 7.0.9 shows the comparative WTW GHG emissions for the 10 hydrogen pathways, shown for both 48 mpgge and 68 mpgge cases. Hydrogen FCEVs have no tailpipe GHG emissions because reacting hydrogen forms water, so the WTP emissions are the same as the WTW emissions.

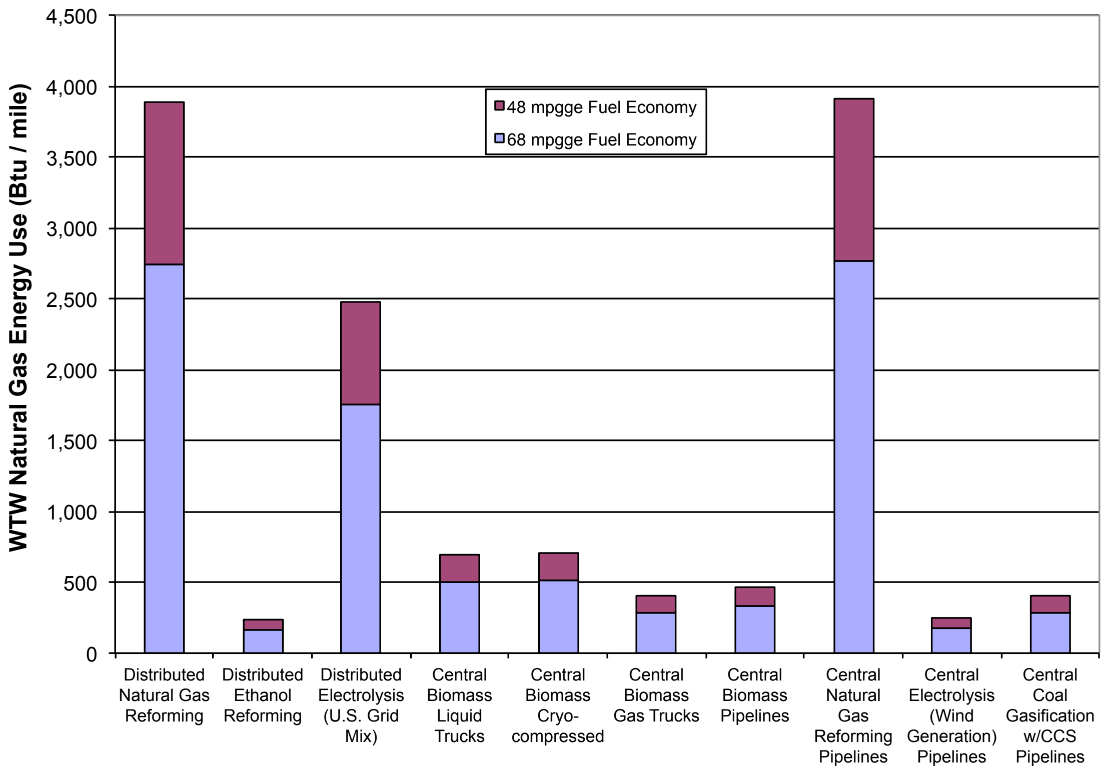


Figure 7.0.8. WTW natural gas energy use for 10 hydrogen pathways

The primary source (66%) of GHG emissions for the distributed natural gas reforming pathway is generation of hydrogen with some additional GHGs generated to produce electricity for CSD and in natural gas recovery and delivery. Distributed ethanol reforming is based on ethanol produced from corn stover, so the GHGs removed from the atmosphere to grow biomass are nearly equivalent to those generated producing ethanol and hydrogen. Additional emissions are generated producing power necessary for CSD. Distributed electrolysis requires 50 kWh electricity per kg H_2 produced, and additional electricity for CSD. The current grid mix produces 660 g CO_2-eq./kWh, so electricity generation is the primary emitter of its 820 g CO_2-eq./mile traveled. In all of the biomass production pathways, the GHGs removed from the atmosphere to grow biomass are essentially equivalent to the GHGs generated in producing hydrogen (see Sections 6.4–6.7 for details). The two biomass pathways utilizing delivery of liquid hydrogen have higher emissions for delivery and dispensing because of the amount of electricity required to liquefy hydrogen. All the GHGs emitted from the central electrolysis of wind electricity pathway are from electricity generation for CSD, which is assumed to be purchased from the grid without wind energy credits. Fifty percent of the GHGs emitted from the central coal with CCS and pipeline delivery pathway are GHGs that were not sequestered in the hydrogen production process, with the most of the remainder emitted during electricity production for CSD and some for coal mining and hydrogen transport.

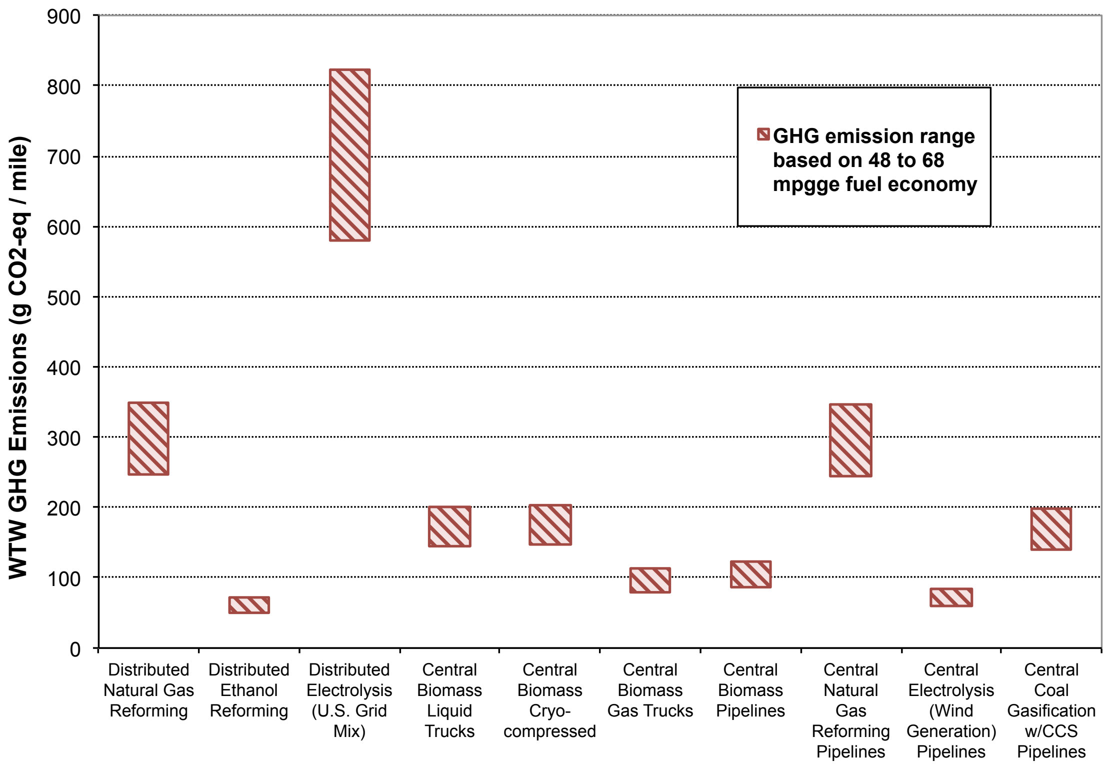


Figure 7.0.9. WTW GHG emissions for 10 hydrogen pathways

As shown in Figure 7.0.9, all of the pathways except distributed electrolysis result in GHG emissions (on a g/mile basis) lower than 400 g/mile based on a fuel economy of 48 mpgge, and below 250 g/mile when a fuel economy of 68 mpgge is considered. Distributed electrolysis has high GHG emissions when compared to the other hydrogen pathways because of the assumed U.S. average electricity grid mix. The pathways that use natural gas as a feedstock use little petroleum but have high GHG emissions compared to most of the other pathways due to the GHGs released in producing hydrogen from natural gas. The coal pathway has slightly lower GHG emissions because of the efficient sequestration system that is assumed. The biomass and ethanol cases have higher petroleum use than all but the distributed electrolysis pathway because the biomass and ethanol are delivered using trucks.

Of the four delivery options from central production, pipeline delivery has the lowest GHG emissions and lowest petroleum use. The two liquid truck delivery options have higher GHG emissions due to emissions from generating electricity for liquefaction. The GHG emissions for liquid hydrogen dispensed as a cryo-compressed liquid are slightly lower than those dispensed as a gas because the liquid pump requires less electricity than the necessary compressor does. Hydrogen delivered in a gas truck has low GHG emissions but high petroleum use because each truckload only carries 520 kg of hydrogen.

Because using hydrogen as a transportation fuel has an effect on both WTW GHG emissions and WTW petroleum use, and because that effect varies depending upon the hydrogen production/delivery pathway, Figure 7.0.10 shows GHG emissions relative to petroleum use for the 10 hydrogen pathways, based on a 48 mpgge fuel economy.

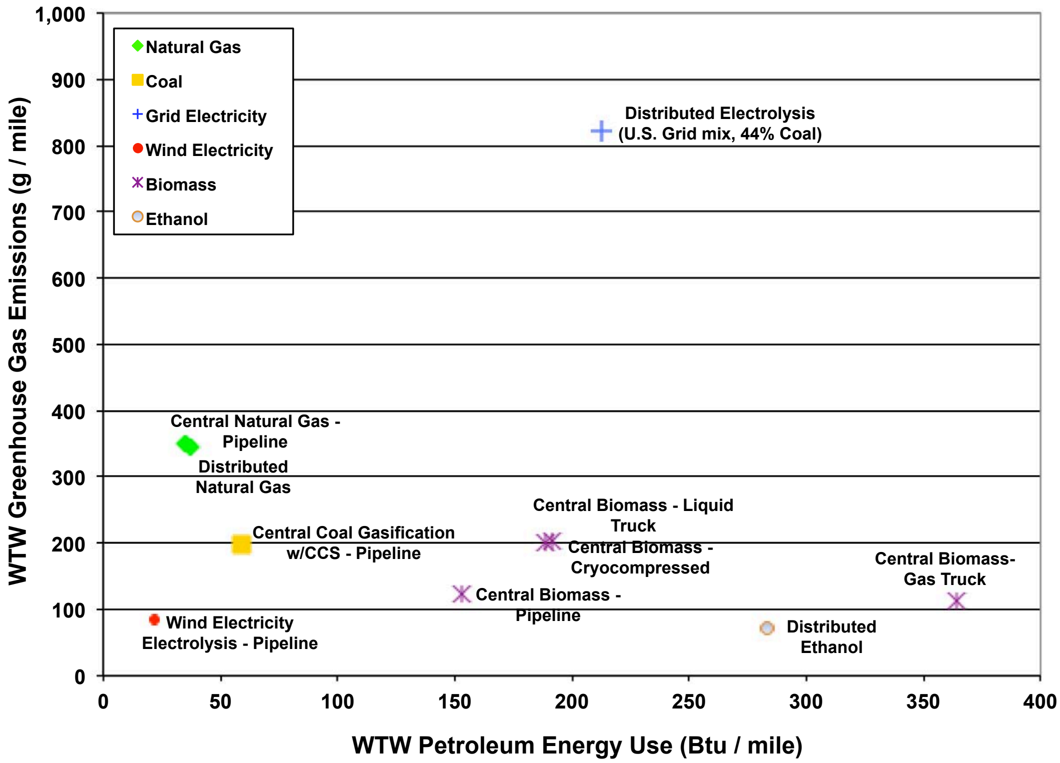


Figure 7.0.10. Comparison of pathways' petroleum use and GHG emissions (48 mpgge)

Figures 7.0.11a and 7.0.11b show the levelized fuel cost per mile and the WTW GHG emissions for the 10 hydrogen pathways analyzed for 48 mpgge and 68 mpgge fuel economies, respectively. Ideally, one technology would be the obvious one to focus on because it has both the lowest cost and the lowest GHG emissions. In this case, there is an obvious tradeoff between GHG emissions and levelized cost. The natural gas technologies have the lowest cost but the highest emissions, and the biomass technologies, ethanol, and wind electrolysis have lower emissions but higher costs.

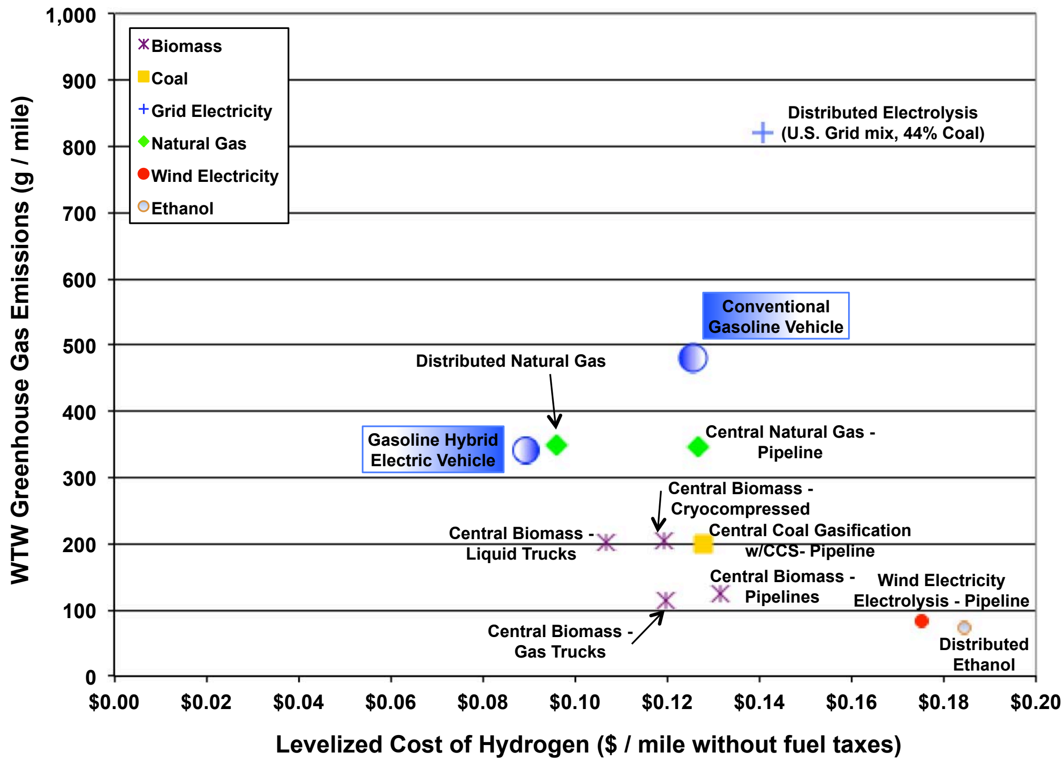


Figure 7.0.11a. Comparison of pathways' levelized costs per mile and GHG emissions (based on 48 mpgge fuel economy)

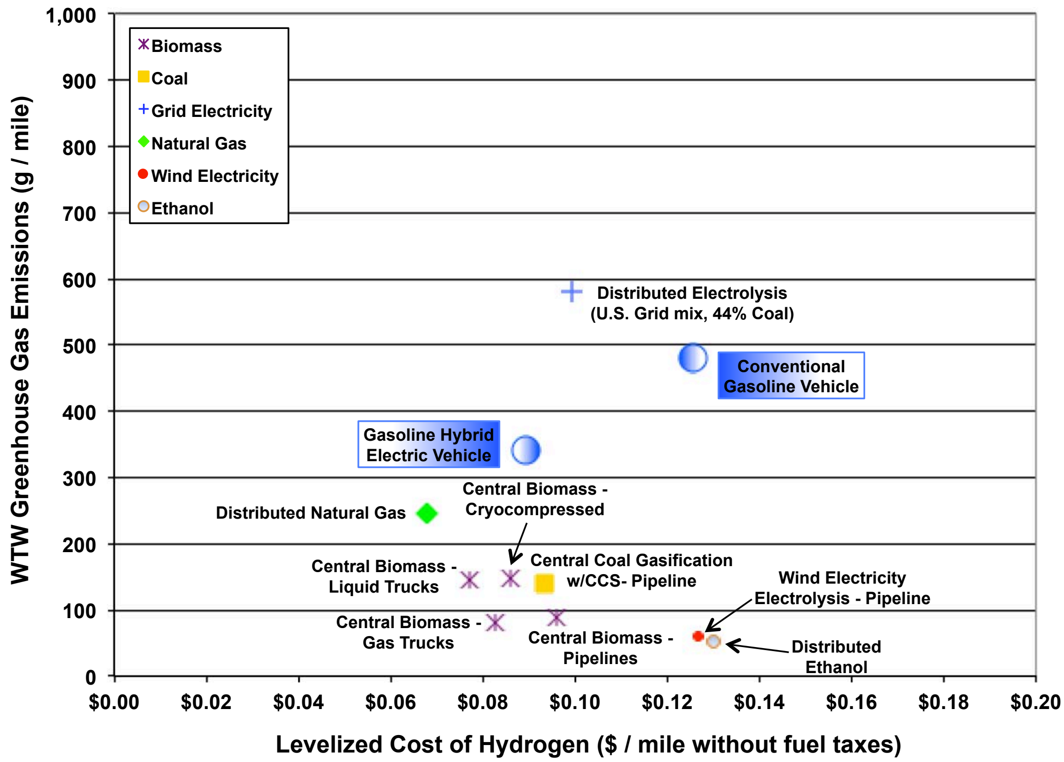


Figure 7.0.11b. Comparison of pathways' levelized costs per mile and GHG emissions (based on 68 mpgge fuel economy)

Figure 7.0.12 shows the levelized cost of hydrogen on a per-mile-traveled basis, calculated for both 48 mpgge and 68 mpgge fuel economies. Figure 7.0.13 shows the levelized cost of hydrogen on a per-mile-traveled basis (assuming 48 mpgge fuel economy) with three possible costs of carbon. The tops of the blue bars match what has been shown previously—levelized cost per mile with no cost of carbon. The tops of the red bars indicate the wholesale, levelized costs including a \$50/ton CO_2-equivalent cost, and the tops of the yellow bars indicate the wholesale, levelized costs including a \$100/ton CO_2-equivalent cost. The carbon cost calculation is based on WTW GHG emissions, so it includes increased costs due to upstream emissions as well as those generated while producing the hydrogen.

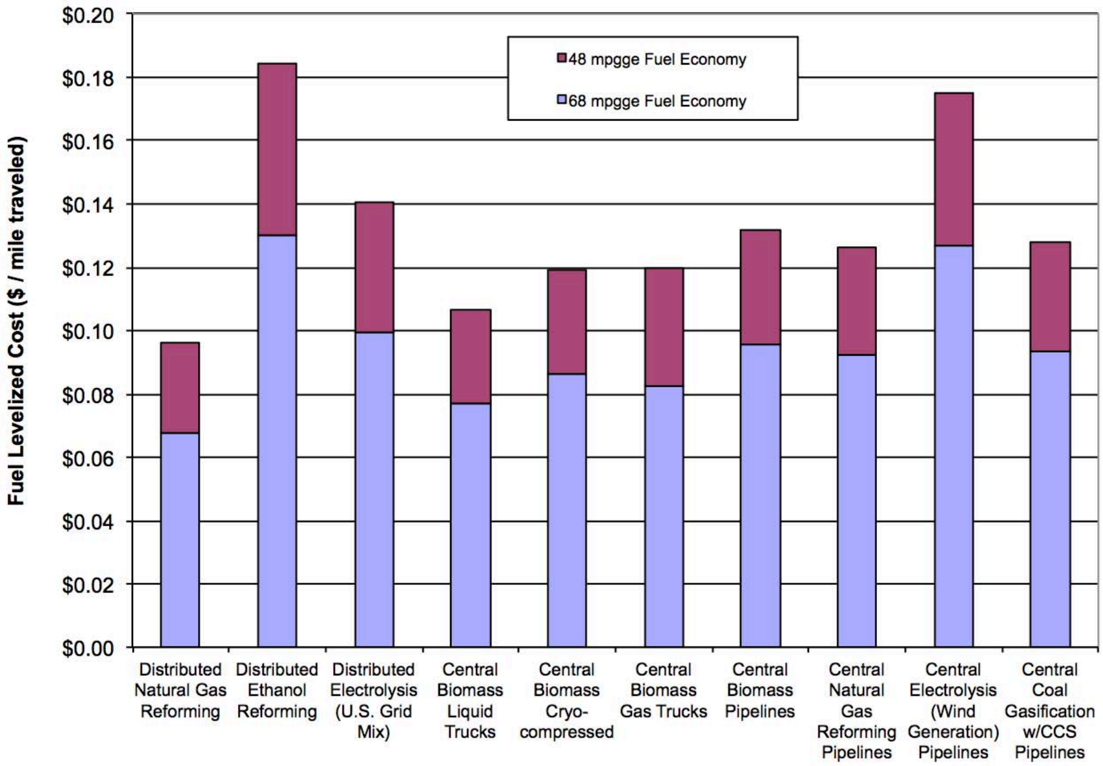


Figure 7.0.12. Per-mile levelized hydrogen costs for 10 hydrogen pathways

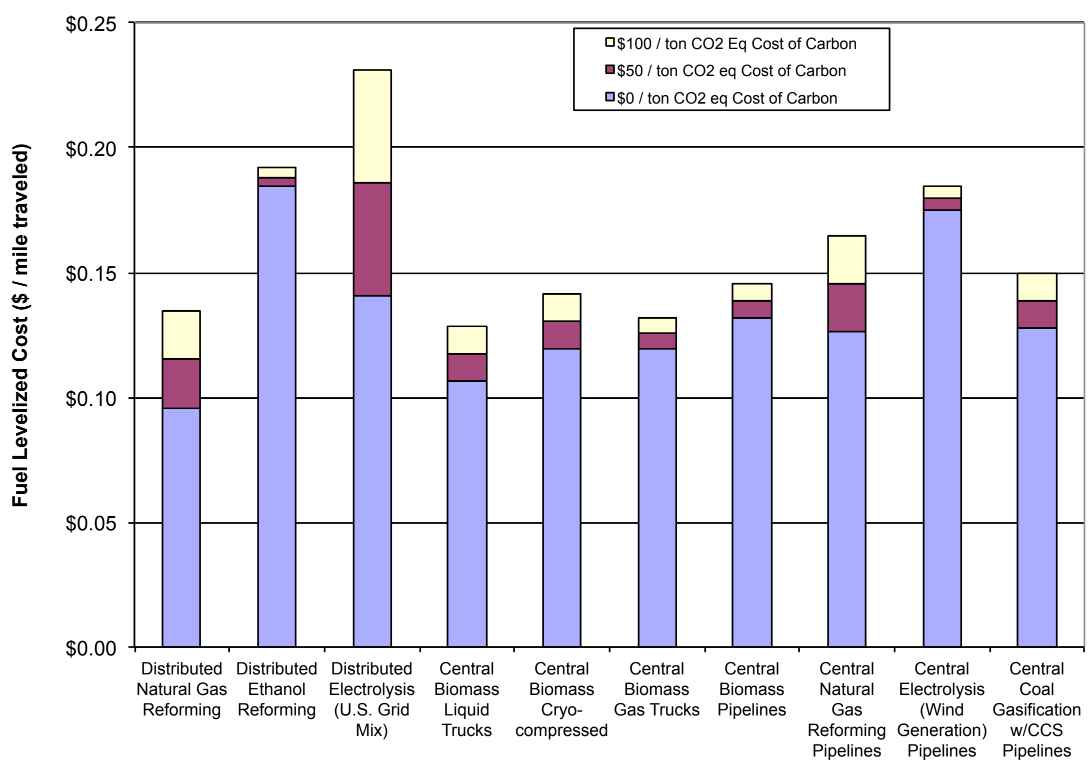


Figure 7.0.13. Levelized hydrogen costs with possible cost of carbon for 10 hydrogen pathways (based on 48 mpgge fuel economy)

8 Analysis Gaps

Though key input parameters have been adjusted in this study, many underlying assumptions used in the analysis rest on the default assumptions of the sub-models incorporated into the MSM (i.e., the default assumptions of the H2A Production, HDSAM, and GREET models). Below is a discussion of some of the analysis and modeling gaps identified during this analysis. Gaps were identified by the authors as well as through a review of the analysis by the Fuel Pathways Integration Technical Team of the U.S. DRIVE partnership, which includes representatives of four energy companies (Phillips 66, ExxonMobil, Chevron, and Shell), NREL, and the Hydrogen Systems Analyst of the U.S. Department of Energy. Some of the gaps and issues that were identified early in the scoping of the evaluation have been incorporated into the assessment and are reflected in the results described in the report. However, some gaps and issues have not yet been addressed or are beyond the scope of this effort; these gaps are noted below.

8.1 Production

- General
  - Limiting the analysis lifetime for distributed production to 20 years handicaps distributed production cases relative to central production cases (that are evaluated over a 40-year lifetime).
- Central biomass gasification
  - Only woody biomass has been included in the analysis. The H2A Production models do not currently include data to model herbaceous biomass feedstocks. The theoretical yields of hydrogen from herbaceous biomass should be compared with those from woody biomass. Empirical kinetic models on biomass gasification exist and may be used.
  - The biomass gasification case has a high enough electricity demand to use industrial rates, yet commercial rates are assumed in the H2A analysis.
- Central natural gas reforming
  - Waste heat is not considered to have any value in this analysis. An option where heat is used would be valuable because most of the reforming facilities built recently have customers for their waste heat.
  - Equipment costs for central natural gas reforming should be further disaggregated to aid in transparency.
  - Additional information on water use for natural gas reforming should be provided.
  - Natural gas reforming should have some planned replacement costs over the 40-year lifetime; however, none are included in the H2A calculation. H2A only has 0.5% per year for unplanned replacement costs.
- Central electrolysis using wind-generated electricity
  - The analysis assumes that the average price of wind electricity matches AEO projections for grid-electricity prices. More detailed analysis of hour-by-hour

wind electricity prices is needed for a more accurate cost accounting of this pathway.

    - The central electrolysis analysis is based on a central electrolysis facility with an operating capacity factor of 97%. A facility may be co-sited with the wind turbines and have a lower operating capacity factor. The optimal location and capacity factor are not included in this analysis.

- Central coal gasification with CCS
    - The H2A model for this technology needs to be updated to 2007$ to be consistent with the other H2A cases.
    - The availability of carbon sequestration sites and the cost of monitoring at and upkeep of those sites are not included in this analysis. A single cost for sequestration is included.
    - Cooling water requirements and costs are not included. More explanation is necessary regarding how the process is cooled.
- Distributed natural gas reforming
    - Cooling water requirements and costs are not included. More explanation is necessary regarding how the process is cooled.
- Distributed electrolysis
    - The hydrogen storage in the distributed electrolysis pathway is not optimized for peak power requirements. To optimize the pathway, the tradeoffs between the effects of full-time operation on the grid (transmission and distribution congestion and peaking power dispatch) and the costs of running the electrolyzers at less-than-full-time need to be understood, and a study over 8,760 hours/year is needed.
    - The CSD electricity cost for distributed electrolysis should be using “industrial rates” due to high electricity usage for production.
    - The efficiency of distributed electrolysis is the same as for central electrolysis; however, distributed electrolysis is likely to have a lower efficiency due to a higher relative parasitic demand.

8.2 Delivery and Dispensing

- Geologic storage is modeled currently with variable pressure; however, constant pressure is required in salt caverns. The pressure requirements for non-salt geologic structures are not well understood and require study.
- Geologic storage costs and requirements should be compared to those for natural gas to provide a cost baseline.
- The need for hydrogen gas clean-up after the hydrogen is extracted from caverns or other geologic storage is not well understood and requires study. Gas clean-up requirements and costs are a gap in the analysis for all of the pathways employing hydrogen delivery by pipeline.

- HDSAM uses a formula to calculate transmission and trunk pipeline costs based on an optimization of pipeline diameters, based on a curve fitting of available data. It appears that there is a problem with this formula; the HDSAM team should investigate and revise HDSAM as necessary.
- Average right-of-way costs are used in this analysis. Improved understanding of those costs and their effects on levelized costs would be helpful.
- There are concerns about the design of the gas truck case:
    - The production facility, geologic storage, and terminal appear to be co-located because there is no equipment for transport between them.
    - The gas-truck delivery case considered in this report requires 76 truck bays, which represents a very large terminal and would likely involve considerable logistics issues.
    - Terminal operators are unlikely to leave a trailer unattached from a tractor at the loading bay; however, the design does not allow for enough tractors to keep all of the trailers hooked up.
    - The number of compressor stages is unchanged between the other cases that have a lower inlet pressure and this one. It is likely that fewer stages are necessary.
    - The terminal has only a single storage compressor. A backup is likely to be necessary.
    - Using two compressors to serve 76 truck bays is likely to cause operational issues. More, smaller compressors are probably necessary.
    - Scenarios with higher minimum on-trailer pressures should be considered because they may allow for less compression at the stations; however, the logistics regarding the number of truck fills need to be kept in mind.
- Additional analysis is needed to determine the ideal size and siting of hydrogen distribution stations.
- Low-pressure storage requirements at stations should be revisited to identify the potential risks regarding downtime due to unplanned outages to determine if the current storage amount is sufficient.
- Cascade storage volumes should be compared to those used for dispensing from natural gas from gas pipelines.
- The on-board storage pressure for all of the analyses in this report is 10,000 psi, which requires a maximum dispensing pressure of 12,688 psi. Tradeoffs should be analyzed.
- The tradeoffs between hydrogen quality and fuel cell performance (i.e., durability, reliability, and efficiency) are not well understood.
- Control and safety equipment costs for liquid delivery are more than 5 times higher than those for gaseous delivery and on-site production. Intuitively, they should be more similar.

- The dispenser cost for liquid delivery (both gaseous and cryo-compressed dispensing) is less than 50% of that for gaseous delivery and on-site production. Intuitively, they should be more similar.
- There are slight errors in the electricity cost calculations for geologic storage and refueling station electricity use that need to be corrected.

8.3 Vehicle Costing

- The tool needs to be adjusted to allow for cryo-compressed storage costs when appropriate instead of just compressed gas onboard storage.
- The vehicle CPM Tool only allows 10,000 and 15,000 miles per year. Adding 12,000 miles per year (as a standard distance driven) would improve the analysis.
- The CPM Tool assumes a 100 kW-sized fuel cell stack for costing purposes, compared to a 70-kW stack assumed in GREET 2.
- Additional information on the tradeoffs between vehicle fuel economy and vehicle costs could be added if those data can be found.

8.4 Pathway Analysis

- Station sizes should be kept more consistent than in this analysis, where distributed production stations have an average daily dispensing rate of 1,330 kg/day; stations for pipelines and liquid truck delivery have an average daily dispensing rate of 1,000 kg/day; and stations for gas truck delivery have an average daily dispensing rate of 800 kg/day.
- The effects of different types of biomass (i.e., corn stover or forest residue instead of just short rotation woody crops) on cost, energy use, and emissions should be considered.
- Other impact parameters such as water withdrawal, water consumption, and land use should be added to the analysis.
- The analysis should balance analysis periods. One such need is to compare two back-to-back distributed production stations (with a 20-year lifetime each) against a single central production unit with a 40-year lifetime.

9 References

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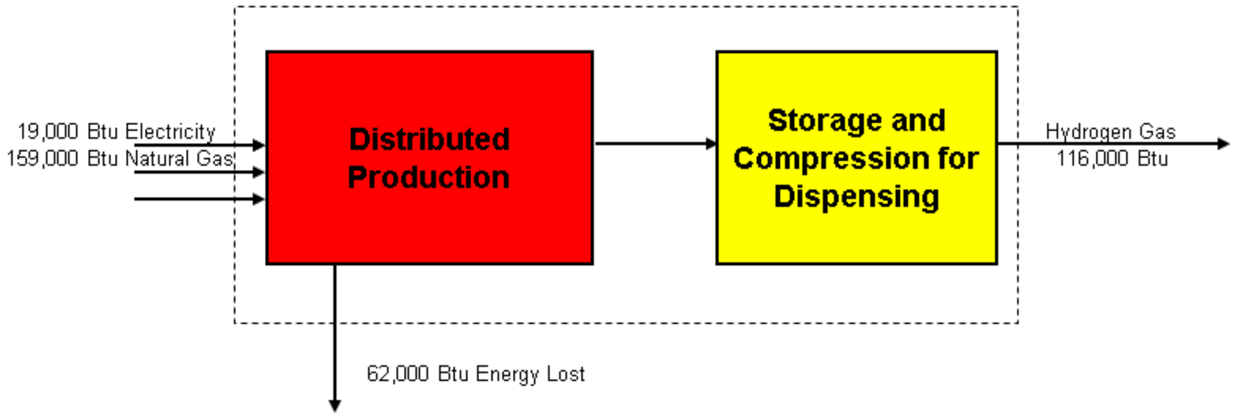
Appendix A: Distributed Natural Gas Supporting Tables and Figures

Distributed Hydrogen Production

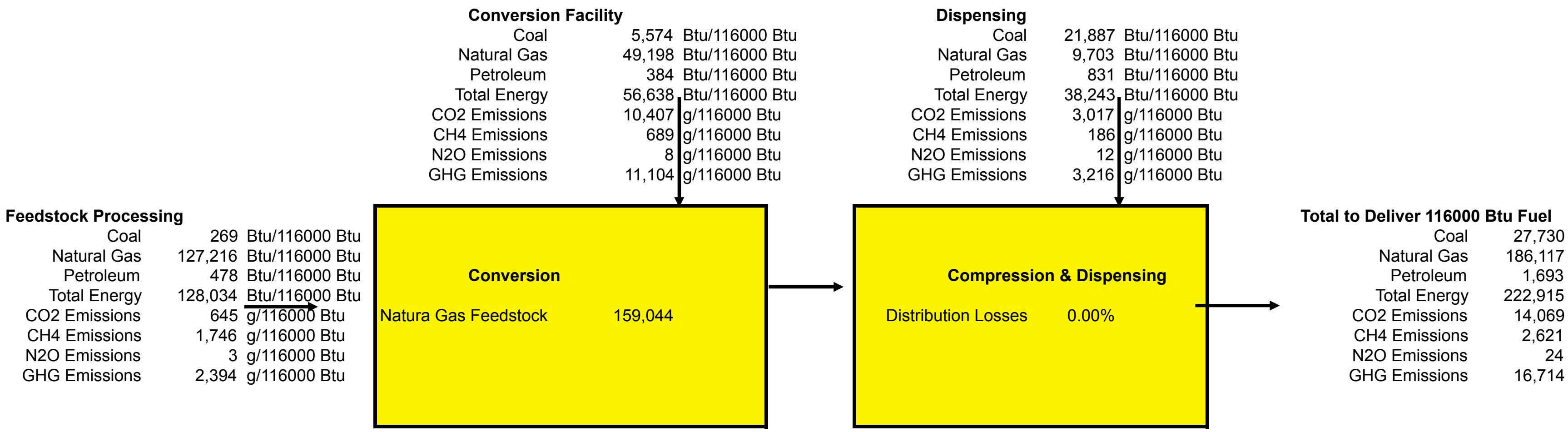


Well-to-Wheels Total Energy Use (Btu/mile)	4,652
Well-to-Wheels Petroleum Energy Use (Btu/mile)	35
Well-to-Wheels Greenhouse Gas Emissions (g/mile)	349
Levelized Cost of H2 at Pump ($/kg)	4.60

Production Process Energy Efficiency	71%
Pathway Efficiency	65%
WTP Efficiency	52%
WTP Emissions (lb CO2 Equivalent / GGE fuel available):	37

Case Definition
Year: 2015
Hydrogen as Gas
Forecourt Production
NATURAL GAS Feedstock
Sequestration: NO
Transport for Delivery: None
Vehicle Efficiency: 48 mile / GGE
City Hydrogen Use: 121096 kg/day

Inputs			Assumptions			Outputs		
						NG Delivery Pressure	Average of gas companies	
			NG Recovery, Processing, & Transport			NG Quality at Delivery	Average of gas companies	
			NG Recovery Efficiency	95.7%				
			NG emitted & combusted during recovery	399	g/MMbtu	NG Cost	$6.09	2007 $ / mmBTU
			NG processing energy efficiency	97.2%		NG Share of H2 Levelized Cost	$1.28	2007$ / kg H2 dispensed
			NG emitted & combusted during processing	33	g/MMbtu			
			NG emitted & combusted during transport	199,400	g/MMbtu	WTG CO2 Emissions	650	g CO2 eq./ 116000 Btu
Coal Input (including upstream)	300	Btu / 116000Btu to Pump	NG transport distance	500	miles	WTG CH4 Emissions	1,750	g CO2 eq./ 116000 Btu
Natural Gas Input (including upstream)	127,200	Btu / 116000Btu to Pump	Compression Req'ts. (stages & efficiency)	Average of gas companies		WTG N2O Emissions	3	g CO2 eq./ 116000 Btu
Petroleum Input (including upstream)	500	Btu / 116000Btu to Pump				WTG GHG Emissions	2,390	g CO2 eq./ 116000 Btu
			Hydrogen Production			Hydrogen Output Pressure	300	psi
Natural gas consumption	0.156	MMBtu/kg H2 produced				Hydrogen Outlet Quality	99.9%	
Electricity consumption	1.11	kWh / kg H2 produced						
Process Water Consumption	5.77	gal / kg H2 produced	Distributed plant design capacity	1,500	kg / day	Total capital investment	$1,150	2007$ / daily kg H2 (effective capacity)
Cooling Water Consumption	0.00	gal / kg H2 produced	Capacity factor	89%		Levelized Cost of Capital	$0.59	2007$ / kg H2 dispensed
			# of Plants Needed to Meet City Demand	92		Fixed O&M Costs	$0.19	2007$ / kg H2 dispensed
Total Capital Investment per station	$1,530,000	2007$	Process energy efficiency	71.4%		Variable O&M Costs	$0.12	2007$ / kg H2 dispensed
			Electricity Mix	US Mix		Total Levelized Cost	$2.17	2007$ / kg H2 dispensed
			After-tax IRR	10%				
Coal Input (including upstream)	5,600	Btu / 116000Btu to Pump	Assumed Plant Life	20		Production CO2 Emissions	10,410	g CO2 eq./ 116000 Btu
Natural Gas Input (including upstream)	49,200	Btu / 116000Btu to Pump				Production CH4 Emissions	690	g CO2 eq./ 116000 Btu
Petroleum Input (including upstream)	400	Btu / 116000Btu to Pump				Production N2O Emissions	8	g CO2 eq./ 116000 Btu
						Production GHG Emissions	11,100	g CO2 eq./ 116000 Btu
Electricity consumption	4.4	kWh / kg H2 produced	**Forecourt Dispensing**			Hydrogen outlet pressure	12,700	psi
						Basis -- Hydrogen Quantity	116,000	Btu (116,000 Btu/gal non-oxygenated conventional unleaded gasoline)
			City Population	1,247,000	people			
Total Capital Investment (per station)	$5,059,000	2007$ / station	Hydrogen Vehicle Penetration	15%				
Total Capital Investment	$465,391,000	2007$ / all stations	City hydrogen use	121,100	kg / day	Total capital investment	$3,810	2007$ / daily kg H2 (effective capacity)
			Average Dispensing Rate per Station	1,330	kg / day	Levelized Cost of Capital	$1.49	2007$ / kg H2 dispensed
			Number of Dispensing Stations	92		Energy & Fuel	$0.40	2007$ / kg H2 dispensed
			Number of Compression Steps	5		Other O&M Costs	$0.54	2007$ / kg H2 dispensed
			Usable Low Pressure Storage per Station	1,450	kg H2	Levelized Cost of Dispensing	$2.43	2007$ / kg H2 dispensed
			Usable Cascade Storage per Station	200	kg H2			
Coal Input (including upstream)	21,900	Btu / 116000Btu to Pump	Site storage	100%	% of design capacity	CSD CO2 Emissions	3,020	g CO2 eq./ 116000 Btu
Natural Gas Input (including upstream)	9,700	Btu / 116000Btu to Pump	# of 2-hose Dispensers per Station	3		CSD CH4 Emissions	190	g CO2 eq./ 116000 Btu
Petroleum Input (including upstream)	800	Btu / 116000Btu to Pump	Hydrogen losses	0.50%		CSD N2O Emissions	12	g CO2 eq./ 116000 Btu
						CSD GHG Emissions	3,220	g CO2 eq./ 116000 Btu
Vehicle Mass	3,020	lb	**Vehicle**			Cost Per Mile	$0.66	2007$ / mi
Fuel cell size	70	kW	Fuel Economy	48.0	mi / GGE	Fuel Share	$0.10	2007$ / mi
Size of hybridization battery	30	kW	Vehicle Miles Traveled	15,000	mi / yr	Maintenance, Tires, Repairs	$0.07	2007$ / mi
			Vehicle Lifetime	160,000	mi	Insurance & Registration	$0.12	2007$ / mi
			Purchase Year	2015		Depreciation	$0.27	2007$ / mi
			Vehicle Purchase Cost	$33,700	2007$	Financing	$0.10	2007$ / mi
			Fuel Cell System Cost	$4,500	2007$			
Coal Input (including upstream)	2,300	Btu / gge fuel consumed	Hydrogen Storage System Cost	$2,400	2007$	Vehicle Cycle CO2 Emissions	1,670	g CO2 eq / gge fuel consumed
Natural Gas Input (including upstream)	12,100	Btu / gge fuel consumed	Tax Credit	$0	2007$	Vehicle Cycle CH4 Emissions	170	g CO2 eq / gge fuel consumed
Petroleum Input (including upstream)	6,900	Btu / gge fuel consumed				Vehicle Cycle N2O Emissions	6	g CO2 eq / gge fuel consumed
						Vehicle Cycle GHG Emissions	1,850	g CO2 eq / gge fuel consumed


Conversion Facility
Coal 5,574 Btu/116000 Btu
Natural Gas 49,198 Btu/116000 Btu
Petroleum 384 Btu/116000 Btu
Total Energy 56,638 Btu/116000 Btu
CO2 Emissions 10,407 g/116000 Btu
CH4 Emissions 689 g/116000 Btu
N2O Emissions 8 g/116000 Btu
GHG Emissions 11,104 g/116000 Btu
Dispensing
Coal 21,887 Btu/116000 Btu
Natural Gas 9,703 Btu/116000 Btu
Petroleum 831 Btu/116000 Btu
Total Energy 38,243 Btu/116000 Btu
CO2 Emissions 3,017 g/116000 Btu
CH4 Emissions 186 g/116000 Btu
N2O Emissions 12 g/116000 Btu
GHG Emissions 3,216 g/116000 Btu
Feedstock Processing
Coal 269 Btu/116000 Btu
Natural Gas 127,216 Btu/116000 Btu
Petroleum 478 Btu/116000 Btu
Total Energy 128,034 Btu/116000 Btu
CO2 Emissions 645 g/116000 Btu
CH4 Emissions 1,746 g/116000 Btu
N2O Emissions 3 g/116000 Btu
GHG Emissions 2,394 g/116000 Btu
Conversion
Natura Gas Feedstock 159,044
Compression & Dispensing
Distribution Losses 0.00%
Total to Deliver 116000 Btu Fuel
Coal 27,730
Natural Gas 186,117
Petroleum 1,693
Total Energy 222,915
CO2 Emissions 14,069
CH4 Emissions 2,621
N2O Emissions 24
GHG Emissions 16,714

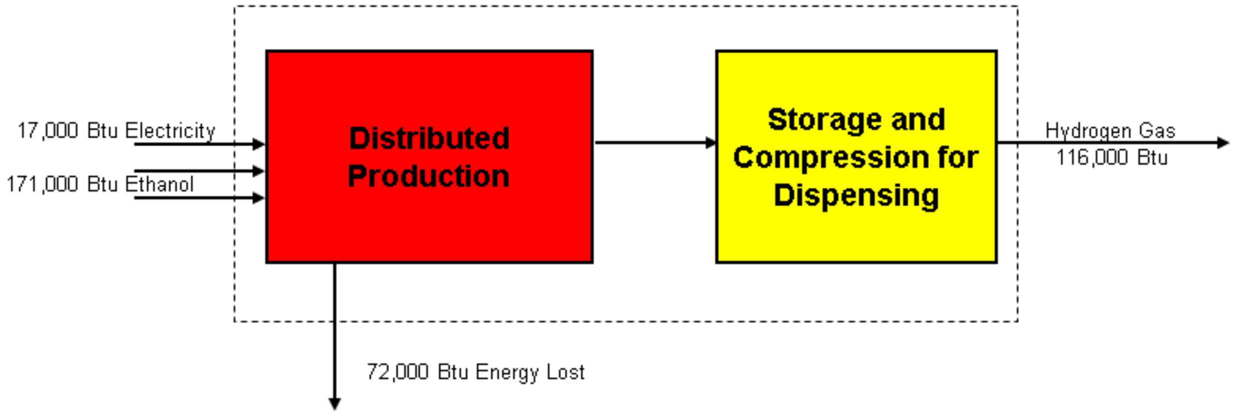
Parameter		Value	Units	Reference	Comments
Case Definition					
	Startup Year	2015		Input	Default for this study's current cases
	Reference Year Dollars	2007		Input	Default for this study's current cases
	Production Technology	NATURAL GAS		Input	Case definition
	Form of H2 During Delivery	Gas		Input	Case definition
	Delivery Mode	None		Input	Case definition
	Dispensing Mode	CASCADE_700_BAR		Input	Case definition
	Forecourt Station Size	1329	kg/day	Input	Case definition
	Vehicle Type	passenger cars		Input	Case definition
	Vehicle materials (conventional or lightweight)	Conventional		Input	Case definition; lightweight materials not currently an MSM option
	Vehicles' Fuel Economy	48.0	mile / gge	Input	Default assumption for this study's current cases
Market Definition					
	City Population	1,247,364	people	Input	Case Definition: Indianapolis, IN
	Market penetration	15%	(% vehicles in city)	Input	Case definition: Basis for Program Plan
	Number of H2 vehicles in city	138,832	H2 vehicles / city	HDSAM Result	
	Miles driven per vehicle	15,000	mile / vehicle year	Input	CPM only allows for 10K, 15K, and 20K/yr.
	Miles driven per vehicle	160,000	miles in vehicle life	Input - GREET2 default	
	City hydrogen use	121,096	kg / d	HDSAM Result	
	Number of H2 refueling stations in city	92		HDSAM Result	
	Number of H2 stations/Number of gasoline stations	14%		HDSAM Result	
	Average distance between stations (mi)	2.50	miles	HDSAM Result	
Other Assumptions for WTW Calculations					
	Share of RFG in Total Gasoline Use	100%		Input: GREET default	Case definition: Basis for Program Plan
	Type of Oxygenate in RFG	None		Input: GREET default	Case definition: Basis for Program Plan
	O2 Content in RFG	0%	wt %	Input: GREET default	Case definition: Basis for Program Plan
	Ratio of FCEV VOCs (emissions) to GVs fueled with CG & RFG	0%		Input: GREET default	
	Ratio of FCEV VOCs (evaporative) to GVs fueled with CG & RFG	0%		Input: GREET default	
	Ratio of FCEV CO emissions to GVs fueled with CG & RFG	0%		Input: GREET default	
	Ratio of FCEV NOx emissions to GVs fueled with CG & RFG	0%		Input: GREET default	
	Ratio of FCEV Exhaust PM10 emissions to GVs fueled with CG & RFG	0%		Input: GREET default	
	Ratio of FCEV Brake & Tire Wear PM10 emissions to GVs fueled with CG & RFG	100%		Input: GREET default	
	Ratio of FCEV Exhaust PM2.5 emissions to GVs fueled with CG & RFG	0%		Input: GREET default	
	Ratio of FCEV Brake & Tire Wear PM2.5 emissions to GVs fueled with CG & RFG	100%		Input: GREET default	
	Ratio of FCEV CH4 emissions to GVs fueled with CG & RFG	0%		Input: GREET default	
	Ratio of FCEV N2O emissions to GVs fueled with CG & RFG	0%		Input: GREET default	
	Marginal Electricity Generation Mix for Transportation Use	US Mix		Input	Case definition: Basis for Program Plan

Parameter			Value	Units	Reference	Comments
Natural Gas						
	Percent of NG that is Shale Gas (remainder is conventional NG)		32.1%		GREET default input	
	NG recovery efficiency		95.7%		GREET default input	
	NG lost during recovery		399	g/MMBtu	GREET default input	Previously reported at percent of total NG not on a MMBtu basis
	Percentage of energy use/loss for recovery that is combusted natural gas		49.0%		GREET default input	
	Shale gas recovery efficiency		96.5%		GREET default input	
	Shale gas lost during recovery		245	g/MMBtu	GREET default input	
	Percentage of energy use/loss for recovery that is combusted shale gas		57.4%		GREET default input	
	NG processing energy efficiency		97.2%		Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Results*. Argonne, IL: Argonne National Laboratory.	GREET uses 97.5% which is comparable to several other models (Table 4.11)
	NG lost during processing		33	g/MMBtu	GREET default input	
	Percentage of energy use for processing that is combusted natural gas		90.7%		GREET default input	
	NG used & lost during transport and distribution		199434	g / MMBtu	GREET default input	
	NG transport distance		500	miles	GREET default input	
Electricity						
	Grid mix for production		US Mix		GREET input	Default
		Biomass Fraction	0.5%		Definition of US Mix	Energy Information Administration. (2007, February). Annual Energy Outlook 2007 with Projections to 2030. DOE/EIA-0383(2007). Washington, D.C. Retreived from www.eia.doe.gov/oiaf/archive/aeo07/index.html National electricity generation data from tables D-7 & D-8 using the 2005 timeframe. Percentages calculated from total generation values reported with all renewables except biomass aggregated into the "Others (Carbon Neutral)" category
		Coal Fraction	44.2%		Definition of US Mix	
		Natural Gas Fraction	21.5%		Definition of US Mix	
		Nuclear Fraction	21.0%		Definition of US Mix	
		Residual Oil Fraction	0.9%		Definition of US Mix	
		Others (Carbon Neutral - Hydroelectric, Wind, Geothermal, Solar PV, etc)	11.8%		Definition of US Mix	
	Biomass Electricity Shares and Efficiency					
		IGCC Share of Biomass Power Plants	1.0%		GREET default input	
		Combustion Share of Biomass Power Plants	99.0%		GREET default input	By difference from IGCC plants
		Biomass IGCC Efficiency	43.0%		GREET default input	
		Biomass Combustion Plant Efficiency	32.1%		GREET default input	
		Effective Efficiency of Biopower Plants	32.2%		GREET default input	
	Coal Electricity Shares and Efficiency					
		IGCC Share of Coal Power Plants	1.0%		GREET default input	
		Combustion Share of Coal Power Plants	99.0%		GREET default input	
		Coal IGCC Efficiency	47.0%		GREET default input	
		Coal Combustion Plant Efficiency	34.1%		GREET default input	
		Effective Efficiency of Coal-Electricity Plants	34.2%		GREET default input	
	Natural Gas Electricity Shares and Efficiency					
		Simple Cycle Gas Turbine Share of Natural Gas Power Plants	37.0%		GREET default input	
		Combined Cycle Gas Turbine Share of Natural Gas Power Plants	46.0%		GREET default input	
		Combustion Boiler Share of Natural Gas Power Plants	17.0%		GREET default input	
		Natural Gas Simple Cycle Gas Turbine Plant Efficiency	33.1%		GREET default input	
		Natural Gas Combined Cycle Efficiency	55.0%		GREET default input	
		Natural Gas Combustion Boiler Plant Efficiency	34.8%		GREET default input	
		Effective Efficiency of Natural Gas-Electricity Plants	40.9%		GREET default input	
	Residual Oil Electricity Efficiency					
		Residual Oil Electricity Plant Efficiency	34.8%		GREET default input	
	Electicity Transmission and Distribution Losses		8.0%		GREET default input	

Parameter			Value	Units	Reference	Comments
Parameters for GREET2						
	Vehicle total mass		3,020	lb	GREET2 Default Input	
	Battery Type for Hybridization		NiMH		GREET2 Default Input	
	Hybridization Battery Size in Peak Hybridization Battery Power		30	kW	GREET2 Default Input	
	Hybridization Battery Specific Power		272	W / lb	GREET2 Default Input	
	Hybridization Battery Mass		110	lb	GREET2 Default Input	
	Number of replacements of hybridization battery over lifetime		2		GREET2 Default Input	
	Starter Battery (Lead Acid) Mass		22	lb	GREET2 Default Input	
	Mass of fluids on-board vehicle		56	lb	GREET2 Default Input	
	Component mass (vehicles without batteries or fluids)		2,832	lb	GREET2 Calculation	
		Powertrain system percentage of component mass	8.0%		GREET2 Default Input	
		Transmission system percentage of component mass	2.6%		GREET2 Default Input	
		Chassis (without battery) percentage of component mass	23.0%		GREET2 Default Input	
		Traction motor percentage of component mass	3.8%		GREET2 Default Input	
		Generator percentage of component mass	0.0%		GREET2 Default Input	
		Electronic controller percentage of component mass	3.4%		GREET2 Default Input	
		Fuel Cell Auxiliary System percentage of component mass	19.3%		GREET2 Default Input	
		Body: including BIW, interior, exterior, and glass	39.9%		GREET2 Default Input	
	Fuel Cell Stack Size		70	kW	GREET2 Default Input	
	Mass of Fuel Cell Stack - Powertrain System		226	lb	GREET2 Calculation	
	Mass of Fuel Cell Stack - Auxiliary Systems		546	lb	GREET2 Calculation	
	Miles driven per vehicle over lifetime		160,000	miles in vehicle life	GREET2 Default Input	Current analysis assumes 5-year life, 10-year analysis is available

Appendix B: Distributed Ethanol Supporting Tables and Figures

Distributed Hydrogen Production



Well-to-Wheels Total Energy Use (Btu/mile)	7,888
Well-to-Wheels Petroleum Energy Use (Btu/mile)	283
Well-to-Wheels Greenhouse Gas Emissions (g/mile)	72
Levelized Cost of H2 at Pump ($/kg)	8.85

Production Process Energy Efficiency	67%
Pathway Efficiency	62%
WTP Efficiency	31%
WTP Emissions (lb CO2 Equivalent / GGE fuel available):	8

Case Definition
Year: 2015
Hydrogen as Gas
Forecourt Production
ETHANOL Feedstock
Sequestration: NO
Transport for Delivery: None
Vehicle Efficiency: 48 mile / GGE
City Hydrogen Use: 121096 kg/day

Inputs			Assumptions			Outputs		
			Ethanol Production					
			Percent from Corn Stover	100%		Ethanol Cost	$3.04	2007 $ / gal
			Corn Stover Production	2.21	dry ton / acre	Ethanol Share of H2 Cost	$5.29	2007$ / kg H2 dispensed
Coal Input (including upstream)	-21,100	Btu / 116000Btu to Pump	Ethanol Yield from Corn Stover	90.0	gal / dry ton			
Natural Gas Input (including upstream)	400	Btu / 116000Btu to Pump	Elec. Co-Prod. from Corn Stover Conversion	2.28	kWh / gal ethanol	WTG CO2 Emissions	-14,010	g CO2 eq./ 116000 Btu
Petroleum Input (including upstream)	12,700	Btu / 116000Btu to Pump				WTG CH4 Emissions	-20	g CO2 eq./ 116000 Btu
			Displacement method used for estimating effects of co-produced electricity on LCA results			WTG N2O Emissions	1,140	g CO2 eq./ 116000 Btu
Energy use and emissions calcs include electricity displaced by ethanol production						WTG GHG Emissions	-12,900	g CO2 eq./ 116000 Btu
			Hydrogen Production			Hydrogen Output Pressure	300	psi
Ethanol Consumption	2.19	gal / kg H2 produced				Hydrogen Outlet Quality	99.9%	
Electricity consumption	0.49	kWh / kg H2 produced						
Process Water Consumption	8.18	gal / kg H2 produced	Distributed plant design capacity	1,500	kg / day	Total capital investment	$1,430	2007$ / daily kg H2 (effective capacity)
Cooling Water Consumption	0.00	gal / kg H2 produced	Capacity factor	89%		Levelized Cost of Capital	$0.83	2007$ / kg H2 dispensed
			# of Plants Needed to Meet City Demand	92		Fixed O&M Costs	$0.24	2007$ / kg H2 dispensed
Total Capital Investment per station	$1,907,000	2007$	Process energy efficiency	67.4%		Variable O&M Costs	$0.07	2007$ / kg H2 dispensed
			Electricity Mix	US Mix		Total Levelized Cost	$6.42	2007$ / kg H2 dispensed
			After-tax IRR	10%				
Coal Input (including upstream)	2,400	Btu / 116000Btu to Pump	Assumed Plant Life	20		SMR CO2 Emissions	13,080	g CO2 eq./ 116000 Btu
Natural Gas Input (including upstream)	1,100	Btu / 116000Btu to Pump				SMR CH4 Emissions	20	g CO2 eq./ 116000 Btu
Petroleum Input (including upstream)	100	Btu / 116000Btu to Pump				SMR N2O Emissions	1	g CO2 eq./ 116000 Btu
						SMR GHG Emissions	14,010	g CO2 eq./ 116000 Btu
Electricity consumption	4.4	kWh / kg H2	**Forecourt Dispensing**			Hydrogen outlet pressure	12,700	psi
						Basis -- Hydrogen Quantity	116,000	Btu (116,000 Btu/gal non-oxygenated conventional unleaded gasoline)
			City Population	1,247,000	people			
Total Capital Investment (per station)	$5,059,000	2007$ / station	Hydrogen Vehicle Penetration	15%		Total capital investment	$3,810	2007$ / daily kg H2 (effective capacity)
Total Capital Investment	$465,390,000	2007$ / all stations	City hydrogen use	121,100	kg / day	Levelized Cost of Capital	$1.49	2007$ / kg H2 dispensed
			Average Dispensing Rate per Station	1,329	kg / day	Energy & Fuel	$0.40	2007$ / kg H2 dispensed
			Number of Dispensing Stations	92		Other O&M Costs	$0.54	2007$ / kg H2 dispensed
			Number of Compression Steps	5		Levelized Cost of Dispensing	$2.43	2007$ / kg H2 dispensed
			Usable Low Pressure Storage per Station	1450	kg H2			
			Usable Cascade Storage per Station	200	kg H2	CSD CO2 Emissions	3,020	g CO2 eq./ 116000 Btu
Coal Input (including upstream)	21,900	Btu / 116000Btu to Pump	Site storage	100%	% of design capacity	CSD CH4 Emissions	190	g CO2 eq./ 116000 Btu
Natural Gas Input (including upstream)	9,700	Btu / 116000Btu to Pump	# of 2-hose Dispensers per Station	3		CSD N2O Emissions	12	g CO2 eq./ 116000 Btu
Petroleum Input (including upstream)	800	Btu / 116000Btu to Pump	Hydrogen losses	0.50%		CSD GHG Emissions	11,320	g CO2 eq./ 116000 Btu
			Vehicle					
Vehicle Mass	3,020	lb				Cost Per Mile	$0.75	2007$ / mi
Fuel cell size	70	kW	Fuel Economy	48.0	mi / GGE	Fuel Share	$0.18	2007$ / mi
Size of hybridization battery	30	kW	Vehicle Miles Traveled	15,000	mi / yr	Maintenance, Tires, Repairs	$0.07	2007$ / mi
			Vehicle Lifetime	160,000	mi	Insurance & Registration	$0.12	2007$ / mi
			Purchase Year	2015		Depreciation	$0.27	2007$ / mi
			Vehicle Purchase Cost	$33,700	2007$	Financing	$0.10	2007$ / mi
			Fuel Cell System Cost	$4,500	2007$			
Coal Input (including upstream)	2,300	Btu / gge fuel consumed	Hydrogen Storage System Cost	$2,400	2007$	Veh. Cycle CO2 Emissions	1,670	g CO2 eq / gge fuel consumed
Natural Gas Input (including upstream)	12,100	Btu / gge fuel consumed	Tax Credit	$0	2007$	Veh. Cycle CH4 Emissions	170	g CO2 eq / gge fuel consumed
Petroleum Input (including upstream)	6,900	Btu / gge fuel consumed				Veh. Cycle N2O Emissions	6	g CO2 eq / gge fuel consumed
						Veh. Cycle GHG Emissions	1,850	g CO2 eq / gge fuel consumed

Conversion Facility

Coal	2,442	Btu/116000 Btu
Natural Gas	1,082	Btu/116000 Btu
Petroleum	93	Btu/116000 Btu
Total Energy	58,568	Btu/116000 Btu
CO2 Emissions	13,084	g CO2 eq/116000 Btu
CH4 Emissions	21	g CO2 eq/116000 Btu
N2O Emissions	1	g CO2 eq/116000 Btu
GHG Emissions	14,009	g CO2 eq/116000 Btu

Dispensing

Coal	21,887	Btu/116000 Btu
Natural Gas	9,703	Btu/116000 Btu
Petroleum	831	Btu/116000 Btu
Total Energy	38,243	Btu/116000 Btu
CO2 Emissions	3,017	g CO2 eq/116000 Btu
CH4 Emissions	186	g CO2 eq/116000 Btu
N2O Emissions	12	g CO2 eq/116000 Btu
GHG Emissions	11,317	g CO2 eq/116000 Btu

Feedstock Processing

Coal	-21,110	Btu/116000 Btu
Natural Gas	433	Btu/116000 Btu
Petroleum	12,653	Btu/116000 Btu
Total Energy	281,185	Btu/116000 Btu
CO2 Emissions	-14,011	g CO2 eq/116000 Btu
CH4 Emissions	-24	g CO2 eq/116000 Btu
N2O Emissions	1,137	g CO2 eq/116000 Btu
GHG Emissions	-12,898	g CO2 eq/116000 Btu

Reforming

Ethanol Feedstock 170,725

CSD

Distribution Losses 0.00%

Total to Deliver 116000 Btu Fuel

Coal	3,219
Natural Gas	11,219
Petroleum	13,577
Total Energy	377,996
CO2 Emissions	2,090
CH4 Emissions	183
N2O Emissions	1,150
GHG Emissions	12,429

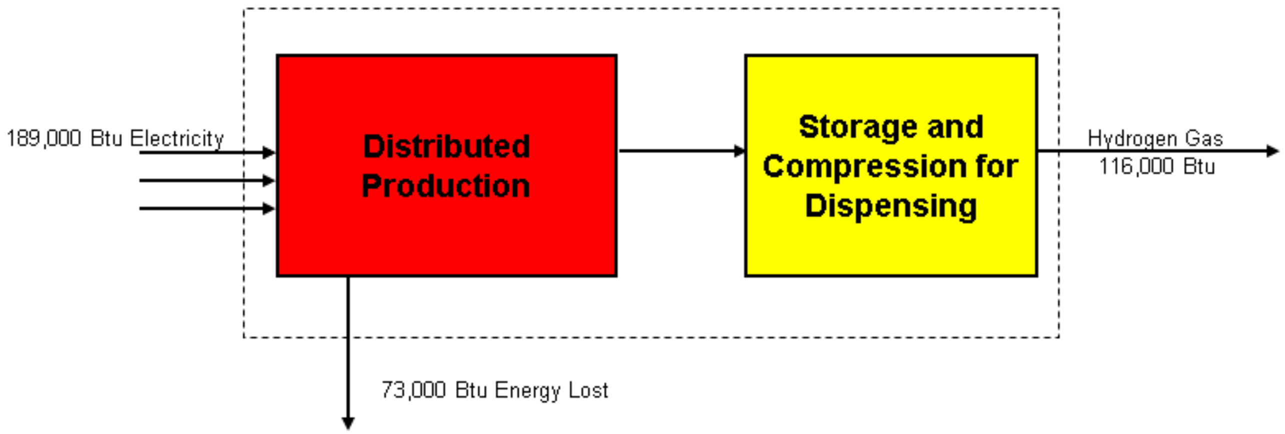
Parameter		Value	Units	Reference	Comments
Case Definition					
	Startup Year	2015		Input	Default for this study's current cases
	Reference Year Dollars	2007		Input	Default for this study's current cases
	Production Technology	ETHANOL		Input	Case definition
	Form of H2 During Delivery	Gas		Input	Case definition
	Delivery Mode	None		Input	Case definition
	Dispensing Mode	CASCADE_700_BAR		Input	Case definition
	Forecourt Station Size	1329	kg/day	Input	Case definition
	Vehicle Type	passenger cars		Input	Case definition
	Vehicle materials (conventional or lightweight)	Conventional		Input	Case definition; lightweight materials not currently an MSM option
	Vehicles' Fuel Economy	48.0	mile / gge	Input	Default assumption for this study's current cases
Market Definition					
	City Population	1,247,364	people	Input	Case Definition: Indianapolis, IN
	Market penetration	15%	(% vehicles in city)	Input	Case definition: Basis for Program Plan
	Number of H2 vehicles in city	138,832	H2 vehicles / city	HDSAM Result	
	Miles driven per vehicle	15,000	mile / vehicle year	Input	CPM only allows for 10K, 15K, and 20K/yr.
	Miles driven per vehicle	160,000	miles in vehicle life	Input - GREET2 default	
	City hydrogen use	121,096	kg / d	HDSAM Result	
	Number of H2 refueling stations in city	92		HDSAM Result	
	Number of H2 stations/Number of gasoline stations	14%		HDSAM Result	
	Average distance between stations (mi)	2.50	miles	HDSAM Result	
Other Assumptions for WTW Calculations					
	Share of RFG in Total Gasoline Use	100%		Input: GREET default	Case definition: Basis for Program Plan
	Type of Oxygenate in RFG	None		Input: GREET default	Case definition: Basis for Program Plan
	O2 Content in RFG	0%	wt %	Input: GREET default	Case definition: Basis for Program Plan
	Ratio of FCEV VOCs (emissions) to GVs fueled with CG & RFG	0%		Input: GREET default	
	Ratio of FCEV VOCs (evaporative) to GVs fueled with CG & RFG	0%		Input: GREET default	
	Ratio of FCEV CO emissions to GVs fueled with CG & RFG	0%		Input: GREET default	
	Ratio of FCEV NOx emissions to GVs fueled with CG & RFG	0%		Input: GREET default	
	Ratio of FCEV Exhaust PM10 emissions to GVs fueled with CG & RFG	0%		Input: GREET default	
	Ratio of FCEV Brake & Tire Wear PM10 emissions to GVs fueled with CG & RFG	100%		Input: GREET default	
	Ratio of FCEV Exhaust PM2.5 emissions to GVs fueled with CG & RFG	0%		Input: GREET default	
	Ratio of FCEV Brake & Tire Wear PM2.5 emissions to GVs fueled with CG & RFG	100%		Input: GREET default	
	Ratio of FCEV CH4 emissions to GVs fueled with CG & RFG	0%		Input: GREET default	
	Ratio of FCEV N2O emissions to GVs fueled with CG & RFG	0%		Input: GREET default	
	Marginal Electricity Generation Mix for Transportation Use	US Mix		Input	Case definition: Basis for Program Plan

Parameter			Value	Units	Reference	Comments
Electricity						
	Grid mix for production		US Mix		GREET input	Default
		Biomass Fraction	0.5%		Definition of US Mix	Energy Information Administration. (2007, February). Annual Energy Outlook 2007 with Projections to 2030. DOE/EIA-0383(2007). Washington, D.C. Retreived from www.eia.doe.gov/oiaf/archive/aeo07/index.html National electricity generation data from tables D-7 & D-8 using the 2005 timeframe. Percentages calculated from total generation values reported with all renewables except biomass aggregated into the "Others (Carbon Neutral)" category
		Coal Fraction	44.2%		Definition of US Mix	
		Natural Gas Fraction	21.5%		Definition of US Mix	
		Nuclear Fraction	21.0%		Definition of US Mix	
		Residual Oil Fraction	0.9%		Definition of US Mix	
		Others (Carbon Neutral - Hydroelectric, Wind, Geothermal, Solar PV, etc)	11.8%		Definition of US Mix	
	Biomass Electricity Shares and Efficiency					
		IGCC Share of Biomass Power Plants	1.0%		GREET default input	
		Combustion Share of Biomass Power Plants	99.0%		GREET default input	By difference from IGCC plants
		Biomass IGCC Efficiency	43.0%		GREET default input	
		Biomass Combustion Plant Efficiency	32.1%		GREET default input	
		Effective Efficiency of Biopower Plants	32.2%		GREET default input	
	Coal Electricity Shares and Efficiency					
		IGCC Share of Coal Power Plants	1.0%		GREET default input	
		Combustion Share of Coal Power Plants	99.0%		GREET default input	
		Coal IGCC Efficiency	47.0%		GREET default input	
		Coal Combustion Plant Efficiency	34.1%		GREET default input	
		Effective Efficiency of Coal-Electricity Plants	34.2%		GREET default input	
	Natural Gas Electricity Shares and Efficiency					
		Simple Cycle Gas Turbine Share of Natural Gas Power Plants	37.0%		GREET default input	
		Combined Cycle Gas Turbine Share of Natural Gas Power Plants	46.0%		GREET default input	
		Combustion Boiler Share of Natural Gas Power Plants	17.0%		GREET default input	
		Natural Gas Simple Cycle Gas Turbine Plant Efficiency	33.1%		GREET default input	
		Natural Gas Combined Cycle Efficiency	55.0%		GREET default input	
		Natural Gas Combustion Boiler Plant Efficiency	34.8%		GREET default input	
		Effective Efficiency of Natural Gas-Electricity Plants	40.9%		GREET default input	
	Residual Oil Electricity Efficiency					
		Residual Oil Electricity Plant Efficiency	34.8%		GREET default input	
	Electicity Transmission and Distribution Losses		8.0%		GREET default input	
Ethanol						
	Percentage of Ethanol from Corn (grain)		0.0%		GREET default input	
	Percentage of Ethanol from Farmed Trees		0.0%		GREET default input	
	Percentage of Ethanol from Switchgrass		0.0%		GREET default input	
	Percentage of Ethanol from Corn Stover		100.0%		GREET default input	
	Percentage of Ethanol from Forest Residue		0.0%		GREET default input	
	Percentage of Ethanol from Sugar Cane		0.0%		GREET default input	
	Corn Stover Farming - Energy Requirement		188,656	Btu / dry ton stover	GREET default input	In addition to corn grain requirement
	Corn Stover Farming - Nitrogen Fertilizer		7,700	g / dry ton stover	GREET default input	In addition to corn grain requirement
	Corn Stover Farming - P2O5 Fertilizer		2,000	g / dry ton stover	GREET default input	In addition to corn grain requirement
	Corn Stover Farming - K2O Fertilizer		12,000	g / dry ton stover	GREET default input	In addition to corn grain requirement
	Corn Stover Farming - Herbicide		0	g / dry ton	GREET default input	In addition to corn grain requirement
	Corn Stover Farming - Insecticide		0	g / dry ton	GREET default input	In addition to corn grain requirement
	Corn Stover Farming - Yield		2.21	dry ton / acre	GREET result	In addition to corn grain requirement
	Are GHG Emissions due to land use change included?		No		GREET default input	In addition to corn grain requirement
	Corn Stover Conversion - Ethanol Yield		90.0	gal / dry ton	GREET default input	
	Corn Stover Conversion - Electricity Co-Product		-2.28	kWh / gal ethanol	GREET default input	

Parameter			Value	Units	Reference	Comments
Parameters for GREET2						
	Vehicle total mass		3,020	lb	GREET2 Default Input	
	Battery Type for Hybridization		NiMH		GREET2 Default Input	
	Hybridization Battery Size in Peak Hybridization Battery Power		30	kW	GREET2 Default Input	
	Hybridization Battery Specific Power		272	W / lb	GREET2 Default Input	
	Hybridization Battery Mass		110	lb	GREET2 Default Input	
	Number of replacements of hybridization battery over lifetime		2		GREET2 Default Input	
	Starter Battery (Lead Acid) Mass		22	lb	GREET2 Default Input	
	Mass of fluids on-board vehicle		56	lb	GREET2 Default Input	
	Component mass (vehicles without batteries or fluids)		2,832	lb	GREET2 Calculation	
		Powertrain system percentage of component mass	8.0%		GREET2 Default Input	
		Transmission system percentage of component mass	2.6%		GREET2 Default Input	
		Chassis (without battery) percentage of component mass	23.0%		GREET2 Default Input	
		Traction motor percentage of component mass	3.8%		GREET2 Default Input	
		Generator percentage of component mass	0.0%		GREET2 Default Input	
		Electronic controller percentage of component mass	3.4%		GREET2 Default Input	
		Fuel Cell Auxiliary System percentage of component mass	19.3%		GREET2 Default Input	
		Body: including BIW, interior, exterior, and glass	39.9%		GREET2 Default Input	
	Fuel Cell Stack Size		70	kW	GREET2 Default Input	
	Mass of Fuel Cell Stack - Powertrain System		226	lb	GREET2 Calculation	
	Mass of Fuel Cell Stack - Auxiliary Systems		546	lb	GREET2 Calculation	
	Miles driven per vehicle over lifetime		160,000	miles in vehicle life	GREET2 Default Input	Current analysis assumes 5-year life, 10-year analysis is available

Appendix C: Distributed Electricity Supporting Tables and Figures

Distributed Hydrogen Production



Well-to-Wheels Total Energy Use (Btu/mile)	9,769
Well-to-Wheels Petroleum Energy Use (Btu/mile)	212
Well-to-Wheels Greenhouse Gas Emissions (g/mile)	822
Levelized Cost of H2 at Pump ($/kg)	6.75

Production Process Energy Efficiency	67%
Pathway Efficiency	61%
WTP Efficiency	25%
WTP Emissions (lb CO2 Equivalent / GGE fuel available):	87

Case Definition
Year: 2015
Hydrogen as Gas
Forecourt Production
ELECTROLYSIS Feedstock
Sequestration: NO
Transport for Delivery: None
Vehicle Efficiency: 48 mile / GGE
City Hydrogen Use: 121096 kg/day

Inputs			Assumptions			Outputs		
			Electricity Generation & Transmission					
			U.S. Grid Mix			Electricity price at H2 production	0.0574	2007$ / kWh
			Biomass Fraction	1%		Electricity Share of H2 Cost	$3.22	2007$ / kg H2 dispensed
			Coal Fraction	44%				
			Natural Gas Fraction	21%		WTG CO2 Emissions	36,930	g CO2 eq./ 116000 Btu
Coal Input (including upstream)	159,600	Btu / 116000Btu to Pump	Nuclear Fraction	21%		WTG CH4 Emissions	2,280	g CO2 eq./ 116000 Btu
Natural Gas Input (including upstream)	70,800	Btu / 116000Btu to Pump	Residual Oil Fraction	1%		WTG N2O Emissions	150	g CO2 eq./ 116000 Btu
Petroleum Input (including upstream)	6,100	Btu / 116000Btu to Pump	Others (Carbon Neutral)	12%		WTG GHG Emissions	39,360	g CO2 eq./ 116000 Btu
						Hydrogen Output Pressure	300	psi
Electricity consumption	50.0	kWh / kg H2 produced	**Hydrogen Production**			Hydrogen Outlet Quality	100.0%	
Process Water Consumption	2.94	gal / kg H2 produced						
Cooling Water Consumption	0.11	gal / kg H2 produced	Distributed plant design capacity	1,500	kg / day	Total capital investment	$1,700	2007$ / daily kg H2 (effective capacity)
			Capacity factor	89%		Levelized Cost of Capital	$0.77	2007$ / kg H2 dispensed
			# of Plants Needed to Meet City Demand	91		Fixed O&M Costs	$0.28	2007$ / kg H2 dispensed
Total Capital Investment per station	$2,258,000	2007$	Process energy efficiency	66.8%		Variable O&M Costs	$0.06	2007$ / kg H2 dispensed
			Electricity Mix	US Mix		Total Levelized Cost	$4.32	2007$ / kg H2 dispensed
			After-tax IRR	10%				
Coal Input (including upstream)	86,400	Btu / 116000Btu to Pump	Assumed Plant Life	20	years	Production CO2 Emissions	0	g CO2 eq./ 116000 Btu
Natural Gas Input (including upstream)	38,300	Btu / 116000Btu to Pump				Production CH4 Emissions	0	g CO2 eq./ 116000 Btu
Petroleum Input (including upstream)	3,300	Btu / 116000Btu to Pump				Production N2O Emissions	0	g CO2 eq./ 116000 Btu
						Production GHG Emissions	0	g CO2 eq./ 116000 Btu
Electricity consumption	4.4	kWh / kg H2	**Forecourt Dispensing**			Hydrogen outlet pressure	12,700	psi
Electricity price	$0.088	2007$ / kWh				Basis -- Hydrogen Quantity	116,000	Btu (116,000 Btu/gal non-oxygenated conventional unleaded gasoline)
			City Population	1,247,000	people			
			Hydrogen Vehicle Penetration	15%				
Total Capital Investment (per station)	$5,059,000	2007$ / station	City hydrogen use	121,100	kg / day	Total capital investment	$3,810	2007$ / daily kg H2 (effective capacity)
Total Capital Investment	$465,391,000	2007$ / all stations	Average Dispensing Rate per Station	1,330	kg / day	Levelized Cost of Capital	$1.49	2007$ / kg H2 dispensed
			Number of Dispensing Stations	92		Energy & Fuel	$0.40	2007$ / kg H2 dispensed
			Number of Compression Steps	0		Other O&M Costs	$0.54	2007$ / kg H2 dispensed
			Usable Low Pressure Storage per Station	1,450	kg H2	Levelized Cost of Dispensing	$2.43	2007$ / kg H2 dispensed
			Usable Cascade Storage per Station	200	kg H2			
Coal Input (including upstream)	21,900	Btu / 116000Btu to Pump	Site storage	100%	% of design capacity	CSD CO2 Emissions	3,020	g CO2 eq./ 116000 Btu
Natural Gas Input (including upstream)	9,700	Btu / 116000Btu to Pump	# of 2-hose Dispensers per Station	3		CSD CH4 Emissions	190	g CO2 eq./ 116000 Btu
Petroleum Input (including upstream)	800	Btu / 116000Btu to Pump	Hydrogen losses	0.50%		CSD N2O Emissions	12	g CO2 eq./ 116000 Btu
						CSD GHG Emissions	3,220	g CO2 eq./ 116000 Btu
Vehicle Mass	3,020	lb	**Vehicle**			Cost Per Mile	$0.71	2007$ / mi
Fuel cell size	70	kW	Fuel Economy	48.0	mi / gge	Fuel Share	$0.14	2007$ / mi
Size of hybridization battery	30	kW	Vehicle Miles Traveled	15,000	mi / yr	Maintenance, Tires, Repairs	$0.07	2007$ / mi
			Vehicle Lifetime	160,000	mi	Insurance & Registration	$0.12	2007$ / mi
			Purchase Year	2015		Depreciation	$0.27	2007$ / mi
			Vehicle Purchase Cost	$33,700	2007$	Financing	$0.10	2007$ / mi
			Fuel Cell System Cost	$4,500	2007$			
Coal Input (including upstream)	2,300	Btu / gge fuel consumed	Hydrogen Storage System Cost	$2,400	2007$	Vehicle Cycle CO2 Emissions	1,670	g CO2 eq / gge fuel consumed
Natural Gas Input (including upstream)	12,100	Btu / gge fuel consumed	Tax Credit	$0	2007$	Vehicle Cycle CH4 Emissions	7	g CO2 eq / gge fuel consumed
Petroleum Input (including upstream)	6,900	Btu / gge fuel consumed				Vehicle Cycle N2O Emissions	0	g CO2 eq / gge fuel consumed
						Vehicle Cycle GHG Emissions	1,850	g CO2 eq / gge fuel consumed

Conversion Facility

Coal	86,402	Btu/116000 Btu
Natural Gas	38,305	Btu/116000 Btu
Petroleum	3,282	Btu/116000 Btu
Total Energy	150,970	Btu/116000 Btu
CO2 Emissions	0	g CO2 eq/116000 Btu
CH4 Emissions	0	g CO2 eq/116000 Btu
N2O Emissions	0	g CO2 eq/116000 Btu
GHG Emissions	0	g CO2 eq/116000 Btu

Dispensing

Coal	21,887	Btu/116000 Btu
Natural Gas	9,703	Btu/116000 Btu
Petroleum	831	Btu/116000 Btu
Total Energy	38,243	Btu/116000 Btu
CO2 Emissions	3,017	g CO2 eq/116000 Btu
CH4 Emissions	186	g CO2 eq/116000 Btu
N2O Emissions	12	g CO2 eq/116000 Btu
GHG Emissions	3,216	g CO2 eq/116000 Btu

Feedstock Processing

Coal	159,645	Btu/116000 Btu
Natural Gas	70,777	Btu/116000 Btu
Petroleum	6,064	Btu/116000 Btu
Total Energy	278,946	Btu/116000 Btu
CO2 Emissions	36,932	g CO2 eq/116000 Btu
CH4 Emissions	2,282	g CO2 eq/116000 Btu
N2O Emissions	150	g CO2 eq/116000 Btu
GHG Emissions	39,364	g CO2 eq/116000 Btu

Electrolysis

Electricity Feedstock	189,369

Dispensing

Dispensing Losses	0.00%

Total to Deliver 116000 Btu Fuel

Coal	267,934
Natural Gas	118,785
Petroleum	10,177
Total Energy	468,159
CO2 Emissions	39,949
CH4 Emissions	2,469
N2O Emissions	162
GHG Emissions	42,580

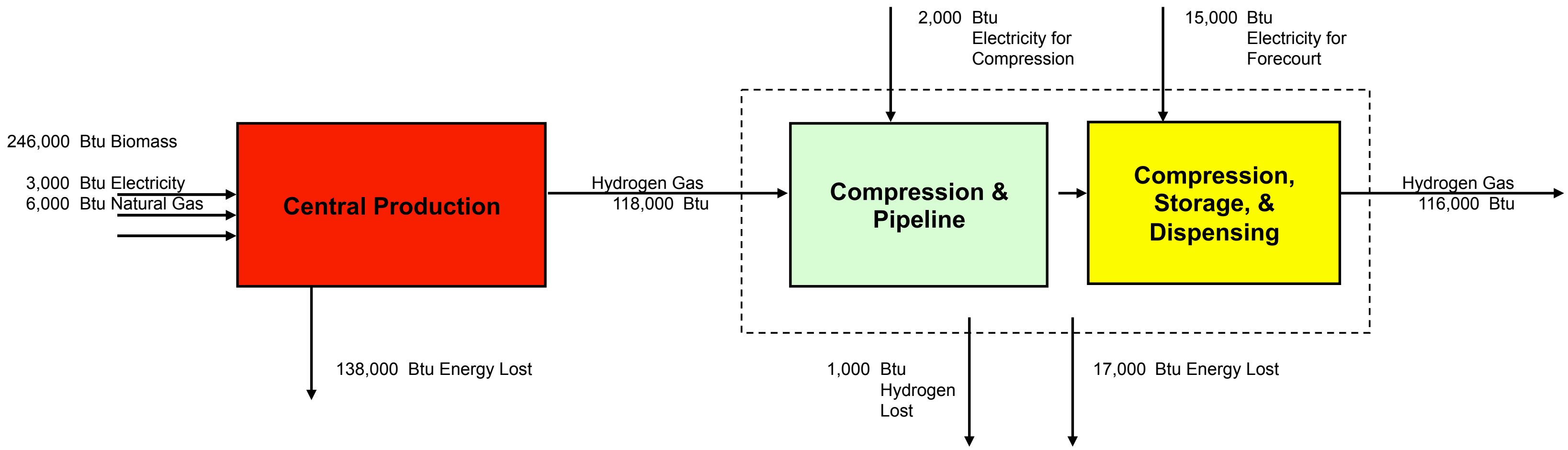
Parameter		Value	Units	Reference	Comments
Case Definition					
	Startup Year	2015		Input	Default for this study's current cases
	Reference Year Dollars	2007		Input	Default for this study's current cases
	Production Technology	ELECTROLYSIS		Input	Case definition
	Form of H2 During Delivery	Gas		Input	Case definition
	Delivery Mode	None		Input	Case definition
	Dispensing Mode	CASCADE_700_BAR		Input	Case definition
	Forecourt Station Size	1329	kg/day	Input	Case definition
	Vehicle Type	passenger cars		Input	Case definition
	Vehicle materials (conventional or lightweight)	Conventional		Input	Case definition; lightweight materials not currently an MSM option
	Vehicles' Fuel Economy	48.0	mile / gge	Input	Default assumption for this study's current cases
Market Definition					
	City Population	1,247,364	people	Input	Case Definition: Indianapolis, IN
	Market penetration	15%	(% vehicles in city)	Input	Case definition: Basis for Program Plan
	Number of H2 vehicles in city	138,832	H2 vehicles / city	HDSAM Result	
	Miles driven per vehicle	15,000	mile / vehicle year	Input	CPM only allows for 10K, 15K, and 20K/yr.
	Miles driven per vehicle	160,000	miles in vehicle life	Input - GREET2 default	
	City hydrogen use	121,096	kg / d	HDSAM Result	
	Number of H2 refueling stations in city	92		HDSAM Result	
	Number of H2 stations/Number of gasoline stations	14%		HDSAM Result	
	Average distance between stations (mi)	2.50	miles	HDSAM Result	
Other Assumptions for WTW Calculations					
	Share of RFG in Total Gasoline Use	100%		Input: GREET default	Case definition: Basis for Program Plan
	Type of Oxygenate in RFG	None		Input: GREET default	Case definition: Basis for Program Plan
	O2 Content in RFG	0%	wt %	Input: GREET default	Case definition: Basis for Program Plan
	Ratio of FCEV VOCs (emissions) to GVs fueled with CG & RFG	0%		Input: GREET default	
	Ratio of FCEV VOCs (evaporative) to GVs fueled with CG & RFG	0%		Input: GREET default	
	Ratio of FCEV CO emissions to GVs fueled with CG & RFG	0%		Input: GREET default	
	Ratio of FCEV NOx emissions to GVs fueled with CG & RFG	0%		Input: GREET default	
	Ratio of FCEV Exhaust PM10 emissions to GVs fueled with CG & RFG	0%		Input: GREET default	
	Ratio of FCEV Brake & Tire Wear PM10 emissions to GVs fueled with CG & RFG	100%		Input: GREET default	
	Ratio of FCEV Exhaust PM2.5 emissions to GVs fueled with CG & RFG	0%		Input: GREET default	
	Ratio of FCEV Brake & Tire Wear PM2.5 emissions to GVs fueled with CG & RFG	100%		Input: GREET default	
	Ratio of FCEV CH4 emissions to GVs fueled with CG & RFG	0%		Input: GREET default	
	Ratio of FCEV N2O emissions to GVs fueled with CG & RFG	0%		Input: GREET default	
	Marginal Electricity Generation Mix for Transportation Use	US Mix		Input	Case definition: Basis for Program Plan

Parameter			Value	Units	Reference	Comments
Electricity						
	Grid mix for production		US Mix		GREET input	Default
		Biomass Fraction	0.5%		Definition of US Mix	Energy Information Administration. (2007, February). Annual Energy Outlook 2007 with Projections to 2030. DOE/EIA-0383(2007). Washington, D.C. Retreived from www.eia.doe.gov/oiaf/archive/aeo07/index.html National electricity generation data from tables D-7 & D-8 using the 2005 timeframe. Percentages calculated from total generation values reported with all renewables except biomass aggregated into the "Others (Carbon Neutral)" category
		Coal Fraction	44.2%		Definition of US Mix	
		Natural Gas Fraction	21.5%		Definition of US Mix	
		Nuclear Fraction	21.0%		Definition of US Mix	
		Residual Oil Fraction	0.9%		Definition of US Mix	
		Others (Carbon Neutral - Hydroelectric, Wind, Geothermal, Solar PV, etc)	11.8%		Definition of US Mix	
	Biomass Electricity Shares and Efficiency					
		IGCC Share of Biomass Power Plants	1.0%		GREET default input	
		Combustion Share of Biomass Power Plants	99.0%		GREET default input	By difference from IGCC plants
		Biomass IGCC Efficiency	43.0%		GREET default input	
		Biomass Combustion Plant Efficiency	32.1%		GREET default input	
		Effective Efficiency of Biopower Plants	32.2%		GREET default input	
	Coal Electricity Shares and Efficiency					
		IGCC Share of Coal Power Plants	1.0%		GREET default input	
		Combustion Share of Coal Power Plants	99.0%		GREET default input	
		Coal IGCC Efficiency	47.0%		GREET default input	
		Coal Combustion Plant Efficiency	34.1%		GREET default input	
		Effective Efficiency of Coal-Electricity Plants	34.2%		GREET default input	
	Natural Gas Electricity Shares and Efficiency					
		Simple Cycle Gas Turbine Share of Natural Gas Power Plants	37.0%		GREET default input	
		Combined Cycle Gas Turbine Share of Natural Gas Power Plants	46.0%		GREET default input	
		Combustion Boiler Share of Natural Gas Power Plants	17.0%		GREET default input	
		Natural Gas Simple Cycle Gas Turbine Plant Efficiency	33.1%		GREET default input	
		Natural Gas Combined Cycle Efficiency	55.0%		GREET default input	
		Natural Gas Combustion Boiler Plant Efficiency	34.8%		GREET default input	
		Effective Efficiency of Natural Gas-Electricity Plants	40.9%		GREET default input	
	Residual Oil Electricity Efficiency					
		Residual Oil Electricity Plant Efficiency	34.8%		GREET default input	
	Electicity Transmission and Distribution Losses		8.0%		GREET default input	

Parameter			Value	Units	Reference	Comments
Parameters for GREET2						
	Vehicle total mass		3,020	lb	GREET2 Default Input	
	Battery Type for Hybridization		NiMH		GREET2 Default Input	
	Hybridization Battery Size in Peak Hybridization Battery Power		30	kW	GREET2 Default Input	
	Hybridization Battery Specific Power		272	W / lb	GREET2 Default Input	
	Hybridization Battery Mass		110	lb	GREET2 Default Input	
	Number of replacements of hybridization battery over lifetime		2		GREET2 Default Input	
	Starter Battery (Lead Acid) Mass		22	lb	GREET2 Default Input	
	Mass of fluids on-board vehicle		56	lb	GREET2 Default Input	
	Component mass (vehicles without batteries or fluids)		2,832	lb	GREET2 Calculation	
		Powertrain system percentage of component mass	8.0%		GREET2 Default Input	
		Transmission system percentage of component mass	2.6%		GREET2 Default Input	
		Chassis (without battery) percentage of component mass	23.0%		GREET2 Default Input	
		Traction motor percentage of component mass	3.8%		GREET2 Default Input	
		Generator percentage of component mass	0.0%		GREET2 Default Input	
		Electronic controller percentage of component mass	3.4%		GREET2 Default Input	
		Fuel Cell Auxiliary System percentage of component mass	19.3%		GREET2 Default Input	
		Body: including BIW, interior, exterior, and glass	39.9%		GREET2 Default Input	
	Fuel Cell Stack Size		70	kW	GREET2 Default Input	
	Mass of Fuel Cell Stack - Powertrain System		226	lb	GREET2 Calculation	
	Mass of Fuel Cell Stack - Auxiliary Systems		546	lb	GREET2 Calculation	
	Miles driven per vehicle over lifetime		160,000	miles in vehicle life	GREET2 Default Input	Current analysis assumes 5-year life, 10-year analysis is available

Appendix D: Central Biomass—Pipeline Delivery Supporting Tables and Figures

Hydrogen Produced In Central Plant and Transported as Gas via Pipeline



Well-to-Wheels Total Energy Use (Btu/mile)	6,594
Well-to-Wheels Petroleum Energy Use (Btu/mile)	153
Well-to-Wheels Greenhouse Gas Emissions (g/mile)	124
Levelized Cost of H2 at Pump ($/kg)	6.32

Production Process Energy Efficiency	46%
Pathway Efficiency	43%
WTP Efficiency	37%
CO2 Equivalent / GGE fuel available): GHG	13

Case Definition
Year: 2015
Hydrogen as Gas
Central Production
WOODY BIOMASS Feedstock
Sequestration: NO
Transport for Delivery: Pipeline
Vehicle Efficiency: 48 mile / GGE
City Hydrogen Use: 121096 kg/day

Inputs		

Biomass Production & Delivery

Inputs

Energy Use for Farming Trees	235,000	Btu / dry ton
Coal Input (including upstream)	200	Btu / 116000Btu to Pump
Natural Gas Input (including upstream)	600	Btu / 116000Btu to Pump
Petroleum Input (including upstream)	2,900	Btu / 116000Btu to Pump

Assumptions

Fraction of Woody Biomass	100%	
LUC GHG changes	='Params - U	g / dry ton
Average dist from farm to H2 production	›stream'!E15	miles

Outputs

Biomass moisture content	25%	
Woody biomass LHV	16,013,200	Btu / dry ton
Biomass price at H2 production	$75	2007 $ / dry ton
Biomass Share of Levelized Cos	$0.97	2007$ / kg H2 dispensed
WTG CO2 Emissions	-24,830	g CO2 eq./ 116000 Btu
WTG CH4 Emissions	13	g CO2 eq./ 116000 Btu
WTG N2O Emissions	35	g CO2 eq./ 116000 Btu
WTG GHG Emissions	-24,780	g CO2 eq./ 116000 Btu

Hydrogen Production

Inputs

Biomass consumption	13.5	kg (dry) / kg H2 produced
Natural gas consumption	0.0059	MMBtu / kg H2 produced
Electricity consumption	0.98	kWh / kg H2 produced
Process Water Consumption	1.32	gal / kg H2 produced
Cooling Water Consumption	79.3	gal / kg H2 produced
Total Capital Investment	$181,080,000	2007$
Coal Input (including upstream)	5,100	Btu / 116000Btu to Pump
Natural Gas Input (including upstream)	9,500	Btu / 116000Btu to Pump
Petroleum Input (including upstream)	3,400	Btu / 116000Btu to Pump

Assumptions

Central plant design capacity	155,200	kg / day
Capacity factor	90%	
Number of production facilities necessary	0.87	
Process energy efficiency	46.0%	
Electricity Mix	US Mix	
After-tax IRR	10%	
Assumed Plant Life	40	

Outputs

Hydrogen Output Pressure	300	psi
Hydrogen Outlet Quality	99.9%	
Total capital investment	$1,300	2007$ / daily kg H2 (effective capacity)
Levelized Cost of Capital	$0.64	2007$ / kg H2 dispensed
Fixed O&M Costs	$0.23	2007$ / kg H2 dispensed
Variable O&M Costs	$0.40	2007$ / kg H2 dispensed
Total Levelized Cost	$2.24	2007$ / kg H2 dispensed
Production CO2 Emissions	26,510	g CO2 eq./ 116000 Btu
Production CH4 Emissions	140	g CO2 eq./ 116000 Btu
Production N2O Emissions	43	g CO2 eq./ 116000 Btu
Production GHG Emissions	26,690	g CO2 eq./ 116000 Btu

Pipelines for Delivery

Inputs

Electricity consumption for compressor	0.56	kWh / kg H2 dispensed
Electricity consumption for geo storage	0.01	kWh / kg H2 dispensed
Total electricity consumption	0.57	kWh / kg H2 dispensed
Total Capital Investment	$404,341,000	2007$
Coal Input (including upstream)	2,800	Btu / 116000Btu to Pump
Natural Gas Input (including upstream)	1,300	Btu / 116000Btu to Pump
Petroleum Input (including upstream)	100	Btu / 116000Btu to Pump

Assumptions

City Population	1,247,000	people
Hydrogen Vehicle Penetration	15%	
City hydrogen use	121,100	kg / day
Distance from City to Production Facility	62	miles
Geologic storage capacity	1,325,000	kg H2
Number of trunk pipelines	3	
Service-line length	1.5	miles / line
Number of service lines	122	
Hydrogen losses	0.80%	

Outputs

Total capital investment	$3,300	2007$ / daily kg H2 (effective capacity)
Levelized Cost of Capital	$1.71	2007$ / kg H2 dispensed
Energy & Fuel	$0.04	2007$ / kg H2 dispensed
Other O&M Costs	$0.40	2007$ / kg H2 dispensed
Levelized Cost of Delivery	$2.15	2007$ / kg H2 dispensed
Delivery CO2 Emissions	390	g CO2 eq./ 116000 Btu
Delivery CH4 Emissions	24	g CO2 eq./ 116000 Btu
Delivery N2O Emissions	2	g CO2 eq./ 116000 Btu
Delivery GHG Emissions	420	g CO2 eq./ 116000 Btu

Forecourt Dispensing

Inputs

Electricity consumption	4.4	kWh / kg H2 dispensed
Total Capital Investment per Station	$2,629,000	2007$ / station
Total Capital Investment	$320,679,000	2007$ / all stations
Inlet pressure of hydrogen at stations	300	psi
Coal Input (including upstream)	24,400	Btu / 116000 Btu to Pump
Natural Gas Input (including upstream)	10,800	Btu / 116000 Btu to Pump
Petroleum Input (including upstream)	900	Btu / 116000 Btu to Pump

Assumptions

Average Dispensing Rate per Station	1,000	kg/day
Number of Dispensing Stations	122	
Number of Compression Steps	5	
Usable Low Pressure Storage per Station	370	kg H2
Usable Cascade Storage per Station	130	kg H2
Site storage	42%	% of design capacity
# of 2-hose Dispensers per Station	2	
Hydrogen Losses	0.50%	

Outputs

Hydrogen outlet pressure	12,700	psi
Basis -- Hydrogen Quantity	116,000	Btu (116,000 Btu/gal non-oxygenated conventional unleaded gasoline)
Total capital investment	$2,650	2007$ / daily kg H2 (effective capacity)
Levelized Cost of Capital	$1.08	2007$ / kg H2 dispensed
Energy & Fuel	$0.41	2007$ / kg H2 dispensed
Other O&M Costs	$0.43	2007$ / kg H2 dispensed
Levelized Cost of Dispensing	$1.93	2007$ / kg H2 dispensed
CSD CO2 Emissions	3,370	g CO2 eq./ 116000 Btu
CSD CH4 Emissions	210	g CO2 eq./ 116000 Btu
CSD N2O Emissions	14	g CO2 eq./ 116000 Btu
CSD GHG Emissions	3,590	g CO2 eq./ 116000 Btu

Vehicle

Inputs

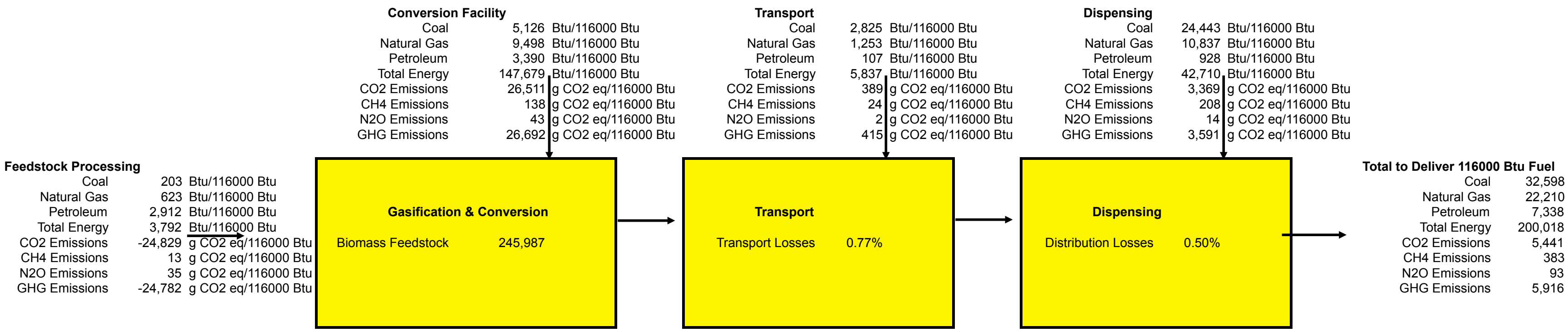
Vehicle Mass	3,020	lb
Fuel cell size	70	kW
Hybridization battery (peak power)	30	kW
Coal Input (including upstream)	2,300	Btu / gge fuel consumed
Natural Gas Input (including upstream)	12,100	Btu / gge fuel consumed
Petroleum Input (including upstream)	6,900	Btu / gge fuel consumed

Assumptions

Fuel Economy	48.0	mi / gge
Vehicle Miles Traveled	15,000	mi / yr
Vehicle Lifetime	160,000	mi
Purchase Year	2015	
Vehicle Purchase Cost	$33,700	2007$
Fuel Cell System Cost	$4,500	2007$
Hydrogen Storage System Cost	$2,400	2007$
Tax Credit	$0	2007$

Outputs

Cost Per Mile	$0.70	2007$ / mi
Fuel Share	$0.13	2007$ / mi
Maintenance, Tires, Repairs	$0.07	2007$ / mi
Insurance & Registration	$0.12	2007$ / mi
Depreciation	$0.27	2007$ / mi
Financing	$0.10	2007$ / mi
Veh. Cycle CO2 Emissions	1,670	g CO2 eq/ gge fuel consumed
Veh. Cycle CH4 Emissions	7	g CO2 eq/ gge fuel consumed
Veh. Cycle N2O Emissions	0	g CO2 eq/ gge fuel consumed
Veh. Cycle GHG Emissions	1,850	g CO2 eq/ gge fuel consumed


Conversion Facility
Coal 5,126 Btu/116000 Btu
Natural Gas 9,498 Btu/116000 Btu
Petroleum 3,390 Btu/116000 Btu
Total Energy 147,679 Btu/116000 Btu
CO2 Emissions 26,511 g CO2 eq/116000 Btu
CH4 Emissions 138 g CO2 eq/116000 Btu
N2O Emissions 43 g CO2 eq/116000 Btu
GHG Emissions 26,692 g CO2 eq/116000 Btu
Transport
Coal 2,825 Btu/116000 Btu
Natural Gas 1,253 Btu/116000 Btu
Petroleum 107 Btu/116000 Btu
Total Energy 5,837 Btu/116000 Btu
CO2 Emissions 389 g CO2 eq/116000 Btu
CH4 Emissions 24 g CO2 eq/116000 Btu
N2O Emissions 2 g CO2 eq/116000 Btu
GHG Emissions 415 g CO2 eq/116000 Btu
Dispensing
Coal 24,443 Btu/116000 Btu
Natural Gas 10,837 Btu/116000 Btu
Petroleum 928 Btu/116000 Btu
Total Energy 42,710 Btu/116000 Btu
CO2 Emissions 3,369 g CO2 eq/116000 Btu
CH4 Emissions 208 g CO2 eq/116000 Btu
N2O Emissions 14 g CO2 eq/116000 Btu
GHG Emissions 3,591 g CO2 eq/116000 Btu
Feedstock Processing
Coal 203 Btu/116000 Btu
Natural Gas 623 Btu/116000 Btu
Petroleum 2,912 Btu/116000 Btu
Total Energy 3,792 Btu/116000 Btu
CO2 Emissions -24,829 g CO2 eq/116000 Btu
CH4 Emissions 13 g CO2 eq/116000 Btu
N2O Emissions 35 g CO2 eq/116000 Btu
GHG Emissions -24,782 g CO2 eq/116000 Btu
Gasification & Conversion
Biomass Feedstock 245,987
Transport
Transport Losses 0.77%
Dispensing
Distribution Losses 0.50%
Total to Deliver 116000 Btu Fuel
Coal 32,598
Natural Gas 22,210
Petroleum 7,338
Total Energy 200,018
CO2 Emissions 5,441
CH4 Emissions 383
N2O Emissions 93
GHG Emissions 5,916

Parameter		Hold	Value	Units	Reference	Comments
Case Definition						
	Startup Year	2015	2015		Input	Default for this study's current cases
	Reference Year Dollars	2007	2007		Input	Default for this study's current cases
	Production Technology	WOODY BIOMASS	WOODY BIOMASS		Input	Case definition
	Form of H2 During Delivery	Gas	Gas		Input	Case definition
	Delivery Mode	Pipeline	Pipeline		Input	Case definition
	Dispensing Mode	CASCADE_700_BAR	CASCADE_700_BAR		Input	Case definition
	Forecourt Station Size	1000	1000	kg/day	Input	Case definition
	Vehicle Type	passenger cars	passenger cars		Input	Case definition
	Vehicle materials (conventional or lightweight)	Conventional	Conventional		Input	Case definition; lightweight materials not currently an MSM option
	Vehicles' Fuel Economy	48.0	48.0	mile / gge	Input	Default assumption for this study's current cases
Market Definition						
	City Population	1,247,364	1,247,364	people	Input	Case Definition: Indianapolis, IN
	Market penetration	15%	15%	(% vehicles in city)	Input	Case definition: Basis for Program Plan
	Number of H2 vehicles in city	138,832	138,832	H2 vehicles / city	HDSAM Result	
	Miles driven per vehicle	15,000	15,000	mile / vehicle year	Input	CPM only allows for 10K, 15K, and 20K/yr.
	Miles driven per vehicle	160,000	160,000	miles in vehicle life	Input - GREET2 default	
	City hydrogen use	121,096	121,096	kg / d	HDSAM Result	
	Number of H2 refueling stations in city	122	122		HDSAM Result	
	Number of H2 stations/Number of gasoline stations	19%	19%		HDSAM Result	
	Average distance between stations (mi)	2.17	2.17	miles	HDSAM Result	
Other Assumptions for WTW Calculations						
	Share of RFG in Total Gasoline Use	100%	100%		Input: GREET default	Case definition: Basis for Program Plan
	Type of Oxygenate in RFG	None	None		Input: GREET default	Case definition: Basis for Program Plan
	O2 Content in RFG	0%	0%	wt %	Input: GREET default	Case definition: Basis for Program Plan
	Ratio of FCEV VOCs (emissions) to GVs fueled with CG & RFG	0%	0%		Input: GREET default	
	Ratio of FCEV VOCs (evaporative) to GVs fueled with CG & RFG	0%	0%		Input: GREET default	
	Ratio of FCEV CO emissions to GVs fueled with CG & RFG	0%	0%		Input: GREET default	
	Ratio of FCEV NOx emissions to GVs fueled with CG & RFG	0%	0%		Input: GREET default	
	Ratio of FCEV Exhaust PM10 emissions to GVs fueled with CG & RFG	0%	0%		Input: GREET default	
	Ratio of FCEV Brake & Tire Wear PM10 emissions to GVs fueled with CG & RFG	100%	100%		Input: GREET default	
	Ratio of FCEV Exhaust PM2.5 emissions to GVs fueled with CG & RFG	0%	0%		Input: GREET default	
	Ratio of FCEV Brake & Tire Wear PM2.5 emissions to GVs fueled with CG & RFG	100%	100%		Input: GREET default	
	Ratio of FCEV CH4 emissions to GVs fueled with CG & RFG	0%	0%		Input: GREET default	
	Ratio of FCEV N2O emissions to GVs fueled with CG & RFG	0%	0%		Input: GREET default	
	Marginal Electricity Generation Mix for Transportation Use	US Mix	US Mix		Input	Case definition: Basis for Program Plan

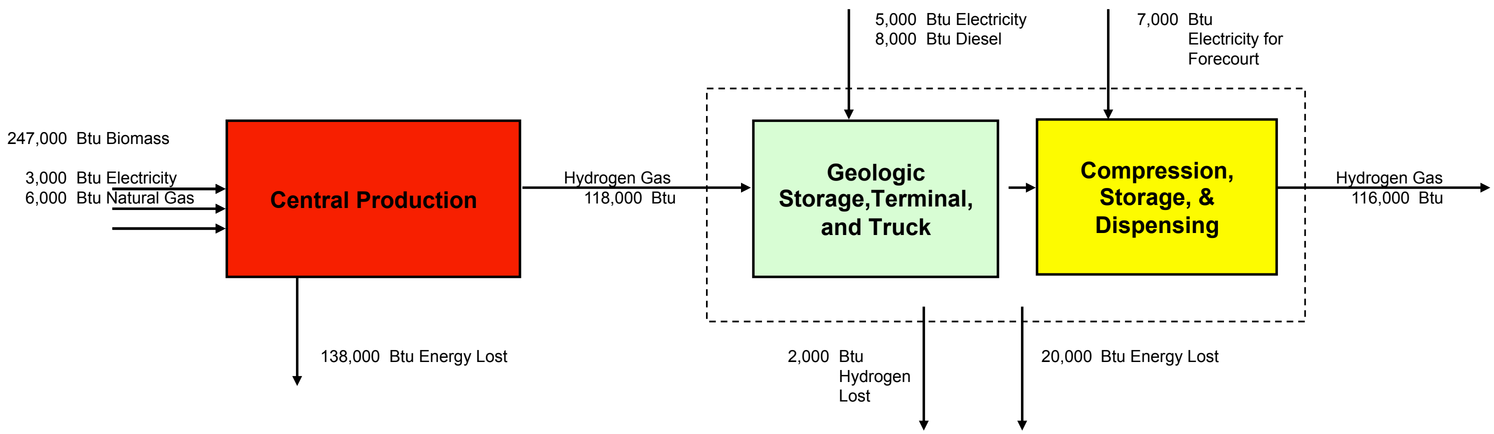
Parameter		Value	Units	Reference	Comments
Biomass					
	Percentage of Woody Biomass (Remainder is Herbaceous)	100%		H2A default	Current central H2A production via biomass gasification based on Mann, M & Steward, D.M. (2008, May 28)
	Biomass (Farmed Trees) Moisture Content	25%		GREET default input	H2A does not specify moisture content so GREET's default was used for GREET calculations
	Energy Use for farming trees	234,964	Btu / dry ton	GREET default input	Energy use and fertilizer based on short rotation woody crops (e.g., willow)
	Percentage that is diesel	94%		GREET default input	
	Percentage that is electricity	5.7%		GREET default input	
	Grams of Nitrogen / short ton biomass (farmed trees)	709	g / dry ton	GREET default input	Equivalent to 75 lb N / ac in the maintenance year Year 3 or 4) which is reported by De La Torre Ugarte, 2003, App 3.1, assuming 6 dry tons biomass per acre, and harvesting once every 8 years. App 3.1 is for planting on cropland that was just used for traditional crops.
	Grams of P2O5 / short ton biomass (farmed trees)	189	g / dry ton	GREET default input	Equivalent to 20 lb P / ac in the maintenance year (Year 3) which is in the range of 15-50 lb P / ac reported by De La Torre Ugarte, 2003, App 3.1, assuming 6 dry tons biomass per acre and harvesting once every 8 years
	Grams of K2O / short ton biomass (farmed trees)	331	g / dry ton	GREET default input	Equivalent to 35 lb K / ac in the maintenance year (Year 3) which is in the range of 15-50 lb K / ac reported by De La Torre Ugarte, 2003, App 3.1, assuming 6 dry tons biomass per acre and harvesting once every 8 years)
	Grams of herbicide / short ton biomass (farmed trees)	24	g / dry ton	GREET default input	Equivalent to 2.0 lb herbicide / ac in the planting year which similar to the 2.0 lb glyphosate / ac reported by De La Torre Ugarte, 2000, App 3.2, assuming 6 dry tons biomass per acre and harvesting once every 8 years. Booth reported Trifluralin (5 L/ha) and Metribuzin (395 g/ha). App 3.2 is for planting on currently idled cropland or cropland that was just used for pasture.
	Grams of insecticide / short ton biomass (farmed trees)	2.0	g / dry ton	GREET default input	As a check, looked at Chastagner: Up to 56% of acreage annually sprayed with Dimethoate (Digon 400, 2-3 pints per acre); up to 56% of acreage annually sprayed with Permethrin 2LB (Ambush, 6.4 ounces per acre); Up to 12% of acreage annually sprayed with Endosulfan 3 EC (24c WA-990025, 2 qts per acre).
	Are GHG Emissions due to land use change included?	No		GREET default input	
	Land use change GHG removal	0	g / dry ton	GREET default input	GREET model default based on ANL personal communications
	Average distance from farm to hydrogen production facility	40	miles	GREET default input	GREET basis: distance could be limited by transport costs?
	Fuel economy on trip from farm to hydrogen production facility	5	mpg diesel	GREET default input	
	Fuel economy on return trip from hydrogen production facility to farm (heavy heavy-dut	5	mpg diesel	GREET default input	

Parameter			Value	Units	Reference	Comments
Natural Gas						
	Percent of NG that is Shale Gas (remainder is conventional NG)		32.1%		GREET default input	
	NG recovery efficiency		95.7%		GREET default input	
	NG lost during recovery		399	g/MMBtu	GREET default input	Previously reported at percent of total NG not on a MMBtu basis
	Percentage of energy use/loss for recovery that is combusted natural gas		49.0%		GREET default input	
	Shale gas recovery efficiency		96.5%		GREET default input	
	Shale gas lost during recovery		245	g/MMBtu	GREET default input	
	Percentage of energy use/loss for recovery that is combusted shale gas		57.4%		GREET default input	
	NG processing energy efficiency		97.2%		Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Results*. Argonne, IL: Argonne National Laboratory.	GREET uses 97.5% which is comparable to several other models (Table 4.11)
	NG lost during processing		33	g/MMBtu	GREET default input	
	Percentage of energy use for processing that is combusted natural gas		90.7%		GREET default input	
	NG used & lost during transport and distribution		199435	g / MMBtu	GREET default input	
	NG transport distance		500	miles	GREET default input	
Electricity						
	Grid mix for production		US Mix		GREET input	Default
		Biomass Fraction	0.5%		Definition of US Mix	Energy Information Administration. (2007, February). Annual Energy Outlook 2007 with Projections to 2030. DOE/EIA-0383(2007). Washington, D.C. Retreived from www.eia.doe.gov/oiaf/archive/aeo07/index.html National electricity generation data from tables D-7 & D-8 using the 2005 timeframe. Percentages calculated from total generation values reported with all renewables except biomass aggregated into the "Others (Carbon Neutral)" category
		Coal Fraction	44.2%		Definition of US Mix	
		Natural Gas Fraction	21.5%		Definition of US Mix	
		Nuclear Fraction	21.0%		Definition of US Mix	
		Residual Oil Fraction	0.9%		Definition of US Mix	
		Others (Carbon Neutral - Hydroelectric, Wind, Geothermal, Solar PV, etc)	11.8%		Definition of US Mix	
	Biomass Electricity Shares and Efficiency					
		IGCC Share of Biomass Power Plants	1.0%		GREET default input	
		Combustion Share of Biomass Power Plants	99.0%		GREET default input	By difference from IGCC plants
		Biomass IGCC Efficiency	43.0%		GREET default input	
		Biomass Combustion Plant Efficiency	32.1%		GREET default input	
		Effective Efficiency of Biopower Plants	32.2%		GREET default input	
	Coal Electricity Shares and Efficiency					
		IGCC Share of Coal Power Plants	1.0%		GREET default input	
		Combustion Share of Coal Power Plants	99.0%		GREET default input	
		Coal IGCC Efficiency	47.0%		GREET default input	
		Coal Combustion Plant Efficiency	34.1%		GREET default input	
		Effective Efficiency of Coal-Electricity Plants	34.2%		GREET default input	
	Natural Gas Electricity Shares and Efficiency					
		Simple Cycle Gas Turbine Share of Natural Gas Power Plants	37.0%		GREET default input	
		Combined Cycle Gas Turbine Share of Natural Gas Power Plants	46.0%		GREET default input	
		Combustion Boiler Share of Natural Gas Power Plants	17.0%		GREET default input	
		Natural Gas Simple Cycle Gas Turbine Plant Efficiency	33.1%		GREET default input	
		Natural Gas Combined Cycle Efficiency	55.0%		GREET default input	
		Natural Gas Combustion Boiler Plant Efficiency	34.8%		GREET default input	
		Effective Efficiency of Natural Gas-Electricity Plants	40.9%		GREET default input	
	Residual Oil Electricity Efficiency					
		Residual Oil Electricity Plant Efficiency	34.8%		GREET default input	
	Electicity Transmission and Distribution Losses		8.0%		GREET default input	

Parameter			Value	Units	Reference	Comments
Parameters for GREET2						
	Vehicle total mass		3,020	lb	GREET2 Default Input	
	Battery Type for Hybridization		NiMH		GREET2 Default Input	
	Hybridization Battery Size in Peak Hybridization Battery Power		30	kW	GREET2 Default Input	
	Hybridization Battery Specific Power		272	W / lb	GREET2 Default Input	
	Hybridization Battery Mass		110	lb	GREET2 Default Input	
	Number of replacements of hybridization battery over lifetime		2		GREET2 Default Input	
	Starter Battery (Lead Acid) Mass		22	lb	GREET2 Default Input	
	Mass of fluids on-board vehicle		56	lb	GREET2 Default Input	
	Component mass (vehicles without batteries or fluids)		2,832	lb	GREET2 Calculation	
		Powertrain system percentage of component mass	8.0%		GREET2 Default Input	
		Transmission system percentage of component mass	2.6%		GREET2 Default Input	
		Chassis (without battery) percentage of component mass	23.0%		GREET2 Default Input	
		Traction motor percentage of component mass	3.8%		GREET2 Default Input	
		Generator percentage of component mass	0.0%		GREET2 Default Input	
		Electronic controller percentage of component mass	3.4%		GREET2 Default Input	
		Fuel Cell Auxiliary System percentage of component mass	19.3%		GREET2 Default Input	
		Body: including BIW, interior, exterior, and glass	39.9%		GREET2 Default Input	
	Fuel Cell Stack Size		70	kW	GREET2 Default Input	
	Mass of Fuel Cell Stack - Powertrain System		226	lb	GREET2 Calculation	
	Mass of Fuel Cell Stack - Auxiliary Systems		546	lb	GREET2 Calculation	
	Miles driven per vehicle over lifetime		160,000	miles in vehicle life	GREET2 Default Input	Current analysis assumes 5-year life, 10-year analysis is available

Appendix E: Central Biomass—Gaseous H_2 Truck Delivery Supporting Tables and Figures

Hydrogen Produced In Central Plant and Transported as Gas via Truck

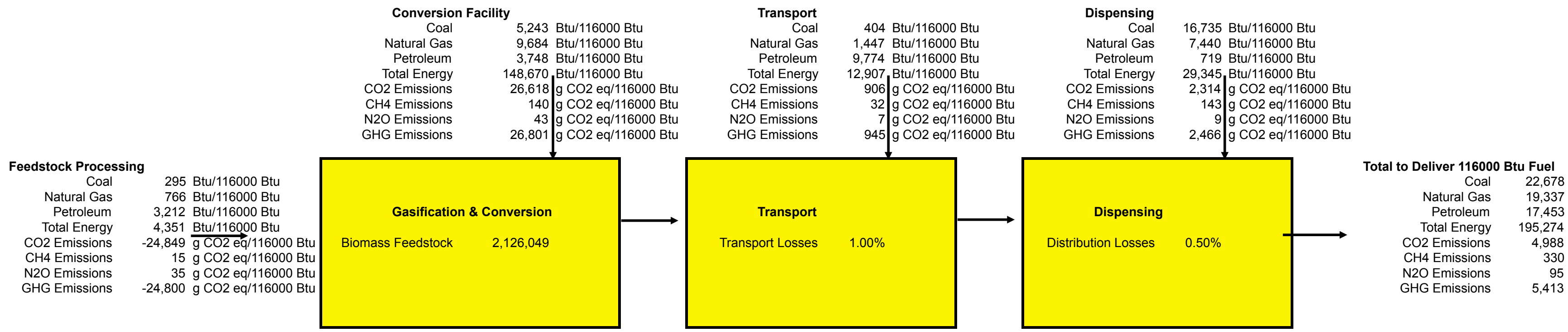


Well-to-Wheels Total Energy Use (Btu/mile)	6,495
Well-to-Wheels Petroleum Energy Use (Btu/mile)	364
Well-to-Wheels Greenhouse Gas Emissions (g/mile)	113
Levelized Cost of H2 at Pump ($/kg)	5.74

Production Process Energy Efficiency	46%
Pathway Efficiency	43%
WTP Efficiency	37%
WTP Emissions (lb CO2 Equivalent / GGE fuel available):	12

Case Definition
Year: 2015
Hydrogen as Gas
Central Production
WOODY BIOMASS Feedstock
Sequestration: NO
Transport for Delivery: Gas Truck
Vehicle Efficiency: 48 mile / GGE
City Hydrogen Use: 121096 kg/day

Inputs			Assumptions			Outputs		
						Biomass moisture content	25%	
			Biomass Production & Delivery			Woody biomass LHV	16,013,000	Btu / dry ton
Energy Use for Farming Trees	235,000	Btu / dry ton				Biomass price at H2 production	$75.02	2007 $ / dry ton
			Fraction of Woody Biomass	100%		Biomass Share of Levelized Cos	$0.97	2007$ / kg H2 dispensed
			LUC GHG changes	0	g / dry ton			
Coal Input (including upstream)	300	Btu / 116000Btu to Pump	Average distance from farm to H2 prod.	40	miles	WTG CO2 Emissions	-24,850	g CO2 eq./ 116000 Btu
Natural Gas Input (including upstream)	800	Btu / 116000Btu to Pump				WTG CH4 Emissions	15	g CO2 eq./ 116000 Btu
Petroleum Input (including upstream)	3,200	Btu / 116000Btu to Pump				WTG N2O Emissions	35	g CO2 eq./ 116000 Btu
						WTG GHG Emissions	-24,800	g CO2 eq./ 116000 Btu
						Hydrogen Output Pressure	300	psi
Biomass consumption	13.5	kg (dry) / kg H2 produced	**Hydrogen Production**			Hydrogen Outlet Quality	99.9%	
Natural gas consumption	0.0059	MMBtu / kg H2 produced						
Electricity consumption	0.98	kWh / kg H2 produced	Central plant design capacity	155,200	kg / day	Total capital investment	$1,300	2007$ / daily kg H2 (effective capacity)
Process Water Consumption	1.32	gal / kg H2 produced	Capacity factor	90%		Levelized Cost of Capital	$0.65	2007$ / kg H2 dispensed
Cooling Water Consumption	79.3	gal / kg H2 produced	Number of production facilities necessary	0.87		Fixed O&M Costs	$0.23	2007$ / kg H2 dispensed
			Process energy efficiency	46.0%		Variable O&M Costs	$0.40	2007$ / kg H2 dispensed
Total Capital Investment	$181,080,000	2007$	Electricity Mix	US Mix		Total Levelized Cost	$2.25	2007$ / kg H2 dispensed
			After-tax IRR	10%				
Coal Input (including upstream)	5,200	Btu / 116000Btu to Pump	Assumed Plant Life	40		Production CO2 Emissions	26,620	g CO2 eq./ 116000 Btu
Natural Gas Input (including upstream)	9,700	Btu / 116000Btu to Pump				Production CH4 Emissions	140	g CO2 eq./ 116000 Btu
Petroleum Input (including upstream)	3,700	Btu / 116000Btu to Pump				Production N2O Emissions	43	g CO2 eq./ 116000 Btu
						Production GHG Emissions	26,800	g CO2 eq./ 116000 Btu
						Total capital investment	$2,100	2007$ / daily kg delivered
Electricity consumption at terminal	1.31	kWh / kg H2 dispensed	**Gas Trucks for Delivery (with Terminal and Geologic Storage)**			Levelized Electricity cost	$0.09	2007$ / kg H2 delivered
Electricity consumption for geo storage	0.01	kWh / kg H2 dispensed				Levelized Diesel cost	$0.20	2007$ / kg H2 delivered
Total electricity consumption	1.32	kWh / kg H2 dispensed	City Population	1,247,000	people	Levelized Labor cost	$0.41	2007$ / kg H2 delivered
Diesel consumption	58.9	gal / 1000 kg H2	Hydrogen Vehicle Penetration	15%		Levelized Other operating costs	$0.34	2007$ / kg H2 delivered
			City hydrogen use	121,100	kg / day			
			One-way distance for delivery	62	miles	Levelized Cost of Delivery	$1.88	2007$ / kg H2 delivered
Total Capital Investment	$254,858,000	2007$	Storage capacity (geologic + terminal)	1,470,000	kg H2			
			Number of truck-trips required	79,700	per year	Delivery CO2 Emissions	910	g CO2 eq./ 116000 Btu
Coal Input (including upstream)	400	Btu / 116000Btu to Pump	Truck hydrogen capacity	560	kg / truckload	Delivery CH4 Emissions	32	g CO2 eq./ 116000 Btu
Natural Gas Input (including upstream)	1,400	Btu / 116000Btu to Pump	Efficiency of truck loading compressors	88.0%		Delivery N2O Emissions	7	g CO2 eq./ 116000 Btu
Petroleum Input (including upstream)	9,800	Btu / 116000Btu to Pump	Hydrogen losses	1.0%		Delivery GHG Emissions	950	g CO2 eq./ 116000 Btu
						Hydrogen outlet pressure	12,700	psi
Electricity consumption	2.1	kWh / kg H2	**Forecourt Dispensing**			Basis -- Hydrogen Quantity	116,000	Btu (116,000 Btu/gal non-oxygenated
Electricity price	$0.096	2007$ / kWh						conventional unleaded gasoline)
			Average Dispensing Rate per Station	800	kg / day	Total capital investment	$2,190	2007$ / daily kg
Total Capital Investment per Station	$1,744,000	2007$ / station	Number of Dispensing Stations	152		Levelized Cost of Capital	$0.95	2007$ / kg H2 dispensed
Total Capital Investment	$265,136,000	2007$ / all stations	Number of Compressor Steps	5		Energy & Fuel	$0.20	2007$ / kg H2 dispensed
			Usable Low Pressure Storage per Station	N/A	(storage on trucks)	Other O&M Costs	$0.46	2007$ / kg H2 dispensed
Minimum inlet pressure from tube trailer	220	psi	Usable Cascade Storage per Station	130	kg H2	Levelized Cost of Dispensing	$1.61	2007$ / kg H2 dispensed
Coal Input (including upstream)	16,700	Btu / 116000Btu to Pump	Site storage	14%	% of design capacity	CSD CO2 Emissions	2,310	g CO2 eq./ 116000 Btu
Natural Gas Input (including upstream)	7,400	Btu / 116000Btu to Pump	# of 2-hose Dispensers per Station	2		CSD CH4 Emissions	140	g CO2 eq./ 116000 Btu
Petroleum Input (including upstream)	700	Btu / 116000Btu to Pump	Hydrogen loss factor	0.50%		CSD N2O Emissions	9	g CO2 eq./ 116000 Btu
						CSD GHG Emissions	2,470	g CO2 eq./ 116000 Btu
						Cost Per Mile	$0.69	2007$ / mi
Vehicle Mass	3,020	lb	**Vehicle**			Fuel Share	$0.12	2007$ / mi
Fuel cell size	70	kW	Fuel Economy	48.0	mi / gge	Maintenance, Tires, Repairs	$0.07	2007$ / mi
Hybridization battery (peak power)	30	kW	Vehicle Miles Traveled	15,000	mi / yr	Insurance & Registration	$0.12	2007$ / mi
			Vehicle Lifetime	160,000	mi	Depreciation	$0.27	2007$ / mi
			Purchase Year	2015		Financing	$0.10	2007$ / mi
			Vehicle Purchase Cost	$33,700	2007$			
Coal Input (including upstream)	2,400	Btu / gge fuel consumed	Fuel Cell System Cost	$4,500	2007$	Vehicle Cycle CO2 Emissions	1,750	g CO2 eq/ gge fuel consumed
Natural Gas Input (including upstream)	12,400	Btu / gge fuel consumed	Hydrogen Storage System Cost	$2,400	2007$	Vehicle Cycle CH4 Emissions	170	g CO2 eq/ gge fuel consumed
Petroleum Input (including upstream)	7,700	Btu / gge fuel consumed	Tax Credit	$0	2007$	Vehicle Cycle N2O Emissions	7	g CO2 eq/ gge fuel consumed
						Vehicle Cycle GHG Emissions	1,940	g CO2 eq/ gge fuel consumed


Conversion Facility
Coal 5,243 Btu/116000 Btu
Natural Gas 9,684 Btu/116000 Btu
Petroleum 3,748 Btu/116000 Btu
Total Energy 148,670 Btu/116000 Btu
CO2 Emissions 26,618 g CO2 eq/116000 Btu
CH4 Emissions 140 g CO2 eq/116000 Btu
N2O Emissions 43 g CO2 eq/116000 Btu
GHG Emissions 26,801 g CO2 eq/116000 Btu
Transport
Coal 404 Btu/116000 Btu
Natural Gas 1,447 Btu/116000 Btu
Petroleum 9,774 Btu/116000 Btu
Total Energy 12,907 Btu/116000 Btu
CO2 Emissions 906 g CO2 eq/116000 Btu
CH4 Emissions 32 g CO2 eq/116000 Btu
N2O Emissions 7 g CO2 eq/116000 Btu
GHG Emissions 945 g CO2 eq/116000 Btu
Dispensing
Coal 16,735 Btu/116000 Btu
Natural Gas 7,440 Btu/116000 Btu
Petroleum 719 Btu/116000 Btu
Total Energy 29,345 Btu/116000 Btu
CO2 Emissions 2,314 g CO2 eq/116000 Btu
CH4 Emissions 143 g CO2 eq/116000 Btu
N2O Emissions 9 g CO2 eq/116000 Btu
GHG Emissions 2,466 g CO2 eq/116000 Btu
Feedstock Processing
Coal 295 Btu/116000 Btu
Natural Gas 766 Btu/116000 Btu
Petroleum 3,212 Btu/116000 Btu
Total Energy 4,351 Btu/116000 Btu
CO2 Emissions -24,849 g CO2 eq/116000 Btu
CH4 Emissions 15 g CO2 eq/116000 Btu
N2O Emissions 35 g CO2 eq/116000 Btu
GHG Emissions -24,800 g CO2 eq/116000 Btu
Gasification & Conversion
Biomass Feedstock 2,126,049
Transport
Transport Losses 1.00%
Dispensing
Distribution Losses 0.50%
Total to Deliver 116000 Btu Fuel
Coal 22,678
Natural Gas 19,337
Petroleum 17,453
Total Energy 195,274
CO2 Emissions 4,988
CH4 Emissions 330
N2O Emissions 95
GHG Emissions 5,413

Parameter		Value	Units	Reference	Comments
Case Definition					
	Startup Year	2015		Input	Default for this study's current cases
	Reference Year Dollars	2007		Input	Default for this study's current cases
	Production Technology	WOODY BIOMASS		Input	Case definition
	Form of H2 During Delivery	Gas		Input	Case definition
	Delivery Mode	Gas Truck		Input	Case definition
	Dispensing Mode	CASCADE_700_BAR		Input	Case definition
	Forecourt Station Size	800	kg/day	Input	Case definition: Limited to two deliveries per day resulting in a maximum of 930 kg/day for gas truck dispensing
	Vehicle Type	passenger cars		Input	Case definition
	Vehicle materials (conventional or lightweight)	Conventional		Input	Case definition; lightweight materials not currently an MSM option
	Vehicle Fuel Economy	48.0	mile / gge	Input	Default assumption for this study's current cases
Market Definition					
	City Population	1,247,364	people	Input	Case Definition: Indianapolis, IN
	Market penetration	15%	(% vehicles in city)	Input	Case definition: Basis for Program Plan
	Number of H2 vehicles in city	138,832	H2 vehicles / city	HDSAM Result	
	Miles driven per vehicle	15,000	mile / vehicle year	Input	CPM only allows for 10K, 15K, and 20K/yr.
	Miles driven per vehicle	160,000	miles in vehicle life	Input - GREET2 default	
	City hydrogen use	121,096	kg / d	HDSAM Result	
	Number of H2 refueling stations in city	152		HDSAM Result	Calculated as city hydrogen demand divided by forecourt station size.
	Number of H2 stations/Number of gasoline stations	23%		HDSAM Result	
	Average distance between stations (mi)	1.94	miles	HDSAM Result	
Other Assumptions for WTW Calculations					
	Share of RFG in Total Gasoline Use	100%		Input: GREET default	Case definition: Basis for Program Plan
	Type of Oxygenate in RFG	None		Input: GREET default	Case definition: Basis for Program Plan
	O2 Content in RFG	0%	wt %	Input: GREET default	Case definition: Basis for Program Plan
	Ratio of FCEV VOCs (emissions) to GVs fueled with CG & RFG	0%		Input: GREET default	
	Ratio of FCEV VOCs (evaporative) to GVs fueled with CG & RFG	0%		Input: GREET default	
	Ratio of FCEV CO emissions to GVs fueled with CG & RFG	0%		Input: GREET default	
	Ratio of FCEV NOx emissions to GVs fueled with CG & RFG	0%		Input: GREET default	
	Ratio of FCEV Exhaust PM10 emissions to GVs fueled with CG & RFG	0%		Input: GREET default	
	Ratio of FCEV Brake & Tire Wear PM10 emissions to GVs fueled with CG & RFG	100%		Input: GREET default	
	Ratio of FCEV Exhaust PM2.5 emissions to GVs fueled with CG & RFG	0%		Input: GREET default	
	Ratio of FCEV Brake & Tire Wear PM2.5 emissions to GVs fueled with CG & RFG	100%		Input: GREET default	
	Ratio of FCEV CH4 emissions to GVs fueled with CG & RFG	0%		Input: GREET default	
	Ratio of FCEV N2O emissions to GVs fueled with CG & RFG	0%		Input: GREET default	
	Marginal Electricity Generation Mix for Transportation Use	US Mix		Input	Case definition: Basis for Program Plan

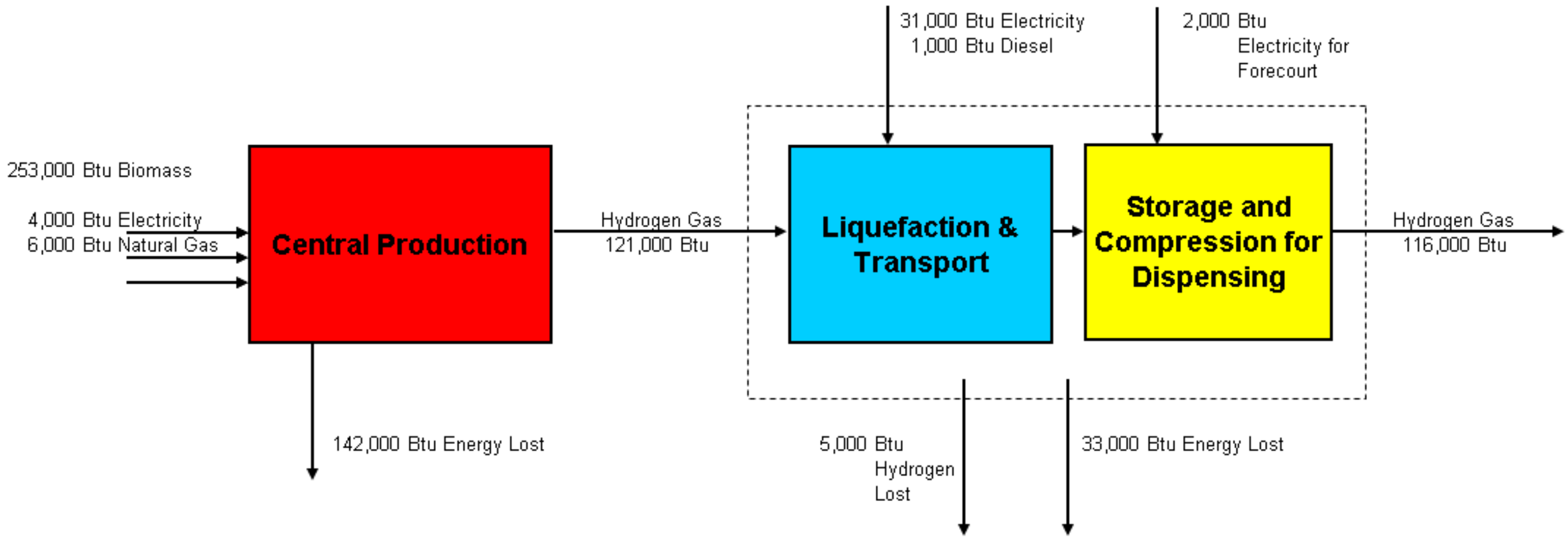
Parameter		Value	Units	Reference	Comments
Biomass					
	Percentage of Woody Biomass (Remainder is Herbaceous)	100%		H2A default	Current central H2A production via biomass gasification based on Mann, M & Steward, D.M. (2008, May 28)
	Biomass (Farmed Trees) Moisture Content	25%		GREET default input	H2A does not specify moisture content so GREET's default was used for GREET calculations
	Energy Use for farming trees	234,964	Btu / dry ton	GREET default input	Energy use and fertilizer based on short rotation woody crops (e.g., willow)
	Percentage that is diesel	94%		GREET default input	
	Percentage that is electricity	5.7%		GREET default input	
	Grams of Nitrogen / short ton biomass (farmed trees)	709	g / dry ton	GREET default input	Equivalent to 75 lb N / ac in the maintenance year Year 3 or 4) which is reported by De La Torre Ugarte, 2003, App 3.1, assuming 6 dry tons biomass per acre, and harvesting once every 8 years. App 3.1 is for planting on cropland that was just used for traditional crops.
	Grams of P2O5 / short ton biomass (farmed trees)	189	g / dry ton	GREET default input	Equivalent to 20 lb P / ac in the maintenance year (Year 3) which is in the range of 15-50 lb P / ac reported by De La Torre Ugarte, 2003, App 3.1, assuming 6 dry tons biomass per acre and harvesting once every 8 years
	Grams of K2O / short ton biomass (farmed trees)	331	g / dry ton	GREET default input	Equivalent to 35 lb K / ac in the maintenance year (Year 3) which is in the range of 15-50 lb K / ac reported by De La Torre Ugarte, 2003, App 3.1, assuming 6 dry tons biomass per acre and harvesting once every 8 years)
	Grams of herbicide / short ton biomass (farmed trees)	24	g / dry ton	GREET default input	Equivalent to 2.0 lb herbicide / ac in the planting year which similar to the 2.0 lb glyphosate / ac reported by De La Torre Ugarte, 2000, App 3.2, assuming 6 dry tons biomass per acre and harvesting once every 8 years. Booth reported Trifluralin (5 L/ha) and Metribuzin (395 g/ha). App 3.2 is for planting on currently idled cropland or cropland that was just used for pasture.
	Grams of insecticide / short ton biomass (farmed trees)	2.0	g / dry ton	GREET default input	From Chastagner: Up to 56% of acreage annually sprayed with Dimethoate (Digon 400, 2-3 pints per acre); up to 56% of acreage annually sprayed with Permethrin 2LB (Ambush, 6.4 ounces per acre); Up to 12% of acreage annually sprayed with Endosulfan 3 EC (24c WA-990025, 2 qts/acre).
	Are GHG Emissions due to land use change included?	No		GREET default input	
	Land use change GHG removal	0	g / dry ton	GREET default input	GREET model default based on ANL personal communications
	Average distance from farm to hydrogen production facility	40	miles	GREET default input	GREET basis: distance could be limited by transport costs?
	Fuel economy on trip from farm to hydrogen production facility	6	mpg diesel	GREET default input	
	Fuel economy on return trip from hydrogen production facility to farm (heavy heavy-dut	6	mpg diesel	GREET default input	

Parameter			Value	Units	Reference	Comments
Natural Gas						
	Percent of NG that is Shale Gas (remainder is conventional NG)		32.1%		GREET default input	
	NG recovery efficiency		95.7%		GREET default input	
	NG lost during recovery		399	g/MMBtu	GREET default input	Previously reported at percent of total NG not on a MMBtu basis
	Percentage of energy use/loss for recovery that is combusted natural gas		49.0%		GREET default input	
	Shale gas recovery efficiency		96.5%		GREET default input	
	Shale gas lost during recovery		245	g/MMBtu	GREET default input	
	Percentage of energy use/loss for recovery that is combusted shale gas		57.4%		GREET default input	
	NG processing energy efficiency		97.2%		Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Results*. Argonne, IL: Argonne National Laboratory.	GREET uses 97.5% which is comparable to several other models (Table 4.11)
	NG lost during processing		33	g/MMBtu	GREET default input	
	Percentage of energy use for processing that is combusted natural gas		90.7%		GREET default input	
	NG used & lost during transport and distribution		124	g / MMBtu	GREET default input	
	NG transport distance		500	miles	GREET default input	
Electricity						
	Grid mix for production		US Mix		GREET input	Default
		Biomass Fraction	0.5%		Definition of US Mix	Energy Information Administration. (2007, February). Annual Energy Outlook 2007 with Projections to 2030. DOE/EIA-0383(2007). Washington, D.C. Retreived from www.eia.doe.gov/oiaf/archive/aeo07/index.html National electricity generation data from tables D-7 & D-8 using the 2005 timeframe. Percentages calculated from total generation values reported with all renewables except biomass aggregated into the "Others (Carbon Neutral)" category
		Coal Fraction	44.2%		Definition of US Mix	
		Natural Gas Fraction	21.5%		Definition of US Mix	
		Nuclear Fraction	21.0%		Definition of US Mix	
		Residual Oil Fraction	0.9%		Definition of US Mix	
		Others (Carbon Neutral - Hydroelectric, Wind, Geothermal, Solar PV, etc)	11.8%		Definition of US Mix	
	Biomass Electricity Shares and Efficiency					
		IGCC Share of Biomass Power Plants	1.0%		GREET default input	
		Combustion Share of Biomass Power Plants	99.0%		GREET default input	By difference from IGCC plants
		Biomass IGCC Efficiency	43.0%		GREET default input	
		Biomass Combustion Plant Efficiency	32.1%		GREET default input	
		Effective Efficiency of Biopower Plants	32.2%		GREET default input	
	Coal Electricity Shares and Efficiency					
		IGCC Share of Coal Power Plants	1.0%		GREET default input	
		Combustion Share of Coal Power Plants	99.0%		GREET default input	
		Coal IGCC Efficiency	47.0%		GREET default input	
		Coal Combustion Plant Efficiency	34.1%		GREET default input	
		Effective Efficiency of Coal-Electricity Plants	34.2%		GREET default input	
	Natural Gas Electricity Shares and Efficiency					
		Simple Cycle Gas Turbine Share of Natural Gas Power Plants	37.0%		GREET default input	
		Combined Cycle Gas Turbine Share of Natural Gas Power Plants	46.0%		GREET default input	
		Combustion Boiler Share of Natural Gas Power Plants	17.0%		GREET default input	
		Natural Gas Simple Cycle Gas Turbine Plant Efficiency	33.1%		GREET default input	
		Natural Gas Combined Cycle Efficiency	55.0%		GREET default input	
		Natural Gas Combustion Boiler Plant Efficiency	34.8%		GREET default input	
		Effective Efficiency of Natural Gas-Electricity Plants	40.9%		GREET default input	
	Residual Oil Electricity Efficiency					
		Residual Oil Electricity Plant Efficiency	34.8%		GREET default input	
	Electicity Transmission and Distribution Losses		8.0%		GREET default input	

Parameter			Value	Units	Reference	Comments
Parameters for GREET2						
	Vehicle total mass		3,020	lb	GREET2 Default Input	
	Battery Type for Hybridization		NiMH		GREET2 Default Input	
	Hybridization Battery Size in Peak Hybridization Battery Power		30	kW	GREET2 Default Input	
	Hybridization Battery Specific Power		272	W / lb	GREET2 Default Input	
	Hybridization Battery Mass		110	lb	GREET2 Default Input	
	Number of replacements of hybridization battery over lifetime		2		GREET2 Default Input	
	Starter Battery (Lead Acid) Mass		22	lb	GREET2 Default Input	
	Mass of fluids on-board vehicle		56	lb	GREET2 Default Input	
	Component mass (vehicles without batteries or fluids)		2,832	lb	GREET2 Calculation	
		Powertrain system percentage of component mass	8.0%		GREET2 Default Input	
		Transmission system percentage of component mass	2.6%		GREET2 Default Input	
		Chassis (without battery) percentage of component mass	23.0%		GREET2 Default Input	
		Traction motor percentage of component mass	3.8%		GREET2 Default Input	
		Generator percentage of component mass	0.0%		GREET2 Default Input	
		Electronic controller percentage of component mass	3.4%		GREET2 Default Input	
		Fuel Cell Auxiliary System percentage of component mass	19.3%		GREET2 Default Input	
		Body: including BIW, interior, exterior, and glass	39.9%		GREET2 Default Input	
	Fuel Cell Stack Size		70	kW	GREET2 Default Input	
	Mass of Fuel Cell Stack - Powertrain System		226	lb	GREET2 Calculation	
	Mass of Fuel Cell Stack - Auxiliary Systems		546	lb	GREET2 Calculation	
	Miles driven per vehicle over lifetime		160,000	miles in vehicle life	GREET2 Default Input	Current analysis assumes 5-year life, 10-year analysis is available

Appendix F: Central Biomass—Liquid Truck Delivery and Gaseous Dispensing Supporting Tables and Figures

Hydrogen Produced In Central Plant and Transported as Liquid via Truck



Well-to-Wheels Total Energy Use (Btu/mile)	7,666
Well-to-Wheels Petroleum Energy Use (Btu/mile)	189
Well-to-Wheels Greenhouse Gas Emissions (g/mile)	201
Levelized Cost of H2 at Pump ($/kg)	5.12

Production Process Energy Efficiency	46%
Pathway Efficiency	39%
WTP Efficiency	32%
WTP Emissions (lb CO2 Equivalent / GGE fuel available):	21

Case Definition
Year: 2015
Hydrogen as Liquid
Central Production
WOODY BIOMASS Feedstock
Sequestration: NO
Transport for Delivery: Liquid Truck
Vehicle Efficiency: 48 mile / GGE
City Hydrogen Use: 121096 kg/day

Inputs			Assumptions			Outputs		

Biomass Production & Delivery

Inputs

Energy Use for Farming Trees	235,000	Btu / dry ton
Coal Input (including upstream)	200	Btu / 116000Btu to Pump
Natural Gas Input (including upstream)	600	Btu / 116000Btu to Pump
Petroleum Input (including upstream)	2,800	Btu / 116000Btu to Pump

Assumptions

Fraction of Woody Biomass	='Params - Upstream'!D3	
LUC GHG changes	='Params - U	g / dry ton
Average distance from farm to H2 prod.	='Params - U	miles

Outputs

Biomass moisture content	25%	
Woody biomass LHV	16,013,000	Btu / dry ton
Biomass price at H2 production	$75	2007 $ / dry ton
Biomass Share of Levelized Cost	$1.00	2007$ / kg H2 dispensed
WTG CO2 Emissions	-25,540	g CO2 eq./ 116000 Btu
WTG CH4 Emissions	13	g CO2 eq./ 116000 Btu
WTG N2O Emissions	36	g CO2 eq./ 116000 Btu
WTG GHG Emissions	-25,490	g CO2 eq./ 116000 Btu

Hydrogen Production

Inputs

Biomass consumption	13.5	kg (dry) / kg H2 produced
Natural gas consumption	0.0059	MMBtu / kg H2 produced
Electricity consumption	0.98	kWh / kg H2 produced
Process Water Consumption	1.32	gal / kg H2 produced
Cooling Water Consumption	79.3	gal / kg H2 produced
Total Capital Investment	$181,080,000	2007$
Coal Input (including upstream)	5,300	Btu / 116000Btu to Pump
Natural Gas Input (including upstream)	9,700	Btu / 116000Btu to Pump
Petroleum Input (including upstream)	3,300	Btu / 116000Btu to Pump

Assumptions

Central plant design capacity	155,200	kg / day
Capacity factor	90%	
Number of production facilities necessary	0.87	
Process energy efficiency	46.0%	
Electricity Mix	US Mix	
After-tax IRR	10%	
Assumed Plant Life	40	

Outputs

Hydrogen Output Pressure	300	psi
Hydrogen Outlet Quality	99.9%	
Total capital investment	$1,300	2007$ / daily kg H2 (effective capacity)
Levelized Cost of Capital	$0.66	2007$ / kg H2 dispensed
Fixed O&M Costs	$0.23	2007$ / kg H2 dispensed
Variable O&M Costs	$0.41	2007$ / kg H2 dispensed
Total Levelized Cost	$2.30	2007$ / kg H2 dispensed
Production CO2 Emissions	27,230	g CO2 eq./ 116000 Btu
Production CH4 Emissions	140	g CO2 eq./ 116000 Btu
Production N2O Emissions	44	g CO2 eq./ 116000 Btu
Production GHG Emissions	27,410	g CO2 eq./ 116000 Btu

Liquefaction and Truck-Delivery

Inputs

Liquefaction electricity consumption	8.5	kWh / kg H2 dispensed
Terminal electricity consumption	0.03	kWh / kg H2 dispensed
Total electricity consumption	8.57	kWh / kg H2 dispensed
Diesel consumption	7.6	gal / 1000 kg H2 dispensed
Total Capital Investment	$239,448,000	2007$
Coal Input (including upstream)	51,700	Btu / 116000Btu to Pump
Natural Gas Input (including upstream)	23,000	Btu / 116000Btu to Pump
Petroleum Input (including upstream)	3,000	Btu / 116000Btu to Pump

Assumptions

City Population	1,247,000	people
Hydrogen Vehicle Penetration	15%	
City hydrogen use	121,100	kg / day
One-way distance for delivery	98	miles
Terminal Design Capacity	1,103,000	kg H2
Number of truck-trips required per year	10,200	
Truck hydrogen capacity	4,400	kg / truckload
Liquefaction energy efficiency	79.3%	
Hydrogen losses	2.8%	

Outputs

Total capital investment	$1,980	2007$ / daily kg H2 (effective capacity)
Levelized Electricity cost	$0.58	2007$ / kg H2 dispensed
Levelized Diesel cost	$0.03	2007$ / kg H2 dispensed
Levelized Labor cost	$0.09	2007$ / kg H2 dispensed
Levelized Other operating costs	$0.24	2007$ / kg H2 dispensed
Levelized Cost of Delivery	$1.80	2007$ / kg H2 delivered
Delivery CO2 Emissions	7,220	g CO2 eq./ 116000 Btu
Delivery CH4 Emissions	440	g CO2 eq./ 116000 Btu
Delivery N2O Emissions	30	g CO2 eq./ 116000 Btu
Delivery GHG Emissions	7,690	g CO2 eq./ 116000 Btu

Forecourt Dispensing

Inputs

Electricity consumption	0.51	kWh / kg H2 dispensed
Total Capital Investment per Station	$1,315,000	2007$ / station
Total Capital Investment	$160,485,000	2007$ / all stations
Coal Input (including upstream)	Included in Delivery Section	
Natural Gas Input (including upstream)	Included in Delivery Section	
Petroleum Input (including upstream)	Included in Delivery Section	

Assumptions

Average Dispensing Rate per Station	1,000	kg / day
Number of Dispensing Stations	122	
Number of Cascade Pumps	1	
Liquid H2 storage capacity per Station	4,600	kg H2
Usable Cascade Storage per Station	70	kg H2
Site storage	400%	% of design capacity
# of 2-hose Dispensers per Station	2	
Hydrogen Losses	1.1%	

Outputs

Onboard Storage Pressure	12,700	psi
Basis -- Hydrogen Quantity	116,000	Btu (116,000 Btu/gal non-oxygenated conventional unleaded gasoline)
Total capital investment	$1,330	2007$ / daily kg H2 (effective capacity)
Levelized Cost of Capital	$0.49	2007$ / kg H2 dispensed
Energy & Fuel	$0.05	2007$ / kg H2 dispensed
Other O&M Costs	$0.48	2007$ / kg H2 dispensed
Levelized Cost of Dispensing	$1.02	2007$ / kg H2 dispensed
CSD CO2 Emissions	Included in Delivery Section	
CSD CH4 Emissions	Included in Delivery Section	
CSD N2O Emissions	Included in Delivery Section	
CSD GHG Emissions	Included in Delivery Section	

Vehicle

Inputs

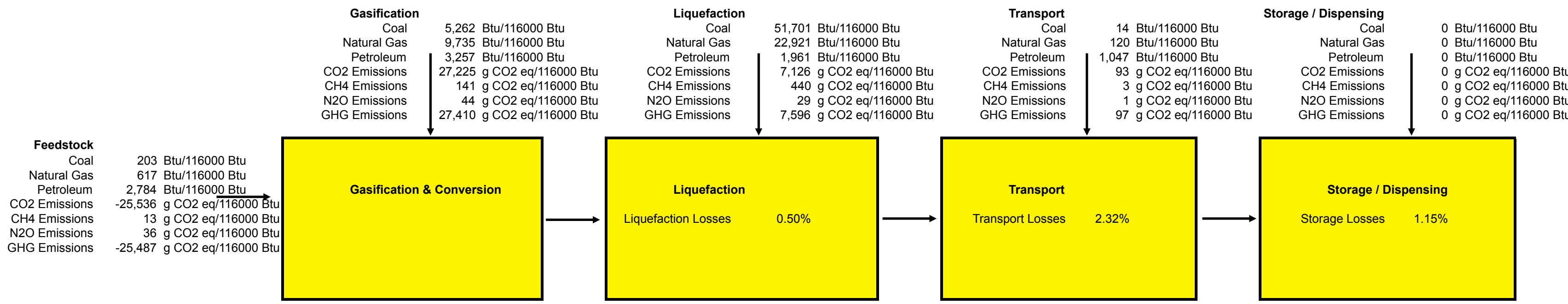
Vehicle Mass	3,020	lb
Fuel cell size	70	kW
Hybridization battery (peak power)	30	kW
Coal Input (including upstream)	2,300	Btu / gge fuel consumed
Natural Gas Input (including upstream)	12,100	Btu / gge fuel consumed
Petroleum Input (including upstream)	6,900	Btu / gge fuel consumed

Assumptions

Fuel Economy	48.0	mi / gge
Vehicle Miles Traveled	15,000	mi / yr
Vehicle Lifetime	160,000	mi
Purchase Year	2015	
Vehicle Purchase Cost	$33,700	2007$
Fuel Cell System Cost	$4,500	2007$
Hydrogen Storage System Cost	$2,400	2007$
Tax Credit	$0	2007$

Outputs

Cost Per Mile	$0.67	2007$ / mi
Fuel Share	$0.11	2007$ / mi
Maintenance, Tires, Repairs	$0.07	2007$ / mi
Insurance & Registration	$0.12	2007$ / mi
Depreciation	$0.27	2007$ / mi
Financing	$0.10	2007$ / mi
Veh. Cycle CO2 Emissions	1,670	g CO2 eq/ gge fuel consumed
Veh. Cycle CH4 Emissions	170	g CO2 eq/ gge fuel consumed
Veh. Cycle N2O Emissions	6	g CO2 eq/ gge fuel consumed
Veh. Cycle GHG Emissions	1,850	g CO2 eq/ gge fuel consumed


Gasification
Coal 5,262 Btu/116000 Btu
Natural Gas 9,735 Btu/116000 Btu
Petroleum 3,257 Btu/116000 Btu
CO2 Emissions 27,225 g CO2 eq/116000 Btu
CH4 Emissions 141 g CO2 eq/116000 Btu
N2O Emissions 44 g CO2 eq/116000 Btu
GHG Emissions 27,410 g CO2 eq/116000 Btu
Liquefaction
Coal 51,701 Btu/116000 Btu
Natural Gas 22,921 Btu/116000 Btu
Petroleum 1,961 Btu/116000 Btu
CO2 Emissions 7,126 g CO2 eq/116000 Btu
CH4 Emissions 440 g CO2 eq/116000 Btu
N2O Emissions 29 g CO2 eq/116000 Btu
GHG Emissions 7,596 g CO2 eq/116000 Btu
Transport
Coal 14 Btu/116000 Btu
Natural Gas 120 Btu/116000 Btu
Petroleum 1,047 Btu/116000 Btu
CO2 Emissions 93 g CO2 eq/116000 Btu
CH4 Emissions 3 g CO2 eq/116000 Btu
N2O Emissions 1 g CO2 eq/116000 Btu
GHG Emissions 97 g CO2 eq/116000 Btu
Storage / Dispensing
Coal 0 Btu/116000 Btu
Natural Gas 0 Btu/116000 Btu
Petroleum 0 Btu/116000 Btu
CO2 Emissions 0 g CO2 eq/116000 Btu
CH4 Emissions 0 g CO2 eq/116000 Btu
N2O Emissions 0 g CO2 eq/116000 Btu
GHG Emissions 0 g CO2 eq/116000 Btu
Feedstock
Coal 203 Btu/116000 Btu
Natural Gas 617 Btu/116000 Btu
Petroleum 2,784 Btu/116000 Btu
CO2 Emissions -25,536 g CO2 eq/116000 Btu
CH4 Emissions 13 g CO2 eq/116000 Btu
N2O Emissions 36 g CO2 eq/116000 Btu
GHG Emissions -25,487 g CO2 eq/116000 Btu
Gasification & Conversion
Liquefaction
Liquefaction Losses 0.50%
Transport
Transport Losses 2.32%
Storage / Dispensing
Storage Losses 1.15%

Parameter		Value	Units	Reference	Comments
Case Definition					
	Startup Year	2015		Input	Default for this study's current cases
	Reference Year Dollars	2007		Input	Default for this study's current cases
	Production Technology	WOODY BIOMASS		Input	Case definition
	Form of H2 During Delivery	Liquid		Input	Case definition
	Delivery Mode	Liquid Truck		Input	Case definition
	Dispensing Mode	LH2_TO_GH2		Input	Case definition
	Forecourt Station Size	1000	kg/day	Input	Case definition
	Vehicle Type	passenger cars		Input	Case definition
	Vehicle materials (conventional or lightweight)	Conventional		Input	Case definition; lightweight materials not currently an MSM option
	Vehicle Fuel Economy	48.0	mile / gge	Input	Default assumption for this study's current cases
Market Definition					
	City Population	1,247,364	people	Input	Case Definition: Indianapolis, IN
	Market penetration	15%	(% vehicles in city)	Input	Case definition: Basis for Program Plan
	Number of H2 vehicles in city	138,832	H2 vehicles / city	HDSAM Result	
	Miles driven per vehicle	15,000	mile / vehicle year	Input	CPM only allows for 10K, 15K, and 20K/yr.
	Miles driven per vehicle	160,000	miles in vehicle life	Input - GREET2 default	
	City hydrogen use	121,096	kg / d	HDSAM Result	
	Number of H2 refueling stations in city	122		HDSAM Result	
	Number of H2 stations/Number of gasoline stations	19%		HDSAM Result	
	Average distance between stations (mi)	2.17	miles	HDSAM Result	
Other Assumptions for WTW Calculations					
	Share of RFG in Total Gasoline Use	100%		Input: GREET default	Case definition: Basis for Program Plan
	Type of Oxygenate in RFG	None		Input: GREET default	Case definition: Basis for Program Plan
	O2 Content in RFG	0%	wt %	Input: GREET default	Case definition: Basis for Program Plan
	Ratio of FCEV VOCs (emissions) to GVs fueled with CG & RFG	0%		Input: GREET default	
	Ratio of FCEV VOCs (evaporative) to GVs fueled with CG & RFG	0%		Input: GREET default	
	Ratio of FCEV CO emissions to GVs fueled with CG & RFG	0%		Input: GREET default	
	Ratio of FCEV NOx emissions to GVs fueled with CG & RFG	0%		Input: GREET default	
	Ratio of FCEV Exhaust PM10 emissions to GVs fueled with CG & RFG	0%		Input: GREET default	
	Ratio of FCEV Brake & Tire Wear PM10 emissions to GVs fueled with CG & RFG	100%		Input: GREET default	
	Ratio of FCEV Exhaust PM2.5 emissions to GVs fueled with CG & RFG	0%		Input: GREET default	
	Ratio of FCEV Brake & Tire Wear PM2.5 emissions to GVs fueled with CG & RFG	100%		Input: GREET default	
	Ratio of FCEV CH4 emissions to GVs fueled with CG & RFG	0%		Input: GREET default	
	Ratio of FCEV N2O emissions to GVs fueled with CG & RFG	0%		Input: GREET default	
	Marginal Electricity Generation Mix for Transportation Use	US Mix		Input	Case definition: Basis for Program Plan

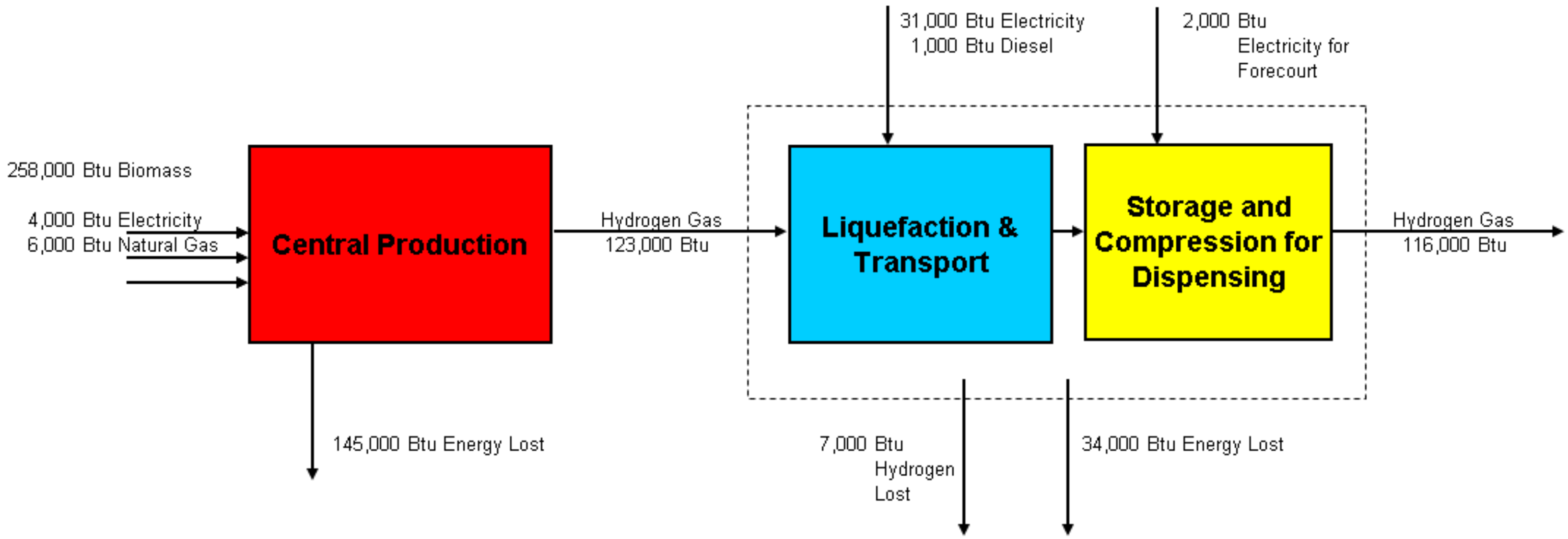
Parameter		Value	Units	Reference	Comments
Biomass					
	Percentage of Woody Biomass (Remainder is Herbaceous)	100%		H2A default	Current central H2A production via biomass gasification based on Mann, M & Steward, D.M. (2008, May 28)
	Biomass (Farmed Trees) Moisture Content	25%		GREET default input	H2A does not specify moisture content so GREET's default was used for GREET calculations
	Energy Use for farming trees	234,964	Btu / dry ton	GREET default input	Energy use and fertilizer based on short rotation woody crops (e.g., willow)
	Percentage that is diesel	94%		GREET default input	
	Percentage that is electricity	5.7%		GREET default input	
	Grams of Nitrogen / short ton biomass (farmed trees)	709	g / dry ton	GREET default input	Equivalent to 75 lb N / ac in the maintenance year Year 3 or 4) which is reported by De La Torre Ugarte, 2003, App 3.1, assuming 6 dry tons biomass per acre, and harvesting once every 8 years. App 3.1 is for planting on cropland that was just used for traditional crops.
	Grams of P2O5 / short ton biomass (farmed trees)	189	g / dry ton	GREET default input	Equivalent to 20 lb P / ac in the maintenance year (Year 3) which is in the range of 15-50 lb P / ac reported by De La Torre Ugarte, 2003, App 3.1, assuming 6 dry tons biomass per acre and harvesting once every 8 years
	Grams of K2O / short ton biomass (farmed trees)	331	g / dry ton	GREET default input	Equivalent to 35 lb K / ac in the maintenance year (Year 3) which is in the range of 15-50 lb K / ac reported by De La Torre Ugarte, 2003, App 3.1, assuming 6 dry tons biomass per acre and harvesting once every 8 years)
	Grams of herbicide / short ton biomass (farmed trees)	24	g / dry ton	GREET default input	Equivalent to 2.0 lb herbicide / ac in the planting year which similar to the 2.0 lb glyphosate / ac reported by De La Torre Ugarte, 2000, App 3.2, assuming 6 dry tons biomass per acre and harvesting once every 8 years. Booth reported Trifluralin (5 L/ha) and Metribuzin (395 g/ha). App 3.2 is for planting on currently idled cropland or cropland that was just used for pasture.
	Grams of insecticide / short ton biomass (farmed trees)	2.0	g / dry ton	GREET default input	From Chastagner: Up to 56% of acreage annually sprayed with Dimethoate (Digon 400, 2-3 pints per acre); up to 56% of acreage annually sprayed with Permethrin 2LB (Ambush, 6.4 ounces per acre); Up to 12% of acreage annually sprayed with Endosulfan 3 EC (24c WA-990025, 2 qts/acre).
	Are GHG Emissions due to land use change included?	No		GREET default input	
	Land use change GHG removal	0	g / dry ton	GREET default input	GREET model default based on ANL personal communications
	Average distance from farm to hydrogen production facility	40	miles	GREET default input	GREET basis: distance could be limited by transport costs?
	Fuel economy on trip from farm to hydrogen production facility	6	mpg diesel	GREET default input	
	Fuel economy on return trip from hydrogen production facility to farm (heavy heavy-dut	6	mpg diesel	GREET default input	

Parameter			Value	Units	Reference	Comments
Natural Gas						
	Percent of NG that is Shale Gas (remainder is conventional NG)		32.1%		GREET default input	
	NG recovery efficiency		95.7%		GREET default input	
	NG lost during recovery		399	g/MMBtu	GREET default input	Previously reported at percent of total NG not on a MMBtu basis
	Percentage of energy use/loss for recovery that is combusted natural gas		49.0%		GREET default input	
	Shale gas recovery efficiency		96.5%		GREET default input	
	Shale gas lost during recovery		245	g/MMBtu	GREET default input	
	Percentage of energy use/loss for recovery that is combusted shale gas		57.4%		GREET default input	
	NG processing energy efficiency		97.2%		Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Results*. Argonne, IL: Argonne National Laboratory.	GREET uses 97.5% which is comparable to several other models (Table 4.11)
	NG lost during processing		33	g/MMBtu	GREET default input	
	Percentage of energy use for processing that is combusted natural gas		90.7%		GREET default input	
	NG used & lost during transport and distribution		124	g / MMBtu	GREET default input	
	NG transport distance		500	miles	GREET default input	
Electricity						
	Grid mix for production		US Mix		GREET input	Default
		Biomass Fraction	0.5%		Definition of US Mix	Energy Information Administration. (2007, February). Annual Energy Outlook 2007 with Projections to 2030. DOE/EIA-0383(2007). Washington, D.C. Retreived from www.eia.doe.gov/oiaf/archive/aeo07/index.html National electricity generation data from tables D-7 & D-8 using the 2005 timeframe. Percentages calculated from total generation values reported with all renewables except biomass aggregated into the "Others (Carbon Neutral)" category
		Coal Fraction	44.2%		Definition of US Mix	
		Natural Gas Fraction	21.5%		Definition of US Mix	
		Nuclear Fraction	21.0%		Definition of US Mix	
		Residual Oil Fraction	0.9%		Definition of US Mix	
		Others (Carbon Neutral - Hydroelectric, Wind, Geothermal, Solar PV, etc)	11.8%		Definition of US Mix	
	Biomass Electricity Shares and Efficiency					
		IGCC Share of Biomass Power Plants	1.0%		GREET default input	
		Combustion Share of Biomass Power Plants	99.0%		GREET default input	By difference from IGCC plants
		Biomass IGCC Efficiency	43.0%		GREET default input	
		Biomass Combustion Plant Efficiency	32.1%		GREET default input	
		Effective Efficiency of Biopower Plants	32.2%		GREET default input	
	Coal Electricity Shares and Efficiency					
		IGCC Share of Coal Power Plants	1.0%		GREET default input	
		Combustion Share of Coal Power Plants	99.0%		GREET default input	
		Coal IGCC Efficiency	47.0%		GREET default input	
		Coal Combustion Plant Efficiency	34.1%		GREET default input	
		Effective Efficiency of Coal-Electricity Plants	34.2%		GREET default input	
	Natural Gas Electricity Shares and Efficiency					
		Simple Cycle Gas Turbine Share of Natural Gas Power Plants	37.0%		GREET default input	
		Combined Cycle Gas Turbine Share of Natural Gas Power Plants	46.0%		GREET default input	
		Combustion Boiler Share of Natural Gas Power Plants	17.0%		GREET default input	
		Natural Gas Simple Cycle Gas Turbine Plant Efficiency	33.1%		GREET default input	
		Natural Gas Combined Cycle Efficiency	55.0%		GREET default input	
		Natural Gas Combustion Boiler Plant Efficiency	34.8%		GREET default input	
		Effective Efficiency of Natural Gas-Electricity Plants	40.9%		GREET default input	
	Residual Oil Electricity Efficiency					
		Residual Oil Electricity Plant Efficiency	34.8%		GREET default input	
	Electicity Transmission and Distribution Losses		8.0%		GREET default input	

Parameter			Value	Units	Reference	Comments
Parameters for GREET2						
	Vehicle total mass		3,020	lb	GREET2 Default Input	
	Battery Type for Hybridization		NiMH		GREET2 Default Input	
	Hybridization Battery Size in Peak Hybridization Battery Power		30	kW	GREET2 Default Input	
	Hybridization Battery Specific Power		272	W / lb	GREET2 Default Input	
	Hybridization Battery Mass		110	lb	GREET2 Default Input	
	Number of replacements of hybridization battery over lifetime		2		GREET2 Default Input	
	Starter Battery (Lead Acid) Mass		22	lb	GREET2 Default Input	
	Mass of fluids on-board vehicle		56	lb	GREET2 Default Input	
	Component mass (vehicles without batteries or fluids)		2,832	lb	GREET2 Calculation	
		Powertrain system percentage of component mass	8.0%		GREET2 Default Input	
		Transmission system percentage of component mass	2.6%		GREET2 Default Input	
		Chassis (without battery) percentage of component mass	23.0%		GREET2 Default Input	
		Traction motor percentage of component mass	3.8%		GREET2 Default Input	
		Generator percentage of component mass	0.0%		GREET2 Default Input	
		Electronic controller percentage of component mass	3.4%		GREET2 Default Input	
		Fuel Cell Auxiliary System percentage of component mass	19.3%		GREET2 Default Input	
		Body: including BIW, interior, exterior, and glass	39.9%		GREET2 Default Input	
	Fuel Cell Stack Size		70	kW	GREET2 Default Input	
	Mass of Fuel Cell Stack - Powertrain System		226	lb	GREET2 Calculation	
	Mass of Fuel Cell Stack - Auxiliary Systems		546	lb	GREET2 Calculation	
	Miles driven per vehicle over lifetime		160,000	miles in vehicle life	GREET2 Default Input	Current analysis assumes 5-year life, 10-year analysis is available

Appendix G: Central Biomass—Liquid Truck Delivery and Cryo-Compressed Dispensing Supporting Tables and Figures

Hydrogen Produced In Central Plant and Transported as Liquid via Truck



Well-to-Wheels Total Energy Use (Btu/mile)	7,806
Well-to-Wheels Petroleum Energy Use (Btu/mile)	192
Well-to-Wheels Greenhouse Gas Emissions (g/mile)	204
Levelized Cost of H2 at Pump ($/kg)	5.73

Production Process Energy Efficiency	46%
Pathway Efficiency	38%
WTP Efficiency	31%
WTP Emissions (lb CO2 Equivalent / GGE fuel available):	22

Case Definition
Year: 2015
Hydrogen as Liquid
Central Production
WOODY BIOMASS Feedstock
Sequestration: NO
Transport for Delivery: Liquid Truck
Vehicle Efficiency: 48 mile / GGE
City Hydrogen Use: 121096 kg/day

Inputs

Energy Use for Farming Trees	235,000	Btu / dry ton
Coal Input (including upstream)	200	Btu / 116000Btu to Pump
Natural Gas Input (including upstream)	600	Btu / 116000Btu to Pump
Petroleum Input (including upstream)	2,800	Btu / 116000Btu to Pump

Biomass consumption	13.5	kg (dry) / kg H2 produced
Natural gas consumption	0.0059	MMBtu / kg H2 produced
Electricity consumption	0.98	kWh / kg H2
Process Water Consumption	1.32	gal / kg H2 produced
Cooling Water Consumption	79.3	gal / kg H2 produced
Total Capital Investment	$181,080,000	2007$
Coal Input (including upstream)	5,400	Btu / 116000Btu to Pump
Natural Gas Input (including upstream)	9,900	Btu / 116000Btu to Pump
Petroleum Input (including upstream)	3,300	Btu / 116000Btu to Pump

Liquefaction electricity consumption	8.5	kWh / kg H2
Terminal electricity consumption	0.02	kWh / kg H3
Total electricity consumption	8.5	kWh / kg H4
Diesel consumption	7.7	gal / 1000 kg H2
Total Capital Investment	$242,361,000	2007$
Coal Input (including upstream)	52,400	Btu / 116000Btu to Pump
Natural Gas Input (including upstream)	23,400	Btu / 116000Btu to Pump
Petroleum Input (including upstream)	3,000	Btu / 116000Btu to Pump

Electricity consumption	0.49	kWh / kg H2
Total Capital Investment per Station	$2,100,000	2007$ / station
Total Capital Investment	$256,147,000	2007$ / all stations
Coal Input (including upstream)	Included in Delivery Section	
Natural Gas Input (including upstream)	Included in Delivery Section	
Petroleum Input (including upstream)	Included in Delivery Section	

Vehicle Mass	3,020	lb
Fuel cell size	70	kW
Hybridization battery (peak power)	30	kW
Coal Input (including upstream)	2,300	Btu / gge fuel consumed
Natural Gas Input (including upstream)	12,100	Btu / gge fuel consumed
Petroleum Input (including upstream)	6,900	Btu / gge fuel consumed

Assumptions

Biomass Production & Delivery

Fraction of Woody Biomass	100%	
LUC GHG changes	0	g / dry ton
Average distance from farm to H2 prod.	40	miles

Hydrogen Production

Central plant design capacity	155,200	kg / day
Capacity factor	90%	
Number of production facilities	0.87	
Process energy efficiency	46.0%	
Electricity Mix	US Mix	
After-tax IRR	10%	
Assumed Plant Life	40	

Liquefaction and Truck-Delivery

City Population	1,247,000	people
Hydrogen Vehicle Penetration	15%	
City hydrogen use	121,100	kg / day
One-way distance for delivery	98	miles
Terminal Design Capacity	1,124,000	kg H2
Number of truck-trips required	10,400	
Truck hydrogen capacity	4,400	kg / truckload
Liquefaction energy efficiency	79.3%	
Hydrogen losses	2.8%	

Cryo-Compressed Dispensing

Total Hydrogen Dispensed	1,000	kg / day
Number of Dispensing Stations	122	
Number of Cascade Pumps	1	
Liquid H2 storage capacity per Station	4,600	kg H2
Usable Cascade Storage per Station	0	kg H2
Site storage	390%	% of design capacity
# of 2-hose Dispensers per Station	2	
Hydrogen losses	3.1%	

Vehicle

Fuel Economy	48.0	mi / gge
Vehicle Miles Traveled	15,000	mi / yr
Vehicle Lifetime	160,000	mi
Purchase Year	2015	
Vehicle Purchase Cost	$33,700	2007$
Fuel Cell System Cost	$4,500	2007$
Storage System Cost (assume 700Bar	$2,400	2007$
Tax Credit	$0	2007$

Outputs

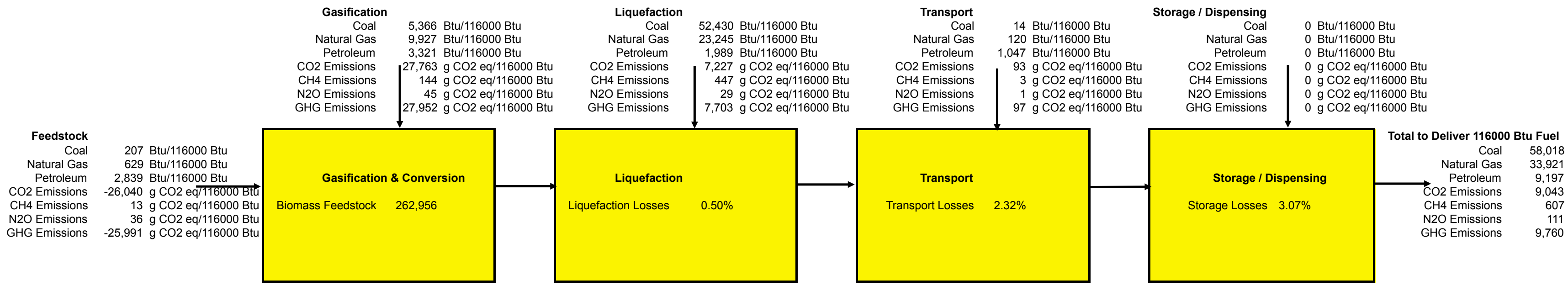
Biomass moisture content	25%	
Woody biomass LHV	16,013,000	Btu / dry ton
Biomass price at H2 production	$75	2007 $ / dry ton
Biomass Share of Levelized Cos	$1.02	2007$ / kg H2 dispensed
WTG CO2 Emissions	-26,040	g CO2 eq./ 116000 Btu
WTG CH4 Emissions	13	g CO2 eq./ 116000 Btu
WTG N2O Emissions	36	g CO2 eq./ 116000 Btu
WTG GHG Emissions	-25,990	g CO2 eq./ 116000 Btu

Hydrogen Output Pressure	300	psi
Hydrogen Outlet Quality	99.9%	
Total capital investment	$1,300	2007$ / daily kg H2 (effective capacity)
Levelized Cost of Capital	$0.67	2007$ / kg H2 dispensed
Fixed O&M Costs	$0.24	2007$ / kg H2 dispensed
Variable O&M Costs	$0.42	2007$ / kg H2 dispensed
Total Levelized Cost	$2.35	2007$ / kg H2 dispensed
Production CO2 Emissions	27,800	g CO2 eq./ 116000 Btu
Production CH4 Emissions	140	g CO2 eq./ 116000 Btu
Production N2O Emissions	45	g CO2 eq./ 116000 Btu
Production GHG Emissions	28,000	g CO2 eq./ 116000 Btu

Total capital investment	$2,000	2007$ / daily kg delivered
Levelized Electricity cost	$0.59	2007$ / kg H2 delivered
Levelized Diesel cost	$0.03	2007$ / kg H2 delivered
Levelized Labor cost	$0.09	2007$ / kg H2 delivered
Levelized Other operating costs	$0.24	2007$ / kg H2 delivered
Levelized Cost of Delivery	$1.82	2007$ / kg H2 delivered
Delivery CO2 Emissions	7,320	g CO2 eq./ 116000 Btu
Delivery CH4 Emissions	450	g CO2 eq./ 116000 Btu
Delivery N2O Emissions	30	g CO2 eq./ 116000 Btu
Delivery GHG Emissions	7,800	g CO2 eq./ 116000 Btu

Hydrogen outlet pressure	12,700	psi
Basis -- Hydrogen Quantity	116,000	Btu (116,000 Btu/gal non-oxygenated conventional unleaded gasoline)
Total capital investment	$2,120	2007$ / daily kg
Levelized Cost of Capital	$0.90	2007$ / kg H2 dispensed
Energy & Fuel	$0.05	2007$ / kg H2 dispensed
Other O&M Costs	$0.61	2007$ / kg H2 dispensed
Levelized Cost of Dispensing	$3.38	2007$ / kg H2 dispensed
CSD CO2 Emissions	Included in Delivery Section	
CSD CH4 Emissions	Included in Delivery Section	
CSD N2O Emissions	Included in Delivery Section	
CSD GHG Emissions	Included in Delivery Section	

Cost Per Mile	$0.69	2007$ / mi
Fuel Share	$0.12	2007$ / mi
Maintenance, Tires, Repairs	$0.07	2007$ / mi
Insurance & Registration	$0.12	2007$ / mi
Depreciation	$0.27	2007$ / mi
Financing	$0.10	2007$ / mi
Veh. Cycle CO2 Emissions	1,670	g / gge fuel consumed
Veh. Cycle CH4 Emissions	170	g / gge fuel consumed
Veh. Cycle N2O Emissions	6	g / gge fuel consumed
Veh. Cycle GHG Emissions	1,850	g / gge fuel consumed


Gasification
Coal 5,366 Btu/116000 Btu
Natural Gas 9,927 Btu/116000 Btu
Petroleum 3,321 Btu/116000 Btu
CO2 Emissions 27,763 g CO2 eq/116000 Btu
CH4 Emissions 144 g CO2 eq/116000 Btu
N2O Emissions 45 g CO2 eq/116000 Btu
GHG Emissions 27,952 g CO2 eq/116000 Btu
Liquefaction
Coal 52,430 Btu/116000 Btu
Natural Gas 23,245 Btu/116000 Btu
Petroleum 1,989 Btu/116000 Btu
CO2 Emissions 7,227 g CO2 eq/116000 Btu
CH4 Emissions 447 g CO2 eq/116000 Btu
N2O Emissions 29 g CO2 eq/116000 Btu
GHG Emissions 7,703 g CO2 eq/116000 Btu
Transport
Coal 14 Btu/116000 Btu
Natural Gas 120 Btu/116000 Btu
Petroleum 1,047 Btu/116000 Btu
CO2 Emissions 93 g CO2 eq/116000 Btu
CH4 Emissions 3 g CO2 eq/116000 Btu
N2O Emissions 1 g CO2 eq/116000 Btu
GHG Emissions 97 g CO2 eq/116000 Btu
Storage / Dispensing
Coal 0 Btu/116000 Btu
Natural Gas 0 Btu/116000 Btu
Petroleum 0 Btu/116000 Btu
CO2 Emissions 0 g CO2 eq/116000 Btu
CH4 Emissions 0 g CO2 eq/116000 Btu
N2O Emissions 0 g CO2 eq/116000 Btu
GHG Emissions 0 g CO2 eq/116000 Btu
Feedstock
Coal 207 Btu/116000 Btu
Natural Gas 629 Btu/116000 Btu
Petroleum 2,839 Btu/116000 Btu
CO2 Emissions -26,040 g CO2 eq/116000 Btu
CH4 Emissions 13 g CO2 eq/116000 Btu
N2O Emissions 36 g CO2 eq/116000 Btu
GHG Emissions -25,991 g CO2 eq/116000 Btu
Gasification & Conversion
Biomass Feedstock 262,956
Liquefaction
Liquefaction Losses 0.50%
Transport
Transport Losses 2.32%
Storage / Dispensing
Storage Losses 3.07%
Total to Deliver 116000 Btu Fuel
Coal 58,018
Natural Gas 33,921
Petroleum 9,197
CO2 Emissions 9,043
CH4 Emissions 607
N2O Emissions 111
GHG Emissions 9,760

Parameter		Value	Units	Reference	Comments
Case Definition					
	Startup Year	2015		Input	Default for this study's current cases
	Reference Year Dollars	2007		Input	Default for this study's current cases
	Production Technology	WOODY BIOMASS		Input	Case definition
	Form of H2 During Delivery	Liquid		Input	Case definition
	Delivery Mode	Liquid Truck		Input	Case definition
	Dispensing Mode	CRYOCOMPRESSED		Input	Case definition
	Forecourt Station Size	1000	kg/day	Input	Case definition
	Vehicle Type	passenger cars		Input	Case definition
	Vehicle materials (conventional or lightweight)	Conventional		Input	Case definition; lightweight materials not currently an MSM option
	Vehicles' Fuel Economy	48.0	mile / gge	Input	Default assumption for this study's current cases
Market Definition					
	City Population	1,247,364	people	Input	Case Definition: Indianapolis, IN
	Market penetration	15%	(% vehicles in city)	Input	Case definition: Basis for Program Plan
	Number of H2 vehicles in city	138,832	H2 vehicles / city	HDSAM Result	
	Miles driven per vehicle	15,000	mile / vehicle year	Input	CPM only allows for 10K, 15K, and 20K/yr.
	Miles driven per vehicle	160,000	miles in vehicle life	Input - GREET2 default	
	City hydrogen use	121,096	kg / d	HDSAM Result	
	Number of H2 refueling stations in city	122		HDSAM Result	
	Number of H2 stations/Number of gasoline stations	19%		HDSAM Result	
	Average distance between stations (mi)	2.17	miles	HDSAM Result	
Other Assumptions for WTW Calculations					
	Share of RFG in Total Gasoline Use	100%		Input: GREET default	Case definition: Basis for Program Plan
	Type of Oxygenate in RFG	None		Input: GREET default	Case definition: Basis for Program Plan
	O2 Content in RFG	0%	wt %	Input: GREET default	Case definition: Basis for Program Plan
	Ratio of FCEV VOCs (emissions) to GVs fueled with CG & RFG	0%		Input: GREET default	
	Ratio of FCEV VOCs (evaporative) to GVs fueled with CG & RFG	0%		Input: GREET default	
	Ratio of FCEV CO emissions to GVs fueled with CG & RFG	0%		Input: GREET default	
	Ratio of FCEV NOx emissions to GVs fueled with CG & RFG	0%		Input: GREET default	
	Ratio of FCEV Exhaust PM10 emissions to GVs fueled with CG & RFG	0%		Input: GREET default	
	Ratio of FCEV Brake & Tire Wear PM10 emissions to GVs fueled with CG & RFG	100%		Input: GREET default	
	Ratio of FCEV Exhaust PM2.5 emissions to GVs fueled with CG & RFG	0%		Input: GREET default	
	Ratio of FCEV Brake & Tire Wear PM2.5 emissions to GVs fueled with CG & RFG	100%		Input: GREET default	
	Ratio of FCEV CH4 emissions to GVs fueled with CG & RFG	0%		Input: GREET default	
	Ratio of FCEV N2O emissions to GVs fueled with CG & RFG	0%		Input: GREET default	
	Marginal Electricity Generation Mix for Transportation Use	US Mix		Input	Case definition: Basis for Program Plan

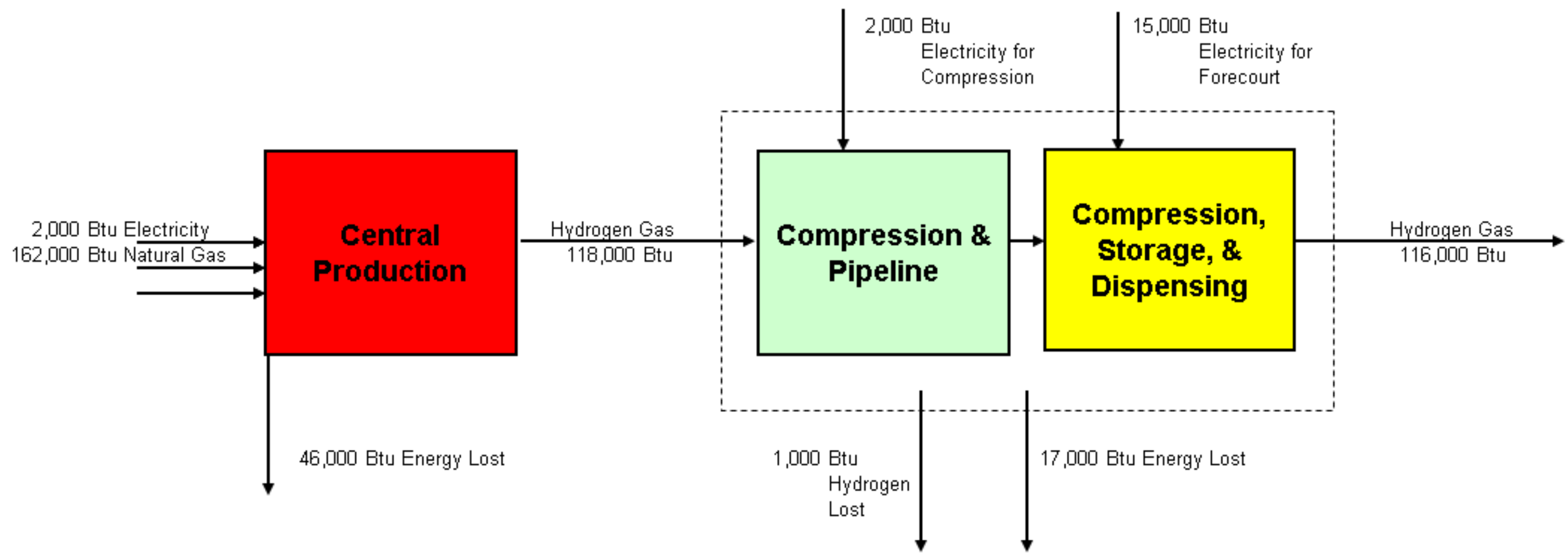
Parameter			Value	Units	Reference	Comments
Biomass						
	Percentage of Woody Biomass (Remainder is Herbaceous)		100%		H2A default	Current central H2A production via biomass gasification based on Mann, M & Steward, D.M. (2008, May 28)
	Biomass (Farmed Trees) Moisture Content		25%		GREET default input	H2A does not specify moisture content so GREET's default was used for GREET calculations
	Energy Use for farming trees		234,964	Btu / dry ton	GREET default input	Energy use and fertilizer based on short rotation woody crops (e.g., willow)
		Percentage that is diesel	94%		GREET default input	
		Percentage that is electricity	5.7%		GREET default input	
	Grams of Nitrogen / short ton biomass (farmed trees)		709	g / dry ton	GREET default input	Equivalent to 75 lb N / ac in the maintenance year Year 3 or 4) which is reported by De La Torre Ugarte, 2003, App 3.1, assuming 6 dry tons biomass per acre, and harvesting once every 8 years. App 3.1 is for planting on cropland that was just used for traditional crops.
	Grams of P2O5 / short ton biomass (farmed trees)		189	g / dry ton	GREET default input	Equivalent to 20 lb P / ac in the maintenance year (Year 3) which is in the range of 15-50 lb P / ac reported by De La Torre Ugarte, 2003, App 3.1, assuming 6 dry tons biomass per acre and harvesting once every 8 years
	Grams of K2O / short ton biomass (farmed trees)		331	g / dry ton	GREET default input	Equivalent to 35 lb K / ac in the maintenance year (Year 3) which is in the range of 15-50 lb K / ac reported by De La Torre Ugarte, 2003, App 3.1, assuming 6 dry tons biomass per acre and harvesting once every 8 years)
	Grams of herbicide / short ton biomass (farmed trees)		24	g / dry ton	GREET default input	Equivalent to 2.0 lb herbicide / ac in the planting year which similar to the 2.0 lb glyphosate / ac reported by De La Torre Ugarte, 2000, App 3.2, assuming 6 dry tons biomass per acre and harvesting once every 8 years. Booth reported Trifluralin (5 L/ha) and Metribuzin (395 g/ha). App 3.2 is for planting on currently idled cropland or cropland that was just used for pasture.
	Grams of insecticide / short ton biomass (farmed trees)		2.0	g / dry ton	GREET default input	From Chastagner: Up to 56% of acreage annually sprayed with Dimethoate (Digon 400, 2-3 pints per acre); up to 56% of acreage annually sprayed with Permethrin 2LB (Ambush, 6.4 ounces per acre); Up to 12% of acreage annually sprayed with Endosulfan 3 EC (24c WA-990025, 2 qts/acre).
	Are GHG Emissions due to land use change included?		No		GREET default input	
	Land use change GHG removal		0	g / dry ton	GREET default input	GREET model default based on ANL personal communications
	Average distance from farm to hydrogen production facility		40	miles	GREET default input	GREET basis: distance could be limited by transport costs?
	Fuel economy on trip from farm to hydrogen production facility		6	mpg diesel	GREET default input	
	Fuel economy on return trip from hydrogen production facility to farm (heavy heavy-dut		6	mpg diesel	GREET default input	

Parameter	Value	Units	Reference	Comments
Natural Gas				
Percent of NG that is Shale Gas (remainder is conventional NG)	32.1%		GREET default input	
NG recovery efficiency	95.7%		GREET default input	
NG lost during recovery	399	g/MMBtu	GREET default input	Previously reported at percent of total NG not on a MMBtu basis
Percentage of energy use/loss for recovery that is combusted natural gas	49.0%		GREET default input	
Shale gas recovery efficiency	96.5%		GREET default input	
Shale gas lost during recovery	245	g/MMBtu	GREET default input	
Percentage of energy use/loss for recovery that is combusted shale gas	57.4%		GREET default input	
NG processing energy efficiency	97.2%		Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Results*. Argonne, IL: Argonne National Laboratory.	GREET uses 97.5% which is comparable to several other models (Table 4.11)
NG lost during processing	33	g/MMBtu	GREET default input	
Percentage of energy use for processing that is combusted natural gas	90.7%		GREET default input	
NG used & lost during transport and distribution	124	g / MMBtu	GREET default input	
NG transport distance	500	miles	GREET default input	
Electricity				
Grid mix for production	US Mix		GREET input	Default
Biomass Fraction	0.5%		Definition of US Mix	Energy Information Administration. (2007, February). Annual Energy Outlook 2007 with Projections to 2030. DOE/EIA-0383(2007). Washington, D.C. Retreived from www.eia.doe.gov/oiaf/archive/aeo07/index.html National electricity generation data from tables D-7 & D-8 using the 2005 timeframe. Percentages calculated from total generation values reported with all renewables except biomass aggregated into the "Others (Carbon Neutral)" category
Coal Fraction	44.2%		Definition of US Mix	
Natural Gas Fraction	21.5%		Definition of US Mix	
Nuclear Fraction	21.0%		Definition of US Mix	
Residual Oil Fraction	0.9%		Definition of US Mix	
Others (Carbon Neutral - Hydroelectric, Wind, Geothermal, Solar PV, etc)	11.8%		Definition of US Mix	
Biomass Electricity Shares and Efficiency				
IGCC Share of Biomass Power Plants	1.0%		GREET default input	
Combustion Share of Biomass Power Plants	99.0%		GREET default input	By difference from IGCC plants
Biomass IGCC Efficiency	43.0%		GREET default input	
Biomass Combustion Plant Efficiency	32.1%		GREET default input	
Effective Efficiency of Biopower Plants	32.2%		GREET default input	
Coal Electricity Shares and Efficiency				
IGCC Share of Coal Power Plants	1.0%		GREET default input	
Combustion Share of Coal Power Plants	99.0%		GREET default input	
Coal IGCC Efficiency	47.0%		GREET default input	
Coal Combustion Plant Efficiency	34.1%		GREET default input	
Effective Efficiency of Coal-Electricity Plants	34.2%		GREET default input	
Natural Gas Electricity Shares and Efficiency				
Simple Cycle Gas Turbine Share of Natural Gas Power Plants	37.0%		GREET default input	
Combined Cycle Gas Turbine Share of Natural Gas Power Plants	46.0%		GREET default input	
Combustion Boiler Share of Natural Gas Power Plants	17.0%		GREET default input	
Natural Gas Simple Cycle Gas Turbine Plant Efficiency	33.1%		GREET default input	
Natural Gas Combined Cycle Efficiency	55.0%		GREET default input	
Natural Gas Combustion Boiler Plant Efficiency	34.8%		GREET default input	
Effective Efficiency of Natural Gas-Electricity Plants	40.9%		GREET default input	
Residual Oil Electricity Efficiency				
Residual Oil Electricity Plant Efficiency	34.8%		GREET default input	
Electicity Transmission and Distribution Losses	8.0%		GREET default input	

Parameter			Value	Units	Reference	Comments
Parameters for GREET2						
	Vehicle total mass		3,020	lb	GREET2 Default Input	
	Battery Type for Hybridization		NiMH		GREET2 Default Input	
	Hybridization Battery Size in Peak Hybridization Battery Power		30	kW	GREET2 Default Input	
	Hybridization Battery Specific Power		272	W / lb	GREET2 Default Input	
	Hybridization Battery Mass		110	lb	GREET2 Default Input	
	Number of replacements of hybridization battery over lifetime		2		GREET2 Default Input	
	Starter Battery (Lead Acid) Mass		22	lb	GREET2 Default Input	
	Mass of fluids on-board vehicle		56	lb	GREET2 Default Input	
	Component mass (vehicles without batteries or fluids)		2,832	lb	GREET2 Calculation	
		Powertrain system percentage of component mass	8.0%		GREET2 Default Input	
		Transmission system percentage of component mass	2.6%		GREET2 Default Input	
		Chassis (without battery) percentage of component mass	23.0%		GREET2 Default Input	
		Traction motor percentage of component mass	3.8%		GREET2 Default Input	
		Generator percentage of component mass	0.0%		GREET2 Default Input	
		Electronic controller percentage of component mass	3.4%		GREET2 Default Input	
		Fuel Cell Auxiliary System percentage of component mass	19.3%		GREET2 Default Input	
		Body: including BIW, interior, exterior, and glass	39.9%		GREET2 Default Input	
	Fuel Cell Stack Size		70	kW	GREET2 Default Input	
	Mass of Fuel Cell Stack - Powertrain System		226	lb	GREET2 Calculation	
	Mass of Fuel Cell Stack - Auxiliary Systems		546	lb	GREET2 Calculation	
	Miles driven per vehicle over lifetime		160,000	miles in vehicle life	GREET2 Default Input	Current analysis assumes 5-year life, 10-year analysis is available

Appendix H: Central Natural Gas—Pipeline Delivery Supporting Tables and Figures

Hydrogen Produced In Central Plant and Transported as Gas via Pipeline



Well-to-Wheels Total Energy Use	4,750
Well-to-Wheels Petroleum Energy	38
Well-to-Wheels Greenhouse Gas Emissions (g/mile)	346
Levelized Cost of H2 at Pump ($/kg)	6.08

Production Process Energy Efficiency	72%
Pathway Efficiency	64%
WTP Efficiency	51%
WTP Emissions (lb CO2 Equivalent / GGE fuel available):	37

Case Definition
Year: 2015
Hydrogen as Gas
Central Production
NATURAL GAS Feedstock
Sequestration: NO
Transport for Delivery: Pipeline
Vehicle Efficiency: 48 mile / GGE
City Hydrogen Use: 121096 kg/day

Inputs			Assumptions			Outputs		
						NG Delivery Pressure	Average of gas companies	
			NG Recovery, Processing, & Transport			NG Quality at Delivery	Average of gas companies	
			NG Recovery Efficiency	95.7%		NG Cost in 2015	$6.09	2007 $ / mmBTU
			NG emitted during recovery	400	g / MMbtu NG	NG Share of Levelized Cost	$1.52	2007$ / kg H2 dispensed
			NG processing energy efficiency	97.2%				
Coal Input (including upstream)	200	Btu / 116000Btu to Pump	NG emitted during processing	30	g / MMbtu NG	WTG CO2 Emissions	600	g CO2 eq./ 116000 Btu
Natural Gas Input (including upstream)	125,600	Btu / 116000Btu to Pump	NG emitted during transport	199,400	g / MMbtu NG	WTG CH4 Emissions	1,260	g CO2 eq./ 116000 Btu
Petroleum Input (including upstream)	500	Btu / 116000Btu to Pump	NG transport distance	500	miles	WTG N2O Emissions	3	g CO2 eq./ 116000 Btu
						WTG GHG Emissions	1,870	g CO2 eq./ 116000 Btu
						Hydrogen Output Pressure	300	psi
Natural gas consumption	0.1564	MMBtu/kg H2 produced	**Hydrogen Production**			Hydrogen Outlet Quality	99.9%	
Electricity consumption	0.57	kWh / kg H2						
Process Water Consumption	3.36	gal / kg H2	Central plant design capacity	379,400	kg / day	Total capital investment	$632	2007$ / daily kg H2 (effective capacity)
Cooling Water Consumption	1.50	gal / kg H2	Capacity factor	90%		Levelized Cost of Capital	$0.34	2007$ / kg H2 dispensed
			necessary	0.35		Fixed O&M Costs	$0.06	2007$ / kg H2 dispensed
Total Capital Investment	$215,844,000	2007$	Process energy efficiency	71.9%		Variable O&M Costs	$0.08	2007$ / kg H2 dispensed
			Electricity Mix	US Mix		Total Levelized Cost	$2.00	2007$ / kg H2 dispensed
			After-tax IRR	10%				
Coal Input (including upstream)	2,900	Btu / 116000Btu to Pump	Assumed Plant Life	40		SMR CO2 Emissions	10,200	g CO2 eq./ 116000 Btu
Natural Gas Input (including upstream)	48,800	Btu / 116000Btu to Pump				SMR CH4 Emissions	500	g CO2 eq./ 116000 Btu
Petroleum Input (including upstream)	300	Btu / 116000Btu to Pump				SMR N2O Emissions	12	g CO2 eq./ 116000 Btu
						SMR GHG Emissions	10,700	g CO2 eq./ 116000 Btu
Electricity consumption for compressor	0.56	kWh / kg H2 produced	**Pipelines for Delivery**			Total capital investment	$3,340	2007$ / daily kg H2 (effective capacity)
Electricity consumption for geo storage	0.01	kWh / kg H2 produced						
Total electricity consumption	0.57	kWh / kg H2 produced	City Population	1,247,000	people	Levelized Cost of Capital	$1.71	2007$ / kg H2 dispensed
			Hydrogen Vehicle Penetration	15%		Energy & Fuel	$0.04	2007$ / kg H2 dispensed
			City hydrogen use	121,100	kg / day	Other O&M Costs	$0.40	2007$ / kg H2 dispensed
Total Capital Investment	$404,341,000	2007$	Distance from City to Production Facility	62	miles	Levelized Cost of Delivery	$2.15	2007$ / kg H2 dispensed
			Geologic storage capacity	1,324,700	kg H2			
			Number of trunk pipelines	3		Delivery CO2 Emissions	390	g CO2 eq./ 116000 Btu
Coal Input (including upstream)	2,800	Btu / 116000Btu to Pump	Service-line length	1.5	miles / line	Delivery CH4 Emissions	24	g CO2 eq./ 116000 Btu
Natural Gas Input (including upstream)	2,200	Btu / 116000Btu to Pump	Number of service lines	122		Delivery N2O Emissions	2	g CO2 eq./ 116000 Btu
Petroleum Input (including upstream)	100	Btu / 116000Btu to Pump	Hydrogen losses	0.80%		Delivery GHG Emissions	420	g CO2 eq./ 116000 Btu
						Hydrogen outlet pressure	12,700	psi
Electricity consumption	4.4	kWh / kg H2 produced	**Forecourt Dispensing**			Basis -- Hydrogen Quantity	116,000	Btu (116,000 Btu/gal non-oxygenated conventional unleaded gasoline)
Total Capital Investment per Station	$2,629,000	2007$ / station	Average Dispensing Rate per Station	1,000	kg / day	Total capital investment	$2,650	2007$ / daily kg H2 (effective capacity)
Total Capital Investment	$320,679,000	2007$ / all stations	Number of Dispensing Stations	122		Levelized Cost of Capital	$1.08	2007$ / kg H2 dispensed
			Number of Compression Steps	5		Energy & Fuel	$0.41	2007$ / kg H2 dispensed
Inlet pressure of hydrogen at stations	300	psi	Usable Low Pressure Storage per Station	370	kg H2	Other O&M Costs	$0.43	2007$ / kg H2 dispensed
			Usable Cascade Storage per Station	130	kg H2	Levelized Cost of Dispensing	$1.93	2007$ / kg H2 dispensed
Coal Input (including upstream)	24,400	Btu / 116000Btu to Pump	Site storage	42%	% of design capacity	CSD CO2 Emissions	3,370	g CO2 eq./ 116000 Btu
Natural Gas Input (including upstream)	10,800	Btu / 116000Btu to Pump	# 2-hose Dispensers per Station	2		CSD CH4 Emissions	210	g CO2 eq./ 116000 Btu
Petroleum Input (including upstream)	900	Btu / 116000Btu to Pump	Hydrogen Losses	0.50%		CSD N2O Emissions	14	g CO2 eq./ 116000 Btu
						CSD GHG Emissions	3,590	g CO2 eq./ 116000 Btu
						Cost Per Mile	$0.69	2007$ / mi
Vehicle Mass	3,020	lb	**Vehicle**			Fuel Share	$0.13	2007$ / mi
Fuel cell size	70	kW	Fuel Economy	48.0	mi / gge	Maintenance, Tires, Repairs	$0.07	2007$ / mi
Hybridization battery (peak power)	30	kW	Vehicle Miles Traveled	15,000	mi / yr	Insurance & Registration	$0.12	2007$ / mi
			Vehicle Lifetime	160,000	mi	Depreciation	$0.27	2007$ / mi
			Purchase Year	2015		Financing	$0.10	2007$ / mi
			Vehicle Purchase Cost	$33,700	2007$			
Coal Input (including upstream)	2,300	Btu / gge fuel consumed	Fuel Cell System Cost	$4,500	2007$	Veh. Cycle CO2 Emissions	1,670	g CO2 eq / gge fuel consumed
Natural Gas Input (including upstream)	12,100	Btu / gge fuel consumed	Hydrogen Storage System Cost	$2,400	2007$	Veh. Cycle CH4 Emissions	170	g CO2 eq / gge fuel consumed
Petroleum Input (including upstream)	6,900	Btu / gge fuel consumed	Tax Credit	$0	2007$	Veh. Cycle N2O Emissions	6	g CO2 eq / gge fuel consumed
						Veh. Cycle GHG Emissions	1,850	g CO2 eq / gge fuel consumed

Feedstock Processing

Coal	210	Btu/116000 Btu
Natural Gas	125,600	Btu/116000 Btu
Petroleum	476	Btu/116000 Btu
Total Energy	126,341	Btu/116000 Btu
CO2 Emissions	598	g CO2 eq/116000 Btu
CH4 Emissions	1,264	g CO2 eq/116000 Btu
N2O Emissions	3	g CO2 eq/116000 Btu
GHG Emissions	1,866	g CO2 eq/116000 Btu

Conversion Facility

Coal	2,919	Btu/116000 Btu
Natural Gas	48,778	Btu/116000 Btu
Petroleum	286	Btu/116000 Btu
Total Energy	52,759	Btu/116000 Btu
CO2 Emissions	10,194	g CO2 eq/116000 Btu
CH4 Emissions	498	g CO2 eq/116000 Btu
N2O Emissions	12	g CO2 eq/116000 Btu
GHG Emissions	10,703	g CO2 eq/116000 Btu

Reforming

NG Feedstock 161,546

Transport

Coal	2,825	Btu/116000 Btu
Natural Gas	2,153	Btu/116000 Btu
Petroleum	107	Btu/116000 Btu
Total Energy	5,837	Btu/116000 Btu
CO2 Emissions	389	g CO2 eq/116000 Btu
CH4 Emissions	24	g CO2 eq/116000 Btu
N2O Emissions	2	g CO2 eq/116000 Btu
GHG Emissions	415	g CO2 eq/116000 Btu

Transport

Transport Losses 0.77%

Dispensing

Coal	24,444	Btu/116000 Btu
Natural Gas	10,837	Btu/116000 Btu
Petroleum	928	Btu/116000 Btu
Total Energy	42,710	Btu/116000 Btu
CO2 Emissions	3,369	g CO2 eq/116000 Btu
CH4 Emissions	208	g CO2 eq/116000 Btu
N2O Emissions	14	g CO2 eq/116000 Btu
GHG Emissions	3,591	g CO2 eq/116000 Btu

Dispensing

Distribution Losses 0.50%

Total to Deliver 116000 Btu Fuel

Coal	30,397
Natural Gas	187,368
Petroleum	1,797
Total Energy	227,647
CO2 Emissions	14,551
CH4 Emissions	1,994
N2O Emissions	30
GHG Emissions	16,575

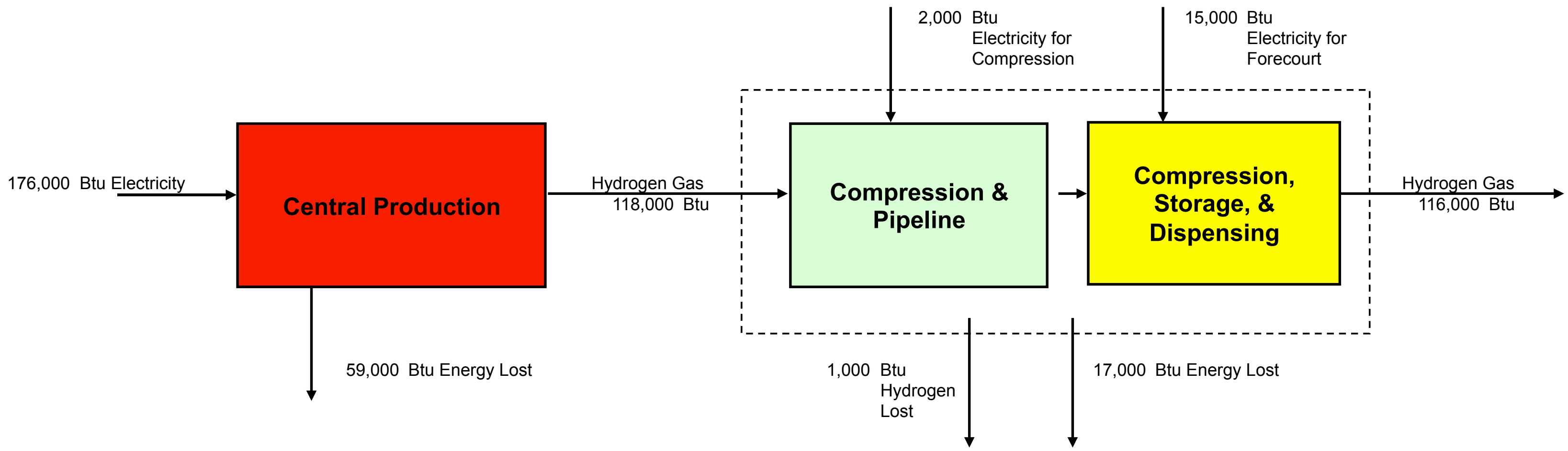
Parameter		Value	Units	Reference	Comments
Case Definition					
	Startup Year	2015		Input	Default for this study's current cases
	Reference Year Dollars	2007		Input	Default for this study's current cases
	Production Technology	NATURAL GAS		Input	Case definition
	Form of H2 During Delivery	Gas		Input	Case definition
	Delivery Mode	Pipeline		Input	Case definition
	Dispensing Mode	CASCADE_700_BAR		Input	Case definition
	Forecourt Station Size	1000	kg/day	Input	Case definition
	Vehicle Type	passenger cars		Input	Case definition
	Vehicle materials (conventional or lightweight)	Conventional		Input	Case definition; lightweight materials not currently an MSM option
	Vehicles' Fuel Economy	48.0	mile / gge	Input	Default assumption for this study's current cases
Market Definition					
	City Population	1,247,364	people	Input	Case Definition: Indianapolis, IN
	Market penetration	15%	(% vehicles in city)	Input	Case definition: Basis for Program Plan
	Number of H2 vehicles in city	138,832	H2 vehicles / city	HDSAM Result	
	Miles driven per vehicle	15,000	mile / vehicle year	Input	CPM only allows for 10K, 15K, and 20K/yr.
	Miles driven per vehicle	160,000	miles in vehicle life	Input - GREET2 default	
	City hydrogen use	121,096	kg / d	HDSAM Result	
	Number of H2 refueling stations in city	122		HDSAM Result	
	Number of H2 stations/Number of gasoline stations	19%		HDSAM Result	
	Average distance between stations (mi)	2.17	miles	HDSAM Result	
Other Assumptions for WTW Calculations					
	Share of RFG in Total Gasoline Use	100%		Input: GREET default	Case definition: Basis for Program Plan
	Type of Oxygenate in RFG	None		Input: GREET default	Case definition: Basis for Program Plan
	O2 Content in RFG	0%	wt %	Input: GREET default	Case definition: Basis for Program Plan
	Ratio of FCEV VOCs (emissions) to GVs fueled with CG & RFG	0%		Input: GREET default	
	Ratio of FCEV VOCs (evaporative) to GVs fueled with CG & RFG	0%		Input: GREET default	
	Ratio of FCEV CO emissions to GVs fueled with CG & RFG	0%		Input: GREET default	
	Ratio of FCEV NOx emissions to GVs fueled with CG & RFG	0%		Input: GREET default	
	Ratio of FCEV Exhaust PM10 emissions to GVs fueled with CG & RFG	0%		Input: GREET default	
	Ratio of FCEV Brake & Tire Wear PM10 emissions to GVs fueled with CG & RFG	100%		Input: GREET default	
	Ratio of FCEV Exhaust PM2.5 emissions to GVs fueled with CG & RFG	0%		Input: GREET default	
	Ratio of FCEV Brake & Tire Wear PM2.5 emissions to GVs fueled with CG & RFG	100%		Input: GREET default	
	Ratio of FCEV CH4 emissions to GVs fueled with CG & RFG	0%		Input: GREET default	
	Ratio of FCEV N2O emissions to GVs fueled with CG & RFG	0%		Input: GREET default	
	Marginal Electricity Generation Mix for Transportation Use	US Mix		Input	Case definition: Basis for Program Plan

Parameter			Value	Units	Reference	Comments
Natural Gas						
	Percent of NG that is Shale Gas (remainder is conventional NG)		32.1%		GREET default input	
	NG recovery efficiency		95.7%		GREET default input	
	NG lost during recovery		399	g/MMBtu	GREET default input	Previously reported at percent of total NG not on a MMBtu basis
	Percentage of energy use/loss for recovery that is combusted natural gas		49.0%		GREET default input	
	Shale gas recovery efficiency		96.5%		GREET default input	
	Shale gas lost during recovery		245	g/MMBtu	GREET default input	
	Percentage of energy use/loss for recovery that is combusted shale gas		57.4%		GREET default input	
	NG processing energy efficiency		97.2%		Wang, M.Q. (1999, August). *GREET 1.5 - Transportation Fuel-Cycle Model Volume 1: Methodology, development, Use and Results*. Argonne, IL: Argonne National Laboratory.	GREET uses 97.5% which is comparable to several other models (Table 4.11)
	NG lost during processing		33	g/MMBtu	GREET default input	
	Percentage of energy use for processing that is combusted natural gas		90.7%		GREET default input	
	NG used & lost during transport and distribution		199434	g / MMBtu	GREET default input	
	NG transport distance		500	miles	GREET default input	
Electricity						
	Grid mix for production		US Mix		GREET input	Default
		Biomass Fraction	0.5%		Definition of US Mix	Energy Information Administration. (2007, February). Annual Energy Outlook 2007 with Projections to 2030. DOE/EIA-0383(2007). Washington, D.C. Retreived from www.eia.doe.gov/oiaf/archive/aeo07/index.html National electricity generation data from tables D-7 & D-8 using the 2005 timeframe. Percentages calculated from total generation values reported with all renewables except biomass aggregated into the "Others (Carbon Neutral)" category
		Coal Fraction	44.2%		Definition of US Mix	
		Natural Gas Fraction	21.5%		Definition of US Mix	
		Nuclear Fraction	21.0%		Definition of US Mix	
		Residual Oil Fraction	0.9%		Definition of US Mix	
		Others (Carbon Neutral - Hydroelectric, Wind, Geothermal, Solar PV, etc)	11.8%		Definition of US Mix	
	Biomass Electricity Shares and Efficiency					
		IGCC Share of Biomass Power Plants	1.0%		GREET default input	
		Combustion Share of Biomass Power Plants	99.0%		GREET default input	By difference from IGCC plants
		Biomass IGCC Efficiency	43.0%		GREET default input	
		Biomass Combustion Plant Efficiency	32.1%		GREET default input	
		Effective Efficiency of Biopower Plants	32.2%		GREET default input	
	Coal Electricity Shares and Efficiency					
		IGCC Share of Coal Power Plants	1.0%		GREET default input	
		Combustion Share of Coal Power Plants	99.0%		GREET default input	
		Coal IGCC Efficiency	47.0%		GREET default input	
		Coal Combustion Plant Efficiency	34.1%		GREET default input	
		Effective Efficiency of Coal-Electricity Plants	34.2%		GREET default input	
	Natural Gas Electricity Shares and Efficiency					
		Simple Cycle Gas Turbine Share of Natural Gas Power Plants	37.0%		GREET default input	
		Combined Cycle Gas Turbine Share of Natural Gas Power Plants	46.0%		GREET default input	
		Combustion Boiler Share of Natural Gas Power Plants	17.0%		GREET default input	
		Natural Gas Simple Cycle Gas Turbine Plant Efficiency	33.1%		GREET default input	
		Natural Gas Combined Cycle Efficiency	55.0%		GREET default input	
		Natural Gas Combustion Boiler Plant Efficiency	34.8%		GREET default input	
		Effective Efficiency of Natural Gas-Electricity Plants	40.9%		GREET default input	
	Residual Oil Electricity Efficiency					
		Residual Oil Electricity Plant Efficiency	34.8%		GREET default input	
	Electicity Transmission and Distribution Losses		8.0%		GREET default input	

Parameter			Value	Units	Reference	Comments
Parameters for GREET2						
	Vehicle total mass		3,020	lb	GREET2 Default Input	
	Battery Type for Hybridization		NiMH		GREET2 Default Input	
	Hybridization Battery Size in Peak Hybridization Battery Power		30	kW	GREET2 Default Input	
	Hybridization Battery Specific Power		272	W / lb	GREET2 Default Input	
	Hybridization Battery Mass		110	lb	GREET2 Default Input	
	Number of replacements of hybridization battery over lifetime		2		GREET2 Default Input	
	Starter Battery (Lead Acid) Mass		22	lb	GREET2 Default Input	
	Mass of fluids on-board vehicle		56	lb	GREET2 Default Input	
	Component mass (vehicles without batteries or fluids)		2,832	lb	GREET2 Calculation	
		Powertrain system percentage of component mass	8.0%		GREET2 Default Input	
		Transmission system percentage of component mass	2.6%		GREET2 Default Input	
		Chassis (without battery) percentage of component mass	23.0%		GREET2 Default Input	
		Traction motor percentage of component mass	3.8%		GREET2 Default Input	
		Generator percentage of component mass	0.0%		GREET2 Default Input	
		Electronic controller percentage of component mass	3.4%		GREET2 Default Input	
		Fuel Cell Auxiliary System percentage of component mass	19.3%		GREET2 Default Input	
		Body: including BIW, interior, exterior, and glass	39.9%		GREET2 Default Input	
	Fuel Cell Stack Size		70	kW	GREET2 Default Input	
	Mass of Fuel Cell Stack - Powertrain System		226	lb	GREET2 Calculation	
	Mass of Fuel Cell Stack - Auxiliary Systems		546	lb	GREET2 Calculation	
	Miles driven per vehicle over lifetime		160,000	miles in vehicle life	GREET2 Default Input	Current analysis assumes 5-year life, 10-year analysis is available

Appendix I: Central Wind Electricity—Pipeline Delivery Supporting Tables and Figures

Hydrogen Produced In Central Plant and Transported as Gas via Pipeline

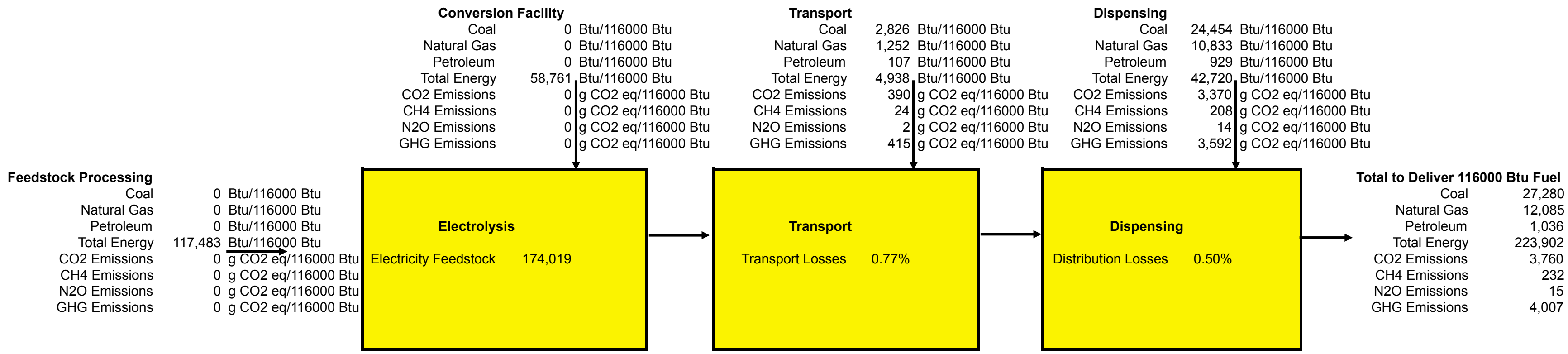


Well-to-Wheels Total Energy Use (Btu/mile)	4,672
Well-to-Wheels Petroleum Energy Use (Btu/mile)	22
Well-to-Wheels Greenhouse Gas Emissions (g/mile)	84
Levelized Cost of H2 at Pump ($/kg)	8.41

Production Process Energy Efficiency	67%
Pathway Efficiency	60%
WTP Efficiency	52%
CO2 Equivalent / GGE fuel available): GHG	9

Case Definition
Year: 2015
Hydrogen as Gas
Central Production
WIND Feedstock
Sequestration: NO
Transport for Delivery: Pipeline
Vehicle Efficiency: 48 mile / GGE
City Hydrogen Use: 121096 kg/day

Inputs			Assumptions			Outputs		
			Wind Electricity					
			Green credits for wind-generated electricity on the grid are assumed.			Electricity price at prod. facility	$0.0574	2007$ / kWh
			The electrolyzers are not necessarily co-located with the wind farm.			Electricity	$3.37	2007$ / kg H2 dispensed
Coal Input (including upstream)	0	Btu / 116000Btu to Pump	A high capacity factor is available due to use of green credits.			WTG CO2 Emissions	0	g CO2 eq./ 116000 Btu
Natural Gas Input (including upstream)	0	Btu / 116000Btu to Pump				WTG CH4 Emissions	0	g CO2 eq./ 116000 Btu
Petroleum Input (including upstream)	0	Btu / 116000Btu to Pump				WTG N2O Emissions	0	g CO2 eq./ 116000 Btu
						WTG GHG Emissions	0	g CO2 eq./ 116000 Btu
			Hydrogen Production			Hydrogen Output Pressure	300	psi
Electricity consumption	50.0	kWh / kg H2 produced				Hydrogen Outlet Quality	99.9%	
Process Water Consumption	2.94	gal / kg H2 produced						
Cooling Water Consumption	294	gal / kg H2 produced	Central plant design capacity	52,300	kg / day	Total capital investment	$1,320	2007$ / daily kg H2 (effective capacity)
			Capacity factor	98%		Levelized Cost of Capital	$0.67	2007$ / kg H2 dispensed
			Number of production facilities necessary	2.36		Fixed O&M Costs	$0.23	2007$ / kg H2 dispensed
Total Capital Investment	$67,634,000	2007$	Process energy efficiency	66.7%		Variable O&M Costs	$0.06	2007$ / kg H2 dispensed
			Electricity Mix	US Mix		Total Levelized Cost	$4.33	2007$ / kg H2 dispensed
			After-tax IRR	10%				
Coal Input (including upstream)	0	Btu / 116000Btu to Pump	Assumed Plant Life	40		Production CO2 Emissions	0	g CO2 eq./ 116000 Btu
Natural Gas Input (including upstream)	0	Btu / 116000Btu to Pump				Production CH4 Emissions	0	g CO2 eq./ 116000 Btu
Petroleum Input (including upstream)	0	Btu / 116000Btu to Pump				Production N2O Emissions	0	g CO2 eq./ 116000 Btu
						Production GHG Emissions	0	g CO2 eq./ 116000 Btu
Electricity consumption for compressor	0.56	kWh / kg H2 dispensed	**Pipelines for Delivery**			Total capital investment	$3,340	2007$ / daily kg H2 (effective capacity)
Electricity consumption for geo storage	0.01	kWh / kg H2 dispensed						
Total electricity consumption	0.57	kWh / kg H2 dispensed	City Population	1,247,000	people	Levelized Cost of Delivery	$1.71	2007$ / kg H2 dispensed
			Hydrogen Vehicle Penetration	15%		Energy & Fuel	$0.04	2007$ / kg H2 dispensed
			City hydrogen use	121,100	kg / day	Other O&M Costs	$0.40	2007$ / kg H2 dispensed
Total Capital Investment	$404,341,000	2007$	Distance from City to Production Facility	62	miles	Levelized Cost of Delivery	$2.15	2007$ / kg H2 dispensed
			Geologic storage capacity	1,324,700	kg H2			
			Number of trunk pipelines	3		Delivery CO2 Emissions	390	g CO2 eq./ 116000 Btu
Coal Input (including upstream)	2,800	Btu / 116000Btu to Pump	Service-line length	1.5	miles / line	Delivery CH4 Emissions	24	g CO2 eq./ 116000 Btu
Natural Gas Input (including upstream)	1,300	Btu / 116000Btu to Pump	Number of service lines	122		Delivery N2O Emissions	2	g CO2 eq./ 116000 Btu
Petroleum Input (including upstream)	100	Btu / 116000Btu to Pump	Hydrogen losses	0.80%		Delivery GHG Emissions	420	g CO2 eq./ 116000 Btu
						Hydrogen outlet pressure	12,700	psi
Electricity consumption	4.4	kWh / kg H2 dispensed	**Forecourt Dispensing**			Basis -- Hydrogen Quantity	116,000	Btu (116,000 Btu/gal non-oxygenated conventional unleaded gasoline)
Total Capital Investment per Station	$2,629,000	2007$ / station	Average Dispensing Rate per Station	1,000	kg/day	Total capital investment	$2,650	2007$ / daily kg H2 (effective capacity)
Total Capital Investment	$320,679,000	2007$ / all stations	Number of Dispensing Stations	122		Levelized Cost of Capital	$1.08	2007$ / kg H2 dispensed
			Number of Compression Steps	5		Energy & Fuel	$0.41	2007$ / kg H2 dispensed
Inlet pressure of hydrogen at stations	300	psi	Useable Low Pressure Storage per Statio	370	kg H2	Other O&M Costs	$0.43	2007$ / kg H2 dispensed
			Useable Cascade Storage per Station	130	kg H2	Levelized Cost of Dispensing	$1.93	2007$ / kg H2 dispensed
Coal Input (including upstream)	24,500	Btu / 116000Btu to Pump	Site storage	42%	% of design capacity	CSD CO2 Emissions	3,370	g CO2 eq./ 116000 Btu
Natural Gas Input (including upstream)	10,800	Btu / 116000Btu to Pump	# of 2-hose Dispensers per Station	2		CSD CH4 Emissions	210	g CO2 eq./ 116000 Btu
Petroleum Input (including upstream)	900	Btu / 116000Btu to Pump	Hydrogen losses	0.50%		CSD N2O Emissions	14	g CO2 eq./ 116000 Btu
						CSD GHG Emissions	3,590	g CO2 eq./ 116000 Btu
						Cost Per Mile	$0.74	2007$ / mi
Vehicle Mass	3,020	lb	**Vehicle**			Fuel Share	$0.18	2007$ / mi
Fuel cell size	70	kW	Fuel Economy	48.0	mi / gge	Maintenance, Tires, Repairs	$0.07	2007$ / mi
Hybridization battery (peak power)	30	kW	Vehicle Miles Traveled	15,000	mi / yr	Insurance & Registration	$0.12	2007$ / mi
			Vehicle Lifetime	160,000	mi	Depreciation	$0.27	2007$ / mi
			Purchase Year	2015		Financing	$0.10	2007$ / mi
			Vehicle Purchase Cost	$33,700	2007$			
Coal Input (including upstream)	2,400	Btu / gge fuel consumed	Fuel Cell System Cost	$4,500	2007$	Vehicle Cycle CO2 Emissions	1,680	g CO2 eq / gge fuel consumed
Natural Gas Input (including upstream)	12,100	Btu / gge fuel consumed	Hydrogen Storage System Cost	$2,400	2007$	Vehicle Cycle CH4 Emissions	170	g CO2 eq / gge fuel consumed
Petroleum Input (including upstream)	6,900	Btu / gge fuel consumed	Tax Credit	$0	2007$	Vehicle Cycle N2O Emissions	6	g CO2 eq / gge fuel consumed
						Vehicle Cycle GHG Emissions	1,850	g CO2 eq / gge fuel consumed


Conversion Facility
Coal 0 Btu/116000 Btu
Natural Gas 0 Btu/116000 Btu
Petroleum 0 Btu/116000 Btu
Total Energy 58,761 Btu/116000 Btu
CO2 Emissions 0 g CO2 eq/116000 Btu
CH4 Emissions 0 g CO2 eq/116000 Btu
N2O Emissions 0 g CO2 eq/116000 Btu
GHG Emissions 0 g CO2 eq/116000 Btu
Transport
Coal 2,826 Btu/116000 Btu
Natural Gas 1,252 Btu/116000 Btu
Petroleum 107 Btu/116000 Btu
Total Energy 4,938 Btu/116000 Btu
CO2 Emissions 390 g CO2 eq/116000 Btu
CH4 Emissions 24 g CO2 eq/116000 Btu
N2O Emissions 2 g CO2 eq/116000 Btu
GHG Emissions 415 g CO2 eq/116000 Btu
Dispensing
Coal 24,454 Btu/116000 Btu
Natural Gas 10,833 Btu/116000 Btu
Petroleum 929 Btu/116000 Btu
Total Energy 42,720 Btu/116000 Btu
CO2 Emissions 3,370 g CO2 eq/116000 Btu
CH4 Emissions 208 g CO2 eq/116000 Btu
N2O Emissions 14 g CO2 eq/116000 Btu
GHG Emissions 3,592 g CO2 eq/116000 Btu
Feedstock Processing
Coal 0 Btu/116000 Btu
Natural Gas 0 Btu/116000 Btu
Petroleum 0 Btu/116000 Btu
Total Energy 117,483 Btu/116000 Btu
CO2 Emissions 0 g CO2 eq/116000 Btu
CH4 Emissions 0 g CO2 eq/116000 Btu
N2O Emissions 0 g CO2 eq/116000 Btu
GHG Emissions 0 g CO2 eq/116000 Btu
Electrolysis
Electricity Feedstock 174,019
Transport
Transport Losses 0.77%
Dispensing
Distribution Losses 0.50%
Total to Deliver 116000 Btu Fuel
Coal 27,280
Natural Gas 12,085
Petroleum 1,036
Total Energy 223,902
CO2 Emissions 3,760
CH4 Emissions 232
N2O Emissions 15
GHG Emissions 4,007

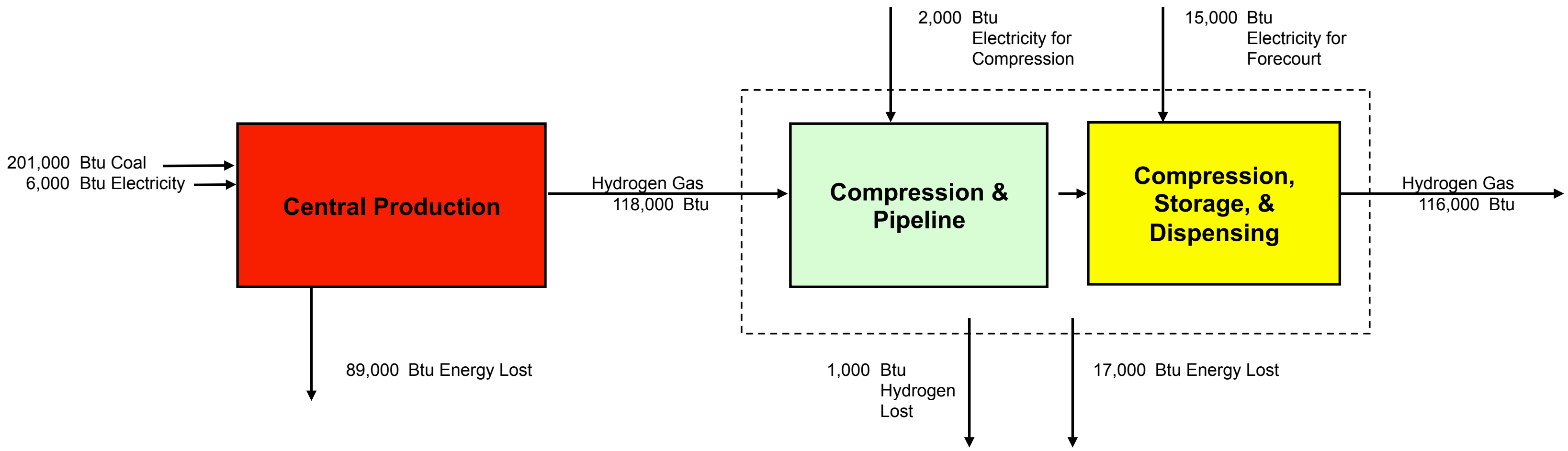
Parameter		Value	Units	Reference	Comments
Case Definition					
	Startup Year	2015		Input	Default for this study's current cases
	Reference Year Dollars	2007		Input	Default for this study's current cases
	Production Technology	WIND		Input	Case definition
	Form of H2 During Delivery	Gas		Input	Case definition
	Delivery Mode	Pipeline		Input	Case definition
	Dispensing Mode	CASCADE_700_BAR		Input	Case definition
	Forecourt Station Size	1000	kg/day	Input	Case definition
	Vehicle Type	passenger cars		Input	Case definition
	Vehicle materials (conventional or lightweight)	Conventional		Input	Case definition; lightweight materials not currently an MSM option
	Vehicles' Fuel Economy	48.0	mile / gge	Input	Default assumption for this study's current cases
Market Definition					
	City Population	1,247,364	people	Input	Case Definition: Indianapolis, IN
	Market penetration	15%	(% vehicles in city)	Input	Case definition: Basis for Program Plan
	Number of H2 vehicles in city	138,832	H2 vehicles / city	HDSAM Result	
	Miles driven per vehicle	15,000	mile / vehicle year	Input	CPM only allows for 10K, 15K, and 20K/yr.
	Miles driven per vehicle	160,000	miles in vehicle life	Input - GREET2 default	
	City hydrogen use	121,096	kg / d	HDSAM Result	
	Number of H2 refueling stations in city	122		HDSAM Result	
	Number of H2 stations/Number of gasoline stations	19%		HDSAM Result	
	Average distance between stations (mi)	2.17	miles	HDSAM Result	
Other Assumptions for WTW Calculations					
	Share of RFG in Total Gasoline Use	100%		Input: GREET default	Case definition: Basis for Program Plan
	Type of Oxygenate in RFG	None		Input: GREET default	Case definition: Basis for Program Plan
	O2 Content in RFG	0%	wt %	Input: GREET default	Case definition: Basis for Program Plan
	Ratio of FCEV VOCs (emissions) to GVs fueled with CG & RFG	0%		Input: GREET default	
	Ratio of FCEV VOCs (evaporative) to GVs fueled with CG & RFG	0%		Input: GREET default	
	Ratio of FCEV CO emissions to GVs fueled with CG & RFG	0%		Input: GREET default	
	Ratio of FCEV NOx emissions to GVs fueled with CG & RFG	0%		Input: GREET default	
	Ratio of FCEV Exhaust PM10 emissions to GVs fueled with CG & RFG	0%		Input: GREET default	
	Ratio of FCEV Brake & Tire Wear PM10 emissions to GVs fueled with CG & RFG	100%		Input: GREET default	
	Ratio of FCEV Exhaust PM2.5 emissions to GVs fueled with CG & RFG	0%		Input: GREET default	
	Ratio of FCEV Brake & Tire Wear PM2.5 emissions to GVs fueled with CG & RFG	100%		Input: GREET default	
	Ratio of FCEV CH4 emissions to GVs fueled with CG & RFG	0%		Input: GREET default	
	Ratio of FCEV N2O emissions to GVs fueled with CG & RFG	0%		Input: GREET default	
	Marginal Electricity Generation Mix for Transportation Use	US Mix		Input	Case definition: Basis for Program Plan

Parameter			Value	Units	Reference	Comments
Electricity						
	Grid mix for production		Green - Zero Carbon			Case Definition
	Grid mix for compression & CSD		US Mix		GREET input	Default
		Biomass Fraction	0.5%		Definition of US Mix	Energy Information Administration. (2007, February). Annual Energy Outlook 2007 with Projections to 2030. DOE/EIA-0383(2007). Washington, D.C. Retreived from www.eia.doe.gov/oiaf/archive/aeo07/index.html National electricity generation data from tables D-7 & D-8 using the 2005 timeframe. Percentages calculated from total generation values reported with all renewables except biomass aggregated into the "Others (Carbon Neutral)" category
		Coal Fraction	44.2%		Definition of US Mix	
		Natural Gas Fraction	21.5%		Definition of US Mix	
		Nuclear Fraction	21.0%		Definition of US Mix	
		Residual Oil Fraction	0.9%		Definition of US Mix	
		Others (Carbon Neutral - Hydroelectric, Wind, Geothermal, Solar PV, etc)	11.8%		Definition of US Mix	
	Biomass Electricity Shares and Efficiency					
		IGCC Share of Biomass Power Plants	1.0%		GREET default input	
		Combustion Share of Biomass Power Plants	99.0%		GREET default input	By difference from IGCC plants
		Biomass IGCC Efficiency	43.0%		GREET default input	
		Biomass Combustion Plant Efficiency	32.1%		GREET default input	
		Effective Efficiency of Biopower Plants	32.2%		GREET default input	
	Coal Electricity Shares and Efficiency					
		IGCC Share of Coal Power Plants	1.0%		GREET default input	
		Combustion Share of Coal Power Plants	99.0%		GREET default input	
		Coal IGCC Efficiency	47.0%		GREET default input	
		Coal Combustion Plant Efficiency	34.1%		GREET default input	
		Effective Efficiency of Coal-Electricity Plants	34.2%		GREET default input	
	Natural Gas Electricity Shares and Efficiency					
		Simple Cycle Gas Turbine Share of Natural Gas Power Plants	37.0%		GREET default input	
		Combined Cycle Gas Turbine Share of Natural Gas Power Plants	46.0%		GREET default input	
		Combustion Boiler Share of Natural Gas Power Plants	17.0%		GREET default input	
		Natural Gas Simple Cycle Gas Turbine Plant Efficiency	33.1%		GREET default input	
		Natural Gas Combined Cycle Efficiency	55.0%		GREET default input	
		Natural Gas Combustion Boiler Plant Efficiency	34.8%		GREET default input	
		Effective Efficiency of Natural Gas-Electricity Plants	40.9%		GREET default input	
	Residual Oil Electricity Efficiency					
		Residual Oil Electricity Plant Efficiency	34.8%		GREET default input	
	Electicity Transmission and Distribution Losses		8.0%		GREET default input	

Parameter		Value	Units	Reference	Comments
Parameters for GREET2					
	Vehicle total mass	3,020	lb	GREET2 Default Input	
	Battery Type for Hybridization	NiMH		GREET2 Default Input	
	Hybridization Battery Size in Peak Hybridization Battery Power	30	kW	GREET2 Default Input	
	Hybridization Battery Specific Power	272	W / lb	GREET2 Default Input	
	Hybridization Battery Mass	110	lb	GREET2 Default Input	
	Number of replacements of hybridization battery over lifetime	2		GREET2 Default Input	
	Starter Battery (Lead Acid) Mass	22	lb	GREET2 Default Input	
	Mass of fluids on-board vehicle	56	lb	GREET2 Default Input	
	Component mass (vehicles without batteries or fluids)	2,832	lb	GREET2 Calculation	
	Powertrain system percentage of component mass	8.0%		GREET2 Default Input	
	Transmission system percentage of component mass	2.6%		GREET2 Default Input	
	Chassis (without battery) percentage of component mass	23.0%		GREET2 Default Input	
	Traction motor percentage of component mass	3.8%		GREET2 Default Input	
	Generator percentage of component mass	0.0%		GREET2 Default Input	
	Electronic controller percentage of component mass	3.4%		GREET2 Default Input	
	Fuel Cell Auxiliary System percentage of component mass	19.3%		GREET2 Default Input	
	Body: including BIW, interior, exterior, and glass	39.9%		GREET2 Default Input	
	Fuel Cell Stack Size	70	kW	GREET2 Default Input	
	Mass of Fuel Cell Stack - Powertrain System	226	lb	GREET2 Calculation	
	Mass of Fuel Cell Stack - Auxiliary Systems	546	lb	GREET2 Calculation	
	Miles driven per vehicle over lifetime	160,000	miles in vehicle life	GREET2 Default Input	Current analysis assumes 5-year life, 10-year analysis is available

Appendix J: Central Coal with Carbon Capture and Storage—Pipeline Delivery Supporting Tables and Figures

Hydrogen Produced In Central Plant and Transported as Gas via Pipeline



Well-to-Wheels Total Energy Use (Btu/mile)	5,800
Well-to-Wheels Petroleum Energy Use (Btu/mile)	59
Well-to-Wheels Greenhouse Gas Emissions (g/mile)	199
Levelized Cost of H2 at Pump ($/kg)	6.14

Hydrogen Production cost in 2005$

Production Process Energy Efficiency	57%
Pathway Efficiency	52%
WTP Efficiency	42%
CO2 Equivalent / GGE fuel available): GHG	21

Case Definition
Year: 2015
Hydrogen as Gas
Central Production
COAL Feedstock
Sequestration: YES
Transport for Delivery: Pipeline
Vehicle Efficiency: 48 mile / GGE
City Hydrogen Use: 121096 kg/day

Inputs			Assumptions			Outputs		
			Coal Production & Delivery			Coal price at H2 production	$34	2007 $ / ton
						Coal Share of Levelized Cost	$0.30	2007$ / kg H2 dispensed
			Energy Recovery	99.3%				
						WTG CO2 Emissions	110	g CO2 eq./ 116000 Btu
Coal Input (including upstream)	116,400	Btu / 116000Btu to Pump				WTG CH4 Emissions	430	g CO2 eq./ 116000 Btu
Natural Gas Input (including upstream)	200	Btu / 116000Btu to Pump				WTG N2O Emissions	1	g CO2 eq./ 116000 Btu
Petroleum Input (including upstream)	700	Btu / 116000Btu to Pump	Average distance from coal mine to H2 prod.	65	miles	WTG GHG Emissions	540	g CO2 eq./ 116000 Btu
						Hydrogen Output Pressure	300	psi
Coal consumption	7.8	kg (dry) / kg H2 produced	**Hydrogen Production & Carbon Capture and Sequestration (CCS)**			Hydrogen Outlet Quality	99.9%	
Natural gas consumption	0.0	MMBtu/kg H2 produced						
Electricity consumption	1.72	kWh / kg H2	Central plant design capacity	307,700	kg / day	Total capital investment	$2,500	2005$ / daily kg H2 (effective capacity)
Process Water Consumption	2.91	gal / kg H2 produced	Capacity factor	90%		Levelized Cost of Capital	$1.29	2005$ / kg H2 dispensed
Cooling Water Consumption	0.00	gal / kg H2 produced	Number of production facilities necessary	0.44		Fixed O&M Costs	$0.30	2005$ / kg H2 dispensed
			Process energy efficiency	56.8%		Variable O&M Costs	$0.18	2005$ / kg H2 dispensed
Total Capital Investment	$691,378,000	2005$	Electricity Mix	US Mix		Total Levelized Cost	$2.06	2005$ / kg H2 dispensed
			After-tax IRR	10%				
Coal Input (including upstream)	99,400	Btu / 116000Btu to Pump	Assumed Plant Life	40		Production CO2 Emissions	4,510	g CO2 eq./ 116000 Btu
Natural Gas Input (including upstream)	7,200	Btu / 116000Btu to Pump	CO2 Captured for Sequestration	90%		Production CH4 Emissions	440	g CO2 eq./ 116000 Btu
Petroleum Input (including upstream)	1,100	Btu / 116000Btu to Pump	CO2 Captured for Sequestration	4,925,000	kg CO2 / day	ProductionN2O Emissions	9	g CO2 eq./ 116000 Btu
						Production GHG Emissions	4,960	g CO2 eq./ 116000 Btu
			Pipelines for Delivery			Total capital investment	$3,340	2007$ / daily kg dispensed
Electricity consumption for compressor	0.56	kWh / kg H2 dispensed						
Electricity consumption for geo storage	0.01	kWh / kg H2 dispensed	City Population	1,247,000	people	Levelized Cost of Capital	$1.71	2007$ / kg H2 dispensed
Total electricity consumption	0.57	kWh / kg H2 dispensed	Hydrogen Vehicle Penetration	15%		Energy & Fuel	$0.04	2007$ / kg H2 dispensed
			City hydrogen use	121,100	kg / day	Other O&M Costs	$0.40	2007$ / kg H2 dispensed
Total Capital Investment	$404,341,000	2007$	Distance from City to Production Facility	62	miles	Levelized Cost of Delivery	$2.15	2007$ / kg H2 dispensed
			Geologic storage capacity	1,325,000	kg H2			
			Number of trunk pipelines	3		Delivery CO2 Emissions	390	g CO2 eq./ 116000 Btu
Coal Input (including upstream)	3,700	Btu / 116000Btu to Pump	Service-line length	1.5	miles / line	Delivery CH4 Emissions	24	g CO2 eq./ 116000 Btu
Natural Gas Input (including upstream)	1,300	Btu / 116000Btu to Pump	Number of service lines	122		Delivery N2O Emissions	2	g CO2 eq./ 116000 Btu
Petroleum Input (including upstream)	100	Btu / 116000Btu to Pump	Hydrogen losses	0.76%		Delivery GHG Emissions	420	g CO2 eq./ 116000 Btu
						Hydrogen outlet pressure	12,700	psi
Electricity consumption	4.4	kWh / kg H2	**Forecourt Dispensing**			Basis -- Hydrogen Quantity	116,000	Btu (116,000 Btu/gal non-oxygenated conventional unleaded gasoline)
Total Capital Investment per Station	$2,629,000	2007$ / station	Average Dispensing Rate per Station	1,000	kg/day	Total capital investment	$2,650	2007$ / daily kg H2 (effective capacity)
Total Capital Investment	$320,679,000	2007$ / all stations	Number of Dispensing Stations	122		Levelized Cost of Capital	$1.08	2007$ / kg H2 dispensed
			Number of Compression Steps	5		Energy & Fuel	$0.41	2007$ / kg H2 dispensed
Inlet pressure of hydrogen at stations	300	psi	Usable Low Pressure Storage per Station	370	kg H2	Other O&M Costs	$0.43	2007$ / kg H2 dispensed
			Usable Cascade Storage per Station	130	kg H2	Levelized Cost of Dispensing	$1.93	2007$ / kg H2 dispensed
Coal Input (including upstream)	24,400	Btu / 116000Btu to Pump	Site storage	42%	% of design capacity	CSD CO2 Emissions	3,370	g CO2 eq./ 116000 Btu
Natural Gas Input (including upstream)	10,800	Btu / 116000Btu to Pump	# of 2-hose Dispensers per Station	2		CSD CH4 Emissions	210	g CO2 eq./ 116000 Btu
Petroleum Input (including upstream)	900	Btu / 116000Btu to Pump	Hydrogen Losses	0.50%		CSD N2O Emissions	14	g CO2 eq./ 116000 Btu
						CSD GHG Emissions	3,590	g CO2 eq./ 116000 Btu
						Cost Per Mile	$0.69	2007$ / mi
Vehicle Mass	3,020	lb	**Vehicle**			Fuel Share	$0.13	2007$ / mi
Fuel cell size	70	kW	Fuel Economy	48.0	mi / gge	Maintenance, Tires, Repairs	$0.07	2007$ / mi
Size of hybridization battery	30	kW	Vehicle Miles Traveled	15,000	mi / yr	Insurance & Registration	$0.12	2007$ / mi
			Vehicle Lifetime	160,000	mi	Depreciation	$0.27	2007$ / mi
			Purchase Year	2015		Financing	$0.10	2007$ / mi
			Vehicle Purchase Cost	$33,700	2007$			
Coal Input (including upstream)	2,300	Btu / gge fuel consumed	Fuel Cell System Cost	$4,500	2007$	Vehicle Cycle CO2 Emissions	1,670	g CO2 eq / gge fuel consumed
Natural Gas Input (including upstream)	12,100	Btu / gge fuel consumed	Hydrogen Storage System Cost	$2,400	2007$	Vehicle Cycle CH4 Emissions	170	g CO2 eq / gge fuel consumed
Petroleum Input (including upstream)	6,900	Btu / gge fuel consumed	Tax Credit	$0	2007$	Vehicle Cycle N2O Emissions	6	g CO2 eq / gge fuel consumed
						Vehicle Cycle GHG Emissions	1,850	g CO2 eq / gge fuel consumed

Conversion Facility

Coal	99,450	Btu/116000 Btu
Natural Gas	7,210	Btu/116000 Btu
Petroleum	1,101	Btu/116000 Btu
Total Energy	112,051	Btu/116000 Btu
CO2 Emissions	4,513	g CO2 eq/116000 Btu
CH4 Emissions	442	g CO2 eq/116000 Btu
N2O Emissions	9	g CO2 eq/116000 Btu
GHG Emissions	4,964	g CO2 eq/116000 Btu

Transport

Coal	3,726	Btu/116000 Btu
Natural Gas	1,253	Btu/116000 Btu
Petroleum	107	Btu/116000 Btu
Total Energy	5,837	Btu/116000 Btu
CO2 Emissions	389	g CO2 eq/116000 Btu
CH4 Emissions	24	g CO2 eq/116000 Btu
N2O Emissions	2	g CO2 eq/116000 Btu
GHG Emissions	415	g CO2 eq/116000 Btu

Dispensing

Coal	24,444	Btu/116000 Btu
Natural Gas	10,837	Btu/116000 Btu
Petroleum	928	Btu/116000 Btu
Total Energy	42,710	Btu/116000 Btu
CO2 Emissions	3,369	g CO2 eq/116000 Btu
CH4 Emissions	208	g CO2 eq/116000 Btu
N2O Emissions	14	g CO2 eq/116000 Btu
GHG Emissions	3,591	g CO2 eq/116000 Btu

Feedstock Processing

Coal	116,370	Btu/116000 Btu
Natural Gas	215	Btu/116000 Btu
Petroleum	700	Btu/116000 Btu
Total Energy	1,364	Btu/116000 Btu
CO2 Emissions	110	g CO2 eq/116000 Btu
CH4 Emissions	432	g CO2 eq/116000 Btu
N2O Emissions	1	g CO2 eq/116000 Btu
GHG Emissions	542	g CO2 eq/116000 Btu

Gasification & Conversion Including CCS

Coal Feedstock 215,819

Transport

Transport Losses 0.77%

CSD

Dispensing Losses 0.50%

Total to Deliver 116000 Btu Fuel

Coal	243,989
Natural Gas	19,515
Petroleum	2,837
Total Energy	161,962
CO2 Emissions	8,381
CH4 Emissions	1,107
N2O Emissions	25
GHG Emissions	9,513

Parameter	Value	Units	Reference	Comments
Case Definition				
Startup Year	2015		Input	Default for this study's current cases
Reference Year Dollars	2007		Input	Default for this study's current cases
Production Technology	COAL		Input	Case definition
Form of H2 During Delivery	Gas		Input	Case definition
Delivery Mode	Pipeline		Input	Case definition
Dispensing Mode	CASCADE_700_BAR		Input	Case definition
Forecourt Station Size	1000	kg/day	Input	Case definition
Vehicle Type	passenger cars		Input	Case definition
Vehicle materials (conventional or lightweight)	Conventional		Input	Case definition; lightweight materials not currently an MSM option
Vehicles' Fuel Economy	48.0	mile / gge	Input	Default assumption for this study's current cases
Market Definition				
City Population	1,247,364	people	Input	Case Definition: Indianapolis, IN
Market penetration	15%	(% vehicles in city)	Input	Case definition: Basis for Program Plan
Number of H2 vehicles in city	138,832	H2 vehicles / city	HDSAM Result	
Miles driven per vehicle	15,000	mile / vehicle year	Input	CPM only allows for 10K, 15K, and 20K/yr.
Miles driven per vehicle	160,000	miles in vehicle life	Input - GREET2 default	
City hydrogen use	121,096	kg / d	HDSAM Result	
Number of H2 refueling stations in city	122		HDSAM Result	
Number of H2 stations/Number of gasoline stations	19%		HDSAM Result	
Average distance between stations (mi)	2.17	miles	HDSAM Result	
Other Assumptions for WTW Calculations				
Share of RFG in Total Gasoline Use	100%		Input: GREET default	Case definition: Basis for Program Plan
Type of Oxygenate in RFG	None		Input: GREET default	Case definition: Basis for Program Plan
O2 Content in RFG	0%	wt %	Input: GREET default	Case definition: Basis for Program Plan
Ratio of FCEV VOCs (emissions) to GVs fueled with CG & RFG	0%		Input: GREET default	
Ratio of FCEV VOCs (evaporative) to GVs fueled with CG & RFG	0%		Input: GREET default	
Ratio of FCEV CO emissions to GVs fueled with CG & RFG	0%		Input: GREET default	
Ratio of FCEV NOx emissions to GVs fueled with CG & RFG	0%		Input: GREET default	
Ratio of FCEV Exhaust PM10 emissions to GVs fueled with CG & RFG	0%		Input: GREET default	
Ratio of FCEV Brake & Tire Wear PM10 emissions to GVs fueled with CG & RFG	100%		Input: GREET default	
Ratio of FCEV Exhaust PM2.5 emissions to GVs fueled with CG & RFG	0%		Input: GREET default	
Ratio of FCEV Brake & Tire Wear PM2.5 emissions to GVs fueled with CG & RFG	100%		Input: GREET default	
Ratio of FCEV CH4 emissions to GVs fueled with CG & RFG	0%		Input: GREET default	
Ratio of FCEV N2O emissions to GVs fueled with CG & RFG	0%		Input: GREET default	
Marginal Electricity Generation Mix for Transportation Use	US Mix		Input	Case definition: Basis for Program Plan

Parameter			Value	Units	Reference	Comments
Coal						
	Energy efficiency of coal mining and cleaning		99.3%			
	Energy requirement for coal mining and cleaning		10,513	Btu/MMBtu Del. Coal		2009 reported value was wrong, should have been ~10513
	Energy requirement for coal transport to H2 plant		1,096	Btu/MMBtu Del. Coal		
	Average distance from coal mine to hydrogen production facility		65	miles		
	Total energy requirement for coal mining, cleaning & delivery		11,609	Btu/MMBtu Del. Coal		
	Share of Resid Oil for coal mining & cleaning		7.0%			
	Share of Diesel for coal mining & cleaning		56.0%			
	Share of Gasoline for coal mining & cleaning		3.0%			
	Share of Natural Gas for coal mining & cleaning		1.0%			
	Share of Coal for coal mining & cleaning		9.0%			
	Share of Electricity for coal mining & cleaning		24.0%			
	Resid Oil requirement for coal mining and cleaning		493	Btu/MMBtu Del. Coal		
	Diesel requirement for coal mining and cleaning		3,948	Btu/MMBtu Del. Coal		
	Gasoline requirement for coal mining and cleaning		211	Btu/MMBtu Del. Coal		
	Natural Gas requirement for coal mining and cleaning		70	Btu/MMBtu Del. Coal		
	Coal requirement for coal mining and cleaning		634	Btu/MMBtu Del. Coal		
	Electricity requirement for coal mining and cleaning		1,692	Btu/MMBtu Del. Coal		
Electricity						
	Grid mix for production		US Mix		GREET input	Default
		Biomass Fraction	0.5%		Definition of US Mix	Energy Information Administration. (2007, February). Annual Energy Outlook 2007 with Projections to 2030. DOE/EIA-0383(2007). Washington, D.C. Retreived from www.eia.doe.gov/oiaf/archive/aeo07/index.html National electricity generation data from tables D-7 & D-8 using the 2005 timeframe. Percentages calculated from total generation values reported with all renewables except biomass aggregated into the "Others (Carbon Neutral)" category
		Coal Fraction	44.2%		Definition of US Mix	
		Natural Gas Fraction	21.5%		Definition of US Mix	
		Nuclear Fraction	21.0%		Definition of US Mix	
		Residual Oil Fraction	0.9%		Definition of US Mix	
		Others (Carbon Neutral - Hydroelectric, Wind, Geothermal, Solar PV, etc)	11.8%		Definition of US Mix	
	Biomass Electricity Shares and Efficiency					
		IGCC Share of Biomass Power Plants	1.0%		GREET default input	
		Combustion Share of Biomass Power Plants	99.0%		GREET default input	By difference from IGCC plants
		Biomass IGCC Efficiency	43.0%		GREET default input	
		Biomass Combustion Plant Efficiency	32.1%		GREET default input	
		Effective Efficiency of Biopower Plants	32.2%		GREET default input	
	Coal Electricity Shares and Efficiency					
		IGCC Share of Coal Power Plants	1.0%		GREET default input	
		Combustion Share of Coal Power Plants	99.0%		GREET default input	
		Coal IGCC Efficiency	47.0%		GREET default input	
		Coal Combustion Plant Efficiency	34.1%		GREET default input	
		Effective Efficiency of Coal-Electricity Plants	34.2%		GREET default input	
	Natural Gas Electricity Shares and Efficiency					
		Simple Cycle Gas Turbine Share of Natural Gas Power Plants	37.0%		GREET default input	
		Combined Cycle Gas Turbine Share of Natural Gas Power Plants	46.0%		GREET default input	
		Combustion Boiler Share of Natural Gas Power Plants	17.0%		GREET default input	
		Natural Gas Simple Cycle Gas Turbine Plant Efficiency	33.1%		GREET default input	
		Natural Gas Combined Cycle Efficiency	55.0%		GREET default input	
		Natural Gas Combustion Boiler Plant Efficiency	34.8%		GREET default input	
		Effective Efficiency of Natural Gas-Electricity Plants	40.9%		GREET default input	
	Residual Oil Electricity Efficiency					
		Residual Oil Electricity Plant Efficiency	34.8%		GREET default input	
	Electicity Transmission and Distribution Losses		8.0%		GREET default input	

Parameter		Value	Units	Reference	Comments
Parameters for GREET2					
	Vehicle total mass	3,020	lb	GREET2 Default Input	
	Battery Type for Hybridization	NiMH		GREET2 Default Input	
	Hybridization Battery Size in Peak Hybridization Battery Power	30	kW	GREET2 Default Input	
	Hybridization Battery Specific Power	272	W / lb	GREET2 Default Input	
	Hybridization Battery Mass	110	lb	GREET2 Default Input	
	Number of replacements of hybridization battery over lifetime	2		GREET2 Default Input	
	Starter Battery (Lead Acid) Mass	22	lb	GREET2 Default Input	
	Mass of fluids on-board vehicle	56	lb	GREET2 Default Input	
	Component mass (vehicles without batteries or fluids)	2,832	lb	GREET2 Calculation	
	Powertrain system percentage of component mass	8.0%		GREET2 Default Input	
	Transmission system percentage of component mass	2.6%		GREET2 Default Input	
	Chassis (without battery) percentage of component mass	23.0%		GREET2 Default Input	
	Traction motor percentage of component mass	3.8%		GREET2 Default Input	
	Generator percentage of component mass	0.0%		GREET2 Default Input	
	Electronic controller percentage of component mass	3.4%		GREET2 Default Input	
	Fuel Cell Auxiliary System percentage of component mass	19.3%		GREET2 Default Input	
	Body: including BIW, interior, exterior, and glass	39.9%		GREET2 Default Input	
	Fuel Cell Stack Size	70	kW	GREET2 Default Input	
	Mass of Fuel Cell Stack - Powertrain System	226	lb	GREET2 Calculation	
	Mass of Fuel Cell Stack - Auxiliary Systems	546	lb	GREET2 Calculation	
	Miles driven per vehicle over lifetime	160,000	miles in vehicle life	GREET2 Default Input	Current analysis assumes 5-year life, 10-year analysis is available